Hydrogen in Michigan: Synthesis of State Agency Findings and the Strategic Role of the Michigan Geological Survey

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Executive Summary

In response to Executive Directive 2026-1 (Appendix 1), multiple State of Michigan agencies evaluated the potential for hydrogen development across production, infrastructure, regulation, and economic impact. Collectively, these reports identify hydrogen as a high-potential, but uncertain opportunity for the state, with the possibility of significant long-term economic, industrial, and environmental benefits.

All agencies align on a central conclusion: Michigan's ability to develop a hydrogen economy is constrained by subsurface uncertainty, infrastructure limitations, and incomplete regulatory and governance frameworks.

This report synthesizes findings from the Michigan Department of Environment, Great Lakes, and Energy (EGLE), Michigan Public Service Commission (MPSC), Michigan Infrastructure Office (MIO), and the Michigan Department of Natural Resources (DNR). The Michigan Geological Survey (MGS) supported EGLE's report providing the Technical Resource Needs as Appendix A to their report, highlighting the necessary research, data acquisition needs, and how MGS is the science-based organization tasked with the role of doing this work. The MGS role and research recommendations are included in this report.

Introduction

Executive Directive 2026-1 directed multiple state agencies to assess Michigan's readiness for hydrogen development across exploration, production, transportation, storage, regulation, and economic impacts. Each agency was tasked with evaluating a specific component of the emerging hydrogen system:

- ***The Department of Environment, Great Lakes, and Energy (EGLE)*** was charged with evaluating geologic potential, environmental considerations, subsurface storage, and permitting requirements.
- ***The Michigan Public Service Commission (MPSC)*** was tasked with assessing infrastructure, including pipeline transportation, system compatibility, safety requirements, and regulatory oversight of energy systems.
- ***The Michigan Infrastructure Office (MIO)*** evaluated economic impacts, including workforce development, job creation, and long-term industry growth potential.
- ***The Department of Natural Resources (DNR)*** was directed to evaluate legal and administrative barriers related to leasing state-owned lands and mineral rights, as well as appropriate resource management frameworks.

This synthesis report integrates these findings to:

- Identify cross-cutting themes and gaps
- Clarify interdependencies across agencies
- Define the strategic role of the MGS

- Provide coordinated recommendations to advance Michigan’s hydrogen position

Overview of the Hydrogen Opportunity in Michigan

Michigan has several enabling characteristics that support hydrogen potential:

- Favorable geology, including the Midcontinent Rift and Michigan Basin
- Existing industrial demand for hydrogen
- Extensive subsurface data and energy infrastructure history

Agency analyses indicate that hydrogen demand in Michigan could grow substantially over time, with potential long-term economic value reaching hundreds of millions of dollars annually under favorable conditions. However, these outcomes depend on confirmation of viable resources, development of infrastructure, and regulatory alignment.

Types of Geologic Hydrogen Systems

Hydrogen in Michigan can occur through multiple pathways that differ in origin, maturity, and development requirements:

- **Natural (Geologic) Hydrogen:** Hydrogen generated naturally in the subsurface through geochemical processes such as reactions between water and iron-rich minerals in crystalline basement rocks. These systems may accumulate in subsurface traps similar to conventional hydrocarbon systems. Also known as “white” hydrogen.
- **Stimulated Hydrogen:** Hydrogen produced by intentionally enhancing or accelerating natural geochemical reactions through engineered interventions such as thermal, mechanical, or fluid-driven stimulation. This pathway is less mature but may expand resource potential if viable. Also known as “orange” hydrogen.
- **Subsurface Hydrogen Storage:** While not a production pathway, hydrogen can also be stored in underground geologic formations, including depleted oil and gas reservoirs, saline formations, and salt caverns, to support energy system reliability.

Together, these pathways highlight that hydrogen development in Michigan is fundamentally tied to subsurface processes and geologic conditions.

Hydrogen Prospectivity in Michigan

Recent national-scale assessments indicate that Michigan is part of a region with elevated potential for geologic hydrogen (Figure 1, Gelman et al., 2025). The U.S. Geological Survey (USGS) has identified large portions of the Michigan Basin and surrounding areas as prospective for natural hydrogen systems based on the presence of:

- Precambrian basement rocks capable of generating hydrogen
- Structural features such as faults and rift-related systems that may enhance migration pathways
- Sedimentary sequences capable of acting as reservoirs and seals

These factors collectively support the potential for hydrogen generation, migration, accumulation, and storage within the state, though resource extent and commercial viability remain uncertain and require further study.

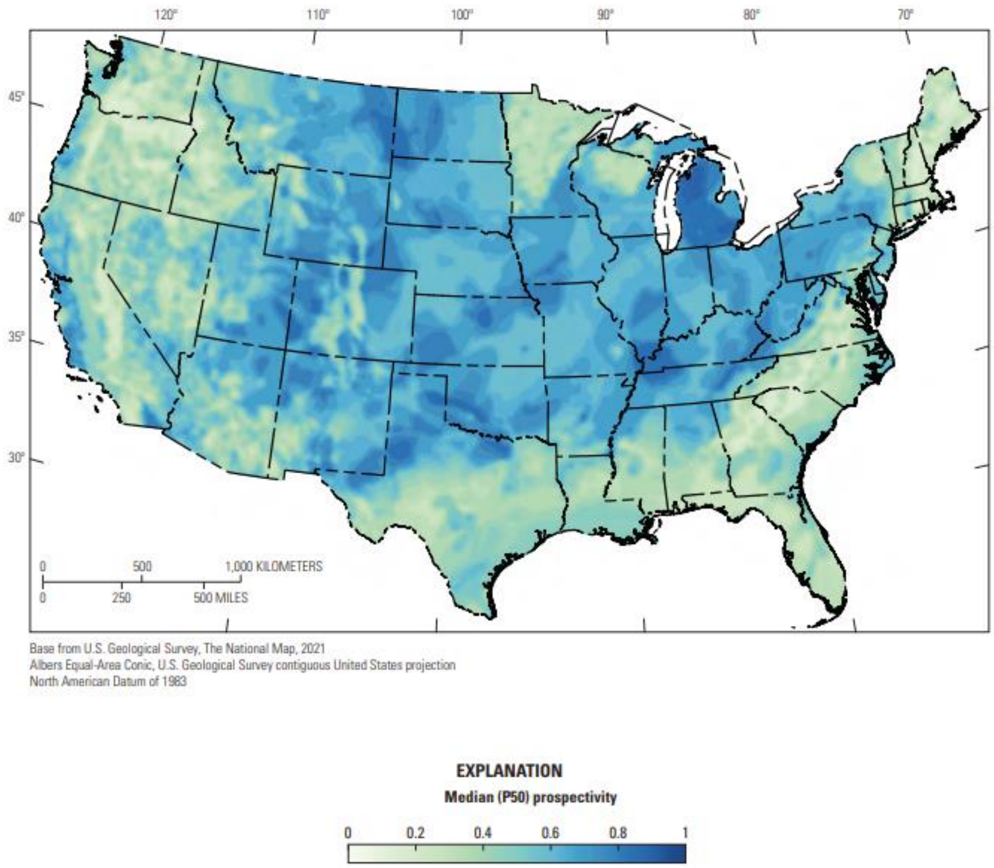


***Figure 1**: Median hydrogen prospectivity map of the United States, where darker blue indicates higher potential. From Gelman et al., 2025.*

In addition to natural hydrogen, there are regions in Michigan, especially in the western portion of the Upper Peninsula, that have high prospectivity for stimulated production of hydrogen.

There is limited data both vertically and geographically that has reported hydrogen levels. However, there is more reported hydrogen (H2) along the Midcontinent rift and in southeast Michigan near known structural features. Deep wells are also limited, providing few data points with core samples or other types of geological/geophysical data for the deeper portion of the Michigan Basin. Most physical samples are located in the southern part of Michigan. Although prospectivity was indicated to be high throughout the central part of the Michigan Basin, better data is needed for verification. (Figure 2)

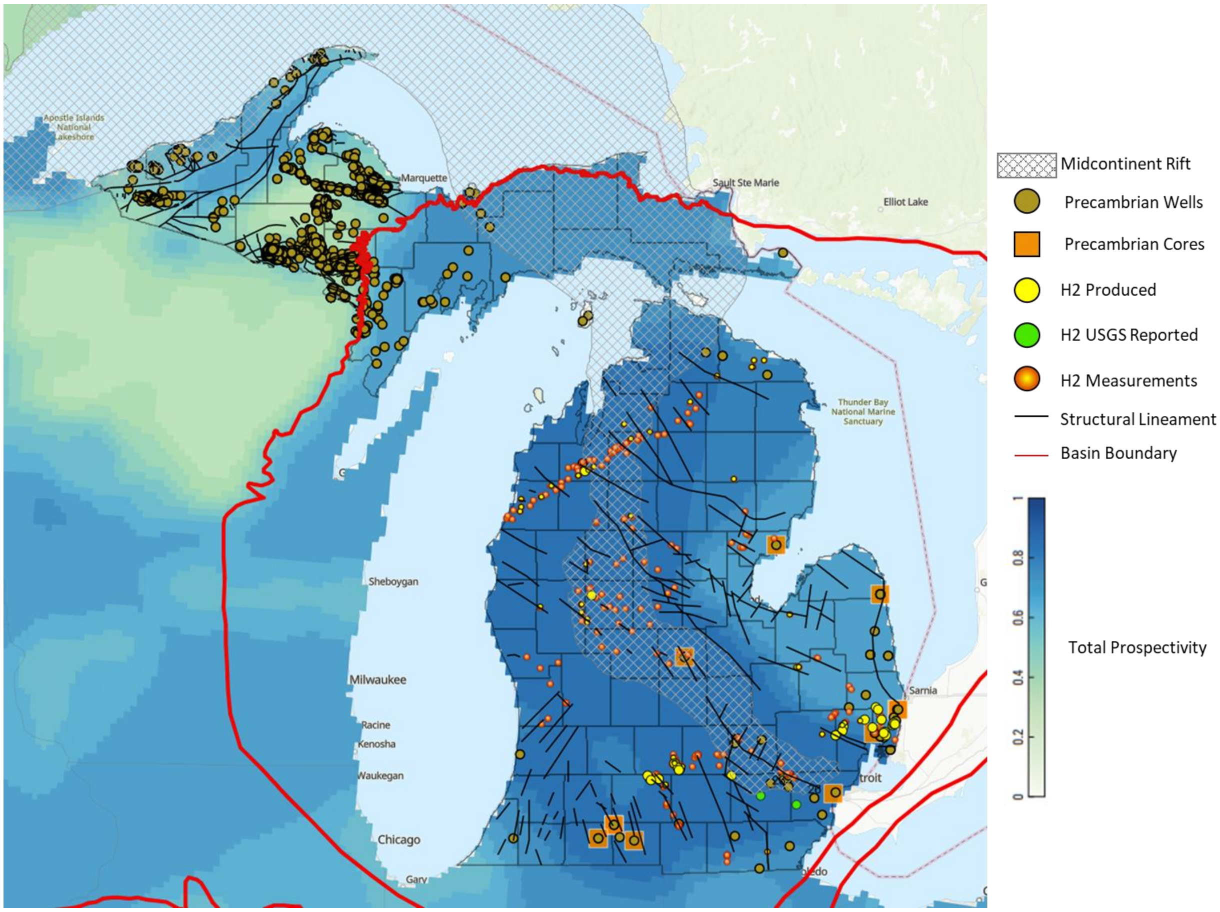


***Figure 2**: Compilation map of USGS hydrogen prospectivity (Gelman et al., 2025) with known data points and structural features.*

Key Findings Across Agencies

EGLE: Subsurface Resources, Environmental Considerations, and Permitting

The report prepared by EGLE focuses on the scientific, environmental, and regulatory foundations for hydrogen development, particularly in the subsurface.

EGLE identifies Michigan as a strong candidate for geologic hydrogen development due to favorable geology, including the Michigan Basin and Precambrian basement rocks. However, it emphasizes that the primary limitation was a lack of subsurface characterization specific to hydrogen systems.

Key findings include:

- Significant data gaps in hydrogen generation, migration, and trapping mechanisms
- Limited direct sampling of Precambrian basement rocks
- Need for integrated datasets combining geologic, geophysical, and geochemical information

EGLE highlights three primary technical focus areas:

- **Geologic Hydrogen Systems**: Understanding natural hydrogen generation in iron-rich basement rocks and identifying potential accumulations
- **Stimulated Hydrogen**: Evaluating the feasibility of enhancing hydrogen production through engineered processes
- **Subsurface Storage**: Assessing reservoirs and seals for safe long-term hydrogen containment

From a regulatory standpoint, EGLE notes that existing frameworks are designed for hydrocarbons and do not fully address hydrogen-specific risks, including:

- Hydrogen leakage due to small molecular size
- Geochemical reactions with formation fluids and rocks
- Long-term monitoring requirements

Overall, EGLE concludes that advancing hydrogen in Michigan requires substantial investment in subsurface research, data integration, and updated regulatory frameworks.

MPSC: Infrastructure, Safety, and Regulatory Oversight

The MPSC report evaluates hydrogen from the perspective of energy infrastructure, focusing on transportation, system compatibility, and regulatory authority.

A central finding is that hydrogen was not readily compatible with existing natural gas infrastructure at scale.

Key technical challenges include:

- Hydrogen's small molecular size increases leakage risk
- Hydrogen can cause embrittlement in steel pipelines
- Existing systems are optimized for methane, not hydrogen

While limited blending (2–20%) may be possible, MPSC concludes:

- Pure hydrogen transport will likely require new, dedicated pipelines
- Existing infrastructure would require significant upgrades for safe use

MPSC also identifies major regulatory gaps:

- No clear siting authority for hydrogen pipelines at the state or federal level
- Existing statutes may restrict repurposing natural gas pipelines for hydrogen transport
- Hydrogen is not explicitly included in clean energy standards, which may limit utility adoption

Additionally, hydrogen's physical properties introduce safety challenges:

- Wide flammability range
- Lack of effective odorants for leak detection
- Increased dispersion compared to natural gas

MPSC concludes that Michigan has a strong regulatory foundation but must address infrastructure limitations, safety considerations, and statutory gaps to enable hydrogen transportation and integration into the energy system.

MIO: Economic Impacts, Workforce, and Market Development

The MIO report evaluates the economic implications of hydrogen development, with a focus on employment, industry growth, and long-term market potential.

MIO finds that geologic hydrogen presents a potentially high-value but uncertain opportunity. Key findings include:

- Current hydrogen demand in Michigan is approximately 39,100 metric tons per year
- Demand could increase significantly, potentially by 420% to 2,700% by 2050 under favorable conditions
- Geologic hydrogen could be produced at lower costs than conventional methods if viable resources are confirmed

Economic impacts are expected to evolve over time:

- **Near-term:** Modest employment focusing on exploration and drilling, similar to oil and gas
- **Mid-term:** Growth in distribution, infrastructure, and industrial applications
- **Long-term:** Potential for thousands of jobs, expanded manufacturing, and large-scale economic activity

MIO also highlights uncertainty drivers:

- Unknown resource magnitude and quality
- Infrastructure development timelines

- Market adoption and cost competitiveness

A key insight is that the primary economic value of geologic hydrogen may reduce input costs for Michigan industries, improving competitiveness and supporting long-term investment. MIO concluded that Michigan should continue evaluating viability while aligning workforce, regulatory, and industrial strategies to capture future opportunities.

DNR: Land Access, Leasing, and Resource Governance

The DNR report identifies statutory, administrative, and capacity-related barriers that currently limit hydrogen development on state-owned lands.

Statutory Definition of Gas

Under existing administrative rules, “gas” is defined as a mixture containing hydrocarbons. Because hydrogen is a non-hydrocarbon gas, it is not included within this definition and is therefore excluded from existing oil and gas leasing authorities.

Leasing Constraints

Although the DNR has authority to lease state-owned lands for oil and gas development, current statutes do not contemplate leasing for geologic hydrogen.
This limitation affects:

- 4.6 million acres of state-owned surface land
- 6.4 million acres of state-owned mineral rights

As a result, a substantial portion of Michigan’s subsurface resource base is currently inaccessible for hydrogen exploration and production.

Required Legislative Changes

The DNR identified a clear path forward:

- Amend Part 5, Section 502 of Michigan's Natural Resources and Environmental Protection Act, PA 451,1994, as amended, to include non-hydrocarbon gases such as hydrogen within the definition of “gas”
- Update administrative rules to align with statutory changes
- Establish provisions for revenue collection and allocation from hydrogen development

Permitting and Capacity

The DNR notes that existing permitting frameworks from other mineral programs could be adapted for hydrogen. However, additional statutory authority and staffing will be required to implement these programs effectively.

Overall, DNR concludes that hydrogen development on state lands will require legislative action, administrative updates, and expanded agency capacity.

Cross-Cutting Challenges

Synthesizing findings across agencies reveals that Michigan's hydrogen opportunity is constrained by a set of interconnected challenges that span science, infrastructure, economics, and governance. These challenges are not independent; rather, they reinforce one another and must be addressed in a coordinated manner.

Integrated Challenge Areas

1) **Subsurface Uncertainty (EGLE, MGS)** - Limited understanding of hydrogen generation, migration, and storage systems remain the foundational constraint. Without sufficient subsurface data and characterization, decisions related to investment, infrastructure, and permitting carry high levels of uncertainty.
2) **Infrastructure Limitations (MPSC)** - Hydrogen is not readily compatible with existing natural gas systems at scale, requiring substantial investment in new or modified infrastructure. This introduces significant cost, timing, and planning challenges for deployment.
3) **Regulatory and Permitting Gaps (EGLE, MPSC)** - Existing regulatory frameworks are designed for hydrocarbon systems and do not fully address hydrogen-specific risks or operations. This creates uncertainty in permitting pathways and oversight authority.
4) **Economic and Market Uncertainty (MIO)** - While long-term economic potential is significant, near-term demand and market adoption remain uncertain. Investment decisions are highly dependent on confirming resource availability and reducing supply costs.
5) **Land Access and Resource Governance (DNR)** - Current statutes do not enable leasing of state-owned lands for hydrogen exploration and development. This restricts access to a substantial portion of Michigan's potential resource base.
6) **Institutional Capacity Constraints (DNR and cross-agency)** - Limited staffing and resources across agencies may restrict the ability to implement new programs, conduct oversight, and support emerging hydrogen activities.

A key finding from this synthesis is that progress in any single area is dependent on progress in others. For example:

- Infrastructure investment depends on validated subsurface resources
- Economic development depends on subsurface resources, infrastructure, and regulatory clarity
- Leasing and development depend on statutory authority and resource definition

This interdependency reinforces that hydrogen development must be approached as a coordinated system, rather than a series of independent initiatives. Most importantly, geologic resource validation and characterization are the keystone of any hydrogen initiative in Michigan. Without a sound understanding of the geology—where hydrogen may occur, whether it can be produced or stored safely, and how subsurface conditions vary—economic development, infrastructure planning, leasing decisions, and an effective regulatory framework cannot move forward with confidence. Table 1 below summarizes the primary roles, key findings, and core constraints identified by each agency.

Table 1: Summary of Key Findings and Constraints from Agency Reports.

Agency	Primary Focus	Key Findings	Core Constraint
EGLE	Subsurface resources, environmental review, permitting	Strong geologic potential but major data gaps; hydrogen-specific regulatory needs	Lack of subsurface characterization and hydrogen-specific regulations
MPSC	Infrastructure, safety, utility regulation	Hydrogen incompatible with existing gas systems at scale; new infrastructure likely required	Infrastructure limitations and lack of siting authority
MIO	Economic impacts, workforce, industry growth	High long-term potential but uncertain timing and scale	Market uncertainty and dependence on cost and supply validation
DNR	Land access, leasing, resource governance	Hydrogen not included in existing gas definitions; leasing not currently allowed	Statutory barriers and limited access to state-owned resources

Taken together, these findings indicate that Michigan's hydrogen opportunity is not limited by a single barrier, but by a combination of interrelated constraints. Addressing these challenges requires:

- Coordinated action across agencies
- Alignment of scientific, regulatory, and economic strategies
- Investment in foundational data and infrastructure
- Legislative updates to enable access and development

This integrated perspective underscores the need for a unified approach that connects subsurface science, infrastructure planning, economic development, and policy reform.

Strategic Role of the Michigan Geological Survey

The MGS is uniquely positioned to address the most critical barrier identified across all agencies: subsurface uncertainty. MGS serves as a statewide data authority for subsurface geology, a technical advisor to agencies and policymakers, a leader in applied geologic research, and a bridge between academia, research, government, and industry.

Agency-identified needs directly align with MGS capabilities. These include:

- Subsurface characterization – MGS manages and preserves the state's core and data archives
- Storage feasibility assessment – MGS has leading experts in subsurface characterization that can assess reservoirs and seals
- Data integration – MGS leads statewide mapping initiatives and has experts in database development and management
- Risk evaluation – MGS has extensive geologic expertise to evaluate and identify potential risks

MGS is actively advancing hydrogen related research by utilizing existing datasets and generating new data. This includes:

- Precambrian core analysis and characterization to assess the potential source of hydrogen
- Statewide geologic mapping efforts to update Precambrian understanding
- Evaluation of regional seismic datasets and identification of new data acquisition opportunities with the goal to develop a precompetitive database
- With partners in WMU's Chemical Engineering department, designing laboratory experiments to assess hydrogen generation and release

These activities aim to address high-priority gaps identified by state agencies.

Conclusions and Recommendations

Hydrogen development in Michigan depends on coordination across three interdependent systems (Table 2). Failure to address any one of these systems will limit overall progress.

Table 2: Integrated System

System	Primary Responsibility	Core Challenge
Subsurface Science	MGS / EGLE	Data and geologic uncertainty
Infrastructure	MPSC	Transportation and storage systems
Resource Governance	DNR/EGLE	Leasing, ownership, access, and permitting

Based on agency reports, MGS recommends a series of actions that are aligned with the key constraint areas identified. These are summarized in Table 3 below.

Table 3: Recommendations

Category	Recommendation Area	Specific Actions	Lead/Supporting Entities
Subsurface & Data	Advance subsurface understanding	Develop a statewide hydrogen subsurface database; expand core, geochemical, and seismic data acquisition; establish standardized hydrogen sampling protocols	MGS (lead), EGLE
Subsurface & Data	Build technical capability	Invest in hydrogen-focused laboratory capacity; support applied research on hydrogen generation, migration, and storage	MGS (lead), Universities, EGLE
Regulatory & Policy	Clarify statutory authority	Update statutes to explicitly include hydrogen within definitions of gas and energy resources; clarify jurisdictional authority	Legislature, EGLE, MPSC, DNR
Regulatory & Policy	Establish permitting frameworks	Develop hydrogen-specific permitting pathways for production and storage; integrate monitoring and safety standards	EGLE (lead), MPSC
Infrastructure	Enable hydrogen transport and storage	Evaluate hydrogen pipeline standards; establish siting authority; plan for purpose-built infrastructure systems	MPSC (lead)
Infrastructure	System integration	Assess integration of hydrogen into existing energy systems, including blending limits and long-term transition strategies	MPSC, Utilities
Land Access & Governance	Enable resource access	Establish leasing authority for hydrogen on state-owned lands; incorporate hydrogen into existing leasing frameworks	DNR (lead), Legislature
Land Access & Governance	Develop revenue structures	Create hydrogen-specific royalty and revenue frameworks aligned with oil and gas models	DNR, Legislature
Capacity & Coordination	Expand institutional capacity	Increase agency staffing, technical expertise, and program funding to support hydrogen oversight	DNR, EGLE, MPSC, MGS
Capacity & Coordination	Coordinate across agencies	Establish an interagency coordination framework; support partnerships with academia, industry, and federal entities	All agencies, MGS (technical support)

Michigan has the potential to play a significant role in the emerging hydrogen economy. However, this opportunity is not guaranteed. Realizing hydrogen development at scale will require:

- Reducing subsurface uncertainty through science and data
- Addressing infrastructure and regulatory gaps
- Enabling access to resources through updated policies

The Survey is central to these efforts, providing the scientific foundation necessary for informed decision-making. Without the capabilities of MGS Michigan cannot effectively evaluate, de-risk, or advance geologic hydrogen development. Ultimately, hydrogen development in Michigan is not solely an energy challenge—it is a coordinated systems challenge requiring alignment across science, infrastructure, and governance.

References

Gelman, S.E., Hearon, J.S., and Ellis, G.S., 2025, Prospectivity mapping for geologic hydrogen (ver. 1.2, January 22, 2025): U.S. Geological Survey Professional Paper 1900, 43 p., https://doi.org/10.3133/pp1900.

Appendix A – Executive Directive 2026-1

MICHIGAN DEPARTMENT OF ENVIRONMENT, GREAT LAKES, AND ENERGY

Governor's Executive Directive No. 2026-1

Establishing the Michigan Geologic Hydrogen Exploration and Preparedness Initiative

April 1, 2026

1.0 Executive Summary

In response to Executive Directive 2026-1, the Department of Environment, Great Lakes, and Energy (EGLE) evaluated the State of Michigan's readiness to oversee potential geologic hydrogen exploration, development, and storage. This assessment determined that existing statutes were designed for hydrocarbon production and mineral extraction and do not clearly cover non-hydrocarbon gases such as naturally occurring or stimulated geologic hydrogen. As a result, targeted statutory clarification and updated permitting pathways are needed to ensure regulatory certainty, prevent waste, protect correlative rights, and establish hydrogen-appropriate standards for well construction, integrity, monitoring, transportation, and storage.

EGLE's analysis also identifies the technical and operational elements required to support responsible evaluation of geologic hydrogen resources. These include coordinated statewide data integration, modernized geologic characterization, hydrogen-focused laboratory and field data acquisition, and early assessment of Michigan's salt formations and reservoirs for potential underground storage. The Department further examined conditions under which existing oil and gas wells, surface sites, pipelines, and subsurface storage assets may be suitable for reuse, noting that hydrogen-compatible materials, demonstrated integrity, and enhanced safety and monitoring practices would be essential. Finally, emissions findings and sector-level considerations from this report provide a basis for assessing whether potential geologic hydrogen development could support Michigan's climate, environmental, and industrial objectives. Collectively, these evaluations establish the regulatory and technical framework necessary for Michigan to prepare for and responsibly assess future geologic hydrogen activities.

2.0 Introduction

Michigan needs to prepare a regulatory structure and policy framework for geologic hydrogen because this emerging energy resource has the potential to play an important role in the state's clean energy transition. Geologic hydrogen offers a potentially low-carbon energy source that could complement renewable energy resources such as wind and solar. According to the U.S. Department of Energy (DOE), hydrogen could supply up to 14 percent of global energy demand by 2050, reducing greenhouse gas emissions by approximately 6 gigatons annually (DOE Hydrogen Program, 2023).

Understanding the potential role of geologic hydrogen in Michigan requires a brief explanation of how hydrogen can occur and be generated within geologic systems. Geologic hydrogen (GH) refers to naturally occurring hydrogen gas present within the Earth's subsurface. The processes that generate GH are varied, but it is primarily associated with natural chemical reactions in the subsurface between water and rocks. These processes include radiolysis associated with radioactive decay in predominantly felsic crystalline rocks, as well as serpentinization reactions involving iron-rich mafic or ultramafic rocks. These processes generate free molecular hydrogen (H_2), which may migrate and accumulate in subsurface reservoirs where geologic conditions provide effective trapping.

In addition to naturally occurring GH, stimulated or enhanced geologic hydrogen (SGH) refers to hydrogen produced in geologic formations by intentionally accelerating naturally occurring subsurface reactions that generate hydrogen. Approaches currently under investigation include methods that increase interactions between water and iron-bearing minerals, as well as processes that stimulate microbial or other geochemical pathways capable of producing hydrogen within geologic formations.

Michigan's unique geologic setting includes features identified in regional assessments as favorable for the generation of GH and the underground storage of produced hydrogen. The Midcontinent Rift (MCR) system, which extends beneath portions of both the Upper and Lower Peninsulas, contains extensive mafic volcanic and intrusive rocks that may support hydrogen generation through natural or enhanced geologic processes. In addition, the entire Lower Peninsula is underlain by the Michigan Basin, a structural basin containing thick sedimentary sequences with porous and permeable reservoir formations, including the Niagaran reef trend, along with laterally extensive confining units capable of restricting vertical fluid migration. These confining units include thick shale, tight carbonate, and anhydrite formations, as well as regionally extensive salt deposits within the Salina and Detroit River Groups, which in many areas reach substantial thickness and are widely recognized as some of the most effective geologic barriers to hydrogen migration. These reservoir and seal systems may not only support the accumulation of naturally occurring geologic hydrogen but may also be suitable for the underground storage of produced hydrogen to support peak energy demand. Historically, these same geologic characteristics have supported extensive underground natural gas storage development, further demonstrating their potential suitability for future hydrogen storage applications.

However, without clear regulatory pathways governing geologic hydrogen exploration, production, and storage, Michigan risks delays in project development, regulatory uncertainty, and potential environmental risks. Establishing a solid regulatory framework would help ensure that future activities are conducted safely, responsibly, and in alignment with the state's energy, environmental, and economic objectives.

Additionally, Michigan's existing energy infrastructure and industrial base position the state to potentially support future hydrogen production, transport, and utilization. The state currently has more than 9,000 miles of natural gas transmission and gathering pipelines with extensive underground natural gas storage capacity that may provide opportunities for future hydrogen transport or storage infrastructure. A proactive policy framework can help address key issues such as permitting, monitoring, environmental protection, and subsurface resource ownership while fostering investor confidence and technological innovation.

This report, prepared by EGLE in response to the Governor's Executive Directive No. 2026-1, Establishing the Michigan Geologic Hydrogen Exploration and Preparedness Initiative, evaluates the regulatory landscape, identifies gaps in existing statutory and regulatory authority, and provides recommendations for the safe exploration and potential production of GH in Michigan. The report also considers the potential role GH could play in reducing carbon emissions within the state if resources are discovered in quantities sufficient to support hydrogen use as an alternative energy source or feedstock, including applications in hard to decarbonize sectors such as transportation and industry

3.0 Directive A – Existing Statutory and Regulatory Authority

Michigan's current regulatory structure for deep well exploration and mineral development activities falls under two statutes with associated administrative rules that are overseen by the Geologic Resources Management Division (GRMD), within EGLE.

Part 615, Supervisor of Wells, of the Natural Resources and Environmental Protection Act, 1994, PA 451, as amended (NREPA), provides for the orderly and efficient development of Michigan's oil, gas, and underground natural gas resources, while preventing waste and damage to other resources, the environment, and public health and safety.

Part 625, Mineral Wells, of the NREPA, regulates drilling and related activities used to investigate, study, or develop Michigan's subsurface mineral or geologic resources through wells or borings. These regulations are intended to prevent waste and protect other natural resources, the environment, and public health and safety. Regulated well types include test wells, solution mining wells, brine production wells, and specific types of disposal and storage wells.

Together, these statutes provide the primary framework for regulating subsurface exploration, well construction activities, and associated operations in Michigan. The following sections evaluate how these authorities may apply to geologic hydrogen exploration (GH and SGH), production, transportation, and underground storage, and identify areas where existing statutes and regulations may be sufficient as well as areas where statutory or regulatory clarification may be needed.

3.1 Exploration

Part 625 of the NREPA, which regulates a variety of well types used to investigate subsurface mineral and geologic resources, defines a *"test well"* under MCL 325.62501(o) as; *"a well, core hole, core test, observation well, or other well drilled from the surface to determine the presence of a mineral, mineral resource, ore, or rock unit, or to obtain geological or geophysical information or other subsurface data related to mineral exploration and extraction. Test well does not include holes drilled in the* *operation of a quarry, open pit, or underground mine, or any wells not related to mineral exploration or extraction."*

Because GH and SGH resources are associated with the subsurface mineral estate, exploratory wells drilled to evaluate geologic conditions, reservoir characteristics, or subsurface gas occurrence would meet the statutory definition of a test well under Part 625. As such, exploratory drilling for GH or SGH could occur under the existing test well provisions without significant regulatory barriers. Limited quantities of gas may also be produced during testing activities conducted under a test well permit for the purpose of evaluating reservoir characteristics or production potential. However, the duration of such activities would be limited and not authorized for sustained or commercial production.

A related statutory provision in Part 625, under MCL 324.62509(3) provides that permit is not required to drill a test well in areas of the Western Upper Peninsula where Precambrian-age rocks directly underlie unconsolidated surface deposits. Even though a permit is not required in these areas, the owner is still required to file records and logs within 2 years, and they must ensure that operations do not cause waste.

Under the current Part 625 statutory and regulatory authority, exploration for GH and SGH could be permitted as test wells and where test wells require permits, the requisite environmental protections and current safeguards are effective to prevent waste and protect groundwater resources and public health and safety.

Recommendation:

Although the current test well definition in Part 625 appears broad enough to accommodate hydrogen exploration activities, statutory clarification explicitly recognizing hydrogen and other monetized subsurface gases in Part 625 or other statute would improve regulatory certainty. Additionally, requiring test well permits statewide for GH and SGH exploration, including in areas currently exempt from permitting under MCL 324.62509(3), would ensure consistent regulatory oversight, data reporting, and environmental protections.

3.2 Production

Under MCL 324.61501(d) of Part 615 of the NREPA, "gas" is defined as; *"a mixture of hydrocarbons and varying quantities of nonhydrocarbons in a gaseous state which may or may not be associated with oil, and includes those liquids resulting from condensation."* Based on this definition, Part 615 has been interpreted to encompass hydrocarbon gas resources, predominantly composed of methane (CH_4) and produced in economically viable quantities. However, hydrogen is exclusively a non-hydrocarbon gas and would not be expected to be co-produced with economic quantities of hydrocarbons. As a result, hydrogen does not clearly fall within the statutory definition of “gas,” creating uncertainty regarding the applicability of Part 615 to the exploration, production, transportation, or storage of hydrogen.

Because GH and SGH resources are associated with the subsurface mineral estate, wells drilled for hydrogen production could potentially fall within the broader mineral well regulatory framework established under Part 625. However, the applicability of Part 625 to hydrogen production depends in part on whether hydrogen would be considered a “mineral” under the statute. While the statute regulates wells used to investigate or develop subsurface mineral or geologic resources, the term “mineral” is not defined. In practice, the existing statutory and regulatory provisions were developed primarily for solid mineral exploration and extraction, such as solution mining of salts and brine production, rather than the sustained production of gas resources.

While Part 625 provides authority for drilling, well construction, and certain operational requirements for mineral wells, the current statutory and regulatory framework does not provide a comprehensive structure for regulating sustained GH or SGH production. In particular, existing statutes do not clearly address key issues such as production well permitting, resource management considerations, financial assurance requirements, or operational standards specific to hydrogen production activities. In addition, some SGH concepts under consideration could rely on completion methods that enhance existing fracture networks or create new fractures to improve fluid circulation pathways within low-permeability crystalline rocks. These approaches can introduce additional considerations related to subsurface pressure response, including the potential for induced seismicity where fracture stimulation or SGH injection activities occur within Precambrian basement rocks. Part 625 provisions do not address these stimulation and injection practices, nor do they provide a framework for evaluating requirements that may accompany water withdrawal demands or for monitoring and operational controls related to pressure management to maintain isolation of the stimulated zone and mitigate induced seismicity potential. Development of defined regulatory criteria for these aspects may be warranted to ensure hydrogen production activities are conducted safely and within defined environmental and operational limits.

As a result, there is currently no statutory or regulatory framework under Part 615, Part 625, or other statutes that clearly governs GH or SGH production in Michigan. In addition, existing statutes governing production-based severance taxes may not clearly apply to GH or SGH production. The Michigan Severance Tax Act (MCL 205.301 et seq.) establishes a production-based tax on oil and gas extracted within the state and has historically been applied to hydrocarbon production. While the statutory language broadly references “gas,” it has been administered in practice in the context of natural gas and associated hydrocarbons. Michigan also imposes a severance tax on nonferrous metallic minerals under the Nonferrous Metallic Minerals Extraction Severance Tax Act (MCL 211.781 et seq.). However, this statute applies to solid mineral substances extracted from mineral producing properties and therefore would not appear applicable to GH. As a result, existing severance tax statutes may not provide a clear mechanism for assessing production-based fees associated with GH extraction

Recommendation:

It is recommended that non-hydrocarbon gas well definitions be added to Part 625 or other statute to include GH, SGH, and that appropriate permit fees and financial assurance requirements be established to drill and produce these types of wells. Because GH and SGH development represents a new category of gas production, statutory updates should focus on establishing clear authority for GH and SGH production well permitting, construction standards, operational controls, and long-term management of hydrogen producing wells. Clarifying statutory authority for hydrogen production under Part 625 may also require explicit recognition of hydrogen and other non-hydrocarbon gases as a mineral resource or otherwise specifying that hydrogen extraction activities fall within the scope of the mineral well regulatory framework. Consideration may also be warranted for clarifying the applicability of existing severance tax statues or establishing an appropriate production-based fee structure should commercial geologic hydrogen production or other non-hydrocarbon gases occur. These updates will help ensure that production of hydrogen and other nonhydrocarbon gases proceeds under a clear and consistent statutory framework.

SGH development would likely involve the injection of water or other fluids into formations that may be located within or below an Underground Source of Drinking Water (USDW), which could require authorization under the Underground Injection Control (UIC) program, administered by the United States Environmental Protection Agency (EPA). As statutory authority for GH and SGH development becomes better defined under Part 625 or another applicable statute, additional administrative rulemaking may be necessary to address UIC aquifer exemptions, well construction standards, operational controls, monitoring requirements, and other safeguards associated with hydrogen production activities. During this rulemaking process and depending on the UIC classification assigned to SGH wells by the EPA, evaluation of potential state primacy and coordination with the EPA may also be warranted.

3.3 Transportation

The transportation of hydrogen is largely outside of EGLE’s purview. On the federal level, there are two key early acts that establish the role of the federal government in pipeline regulations:

1. The Natural Gas Pipeline Safety Act (NGPSA) of 1968

2. The Hazardous Liquid Pipeline Safety Act (HLPSA) of 1979

Under each of these statutes, the Secretary of Transportation is given primary authority to regulate key aspects of interstate pipeline safety. The NGPSA authorized the Department of Transportation (DOT) to regulate pipeline transportation of natural gas and certain other gases as well as transportation and storage of liquified natural gas (LNG) and the HLPSA authorized the DOT to regulate pipeline transportation of hazardous liquids.

Each of the acts have been recodified in Title 49 of the United States Code (49 U.S.C. 60101-60141), which provides the statutory basis for federal pipeline safety regulation. Implementing regulations are codified in Title 49 of the Code of Federal Regulations (49 C.F.R Parts 190-199) and establish safety standards and specifications for the design, construction, testing, inspection, operation, and maintenance of pipelines. The Federal Energy Regulatory Commission (FERC) has exclusive authority to regulate the siting of interstate natural gas pipelines and may also have a role for hydrogen-related infrastructure, should federal jurisdiction be expanded or clarified.

The Michigan Public Service Commission (MPSC) inspects and enforces pipeline regulations for all intrastate natural gas pipelines. The MPSC also inspects interstate natural gas pipelines, but the Pipeline and Hazardous Materials Safety Administration (PHMSA) within the DOT enforces pipeline safety regulations for the interstate natural gas pipelines based upon the inspections performed by the state. The MPSC is responsible for approving construction, including siting and routing of new petroleum pipelines in Michigan.

The transportation of hazardous materials has other DOT defined requirements pursuant to transportation that applies to motor carriers, shippers, drivers, and cargo tank facilities. The DOT hazardous material regulations are adopted into state law under Public Act 181 of 1963, as amended (Act 181) and are enforced by Motor Carrier Officers of the Michigan State Police.

Recommendation:

The statutory or regulatory authority for transportation of hydrogen resides with and is best developed on the state level by the MPSC or on the federal level by FERC or PHMSA under the DOT.

3.4 Storage

Fluids associated with hydrogen production may be stored at the surface in tanks or pressurized vessels, or in the subsurface within geologic formations. Aboveground storage of hydrogen downstream of the production site is largely outside of EGLE's direct regulatory purview and is generally governed by fire and safety codes administered by the Department of Licensing and Regulatory Affairs (LARA) under Michigan's Fire Prevention Code (Act 207), along with applicable federal regulations and industry safety standards for compressed gas storage and handling. The discussion below focuses on downstream underground hydrogen storage (UHS) within geologic formations, as potential development and reliable availability of GH resources are likely to be closely tied to UHS because it offers more economical options for large-volume storage compared to aboveground facilities. UHS also introduces additional technical and regulatory considerations for GH that warrant further evaluation.

Underground hydrogen storage may occur in either engineered cavern systems or porous geologic formations. However, solution-mined salt caverns represent the most established geologic storage method for hydrogen, while storage in porous formations such as depleted hydrocarbon reservoirs or deep saline aquifers remains an area of ongoing technical evaluation and its commercial-scale viability remains uncertain.

Part 615 regulates well construction and operations associated with underground natural gas storage, while the designation of underground natural gas storage fields is governed separately by MPSC under Public Act 238. However, Part 615's authority is currently limited to the storage of hydrocarbon resources. Additionally, Part 615 was developed primarily to regulate storage within depleted oil and gas reservoirs and does not include provisions addressing the development or operation of solution-mined salt caverns. This distinction is relevant because UHS is most commonly associated with salt caverns, rather than depleted hydrocarbon reservoirs.

In contrast, Part 625 explicitly excludes hydrocarbon storage and defines "stored product" in Administrative Rule 299.2304(e) as any substance, *other than liquid hydrocarbons, liquefied petroleum gas, or dry natural gas*, that is injected into an underground storage cavity for later withdrawal. Because hydrogen is not a hydrocarbon gas and is not otherwise excluded under this definition, it could fall within the range of substances eligible for storage under Part 625. However, MCL 324.62501(l) defines a "storage well" *as a well drilled into a subsurface formation to develop an underground storage cavity*. This framework should provide a statutory pathway for hydrogen storage in engineered cavern storage systems but does not clearly extend to porous media- storage, which relies on reservoir containment rather than finite cavern boundaries.

Initial UHS operations would most likely target solution -mined salt caverns, which fall within the regulatory authority of Part 625. Engineering considerations for these facilities/operations would include host formation geomechanics, caprock integrity, well design and cement isolation, resistance of tubulars and wellhead components to hydrogen embrittlement, cushion gas management, pressure- cycling- limits, and leak detection and monitoring systems. Although many of these considerations parallel those applied to natural gas storage, hydrogen's smaller molecular size, higher diffusivity, and potential geochemical or microbial reactivity introduce additional performance factors not explicitly addressed in existing Part 625 rules. If ongoing research and technical analyses confirm the feasibility of hydrogen storage in porous geologic formations, then Part 625 would require clarification or updating to explicitly address subsurface storage in non-salt cavern settings and to consider appropriate reservoir management criteria.

Part 625 provides a foundational permitting structure for drilling, completing, and operating non-hydrocarbon, cavern storage wells, including requirements for well construction, casing and cementing, testing, and plugging. However, hydrogen is not expressly identified as a regulated storage substance, and current rule language was drafted primarily for brine production, solution mining, and mineral extraction, rather than cyclic gas storage. As a result, hydrogen storage under Part 625 would rely on interpretation of general “storage well” authority rather than explicit hydrogen-specific provisions.

Recommendation:

Part 625 provides a viable regulatory foundation for UHS in Michigan. However, targeted statutory clarification and rule enhancements would help ensure that hydrogen’s unique physical and chemical characteristics are explicitly considered within the mineral well regulatory framework (or other statute) rather than addressed solely through case-by-case interpretation.

If future research demonstrates that hydrogen can be stored safely and effectively in depleted hydrocarbon reservoirs (e.g., Niagaran reef systems) or deep saline aquifers, additional modifications to Part 625 (or addressed in other statute) would likely be necessary to address porous-media storage. Unlike cavern storage, which relies primarily on structural containment within salt, porous formations depend on caprock integrity, reservoir pressure management, plume-migration control, legacy-well evaluation, and long-term geochemical and microbial stability. To ensure regulatory certainty and groundwater protection, rulemaking should establish hydrogen-specific requirements for reservoir characterization, area-of-review evaluations, cyclic mechanical-integrity testing, monitoring thresholds, and pressure-management criteria appropriate for porous-media systems. Without such updates, authorization of hydrogen storage in depleted reservoirs or saline formations would rely on regulatory interpretation rather than clearly defined statutory or rule-based standards.

Although natural gas storage wells are exempt from federal UIC requirements, hydrogen injection and withdrawal operations may require UIC authorization, depending on how the EPA ultimately classifies hydrogen storage activities. The EPA’s 2024 *Subsurface Hydrogen Storage Technical Considerations* white paper highlights several risks and uncertainties associated with protecting underground sources of drinking water, suggesting that future hydrogen storage projects may necessitate coordinated state–federal review. Such coordination would help ensure compliance with applicable aquifer protection standards, mechanical integrity testing requirements, and no-endangerment demonstrations, and may require clarification or updates to Part 625 or other statutes to accommodate potential UIC involvement.

Accordingly, several areas may warrant statutory clarification or additional rulemaking under Part 625, or another applicable statute, to address hydrogen storage explicitly. These areas include:

- Direct recognition of hydrogen as an allowable storage gas under statute or rule.
- Development of hydrogen-specific well construction and material compatibility standards addressing embrittlement and permeability concerns.
- Establishment of mechanical integrity testing protocols appropriate for cyclic hydrogen injection and withdrawal.
- Implementation of monitoring and leak-detection requirements tailored to hydrogen's physical properties, including appropriate measures for surface infrastructure to ensure worker and public safety.
- If the EPA establishes UIC jurisdiction over subsurface hydrogen storage, then Part 625 or other applicable statutes should be updated to ensure state permitting aligns with federal UIC requirements.

Addressing these areas would strengthen groundwater protection, improve regulatory clarity, and ensure that hydrogen storage is governed by standards appropriate for hydrogen's unique storage behavior, integrity risks, and long-term operational considerations.

3.5 Regulatory Gaps and Impediments Summary

The preceding analysis evaluated Michigan's existing statutory and regulatory framework under Part 615 and Part 625 of the NREPA, along with related authorities, to determine whether regulatory gaps or impediments exist for potential geologic hydrogen exploration, production, transportation, and storage activities.

Exploration: The current Part 625 statute and administrative rules provide sufficient regulatory authority to allow GH and SGH exploratory test well drilling. While the framework does not present significant statutory barriers to exploration, refinements in definitions within Part 625 would help improve clarity regarding the scope of permissible exploratory activities. Additionally, specifying that permitting requirements apply statewide for all test wells by removing current exemptions would help ensure that environmental, public health, and safety protections are applied consistently across Michigan.

Production: Michigan's current statutory framework does not clearly address the production of GH or SGH and would require substantial statutory revisions to prevent waste, protect mineral interests, ensure orderly development, provide adequate funding for regulatory oversight, and reduce risks associated with production and operations. Part 615 is oriented exclusively toward hydrocarbon oil and gas production, while Part 625 governs mineral wells but does not explicitly contemplate sustained production of nonhydrocarbon gases such as hydrogen. Michigan also lacks a regulatory structure for administering production- based- fees or resource management provisions for GH or SGH comparable to those applied to natural gas production. In addition, SGH development will involve the injection of water or other fluids into subsurface formations, which could introduce additional regulatory obligations under the UIC program and may also require evaluation of related considerations such as potential fracture -stimulation activities.

Transportation: Other state and federal regulatory agencies beyond EGLE currently have and would continue to have regulatory authority over hydrogen transportation methods and oversight.

Storage: Surface storage downstream of production operations would largely fall outside EGLE's direct purview and be regulated by other state and federal agencies. Surface storage of hydrogen at the wellsite associated with upstream operations would likely fall under the regulatory authority of EGLE's GRMD and may require statutory updates or clarification to address hydrogen-specific safety and operational considerations. Part 625 provides a potential foundation for UHS in solution mined- salt caverns. However, hydrogen is not expressly identified as a permissible stored product under the current statute. The definition of storage wells under Part 625 is also tied to underground storage cavities, which may not clearly accommodate hydrogen storage within porous geologic formations, such as depleted oil and gas reservoirs or deep saline formations. Clarification of hydrogen storage authority and potential rulemaking addressing both cavern and porous media storage would improve regulatory certainty for future hydrogen storage projects. In addition, depending on the EPA determination regarding UIC applicability, corresponding updates to state statutes or rules may also be warranted for storage wells/operations.

4.0 Directive B – Permitting Frameworks for Geologic Hydrogen

The permitting frameworks appropriate for GH development should follow the established safeguards within Michigan's Part 615 and Part 625 programs and must cover the entire lifecycle of the individual wells that may be used in developing this resource. A central component within these existing provisions is that the activities are conducted in a manner that protects the interests of Michigan's citizens from unwarranted waste, threats to health and safety, damage to property, and environmental hazards. As such, regulatory oversight and conditions should be applied to the following phases of development:

- Application Submittals and Reviews (Permitting)
- Site Construction and Drilling (Inspections and Reporting)
- Production and Operations (Inspections and Reporting)
- Final Plugging and Site Restoration (Instructions, Inspections, and Reporting)

4.1 Application Submittals and Reviews (Permitting)

Under Michigan's existing oil and gas, and mineral well regulations, permit applications are submitted upon prescribed forms and reviewed for overall well site suitability, access, and environmental impact considerations. Hydrogen development wells should undergo a similar permit application review process to ensure consistent evaluation of site conditions, environmental protections, and operational requirements.

This process includes evaluating wetlands, floodplains, surface waters, and other environmentally sensitive areas within the project area or surrounding area of review. Complete applications must demonstrate that potential impacts are identified, mitigated, or avoided, and that required setbacks from buildings, water wells, and other regulated features are maintained to protect property and public safety. Well design and cementing plans must also be reviewed during this phase to ensure that the well construction is tailored to local geologic conditions, designed to prevent fluid migration, and is protective of freshwater resources over the well's lifecycle. Due to the unique properties of hydrogen, the well design must also take into account the potential for casing embrittlement and the need for specialized cements, drilling muds, and drilling techniques.

Applications must allow adequate time for technical review, including an associated permit fee, and must provide appropriate financial assurance. Permits can only be issued for applications that are properly submitted, administratively complete, and meet all applicable technical and regulatory requirements. To promote transparency, public notice and comment periods for proposals should be required prior to issuing permits. Final permits should impose specific casing and cementing requirements and may include additional permit conditions as necessary to ensure safe and compliant well construction and operations.

4.2 Site Construction and Drilling (Inspections and Reporting)

Site construction and drilling activity should be inspected regularly by EGLE staff. This is especially important during key phases of drilling and well completion to ensure that the work is performed in accordance with permit conditions. As part of these requirements, the operator must provide well drilling records that document the geology encountered, logs and surveys performed, casing and cementing activities, and any testing or completion operations that were conducted.

4.3 Production and Operations (Inspections and Reporting)

Production and operations at well sites should be inspected regularly by EGLE staff to verify compliance with regulatory requirements and ensure safe operational practices. Any well rework activities must be submitted through a formal application, approved by EGLE, and completed in accordance with specified conditions. Records documenting rework operations and well production must be submitted to EGLE in accordance with established reporting timeframes throughout the well's operating life. Regular mechanical integrity testing and associated reporting may also be appropriate for hydrogen production wells during the operating phase to verify that casing and cement remain structurally sound and that well materials are not degrading due to potential hydrogen exposure.

4.4 Final Plugging and Site Restoration (Standards, Oversight, Reporting)

Wells should be plugged based upon prescribed and approved plugging instructions provided by EGLE. This typically involves placing multiple cement plugs and/or mechanical plugs set at various depths within the wellbore to ensure long-term zonal isolation of producing formation(s) and protection of freshwater resources. The casing is then cut at least 4 feet below the ground surface and capped with a welded steel plate. The plugging activity is inspected by EGLE staff and records are provided by the operator documenting how the well was plugged. Once plugging is completed, all surface equipment is removed, the site is leveled and revegetated, and the area is restored. After restoration is confirmed, the well is considered properly plugged and financial assurance may be returned to the operator.

4.5 Surface, Minerals, and Correlative Rights

Another important consideration with the development of GH involves mineral rights, surface rights, and the concept of correlative rights, which ensures that landowners receive their just and equitable share of the resource being developed. These concepts are important to ensure that development is orderly and efficient and that the resource is produced without drilling unnecessary wells or creating waste.

Geologic hydrogen development would be considered a mineral right and subject to control over the mineral resources by either a lease or ownership. Michigan’s oil and gas program has addressed orderly development and compensation for drainage of hydrocarbon resources by establishing a ‘drilling unit’ that is associated with well production. Under MCL 324.61513(2), a drilling unit is described as, “…the maximum area that may be efficiently and economically drained by 1 well.” Drillings units are defined based upon the quarter-quarter grids associated with the Public Land Survey System. For oil and gas wells, drilling units have been established based upon the estimated area of the mineral resource that may be efficiently drained by a single well. These units vary in size from a 40-acre tract to a 640-acre tract, depending upon the reservoir characteristics, target formation, and whether oil or natural gas is being produced. A similar concept for establishing drilling units for GH would likely be appropriate. However, additional information, including but not limited to hydrogen migration pathways, accumulation behavior, and reservoir drainage characteristics, would be necessary to determine appropriate unit size and ensure that development remains orderly and correlative rights are protected.

Hydrogen storage in the subsurface would also require surface rights permissions associated with the use of pore space. In this case, an agreement through lease or ownership of the surface over which storage is occurring would be necessary. It is likely that EGLE and other state and federal partners would have roles in establishing hydrogen storage fields. Because of the limitations in the current regulatory structure described previously, particularly the lack of explicit statutory provisions addressing hydrogen storage and the absence of a defined framework for establishing hydrogen storage fields, a permitting program to authorize such storage fields and provide additional regulatory protections would likely be necessary.

5.0 Directive C – Technical Research Needs and Opportunities

The following discussion incorporates technical input and supporting materials submitted by the Michigan Geological Survey (MGS) at Western Michigan University, which informed the development of GH research priorities for Michigan. The MGS, and their team of scientists, work to better understand, investigate, preserve, and share Michigan geology. MGS conducts geological investigation of Michigan's natural resources and provides the public access to the state geological data repository. Technical details, preliminary cost considerations, and planned GH research activities associated with the MGS submissions are summarized in Appendices A1 through A3. These contributions, combined with additional analysis and stakeholder perspectives, were used to develop a consolidated set of research needs and process improvements required to evaluate Michigan's GH, SGH, and underground hydrogen storage resource potential.

Michigan can most effectively advance understanding of its geologic hydrogen systems and resource potential through a coordinated effort of public and private research involving state agencies, universities, private sector operators, and federal partners. The State will focus on foundational geologic characterization and shared data infrastructure, while exploration, testing, and technology development will likely be led by industry and research institutions. As in other subsurface sectors, publicly available data, academic research, and private sector activities will continue to refine assessments of resource potential. Michigan can accelerate progress by funding early-stage data acquisition, enabling data sharing, and deploying targeted incentives and partnerships that support responsible exploration and protect public resources

Given the prominence of the MCR across Michigan and the established role of serpentinization as a primary mechanism for GH generation, early research should prioritize Rift associated mafic, ultramafic, and iron rich basement lithologies as favorable settings for GH and SGH. However, the distribution, composition, alteration state, and structural connectivity of these units have not been systematically evaluated from a hydrogen resource perspective. Near-term work should emphasize detailed mapping of Rift related rocks and structural features, refinement of the Precambrian–Cambrian contact across the Michigan Basin, evaluation of lithologic variability within basement terranes, and reevaluation of reservoirs and confining units within the Michigan Basin for hydrogen containment. At the same time, research should consider a range of hydrogen generation pathways, including radiolysis, deeper crustal or lithospheric structures, and iron rich, non-mafic rocks such as banded iron formations that may support other water–rock redox reactions. Because these processes can operate independently of Rift related geology, GH or SGH resources may not always align with Rift features, and evaluation of multiple geologic mechanisms will be necessary to fully assess Michigan’s hydrogen resource potential.

5.1 Data Integration, Strategic Technical Partnerships, and Data Management

Evaluation of GH, SGH, and UHS resources in Michigan can be accelerated through coordinated statewide data development and sustained collaboration among government, academic, and private-sector partners. This effort will require integrating geological, geophysical, geochemical, and surface-measurement datasets into a common foundation for GH resource assessment. Input from MGS and other stakeholders highlights the value of a shared, integrated database that can rapidly incorporate new subsurface, surface, and analytical data and make it accessible to interested parties. Developing this resource will promote consistent statewide analysis and support continuous incorporation of new data. With this system in place, the next priority is establishing consistent approaches for data acquisition to improve the resolution, coverage, and relevance of hydrogen-related observations across the state.

Near-term progress will require consistent strategies to acquire new subsurface and surface datasets for incorporation into the statewide framework. Priority activities include collecting standardized geological and geochemical information from new deep wells, analyzing groundwater and formation-fluid samples, and expanding surface and airborne datasets such as LiDAR, gravity, magnetic, and soil-gas surveys. When coordinated across agencies, academic institutions, and industry operators, these efforts will improve spatial resolution and data density for assessing hydrogen generation, migration pathways, and reservoir or seal properties.

Integrated interpretation and mapping workflows will be essential to maximize data value and enable statewide screening and prioritization. Layered, thematic mapping—consistent with the MGS data-layering framework—provides a systematic approach to integrate geologic, geophysical, geochemical, and surface measurements into coherent spatial products. Integrating seismic interpretations, structural features, gravity and magnetic anomalies, surface-flux indicators, and reservoir or confining-unit properties enables multiscale assessment from regional to site-specific analyses. These activities depend on a centralized, accessible data-management system with structured metadata, standardized formats, and role-based access capable of supporting core and cuttings analyses, groundwater and formation-fluid chemistry, soil-gas measurements, geophysical surveys, seismic interpretations, and historical oil-and-gas records. Improved organization and accessibility will reduce duplication, enhance interpretive transparency, and support continuous refinement of geologic and hydrogen-system models as new data become available.

Sustained collaboration among state agencies, MGS, universities, and private-sector operators is essential to align data-collection priorities, analytical methods, and interpretive workflows. Establishing shared protocols for sampling, laboratory analysis, data submission, and technical review will strengthen Michigan's scientific foundation for evaluating GH, SGH, and subsurface hydrogen storage. This coordinated research framework establishes the foundation for GH, SGH, and subsurface storage technical requirements discussed in the following subsections.

5.2 Technical Research Needs for Geologic Hydrogen

Evaluating Michigan's potential GH resources depends on improving the understanding of subsurface conditions across the State, including key features related to the Michigan Basin and MCR. These needs fall into three broad categories, geophysical characterization of basement structures and reactive lithologies, re-evaluation of existing subsurface datasets with a hydrogen-focus, and incorporation of new, targeted sampling and data collection- efforts with hydrogen-specific measurements.

5.2.1 Geophysical Characterization and Mapping

A primary objective should be improved mapping of mafic and ultramafic lithologies associated with the MCR, including refinement of the Precambrian–Cambrian contact across the Michigan Basin. Much of Michigan's existing seismic dataset was acquired for hydrocarbon exploration and does not optimally resolve basement architecture. Modern reprocessing of legacy seismic data with targeted acquisition of high-resolution seismic within Rift-influenced regions, would enhance understanding of Rift geometry, intrusive bodies, fault segmentation, basement highs, and deep fracture systems that may influence hydrogen generation and migration pathways. Particular attention should be given to identifying structural corridors that could facilitate fluid circulation within reactive iron-rich lithologies. Integrating reprocessed seismic with high-resolution gravity and other geophysical datasets is increasingly recognized as best practice for basement characterization. Additional information from MGS regarding acquisition and processing of an available regional seismic dataset is provided in Appendix A-2.

Regional magnetic datasets for Michigan's Lower Peninsula are decades old and were collected with coarse line spacing, extending up to 6 miles, limiting resolution of Rift-related features, intrusive bodies, and fault systems. Updated processing may improve interpretations but conducting new high-resolution magnetic surveys with line spacings on the order of a few hundred meters would significantly enhance delineation of basement lithologies and structures relevant to hydrogen generation and migration. interpretation of modern magnetic data with gravity and electromagnetic datasets will further support subsurface characterization and resource assessment.

5.2.2 Re-evaluation of Existing Subsurface Data

Archived basement cores and deep formation samples should be systematically reexamined to quantify hydrogen generation potential. MGS's Michigan Geological

Repository for Research and Education at Western Michigan University and EGLE's Upper Peninsula Geologic Repository each have extensive resources of stored rock core, along with examination, preparation, and testing areas. Petrographic, mineralogical, and geochemical analyses can identify iron bearing minerals and alteration textures associated with serpentinization and other water–rock reactions that generate hydrogen in mafic and ultramafic lithologies. Advanced analytical methods, including fluid inclusion petrography and gas chromatography, may further identify trapped hydrogen, precursor gases, and indicators of past migration. Evaluation of uranium and thorium bearing minerals in felsic crystalline rocks can help characterize radiolysis related hydrogen pathways. Samples obtained from future deep drilling campaigns could supplement these efforts through coordinated collaboration with operators and research partners, supported by consistent and appropriate sampling protocols. To support these efforts, MGS has identified expanded laboratory capacity as a technical need to enable rapid subsurface sample analysis and improve hydrogen related data availability, with additional details provided in Appendices A1 and A2.

Reanalysis of appropriate existing wireline logs, including density, neutron, sonic, resistivity, and borehole imaging logs should be conducted to identify fracture density, lithologic heterogeneity, and alteration zones within both the sedimentary sequence and basement rocks. Historical drilling records may also contain unrecognized gas shows or anomalous log responses that warrant reassessment under a hydrogen-focused framework. Where available, advanced borehole image logs can further delineate fracture networks and zones of mineral or diagenetic alteration that may influence hydrogen generation, migration, or accumulation. Although log coverage within crystalline basement intervals is limited, systematic reevaluation of logs across the sedimentary section and basement provides a cost-effective means of identifying subsurface intervals with potential relevance to geologic hydrogen systems.

5.2.3 New Sampling and Data Acquisition

Because opportunities to obtain deep subsurface samples are limited, Michigan should incentivize coordinating hydrogen related sampling at Part 615 and Part 625 drilling operations that target reservoirs in the Michigan Basin or Precambrian basement rocks. To date, this aspect has been largely overlooked. Implementing standardized procedures, including hydrogen focused mudlogging protocols, continuous gas analysis with chromatographs configured and calibrated for hydrogen detection, and consistent documentation of drilling conditions would improve statewide consistency in data quality and enhance interpretation of hydrogen related anomalies. Collaboration among operators, state agencies, MGS, and academic partners will be essential to ensure that data collected during industry drilling programs meet research needs and are accessible for long term evaluation.

Surface and near-surface hydrogen surveys in select regions may be appropriate to help identify potential hydrogen seepage along faults or fracture systems associated with Rift-related basement structures. Soil-gas sampling programs should include structured transects, repeated measurements, and multi-gas sampling that includes hydrogen, helium, carbon dioxide, methane, and nitrogen. Selection of viable locations can be enhanced by integrating updated geophysical interpretations of structural controls with high-resolution LiDAR or aerial imagery to identify vegetation or surface anomalies that may indicate gas occurrence or fluid migration associated with GH.

Near-term efforts should include controlled laboratory experiments using representative samples of Michigan's basement lithologies to quantify hydrogen generation rates under relevant temperature and pressure conditions. Studies should evaluate serpentinization pathways, oxidation of ferrous minerals, radiolysis-related reactions, and the stability of alteration products. Laboratory testing can also support preliminary assessments of potential geochemical byproducts and mineralogical changes. When appropriate, geochemical reaction-path modeling should accompany experimental work to guide expectations of hydrogen yield and to define key variables that influence reaction efficiency prior to any field-scale investigations.

5.3 Technical Research Needs for Stimulated Geologic Hydrogen

Because SGH involves intentionally accelerating subsurface reactions and will likely involve underground injection, its evaluation requires research that is distinct from the needs associated with naturally occurring GH systems. Early efforts should prioritize controlled laboratory studies to determine feasibility, reaction behavior, and potential byproducts under Michigan-specific conditions. If these results are encouraging, additional work will be needed to address field-scale considerations, including operational risks, monitoring requirements, and safeguards. The following subsections outline these high-level research priorities, with detailed technical information provided by MGS in Appendix A-1.

5.3.1 Laboratory Evaluation and Geochemical Reaction Assessment

Laboratory testing should be initiated during the short-term phase to evaluate both native and stimulated hydrogen generation potential. Controlled water-rock interaction experiments using representative rock samples from Michigan's basement lithologies can quantify hydrogen yield rates under realistic temperature and pressure conditions representative of Michigan's subsurface. Particular attention should be given to understanding changes in mineralogy, pore structure, and water–rock ratios, as these factors strongly affect reaction continuity and long-term hydrogen-generation potential. Additional laboratory studies should evaluate the feasibility of SGH through enhanced thermal or catalyst-assisted reactions, including assessments of reaction kinetics, sustainability, potential geochemical byproducts, and system scalability.

Complementary modeling, such as reaction-path analysis and sensitivity testing should be conducted alongside laboratory work to evaluate the variables that most strongly shape hydrogen yields, reaction sustainability, and potential byproducts prior to considering any field-scale stimulation. These evaluations can help define realistic operating windows, identify potential undesirable byproducts, and assess whether stimulated hydrogen production could be maintained under field conditions. Conducting this work at laboratory scale allows the State to generate meaningful technical data without subsurface injection or potential environmental impacts or risks associated with field testing. Additional technical approaches and methods provided by MGS are outlined in Appendix A-1.

5.3.2 Field-Scale Considerations, Operational Risks, and Monitoring Needs

If laboratory and modeling results indicate that SGH is technically feasible, the next step is to evaluate the geologic and operational factors that would be incorporated into a field-scale pilot application. This process would include evaluating how stimulation might affect subsurface pressure behavior, fracture development, and interactions with existing structural features. Additional considerations include understanding potential changes in fluid chemistry, the formation of reaction byproducts and potential environmental effects, and mechanisms that may influence hydrogen migration or containment, such as diffusive losses or microbial consumption. Any potential for induced seismicity or unintentional fracture propagation must also be examined, along with the monitoring strategies needed to detect and manage such risks. Field scale feasibility should be evaluated within a framework that includes baseline data collection, real time monitoring capabilities, and clear operational safeguards. Any future pilot testing should proceed only after a comprehensive risk assessment and independent technical review.

5.4 Underground Hydrogen Storage

Initial research should begin with a preliminary assessment of the suitability of Michigan’s salt units within the Salina and Detroit River Groups for UHS. Updated seismic interpretation, supplemented by acquisition of new seismic data can be used to refine estimates of salt thickness, depth, structural continuity, and proximity to faults that may influence cavern development across Michigan’s evaporite sequences. Additional information on the available regional seismic dataset provided by MGS is presented in Appendix A-2. Further evaluation of the salt units should include analysis of cored salt intervals and overlying caprock units to understand salt purity, mechanical strength, sealing capacity, and the presence of interbeds that may affect cavern performance. Because Michigan’s evaporite sequences occur as layered deposits rather than diapiric salt domes, additional attention is warranted to evaluate lateral continuity, unit thickness, deformation behavior, and the mechanical impact of non-salt layers. These screening-level evaluations will help identify where Michigan’s salt resources offer the greatest potential for future UHS, should GH resource be confirmed and developed at sufficient scale.

Future evaluations may expand beyond salt caverns to consider storage in porous reservoirs if hydrogen supply potential and market needs warrant additional underground storage options. These systems introduce added uncertainties compared with cavern storage, including greater sensitivity to caprock performance, cushion gas requirements, reservoir heterogeneity, system behavior under repeated injection and withdrawal cycles, and typically, greater number of legacy wells. Evaluating these formations would require assessment of structural closure, pressure-containment capacity, hydrogen–brine–rock interactions, and possible microbial consumption of hydrogen before any field scale applications are considered.

In general, all storage options should be evaluated for reservoir and seal characteristics that govern safe hydrogen containment in any geologic setting. This includes high-level evaluation of porosity, permeability, fracture networks, caprock integrity, legacy wellbore penetrations, as well as potential geochemical interactions between hydrogen, formation fluids, and reservoir or seal mineralogy. Because hydrogen is highly mobile and diffuses more readily than other stored gases, additional attention is warranted for potential loss mechanisms, mineralogical changes, and microbial activity that may influence long-term containment. Laboratory-scale containment tests and reaction assessments can help evaluate diffusion behavior, capillary sealing performance, and possible alteration of reservoir or caprock materials, while 3D geologic and reservoir modeling can support early projections of plume behavior, pressure evolution, and storage performance. Further technical details on geologic assessment for UHS is provided by MGS in Appendix A-1.

Development of a regional screening framework may also support identification and prioritization of potential storage locations based on geologic, operational, and infrastructure considerations. Such a framework would help integrate available subsurface data, identify knowledge gaps, and support coordinated planning for future hydrogen storage opportunities in Michigan.

Recommendation:

Michigan's evaluation of GH, SGH, and UHS requires a coordinated, statewide technical research effort focused on foundational geologic characterization, modernized data acquisition, and integrated analysis across state agencies, MGS, universities, and private sector partners. Early priorities include refining subsurface understanding of MCR–related lithologies, reanalyzing existing subsurface datasets through a - GH focused lens, and implementing standardized, - hydrogen specific - sampling and measurement protocols during Part 615 and Part 625 drilling. Complementary laboratory testing and geochemical modeling of representative Michigan rock types will help assess natural and stimulated hydrogen generation pathways, while initial screening of Michigan's salt units and porous reservoir systems will inform the feasibility of future UHS. Building shared data infrastructure, consistent statewide protocols, and sustained technical collaboration will be essential to accelerate resource assessment, ensure data quality, and support responsible exploration and development of GH, SGH, and UHS opportunities across Michigan

6.0 Directive D – Carbon and Criteria Pollutant Change Estimates

Directive D requests evaluation of greenhouse gas and criteria pollutant emissions associated with GH, particularly in the context of potential future exploration and production in Michigan. Recent assessments indicate favorable GH prospectivity, although exploration to confirm the presence, composition, and viability of such resources has not yet occurred. Because GH production may offer lower greenhouse gas emissions relative to some conventional energy sources, understanding potential emissions characteristics is necessary for anticipating future development scenarios and progress towards commitments in the state's MI Healthy Climate Plan.

Emissions are commonly expressed as **carbon dioxide equivalent (CO_2e)**, a standardized metric that converts the warming impact of different greenhouse gases into an equivalent amount of carbon dioxide using global warming potential factors. This allows combined reporting of gases with differing atmospheric lifetimes and heat trapping strengths, including carbon dioxide, methane, and, where established, indirect effects associated with hydrogen leakage.

For geologic hydrogen, emissions would be expected to vary based on site-specific factors such as raw gas composition, production methods, and the extent of processing, compression, and transport required. In addition to greenhouse gases, potential emissions of criteria air pollutants may also vary depending on how hydrogen is produced, processed, and ultimately used. The following discussion summarizes available information relevant to Directive D, recognizing that emissions characteristics will depend on resource quality, production methods, and end use applications.

6.1 Lifecycle Emissions Profile

Lifecycle assessments (LCAs) provide a standardized methodology for comparing greenhouse gas emissions across energy pathways. For geologic hydrogen, the primary peer-reviewed assessment (Brandt et al. 2023, Joule) estimates site-boundary emissions of 0.4 to 1.5 kg CO_2e/kg H_2, encompassing extraction through on-site compression. Transportation and distribution infrastructure can add 50 to 100 percent to these values, yielding delivered intensities of 0.6 to 2.1 kg CO_2e/kg H_2. See Appendix B for detailed methodology.

Key emission sources within the site boundary include: (1) drilling and well construction (embodied emissions from materials and diesel), (2) production and fugitive emissions (hydrogen has an indirect global warming potential (GWP) of approximately 5; co-produced methane contributes directly), (3) processing and separation (approximately 8 percent of extracted hydrogen consumed as fuel), and (4) on-site compression to pipeline-ready pressure.

Emission intensity varies primarily with raw gas composition, particularly the methane fraction, yielding site-boundary estimates ranging from 0.4 to 1.5 kg CO_2e/kg H_2. These estimates apply to native (passive) geologic hydrogen. No peer-reviewed lifecycle assessment currently exists for stimulated geologic hydrogen; the U.S. Department of Energy (DOE) has set a target of less than 0.45 kg CO_2e/kg H_2 for that pathway. See Appendix B for sensitivity analysis details.

6.2 Comparison to Other Hydrogen Pathways

Geologic hydrogen's emissions intensity (0.4 to 1.5 kg CO_2e/kg H_2 site-boundary; 0.6 to 2.1 delivered) is comparable to the cleanest green hydrogen pathways (IEA 2024) and far below the 10 to 12 kg CO_2e/kg H_2 from conventional steam methane reforming. Apart from one small-scale operational site in Mali, no commercial geologic hydrogen production facilities exist; values derive primarily from engineering models. See Appendix B for generation technology comparison.

6.3 Criteria Air Pollutant Considerations

Criteria air pollutants are six common pollutants regulated by the EPA that are harmful to human health and the environment: carbon monoxide (CO), lead, nitrogen dioxide (NO_2), ozone, particulate matter (PM), and sulfur dioxide (SO_2). High-temperature hydrogen combustion can generate nitrogen oxides (NOx) because NOx formation occurs when air is exposed to high temperatures. Fuel cell applications produce no NOx.

Limited U.S. data exists for air emissions from hydrogen use in industrial applications. A Gerdau air permit to install application (September 2025) for hydrogen fuel trials at the Special Steel Monroe Mill (Gerdau) projects CO emissions reduced by over 99 percent, slight decreases in PM, SO_2, VOC, and lead, and slightly higher NOx emissions compared to natural gas. This trial uses hydrogen as a combustion fuel for process heat, which differs from hydrogen-based direct reduced iron (H_2-DRI) steelmaking where hydrogen serves as a chemical reductant; criteria pollutant profiles may vary between applications. Quantified estimates for industrial-scale deployment remain limited due to the nascent state of hydrogen technology and the absence of facility-specific emissions data beyond the Gerdau trial. See Appendix B for detailed analysis.

7.0 Directive E – Industrial and Transportation Emission Changes

Directive E requests estimation of how GH could influence emissions in key industrial and transportation sectors, assessed in relation to the targets outlined in the MI Healthy Climate Plan (MHCP). These sectors include activities where electrification faces technical or economic constraints, and where alternative decarbonization pathways may be needed. Emissions in this section are expressed in million metric tons of carbon dioxide equivalent ($MMTCO_2e$), a standard unit for comparing greenhouse gases based on their global warming potential. As Michigan evaluates the potential role of GH, understanding how its use may affect emissions in hard to decarbonize applications is important for assessing future mitigation pathways, technology options, and related policy considerations. The following discussion summarizes available information relevant to Directive E.

7.1 Hard-to-Decarbonize Emissions Context

The MHCP is Michigan's roadmap to achieve carbon neutrality by 2050 while addressing environmental injustices, improving public health, and spurring economic opportunity. While this report focuses on changes to emissions, to realize the goals of the MHCP, Michigan must also consider the potential impacts of GH on environmental justice communities and the broader environment.

Michigan's Comprehensive Climate Action Plan projects 16.30 $MMTCO_2e$ in hard-to-decarbonize emissions by 2050 (7.28 $MMTCO_2e$ industrial, 9.02 $MMTCO_2e$ transportation) where electrification faces fundamental technical or economic barriers. The MPSC Building and Process Electrification Study (October 2025) finds industrial electrification has a benefit-cost ratio of only 0.42 to 0.48, and high-temperature process heat exceeding 1,000°C cannot feasibly be electrified.

Geologic hydrogen addresses a different gap than electrification: it can serve as a chemical reductant in metallurgical processes, a feedstock in chemical manufacturing, or a combustion fuel for high-temperature process heat. This positions GH as complementary resource to electrification strategies.

7.2 Case Study Summary

This analysis evaluated hydrogen applications in two sectors: (1) industrial (iron/steel production and chemical manufacturing; see Appendix BBD) and (2) transportation (Great Lakes maritime high-relevance segments including tugs, ferries, and port equipment; see Appendix BBE).

Sector	Addressable Emissions ($MMTCO_2e$)	H_2 Demand (t/yr)	Net Reduction (Mid case, $MMTCO_2e$)	Percent Emissions Reduced
Iron & Steel	2.5	100,000	2.36	94%
Chemicals	1.5	150,000	1.29	86%
Maritime (HIGH)	0.075	7,500	0.065	86%
Combined Total	**4.08 $MMTCO_2e$**	**257,500**	**3.70 $MMTCO_2e$**	**91%**

Table 1. Combined Case Study Summary.

7.3 Key Findings

Industry: Approximately 4.0 $MMTCO_2e$ from steel production and chemical manufacturing could be addressed with 250,000 t H_2/year, eliminating 3.5 to 3.9 $MMTCO_2e$ (87 to 96 percent of addressable emissions).

Maritime: High-relevance segments (tugs, ferries, port equipment) account for 75,000 t CO_2e annually. Converting these would require 7,500 t H_2/year and could eliminate 60,000 to 71,000 t CO_2e (79 to 94 percent).

Policy Alignment: The Michigan Maritime Strategy (anticipated April 2026) identifies hydrogen among priority alternative marine fuels. Michigan is a MachH2 subrecipient, which identifies Great Lakes maritime as a priority end use.

7.4 Limitations and Caveats

These estimates reflect modeled scenarios for a limited set of industrial and maritime applications and should not be interpreted as a comprehensive assessment of hydrogen applications across Michigan's industrial or transportation sectors. The estimated reductions correspond to a portion of the state's projected hard-to-decarbonize emissions (16.3 MMTCO_2e by 2050) and depend on hydrogen resource characteristics, infrastructure requirements, and successful technology deployment. The applications examined could technically use any low-carbon hydrogen source. See Appendix B for key assumptions.

8.0 Directive F – Reuse of Existing Oil & Gas Well Infrastructure

Michigan's extensive oil and gas infrastructure may provide opportunities for reuse or modification if GH or SGH development were to occur. Most of this infrastructure is concentrated in the Lower Peninsula, where the thick sedimentary sequence of the Michigan Basin has supported approximately 60,000 wells drilled for oil and gas exploration with about 12,000 wells still producing. In contrast, the Upper Peninsula contains only about 14 historical wells that targeted oil and gas, reflecting its limited sedimentary cover and the exposure of Precambrian crystalline rocks across much of the Western Upper Peninsula. Without adequate reservoirs, seals, or salt deposits, the Upper Peninsula likely offers little potential for natural GH production from sedimentary reservoirs or UHS but may still present opportunities for SGH development. Within this broader context, the feasibility of repurposing existing infrastructure differs across Michigan and depends on both well integrity and the regional geologic conditions that affected oil and gas development and future GH prospectivity.

Given this variability, understanding hydrogen's physical and chemical behavior in subsurface and surface systems is essential when evaluating potential reuse of Michigan's existing oil and gas infrastructure. Hydrogen has properties distinct from natural gas (methane) and oil, including small molecular size, rapid diffusivity, high flammability, and the potential for hydrogen embrittlement. These characteristics directly influence the suitability of wells, reservoirs, and surface facilities for hydrogen service. Exposure to hydrogen can affect downhole tubulars, cement performance, zonal isolation, and above-ground equipment such as wellheads, compressors, flowlines, and processing systems. As a result, careful engineering assessment and proper planning would be necessary before converting existing wells, using depleted reservoir systems, or reusing surface infrastructure for hydrogen-related operations. Together, these factors highlight the need for hydrogen-specific technical and regulatory considerations in Michigan.

Earlier sections of this report discussed Michigan's geologic setting for GH resources (Section 3), the permitting frameworks that could apply to hydrogen development (Section 4), and technical research needs for evaluating hydrogen potential within the State (Section 5). Building on those discussions, this section examines how Michigan's existing wells and associated infrastructure could potentially be utilized or modified for hydrogen-related activities and identifies circumstances where new hydrogen-specific infrastructure may be required.

8.1 Properties of Associated Non-Hydrocarbon Gases

As discussed in earlier sections, interest in GH is increasing nationally, particularly in regions associated with the MCR. Active exploration is occurring in Kansas, Nebraska, Iowa, and Minnesota, and the MCR also extends into Michigan's Upper and Lower Peninsulas. Although no GH exploration is currently underway in Michigan, the geologic setting and recent findings from the U.S. Geological Survey's 2025 Professional Paper 1900 indicate that portions of the state exhibit some of the highest GH prospectivity in the country. Gas compositions encountered in other parts of the MCR provide useful analogs for what could accompany GH in Michigan.

One such example is a geologic helium (He) gas mixture recently discovered in northern Minnesota, which contained approximately 15 percent helium by volume and about 65 percent carbon dioxide (CO_2). While helium concentrations above about 0.3 mole percent are typically required for economic recovery, moderate helium concentrations may still be commercially viable when coproduced with GH. Carbon dioxide is also commonly associated with GH, geologic helium, and hydrocarbon systems, and its presence has operational, safety, and potential economic implications. CO_2 influences well design, corrosion control, and surface facility requirements, and in some cases may be managed through carbon utilization or geologic sequestration. Later sections of this report describe how the physical and chemical behaviors of H_2, He, and CO_2 affect well integrity, materials selection, and facility design relevant to hydrogen operations.

Hydrogen is the lightest element, existing under standard conditions as a colorless, odorless, tasteless, and non-toxic gas. It is highly flammable, forms explosive mixtures with air, and burns with a nearly invisible pale blue flame. Hydrogen also has a very low minimum ignition energy (approximately one-tenth that of methane), which increases susceptibility to ignition from static discharge or minor spark sources. Although hydrogen is not corrosive in a chemical sense, it can cause hydrogen embrittlement in susceptible metals such as certain steels, aluminum, and titanium alloys, reducing ductility and increasing the likelihood of cracking under stress. Embrittlement mechanisms may include hydrogen-induced cracking, stress-corrosion cracking, and related hydrogen-assisted degradation. While non-toxic, hydrogen can act as a simple asphyxiant by displacing oxygen in confined spaces. Hydrogen's extremely small molecular size, high diffusivity, and very low density (about 14.5 times lighter than air) allow it to migrate quickly and rise at high velocities. These characteristics contribute to increased leakage potential, permeation through seals and elastomers, degradation of rubber components, and the possibility of cement or sealant failure or annular pressure buildup in well systems. Hydrogen also has a wide flammability range of 4 to 75 percent in air, significantly broader than methane's range of 5 to 15 percent, which increases the importance of robust leak detection and ventilation in hydrogen-related operations.

Helium (He) is an odorless, non-toxic, colorless, and inert gas with extremely low chemical reactivity. Because helium atoms are small and non-reactive, the gas exhibits very high mobility and can migrate through micro-fractures, seals, and elastomers, similar to hydrogen. This high diffusivity can contribute to leakage pathways, seepage, and potential annular pressure buildup in well systems. However, unlike hydrogen, helium does not cause embrittlement in metals and does not degrade metallic mechanical properties. Its behavior in subsurface systems is controlled primarily by its mobility and buoyancy, rather than chemical interactions with materials. Helium also has extremely low solubility in water, further enhancing its tendency to migrate through porous and fractured geologic formations.

Carbon dioxide (CO_2) is a colorless, odorless, non-flammable gas at standard temperature and pressure and is approximately 1.5 times denser than air. It readily dissolves in water to form carbonic acid, which can accelerate corrosion in carbon-steel components used in wells, pipelines, and surface equipment. Although non-flammable, CO_2 can displace oxygen and create asphyxiation hazards in confined or low-lying areas. Carbon dioxide is also commonly associated with GH and geologic helium systems, and its presence has operational implications for materials selection, corrosion control, well design, and surface facility requirements. Industrial hydrogen is often produced using natural gas through steam methane reforming (SMR), generating CO_2 as a byproduct. Hydrogen produced through this pathway is classified as "gray hydrogen" when the CO_2 is released to the atmosphere, or "blue hydrogen" when the CO_2 is captured and geologically sequestered. In deep subsurface environments, CO_2 may also exist in a supercritical state, which affects its flow behavior, density, and interactions with reservoir materials.

Recommendation:

When evaluating best practices for GH / SGH exploration, production, or hydrogen storage, design considerations should incorporate the behaviors and material impacts of helium and carbon dioxide in addition to hydrogen. These gases may be present in subsurface accumulations or produced streams and should be addressed when assessing well integrity, casing and cement performance, and surface facility design.

8.2 Metallurgical and Material Compatibility Considerations

Hydrogen service introduces material compatibility challenges that must be considered when evaluating both existing and newly constructed infrastructure. Hydrogen embrittlement occurs when atomic hydrogen diffuses into certain metals, reducing ductility and increasing susceptibility to cracking under stress. This phenomenon is particularly relevant for high-strength steels commonly used in oil and gas infrastructure.

Appropriate materials selection is therefore critical for wells, flowlines, and pressure-containing equipment exposed to hydrogen. Austenitic stainless steels, aluminum alloys, copper alloys, and certain lower strength steels are generally more resistant to hydrogen-related degradation under appropriate operating conditions. Low-strength steels such as API 5L PSL2 Grades X42 and X52 are commonly suggested for gaseous hydrogen transportation because of their reduced susceptibility to hydrogen embrittlement. Protective coatings or liners may also reduce hydrogen diffusion into metallic components and extend equipment service life. Advanced surface treatments, such as aluminum or ceramic coatings, can also limit hydrogen ingress and extend tubular performance.

In well applications, certain API-5CT casing and tubing grade, including L80, C90, T95, and C110, are generally more suitable for hydrogen-rich environments, while carbon-steel grades such as J55 or K55 may be adequate only in low pressure or non-corrosive service conditions. Existing oil and gas infrastructure was designed primarily for hydrocarbon service and may not meet all requirements for hydrogen operations. Components such as valves, seals, compressors, and flow-measurement devices may also require evaluation or replacement to ensure compatibility with hydrogen-rich gas streams, if piping/casing is deemed appropriate for use.

In addition to metallic systems, non-steel pipeline alternatives such as Fiber-Reinforced Polymer (FRP) and Thermoplastic Composite Pipe (TCP) offer corrosion resistance and are not susceptible to hydrogen embrittlement, making them suitable for certain hydrogen transport applications. These materials may also provide advantages where both hydrogen and carbon dioxide are present. When CO_2 is part of a produced or transported stream, carbonic acid formation can aggressively corrode conventional carbon steels. Therefore, FRP, TCP, and other non-metallic materials may offer dual benefits for infrastructure operating in mixed hydrogen–CO_2 environments.

Industry standards such as ASME B31.12 (Hydrogen Piping and Pipelines) and NACE MR0175 / ISO 15156 provide guidance for materials used in hydrogen environments and may serve as references when evaluating infrastructure modifications. For CO_2 service, ASME B31.4 is the primary design code for CO_2 pipelines, and API RP 1192 (2025) provides additional guidance relevant to design and operation.

Recommendation:

Hydrogen piping and pipelines should follow the guidance provided in ASME B31.12 (Hydrogen Piping and Pipelines) and NACE MR0175 / ISO 15156 for materials selection in hydrogen rich and cracking susceptible environments. Since carbon dioxide may be associated with GH production, ASME B31.4 and API RP 1192 should be consulted for CO_2 containing systems. Where operational conditions permit, non-metallic materials such as FRP and TCP should be considered, as they are not susceptible to hydrogen embrittlement and may provide additional protection where CO_2-induced corrosion is also a concern.

8.3 Cement Requirements and Well Integrity

Cementing recommendations for GH and SGH wells would prioritize long-term zonal isolation. Traditional Portland cement systems may be susceptible to mechanical fatigue under cyclic pressure conditions that can occur during hydrogen production and are especially significant in storage applications. Recent studies generally indicate limited abiotic reactions between hydrogen and traditional oil-well cements under typical subsurface conditions. However, research findings regarding the effects of hydrogen exposure on cement sealing performance and mechanical properties such as compressive strength, porosity, and permeability remain mixed. Some studies suggest potential reductions in external mechanical integrity, while others report minimal change or indicate changes in permeability that could increase or decrease gas or fluid migration through the cement matrix.

Recommendations for cementing GH and SGH wells emphasize cement systems that can withstand cyclic stress and limit potential leakage pathways. API Class G cement is commonly used because its finer grind produces a denser matrix with improved resistance to gas migration. Additives that enhance crack-sealing behavior can reduce long-term leakage risks, while elastomer-modified or lower-modulus systems can better tolerate thermal and mechanical cycling without cracking. Ultrafine particles or gel-forming materials may also be incorporated to seal pore throats and restrict hydrogen transport. Legacy wells considered for reuse should undergo evaluation of casing conditions, cement bonding, and historical construction records to determine whether remediation or workover is required to ensure long-term integrity.

Current best practices reference standards such as API Spec 10A for cement and material specifications and API RP 10B-2 for testing and evaluation of well cements under downhole conditions. Although API RP 1170 and API RP 1171 were developed for underground natural gas storage, many of its core well-integrity and monitoring principles, such as cement performance verification, pressure monitoring, and mechanical-integrity testing, offer practical analogs that could help guide the development of hydrogen storage requirements. These natural gas-based practices provide a useful foundation for identifying performance expectations and risk-management approaches that may be adapted for future hydrogen-specific regulations.

Recommendation:

Best practices for cementing hydrogen wells should follow API Spec 10A and API RP 10B-2 and draw on relevant cementing and mechanical-integrity testing concepts from API RP 1170 and 1171 until hydrogen-specific standards are developed. Legacy wells should be evaluated for casing condition, cement bonding, and proper cement placement, including confirmation that cement extends through and above key confining units to ensure reservoir isolation and protection of USDWs. Well designs should also account for cyclic pressure conditions and the potential for microcrack development, and cement systems should incorporate materials and additives that support durable, long-term zonal isolation in hydrogen-rich environments.

8.4 Repurposing Oil and Gas Wells for Hydrogen Operations

Existing oil and gas wells in Michigan may provide opportunities for limited reuse in GH or SGH development, provided that well integrity, construction design, and formation suitability are carefully evaluated. The Lower Peninsula contains a large inventory of legacy wells associated with historical hydrocarbon exploration and production within the Michigan Basin. Some of these wells may offer potential value for hydrogen-related activities, including exploratory production testing, reservoir evaluation, or monitoring of subsurface conditions.

Reuse of existing wells for hydrogen production requires verifying that well construction and materials meet the hydrogen-related criteria established in earlier sections. Evaluations should confirm that the well's design, condition, and barrier systems provide adequate long-term containment, based on review of construction records, documented repairs, and appropriate integrity testing.

Existing wells may also be suitable for subsurface monitoring in GH or SGH projects where depth, completion interval, location relative to the target reservoir and confining units, and overall wellbore condition are appropriate. Monitoring wells positioned above a confining formation can provide useful information on seal performance and potential migration pathways. In SGH systems, which may involve elevated temperatures, reactive fluids, or pressure cycling, monitoring wells can support evaluation of reservoir response and containment, but these conditions may further limit reuse of legacy wells and may require remediation or recompletion before use

Recommendation:

Existing wells should be reused only after a comprehensive engineering evaluation confirms that construction, materials, and zonal isolation satisfy the hydrogen-related criteria described earlier. Wells that do not meet these standards should be remediated or properly plugged to prevent potential gas migration.

8.5 Utilization of Existing Oil and Gas Infrastructure

Existing oil and gas well sites often contain surface infrastructure that offer opportunities for partial reuse in GH or SGH operations. Typical wellsite infrastructure includes wellheads, separators, tank batteries, dehydration units, and short flowlines that transport produced fluids and gases. Reuse of portions of this infrastructure could reduce development costs and minimize additional land disturbance where suitable facilities already exist. Prior to reuse, operators must evaluate whether existing equipment can safely support hydrogen-related operations. While site features such as well pads, access roads, electrical service, and structural foundations are often suitable for reuse, pressure-containing equipment and gas handling components may require modification or replacement due to hydrogen's material compatibility and leakage characteristics. Infrastructure reuse may also depend on the intended application, as natural GH production may involve multi-gas streams requiring specialized separation equipment. SGH systems may also require additional surface equipment for injection and pre-treatment processes, such as chemical mixing units or heating equipment that support subsurface reaction processes.

Converting existing oil and gas surface storage and processing infrastructure for hydrogen service is generally not feasible. Because of hydrogen's small molecular size and physical behavior at surface conditions, most existing facility piping, compressors, and atmospheric or low-pressure storage tanks are unsuitable for hydrogen handling without substantial modification. While hydrogen can be transported and stored as a gas, doing so requires leak tight components, materials compatible with hydrogen service, and equipment rated for high pressures. These requirements typically replace legacy equipment with components qualified for hydrogen service.

Repurposing existing oil and gas pipelines for hydrogen transport provides notable benefits. Costs are estimated at approximately 53 to 82 percent of new construction, and using established corridors avoids the land disturbance and permitting challenges associated with greenfield development. Converting the network to hydrogen could reduce pipeline-related emissions by up to 99 percent and decrease the overall life-cycle climate impact by approximately 90 percent. Additionally, most natural gas systems can already transport hydrogen blends of up to 20 percent by volume with minimal modification.

While repurposing existing pipelines can extend the useful life of stranded assets, it introduces significant material and operational challenges. Hydrogen's small molecular size increases leakage potential and its tendency to cause embrittlement in certain steels raise long-term integrity concerns. In addition, hydrogen has only one-third the energy content of natural gas by volume, meaning transporting an equivalent amount of energy requires roughly three times the volume, which may exceed current pipeline capacities. Standard compressors, valves, and meters are often unsuitable because hydrogen's low molecular weight reduces equipment efficiency and increases leakage risk. Safety risks also differ from natural gas: hydrogen ignites more easily, has a wider flammability range (4 to 75 percent in air), and burns with a flame that is nearly invisible, complicating detection during operations or emergency response activities.

Repurposing natural gas pipelines for pure hydrogen requires abandonment authorization from the Federal Energy Regulatory Commission under NGA section 7b. Modifications typically include replacing compressors, valves, and seals with materials compatible with hydrogen and upgrading leak detection, monitoring, and emergency shutoff systems to address hydrogen's higher diffusivity and flammability. Operators may also need to conduct integrity assessments to evaluate susceptibility to hydrogen embrittlement and confirm that pipeline pressure ratings, wall thickness, and weld quality are adequate for hydrogen service. In some cases, inline inspection tools designed specifically for hydrogen environments may be required. As part of the Governor's Executive Directive No. 2026-1, the Michigan Public Service Commission (MPSC) has taken the lead in analyzing the suitability of existing pipeline infrastructure, safety requirements, system constraints, necessary upgrades, and related planning issues. Readers should refer to MPSC's report for the Executive Directive for more in-depth pipeline information.

Recommendation:

Existing well-site infrastructure may be reused where equipment compatibility and safety requirements can be demonstrated. Operators should evaluate surface equipment and flowlines to confirm that they are suitable for hydrogen-related operations, and infrastructure that cannot meet these requirements should be modified or replaced to ensure safe operation. Operators should also upgrade leak-detection, flame-detection, and emergency-shutoff systems to account for hydrogen's higher diffusivity, wider flammability range, and nearly invisible flame.

8.6 Reuse of Existing Salt Caverns and Depleted Reservoirs

As interest grows in the potential use of hydrogen as an energy source, the ability to store significant volumes of hydrogen to ensure supply availability will be a critical factor. Subsurface storage in salt caverns or depleted reservoirs can provide several advantages over aboveground storage, including the ability to store significantly larger quantities of gas while limiting surface infrastructure requirements. Where suitable conditions exist, repurposing existing underground storage resources may provide significant cost reductions compared to developing new infrastructure.

Michigan has 47 active underground natural gas storage (UNGS) fields; all located within the Lower Peninsula. With the exception of two solution-mined salt cavern facilities, these fields utilize depleted oil or natural gas reservoirs that have supported UNGS operations for decades. These facilities demonstrate that portions of the subsurface possess the geologic conditions necessary for long-term storage of buoyant gases, including suitable reservoir properties, structural closure, and competent confining formations. This existing infrastructure provides an important starting point for evaluating whether some storage fields or caverns could be repurposed for hydrogen storage applications

8.6.1 Salt Caverns

Effective containment and storage of hydrogen in solution-mined salt caverns have been demonstrated for several decades and are widely regarded as the most technically viable geologic option for UHS. Early operations began in the United Kingdom in the early 1970s, followed by facilities along the U.S. Gulf Coast in 1983, with more recent developments in Europe, including the Etrez hydrogen storage site in France. Because drilling and solution mining for a new cavern can cost approximately 20 to 40 million dollars per cavern and often represent 40 to 60 percent of total project capital cost, repurposing existing solution-mined caverns, where suitable conditions exist, may provide substantial cost savings by avoiding much of the cavern creation required for new storage facilities. In addition, large-scale hydrogen storage in salt caverns is likely several times less expensive than comparable surface storage systems for storing large gas volumes.

Michigan contains extensive layered salt deposits in the Salina and Detroit River Groups that occur across much of the Lower Peninsula, making the state well-situated for salt cavern storage. Currently, 47 solution-mined salt caverns are actively used for the storage of natural gas and liquefied petroleum gases, demonstrating the suitability of these solution-mined caverns for subsurface storage. Salt formations are highly favorable for hydrogen storage because they exhibit extremely low permeability, are non-reactive with hydrogen, exhibit self-healing behavior that facilitates the closure of micro-fractures, have high mechanical strength and ductility, support rapid and repeated injection and withdrawal cycles, and have defined boundaries that reduce offsite migration risks compared to traditional reservoirs.

However, repurposing existing hydrocarbon storage caverns for hydrogen service would require a thorough evaluation of cavern integrity, possibly including sonar surveys, pressure-testing, and other engineering assessments. The allowable pressure range for hydrogen storage would also need to be evaluated to ensure cavern operations remain within safe limits to maintain storage integrity. Additional reviews would need to evaluate well construction and infrastructure compatibility and potential interactions between hydrogen and residual hydrocarbons/stored product. Furthermore, the layered salt deposits in Michigan may introduce additional considerations for hydrogen storage due to variable salt-unit thickness, impurities, and interbedded lithologies that could affect containment. These evaluations are particularly important given hydrogen’s higher diffusivity and mobility compared to methane, which may require updated monitoring practices, operational controls, or regulatory guidance to ensure adequate containment and long-term performance. Finally, many salt caverns in Michigan were originally created through solution mining for commercial salt production and were later repurposed for hydrocarbon storage. Caverns currently used for natural gas or LPG storage have generally undergone thorough engineering evaluations for cavern integrity, including roof beam thickness, cavern geometry, and overall structural stability. In contrast, older abandoned caverns, or those never utilized for storage, would require a full evaluation against established cavern development and storage criteria referenced in industry-accepted practice, such as API RP 1170, API RP 1114, and API RP 111, until hydrogen-specific requirements are established.

8.6.2 Depleted Hydrocarbon Reservoirs

Although recent studies have reported encouraging results regarding the potential use of depleted hydrocarbon reservoirs for hydrogen storage, additional research and field-scale testing are still needed to confirm long-term technical and operational viability. Both existing UNGS fields and other depleted oil or gas reservoirs may represent potential candidates for hydrogen storage. However, depleted natural gas reservoirs are considered more favorable candidates than depleted oil reservoirs because they have already demonstrated the ability to store compressible gases and typically contain minimal residual oil phases that could influence hydrogen storage performance or recovery.

In Michigan, most UNGS fields are associated with Niagaran reef reservoirs. These isolated, steep-sided pinnacle reef buildups contain high-porosity reservoir intervals that are overlain laterally and vertically by evaporite-rich formations functioning as competent confining units and are often described as “naturally occurring storage compartments.” Decades of UNGS operations in these reservoirs have generated extensive data on reservoir pressure behavior, seal performance, and well integrity. While these characteristics may make certain reef reservoirs attractive candidates for evaluating hydrogen storage potential, verification would still be required to confirm that the confining formations and sealing mechanisms that successfully contain natural gas are also capable of preventing hydrogen migration under hydrogen storage conditions.

Hydrogen storage in depleted reservoirs introduces additional uncertainties that require careful evaluation. These include potential mixing between injected hydrogen and residual hydrocarbons, management of existing cushion-gas volumes, and the presence of legacy wells that could act as migration pathways, particularly in storage fields where well densities may be relatively high. Because porous-reservoir seals are typically composed of shale, carbonate, or evaporite units rather than the essentially impermeable salt formations used for cavern storage, verification of caprock sealing capacity and hydrogen migration potential is also necessary. Reservoir conditions may also support microbial processes capable of consuming hydrogen or altering gas composition, including methanogenesis or sulfate reduction, which could impact hydrogen recovery efficiency, gas purity, and corrosion risks. These factors may require enhanced monitoring of gas composition, reservoir-pressure behavior, and well integrity during hydrogen storage operations to confirm storage performance and long-term containment.

Recommendation:

Existing solution-mined salt caverns currently used for natural gas or liquefied petroleum gas storage, may represent the most practical initial opportunities for evaluating UHS in Michigan. However, conversion of these caverns to hydrogen service would require detailed assessment of cavern integrity, allowable operating pressure ranges, presence/effects of residual hydrocarbons, compatibility of well construction and infrastructure with hydrogen service, and effectiveness of layered salt formations in maintaining containment. API RP 1170, which governs functional integrity for natural gas storage in solution-mined caverns, may provide interim guidance for hydrogen storage assessments. Similarly, API RP 1114 and 1115, although intended for liquid hydrocarbon storage, offer applicable guidance on considerations for cavern design, pressure management, integrity monitoring, and operational controls.

Depleted oil and gas reservoirs and existing underground natural gas storage fields may also be considered for hydrogen storage but introduce greater uncertainties than salt caverns. Repurposing these reservoirs would require more extensive evaluation of reservoir and caprock integrity, legacy well conditions, residual hydrocarbons, and the compatibility of well construction and surface facilities with hydrogen service. Additional considerations include cushion-gas suitability, expected injection and withdrawal cycles, gas-quality monitoring needs, and the potential for stimulating microbial reactions that could alter gas composition, decrease reservoir performance, or contribute to corrosive conditions. API Recommended Practice 1171, which addresses depleted-reservoir storage of natural gas, may serve as an interim reference for integrity monitoring, evaluation, and risk management until hydrogen-specific guidance is available.

8.7 Stimulated Hydrogen Production in Depleted Reservoirs

Technical research has explored the potential for generating hydrogen within depleted or inactive hydrocarbon reservoirs. One concept involves bio-stimulation, where water, nutrients, or other amendments are injected into a depleted reservoir to stimulate indigenous microbial communities capable of producing hydrogen through metabolic interactions with residual hydrocarbons or reservoir fluids under favorable geochemical conditions. Hydrogen generated within the reservoir could potentially accumulate in the gas phase and be recovered through conventional production wells and associated infrastructure

Although these concepts show promise, they remain in early-stage development, and bio-stimulation has not yet been demonstrated at commercial scale. Uncertainties remain regarding achievable hydrogen production rates, reservoir response to stimulation, and the potential for competing microbial pathways that could consume hydrogen or alter gas composition. Significant co-production of hydrogen with economic quantities of hydrocarbons is unlikely because hydrogen is highly reactive in reservoir environments and is typically consumed through competing microbial and geochemical processes. Additionally, as discussed in previous sections, many depleted reservoirs contain legacy wells that may present potential leakage pathways and would require careful evaluation of well construction records, cement condition, and casing and wellbore integrity to ensure that stimulation activities do not create unintended migration pathways for hydrogen or other gases.

Recommendation:

As discussed in Section 3, Michigan's Part 615 and Part 625 regulations do not explicitly address hydrogen production. Therefore, although bio-stimulation in depleted reservoirs is not currently utilized in Michigan, any future application would require evaluation of the appropriate regulatory framework based on the project's design and primary purpose. Because bio-stimulation involves injection, additional UIC regulatory requirements may be applicable depending on the proposed injectate, injection criteria, and project design parameters. Additional statutory or regulatory provisions may be needed to establish standards for well construction, injection practices, production operations, and monitoring requirements. Such projects would also require careful evaluation of legacy wells and reservoir integrity to ensure stimulation activities do not create unintended migration pathways for hydrogen or other gases and that appropriate environmental safeguards are maintained.

8.8 Monitoring, Safety, and Best Practices for Hydrogen Operations

Hydrogen (H_2), helium (He), and carbon dioxide (CO_2) present distinct safety challenges that depend on their physical properties and the operational environment. As described in Section 8.1, these gases differ significantly in mobility, density, and interaction with materials, and these differences directly inform monitoring, detection, and protective measures. All three exist as free gases at surface conditions and require compression for storage, introducing additional pressure-containment and hazard-prevention considerations.

8.8.1 Hydrogen

Hydrogen is highly flammable, has an extremely low minimum ignition energy, and burns with a nearly invisible flame. Its flame produces little radiant heat and no soot, making identification difficult without specialized detection equipment. Hydrogen can ignite at concentrations between 4% and 75% in air, and because it is colorless and odorless, releases are not detectable by human senses. Continuous hydrogen and oxygen monitoring is therefore essential in areas where hydrogen is handled.

Thermal imaging devices or dedicated flame detectors may be used to identify hydrogen flames, and small leaks may be located using approved soap-solution techniques. Hydrogen's compatibility with metals must also be considered: certain steels and alloys can experience hydrogen embrittlement, which can lead to cracking or structural failure.

Material selection should follow the compatibility guidance provided in Section 8.2 and may include austenitic stainless steels or other hydrogen compatible alloys depending on operating conditions. Hydrogen, which is approximately 14 times lighter than air, disperses rapidly due to its low density, reducing the likelihood of accumulation in open environments. For this reason, hydrogen-handling equipment should generally not be placed in enclosed structures unless specifically engineered with adequate ventilation and safety systems to maintain safe operating conditions. Flame-resistant and anti-static clothing are also recommended to minimize ignition risks.

8.8.2 Carbon Dioxide (CO2)

Carbon dioxide presents both asphyxiation and physiological hazards. Although non-flammable, CO_2 can produce significant health effects even when oxygen is still Present in the air. OSHA's permissible exposure limit (PEL) is 5,000 ppm (0.5 percent) averaged over an eight-hour period. Moderate concentrations can cause headaches, increased respiration, and drowsiness, while higher concentrations may lead to confusion, rapid breathing, elevated blood pressure, and cardiac arrhythmia.

Because CO_2 is approximately 1.5 times heavier than air, it tends to accumulate in low-lying areas such as pits, basements, and enclosed spaces, creating oxygen-deficient conditions. This makes continuous or portable oxygen-deficiency monitoring essential in areas where CO_2 may be present. Contact with rapidly expanding CO_2 gas or solid CO_2 (dry ice) can also result in severe frostbite or cold-related injuries.

8.8.3 Helium (He)

Helium is chemically inert, non-flammable, and non-toxic, but it poses an asphyxiation hazard by displacing oxygen in confined or poorly ventilated spaces. Because helium is significantly lighter than air, it can migrate upward and accumulate near ceilings or high points within enclosed structures. Continuous or portable oxygen monitoring is therefore recommended in any location where helium releases may occur.

As noted in Section 8.1, He has a very high mobility due to its atomic size, which can allow it to migrate through seals, elastomers, and micro-fractures more readily than many other gases. This property can lead to subtle leak pathways or contribute to annular pressure variations in well systems. Although helium does not cause metal embrittlement or chemical degradation, its ability to escape through small openings warrants careful attention to sealing materials, joint integrity, and wellhead components

Personnel working around helium systems should be aware of the potential for rapid oxygen displacement in enclosed areas and ensure proper ventilation and oxygen monitoring are in place. Cryogenic helium handling (e.g., liquid helium) requires cold-weather protective equipment due to significant frostbite hazards, although such conditions are unlikely in most GH/SGH-related field operation

8.8.4 PPE for Hydrogen Wellsite's and Compressed Gas Facilities

Personnel inspecting wellsite's or facilities that handle hydrogen, carbon dioxide, or helium as compressed gases, including potential atmospheric releases, must wear portable, calibrated personal gas monitors in the breathing zone to identify oxygen-deficient atmospheres, or hazardous gas concentrations. When working near hydrogen production or storage operations, anti-static and flame-resistant clothing is essential due to hydrogen's low ignition energy and sensitivity to static discharge; synthetic materials that generate static, such as nylon or silk, should be avoided.

Standard PPE for Field Inspections:

- Wear a portable, calibrated personal gas monitor
- FR clothing
- Hard hats
- Eye protection (safety glasses with side shields or goggles)
- non-conductive steel-toed safety boots
- Hearing protection in high-noise environments.

Recommended GRMD-Specific PPE Procedures or Equipment:

- Eagle II low-level monitors configured for hydrogen detection using approved correction factors.
- GRMD's 4-gas meters can measure hydrogen similarly to methane when calibrated with hydrogen-specific calibration gas.
- Where higher-sensitivity leak detection is required, dedicated hydrogen meters capable of parts-per-million detection are commercially available and typically cost approximately $500 per unit.

8.8.5 Specialized Hydrogen PPE for Cryogenic Facilities (LH2 or LCO2)

Cryogenic hydrogen (LH_2) and cryogenic carbon dioxide (LCO_2) systems can present significant frostbite and cold burn hazards due to the extremely low temperatures of these liquids and their associated vapor clouds. Although cryogenic systems are unlikely to be encountered in GH or SGH field operations in Michigan, and no such activities have yet been initiated, the following precautions are included for completeness and to address potential future applications involving cryogenic hydrogen handling or storage.

Specialized Cryogenic PPE:

- Increased awareness of potential cold-surface hazards on piping, valves, or fittings exposed to cryogenic fluids or expanding CO_2 gas.
- Full face shield worn over impact-rated goggles to protect against splashes or cold vapor exposure.

- Wear cryogenic-rated, insulated gloves that remain flexible at low temperatures and are loose-fitting to allow quick removal if contaminated by liquid.
- Utilize oxygen-deficiency monitoring in areas where cryogenic releases may displace oxygen.
- Respiratory protection (SAR or SCBA) when required by a site-specific hazard assessment in confined or poorly ventilated spaces.
- Cryogenic-rated apron to protect the torso during transfer, venting, or disconnection activities.

8.8.6 Summary of Hydrogen Operation Hazards and Field Guidance

Field personnel should evaluate site hazards based on gas behavior, operational conditions, and equipment configuration. Although hydrogen, carbon dioxide, and helium hazards are described in detail in Section 8.8.1 through 8.8.3, the following summary provides practical guidance for field inspections and hydrogen-related operations.

Hydrogen Specific Hazard Considerations – Hydrogen represents the highest operational risk due to its extremely low ignition energy, invisible flame, and wide flammability range. Field evaluation and methodology should focus on:

- Identifying potential ignition sources, including static discharge
- Verifying adequate ventilation in areas where hydrogen may accumulate
- Assessing leak-detection systems and continuous monitoring equipment
- Confirming the use of anti-static and flame-resistant clothing
- Ensuring enclosed structures are avoided unless engineered for hydrogen service

Carbon Dioxide Hazard Considerations – Carbon dioxide is a heavy gas that may create oxygen-deficient conditions in low-lying or confined spaces. Field personnel should be aware of and prepared for the following safety considerations:

- Potential for CO_2 accumulation in pits, basements, cellars, or trenches.
- Confirming that oxygen-deficiency monitors are in use and correctly calibrated
- Identifying cold expansion/cryogenic hazards during venting or depressurization of CO_2 systems
- Use of insulated gloves and eye protection

Helium Hazard Considerations – Helium is non-flammable but can displace oxygen and migrate through seals or confined spaces due to its high mobility. Field personnel should be aware of and prepared for the following safety considerations.

- Oxygen-monitoring required in enclosed areas
- Potential issue with equipment sealing integrity and subtle leak pathways
- Helium migration potential along wellbores and effects on annular pressure or wellhead components.

Recommendations:

EGLE should update existing inspection policies and safety procedures to address hydrogen specific considerations at wells, surface facilities, and repurposed infrastructure. Field staff should receive training on hydrogen and helium hazards, including monitoring equipment, leak detection practices, oxygen deficiency risks, and emergency response measures. These topics can be incorporated into annual 8-hour HAZWOPER refresher training to ensure ongoing competency and alignment with evolving hydrogen safety practices.

Staff training for hydrogen operations must be grounded in established hydrogen safety standards and recognized guidance materials, some of which are summarized below. Additional or more specialized resources may also be appropriate depending on the nature or extent of GH or SGH development that occurs in Michigan.

- ANSI/AIAA G095A-2017, *Guide to Safety of Hydrogen and Hydrogen Systems*, foundational reference for hydrogen properties, hazards, system design, detection, emergency procedures, and training.
- ANSI/AIAA G095A-2017, *Guide to Safety of Hydrogen and Hydrogen Systems*, provides a comprehensive foundation on hydrogen properties, system-level hazards, mitigation strategies, and operational safety practices.
- NFPA 2, the *Hydrogen Technologies Code*, establishes requirements for the generation, storage, transfer, piping, and use of both gaseous and liquid hydrogen.
- OSHA 29 CFR 1910.103 outlines federal safety requirements for gaseous and liquefied hydrogen systems, including equipment design, installation, and protective measures.
- ASME Boiler and Pressure Vessel Code (Section VIII, Division 3) and ISO 15869 address high-pressure hydrogen storage vessel design, pressure integrity, and performance under service conditions.
- ASME B31.12 (2023), *Hydrogen Piping and Pipelines*, specifies materials, design, fabrication, and inspection requirements for hydrogen piping systems, emphasizing embrittlement-resistant materials, leak-tight construction, and safe operation under high-pressure and cryogenic conditions.

8.9 Considerations and Strategies for Repurposing Infrastructure

The feasibility of reusing Michigan's existing oil and gas infrastructure for GH or SGH development depends on well integrity, materials compatibility, geologic suitability, and the operational requirements of hydrogen service. Early planning should also evaluate whether candidate locations offer viable pathways for hydrogen storage, transportation, and near-site utilization, including access to existing storage formations, feasible pipeline corridors, and end-use markets. Earlier subsections provide the detailed technical basis for these considerations. This subsection summarizes high-level strategies that can guide early screening and decision-making when evaluating whether legacy infrastructure may be suitable for hydrogen-related activities.

1. **Prioritize infrastructure with known construction quality and verifiable integrity.**
   Wells, pipelines, caverns, and surface facilities with complete construction records, accessible integrity data, and modern materials present the strongest candidates for repurposing. Legacy assets with uncertain history, inadequate well construction documentation, or evidence of degradation typically require remediation or replacement before hydrogen service is considered.

2. **Focus reuse on components least affected by hydrogen's unique properties.**

   Surface features like pads, access roads, utilities, and rights-of-way are often suitable for reuse and can significantly reduce land disturbance and overall project footprint. However, pressure containing components generally require replacement due to the hydrogen-related compatibility and integrity issues outlined earlier. Reuse strategies should differentiate low risk site infrastructure from high-risk containment equipment.

3. **Consider location suitability and system needs early in project planning.**

   Reuse potential varies across Michigan due to differences in geology, legacy development, and infrastructure needs. Early screening should assess proximity to suitable storage formations, feasible transportation corridors, and potential end-use markets, as these factors strongly influence project viability.

4. **Identify subsurface infrastructure most likely to support hydrogen storage**

   Existing solution-mined salt caverns remain the most feasible near-term reuse option for hydrogen storage, and repurposing could reduce startup costs by roughly 20–40% depending on cavern condition and required upgrades. Depleted reservoirs may also be considered, but reuse strategies must address uncertainties in sealing performance, residual fluids, microbial activity, and legacy well integrity. Reservoirs with strong integrity records and proven containment offer the best candidates for future evaluation.

5. **Recognize that SGH development requires well-characterized reservoir conditions**

   Only depleted reservoirs with strong geologic and well integrity data may be suitable for small-scale SGH pilots due to the additional uncertainties associated with stimulated hydrogen generation.

6. **Assess pipelines and gathering lines for potential reuse in hydrogen service**

   Pipelines beyond the point of sale are outside of EGLE's regulatory purview and fall under the jurisdiction of MPSC and PHMSA. Within this context, pipelines may offer opportunities for reuse if hydrogen or blended gas streams meet applicable technical and safety criteria. Any repurposing effort should include an evaluation of pipeline condition, material compatibility, and allowable blending limits. Planning should also consider the deliverability and capacity of existing gathering or distribution lines to ensure they can meet project needs under hydrogen service. Opportunities to utilize existing gathering systems through strategic partnerships may also help reduce development costs and avoid the regulatory delays associated with constructing new infrastructure.

7. **Evaluate Upgraded monitoring, detection, and safety requirements during reuse planning**

   When repurposing wells, surface facilities, salt caverns, or depleted reservoirs for hydrogen-related operations, early planning should account for the need to enhance site monitoring systems, integrity tracking, and safety equipment. This may include improvements to pressure and temperature surveillance, annular monitoring, hydrogen-capable gas and flame detection, and other instrumentation necessary to maintain storage integrity. Field operations should also emphasize appropriate PPE and safety practices consistent with the guidance summarized in Section 8.8.

9.0 Geologic Hydrogen Summary and Path Forward for Michigan

Michigan's geologic setting, including the MCR's mafic and ultramafic basement rocks and the Michigan Basin's thick sedimentary sequence with laterally extensive reservoir units and confining formations, particularly the significant bedded salt deposits of the Lower Peninsula, provides a credible foundation for evaluating GH and SGH prospectivity. While overall resource potential remains uncertain, the state's long history of subsurface resource development, robust oil and gas infrastructure, accessible geologic datasets, and considerable underground storage capacity position Michigan to assess these opportunities in a controlled, evidence-based manner. At the same time, hydrogen's distinct physical and chemical properties, together with the fact that naturally occurring hydrogen was not historically contemplated in Michigan's oil, gas, or mineral statutes, highlight the need for clearer and more explicit regulatory coverage than currently provided under Parts 615 and 625.

Moving forward, Michigan's most immediate needs involve regulatory clarity, well-integrity and safety standards, and explicit authority for hydrogen exploration, production, and storage. Near-term legislative updates should define non-hydrocarbon gas wells, recognize GH and SGH activities under statute, and establish permitting, financial assurance, and resource-management provisions adequate to prevent waste and protect correlative rights. Statutory clarification should encompass hydrogen and other non-hydrocarbon gases, including helium, to ensure consistent regulatory treatment and prevent future ambiguity. Additional rulemaking should anticipate the need to incorporate hydrogen-specific well design, construction, integrity testing, and monitoring standards as scientific understanding and industry best practices continue to develop. Depending on how SGH well and hydrogen storage wells are ultimately classified, coordination with the EPA and alignment with applicable UIC requirements may also be necessary.

At the technical level, Michigan should pursue a phased research and development strategy that builds a consistent statewide data foundation, advances high-resolution characterization of Rift-related basement rocks and Michigan Basin reservoir and seal systems, and supports laboratory evaluations of hydrogen generation and containment. This work should include reassessment of legacy cores and logs, standardized hydrogen-focused sampling during drilling, and early screening of salt formations for potential cavern storage while evaluating porous formations as evidence warrants. Opportunities to reuse existing wells, sites, pipelines, and caverns should be considered cautiously and only where hydrogen-compatible materials and verified integrity can be demonstrated. As this staged approach progresses, combining regulatory updates, and targeted research, Michigan can integrate emissions findings and sector-level insights from Sections 6 and 7 to ensure that any future GH or SGH development provides measurable environmental benefits while maintaining protection of natural resources, public health, and safety.

10.0 Appendices

10.1 Appendix A – Michigan Geological Survey Technical Resource Evaluation

10.1.1 Appendix A-1 – Statement of Technical Research Needs

Statement of Technical Research Needs to Advance Michigan's Geological Hydrogen Exploration and Preparedness Initiative

Prepared by: Michigan Geological Survey

Michigan's subsurface geology positions the state as one of the most promising regions in the United States for natural geologic hydrogen generation and geologic hydrogen storage, offering strategic opportunities to support statewide decarbonization, energy independence, and the goals of the MI Healthy Climate Plan. The Executive Order establishing the Michigan Geological Hydrogen Exploration and Preparedness Initiative calls for identifying the technical research needed to understand and responsibly develop geologic hydrogen resources.

This statement outlines the research priorities necessary to evaluate three key areas, with emphasis on targeted scientific investigations, data needs, and coordinated statewide research infrastructure:

1. ***Geologic hydrogen*** – also called natural hydrogen or white hydrogen, is hydrogen generated within the subsurface by naturally occurring geochemical processes, without human intervention
2. ***Stimulated hydrogen*** – also called orange hydrogen, is artificially produced in the subsurface by accelerating or inducing natural hydrogen-generating reactions through engineered interventions
3. ***Subsurface hydrogen storage*** – subsurface geologic units used to safely store hydrogen until it is needed, must have adequate storage, a proper seal, and ability to easily track and manage hydrogen

Geologic Hydrogen Research Needs

Natural hydrogen refers to hydrogen generated through ongoing geologic processes—particularly reactions between water and iron-rich minerals within Precambrian basement rocks. Michigan's **Midcontinent Rift** and associated crystalline terranes make it a top U.S. candidate for natural hydrogen formation. To characterize this potential, the following research activities are recommended and summarized below.

Subsurface sampling and core/cuttings analysis: The Michigan Geological Repository for Research and Education (MGRRE) possesses more than 600,000 linear feet of core and cuttings from more than 30,000 wells in the Lower Peninsula of Michigan. Technical research needs include:

- Comprehensive geochemical and mineralogical characterization (XRD, XRF, SEM, thin section petrography, core scanning, FTIR, etc.)
- Evaluation of Precambrian basement rocks for hydrogen-generating mineral assemblages
- Fluid inclusion and gas chromatographic analyses to identify trapped hydrogen, precursor gases, and/or evidence of hydrogen migration
- Laboratory experiments to assess samples for trapped hydrogen
- Integration of newly collected samples from deep wells that penetrate basement rock or overlying units
- **Recommend:** Establishing proper laboratory at MGS for rapid response analyses

Piggyback Data Collection in New Wells: Because few wells reach the Precambrian basement, Michigan must leverage opportunities to sample deep drilling campaigns, particularly those conducted by industry or state agencies. Samples could include cores, cuttings, fluids, well tests, etc. Many companies cannot afford to collect advanced data or analyses, so there is an opportunity to offer assistance and share the results. Research opportunities include:

- Standardized hydrogen-focused mudlogging protocols
- In-situ gas sampling from drilling fluids, cores, and cuttings
- Coordinated industry partnerships (state, industry, MGS, academia) to ensure long-term data acquisition and analysis

Feasibility Mapping for Natural Hydrogen Systems: A statewide layered feasibility mapping framework is needed to identify areas with favorable geologic conditions for natural hydrogen accumulation, including hydrogen source(s), migration pathways, and traps. Research opportunities include:

- Evaluation of structure such as faults, folds, rift-related features
- Legacy oil and gas field data and gas analysis integration
- Assessment of migration pathways and potential trapping formations
- Update existing maps and generate new maps
- **Recommend:** purchasing and synthesizing regional 2D and 3D seismic data (see supplemental information)
- **Recommend:** integration of core/cuttings data, fluid analyses, and seismic with aerial-based geophysical data to validate interpretations and broaden interpolation

Remote Sensing and Surface Flux Identification: Surface anomalies, including “fairy circles”, may indicate hydrogen seepage. Research needs include:

- High-resolution LiDAR, gravity, and magnetic anomaly analyses
- Correlation of surface anomalies with subsurface geology and soil gas measurements
- Targeted ground-truthing with soil gas flux surveys

3D Geological and Reservoir Modeling: Following characterization and mapping efforts, 3D modeling could be deployed to visualize the subsurface, simulate hydrogen flow and extraction, and run multiple scenarios to determine potential production yields and recommendations for safe operating procedures.

Stimulated Hydrogen Research Needs

Stimulated hydrogen involves intentionally accelerating natural hydrogen-generating reactions through thermal, mechanical, or catalytic enhancement. Although early in development worldwide, Michigan's basement mineralogy and structural history suggest promising conditions. There is potential for locations in both the Lower Peninsula and Upper Peninsula. To characterize this potential, the following research activities are recommended and summarized below:

Geochemical Characterization of Hydrogen-Producing Reactions: An understanding of the geochemical properties of feasible rocks is needed along with understanding how they react to different stimuli, to produce stimulated hydrogen. Research needs include:

- Experiments to quantify hydrogen production potential from Michigan's specific rock types under elevated temperature and pressure conditions
- Assessment of mineral alteration pathways (e.g., serpentinization, oxidation of ferrous minerals)
- Evaluation of reaction kinetics using core samples
- **Recommend:** Establishing proper laboratory at MGS/WMU Engineering for rapid response analyses

Stimulation Mechanism Testing: An understanding of the geomechanical properties of rocks and the mechanical processes needed to release stimulated hydrogen is needed. Research needs include:

- Laboratory studies of mechanical stimulation (e.g., fracturing) to increase reactive surface area and quantify released gases
- Experiments assessing catalytic enhancement using naturally occurring minerals and fluids
- Modeling of heat-assisted or fluid-assisted stimulation scenarios to estimate scalable hydrogen yields

Environmental and Operational Risk Assessment: The potential environmental and operational risks are heighted for stimulated hydrogen due to the dynamic changes needed to release hydrogen in the subsurface. Research needs include:

- Analysis of potential induced seismicity from stimulated reactions
- Evaluation of byproducts and subsurface fluid chemistry
- Development of monitoring protocols for potential gas migration pathways

- 3D modeling to simulate stimulation practices over a variety of scenarios

Subsurface Storage Research Needs

Michigan holds several of the most geologically favorable storage options in the Midwest, including salt caverns, deep saline formations, and depleted oil and gas reservoirs. To support safe and long-term hydrogen storage, the following technical research needs are summarized below.

Reservoir and Seal Characterization: Hydrogen molecules are much smaller than other fluids and gases stored underground, thus requiring different criteria to safely store and manage in the subsurface. Recommended research needs include:

- Detailed core and cuttings analysis such as porosity, permeability, fracture networks, pore connectivity, and mineralogy of candidate reservoirs
- Seal integrity and hydrogen containment properties of confining units
- Geochemical reactions between hydrogen, formation fluids, and rocks (both reservoir and confining units)

Storage Feasibility Mapping: A statewide assessment of potential storage formations and associated seals is needed. Research needs include:

- Depth, thickness, and structural geometry of candidate formations
- Reservoir properties influencing injectivity, migration, and working gas capacity
- Proximity to industrial hydrogen users and future hydrogen hubs
- Volumetric assessments

3D Geological and Reservoir Modeling: Michigan must develop 3D static earth models and reservoir simulations to evaluate storage performance. This includes stratigraphic frameworks and facies models, injection-withdrawal cycle simulations, pressure evolution and plume migration analysis, and assessment of storage capacity and long-term containment reliability.

Laboratory Containment Tests: To ensure long-term storage and safety of hydrogen, laboratory experiments are essential to evaluate capillary breakthrough pressures of seals, diffusion and adsorption effects in reservoir and caprock samples, potential mineralogical changes triggered by hydrogen exposure.

Cross-Cutting Research Infrastructure Needs

For all areas of research (geologic hydrogen, stimulated hydrogen, and storage), there are cross-cutting research needs that would benefit each area. These include:

- Development of a statewide subsurface database
- Coordinated sampling access through industry partnerships
- Workforce and laboratory capacity building

Additionally, the State should be aware of synergist opportunities involving hydrogen and potential competition. These considerations could include:

- Exploring synergies between hydrogen, critical minerals, CCUS, and geothermal
- Developing a roadmap to building a hydrogen industry in Michigan, using a holistic approach from source, to reservoir, to production, to transportation, to products, etc.
- Subsurface usage should be prioritized and optimized for current and future needs (see table below). Meaning, there will be competition for subsurface rights, and what is stored/extracted should be prioritized

Competitor / Sector	Description of Competition	Prob.	Impact	Overall Risk	Supporting Notes / Evidence
Carbon Capture, Utilization & Storage (CCUS)	Competes directly for deep saline reservoirs, depleted fields, and key structural traps used for hydrogen storage. CCUS is expanding quickly with strong federal incentives.	High	High	Critical	CCUS and hydrogen share overlapping pore-space and subsurface infrastructure needs; CCUS deployment is accelerating due to 45Q incentives and established workflows.
Geothermal Energy (including Enhanced Geothermal Systems)	Competes for deep high-permeability fracture systems, drilling capacity, and subsurface temperature data.	Low	Medium–High	Mod	Subsurface synergies between geothermal and CCUS highlight overlapping infrastructure and subsurface domains.
Critical Minerals Mining (Nickel, Cobalt, Platinum-Group Elements)	Competes for access to ultramafic rocks, land positions, drill permitting, and core/sample acquisition.	Med	High	High	DOE-funded geologic hydrogen work is already co-located with critical mineral deposits in ultramafic complexes. These rock types host both hydrogen potential and mineral value.
Lithium Brine Extraction	Potential competition for subsurface brines, particularly in deep basin structures or geothermal-linked settings.	Med	Med	Mod	Geothermal–lithium–hydrogen co-production is increasingly discussed in subsurface technical forums; brine resources often overlap with hydrogen-producing or

					storage-capable formations.
Natural Gas Storage Operators	Compete for ideal depleted reservoirs with proven containment (best candidates for hydrogen storage).	Low-Med	High	Mod–High	Long history of underground gas storage success and infrastructure sets precedent for claims on pore space. Hydrogen storage is expected to follow similar reservoir suitability patterns.
Oil & Gas Exploration and Production	Competes for drilling rigs, subsurface data, and sometimes reservoir pressure management space.	Med	Med	Mod	Oil & gas subsurface technologies increasingly support renewable subsurface sectors, but active operations still compete for drilling and data access.
CO_2-Plume Geothermal (CPG)	Emerging system using CO_2 injection to harvest heat; competes for pore space and model-based subsurface management.	Low	Med	Mod	Geothermal–CCUS hybrid systems show shared infrastructure and overlapping subsurface domains.

Michigan can position itself as a leader by establishing statewide subsurface coordination framework, leveraging Michigan's existing data infrastructure, and incentivizing co-development of projects.

Michigan already has robust universities capable of providing and/or expanding offerings to support the growing hydrogen interest. There is a strong opportunity to develop a research coalition, which unites Michigan Universities and organizations, such as Michigan Geological Survey, Michigan Geological Repository for Research and Education, Western Michigan University, Michigan State University, University of Michigan, and Michigan Technological University. All these identified entities are currently collaborating and discussing how to establish a joint research coalition, playing to the strengths that each team has to offer. A summary of team offerings is below:

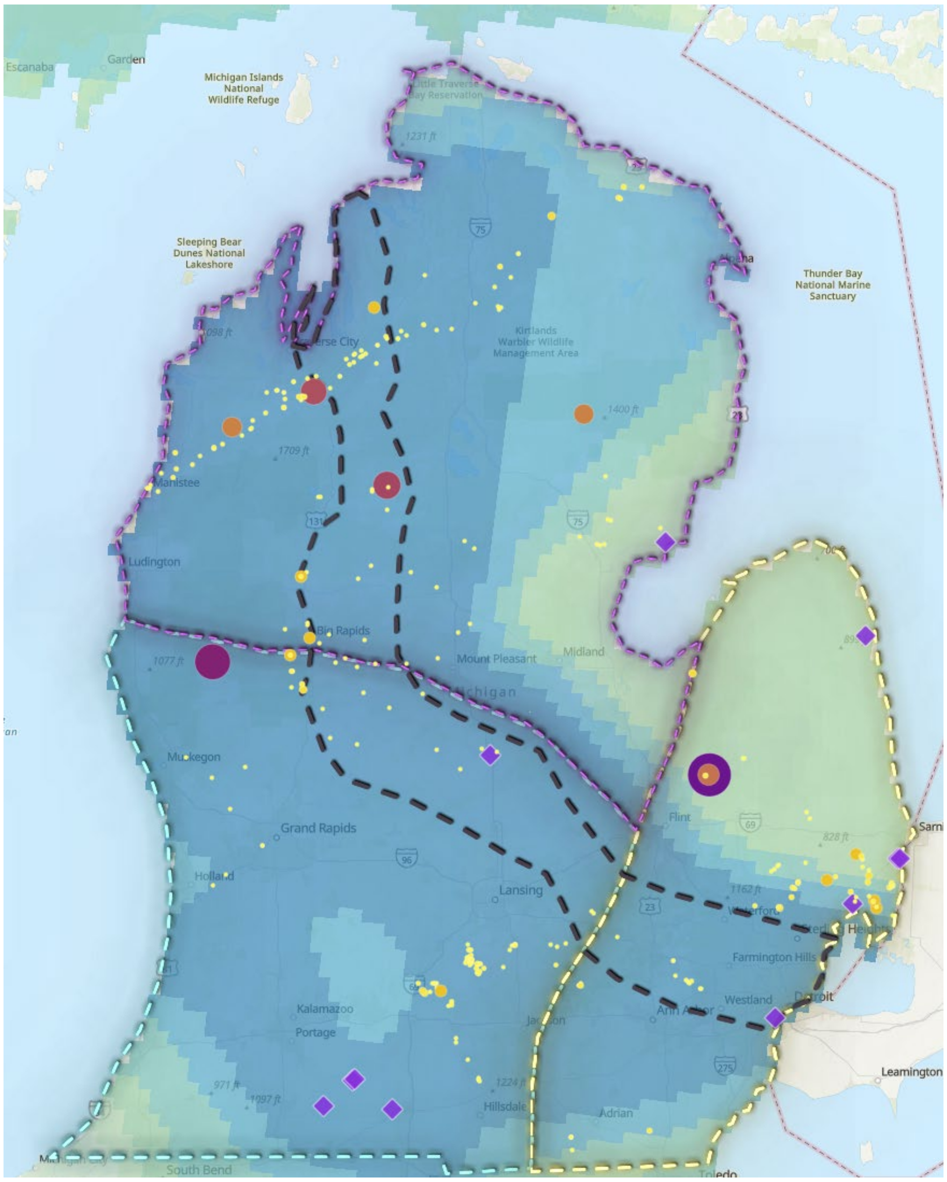
Entity	Offering
Michigan Geological Survey	State geologic experts, repository of samples and data, geologic characterization capabilities, bridge between academia, industry, and general public
Western Michigan University	Multi-disciplinary experts in geological and environmental sciences, chemical engineering, and civil engineering who can develop and run laboratory experiments, design new products, and link geology to engineering solutions
Michigan State University	Geological expertise in understanding micro-biological influences on hydrogen production, laboratory offerings, and engineering offerings
University of Michigan	Multi-disciplinary experts in engineering, linking life-cycle assessments, "cradle-to-grave" scenarios, developing

	engineering solutions, and exploring other types of hydrogen to expand from geologic based solutions
Michigan Technological University	Geological experts in Precambrian rocks, especially those found in the Upper Peninsula of Michigan, 3D modeling and simulation, core and sample characterization

Current Relevant Data

Recommended resources and references are provided in the attached references section. In addition to these readings, MGS hosts relevant sample and data needed to address the recommended research opportunities. MGS has cores from 10 locations, totaling 135 feet of Precambrian coverage (table below), along with cuttings from approximately 50 wells (needs validation). The map below illustrates major structural elements, locations of Precambrian core samples, and locations of hydrogen measurements, which demonstrates the paucity of geology data and coverage.

County	Operator	Lease Name	Permit Number	Cored Geologic Material	Cored Footage
Arenac	Petrostar	State Sims 2-7	P#42858	10 feet of Gneissic Basement	15504-15514
Branch	Consumers Power Company	Lindsey & Hostetler Et Al 1	P#29779	29 feet of Metamorphic Basement	5409-5438
Branch	Consumers Power Company	Clark, Harvey 1	P#29969	44 feet of Metamorphic Basement	5426-5470
Branch	Atlantic Richfield	Arco & Gaglio 1-13	P#38045	7 feet of Granitic Basement	5370-5377
Gratiot	McClure Oil	Sparks R&J, & Eckelbarger K&V, & Whightsil 1-8	P#29739	143 feet of PC sedimentary rock core and a little ultramafic basalt or Diorite	13372-13403; 15049-15077; 16397-16417; 17439-17463
Saint Clair	Consumers Energy	Consumers Power Co BD 1 aka BDW 139	P#00139	28 feet of Metamorphic Basement	4605-4633
Saint Clair	Consumers Energy	Consumers Power Co BD 1-7 aka BD 151	P#00151	19 feet of Metamorphic Basement	4714-4733
Saint Clair	Consumers Power	Consumers Power Co Bd 2-7 Aka BD152	P#00152	9 feet of Metamorphic Basement	4680-4689
Saint Joseph	Marathon Oil Co.	Cupp, Lloyd 1-11	P#31335	5 feet of Granitic Basement	5073-5078
Wayne	Honeywell International	Semet-Solvay No. 2	P#00155	4 feet of Granitic Basement	4104-4108



Conclusion

Advancing Michigan’s geologic hydrogen economy depends on a systematic and science-driven research agenda. By investing in subsurface characterization, geochemical analysis, feasibility mapping, reservoir modeling, and laboratory testing, Michigan can position itself as a national leader in hydrogen production and storage while supporting the state’s long-term climate and energy independence goals. Geological and engineering research is essential to guide the safe exploration for hydrogen, providing critical data and information needed by industry and regulators alike.

Recommended Resources and References

General Information

Considerable general information relating to Geologic Hydrogen can be found in documents on the internet.

The United States Geological Survey (U.S.G.S.) published the first map of the prospective locations of naturally-occurring geologic hydrogen resources in the contiguous United States in January 2025. Much of the Lower Peninsula of Michigan was shown as one of the highly prospective areas in the U.S. https://www.usgs.gov/news/national-news-release/usgs-releases-first-ever-map-potential-geologic-hydrogen-us

A geologic report accompanies the map along with a data release. https://pubs.usgs.gov/pp/1900/pp1900.pdf

U.S.G.S. paper on model predictions of global geologic hydrogen resources

https://www.science.org/doi/10.1126/sciadv.ado0955

Interest in Geologic Hydrogen grew substantially during the latter half of 2025.

Michigan Governor Gretchen Whitmer signed Executive Directive No. 2026-1 “Establishing the Michigan Geologic Hydrogen Exploration and Preparedness Initiative”

https://www.michigan.gov/whitmer/-/media/Project/Websites/Whitmer/Documents/Exec-Directives/ED-20261--GHEP-Initiative-signed.pdf?rev=f6c7befc30024841bb3b381e983e5acf&hash=11B35DCE16D1B7E48FA0E68BFCF31EEE

The Michigan Economic Development Commission published a web document entitled “Generation Hydrogen: Michigan’s Clean-Energy Transition” on January 15, 2026, in response to Governor Whitmer’s Executive Directive. https://www.michiganbusiness.org/news/2023/12/hydrogen/

The University of Michigan has developed a research Initiative relating to Geologic Hydrogen. https://research.umich.edu/mi-hydrogen/

The Michigan Geological Survey is well-positioned to help in the geological assessment and delineation of subsurface deposits and conditions that can be used to document potential Geologic Hydrogen natural systems from source to migration pathways to potential reservoir and trap/seal geological formations.

The Michigan Survey maintains a vast collection of physical samples and data relating to Michigan’s subsurface and surficial geology. Michigan has a long history of discovery, development, management and utilization of geological natural resources.

https://mgs.wmich.edu/

Energy production of petroleum and natural gas in Michigan has history dating back to the early 20th century

https://www.emmetrealtors.com/documents/MOGA-Facts.pdf

and mineral development from the mid-19th century. Dr. Peter Voice overview PowerPoint presentation on Michigan Minerals

https://files.wmich.edu/s3fs-public/attachments/u263/2016/A%20survey%20of%20Production%20Statistics_0.pdf

U.S. Geological Survey Summary of Michigan's Mineral production History for 2018-2019 https://www.usgs.gov/centers/national-minerals-information-center/mineral-industry-michigan

Michigan also leads the nation in the underground storage of natural gas and has network of natural gas transmission and underground storage reservoirs.

https://www.michigan.gov/-/media/Project/Websites/mpsc/regulatory/nat-gas/About_Natural_Gas.pdf?rev=eec2e486ca434cedbfdc30426680bad9

Michigan Geological Survey staff have also been leading researchers in the study and development of Carbon sequestration, utilization and storage through federally-funded cooperative programs.

https://netl.doe.gov/coal/carbon-storage/atlas/mrcsp

https://www.battelle.org/insights/case-studies/case-study-details/bringing-carbon-capture-utilization-and-storage-(ccus)-to-commercial-scale-through-the-midwest-regional-carbon-sequestration-partners https://netl.doe.gov/coal/carbon-storage/atlas/mrcsphip-(mrcsp)

https://www.midwestccus.org/

General Michigan Geology

State of Michigan General geologic overview

https://www.michigan.gov/-/media/Project/Websites/egle/Documents/Programs/GRMD/Catalog/04/GIMDL-GGGM.pdf?rev=ae187fc807c0454e9638dd5ef61e6d19

W.B Harrison PowerPoint on Michigan Geology

https://files.wmich.edu/s3fs-public/attachments/u584/2016/Geology%20of%20Michigan%20PowerPoint.pdf

Michigan Stratigraphy and Petroleum Geology

Catacosinos, P.A., Daniels, P.A., Jr., and Harrison, W.B., III, 1991, Structure, stratigraphy and petroleum geology of the Michigan Basin, in Leighton, M.W., Kolata, D.R., Oltz, D.F., and Eidel, J.J., eds., Interior Cratonic Basins: American Association of Petroleum Geologists Memoir 51, p. 561–602.

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10.1.2 Appendix A-2 – Michigan Basin Seismic Data Acquisition

Strategic Acquisition of Michigan Basin Seismic Data to Accelerate Geologic Hydrogen Exploration

Prepared by Dr. Autumn Haagsma, Assistant Director of the Michigan Geological Survey

Executive Summary

Michigan is emerging as one of the most promising regions for naturally occurring geologic hydrogen following Governor Whitmer's Executive Directive 2026-1, which launches the Michigan Geologic Hydrogen Exploration and Preparedness Initiative. The directive highlights that Michigan's Midcontinent Rift has a high likelihood for hydrogen production at a scale competitive with fossil fuels, with potential to generate tens of millions in direct annual revenue and catalyze billions in economic activity if commercially viable.

A unique opportunity exists to purchase a large regional seismic dataset representing the highest-quality seismic grid in the Michigan Basin, originally acquired for approximately $10 million and offered today to MGS, as a research institution, for $400,000—well below modern replacement cost ($20-40M). The sale price equates to less than $300/mile, while lease price through seismic brokers, is typically $2,000-2,600/mile. The purchase gives full ownership and rights, whereas leasing data has limited rights.

Relevance to Michigan's Hydrogen Initiative

The Executive Directive mandates a coordinated strategy to evaluate hydrogen feasibility, including geologic potential, regulatory frameworks, infrastructure reuse, and pilot-program design with agency reports due by April 2026. Access to basin-scale seismic data will allow MGS to:

- Map reservoir and seal pairs are essential for hydrogen accumulation and retention.
- Support evaluation of existing oil & gas infrastructure for hydrogen production, storage, and monitoring.
- Identify high-potential traps and fault-controlled structures to guide pilot well siting and reduce exploration risk.
- Use the data to interpret the hydrogen ecosystem from source, through migration, and to traps

About the Michigan Basin Survey Dataset

Acquired by Seismic Specialists, Inc. (1986–1991) and updated in 2021, the dataset is ready to load into modern interpretation software and includes approximately 1,335 miles of long regional lines acquired with 40-fold and 60-fold mini-hole dynamite. Final enhanced stacks (and some migrated) are available. Coverage spans key formations—Traverse, Dundee, Richfield, Niagaran, Glenwood, Trenton/Black River, and Collingwood (Lower Utica/Upper Trenton)—and includes lines within one mile of the State Pioneer well (initial ~3 MMcf/d). It also provides strong coverage across Isabella, Bay, Midland, and Saginaw Counties, which covers the central portion of the Basin. The lines cover the Mid-continent rift, which has been verified as observable in the dataset.

Why This Dataset is Strategic for Hydrogen Research

1. Unrepeatable acquisition conditions and cost advantage

Modern environmental and permitting constraints make an equivalent survey difficult to execute today. Replacement cost is estimated at $20–40 million versus a $400,000 purchase price—representing a 95–99% savings and immediate availability.

2. Critical insights for prospectivity

Michigan's geology offers sources of hydrogen generation, porous reservoirs, and effective caprocks; high-resolution seismic is essential to delineate these components and rift-related trap geometries. Seismic connects the dots between sparse datapoints, to allow the expansion of interpolation broadly across the state.

3. Supports storage and infrastructure assessment

Seismic helps evaluate salt formations for potential hydrogen storage caverns and assess proximity to legacy oil & gas infrastructure for repurposing. It also helps with map confining system/seal continuity, to ensure safe, and long-term storage solutions.

4. Accelerates competitive advantage

The dataset reduces geologic uncertainty, supports timely regulatory guidance, and strengthens Michigan's position for federal funding and private investment.

The Ask

- $400,000 to purchase the regional seismic dataset
- $400,000 to conduct seismic interpretations, integrate with additional data sets, and generate a formal report on hydrogen prospectivity in the State

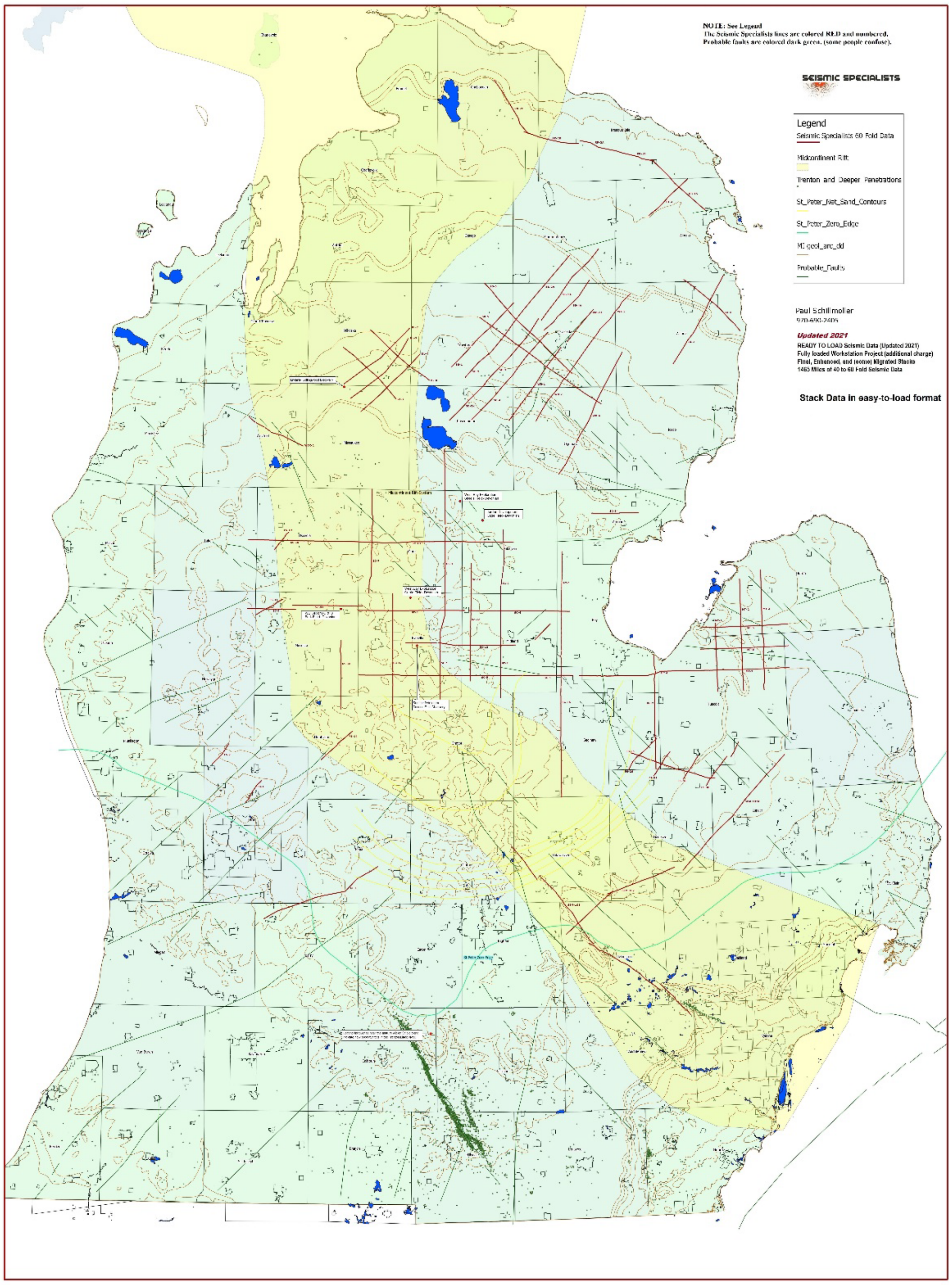
Return on Investment

- Immediate access to the best regional seismic coverage in the Michigan Basin for a fraction of replacement cost.

- Enables high-value research on hydrogen, carbon management, and geothermal co-benefits.
- Directly supports state agencies' near-term reporting and pilot-program planning.
- Improves attractiveness for industry partnerships and federal grant proposals.

Conclusion

Purchasing the Michigan Basin Survey seismic dataset is a high-impact, low-cost action that aligns directly with the 2026 directive, provides the subsurface intelligence required for responsible geologic hydrogen evaluation, and positions Michigan at the forefront of clean-energy innovation.



Map of 2D seismic data provided by Seismic Specialists, LLC. Seismic lines are drawn in red. The Midcontinent rift is outlined in yellow.

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4. Seismic Specialists, Inc. Michigan Basin Survey summary and map (updated 2021).

10.1.3 Appendix A-3 – MGS Planned Activities to Support Hydrogen Research

MGS Planned Activities to Support Hydrogen Research in Michigan

MGS has four activities/projects under development that will support hydrogen research in Michigan. These projects include: 1) Precambrian core analysis, 2) Precambrian mapping, 3) regional seismic analysis, and 4) laboratory experiments. Each activity is summarized further below.

Precambrian Core Analysis – MGS is partnering with MSU and NETL to characterize Precambrian core samples. We house approximately 135 feet of cores from the crystalline basement. The cores are currently being prepared to ship to NETL in West Virginia. The analysis will include:

- High resolution core scanning – Gamma ray, density, velocity, magnetic susceptibility, XRF, and infrared spectroscopy (NETL)
- Medical 3D CT scans (NETL)
- Micro 3D CT scans of 15 samples (NETL)
- Thin section petrography and fluid inclusion analysis (MSU)
- FTIR analysis (MSU)

This data will provide critical information on the characteristics of the Precambrian rocks, which are the likely source rocks for hydrogen in the state.

Precambrian Mapping – MGS is preparing a proposal for the USGS STATEMAP program to update the mapping of the Precambrian across the State. This task will include:

- Integration of rock properties with airborne geophysical data to calibrate and update maps
- Analysis of cuttings from approximately 50 wells which contain samples from the Precambrian
- Petrophysical analysis of wireline logs collected in the Precambrian, integrate and calibrate with rock properties
- Produce updated Precambrian maps such as provinces and rock types, structural controls, and depth to Precambrian

The results of the mapping program will provide information on the underlying structural controls and geographic variability in rock properties. In addition to the STATEMAP program, MGS is in the process of integrating subsurface geological, geophysical, and geochemical data in a web mapping application.

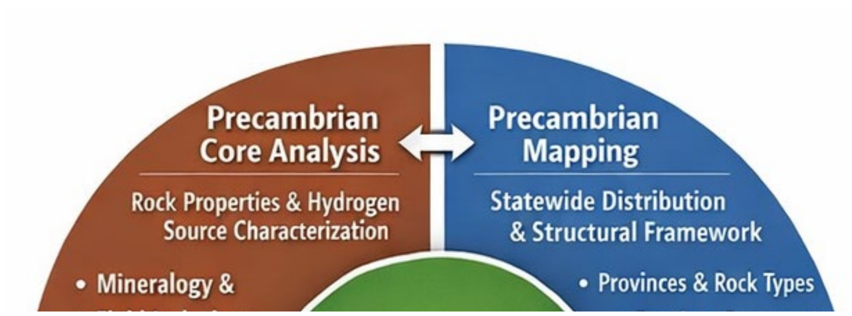
Regional Seismic Analysis – MGS is currently exploring the purchasing of a regional 2D seismic database, which includes over 1,300 miles of high-quality data. Some of the seismic lines have been verified to capture the Midcontinent Rift. The analysis could include:

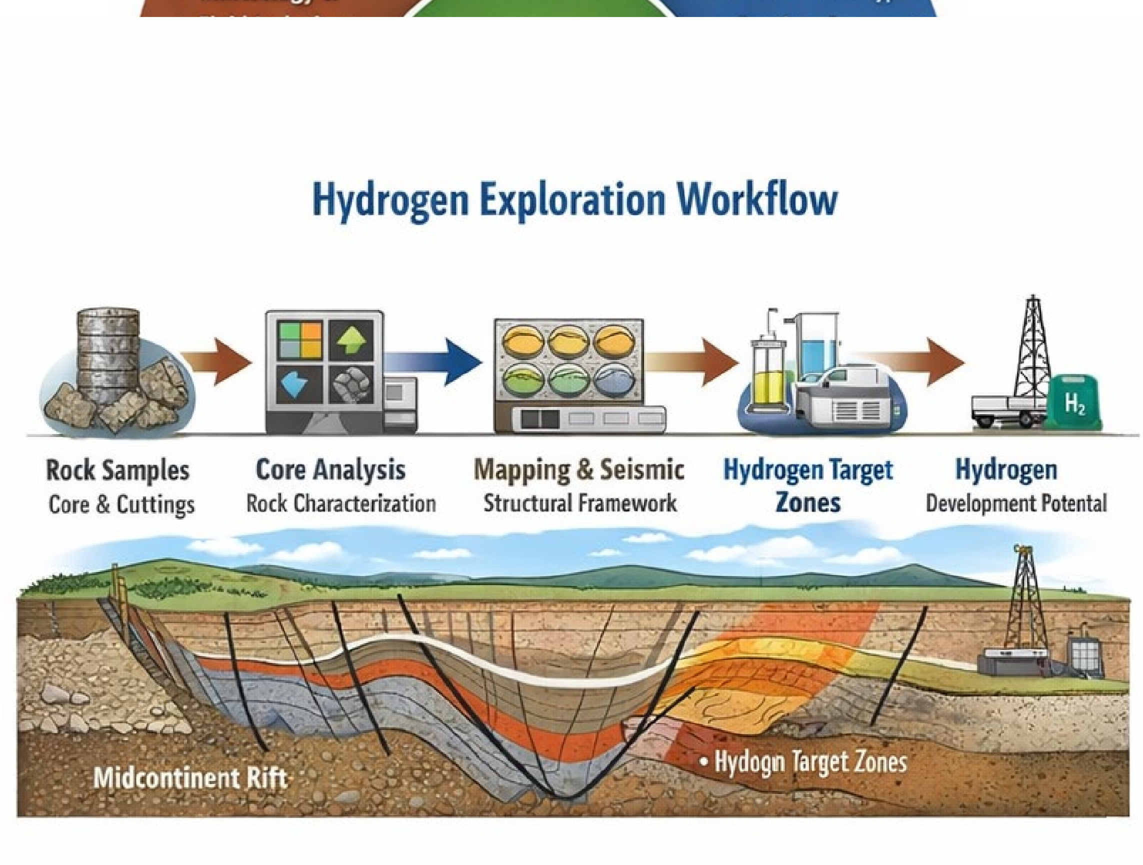
- Seismic well ties with nearby wireline logs

- Interpretation of seismic lines for key horizons, boundaries, and structural elements
- Integration of seismic data with other data such as aerial geophysics

The results of the regional seismic assessment will provide verified information on structure, extends, continuity, variability, and more for the Precambrian and overlying units.

Laboratory Experiments: MGS is collaborating with WMU's Department of Chemical and Paper Engineering to design experiments to release trapped hydrogen gases from rock samples. The experiments will use thermal shocking under controlled environment to induce cracking of the rock samples. The released gases will be captured and analyzed for composition. The results of the study will provide evidence of hydrogen and/or hydrogen migration and temperature needed to release hydrogen for stimulated approaches.





10.2 Appendix B – Carbon Emissions and Criteria Pollutant Estimates

This appendix provides detailed methodology, assumptions, and supporting calculations referenced in Sections 6 and 7.

Lifecycle Emissions Methodology

System Boundary Definition

Lifecycle assessments (LCAs) provide a standardized methodology for comparing total greenhouse gas emissions across energy pathways. For geologic hydrogen, an LCA encompasses emissions from extraction, processing, transportation, and end use. This section summarizes the emissions profile of geologic hydrogen based on Brandt et al. (2023), published in Joule, which represents the primary peer-reviewed lifecycle assessment for geologic hydrogen cited in current literature.

Site-boundary emissions refer to all greenhouse gas emissions from geologic hydrogen extraction to on-site compression to reach pipeline-ready pressure (approximately 3 MPa / 450 psia). This boundary excludes long-distance pipeline transportation, distribution infrastructure, and off-site storage. The Brandt et al. (2023) estimates of 0.4 to 1.5 kg CO_2e/kg H_2 represent site-boundary emissions only.

The emission estimates in this analysis apply to native (passive) geologic hydrogen, i.e., naturally occurring hydrogen extracted from subsurface accumulations without intervention to generate additional hydrogen. This pathway is distinct from manufactured hydrogen (gray, blue, or green) in that geologic hydrogen exists naturally and requires extraction rather than production.

Enhanced or Stimulated Geologic Hydrogen (SGH) is a subcategory where hydrogen is produced in place by artificially enhancing natural chemical reactions within the Earth. This pathway involves injecting water into iron-rich formations to induce serpentinization reactions that generate hydrogen. SGH may have higher emissions due to additional drilling and horizontal well requirements, energy for water injection and permeability enhancement, and lower reaction efficiencies (0.1 to 25 percent of theoretical yield per Mathur et al. 2024). No peer-reviewed LCA currently exists for stimulated hydrogen. The U.S. Department of Energy has set a target of less than 0.45 kg CO_2e/kg H_2 for this pathway.

Site Boundary Emission Sources

Drilling and Well Construction: Embodied emissions from steel casing, cement, and diesel consumed during drilling. These fixed emissions are amortized over total production, so low-productivity wells have higher per-kilogram intensity.

Production and Fugitive Emissions: The largest emission source. While hydrogen itself is not a direct greenhouse gas, it has an indirect global warming potential (GWP) of approximately 5 (GWP_{100}) because it reacts with atmospheric hydroxyl radicals, which initiate the oxidation of methane in the troposphere, thereby extending methane's atmospheric lifetime. Methane co-produced with geologic hydrogen (typically ranging anywhere from 1.5 to 22 percent of raw gas) contributes directly to greenhouse gas intensity through fugitive losses.

Processing and Separation: Raw geologic hydrogen requires separation from co-produced gases (N_2, CH_4, He) via pressure-swing adsorption, plus dewatering. These purification steps are energy-intensive: approximately 8 percent of the gross hydrogen extracted is consumed as fuel to power the separation and dewatering equipment, reducing the net hydrogen available for sale or use.

On-Site Compression: Extracted hydrogen must be compressed to pipeline-ready pressure (approximately 3 MPa / 450 psia) before transport. In the Brandt et al. (2023) reference scenario, which assumes a fully operational extraction site with no external energy inputs, this compression is powered by burning a portion of the extracted hydrogen itself rather than using grid electricity or diesel generators. This "self-consumption" approach yields zero direct combustion emissions from external fuels but further reduces net hydrogen output.

Transportation and Distribution Emissions

Hydrogen's low volumetric energy density (approximately one-third that of natural gas at equivalent pressure) increases compression and transportation requirements. The Brandt et al. (2023) analysis of hydrogen delivery indicates transportation and storage infrastructure can potentially double both delivered cost and emission intensity depending on distance and mode. Pipeline transportation, trucking, and distribution infrastructure can add 50 to 100 percent to site-boundary emissions depending on distance and mode, yielding delivered intensities of 0.6 to 2.1 kg CO_2e/kg H_2.

End Use: Hydrogen combustion produces only water vapor without direct CO_2 emissions at point of use. High-temperature combustion can generate nitrogen oxides (NOx); fuel cell applications produce no NOx.

Emissions Variability and Sensitivity Analysis

Brandt's sensitivity analysis found emission intensity most sensitive to raw gas composition, specifically the methane fraction. A reservoir with 85 percent H_2 and 1.5 percent CH_4 yields approximately 0.4 kg CO_2e/kg H_2 (low emissions scenario), while 75 percent H_2 with 22.5 percent CH_4 produces approximately 1.5 kg CO_2e/kg H_2 (high emissions scenario).

Comparison to Other Energy Pathways

The National Laboratory of the Rockies (formerly National Renewable Energy Laboratory or NREL) LCA Harmonization Project has established authoritative emission factors for electricity generation technologies based on systematic review of over 2,100 published studies. Table B.1 compares geologic hydrogen to these benchmarks.

Important framing note: The hydrogen LCA literature, regardless of hydrogen production pathway, predominantly evaluates climate impact through fuel and feedstock applications (e.g., steel production, ammonia synthesis) rather than as a direct comparator to electricity generation. The conversion to g CO_2e/kWh enables comparison with National Laboratory of the Rockies (NLR) benchmarks but represents an analytical construct that has yet to be verified in real-world applications.

Technology	Lifecycle Emissions (Median g CO_2e/kWh)	Source
Geologic Hydrogen*†	12-45 (midpoint approximately 28)	Brandt et al. 2023
Solar PV	43	NLR (formerly NREL) 2021
Wind (Onshore)	13	NLR (formerly NREL) 2021
Nuclear	13	NLR (formerly NREL) 2021
Natural Gas	486	NLR (formerly NREL) 2021
Gray Hydrogen (SMR)**	300-360	IEA 2024
Coal	1,001	NLR (formerly NREL) 2021

*Table B.1. Lifecycle Emission Comparison by Generation Technology. *Geologic hydrogen emissions (0.4-1.5 kg CO_2e/kg H_2) converted using hydrogen's lower heating value of 33.3 kWh/kg (DOE/NLR standard). **SMR emits 10-12 kg CO_2e/kg H_2; lower bound reflects direct emissions only. †Geologic hydrogen estimates are prospective; apart from one small-scale site in Mali, no commercial production facilities exist; values derive primarily from engineering models.*

Criteria Air Pollutant Analysis

Overview

Criteria air pollutants are six common pollutants identified by the EPA that are harmful to human health and the environment. These pollutants include carbon monoxide (CO), lead, nitrogen dioxide, ozone (measured via volatile organic compounds), particulate matter (PM), and sulfur dioxide. Criteria air pollutants are regulated by the EPA and tracked by industry. Internal combustion of fossil fuel produces pollutants including CO, nitrogen oxide (NOx), and PM. Hydrogen fuel has been identified as a potential fuel substitute for carbon intensive industries and CO and PM emissions reductions. However, NOx is still emitted where hydrogen is combusted.

Hydrogen Combustion Profile

Hydrogen burns at a high temperature and NOx formation occurs when air (which contains nitrogen and oxygen) is exposed to high temperatures. In a recent review of hydrogen-based steelmaking technologies, only one facility was identified in the United States. Currently, there are no permits granted to combustion or processing operations at steel plants in Michigan that use hydrogen as a fuel or reducing agent at scale.

Gerdau Case Study

We are citing a state air Permit to Install for a retrofitting study at the Special Steel Monroe Mill (Gerdau) as an example of the extent of available information for criteria pollutant emissions related to hydrogen use in industry.

Gerdau has proposed to use hydrogen gas as a fuel for reheating furnaces in steel production in lieu of fossil fuels as part of a trial investigation with the U.S. Department of Energy between August 2026 and August 2027. This investigation will include a comparison between different combustion scenarios using natural gas and hydrogen at different levels of oxygen. Gerdau used emission data from prior stack testing and technical data from Linde burner technology to calculate projected annual emissions for each combustion scenario.

Pollutant	Natural Gas (t/yr)	Hydrogen (t/yr)	Change
CO	9.39	0.021	-99.8%
NOx	41.53	42.21	+1.6%
PM	1.5	1.29	-14%
SO_2	0.47	0.41	-13%
VOC	4.34	3.73	-14%
Lead	3.95E-04	3.39E-04	Marginal Decrease

Table C.1. Projected Annual Emissions: Gerdau Hydrogen Trial. Source: Gerdau permit application from September 5, 2025, for Permit to Install PTI0000136 v1.0.

The projected annual emissions describe a 99.8% decrease in CO. There is also a slight projected decrease in particulate matter (PM), SO_2, volatile organic compounds (VOC), and lead. The hydrogen gas conditions are projected to have slightly higher NOx emissions compared to natural gas because of the NOx formation from air given the high burn temperature of hydrogen. While the Gerdau permit includes CO_2e emission limits, calculations for CO_2e from hydrogen fuel were not required due to the scale of this project. The primary sources of these criteria pollutant emissions are the raw materials used in steel production, not hydrogen fuel, since hydrogen fuel combustion does not result in these emissions.

Gerdau's trial uses hydrogen as a combustion fuel for process heat, which differs from H_2-DRI steelmaking where hydrogen serves as a chemical reductant. Criteria pollutant profiles may vary between these applications. The Gerdau investigation represents a relatively small amount of emissions compared to the total emissions in Michigan from steel production.

Michigan Baseline Emissions

The total criteria pollutant emissions from iron and steel mills and ferroalloy manufacturing in Michigan during 2024 are summarized in Table C.2. The steel production process is different at each facility, so it is difficult to make a direct comparison and estimate the potential reduction in CO emissions. A more precise comparison would require isolating emissions from reheating furnaces that combust a variety of fuel types across Michigan facilities; however, given the absence of currently operating reheat furnaces in Michigan beyond the Gerdau trial units, a present-day comparative analysis is not feasible.

Pollutant	Total (tons)	NAICS	Facilities
CO	4,976	331110	4
NOx	445	331110	4
PM_{10}	243	331110	4
$PM_{2.5}$	188	331110	4
SO_2	577	331110	4
VOC	97	331110	4
Lead	0.13	331110	4

*Table C.2. Criteria Pollutant Emissions from Iron and Steel Mills and Ferroalloy Manufacturing in Michigan during 2024. *These values are as reported in tons in Air Emission Reports submitted to EGLE by four different facilities that use the NAICS code: 331110.*

Industrial Sector Case Study

Subsector Screening

Within Michigan's 7.28 $MMTCO_2e$ industrial hard-to-decarbonize emissions, approximately 4.0 $MMTCO_2e$ falls within subsectors where geologic hydrogen could serve as either a chemical reductant or a clean feedstock replacement. Table D.1 summarizes the hydrogen relevance assessment for each industrial subsector.

Subsector	Emissions ($MMTCO_2e$)	H_2 Relevance	Rationale
Iron & Steel	2.0 – 2.5	HIGH	H_2-DRI replaces carbon as reductant (5 Lakes Energy, 2024)
Chemicals (NH_3, MeOH)	1.5 – 2.0	HIGH	H_2 is direct feedstock; 1:1 substitution
Cement	1.5 – 2.0	LOW	Approximately 60% of emissions derive from limestone calcination ($CaCO_3$ → Caite + CO_2), CO_2 released from rock, not fuel. H_2 cannot mitigate emissions.
Oil & Gas (fugitives)	1.0 – 1.5	LOW	Hydrogen production does not address methane leakage
Other high-temp industrial	0.5 – 1.0	MEDIUM	Hydrogen can substitute for natural gas as a combustion fuel to generate high-temperature process heat (e.g., glass melting, ceramics firing, aluminum smelting) if electric alternatives prove technically or economically infeasible (e.g., Gerdau reheating furnace trial)

Table D.1. Industrial Subsector Hydrogen Relevance Assessment. Iron, steel, and chemical manufacturing were selected as case studies because they represent the clearest hydrogen use cases with established technology pathways and the largest share of potential emissions reductions.

Iron and Steel

Challenge

Steel process emissions arise from chemical reactions, not energy consumption alone. Conventional blast furnace iron reduction uses carbon as a reductant, producing CO_2 as an inherent byproduct:

$$Fe_2O_3 + C \rightarrow Fe + CO_2$$

Electrifying the heat source does not eliminate these emissions. Hydrogen-based direct reduced iron (H_2-DRI) substitutes hydrogen for carbon:

$$Fe_2O_3 + H_2 \rightarrow Fe + H_2O$$

This produces water instead of CO_2, a fundamentally different decarbonization pathway requiring hydrogen as a material input.

Methodology

Table D.2 presents the methodology for calculating hydrogen demand in the iron and steel sector.

Parameter	Value	Source
Addressable Emissions (2050)	2.5 $MMTCO_2e$	MI CCAP (steel portion of 7.28 $MMTCO_2e$)
Process Emission Factor	1.4 t CO_2e/t steel	IEA Iron and Steel Roadmap 2020
Implied Steel Production	1.8 million t/year	2.5 $MMTCO_2e$ ÷ 1.4 t CO_2e/t steel
H_2 Intensity (DRI conversion factor)	55 kg H_2/t steel	Industry consensus midpoint (range: 50–60 kg H_2/t steel); see Steel Watch 2025; Bellona/Roland Berger 2023; IEA Iron and Steel Technology Roadmap 2020
H_2 Demand	100,000 t H_2/year	Derived (1,800,000 t steel × 55 kg H2/t steel ÷ 1000 kg/t)

Table D.2. Iron and Steel Hydrogen Demand Calculation. Validation: The 5 Lakes Energy Dearborn Works study (October 2024) reports H_2 intensity of 56 kg H_2 per metric ton steel for Cleveland-Cliffs' Michigan facility, closely aligning with the IEA-derived factor used here.

Results

"Net emission reduction" represents the climate benefit after subtracting hydrogen production and delivery emissions from the gross emissions avoided. Table D.3 presents net decarbonization (emission reduction) scenarios applying geologic hydrogen delivered emission intensities (site-boundary plus transport adder).

Scenario	Delivered Intensity ($kg\ CO_2e/kg\ H_2$)	Production Emissions ($MMTCO_2e$)	Net Reduction ($MMTCO_2e$)	Percent of Addressable Emissions Reduced
Low Emissions	0.6	0.06	2.44	98%
Mid Emissions	1.4	0.14	2.36	94%
High	2.1	0.21	2.29	92%

Table D.3. Iron and Steel Net Decarbonization Scenarios.

Chemical Manufacturing

Challenge

Hydrogen is a direct feedstock for ammonia (NH_3) and methanol production. Currently, this hydrogen is produced via steam methane reforming (gray hydrogen), which emits 10 to 12 kg CO_2e per kg H_2. Electrifying chemical plants does not change the feedstock requirement; clean hydrogen must substitute for gray hydrogen on a one-to-one basis.

Methodology

Table D.4 presents the methodology for calculating hydrogen demand in the chemical manufacturing sector.

Parameter	Value	Source
Addressable Emissions (2050)	1.5 MMTCO$_2$e	MI CCAP (chemicals portion)
Gray H_2 Intensity (emissions factor)	10 kg CO_2e/kg H_2	IEA Global Hydrogen Review 2024 (range: 10–12 kg CO_2e/kg H_2)
Implied H_2 Demand	150,000 t H_2/year	Derived (1.5 MMTCO$_2$e ÷ 10 kg/kg)

Table D.4. Chemical Manufacturing Hydrogen Demand Calculation.

Results

Table D.5 presents net decarbonization (emission reduction) scenarios for chemical manufacturing.

Scenario	Delivered Intensity (kg CO_2e/kg H_2)	Production Emissions (MMTCO$_2$e)	Net Reduction (MMTCO$_2$e)	Percent of Addressable Emissions Reduced
Low Emissions	0.6	0.09	1.41	94%
Mid Emissions	1.35	0.20	1.29	86%
High Emissions	2.1	0.32	1.18	79%

Table D.5. Chemical Manufacturing Net Decarbonization Scenarios.

Transportation Sector Case Study

Maritime Context

Hard-to-decarbonize emissions projected from Michigan's transportation sector by 2050 (9.02 MMTCO_2e) encompass multiple modes. While MI CCAP does not disaggregate maritime emissions from the broader transportation sector, Great Lakes shipping presents a distinct hydrogen use case for several reasons:

Policy alignment: The Michigan Maritime Strategy (anticipated release April 2026) explicitly identifies hydrogen among priority alternative marine fuels under Goal 3: Accelerate Adoption of Advanced Vessel Technologies and Fuels. Michigan is a subrecipient of the Midwest Alliance for Clean Hydrogen (MachH2) grant award. MachH2 identifies Great Lakes maritime as a priority end use, though program funding beyond Phase 1 ($22.2 million awarded November 2024) remains subject to federal budget decisions.

Proven technology: Hydrogen-powered ferries are already operating commercially. MF Hydra in Norway and Sea Change in California demonstrate technical viability.

Fixed routes: Ferries and regular cargo routes enable predictable hydrogen refueling infrastructure investment.

Clean Exhaust: Hydrogen fuel cells emit only water vapor, with no CO_2, SOx, or particulate matter, eliminating air quality impacts in port areas and enclosed waterways.

Hard to Decarbonize Vehicle Context:

Maritime shipping shares characteristics with other hard-to-decarbonize transportation segments. Light-duty vehicles can largely be addressed through battery electrification, but medium- and heavy-duty vehicles, including long-haul trucking, aviation, and maritime, face energy density constraints that can at times favor hydrogen or hydrogen-derived fuels.

A growing body of research compares lifecycle emissions across vehicle powertrains. Compared to conventional diesel alternatives, battery electric vehicles (BEVs) powered by the grid reduce emissions by 55 to 75 percent, while fuel cell electric vehicles (FCEVs) using hydrogen from steam methane reforming reduce emissions by 1 to 45 percent. When powered by renewable electricity, BEVs achieve 89 to 94 percent reductions and FCEVs achieve 81 to 87 percent reductions (Kaushik et al. 2025). For medium- and heavy-duty applications, the optimal pathway depends on duty cycle, range requirements, and payload constraints; FCEVs may offer advantages for long-range, high-payload operations where battery weight becomes a limiting factor (Togun et al. 2025; Halder et al. 2024; ICCT 2023; Fuel Cells Works 2025).

Michigan's automotive industry has developed hydrogen fuel cell expertise through R&D programs and manufacturing partnerships. Testing and evaluation of hydrogen fuel cell systems for medium- and heavy-duty vehicles has occurred at facilities including GM's

Milford Proving Ground. This existing technical capacity and workforce expertise positions Michigan to support hydrogen vehicle deployment as infrastructure and market conditions develop.

The maritime case study demonstrates the methodology that could be extended to other transportation subsectors as data and policy priorities evolve.

Segment Assessment

Michigan's Great Lakes maritime emissions total approximately 330,000 metric tons CO_2e annually, representing approximately 23 percent of regional Great Lakes-St. Lawrence Seaway (GL-SLS) emissions. The GL-SLS consumed approximately 500,000 metric tons of marine fuel in 2019, predominantly marine gas oil and marine diesel oil, as required under Emission Control Area (ECA) sulfur limits, producing approximately 1.6 million metric tons of direct CO_2 emissions (ICCT 2022; emission factors per IMO Fourth GHG Study 2020). Michigan's approximately 23 percent share (MMS Supplemental Appendix 9) implies approximately 115,000 metric tons of fuel consumption and approximately 330,000 metric tons CO_2.

Not all maritime segments are equally suited for hydrogen. The segment breakdown in Table E.1 derives from ICCT 2022 GL-SLS regional vessel-type shares applied to Michigan's emissions allocation.

Segment	Estimated CO_2 (t/yr)	H_2 Demand (t/yr)	H_2 Relevance	Rationale
Bulk Carriers	205,000	18,000	MEDIUM	Long range: other alternative fuels may be preferred
Chemical Tankers	33,000	3,000	MEDIUM	Mixed route lengths
Tugs	30,000	3,000	HIGH	Port-based; proven H_2 applications
Ferries	30,000	3,000	HIGH	Fixed routes; proven technology
Port Equipment	15,000	1,500	HIGH	Land-based; established H_2 forklifts/handlers
Other	14,000	1,500	MEDIUM	Case-by-case assessment
Total	**330,000**	**30,000**		

Table E.1. Michigan Maritime Segment Assessment. Segment methodology note: ICCT 2022 reports bulk carriers (62 percent), chemical tankers (10 percent), and tugs (9 percent) as top regional emitters. Ferry estimate is based on Michigan Maritime Strategy fleet data (63 ferries on 16 routes). Port equipment is land-based and outside ICCT vessel scope; estimate from the EPA port emissions literature.

HIGH-relevance segments (tugs, ferries, port equipment) total approximately 75,000 t CO_2e annually and require approximately 7,500 t H_2/year, a realistic near-term deployment target.

Hydrogen Demand Methodology

Maritime hydrogen demand can be estimated from fuel displacement. Table E.2 presents the conversion factors used to calculate hydrogen demand.

Parameter	Value	Source
Diesel CO_2 Factor	3.2 kg CO_2/kg fuel	IMO Fourth GHG Study (2020)
Diesel Energy Content	42.7 MJ/kg (LHV)	IMO Fourth GHG Study (2020)
H_2 Energy Content	120 MJ/kg (LHV)	DOE Hydrogen Program
Fuel Cell Efficiency	55% (midpoint of 50–60%)	MDPI research article; Sandia; Ezgi (2023)

Table E.2. Maritime Hydrogen Conversion Factors.

Net Emissions Scenarios

Table E.3 presents net emissions scenarios for HIGH-relevance maritime segments. The "Delivered Intensity" column represents the lifecycle greenhouse gas emissions associated with producing and delivering one kilogram of geologic hydrogen, derived from Brandt et al. (2023) site-boundary estimates (0.4 to 1.5 kg CO_2e/kg H_2) plus a 50 to 100 percent transport adder to account for pipeline or trucking delivery to port bunkering facilities. The three scenarios (low, mid, and high emissions) reflect uncertainty in reservoir gas composition and delivery distance.

Scenario	Delivered Intensity (kg CO_2e/kg H_2)	Production Emissions (tCO_2e)	Net Reduction (tCO_2e)	Percent of Addressable Emissions Reduced
Low Emissions	0.6	4,500	70,500	94%
Mid Emissions	1.4	10,125	64,875	86%
High Emissions	2.1	15,750	59,250	79%

Table E.3. Maritime Net Decarbonization Scenarios (HIGH-Relevance Segments: 75,000 t CO_2e addressable, 7,500 t H_2/year demand).

Maritime represents smaller hydrogen demand than industry but offers proven technology, existing policy support, and near-term demonstration potential that could inform broader transportation decarbonization strategies.

Combined Results and Assumptions

Combined Results Table

Table F.1 presents the combined hydrogen demand and net decarbonization potential across all case studies.

Sector	Addressable	H_2 Demand	Net Reduction	Percent of Addressable Emissions Reduced
Iron & Steel	2.5 $MMTCO_2e$	100,000 t/yr	2.36 $MMTCO_2e$	94%
Chemicals	1.5 $MMTCO_2e$	150,000 t/yr	1.29 $MMTCO_2e$	86%
Industry Subtotal	**4.0 $MMTCO_2e$**	**250,000 t/yr**	**3.65 $MMTCO_2e$**	**91%**
Maritime (HIGH)	0.075 $MMTCO_2e$	7,500 t/yr	0.065 $MMTCO_2e$	86%
Combined Total	**4.08 $MMTCO_2e$**	**257,500 t/yr**	**3.70 $MMTCO_2e$**	**91%**

Table F.1. Combined Case Study Summary. All net reductions reflect mid-case scenario

Key Assumptions

This analysis relies on the following key assumptions:

Geologic hydrogen emission intensity: Site-boundary emissions of 0.4 to 1.5 kg $CO_2e/kg\ H_2$ per Brandt et al. (2023), with 50 to 100 percent transport adder for delivered intensity (0.6 to 2.1 kg $CO_2e/kg\ H_2$).

H_2-DRI conversion factor: 55 kg H_2 per metric ton of crude steel produced (industry consensus midpoint, range 50 to 60 kg H_2/t steel; Steel Watch 2025; Bellona/Roland Berger 2023); validated against 5 Lakes Energy Dearborn Works study (56 kg H_2/t for Cleveland-Cliffs Michigan).

Gray hydrogen baseline: 10 kg $CO_2e/kg\ H_2$ (IEA midpoint for steam methane reforming without carbon capture).

Maritime emission factors: IMO Fourth GHG Study 2020; Michigan share from MMS Supplemental Appendix 9 using ICCT SAVE model with 2022 port-based activity data.

2050 hard-to-decarbonize emissions: MI CCAP industrial hard-to-decarbonize of 7.28 $MMTCO_2e$ and transportation hard-to-decarbonize of 9.02 $MMTCO_2e$ assume electrification reaches technical and economic limits but do not assume hydrogen deployment.

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Geologic Hydrogen and Michigan's Emerging Hydrogen Economy: Economic Impacts on Employment, Business Formation, and Mobility

Report to the Executive Office of the Governor | Michigan Infrastructure Office | April 2026

MICHIGAN INFRASTRUCTURE OFFICE

Executive Summary

This report assesses the potential economic implications of geologic hydrogen for Michigan in response to Executive Directive No. 2026-1. The central finding is that geologic hydrogen presents a potentially significant but highly uncertain opportunity. Michigan's current hydrogen demand is approximately 39,100 metric tons per year, and University of Michigan analysis indicates that demand could grow substantially over time if costs decline and infrastructure expands. Recent techno-economic analysis also suggests that geologic hydrogen could potentially be produced at costs below most conventional hydrogen pathways under favorable conditions. If commercially recoverable resources are confirmed in Michigan, geologic hydrogen could materially improve the economics of hydrogen adoption across several sectors.

In the near term, economic impacts are likely to be modest. Early employment would most likely resemble upstream oil and gas, with jobs concentrated in exploration, drilling, appraisal, field services, and limited initial distribution. Michigan already has a base of transferable skills in drilling, chemical manufacturing, construction, maintenance, and related industrial occupations that could support early development. Over time, lower-cost in-state hydrogen could strengthen the competitiveness of existing industrial users, support new business formation, and expand opportunities in equipment manufacturing, chemical production, storage systems, and related services. Illustrative analysis in this report suggests that geologic hydrogen could represent tens of millions of dollars per year in economic value in an early market, with hundreds of millions of dollars per year by 2050 plausible under commercially successful development.

The report concludes that geologic hydrogen is not an assured near-term economic driver, but it is a potentially high-value strategic resource for Michigan. Its ultimate significance will depend on resource quality, production economics, infrastructure development, and downstream market adoption. The clearest policy implication is that Michigan should continue evaluating commercial viability while aligning workforce, regulatory, and industrial policy so the state is prepared to capture economic value if viable resources are confirmed.

Introduction

The long-term scale and commercial viability of geologic hydrogen remain uncertain.   In the context of conventional hydrogen production (i.e., sources other than geologic), Michigan's existing demand is 39,100 metric tons per year and is almost entirely for industrial feedstock, with negligible fuel use.[2] The industries and infrastructure that could drive significant demand growth, including heavy-duty trucking and steel decarbonization, are at early stages of deployment. Recent analysis by the University of Michigan suggests that hydrogen demand in Michigan has the potential to increase by up to 60%

by 2030, driven by new opportunities in steelmaking and medium- and heavy-duty vehicle applications, and by between 420% and 2,700% by 2050.[2] This is, however, a potential increase rather than a forecast and is heavily dependent upon cost reductions, infrastructure deployment, and investment in the sector. Scenario analysis suggests that under favorable conditions, the state's hydrogen economy could support thousands of jobs, billions of dollars in economic activity, and reductions in greenhouse gas emissions by 2035. Under less favorable conditions, hydrogen demand is projected to remain near current levels, with only marginal growth.[2]

A 2025 techno-economic analysis by Stanford University found that natural geologic hydrogen could be produced at approximately $0.54/kg and stimulated geologic hydrogen at approximately $0.92/kg under optimal conditions, with total delivered costs remaining below $1/kg in favorable scenarios. These estimates are considerably lower than current hydrogen production costs ($2-$12/kg depending on pathway) and approach long-term cost targets required for widespread transportation use and broader hydrogen-technology adoption. Even after accounting for key sensitivities, including production flow rates, gas purity, delivery pressure, and exploration costs (up to ~$0.25/kg), the analysis suggests geologic hydrogen could deliver near $1/kg fuel at scale.[3]

If found to be commercially recoverable in Michigan, it is expected that geologic hydrogen would significantly reduce the cost of hydrogen production, drive investment in new and early-stage technologies, spur new economic opportunities, and strengthen the broader hydrogen ecosystem.

1. Potential Impact on Michigan's Job Market

1.1 Current Employment Levels

Michigan's hydrogen-adjacent sectors already employ several thousand workers across the state, which could serve as a baseline workforce for expansion of Michigan's hydrogen economy. BLS Quarterly Census of Employment and Wages data show that the industrial gas manufacturing sector in Michigan (NAICS 325120) grew from 386 workers in 2021 to 476 in 2024, across 14 establishments.[4] The inorganic chemical manufacturing sector (NAICS 325180) employed 819 workers in Michigan in 2024.[4] Support activities for mining (NAICS 213112), the sector most analogous to geologic hydrogen field services, employed 917 workers in Michigan in 2024.[4]

These figures reflect current employment levels rather than the workforce required for a scaled hydrogen economy inclusive of production, distribution, and end use demand. Because this infrastructure is largely undeveloped, current employment in these areas is negligible. The University of Michigan's 2024 Hydrogen Demand Analysis report notes that the state had only 5.5 miles of dedicated hydrogen pipelines, and nearly all current hydrogen is produced on-site or nearby end-use facilities.[2]

1.2 Projected Job Growth from Hydrogen Production and Distribution

Geologic hydrogen has the potential to create new employment opportunities across Michigan's economy tied to hydrogen production, processing, transport, storage, and downstream use. Any projection of job growth tied to specific NAICS classifications must be treated as highly uncertain at this stage, however. As the specific location, scale, production profile, and commercial viability of geologic hydrogen resources in Michigan remain unknown, it is not yet possible to estimate with confidence the timing or magnitude of resulting employment growth. The analysis that follows draws on existing projections of hydrogen demand growth in Michigan and on the current employment bases in hydrogen, petrochemical, and energy-related industries outlined above to identify where labor demand could plausibly expand if a geologic hydrogen industry emerges. To the extent that in-state geologic hydrogen production lowers supply costs or accelerates hydrogen market development, it could increase demand beyond currently published forecasts and amplify employment effects across the relevant sectors. In the near-term, employment impacts are expected to be modest.

Geologic hydrogen development may take at least two broad forms: naturally occurring accumulations, which are conceptually similar to gaseous deposits such as natural gas, and stimulated systems, in which subsurface reactions are induced or enhanced to generate recoverable hydrogen. As no commercial geologic hydrogen field has yet been developed in the Midwest, and the only well-documented example of a production site worldwide (Bourakébougou, Mali) is better thought of as small pilot-scale project, the best analogue for early-stage employment is likely upstream oil and gas.[21] In a natural-accumulation case specifically, initial work would likely resemble conventional petroleum development, including prospect generation, leasing, exploratory drilling, appraisal, well testing, completion design, surface handling, and field operations. Sandia National Laboratories notes that naturally accumulated geologic hydrogen would be the easiest form to produce because most of the required collection technologies and methods already exist in the oil and gas industry.[5] Similarly, the U.S. Geological Survey couches geologic-hydrogen assessment in a model based on the petroleum-systems concept, reinforcing the validity of using oil and gas as a baseline comparison for workforce needs.[6]

The Baker Institute study of upstream oil-and-gas investment offers a useful comparison for a high-level employment estimate. The study states that one additional active rig is associated with roughly 31 immediate new jobs and about 315 long-term jobs statewide.[7] While the applicability of these numbers to geologic hydrogen is uncertain, they do provide a reasonable reference for the scale of employment that early-stage activity could support. This suggests that initial exploration and production could generate employment in the tens during active drilling and appraisal, with broader spillover effects likely reaching into the low-to-mid hundreds if commercial production follows. The occupational mix would likely also resemble early upstream oil and gas, including geoscientists, petroleum and drilling engineers, drill operators, service-unit operators, laborers, pump operators, truck drivers, welders, electricians, and environmental and permitting staff.

Before hydrogen can support end uses in Michigan, it must be transported from the point of production to the point of use. Although this could theoretically occur by pipeline, marine shipment, rail, or truck, trucking is the most plausible early-stage option. DOE notes that hydrogen is currently transported primarily by pipeline and by road in liquid tanker trucks or gaseous tube trailers. Rail and marine transport remain less developed for hydrogen, particularly at commercial scale, and new pipeline infrastructure is capital intensive and unlikely to emerge at scale absent significant growth in the industry.[8] As a result, a Michigan geologic hydrogen industry would likely begin with truck-based distribution, with other transport modes emerging only as production volumes and market demand increase.

In 2022, McKinsey prepared a workforce analysis for the State of Michigan evaluating hydrogen's role in the labor force to support and inform strategy tied to Bipartisan Infrastructure Law funding. This analysis is best thought of as a high-demand high-investment scenario outlining the potential scope of Michigan's broader hydrogen transportation economy long-term. The report does not include a review of the potential for geologic hydrogen but does provide an illustrative look at key aspects of a potential mature hydrogen economy. Prepared in the context of considerable amounts of anticipated federal, state, and private-sector investment, the analysis modeled a full hydrogen transport value chain that included production, compression, distribution, refueling, and heavy-duty fuel-cell truck manufacturing. Under its low and high cases, McKinsey assumed Michigan would support 26 to 43 production facilities, 26 to 43 compression centers, 26 to 43 distribution centers, and approximately 520 hydrogen refueling stations by 2035, with total employment across the value chain reaching 6,500 to 8,400 jobs, including 1,030 to 1,240 construction jobs and 5,500 to 7,150 operational FTEs.[9]

These assumptions are aggressive and exceed plausible near- to medium-term geologic hydrogen distribution needs in Michigan. Even within the McKinsey document, employment tied specifically to refueling infrastructure is much smaller than the top line value-chain total. It is estimated that the build-out of approximately 520 refueling stations would support about 750 jobs, including roughly 430 construction-related jobs and 340 operations- and supply-chain-related jobs.[9] The distribution element itself is smaller still. McKinsey's breakdown shows that hydrogen compression and distribution account for only a modest share of projected employment relative to refueling and vehicle manufacturing, indicating that if Michigan geologic hydrogen production emerges gradually, jobs tied specifically to distribution would more plausibly number in the tens or low hundreds in the near-term, rather than the thousands associated with the build-out of statewide hydrogen transport infrastructure.

This interpretation is consistent with recent University of Michigan work, which suggests a more uncertain and longer-term demand trajectory than the rapid build-out implied by the McKinsey scenarios. This study does not review the impact of geologic hydrogen either and focuses instead on existing production pathways. The University of Michigan's statewide hydrogen demand analysis estimates current Michigan demand at roughly 39,100 metric tons per year and finds that 2050 demand could increase substantially, but over a very wide range depending on cost, infrastructure, and production scale.[2] In that context, the McKinsey results are best used as an upper-bound planning case for what an eventual, mature, hydrogen-powered transportation sector, inclusive of a built-out hydrogen distribution network, might eventually support. As noted, neither of these sources have evaluated the potential impact of geologic hydrogen on the market and it is very likely that the exceedingly low cost of hydrogen resulting from naturally occurring or induced sources would have significant impacts on the market, including rapid acceleration of technology adoption.

1.3 Downstream Industrial Employment

Beyond production and distribution, downstream hydrogen use in steel, semiconductors, and transportation could sustain or create manufacturing and operations jobs across Michigan's industrial base. University of Michigan analysis identifies the Cleveland-Cliffs Dearborn Works facility as a leading near-term steel application, estimating that hydrogen injection sufficient to replace 30 percent of coke in blast furnace operations would generate approximately 19,200 metric tons of annual hydrogen demand by 2030. The semiconductor sector, led by Hemlock Semiconductor and supported by CHIPS Act investment, is also projected to increase its hydrogen feedstock demand through the 2030 timeframe.[2]

As noted in the previous section, McKinsey's scenario for a mature hydrogen-powered transportation sector in Michigan estimates that hydrogen deployment across transportation and related infrastructure could support 6,500 to 8,400 jobs statewide.[9] However, these figures depend on substantial medium and heavy-duty hydrogen-vehicle adoption, sustained declines in hydrogen cost, and large-scale infrastructure investment. In practice, the realization of these employment gains would depend in part on the availability of lower-cost hydrogen supply, including any cost advantage that geologic hydrogen may provide.

Beyond existing downstream demand in petroleum refining, semiconductors, glass, and emerging transportation applications, additional industrial uses could become more viable in Michigan if low-cost, reliable hydrogen supply is established. Such a supply could support ammonia production, which has potential applications in fertilizer and chemical manufacturing, as a denser medium for hydrogen fuel transport, and in food processing. It could also strengthen the case for investment in fuel-cell and hydrogen-vehicle manufacturing, grid-scale long-duration chemical energy storage, and the commercialization of hydrogen-based technologies in aviation and marine transport. Because hydrogen is a flexible energy carrier and industrial input, broader availability could also create longer-term economic opportunities in areas such as defense applications, interstate exports, and other emerging industrial markets.

2. Workforce Needs and Retraining Opportunities

2.1 Skills Needed to Build and Operate a Hydrogen Economy

The hydrogen economy requires several core occupational categories, including construction trades for building facilities, operations and maintenance technicians for storage and transfer equipment, commercial vehicle mechanics for hydrogen powered truck fleets, and operators for end-use activities such as refueling stations or steel production.9

BLS occupational data provides a current snapshot of relevant Michigan workers. In chemical manufacturing (NAICS 3250A1), the largest occupation is Chemical Equipment Operators and Tenders at approximately 2,050 workers (17.9% of sector employment), followed by Chemists (570), Industrial Engineers (410), and Chemical Technicians (350).10 These occupations are transferable to hydrogen production facility operations.

The University of Michigan's demand analysis highlights that hydrogen also introduces specific safety training requirements that go beyond conventional chemical industry norms, including risks from metal embrittlement, odorless leakage, wide flammability range, and high flame temperatures.2 The report recommends that first responders receive dedicated hydrogen and fuel cell incident training. This creates a workforce development need that extends beyond production and transportation workers to emergency services personnel across the state.2

As discussed earlier, the best identifiable analogs indicate that the initial workforce needed for geologic hydrogen would be focused on exploration and drilling, tapping existing skills from the oil and gas industry. There would be modest training needs to address the specific handling of hydrogen for this early cohort. Future workforce development will need to be closely aligned with industrial sectors that invest in hydrogen technologies. Specifically, workforce development and training initiatives will require extensive coordination between the employers and training providers, a model which is already supported in other areas. The state can leverage existing registered apprenticeship programs that align with the hydrogen economy and existing employer engagement efforts at the Department of Labor and Economic Opportunity to begin building this pipeline.

2.2 Retraining Pathways

Michigan's existing oil and gas field services workforce represents a relevant retraining pool for geologic hydrogen exploration. The 917 workers currently employed in Support Activities for Mining possess skills in drilling operations, wellhead maintenance, and subsurface assessment that could translate directly to geologic hydrogen exploration work.[10]

State-level employment projections from the Michigan Center for Data and Analytics project a 5.1% decline in this sector from 2022 to 2032, which runs counter to the 2.4% national growth projected over a similar window by BLS.[11,12] This divergence suggests that Michigan's field services workforce may face contracting employment under the baseline and could represent an available pool of workers whose skills are directly applicable to geologic hydrogen exploration activity.

More broadly, industrial machinery mechanics, a critical occupation for hydrogen equipment maintenance, are projected to grow 14.4% in Michigan by 2032, adding approximately 2,970 net new positions statewide.[12] Chemical manufacturing sector employment is projected to grow by approximately 410 positions over the same period.[12] These baseline growth figures underscore that hydrogen represents a viable path for Michigan to outperform existing long-term projections for growth in these industries by expanding and adding opportunities across industrial sectors.

2.3 Policy Response: Building Coordinated and Responsive Sector Strategy for the State

Given the difficulty of forecasting the economic, industry, and workforce implications of geologic hydrogen, the state should establish mechanisms to bring policymakers, industry, academic institutions, labor, and other stakeholders together to identify emerging challenges and coordinate responses over time.

One model is proposed in the Council on Future Mobility and Electrification's 2025 Annual Report, which recommends establishing a Michigan Hydrogen Collaborative as a public-private initiative involving industry and academic partners. The proposed Collaborative, previously developed by an internal State of Michigan working group led by the Michigan Infrastructure Office, would support workforce development efforts in hard-to-abate sectors such as freight, medium- and heavy-duty trucking, steel manufacturing, marine transportation, and aviation, while also offering research and development funding and broader ecosystem building.[13]

This concept would complement Michigan's broader workforce development strategy and help create a training pipeline spanning exploration, production, distribution, and end use. As the hydrogen economy evolves, training programs would likely expand to address emerging opportunities in areas such as clean energy generation and storage, hydrogen technology manufacturing, and ammonia production. In addition, economically viable geologic hydrogen resources could give rise to region-specific opportunities and demand that would likely require support beyond a statewide coordinating body, including direct engagement with other states and federal partners on issues such as interstate hydrogen transport, regulatory alignment, and infrastructure deployment.

3. Projected Growth in New Business Formation

If economically recoverable, geologic hydrogen has strong potential to support new business formation in Michigan, but the opportunity is dependent upon cost, scale, and reliability of supply. The strongest economic rationale is that lower-cost, in-state hydrogen could improve the business case for downstream users and equipment suppliers that are currently constrained by high hydrogen costs and uncertain market demand. University of Michigan analysis estimates current statewide hydrogen demand at roughly 39,100 metric tons per year, with near-term demand growth of as much as 60 percent by 2030 and much larger long-term growth potential depending on costs, infrastructure, and production scale.[2] If geologic hydrogen can be produced competitively, Michigan would be better positioned to attract firms involved in hydrogen handling, storage, distribution equipment, industrial services, and chemical production.

Michigan already has a partial foundation for such a cluster, although recent developments suggest that growth is likely to be uneven rather than linear unless the hydrogen supply chain undergoes a fundamental shift, such as the one geologic hydrogen could provide. OPmobility announced plans in 2023 to establish a hydrogen storage manufacturing plant in Grand Blanc Township for high-pressure storage systems used in medium- and heavy-duty zero-emission mobility.[17] Bosch expanded its hydrogen presence in Michigan in March 2026, commissioning a new electrolyzer facility in Farmington Hills and identifying the site as its North American headquarters for electrolyzer and fuel-cell application engineering and testing.[18] At the same time, some earlier flagship projects have weakened or stalled. Nel hydrogen confirmed in their 2024 annual report that their proposed Plymouth-area electrolyzer gigafactory, expected to anchor a major clean-hydrogen manufacturing investment, has been “delayed due to a slower than expected growth in the electrolyser market in the United States”.[19] Honda also announced in January 2026 that it would discontinue production of fuel-cell systems at Fuel Cell System Manufacturing LLC in Brownstown, its joint venture with General Motors, before the end of 2026.[20]

Taken together, these developments suggest that Michigan’s opportunity is real, but that projections of new business formation should remain cautious. The state’s industrial base, engineering talent, freight connectivity, and potential subsurface storage advantages make it an attractive location for hydrogen-related manufacturing and industrial use over time. However, the recent pause or retrenchment of several announced projects underscores that the sector is still highly sensitive to policy uncertainty, capital costs, and unresolved demand. In that context, geologic hydrogen's principal economic value may be less in guaranteeing a wave of immediate new business formation than in improving the long-term competitiveness of Michigan as a location for hydrogen-related manufacturing, industrial use, and supporting services. In effect, geologic hydrogen could represent a potential solution to the "chicken-or-egg" question of hydrogen supply and demand.

4. Anticipated Statewide Economic Benefit

4.2 Characterizing the Scale of the Opportunity

As the location, scale, purity, producibility, and deliverability of geologic hydrogen resources in Michigan remain unknown, any estimate of statewide economic benefit is equally uncertain. A potential way to bound that uncertainty is to treat geologic hydrogen's economic value first as a potential cost advantage for Michigan hydrogen users rather than as a forecast of GDP or tax revenue. The University of Michigan estimates current statewide hydrogen demand at approximately 39,100 metric tons per year and finds that, by 2050, demand has the potential to grow by 420% to 2,700% depending on costs, infrastructure, and production scale.[2] That implies a long-term demand range of roughly 203,000 to 1.095 million metric tons per year under favorable economic conditions and a supportive policy/regulatory framework.

Recent techno-economic analysis of geologic hydrogen estimates production costs of $0.54/kg for natural hydrogen and $0.92/kg for stimulated geologic hydrogen under optimal conditions[3], indicating that geologic hydrogen could be materially cheaper than other supply pathways (e.g., steam methane reformation of natural gas is estimated to cost $1.50 - $2.50/kg)[14], if favorable resources are confirmed.

Using those demand figures, a simple illustrative calculation can be used to characterize the scale of possible statewide economic value. This specifically represents potential savings for buyers resulting from the lower costs of geologic hydrogen vs conventional production methods. This calculation applies an assumed delivered cost advantage for geologic hydrogen of $0.50 to $2.00 per kilogram relative to gray hydrogen, the next-cheapest conventional supply pathway, to demand levels projected for Michigan in the University of Michigan demand study. This calculation, in effect, estimates the gross annual value of meeting Michigan demand with lower-cost, Michigan-produced geologic hydrogen rather than a higher-cost alternative. Under that assumption, and assuming geologic hydrogen satisfies the full in-state market, the implied annual value of the cost advantage would be approximately $102 million to $407 million in the lower-demand 2050 case and $547 million to $2.19 billion in the upper-demand case. Expressed differently, that suggests geologic hydrogen's statewide economic value is most plausibly in the tens of millions of dollars per year in an early market, with hundreds of millions of dollars per year by 2050, a reasonable long-term planning range if commercially viable resources are confirmed and capture a meaningful share of Michigan demand. Billion-dollar annual benefits are possible, but likely only under high-resource, high-demand, high-utilization scenarios. These figures are estimates of gross annual cost-advantage ranges, not net economic-impact estimates, i.e., they do not account for exploration risk, unsuccessful wells, transport and storage build-out, regulatory costs, the pace of downstream market adoption, or economic benefits resulting from broader regional impacts.

4.2 Industrial Competitiveness and Cost Reduction

The most immediate statewide economic benefit of geologic hydrogen would likely result from improved competitiveness in industries that already use hydrogen or could adopt it if costs decline. The University of Michigan identifies steel, cement, refining, semiconductors, and glass among the state's most significant hydrogen demand centers. Among these, steel presents one of the clearest near-term applications. Hydrogen injection sufficient to replace 30 percent of coke at the Cleveland-Cliffs Dearborn Works facility would create approximately 19,200 metric tons of annual hydrogen demand by 2030. More broadly, the University of Michigan's long-term scenarios indicate that hydrogen demand could increase substantially if production costs fall and infrastructure expands, though the study is explicit that these scenarios are planning tools rather than forecasts.[2]

In this context, geologic hydrogen's economic significance lies in its potential to change the cost side of the equation. Hydrogen remains more expensive than incumbent fuels or feedstocks in several sectors, which limits adoption under current market conditions. If geologic hydrogen can be produced and delivered at materially lower cost, it could improve the economics of industrial decarbonization, reduce input costs for some facilities, and strengthen the case for retaining or expanding hydrogen-using industries in Michigan. This would be especially relevant for sectors facing long-term pressure to reduce emissions while maintaining cost competitiveness, including steel, chemicals, refining, and potentially ammonia production.

4.3 Business Formation, Capital Investment, and Job Creation

As discussed in Section 3, geologic hydrogen could support new business formation and expanded capital investment in Michigan if commercially viable, low-cost supply is confirmed. From a statewide economic perspective, the significance of that activity lies not only in the creation or attraction of individual firms, but in the broader economic effects that would follow, including direct employment in production and manufacturing, indirect employment across supply chains, increased demand for engineering and field services, and greater retention of energy-related spending within the state.

4.4 Regional Economic Effects, Energy Retention, and Export Potential

Geologic hydrogen could also generate broader regional economic benefits by retaining more energy-related spending within Michigan and, over time, positioning the state as a supplier to external markets. To the extent that hydrogen used in Michigan is produced in-state rather than imported or manufactured through higher-cost pathways, a larger share of the associated economic value would remain within the state economy. That could include wages, lease payments, service contracts, tax revenues, and business income tied to production, processing, storage, and downstream use. In regions where commercially viable geologic hydrogen resources are confirmed, local effects could include increased demand for field services, infrastructure upgrades, industrial development, and supporting commercial activity.

Over the longer term, if production volumes prove sufficient, Michigan could also benefit from interstate sales or regional export opportunities. Its industrial base, freight connectivity, and border infrastructure could support a broader role in hydrogen supply and related industrial activity. While these opportunities remain uncertain, they illustrate that the statewide economic benefit of geologic hydrogen is not limited to direct production alone. If resource quality, production economics, and infrastructure development align, geologic hydrogen could support a broader set of economic gains, including improved industrial competitiveness, new private investment, employment growth, and a stronger long-term position for Michigan in emerging hydrogen and low-carbon industrial markets.

5. Assessment of Geologic Hydrogen's Role in Advancing the MI Future Mobility Plan

5.1 Mobility Plan Priorities

The MI Future Mobility Plan 2.0 identifies hydrogen as a focus area under Goal 3, Strategy 3.2, which calls for the digital and physical infrastructure needed to support transformative mobility and improve safe, clean, and reliable transportation in Michigan.[15] In this context, the Plan's references to hydrogen focus on expanding refueling infrastructure for medium- and heavy-duty vehicles, supporting hydrogen-powered transit applications, and encouraging hydrogen production near end-use locations. Together, these investments are intended to reduce early infrastructure barriers and create a practical pathway for broader hydrogen adoption in transportation, giving policymakers a concrete mechanism to influence the pace of market development.

There are also ongoing efforts in Southeast Michigan to test hydrogen applications beyond these initial focus areas, including the use of mobile refueling and other flexible deployment models for return-to-base fleets such as buses, refuse trucks, delivery vehicles, and marine equipment. These pilot efforts are important because they can provide proof of concept, build familiarity with the technology, and reduce uncertainty around future deployment. More broadly, these priorities align with the University of Michigan's finding that near-term hydrogen demand growth in Michigan is most likely to come from steelmaking and expanded medium- and heavy-duty vehicle use, rather than from immediate mass-market adoption across the transportation sector.[2]

5.2 How Geologic Hydrogen Could Advance These Goals

The connection between geologic hydrogen and the Mobility Plan's transportation goals is indirect but considerable in two respects.

First, the refueling economics that determine hydrogen powered vehicle adoption rates are highly sensitive to delivered hydrogen cost. A kilogram of hydrogen is often cited as equivalent to a gallon of diesel, with the Alliance for Sustainable Energy citing $5/kg of hydrogen as the point at which total cost of ownership becomes competitive for heavy-duty trucks.[16] If geologic hydrogen were commercially recoverable in Michigan, it would represent a lower-cost domestic supply input that could radically improve the economics by offering hydrogen fuel prices closer to $1/kg.

Second, it is plausible that a geologic hydrogen well could be established at a remote site where transporting hydrogen to end-use locations, such as hydrogen vehicle fueling markets, would be prohibitively expensive. In that case, an alternative would be to generate electricity at the wellhead and, in effect, move that energy as electrons, a use case already demonstrated by the hydrogen field in Bourakébougou, Mali where a small power plant produces electricity for local energy needs.[22] This approach could help decarbonize Michigan's power sector while expanding the supply of low-carbon electricity available to meet projected growth in overall electricity demand, including for electric vehicles.

5.3 Timeline and Conditions

The geologic hydrogen exploration process established by Executive Directive No. 2026-1 will require time for geological assessment, permitting, and, if warranted, pilot extraction before any commercial-scale production could contribute to that supply picture.[7]

This means that geologic hydrogen will not factor in to the plan's goals in the near-term as a low-carbon/carbon free fuel source, rather Its early-stage contribution is more likely to come through knowledge generation and early-stage market signals. If exploration yields commercially viable findings, geologic hydrogen would represent a strong justification for new investment into hydrogen mobility technologies in anticipation of a future supply chain. In this scenario, geologic hydrogen would become a meaningful supply source for a later phase of refueling infrastructure investment, though the timeline for commercial readiness remains speculative in the absence of exploration data.

Conclusions

Based on the information reviewed, geologic hydrogen presents a potentially significant but uncertain economic opportunity for Michigan. The scale of that opportunity depends upon whether commercially recoverable resources exist in the state, whether they can be produced and delivered at costs meaningfully below other hydrogen pathways, and whether downstream demand develops at sufficient scale to justify investment in production, distribution, and end-use infrastructure. Geologic hydrogen represents a strategic opportunity with potentially large upside but is not an assured near-term economic driver.

1. Job market impact

If commercially viable geologic hydrogen resources are identified in Michigan, early employment is likely to resemble upstream oil and gas, with near-term jobs concentrated in exploration, drilling, appraisal, field services, and limited early-stage distribution. Initial impacts would likely be modest, with employment in the tens during active exploration and appraisal, with broader spillover effects potentially reaching the hundreds if commercial production follows. Larger job totals cited in statewide hydrogen planning documents are best thought of as upper-bound scenarios for a mature hydrogen economy with an undefined timeline, rather than as forecasts for geologic hydrogen alone.

2. Workforce needs and retraining

Michigan has a relevant base of transferable skills in drilling, field services, chemical manufacturing, construction trades, industrial maintenance, and emergency response that could support early geologic hydrogen activity. However, hydrogen-specific safety, handling, and operational requirements will require targeted training and coordination between employers, training providers, labor, and state agencies. A coordinated statewide strategy would improve the state's ability to respond as workforce needs evolve from exploration to production, distribution, and end use.

3. New business formation

Geologic hydrogen could support new business formation in Michigan, but the effect is likely to be gradual, rather than immediate, and is dependent upon delivered cost of hydrogen fuel and broader investment in the sector and related infrastructure. The most important economic mechanism is the possibility that lower-cost, in-state hydrogen supply could improve the business case for downstream manufacturers, industrial users, and specialized service providers that are currently constrained by cost and market uncertainty. Michigan's industrial base and logistics assets provide a strong foundation, but recent hydrogen-sector developments also show that the market remains sensitive to policy conditions, capital costs, and unresolved demand. Validation of commercially viable geologic hydrogen resources would be a significant early milestone signaling that these longer-term opportunities for business formation, industrial expansion, and supply-chain growth are increasingly attainable.

4. Statewide economic benefit

The statewide economic benefit of geologic hydrogen is difficult to predict precisely, but it could be substantial if favorable resource and cost conditions are confirmed. The draft analysis suggests that geologic hydrogen's principal economic value would come from lowering hydrogen supply costs for Michigan users, improving industrial competitiveness, attracting private investment, supporting new business activity, and retaining more energy-related spending within the state. As illustrated in section four, the potential economic value is most plausibly in the tens of millions of dollars in an early market, with hundreds of millions of dollars per year by 2050.

5. Role in advancing the Mobility Plan

Geologic hydrogen could strengthen the long-term economics of hydrogen mobility and related infrastructure by lowering delivered fuel costs and supporting future investment in refueling and end-use applications. However, given the time required to develop production and distribution systems, geologic hydrogen is unlikely to represent a source of low-carbon/carbon-free fuel in the near term. Geologic hydrogen instead creates a stronger economic rationale for later hydrogen mobility investment if commercial resources are confirmed.

Overall Conclusion

At this stage, the strongest policy conclusion is that geologic hydrogen is a potentially high-value strategic resource whose ultimate significance will depend on resource quality, production economics, infrastructure development, and downstream market adoption. Taking an early and coordinated approach could give Michigan an advantage in attracting investment and shaping the development of this emerging sector. Michigan's most prudent course is to continue evaluating commercial viability while aligning workforce, regulatory, and industrial policy so that the state is prepared to capture economic value if viable resources are confirmed.

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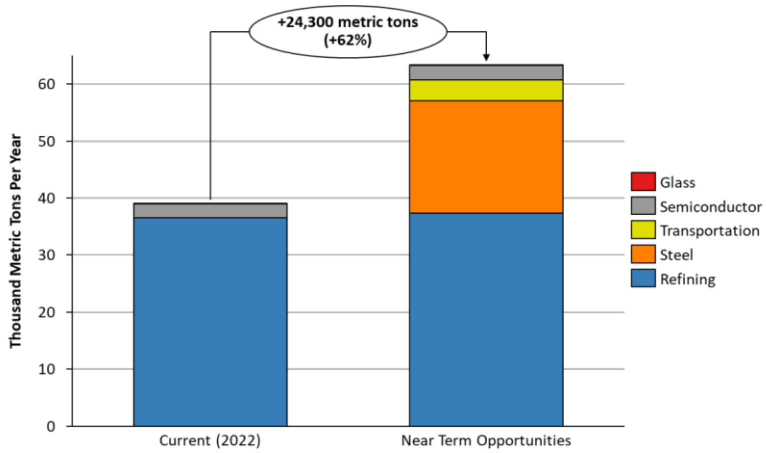
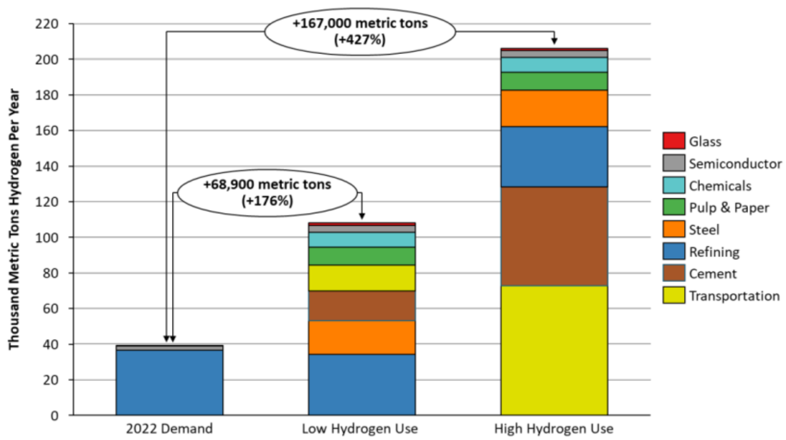
Appendix

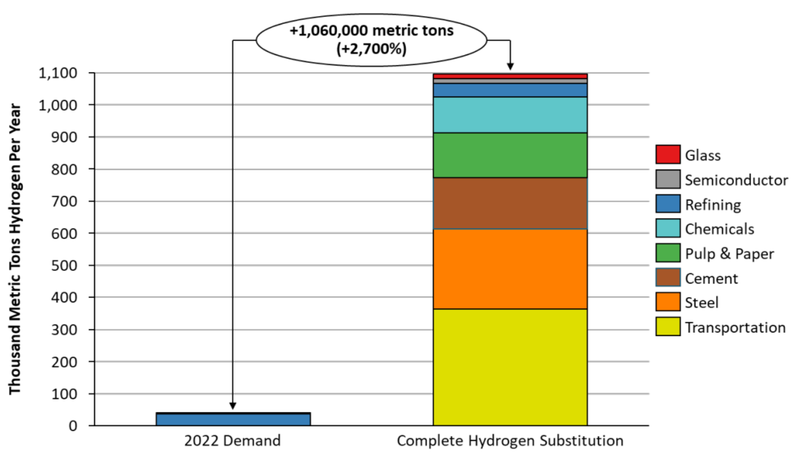
Charts from *State of Michigan Hydrogen Demand Analysis* by the University of Michigan [2]



Annual hydrogen demand in the "Near-Term Opportunities" scenario for 2030 indicates an increase in demand by 62% from current (2022) demand, with petroleum refining and steel accounting for a majority of the scenario's demand.[2]



Long-term (2050) potential hydrogen demand in the "Low Hydrogen Use" and "High Hydrogen Use" scenarios as compared to current (2022) hydrogen demand.[2]



Long-term (2050) potential hydrogen demand in the "Complete Hydrogen Substitution" scenario as compared to current (2022) hydrogen demand.[2]

Preparing for Hydrogen

Submitted to the Executive Office of the Governor in Response to Executive Directive 2026 - 1

April 16, 2026

Dan Scripps, Chair

Katherine Peretick, Commissioner

Shaquila Myers, Commissioner

Table of Contents

Executive Summary

On January 15, 2026, Governor Gretchen Whitmer issued *Executive Directive 2026 – 1 Establishing the Michigan Geologic Hydrogen Exploration and Preparedness Initiative*. As part of this directive, the Commission was asked to submit a report to the Executive Office of the Governor detailing

1. The suitability of existing energy infrastructure – including but not limited to natural gas pipelines – for hydrogen blending, transport, or dedicated use,
2. Associated safety requirements and system constraints,
3. Necessary upgrades,
4. Long-term infrastructure planning considerations, and
5. Jurisdictional, utility planning, and legal or policy issues related to hydrogen transportation or storage in regulated systems.

Broadly speaking, Michigan is well positioned from a regulatory perspective to incorporate hydrogen into the energy economy. The State's Gas Safety Standards, cost recovery mechanisms, and long-term electric utility planning processes can all be applied to hydrogen related pipeline transportation, utility costs, and utility planning. Siting authority for hydrogen specific pipelines however does not exist at either the state or federal level and addressing this deficiency is important to enabling broad hydrogen utilization. For this reason, Public Act 9 of 1929 would need to be amended to bring the Commission's regulatory authority over hydrogen pipelines to parity with the authority it has over natural gas pipelines.

The physical and safety characteristics of hydrogen create several challenges for its transportation using existing pipeline infrastructure including leak detection, effective odorization, compatibility of system components, and embrittlement, which will remain impediments to converting pure hydrogen pipelines until such a time that solutions can be identified and implemented. As such, it is most likely that hydrogen pipelines in Michigan would be new, purpose-built pipelines akin to hydrogen pipelines in the Gulf Coast Region which serve industrial demand and where hydrogen is transported a short distance compared to natural gas transmission, and at a constant, relatively low pressure.

Introduction

As governments and industry look for opportunities to reduce carbon emissions, especially in hard-to-abate applications, the potential role that hydrogen could play in these efforts is of interest. Executive Directive 2026 – 1 asks the Commission to prepare a report addressing:

1. The suitability of existing energy infrastructure – including but not limited to natural gas pipelines – for hydrogen blending, transport, or dedicated use,
2. Associated safety requirements and system constraints,
3. Necessary upgrades,
4. Long-term infrastructure planning considerations, and
5. Jurisdictional, utility planning, and legal or policy issues related to hydrogen transportation or storage in regulated systems.

The following report is prepared in response to this request.

Hydrogen Transportation

Similar to other fuels, hydrogen must be transported from the point of production to the point of use. This transportation is most efficiently and cost effectively accomplished via pipeline, which, depending on the end use of the hydrogen, may include elements of transmission, storage, compression, blending, and distribution. Because these elements are present in the existing pipeline systems that transport natural gas, there is an interest in understanding the extent to which existing infrastructure could be used or repurposed to transport hydrogen.

The Physical Properties of Hydrogen

Hydrogen gas can be transported in pipelines either as a blend of natural gas and hydrogen or as pure hydrogen. It is technically feasible that hydrogen blended with natural gas at low concentrations could use existing natural gas infrastructure, however it is most likely that pure hydrogen would be transported in dedicated, purpose-built hydrogen pipelines. The effects of introducing hydrogen, either pure hydrogen or blended with natural gas, into existing natural gas transportation infrastructure, infrastructure materials, and end-use equipment are being studied in a litany of research and development initiatives.[1]

The physical and safety characteristics of hydrogen present unique considerations for its transportation. Hydrogen, the lightest and smallest element, is

[1] PHMSA Website for All Research & Development Program Awards: https://primis.phmsa.dot.gov/rd/matrix/search/

a gas under atmospheric conditions and therefore prone to leakage; it is also odorless, colorless, and tasteless, presenting challenges to leak detection. While hydrogen is non-corrosive, it is highly flammable and can embrittle some metals, including steel. Because of its atomic weight, gaseous hydrogen disperses more quickly, through less porous material, and farther than natural gas under similar conditions. To date, odorants have not been used with pure hydrogen because there are no known odorants light enough to disperse with hydrogen at the same rate. In the event of a hydrogen release, the odorant would not provide adequate indication of a leak because hydrogen, being lighter and smaller, would disperse further and faster than the odorant. Additionally, hydrogen has a flammability range of 4 – 75% gas in air compared to 5 -15% for methane.[2] This means that hydrogen can ignite in much broader concentrations as compared to other fuels such as gasoline, propane, and natural gas. It also has a much lower auto-ignition temperature which means it can ignite without the presence of an actual flame or spark. Therefore, a leak of any kind is cause for concern.

Technological Considerations and Infrastructure

There are just over 1,600 miles of hydrogen gas pipeline operated in the United States by 31 operators. Of this, there are approximately 700 miles of interstate hydrogen pipelines and about 900 miles of intrastate hydrogen pipelines. These steel pipelines are primarily located in the Gulf Coast Region serving industrial demand such as petroleum refineries and chemical plants where hydrogen is transported a short distance compared to natural gas transmission, and at a constant, relatively low pressure.[3]

By way of contrast, as of 2024, the Pipeline and Hazardous Materials Safety Administration (PHMSA) reports there are approximately 300,000 miles of natural gas transmission and approximately 2.4 million miles of natural gas distribution pipeline in the United States. Michigan has approximately 8,700 miles of natural gas transmission pipeline managed by 36 operators (Figure 1). Nearly all (99.67%) of the natural gas transmission pipelines in Michigan are composed of steel.[4]

Additionally, there are approximately 3,500 miles of hazardous liquid pipeline in Michigan (Figure 2). These pipelines transport crude oil (~1,500 miles); refined petroleum products (~1,400 miles); and highly volatile liquids, flammable liquids, and toxic liquids (~600 miles).

There was previously one hydrogen gas pipeline segment (5.5 miles) in Michigan operated by Linde (formerly Praxair); however this line was permanently removed from service in March of 2021 by disconnecting the pipeline from all sources and supplies of gas and purging the pipeline in accordance with the Michigan Gas Safety Standards and Code of Federal Regulations Part 192, Transportation of Natural and

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[2] Pacific Northwest National Laboratory (PNNL), "Hydrogen Compared with Other Fuels," Hydrogen Tools Portal, 2020, https://h2tools.org/bestpractices/hydrogen-compared-other-fuels.

[3] PHMSA website Pipeline Safety Stakeholder Communications: https://primis.phmsa.dot.gov/comm/hydrogen.htm

[4] PHMSA website Annual Report Mileage Summary Statistics: https://www.phmsa.dot.gov/data-and-statistics/pipeline/data-and-statistics-overview

Other Gas by Pipeline: Minimum Federal Safety Standards. MPSC Staff conducted pipeline safety inspections of this pipeline pursuant to PA 165 of 1969 while it was operational.

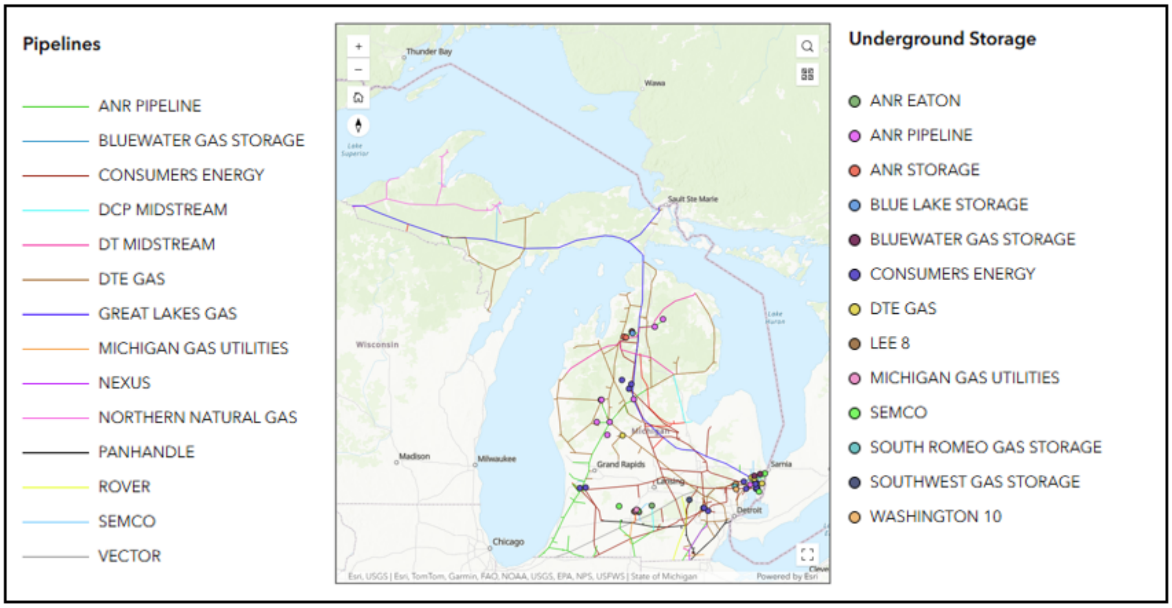

Figure 1. Natural Gas Transmission Pipelines and Underground Natural Gas Storage in Michigan[5]

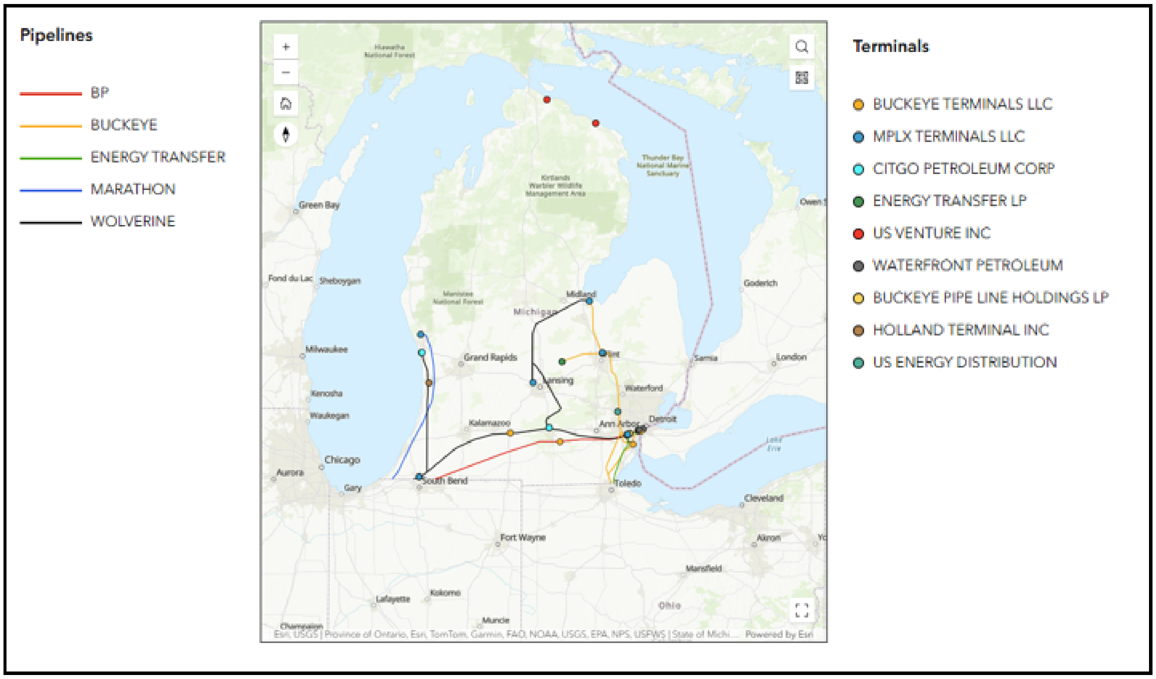

Figure 2. Refined Petroleum Product Pipelines and Terminals in Michigan[6]

Turning to the natural gas distribution system, Michigan's natural gas system has over 63,000 miles of distribution pipelines and close to 3.4 million service lines. In the mid-1970s and early 1980s, the industry began shifting to using predominantly plastic pipes for the distribution system. Beginning in 2011, Michigan natural gas

[5] Michigan Public Service Commission GIS Hub: https://data-michiganpsc.hub.arcgis.com/pages/natural-gas
[6] Michigan Public Service Commission GIS Hub: https://data-michiganpsc.hub.arcgis.com/pages

distribution utilities increased the replacement of leak prone cast iron and steel distribution lines with plastic lines, and these efforts are still ongoing. Today, a majority of distribution pipelines in Michigan are plastic. In addition to being used for distribution lines, plastic lines are also used for a majority of service lines.

The existing natural gas pipeline system in Michigan may be able to be used to transport hydrogen either as an admixture at low concentration (that is hydrogen blended with natural gas) or by converting pipelines to dedicated hydrogen pipelines. In either case, there are several pipeline safety considerations that must be addressed. Additionally, the design of the natural gas system itself presents technological challenges to transporting both hydrogen blends and pure hydrogen. The natural gas pipeline system is optimized for methane, not hydrogen. Compared to natural gas, hydrogen has a smaller mass, molecule size, and lower British Thermal Unit (Btu) content, and would require additional energy to move the hydrogen through the distribution system for delivery to customers.[7] Given these different physical qualities, several possible issues may arise when attempting to introduce hydrogen into a methane-optimized system.

Hydrogen?Natural Gas Blends

When considering blending hydrogen into existing transmission and/or distribution pipelines, the first item that must be addressed is the amount of hydrogen in the blend. It is important that the amount of hydrogen in the system be set at a level that does not compromise system integrity and does not negatively affect end users or appliances. Blends of 2-20% hydrogen have been investigated in the natural gas system.[8] However, some studies have shown that embrittlement of steel pipelines can occur with hydrogen concentrations as low as 5%. Additionally, concentrations greater than 20% hydrogen increase the risk of permeating plastic pipes.[9]

Leakage

In steel transmission pipes, system leakage generally occurs at joints, microscopic cracks, and seals. Given the increased mobility of hydrogen compared to natural gas, hydrogen is more prone to leak in steel transmission lines than natural gas. Therefore, the age and condition of each specific existing steel pipeline under consideration for transporting a hydrogen blend would have to be understood before determining if it could be a candidate for carrying a hydrogen blend.

In polymer materials, including plastic pipes and seals, hydrogen's increased mobility makes permeation more likely. Permeation rates, meaning the speed at which a chemical passes through a solid material, are 4 to 5 times faster for

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[7] Compressing hydrogen into liquified hydrogen requires 40% more energy than what is needed to compress natural gas into liquified natural gas (LNG). Michigan does not have LNG operations presently. https://www.sciencedirect.com/science/article/pii/S0016236123013923, retrieved March 6, 2026.

[8] GPI Hydrogen Transportation Brief: https://betterenergy.org/wp-content/uploads/2024/06/Hydrogen-Transportation-Issue-Brief.pdf

[9] Miroslav Penchev, Taehoon Lim, Michael Todd, Oren Lever, Ernest Lever, Suveen Mathaudhu, Alfredo Martinez-Morales, and Arun S.K. Raju*. 2022. Hydrogen Blending Impacts Study Final Report. Agreement Number: 19NS1662. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF

hydrogen than methane in the plastic pipes typically used in the distribution system. This means that hydrogen can escape from these pipes even where there are no cracks or other anomalies that would traditionally give rise to leakage concerns, perpetuating concern about hydrogen leakage when utilizing the existing infrastructure. While some permeation of natural gas in plastic pipelines also occurs (as shown in Table 1 below), natural gas permeation occurs at a significantly lower rate and is typically contained within the plastic pipeline itself. The permeation rate also increases with pressure. Natural gas distribution systems generally range from 0.25 psig to 60 psig, however there are distribution systems that operate at higher pressures as well.

Hydrogen Content	At 60 psig			At 3 psig			At 0.25 psig		
	H_2	CH_4	Total	H_2	CH_4	Total	H_2	CH_4	Total
0%	0.0	49.4	49.4	0.0	2.5	2.5	0.0	0.2	0.2
10%	32.9	44.5	77.4	1.6	2.2	3.9	0.1	0.2	0.3
20%	65.9	39.5	105.4	3.3	2.0	5.3	0.3	0.2	0.4
50%	164.7	24.7	189.4	8.2	1.2	9.5	0.7	0.1	0.8
100%	329.3	0.0	329.3	16.5	0.0	16.5	1.4	0.0	1.4

Table 1: The Calculated Gas Loss Rate (ft^3/mile/year) Based on Literature Data for High-Density Polyethylene (HDPE) Pipes at the Operating Pressures of 60 psig, 3 psig and 0.25 psig.[10] CH_4 is Methan while H_2 is Hydrogen.

In order to transport a hydrogen blend or pure hydrogen in the existing natural gas system, an operator would need to ensure all elements of the system, pipes, materials in compressor stations, and other components, were compatible with hydrogen, not only for transportation, but also for monitoring pressure and volumes throughout the system. For both transmission and distribution systems, operators would need to modify and upgrade leak detection equipment to be compatible with hydrogen. A research project investigating the impact of hydrogen on leak detection equipment[11] was conducted between 2022 and 2025, but a final report has not been issued. Research projects are ongoing to develop best practices related to repair and maintenance methods for steel and plastic pipes[12] and appropriate inspection intervals for natural gas systems transporting blended hydrogen[13], but results are not yet available.

Hydrogen embrittlement

The presence of hydrogen can deteriorate steel pipe, pipe welds, valves, and fittings through a variety of mechanisms. This is referred to as hydrogen embrittlement. When atomic (unpaired) hydrogen diffuses into the material, it causes hydrogen embrittlement, which can lead to cracking, blistering, and

[10] GTI Project Number 21029, Final Report, Review Studies of Hydrogen Use in Natural Gas Distribution Systems, 2010. https://docs.nlr.gov/docs/fy13osti/51995.pdf
[11] https://primis.phmsa.dot.gov/rd/projects/979/
[12] https://primis.phmsa.dot.gov/rd/projects/1036/
[13] https://primis.phmsa.dot.gov/rd/projects/1009/

weakness under tension. Hydrogen embrittlement is a greater risk in the types of high-pressure, high-strength steel typically used for natural gas transmission than in low-pressure, low-strength distribution pipes. The susceptibility of a given pipeline to hydrogen embrittlement depends on many factors, including hydrogen pressure, concentration, and temperature, as well as the specific properties of the type of materials used and other operating conditions. [14]

Hydrogen embrittlement can potentially be mitigated by coating the inner wall of the steel pipe, more advanced leak monitoring, or purpose-built pipes. The U.S. Department of Energy (DOE) has investigated the use of fiber reinforced polymer (FRP) pipelines as an alternative to steel for the transportation of hydrogen in newly built pipelines because it is available in longer lengths than steel (~0.5 miles) which would require fewer welds compared to a similar length steel pipe. Additionally, FRP is not susceptible to hydrogen embrittlement and has a comparable cost to steel[15] making it particularly attractive for purpose built, hydrogen pipelines.

Hydrogen impact on residential gas meters, customer piping, and appliances

The issues of leakage and embrittlement that can impact the transmission and distribution system also impact customer piping and equipment. While embrittlement and leak risks are lower in low-pressure piping, such as those in customer facilities, compared to the high-pressure piping of the transmission and distribution systems, risks remain.

The introduction of a hydrogen blend into the natural gas system would require attention to several customer-facing considerations. In a residential setting, gas meters, customer fuel lines, and customer appliances may not be compatible with a blended fuel and could be prone to leaks, increasing the risk of explosions or fire. Without a readily available in-home detection method, this risk is exacerbated. Customer fuel lines are not regulated by the MPSC or PHMSA.

Presently, there are only pilot pojects to deliver blended natural gas and hydrogen distribution to residential customers in the United States[16]. At least in the near term, it is not clear that there is a viable pathway to mitigate the health and safety risks associated with hydrogen blending for residential use at scale.

Hydrogen energy content

Natural gas has about three times more energy by volume than hydrogen. Consequently, a blend of natural gas and hydrogen would provide proportionally less energy for the end use when compared to the same volume of natural gas alone.

The lower energy content of a natural gas and hydrogen blend leads to potential system impacts. It is possible that the energy content of the blended gas delivered to customers could be below the threshold specified by the MPSC Technical Standards for gas service. Additionally, a potentially lower energy content gas, like a hydrogen blend, could require overall system modifications to ensure there will be adequate fuel availability on peak fuel days during the winter heating season.

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[14] NREL Report, Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues. https://docs.nlr.gov/docs/fy13osti/51995.pdf

[15] U.S. Department of Energy Website: https://www.energy.gov/eere/fuelcells/hydrogen-pipelines

[16] American Gas Association Hydrogen Projects and Research website: https://www.aga.org/wp-content/uploads/2023/08/Hydrogen-Activity-Tracker.docx

Integrity management

Adding hydrogen into the pipeline network changes the pipeline operating environment, which may accelerate crack propagation or fatigue failures from existing anomalies, and thus adversely impact pipeline integrity. There may be certain anomalies which are acceptable under current integrity management criteria (i.e. natural gas only) which will become critical if hydrogen is introduced due to the material property change in an environment containing hydrogen. The acceptable anomalies in the natural gas pipeline systems are defined in the current integrity program by the number, type, distribution and the shape of the anomaly. The concerns that arise relative to these anomalies when hydrogen is introduced include the stress generated at an anomaly and the rate at which the anomaly can propagate if the stress is over the critical value for crack propagation. To ensure appropriate pipeline integrity and address these concerns, an operator would need to incorporate hydrogen-related considerations into their integrity management programs for transmission and distribution.[17]

Downstream extraction

While discussions of the impact of hydrogen on the distribution system assume that blended natural gas and hydrogen would replace a natural gas-only distribution service, downstream extraction of hydrogen may occur provided that the hydrogen in a blend is separated before entering the distribution system and used elsewhere as pure hydrogen, for instance by an industrial customer. This would limit the impacts of the challenges identified above to the transmission system only and create a transportation option for hydrogen where the end use required pure hydrogen as opposed to a hydrogen blend.

There are several methods that can be used to accomplish downstream extraction of hydrogen.[18] Importantly, unless the unblending occurred at an existing pressure reduction facility, separation facilities would be required, and the natural gas remaining from the unblending would need to be recompressed for continued transport through the system. This would require additional facilities and resources, which would have a cost impact.

100% hydrogen pipelines

It is likely that transport of hydrogen to industrial customers would occur with new, purpose-built hydrogen pipelines made of steel or potentially from a composite material such as fiber reinforced polymer[19]

Using existing gas infrastructure to accommodate 100% hydrogen is not likely to be feasible. Pipeline integrity, leaks, effective odorization, compatibility of system

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[17] Operators would need to comply with Federal regulations governing integrity management programs, specifically 49 CFR subpart P and 49 CFR subpart O. Several states have hydrogen transmission pipelines. Texas (~1,000 miles) and Louisiana (~500 miles) have over 90% of the ~1600 miles of hydrogen transmission pipelines in the U.S. . Other States with hydrogen transmission pipelines include Alabama (~31 miles), California (~ 27 miles), Ohio (9.2 miles), and Oklahoma (1.5 miles). Additionally, Pennsylvania has 1.8 miles of hydrogen distribution line with 5 services. Michigan based operators could look to operations in these states to inform the development of their required programs.

[18] Gas Technology Institute (GTI) Project Number 21029: Review of Hydrogen Use in Natural Gas Distribution Systems, 2010. https://docs.nlr.gov/docs/fy13osti/51995.pdf

[19] U.S Department of Energy Webpage: https://www.energy.gov/cmei/fuels/hydrogen-pipelines

components, and embrittlement remain impediments to converted pure hydrogen pipelines until such a time that solutions can be identified and implemented.

Regulatory Considerations

In considering Michigan's regulatory framework around hydrogen, the Gas Safety Standards, Public Act 165 of 1969 (MCL 483.151 – 483.162), define "gas" as "natural gas, flammable gas, or gas that is toxic or corrosive." This is the same definition used in the Code of Federal Regulations, 49 CFR 191.3 and 49 CFE 192.3. Where a statute uses the term "gas" but does not define it, we utilize this same definition. Because hydrogen is a "flammable gas," Michigan laws that reference "gas" without any further qualifier and any delegation of federal authority related to "gas" can, therefore, be read to encompass hydrogen. As noted above, such a reading has been previously adopted by the Commission to support hydrogen pipeline safety inspection activities.

Pipeline Safety

Presently, there are limited regulatory differences between hydrogen and natural gas pipeline transportation. Hydrogen and natural gas blends are not defined in federal regulations; however, the U.S. Department of Transportation (DOT) has regulated hydrogen pipelines since 1970 under 49 CFR Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards.

Federal regulations (49 CFR 192.53) require that materials for pipe and components must be able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated; are chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and are qualified with the applicable requirements of Subpart B of Part 192. This means that any pipe and components that transport hydrogen or a hydrogen blend must be chemically compatible with hydrogen; must be able to keep the product in the pipe; and these materials must meet the minimum requirements prescribed in Subpart B regarding material selection, handling, and records.

Additionally, 49 CFR 192.625 requires that after December 31, 1976, combustible gas in a transmission line in urban areas must be odorized unless it is hydrogen that is used as a raw material or ingredient in a manufacturing process. An example of this is using hydrogen in ammonia synthesis to create nitrogen fertilizer. As noted previously, the physical properties of hydrogen present a challenge to complying with this requirement that must be addressed before hydrogen could be utilized more broadly.

In addition to federal regulations, which are adopted by Michigan, the Michigan Gas Safety Standards and Technical Standards for Gas Service[20] are not specific to natural gas; rather, they are applicable to any "flammable gas," including hydrogen. As a result of this broad statutory authority, Michigan is well positioned to regulate the safety of pipelines carrying either hydrogen blends or pure hydrogen.

Pipeline and Storage Siting

While the MPSC has pipeline siting authority for natural gas, carbon dioxide, crude oil, and petroleum or petroleum products, it does not have pipeline siting authority for hydrogen. Public Act 9 of 1929 (MCL 483.101-483.120) grants the MPSC siting authority for intrastate natural gas pipelines while Public Act 16 of 1929 (MCL 483.1 – 483.11) grants the Commission siting authority for both intra and interstate liquid pipelines, including carbon dioxide. The Federal Energy Regulatory Commission (FERC) holds jurisdiction over interstate natural gas pipeline siting pursuant to the Natural Gas Act (15 U.S. Code Chapter 15B). However, because the Natural Gas Act does not include hydrogen in its definition of "natural gas," FERC does not have siting authority for pure hydrogen pipelines.[21] As neither FERC nor the MPSC have authority to site these lines, a significant gap exists that would need to be addressed.

Michigan has the most underground natural gas storage by volume of any state in the United States. If geologic hydrogen is discovered and produced in Michigan, hydrogen storage would likely be required. Storage of hydrogen would most likely occur in one of two ways: 1) underground storage in a salt cavern (as is done in Michigan with natural gas today), or 2) above ground in storage tanks (as is done with natural gas in many other states). In either case, the MPSC does not have siting authority for hydrogen storage. Public Act 238 of 1923 (MCL486.251 – 486.255) grants the Commission authority to site underground natural gas storage, but this is specific to natural gas and is therefore not applicable for underground storage of hydrogen.

Storage of gaseous or liquified hydrogen in aboveground tanks is regulated by the Department of Licensing and Regulatory Affairs (LARA), Storage Tanks Section. If hydrogen is stored in a subsurface salt cavern, the Michigan Department of Environment, Great Lakes, and Energy (EGLE) Geologic Resources and Mineral Division (GRMD) would lead on obtaining siting authority.

Additionally, the MPSC does not have any authority for hydrogen production facilities. Rather, authority for regulating hydrogen production facilities creating hydrogen by Steam Methane Reforming, electrolysis or other processes is held by the Occupational Safety and Health Administration (OSHA) under 29 CFR 1910.103 which governs construction requirements for gaseous or liquid hydrogen facilities, including setbacks from other buildings and where there is a concentration of

[20] Michigan Public Service Commission Administrative Rules and Laws: https://www.michigan.gov/mpsc/regulatory/administrative-rules-laws

[21] 15 USC 717 defines "natural gas" as "either natural gas unmixed, or any mixture of natural and artificial gas."

people. For geologic hydrogen, EGLE GRMD would regulate the permitting and wellsite facilities required to drill and operate a hydrogen well whether it be as a byproduct of oil and gas production, a free-flowing hydrogen producing well, or a hydraulically fractured hydrogen producing well.

Existing Pipelines and Pipeline Easements

As discussed above, intrastate natural gas pipelines are sited by the Commission pursuant to Public Act 9 of 1929. Section 9 of Act 9 (MCL 483.102) says that no one will be granted the right of condemnation and access to the highways to "lay or construct, maintain or operate a pipeline or lines for the transmission or transportation of natural gas unless and except such pipe line or lines are to be used solely and exclusively for the transmission, transportation and distribution of natural gas within the state of Michigan." The "solely and exclusively" language of the act could impede the ability to convert the existing natural gas system to transportation of pure hydrogen if a party with legal standing successfully challenged such conversion. It is also possible that successful challenges could be made to the transportation of hydrogen blends though Act 9 sited lines. Amendments to Act 9 or other statutory changes specifically allowing for the transportation of blended hydrogen in natural gas pipelines would foreclose such challenges. Whether existing easements could be used for new hydrogen pipelines would be dependent upon the terms of the individual easements.

Franchise Agreements and Certificates of Necessity

Pursuant to Public Act 69 of 1929 (MCL 460.501 – 460.506), any public utility seeking to serve a municipality (including a city, village, or township) must have a franchise from the municipality and obtain a Certificate of Convenience and Necessity from the Commission to serve the specifically proposed service territory. PA 69 defines "public utility" as "persons and corporations . . . owning or operating . . . equipment or facilities for producing, generating, transmitting, delivering or furnishing gas or electricity for the production of light, heat or power to or for the public for consumption." The Act 69 requirement applies to "gas" and thus is not specific to only natural gas. Indeed, the requirements of Act 69 have been applied to both natural gas and propane. Distribution of hydrogen gas for industrial uses is likely to be subject to PA 69's franchise and Certificate of Convenience and Necessity requirements. Whether existing franchise agreements and Certificates of Convenience and Necessity granted under PA 69 would encompass hydrogen service is likely to turn on the terms used in the specific franchise agreement and applicable Certificate.

Cost Recovery and Long-Term Planning

The MPSC has significant authority related to utility cost recovery and long-term planning that is applicable to both regulated electric and gas utilities.

Turing first to cost recovery, cost recovery for both electric and gas utilities occurs primarily through two proceedings. The first is the rate case proceeding established in MCL 460.6a where utilities seek recovery of capital investments as well as operations and maintenance and other costs. It is through the rate case process that gas utilities would seek to recover investments needed to modify the existing natural gas system to accommodate hydrogen transportation and distribution. Electric utilities would use this same process to recover any investments made to build or adapt generation facilities to allow for a hydrogen or hydrogen-blend fuel to generate electricity. No changes to statute are necessary to allow for the recovery of these costs. Rather, it would fall to the utility to demonstrate that the expenditures meet the appropriate legal threshold of being "reasonable and prudent." The utility would also need to demonstrate that the expenditures were for assets that were "used and useful."

Next, both electric and gas utilities utilize cost recovery plans and reconciliations (power supply cost recovery for electric utilities and gas cost recovery for gas utilities) to recover the cost of purchased power and fuel (for electric utilities) as well as natural gas (gas utilities). Both gas and electric utilities may be able to recover the cost of hydrogen fuel through these cost recovery mechanisms pursuant to MCL 460.6h and MCL 460.6j and no additional statutory authority is required to allow for this cost recovery.[22] Additionally, the existing rate case and cost recovery processes are not specific to natural gas or natural gas utilities, instead referencing "gas." Therefore, these statutory cost recovery processes could also be utilized by new hydrogen focused public utilities should such utilities be established.

In addition to seeking cost recovery, it is also likely that an electric utility seeking to incorporate hydrogen fuel into its generation fleet would desire to mitigate cost recovery risk associated with new or modified generation facilities by seeking approval for the resource as part of the utility's Integrated Resource Plan (IRP) pursuant to MCL 460.6t. Rate regulated electric utilities must file IRPs at least every five years and these plans layout how the utility plans to serve its customers over the near, mid, and long term. Included in the IRP is any new proposed generation resource or modification to existing resources needed to serve customers. The Commission reviews the IRP to determine whether it represents "the most reasonable and prudent" course of action to meet the needs of the utility customers. Resources approved in the IRP are presumed reasonable for cost recovery so long as they commence construction in the first 3 years of the plan following the Commission's final order.

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[22] While there are no explicit statutory barriers to using PA 304 to recover the cost of hydrogen, 406.6h(3) requires the utility to provide "an explanation of the legal and regulatory actions taken by the utility to <u>minimize</u> the cost of gas purchased by the utility." (Emphasis added) In practice, based on this statutory language, the Commission has not been persuaded to date to approve higher costs for gas purchases where the premium was for environmental attributes alone, as such purchases did not minimize the cost of gas being purchased. If, as expected, hydrogen is more expensive that traditional natural gas, this could create a de facto barrier to recovering the costs of higher-cost hydrogen absent legislative action.

In addition to filing an IRP, a utility seeking to construct a new electric generation facility, or to construct an addition to an existing generation facility, of 225 MW or more must also file for, and receive, a Certificate of Necessity pursuant to MCL 460.6s. New generation facilities using hydrogen fuel or the expansion of existing generation facilities to incorporate hydrogen fuel for electricity generation would be subject to the IRP requirement and could also be subject to the electric generation Certificate of Necessity process depending upon the size of the facility. Notably, changes to the existing statutory framework are not necessary to facilitate these filings, reviews, or approvals.

Several factors influence electric utilities' choices of generation portfolio. While many of these factors are outside the influence of policy makers and regulators, the Clean Energy Standard enacted by Public Act 235 of 2023 (PA 235) will have a significant impact on the choices of Michigan electric utilities. Under PA 235, electric utilities must achieve an 80% clean energy portfolio by 2035 and a 100% clean energy portfolio by 2040. While PA 235 identifies several clean energy resources, hydrogen is not among those resources listed in the Act. Without hydrogen being designated as a resource that complies with the clean energy standard, it is unlikely that electric utilities would make the necessary infrastructure investments to utilize hydrogen as a fuel source for electric generation. This challenge could be addressed either by amending PA 235 or through a Commission Rulemaking that establishes hydrogen as a clean energy resources consistent with the authority granted to the Commission in PA 235 to establish other resources as clean energy systems consistent with the purpose of the Act (MCL 460.1003(i)(v)).

Recommendations

While solutions to the technical challenges of transporting hydrogen and incorporating it into regular utility uses must still be developed, Michigan is well positioned to ensure effective safety oversight and cost-recovery of utility investment related to the utilization and incorporation of hydrogen in this space. Siting authority for hydrogen specific pipelines, however, does not exist under either Michigan or federal law and is critical to ensuring the ability to transport hydrogen at scale. Therefore, Public Act 9 of 1929 would need to be amended to provide parity in the Commission's authority over the transportation of hydrogen, including hydrogen pipeline siting, with its authority over natural gas.

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MPSC

MICHIGAN PUBLIC SERVICE COMMISSION

STATE OF MICHIGAN
DEPARTMENT OF NATURAL RESOURCES
LANSING

GRETCHEN WHITMER
GOVERNOR

M. SCOTT BOWEN
DIRECTOR

TO: Executive Office of the Governor

FROM: Department of Natural Resources

DATE: March 24, 2026

SUBJECT: Response to ED 2026-1, Michigan Geologic Hydrogen Exploration and Preparedness Initiative

Executive Directive 2026-1, issued by Governor Gretchen Whitmer on January 15, 2026, established the Michigan Geologic Hydrogen Exploration and Preparedness Initiative. This order directed certain departments to take actions to prepare to process requests for responsible exploration for and evaluation and potential development of geologic hydrogen resources in the state.

As part of the executive directive (ED), the Department of Natural Resources (DNR) was instructed to submit a report to the Executive Office of the Governor on or before April 1, 2026 that details:

A. Any legal impediments to leasing state-owned subsurface rights for hydrogen exploration and production,
B. Any changes in legal or administrative procedures necessary to enable leasing, and
C. Permitting frameworks and resource stewardship appropriate for hydrogen development.

While existing DNR procedures and permitting frameworks exist to address leasing of state-owned subsurface rights and potential use of state-owned surface for exploration and development of hydrogen resources, some legislative changes are needed to provide the DNR with the required authority to lease for geologic hydrogen. Existing Michigan law and administrative rules do not contemplate leases for geologic, or naturally occurring, hydrogen gas on state-owned property.

Pursuant to Part 5, Section 502, Subsection 3, of the Natural Resources and Environmental Protection Act (NREPA), the DNR is responsible for managing state-owned lands and mineral resources to ensure protection and enhancement of the public trust and may enter into contracts for the taking of oil and gas from state-owned lands. MCL 324.502(3).

Although Part 5 of the NREPA does not contain a definition of the term “gas”, Michigan Administrative Code, R 299.8101(f), defines gas as “a mixture of hydrocarbons and varying quantities of non-hydrocarbons in a gaseous state which may or may not be associated with oil, including those liquids resulting from condensation, including, but not limited to, natural gas and casinghead gas.”

The definition above indicates that the gas “mixture” covered by the statute and rule must contain at least some quantity of hydrocarbons. This definition is most likely referencing fossil fuel natural gases, which are made up mostly of hydrocarbons, but contain some non-hydrocarbon gases, like carbon dioxide and water vapor. Hydrogen gas is exclusively a non-hydrocarbon gas and would not be covered by this definition.

The most logical resolution to this impediment is to amend Part 5, Section 502 of NREPA to incorporate an expanded definition of “gas” that includes both hydrocarbon and non-hydrocarbon gases, or any mixture thereof, under Subsection 18 (definitions). Additional changes will be necessary to stipulate where revenue from contracts for the capture, disposal or storage of gas will be deposited. Similar modifications to Admin Code R 299.8101(f) would be necessary to make rules pertaining to oil and gas leasing consistent with statute to include both hydrocarbon and non-hydrocarbon gases. Thus, in response to items A and B directed at the DNR in ED 2026-01, these outlined changes would provide the necessary legal and administrative constructs to enable leasing of state-owned subsurface rights for hydrogen exploration and production.

With respect to item C in the ED, permitting frameworks and resource stewardship programs appropriate to address hydrogen exploration and production exist for other mineral programs managed by the DNR. However, additional staff may be needed to handle administration of these functions.