STATE OF MICHIGAN HYDROGEN DEMAND ANALYSIS:
Current (2022), Near-term (2030), and Long-term (2050)

By
Brooke Alsterlind | Patrick Killian | Stephen Lipshaw
Sara Murphy | Shagun Parekh | Yaqi Zhang

A project submitted
in partial fulfillment of the requirements
for the degree of
Master of Science
(School for the Environment and Sustainability)
in the University of Michigan
April 2024

Client

Center for Sustainable Systems, University of Michigan

Project Advisor

Professor Gregory Keoleian, Peter M. Wege Endowed Professor of Sustainable Systems; co-Director, Center for Sustainable Systems; co-Director, MI Hydrogen

Acknowledgments

This project was supported by funding from the School for Environment and Sustainability and the University of Michigan MI Hydrogen Initiative. Throughout the duration of this project many industry stakeholders, state and federal government officials, and academics provided their input and reviewed the analysis. Their comments and suggestions were of great value. They include:

J. Clarke, Z. Thobe, J. Tomlinson	Marathon Petroleum
S. Holty, J. Miller, C. Walker	Hemlock Semiconductor
B. Foss	POET
G. Baier	Dow
K. Soper	Corteva Agriscience
B. Fadden	Graphic Packaging International
S. Davis, A. Whittredge,	Guardian Glass
M. Elzohiery, M. Finelli, S. Li	Guardian Glass
J. Hill	Cleveland Cliffs
J. Scott, S. Akhtar	Holcim
N. Popoff, A. Aqui	St Marys Cement (Votorantim Cimentos)
C.H. Kim	Ford Motor Company
J. Mercurio	General Motors
N. Kemp	Fresh Coast Climate Solutions
K. Mehren, Z. Kolodin	Michigan Infrastructure Office
J. Gwilliams, Z. Rable	Michigan Department of Transportation
N. Annelin, K. Krzeminski	Michigan Department of Transportation
E. Potter, C. Hundt	Michigan Department of Transportation
C. Matthews, D. Garrison	Flint Mass Transportation Authority
R. Ellsworth, S. Nori	Flint Mass Transportation Authority
V. Sujan	Oak Ridge National Laboratory
J. Kelly	Argonne National Laboratory
C. McMillan	National Renewable Energy Laboratory
D. Cooper, Y. Zhu	University of Michigan
T.J. Wallington, G. Lewis	University of Michigan
M. Woody	University of Michigan

Table of Contents

List of Tables

List of Figures

List of Appendices

Executive Summary

Climate Change & Hydrogen as a Decarbonization Strategy

Climate change will have significant consequences should global warming exceed a 1.5 °C increase over pre-industrial levels. Limiting warming to 1.5°C requires significant greenhouse gas (GHG) emission reductions, including reaching net zero emissions by 2050. Key actions to achieve global net zero emissions by 2050 include decarbonizing GHG intensive sectors by electrifying or deploying low-carbon alternatives in the place of fossil fuels.

Hydrogen can play a vital role in achieving decarbonization goals by reducing GHG emissions in both the industrial and transportation sector, particularly where electrification is challenging to implement. Hydrogen can be produced through various pathways, each with its own associated GHG emissions; while electrolysis is generally considered to be the leading candidate for decarbonization when powered from renewable energy or nuclear generation, natural gas steam methane reforming (SMR) with carbon capture and storage (CCS) has the potential to be another low-carbon alternative. Industrial pilots have shown the potential for hydrogen to be used in high-temperature process heat applications as well as to displace incumbent fossil fuels (e.g., natural gas, coal, coke) in various end-uses including glassmaking, steelmaking, and cement production. In the transportation sector, hydrogen-powered fuel cell electric vehicles (FCEVs) have been both piloted and deployed, with advantages including zero tank-to-wheel emissions and higher powertrain efficiencies than diesel-powered internal combustion engine vehicles (ICEVs) in medium- and heavy-duty vehicle (MHDV) applications.

Hydrogen Deployment in Michigan

Significant federal support for hydrogen programs, including the $8 billion designated in Bipartisan Infrastructure Law (BIL) has enabled the Department of Energy (DOE) to focus on creating “hydrogen ecosystems" throughout the United States. These “hydrogen hubs" serve to accelerate the use of hydrogen as a clean energy carrier, while diversifying end-users and the pathways to produce hydrogen. Michigan’s interest in hydrogen deployment is indicated in the “MI Healthy Climate Plan” and the state’s involvement in the Midwest Alliance for Clean Hydrogen (MachH2), which was selected to receive $0.9 billion of H2Hubs funding. Given its robust manufacturing economy and strategic transportation corridors, Michigan also stands out as a pivotal arena for hydrogen deployment.

The University of Michigan's Center for Sustainable Systems (CSS) conducted a workshop to identify hydrogen deployment opportunities within the state, resulting in the "Michigan Hydrogen Roadmap Report" and the creation of the MI Hydrogen Initiative (MI Hydrogen). This initiative brings together UM research expertise to create hydrogen solutions that accelerate clean and just energy transitions. MI Hydrogen developed four initial projects, including a Michigan-specific hydrogen demand analysis as its first priority.

Analysis Objectives & Scope Determination

The present project targets Michigan's industrial and transportation sectors. Its core objectives are to analyze current hydrogen demand, project future demand in 2030 and 2050, and quantify the potential to reduce GHG and nitrogen oxide (NO_x) emissions through hydrogen deployment. The findings from the present study will contribute to the planning and execution of a regional hydrogen ecosystem such as the MachH2 hub.

Based on prior work from the CSS as well as a literature review and informational interviews, this analysis focused on eight uses including petroleum refining, chemicals, pulp and paper, steelmaking, cement, glass, semiconductor manufacturing, and medium- and heavy-duty vehicles (MHDVs). These end-uses were selected due to current hydrogen usage, future hydrogen opportunities, and decarbonization potential. The analysis excludes light-duty vehicles, non-road transportation, power generation, and commercial and residential heating as other decarbonization pathways such as electrification may be more efficient. State-specific data was also difficult to occur for some of these end-uses which also led to their omission.

Demand Analysis Model (2022, 2030, 2050)

MHDVs were the focus of the transportation analysis, as they contributed 11.1 million metric tons of CO_2eq in 2019, 21% of Michigan's entire transportation sector. The analysis specifically focused on seven MHDV classes that are difficult to electrify, so that hydrogen could be explored as a potential decarbonization strategy. For the industry analysis, the latest Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP) dataset was utilized to identify in-scope industrial facilities and to provide emissions data for indirect fuel demand estimates. Using the GHGRP dataset, 25 Michigan facilities were selected for analysis, each with substantial fossil fuel use and GHG emissions. The 25 analyzed facilities reported 7.75 million metric tons of CO_2eq to GHGRP in 2022 including the combustion of fuels, process emissions, and merchant hydrogen production emissions. In comparison, the "MI Healthy Climate Plan" reported 28.05 million metric tons of CO_2eq were emitted by Michigan's "energy intensive" industries (oil, gas, and industry) in 2019. As a result, the 25 facilities analyzed account for about 28% of state-wide industrial emissions and their decarbonization would contribute substantially to state-wide efforts to reduce GHG emissions.

To assess current hydrogen demand and forecast future demand, the study required facility-level metrics such as annual hydrogen consumption or hydrogen intensity, incumbent fossil fuel use, and production capacities. Data acquired directly from stakeholders included facility-specific fuel mixes for the cement industry, hydrogen demand for Flint MTA's public transit operations, and statewide vehicle mileage for MHDVs. For sectors where data was unavailable or proprietary, the demand model was informed through decarbonization and hydrogen roadmaps, industry and transportation pilots, and federal datasets and tools.

The demand model indirectly estimated current (2022) hydrogen production and energy demand from incumbent fossil fuels using facility CO_2 emissions. For the transportation sector, state MHDV miles traveled were utilized to estimate annual energy demand. These estimates were converted to hydrogen demand and incumbent fossil fuel use by utilizing the physical properties of the fuels and feedstocks and assuming process parameters. To evaluate future demand, different deployment scenarios were designed for the near-term (2030) and long-term (2050) to reflect feasible hydrogen applications for each sector, in each year. These scenarios represent a range of hydrogen demand for 2030 and 2050, reflecting different hydrogen applications for each sector, in each year. For 2030, two hydrogen deployment scenarios were defined to encompass the continuation of current uses of hydrogen as well as new uses in steelmaking and increased use in the transportation sector. For 2050, four hydrogen deployment scenarios were outlined. As in 2030, one scenario reflects status-quo hydrogen use in the petroleum refining, semiconductor, glass and transportation sector. The "Low Use" scenario also accounts for 20% hydrogen blending for process heat, partial thermal replacement in cement kilns, 4% MHDV fleet penetration with FCEVs, and 30% coke replacement in steelmaking. The "High Use" scenario maintains the same hydrogen blending percentage for process heat but explores increased MHDV fleet penetration, increased thermal replacement in cement kilns, and the addition of hydrogen-enhanced electric arc furnaces in steelmaking. A theoretical upper limit for hydrogen demand is modeled in the "Complete Hydrogen Substitution" scenario, where hydrogen use is projected for 100% of industrial process heat demands, complete MHDV fleet adoption, and remaining feedstock applications. Since these future demand estimates utilize a 2022 baseline, they were scaled to reflect future demand using projections of economic growth for industry and vehicle miles traveled (VMT) for transportation, for analysis years, 2030 and 2050.

GHG & NO_x Emissions Analysis Model

The emissions analysis model assessed the GHG and NO_x reduction potential associated with displacing fossil fuels when used as both feedstocks and fuels with hydrogen. The production and combustion emissions associated with current hydrogen use and incumbent fossil fuels (coal, coke, natural gas, etc.) were compared to the emissions from hydrogen deployment opportunities in 2030 and 2050. For each demand scenario in each target analysis year (2022, 2030, and 2050) different hydrogen production pathways were modeled including: natural gas steam methane reforming (SMR) with and without CCS, PEM electrolysis with renewables, solid oxide electrolyzer cell (SOEC) electrolysis with nuclear, and PEM electrolysis with RFC grid mix. The emissions analysis also accounted for changes in feedstock or fuel mix in industries such as steelmaking, glassmaking and cement production, where emission sources may change as a result of hydrogen deployment. For the transportation sector, the seven MHDV classes were modeled to compare the emissions of FCEVs with those of incumbent, diesel-powered ICEVs. The emissions analysis model also presumes that hydrogen is produced on-site for industrial sectors, thus excluding transport-related emissions. While for the transportation sector, the emissions associated with the transport of both hydrogen and diesel were included in order to compare total resulting emissions for both fuels.

Hydrogen Demand Results (2022, 2030, 2050)

The results of the demand analysis are summarized in **Table ES1 – Table ES3**, with key findings separated into current (2022), near-term (2030), and long-term (2050) time horizons.

Michigan's current (2022) annual hydrogen demand was estimated to be 39,100 metric tons with sources of demand comprising petroleum refining, semiconductor, glass, and transportation. As seen in **Table ES1**, the two largest consumers of hydrogen are the petroleum refining sector (93.4%) and the semiconductor sector (6.3%). Both of these sectors meet their hydrogen demand by producing hydrogen on-site via a natural gas SMR facility. Guardian Glass, the only in-scope glass facility, has minimal annual hydrogen demand (0.21%) and has their hydrogen delivered via liquefied tanker truck and stored on-site. The transportation sector has the lowest estimated hydrogen demand in 2022 as the only user is Flint Mass Transportation Authority (MTA), which currently operates one hydrogen fuel cell bus. Flint MTA produces hydrogen on-site through a PEM electrolyzer that is powered by the grid electricity.

Near-term (2030) annual hydrogen demand was estimated to range from 40,100 metric tons ("Incumbent Technology" scenario) to 63,400 metric tons ("Near-term Hydrogen Opportunities" scenario). While the "Incumbent Technology" scenario assumes that no advancements are made in the deployment of hydrogen, the near-term scenarios involve numerous new deployment opportunities. Though it is important to note the variance in near-term estimates among different sectors; estimates vary based on the cost of hydrogen, technology readiness, and adoption. Similar to current (2022) demand, **Table ES2** shows that petroleum refining accounts for the majority of demand at 93.3% with the semiconductor sector following in second with 6.4% of demand. The glass sector is projected to decrease in demand since the facility does not expect to undergo major furnace modifications needed to generate new hydrogen demand. Conversely, more significant growth is projected in the near-term scenarios for the steel and transportation sectors. Steel generates demand from replacing 30% of the coke used in the blast furnace with hydrogen, and transportation estimates the conversion of 1% of MHDVs to hydrogen FCEVs, along with the addition of two new fuel cell buses to Flint MTA's fleet.

Long-term (2050) annual hydrogen demand was estimated through four different scenarios, as characterized in **Table ES3**, ranging from 36,700 metric tons ("Incumbent Technology" scenario) through 108,000 metric tons ("Low Use" scenario) to 206,000 metric tons ("High Use" scenario); the fourth scenario then represents the theoretical upper limit of 1,096,800 metric tons ("Complete Substitution" scenario). Numerous scenarios are included to account for the increased uncertainty of the extended timeline, and it should be noted that the sector with the highest relative demand differs based on the scenario. While refining remains the highest-demand sector in both the "Incumbent Technology" (91.1%) and "Low Use" (31.6%) scenarios, transportation becomes the highest-demand sector in the "High Use" (35.3%) scenario with 20% penetration among all MHDV classes, and remains the highest in the "Complete Substitution" (33.2%) scenario as well. Also noteworthy is that the "Incumbent Technology" scenario has a lower hydrogen demand in 2050 relative to 2030; this is because demand for petroleum refining products is projected to decrease in 2050 relative to 2022, which therefore decreases the estimated hydrogen demand.

Total GHG & NO_x Emission Reduction Results

Results from the GHG and NO_x emissions analysis are highlighted in **Table ES4**. Like the estimates of future hydrogen demand, the potential to reduce emissions from hydrogen deployment ranges, as it is especially dependent on the hydrogen production pathway. From the analysis, it is apparent that the deployment of hydrogen has the potential to reduce emissions regardless of production pathway. However, it is evident that low-carbon pathways (PEM electrolysis via renewables, nuclear) result in the greatest emission reduction across years and demand scenarios. Other pathways have tradeoffs, as seen with introducing CCS to natural gas SMR, resulting in greater GHG emission reductions but lower NO_x reduction due to the CCS technology.

For example, the 2030 “Near-Term Hydrogen Opportunities” scenario, has a GHG emission reduction potential of 3.0 million metric tons with PEM electrolysis with renewables when compared to emissions from the “Incumbent Technology” scenario. In comparison, for the same scenario, PEM electrolysis with the RFC grid mix, would only result in a GHG emission reduction of 1.7 million metric tons. Similar trends exist with NO_x emissions, with PEM electrolysis via renewables leading to 2.2 thousand metric tons of reduction and PEM electrolysis via RFC grid mix having 1.3 thousand metric tons for the “Near-term Hydrogen Opportunities” scenario. In 2050, GHG and NO_x emission reduction potential varies considerably across scenarios and production pathways. The GHG reductions range from 5.3 million metric tons in the “Low Hydrogen Use” scenario with the PEM electrolysis via RFC grid mix to 7.5 million metric tons in the “High Hydrogen Use” scenario with PEM electrolysis via renewables. NO_x emission reductions also exhibit a large range with the same scenarios and production pathways as mentioned prior yielding a reduction range of 6.5 thousand metric tons to 14 thousand metric tons. The “Complete Hydrogen Substitution” scenario with PEM electrolysis via renewables leads to the greatest GHG and NO_x emission reduction, 20 million metric tons, and 14 thousand metric tons, respectively, due to the scale of hydrogen deployed in this scenario. While this analysis finds that hydrogen deployment has the potential to reduce GHG and NO_x emissions, it is important to note that there is still ongoing research regarding other climatic impacts from increasing hydrogen use such as atmospheric methane and hydrogen leaks.

Table ES1. Current (2022) Hydrogen Demand

Sector	Annual Demand (metric tons)	Characterization of Hydrogen Demand
Petroleum Refining	36,500	• Feedstock in processes such as hydrocracking and isomerization • Produced on-site via natural gas SMR by a merchant hydrogen producer, Air Products
Semiconductor	2,470	• Feedstock in the Siemens process to produce high-purity polysilicon • Produced on-site via natural gas SMR by a merchant producer, Linde
Glass	83	• Feedstock in the float process to prevent oxidation of molten tin bath • Vaporized hydrogen delivered to on-site storage via tanker truck
Steel **Chemicals** **Pulp & Paper** **Cement**	-	• No current demand (feedstock or fuel) was identified in Michigan for these sectors
Transportation	13	• Flint MTA currently operates one fuel-cell transit bus as part of its public transit fleet • Produced and stored on-site using PEM electrolysis with grid electricity ○ On-site renewable electricity generation not viable

Table ES2. Near-term (2030) Potential Hydrogen Demand

Sector	Scenario	Annual Demand (metric tons)	Characterization of Hydrogen Demand
Petroleum Refining	*Incumbent* / *Near-term*	37,400 [a]	• Feedstock demand expected to continue but scale may be impacted incrementally with approval of Marathon's current air permit request • Fuel demand is unlikely as refinery byproducts are used for process heat
Semiconductor	*Incumbent* / *Near-term*	2,580 [a]	• Feedstock demand expected to continue and potentially increase ○ Hemlock Semiconductor to expand due to CHIPS & Science Act • Fuel demand unlikely due to natural gas blending obstacles and hydrogen cost
Glass	*Incumbent* / *Near-term*	75 [a]	• Feedstock demand expected to continue as it is essential for the float glass process • Fuel demand unlikely due to large renovation requirements and lengthy replacement schedule of existing furnace (15 - 20 years)
Steel	*Incumbent*	-	• No incumbent demand identified
	Near-term	19,700	• 30% coke replacement in the blast furnace at Cleveland Cliffs integrated mill ○ High technology readiness level (TRL), 7 and ongoing pilots • Replacement heat in the BOF due to a reduction in BFG from coke replacement
Chemicals	*Incumbent* / *Near-term*	-	• No incumbent demand due to lack of ammonia or methanol plants in Michigan • Fuel demand unlikely due to natural gas blending obstacles and hydrogen cost
Pulp & Paper	*Incumbent* / *Near-term*	-	• No incumbent demand identified • Fuel demand unlikely due to natural gas blending obstacles and hydrogen cost
Cement	*Incumbent* / *Near-term*	-	• No incumbent demand identified • Fuel demand unlikely due to incumbent and alternative fuels like tire-derived fuels and plastics being more cost-effective
Transportation	*Incumbent*	38	• Flint MTA demand to increase due to two fuel cell buses being added to the fleet ○ Funding from the Bipartisan Infrastructure Law (BIL)
	Near-term	3,620	• 1% penetration among all MHDV classes (including Flint MTA incumbent demand) ○ Higher adoption limited due to TRL, refueling infrastructure, cost of hydrogen

[a] Hydrogen demand was assumed to be the same for the "Incumbent" and "Near-term H_2 Opportunities" scenario. It is expected that incumbent feedstock demand will remain in 2030, but no new demand will emerge, as no new hydrogen opportunities were identified for these sectors.

Table ES3. Long-term (2050) Potential Hydrogen Demand

Sector	Scenario	Annual Demand (metric tons)	Characterization of Hydrogen Demand

Petroleum Refining	*Incumbent*	33,500	• Uncertainty about feedstock demand
			  ○ Different growth projections depending on historic operations vs. net-zero targets
			• Challenging economic justification for refineries to switch to low-carbon hydrogen production
			  ○ Retrofits or expansion into renewable diesel may encourage low-carbon hydrogen use

	Low Use / *High Use*	34,100 [b]	• Feedstock + fuel demand due to 20% blending with natural gas for process heat
			  ○ Utility blending may be constrained by natural gas distribution infrastructure
			  ○ If done on-site or use-specific, higher blending percentages may be possible

	Complete	42,200	• Feedstock + fuel demand from 100% substitution of natural gas process heat ○ Limited fuel demand due to continued use of byproducts for process heat
Semiconductor	*Incumbent*	3,150	• Feedstock demand expected to continue • Uncertainty about growth, EIA growth rate ("Other Nonmetallic Mineral Products") may not accurately reflect the industry ○ May be higher as HSC continues to expand and Michigan semiconductor industry grows

	Low Use / *High Use*	4,010 [b]	• Feedstock + fuel demand due to 20% blending with natural gas for process heat
			  ○ Utility blending may be constrained by natural gas distribution infrastructure
			  ○ If done on-site or use-specific, higher blending percentages may be possible

	Complete	15,000	• Feedstock + fuel demand from 100% substitution of natural gas process heat
Glass	*Incumbent*	80	• Feedstock demand continues as hydrogen is critical for the float glass process ○ Slight reduction from current demand due to projected reduction in growth (EIA)

	Low Use / *High Use*	1,250 [b]	• Feedstock + fuel demand due to 20% blending with natural gas for process heat
			  ○ Utility blending may be constrained by natural gas distribution infrastructure
			  ○ If done on-site or use-specific, higher blending percentages may be possible

	Complete	14,800	• Feedstock + fuel demand from 100% oxy-hydrogen firing in furnace, annealing lehr
	Incumbent	-	• No incumbent demand identified

Steel	*Low Use*	19,100	• 30% coke replacement in the blast furnace at Cleveland Cliffs integrated mill • Makeup heat in BOF due a reduction in blast furnace gas from coke displacement • 20% blending for other natural gas process heat for integrated and mini mills
	High Use	20,300	• Same assumptions as “Low Use” + hydrogen-enhanced EAF at mini mill
	Complete	250,000	• 100% hydrogen shaft furnace and hydrogen-enhanced EAF at integrated mill • Hydrogen-enhanced EAF at mini mill • 100% substitution of remaining natural gas process heat at integrated and mini mills
Chemicals	*Incumbent*	-	• No incumbent demand identified

	Low Use	8,210 [b]	• Fuel demand due to 20% blending with natural gas for process heat
			  ○ Utility blending may be constrained by natural gas distribution infrastructure
			  ○ If done on-site or use-specific, higher blending percentages may be possible
			• Other potential sources of future demand include decentralized ammonia production (AmmPower) but this was not modeled

	High Use		

	Complete	113,000	• Fuel demand from 100% substitution of natural gas process heat
			  ○ Highly unlikely as most process heat is low or medium temperature
			  ○ Stakeholders described electrification as primary decarbonization strategy

Pulp & Paper	*Incumbent*	-	• No incumbent demand identified

	Low Use	10,100 [b]	• Fuel demand due to 20% blending with natural gas for process heat
			  ○ Utility blending may be constrained by natural gas distribution infrastructure
			  ○ If done on-site or use-specific, higher blending percentages may be possible

	High Use		

	Complete	138,000	• Fuel demand from 100% substitution of natural gas process heat
			  ○ Highly unlikely as most process heat is low or medium temperature and the leading decarbonization strategy is electrification
			  ○ Stakeholders demonstrated an interest in hydrogen process heat

Cement	*Incumbent*	-	• No incumbent demand identified
	Low Use	16,600	• 9% of the cement kiln’s thermal energy ○ Highly dependent on the cost of H_2 and effect on cement quality
	High Use	55,500	• A contact-specified (confidential) percentage of the cement kiln’s thermal energy demand ○ Highly dependent on the cost of H_2 and and effect on cement quality

	Complete	160,000	• 100% of the cement kiln's thermal energy
Transportation	*Incumbent*	38	• Flint MTA demand is the same as 2030 ○ Currently no plans in place to increase the hydrogen fuel cell transit bus fleet
	Low Use	14,500	• 4% penetration among all MHDV classes (including Flint MTA incumbent demand)
	High Use	72,700	• 20% penetration among all MHDV classes (including Flint MTA incumbent demand) ○ Higher adoption may be limited due to refueling infrastructure, cost of H_2, electrification of some MDV classes
	Complete	364,000	• 100% penetration among all MHDV classes (including Flint MTA incumbent demand)

[b] Hydrogen demand is the same for the "Low Use" and the "High Use" scenario for these sectors because natural gas blending was the only hydrogen deployment opportunity selected and it was assumed to be 20% by volume for both scenarios.

Table ES4. Total GHG & NO_x Emission Reductions

Timeframe	Scenario	Characterization of GHG & NO_x Emission Reduction
Near-term (2030)	*Incumbent*	• Upstream emissions associated with hydrogen production for industrial uses (natural gas SMR) and transportation applications (electrolysis via the RFC grid mix) • Emissions (upstream & combustion) for incumbent fossil fuels that could be displaced with hydrogen (coal, natural gas, coke, diesel)

	Near-term H_2 Opportunities	• All hydrogen production pathways result in modest reductions when compared to incumbent
		  ○ PEM electrolysis with renewables achieves the highest reduction (GHG: 3.04 million metric tons (16%); NO_x: 2.23 thousand metric tons (14%))
		    ■ Similar results with SOEC electrolysis, nuclear
		  ○ While natural gas SMR with CCS results in a greater GHG reduction, SMR without CCS performs better with regards to NO_x
		• Overall, reduction potential is modest (< 3.04 million metric tons, 16%) due to limited hydrogen deployment opportunities

Long-term (2050)	*Incumbent*	• Upstream emissions associated with hydrogen production for industrial uses (natural gas SMR) and transportation applications (electrolysis via the RFC grid mix) • Emissions (upstream & combustion) for incumbent fossil fuels that could be displaced with hydrogen (coal, natural gas, coke, diesel)

	Low Use
	High Use
		• All hydrogen-producing pathways can achieve at least 4.60 million metric tons (22%) GHG reduction; and 6.53 thousand metric tons NO_x reduction (33%)
		  ○ PEM electrolysis via renewables results in the greatest reduction potential, while PEM electrolysis via the RFC grid has the least potential to reduce emissions
		    ■ Similar results to PEM electrolysis via renewable for SOEC electrolysis via nuclear generation
		  ○ Similar emissions findings regarding natural gas SMR with and without CCS as 2030

	Complete Substitution	• PEM electrolysis via renewables results in almost a complete reduction of GHG emissions (20.11 million metric tons (99.9%)) • If PEM electrolysis via the RFC grid was used this would result in an increase in emissions (GHG: 1.97 million metric tons (9.7%); NO_x: 0.83 thousand metric tons (4.4%)) ○ This is due to the emissions intensity of the RFC grid and the scale of demand

1. Introduction

1.1 Climate Change & Decarbonization

If unaddressed, climate change will have significant consequences for both humanity and the Earth's diverse ecosystems.[1] Not only are the damages from exceeding 1.5 °C in global warming over pre-industrial levels well-documented, but they are already being felt by many communities.[2] According to the Intergovernmental Panel on Climate Change (IPCC), limiting warming to 1.5°C requires that greenhouse gas (GHG) emissions decrease by 45% by 2030 as compared to 2010 and reach net zero by 2050.[3] Net zero roadmaps, such as those published by the International Energy Agency (IEA), identify key actions for the international community to achieve net zero by 2050. These actions include decreasing the demand for fossil fuels by electrifying or deploying low-carbon alternatives in end-uses that would otherwise continue to use fossil fuels. For instance, the IEA's Net Zero Emissions by 2050 (NZE) scenario projects an over 25% decline in fossil fuel demand by 2030 as a result of scaling clean energy.[4]

As of 2021, the United States (U.S.) industrial and transportation sectors combined accounted for 52% of annual GHG emissions, making decarbonization of these sectors essential to meet GHG reduction goals.[5] Decarbonization strategies for industry and transportation, notably electrification and the adoption of low-carbon fuels, have seen significant technological advancement and end-use implementation.[6,7] However, hard-to-abate industries like steel, cement, and petrochemicals have proven to be more difficult to decarbonize due to factors like process heterogeneity, high process temperature requirements, and dependency on fossil fuel feedstocks.[8–10] In the transportation sector, freight options like medium- and heavy-duty trucking are challenging to decarbonize through electrification largely due to the current energy density constraints of commercial battery technology, which create logistical obstacles regarding payload, range, and recharge time.[11,12]

1.2 Hydrogen as a Decarbonization Strategy

Existing literature suggests that hydrogen deployment will be an important strategy for the decarbonization of the industrial and transportation sectors.[4,9,10,13] In industrial settings, hydrogen can be used as a fuel to achieve high-temperature process heat, as a feedstock to displace incumbent fossil fuels, and to reduce emissions as its combustion does not result in GHG emissions.[9] For transportation, hydrogen can be deployed in fuel-cell electric vehicles (FCEVs), which have zero tank-to-wheel (TTW) emissions and higher total drivetrain efficiencies than diesel internal combustion engine vehicles (ICEVs).[14] While hydrogen is a compelling decarbonization strategy, there are concerns that greater hydrogen deployment may lead to an increase in nitrogen oxide (NO_x) emissions and atmospheric methane.[15,16] It has also been recently reported that the indirect radiative forcing associated with hydrogen leakage may reduce the climate benefits of hydrogen use considerably.[17]

1.2.1 Industry & Transportation Pilots

Hydrogen technologies are in various stages of commercial development with recent industrial pilots including partial or complete substitution of natural gas in glassmaking,[18] direct kiln injection and net-zero firing in cement production,[19,20] and hydrogen-driven direct reduction of iron (DRI) and fossil fuel heat displacement in steelmaking.[21–24] Various studies have explored the impact of hydrogen blending on natural gas distribution networks that primarily serve residential and commercial end-users, with hydrogen blends ranging from 2% to 30%.[25] There have also been demonstrations in the transportation sector, with Hyundai deploying 50 heavy-duty FCEVs in Switzerland in 2020. Hyundai plans to continue expanding their FCEV business, with plans to sell vehicles in the United States and broaden manufacturing efforts to include other medium- and heavy-duty vehicle (MHDV) classes.[14,26] Some U.S. firms have already deployed FCEVs, such as SunLine Transit Agency which currently (2023) operates 26 hydrogen fuel cell buses in California.[27]

1.2.2 Production Pathways

Though there are many different pathways to produce hydrogen, not all of them are considered low-carbon. According to the Department of Energy (DOE), low-carbon hydrogen is hydrogen that does not result in more than 4.0 kg of CO_2eq per kg produced.[28] The predominant pathway, natural gas steam methane reforming (SMR), has an average GHG emissions intensity of 9.0 kg of CO_2eq/kg of H_2.[29] During SMR, methane in natural gas reacts with high-temperature steam in the presence of a catalyst to yield hydrogen, carbon monoxide, and carbon dioxide.[30] Recent efforts to decarbonize hydrogen production have led to a growing interest in implementing carbon capture and storage (CCS) within SMR facilities. This technology adoption has been demonstrated by a variety of pilot projects including Air Products' Port Arthur Project (USA), Shell's Quest Project (Canada), and Air Liquide's Port Jerome Project (France).[31] The GHG intensity for hydrogen produced via SMR with CCS ranges from 1.5 to 6.2 kg of CO_2eq/kg of H_2, depending on the global upstream and midstream emissions for the natural gas supply. [29] However, CCS technologies involve concerns including the potential of carbon lock-in and risks associated with leaks from underground storage or pipelines.[32,33]

Another production pathway of increasing interest is electrolysis, in which electricity is used to split water molecules into gaseous hydrogen and oxygen in a unit called an electrolyzer.[34] This analysis primarily considered polymer electrolyte membrane (PEM) electrolyzers and high-temperature steam electrolyzers (HTSE) as these are the most mature technologies.[35] Other designs such as alkaline electrolyzers were excluded as they are considered nascent technology.[35] The GHG intensity of electrolysis is highly dependent on the source of electricity. If the electricity is from renewable sources such as solar, wind, or other low-carbon sources (e.g., nuclear), electrolysis can be a source of low-carbon hydrogen. Grid electricity also has the potential to yield low-carbon hydrogen but is contingent upon the generation mix. The intensity of grid electrolysis has been found to be between 0.5 and 24 kg CO_2eq/kg of H_2, with the lower end of the range reflecting countries like Sweden, which has the lowest intensity for electricity production in the world. The upper end of this range assumes that the electricity used to produce hydrogen has a CO_2 intensity that reflects the current average of global electricity production (460 kg CO_2eq/kWh).[29]

The nuclear power industry has explored integrating HTSEs—specifically, solid oxide electrolyzer cells (SOEC) with light-water reactors (LWR)—as these reactors produce an abundance of steam. HTSEs use steam that would otherwise be sent to a turbine to generate power, and thus the GHG intensity of this pathway is similar to that of nuclear power generation. While nuclear power generation does not emit CO_2 directly, it does result in a GHG intensity between 0.1 and 0.3 kg of CO_2eq/kg of H_2 when accounting for upstream emissions from uranium mining, conversion, enrichment, and fuel fabrication.[29,36] While the reported GHG intensities capture the upstream emissions of producing hydrogen, hydrogen emits no GHGs at the point of combustion. However, it is important to acknowledge that nitrogen oxide (NO_x) emissions are possible when combusting hydrogen in industrial settings, and other air pollutant emissions such as particulate matter (PM10, PM2.5) are also important to consider.[15]

Hydrogen production is also often characterized by the location and owner of the production facility. For instance, on-site production and consumption that is owned by the end-user is considered captive hydrogen. In contrast, production facilities that deliver to industrial gas users by pipeline or truck are considered merchant hydrogen producers. Historically, captive hydrogen production has dominated the U.S. market, making up as much as 60% of the total market.[37] By-product hydrogen is another form of production and is where hydrogen is recovered from by-product streams and can be consumed internally (captive) or sold externally (merchant). It is most common at petroleum refineries and chemical plants due to the chemical processes associated with these facilities.[38]

1.3 Hydrogen Deployment in Michigan

1.3.1 Federal & State Support for Hydrogen

In recent years, there has been significant federal and state support for the production and deployment of low-carbon hydrogen. The Bipartisan Infrastructure Law (BIL) allocated $9.5 billion to “clean hydrogen” efforts, of which $8 billion was earmarked for the establishment of “at least 4 hydrogen hubs.”[39] As a result of this funding, the DOE issued a Funding Opportunity Announcement (FOA) entitled “Regional Clean Hydrogen Hubs” (H2Hubs) with the overall goal of creating “hydrogen ecosystems" where hydrogen producers, consumers, and local connective infrastructure accelerate the use of hydrogen as a clean energy carrier.[40] DOE established selection criteria to demonstrate different production pathways, to diversify end-users, and to be distributed throughout the United States.

Similar to the BIL, the Inflation Reduction Act (IRA) also contained provisions regarding clean hydrogen, including the creation of the “Clean Hydrogen Production Tax Credit” (PTC).[41] The 10-year incentive prompted the Department of Treasury to revise the Internal Revenue Code, specifically Section 45V, to include provisions about what qualifies as “clean hydrogen.” Treasury’s proposed rule states that hydrogen with a lifecycle GHG emission rate of less than 0.45 kg CO_2eq per kg hydrogen will be eligible to receive the maximum $3 per kg credit. However, the rule also asserts that other more GHG-intensive production pathways will be able to receive a specific percentage of the full credit based on their GHG emission intensity.[42] The IRA also extended the 30% investment tax credit (ITC) under Section 48 of the Internal Revenue Code, which clean hydrogen projects can opt to claim instead of the PTC. Since the IRA’s subsidies are directed towards production, they pair well with the DOE’s “Hydrogen Shot Initiative,” an effort launched in 2021 to decrease the cost of clean hydrogen by 80%. It is known as the “1 1 1” program, which aims to foster research and development to achieve clean hydrogen at $1 per kg within a decade.[43]

1.3.2 Michigan as a Climate Leader

Michigan possesses robust industrial infrastructure with the 5th largest advanced manufacturing workforce in the county and the state being home to nearly 19% of all U.S. auto manufacturing.[44] The state also has strategic transportation corridors with one of the busiest border crossings in North America, carrying 25% of all goods commercially traded between the U.S. and Canada.[45] Michigan’s state government recognizes these strengths and hopes to position the state as a leader in the just energy transition. This is demonstrated by the creation of the “MI Healthy Climate Plan,” which serves as a roadmap for Michigan’s clean energy future as well as the recent enactment of a suite of clean energy and climate action bills.[46]

Michigan’s “MI Healthy Climate Plan” proposes clean hydrogen as an alternative to natural gas heating in commercial and residential buildings. It also advocates for industrial facilities to adopt low-carbon fuels, such as hydrogen, as part of their decarbonization plans.[44] The state of Michigan is also a member of the Midwest Alliance for Clean Hydrogen (MachH2) hub, which was selected to receive $900 million in funding from DOE’s H2Hubs program.[47] These policies are attracting industry to Michigan, with Nel Hydrogen recently announcing plans for a gigafactory in Plymouth, MI, comprising 4 GW of Alkaline and PEM electrolyzers and a capital investment of $400 million.[48] In addition, Plastic Omnium intends to build North America’s largest hydrogen storage plant in Grand Blanc Township, MI, to supply high-pressure storage systems to American automakers.[49]

1.3.3 Michigan Hydrogen Roadmap Workshop & Report

In response to both the “H2Hubs” FOA and the “MI Healthy Climate Plan,” the Center for Sustainable Systems (CSS) at the University of Michigan, with support from the Michigan Economic Development Corporation (MEDC) and the University of Michigan Office of Research (UMOR), hosted a workshop to identify “near- and long-term hydrogen deployment opportunities and key enabling factors.” The findings from the workshop were synthesized by CSS in a 2022 publication titled “Michigan Hydrogen Roadmap Report.”[50] The report recommended that a hydrogen demand analysis be conducted to understand near- and long-term hydrogen deployment opportunities within Michigan and contributed to the creation of the MI Hydrogen Initiative.

The MI Hydrogen Initiative, launched in December 2022, is a collaborative effort sponsored by the Office of the Vice President for Research, the School for Environment and Sustainability, and the College of Engineering at the University of Michigan. This initiative aims to develop a knowledge base on low-carbon hydrogen supply and demand, thereby informing how low-carbon hydrogen can accelerate a just and clean energy transition in the Great Lakes region and beyond. To achieve this goal, MI Hydrogen engages faculty across disciplines and partners across industry, government, academia, and community groups. The initiative also supports interdisciplinary research projects that focus on hydrogen deployment opportunities and their role in industrial and transportation sectors. This demand analysis study was one of four priority research projects when MI Hydrogen was initially established.

1.3.4 Project Objectives

This project aims to assess current hydrogen demand, to estimate future demand, and to quantify the greenhouse gas reduction potential associated with the displacement of fossil fuels by hydrogen within Michigan. Additionally, NO_x emissions associated with switching to hydrogen end-uses are examined in light of concerns of increased NO_x emissions from hydrogen combustion. To assess hydrogen's potential in the future, this analysis incorporated two different timescales: the near-term (2030) and the long-term (2050).

The principal objectives of the project included the following:

1. Determine current hydrogen demand in Michigan's industrial and transportation sectors
2. Estimate future hydrogen demand in 2030 and 2050 for these sectors by modeling different hydrogen deployment scenarios
3. Quantify the GHG and NO_X reduction potential associated with switching incumbent processes to low-carbon hydrogen

To accomplish these objectives, this project developed methods to conduct a regional hydrogen demand analysis. This is a vital contribution as other studies have estimated hydrogen demand in industrial and transportation applications on international and national scales, but research on regional demand has been limited.[9,10] Additionally, as federal funds are distributed to support the development of hydrogen infrastructure, identifying clusters of hydrogen demand and production will be critical for planning a regional ecosystem. This demand analysis will therefore inform the planning of the MachH2 hub and the scaling of low-carbon hydrogen production and use in the state of Michigan.[47]

2. Methods

2.1 Data Collection & Stakeholder Outreach

The “Michigan Hydrogen Roadmap Workshop Report” examined fourteen possible hydrogen end-uses in the Midwest region as of 2022: light-duty vehicles, medium- and heavy-duty vehicles, ships, rail, airplanes, refineries and chemical plants, ammonia, process heat, steelmaking, cement production, glass manufacturing, semiconductor manufacturing, buildings, and power generation.[50] A literature review was conducted to further characterize the hydrogen end-uses applicable to Michigan’s industrial and transportation sectors and the potential contribution of these end-uses to sector decarbonization. This literature review included academic peer-reviewed journal articles, national roadmaps and reports, industry white papers, non-governmental organization reports, and DOE technical reports.

Various data needs were identified to estimate current hydrogen demand, future hydrogen demand, and emissions reduction potential associated with switching incumbent fuels and feedstocks to hydrogen. To estimate current demand, mass of hydrogen used per year, hydrogen intensity (i.e., mass of hydrogen per mass of product or fuel economy), production volume, production capacity, and total vehicle miles traveled were identified as pertinent parameters. Future hydrogen demand required data on projections for hydrogen use in the state including emerging technologies in industry and transportation and their anticipated technological readiness for the analysis years (2030 and 2050), anticipated hydrogen intensity, substitution ratios for the replacement of fossil fuels with hydrogen, and forecasted growth in industry (output) or transportation (vehicle miles traveled). For the estimation of carbon reduction through hydrogen implementation, data types identified as necessary were current emissions, emissions intensity of hydrogen production, and projected future emissions.

Following the initial literature review, relevant industrial and transportation stakeholders were identified and interviewed. During these meetings, stakeholders were queried about the selected data types (**Appendix A, Item 1**). Where data was proprietary, hydrogen and decarbonization roadmaps, such as the U.S. National Clean Hydrogen Strategy and Roadmap, were utilized to identify forecasted hydrogen use in the target analysis years. Publicly available data on industry pilots and research (not necessarily specific to Michigan) were sourced for information about substitution ratios and hydrogen-specific technologies. Federal datasets and tools were used to source emissions factors, facility-level combustion emissions from fossil fuels, high and low heating values of fuels, and MHDV payload values (used to calculate fuel economies). Finally, additional publicly accessible data sources filled any remaining data gaps, such as facility-level fuel mix and production capacity. Due to the proprietary nature of necessary data, various sources were required to produce parameters for the estimation of current hydrogen demand, future hydrogen demand, and accompanying carbon reduction potential. **Figure 1** summarizes data needs for analysis and data hierarchy for sources.

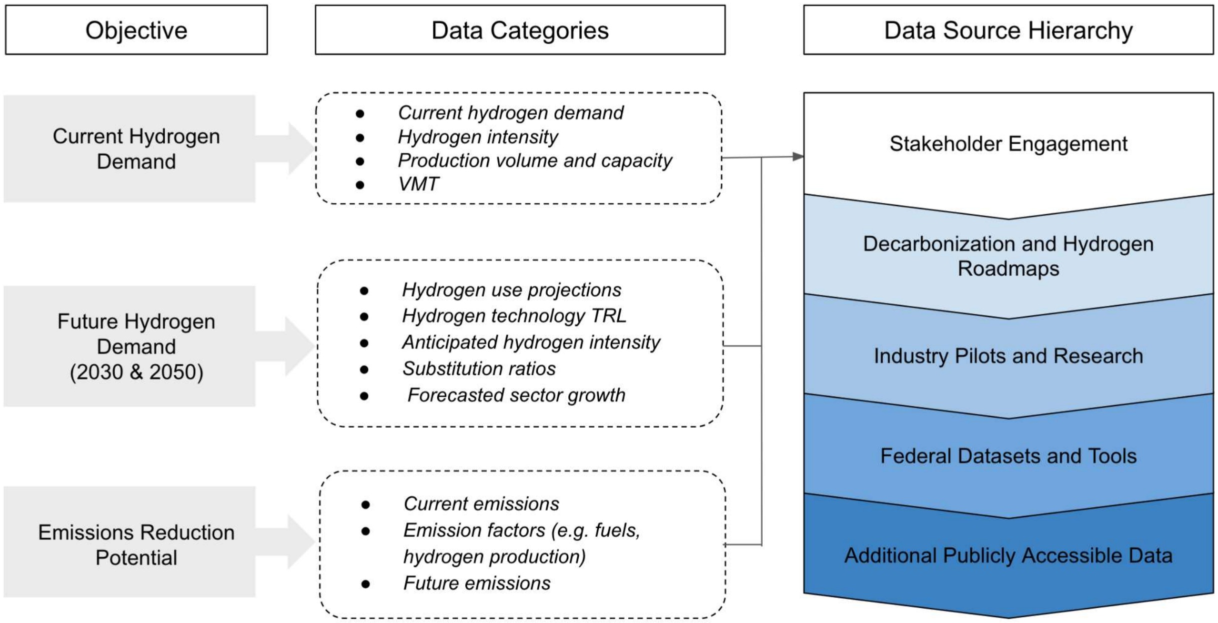

Figure 1. Data categories utilized and the hierarchy of data sources in the present study's demand and emissions reduction models.

2.2 Scope Determination

Based on literature review and stakeholder engagement, the scope for this analysis was created to include eight hydrogen end-uses within the Michigan state boundary: petroleum refining, chemicals (including ethanol), pulp and paper, steelmaking, cement production, glass manufacturing, semiconductor manufacturing, and medium- and heavy-duty vehicles (MHDVs).

Petroleum refining, glass, and semiconductor sectors currently use hydrogen as a feedstock and were therefore included in this analysis.[51–53] Steel and cement industries were selected because they require high process temperatures for their respective manufacturing processes.[54,55] The chemicals industry was initially included due to high process heat demand and hydrogen feedstock applications in ammonia and methanol production.[50] Though there are no ammonia or methanol plants in Michigan, it was determined that process heat is still a potential end-use for hydrogen within the state. While electrification is the primary strategy to decarbonize to low- and medium-temperature process heat, sectors with these temperature requirements were included in this analysis as hydrogen deployment opportunities due to stakeholder interest and supportive literature.[9,56,57] Pulp and paper and ethanol facilities both utilize low- and medium-temperature process heat and thus were considered in-scope despite not being included in the "Michigan Hydrogen Roadmap Workshop Report."

Transportation scope was limited to road transportation due to its major contribution to national emissions; in the United States, road transit accounts for 70% of total transportation emissions.[58] In addition, light-duty vehicles (LDVs) and MHDVs collectively represent around 75% of all primary energy consumption within the transportation sector.[58,59] MHDVs in particular contribute to 23% of total transportation emissions despite comprising just 4% of the vehicles on the road in the United States.[60,61] In comparison, non-road transportation end-uses such as forklifts require less energy and are less carbon intensive.[58] Though hydrogen is currently used as a fuel for forklifts, forklift demand was not modeled in this study as it is expected to be relatively low compared to road transport demand in Michigan.[62,63] Additionally, though hydrogen use in rail, ferries (maritime), and aviation were discussed in the "Michigan Hydrogen Roadmap Workshop Report," these end-uses were not analyzed in this work as scope was limited to road transportation within the Michigan state boundary. It is likely that electrification is the key decarbonization strategy for LDVs.[50,58] Light duty battery electric vehicles have greater maturity, more market offerings, and a higher energy efficiency (defined as the ratio of energy to the wheels to electrical energy input) relative to hydrogen fuel cell vehicles (65% versus 22%).[50,64,65] Therefore, LDVs were excluded from this analysis.

Of the remaining end-uses discussed in the "Michigan Hydrogen Roadmap Workshop Report," power generation and heating for buildings were both omitted from scope. Power generation was omitted due to hydrogen's low round-trip efficiencies for electricity generation and storage.[66] However, the potential to use hydrogen in power generation for electricity may increase provided that hydrogen costs decrease and round-trip production efficiencies improve.[67] Heating in residential and commercial buildings was eliminated from scope due to the advantages of electrification in these applications.[50] Other energy-intensive industries such as lime, aluminum, and food manufacturing were not modeled in this work as these end-uses were not discussed in the "Michigan Hydrogen Roadmap Workshop Report," though hydrogen is of interest in these sectors.[68–71]

Future hydrogen demand in the state was informed by forecasts of hydrogen demand from stakeholder interviews, national roadmap reports, and academic literature. Though this analysis did not conduct a detailed economic analysis in projecting future hydrogen demand, this factor was highlighted in responses from industry stakeholders and embedded in roadmaps and other forecasts.

2.2.1 Industry Scope

Industrial facilities with high fuel use and GHG emissions were the target of this analysis to maximize the decarbonization potential of hydrogen. Due to the lack of publicly available fuel use data, carbon emissions from the combustion of fuels was used to identify facilities for inclusion.

Industrial facilities in sectors of interest that report to the Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP), which includes facilities emitting at least 25,000 metric tons of carbon dioxide equivalence annually, were included in this analysis.[72] The most recent reporting year (2022) was selected for this analysis and is used as a proxy for current emissions (**Appendix B, Table B1**). This screening resulted in 25 facilities (**Table 1**). While GHGRP differentiates between ethanol and chemical facilities based on six digit North American Industry Classification System (NAICS) codes, this demand analysis includes ethanol facilities in the "Chemicals" sector based on three digit NAICS codes and because process heat replacement is the main hydrogen opportunity in both industries. The emissions of the two sole hydrogen production facilities in Michigan, Linde and Air Products, were assigned to the industries that receive the hydrogen output (semiconductors and refineries, respectively). The 25 analyzed facilities reported 7.75 million metric tons of CO_2eq to GHGRP in 2022 including the combustion of fuels, process emissions, and merchant hydrogen production emissions.[73] In comparison, the "MI Healthy Climate Plan" reported 28.05 million metric tons of CO_2eq were emitted by Michigan's "energy intensive" industries (oil, gas, and industry) in 2019.[44] As a result, the 25 facilities analyzed account for about 28% of state-wide industrial emissions and their decarbonization would contribute substantially to state-wide efforts to reduce GHG emissions.

Table 1. Summary of Michigan industrial facilities analyzed including sector, number of facilities within a given sector, facility name, and facility location.

Industry (Number of facilities)	Facility Name	Location (City, State)
Petroleum Refining (1)	Detroit Refinery	Detroit, MI
Semiconductor (1)	Hemlock Semiconductor	Hemlock, MI
Glass (1)	Guardian Glass	Carleton, MI
Steel (2)	Cleveland-Cliffs Steel - Dearborn Works	Dearborn, MI
	Gerdau Macsteel Monroe	Monroe, MI
Chemicals (9)	BASF Corporation	Wyandotte, MI
	Corteva Agriscience	Harbor Beach, MI
	Dow Midland	Midland, MI
	Occidental Chemical Corporation	Ludington, MI
	Pfizer, inc. (formerly Pharmacia & UpJohn)	Kalamazoo, MI
	Carbon Green Bioenergy	Lake Odessa, MI
	Marysville Ethanol	Marysville, MI
	POET Biorefining	Caro, MI
	Andersons Marathon Holdings	Albion, MI
Pulp & Paper (9)	Packaging Corp of America	Filer City, MI
	Verso Escanaba	Escanaba, MI
	Verso Quinnesec	Quinnesec, MI
	UP Paper LLC	Manistique, MI
	Graphic Packaging International	Kalamazoo, MI

	Westrock California	Battle Creek, MI
	Fibek	Menominee, MI
	Ox Paperboard WP Mill	White Pigeon, MI
	Neenah Paper Michigan Inc.	Munising, MI
Cement (2)	Holcim	Alpena, MI
	St. Mary's Cement	Charlevoix, MI

2.2.2 Transportation Scope

The MHDVs modeled were chosen to represent vehicle classes unlikely to be electrified, or with multiple potential alternative fuel pathways.[11,64,74] MHDVs in the state of Michigan accounted for 11.1 million metric tons of CO_2eq in 2019, which is 21% of the entire transportation sector.[44] It is important to note, that these emissions are just from the combustion of diesel, while this study investigates the total fuel cycle. Regardless , these vehicles present a large opportunity to significantly reduce emissions throughout the state by switching to alternative fuels. The vehicle classes modeled in the current study can be found in **Table 2**.

Table 2. MHDV classes categorized by vehicle weight class, EPA class, and vehicle type**.**

Vehicle Weight Class	EPA Class	Vehicle Type
Medium-Duty	Class 4	Light Heavy Duty (LHD) Vocational Vehicles
	Class 6	School Buses
	Class 6	Pickup and Delivery (PnD) Trucks
Heavy-Duty	Class 7	Transit Buses
	Class 8a	Refuse Trucks
	Class 8b	Day Cab Trucks, trailer attached (Short-Haul)
	Class 8b	Sleeper Cab Trucks, trailer attached (Long-Haul)

Hydrogen can be deployed in fuel cell electric vehicles (FCEVs) and internal combustion engines (ICEs). In FCEVs, a fuel cell that is powered by hydrogen produces electricity that powers an electric motor.[75] This differs from ICEs where the fuel combusts within the engine and powers the powertrain.[76] For this study, FCEVs were selected because they create no emissions during operation, whereas hydrogen ICEs create NO_x.[77] In addition, FCEVs have been used in actual on-road applications in different classes for years, while hydrogen ICEs have not. This technology readiness component influenced the decision of narrowing the scope to FCEVs.

For this analysis, diesel was assumed to be the incumbent fuel for all vehicle classes. Electric MHDVs require significantly larger batteries when compared to LDVs, which reduces the maximum payload capacity.[12] Electrified MHDVs also have lengthy recharging times, which can pose challenges to their operational efficiencies and cause logistical delays.[12] In contrast, FCEVs experience minimal weight increases compared to their ICE counterparts, but weigh significantly less than battery electric MHDVs. In addition, FCEVs can be refilled quickly; for example, a hydrogen fuel cell transit bus can be refilled in around 10 minutes.[78] Therefore, the electrification of MHDVs was not considered in this analysis.

The Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model (GREET)—a life cycle modeling tool developed by Argonne National Laboratory—was used for this analysis.[79,80] Values collected from GREET for each vehicle class include the following: payload values, fuel economies for both diesel and hydrogen, fuel economy improvements compared to 2022 for both fuels for 2030 and 2050, empty vehicle weights, and emission factors.

There are two main vehicle classification systems in the United States; the EPA categorizes vehicles by gross vehicle weight rating (GVWR), while the Federal Highway Administration (FHWA) categorizes vehicles by the number of axles.[81,82] In this analysis, the EPA's vehicle classification was used. However, since vehicle count and payload data were obtained from sources that used the FHWA classification system, the vehicle classes had to be aligned. The GVWRs for FHWA vehicle classes were determined to align them to the appropriate EPA classes. Notably, the EPA system lacks the "medium-duty vehicle" class present in the FHWA classification. So, the vehicle classes that had a GVWR of a "medium-duty" vehicle by the FHWA were categorized as "medium-duty" in the EPA system that was used in the current study after alignment. This resulted in classifying medium-duty vehicles to include the EPA's Heavy Duty Vehicle 4 and Heavy Duty Vehicle 6 classifications (considered Class 4 and Class 6, respectively, in this study).[82] The classification alignment used in this study can be found in **Appendix C** (**Table C1**).

2.3 Current Hydrogen Demand

Michigan's current hydrogen demand was estimated through a variety of methods including stakeholder engagement and estimation from publicly available CO_2 emissions data. As determined through stakeholder engagement, in 2022 the industrial consumers of hydrogen were Michigan's petroleum refining, semiconductor manufacturing, and glass manufacturing industries, all of which use hydrogen as a feedstock. In terms of transportation demand, Flint Mass Transportation Authority (MTA) in Flint, MI, currently operates one hydrogen fuel cell bus.

2.3.1 Feedstock Demand

Using the 2022 GHGRP dataset, two large-scale hydrogen producers in Michigan were identified: Air Products, which is located adjacent to Marathon Petroleum's refinery in Detroit, MI; and Linde, which is located next to Hemlock Semiconductor LLC in Hemlock, MI.[73] Guardian Industries confirmed their use of hydrogen as feedstock at their facility in Carleton, MI.[53]

For the refining and semiconductor industries, hydrogen demand was estimated using the facility-specific CO_2 emissions from GHGRP, as CO_2 is a byproduct of hydrogen production via natural gas steam methane reforming. Since GHGRP does not distinguish between CO_2 emissions from the SMR process and combustion of fossil fuels for process heat, it was assumed that 28.4% of the total emissions could be attributed to the SMR process. This assumption is based on previous work from Argonne National Laboratory, which found that 28.4% was the median percentage for process-specific emissions when examining previous research on hydrogen production from SMR facilities.[83] It was also assumed that the CO_2 intensity of hydrogen production was 7.91 kg CO_2 per kg of H_2; this was calculated using an emission factor of 55.7 g CO_2 per MJ of H_2,[83] the higher heating value (HHV) of hydrogen (141.9 MJ/kg, 343 Btu/ft^3),[84] and the density of hydrogen (0.090 kg/m^3, 2.55 g/ft^3) at standard temperature and pressure.[84] **Eq. 1** highlights how hydrogen demand (metric tons) for each facility *i* was calculated for current use in the refining and semiconductor industries.

$$m_{i, H_2} = m_{i, CO_2 - H_2\,Production} \times N \times \frac{1}{EF_{H_2\,Production}} \times C_{kg-mt} \quad (1)$$

where m_{i, H_2} is the mass of annual hydrogen demand for facility i (metric tons), $m_{i, CO_2 - H_2\,Production}$ is the total mass of annual CO_2 emissions from facility i's hydrogen production (kg), N is the percentage of the total CO_2 emissions that are from the SMR process (%), $EF_{H_2\,Production}$ is the CO_2 intensity of hydrogen production, excluding combustion emissions (kg CO_2/kg H_2), and C_{kg-mt} is the conversion factor from kg to metric tons.

In the glass sector, an atmosphere of 6% hydrogen and 94% nitrogen is used in the float process to prevent the oxidation of the molten tin bath. This hydrogen is currently delivered to on-site storage via liquid tanker trucks and is subsequently vaporized prior to use.[85] Guardian Industries provided a theoretical hydrogen demand for a 600 metric ton per day (TPD) glass furnace. To scale this hydrogen use to the Carleton plant's production capacity of 1090 metric TPD, a hydrogen intensity factor was determined by dividing the provided feedstock demand by 600 TPD (**Eq. 2**).[86] It was assumed that the facility operates at capacity 365 days a year.

$$m_{Guardian, H_2} = PC_{Guardian} \times Y_{Guardian, H_2} \times t \quad (2)$$

where $m_{Guardian, H_2}$ is the mass of annual hydrogen demand of the Guardian facility, $PC_{Guardian}$ is the production capacity of the facility (metric tons glass/day), $Y_{Guardian, H_2}$ is the hydrogen intensity factor for a 600 TPD furnace as provided by Guardian Industries (kg H_2/metric ton glass), and t is the number of operational days per year.

2.3.2 Flint Mass Transportation Authority (MTA) Demand

Current hydrogen demand was calculated for the one hydrogen fuel cell bus operated by Flint Mass Transportation Authority (MTA). Flint MTA provided data that one transit bus requires 35 kilograms of hydrogen per day.[87] Annual hydrogen demand was calculated by multiplying daily demand by Flint MTA's operational days per year, 359, and converting this value to metric tons.[87] Flint currently produces gaseous hydrogen onsite through a PEM electrolyzer powered by grid electricity. The electrolyzer requires 480 Volts of electricity from the grid for each of the three cells. Collectively, the three electrolyzer cells generate three kilograms of gaseous hydrogen per hour.[88]

2.4 Incumbent Fuels & Feedstocks

The current demand for fossil fuel feedstocks and fuels for which there are future hydrogen opportunities was also estimated. This was done to generate inputs for the emissions analysis model and assess the potential to reduce future GHG and NOx emissions by displacing incumbent fossil fuels.

2.4.1 Natural Gas Process Heat

Current (2022) natural gas use was calculated in order to estimate the potential for hydrogen to supply future process heat. Due to a lack of publicly available data on natural gas use in industrial facilities, an estimate was made using annual CO_2 emissions from the combustion of NG reported to GHGRP. This method was adapted from a 2016 DOE technical report and applied to chemical, refining, semiconductor, pulp and paper, steelmaking, and glass facilities (**Eq. 3**).[7] The method employs the default EPA CO_2 emission factor for natural gas combustion, 0.0503 kg CO_2/MJ of natural gas (53.06 kg CO_2/MMBtu NG).[89] The HHV of natural gas was used in keeping with industry standards and was assumed to be 52.23 MJ/kg (1,089 Btu/ft^3) based on the GREET model.[84,90,91] This HHV was selected to maintain consistency with a GREET-based emissions analysis.

$$m_{i,\,NG} = m_{i,\,CO_2-NG\ Combustion} \times \frac{1}{EF_{NG\ Combustion}} \times HHV_{NG} \times C_{kg-mt} \tag{3}$$

where $m_{i,\,NG}$ is the mass of annual natural gas demand for facility *i* (metric tons), $m_{i,\,CO_2-NG\ Combustion}$ is the mass of annual CO_2 emissions from natural gas combustion for facility *i* (kg), $EF_{NG\ Combustion}$ is the CO_2 intensity from combusting natural gas (kg CO_2/MJ NG), and HHV_{NG} is the higher heating value of natural gas (MJ/kg NG).

2.4.2 Industry-specific Feedstocks & Fuels

Steel Industry (Coke, Blast Furnace Gas)

While natural gas provides most of the process heat in both integrated mills and mini-mills, other critical fossil fuels are also used in steel facilities. For instance, blast furnaces (BFs) in integrated mills utilize coke as both a reductant and a heat source. Within the BF, coke supplies the heat required to melt the iron ore while also producing carbon monoxide, which reduces iron ore to metallic iron. Blast furnace gas (BFG), a byproduct of coke use in the BF, is often harnessed to meet on-site thermal demand including but not limited to rolling mills and the preheating of blast furnace air.[92]

Due to the lack of publicly available data on coke use and thus blast furnace gas production, an analogous method to "Natural Gas Process Heat" (Section 2.4.1) was developed for the integrated mill Cleveland-Cliffs Dearborn Works. Annual production of BFG was calculated for integrated mills using the annual reported CO_2 emissions from BFG combustion (**Eq. 4**). For this calculation, the CO_2 emission factor from GREET for BFG combustion was assumed (0.26 kg CO_2/MJ).[84] The HHV of BFG from the EPA (2.74 MJ/kg, 0.000092 mmBtu/ft^3) was used as GREET does not provide an HHV for BFG.[89]

$$m_{Dearborn, BFG} = m_{Dearborn,\ CO_2-BFG\ Combustion} \times \frac{1}{EF_{BFG\ Combustion}} \times HHV_{BFG} \times C_{kg-mt} \tag{4}$$

where $m_{Dearborn, BFG}$ is the mass of annual blast furnace gas demand for integrated mill (metric tons), $m_{Dearborn,\ CO_2-BFG\ Combustion}$ is the mass of annual CO_2 emissions from blast furnace gas combustion for the integrated mill (kg), $EF_{BFG\ Combustion}$ is the CO_2 intensity from combusting blast furnace gas (kg CO_2 / MJ BFG), and HHV_{BFG} is the higher heating value of blast furnace gas (MJ/kg).

Given the interdependence between BFG and coke, the consumption of coke was inferred through a ratio of coke required per metric ton of blast furnace gas ($R_{Dearborn,\ Coke-BFG}$). Since this ratio is usually a range, to calculate the maximum of coke needed per unit metric ton of blast furnace gas, EPA iron production material data on coke and BFG along with **Eq. 5** were utilized to derive a ratio of 0.26.[93] **Eq. 6** highlights how coke demand for the integrated mill was estimated.

$$R_{Dearborn,\ Coke-BFG} = \frac{U_{coke}}{L_{BFG}} \tag{5}$$

$$m_{Dearborn, coke} = m_{Dearborn, BFG} \times R_{Dearborn,\ Coke-BFG} \tag{6}$$

where $R_{Dearborn,\ Coke\ -BFG}$ is the maximum ratio of coke required per unit metric ton of blast furnace gas (metric ton coke / metric ton BFG), U_{coke} is the upper limit of coke required per metric ton of iron produced (metric ton coke / metric ton iron), L_{BFG} is the lower limit of coke required per metric ton of iron produced (metric ton iron / metric ton BFG), $m_{Dearborn, coke}$ is the mass of annual coke demand for the integrated mill (metric tons).

Cement Industry (Coke, Coal, Natural Gas, TDF, Plastics)
Cement manufacturing is a multi-step process that requires high-temperature process heat to facilitate calcination and clinker formation. Temperatures of up to 1450 °C are required in the kiln with thermal energy conventionally generated by combusting fossil fuels.[54] Coal and petroleum coke fuels are most commonly used for this purpose in the cement industry due to their low cost and relatively high abundance, followed by natural gas and other alternative fuels like tires and plastics.[94–96]

This section details how current (2022) process heat demand for conventional fuels (natural gas, coal, and petroleum coke) and alternative fuels (tire derived fuel [TDF] and plastics) is estimated for the cement industry. The mass of TDF and plastics was calculated to represent the ongoing trend within the cement manufacturing industry to partially offset fossil fuel consumption with alternative fuels. Due to differences in data availability, two separate methodologies were used to estimate fuel use for the two in-scope cement facilities. For the Holcim plant in Alpena, MI, the heat consumption in the rotary kiln per metric ton of cement produced (or specific heat consumption), fuel mix of the kiln, and annual production capacity were provided by an industry representative.[97,98] The HHVs for all fossil fuels and TDF were sourced from GREET. The HHV of plastics was sourced from the EPA as this HHV is not included in GREET.[84,99] These parameters were used to estimate each fuel's 2022 demand for the Holcim Alpena plant (**Eq. 7**).

$$m_{Holcim,\,k} = q_{Holcim} \times PC_{Holcim} \times f_{Holcim,\,k} \times \frac{1}{HHV_k} \times C_{kg-mt} \tag{7}$$

where $m_{Holcim,\,k}$ is the mass of fuel *k* (natural gas, coal, petroleum coke, TDF, or plastics) used annually in the Holcim plant (metric tons), q_{Holcim} is the Holcim plant's specific heat consumption (MJ/metric ton of cement produced), PC_{Holcim} is the Holcim plant's annual production capacity (metric tons of cement), $f_{Holcim,\,k}$ is the thermal energy contribution of each fuel *k* in Holcim's kiln fuel mix (%), HHV_k is the higher heating value of each fuel *k*, and C_{kg-mt} is the conversion factor from kilograms to metric tons.

For the St. Marys Cement (SMC) plant in Charlevoix, MI, facility-level fuel use was estimated using publicly available data. First, an article from the International Cement Review was used to source a combined coal-and-coke ball mill capacity of 38 metric tons per hour, a 5% thermal contribution coming from shredded plastics, and a production capacity of 2.1 million metric tons of cement.[96] The capacity of the ball mill, which is a rotating horizontal steel tube filled with steel balls that crushes solid fuels, was used as a proxy to approximate the combined mass of coal and coke used in the plant.[100] To split this aggregate value into individual masses of coal and coke, the mass ratio of coal use to coke use from an SMC plant in Bowmanville, Ontario, was used as a proxy for the Charlevoix plant (**Eq. 8**).[101] Moreover, it was assumed that no natural gas or TDF is used in the SMC Charlevoix plant.[96]

$$m_{SMC,\,k} = PC_{SMC,\,coal-and-coke} \times C_{hourly-annual} \times f_{SMC,\,k} \tag{8}$$

where $m_{SMC,\,k}$ is the mass of fuel k (coal or coke) used annually in the SMC plant (metric tons), $PC_{SMC,\,coal-and-coke}$ is the coal-and-coke mill capacity for the SMC plant (metric tons/hour), $C_{hourly-annual}$ is the conversion factor from hourly to annual mill capacity assuming 24/7 operation[102], and $f_{SMC,\,k}$ is the mass fraction of fuel k (coal or coke) relative to the total mass (coal and coke) for the SMC plant. The estimated mass of plastics used in the SMC plant is calculated using **Eq. 9**.

$$m_{SMC,\,plastic} = \sum_{k}[m_{SMC,\,k} \times HHV_{k}] \times f_{SMC,\,plastics} \times \frac{1}{HHV_{plastics}} \tag{9}$$

where $m_{SMC,\,plastic}$ is the mass of plastics used annually in the SMC plant (metric tons), HHV_{k} is the higher heating value of each fuel k (coal or coke) (MJ/kg), $f_{SMC,\,plastics}$ is equal to 5/95 and represents the 5% thermal energy contribution of plastics in the SMC plant, and $HHV_{plastics}$ is the higher heating value of plastics (MJ/kg).

2.4.3 Diesel MHDVs

It was assumed that diesel was the incumbent fuel for all MHDVs in Michigan.[103] Each vehicle's diesel consumption, and therefore fuel economy, is dependent on both its weight and payload. As a vehicle's weight increases, its fuel economy decreases since it needs more fuel and energy to travel the same distance. The representative payload, fuel economy, and energy consumption were estimated for each vehicle class to calculate the associated demand for diesel. The average liters of diesel fuel required by each vehicle class set the baseline for comparing future diesel demand with future hydrogen demand, as well as the emissions reduction potential of switching from diesel to hydrogen.

Diesel consumption in MHDVs was calculated based on adjusted payload and fuel economy values from GREET. While GREET generally calculates its payload and fuel economy values based on the average effective payload (which represents both loaded and empty payloads in a single value) of each vehicle, this study separated loaded and empty payloads to calculate adjusted fuel economies for each class in each scenario—i.e., one for loaded and one for empty. Fuel economies were calculated separately to appropriately account for the effect of payloads on fuel use. In comparison to diesel-fueled MHDVs, battery electric and fuel cell MHDVs require additional equipment, which may increase weight and reduce payload capacity.[64] In this analysis, however, it was simply assumed that FCEVs would have the same payload as incumbent MHDVs when comparing fuel economies of loaded vehicles.This was done to allow for an equal comparison between diesel and hydrogen fuel economies, given that the fuel economies differ even when the payload is held constant.

Payload and VMT Estimates
For the HDV freight classes assessed (8a and 8b), a 2018 county-level freight movement dataset from MDOT was analyzed to estimate payload values—calculated as average tons per loaded truck—and vehicle miles traveled (VMT) for each class. Measurements of interest for this demand analysis were road length, total tons of freight, and total vehicle counts (including empty vehicles). For each sample, total VMT and average metric tons per truck for loaded (i.e., non-empty) vehicles were calculated. The VMT calculations can be found in **Eq. 10** and **Eq. 11**.

$$VMT_r = L_r \times N_r \tag{10}$$

$$VMT_{total} = \sum_r VMT_r \tag{11}$$

where VMT_r is the VMT (miles) for each individual road segment, r in the dataset, L_r is the length (miles) of each road segment, N_r is the number of trucks that traverse each road segment, and VMT_{total} is the aggregate annual VMT (miles) for all roads in Michigan.

Based on payload estimates (average tons per loaded truck), each road segment was then assigned the HDV class estimated to be most representative of freight movement on that road: 8a for payload estimates under 17 tons or 8b for payload estimates over 17 tons. Once all samples from the dataset had been assigned either class 8a or 8b, aggregate payload estimates were calculated after grouping by each estimated class, and total VMT estimates for 2018 were extrapolated to 2022 based on MDOT 2045 projections.[104,105] Additionally, annual typical mileage per vehicle values from GREET for 8b long-haul (105,160 miles) and short-haul (57,580 miles) trucks were applied as a ratio to disaggregate class 8b VMT estimates into long-haul (sleeper) and short-haul (day) subcategories, assuming an equal number of long-haul and short-haul trucks on Michigan roads.[106] The resulting ratio of long-haul VMT to short-haul VMT was approximately 13:7 (about 65% to 35%).

For MDV classes, a separate statewide MDOT dataset from 2015 was analyzed, which consisted of Single-Unit Truck (SUT) and Multi-Unit Truck (MUT) counts that were tracked from road segments spanning the state. VMT totals were specifically calculated for total SUT counts, corresponding to MDVs that were modeled in the analysis; MUT counts were disregarded since they were already accounted for in the separate freight dataset. To proportionately allocate the SUT total VMT into estimated classes, Annual Average Daily Traffic (AADT) distributions from the Federal Highway Administration (FHWA) were applied. The 2015 data was then extrapolated to 2022 to represent current VMT by applying the FHWA projected SUT annual growth rate of 1.8% for each estimated class.[107]

For the MDV classes assessed, tonnage was not included in the dataset; instead, average payloads were calculated using samples from 35 Weigh-in-Motion stations representing both trunkline (state highways) and non-trunkline roads to reduce any potential bias from having one road type skew the data. To gather these WIM samples, MDOT's Transportation Data

Management System (TDMS) was utilized, which provided the average payload delineated by vehicle class for 2022 (after converting the WIM data from Kips to Pounds).[108] This allowed for the estimation of average payloads for class 4 Light Heavy-Duty Vocational Vehicles and class 6 Pickup and Delivery (PnD) trucks. A map of the locations of the WIM stations that were sampled can be found in the **Appendix C, Figure C1**.

For Class 6 School Buses, payloads were calculated based on occupancy measured in the number of passengers. Total vehicle weight increases with more passengers, reducing the fuel economy of the School Bus and requiring more fuel. For Class 6 School Buses, there are various types of school buses that make up each school district's fleet. The most common school bus type (Type C) was used as a proxy for all school buses to determine occupancy, fuel economy, and vehicle weight.[106] To account for passenger weight, the capacity of the school bus had to be determined. The number of students that can fit on a school bus depends on if they are elementary (3 per seat) or middle/high school students (2 per seat).[109] Since most school buses handle each type of student, the average number of students that a school bus can hold was calculated based on averaging the maximum number of each type of student. It was determined that the capacity of a Class 6 School Bus was 56 students. Since school buses are constantly picking up and dropping off students depending on the time of day, they do not have the maximum number of students for a consistent amount of time. A paper from the FHWA provides a formula to calculate the average vehicle occupancy (AVO), which accounts for the time the bus is full and empty (**Eq. 12**).[110] Since with every other vehicle, the payload or occupancy has been separated into empty and full, the AVO had to be adjusted to remove the empty occupancy effect. Therefore, an extra calculation (**Eq. 13**) was used after determining the AVO to find the occupancy of the bus and ensure consistency with the methods of this study. From **Eq. 12**, the AVO was calculated to be 14.18.

$$AVO = 1 + (C \times L_F) \tag{12}$$

where AVO is the average vehicle occupancy (accounting for the full and empty occupancies), 1 accounts for the bus driver, C is the capacity of the school bus (which is assumed to be 56 students), and L_F is the weighted average loading factor (0.235) which takes into account the school bus loading factor (%) and route distances.

To determine the vehicle occupancy for when the school bus was loaded (has any number of passengers greater than zero excluding the bus driver), the percentage of time the school bus had an occupancy (was not empty) was applied to the AVO, defined as 1 minus the time the bus was empty. Use of the empty bus percentage negates the influence of an empty bus on the AVO, allowing for the determination of the school bus occupancy when there is at least 1 student on the bus. [111] This approach (**Eq. 13)** was used to calculate the school bus occupancy that applied to this study. From **Eq. 13**, the full occupancy for school buses in this study was determined to be 22 students.

$$14.18 = T_F \times P_F + T_E \times P_E \tag{13}$$
$$14.18 = T_F \times P_F$$
$$T_F = \frac{14.18}{P_F}$$

where T_F is the number of passengers when considered full (vehicle occupancy), T_E is the number of passengers when the bus is empty (so $T_E = 0$), P_F is the percent of time the bus is full (65%), and P_E is the percentage of time the bus is empty (35%).[111]

For Class 7 Transit Buses, payload did not need to be determined because of the daily hydrogen demand data provided by Flint MTA.

Fuel Economy Calculations

Two different approaches were used to calculate the fuel economies for empty and loaded vehicles. To calculate empty fuel economies for all classes, existing GREET data for classes 6 PnD and 8b long-haul were used. The loaded and empty miles per diesel gallon equivalent (MPDGE) values from GREET were compared to calculate corresponding payload-fuel relation factors, which were then used to construct a linear model to calculate fuel economies for other classes based on payload as the input variable.[79] These factors were calculated separately for 2022, 2030, and 2050 for all vehicle classes selected for the demand analysis.

To determine the full payload fuel economies **Eq. 14** was used, which had the initial fuel economies from GREET as inputs, along with a fuel reduction value (FRV) **Eq. 14**.[112] FRVs (liter/(100 kilometers*100 kilograms)) are the reduction in fuel consumption (liter / 100 kilometers) per 100 kilogram reduction in mass of the vehicle.[113] They are generally used to determine the fuel economy improvements due to lightweighting of vehicles, usually from changing materials from steel to aluminum for example.[114] In this study, the FRVs were used to calculate the fuel economies based on the larger payload values found from the MDOT data compared to the initial GREET payload values. To find the new fuel economies, a similar formula as the one used for lightweighting was applied. The main difference is that Δm, which is the difference between the typical payload (MDOT) and the initial payload (GREET), was multiplied by negative one to account for the increased payload. This value is important as it determines the change in mass which is directly proportional to the FRV.

$$FE_{2,d} = (FE_{1,d} + (\Delta m \times FRV_d)) * C_{km-mi} * C_{liter-dge} \tag{14}$$

where $FE_{2,d}$ is the diesel fuel economy calculated for this study (diesel gallon equivalent/mile), $FE_{1,d}$ is the diesel fuel economy of the base vehicle from GREET (km/L),[84] Δm is the difference between the typical payload determined from the MDOT data and the payload in GREET (average typical payload) (kilograms), FRV_d is the fuel reduction value for diesel for the specific vehicle (liters/kilometer*kilogram), C_{km-mi} is the conversion factor from km to mi, and $C_{liter-dge}$ is the conversion factor from liters to diesel gallon equivalent (DGE). FRVs vary based on vehicle class and fuel type. The exact FRVs used can be found in **Appendix C** (**Table C2)**.

Total Energy Consumption Estimates - Diesel Fuel
The annual VMT for each class was separated based on the amount of time each vehicle has a full and empty payload. Those VMT values were then multiplied by the new fuel economies for each class to calculate the energy consumption (MJ/mile). The formula to calculate energy consumption can be found in **Eq. 15** and **Eq. 16**.

$$EC_{i,d} = LHV_{CD} \times FE_{2,d} \tag{15}$$

$$EC_{vc,d} = EC_{i,d} \times VMT_{vc,d} \tag{16}$$

where $EC_{i,d}$ is the energy consumption (MJ/mile) for each individual vehicle modeled (i) fueled by diesel, LHV_{CD} is the lower heating value of US conventional diesel (MJ/gal)[79], $FE_{2,d}$ is the diesel fuel economy calculated for this study (diesel gallon equivalent / mile), $VMT_{vc,d}$ is the annual VMT for each vehicle class (vc) fueled by diesel, and $EC_{vc,d}$ is the total energy consumption for each vehicle class (vc) fueled by diesel (MJ).

After determining the total energy consumption values for each vehicle class with a full and empty payload, a conversion factor was applied to determine the amount of liters of diesel per year for each class. This calculation can be found in **Eq. 17**.

$$N_{L,p} = EC_{vc,d} \times \frac{1}{LHV_{CD}} \times C_{gal-liter} \tag{17}$$

where $N_{L,p}$ is the number of liters (L) for payload (p) (full or empty) of each vehicle class, $EC_{vc,d}$ is the total energy consumption (MJ) for each vehicle class (vc) fueled by diesel, LHV_{CD} is the lower heating value of US conventional diesel (MJ/gal), and $C_{gal-liter}$ is the conversion factor from gallons to liters.[79]

2.5 Future Projections
For many of the modeled sectors, future demand was determined by scaling current (2022) data to 2030 and 2050 using projections such as economic growth for industrial facilities and predicted increases in VMT for MHDV applications.

2.5.1 Industry Economic Growth
Economic growth was essential to account for in the future demand models as it has the potential to increase hydrogen demand. The projected economic growth of industrial facilities

(2030, 2050) was derived using industrial macroeconomic data from the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook (AEO) 2023* Reference case.[115] One major advantage of using this dataset was that the projections were regionalized to the Midwest (East North Central). To be able to use EIA data to model economic growth, two assumptions were made. The first assumption was that the EIA's "Real Value of Shipments" metric, synonymous with sector revenue, accurately reflects sectoral output.[116] For modeling simplicity, it was also assumed that a change in sector output would result in a proportional change in the amount of feedstock or fuels being used at a facility. In this case study, this change was referred to as the growth rate and was applied to hydrogen demand as well as incumbent fossil fuel use in both the 2030 and 2050 scenarios. The growth rate ($GR_{x,y}$) for each EIA IND category (*x*) was calculated for each respective year *y* (2030, 2050) by multiplying the compound annual growth rate by the number of years, *n* elapsed between 2022 and year *y* (**Eq. 18**).

$$GR_{x,y} = [((\frac{S_{x,y}}{S_{x,2022}})^{\frac{1}{n}} - 1) \times n) + 1] \tag{18}$$

where $S_{x,y}$ is the real value of shipments (billion 2012 $) for industry sector *x* in year *y* (2030 or 2050), $S_{x,2022}$ is the real value of shipments (billion 2012 $) for industry sector *x* in 2022, n is the number of years between 2022 and year *y* (n = 8 for y = 2030, n = 28 for y = 2050).

For ethanol facilities, the 2030 and 2050 growth rate was determined using *AEO* projections of future ethanol demand rather than the "Real Value of Shipments" metric. This was because EIA's 2022 industrial macroeconomic dataset did not specify ethanol as a manufacturing sector. It was also not accurate to use the "Organic Chemicals" growth rate, as ethanol production is highly dependent on gasoline markets and subsidies, which are not reflected in this projection. Total projected ethanol demand (quads) was calculated by summing projections of ethanol use in gasoline blending ($E_{Blending,y}$) and in E85 applications ($E_{E85,y}$). Unlike the industrial macroeconomic data, projections regarding ethanol demand were not able to be regionalized, as EIA does not provide ethanol data within this resolution. **Eq. 19** determines the growth rate ($GR_{EtOH,y}$) for ethanol facilities for each respective year *y* (2030, 2050) by multiplying the compound annual growth rate by the number of years elapsed between 2022 and year *y.*

$$GR_{EtOH,y} = [((\frac{E_{E85,y} + E_{Blending,y}}{E_{E85,2022} + E_{Blending,2022}})^{\frac{1}{n}} - 1) \times n) + 1] \tag{19}$$

where $GR_{EtOH,y}$ is the economic growth rate of ethanol facilities in year *y* (2030, 2050), $E_{E85,y}$ is the energy of ethanol (quad) used for E85 applications in year *y*, $E_{Blending,y}$ is the energy of ethanol (quad) used for blending with gasoline in year *y*, $E_{E85,2022}$ is the energy of ethanol (quad) used for E85 applications in 2022, and $E_{Blending,\,2022}$ is the energy of ethanol (quad) used for blending with gasoline in 2022.

EIA IND category growth rates were then mapped onto facilities using facility-specific NAICS codes and aligning them with respective EIA IND codes (**Appendix B, Table B2**). This was necessary as EIA IND codes are specific to the EIA's National Energy Modeling System (NEMS) and are not utilized by industry.[116] **Eq. 20** highlights how the growth rates (**Appendix B, Table B3**) were used to scale each facility's hydrogen and incumbent fossil fuel demand based on current data to 2030 and 2050, respectively.

$$m_{i,\,j,\,y} = GR_{x,\,y} \times m_{i,\,j,\,2022} \tag{20}$$

where $m_{i,\,j,\,y}$ is the mass of annual demand for fuel or feedstock *j* (hydrogen or fossil fuels) in year *y* (2030, 2050) at facility *i* (metric tons), and $m_{i,\,j,\,2022}$ is the mass of annual demand for fuel or feedstock feedstock *j* (hydrogen or fossil fuels) in 2022 at facility *i* (metric tons).

2.5.2 MHDV Projections

For HDV freight classes, total VMT values from the MDOT freight dataset for 2018 and 2045 were fitted to a linear model, which was used to calculate 2030 and 2050 estimates within each class, applying the same VMT equations used for Diesel MHDV calculations (Section 2.4.3).

For MDV classes, total VMT values from the MDOT 2015 data were similarly extrapolated to 2030 and 2050 by again applying the FHWA projected SUT annual growth rate of 1.8% for each estimated class.[117] All payloads were assumed to remain constant, as estimated for Diesel MHDV calculations (Section 2.4.3).

2.6 Near-term Demand (2030)

Demand scenarios were designed to capture the different hydrogen deployment opportunities viable in 2030 in each respective sector and to estimate potential hydrogen demand. The methods employed to calculate demand in the 2030 scenarios either scaled current fuel/feedstock usage or assumed a specific hydrogen use to displace incumbent fossil fuels.

2.6.1 2030 Demand Scenarios

Hydrogen demand scenarios were designed to distinguish between status quo hydrogen use ("Incumbent Technology ") and demand resulting from the deployment of near-term hydrogen opportunities ("Near-Term Hydrogen Opportunities"). Both scenarios and their respective assumptions are shown in **Table 3**.

Table 3. Near-term (2030) hydrogen demand scenarios created for Michigan's industrial and transportation sectors. The "Incumbent Technology " scenario includes hydrogen applications that currently (2022) exist while the "Near-Term Hydrogen Opportunities" scenario layers on additional hydrogen demand from use in steel and increased FCEV penetration in transportation.

Sector		Incumbent Technology	Near-Term Hydrogen Opportunities
Petroleum Refining		Feedstock Use	Feedstock Use
Semiconductor			
Glass			
Steel	*Integrated mills*	-	30% maximum replacement of coke & process heat makeup from BFG loss
	Mini mills	-	-
Chemicals		-	-
Pulp & Paper			
Cement			
Transportation		3 transit buses in Flint MTA	1% of each vehicle class

Incumbent Technology
This scenario serves as a demand and emissions baseline for comparison to the other 2030 scenario. The “Incumbent Technology” scenario includes the current (2022) hydrogen demand from petroleum refining, semiconductor manufacturing, glassmaking, and transportation and accounts for each sector’s growth from 2022 to 2030. For industrial facilities, the 2030 growth rate determined from EIA projections was applied to current hydrogen and fossil fuel use (Section 2.5.1). For the transportation sector, it was assumed that Flint MTA would expand their fuel cell transit bus fleet to 3 vehicles by 2030. This assumption was based on Flint MTA purchasing two additional fuel cell buses in 2023 and expressing that they had no other current plans to expand the fleet before 2030.[78] While there is no hydrogen demand for the cement sector in the near-term, a 5% thermal contribution from plastic was assumed for the St. Marys Cement plant and a confidential mix of alternative fuels was assumed for the Holcim plant for both the “Incumbent Technology” scenario and the “Near-term Hydrogen Opportunities” scenario.[98] This is important to mention as the increasing prevalence of alternative fuels (plastics, TDF) displaces the need for fossil fuels in cement manufacturing, which is reflected in the 2030 emissions for the cement industry.

Near-term Hydrogen Opportunities
The “Near-Term Hydrogen Opportunities" scenario includes existing hydrogen use scaled for growth as well as hydrogen deployment opportunities viable in 2030 for the steel industry and transportation sector. For steelmaking, it was assumed that Cleveland Cliffs’ integrated mill in Dearborn, MI, would begin displacing 30% of coke in the blast furnace (BF) with hydrogen. This assumption was based on the IEA”s “Global Hydrogen Review” (2022), which asserts that hydrogen can be blended into current BF systems at a maximum of 30% without upgrading the existing equipment.[118] This hydrogen deployment opportunity has a technology readiness level of 7 and has been successfully piloted in two blast furnace hydrogen injection trials in Cleveland-Cliffs Middletown Works and Indiana Harbor.[22,92,119] To address the reduction in BFG

which results from displacing coke, it was assumed that hydrogen would be combusted in the downstream processes to provide the heat that is previously accounted for by BFG. Since literature about pilots and hydrogen DRI does not comment on how lost BFG heat is managed, this assumption was made for the purpose of this analysis. The IEA's "Net Zero Roadmap" informed near-term hydrogen demand for the transportation sector, as the IEA asserts that 1% of all road transportation will be powered by hydrogen in 2030.[4] The IEA projects this penetration based on limited hydrogen refueling infrastructure and low technology readiness in the 2030 time horizon. In addition, the adoption of electric vehicles is expected to dominate road transportation in the near term.[4] It is important to note that the 1% projected by the IEA is not delineated by transportation mode, so for this scenario it was assumed that 1% of each MHDV class would be a FCEV.

Hydrogen for process heat was excluded from this scenario, as the cost of hydrogen is still expected to be high in 2030 and upgrades to existing equipment are required for effective hydrogen combustion.[120] In addition, hydrogen blending with natural gas was not modeled in this scenario as DOE predicts that blending will be deployed after 2030 unless the cost of hydrogen declines considerably.[116] It is for these reasons that there is no projected demand in the chemicals and pulp and paper industry. For the glass industry, contacts at Guardian Glass indicated that large renovations, or "cold tank repairs," would be needed to implement hydrogen-based technologies in the furnace and lehr. Since glass manufacturing lines typically run 24/7, year round, cold tank repairs only happen every 15-20 years.[121] Considering that the last modifications to Guardian Glass' Carleton plant occurred in 2018, no near-term opportunities for hydrogen use are expected at this facility. From stakeholder input, it was assumed that there would be no hydrogen deployment in Michigan's cement sector in 2030.

2.6.2 Industrial 2030 Methods

Petroleum Refining, Semiconductor, Glass Industries

Future feedstock demand at petroleum refining, semiconductor, and glass facilities were determined by scaling current demand (Section 2.3.1) by the respective EIA growth rate for 2030 (Section 2.5.1).

Steel Industry

To estimate hydrogen demand within the steel industry, the following method was developed for integrated steel mills. The operation of the blast furnace (BF) and basic oxygen furnace (BOF) is sequential, with a portion of the heat required by the BOF being supplied by blast furnace gas (BFG) which is produced in the BF. Given the interdependence between BFG and coke, since BFG is a byproduct of coke usage in the BF, the substitution of coke with hydrogen in the BF will lead to a reduction in BFG, and thus a need to makeup heat in the BOF. To compensate for this loss, it was assumed that hydrogen would be combusted to provide the heat previously accounted for by BFG. The quantities of coke and blast furnace gas determined in "Industry-Specific Feedstock and Fuels" (Section 2.4.2) were utilized to ascertain the potential hydrogen demand, as outlined in **Eq. 21** and **Eq. 22.**

$$m_{Dearborn,\,coke-H_2} = m_{Dearborn,\,Coke} \times R_{Dearborn,\ Coke} \times HHV_{coke} \times \frac{1}{HHV_{H_2}} \quad (21)$$

$$m_{Dearborn,\,BFG-H_2} = m_{Dearborn,\,BFG} \times R_{Dearborn,\ BFG} \times HHV_{BFG} \times \frac{1}{HHV_{H_2}} \quad (22)$$

where $m_{Dearborn,\,coke-H_2}$ and $m_{Dearborn,\,BFG-H_2}$ are the masses of annual hydrogen demand due to coke and BFG replacement for the integrated mill, respectively (metric tons); $m_{Dearborn,\,Coke}$ and $m_{Dearborn,\,BFG}$ are the annual coke and BFG demands for the integrated mill, respectively (metric tons); $R_{Dearborn,\ Coke}$ and $R_{Dearborn,\ BFG}$ are the 30% hydrogen replacement ratios of coke and blast furnace gas of the integrated mill, respectively; HHV_{coke}, HHV_{BFG}, and HHV_{H_2} are the higher heating values of coke, blast furnace gas, and hydrogen, respectively (MJ/kg).

Cement Industry

Though no hydrogen use is assumed in 2030, it was necessary to estimate the fuel mix of both cement facilities to account for the increased use of alternative fuels (AFs) to replace fossil fuels and to inform the emissions reduction analysis. Using the fuel mix previously calculated (Section 2.4.2), the replacement order of incumbent fossil fuels in 2030 was determined based on their relative prices—i.e., the most expensive fossil fuels were replaced first by AFs. If the most expensive fuel's kiln thermal contribution drops to zero percent, the second-most expensive fuel is then replaced by additional AFs. Projected 'natural gas' and 'metallurgical coal' prices for the 'industrial' sector were sourced from the *Annual Energy Outlook (AEO) 2023* Reference case.[115] The price of petroleum coke in 2022, 2030, and 2050 was sourced from Energy and Environmental Economics Inc. in 2012 \$/MMBtu.[122] To convert these prices to 2022 \$/MMBtu, the consumer price index (CPI) from the U.S. Bureau of Labor Statistics was used.[123] Specifically, the monthly change in CPI across years (Jan 2012 to Jan 2022, Feb 2012 to Feb 2022, etc.) was averaged to create a single measure of inflation and applied to price in 2012 \$ to obtain 2022 \$ (**Eq. 23**).

$$P_{2022\$} = P_{2012\$} * \frac{1}{12} * \sum_{m=1}^{12} \left(\frac{CPI_{2022,\,m}}{CPI_{2012,\,m}}\right) \quad (23)$$

where P_{2022} is the price of petroleum coke in 2022 \$/MMBtu, P_{2012} is the price of petroleum coke in 2012 \$/MMBtu, $CPI_{2022,\,m}$ is the CPI in month m of 2022, and $CPI_{2012,\,m}$ is the CPI in month m of 2012. Here, m = 1 refers to January while m = 12 refers to December. It is important to note that this equation is used to calculate the price of petroleum coke individually for 2022, 2030, and 2050. From these projections, coal was found to be the most expensive fuel in 2030 followed by petroleum coke and natural gas.

It was assumed that AFs only replace incumbent fossil fuels, and not each other, from the fuel mix. Due to the lack of technical data on fuel-switching projects within the cement sector, a 1:1

substitution ratio on a Btu basis was assumed when replacing incumbent fossil fuels with AFs. Using the incumbent kiln fuel mix in 2022, making assumptions of future thermal contributions of AFs, and applying the replacement logic described above, updated fuel mixes were generated for both Holcim and SMC plants. Finally, the total kiln thermal energy for each plant was calculated (**Eq. 24**) and the updated fuel mixes were used to estimate each fuel's respective annual demand in 2030 (**Eq. 25**). Since the 2030 fuel use estimates are based on 2022 operations, the 2030 economic growth projections (Section 2.6.2) were applied to reflect future economic activity in the cement sector.

$$TE_i = \sum_k [m_{i,k} \times C_{mt-kg} \times HHV_k] \tag{24}$$

where TE_i is the total thermal energy used in the kiln for facility *i* (Holcim or SMC) (MJ), $m_{i,k}$ is the mass of fuel *k* (natural gas, coal, petroleum coke, tire derived fuel [TDF], or plastics) used annually in plant *i* (metric tons), and C_{mt-kg} is the conversion factor from metric tons to kg.

$$m_{i,k,y} = TE_i \times f_{i,k,y} \times \frac{1}{HHV_k} \times C_{kg-mt} \tag{25}$$

where $m_{i,k,m}$ is the mass of fuel *k* in facility *i* in year *y* (2030) and $f_{i,k,y}$ is the kiln thermal energy contribution of fuel *k* in facility *i* in year *y* as estimated using the aforementioned method.

2.6.3 Transportation 2030 Methods

Demand for 2030 for the selected MHDVs was calculated by scaling VMT values for each class as explained in "MHDV Projections" (Section 2.5.2).

To determine the loaded payload fuel economies for both diesel and hydrogen vehicles, base data from GREET for diesel and hydrogen was used as well as and the default GREET values for 2030. The full payload fuel economies for the diesel vehicles were found from using **Eq. 14**, and **Eq. 15 - Eq. 17** (Section 2.4.3) to find the energy consumption and number of liters of diesel. The same approach was used to calculate the improved fuel economies for the hydrogen vehicles based on loaded and empty payloads. In addition, a similar method to the one used to calculate the empty diesel fuel economies, (Section 2.4.3) was utilized to determine the empty hydrogen fuel economies. The only differences between these methods was the FRV used was for hydrogen fueled vehicles rather than diesel, and the initial fuel economy was for a hydrogen vehicle. The fuel economy for the hydrogen vehicles is still in diesel gallon equivalent/mile because those are the units the fuel economies are initially in from GREET ($FE_{1,h}$) before being converted to km/L to be used in the FRV formula.

$$FE_{2,h} = (FE_{1,h} + (\Delta m \times FRV_h)) * C_{km-mi} * C_{liter-dge} \tag{26}$$

where $FE_{2,h}$ is the hydrogen fuel economy calculated for this study (diesel gallon equivalent/mile), $FE_{1,h}$ is the hydrogen fuel economy of the base vehicle from GREET (km/L),[84] Δm is the difference between the typical payload determined from MDOT data and the payload in GREET (average typical payload) (kilograms), FRV_h is the fuel reduction value for hydrogen for the specific vehicle (liters/kilometer*kilogram), C_{km-mi} is the conversion factor from km to mi, and $C_{liter-dge}$ is the conversion factor from liters to diesel gallon equivalent (DGE). The exact FRVs used can be found in **Appendix C** (**Table C2**).

Total energy consumption for hydrogen vehicles was determined in a similar method to the diesel vehicle calculations as seen in **Eq. 27** and **Eq. 28.** The differences are the application of the diesel gallon equivalent conversion factor, the density of gaseous hydrogen at standard temperature and pressure (STP), and the lower heating value of gaseous hydrogen in **Eq. 27,** while **Eq. 28** is exactly the same as **Eq. 16** but for hydrogen fuel.

$$EC_{i,h} = FE_{2,h} \times DGE_{kg\,H_2} \times \frac{1}{\rho_{GH_2}} \times LHV_{GH_2} \tag{27}$$

$$EC_{vc,h} = EC_{i,h} * VMT_{vc,h} \tag{28}$$

where $EC_{i,h}$ is the energy consumption for each individual vehicle (i) fueled by hydrogen (MJ/miles), $FE_{2,h}$ is the hydrogen fuel economy calculated for this study (diesel gallon equivalent/miles), $DGE_{kg\,H_2}$ is the conversion factor from diesel gallon equivalent (DGE) to kilograms of gaseous hydrogen[79], ρ_{GH_2} is the density of gaseous hydrogen at STP (kg/ft^3)[79], LHV_{GH_2} is the lower heating value for gaseous hydrogen (MJ/ft^3), $VMT_{vc,h}$ is the annual VMT for each vehicle class (vc), and $EC_{vc,h}$ is the total energy consumption for each vehicle class (vc) fueled by hydrogen (MJ).

After determining the total energy consumption for each vehicle with a loaded and empty payload, conversion factors were applied to calculate the metric tonnes of hydrogen required by each vehicle class with the separate payloads. This calculation can be found in **Eq. 29**.

$$N_{mt,p} = EC_{vc,h} \times \rho_{GH_2} \times \frac{1}{LHV_{GH_2}} \times C_{kg\,H_2-metric\ tonnes} \tag{29}$$

where $N_{mt,p}$ is the number of metric tonnes of hydrogen per year for each class with payload p (full or empty), $EC_{vc,h}$ is the total energy consumption (MJ) for each vehicle class fueled by hydrogen, ρ_{GH_2} is the density of gaseous hydrogen at STP (kg/ft^3), $LHV_{G\,H_2}$ is the lower heating values of gaseous hydrogen (MJ/ft^3), and $C_{kg\ H_2 - metric\ tonnes}$ is the conversion factor from kilograms of hydrogen to metric tonnes.

2.7 Long-term Demand (2050)

Hydrogen demand scenarios were similarly outlined for 2050 to differentiate between hydrogen deployment opportunities in Michigan and provide a potential range of demand. Four scenarios were created for 2050 as it was assumed that there would be more hydrogen deployment opportunities available due to technological advances and a lower cost of hydrogen.
As in 2030, the methods used to estimate demand in the 2050 scenarios consisted of scaling current (2022) demand and assuming specific hydrogen uses in respective sectors to displace incumbent fossil fuels.

2.7.1 2050 Demand Scenarios

In addition to the "Incumbent Technology" scenario, three additional scenarios were introduced in 2050, including "Low Hydrogen Use," "High Hydrogen Use," and "Complete Hydrogen Substitution." These scenarios were designed to capture a broad range of hydrogen use cases while taking into account technology readiness, projected adoption rates, data availability, and stakeholder engagement. **Table 4** provides a high-level overview of the assumptions made to inform the "Long-Term Hydrogen Demand" scenarios.

Table 4. Long-term (2050) hydrogen demand scenarios created for Michigan's industrial and transportation sectors. The four scenarios explore a variety of hydrogen deployment opportunities, from the "Incumbent Technology" scenario, which reflects the continued use of hydrogen exclusively in applications that currently (2022) exist, to the "Complete Hydrogen Substitution" scenario, where hydrogen meets all process heat requirements and 100% of MHDV fuel requirements in addition to feedstock uses. The "Low Hydrogen Use" and "High Hydrogen Use" scenarios represent more modest applications of hydrogen in the future as compared to the "Complete Hydrogen Substitution" scenario.

Sector		**Incumbent Technology**	**Low Hydrogen Use**	**High Hydrogen Use**	**Complete Hydrogen Substitution**
Petroleum Refining		Feedstock Use	Feedstock Use, 20% Blending		Feedstock Use, 100% Process Heat *
Semiconductor					
Glass		Feedstock Use	Feedstock Use, 20% Blending		Feedstock Use, 100% Oxy-hydrogen firing in furnace and annealing lehr
Steel	*Integrated mills*	-	30% replacement of coke, process heat makeup from BFG loss, 20% Blending	30% replacement of coke, process heat makeup from BFG loss, 20% Blending	100% Hydrogen DRI, H_2-enhanced EAF, 100% Process Heat *

	Mini mills	-	20% Blending	H_2-Enhanced EAF, 20% Blending	H_2-Enhanced EAF, 100% Process Heat *
Chemicals		-	20% Blending		100% Process Heat *
Pulp & Paper					
Cement		-	9% of thermal energy	Contact-specified % of thermal energy	100% Process Heat *
Transportation		3 transit buses in Flint MTA	4% of each vehicle class	20% of each vehicle class	100% of each vehicle class

** "100% Process Heat" refers to displacing the incumbent fossil fuels (coal, coke, natural gas) which provide process heat (boilers, furnaces, kilns, etc) with 100% hydrogen.*

Incumbent Technology

As in 2030, the 2050 "Incumbent Technology" scenario serves as a baseline for hydrogen demand and emissions, enabling status quo hydrogen use to be compared to other 2050 scenarios. This scenario encompasses current (2022) hydrogen demand from petroleum refining, semiconductor manufacturing, glassmaking, and transportation and considers each sector's growth from 2022 to 2050. For industrial hydrogen demand, the 2050 growth rate was determined from EIA projections and was applied to current hydrogen and fossil fuel use (Section 2.5.1). In terms of the transportation sector, it was assumed that Flint MTA's hydrogen bus fleet would remain at three in the 2050 "Incumbent Technology" scenario. This was because Flint MTA does not have any current orders placed for additional hydrogen buses.[124]

Low Hydrogen Use

In the "Low Hydrogen Use" scenario, a 20% blend of hydrogen with natural gas for process heat was assumed across all industrial sectors except for cement. This blending assumption was based off prior work at the National Renewable Energy Laboratory (NREL), which found that natural gas infrastructure and most existing end-use equipment in the U.S. could handle hydrogen blends of up to 20% without significant modifications.[125] A lower blending percentage was not used for the "Low Hydrogen Use" scenario since blending percentages as low as 5% are not on track with net-zero 2050 targets. For process heat in the cement industry, it was presumed that hydrogen will account for 9% of both cement plants' thermal energy use.[126] Other assumptions regarding the cement industry include that plastics contribute 5% of the thermal demand for the St. Marys Cement plant and a contact-specified, proprietary mix of alternative fuels was utilized for the Holcim plant.[96] In this scenario, integrated steel mills are assumed to use the maximum 30% hydrogen substitution for coke in the blast furnace. Steel mini mills, which exclusively utilizes the electric arc furnaces (EAF) to process steel production from scrap, were limited to 20% hydrogen blending for process heat needs. For the transportation sector, it was assumed that 4% of all MHDV classes would be FCEVs. This was calculated from projections in the "U.S. National Clean Hydrogen Strategy and Roadmap" that estimated a range of hydrogen demand for 2050 for transportation (Section 2.7.3). The roadmap determined these ranges based on the projected cost of hydrogen in 2050, implications from policies like the IRA, potential regulatory pressure, and improvements in technology performance and their associated costs.[13]

High Hydrogen Use

This scenario encompasses existing (2022) uses of hydrogen and assumes that all industrial sectors except for cement will utilize a 20% hydrogen blend with natural gas for process heat. A blending percentage higher than 20% was not used for the “High Hydrogen Use” scenario as higher blending percentages would necessitate significant changes to existing natural gas infrastructure and end-use applications.[125] However, higher blending percentages may be possible if done on-site or for specific end-uses, but those opportunities were not captured in the 2050 scenarios as data was not available for facility-specific process temperatures or equipment. For both cement facilities, the thermal contribution of hydrogen was determined from contact-specified percentages, while the contribution of alternative fuels was assumed to be the same as in the “Low Hydrogen Use” scenario. In the “High Hydrogen Use” scenario, integrated steel mills continue to utilize a 30% maximum coke replacement in the blast furnace and make up lost BFG heat with hydrogen. For steel mini mills, it was assumed that these facilities would enhance the electric arc furnace process by incorporating hydrogen as a supplementary heat input. There are currently two pilot plants in Europe, CELSA in Spain and FERRIERE NORD in Italy that are leveraging this technology.[127] This scenario also presumed that 20% of all MHDV classes would be hydrogen FCEVs in 2050. Like the 4% assumption utilized in the the “Low Hydrogen Use” scenario, this percentage was calculated from projections in the “U.S. National Clean Hydrogen Strategy and Roadmap” (Section 2.7.3).[13]

The low and high end of the range mainly differed due to the projected costs of hydrogen in 2050.

Complete Hydrogen Substitution

The “Complete Hydrogen Substitution” scenario is meant to demonstrate the scale of hydrogen demand and emission reductions if all the hydrogen deployment opportunities available in 2050 were utilized. Existing feedstock applications (petroleum refining, semiconductor, glass) remain in this scenario and are scaled to reflect sectoral economic growth from 2022 to 2050. Integrated steel mills are assumed to adopt 100% hydrogen DRI while mini mills will be employing hydrogen enhanced EAF. For process heat, this scenario models that hydrogen would completely replace natural gas process heat as well as other fossil fuels (petroleum coke, coal) in cement kilns. For cement manufacturing, the thermal contribution of alternative fuels was assumed to be the same as the “Low Hydrogen Use” and “High Hydrogen Use scenario. In addition, for the glass industry it was presumed that hydrogen would be used in oxyfuel combustion in the furnace and the annealing lehr. Since hydrogen’s high adiabatic flame temperature makes it susceptible to the formation of “thermal NO_x”, oxy-hydrogen firing was assumed to control NO_x emissions in the glass furnace. Since 1991, over 300 commercial glass furnaces have been converted to oxy-fuel, demonstrating high technology readiness.[128] Moreover, industry leaders in combustion technologies such as Linde, Flammatech, and Air Products all offer oxy-hydrogen burner technologies for glass furnaces.[129–131] In this scenario it was also assumed that 100% MHDV classes were transitioned to hydrogen FCEVs in 2050.

2.7.2 Industrial 2050 Methods

Petroleum Refining, Semiconductor, Glass Industries

Demand for feedstock hydrogen is expected to continue into 2050 in the petroleum refining, semiconductor, and glass industries. This was calculated by scaling 2022 demand (Section 2.3.1) by the respective EIA growth rates for 2050 (Section 2.5.1).

Natural Gas Blending

One potential source of future hydrogen demand is the blending of hydrogen with natural gas to supply industrial process heat. For both the "Low Hydrogen Use" and the "High Hydrogen Use" scenarios in 2050, a hydrogen blend of 20% by volume was assumed.

Eq. 31 and **Eq. 32** were used to estimate natural gas and hydrogen demand in the 2050 blending scenarios. To perform this estimation, a new HHV for the mixture of gasses was calculated, resulting in an HHV for the 20% blend of 35.0 MJ per cubic meter (**Eq. 30**). For this calculation, the assumed HHVs were 39.2 MJ per cubic meter (1,089 Btu per cubic feet) for natural gas and 12.8 MJ per cubic meter (343 Btu per cubic feet) for hydrogen, respectively. This set of equations uses HHV in terms of volume rather than mass since the blending percentage is on a volumetric basis. As a result, each gas density was also included in **Eq. 31** and **Eq. 32** and was assumed to be the GREET default, which is at standard conditions to align with prior HHV assumptions (0.777 kg per cubic meter for natural gas and 0.090 kg per cubic meter for hydrogen).[84]

$$HHV_{Blend} = (N_{NG,\,Blend\,\%} \times HHV_{NG}) + (N_{H_2,\,Blend\,\%} \times HHV_{H_2}) \tag{30}$$

where HHV_{Blend} is the higher heating value of hydrogen and natural gas blend (MJ/m^3), $N_{NG,\,Blend\,\%}$ is the percentage (by volume) of natural gas (80%), HHV_{NG} is the higher heating value of natural gas (MJ/m^3), $N_{H_2,\,Blend\,\%}$ is the percentage of hydrogen (by volume) in the blend (20%), HHV_{H_2} is the higher heating value of hydrogen (MJ/m^3).

$$m_{i,\,NG} = m_{i,\,CO_2-NG\ Combustion} \times \frac{1}{EF_{NG\ Combustion}} \times \frac{1}{HHV_{Blend}} \times N_{NG,\,Blend\,\%} \times \rho_{NG} \times C_{kg-mt} \tag{31}$$

$$m_{i,\,H_2} = m_{i,\,CO_2-NG\ Combustion} \times \frac{1}{EF_{NG\ Combustion}} \times \frac{1}{HHV_{Blend}} \times N_{H_2,\,Blend\,\%} \times \rho_{H_2} \times C_{kg-mt} \tag{32}$$

where ρ_{NG} is the density of natural gas (kg/m^3), and ρ_{H_2} is the density of hydrogen (kg/m^3).

100% Hydrogen Process Heat

Hydrogen has been proposed as an alternative to natural gas for industrial process heat, especially for medium or high temperature processes.[67,132] This deployment opportunity represents the upper limit for process heat demand, assuming that all process heat met via natural gas at facilities could be replaced with hydrogen on a 1:1 MJ basis. All natural gas was considered due to lack of available data regarding facility process heat temperatures. A similar calculation to **Eq. 3** was employed to calculate how much hydrogen would be required to replace all natural gas for facilities. Annual CO_2 emissions from natural gas combustion ($m_{i,\, CO_2\, Combustion}$) were obtained from the GHGRP for facilities. GHGRP emissions data was then used to estimate the annual energy demand from natural gas for each facility, assuming a combustion factor of 0.0503 kg CO_2/MJ of natural gas (53.06 kg CO_2/MMBtu NG).[89] This annual energy estimate was then multiplied by the HHV of hydrogen (141.9 MJ/kg, 343 Btu/ft^3)[84] to calculate the mass of hydrogen (metric tons) each facility would need to produce an equivalent amount of energy (**Eq. 33**).

$$m_{i,\, H_2} = m_{i,\, CO_2 - NG\ Combustion} \times \frac{1}{EF_{NG\ Combustion}} \times HHV_{H_2} \times C_{kg-mt} \tag{33}$$

Steel Industry

In the “Low Hydrogen Use” and “High Hydrogen Use” scenarios, the same 30% maximum coke replacement strategy was employed for the integrated mill together with the hydrogen blending. For the mini mill, it was assumed that the electric arc furnace (EAF) would be upgraded to hydrogen-enhanced EAF in the “High Hydrogen Use” and “Complete Hydrogen Substitution” scenarios. EAF is instrumental in manufacturing steel from scrap material for mini mills and refining the output from blast or shaft furnaces for integrated mills. Conventionally, EAF utilizes natural gas as an ancillary heat source. Nevertheless, advancements are underway through a project in Europe focusing on the development of a hydrogen-enhanced EAF, which has achieved significant progress.[127] The hydrogen requirement for hydrogen-enhanced EAF was estimated (**Eq. 34**) based on the method previously introduced (Section 2.6.2).

$$m_{i,\, H_2} = m_{i,\, EAF\ CO_2 - NG\ Combustion} \times \frac{1}{EF_{EAF\ NG\ Combustion}} \times HHV_{H_2} \times C_{kg-mt} \tag{34}$$

where $m_{i,\, H_2}$ is the mass of annual hydrogen demand for facility *i* (metric tons), $m_{i,\, EAF\ CO_2 - NG\ Combustion}$ is the mass of annual CO_2 emissions from EAF natural gas combustion for facility *i* (kg), $EF_{EAF\ NG\ Combustion}$ is the CO_2 intensity from EAF combusting natural gas (kg CO_2/MJ NG), and HHV_{H_2} is the higher heating value of hydrogen (MJ/kg).

In the “Complete Hydrogen Substitution” scenario for the integrated mill, the flash ironmaking technology–electric arc furnace–hydrogen (FIT–EAF–H_2) technology was employed, which is an innovative approach to steelmaking that incorporates hydrogen as a reducing agent or heat source in the EAF, aiming to enhance the efficiency and reduce carbon emissions in the process.[133] The natural gas-based EAF was modified to be the fully hydrogen-enhanced EAF, and the hydrogen intensity ($Y_{H_2-modified}$) was then calculated by **Eq. 35.** using the original number of 83.73 kg H_2 per metric ton of steel. Utilizing the annual capacity metrics of the integrated mills, the annual hydrogen demand was subsequently computed by **Eq. 36**.

$$Y_{H_2-modified} = Y_{H_2-original} + \frac{m_{NG-original} \times HHV_{NG}}{HHV_{H_2}} \tag{35}$$

$$m_{Dearborn, H_2} = PC_{Dearborn} \times Y_{H_2-modified} \tag{36}$$

where $Y_{H_2-original}$ is the original hydrogen intensity from the literature (kg H_2/metric ton steel), $m_{NG-original}$ is the mass of NG usage for original FIT–EAF–H_2 technology in the EAF (kg), $m_{Dearborn, H_2}$ is the mass of annual hydrogen demand for integrated mill (metric tons), $PC_{Dearborn}$ is the annual production capacity of an integrated mill (metric tons).

Glass Industry

The “Low Hydrogen Use” and “High Hydrogen Use” demand was calculated using the natural gas blending methods previously described (Section 2.7.2).

For the “Complete Hydrogen Substitution” scenario, it was assumed that oxy-hydrogen firing would be used to provide 100% of process heat needs in the furnace and annealing lehr. To model this, correction factors were applied for the glass industry to the 100% hydrogen process heat calculations. First, conversion from air-methane to oxy-methane firing was assumed to generate a 10% specific fuel reduction over the furnace lifetime.[128,134] Next, a 1% increase in specific energy consumption was assumed when converting from oxy-methane firing to oxy-hydrogen firing.[128] This 1% correction factor is embedded as a substitution ratio. Finally, one metric ton of oxygen is required to combust 13,956 MJ-HHV of methane (1 short ton of oxygen to combust 12 MMBtu-HHV), but oxy-hydrogen firing was assumed to generate a 15% reduction in specific oxygen combustion.[128] The resulting equations to calculate hydrogen demand for process heat and oxygen demand for oxy-fuel firing are described by (**Eq. 37**) and (**Eq. 38**), respectively.

$$m_{H_2} = m_{CO_2-NG\ Combustion} \times \frac{1}{EF_{NG\ Combustion}} \times FR_{Oxyfuel} \times SR \times HHV_{H_2} \times C_{kg-mt} \tag{37}$$

$$\begin{aligned} m_{O_2} = m_{CO_2-NG\ Combustion} \times \frac{1}{EF_{NG\ Combustion}} \times HHV_{H_2} \times FR_{Oxyfuel} \\ \times OF_{Oxy-methane} \times OR_{Oxy-H_2} \times C_{st-mt} \end{aligned} \tag{38}$$

where m_{H_2} and m_{O_2} are the respective masses of hydrogen and oxygen used for process heat (metric tons), $FR_{Oxyfuel}$ is the fuel reduction achieved by switching from air-methane combustion to oxy-methane combustion (10% specific fuel reduction), SR is the substitution ratio required when switching from oxy-methane to oxy-hydrogen firing (1% specific fuel increase), $OF_{Oxy-methane}$ is the oxygen required to combust natural gas (1 metric O_2/13956 MJ-HHV of natural gas), and OR_{Oxy-H_2} is the reduction in specific oxygen consumption when switching from oxy-methane to oxy-hydrogen firing (15% specific oxygen reduction).

Cement Industry

For the 2050 "Incumbent Technology" scenario, no hydrogen use was assumed to align with the existing fuel mix in both cement plants. New hydrogen deployment opportunities were accounted for in the "Low Hydrogen Use," "High Hydrogen Use," and "Complete Hydrogen Substitution" scenarios. The replacement order of incumbent fossil fuels in these 2050 scenarios was also determined based on their relative prices—i.e., the most expensive fossil fuels were replaced first by hydrogen or AFs (Section 2.6.2). Based on these projections, coal was also found to be the most expensive fuel in 2050 followed by petroleum coke and natural gas.

While this method makes similar assumptions to the 2030 method (Section 2.6.2), it also considers the implementation of hydrogen. It was assumed that hydrogen and AFs only replace incumbent fossil fuels, and not each other, from the fuel mix. As in 2030, the total kiln thermal energy for each plant was calculated (**Eq. 24**) and the updated fuel mixes were used to estimate each fuel's respective annual demand in 2050 (**Eq. 25**).

Due to the lack of technical data on fuel-switching projects within the cement sector, a 1:1 substitution ratio on a MJ basis was assumed when replacing incumbent fossil fuels with hydrogen and AFs. Updated fuel mixes were generated for both Holcim and SMC plants by using the incumbent kiln fuel mix in 2022, making assumptions of future thermal contributions of hydrogen and AFs, and applying the replacement logic described above. Finally, the total kiln thermal energy for each plant was calculated (**Eq. 39**) and the updated fuel mixes were used to estimate each fuel's respective annual demand in 2050 (**Eq. 40**).

$$TE_i = \sum_k [m_{i,k} \times C_{mt-kg} \times HHV_k] \tag{39}$$

where TE_i is the total thermal energy used in the kiln for facility *i* (Holcim or SMC) (MJ), $m_{i,k}$ is the mass of fuel *k* (natural gas, coal, petroleum coke, tire derived fuel [TDF], or plastics) used annually in plant *i* (metric tons), and C_{mt-kg} is the conversion factor from metric tons to kg.

$$m_{i,k,y} = TE_i \times f_{i,k,y} \times \frac{1}{HHV_k} \times C_{kg-mt} \tag{40}$$

where $m_{i,k,m}$ is the mass of fuel *k* in facility *i* in year *y* (2050) and $f_{i,k,y}$ is the kiln thermal energy contribution of fuel *k* in facility *i* in year *y* as estimated using the aforementioned method. Since the 2050 fuel use estimates are based on 2022 operations, the sector's economic growth projection (Section 2.5.1) was applied to reflect future economic activity in the cement sector.

2.7.3 Transportation 2050 Methods

Transportation demand for 2050 was calculated by scaling VMT values for each class as explained in "MHDV Projections" (Section 2.5.2).

Since it is uncertain how much hydrogen adoption will occur within each class (and which classes will be electrified), scenarios were aligned with predictions made in the DOE Hydrogen Roadmap.[13] In the Roadmap, hydrogen demand in 2050 ranges from 2 to 11 MMT/year.[13] **Eq. 41** was used to estimate the percentage of vehicles in each class that are fueled by hydrogen for the various scenarios based on these total national demand values, assuming the same adoption rate across selected MHDV classes. This estimate assumes that demand is distributed evenly throughout the country.

$$VP_{2050} = D_m \times C_{MMT-kg\,H_2} \times \frac{1}{LHV_{kg\,GH_2}} \times C_{MJ-Btu} \times \frac{1}{TEC_{TEDB}} \tag{41}$$

where VP_{2050} is the percentage of vehicles in 2050 that are fueled by hydrogen, D_m is either the minimum (2 MMT) or maximum (11 MMT) demand for hydrogen in 2050 for all MHDVs, $C_{MMT-kg\,H_2}$ is the conversion factor from million metric tonnes (MMT) to kg H_2, $LHV_{kgG\,H_2}$ is the lower heating value of gaseous hydrogen (kg/MJ), C_{MJ-Btu} is the conversion factor from MJ to Btu, and TEC_{TEDB} is the total energy consumed by MHDVs in 2018-2019 (trillion Btu)*.[103]

**multiplied by the 2050 demand (D_m) to scale accordingly*

When the minimum hydrogen demand of 2 MMT is assumed, a hydrogen penetration of 4% is calculated. This percentage represents the penetration that hydrogen comprises within each vehicle class for the Low Hydrogen Use Scenario. This method was utilized due to data limitations regarding the total number of vehicles in each class, except for Class 6 School Buses and Class 7 Transit Buses in the state of Michigan. Since that data was not available, and due to the uncertainty around which classes would make up the 4%, it was assumed that the percentage was just applied to each vehicle class individually. This percentage was then multiplied to the sum of the number of metric tonnes of hydrogen for each vehicle with a full and empty payload to get the total demand.

2.8 GHG & NO_x Emission Reduction Potential

An analysis of GHG and NO_x emissions was conducted for each of the 2030 and 2050 hydrogen demand scenarios and for different hydrogen production pathways. Five hydrogen production pathways were modeled: natural gas SMR, natural gas SMR with CCS, PEM electrolysis with electricity from the the RFC electric grid (which includes Michigan), PEM electrolysis with electricity from renewables (solar, wind, and hydroelectric), and HTSE electrolysis with electricity from nuclear generation. These pathways were chosen due to their technology readiness level and range of respective GHG intensities.[29] Emissions modeled for hydrogen demand include the upstream emissions from producing hydrogen and emissions from the combustion of hydrogen. While there are concerns that greater hydrogen deployment may lead to atmospheric methane emissions and hydrogen leaks, each of which have climate impacts, these emissions were not accounted for in the analysis, as they are still active areas of research.

In industrial fuel applications, hydrogen was assumed to be combusted directly in the furnace alone or mixed with natural gas. While for the transportation fuel application, it was assumed that hydrogen served as the fuel supply of fuel cells. This distinction underscores the differing roles of hydrogen in industrial versus transportation contexts. Changes in industrial inputs that result from hydrogen deployment were also incorporated in emissions analysis, such as oxygen required for oxy-fuel technology in glassmaking. Additionally, the analysis accounts for the upstream emissions associated with fossil fuel production and the combustion emissions for fossil fuels that are replaced by hydrogen in future end-uses, such as diesel, coke, natural gas, and coal in the future demand analysis scenarios. Potential changes in emissions factors (GHG, NO_x) intensity of hydrogen and relevant fossil fuels were accounted for in 2030 and 2050, based on GREET projections. However, it is important to note that GREET does not provide projections for all the potential sources modeled in this analysis. Where projections were not available, the base (2022) emission factor was used.

In integrated steel mills, coke is combusted in the blast furnace (BF), resulting in blast furnace gas (BFG) which comprises mostly nitrogen, carbon monoxide, and carbon dioxide. BFG is often used downstream in the basic oxygen furnace (BOF) to supply process heat. As a result, only coke's upstream emissions and BFG's combustion emissions were considered for integrated mills. In addition, while cement facilities are expected to see an increase in alternative fuels to replace fossil fuels, the impacts associated with the production and combustion of such fuels (e.g., tire-derived fuels, plastics) are omitted from this analysis, as it is assumed that hydrogen will not be replacing these fuels. As such, this emissions analysis is not representative of all emissions associated with a facility or an industrial sector, as there may be other emission sources for which there is no feasible hydrogen application.

Different emissions factors were used for the analysis of industry and transportation, with industry using an HHV basis and transportation using an LHV basis, to align with the established standards of each sector. For industry, all emission factors were obtained from the default GREET model, with the exception that electricity inputs were changed to the "Distributed - RFC Mix" to represent Michigan's electricity mix. It was also assumed that hydrogen would be produced on-site at industrial facilities,so emissions associated with the transport of hydrogen were omitted from the industry emissions analysis. To obtain the emission factors for transportation, the default GREET fuel economies and payloads were manually changed to reflect those modeled in this study (Section 2.4.3). Emission factors were determined for full and empty payloads separately since the different payloads led to different fuel economies which resulted in different fuel cycles and emission factors. The emission factors for full and empty payloads for each vehicle class were then summed to determine the total emission factor for each vehicle class in each respective year. Like industry, the transportation analysis also altered the electricity mix input to "Distributed - RFC Mix" to reflect Michigan's electricity mix. Though unlike industry, the emission factors for the transportation sector included the transportation of diesel and the compression and transportation of hydrogen to refueling stations. An assumption made about the emission factors are that the distance the fuel is traveling to the refueling station is the same for every pathway. It was also assumed that when the hydrogen was produced via renewable electricity, the compression of the hydrogen would also be performed using renewable electricity.

Eq. 42 is the generic equation that demonstrates how the total GHG or NO_x emissions for each industrial facility was calculated in a target analysis year. The total emissions of a sector were determined by summing the total facility emissions for facilities within a respective sector. **Appendix D, Table D1** – **Table D4** list the emissions factors used for industry in the target analysis years of 2030 and 2050, respectively.

$$\begin{aligned} E_i = {} & (EF_{Production,\,NG\,,y} + EF_{Combustion,\,NG,\,y}) \times m_{i,NG,y} + \\ & (EF_{Production,\,Coal\,,y} + EF_{Combustion,\,Coal,\,y}) \times m_{i,Coal,y} + \\ & (EF_{Production,\,O2\,,y} + EF_{Combustion,\,O2,\,y}) \times m_{i,O2,y} + \\ & EF_{Production,\,Coke\,,y} \times m_{i,\,Coke\,,y} + EF_{Combustion,\,BFG,\,y} \times m_{i,BFG,y} + \\ & EF_{Production,\,H2\,,y} \times m_{i,\,H2\,,y} + EF_{Combustion,\,H2,\,y} \times m_{i,H2,y}) \times C_{kg-mt} \end{aligned} \tag{42}$$

where the total emissions (E_i) of facility *i*, $EF_{Production,\,f\,,y}$ is the emissions factor for the production of a given fuel or feedstock, *f* (natural gas, hydrogen for the five modeled production pathways, coke, coal, and oxygen) in the target analysis year, *y* (2030 or 2050), $m_{i,\,f\,,y}$ is the mass of the given fuel or feedstock, *f*, in year y (2030 or 2050) for facility i, $EF_{Combustion,\,f,\,y}$ is the emissions factor for the combustion of a given fuel, *f* (natural gas, hydrogen for the five modeled production pathways, blast furnace gas, coal, and oxygen), and C_{kg-mt} is the conversion factor to convert from kg to metric tons.

For transportation, **Eq. 43** and **Eq. 44** were utilized to calculate the well-to-wheel emissions for each vehicle class fueled solely by diesel versus hydrogen produced by the five different pathways modeled. **Appendix E, Table E1 – Table E4** lists the emissions factors used in the transportation sector analysis.

$$\begin{aligned} E_d = {} & ((N_{L,p,e} \times C_{liters-MMBtu} \times (EF_{Operation,e,d} + EF_{fuel\,pt,e,d})) + \\ & (N_{L,p,f} \times C_{liters-MMBtu} \times (EF_{Operation,f,d} + EF_{fuel\,pt,f,d}))) \times C_{gram-mt} \end{aligned} \tag{43}$$

where E_d is the total emissions for a vehicle fueled by diesel, $N_{L,p,e}$ and $N_{mt,p,f}$ are the number of liters of diesel for a vehicle with an empty (e) and full (f) payload, respectively, $C_{liters-MMBtu}$ is the conversion factor from liters to MMBtu, $EF_{Operation,e,d}$ and $EF_{Operation,f,d}$are the emission factors for operation of the vehicle when it is powered by diesel for when it has an empty (e) and full (f) payload, respectively (g/MMBtu), $EF_{fuel\,pt,e,d}$ and $EF_{fuel\,pt,f,d}$ are the emission factors for the fuel production and transportation of diesel for when the vehicle has an empty (e) and full (f) payload, respectively (g/MMBtu), and $C_{grams-mt}$ is the conversion factor from grams to metric tons.

$$E_h = ((N_{mt,p,e} \times C_{kg\ H_2-metric\ tons} \times LHV_{MMBtu\,H_2} \times (EF_{Operation,e,h} + EF_{fuel\,pt,e,h})) + (N_{mt,p,f} \times C_{kg\ H_2-metric\ tons} \times LHV_{MMBtu\,H_2} \times (EF_{Operation,f,h} + EF_{fuel\,pt,f,h}))) \times C_{g-mt} \quad (44)$$

where E_h is the total emissions for a vehicle fueled by hydrogen, $N_{mt,p,e}$ and $N_{mt,p,f}$ are the number of metric tonnes of hydrogen for a vehicle with an empty (e) and full (f) payload, respectively, $C_{kg\,H_2-\,metric\ tons}$ is the conversion factor from kg of gaseous hydrogen to metric tonnes, $LHV_{MMBtu\,H_2}$is the lower heating value for hydrogen, $EF_{Operation,e,h}$ and $EF_{Operation,f,h}$are the emission factors for operation of the vehicle when it is powered by hydrogen for when it has an empty (e) and full (f) payload, respectively (g/MMBtu), $EF_{fuel\,pt,e,h}$ and $EF_{fuel\,pt,f,h}$ are the emission factors for the fuel production, compression, and transportation of hydrogen for when the vehicle has an empty (e) and full (f) payload, respectively (g/MMBtu), and $C_{grams-mt}$ is the conversion factor from grams to metric tons.

3. Results

3.1 Current Hydrogen Demand (2022)

Michigan's current (2022) annual hydrogen demand is estimated to be 39,100 metric tons (**Table 5**). Industrial demand for hydrogen only occurs as a feedstock in the petroleum refining, semiconductor, and glass industries and accounts for over 99% of Michigan's total hydrogen demand. Demand in the transportation sector results from the operation of one hydrogen fuel cell bus.

Table 5. Current (2022) annual hydrogen demand by sector. While the analysis investigated eight hydrogen end-uses within Michigan, only four end-uses exhibit hydrogen demand in 2022 with petroleum refining having the largest demand.

Sector	Hydrogen Demand (metric tons/year)
Petroleum Refining	36,500
Semiconductor	2,470
Glass	83
Transportation	13
TOTAL	**39,100**

The petroleum refining sector accounts for 93.4% of total annual demand amounting to 36,500 metric tons of hydrogen. This hydrogen is produced on-site at Marathon Petroleum's refinery in Detroit, MI, via a natural gas SMR facility operated by Air Products.[135] The semiconductor industry is the next largest source of demand at 2,470 metric tons, representing 6.3% of Michigan's total annual hydrogen demand. Hemlock Semiconductor LLC (HSC) is the only semiconductor facility in-scope and currently receives their hydrogen from on-site via a natural gas SMR facility operated by Linde Inc.[136,137] The Guardian Industries float glass manufacturing plant in Carleton, MI, uses 83 metric tons of hydrogen annually, accounting for only 0.21% of current hydrogen demand. Guardian's hydrogen is delivered via liquefied tanker truck and stored on-site, as is typical for applications that require less than 250 kilograms of hydrogen per day.[138] The transportation sector has the lowest estimated hydrogen demand in 2022 as the only user is Flint MTA, which currently operates one hydrogen fuel cell bus. Flint MTA produces hydrogen on-site through a PEM electrolyzer that is powered by grid electricity. Therefore, it is estimated that aside from Flint MTA, hydrogen demand in 2022 only consists of a limited number of specialized feedstock applications.

3.2 Near-Term (2030) Results

3.2.1 Hydrogen Demand (2030)

The 2030 “Incumbent Technology” scenario represents demand if no advancements are made in the deployment of hydrogen-based technology from 2022 while accounting for growth of each sector from 2022 to 2030 (**Table 6**). Hydrogen demand in this scenario follows similar patterns to current demand with petroleum refining accounting for 93.3% of total annual demand with 37,400 metric tons, semiconductor manufacturing accounting for 6.4% of total demand with 2,580 metric tons, and glass manufacturing accounting for 0.2% with 75 metric tons. In the transportation sector, the hydrogen demand was calculated to be 38 metric tons from accounting for two additional FCEV buses that were ordered by Flint MTA and delivered in March 2024.

Table 6. Annual hydrogen demand for the “Incumbent Technology” scenario (2030) by sector. The petroleum refining sector continues to have the largest demand with the semiconductor sector being the next highest consumer.

Sector	Hydrogen Demand (metric tons/year)
Petroleum Refining	37,400
Semiconductor	2,580
Glass	75
Transportation	38
TOTAL	**40,100**

The “Near-Term Hydrogen Opportunities" scenario (**Figure 2**) has the same feedstock demand as described above (petroleum refining, semiconductor, glass), but layers on two additional demand opportunities. First, hydrogen was assumed to substitute 30% of the coke in the Cleveland-Cliffs Dearborn Works blast furnace resulting in 19,200 metric tons of annual demand. Next, 1% of the vehicles in each MHDV class were assumed to be hydrogen FCEVs, resulting in an annual hydrogen demand of 3,620 metric tons for the transportation sector.[4] Notably, the petroleum refining industry continues to dominate hydrogen demand in Michigan, even in the “Near-Term Opportunities'' scenario. For the glass industry, no near-term hydrogen opportunities are expected as Guardian Industries’ Carleton facility recently underwent a furnace renovation in 2018.[139] Sectors that rely primarily on natural gas for process heat such as chemicals and pulp and paper do not contribute to annual hydrogen demand in this scenario as hydrogen–natural gas blending opportunities are not projected to be viable in 2030.[13]

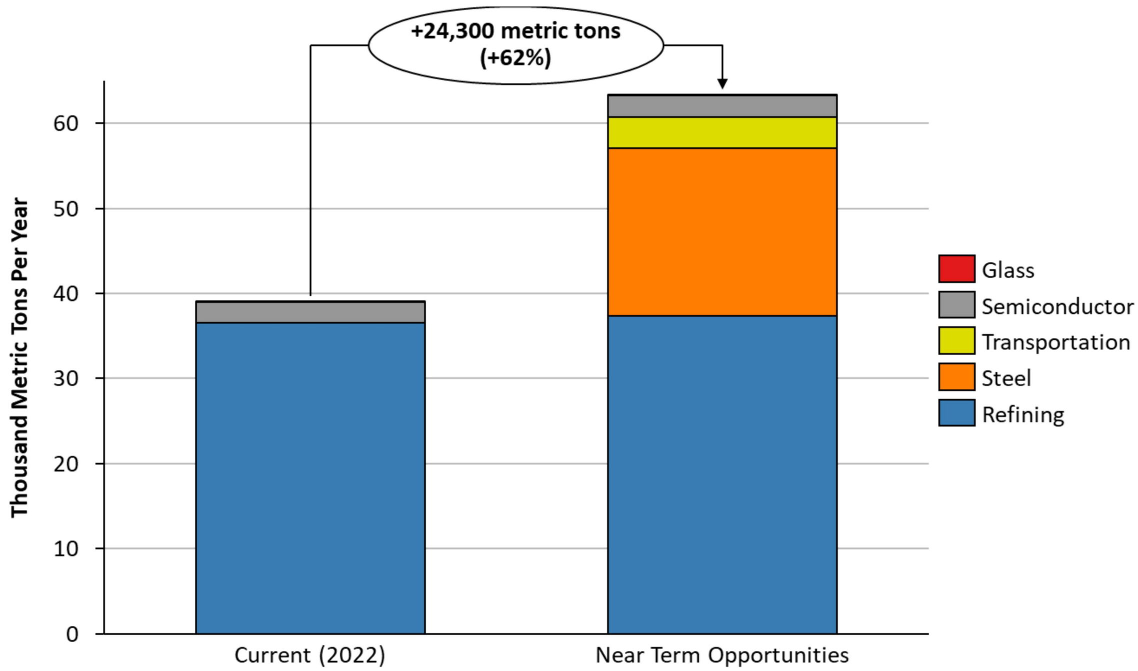

Figure 2. Annual hydrogen demand in the "Near-Term Opportunities" scenario for 2030 indicates an increase in demand by 62% from current (2022) demand, with petroleum refining and steel accounting for a majority of the scenario's demand.

3.2.2 Total Emission Reduction Potential (2030)

To model the incumbent emissions ("Incumbent Technology") from hydrogen production, the natural gas SMR production pathway was used for industrial demand, and the PEM electrolysis via RFC grid pathway was utilized for transportation demand. This baseline also includes the emissions associated with the upstream processes and combustion of fossil fuels that could be replaced by hydrogen and the combustion of hydrogen, when applicable. Overall the "Incumbent Technology" scenario amounts to about 19 million metric tons of GHG emissions and 16 thousand metric tons of NO_x, respectively. These values are represented by the dashed lines in **Figure 3** and **Figure 4**, enabling emissions from the "Incumbent Technology" scenario to be compared with the "Near-Term Opportunities" scenario with varied hydrogen production pathways.

The GHG emission reduction potential for the “Near-Term Opportunities” scenario is shown in **Figure 3**. It reveals that producing the estimated hydrogen demand through electrolysis with renewables or nuclear energy leads to the greatest reduction of GHG emissions when compared to the incumbent. Although hydrogen produced via natural gas SMR and electrolysis with the RFC grid mix is considered carbon-intensive, it also results in GHG emission reductions. This is because hydrogen is displacing coke in steel mills and diesel MHDVs, which are even more GHG-intensive than these production pathways. Overall, the potential to reduce GHG emissions when compared to the incumbent is limited (8.8%–15.7%). Emission reductions are constrained by the fact that there are limited hydrogen opportunities viable in 2030.

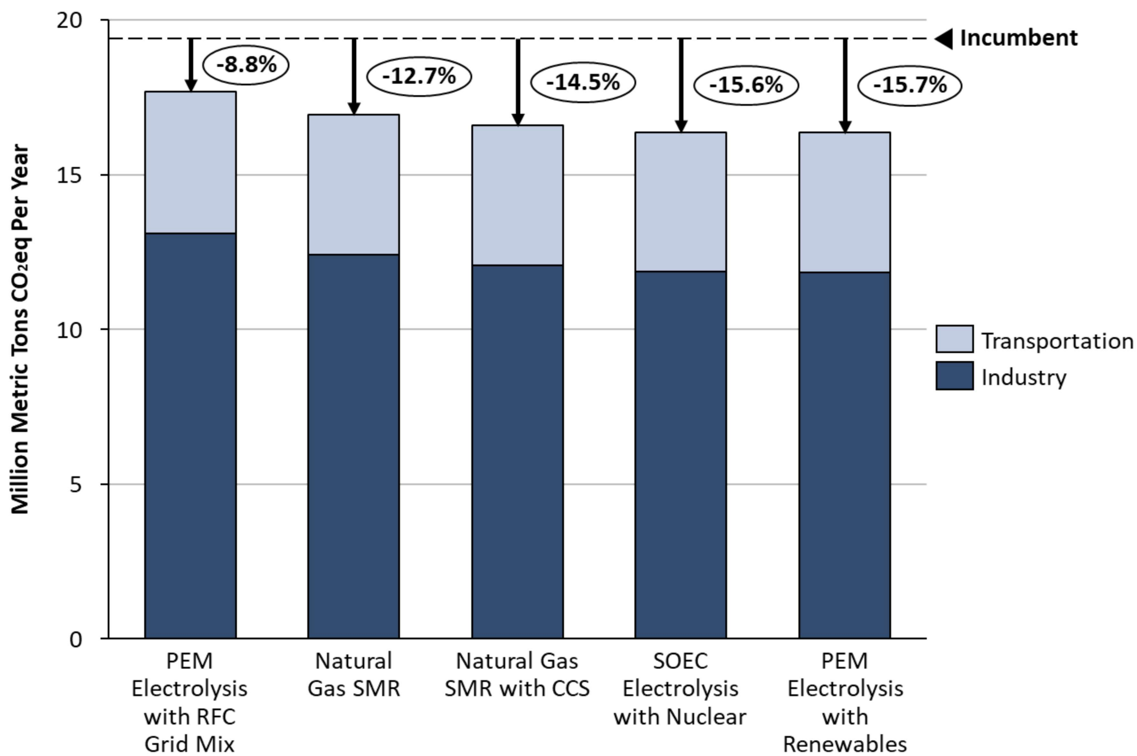

Figure 3. Total GHG emissions for the “Near-Term Opportunities” scenario compared to “Incumbent Technology” scenario emissions (dashed line).

Total NO_x emissions reductions (**Figure 4**) follow similar patterns as GHG emissions across all hydrogen production pathways in the “Near-Term Opportunities" scenario, with potential NO_x reductions ranging from 1.33 thousand metric tons (8.3%) to 2.23 thousand metric tons (14.0%). While natural gas SMR with CCS technology is more effective at reducing GHG emissions, it does not achieve better reductions in NO_x emissions compared to natural gas SMR without CCS; this is because natural gas SMR has a higher NO_x emission factor in GREET (**Appendix D, Table D2**). A detailed summary of the total GHG and NO_x emission reduction results for the “Near-Term Opportunities” scenario is available in **Appendix F** in **Table F1** and **Table F2**.

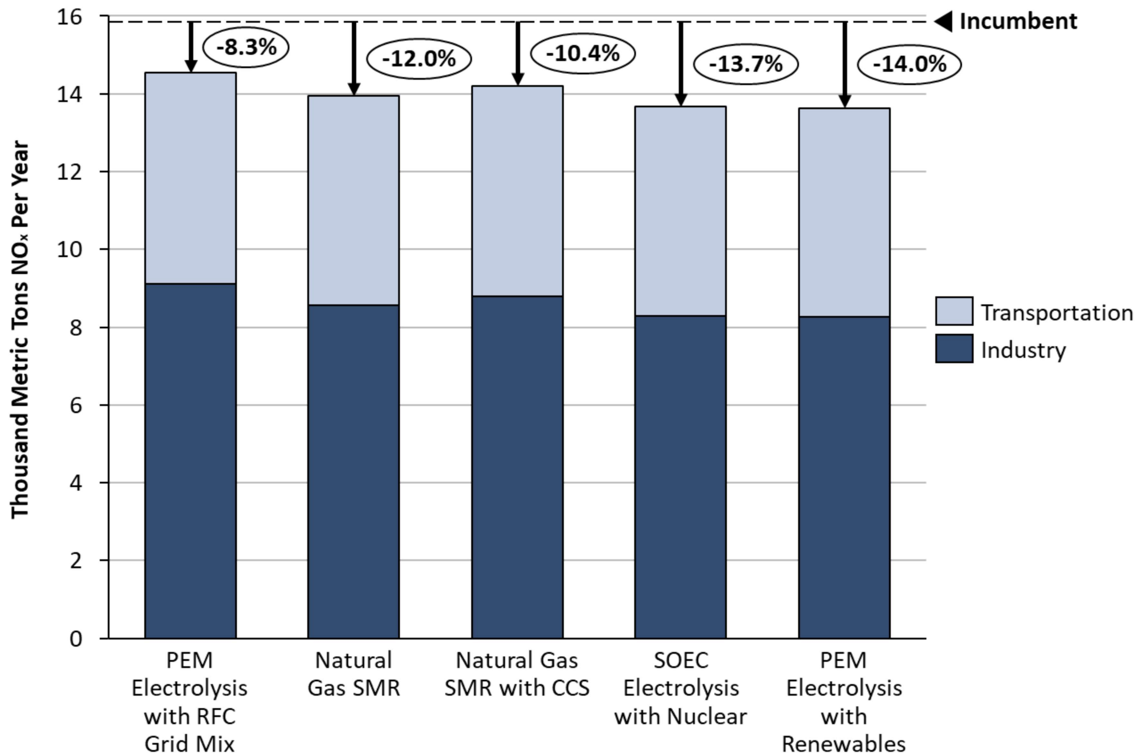

Figure 4. Total NO_x emissions for the “Near-Term Opportunities” scenario compared to “Incumbent Technology” scenario emissions (dashed line).

3.3 Long-Term (2050) Results

3.3.1 Hydrogen Demand (2050)

The 2050 demand is characterized by four scenarios: Incumbent Technology, Low Hydrogen Use, High Hydrogen Use, and Complete Hydrogen Substitution. As in 2030, the “Incumbent Technology” scenario in 2050 continues the use of existing hydrogen applications and results in an annual hydrogen demand of 36,700 metric tons (**Table 7**). In this scenario, petroleum refining accounts for 91.1% of total demand with 33,500 metric tons, semiconductor manufacturing accounts for 8.6% of total demand with 3,150 metric tons, and glass manufacturing accounts for 0.2% with 80 metric tons. Demand in the transportation sector was assumed to remain constant at 38 metric tons between the 2030 and 2050 “Incumbent Technology” scenarios as Flint MTA does not currently have any orders placed for additional hydrogen buses.[124] Notably, the

“Incumbent Technology” scenario has a lower hydrogen demand in 2050 relative to 2022. This is a consequence of the EIA projecting that demand for petroleum refining products will decrease in 2050 relative to 2022, which therefore decreases the estimated hydrogen demand.

Table 7. Annual hydrogen demand for the “Incumbent Technology” scenario (2030) by sector. The petroleum refining sector continues to have the largest demand with the semiconductor sector being the next highest consumer.

Sector	Hydrogen Demand (metric tons/year)
Petroleum Refining	33,500
Semiconductor	3,150
Glass	80
Transportation	38
TOTAL	**36,700***

**total demand does not equal the sum of individual sector demands due to rounding*

Figure 5 highlights a range of potential hydrogen demand in 2050 by comparing current (2022) demand to projections from the “Low Hydrogen Use” and “High Hydrogen Use” scenarios. The “Low Hydrogen Use” scenario resulted in a total annual hydrogen demand of 108,000 metric tons, representing a 68,900 metric ton (176%) increase relative to 2022 demand. Petroleum refining continues to have the greatest demand of any sector at 34,100 metric tons, with the majority of hydrogen used as a feedstock (33,500 metric tons) and the remaining demand as a fuel (642 metric tons). Refineries have limited demand for blended hydrogen as a fuel due to the preference for refinery gas and other low-value intermediates for process heat over natural gas.[140] This is also due to hydrogen’s low volumetric energy density: hydrogen contributes less than 10% of the heat output from a 20% blend with natural gas by volume.[141] The chemicals and pulp and paper industries use a hydrogen–natural gas blend for process heat and generate an annual hydrogen demand of 8,210 and 10,100 metric tons, respectively. This demand is primarily driven by each sector housing 9 facilities in Michigan. The in-scope cement facilities are characterized by large production capacity and high-temperature process heat requirements. Therefore, a 9% thermal replacement of incumbent fossil fuels with hydrogen in the kiln amounts to an annual hydrogen demand of 16,600 metric tons. In the steel industry, 30% coke replacement with hydrogen and a 20% hydrogen blend by volume with natural gas generate an annual demand of 19,100 metric tons. The “Low Hydrogen Use” scenario assumes that 4% of all MHDV classes will be transitioned to hydrogen FCEVs, amounting to an annual hydrogen demand of 14,500 metric tons. Class 8b sleeper cabs had the largest demand at 7,800 metric tons, while Class 8b day cabs followed with 4,800 metric tons. Semiconductor and glass manufacturing are the lowest contributors to hydrogen demand in this scenario at 4,010 and 1,250 metric tons, respectively. Like petroleum refineries, the semiconductor industry also has a higher demand for hydrogen as a feedstock (3,150 metric tons) than as a fuel (864 metric tons).

The “High Hydrogen Use” scenario resulted in an annual hydrogen demand of 206,000 metric tons, representing a 167,000 metric ton (427%) increase relative to the hydrogen demand estimated for 2022. Like the “Low Hydrogen Use” scenario, the “High Hydrogen Use” scenario assumes a 20% blend of hydrogen in natural gas for process heat applications. As mentioned in the 2050 Scenario Design (Section 2.7.1), this blend percentage was chosen in the “High Hydrogen Use” scenario while accounting for the technology readiness of end-use applications and the physical limitations of existing natural gas pipelines. Therefore, the sectors where natural gas process heat was modeled—glass, semiconductor, chemicals, pulp and paper, and petroleum refining—have the same hydrogen demand as in the “Low Hydrogen Use” scenario. In the steel industry, 30% replacement of coke with hydrogen, a 20% blend with natural gas, and hydrogen-enhanced EAF generate an annual demand of 20,300 metric tons. Direct thermal replacement drives hydrogen deployment in the cement industry as well, with an annual demand of 55,500 metric tons. Finally, a 20% displacement of diesel MHDVs with FCEVs generates a hydrogen demand of 72,700 metric tons. Within transportation, as in the “Low Hydrogen Use” scenario, class 8b sleeper cabs had the largest hydrogen demand with 39,300 metric tons. Class 8b day cabs were in second with 24,500 metric tons. Then in third was class 7 transit buses with a demand of 8,060 metric tons.

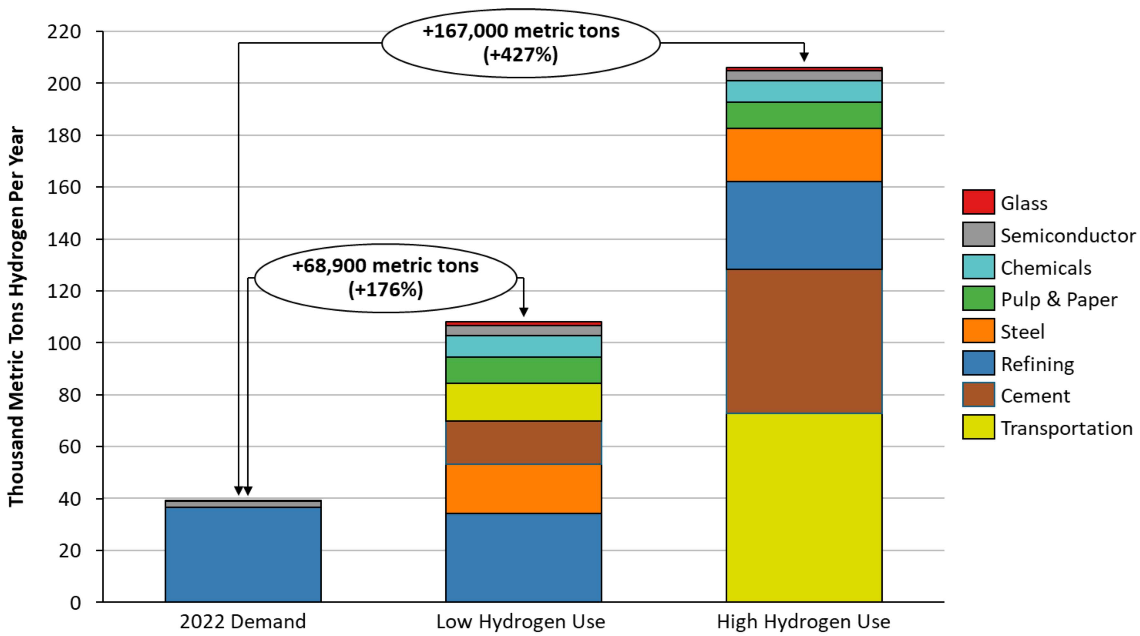

Figure 5. Long-term (2050) potential hydrogen demand in the “Low Hydrogen Use” and “High Hydrogen Use” scenarios as compared to current (2022) hydrogen demand.

The “Complete Hydrogen Substitution” scenario (**Figure 6**) assumes full displacement of natural gas process heat, diesel MHDVs, and additional fossil fuels in the cement and steel sectors with hydrogen. This results in a total annual hydrogen demand of 1.10 million metric tons, representing a 1.06 million metric ton (2,700%) increase relative to current (2022) demand. In this scenario, the transportation sector generates the greatest annual demand of 364,000 metric tons by converting all MHDV classes to FCEVs. In transportation, class 8b sleeper cabs (196,00 metric tons) again had the greatest demand, with class 8b day cabs (122,00 metric tons) following in second. Class 7 transit buses had the third largest demand with 40,300 metric tons. Due to high production capacities and high-temperature process heat requirements, both the steel and cement manufacturing industries generate significant hydrogen demands of 250,000 and 160,000 metric tons, respectively. Other industries with significant process heat needs such as pulp and paper (138,000 metric tons), chemicals (112,000 metric tons), semiconductor (15,000 metric tons), and glass (15,000 metric tons) also contribute to the hydrogen demand in this scenario. The chemicals and pulp and paper industries have especially large annual demand as each sector has 9 facilities located within Michigan. With an annual hydrogen demand of 42,200 metric tons, the petroleum refining industry is estimated to have the lowest demand for the "Complete Hydrogen Substitution" scenario. This is primarily because refineries are projected by the EIA to see a decline in sectoral output and because they use relatively low amounts of natural gas for process heat.

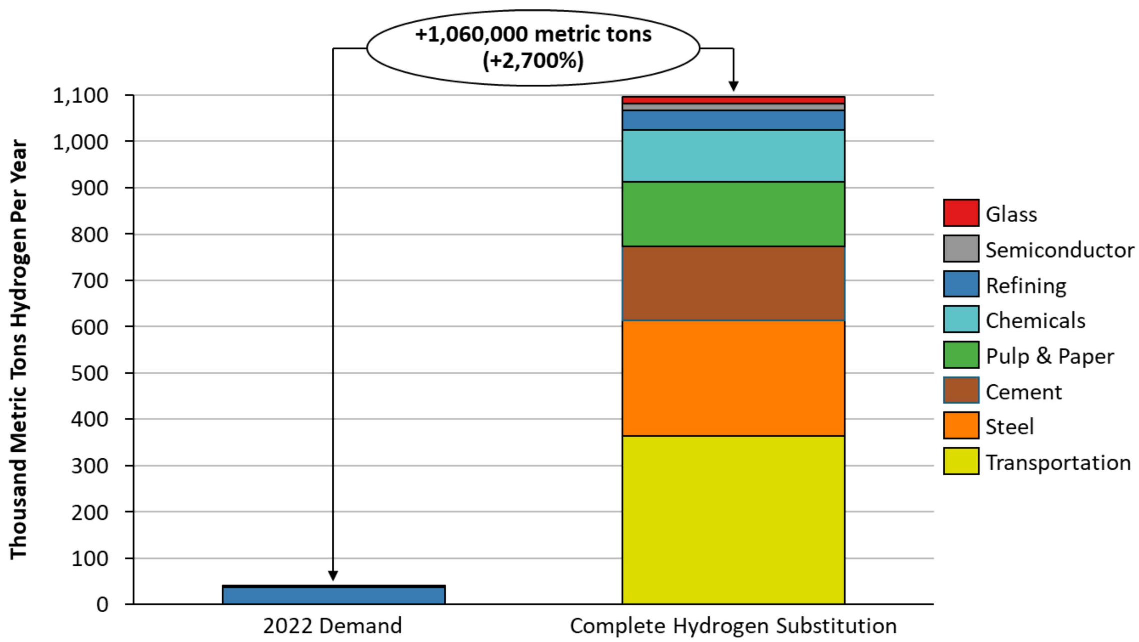

Figure 6. Long-term (2050) potential hydrogen demand in the "Complete Hydrogen Substitution" scenario as compared to current (2022) hydrogen demand.

3.3.2 Total Emission Reduction Potential (2050)

Similar to 2030, the "Incumbent Technology" scenario includes emissions from status quo hydrogen production (natural gas SMR, electrolysis via RFC grid mix), as well as the production and combustion emissions associated with fossil fuels that could be replaced with hydrogen. In 2050, the "Incumbent Technology" scenario equates to about 20 million metric tons of GHG emissions and 19 thousand metric tons of NO_x emissions. "Incumbent" emissions in 2050 are represented by the dashed line in **Figure 7** through **Figure 12.**

In the 2050 Low Hydrogen Use scenario, electrolysis via renewables and nuclear energy results in the greatest GHG emission reduction when compared to incumbent emissions, with reductions of approximately 7.48 million metric tons (**Figure 7**). Natural gas SMR pathways lead to GHG emissions reductions up to 35.5%, or 7.12 million metric tons when paired with CCS. PEMelectrolysis powered by the RFC grid mix can achieve 5.34 million metric tons (26.6%) reduction in GHG emissions as compared to emissions produced by the 2050 incumbent technology scenario (**Figure 7**).

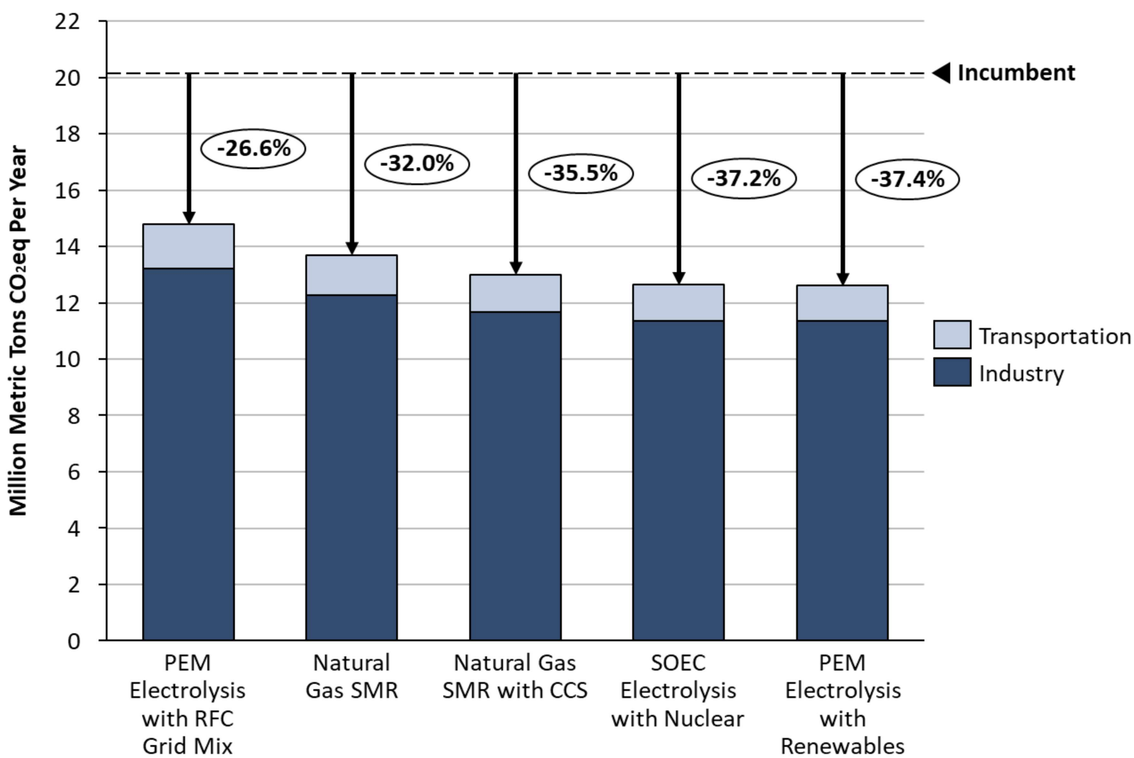

Figure 7. Total GHG emission reductions for the "2050 Low Hydrogen Use" scenario compared to "Incumbent Technology" scenario emissions (dashed line).

For 2050, under the “High Hydrogen Use” scenario, hydrogen generated from low-carbon production pathways, such as SOEC electrolysis with nuclear technology, and PEM electrolysis powered by renewables, is projected to yield GHG emission reductions of over 40%. Despite the use of fossil fuels, SMR hydrogen can reduce GHG emissions by 33%, or 6.62 million metric tons through the displacement of coal and coke in the steel and cement sectors. Electrolysis with the RFC grid mix achieves a 22.9%, or 4.60 million metric tons reduction in GHG emissions (**Figure 8**). A detailed summary of the total GHG emission reduction results for both the “Low Hydrogen Use” and “High Hydrogen Use” scenarios are available in **Appendix G** in **Table G1** and **Table G3**.

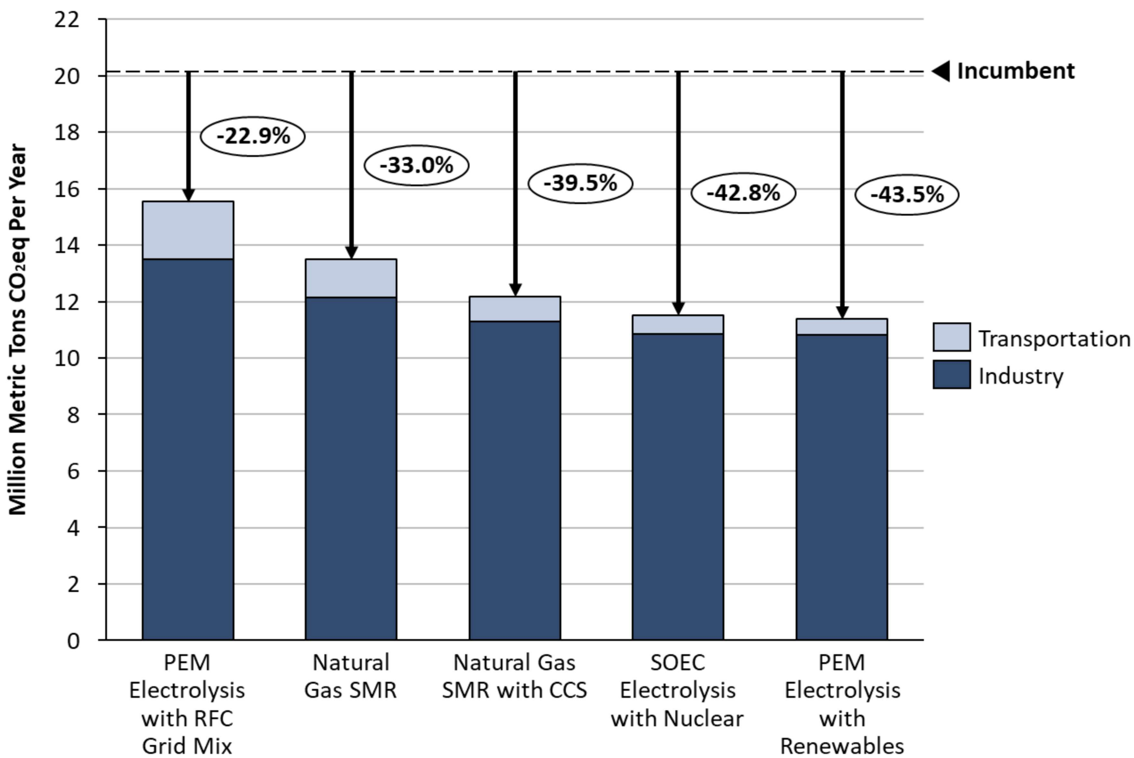

Figure 8. Total GHG emission reductions for the “2050 High Hydrogen Use” scenario compared to “Incumbent Technology” scenario emissions (dashed line).

In the 2050 “Low Hydrogen Use” scenario, total NO_x emissions reductions (**Figure 9**) follow a similar trend as GHG emission reductions in this scenario, ranging from 33.4% to 40.9%, or 6.53 thousand metric tons (33.4%) to 8 thousand metric tons (40.9%) of reduced reduction in NO_x. In the 2050 “High Hydrogen Use” scenario, NO_x emission reduction shows a similar pattern as GHG emission reduction, ranging from 33.5% to 47.6%, or 6.55 thousand metric tons to 9.31 thousand metric tons compared with the incumbent technology emissions (**Figure 10**).

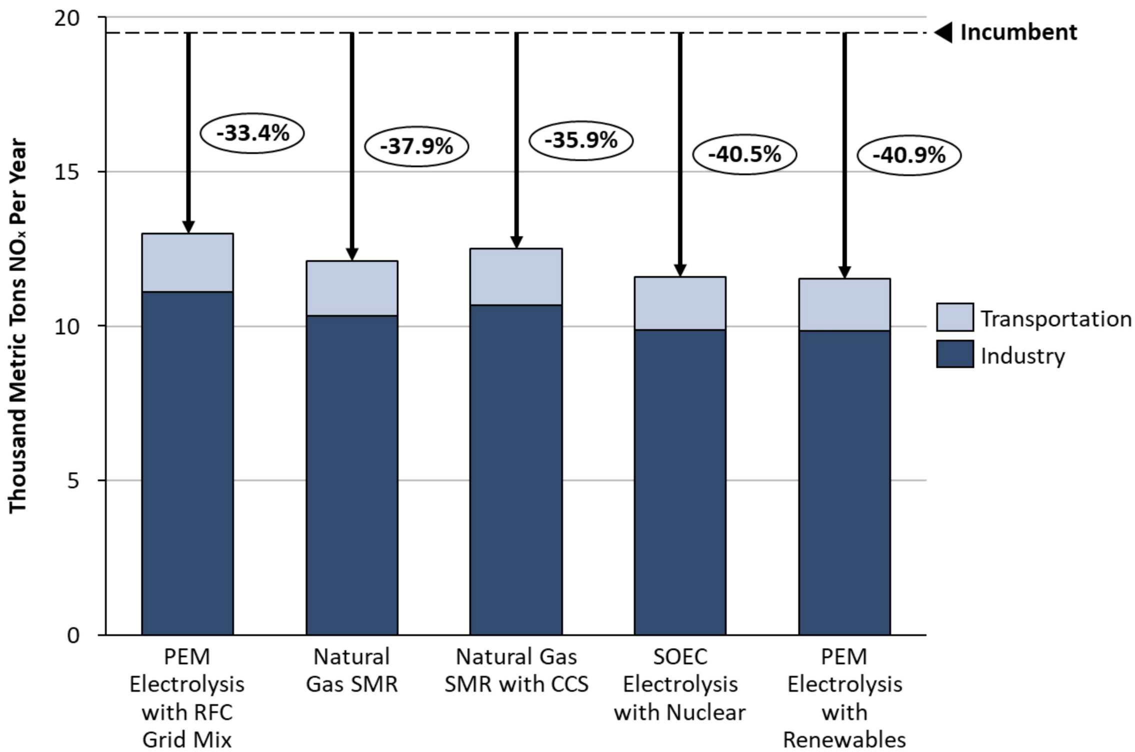

Figure 9. Total NO_x emission reductions for the “2050 Low Hydrogen Use” scenario compared to “Incumbent Technology” scenario emissions (dashed line).

In the 2050 “High Hydrogen Use” scenario, NO_x emission reduction shows a similar pattern as GHG emission reduction, ranging from 33.5% to 47.6%, or 6.55 thousand metric tons to 9.31 thousand metric tons compared with the incumbent technology emissions (**Figure 10**). A detailed summary of the total NO_x emission reduction results for both the “Low Hydrogen Use” and “High Hydrogen Use” scenarios are available in **Appendix G** in **Table G2** and **Table G4**.

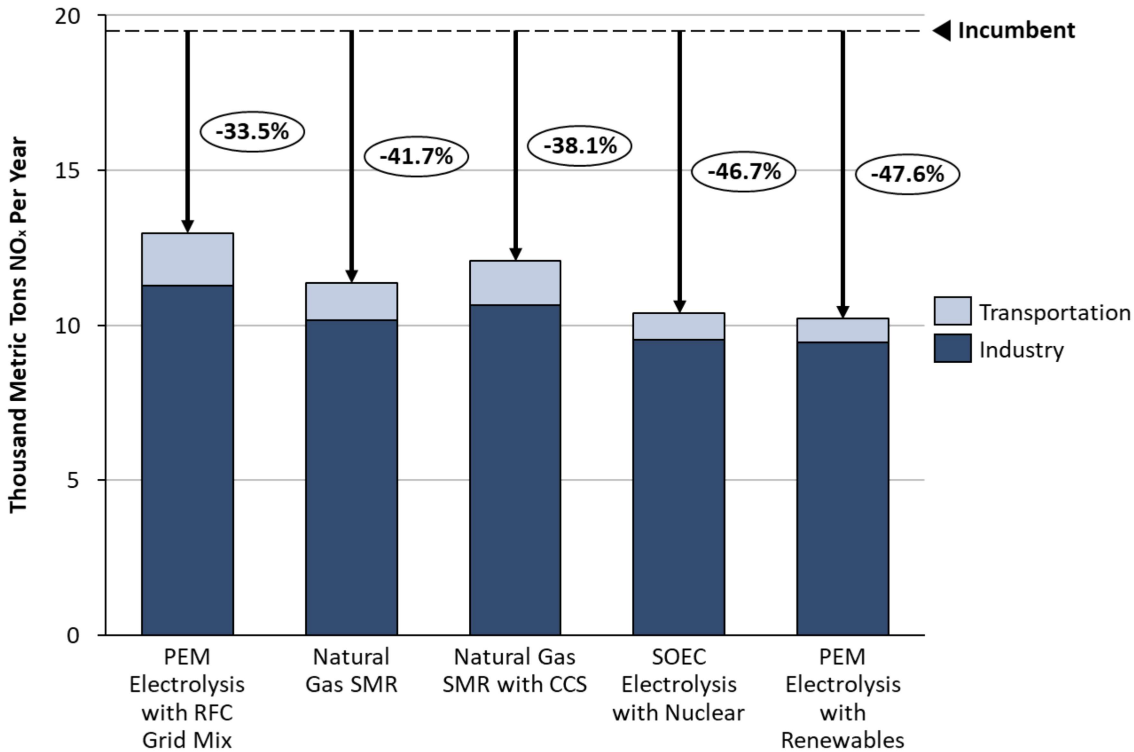

Figure 10. Total NO_x emission reductions for the “2050 High Hydrogen Use” scenario compared to “Incumbent Technology” scenario emissions (dashed line).

In the 2050 “Complete Hydrogen Substitution” scenario (**Figure 11**), PEM electrolysis with the RFC grid mix actually results in an increase of GHG emissions of 1.97 million metric tons (9.7%). This occurs because this scenario estimates a significant amount of hydrogen demand in 2050 with all of it being produced via electrolysis using the RFC grid, which is projected to remain a GHG-intensive grid even in 2050. However, PEM electrolysis with renewables demonstrates a 20.1 million metric tons reduction (99.9%) in GHG emissions when compared to incumbent emissions. SOEC electrolysis with nuclear energy has a similar GHG reduction potential of 19.4 million metric tons (96.3%). The significant reduction potential of both of these pathways emphasizes the need for low-carbon electricity and nuclear technology when producing hydrogen. This is especially the case if hydrogen deployment is to become a primary decarbonization strategy. A detailed summary of the total GHG emission reduction results for the “Complete Hydrogen Substitution” scenario are available in **Appendix G** in **Table G5.**

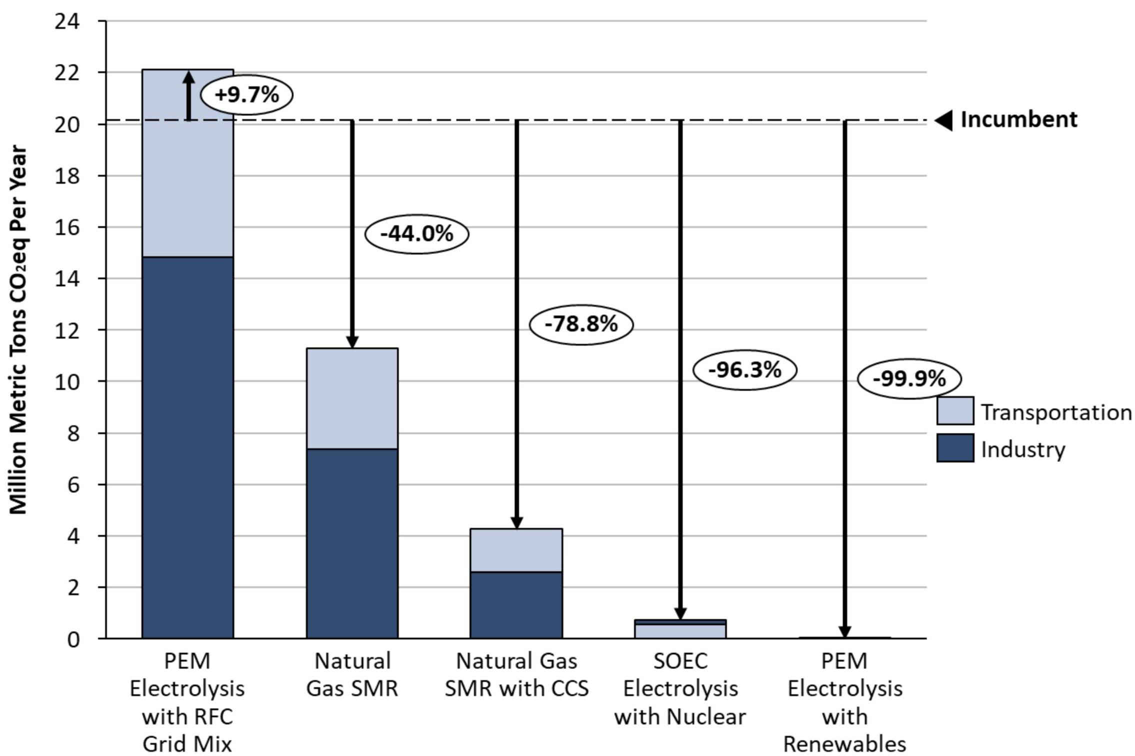

Figure 11. Total GHG emission reductions for the “Complete Hydrogen Substitution” scenario compared to “Incumbent Technology” scenario emissions (dashed line).

The total NO_x emission reduction results (**Figure 12**) follow trends similar to the GHG emission reduction results for the "Complete Hydrogen Substitution" scenario. For instance, PEM electrolysis with the RFC grid mix leads to an increase in NO_x emissions (4.4%) when compared to emissions from the "Incumbent Technology" scenario. PEM electrolysis with renewables has the highest reduction potential at 13.9 thousand metric tons (71.1%), followed by SOEC electrolysis with nuclear energy at 13 thousand metric tons. A detailed summary of the total NO_x emission reduction results for the "Complete Hydrogen Substitution" scenario is available in **Appendix G** in **Table G6**.

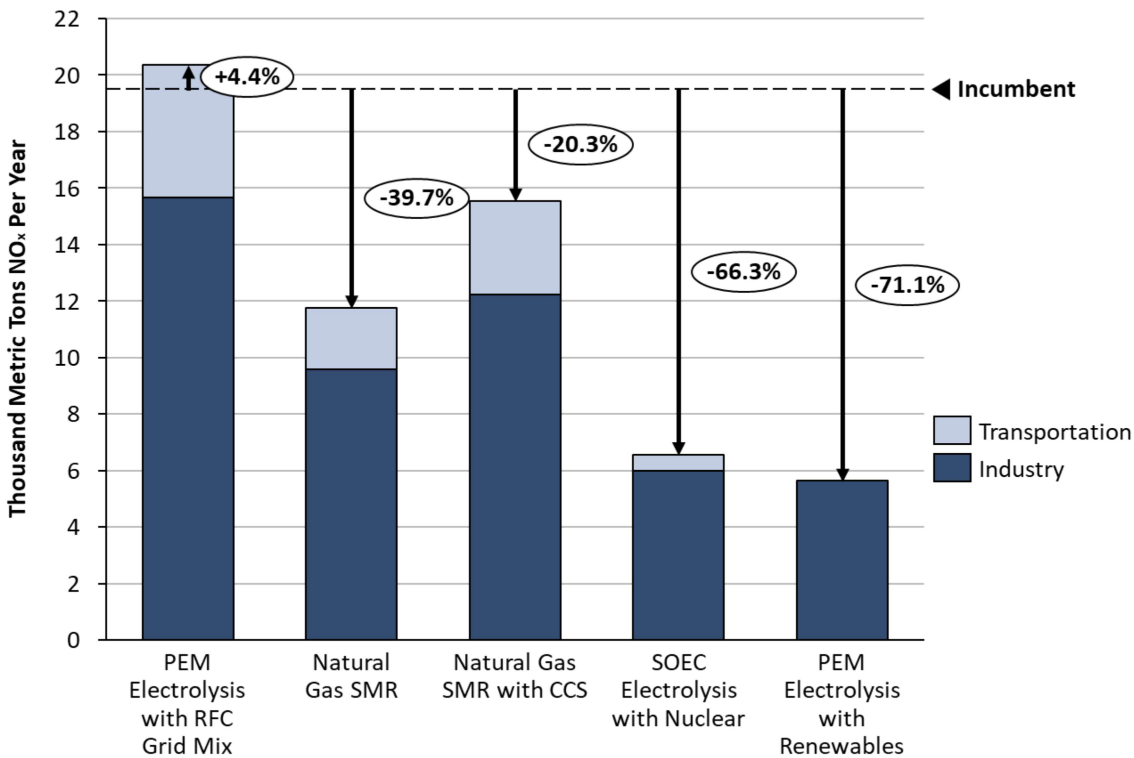

Figure 12. Total NO_x emission reductions for the "Complete Hydrogen Substitution" scenario compared to "Incumbent Technology" scenario emissions (dashed line). GHG emissions encompass both production and combustion processes associated with fossil fuels identified as potential candidates for replacement with hydrogen. The analysis also includes the production and combustion of hydrogen itself, considering five different hydrogen production pathways.

4. Discussion

4.1 Current (2022) Hydrogen Demand

Michigan's current annual hydrogen demand consists of fuel use in Flint MTA's singular hydrogen fuel cell bus and feedstock use in the petroleum refining, semiconductor, and glass sector. There is no feedstock demand in Michigan's chemicals sector due to the absence of ammonia and methanol production within the state. While chemicals, pulp and paper, cement, and steelmaking have significant process heat requirements, these sectors currently rely on fossil fuels to produce process heat and thus do not have any hydrogen demand. Current annual hydrogen demand was estimated to be 39,100 metric tons with 93.4% of demand attributed to Marathon Petroleum's refinery and 6.3% to HSC's manufacturing facility. Notably, the CO_2 emissions used to estimate HSC's hydrogen demand were lower than historic averages and thus may be an underestimate of actual demand.

Hydrogen demand for the refinery and semiconductor facility is met by on-site natural gas SMR plants operated by Air Products and Linde, respectively. While refineries also generate hydrogen as a byproduct, this was not accounted for in this analysis.[142] Hydrogen for Flint MTA's fuel cell bus is produced on-site using a PEM electrolyzer powered by grid electricity and is stored on-site in proximity to the refueling station.[78] Guardian Industries' facility has its hydrogen delivered via liquid tanker trucks and is stored as a liquid on-site.[138] As indicated by Guardian Industries, bulk delivery is common in the U.S. for customers using under 250 kilograms of hydrogen per day.[138]

Current hydrogen demand is predominantly provided by natural gas SMR facilities for industrial consumers and an electrolyzer powered by grid electricity for the transportation sector. These production pathways are more GHG intensive than other alternatives as the SMR process produces carbon dioxide and Michigan's grid still relies predominantly on fossil fuel assets. Flint MTA is unable to pursue lower-carbon electricity, as photovoltaics would require a large area of land and wind power is infeasible due to Flint MTA's proximity to the Flint Bishop International Airport.[124] As such, decarbonization options for incumbent hydrogen production pathways include CCS on natural gas SMR facilities and regional grid decarbonization.[143] Given that these decarbonization options occur over long timelines, it is likely that existing hydrogen production in Michigan will be linked to significant GHG emissions.[133,134]

The prevalence of on-site production for almost all existing hydrogen demand highlights the lack of a hydrogen distribution system. In fact, there are only 5.5 miles of dedicated hydrogen pipelines in the state of Michigan.[50,144] Though current production is largely limited to industrial merchant producers or Flint MTA's on-site electrolyzer, two other transit authorities located in Michigan have approached Flint MTA to learn about its hydrogen fueling facility. This demonstrates existing interest throughout Michigan in the production, storage, and use of hydrogen.[145,146] Moreover, federal funding for the MachH2 hydrogen hub and production facilities like Nel Hydrogen and BayoTech establishing facilities in Michigan may spur further development of a hydrogen ecosystem in Michigan.[147,148]

4.2 Near-term (2030) Hydrogen Demand

Near-term hydrogen demand is characterized by new hydrogen deployment opportunities in the steelmaking and transportation sectors. In steelmaking, preliminary trials are underway worldwide to replace 30% of coke from the BF-BOF route with hydrogen.[143] While additional research is needed to demonstrate commercial readiness, funding from the MachH2 hub and trials conducted by regional assets may accelerate hydrogen injection into blast furnaces by 2030.[22,119] The introduction of green premiums in the steel sector may also play a role in accelerating hydrogen injection in the BF-BOF and DRI routes in the near term.[149] In the transportation sector, it is assumed that 1% of all MHDVs will be powered by hydrogen in 2030. This 1% value does not account for any demand that may happen due to the expected deployment of FCEVs due to the Mach H2 Hub. This low adoption rate can primarily be attributed to the lack of refueling stations in the U.S. outside California and other infrastructure limitations in the production and transport of hydrogen.[150] However, given that the state of Michigan accounts for 19% of all U.S. auto production and 62% of total U.S. spending on mobility and automotive R&D, it has an opportunity to be a leader in hydrogen deployment in the transportation sector.[151] For example, Fuel Cell System Manufacturing (FCSM)—based in Brownstown, MI—is a joint venture between General Motors and Honda that aims to mass-produce fuel cells and began operation in January, 2024.[152] Fuel cells produced through this venture will be used to power both medium- and heavy-duty vehicles.[153,154] Federal funding may also accelerate hydrogen deployment in the transportation sector: The acquisition of two additional hydrogen fuel cell buses by Flint MTA was made possible by a $4.3 million grant from the U.S. DOT Federal Transit Administration, funded by the Bipartisan Infrastructure Law.[155,156]

While the chemicals (ammonia, methanol) industry typically uses significant quantities of hydrogen as a feedstock at large centralized facilities, no such plants exist in the state of Michigan.[157–159] However, decentralized demand for feedstock hydrogen may increase in Michigan's industrial and agricultural applications due to modular solutions from companies like Ammpower.[160] New hydrogen deployment in the near term may also come from facility-level expansions planned throughout the state. For example, Hemlock's semiconductor manufacturing facility in Thomas Township, MI, is planning a $375 million expansion project to increase the purity of its polysilicon and increase production to meet the rising global demand.[137] Marathon's refining facility in Detroit, MI, is also proposing to remove material throughput limits and operate at full capacity.[161] Therefore, it is likely that feedstock hydrogen demand for these three industries will undergo changes in the 2030 timeframe. Conversely, Guardian Glass' manufacturing plant in Carleton, MI, is not expected to undergo major furnace modifications in the near-term and will therefore not generate new hydrogen demand in 2030. This illustrates how near-term hydrogen deployment is affected by both the commercial readiness of hydrogen-based technologies and the age of existing equipment.

While many utilities across the US are currently investigating the role of hydrogen blending with natural gas, no blending of hydrogen was assumed in 2030 to align with the DOE's clean hydrogen strategy roadmap.[13,162] Therefore, industries can not rely on the existing natural gas infrastructure to support their hydrogen demand in the near-term and must instead invest in on-site hydrogen production and storage. Dedicated refueling stations must also be set up to support hydrogen-powered MHDVs. This poses a significant barrier to hydrogen deployment in 2030 and underscores the need for a hydrogen ecosystem in the state of Michigan. This limited hydrogen demand is further emphasized by the modest 9-16% of GHG emissions reductions in the 2030 Near-term Opportunities Scenario. Therefore, while federal funding may accelerate the development of hydrogen-based technologies in the industrial and transportation sectors, a significant effort must also be made to build infrastructure capable of transporting large quantities of hydrogen. Without this, hydrogen demand in 2030 will closely emulate hydrogen demand in 2022.

4.3 Long-term (2050) Hydrogen Demand

Hydrogen demand in 2050 is characterized by significant, but uncertain, deployment opportunities across all sectors. For instance, the EIA reference scenario projects an 8.41% reduction in refinery output from 2022 to 2050. While other projections of petroleum refining outputs in 2050 vary widely, the EIA projection indicates a minimal change in the operation of refineries and falls considerably short of aligning with net zero pathways. In fact, net zero pathways often call for significant reductions in crude-oil processing by 2050.[126] This might suggest that existing policies assumed in the EIA AEO 2023 Reference Case are not sufficient to incentivize the use of low-carbon hydrogen in crude oil refining. In fact, while some facilities on the west coast have switched operations to instead produce renewable diesel due to a range of low-carbon fuel incentives, most other facilities like Marathon's Detroit refining plant continue existing operations on crude oil.[51,163–165] This switch to renewable diesel can lead to greater demand for low-carbon hydrogen to meet process requirements and available low-carbon fuel incentives.[166–168]

The 20% hydrogen blending scenarios in 2050 are also subject to uncertainty. While several projects on blending have been proposed throughout the U.S., blend ratios in natural gas pipelines vary from 2% to 30%.[25,162] Moreover, a 30% hydrogen blend by volume only results in 6% reductions in lifecycle greenhouse gas emissions.[169] The continued use of natural gas at this scale does not align with net zero emissions pathways.[126] In comparison, the direct replacement of fossil fuels with hydrogen as seen in the cement and steel sectors can generate greater hydrogen demand and emissions reductions. However, the significant remaining contribution of unabated fossil fuels in both of these sectors also does not align with net zero pathways and will need to be addressed.[126] Aggressive deployment of a variety of decarbonization strategies including hydrogen, electrification, energy efficiency, CCS, and alternative production pathways like H_2-DRI in the steel sector will likely be needed to completely address emissions from these high process heat industries.[170] Notably, a variety of initiatives to facilitate the procurement of “green” cement and steel are underway and may accelerate decarbonization in these industries.[171] This transition is exemplified by regional assets: Holcim’s “OneCem” reduced clinker cement and Cleveland Cliff’s $500 million grant for the installation of one hydrogen-ready DRI furnace and two electric melting furnaces at their plant in Middletown, Ohio.[170,172]

Semiconductor manufacturing is poised to be a high growth sector in the coming decades. With federal funding from the Creating Helpful Incentives to Produce Semiconductors (CHIPS) and Science Act, new investments in manufacturing and R&D have been made in Michigan and will likely continue in the 2050 time frame and drive hydrogen demand.[173] On the other hand, the role of hydrogen in decarbonizing the chemicals and paper and pulp industries is unclear. While chemical sector stakeholders indicated that electrification is favorable over hydrogen for decarbonization in the low-to-medium process heat temperature range, a contact in the paper and pulp industry demonstrated strong interest in hydrogen. The lack of ethylene production in Michigan, which requires high temperature process heat requirements for steam cracking, further limits hydrogen deployment potential in the chemicals industry.[9] The ongoing electrification of MDVs creates uncertainty for 2050 hydrogen demand in the transportation sector.[174,175] However, the transportation sector demonstrates the highest hydrogen deployment potential of all sectors and will be pivotal in anchoring the hydrogen ecosystem in the state. Initiatives like "Truck Stop of the Future" may further accelerate the building and testing of hydrogen-powered HDVs and displace fossil-fuel powered vehicles along important transportation corridors.[174]

The complete hydrogen substitution scenario, while not prescriptive, provides insight into the theoretical upper limit of hydrogen deployment for in-scope sectors. With steel, cement, and transportation sectors accounting for over 70% of total hydrogen demand, this scenario underscores the importance of direct thermal replacement and hydrogen-powered MHDVs in driving demand. Furthermore, it allows the state of Michigan to visualize several important planning aspects of a hydrogen ecosystem. For instance, PEM electrolysis with renewables demonstrates a 99.9% reduction in GHG emissions in this scenario compared to incumbent emissions. This production pathway would require 45 billion kWh of renewable electricity. For reference, the net electricity generation in Michigan in 2022 was 117.5 billion kWh, of which 13.7 billion kWh came from renewables including conventional hydroelectric power.[176] Therefore, the state would have to approximately triple its current renewable electricity generation to meet the electricity demand for the production of low-carbon hydrogen in this scenario. Using such comparisons, the complete substitution scenario enables the long-term planning of a hydrogen ecosystem while accounting for the effect of ramping hydrogen demand across both industry and transportation sectors.

4.4 Uncertainty in Demand and Emissions Estimates

A variety of parameters were required to fully characterize current demand, future demand, and emissions reduction potential. As described in "Data Collection and Stakeholder Outreach" (Section 2.1), data was first queried from stakeholders and where information was not directly available due to confidentiality constraints, a variety of sources were pursued to fill in data gaps. For industrial hydrogen end-uses, this created uncertainty in facility-level parameters like final product (for the chemical sector) and production capacity, fuel mix, mass of fuels used per year, hydrogen intensity, and substitution ratio. Public information from news reports, conversion factors from scientific literature, and data from other proxy facilities were instead used to estimate hydrogen demand.

In the transportation sector, the mismatch between the EPA and FHWA classification systems was a source of uncertainty. As such, the associated calculations on payloads, fuel economies, and hydrogen deployment may also have uncertainty. For future hydrogen demand, scenario design was primarily informed by international decarbonization roadmaps, US-specific DOE reports, and demonstration projects in other countries. As such, it is possible that this analysis may not fully represent the technology readiness and hydrogen deployment potential of Michigan-specific assets. Finally, where alternative data sources were not readily available, simplifications were made to characterize hydrogen demand. For example, the DOE provides ranges of potential hydrogen demand in the transportation sector. This rate was applied evenly across all MHDV classes since class-specific breakdowns were not available. Additionally, while blending hydrogen with natural gas may vary based on end-use applications, the 20% blending percentage was held constant across all sectors. In the cement sector, fuel switching to hydrogen and AFs was determined based on fossil fuel prices in 2030 and 2050. However, the inherent uncertainty in fuel price estimates may impart uncertainty in the associated demand and emissions reduction estimates. Finally, in the refining sector, hydrogen may be produced as a by-product from the catalytic refining of naphtha. However, this hydrogen may only meet a fraction of the facility's demand and was not modeled in this analysis.[142]

Industrial Economic Growth

The economic projections modeled in this study may also be imprecise due to challenges in matching NAICS codes to the EIA's IND index. In the chemicals sector NAICS-EIA IND alignment proved challenging as some in-scope facilities reported more than one NAICS code. In this case, the EIA category most closely related to the facility's operations was chosen based on communications with industry contacts and public permits. However, a singular EIA index may not accurately reflect the entire facility's product outputs. This challenge also persisted with the semiconductor industry, where Hemlock Semiconductor falls under the EIA IND for "Other Nonmetallic Mineral Products." As such, the corresponding EIA growth rates may not completely represent ongoing growth in the semiconductor industry.

In addition, there are also potential issues with using data from *AEO 2022*, as it does not currently account for the impacts of the *Inflation Reduction Act.* This may explain the petroleum refining sector's macroeconomic indicators to show strong deviations from net zero pathways. The EIA recognizes these limitations and will not be publishing an *AEO* in 2024 in order to focus on accurately modeling hydrogen and other climate technologies in future releases.[177] Despite the EIA's dataset not being completely representative, it is the most comprehensive and widely accepted dataset currently available and was therefore used in this case study.

Finally, it is important to note that the approach used to model economic growth in this study may not be accurate for all facilities, all of the time. The underlying growth rates used in this study reflect the real output value for industrial and service sectors across the nine census divisions.[116] Since the growth was regionalized to the "East North Central" division, the corresponding rates may not accurately represent economic activity in Michigan.[178] Moreover, the growth rates represent industry-wide activity, which signifies an inherent deviation from facility level operations.

VMT Projections
It is important to consider the differences in methods between HDV and MDV estimates, particularly in the context of the likelihood of future adoption. For HDV estimates, the total VMT for all HDVs (from the MDOT freight dataset) was represented to account for the higher likelihood of hydrogen technology adoption among HDVs, due to the challenges of electrification (Section 2.2.2). Total VMT was then distributed among the selected classes of 8a, 8b long-haul, and 8b short-haul. These classes were chosen to align with classes available in GREET for the bottom-up modeling of energy consumption and emissions. This also allowed for consistency between VMT and payload estimates, which similarly represent all HDV freight on Michigan roads.

In comparison, VMT estimates for MDV classes were selectively applied to only the chosen classes by applying the percentage representation of each class (as determined by WIM station traffic counts) to assign only the corresponding fraction of the total VMT to each class. This was done to avoid overestimating the potential demand for MDVs, given the relatively lower likelihood of hydrogen technology adoption among MDVs as compared to HDVs (Section 2.2.2).

Additionally, certain assumptions were made for this analysis. One significant assumption for future estimates was that percentage adoption among chosen classes would be equally distributed, though it should be noted that different classes would likely have different adoption rates. Future research could model different percentage adoption rates for different classes, and could be expanded to include additional HDV and MDV classes that were not included in this analysis.

4.5 Additional Considerations
The cost of hydrogen is the most significant barrier to adoption in both industry and transportation. In the cement manufacturing industry, hydrogen is up to five times more expensive than incumbent fuels.[98] Additionally, not all production pathways may qualify for the 45V production tax credit, thereby restricting the financial incentives associated with producing low-carbon hydrogen. FCEVs also see elevated fuel prices at the pump over their gasoline counterparts.[179] While the DOE's Hydrogen Shot Initiative is expected to play a role in addressing the cost disparity between hydrogen and incumbent fossil fuels, the difficulty for industries to make commitments on hydrogen today based on future outlooks still stands. However, a MI-specific analysis on different sectors' willingness to pay and this demand analysis can be used in tandem to further inform the planning of a regional hydrogen ecosystem.

Significant concerns with safety exist due to hydrogen's likelihood of metal fracture and leakage, lack of odor, lack of a visible flame, large flammability range, high flame propagation speed, high flame temperature, and potential chance of inadvertent contact with a flame.[141,180,181] As such, the additional cost of leakage prevention, flame detection, and general safety training are barriers to hydrogen use in process heat applications. Adapting burner designs and addressing degradation of refractory walls due to high flame temperatures, the effect of high water vapor concentrations on final product quality, and generation of NO_x are also notable challenges in the deployment of hydrogen. Addressing NO_x generation by implementing oxy-fuel firing would further drive up operational costs due to the production of oxygen.[128] In the transportation sector, public perception on the safety of FCEVs may be a barrier to deployment. Therefore, it is imperative that first responders are well trained on hydrogen and fuel cell related incidents.[182] Finally, there are concerns about the lack of hydrogen supply and that blending with natural gas would likely be implemented only if the distributive infrastructure was operated by local utilities.[183,184] Future work should emphasize the additional safety measures, concerns, and costs associated with hydrogen deployment.

When calculating the demand for hydrogen in process heat applications, it was assumed that hydrogen would replace incumbent fossil fuels on a 1:1 Btu basis. However, additional energy input may be needed when using hydrogen for process heat due to its unique combustion properties.[53] Due to the lack of literature on fuel switching projects in commercial furnaces, a substitution ratio representing this additional energy was only accounted for in the glass industry. This analysis may therefore underestimate the hydrogen demand from industries that have high process heat requirements. The substitution ratio of 1.01 specifically assumed in the glass industry is also uncertain: some industry contacts note hydrogen's non-luminous flame and low radiative heat transfer to be significant while other reports suggest that high water vapor concentrations in oxy-hydrogen combustion products lead to excellent radiative heat transfer.[98,128,185] Hence, it is clear that additional research is needed to identify the substitution ratio of hydrogen for industrial process heat applications.

An analysis of the environmental justice impacts of deploying hydrogen in Michigan's industrial and transportation sectors was outside the scope of this study. However, a discussion of environmental justice is pertinent when analyzing a transition away from fossil fuels, which have significant climate and health impacts, to hydrogen, which can be generated using renewables and release water vapor upon combustion.[186] Specifically in Michigan, there are 215 large industrial facilities as reported by the EPA GHGRP and some of the largest freight corridors in the continent.[72,187] Given that the deleterious health and economical effects of industrial activity have historically been concentrated in marginalized communities, it is imperative that economy-wide transitions to "green" technologies do not perpetuate these same inequities.[188–190] In fact, recent literature on the climate impacts of hydrogen leakage notes that certain hydrogen production pathways could significantly increase warming in the near term.[17] While these warming effects have not been considered in this analysis, it is imperative that the complete climate impacts of a hydrogen ecosystem are aptly accounted for. Hence, it is strongly recommended that the planning of a regional hydrogen ecosystem in Michigan is accompanied by an in-depth analysis of climate impacts, health impacts, access to affordable water and electricity, and additional Justice40 metrics.[191]

5. Conclusion

Hydrogen has the potential to contribute to the decarbonization of Michigan's industrial and transportation sectors particularly where electrification is problematic. Decarbonization can be achieved through low-carbon production pathways for existing and new hydrogen deployment in both fuel and feedstock applications that displace fossil fuels. Current (2022) demand for hydrogen is 39,100 metric tons and dominated by feedstock applications in the industrial sector, particularly petroleum refining and semiconductor manufacturing. The expansion of the semiconductor industry, uptake of FCEVs in the transportation sector, and new hydrogen deployment in steel blast furnaces can drive hydrogen deployment in the 2030 timeframe. As such, near-term (2030) demand was estimated to range from 40,100 to 63,400 metric tons. All eight end-uses analyzed—particularly the cement, steel, and transportation sectors—have the potential to generate significant hydrogen demand in the 2050 timeframe. The extent to which hydrogen can contribute to industrial and transportation decarbonization was explored by estimating demand for a range of scenarios including an upper limit based on "Complete Hydrogen Substitution." Future demand estimates are highly uncertain and will depend on dramatic reductions in the cost of low-carbon hydrogen production, the development of hydrogen infrastructure, and investment to drive scaling of hydrogen production and end-use technologies. Demand in 2050 therefore ranges from 108,000 to 206,000 metric tons in the "Low Hydrogen Use" and "High Hydrogen Use" scenarios, with the "Complete Hydrogen Substitution" scenario deploying up to 1.1 million metric tons of annual demand. These demand estimates across end-use applications through 2050 aim to inform the planning of a hydrogen ecosystem in Michigan and the Midwest region. In addition, hydrogen ecosystem planning will need to consider other key factors such as facility siting and safety and how hydrogen deployment can best contribute to a just and equitable energy transition.

6. References

(1) Shivanna, K. R. Climate Change and Its Impact on Biodiversity and Human Welfare. *Proc. Indian Natl. Sci. Acad.* **2022**, *88*, 160–171. https://doi.org/10.1007/s43538-022-00073-6.

(2) Impacts of 1.5°C Global Warming on Natural and Human Systems. In *Global Warming of 1.5°C: IPCC Special Report on Impacts of Global Warming of 1.5°C above Pre-industrial Levels in Context of Strengthening Response to Climate Change, Sustainable Development, and Efforts to Eradicate Poverty*; Intergovernmental Panel on Climate Change (IPCC), Ed.; Cambridge University Press: Cambridge, 2022; pp 175–312. https://doi.org/10.1017/9781009157940.005.

(3) Masson-Delmotte, V.; Zhai, P.; Pörtne, H.-O.; Roberts, D.; Skea, J.; Shukla, P.; Pirani, A.; Moufouma-Okia, W.; Pidcock, P.; Connors, S.; Matthews, J. B.; Chen, Y.; Zhou, X.; Gomis, M.; Lonnoy, E.; Maycock, T.; Tignor, M.; Waterfield, T. *Global Warming of 1.5°C. An IPCC Special Report on the Impacts of Global Warming of 1.5°C above Pre-Industrial Levels and Related Global Greenhouse Gas Emission Pathways, in the Context of Strengthening the Global Response to the Threat of Climate Change, Sustainable Development, and Efforts to Eradicate Poverty*; Intergovernmental Panel on Climate Change, 2018; pp 3–24. https://www.ipcc.ch/site/assets/uploads/sites/2/2022/06/SPM_version_report_LR.pdf (accessed 2023-09-14).

(4) IEA. *Net Zero Roadmap: A Global Pathway to Keep the 1.5 °C Goal in Reach*; IEA: Paris, 2023. https://www.iea.org/reports/net-zero-roadmap-a-global-pathway-to-keep-the-15-0c-goal-in-reach,.

(5) *EPA (2023) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021.*; EPA 430-R-23-002; U.S. Environmental Protection Agency. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2021.

(6) Woodall, C. M.; Fan, Z.; Lou, Y.; Bhardwaj, A.; Khatri, A.; Agrawal, M.; McCormick, C. F.; Friedmann, S. J. Technology Options and Policy Design to Facilitate Decarbonization of Chemical Manufacturing. *Joule* **2022**, *6* (11), 2474–2499. https://doi.org/10.1016/j.joule.2022.10.006.

(7) McMillan, C.; Boardman, R.; McKellar, M.; Sabharwall, P.; Ruth, M.; Bragg-Sitton, S. *Generation and Use of Thermal Energy in the U.S. Industrial Sector and Opportunities to Reduce Its Carbon Emissions*; Idaho National Laboratory: United States, 2016. https://www.nrel.gov/docs/fy17osti/66763.pdf.

(8) Thiel, G. P.; Stark, A. K. To Decarbonize Industry, We Must Decarbonize Heat. *Joule* **2021**, *5* (3), 531–550. https://doi.org/10.1016/j.joule.2020.12.007.

(9) Neuwirth, M.; Fleiter, T.; Manz, P.; Hofmann, R. The Future Potential Hydrogen Demand in Energy-Intensive Industries - a Site-Specific Approach Applied to Germany. *Energy Convers. Manag.* **2022**, *252*. https://doi.org/10.1016/j.enconman.2021.115052.

(10) Yang, X.; Nielsen, C. P.; Song, S.; McElroy, M. B. Breaking the Hard-to-Abate Bottleneck in China's Path to Carbon Neutrality with Clean Hydrogen. *Nat. Energy* **2022**, *7*, 955–965. https://doi.org/10.1038/s41560-022-01114-6.

(11) Gross, S. *The Challenge of Decarbonizing Heavy Transport*; Brookings Institution, 2020. https://www.brookings.edu/wp-content/uploads/2020/09/FP_20201001_challenge_of_decarbonizing_heavy_transport.pdf.

(12) Smith, D.; Ozpineci, B.; Graves, R. L.; Jones, P. T.; Lustbader, J.; Kelly, K.; Walkowicz, K.; Birky, A.; Payne, G.; Sigler, C.; Mosbacher, J. *Medium- and Heavy-Duty Vehicle*

Electrification: An Assessment of Technology and Knowledge Gaps; ORNL/SPR-2020/7; Oak Ridge National Laboratory (ORNL), Oak Ridge, TN (United States), 2020. https://doi.org/10.2172/1615213.
(13) *U.S. National Clean Hydrogen Strategy and Roadmap*; U.S. Department of Energy, 2023. https://www.hydrogen.energy.gov/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf.
(14) Gray, N.; O'Shea, R.; Wall, D.; Smyth, B.; Lens, P. N. L.; Murphy, J. D. Batteries, Fuel Cells, or Engines? A Probabilistic Economic and Environmental Assessment of Electricity and Electrofuels for Heavy Goods Vehicles. *Adv. Appl. Energy* **2022**, *8*, 100110. https://doi.org/10.1016/j.adapen.2022.100110.
(15) Lewis, A. C. Optimising Air Quality Co-Benefits in a Hydrogen Economy: A Case for Hydrogen-Specific Standards for NOx Emissions. *Environ. Sci. Atmospheres* **2021**, *1*. https://doi.org/10.1039/d1ea00037c.
(16) Bertagni, M. B.; Pacala, S. W.; Paulot, F.; Porporato, A. Risk of the Hydrogen Economy for Atmospheric Methane. *Nat. Commun.* **2022**, *13*. https://doi.org/10.1038/s41467-022-35419-7.
(17) Sun, T.; Shrestha, E.; Hamburg, S. P.; Kupers, R.; Ocko, I. B. Climate Impacts of Hydrogen and Methane Emissions Can Considerably Reduce the Climate Benefits across Key Hydrogen Use Cases and Time Scales. *Environ. Sci. Technol.* **2024**, *58* (12), 5299–5309. https://doi.org/10.1021/acs.est.3c09030.
(18) McDonald, L. *Video: Hydrogen trials show promise at glassmaking plants*. The American Ceramic Society. https://ceramics.org/ceramic-tech-today/ceramic-video/video-hydrogen-trials-show-promise-at-glassmaking-plants/ (accessed 2024-04-14).
(19) Mineral Products Association; VDZ gGmbH; Cinar Ltd; Hanson; Tarmac. *State of the Art Fuel Mix for UK Cement Production to Test the Path for 'Net Zero': A Technical, Environmental and Safety Demonstration.*; Department for Business Energy and Industrial Strategy, 2022. https://assets.publishing.service.gov.uk/media/637e4d85d3bf7f154955962d/phase_3_state_of_the_art_fuel_mix_for_UK_cement_production_to_test_the_path_for_net_zero.pdf (accessed 2024-04-14).
(20) Beumelburg, C. *HeidelbergCement produces cement with climate-neutral fuel mix using hydrogen technology*. Heidelberg Materials. https://www.heidelbergmaterials.com/en/pr-01-10-2021 (accessed 2024-04-14).
(21) *First in the world to heat steel using hydrogen*. Ovako. https://www.ovako.com/en/newsevents/stories/first-in-the-world-to-heat-steel-using-hydrogen/ (accessed 2024-04-14).
(22) Persico, P. *Cleveland-Cliffs Completes Successful Blast Furnace Hydrogen Injection Trial at Middletown Works*. Business Wire. https://www.businesswire.com/news/home/20230508005542/en/ (accessed 2024-04-14).
(23) *Sustainable steel: Review of phase 1 of the injection trials*. thyssenkrupp. https://www.thyssenkrupp.com/en/stories/sustainability-and-climate-protection/green-steel-review-of-phase-1-of-the-injection-trials (accessed 2024-04-14).
(24) *Pilot scale direct reduction with hydrogen*. HYBRIT. https://www.hybritdevelopment.se/en/a-fossil-free-development/direct-reduction-hydrogen-pilotscale/ (accessed 2024-04-14).
(25) Topolski, K.; Reznicek, E.; Erdener, B. C.; San Marchi, C.; Ronevich, J.; Fring, L.; Simmons, K.; Guerra Fernandez, O. J.; Hodge, B.-M.; Chung, M. *Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology*; National Renewable Energy Laboratory: Golden, Colorado, 2022. https://www.nrel.gov/docs/fy23osti/81704.pdf.
(26) *Hyundai today delivered the first seven units of its XCIENT Fuel Cell*. Hyundai.

https://www.hyundai.news/eu/articles/press-releases/hyundai-today-delivered-the-first-seven-units-of-its-xcient-fuel-cell.html (accessed 2024-04-14).
(27) *Clean Fleet, Pioneers in fuel cell technology*. SunLine Transit Agency. https://www.sunline.org/projects/alternative-fuels/clean-fleet (accessed 2024-03-26).
(28) U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Guidance, 2023. https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard-guidance.pdf (accessed 2023-09-08).
(29) Bennett, S.; Evangelopoulou, S.; Fajardy, M.; Greenfield, C.; Pavan, F.; Pizarro Alonso, A. Towards Hydrogen Definitions Based on Their Emissions Intensity, 2023. https://iea.blob.core.windows.net/assets/acc7a642-e42b-4972-8893-2f03bf0bfa03/Towardshydrogendefinitionsbasedontheiremissionsintensity.pdf (accessed 2023-09-08).
(30) *Hydrogen Production: Natural Gas Reforming*. Office of Energy Efficiency & Renewable Energy. https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming#:~:text=In%20steam%2Dmethane%20reforming%2C%20methane,for%20the%20reaction%20to%20proceed. (accessed 2023-09-08).
(31) Collodi, G.; Azzaro, G.; Ferrari, N.; Santos, S. Techno-Economic Evaluation of Deploying CCS in SMR Based Merchant H2 Production with NG as Feedstock and Fuel. *Energy Procedia* **2017**, *114*, 2690–2712. https://doi.org/10.1016/j.egypro.2017.03.1533.
(32) Asayama, S. The Oxymoron of Carbon Dioxide Removal: Escaping Carbon Lock-In and yet Perpetuating the Fossil Status Quo? *Front. Clim.* **2021**, *3*. https://doi.org/10.3389/fclim.2021.673515.
(33) Vinca, A.; Emmerling, J.; Tavoni, M. Bearing the Cost of Stored Carbon Leakage. *Front. Energy Res.* **2018**, *6*. https://doi.org/10.3389/fenrg.2018.00040.
(34) *Hydrogen Production: Electrolysis*. Office of Energy Efficiency & Renewable Energy. https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis (accessed 2023-09-11).
(35) Malik, F.; Yuan, H.-B.; Morgan, J.; Tippayawong, N. Overview of Hydrogen Production Technologies for Fuel Cell Utilization. *Eng. Sci. Technol. Int. J.* **2023**, *43*. https://doi.org/10.1016/j.jestch.2023.101452.
(36) Elgowainy, A.; Frank, E.; Vyawahare, P.; Ng, C.; Bafana, A.; Burnham, A.; Sun, P.; Cai, H.; Lee, U.; Reddi, K.; Wang, M. *Hydrogen Life-Cycle Analysis in Support of Clean Hydrogen Production*; Energy Systems and Infrastructure Analsysis Division, Argonne National Laboratory, 2022. https://greet.es.anl.gov/publication-hydrogenreport2022 (accessed 2023-09-14).
(37) Connelly, E.; Elgowainy, A.; Ruth, M. DOE Hydrogen and Fuel Cells Program Record, 2019. https://www.hydrogen.energy.gov/pdfs/19002-hydrogen-market-domestic-global.pdf (accessed 2024-04-14).
(38) Hicks, S.; Gross, P. *Hydrogen for refineries is increasingly provided by industrial suppliers*. U.S. Energy Information Adminstration. https://www.eia.gov/todayinenergy/detail.php?id=24612 (accessed 2024-04-15).
(39) *H.R.3684 - 117th Congress (2021-2022): Infrastructure Investment and Jobs Act.*; Library of Congress: Congress.gov, 2021. https://www.congress.gov/bill/117th-congress/house-bill/3684. (accessed 2024-04-14).
(40) *Funding Notice: Regional Clean Hydrogen Hub*. Office of Clean Energy Demonstrations. https://www.energy.gov/oced/funding-notice-regional-clean-hydrogen-hubs (accessed 2024-04-14).
(41) *H.R.5376 - 117th Congress (2021-2022): Inflation Reduction Act of 2022.*; Library of Congress: Congress.gov, 2022. https://www.congress.gov/bill/117th-congress/house-bill/5376/text (accessed

2024-04-14).
(42) *Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election To Treat Clean Hydrogen Production Facilities as Energy Property*. Federal Register. https://www.federalregister.gov/documents/2023/12/26/2023-28359/section-45v-credit-for-production-of-clean-hydrogen-section-48a15-election-to-treat-clean-hydrogen (accessed 2024-04-14).
(43) Hydrogen Shot: An Introduction, 2021. https://www.energy.gov/eere/fuelcells/articles/hydrogen-shot-introduction (accessed 2024-04-14).
(44) *MI HEALTHY CLIMATE PLAN*; Michigan Department of Environment, Great Lakes, and Energy, 2022. https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf?rev=d13f4adc2b1d45909bd708cafccbfffa (accessed 2024-04-14).
(45) Lawder, D. Truckers in Perfect Spot to Threaten Cross-Border Trade. *Reuters*. February 11, 2022. https://www.reuters.com/world/americas/truckers-ambassador-bridge-perfect-spot-threaten-us-canada-trade-2022-02-11/ (accessed 2024-02-09).
(46) *Governor Whitmer Signs Historic Clean Energy & Climate Action Package*. Governor Gretchen Whitmer. https://www.michigan.gov/whitmer/news/press-releases/2023/11/28/governor-whitmer-signs-historic-clean-energy-climate-action-package (accessed 2024-04-02).
(47) *Biden-Harris Administration Announces $7 Billion For America's First Clean Hydrogen Hubs, Driving Clean Manufacturing and Delivering New Economic Opportunities Nationwide*. Department of Energy. https://www.energy.gov/articles/biden-harris-administration-announces-7-billion-americas-first-clean-hydrogen-hubs-driving.
(48) *Gov. Whitmer Announces Nel Hydrogen to Build Gigafactory in Plymouth Township, Bringing 517 Jobs and $400 Million Investment to Michigan*. Governor Gretchen Whitmer. https://www.michigan.gov/whitmer/news/press-releases/2023/09/26/whitmer-announces-nel-hydrogen-to-build-gigafactory-in-plymouth-township-bringing-517-jobs (accessed 2024-04-14).
(49) Adil, S. PLASTIC OMNIUM TO SET UP LARGEST HYDROGEN STORAGE PRODUCTION PLANT IN MICHIGAN, U.S.A., 2023. https://www.opmobility.com/wp-content/uploads/2023/08/plastic-omnium-press-release-plastic-omnium-to-set-up-largest-hydrogen-storage-production-plant-in-michigan-en.pdf (accessed 2024-04-14).
(50) Keoleian, G.; Lewis, G.; Buchanan, C.; Calzavara, J.; Woody, M. *Hydrogen Roadmap for the State of Michigan Workshop Report*; CSS22-17; University of Michigan: Center for Sustainable Systems, 2022. https://deepblue.lib.umich.edu/bitstream/handle/2027.42/191567/CSS22-17_MI%20Hydrogen%20Roadmap%20Workshop%20Report.pdf?sequence=1&isAllowed=y (accessed 2024-04-14).
(51) Clarke, J.; Thobe, Z. Meeting with James Clarke, Zachary Thobe from Marathon Petroleum, 2023.
(52) Miller, J.; Walker, C. Meeting with Jeff Miller and Caleb Walker from Hemlock Semiconductor Corporation - First Meeting, 2023.
(53) Davis, S.; Whittredge, A. Meeting with Sheldon Davis and Amy Whittredge from Guardian Glass - First Meeting, 2023.
(54) Bains, P.; Psarras, P.; Wilcox, J. CO2 Capture from the Industry Sector. *Prog. Energy Combust. Sci.* **2017**, *63*, 146–172. https://doi.org/10.1016/j.pecs.2017.07.001.

(55) Sun, Y.; Zhang, Z. Energy Saving and Emission Reduction from the Steel Industry: Heat Recovery from High Temperature Slags. In *Energy Solutions to Combat Global Warming*; Zhang, X., Dincer, I., Eds.; Springer International Publishing: Cham, 2016; pp 249–280. https://doi.org/10.1007/978-3-319-26950-4_12.
(56) Fadden, B. Meeting with Brad Fadden from Graphic Packaging International - Kalamazoo - First Meeting, 2023.
(57) McMillan, C. Meeting with Colin McMillan from the National Renewable Energy Laboratory - First Meeting, 2023.
(58) Berube, M.; Wishnia, A.; Simon, K.; Pelosi, A.; Muratori, M.; Kunz, T.; Hula, A.; Michael Freedberg. *THE U.S. NATIONAL BLUEPRINT FOR TRANSPORTATION DECARBONIZATION*; U.S. Department of Energy, U.S. Deparment of Transportation, U.S. Environmental Protection Agency, U.S. Department of Housing, 2023. https://www.energy.gov/sites/default/files/2023-01/the-us-national-blueprint-for-transportation-decarbonization.pdf (accessed 2023-09-14).
(59) 21st Century Truck Partnership. Electrification Technologies Sector Team Roadmap. *2023*.
(60) *Fact #951: November 14, 2016 Medium and Heavy Trucks Account for About a Quarter of Highway Vehicle Fuel Use*. Energy.gov. https://www.energy.gov/eere/vehicles/fact-951-november-14-2016-medium-and-heavy-trucks-account-about-quarter-highway (accessed 2024-02-04).
(61) US EPA, O. *Fast Facts on Transportation Greenhouse Gas Emissions*. https://www.epa.gov/greenvehicles/fast-facts-transportation-greenhouse-gas-emissions (accessed 2024-02-04).
(62) Satyapal, Dr. S.; US Department of Energy. *DOE-H2-Program-National-Strategy-Remarks-jan2024.pdf*. https://www.energy.gov/sites/default/files/2024-02/doe-h2-program-national-strategy-remarks-jan2024.pdf (accessed 2024-04-26).
(63) US Department of Energy. *DOE Technical Targets for Hydrogen Storage Systems for Material Handling Equipment*. Energy.gov. https://www.energy.gov/eere/fuelcells/doe-technical-targets-hydrogen-storage-systems-material-handling-equipment (accessed 2024-04-26).
(64) Iyer, R. K.; Kelly, J. C.; Elgowainy, A. Vehicle-Cycle and Life-Cycle Analysis of Medium-Duty and Heavy-Duty Trucks in the United States. *Sci. Total Environ.* **2023**, *891*, 164093. https://doi.org/10.1016/j.scitotenv.2023.164093.
(65) Wallington, T. J.; Woody, M.; Lewis, G. M.; Keoleian, G. A.; Adler, E. J.; Martins, J. R. R. A.; Collette, M. D. Green Hydrogen: Energy Efficiency and Intensity in Ground, Air, and Marine Transportation.
(66) Elgowainy, A. Opportunities and Challenges for Hydrogen to Decarbonize Energy Sectors, 2023.
(67) *Asssessment of Green Hydrogen for Industrial Heat*; Deloitte, 2023. https://www2.deloitte.com/content/dam/Deloitte/us/Documents/Advisory/us-advisory-assessment-of-green-hydrogen-for-industrial-heat.pdf (accessed 2024-04-14).
(68) Industrial Sector Energy Consumption. **2016**.
(69) Vavra, C. *Hydrogen technology developed to curtail food, beverage greenhouse gases*. Plant Engineering. https://www.plantengineering.com/articles/hydrogen-technology-developed-to-curtail-food-beverage-greenhouse-gases/ (accessed 2024-04-15).
(70) BEIS. *phase_3_alternatives_to_natural_gas_for_high_calcium_lime_manufacturing_hydrogen.pdf*. https://assets.publishing.service.gov.uk/media/637e4d28e90e072346aae0cb/phase_3_alt

ernatives_to_natural_gas_for_high_calcium_lime_manufacturing_hydrogen.pdf (accessed 2024-04-15).
(71) Aluminum International Today. Can Hydrogen and the Latest Burners Reduce Carbon Emissions?, 2021. https://www.airproducts.com/-/media/files/external/aluminium-international-today/greener-alu-air-products.pdf.
(72) US EPA, O. *Learn About the Greenhouse Gas Reporting Program (GHGRP)*. https://www.epa.gov/ghgreporting/learn-about-greenhouse-gas-reporting-program-ghgrp (accessed 2024-04-15).
(73) Greenhouse Gas Reporting Program (GHGRP), 2022. www.epa.gov/ghgreporting.
(74) Lee, D.-Y.; Elgowainy, A.; Vijayagopal, R. Well-to-Wheel Environmental Implications of Fuel Economy Targets for Hydrogen Fuel Cell Electric Buses in the United States. *Energy Policy* **2019**, *128*, 565–583. https://doi.org/10.1016/j.enpol.2019.01.021.
(75) *Alternative Fuels Data Center: How Do Fuel Cell Electric Vehicles Work Using Hydrogen?* https://afdc.energy.gov/vehicles/how-do-fuel-cell-electric-cars-work (accessed 2024-03-31).
(76) *Internal Combustion Engine Basics*. Energy.gov. https://www.energy.gov/eere/vehicles/articles/internal-combustion-engine-basics (accessed 2024-03-31).
(77) *February H2IQ Hour: Overview of Hydrogen Internal Combustion Engine (H2ICE) Technologies: Text Version*. Energy.gov. https://www.energy.gov/eere/fuelcells/february-h2iq-hour-overview-hydrogen-internal-combustion-engine-h2ice-technologies-0 (accessed 2024-03-31).
(78) Corwin Matthews. Zoom Meeting with Corwin Matthews from Flint MTA - First Meeting, 2023.
(79) *GREET: The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model*. Energy.gov. https://www.energy.gov/eere/bioenergy/articles/greet-greenhouse-gases-regulated-emissions-and-energy-use-transportation (accessed 2024-03-10).
(80) Wang, M.; Elgowainy, A.; Lee, U.; Baek, K.; Balchandani, S.; Benavides, P.; Burnham, A.; Cai, H.; Chen, P.; Gan, Y.; Gracida-Alvarez, U.; Hawkins, T.; Huang, T.-Y.; Iyer, R.; Kar, S.; Kelly, J.; Kim, T.; Kolodziej, C.; Lee, K.; Liu, X.; Lu, Z.; Masum, F.; Morales, M.; Ng, C.; Ou, L.; Poddar, T.; Reddi, K.; Shukla, S.; Singh, U.; Sun, L.; Sun, P.; Sykora, T.; Vyawahare, P.; Zhang, J. Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model ® (2023 Excel), 2023. https://doi.org/10.11578/GREET-EXCEL-2023/DC.20230907.1.
(81) *MS2 - FHWA Vehicle Classifications*. https://www.ms2soft.com/about-us/fhwa-vehicle-classifications/ (accessed 2023-12-21).
(82) *Alternative Fuels Data Center: Maps and Data - Vehicle Weight Classes & Categories*. https://afdc.energy.gov/data/10380 (accessed 2023-12-13).
(83) Sun, P.; Young, B.; Elgowainy, A.; Lu, Z.; Wang, M.; Morelli, B.; Hawkins, T. Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Methane Reforming Facilities. *Environ. Sci. Technol.* **2019**, *53* (12), 7103–7113. https://doi.org/10.1021/acs.est.8b06197.
(84) Wang, M.; Elgowainy, A.; Lu, Z.; Baek, K.; Balchandani, S.; Benavides, P.; Burnham, A.; Cai, H.; Chen, P.; Gan, Y.; Gracida-Alvarez, U.; Hawkins, T.; Huang, T.-Y.; Iyer, R.; Kar, S.; Kelly, J.; Kim, T.; Kolodziej, C.; Lee, K.; Lee, U.; Liu, X.; Masum, F.; Morales, M.; Ng, C.; Ou, L.; Poddar, T.; Reddi, K.; Shukla, S.; Singh, U.; Sun, L.; Sun, P.; Sykora, T.; Vyawahare, P.; Zhang, J. Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model ® (2023 .Net), 2023. https://doi.org/10.11578/GREET-NET-2023/DC.20230907.2.

(85) Li, S. Feedback Requested - Michigan Hydrogen Demand Analysis, Guardian Industries, 2024.
(86) Permit to Install, 2023. https://www.google.com/url?q=https://www.egle.state.mi.us/aps/downloads/permits/finptic on/2023/144-23.pdf&sa=D&source=docs&ust=1713197677845704&usg=AOvVaw0ycV_wpIgewx860JjGtCLr.
(87) Matthews, C. RE: MI Hydrogen Demand Analysis - Flint's Hydrogen Fuel Cell Buses, 2023.
(88) Garrison, D. Re: Feedback Requested - Michigan Hydrogen Demand Analysis Report, 2024.
(89) Emission Factors for Greenhouse Gas Inventories, 2023. https://www.epa.gov/system/files/documents/2023-03/ghg_emission_factors_hub.pdf.
(90) Margolis, N.; Brindle, R. Energy and Environmental Profile of the U.S. Iron and Steel Industry, 2000.
(91) McMillan, C. RE: MI Hydrogen Demand Analysis Follow-Up, 2024.
(92) Iron and Steel Technology Roadmap - Towards More Sustainable Steelmaking.
(93) C12s05.Pdf. https://www3.epa.gov/ttnchie1/ap42/ch12/final/c12s05.pdf (accessed 2024-04-04).
(94) *Holcim Alpena Cement Plant Opens Tire-Derived Fuel Facility*. https://www.holcim.us/alpena-alternative-fuel-2023 (accessed 2024-04-15).
(95) *Coal for cement: Present and future trends*. https://www.globalcement.com/magazine/articles/974-coal-for-cement-present-and-future-trends (accessed 2024-04-15).
(96) *Revitalising St Marys Cement*. International Cement Review. https://www.cemnet.com/Articles/story/164001/revitalising-st-marys-cement.html (accessed 2024-04-15).
(97) EGLE. *www.egle.state.mi.us - /aps/downloads/ROP/pub_ntce/B1477/*. https://www.egle.state.mi.us/aps/downloads/ROP/pub_ntce/B1477/ (accessed 2024-04-15).
(98) Akhtar, S. S. Zoom Meeting with Syed Suhail Akhtar, 2023.
(99) *40 CFR Part 98 Subpart C -- General Stationary Fuel Combustion Sources*. https://www.ecfr.gov/current/title-40/part-98/subpart-C (accessed 2024-04-15).
(100) EGLE. *Holcim - Renewable Operating Permit - B1477 FINAL 08-09-23.pdf*. https://www.egle.state.mi.us/aps/downloads/ROP/pub_ntce/B1477/B1477%20FINAL%20 08-09-23.pdf (accessed 2024-04-15).
(101) El-Emam, R. S.; Gabriel, K. S. Synergizing Hydrogen and Cement Industries for Canada's Climate Plan – Case Study. *Energy Sources Part Recovery Util. Environ. Eff.* **2021**, *43* (23), 3151–3165. https://doi.org/10.1080/15567036.2021.1936699.
(102) *Energy & Environment Priorities*. https://www.cement.org/issues-advocacy/legislative-priorities/energy-environment-prioritie s (accessed 2024-04-15).
(103) Davis, S. C.; Boundy, R. G. Transportation Energy Data Book: Edition 40.
(104) Michigan Department of Transportation (MDOT). MDOT Transearch 2018 Dataset (Shapefiles), 2018.
(105) Michigan Department of Transportation (MDOT). MDOT Model Network 2015 Dataset (Shapefiles), 2015.
(106) *Argonne GREET Publication : The GREET Model Expansion for Well-to-Wheels Analysis of Heavy-Duty Vehicles*. https://greet.anl.gov/publication-heavy-duty (accessed 2023-12-13).
(107) *2023 FHWA Forecasts of Vehicle Miles Traveled (VMT) - Policy | Federal Highway Administration*.

https://www.fhwa.dot.gov/policyinformation/tables/vmt/vmt_forecast_sum.cfm#ftn4 (accessed 2023-12-21).
(108) Michigan Department of Transportation. *Transportation Data Management System*. https://mdot.public.ms2soft.com/tcds/tsearch.asp?loc=Mdot&mod=TCDS (accessed 2023-12-13).
(109) Gurupackiam, S.; Turner, D. S.; Lindly, J. K.; Jones, S.; Tedla, E. Reduction of Capacity and Projected Costs Associated with Seat Belt Installation on School Buses. *Transp. Res. Part Policy Pract.* **2014**, *67*, 59–68. https://doi.org/10.1016/j.tra.2014.06.005.
(110) FHWA. Developing a Statistically Valid and Practical Method to Compute Bus and Truck Occupancy Data. **2019**.
(111) *Why Miles Matter - Management - School Bus Fleet*. https://www.schoolbusfleet.com/10010279/why-miles-matter (accessed 2023-12-13).
(112) *Energy Savings by Light-Weighting IFEU – 2016 Update - International Aluminium Institute*. https://international-aluminium.org/resource/energy-savings-by-light-weighting-ifeu-2016-update/ (accessed 2023-12-13).
(113) Luk, J. M.; Kim, H. C.; De Kleine, R.; Wallington, T. J.; MacLean, H. L. Review of the Fuel Saving, Life Cycle GHG Emission, and Ownership Cost Impacts of Lightweighting Vehicles with Different Powertrains. *Environ. Sci. Technol.* **2017**, *51* (15), 8215–8228. https://doi.org/10.1021/acs.est.7b00909.
(114) Kim, H. C.; Wallington, T. J. Life Cycle Assessment of Vehicle Lightweighting: A Physics-Based Model of Mass-Induced Fuel Consumption. *Environ. Sci. Technol.* **2013**, *47* (24), 14358–14366. https://doi.org/10.1021/es402954w.
(115) Annual Energy Outlook 2023, 2023. https://www.eia.gov/outlooks/aeo/ (accessed 2024-04-14).
(116) Macroeconomic Activity Module of the National Energy Modeling System: Model Documentation 2022, 2022. https://www.eia.gov/outlooks/aeo/nems/documentation/macroeconomic/pdf/MAM_2022.pdf (accessed 2024-04-14).
(117) *2023 FHWA Forecasts of Vehicle Miles Traveled (VMT) - Policy | Federal Highway Administration*. https://www.fhwa.dot.gov/policyinformation/tables/vmt/vmt_forecast_sum.cfm#ftn4 (accessed 2023-12-21).
(118) IEA. Global Hydrogen Review 2022. **2022**.
(119) Cleveland-Cliffs. *Cleveland-Cliffs Completes Successful Blast Furnace Hydrogen Injection Trial at Indiana Harbor #7 Blast Furnace*. Cleveland-Cliffs Inc. https://www.clevelandcliffs.com/news/news-releases/detail/620/cleveland-cliffs-completes-successful-blast-furnace (accessed 2024-04-15).
(120) IEA. *ETP Clean Energy Technology Guide – Data Tools*. IEA. https://www.iea.org/data-and-statistics/data-tools/etp-clean-energy-technology-guide (accessed 2024-04-15).
(121) Whittredge, A. RE: MI Hydrogen Industry Collaboration - Guardian Industries, 2023.
(122) Energy and Environmental Economics, Inc. Decarbonizing Pipeline Gas to Help Meet California's 2050 Greenhouse Gas Reduction Goal, 2015. https://www.ethree.com/wp-content/uploads/2017/02/E3_Decarbonizing_Pipeline_01-27-2015.pdf.
(123) U.S. Bureau of Labor Statistics. *CPI Inflation Calculator*. https://www.bls.gov/data/inflation_calculator.htm.
(124) Matthews, C.; Garrison, D.; Ellsworth, R.; Nori, S. Flint MTA Hydrogen Production and Hydrogen Bus Tour, 2023.
(125) Melaina, M.; Antonia, O.; Penev, M. *Blending Hydrogen into Natural Gas Pipeline*

Networks: A Review of Key Issues; NREL/TP-5600-51995; National Renewable Energy Laboratory, 2013. https://www.nrel.gov/docs/fy13osti/51995.pdf.
(126) International Energy Agency (IEA). Net Zero Roadmap: A Global Pathway to Keep the 1.5 °C Goal in Reach - 2023 Update.
(127) *Project Description | DevH2forEAF*. https://www.devh2eaf.eu/project-description.html (accessed 2024-04-04).
(128) Kobayashi, H. Future of Oxy-Fuel Glass Melting: Oxygen Production, Energy Efficiency, Emissions and Co2 Neutral Glass Melting. In *80th Conference on Glass Problems*; John Wiley & Sons, Ltd, 2021; pp 1–12. https://doi.org/10.1002/9781119744931.ch1.
(129) Flammatec. *Hydrogen CF*. Flammatec. https://www.flammatec.com/services-products/burners/gaseous-fuels/hydrogen-carbon-free/ (accessed 2024-04-15).
(130) Gallagher, M. J.; Vinod, A.; Dewing, R. A. Blue and Green Hydrogen Production, Distribution, and Supply for the Glass Industry and the Potential Impact of Hydrogen Fuel Blending in Glass Furnaces, 2022.
(131) Linde. *Gas & Technology for Enhanced Glass Surface Quality*. https://www.lindeus.com/industries/glass/glass-surface-treatment (accessed 2024-04-15).
(132) Cresko, J.; Rightor, E.; Carpenter, A.; Peretti, K.; Elliott, N.; Nimbalkar, S.; Morrow III, W.; Hasanbeigi, A.; Hedman, B. *Industrial Decarbonization Roadmap*; DOE/EE-2635; U.S. Department of Energy: Washington, D.C., 2022. https://www.energy.gov/sites/default/files/2022-09/Industrial%20Decarbonization%20Roadmap.pdf (accessed 2023-09-14).
(133) *Cost and Life Cycle Analysis for Deep CO2 Emissions Reduction for Steel Making: Direct Reduced Iron Technologies - Zang - 2023 - steel research international - Wiley Online Library*. https://onlinelibrary.wiley.com/doi/10.1002/srin.202200297 (accessed 2024-04-04).
(134) *Alternative Fuels Data Center: Ethanol Production*. https://afdc.energy.gov/fuels/ethanol_production.html (accessed 2023-09-23).
(135) EPA. *GHG Facility Details*. https://ghgdata.epa.gov/ghgp/service/facilityDetail/2021?id=1010625&ds=E&et=&popup=true (accessed 2024-04-15).
(136) Michigan Department of Environment, Gre. *Renewable Operating Permit - Hemlock Semiconductor Operations LLC and Linde Inc - B2644 Staff Report 06-06-22.pdf*. https://www.egle.state.mi.us/aps/downloads/ROP/pub_ntce/B2644/B2644%20Staff%20Report%2006-06-22.pdf (accessed 2024-04-15).
(137) *Michigan Hemlock Semiconductor Expansion Project*. Center for American Progress. https://www.americanprogress.org/article/michigan-hemlock-semiconductor-expansion-project/ (accessed 2024-04-15).
(138) Elzohiery, M.; Whittredge, A.; Finelli, M. Feedback Requested - Michigan Hydrogen Demand Analysis, 2024.
(139) MICHIGAN DEPARTMENT OF ENVIRONMENT, GREAT LAKES, AND ENERGY. Renewable Operating Permit - Guardian Industries, LLC, 2021. https://www.egle.state.mi.us/aps/downloads/ROP/pub_ntce/B1877/B1877%20FINAL%2008-18-21.docx.
(140) McKinsey. *Refinery fuel*. http://www.mckinseyenergyinsights.com/resources/refinery-reference-desk/refinery-fuel/ (accessed 2024-04-25).
(141) Goldmeer, D. J. Fuel Flexible Gas Turbines as Enablers for a Low or Reduced Carbon Energy Ecosystem.
(142) EIA. *Hydrogen for refineries is increasingly provided by industrial suppliers - U.S. Energy Information Administration (EIA)*. https://www.eia.gov/todayinenergy/detail.php?id=24612

(accessed 2024-04-15).
(143) Shahabuddin, M.; Brooks, G.; Rhamdhani, M. A. Decarbonisation and Hydrogen Integration of Steel Industries: Recent Development, Challenges and Technoeconomic Analysis. *J. Clean. Prod.* **2023**, *395*, 136391. https://doi.org/10.1016/j.jclepro.2023.136391.
(144) US Department of Transportation. *Pipeline Mileage and Facilities* | *PHMSA*. https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-mileage-and-facilities (accessed 2024-04-15).
(145) jhicks3@mlive.com, J. P. H. |. *Flint to trade last diesel buses in for hydrogen*. mlive. https://www.mlive.com/public-interest/2023/04/flint-to-trade-last-diesel-buses-in-for-hydrogen.html (accessed 2024-04-15).
(146) Matthews, C. Conversation with Flint MTA during the January 12th Seminar “MI Hydrogen Demand Stakeholder Results Workshop,” 2024.
(147) Achtenberg, K. *Michigan Wins More than 500 Jobs, Up to $400 Million Investment from Norway’s Nel Hydrogen* | *Michigan Business*. Michigan Economic Development Corporation (MEDC). https://www.michiganbusiness.org/press-releases/2023/05/nel-hydrogen/ (accessed 2024-04-15).
(148) Bayotech. *BayoTech Expands Distributed Hydrogen Network into Michigan in Partnership with American Center for Mobility - BayoTech*. https://bayotech.us/bayotech-expands-distributed-hydrogen-network-into-michigan-in-partnership-with-american-center-for-mobility/ (accessed 2024-04-15).
(149) McKinsey. *Capturing the green-premium value from sustainable materials* | *McKinsey*. https://www.mckinsey.com/industries/metals-and-mining/our-insights/capturing-the-green-premium-value-from-sustainable-materials (accessed 2024-04-15).
(150) US Department of Energy. *Alternative Fuels Data Center: Hydrogen Fueling Stations*. https://afdc.energy.gov/fuels/hydrogen-stations (accessed 2024-04-15).
(151) Michigan Economic Development Corporation. *Mobility & Automotive Manufacturing* | *Industries*. Michigan Economic Development Corporation (MEDC). https://www.michiganbusiness.org/industries/mobility-and-automotive-manufacturing/ (accessed 2024-04-15).
(152) Mercurio, J. Michigan Hydrogen Demand Analysis Project - FCSM Question, 2024.
(153) GM. *GM Fuel Cell Pilot Program Extends Beyond Hydrogen Trucks to Create Blueprint for Low-Emissions Worksites* | *General Motors Company*. https://investor.gm.com/news-releases/news-release-details/gm-fuel-cell-pilot-program-extends-beyond-hydrogen-trucks-create/ (accessed 2024-04-15).
(154) GM. *GM and Autocar Collaborate on Zero Tailpipe Emissions Commercial Vehicles*. https://news.gm.com/public/us/en/gm/home/newsroom.detail.html/Pages/news/us/en/2023/dec/1207-autocar.html (accessed 2024-04-15).
(155) Michigan Department of Treasury. *Federal grants awarded to MDOT Flint MTA Detroit DOT City of Midland*. https://www.michigan.gov/mdot/news-outreach/pressreleases/2022/08/16/federal-grants-awarded-to-mdot-flint-mta-detroit-dot-city-of-midland (accessed 2024-04-15).
(156) Goetz, D. *$4.3M grant will help Flint MTA replace last two diesel buses in fleet*. mlive. https://www.mlive.com/news/flint/2022/08/43m-grant-will-help-flint-mta-replace-last-two-diesel-buses-in-fleet.html (accessed 2024-04-15).
(157) EPA. *Anhydrous Ammonia Supply Chain Profile.pdf*. https://www.epa.gov/system/files/documents/2023-03/Anhydrous%20Ammonia%20Supply%20Chain%20Profile.pdf (accessed 2024-04-15).
(158) Nutrien. *Nutrien_2023Fact Book_Update_112723.pdf*. https://nutrien-prod-asset.s3.us-east-2.amazonaws.com/s3fs-public/uploads/2023-11/Nutr

ien_2023Fact%20Book_Update_112723.pdf (accessed 2024-04-15).
(159) EIA. *New methanol plants expected to increase industrial natural gas use through 2020 - U.S. Energy Information Administration (EIA)*. https://www.eia.gov/todayinenergy/detail.php?id=38412 (accessed 2024-04-15).
(160) Ammpower. *Ammpower - Market-ready Solution for Decentralized Ammonia Production*. https://www.ammoniaenergy.org/wp-content/uploads/2022/10/AEA-2022-AmmPower-final.pdf (accessed 2024-04-15).
(161) EGLE. *Marathon Detroit Permitting Project - PUB-COM-20240306PPS.pdf*. https://www.egle.state.mi.us/aps/downloads/permits/PubNotice/PUB-COM-20240306/PUB-COM-20240306PPS.pdf (accessed 2024-04-15).
(162) Clean Energy Group. *Hydrogen Projects in the US*. Clean Energy Group. https://www.cleanegroup.org/initiatives/hydrogen/projects-in-the-us/ (accessed 2024-04-15).
(163) US Department of Energy. *Alternative Fuels Data Center: Renewable Diesel*. https://afdc.energy.gov/fuels/renewable-diesel (accessed 2024-04-15).
(164) McKinsey. *Converting refineries to renewable fuels | McKinsey*. https://www.mckinsey.com/industries/oil-and-gas/our-insights/converting-refineries-to-renewable-fuels-no-simple-switch (accessed 2024-04-15).
(165) US Department of Energy. *Alternative Fuels Data Center: Biodiesel Laws and Incentives in California*. https://afdc.energy.gov/fuels/laws/BIOD?state=CA (accessed 2024-04-15).
(166) Green, Dr. S. *Key considerations for design and operation of a renewable diesel unit*. https://www.hydrocarbonprocessing.com/news/2021/10/key-considerations-for-design-and-operation-of-a-renewable-diesel-unit (accessed 2024-04-15).
(167) Neste. *neste_renewable_diesel_handbook.pdf*. https://www-old.neste.com/sites/default/files/attachments/neste_renewable_diesel_handbook.pdf (accessed 2024-04-15).
(168) Lessons. *Energy Transition Deep Dive: Top 6 Challenges Renewable Diesel Producers Face*. https://blog.veolianorthamerica.com/energy-transition-deep-dive-top-6-challenges-renewable-diesel-producers-face (accessed 2024-04-15).
(169) DiChristopher, T. *Hydrogen blending in gas pipelines faces limits due to leakage: US DOE lab*. https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/102723-hydrogen-blending-in-gas-pipelines-faces-limits-due-to-leakage-us-doe-lab (accessed 2024-04-15).
(170) Cleveland-Cliffs. *Cleveland-Cliffs Selected to Receive $575 Million in US Department of Energy Investments for Two Projects to Accelerate Industrial Decarbonization Technologies*. Cleveland-Cliffs Inc. https://www.clevelandcliffs.com/news/news-releases/detail/629/cleveland-cliffs-selected-to-receive-575-million-in-us (accessed 2024-04-15).
(171) Gangotra, A.; Lebling, K.; Feldmann, J.; Kennedy, K. What Does ‘Green’ Procurement Mean? Initiatives and Standards for Cement and Steel. **2023**.
(172) Holcim. *OneCem Green Cement | Holcim US*. https://www.holcim.us/onecem (accessed 2024-04-15).
(173) Executive Office of the Governor. *At CHIPS Act One Year Anniversary Michigan Builds on its Semiconductor Leadership*. https://www.michigan.gov/whitmer/news/press-releases/2023/08/09/at-chips-act-one-year-anniversary-michigan-builds-on-its-semiconductor-leadership (accessed 2024-04-15).
(174) *Regional Electric Vehicle Midwest Coalition Memorandum of Understanding Between Illinois, Indiana, Michigan, Minnesota, and Wisconsin*. https://www.michigan.gov/-/media/Project/Websites/leo/REV_Midwest_MOU_master.pdf?

rev=6dd781b5a4eb4551b3b3a5b875d67fb9 (accessed 2024-04-15).
(175) Department of Environment, Great Lakes, and Energy. *Nearly $6 Million from EPA powers Pontiac schools' full transition to electric buses*. https://www.michigan.gov/egle/newsroom/mi-environment/2024/03/25/nearly-6-million-dollars-from-epa-powers-pontiac-schools-full-transition-to-electric-buses (accessed 2024-04-15).
(176) EIA. *Electricity data browser - Net generation for all fuels (utility-scale)*. https://www.eia.gov/electricity/data/browser/#/topic/0?agg=1,0,2&fuel=g&geo=vvvvvvvvvvvvo&sec=o3g&linechart=ELEC.GEN.ALL-NEW-99.A~ELEC.GEN.ALL-MAT-99.A~ELEC.GEN.ALL-ENC-99.A~ELEC.GEN.ALL-WNC-99.A~ELEC.GEN.ALL-SAT-99.A~ELEC.GEN.ALL-ESC-99.A~ELEC.GEN.ALL-MTN-99.A~ELEC.GEN.ALL-WSC-99.A~ELEC.GEN.ALL-PCN-99.A~ELEC.GEN.ALL-PCC-99.A&columnchart=ELEC.GEN.ALL-NEW-99.A~ELEC.GEN.ALL-MAT-99.A~ELEC.GEN.ALL-ENC-99.A~ELEC.GEN.ALL-WNC-99.A~ELEC.GEN.ALL-SAT-99.A~ELEC.GEN.ALL-ESC-99.A~ELEC.GEN.ALL-MTN-99.A~ELEC.GEN.ALL-WSC-99.A~ELEC.GEN.ALL-PCN-99.A~ELEC.GEN.ALL-PCC-99.A&map=ELEC.GEN.ALL-US-99.A&freq=A&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0 (accessed 2024-04-29).
(177) EIA. *U.S. Energy Information Administration - EIA - Independent Statistics and Analysis*. https://www.eia.gov/pressroom/releases/press537.php (accessed 2024-04-15).
(178) US Census Bureau; U.S. Department of Commerce Economics and Statistics Administration. *Census Regions and Divisions of the United States*. https://www2.census.gov/geo/pdfs/maps-data/maps/reference/us_regdiv.pdf (accessed 2024-04-15).
(179) Soria, S. C.; Weeks, D. *Logistical woes and high pump prices stall California H2 market development*. https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/012324-logistical-woes-and-high-pump-prices-stall-california-h2-market-development (accessed 2024-04-15).
(180) *Guide to Safety of Hydrogen and Hydrogen Systems (ANSI/AIAA G-095A-2017)*; American Institute of Aeronautics and Astronautics, Ed.; American Institute of Aeronautics and Astronautics, Inc.: 12700 Sunrise Vally Drive, Reston, VA 20191, 2017. https://doi.org/10.2514/4.105197.
(181) Hydrogen Tools. *Hydrogen Properties & Leak Detection Considerations | Hydrogen Tools*. https://h2tools.org/bestpractices/hydrogen-properties-leak-detection-considerations (accessed 2024-04-15).
(182) Barilo, N. F.; Hamilton, J. J.; Weiner, S. C. First Responder Training: Supporting Commercialization of Hydrogen and Fuel Cell Technologies. *Int. J. Hydrog. Energy* **2017**, *42* (11), 7536–7541. https://doi.org/10.1016/j.ijhydene.2016.06.226.
(183) Akhtar, S. S. Conversation with Holcim during the January 12th Seminar "MI Hydrogen Demand Stakeholder Results Workshop," 2024.
(184) Baier, G. Conversation with Dow during the January 12th Seminar "MI Hydrogen Demand Stakeholder Results Workshop," 2024.
(185) Shaddix, C. Oxyfuel Combustion: Basic Principles and Results from Small-Scale Investigations. **2016**.
(186) EESI. *Fact Sheet | Climate, Environmental, and Health Impacts of Fossil Fuels (2021) | White Papers | EESI*. https://www.eesi.org/papers/view/fact-sheet-climate-environmental-and-health-impacts-of-fossil-fuels-2021 (accessed 2024-04-15).
(187) *Michigan Leads on Hydrogen*. https://www.michigan.gov/whitmer/issues/michigan-infrastructure-office/michigan-leads-on-hydrogen (accessed 2024-03-30).

(188) *If You're a Minority and Poor, You're More Likely to Live Near a Toxic Waste Site*. Fortune. https://fortune.com/2016/02/04/environmental-race-poverty-flint/ (accessed 2024-04-15).
(189) Semuels, A. *The Role of Highways in American Poverty*. The Atlantic. https://www.theatlantic.com/business/archive/2016/03/role-of-highways-in-american-poverty/474282/ (accessed 2024-04-15).
(190) Ard, K.; Smiley, K. Examining the Relationship Between Racialized Poverty Segregation and Hazardous Industrial Facilities in the U.S. Over Time. *Am. Behav. Sci.* **2022**, *66* (7), 974–988. https://doi.org/10.1177/00027642211013417.
(191) *Justice40 Initiative*. Energy.gov. https://www.energy.gov/justice/justice40-initiative (accessed 2024-04-15).

7. Appendices

APPENDIX A. STAKEHOLDER ENGAGEMENT

Item 1: Stakeholder Data Request Questionnaire

An example questionnaire is provided below, detailing specific questions made to Hemlock Semiconductor LLC (HSC) about production metrics, current hydrogen use, process heat HSC facility, and company projections and ESG commitments. The questionnaire was paired with a project brief to introduce the project. Questions were tailored to the facility and industry of focus.

Hemlock Semiconductor LLC (HSC) Questionnaire

The data and information collected from this questionnaire will be used for research purposes related to (1) drafting a peer-reviewed journal article; (2) a report published by the University of Michigan Library; (3) a public presentation at the School for the Environment & Sustainability, and (4) future MI Hydrogen work. We appreciate HSC's participation, and the data provided will be handled with confidentiality. For more information regarding our data management practices, refer to the project brief.

Production Metrics

1. What is the current daily production of polysilicon? If unable to provide actual production, can the designed capacity of the facility be provided?

2. What are the operational hours of HSC's facility in Hemlock, MI? Is this uniform across operations?

Current Hydrogen Use

If hydrogen is not currently used in operations, please skip this section and proceed to the "Process Heat" section.

3. What is the daily input of hydrogen to:
   a) Production of polysilicon (Siemens process)?

4. Are there other processes/operations that use hydrogen as a feedstock or fuel that are not listed above?

5. Is hydrogen produced on-site or off-site? If on-site, is the hydrogen production in-house or from an external provider?

Process Heat

6. What are the main processes that require process heat and what is the fuel source? (Natural gas, electricity, biomass, coal, oil, etc.)

7. What equipment is used for generating process heat and at what temperature ranges do processes typically operate?

8. For the equipment listed above what is the daily fuel consumption (Btu)? If an individual breakdown is not available, please provide a facility total and a rough percentage of what is used for process heat.

Company Projections & ESG Commitments

9. Are there plans to alter or expand operations in Michigan? If yes, are there projections about how this will impact production and the consumption of inputs such as hydrogen and fuel?

10. What greenhouse gas (GHG) reduction targets or other environmental goals does HSC have? Does the strategy to meet these targets include transitioning to low-carbon hydrogen as either a future feedstock or fuel?

APPENDIX B. INDUSTRY ANALYSIS RESOURCES

Table B1 reports the emissions from the combustion of natural gas, blast furnace gas, and from hydrogen production via SMR as reported by facilities included in this analysis the the EPA GHGRP. Combustion and production emissions were used as inputs in current and future demand models.

Table B1. Reported 2022 GHGRP CO_2 Emissions for Michigan Facilities (metric tons)

Industrial Facility	Combustion of Natural Gas	Combustion of Blast Furnace Gas	SMR Hydrogen Production
BASF Corporation	34,722	N/A	N/A
Corteva Agriscience	61,233	N/A	N/A
Dow Midland	39,533	N/A	N/A
Occidental Chemical Corporation	47,979	N/A	N/A
Pfizer, inc. (formerly Pharmacia & UpJohn)	91,367	N/A	N/A
Carbon Green Bioenergy	76,165	N/A	N/A
Marysville Ethanol	84,005	N/A	N/A
POET Biorefining	100,576	N/A	N/A
Andersons Marathon Holdings	207,454	N/A	N/A
Detroit Refinery*	68,505	N/A	403,262
Hemlock Semiconductor*	66,359	N/A	27,281
Guardian Glass	118,241	N/A	N/A
Cleveland-Cliffs Steel Corp.	112,241	623,961	N/A
Gerdau Macsteel Monroe	61,163	N/A	N/A
Packaging Corp of America	146,444	N/A	N/A
Verso Escanaba	370,429	N/A	N/A
Verso Quinnesec	34,111	N/A	N/A
UP Paper LLC	55,632	N/A	N/A
Graphic Packaging International - Kalamazoo	245,584	N/A	N/A
Westrock California	56,977	N/A	N/A
Fibek	25,559	N/A	N/A

Ox Paperboard WP Mill	17,475	N/A	N/A
Neenah Paper Michigan Inc.	15,289	N/A	N/A
Holcim**	347	N/A	N/A
St. Mary's Charlevoix**	N/A	N/A	N/A

** Emissions reported by merchant hydrogen producer and allocated to recipient facility for analysis*

*** Emissions from cement plants were not used in demand models*

Table B2 lists the facilities analyzed, reported NAICS codes, and selected EIA IND codes and categories aligned with NAICS codes.

Table B2. Industry NAICS - EIA IND Code Alignment

Industrial Sector	Facility Name	Reported NAICS	EIA IND Code
Chemicals	BASF Corporation	325199, 325211,325991, 326199	IND 11/27
Chemicals	Corteva Agriscience	325320	IND 8/19
Chemicals	Dow Midland	325998	IND 9/20
Chemicals	Occidental Chemical Corporation	325180	IND 8/15
Chemicals	Pfizer, inc. (formerly Pharmacia & UpJohn)	325412	IND 9/20
Chemicals	Carbon Green Bioenergy	325193	See Section 2.5.1
Chemicals	Marysville Ethanol	325193	
Chemicals	POET Biorefining	325193	
Chemicals	Andersons Marathon Holdings	325193	
Petroleum Refining	Detroit Refinery*	324110	IND 10/25
Semiconductor	Hemlock Semiconductor*	327992	IND 12/32
Glass	Guardian Glass	327211	IND 12/19
Steel	Cleveland-Cliffs Steel Corp.	331110	IND 13/33
Steel	Gerdau Macsteel Monroe	331110	IND 13/33
Pulp and Paper	Packaging Corp of America	322121	IND 6/11
Pulp and Paper	Verso Escanaba	322121	IND 6/11
Pulp and Paper	Verso Quinnesec	322121	IND 6/11
Pulp and Paper	UP Paper LLC	322121	IND 6/11
Pulp and Paper	Graphic Packaging International	322130	IND 6/11
Pulp and Paper	Westrock California	322130	IND 6/11
Pulp and Paper	Fibek	322121	IND 6/11
Pulp and Paper	Ox Paperboard WP Mill	322130	IND 6/11
Pulp and Paper	Neenah Paper Michigan Inc.	322121	IND 6/11
Cement	Holcim	327310	IND 12/30
Cement	St. Mary’s Charlevoix	327310	IND 12/30

Table B3 demonstrates the growth rates calculated for EIA Industry categories, based on EIA IND codes, used in projecting future hydrogen demand in the target analysis years of 2030 and 2050, respectively.

Table B3. Industry Sector Growth Rates, 2030 and 2050

EIA IND Code	EIA IND Category	2030 Reference Growth Rate (%)	2050 Reference Growth Rate (%)
IND 8/15	Basic Inorganic Chemicals	5.56%	3.37%
IND 8/19	Agricultural Chemicals	17.27%	19.61%
IND 9/20	Other Chemical Products	-2.58%	32.44%
IND 11/27	Plastics and Rubber Products	5.61%	27.68%
IND 10/25	Petroleum Refineries	2.32%	-8.41%
IND 12/19	Flat Glass	-8.94%	-3.03%
IND 12/30	Cement Manufacturing	-0.42%	15.91%
IND 6/11	Paper & Pulp Mills	-4.52%	2.17%
IND 13/33	Iron and Steel Mills and Products	1.35%	-9.79%
IND 12/32	Other Non-metallic Mineral Products	4.48%	27.27%

APPENDIX C. TRANSPORTATION ANALYSIS RESOURCES

Table C1 showcases how the FHWA and EPA classification systems are categorized, with the FHWA by number of axles and EPA by GVWR. The “Adjusted EPA Classification” column indicates how vehicle classes were aligned for this study and the “Vehicle” column provides which vehicle from the current study fits in each class.

Table C1. FHWA and EPA Vehicle Classifications Alignment [81,82]

Federal Highway Administration (FHWA) Classification	Environmental Protection Agency (EPA) Classification	Adjusted EPA Classification (Used for This Study)	Vehicle
Class 4: Buses	Heavy Duty Vehicle 6: GVWR 19,501 - 26,000 lbs	Class 6 (Medium-Duty)	School Buses
Class 4: Buses	Heavy Duty Vehicle 7: GVWR 26,001 - 33,000 lbs	Class 7 (Heavy-Duty)	Transit Buses
Class 5: Single Unit - 2-Axle Trucks 2 axles, 6 tires	Heavy Duty Vehicle 4: GVWR 14,001 - 16,000 lbs	Class 4 (Medium-Duty)	Light Heavy Duty (LHD) Vocational Vehicles
Class 6: Single Unit 3-Axle Trucks	Heavy Duty Vehicle 6: GVWR 19,501 - 26,000 lbs	Class 6 (Medium-Duty)	Pickup and Delivery Trucks
Class 7: Single Unit 4 or More Axle Trucks	Heavy Duty Vehicle 8a: GVWR 33,001 - 60,000 lbs	Class 8a (Heavy-Duty)	Refuse Trucks
Class 9: Single Trailer 5-Axle Trucks, Single Trailer	Heavy Duty Vehicle 8b: GVWR > 60,001 lbs	Class 8b (Heavy-Duty)	Day Cab Trucks, trailer attached (Short-Haul)
Class 10: Single Trailer 6 or More-Axle Trucks, Single Trailer	Heavy Duty Vehicle 8b: GVWR > 60,001 lbs	Class 8b (Heavy-Duty)	Sleeper Cab Trucks, trailer attached (Long-Haul)

Table C2 lists the fuel reduction values (FRVs) that were used in this study and how they were delineated by vehicle class and engine type. For the respective vehicle class and engine type, the specific FRV was applied to **Eq. 12** to determine the fuel economies for each vehicle.

Table C2. Fuel Reduction Values for MHDVs (liter equivalent per km kg)[112]

Vehicle Class/Vehicle	Engine Type	FRV (per km kg)
Class 4-6*	ICE (Diesel Fuel)	0.000009
Class 7-8*	ICE (Diesel Fuel)	0.000007
Class 4-8*	EV/FC (Electricity/Hydrogen)	0.000044
Transit Bus	ICE (Diesel Fuel)	0.00001
Transit Bus	EV/FC (Electricity/Hydrogen)	0.0000032

*School buses were included here due to the vehicle weight breakdown from the cited paper

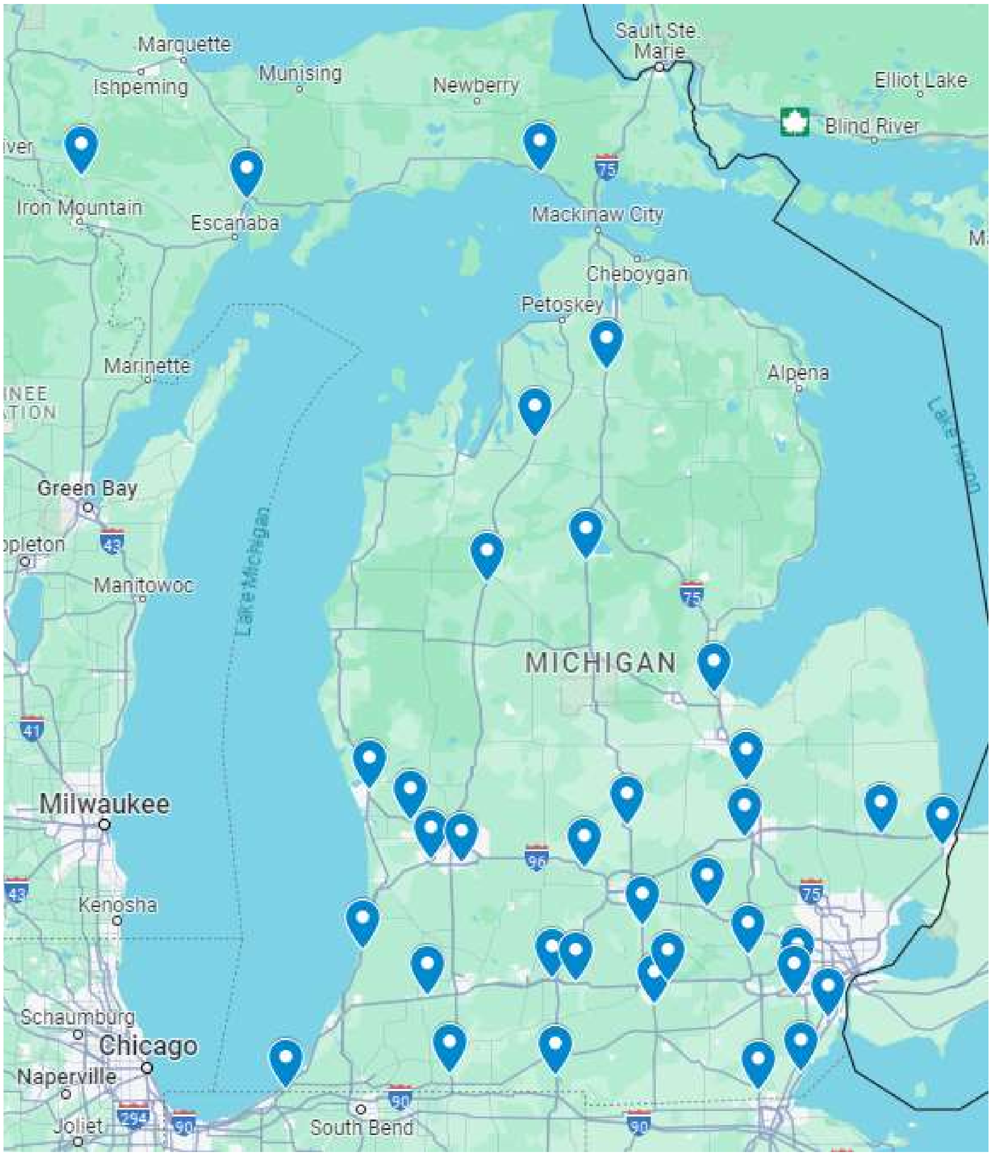

Figure C1. Map of the Weigh-in-Motion (WIM) Stations Where Data was Pulled From to determine the Vehicle Payloads for Class 6 PnD and Class 4 LHD Vocational Vehicles

APPENDIX D - INDUSTRY GHG & NO_x EMISSION FACTORS

Table D1 and **D3** list the different industry GHG emission factors extracted from GREET for analysis years of 2030 and 2050, respectively. **Table D2** and **D4** display the industry NO_x emissions factors also pulled from GREET for analysis years of 2030 and 2050, respectively. Both sets of emission factors are broken down by the type of fuel, the production pathway, and the combustion type. Emissions from transportating hydrogen were omitted from the industry emissions analysis as it was assumed that hydrogen would be produced on-site for the purpose of the analysis.

Table D1. Industry GHG Emission Factors from GREET (2030)

Fuel	Production Pathway	Production Emissions (grams / MMBtu)	Combustion Type	Combustion Emissions (grams / MMBtu)
Natural Gas	*Natural Gas as Stationary Fuels*	12,644	*NG boiler/ Industrial Boiler (> 100 MMBtu/hr)*	53,808
Hydrogen	*NG SMR*	74,769	*Boiler*	0
	NG SMR with CCS	26,420		
	Low Temperature Electrolysis using PEM via renewables	0		
	Low Temperature Electrolysis using PEM via RFC Grid Mix	156,925		
	High Temperature Electrolysis with SOEC using Nuclear LWR	1,786		
Coke	*Coke from Coal Production for Steel Manfact.*	13,617	*Industrial Boiler - Petroleum Coke*	101,045
Coal	*Coal for Power Plants*	5,840.60	*Industrial Boiler - Coal*	94,471
Oxygen	*Production of oxygen (grams per ton of oxygen)*	127,911	N/A	N/A
Blast Furnace Gas	N/A	N/A	*Blast Furnace Gas Combustion*	294,200

Table D2. Industry NO_x Emission Factors from GREET (2030)

Fuel	Production Pathway	Production Emissions (grams / MMBtu)	Combustion Type	Combustion Emissions (grams / MMBtu)
Natural Gas	*Natural Gas as Stationary Fuels*	38.8362	*NG boiler/ Industrial Boiler (> 100 MMBtu/hr)*	34.50
Hydrogen	*NG SMR*	40.0958	*Boiler*	60
	NG SMR with CCS	67.0528		
	Low Temperature Electrolysis using PEM via renewables	0		
	Low Temperature Electrolysis using PEM via RFC Grid Mix	106.1		
	High Temperature Electrolysis with SOEC using Nuclear LWR	3.8849		
Coke	*Coke from Coal Production for Steel Manfact.*	35.3424	*Industrial Boiler - Petroleum Coke*	121.63
Coal	*Coal for Power Plants*	5.1984	*Industrial Boiler - Coal*	121.63
Oxygen	*Production of oxygen (grams per ton of oxygen)*	96.7498	N/A	N/A
Blast Furnace Gas	N/A	N/A	*Blast Furnace Gas Combustion*	127.741

Table D3. Industry GHG Emission Factors from GREET (2050)

Fuel	Production Pathway	Production Emissions (grams / MMBtu)	Combustion Type	Combustion Emissions (grams / MMBtu)
Natural Gas	*Natural Gas as Stationary Fuels*	12,621	*NG boiler/ Industrial Boiler (> 100 MMBtu/hr)*	53,808
Hydrogen	*NG SMR*	53,808	*Boiler*	0
	NG SMR with CCS	26,192		
	Low Temperature Electrolysis using PEM via renewables	0		
	Low Temperature Electrolysis using PEM via RFC Grid Mix	150,302		
	High Temperature Electrolysis with SOEC using Nuclear LWR	1,600		
Coke	*Coke from Coal Production for Steel Manfact.*	13,499	*Industrial Boiler - Petroleum Coke*	101,045
Coal	*Coal for Power Plants*	5,807.30	*Industrial Boiler - Coal*	94,471
Oxygen	*Production of oxygen (grams per ton of oxygen)*	106,576	N/A	N/A
Blast Furnace Gas	N/A	N/A	*Blast Furnace Gas Combustion*	294,200

Table D4. Industry NO_x Emission Factors from GREET (2050)

Fuel	Production Pathway	Production Emissions (grams / MMBtu)	Combustion Type	Combustion Emissions (grams / MMBtu)
Natural Gas	*Natural Gas as Stationary Fuels*	38.8171	*NG boiler/ Industrial Boiler (> 100 MMBtu/hr)*	36.40
Hydrogen	*NG SMR*	40.0629	*Boiler*	60
	NG SMR with CCS	66.8929		
	Low Temperature Electrolysis using PEM via renewables	0		
	Low Temperature Electrolysis using PEM via RFC Grid Mix	101.6		
	High Temperature Electrolysis with SOEC using Nuclear LWR	3.7315		
Coke	*Coke from Coal Production for Steel Manfact.*	35.2487	*Industrial Boiler - Petroleum Coke*	121.63
Coal	*Coal for Power Plants*	5.1761	*Industrial Boiler - Coal*	121.63
Oxygen	*Production of oxygen (grams per ton of oxygen)*	79.0113	N/A	N/A
Blast Furnace Gas	N/A	N/A	*Blast Furnace Gas Combustion*	127.741

APPENDIX E - TRANSPORTATION GHG & NO_x EMISSION FACTORS

Table E1 and **E3** list the different transportation GHG emission factors used for the modeled vehicle classes for 2030 and 2050, respectively. **Table E2** and **E4** display the transportation NO_x emissions factors for the same vehicle classes for 2030 and 2050, respectively. The emission factors are broken down by fuel type, production pathway, and vehicle class. For emissions from diesel, most vehicle classes have similar emission factors, especially vehicles that have similar engines and weights. These tables also include different hydrogen production pathways and their relative GHG and NO_x emissions intensities.

Table E1. Transportation GHG Emission Factors from GREET (2030)

Fuel	Production Pathway	Production, Transportation, and Compression Emissions (grams / MMBtu)	Vehicle Class	Operation Emissions With a Full Payload (grams / MMBtu)	Operation Emissions With an Empty Payload (grams / MMBtu)
Diesel	*Conventional Diesel*	15,854	Class 8b: Sleeper Cab	79,081	79,081
			Class 8b: Day Cab	79,081	79,081
			Class 8a: Refuse Trucks	79,081	79,081
			Class 7: Transit Bus	79,081	79,081
			Class 6: PnD	79,186	79,186
			Class 6: School Bus	79,186	79,186
			Class 4: LHD Vocational	79,186	79,291
Hydrogen	*NG SMR*	95,213	All Vehicles	0	0
	NG SMR with CCS	41,426			
	Low Temperature Electrolysis using PEM via renewables	0			
	Low Temperature Electrolysis using PEM via RFC Grid Mix	182,641			

	High Temperature Electrolysis with SOEC using Nuclear LWR	14,678			

Table E2. Transportation NO_x Emission Factors from GREET (2030)

Fuel	Production Pathway	Production, Transportation, and Compression Emissions (grams / MMBtu)	Vehicle Class	Operation Emissions With a Full Payload (grams / MMBtu)	Operation Emissions With an Empty Payload (grams / MMBtu)
Diesel	*Conventional Diesel*	17	Class 8b: Sleeper Cab	106	142
			Class 8b: Day Cab	72	91
			Class 8a: Refuse Trucks	108	129
			Class 7: Transit Bus	129	83
			Class 6: PnD	73	80
			Class 6: School Bus	77	137
			Class 4: LHD Vocational	45	49
Hydrogen	*NG SMR*	53	All Vehicles	0	0
	NG SMR with CCS	81			
	Low Temperature Electrolysis using PEM via renewables	0			
	Low Temperature Electrolysis using PEM via RFC Grid Mix	118			
	High Temperature Electrolysis with SOEC using Nuclear LWR	14			

Table E3. Transportation GHG Emission Factors from GREET (2050)

Fuel	Production Pathway	Production, Transportation, and Compression Emissions (grams / MMBtu)	Vehicle Class	Operation Emissions With a Full Payload (grams / MMBtu)	Operation Emissions With an Empty Payload (grams / MMBtu)
Diesel	*Conventional Diesel*	15,778	Class 8b: Sleeper Cab	79,081	79,081
			Class 8b: Day Cab	79,081	79,081
			Class 8a: Refuse Trucks	79,081	79,081
			Class 7: Transit Bus	79,186	79,186
			Class 6: PnD	79,186	79,186
			Class 6: School Bus	79,186	79,186
			Class 4: LHD Vocational	79,186	79,291
Hydrogen	*NG SMR*	94,355	All Vehicles	0	0
	NG SMR with CCS	40,392			
	Low Temperature Electrolysis using PEM via renewables	0			
	Low Temperature Electrolysis using PEM via RFC Grid Mix	175,585			
	High Temperature Electrolysis with SOEC using Nuclear LWR	13,668			

Table E4. Transportation NO_x Emission Factors from GREET (2050)

Fuel	Production Pathway	Production, Transportation, and Compression Emissions (grams / MMBtu)	Vehicle Class	Operation Emissions With a Full Payload (grams / MMBtu)	Operation Emissions With an Empty Payload (grams / MMBtu)
Diesel	*Conventional Diesel*	18	Class 8b: Sleeper Cab	128	173
			Class 8b: Day Cab	77	98
			Class 8a: Refuse Trucks	121	144
			Class 7: Transit Bus	147	155
			Class 6: PnD	78	90
			Class 6: School Bus	84	87
			Class 4: LHD Vocational	48	52
Hydrogen	*NG SMR*	53	All Vehicles	0	0
	NG SMR with CCS	80			
	Low Temperature Electrolysis using PEM via renewables	0			
	Low Temperature Electrolysis using PEM via RFC Grid Mix	114			
	High Temperature Electrolysis with SOEC using Nuclear LWR	14			

APPENDIX F - TOTAL NEAR-TERM (2030) GHG & NO_x EMISSION REDUCTIONS

Table F1. and **Table F2.** demonstrate the GHG and NO_x emissions of the 2030 “Near-Term Hydrogen Opportunities” scenario, including emissions from the industry sector, the transportation sector, total sum of emissions, and the total net emission reduction compared to the “Incumbent Technology” scenario.

Table F1. GHG Emissions Summary for 2030 “Near-Term Opportunities” Scenario

Technologies	Industry (million metric tons/year)	Transportation (million metric tons/year)	Sum (million metric tons/year)	Net Reduction Compared to the Incumbent (million metric tons/year)
Incumbent	13.77	5.62	19.39	/
PEM Electrolysis with RFC Grid Mix	13.12	4.57	17.69	1.70
Natural Gas SMR with CCS	12.07	4.52	16.58	2.81
Natural Gas SMR	12.40	4.54	16.94	2.45
SOEC Electrolysis with Nuclear	11.87	4.51	16.37	3.02
PEM Electrolysis with Renewables	11.85	4.50	16.35	3.04

Table F2. NO_x Emissions Summary for 2030 “Near-Term Opportunities” Scenario

Technologies	Industry (thousand metric tons/year)	Transportation (thousand metric tons/year)	Sum (thousand metric tons/year)	Net Reduction Compared to the Incumbent (thousand metric tons/year)
Incumbent	9.15	6.72	15.87	/
PEM Electrolysis with RFC Grid Mix	9.11	5.42	14.54	1.33
Natural Gas SMR with CCS	8.80	5.41	14.21	1.66
Natural Gas SMR	8.55	5.40	13.95	1.92
SOEC Electrolysis with Nuclear	8.29	5.38	13.67	2.20
PEM Electrolysis with Renewables	8.26	5.37	13.63	2.23

APPENDIX G - TOTAL LONG-TERM (2050) GHG & NO_x EMISSION REDUCTIONS

Table G1. and **Table G2.** demonstrate the GHG and NO_x emissions of the 2050 "Low Hydrogen Use" scenario, including emissions from the industry sector, the transportation sector, total sum of emissions, and the total net emission reduction compared to the "Incumbent Technology" scenario.

Table G1. GHG Emissions Summary for 2050 "Low Hydrogen Use" Scenario

Technologies	Industry (million metric tons/year)	Transportation (million metric tons/year)	Sum (million metric tons/year)	Net Reduction Compared to the Incumbent (million metric tons/year)
Incumbent	13.80	6.33	20.13	/
PEM Electrolysis with RFC Grid Mix	13.23	1.56	14.79	5.34
Natural Gas SMR with CCS	11.67	1.33	13.00	7.12
Natural Gas SMR	12.28	1.42	13.70	6.42
SOEC Electrolysis with Nuclear	11.36	1.29	12.65	7.48
PEM Electrolysis with Renewables	11.34	1.27	12.61	7.52

Table G2. NO_x Emissions Summary for 2050 "Low Hydrogen Use" Scenario

Technologies	Industry (thousand metric tons/year)	Transportation (thousand metric tons/year)	Sum (thousand metric tons/year)	Net Reduction Compared to the Incumbent (thousand metric tons/year)
Incumbent	11.06	8.46	19.52	/
PEM Electrolysis with RFC Grid Mix	11.11	1.88	12.99	6.53
Natural Gas SMR with CCS	10.68	1.82	12.50	7.02
Natural Gas SMR	10.34	1.78	12.12	7.41
SOEC Electrolysis with Nuclear	9.88	1.71	11.60	7.93
PEM Electrolysis with Renewables	9.83	1.69	11.53	8.00

Table G3. and **Table G4.** demonstrate the GHG and NO_x emissions of the 2050 "High Hydrogen Use" scenario, including emissions from the industry sector, the transportation sector, total sum of emissions, and the total net emission reduction compared to the "Incumbent Technology" scenario.

Table G3. GHG Emissions Summary for 2050 "High Hydrogen Use" Scenario

Technologies	Industry (million metric tons/year)	Transportation (million metric tons/year)	Sum (million metric tons/year)	Net Reduction Compared to the Incumbent (million metric tons/year)
Incumbent	13.80	6.33	20.13	/
PEM Electrolysis with RFC Grid Mix	13.51	2.02	15.53	4.60
Natural Gas SMR with CCS	11.28	0.90	12.18	7.94
Natural Gas SMR	12.15	1.35	13.50	6.62
SOEC Electrolysis with Nuclear	10.84	0.68	11.52	8.60
PEM Electrolysis with Renewables	10.81	0.57	11.38	8.75

.

Table G4. NO_x Emissions Summary for 2050 "High Hydrogen Use" Scenario

Technologies	Industry (thousand metric tons/year)	Transportation (thousand metric tons/year)	Sum (thousand metric tons/year)	Net Reduction Compared to the Incumbent (thousand metric tons/year)
Incumbent	11.06	8.46	19.52	/
PEM Electrolysis with RFC Grid Mix	11.28	1.70	12.98	6.55
Natural Gas SMR with CCS	10.65	1.43	12.08	7.45
Natural Gas SMR	10.17	1.20	11.37	8.16
SOEC Electrolysis with Nuclear	9.52	0.87	10.39	9.13
PEM Electrolysis with Renewables	9.45	0.76	10.21	9.31

Table G5. and **Table G6.** demonstrate the GHG and NO_x emissions of the 2050 “Complete Hydrogen Substitution” scenario, including emissions from the industry sector, the transportation sector, total sum of emissions, and the total net emission reduction compared to the “Incumbent Technology” scenario.

Table G5. GHG Emissions Summary for 2050 “Complete Substitution” Scenario

Technologies	Industry (million metric tons/year)	Transportation (million metric tons/year)	Sum (million metric tons/year)	Net Reduction Compared to the Incumbent (million metric tons/year)
Incumbent	13.80	6.33	20.13	/
PEM Electrolysis with RFC Grid Mix	14.84	7.26	22.10	-1.97
Natural Gas SMR with CCS	2.60	1.67	4.27	15.86
Natural Gas SMR	7.38	3.90	11.29	8.84
SOEC Electrolysis with Nuclear	0.17	0.57	0.74	19.39
PEM Electrolysis with Renewables	0.01	0.00	0.01	20.11

Table G6. NO_x Emissions Summary for 2050 “Complete Substitution” Scenario

Technologies	Industry (thousand metric tons/year)	Transportation (thousand metric tons/year)	Sum (thousand metric tons/year)	Net Reduction Compared to the Incumbent (thousand metric tons/year)
Incumbent	11.06	8.46	19.52	/
PEM Electrolysis with RFC Grid Mix	15.65	4.70	20.35	-0.83
Natural Gas SMR with CCS	12.23	3.32	15.55	3.97
Natural Gas SMR	9.58	2.17	11.76	7.77
SOEC Electrolysis with Nuclear	6.00	0.56	6.56	12.96
PEM Electrolysis with Renewables	5.63	0.00	5.63	13.89