

ABSTRACT

Title of Dissertation: AN INTEGRATED ASSESSMENT OF THE FUTURE
“HYDROGEN ECONOMY”: DECARBONIZATION
POTENTIAL, SOCIETAL IMPLICATIONS, AND POLICY
APPROACHES

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Recently clean hydrogen has captured the attention of policy communities, as evidenced by the publication of hydrogen “roadmaps” or “strategies” by dozens of nations. This is partly because it can be produced from numerous primary energy resources and utilized in a plethora of ways to enable decarbonization. However, there remain open questions as to how the energy carrier should contribute toward carbon dioxide (CO₂) mitigation. Additionally, less is known about its impacts on other societal objectives and whether government plans for hydrogen are driven by realistic expectations regarding its ability to facilitate emissions reductions.

This dissertation involves three studies which simulate energy transitions within the Global Change Analysis Model (GCAM), each aiming to help illuminate hydrogen’s potential impact on society. First, clean hydrogen supply and demand within the context of

decarbonization is investigated. In this research, it is found that hydrogen could be a decentralized energy carrier, as a large portion of its production is enabled by onsite production (i.e., at the location of the end user). In terms of demand, although it will represent a smaller portion of global final energy compared to alternatives, hydrogen enables CO₂ mitigation in difficult-to-electrify end uses (e.g., satiating demand for industrial high-temperature heat).

The second topic of this dissertation examines hydrogen's potential implications for the water-energy-food nexus. It is found that clean hydrogen production is unlikely to be a large source of water demand, however, its availability in the forthcoming energy transition could cause larger indirect changes in water demand for many regions of the world. Additionally, clean hydrogen availability is found to enable lower staple crop prices, as it provides a method of reducing CO₂ associated with fertilizer manufacturing.

Lastly, this dissertation analyzed the Japanese and Korean national hydrogen plans. Aligning with the results from the first research topic of this work, hydrogen's use within their economies is lower than alternative decarbonization strategies (e.g., direct electrification). As a result, the national plans of both nations are found to be overestimating the scale of hydrogen supply. Further, both countries are generally setting numerical goals for hydrogen deployment in areas of the economy that are less economically efficient compared to alternative sectors where it could both facilitate decarbonization as well as bolster their economies.

**AN INTEGRATED ASSESSMENT OF THE FUTURE “HYDROGEN ECONOMY”:
DECARBONIZATION POTENTIAL, SOCIETAL IMPLICATIONS,
AND POLICY APPROACHES**

by

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Chapter 1: Introduction

1.A. Current understanding of the “hydrogen economy”

The use of hydrogen for energy was originally popularized in the aftermath of the 1970s oil crisis.¹ While it is debated who first coined the phrase^{A, 2, 3}, the notion of the ‘hydrogen economy’ consistently presented the energy carrier as a ‘Swiss army knife’ tool for ensuring energy security, particularly for western nations hoping to reduce their dependence on foreign oil (e.g., the United States).^{4, 5} Hydrogen (H₂) was celebrated for its versatility and flexibility, as it could satiate energy demand in most end-use sectors (within buildings, industry, and transport) as well as be produced from a number of energy sources (e.g., fossil fuels, biomass, and electricity). Given the concerns of oil availability and affordability, hydrogen’s use in the transportation sector was considered particularly valuable at this point. Proponents were quick to note that hydrogen could be burned in an internal combustion engine, used with a fuel cell, or leveraged to create synthetic liquid hydrocarbons capable of powering conventional vehicles. Over time, the urgency to reduce dependence on foreign oil waned for many developed nations but fuel cell applications regained attention, particularly as a means of reducing traditional air pollutants from road-based vehicles.⁶

The promise of a ‘hydrogen economy’ never materialized in either case, but hydrogen is once again receiving renewed interest from policymakers and researchers as it could facilitate climate change mitigation. However, hydrogen can only contribute to decarbonization if it is produced from low- to zero-carbon methods. And while it could be leveraged to reduce greenhouse gas (GHG) emissions in a plethora of end uses, it should likely be confined to areas

^A Silverstein (1980) noted that the earliest use he was aware of for the ‘hydrogen economy’ was made by Derek P. Gregory, but that the term had also been attributed to Jules Verne. Alternatively, Oliveira et al. (2021) suggested that John Bockris invented the phrase.

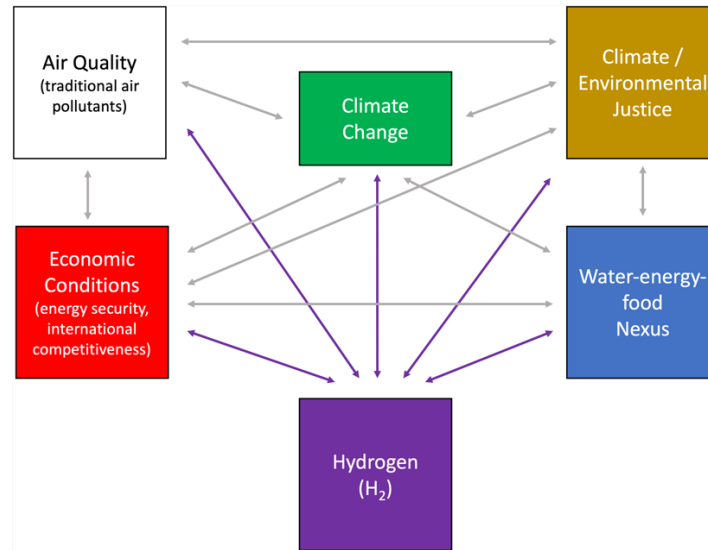


Figure 1.1. Hydrogen and related policy domain interactions.

that are difficult or impossible to electrify, given the large energy requirements needed for its production. Additionally, policymakers will need to take a more holistic view for hydrogen than has occurred previously, as there are serious questions regarding its potential to interact with other societal interests. As shown in Figure 1.1, energy policy will need to not only consider the climate, air quality, and the economic implications of hydrogen deployment (e.g., energy security) – but also consider how it could impact food and water systems as well as environmental/climate justice. In the subsections which follow, these domains as well as their interactions, are considered to help detail the current understanding of the “hydrogen economy” in order to motivate the research for this dissertation. Section 1.A.1 and 1.A.2 focus on the current understanding of hydrogen’s ability to contribute to climate change mitigation, with a discussion on relevant supply and demand technologies. Section 1.A.3 details the current understanding of hydrogen utilization’s impact on air quality as well as food and water systems, Section 1.A.4 describes the potential for hydrogen to contribute to national economies, and section 1.A.5 makes clear that hydrogen use should not replicate the injustices of past energy

systems and that policymakers should be particularly aware of potential climate/environmental justice and safety concerns for the energy carrier.

1.A.1. Supplying clean hydrogen for the energy transition

While hydrogen can be produced from a wide range of energy sources, in order to contribute to GHG emissions mitigation it must be produced using clean methods. For instance, zero-carbon hydrogen can be made via renewable-based water electrolysis ('green' hydrogen⁷) or biomass gasification.⁸ The latter of these two methods could even be coupled with carbon capture and sequestration (CCS) to create a negative-emissions source of energy.⁹ Low-carbon hydrogen could be made from conventional methods of producing hydrogen with fossil fuels if combined with CCS. 'Blue' hydrogen, or hydrogen from natural gas with CCS¹⁰ (e.g., via natural gas steam methane reforming [SMR]), has therefore also been commonly discussed as a potentially beneficial production pathway.

However, recent literature has suggested that fossil fuel with CCS pathways may not be able to contribute to decarbonization in as meaningful of a way as previously thought. This is because fossil fuel technologies with CCS are not able to capture 100% of their direct carbon emissions and their feedstock utilization also entails upstream GHG emissions (e.g., methane leakage in natural gas transmission and distribution networks). Further, regardless of the means of production, hydrogen itself has an indirect greenhouse gas effect – with recent estimates suggesting a 100-year global warming potential (GWP-100) of 12.8 ± 5.2 .¹¹ This climate impact is mainly caused by: (1) the fact that hydrogen reduces methane's atmospheric OH sink and thus extends the atmospheric lifetime of methane (CH₄); (2) hydrogen is a precursor to the

tropospheric short-lived climate pollutant ozone (O₃); and (3) it leads to stratospheric water vapor which has an associated warming impact as well.¹² Therefore, fugitive hydrogen emissions reduce the climate benefit of the energy carrier. Taken together, this limits the potential for production methods which have a direct climate impact – i.e., those which emit greenhouse gases. Recent analysis by Bertagni et al. (2022) found that green hydrogen could help reduce atmospheric methane with up to ~9% hydrogen leakage rates across the supply chain, but blue hydrogen could only do so if hydrogen leakage rates were 4.5% or less and if upstream methane leakage was at most 0.5%.¹³ An additional analysis by Hauglustaine et al. (2022) found similar results, and noted that when using a GWP-100 “...a portfolio composed of >60% of blue hydrogen has basically no climate benefit if the [H₂] leakage rate is >7%.”¹⁴

This suggests that zero-carbon hydrogen production (i.e., renewable electrolysis) should likely receive more political support than its low-carbon hydrogen counterparts (i.e., fossil fuels with CCS). However, it remains unclear from the literature what specific configuration for electrolysis-based hydrogen is the most sensible (i.e., grid, nuclear, or renewable electrolysis, as well as central vs. onsite production). For example, green hydrogen could be produced centrally with the electrolyzer co-located with solar panels or wind turbines. In turn this hydrogen would then need to be delivered to end users. Alternatively, electrolyzers could be co-located with end-use technologies (e.g., a cement plant). In this design hydrogen would be produced at a consumer’s facility and renewable electrons would be delivered over the electricity grid. It remains uncertain whether supply would benefit from the economies of scale that come with centralized production or from distributed supply which would also avoid the potential for hydrogen leakage.

A wide range of hydrogen leakage rates across the hydrogen supply chain have been published in the literature – with estimates between 0.3 to 20% from producer to consumer.^{15, 16,}

¹⁷ This situation is also complicated by the fact that there are no hydrogen leakage detection systems commercially available for identifying leakage on a parts per billion (ppb) basis.¹⁸

Considerable losses occur during delivery, with estimates for liquid hydrogen trucks ranging from 2 – 10% leakage.^{19, 20} Pipelines are thought to have lower leakage intensity (0.1 – 5%^{21, 22}), but they are more capital intensive and would likely take years to receive proper permitting and to construct. The literature, however, also remains unclear on whether a centralized hydrogen supply would require pipeline infrastructures.

On the other hand, less than half a percent of produced hydrogen is lost from electrolysis and SMR production.²³ In fact, one of the benefits of hydrogen is that it can enable decentralization in the energy system as it has the potential to be distributed in nature. Distributed green generation would not only avoid the high leakage rates of current hydrogen transmission and distribution systems but also the upstream feedstock climate impacts incurred from fossil-based production. This is because onsite hydrogen production can leverage existing infrastructures to enhance its contribution to decarbonization. For example, electricity infrastructure currently exists, and deep decarbonization already requires that such grids become more resilient and expansive. Hydrogen diffusion could therefore benefit from improvements in electrical infrastructures, and onsite production may be preferable at least in the near term while leakage issues are still being addressed for delivery networks. This research therefore aims to help evaluate the potential for central versus distributed clean hydrogen production, as well as the viability and extent of the various means of delivering hydrogen (e.g., liquid hydrogen truck

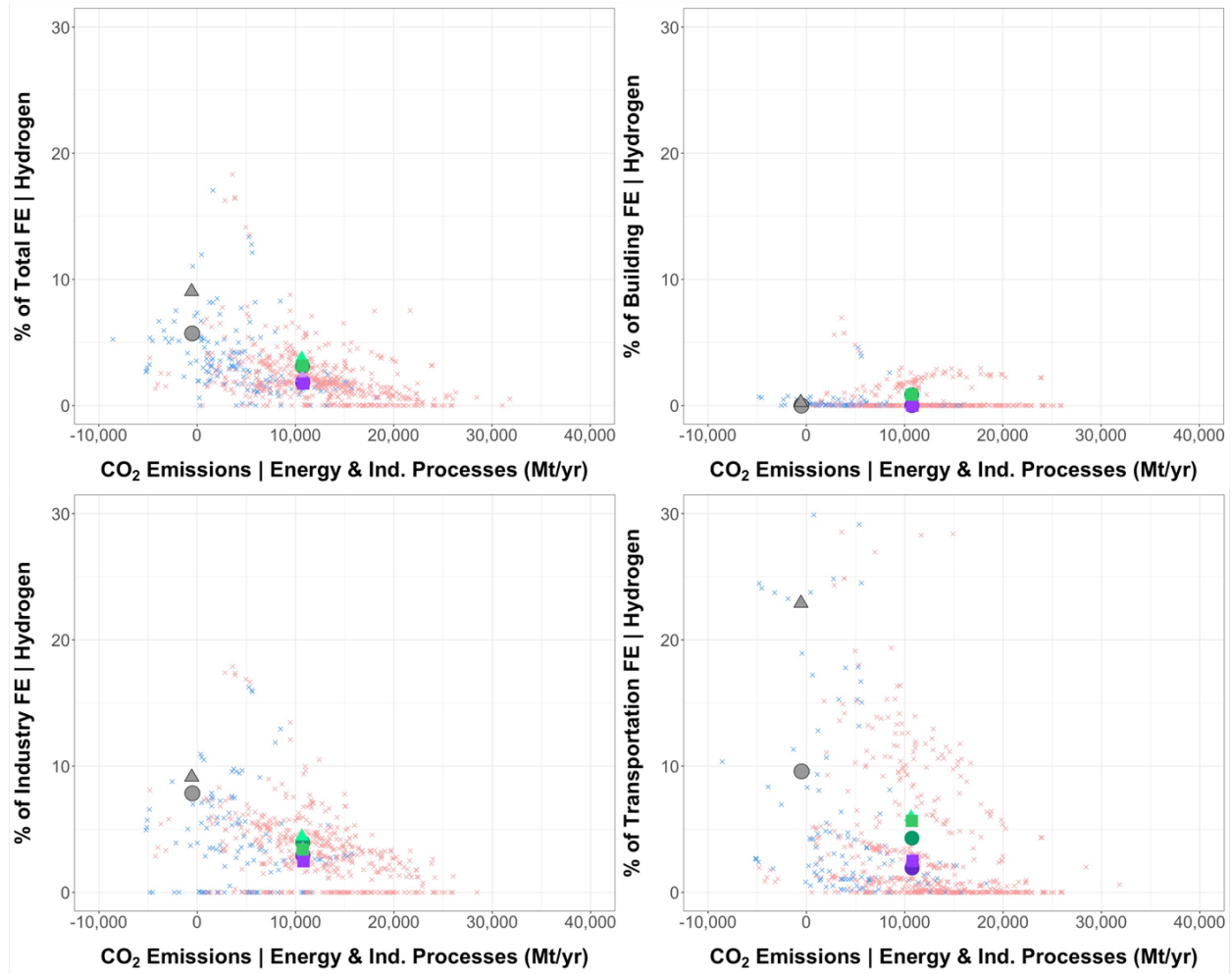
vs. gaseous pipelines). Still, policymakers should develop regulations on allowed leakage rates for hydrogen supply chains, irrespective of the production method or location of the electrolyzer relative to the consumer, to enable a more impactful contribution to climate change mitigation.

1.A.2. Prioritizing hydrogen deployment in relevant end-use applications

Clean hydrogen could be utilized for a diverse set of purposes and by a variety of methods. Barreto et al. (2003) found that hydrogen could potentially provide roughly half of all global final energy by the end of the century.²⁴ However, more recent studies have made clear the priority for hydrogen deployment should be in areas of the economy that are difficult, if not impossible, to directly electrify. For instance, the combustion of hydrogen, or its use with a fuel cell for combined heat and power, could provide a low-carbon method of heating water and building space in the commercial and residential sectors.^{25, 26} But direct electrification appears to be the more sensible solution for low-temperature building heating. Many areas of the world will likely have their building heat needs fulfilled with lower-cost and/or more efficient alternatives (e.g., electric heat pumps²⁷). Moreover, supplying blended gas and low-carbon hydrogen to buildings for heat would reduce emissions intensity by 7% at most, as some existing appliances may only be able to tolerate up to 20% hydrogen by volume.²⁸ This would likely not reduce emissions in a sufficient manner to meaningfully contribute to decarbonization in the long term, and analysis which competes this method of delivery versus others as well as hydrogen-only consuming technologies would further clarify this position. As seen in Figure 1.2, the mitigation scenarios assessed by the Intergovernmental Panel on Climate Change's (IPCC) AR6 report²⁹ corroborate the limited possibility for hydrogen in buildings – as hydrogen generally has been found to provide less than 5% of total final energy for the sector.

The scenarios do, however, see a larger contribution for the energy carrier within the transportation and industrial sectors. Similarly, Oshiro and Fujimori (2022) found that by midcentury hydrogen and hydrogen-derived energy carriers could also provide significant value to decarbonizing these areas.³⁰ Edmonds et al. (2004) found hydrogen could satisfy a significant share of global transportation final energy under emissions mitigation, but only if advanced technological assumptions were realized (e.g., low-cost production and higher efficiency fuel cells).³¹ And although Anandarajah et al. (2013) found that hydrogen could contribute meaningfully to the decarbonization of road-based transportation³², it seems unlikely that hydrogen will play a large role in passenger vehicles given recent advancements in battery electric vehicles (BEVs). While much research has evaluated the competitiveness of road-based transportation, often in terms of passenger vehicles, the competitiveness of hydrogen for fulfilling energy demand for long-haul and heavy-duty modes of transport as well as industrial applications would benefit from additional examination.

Although it seems unlikely that hydrogen will penetrate the global passenger vehicle market to a large extent, it may facilitate mitigation for heavy-duty trucking.³³ This would also necessitate a reduction in refueling station leakage rates though, as liquid refueling stations are thought to have an 8.5% loss rate at present.³⁴ The most probable transportation application may be hydrogen-based fuels for marine vessels.³⁵ There remain issues which must be addressed though, as it is unclear what form of hydrogen-based energy this will entail. The low volumetric energy density of hydrogen and the energy requirements of international shipping will require hydrogen to either be stored as liquid hydrogen, ammonia (NH₃), or liquid organic hydrogen



IPCC AR6 Database Scenarios:

- × 0°C ≤ 2100 temp. ≤ 1.5°C
- × 1.5°C < 2100 temp. ≤ 2.0°C

GCAM Study Scenarios:

- No Dedicated H2 T&D
- Truck H2 T&D
- ▲ Pipeline H2 T&D
- No Dedicated H2 T&D - High Demand
- Truck H2 T&D - High Demand
- ▲ Pipeline H2 T&D - High Demand

Below 2°C

- No Dedicated H2 T&D
- ▲ Pipeline H2 T&D - High Demand

1.5°C

Figure 1.2. Percentage of global final energy by type in 2050 – core scenarios for Chapter 2 of this dissertation vs. IPCC AR6 scenarios. “Reference Demand” scenarios from this section of the dissertation are portrayed in shades of purple, while “High Demand” scenarios are portrayed in shades of green (however, the 1.5°C sensitivities are all portrayed in grey). IPCC AR6 database scenarios are defined by their temperature in 2100. See Chapter 2 for additional details.

carriers (LOHCs). Ammonia is considered by many to be the cost-effective solution – but its use could significantly reduce the climate benefit of hydrogen. Recent research found that if 0.4% of the nitrogen was converted to nitrous oxide (N₂O) this would negate the climate benefit of using ammonia – even if the hydrogen contained within the fuel was produced with zero carbon emissions.³⁶ LOHCs such as methanol may also be problematic given that they bind hydrogen to carbon.³⁷ Therefore, despite the high energy requirements for liquid hydrogen storage, this might be the preferable means of storing and using hydrogen in marine vessels. Still, additional research is needed to assess these possibilities and establish whether hydrogen-powered marine vessels indeed provide a promising route to decarbonizing global marine applications.

Hydrogen could also be combined with captured carbon dioxide (CO₂) in order to create synthetic hydrocarbon fuels (such as “air to fuels” or “e-fuels”) to be used in marine applications or airplanes. Such an energy transformation is extremely costly and may only be necessary if biomass and/or carbon sequestration resources are constrained (by cost or policy). In the industrial sector, hydrogen could provide a clean fuel for high-temperature process heat (e.g., for cement or steel)³⁸, be used as a reducing agent for iron ore (hydrogen direct reduction of iron [HDRI]),^{39, 40} or provide low-carbon feedstocks for chemicals and fertilizers.⁴¹ The latter two uses are niche markets for conventional hydrogen at present, as hydrogen is a necessary feedstock for ammonia, for example.⁴² These feedstock applications are therefore the most likely avenue for clean hydrogen to contribute to decarbonization, as these processes will require its use if they are going to mitigate their emissions without offsets coming from elsewhere in the economy.

The IPCC scenarios also make clear that the share of final energy coming from hydrogen in the industrial and transportation sectors increases with increased climate policy ambition (i.e., lower carbon emissions and temperature outcomes). This is consistent with Lazarou et al. (2018)’s analysis that found larger hydrogen deployment under increasingly stringent climate constraints simulated with the Global Change Analysis Model (GCAM).⁴³ This is intuitive, given clean hydrogen use is most valuable in difficult to decarbonize areas of the economy, and increasing climate policy ambition will make mitigation in these areas a necessity. Lastly, critical to the widespread use of variable renewable electricity (VRE), hydrogen can facilitate long-term electricity storage.⁴⁴ McPherson et al.’s (2018) results indicated that hydrogen could assist intermittent renewable deployment by providing electricity storage and firm electricity generation under emissions mitigation.⁴⁵

It is clear that hydrogen can be used in many ways, but it likely should only be leveraged to mitigate emissions in difficult electrify sectors – e.g., heavy-duty and long-distance transportation, high-temperature process heat for industrial needs, and chemical feedstocks. These are still critical areas of the global economy which must reduce their GHG emissions. Although using clean hydrogen to provide feedstock for the chemical industry (e.g., fertilizer) seems inevitable, further research is needed to confirm the viability of using hydrogen or hydrogen-derived energy (i.e., synthetic hydrocarbons and ammonia) in these other areas. Given the number of possible means of using the energy carrier to decarbonize hard-to-abate sectors, hydrogen has also captured the attention of policymakers, evidenced by the publication of hydrogen “strategies” and “roadmaps” by dozens of countries, including: Australia, Canada, Chile, Colombia, the Czech Republic, France, Germany, Hungary, Japan, the Netherlands,

Norway, New Zealand, Portugal, Spain, the United Kingdom, and the United States of America.^{46, 47, 48, 49, 50, 51, 52, 53, 54, 55, 56, 57, 58, 59, 60, 61, 62, 63, 64, 65, 66, 67, 68, 69, 70, 71, 72} However, a critical analysis of these plans is warranted. Research should determine if such strategies are targeting meaningful methods and scales of supply, as well as viable hydrogen utilization applications.

1.A.3. The implications of hydrogen's use on air quality as well as food and water systems

Although electricity is likely to be the dominant final energy carrier under climate mitigation, clean hydrogen will nonetheless contribute to a 'net-zero' greenhouse gas future in some capacity. Exactly how the energy carrier could impact concentrations of traditional air pollutants has received less comprehensive investigation – despite being the rationale behind the second surge in enthusiasm for a 'hydrogen economy'. Early studies suggested large improvements in air quality from hydrogen-consuming technologies. Schultz (2003) noted possible declines of up to 50% for anthropogenic carbon monoxide (CO) and nitrogen oxide (NO_x) emissions.⁷³ In addition to decreases in CO and NO_x emissions, Ruijven et al. (2011) also found reductions in sulfur dioxide (SO₂).⁷⁴ However, both of these studies were focused on fuel cell deployment, which is typically associated with road-based transportation – where hydrogen's potential to contribute to climate change mitigation now seems potentially limited to heavy-duty trucks. When evaluating other modes of transport, such as ships and airplanes, the impact of hydrogen's use would depend on the form the energy carrier takes and how it powers movement. Synthetic liquid fuels would presumably have the same emissions intensity as the fossil liquids they are replacing, but hydrogen converted to NH₃ and subsequently combusted could result in large quantities of NO_x emissions⁷⁵ without additional controls. Hydrogen itself has a higher NO_x emissions intensity than natural gas when combusted as well. Gee et al.

(2022)'s study found that combusting hydrogen could result in roughly 4 to 5 times as much NO₂, a subset of NO_x, compared to combusting natural gas on a per unit of energy basis.^{76, B} This would therefore impact air quality in ports unless additional emissions technologies are installed – but could be altogether avoided with hydrogen fuel cells.

Although fuel cells could reduce traditional air pollution for marine applications, they appear less valuable for many stationary energy consumers. Hydrogen is believed to be a promising means of providing high-temperature heat for industrial processes and this dictates hydrogen combustion. Given hydrogen's higher NO_x emissions intensity, substituting hydrogen for natural gas in industrial heat applications would increase NO_x emissions without additional control technologies. Moreover, hydrogen's potential to facilitate VRE deployment is often predicated on the deployment of combustion turbines, in addition to fuel cells, for converting the energy carrier back to electricity.^{77, 78} Combusting hydrogen blended with natural gas could likewise increase NO_x emissions. A 2017 study found that even a 25% hydrogen and 75% natural gas blend would increase NO_x emissions by nearly 90% compared to the combustion of natural gas.⁷⁹ Co-firing ammonia with coal for power generation has even been proposed by the Republic of Korea's government as a decarbonization strategy.⁸⁰ As with natural gas and hydrogen blending, burning coal with ammonia could be of low value to climate change mitigation as it likely does not sufficiently reduce the carbon intensity of the process, and similarly the co-firing could increase NO_x emissions without additional controls.

^B Values estimated based on Figure 12 from Gee et al. (2022).

Despite these air quality concerns, it is unclear whether most modeling efforts that have demonstrated hydrogen's potential for decarbonizing high-temperature heat (in the power or industrial sectors) are also considering traditional air pollutant emissions. Hernandez and Gencer (2021)⁸¹ and Fuhrman et al. (2024)⁸² are the only mitigation studies the author is aware of that explicitly included and detailed the additional capital costs required to mitigate NOx pollution resulting from hydrogen combustion. The literature and policy communities would therefore benefit significantly from transparency and an explicit assessment of clean hydrogen's potential to impact air quality with the inclusion of combusted hydrogen applications. Further, it should be investigated whether hydrogen-based energy can still facilitate climate change mitigation when combusted in technologies with NOx emission controls, as such controls would come at an additional cost which could in turn make the energy carrier less competitive with alternative decarbonization options.

In addition to air quality concerns from hydrogen combustion, policymakers will also need to consider the potential for hydrogen to impact water and food systems. All forms of hydrogen production which are prominently discussed by policymakers and the literature directly require water (see Table 3.1 within Chapter 3 of this dissertation). For certain technologies, such as fossil and biomass pathways, the water is required for process and cooling needs. In the case of electrolysis, the water is the feedstock from which hydrogen is extracted. Additionally, bioenergy indirectly requires water, as the biomass feedstock must be grown. Studies have demonstrated that extensive use of bioenergy can exacerbate water scarcity issues⁸³ as well as influence agricultural markets by competing with food crops for available land and water.⁸⁴ This complicates hydrogen's potential impact on food and water systems, given that hydrogen could

both be produced from biomass as well as compete with bioenergy as a means of providing various services for the economy. Research has also already shown that climate change will cause freshwater scarcity issues and reduce agricultural yields⁸⁵ in many regions of the world, but less is known about how hydrogen will impact water availability and food systems.

Studies that have thus far examined hydrogen's effects on hydrological systems have only provided a partial view of potential impacts by generally focusing on global change, renewable electrolysis, and/or have focused on either water consumption or water withdrawals. Additionally, previous authors often have not competed hydrogen against other sources of energy (or competed various methods of hydrogen production amongst each other) within an internally consistent model in order to endogenously determine the scale of hydrogen deployment within their studies.^C Beswick et al. (2021) made a significant advancement in this area while investigating whether hydrogen produced from renewable-based electricity resulted in negative implications for water systems.⁸⁶ The authors made clear that the water impact of hydrogen is not only based on the additional water requirements for producing the energy carrier, but also entails the reduction in water requirements for traditional energy forms which are being displaced (e.g., fossil fuels). Their research determined that green hydrogen would have a minimal impact on global water withdrawals and consumption. However, this analysis did not include the other forms of clean hydrogen that are being considered for the energy transition (e.g., natural gas with CCS and biomass-based hydrogen), and the scale of the energy carrier was exogenously stipulated.

^C Where applicable for previous literature, this is henceforth referred to as exogenously stipulating the scale of hydrogen within this chapter.

Tonelli et al. (2023) further advanced this line of research by investigating the matter at the country level, finding that it was unlikely to be the cause of water scarcity but could contribute to the matter.⁸⁷ Yet, they likewise only considered green hydrogen with an exogenous demand, inspected only water withdrawals, and did not include the reduction of water for displaced oil-based refining.⁸⁸ Given that global- and country-level water availability does not directly imply local water availability, there may be instances where water resources in specific locations are more constrained than their availability at the global or country scope. Future research which considers endogenously where hydrogen production is likely to occur and at a finer spatial resolution would help illuminate whether – and where – hydrogen production’s water requirements would be problematic.

Receiving even less attention is the matter of how, and to what extent, clean hydrogen may influence agricultural systems. Clean hydrogen can also directly impact food systems, given its potential feedstock application for nitrogen-based fertilizers. While studies and reports have detailed decarbonization pathways for nitrogen-based fertilizer production as well as the potential competitiveness of clean fertilizers^{89, 90, 91}, it remains unclear how hydrogen’s use on an economy-wide basis could affect crop markets. It is therefore important to understand how hydrogen may further affect food and water systems, in addition to air quality, under mitigation and energy transitions. This is an area where integrated assessment models (IAMs) could provide more clarity, given that they couple land, water, climate, and energy systems.

1.A.4. Economic considerations for clean hydrogen

The potential for clean hydrogen to emerge as an important form of energy in the future has also led to economic considerations regarding its use. Many of the national hydrogen roadmaps noted previously related their strategies to the possibility for job creation. Chile, for example, emphasized that their hydrogen ambitions could result in “...creating up to 100,000 new sophisticated and satisfactory jobs, during the next few decades.”⁹² The potential for new employment opportunities arises from the fact that not only will hydrogen producers require human labor, but so will manufacturers of production, end-use, and delivery technologies (e.g., electrolyzers, fuel cells, or pipeline components).

Hydrogen utilization has in fact long been connected in the literature to the state of national economies. As noted, the ‘hydrogen economy’ was initially conceived in the wake of the 1970s oil crisis. Energy supply disruptions caused economic turmoil in many regions of the world, and as such national leaders sought strategies for reducing their dependence on foreign oil. Hydrogen therefore emerged as a means of obtaining energy security, particularly for western nations such as the United States. Azzuni and Breyer (2018) define energy security as “...the feature (measure, situation, or a status) in which a related [energy] system functions optimally and sustainably in all its dimensions, freely from any threats.”⁹³ Importantly, the authors made clear this entails not only energy availability but also affordability. Under the guise of ‘electricity too cheap to meter’, nuclear technologies were considered a promising means for producing hydrogen^{94, 95, 96, 97}, which could then be used to supplant oil demand – particularly in the transportation sector. But the high cost of nuclear-based hydrogen meant that such a transition never came to fruition.

While the flexibility provided by the many potential avenues to producing clean hydrogen implies the energy carrier could be made *available* using domestic resources in many nations, all forms of clean hydrogen are expensive at present implying issues with *affordability*. Currently, producing hydrogen from wind-based electrolysis costs nearly \$50 per gigajoule (GJ) in the U.S.^{98, 99, D} Hydrogen is often discussed as substitute for natural gas, and for comparison a GJ of natural gas delivered to the U.S. industrial sector cost only ~\$3.34 in 2020.¹⁰⁰ Still, our energy system will need to be decarbonized and more affordable hydrogen is expected in the years to come. Given the energy market disruptions following Russia's invasion of Ukraine, the need for a secure supply of clean energy may even increase the demand for clean hydrogen in certain nations.

Several of the national hydrogen roadmaps also note the potential need to import hydrogen (e.g., Japan, the Czech Republic, Germany, the Netherlands). While imports could provide access to clean energy, other aspects of energy security can be diminished as citizens and domestic markets would become vulnerable to the actions of foreign powers. The Czech Republic has even mentioned the possibility of importing hydrogen from North African countries and the Middle East.¹⁰¹ Importing hydrogen from the Middle East could include producers who have previously been involved in other global energy market disruptions (i.e., OPEC members). Azzuni and Breyer (2018) also note that diversification is important to a secure energy supply, thus nations with plans to import hydrogen would benefit from not heavily relying on one, or a few, foreign suppliers.

^D This cost is in \$2020 USD and has been calculated using a USA national average onshore wind turbine capacity factor of 37% and includes the costs of associated wind turbines as well as the electrolyzer.

Many nations have also made clear their export ambitions and the potential of exports to benefit their economies (e.g., Chile, Australia, and countries in Northern Africa as well as the Middle East). However, policymakers would benefit from more clarity on the actual potential for hydrogen imports and exports. While Timmerberg and Kaltschmitt (2019) noted the possibility of exporting vast quantities of green hydrogen from Northern Africa to Central Europe through existing gas infrastructures, this was facilitated by a 10% hydrogen by volume blend.¹⁰² Such a low concentration of hydrogen seems unlikely to sufficiently decarbonize gas-fired technologies in a manner which would enable a significant contribution to climate change mitigation in the long run. Further, it remains unclear how affordable importing non-blended hydrogen will be, as this is a function of the production cost, distance from production location, and the form the hydrogen is delivered in. Delivering hydrogen over large distances entails significant energy requirements, which comes at a cost. If sent by ship, the hydrogen will either need to be liquefied or alternatively converted to NH_3 or a LOHC – and if such a conversion occurs it will necessitate reconversion at the import location if the hydrogen-based energy carrier isn't used directly. As noted in section 1.A.1, pipeline distribution will also involve hydrogen leakage – and losses are not avoided by oceanic delivery. Smith et al. (2022) estimated that marine delivery of liquefied hydrogen can result in nearly 1% losses per day from boil-off.¹⁰³ Therefore, the potential for hydrogen to be sent across continental or oceanic scales appears to be limited given the extensive energy requirements, costs, and losses. Brändle et al. (2021) found some potential for hydrogen exports, but their results suggested such hydrogen delivery would largely be confined to regional networks connected by pipelines.¹⁰⁴ Still, questions remain as this analysis only considered hydrogen pipeline as well as liquid hydrogen delivery and did not involve endogenously calculated demands for hydrogen, as the study focused on estimating hydrogen supply costs.

The additional energy needs for exporting hydrogen will not only result in additional costs and therefore impact affordability, but they could result in GHG emissions as well. The life cycle emissions of the imported hydrogen will need to be accounted for if hydrogen is to truly enable climate change mitigation which may necessitate certification schemes. As noted by White et al. (2021), such a scheme would benefit from a modular design whereas certification takes place at each stage of the supply chain (e.g., production, transport, conversion, reconversion).¹⁰⁵ Such an approach would be beneficial to hydrogen trade as it wouldn't require clean producers to manage the life cycle impact of their product beyond what occurs in their facility. This is also an area where integrated assessment modeling could provide more clarity since these models are able to endogenously consider the GHG emissions associated with the entire supply chain and imported hydrogen's economic competitiveness with alternative energy options.

1.A.5. Just transitions, climate/environmental justice, safety, and clean hydrogen

Hydrogen's potential to impact the economy is not only through energy security. Many national plans have also highlighted its potential to enable a 'just transition'. For instance, the Czech Republic explicitly outlined how hydrogen could contribute to a 'just transition', which entailed plans for "...mitigating the negative impacts of the shift away from coal in regions that will face serious socio-economic problems because of the transition to a climate-neutral economy...".¹⁰⁶ The Czech Republic even defined which regions they had in mind for this: Karlovy Vary, Moravian-Silesian, and Ústí nad Labem.¹⁰⁷ Just transition considerations are not only ethically warranted but they may also be important for gaining public support for decarbonization policies.

For a transition to be just it cannot solely emphasize strategies for reducing the potential for change to harm communities which have benefited from the status quo though – the transition must also consider those who have been traditionally damaged by our energy systems. Low-income and marginalized communities often have borne the safety and pollution risks of our economy, and climate change mitigation should not prioritize decarbonization over their wellbeing. Multiple studies have detailed how NO_x pollution disproportionately impacts minority groups in the United States.^{108, 109} Replacing natural gas with hydrogen for combustion in industrial or power sector applications could thus exacerbate air quality issues for these communities unless additional emissions controls are installed. In fact, such concerns were noted after Los Angeles’s City Council recently announced its intention to convert a natural gas powerplant to a hydrogen combustion electricity generating unit.¹¹⁰

There is also an increased safety concern for the use of hydrogen, compared to fossil fuels. The risk of ignition is higher for hydrogen than natural gas¹¹¹, and has long been considered dangerous by many. The concern was even apparent for early promoters of the hydrogen economy, with Silverstein (1980) stating “...The Hindenburg disaster and subsequent replays of this tragedy have given rise to what one sociologist has termed the “Hindenburg Syndrome,” whereby the word hydrogen has become synonymous with danger in the public mind.”¹¹² Ammonia is also flammable and toxic to humans. In 2022, an ammonia-based fertilizer manufacturing facility in North Carolina caught fire and residents within a mile of the plant were asked to evacuate given the explosive risk.^{113, 114} Those within the evacuation boundary also happened to be primarily minorities – nearly 75% these residents were estimated to be black or Hispanic.¹¹⁵ Vulnerable and traditionally marginalized populations often have less

capacity to respond to external influences, and here it appears they may have been left to fend for themselves as it is unclear if temporary housing was provided to these individuals while the facility burned for nearly 4 days¹¹⁶ releasing large amounts of NO_x as well as other pollutants into the air.¹¹⁷ As such, communities located near facilities with vast amounts of hydrogen-based energy storage could not only face air quality issues but would also be vulnerable to explosive risks.

Similar concerns exist for the delivery of hydrogen through pipeline infrastructures. Blending and sending hydrogen through existing natural gas pipelines increases the explosive risk level of such infrastructures. An analysis by NREL (2013) showed that higher shares of hydrogen have an increased likelihood of causing a fatality from pipeline ignition within roughly 250 meters of the pipeline.^{118, E} Moreover, natural gas pipeline networks are concentrated in low-income and traditionally marginalized communities, at least within the United States. A 2021 study showed that U.S. counties “...with more socially vulnerable populations have significantly higher pipeline densities than counties with less socially vulnerable populations.”¹¹⁹ For instance, more than 80% of the ~500-mile Sabal Trail natural gas pipeline is within a mile of low-income and/or minority communities.^{120, 121} Therefore, using natural gas pipelines to deliver hydrogen could exacerbate current injustices in our energy system. What is less clear, however, is the risk from delivering hydrogen within dedicated hydrogen pipelines, and the literature should further investigate this matter to ensure the safety of those most vulnerable during our energy transition.

^E Distance estimated from figure within Melaina et al. (2013), pg. 17.

Fossil fuel infrastructures have also typically infringed on indigenous communities in many areas of the world. For example, a portion of the Dakota Access pipeline passes within a mile of the Standing Rock Sioux Reservation¹²² and traverses under Lake Oahe, which the tribe considers sacred and relies upon.¹²³ If dedicated hydrogen pipeline infrastructure is to be constructed it therefore should avoid replicating the injustices of fossil pipeline networks and consider the preferences of local communities. Some of these concerns would be alleviated by onsite production of hydrogen (e.g., at marine ports or industrial facilities). This would not only enhance the climate benefit of hydrogen, given leakage concerns, but also reduce the risks and injustices associated with energy delivery in many regions of the world. However, onsite production would still not reduce the possibility of explosive risk or air quality issues from hydrogen combustion. Only additional pollution controls for hydrogen combustion and placing these facilities away from communities would enable progress in these areas. Therefore, it may be favorable for policymakers to promote production methods which minimize the distance between producers and end users (ideally via onsite production) and locating end users for hydrogen combustion away from population centers, if possible, as well as establishing requirements for NO_x emission controls.

Several developing nations have also been highlighted as potential hydrogen exporters (e.g., Chile, as well as Northern Africa and the Middle Eastern countries). This could result in replicating other forms of injustice associated with our current energy regimes. Many developing countries have been energy or resource exporters, in turn helping more developed nations fuel their economies. Unfortunately, it has not been uncommon for domestic energy poverty to persist for such ‘developing’ exporters. Additionally, given hydrogen production’s water requirements it

is possible that foreign energy demand could infringe on water availability for local communities in exporting nations. In a way this can be thought of as ‘virtual water trade’ (VMT), more commonly discussed in relation to exporting agricultural or biomass-derived products.^{124, 125} Nations considering imports should therefore ensure that delivered hydrogen is not only clean but is not causing water access issues at the source of production.

Of the national hydrogen strategies the author is aware of, some do not address water availability considerations related to hydrogen production at all (e.g., Japan and the Netherlands). Additionally, while several nations with advanced economies plan on potentially importing hydrogen, only some seem to fully expanded consideration of water availability beyond their own citizens when discussing hydrogen produced externally. For example, Germany’s plan states that “...the sustainable supply of water in arid regions of these countries must not be impaired by the production of hydrogen. The aim is to achieve sustainable production along the entire supply chain.”¹²⁶ This was noteworthy as many potential exporters are in arid regions where freshwater availability is already challenging (e.g., Northern Africa, the Middle East, and portions of Chile). In addition to safety and pollution risks, the location of hydrogen production plants should therefore be sensitive to both water availability now and in the future. It is hoped that results from this dissertation can also provide insights into whether hydrogen may contribute to, or hinder, climate/environmental justice as well as just transitions.

1.B. This dissertation's contribution to addressing the gaps in the “hydrogen economy” literature

While hydrogen has the potential to facilitate deep decarbonization, it likely should not be the first option for mitigation in most energy demanding end uses. In terms of providing low-temperature heat for buildings and powering passenger vehicles, there are better options available in most regions of the world. Yet, hydrogen will be critical for decarbonizing the processes which already rely on the energy carrier at present (e.g., ammonia production). Hydrogen may also be valuable in the industrial sector by enabling mitigation for steel manufacturing as well as providing a source for high-temperature heat. However, the combustion of hydrogen will result in significant NO_x emissions without additional controls. The literature should clarify hydrogen's potential in these areas, how hydrogen use will impact air quality, and whether additional control technologies for traditional air pollutants will diminish the capacity of hydrogen use to mitigate GHG emissions in an economically efficient manner.

Hydrogen may also enable long-distance, heavy-duty transportation (e.g., marine applications) – but there are still questions about the viability of doing so in a cost-effective manner, and what form the energy carrier will take (i.e., liquid H₂, NH₃, or LOHCs). Further, in order for hydrogen to actually contribute to mitigation it will need to be produced from clean methods. Issues with hydrogen leakage will also need to be addressed, warranting further examination of the extent of needed hydrogen delivery as well as the competitiveness of onsite production. Nonetheless, policymakers will need to consider the safety, energy security, and justice implications for any form of clean hydrogen. Further research is thus required to discern the preferable hydrogen supply configuration (i.e., method of clean production, central vs. onsite

production, and preferable method of distribution if delivery is required) for emissions mitigation, and how, if at all, this may have implications for other societal objectives. Hydrogen production should also not infringe upon freshwater availability, and policymakers should avoid replicating the injustices of past energy systems when considering the location of hydrogen delivery infrastructure and end-use technologies, as well as potential international trade partnerships. Lastly, as the number of national hydrogen strategies and roadmaps continue to proliferate, research should analyze whether such plans are justifiable.

While this dissertation will not be able to cover all of the gaps in the literature, it is hoped that this work will help advance the understanding of the “hydrogen economy” in many of these areas and also help inform policy communities of hydrogen’s potential for decarbonization as well as its potential to impact other societal objectives. Specifically, the central research question for this dissertation is the following: *what are the competing visions for the ‘hydrogen economy’ and what are the implications of these various pathways for society?* This dissertation will answer this central research question with the following three research topics, each containing their own central research question (RQ1-RQ3) with accompanying sub-questions (SQ1-SQ7). These topics are motivated by the goal of reducing the aforementioned gaps in the literature.

Research Topic 1 - Supply and demand drivers of global hydrogen deployment in the transition toward a decarbonized energy system

Research Question #1 [RQ1]: What specific hydrogen supply and demand technologies are economically efficient to deploy?

Sub-question #1 [SQ1]: What hydrogen supply technologies are economically efficient to deploy? ('Supply' includes both hydrogen production and delivery technologies.)

Sub-question #2 [SQ2]: Which final energy sectors does hydrogen preferentially deploy in and how does the scale of hydrogen deployment compare to other potential final energy sources?

Sub-question #3 [SQ3]: How do uncertainties in delivery infrastructure availability, technological cost, climate policy ambition, and sequestration as well as bioenergy utilization influence the policy implications for hydrogen supply and demand?

Research topic 2 - Mid-century impacts of the “hydrogen economy” on the water-energy-food nexus

Research Question #3 [RQ2]: What are the potential implications of a “hydrogen economy” for the water-energy-food nexus?

Sub-question #6 [SQ4]: How, if it all, will the “hydrogen economy” impact water systems?

Sub-question #7 [SQ5]: How, if it all, will the “hydrogen economy” impact staple crops?

Research Topic 3 - Evaluating national hydrogen strategies: Japan and the Republic of Korea

Research Question #2 [RQ3]: Are the prospects for clean hydrogen-based energy sufficient to justify national policymaker expectations and plans?

Sub-question #4 [SQ6]: Are policymakers over- or underestimating hydrogen-based energy supply? (i.e., the scale of supply, production method, and relative importance of domestic vs. imported energy)

Sub-question #5 [SQ7]: Are plans for hydrogen demand in line with potentially viable hydrogen-based applications? (i.e., end-use applications)

Chapter 2:
Supply and demand drivers of global hydrogen deployment in the transition towards a decarbonized energy system^F

^F **Publication:** O'Rourke, Patrick, Bryan K. Mignone, Page Kyle, Bryan R. Chapman, Jay Fuhrman, Paul Wolfram, and Haewon McJeon. "Supply and Demand Drivers of Global Hydrogen Deployment in the Transition toward a Decarbonized Energy System." *Environmental Science & Technology* 57, no. 48 (December 5, 2023): 19508–18. <https://doi.org/10.1021/acs.est.3c03751>.

2.A. Introduction

The possibility of using hydrogen (H₂) as an energy carrier has been discussed for nearly a half century. While literature in the 1970s and 1980s noted its potential to enhance national energy security^{127,128,129,130}, a more recent focus has been its role in decarbonization, particularly in end-use sectors that are difficult to electrify. Like electricity, hydrogen can be produced from numerous primary energy sources using different production processes. But to contribute to decarbonization goals, it must be produced using low-carbon technologies. Examples include natural gas reforming with carbon capture and sequestration (CCS) to make ‘blue’ hydrogen,¹³¹ or renewable-based water electrolysis (‘green’ hydrogen¹³²) and biomass gasification.¹³³ The last of these methods could be coupled with CCS to produce hydrogen with negative emissions.¹³⁴

Once produced, low-carbon hydrogen could be used to reduce emissions in several areas of the global energy system. In the industrial sector, hydrogen could provide a low-carbon fuel for high-temperature process heat¹³⁵, be used directly as a reducing agent for iron (hydrogen direct reduced iron [DRI])^{136, 137} or provide low-carbon feedstocks for chemical and fertilizer manufacturing.¹³⁸ Hydrogen could similarly mitigate carbon dioxide (CO₂) emissions in the transportation sector – particularly in heavy-duty transportation (e.g., trucks¹³⁹ and marine vessels¹⁴⁰). Furthermore, blending low-carbon hydrogen with natural gas¹⁴¹ could lower the carbon intensity of technologies that consume natural gas. Given such versatility, hydrogen has captured the attention of policymakers, as evidenced by the publication of hydrogen “roadmaps” by over a dozen nations.^{142, 143, 144, 145, 146, 147, 148, 149, 150, 151, 152, 153, 154,155, 156, 157}

Evaluating the role of hydrogen in the energy transition involves understanding where and when it could be competitive with other decarbonization options. The role of hydrogen has been examined in some energy system models in the context of net-zero scenarios but typically at the country or regional level, and often using exogenous assumptions about end-use demand.^{158, 159, 160, 161, 162} For this reason, technology rich integrated assessment models (IAMs) are particularly well suited to advance our understanding, given that they have global coverage and endogenously represent competition within end-use demand sectors as well as within energy supply sectors. For a deeper discussion of IAMs, please see the following cited references.^{163, 164} Several IAM-based studies have considered the role of hydrogen in climate mitigation. Barreto et al. (2003) employed MESSAGE-MACRO and found that hydrogen could potentially provide nearly half of all global final energy by the end of the century.¹⁶⁵ Other early IAM studies found a more modest role for hydrogen, typically centered on the transportation sector. Using MiniCAM, Edmonds et al. (2004) found hydrogen could supply a significant share of global transportation final energy under emissions mitigation, but only if advanced technological assumptions were realized (e.g., low-cost production and higher efficiency fuel cells).¹⁶⁶ van Ruijven et al. (2007) similarly found, using TIMER 2.0, that hydrogen could play a key role in the transportation sector, but primarily in the second half of the century.¹⁶⁷ Using TIAM-UCL, Anandarajah et al. (2013) also found that hydrogen could contribute meaningfully to the decarbonization of road-based transportation.¹⁶⁸

Recent studies have begun to consider hydrogen's role in more detail. Using the Global Change Analysis Model (GCAM), Lazarou et al. (2018) found that hydrogen deployment was higher under increasingly stringent climate constraints.¹⁶⁹ McPherson et al. (2018), using

MESSAGE, demonstrated how hydrogen could support variable renewable electricity (VRE) deployment by providing electricity storage and firm electricity generation capacity under mitigation.¹⁷⁰ More recently, an assessment by Oshiro and Fujimori (2022) using the AIM/Technology model found that by midcentury hydrogen and hydrogen-derived energy carriers could provide up to ~9% of global industrial final energy demand and up to ~50% of global transportation energy needs in scenarios that limited warming to 1.5-2°C.¹⁷¹ While hydrogen was not the main focus of their analysis, Luderer et al.(2022) also showed pathways in REMIND–MAGPIE with significant amounts of hydrogen deployment under climate policy.¹⁷²

However, to our knowledge, no IAM studies have explicitly evaluated the impact of hydrogen delivery infrastructure, even though hydrogen transmission and distribution (T&D) costs are expected to be substantial and therefore an important factor in determining the hydrogen production mix and its competitiveness with other energy carriers. And while electrolysis-based hydrogen has received attention from the IAM literature, it remains less clear whether this production pathway will utilize grid electricity or dedicated renewable energy, as well as whether supply in general will be centralized or distributed. In addition, many possible hydrogen end-use technologies discussed by policymakers and the research community have not been fully incorporated into models. Oshiro and Fujimori (2022) included hydrogen-derived synthetic fuel utilization for rail and ammonia-powered marine applications, but they did not model hydrogen fuel cell technologies for these end uses. Similarly, Lazarou et al. (2018) only included hydrogen use in aggregate industry and light-duty vehicles. Anandarajah et al. (2013) evaluated hydrogen usage for road-based transportation, but they did not evaluate non-road modes of transport or other end-use sectors.

In this study we represent all major low-carbon hydrogen production methods, including both distributed (onsite) and central production, multiple hydrogen delivery options, and a rich set of hydrogen end-use technologies within GCAM. Compared to prior studies, this work considers a wider range of hydrogen uses across all major end-use sectors and calls attention to the role of hydrogen T&D in driving choices about hydrogen supply chains. Our results suggest that outcomes such as the production mix, the share of onsite production, and hydrogen's contribution to mitigation in different end uses vary with key assumptions.

2.B. Methods

This research utilized the Global Change Analysis Model (GCAM),¹⁷³ a publicly available global hierarchical equilibrium IAM. Specifically, GCAM version 5.4¹⁷⁴ was used as it was the most recent publicly available version of the model when this research began. Model enhancements were made to hydrogen-based technologies, as shown in Figure 2.1 and described below, as well as other aspects of the energy system unrelated to hydrogen which are detailed in McJeon et al. (2021).¹⁷⁵ GCAM links human and earth systems (the climate, water, land and energy systems, as well as the economy), enabling examination of their interactions and responses to policy or technology changes. GCAM contains 32 energy and economic regions, 384 land areas, and 235 water basins, and the model projects various scenarios to the end of the century, running in five-year timesteps. Final energy demand in the model is driven by exogenous assumptions for income (GDP per capita) and population as well as endogenous changes in the cost of producing a given service (e.g., vehicle miles). The “middle-of-the-road” Shared Socioeconomic Pathway 2 (SSP2) assumptions¹⁷⁶ are used in this study for population and GDP.

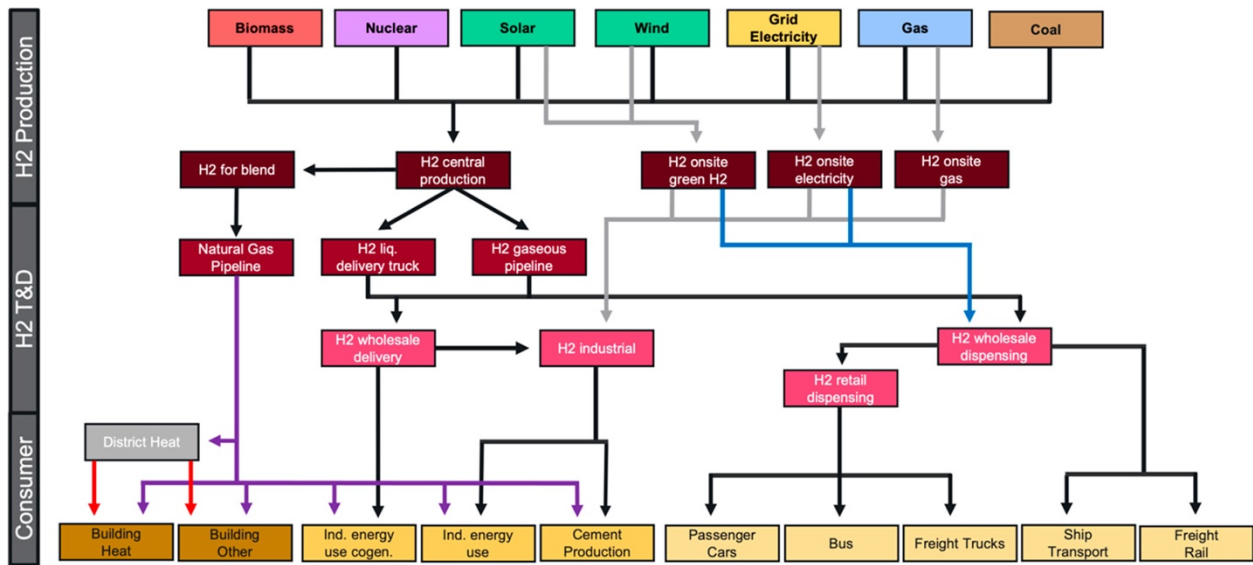


Figure 2.1. Representation of GCAMv5.4 hydrogen supply and demand, as modified for this study.

In each end-use sector, hydrogen competes with other energy carriers based on the levelized cost of supplying a given service (e.g., process heat for industrial needs) using a logit choice formulation.^{177, 178} Hydrogen production technologies compete based on cost in a similar manner. When emissions are priced, as they are in climate mitigation scenarios, differences in emissions between technologies also affect competition. Emissions associated with resource production (e.g., natural gas) and energy conversion (e.g., electricity generation), along with emissions associated with energy requirements for T&D, are included within GCAM. In this way, GCAM accounts for the major sources of emissions across the life cycles of different fuels.

2.B.1. Hydrogen production

Figure 2.1 shows the hydrogen structure in the updated version of GCAM used for this paper. This configuration allows hydrogen to be produced from biomass with or without CCS, fossil fuels with CCS, as well as from multiple electrolysis pathways, including grid electrolysis,

dedicated wind and solar electrolysis, and nuclear high temperature electrolysis (HTE).

Hydrogen produced from fossil sources without CCS are not included given the focus on climate change mitigation scenarios in this study. Hydrogen can be produced centrally (i.e., at large-scale facilities that produce hydrogen that is subsequently delivered to end users) for all production methods. Alternatively, it can also be produced onsite at the physical location of the end user, but onsite production is restricted to grid electrolysis, renewable electrolysis (green hydrogen), and natural gas with CCS (blue hydrogen). Onsite blue hydrogen is assumed to be available only within industry given the scale required for CO₂ capture. The representation of onsite green hydrogen assumes that renewable electricity is transmitted by the electricity grid from the VRE source to the end user that is producing hydrogen onsite. In contrast, central green hydrogen production is assumed to generate hydrogen at the VRE source, with hydrogen moved to the end user. While we assume both types of green hydrogen are produced synchronously with renewable electricity generation, the difference in their configurations allows one to investigate whether it may be advantageous to distribute green hydrogen rather than deliver green electricity for onsite production and use of hydrogen. Onsite and central grid electrolysis are represented in a similar manner. However, these configurations are agnostic to the source of the electricity and therefore are assumed to operate at high capacity factors.

Hydrogen production assumptions are harmonized with the National Renewable Energy Laboratory's (NREL's) Hydrogen Analysis Production Models (H2A) version 3.2018,¹⁷⁹ except for assumptions about electricity generation needed for green hydrogen, nuclear HTE, and bioenergy with CCS (BECCS), which are described below. Blue hydrogen is based on assumptions for gas steam methane reforming (SMR) with CCS. All forms of electrolysis utilize

H2A's data for proton exchange membrane (PEM) electrolyzers, which are considered compatible with intermittent electricity.^{180, 181} Levelized costs are calculated using the regional capacity factors of their paired renewables. Solar panel and wind turbine non-energy costs were aligned with GCAM's default power sector assumptions, which are based on NREL's Annual Technology Baseline (ATB) version 2019.¹⁸² Additional details regarding GCAM's power sector methodology can be found in Muratori et al (2017).¹⁸³ Nuclear HTE assumptions are also informed by NREL's H2A models, but because there is no 2018 H2A version for this technology, we utilized the 2008 H2A version¹⁸⁴, the most recent publicly available, and updated the reactor costs using ATB version 2019. The H2A models provide assumptions for biomass hydrogen without CCS, so the additional costs and energy requirements for CCS were added to define the BECCS hydrogen technology. For all hydrogen production technologies coupled with CCS, capture fractions increase from 91% in 2020 to 93% in 2050.

Table A.1 contains the levelized non-energy costs for hydrogen production as well as feedstock and/or energy requirements for each production technology. Given the global scope and projection horizon, specific policy measures related to hydrogen that have been adopted by some countries, such as the Inflation Reduction Act in the US, are not included in this analysis. Regional policy measures, combined with differences in market conditions across regions, may lead to differences in the realized costs of hydrogen production technologies. Additional hydrogen production assumptions are discussed in the Appendix (A.1.A).

2.B.2. Hydrogen transmission and distribution

As a means of delivering centrally produced hydrogen, we represent liquid hydrogen truck and gaseous hydrogen pipeline T&D (both are referred to as dedicated hydrogen T&D in this study). The cost and efficiency assumptions for hydrogen delivery, found in Table A.2, are based on Argonne National Laboratory's Hydrogen Delivery Scenario Analysis Model (HDSAM) version 3.1.¹⁸⁵ Hydrogen delivery from central production facilities is assumed to require 100 km transmission to the end user, except for central green hydrogen production, which is assumed to require 500 km of transmission. The additional distance reflects an assumption that electrolyzers would be co-located with large wind or solar farms, which are generally sited where the renewable resource quality is highest, not near hydrogen demand centers. The first year for pipeline expansion in cases that allow pipeline delivery is 2030, reflecting that it would take time to build out the hydrogen pipeline network. Trade of hydrogen between GCAM's native 32 regions via continental pipelines or oceanic-based tankers is not included within this analysis.

The modified version of GCAM also allows blending of hydrogen into natural gas T&D networks as a third method of transporting hydrogen to consumers. The share of hydrogen blended into natural gas pipelines could be limited by multiple factors, including the potential for hydrogen to degrade the structural integrity of pipelines and compatibility with end-use technologies. This blend tolerance varies not only by pipeline type (materials) but also by end-use technology. A wide range of blend limits ranging from 2-30% have been reported within the literature.^{186, 187, 188, 189} In the High Demand cases (discussed below) we assume a 20% blend by volume, or roughly a 7% blend by energy content,¹⁹⁰ phased into natural gas distribution

networks such that all new gas technologies in the relevant end-use sectors are consuming the blend by midcentury. In the Reference Demand cases (discussed below), we do not allow any hydrogen blending with natural gas. See Appendix section A.1.B. for additional details on hydrogen T&D and blend assumptions. Figure 2.2 provides 2050 levelized costs of hydrogen production for several key technologies in GCAM.

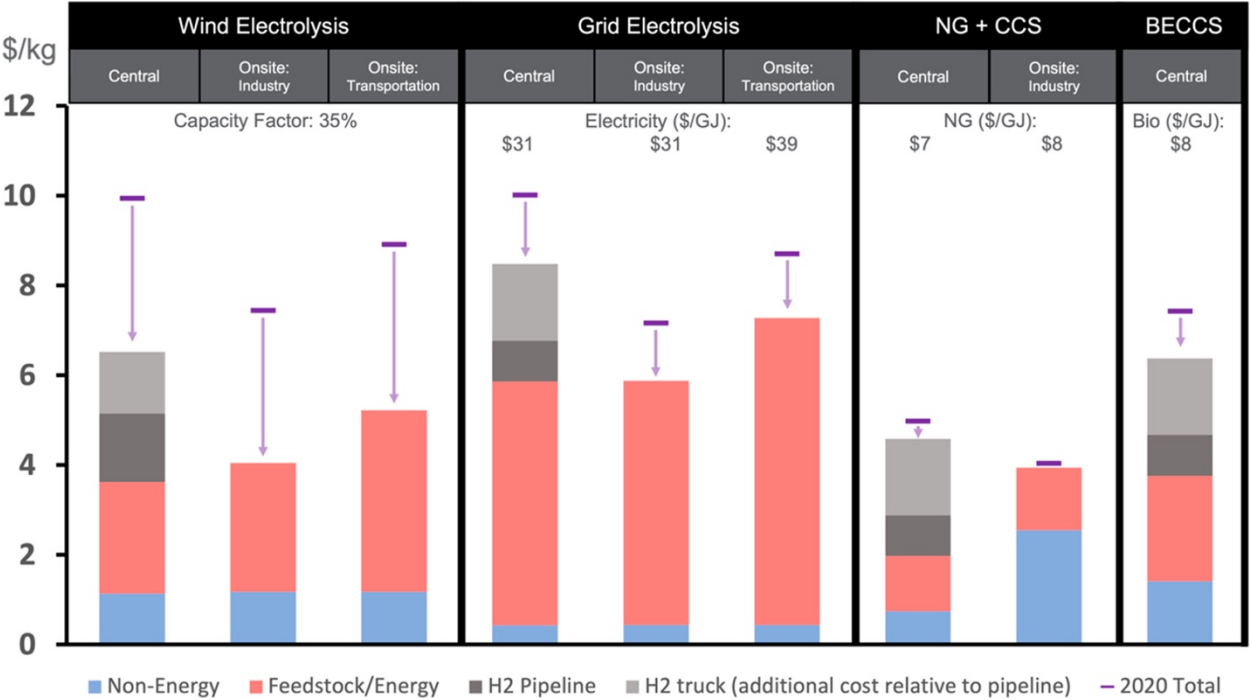


Figure 2.2. Levelized Cost of Hydrogen (LCOH) in 2020 dollars per kg of H₂ in 2050. The LCOH for a given production method varies regionally and across scenarios due to differences in the projected prices of delivered energy as well as renewable capacity factors. LCOH values presented here use illustrative delivered energy prices and renewable capacity factors which are within the model’s ranges for these assumptions and projections across regions. “Non-Energy” costs refer to levelized capital and operating expenses. “Feedstock/Energy” costs refer to the costs associated with the feedstock and other energy inputs. The “Feedstock/Energy” cost for electrolysis is primarily the cost of electricity, which is either purchased (e.g., grid electrolysis) or produced onsite (e.g., central wind electrolysis). The total cost of delivering hydrogen via trucks is equal to the sum of costs for “H₂ pipeline” and “H₂ truck (additional cost relative to H₂ pipeline)”. The “2020 Total” is the total levelized cost for a given production technology in 2020.

2.B.3. Hydrogen end uses

End-use consumption of hydrogen is limited to final energy applications: cement production process heat, other industrial energy use (e.g., process heat and cogeneration of

power plus heat), passenger cars (multiple size classes), buses, freight trucks (multiple size classes), marine vessels (domestic and international), and freight rail transport. We use the term ‘other industrial energy use’ to refer GCAM’s ‘industrial energy use’ sector, which considers all energy use for industrial applications that are not already explicitly represented as separate sectors within this version of the model (note that energy used for mining, construction, and agriculture is included in ‘other industrial energy use’). While hydrogen-powered aviation has also been considered as a potential future hydrogen application, it was not included in this analysis as there is a high level of uncertainty around this technology, making it difficult to identify plausible techno-economic assumptions. Given this study’s focus on hydrogen’s use for final energy, we do not consider hydrogen utilization for feedstocks (e.g., chemicals or hydrogen-derived fuels) or within the electricity sector. Hydrogen storage costs and energy requirements are included for refueling stations in the transportation sector (based on HDSAM) but not for the industrial sector given that comparable costs (e.g., onsite fuel storage) for other industrial technologies are not included within GCAM. When available, the hydrogen/natural gas blend can be consumed by specific end uses: cement manufacturing (process heat), other industrial energy use (process heat and cogeneration), and building and industrial heat (district heat, direct residential and commercial heat as well as other building energy needs such as water heating and cooking). Given that the blend limit and decision to phase in the blend are based on delivery tolerance and end-use technology thresholds, we do not include additional costs for end users to consume the blend above the cost differential of the fuel. However, we do include the additional cost of compressing hydrogen for delivery through natural gas pipelines.

2.B.4. Energy transition scenarios

Table 2.1 describes the core scenarios examined using GCAM, which are defined by supply and demand assumptions. In this study, GCAM is coupled with the MAGICCv5.3 climate model.¹⁹¹ All core scenarios limit warming below 2°C through the century, with a terminal temperature of 1.75°C, by imposing a uniform global carbon price beginning in 2025 which rises 3% annually. Non-CO₂ emissions (converted to CO₂e emissions using the GWP-100) are abated using a marginal abatement cost curve to estimate the amount of abatement that would occur at the realized carbon price each year.¹⁹² The starting values of the carbon price are adjusted to attain the climate objective. We also consider a reduced set of scenarios that limit warming to 1.5°C (with a terminal temperature of 1.35°C, see Appendix section A.3). Temperature outcomes were also calculated using MAGICC v7.5.3 under the "IPCC AR6 WGI (Probabilistic)" setting, returning a median 1.84°C temperature in 2100 for the below 2°C scenarios, and 1.5°C median for the more stringent climate objective.¹⁹³ For the below 2°C climate objective, we consider three options for hydrogen delivery:

- (1) No dedicated hydrogen T&D infrastructure available (only onsite production allowed)
- (2) Hydrogen delivery by hydrogen trucks is allowed (in addition to onsite production)
- (3) Hydrogen delivery by dedicated pipelines is allowed beginning in 2030 (in addition to truck delivery and onsite production).

We also consider two sets of assumptions for hydrogen demand technologies:

- (1) *Reference Demand*: capital costs for hydrogen technologies in the transportation and industrial sectors remain constant after their first year of availability (see Table A.3 for availability years).

(2) *High Demand*: capital costs for hydrogen technologies in the transportation sector decline after their first year of availability; non-energy costs for hydrogen technologies in the industrial sector also decline, attaining a 25% cost reduction between 2020 and 2050; and hydrogen blending into natural gas networks is allowed.

Scenario	H ₂ Demand Assumptions	H ₂ Supply Assumptions: T&D Infrastructure
No Dedicated H ₂ T&D	Reference Demand Costs (Industry & Transportation)	Unavailable
Truck H ₂ T&D		H ₂ truck available
Pipeline H ₂ T&D		H ₂ truck and pipeline available
No Dedicated H ₂ T&D, High Demand	High Demand Costs (Industry & Transportation) + H ₂ / NG Blend Available	Unavailable
Truck H ₂ T&D, High Demand		H ₂ truck available
Pipeline H ₂ T&D, High Demand		H ₂ truck and pipeline available

Table 2.1. Core scenarios examined in this study. T&D refers to transmission and distribution. All core scenarios limit warming below 2°C through the century. Additional sensitivities, including scenarios that limit warming to 1.5°C, can be found in the Appendix (see sections A.3-A.4).

In addition to 1.5°C sensitivity cases, we consider several other sensitivities in the Appendix. Two scenarios limit bioenergy consumption globally, with one further constraining the amount of globally available carbon sequestration (“Bio Low” and “Bio Low / “CCS Low”, A.4.A). We also include sensitivity scenarios (A.4.B- A.4.C) that restrict hydrogen production to central facilities and include direct air capture (DAC).

2.C. Results

2.C.1. Global hydrogen production through midcentury

In all core scenarios, global hydrogen production remains below 2.5 EJ through 2030, but reaches 10-22 EJ across scenarios by 2050 (Figure 2.3). For a sense of scale, in 2050, this equates to roughly 9-20% of total final energy consumed within the transportation sector in 2015 (113 EJ). In each case, green hydrogen provides the largest share of production by midcentury – ranging from 36% to 69% of all hydrogen produced. The vast majority (>90%) of green hydrogen is produced onsite due to its lower cost (Figure 2.3). Onsite production has slightly higher non-energy costs (since electrolyzer costs are lower for central production due to economies of scale) as well as higher feedstock/energy costs (primarily from the cost of delivering solar- or wind-based electricity produced offsite), but these additional costs are more than offset by the cost savings from avoiding hydrogen T&D. Onsite green hydrogen production (and its share of total production) further increases when warming is limited to 1.5°C (Appendix section A.3).

A key insight from this analysis is that onsite production of hydrogen, which is dominated by onsite green hydrogen in all GCAM scenarios, is a substantial proportion of total hydrogen production. In 2050 onsite production of hydrogen accounts for more than half of total hydrogen production in all but one of the six scenarios (in which it accounts for 43%). Furthermore, the role for onsite production is not limited to green hydrogen, as industrial onsite blue hydrogen is also competitive with other technologies (Figure 2.3). Blue hydrogen accounts for 24-29% of total hydrogen production in 2050. But even when central blue hydrogen is available (with dedicated hydrogen T&D), 33-66% of all blue hydrogen is produced onsite.

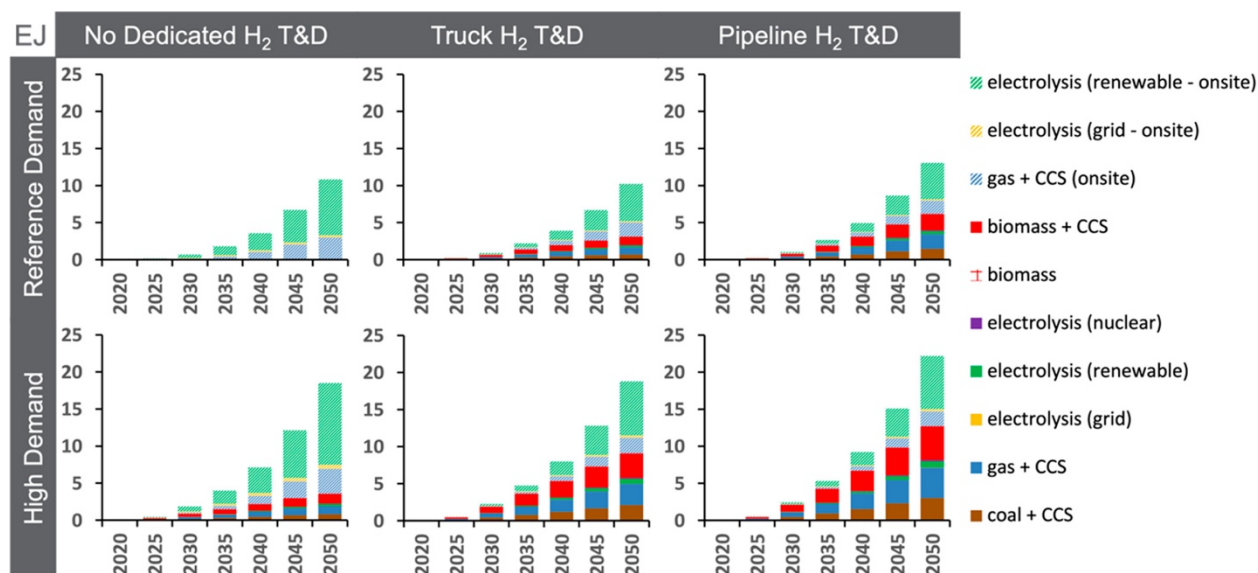


Figure 2.3. Annual global hydrogen production (EJ) by technology through midcentury for the core scenarios. Centrally produced hydrogen is shown using solid colors, whereas onsite production is shown using diagonal hashed colors. For the hydrogen production mix by end-use sector, see Figure A.4. The production mix also varies by region, primarily due to differences in regional energy/feedstock costs and renewable capacity factors.

Interestingly, the scale of hydrogen deployment is largely unaffected by the availability of dedicated hydrogen T&D infrastructure. Under Reference Demand assumptions, allowing both pipelines and truck delivery increases total hydrogen production by < 2 EJ in 2050. While not materially impacting the scale of hydrogen production, dedicated hydrogen T&D enables delivered hydrogen to play a larger role. For instance, central production accounts for 0-19% without dedicated T&D (blending with natural gas allows for some central production), 30-48% when trucks are available, and 47-57% when pipelines are available. High Demand scenarios exhibit higher overall hydrogen deployment than their corresponding Reference Demand scenarios, but a similar production mix. As shown in Figure A.11, the scale of hydrogen deployment is also found to be strongly sensitive to the climate objective, more than doubling by midcentury under scenarios limiting warming to 1.5°C (30-48 EJ).

The introduction of dedicated hydrogen T&D opens the door for hydrogen produced centrally using natural gas with CCS, coal with CCS, biomass (including BECCS), and nuclear to contribute to emissions mitigation. Among these options, natural gas with CCS and BECCS are the most competitive (Figure 2.3). Although BECCS has a higher total levelized cost than industrial onsite green and blue hydrogen when there is no carbon price, BECCS provides a source of negative emissions and receives a subsidy under carbon policies. By 2050, BECCS hydrogen ranges from 1.2 to 4.6 EJ or 11 to 21% of total hydrogen production (with dedicated hydrogen T&D). However, BECCS hydrogen is only a small share of total biomass consumption (4% of modern biomass consumption in 2050 when pipelines are available under the Reference Demand assumptions), because other BECCS options (e.g., in power, liquids production) are more attractive, either due to cost or their potential deployment scale. We consider two sensitivity scenarios – one in which biomass is limited and a second in which carbon sequestration is also limited – in the Appendix (section A.4.A). Lastly, the production mix (shares of each production type) as well as hydrogen production volumes in our core scenarios are well within the ranges found in scenarios limiting warming to 2°C in the IPCC AR6 database¹⁹⁴ (Figures A.5 and A.6).

2.C.2. Global hydrogen consumption through midcentury

Under both Reference and High Demand scenarios, industrial hydrogen demand by 2050 is comparable to or larger than transportation hydrogen demand, accounting for 40% to 76% of hydrogen consumption, or ~ 7 to 11 EJ (or up to 12.5 EJ when including hydrogen blended with gas, Figure 2.4 and Table 2.2). Total hydrogen consumption in the High Demand scenarios is higher than in the corresponding Reference Demand scenarios by 8-9 EJ (or 70-84%) in 2050.

Assumed cost reductions in hydrogen-based transportation lead to a noticeable increase in hydrogen consumption for road transportation. However, even with High Demand assumptions and the ability to deliver hydrogen in pipelines, only 7% of freight road and 5% of international shipping service demand (tonne-km) are fulfilled by hydrogen technologies in 2050. Most of the remaining demand (66% of freight road and 94% of international shipping) is met by technologies consuming liquid fuels.

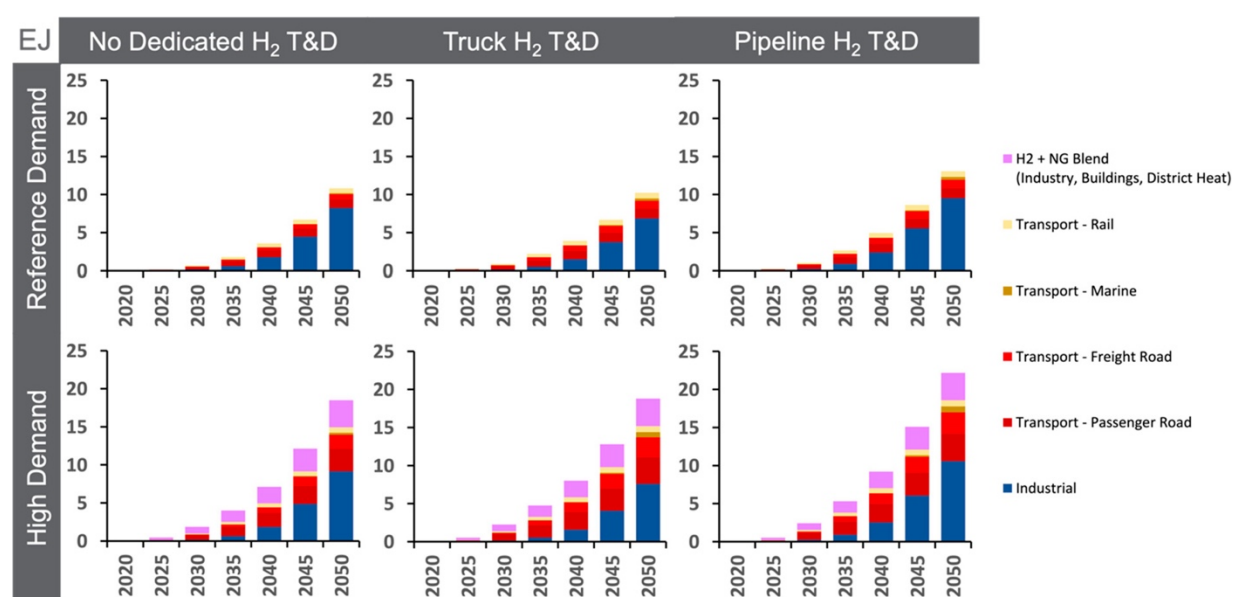


Figure 2.4. Annual global hydrogen consumption (EJ) by end-use sector through midcentury for the core scenarios. Only the amount of hydrogen within the hydrogen/natural gas blend is included in the pink part of each bar.

Compared to other energy carriers, hydrogen provides a smaller share of total final energy at midcentury (2-4%), with a similar share in transportation (2-6%) and industry (2-4%, including industrial feedstocks). The shares of hydrogen in final energy in the transportation and industrial sectors in our scenarios are well within the ranges for these outcomes assessed by the IPCC AR6¹⁹⁵ with comparable climate objectives (Figure A.7). Despite being a small portion of total final energy in 2050, hydrogen deployment could further increase after midcentury, or before midcentury under more stringent climate objectives. For example, while the role of

hydrogen in international shipping is modest through 2050 in the core scenarios, we find hydrogen-fueled international ships provide 65-89% of this subsector's final energy by 2100 (Appendix section A.2.A). In addition, hydrogen provides 58-90% of final energy in international shipping by 2050 in scenarios that limit warming to 1.5°C (Table A.7).

Within industry, most hydrogen is expected to be used in processes that require high-temperature heat ($> 400^{\circ}\text{C}$). IEA (2017) noted that high-temperature heat accounted for 48% of global industrial heat requirements, or nearly 36% of industrial energy demand (not including feedstocks).¹⁹⁶ These applications are contained within GCAM's cement and 'industrial energy use' sectors, in which hydrogen deployment is relatively modest through midcentury across scenarios (e.g., $< 10\%$ of final energy for cement). However, as noted for international shipping, these subsectors decarbonize more substantially after midcentury in the core scenarios, or before midcentury when the climate objective is tightened (Table A.7).

In the High Demand scenarios, hydrogen blended into the natural gas pipeline network accounts for 36-47% of hydrogen consumption (~ 0.9 EJ) in 2030. But by midcentury the proportion of hydrogen consumption from the blend shrinks to 16-19%. This is because the approximate 7% emissions reduction from a 20% hydrogen blend by volume¹⁹⁷ is not sufficient to avoid the increasing penalty on carbon emissions from natural gas. And although the blend (hydrogen + natural gas) represents $\sim 38\%$ of final energy for heating buildings across the High Demand scenarios in 2050, the hydrogen contained within the blend represents $< 3\%$ of final energy for building heating, and a smaller share of total buildings final energy. See Table 2.2 for additional details about hydrogen consumption by end use.

Sector	Scenario:							
	No Dedicated H ₂ T&D, Reference Demand				Pipeline H ₂ T&D, High Demand			
	Final energy (EJ)	H ₂ demand (EJ)	% final energy	% service output	Final energy (EJ)	H ₂ demand (EJ)	% final energy	% service output
Industry	278.9	8.2	3.0%	----	281.4	12.5	4.4%	----
Cement	15.3	1.2	7.6%	----	15.3	1.4	9.1%	----
Other industrial energy use	196.3	7.1	3.6%	----	198.5	11.1	5.6%	----
Transportation	135.0	2.6	1.9%	----	134.2	8.0	6%	----
Passenger Vehicle	39.0	0.6	1.4%	1.5%	38.6	3.0	7.7%	8.3%
Bus	6.0	0.6	9.8%	22.1%	6.0	0.7	11.1%	24.6%
Freight Road	47.8	0.7	1.5%	1.7%	47.1	2.8	6.0%	6.9%
Freight Rail	3.8	0.7	17.3%	16.5%	4.0	0.8	20.7%	19.7%
Domestic Shipping	2.3	0.03	1.4%	1.5%	2.3	0.2	8.2%	8.7%
International Shipping	13.2	0.1	0.6%	0.7%	13.2	0.6	4.4%	5.5%
Buildings	171.0	0	0%	----	171.9	1.5	0.9%	----
Heat	33.2	0	0%	----	33.5	0.9	2.7%	----
Other	121.3	0	0%	----	121.7	0.6	0.5%	----
Total	584.9	10.8	1.9%	----	587.4	22.0	3.7%	----

Table 2.2. Annual global hydrogen consumption (EJ) by each end-use sector in 2050 for two of the core scenarios. Values (EJ and %) are rounded to the nearest tenth if larger than or equal to 0.05 (otherwise values are presented to the nearest hundredth). 'Other industrial energy use' refers to the GCAM sector 'industrial energy use'. The subsector 'Other' within the buildings sector refers to the sum of GCAM's 'residential other' and 'commercial other' subsectors. Hydrogen contained within the hydrogen/natural gas blend is also included within these values. Subsectors will not sum to the sector total given that there are subsectors that do not consume hydrogen and are thus not reported here (e.g., building cooling, aviation, industrial feedstocks, N fertilizer production, and energy for water).

2.C.3. Connecting hydrogen supply and demand: delivery pathways to end uses

Figure 2.5 shows hydrogen consumption by major end-use sector and delivery pathway.

Truck and pipeline transport can be significant, with pipeline transport generally favored over truck transport when both are available due to differences in assumed costs. However, in all cases onsite production is significant and is larger than the amount of hydrogen delivered by truck or pipeline (as well as the amount blended into the natural gas networks). Furthermore,

consumption by industry is comparable to and often larger than consumption by the transportation sector. These results are relevant to the evaluation of hydrogen leakage potential, which is of increasing interest, in part, due to the indirect impact of hydrogen emissions on the climate.^{198, 199} Other work has begun to evaluate which areas of the supply chain would have greater or lesser leakage risk, with production, transportation by pipeline, and industrial uses appearing to have lower risk than truck transport or use in transportation.²⁰⁰

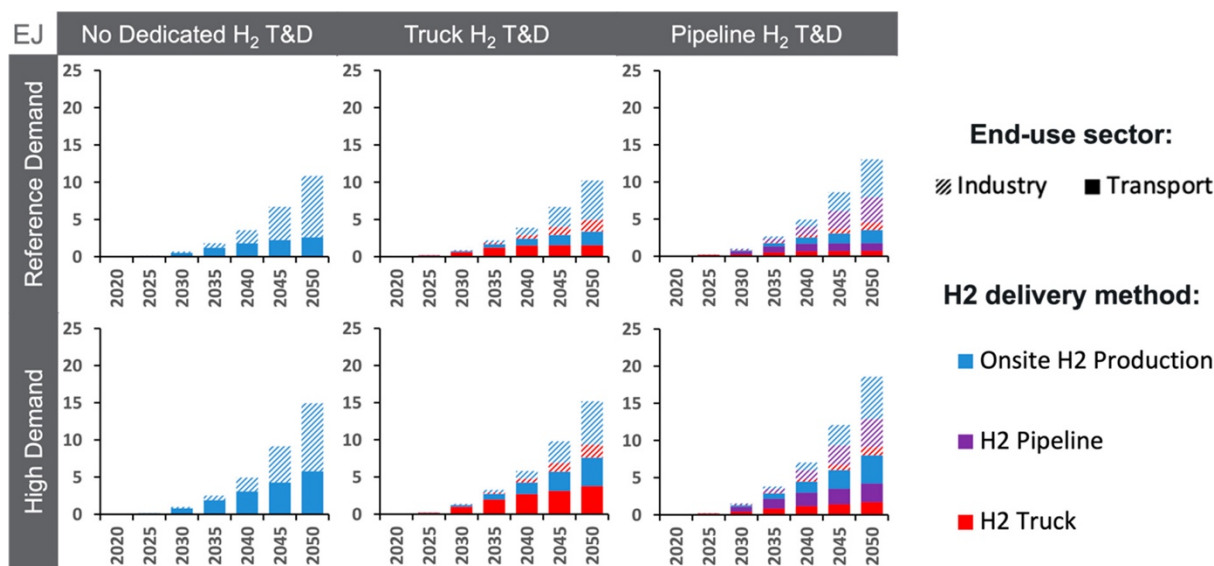


Figure 2.5. Annual global hydrogen consumption by delivery method to end-use sectors through midcentury for the core scenarios. The figure does not include hydrogen blended with natural gas and delivered by the natural gas pipeline network.

A wide range of hydrogen leakage rates across hydrogen supply and demand have been published in the literature.^{201, 202, 203, 204} The hydrogen leakage rate could be reduced if hydrogen were produced onsite, with estimates suggesting less than half a percent lost from electrolysis and SMR²⁰⁵ (not withstanding losses from storage). Leakage potential is also thought to be lower for dedicated gaseous pipeline delivery than for liquid hydrogen truck T&D.^{206, 207} Our results show that when pipelines are available, truck delivery plays a smaller role. When both hydrogen T&D options are available, 13-15% of total hydrogen is distributed by trucks and 34% by

pipelines in 2050 (not including blended hydrogen). Thus, leakage potential is likely reduced with pipeline availability relative to a scenario in which T&D is limited to trucks. Greater leakage risk is likely to occur when hydrogen is delivered by truck to the transportation sector, because, after hydrogen is loaded onto trucks, additional hydrogen can be lost at refueling stations.²⁰⁸ Yet, we find truck delivery to the transportation sector to be a small portion of total hydrogen consumption across scenarios (less than 9% in 2050, not including blended hydrogen). Further study of leakage rates across different production, delivery, and consumption pathways would help to inform an assessment of overall H₂ leakage potential and options to mitigate leakage.

2.D. Discussion

This study investigated hydrogen's potential contribution to decarbonization focusing on the role of hydrogen T&D infrastructure availability, end-use technology costs, and climate policy stringency in GCAM scenarios. Results from these scenarios suggest several insights about the potential role for hydrogen in an energy transition. On the supply side, when distributed production options are represented, the availability of hydrogen T&D primarily affects the production mix rather than the scale of hydrogen deployment. In effect, onsite production places a floor on production in our scenarios and is found to be cost-effective (accounting for over half of production in five of the six core scenarios) even when T&D infrastructure is available to deliver centrally produced hydrogen. Consistent with other recent IAM analyses that have noted the potential role for electrolysis-based hydrogen²⁰⁹ we find that the largest share of onsite production is from green hydrogen due to its modularity. However, the role of onsite blue hydrogen in industry is also significant.

The large portion of onsite generation coming from green hydrogen is notable as modular electrolyzers are ‘granular’ technologies (smaller in physical and/or economic scale per unit), and it has been demonstrated that increased granularity can be associated with quicker learning and diffusion timeframes as well as lower investor risk.²¹⁰ Onsite production of low-carbon hydrogen (whether blue or green) could also avoid aspects of the ‘three-sided chicken-and-egg’ problem,²¹¹ or the need to simultaneously foster demand, supply, and delivery infrastructure. This is because supply and demand for hydrogen would be balanced within a facility (i.e., a consumer need not wait for a centralized supply of hydrogen, which may not materialize until demand is apparent). While hydrogen exports may expand the role of centrally produced hydrogen, the inclusion of hydrogen trade across GCAM regions is not likely to significantly change our results since the high cost of moving hydrogen regionally already limits the deployment of centralized supply.

On the demand side, industrial use of hydrogen, primarily for high-temperature heat, is found to be greater than the sum of all transportation uses in most of our core scenarios, reflecting in part the overall size of final energy demand in these sectors (industrial final energy demand is about twice transportation final energy demand in 2050). However, in scenarios with lower end-use costs, the hydrogen share of transportation final energy is greater than the hydrogen share of industrial final energy, suggesting that hydrogen demand is more sensitive to end-use technology costs. Indeed, we find that the overall amount of deployment is driven more by end-use technology costs than by assumptions about T&D infrastructure. In addition, we find that overall hydrogen deployment is sensitive to increased climate policy stringency (increasing

both in absolute terms and as a share of final energy), suggesting that hydrogen will remain a key focus in policy and planning related to the energy transition.

We also note that the small share of hydrogen transported by truck and delivered to the transportation sector across our scenarios diminishes the risk of leakage relative to scenarios in which those pathways are more dominant. Leakage risk would also presumably be lower when a larger share of hydrogen is produced and consumed onsite. Given the pathways by which hydrogen is produced and consumed in GCAM scenarios, and the increasing discussion of hydrogen leakage, it would be helpful for future research to consider leakage at each stage of the supply chain explicitly, such that leakage assumptions are consistent with the pathways. Finally, while our focus has been on hydrogen demand by energy end uses, there remain questions about the role of hydrogen in the power sector and in the production of hydrogen-derived fuels, which will be a focus of future GCAM development.

Chapter 3:

Mid-century impacts of the “Hydrogen Economy” on the water-energy-food nexus^G

^G This chapter is currently in preparation for potential submission to a journal for publication consideration. Contributions are centrally from the author of this dissertation and the publication will include the following co-authors: Leon Clarke, Jay Fuhrman, Nathan Hultman, Page Kyle, Haewon McJeon, Hassan Niazi, and Paul Wolfram.

3.A. Introduction

It is generally accepted that low- to zero-carbon hydrogen will be required to contribute to carbon dioxide (CO₂) emissions mitigation in our path towards maintaining global average temperatures below the 2°C, or more ambitiously 1.5°C, rise relative to the pre-industrial levels.²¹² If conventional applications of hydrogen are to be decarbonized, rather than offset elsewhere, hydrogen produced from clean methods will be a necessity. Such uses include refining, fertilizer manufacturing, and other chemical feedstock needs.²¹³ “Clean hydrogen” will also likely help facilitate decarbonization in other areas of the global economy that are difficult or impossible to directly electrify. For example, the energy carrier shows promise in mitigating emissions from heavy-duty and long-distance modes of transport^{214, 215}, satiating energy demand for high-temperature industrial processes²¹⁶, and reducing iron ore for steel production.²¹⁷ This is not to suggest that hydrogen’s role in climate change mitigation has been fully settled. There are open-ended questions concerning the necessity of certain uses of the energy carrier, such as feedstocks for hydrogen-based energy and hydrogen-derived fuels (e.g., non-biomass synthetic fuels²¹⁸ as well as methanol²¹⁹ and ammonia for energy²²⁰). Additionally, less extensively investigated questions remain regarding hydrogen’s potential impact on societal objectives other than climate change mitigation, such as its potential to influence food markets and water availability.

Securing fresh water and food for a growing world population has been enshrined within the globally agreed upon Sustainable Development Goals²²¹ (SDGs; SDG2 and SDG6 for food and water²²², respectively). Policy and research communities have likewise acknowledged the growing interconnectedness of energy, water, and food systems. Under this understanding, the

“water-energy-food” nexus (WEF) has emerged as a framework for understanding the linkages between, and impacts on, each of these components. A similar nexus has been coined under the term “water-energy-land nexus”²²³, as well as a subset of literature coined the “water-energy” nexus.²²⁴ Although the beginnings of the WEF structure can be traced to the late 1940s²²⁵, a heightened attention to these issues has occurred over the past two decades.²²⁶ A number of studies focusing on the nexus between water, energy, and food systems have been published with global^{227, 228}, regional (e.g., Europe^{229, 230}, Africa²³¹, East Asia²³², as well as Latin America and the Caribbean²³³), and country scope levels (e.g., the United States²³⁴, China²³⁵, Australia²³⁶, and Iran²³⁷).

Analysis has also been conducted within the WEF and water-energy frameworks with a special focus on certain areas of the energy system or certain sources of primary energy. This includes publications examining electricity generation^{238, 239, 240, 241, 242} as well as fossil fuel supply and use.^{243, 244, 245, 246, 247} Other studies have examined bioenergy’s impact on land, food, and water systems (e.g.,^{248, 249, 250, 251}). This may come as no surprise, given that bioenergy can directly compete with other agricultural commodities for arable land, freshwater resources, and fertilizer inputs. The use of bioenergy can likewise involve additional water demand beyond what is required for its cultivation (e.g., for cooling processes in thermal electricity generation). Previous studies have demonstrated that extensive use of bioenergy could therefore exacerbate water scarcity issues²⁵² as well as negatively influence agricultural markets.²⁵³

By contrast, little is known about how clean hydrogen, which will likely play a growing role in our energy system, could impact hydrological and agricultural systems in the future. This

is despite the fact that there are several direct and indirect routes for the energy carrier to influence the WEF nexus. To begin, all forms of hydrogen production that are prominently discussed by policymakers and in the literature directly require water, both as a means of feedstock from which hydrogen is extracted (i.e., electrolysis) or for cooling and process needs (e.g., fossil- and biomass-based production). Biomass-based hydrogen will also involve water upstream of the energy transformation process, as any purpose-grown biomass feedstock must be cultivated. Hydrogen can also directly impact food systems, given its use for feedstock during ammonia-based fertilizer manufacturing, which would in turn enable crop and bioenergy growth. Further complicating the matter, hydrogen could displace other forms of energy (e.g., bioenergy, electricity, and fossil fuels) which have associated water and crop impacts. Lastly, global markets for commodities are associated with virtual water trade (VWT), or the trade of water which was consumed during the production of a given good. While VWT in the context of agricultural products has been discussed by Graham et al. (2020)²⁵⁴ and Delpasand et al. (2023)'s analysis of industrial as well as agricultural goods²⁵⁵, the implications of an international market for hydrogen on water systems has not been explored.

Studies that have thus far explored hydrogen's effects on water systems have only provided a partial view of potential impacts by generally focusing on global change, renewable electrolysis ("green hydrogen"), and/or often focus on either water consumption or water withdrawals. Both concepts are important for hydrological evaluations, as withdrawals represent the total water extracted for a particular use while consumption entails the amount of water that is used within a given process that cannot be returned to the water system or reused immediately. Additionally, previous authors often have not competed hydrogen against other sources of

energy (or competed various methods of hydrogen production amongst each other) within an internally consistent model in order to endogenously determine the scale of hydrogen deployment within their studies.^H Beswick et al. (2021) determined that hydrogen would have a minimal impact on water consumption as well as withdrawals and made clear that the water impact of hydrogen is not only based on the water for producing the energy carrier, but also entails the reduction in water used for traditional energy sources which are being displaced (e.g., fossil fuels).²⁵⁶ However, the authors only considered green hydrogen production, the scale of the energy carrier was exogenously stipulated, and the analysis was at the global level.

Tonelli et al. (2023) further advanced this line of research by investigating the matter at the country level, finding that it was unlikely to be the cause of water scarcity but could contribute to the matter.²⁵⁷ Yet, they likewise only considered green hydrogen with an exogenous demand, inspected only water withdrawals, and did not include the reduction of water for displaced oil-based refining.²⁵⁸ Lastly, Wei et al. (2024)'s life cycle analysis of hydrogen suggested it would impact global water use minimally.²⁵⁹ This work did include multiple production technologies but had exogenously defined scales of hydrogen production.

Receiving even less attention is the matter of how, and to what extent, clean hydrogen may influence agricultural systems. It is well known that fertilizers are an important input to crop cultivation and the literature has detailed how its traditionally carbon-intensive manufacturing process can be decarbonized with clean hydrogen feedstock as well as the potential competitiveness of distributed clean fertilizers.^{260, 261, 262} However, the authors of the current

^H Where applicable for previous literature, this is henceforth referred to as exogenously stipulating the scale of hydrogen within this chapter.

study are unaware of any peer-reviewed literature examining how hydrogen's use on an economy-wide basis could affect crops markets.

The objective of this study is to address these water- and crop-related gaps in the literature. The analysis is enabled by an integrated assessment model (IAM), given its ability to handle the complex interactions between the water, energy, and food systems (see the Methods section for more details). This work will specifically aim to answer the following research question: *what are the potential implications of the "hydrogen economy" on water and staple crops?* This effect will be studied by simulating energy transitions under climate change mitigation, and will analyze impacts at the global, regional, and water basin level. It will further consider both water withdrawals and consumption, as well as allow for multiple methods of producing hydrogen with both an endogenously calculated and exogenously stipulated demand for the energy carrier considered. Further, this study considers scenarios in which hydrogen supply is constrained to regional markets as well as available within a global market allowing for international trade, as this too could influence the water-energy-food nexus.

3.B. Methods

The Global Change Analysis Model (GCAM)²⁶³ is leveraged in this study in order to investigate clean hydrogen's impact on the WEF nexus. GCAM is an open-source partial equilibrium IAM with global coverage and regionally heterogeneous energy, water, and land units. An enhanced version of latest release, version 7²⁶⁴, was utilized here, with model modifications undertaken to improve the representation of hydrogen that are detailed in the subsequent section. GCAM is particularly well suited for this line of research, given that it links

the economy with the energy, land, water, and climate systems in an internally consistent framework.²⁶⁵ Regional coverage for these human and earth systems are as follows: 32 economic and energy regions, 235 water basins, 384 land zones, and a global climate system. Simulations through midcentury, which run in 5-year timesteps, are conducted in this analysis. Demand for various economic services and final energy is driven endogenously by changes to the cost of various services, and by population as well as GDP per capita (which are both exogenously stipulated in this work). Assumptions for GDP and population are derived from the “middle-of-the-road” Shared Socio-economic Pathway 2 (SSP2).²⁶⁶ Competition between technological alternatives for a given service within a region’s energy system is based on levelized cost and a logit choice formulation.²⁶⁷ Total levelized costs include the costs for required energy and feedstock inputs (endogenously calculated), non-energy costs (based on exogenous assumptions regarding capital as well as operation and maintenance), and the associated price imposed on CO₂ emissions for a given technology (which is endogenously computed in this work).

3.B.1. H₂-based energy supply and demand

The hydrogen modeling structure utilized within this study is depicted in Figure 3.1. Clean hydrogen, henceforth referred to as hydrogen unless otherwise stipulated, can be produced via various forms of electrolysis, fossil fuels with carbon capture and storage (CCS), or biomass with or without CCS. All forms of production can be produced at centralized supply facilities, which require delivery via a liquid hydrogen truck or gaseous hydrogen pipeline. Grid electrolysis, green hydrogen, and gas with CCS (“blue hydrogen”) are also available as onsite production methods (i.e., produced and consumed at the end-use facility). Hydrogen production and delivery assumptions are largely harmonized with those developed, and detailed at length, in

O'Rourke et al. (2023).²⁶⁸ Exceptions include assumptions for biomass-based hydrogen and the inclusion of hydrogen losses during delivery. Both of these additional developments are detailed in GCAM documentation.²⁶⁹

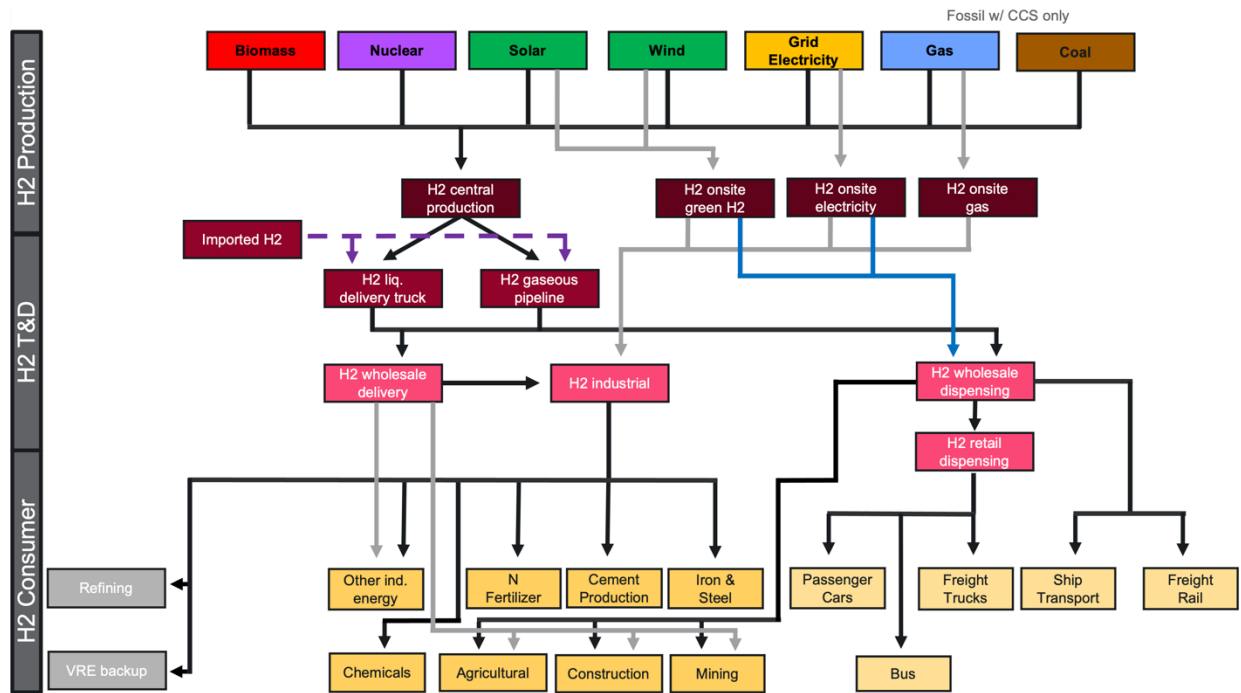


Figure 3.1. Representation of GCAMv7 modeling structure used in this study for hydrogen supply and demand. Refining includes hydrogen for bioliquids. VRE refers to variable renewable energy. Hydrogen trade is only available in a subset of scenarios considered here and therefore the outgoing flow from “Imported H2” is depicted in dashed lines.

Additionally, to the best of our knowledge, this version of GCAM is the first to incorporate hydrogen trade between the model’s 32 economic regions. This trade is represented with a single global market which hydrogen is exported to and imported from. GCAM regions can consume or export domestic hydrogen as well as consume imports from other regions. Model assumptions for trade costs are tied to the version of natural gas trade in GCAM that does not differentiate between liquefied or gaseous delivery. Specifically, these costs are conservatively assumed to be 150% of the cost of trading natural gas (0.95 \$2020/GJ), resulting

in a cost of 1.47 \$2020/GJ for hydrogen. This is believed to be appropriate given the fact that hydrogen requires more energy than natural gas for compression^{270, 271} or liquefaction²⁷² prior to delivery, and costs for gaseous hydrogen pipelines are more than the analogous natural gas technologies.²⁷³

The trade structure also considers hydrogen losses which are assumed to be equal to 150% of the losses imposed on domestic hydrogen delivered by gaseous pipelines in GCAM (for each model period). For example, 1.018 GJ of hydrogen are required to deliver 1 GJ by pipeline to end-use technologies in 2030. Therefore, for the same year 1.027 GJ of hydrogen are required to deliver 1 GJ of imported hydrogen to a given GCAM region. This is believed to be a reasonable approximation, given that hydrogen pipelines between GCAM regions would likely be longer in length than the 100km length assumed for domestic transmission pipelines, as well as the fact that hydrogen could be liquefied and delivered via ship which would entail boil-off rates of roughly 1% per day.²⁷⁴ For context, a cargo ship leaving Darwin in northern Australia and traveling at an average speed of 22 knots would take more than 5 days to reach Tokyo, Japan.²⁷⁵ Once imported, traded hydrogen can be delivered to domestic consumers via liquid hydrogen truck or gaseous hydrogen pipeline, and assumes the same energy requirements, non-energy costs, and hydrogen losses that are levied on domestically produced and delivered hydrogen. Hydrogen trade between GCAM regions is first available in 2030 and reaches non-cost parity with domestic production in 2040.¹

¹ Non-cost parity is modeled within GCAM with share-weight parameters. Share-weights capture non-levelized cost considerations that can impact competition between technological alternatives (such as preferences). Non-cost parity for imported hydrogen is achieved when the share-weight has a value of 1.

Hydrogen-consuming technologies are included for numerous potential applications. In the industrial sector hydrogen can be utilized for various processes (e.g., nitrogen-based fertilizer manufacturing) and energy requirements (e.g., process heat for cement). Within the transportation sector, the energy carrier is made available for road-, rail-, and ship-based transport. Hydrogen can also be consumed as a complimentary feedstock for bioliquid refining and as a means of generating backup peaker electricity for variable renewable electricity. Assumptions regarding the non-energy cost and energy requirements for these applications are detailed in GCAM documentation^{276, 277} and have been used in previous peer-reviewed publications^{278, 279, 280, 281}.

3.B.2. Model structure for water and agricultural systems

GCAM's detailed model structure of water is resolved for 235 water basins that represent the spatial delineation of water sources within the world's hydrological system. Water can be supplied to various uses through depletable groundwater extraction, renewable runoff utilization, and desalination. Similar to other markets in GCAM, Kim et al. (2016) describes that the supply of groundwater, runoff, and desalination resources are balanced by sectoral demands.²⁸² Irrigation demands are spatially defined at the intersection of GCAM's water basins and energy regions and at the energy-economic regions for other sectors. The representation of water includes demand for primary energy supply (e.g., for extraction), energy transformations (e.g., electricity generation and hydrogen production), direct air capture with carbon storage (DACCS), municipal and other industrial needs, as well as livestock rearing and agricultural crop production. This demand-supply balance accounts for both water withdrawals and consumption.

For more details on GCAM's representation of the water supply and demand, see Niazi et al. (2024a)²⁸³, Liu et al. (2018)²⁸⁴, and GCAM version 7's documentation.²⁸⁵

Water requirements for hydrogen production are derived from the National Renewable Energy Laboratory's (NREL's) Hydrogen Analysis Production Models (H2A) and are shown in Table 3.1. H2A version 3.2018²⁸⁶ is used for all technologies other than biomass-based hydrogen and nuclear high temperature electrolysis (HTE). The latter leverages assumptions from the most recent available H2A version (v2.1.1²⁸⁷) for this technology, while biomass-based hydrogen water requirements are based on a NREL technical report.²⁸⁸ Water requirements for 2020 through 2035 are generally set by calculating an improvement rate that is applied in each model period in order to achieve the specified input requirements in 2040. This is true for all technologies other than coal gasification with CCS and nuclear HTE. Future (2040) assumptions for coal with CCS are not provided by H2A version 3.2018, thus water requirements are conservatively assumed to be constant for all periods. Similarly, H2A v2.1.1 did not include current (2015) assumptions for nuclear HTE, and thus all periods assume the same water requirements as the those from future assumptions. No improvement in water inputs is assumed after 2040 for any hydrogen production technology.

Not only does GCAM include demand for water by the agricultural and energy systems, but it also includes energy demand for water supply. This feature further empowers the model to investigate the interactions within the WEF nexus. Assumptions for energy used during water treatment (i.e., for desalination, industrial, and municipal water uses), abstraction (i.e., for irrigation, industrial, and municipal water uses), municipal water distribution, and wastewater treatment are documented in Kyle et al. (2021).²⁸⁹

Hydrogen production method	Water Withdrawals or Consumption	2015	2040	Units
Coal Gasification + CCS	Withdrawals	10.060	10.060	gal / kgH2 out
	Consumption	10.060	10.060	
Natural Gas SMR + CCS	Withdrawals	4.850	4.850	gal / kgH2 out
	Consumption	4.493	4.493	
Natural Gas SMR + CCS (onsite)	Withdrawals	4.850	4.850	gal / kgH2 out
	Consumption	4.493	4.493	
Nuclear HTE	Withdrawals	2.361	2.361	gal / kgH2 out
	Consumption	2.361	2.361	
Biomass Gasification	Withdrawals	3.370	3.280	gal / kgH2 out
	Consumption	3.274	3.188	
Biomass Gasification + CCS	Withdrawals	3.370	3.280	gal / kgH2 out
	Consumption	3.274	3.188	
PEM Electrolysis	Withdrawals	4.760	3.980	gal / kgH2 out
	Consumption	4.760	3.980	
PEM Electrolysis (onsite)	Withdrawals	4.760	3.980	gal / kgH2 out
	Consumption	4.760	3.980	

Table 3.1. H₂ production water requirement assumptions. CCS refers to carbon capture and sequestration, HTE refers to high temperature electrolysis, and PEM refers to proton exchange membrane. PEM assumptions apply to grid and renewable electrolysis.

The model also represents 384 land areas which allow for use conversion by competition between uses based on profitability and a logit formulation. Land is divided into non-commercial (e.g., unmanaged pasture and forests), commercial (e.g., cropland and managed pasture), and inarable land (e.g., tundra, desert, and urban areas). The latter of these divisions is exogenously assigned land area. In terms of cropland, cultivation can occur for purpose-grown energy crops (e.g., biomass crops of woody and herbaceous nature), staple crops (i.e., corn, rice, root tuber, and wheat), non-staples (e.g., oil crops, palm fruit, sugar crops, fiber crops, etc.), and fodder crops. Crops can either be rainfed or irrigated, with irrigated water demand linked to subregional water markets. In addition, crop production technologies are differentiated by fertilizer use, which is linked to the fertilizer supply from the energy and industrial module. GCAM's detailed technology representation allows for endogenous productivity responses via production technology transformations, such as intensification with irrigation or higher fertilizer application. Agricultural products, including crops, can also be traded between GCAM's 32 economic

regions, represented by a logit-based Armington framework. For more information on the model's agricultural, crop, and land representation, see Zhao et al. (2020)²⁹⁰, Zhao et al. (2022)²⁹¹, and Zhao et al. (2024).²⁹² Given this multifaceted representation of land, water, as well as water's demand for energy, GCAM has been used to investigate complex water and agricultural issues in a number of peer-reviewed studies (e.g., ^{293, 294, 295, 296, 297}).

3.B.3. Energy transition scenarios

Several scenarios were simulated through midcentury (Table 3.2). The first scenario involves a counterfactual where no hydrogen is available within the simulated energy transition (“*No H₂*”). This allows the research to tease out how hydrogen impacts water and food systems relative to a transition without the energy carrier. The remaining six scenarios allow for hydrogen and simultaneously vary along two dimensions: (A) hydrogen production technological availability and supply scale, as well (B) availability of hydrogen trade leveraging the newly added feature in the model. Regarding the first dimension (A), three scenario components are considered within the research design:

- (1) “*H₂ available*”: all hydrogen production methods are available to contribute to hydrogen supply and the scale of hydrogen deployment is endogenously calculated by the model.
- (2) “*H₂ green*”: only renewable electrolysis (“green hydrogen”) methods of production are available for hydrogen supply and the scale of hydrogen deployment is endogenously calculated by the model.
- (3) “*H₂ High*”: all hydrogen production methods are available to contribute to hydrogen supply and the scale of hydrogen deployment is exogenously set to the levels defined

within the Hydrogen Council’s *Hydrogen Scaling Up: a sustainable pathway for the global energy transition* 2017 report.²⁹⁸

The Hydrogen Council’s report was selected as the basis for the “H₂ High” scenario component given that it represents an ambitious scale up of the energy carrier (resulting in a 63% – 82% increase in hydrogen deployment globally compared to any of the other scenarios simulated with hydrogen availability here), and the fact that it is often referenced in peer-reviewed literature^{299, 300, 301, 302, 303, 304, 305} and national hydrogen strategies.^{306, 307, 308}

Scenario name	H ₂ Availability (H ₂ scale)	H ₂ trade
No H ₂	No	NA
H ₂ available	H ₂ available (model determined scale)	No H ₂ trade between GCAM regions
H ₂ Green	Green H ₂ available (model determined scale)	
H ₂ High	H ₂ available (Hydrogen Council 2017 scale)	
H ₂ available with trade	H ₂ available (model determined scale)	H ₂ trade available between GCAM regions
H ₂ Green with trade	Green H ₂ available (model determined scale)	
H ₂ High with trade	H ₂ available (Hydrogen Council 2017 scale)	

Table 3.2. Scenario design for this study. All scenarios achieve net-zero CO₂ emissions in 2050.

Given that hydrogen trade could influence the water and food impacts of the energy carrier, the second dimension (B) varies whether such trade between GCAM regions is allowed. Together, these two dimensions form a two by three matrix comprising six scenarios where hydrogen is available. All scenarios, including the counterfactual, begin with a global total of 33.4 Gt of CO₂ emissions in 2025 which linearly declines to net 0 Gt of CO₂ emissions in 2050. The climate objective is achieved by applying an endogenously calculated global carbon price to

carbon emissions from the energy and industrial sectors. While not included in the emissions constraint, carbon emissions from land-use change face a carbon price which is a fraction of the price applied to emissions from the energy and industrial sectors. The fraction assumed matches the default settings for this version of GCAM. Despite not being considered within the CO₂ constraint, global land-use change emissions are net negative across scenarios in 2050, resulting in total net emissions across the economy that are slightly less than zero Gt for that year.

3.C. Results

3.C.1. Hydrogen’s impact on the water withdrawals

Hydrogen production will constitute a relatively minor amount of total water withdrawals globally and across model regions. Across scenarios, global water withdrawals rise from 3,648 cubic kilometers (km³) in 2020 to 4481 – 4558 km³ at midcentury. When hydrogen is available, only 5.4 to 11.8 km³ of water withdrawals are required for its production for the same year. The lower end of this range corresponds to the scenarios where only green hydrogen is available, which is a reflection of the fact that renewable electrolysis requires less water withdrawals than some technologies (e.g., coal or natural gas with CCS) and that hydrogen production is slightly lower when green hydrogen is the only means of producing the energy carrier (43 EJ globally, as compared to 48 EJ in the “H₂ available” case; see Figures B.1a–B.1b). Intuitively, the higher end of this range is for the “H₂ High” scenarios where hydrogen production is the largest (78 EJ). Despite multiple km³ of water withdrawals being required, hydrogen production itself represents a very minor percentage of total global withdrawals – amounting to only 0.12 – 0.26% across the cases examined here. This is not surprising, given that the energy carrier only represents 5.8 – 11.5% of global final energy (see Figure B.3 for regional results), and the energy system is only

a portion of total water withdrawals (35-36% across scenarios in 2050; see Figure B.4). These findings are also not sensitive to the availability of trade, as across scenarios absolute withdrawals and the percent of total withdrawals used for hydrogen production are stable.

Figure 3.2 portrays hydrogen's impact on water withdrawals on a regional basis. Although there is variation in the percentage of water withdrawals for hydrogen production across regions, the midcentury results are qualitatively similar to what was found globally (Figure 3.2, Panel A). For instance, in the "H₂ available" scenario this proportion ranges from 0.03% (in Central Asia) to 0.5% (in Africa Western). In Panel C it can be seen that when the scale of hydrogen supply is exogenously set to an ambitious level ("H₂ High") some regions exceed 0.5% (e.g., 1% in Africa Western) and hydrogen trade does increase the percentage across paired scenarios for some regions (e.g., 1.3% in South America Northern in the "H₂ High trade available" case). Still, hydrogen remains a minor contributor to total withdrawals across regions and scenarios. This is true even when the proportion of final energy provided by the energy carrier reaches its highest range across scenarios in the "H₂ High" cases, where H₂ represents 6.3 – 20.4% of final energy across regions at midcentury (Figure B.3).

Globally, hydrogen availability results in a small increase in total water withdrawals in 2050 relative to the counterfactual (+1.6 to +1.7%). Yet there is large variance in the change at the regional level (Figure 3.2, Panel B), signifying the importance of regional water-energy-land resource dynamics resulting in pronounced local impacts. Hydrogen availability leads to some regions having a decrease in water withdrawals while others see an increase. More specifically, for the "H₂ available" case, the region with the largest decrease is Africa Western (-3.8%) while

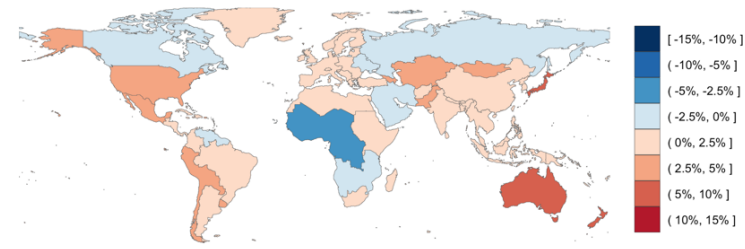
Australia and New Zealand (+8.7%) see the largest increase. Impacts also vary by model regions that are located within the same area of the world. In North America for the same scenario, Mexico (+4.6%) and the United States (+5%) see increases while Canada sees a minor decrease (-0.1%). Most model regions within Latin America and the Caribbean see increases, other than South America Northern (-0.2%). The outlook is slightly more favorable for some regions in Africa and the Middle East. Water withdrawals are reduced in Africa Southern (-1.9%) and the Middle East (-1.2%), and as noted they also are reduced for Africa Western. Africa Eastern and South Africa see expansions in withdrawals which are all less than 0.7%, although the rise is larger for Africa Northern (+2%). On the other hand, all regions in Asia see increases in withdrawals, and for this area of the world the rise is largest for Japan (+6.2%). And while decreases are seen in Russia (-1.2%) and Eastern Europe (-0.1%), hydrogen availability causes the remainder of Europe to increase water withdrawals.

Similar changes are found in the remaining scenarios with hydrogen available, although the range of change expands in width for the “H₂ High” scenarios (-4.5% to 10.8%) and Japan replaces Australia and New Zealand as the region with largest increase in withdrawals for the same scenarios. However, the relative change versus the counterfactual is even more pronounced when viewed at the basin level (Figure B.5). Across scenarios, the impact of hydrogen availability causes a range of -8.8% to +28.5% change in basin level withdrawals and basin level changes are generally similar across scenarios (although the range is widest for the “H₂ High” scenarios). While global and country level increases are smaller in magnitude, basin level impacts suggest potential implications that may need to be further investigated for countries with hydrogen export ambitions. In all scenarios, there are Chilean and Australian basins which see

Panel (A): Percentage of water withdrawals for H_2 production in 2050 for the “ H_2 available” scenario



Panel (B): Percentage change in total water withdrawals in 2050 for the “ H_2 available” scenario compared to the “No H_2 ” scenario.



Panel (C): Results for remaining scenarios.

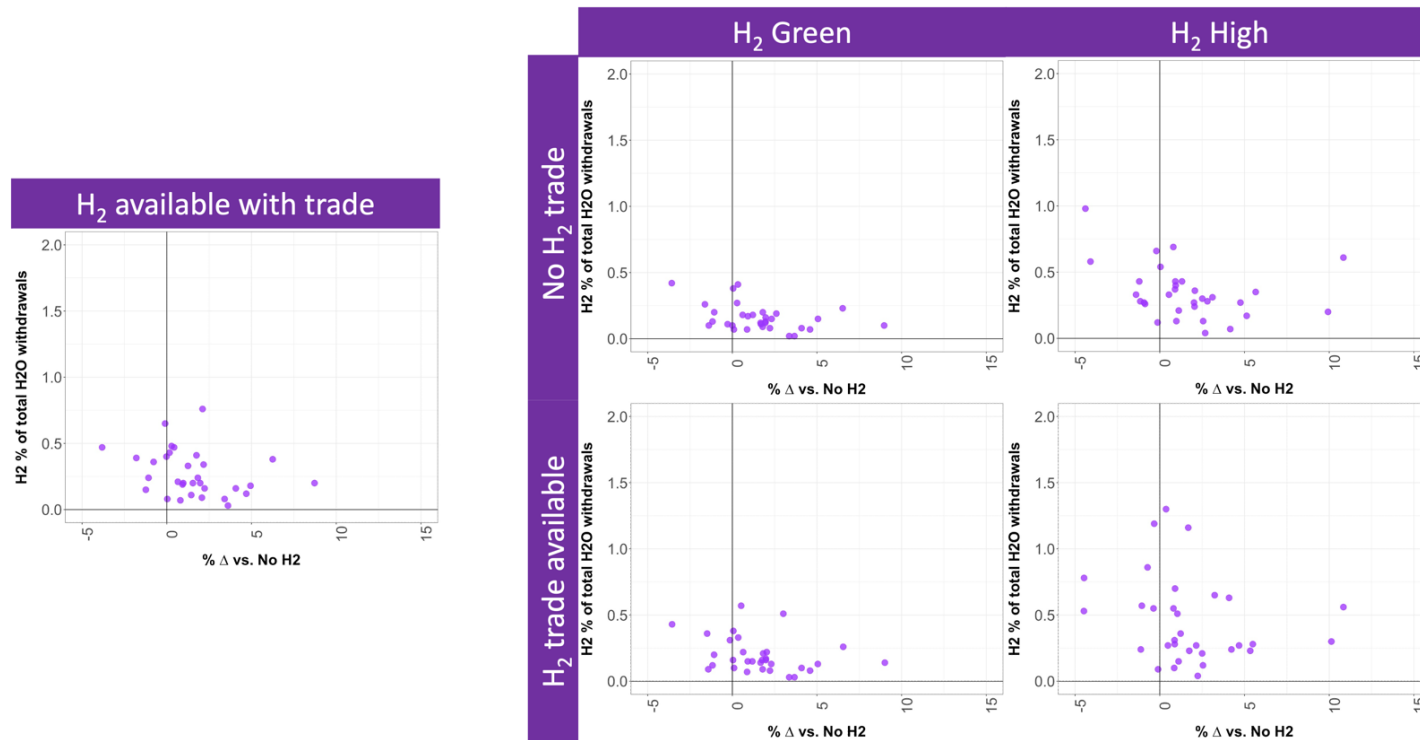


Figure 3.2. Hydrogen’s impact on water withdrawals by scenario and GCAM region in 2050. Panel (A) portrays the percentage of water withdrawals for hydrogen production by economic region for the “ H_2 available” scenario. Panel (B) depicts the percentage change in total water withdrawals with clean hydrogen availability relative to the counterfactual where no clean hydrogen is available for the “ H_2 available” scenario. Panel (C) shows results for the remaining 5 scenarios with hydrogen availability.

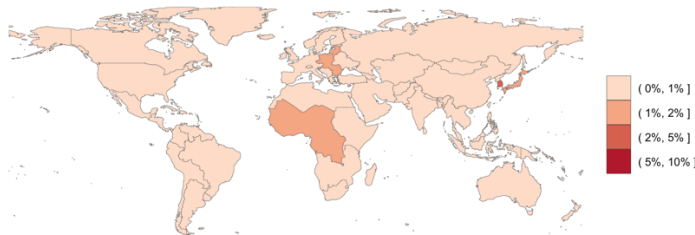
notable increases in water withdrawals and both nations hope to export hydrogen-based energy (e.g., liquefied hydrogen, ammonia, and synthetic fuels). National policymakers will need to consider water resources when approving hydrogen production locations, although – as will be seen in the subsequent subsection – water stresses from the availability of hydrogen are not directly from hydrogen production itself.

3.C.2. Hydrogen’s impact on the water consumption

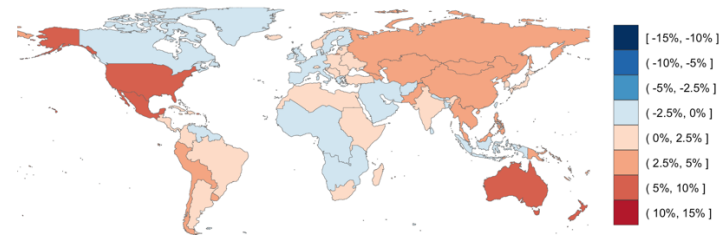
As with water withdrawals, hydrogen production is only a small portion of global water consumption, and this is generally the case for regional withdrawals as well. Total global water consumption across modeled cases increases from 1,463 km³ in 2020 to 1975 – 2018 km³ in 2050. Hydrogen production at midcentury consumes only 5.4 km³ to 11.4 km³ of water, with the lower and upper ends of this range once again corresponding to the “H₂ Green” and “H₂ High” scenarios, respectively. Similarly, hydrogen production accounts for less than 1% of total global water consumption across all scenarios, although the percentage (0.27% – 0.57%) is slightly larger than it was for total withdrawals (0.12% – 0.26%). Results at the global level are also similar between paired scenarios with and without hydrogen trade.

The percentage of water consumption from hydrogen production is also small for the majority of regions. As seen in Panel (A) of Figure 3.3, in the “H₂ available” case this percentage is greater than 1% for only four regions but never exceeds 2.1%: EU-12 (1.2%), Japan (1.2%), Africa Western (1.4%), and South Korea (2%). Yet, the “H₂ High” scenarios do see multiple regions exceeding this proportion, even reaching 3.1% for South Korea when hydrogen trade is not allowed as well as 3.3% in Russia when such trade is available (Panel (C)). This is also the

Panel (A): Percentage of water consumption for H_2 production in 2050 for the “ H_2 available” scenario



Panel (B): Percentage change in total water consumption in 2050 for the “ H_2 available” scenario compared to the “No H_2 ” scenario.



Panel (C): Results for remaining scenarios.

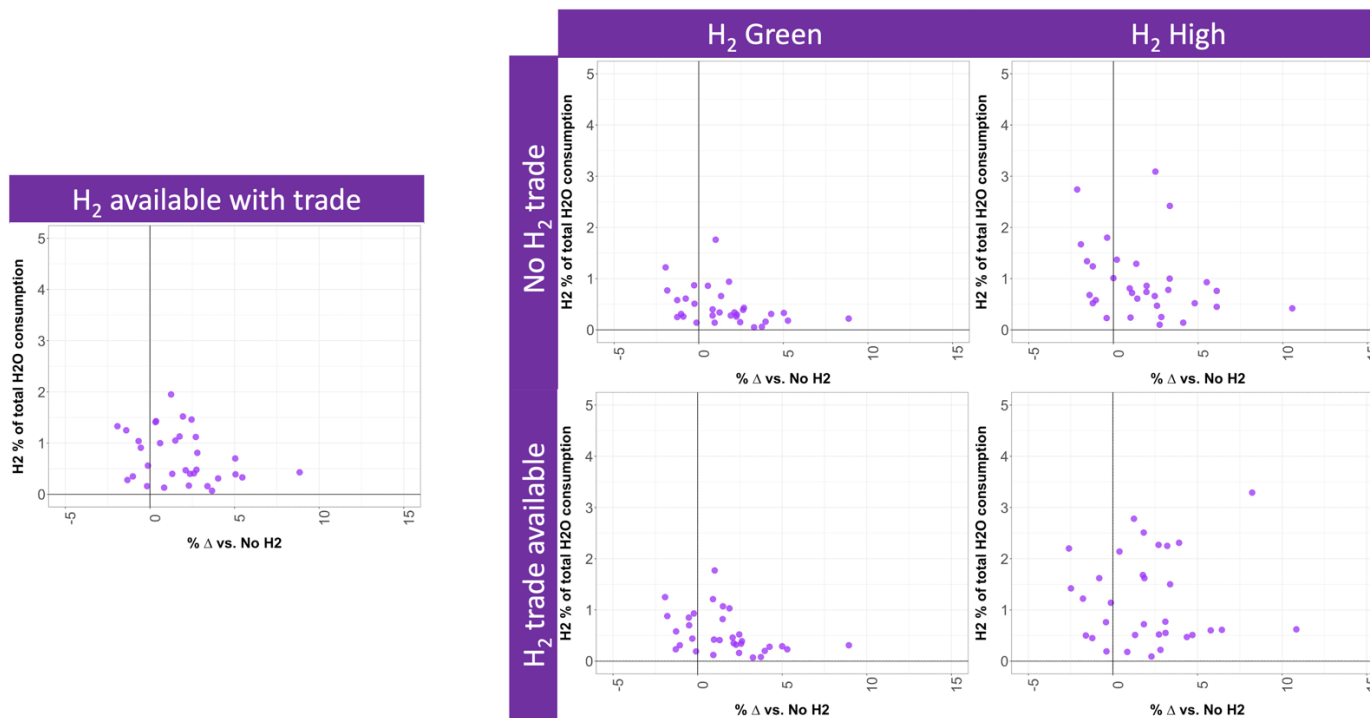


Figure 3.3. Hydrogen’s impact on water consumption by scenario and GCAM region in 2050. Panel (A) portrays the percentage of water consumption for hydrogen production by economic region for the “ H_2 available” scenario. Panel (B) depicts the percentage change in total water consumption with clean hydrogen availability relative to the counterfactual where no clean hydrogen is available for the “ H_2 available” scenario. Panel (C) shows results for the remaining 5 scenarios with hydrogen availability.

pair of scenarios where trade availability impacts water consumption to the greatest degree, with the number of regions surpassing 2% of total water consumption for hydrogen production growing from three to eight with a globalized hydrogen market. Regardless, these findings highlight that hydrogen is not only a minor contributor to regional water withdrawals, but also regional water consumption.

The ability to use hydrogen in the energy transition leads to global increases in water consumption by 2050 relative to the counterfactual (1.9% – 2.2% across scenarios). On a regional basis for the “H₂ available” case, the impact of hydrogen availability on water consumption ranges from -1.9% in Africa Western to +8.7% in Australia and New Zealand (Figure 3.3, Panel (B)). These two regions were similarly the extremes for water withdrawals. A similar, but somewhat expanded, range in change is found for the remaining scenarios (-2.6% to 10.8%), and the range does not appear sensitive to the ability to trade hydrogen (Panel C). While the directional change for consumption is similar to withdrawals for many model regions in this scenario (e.g., those within North and Latin America, the Caribbean, Africa and the Middle East, as well as Australia and New Zealand), some model regions see reversed trends for consumption. For example, despite Russia and Eastern Europe lowering withdrawals for the “H₂ available” case, they have increased consumption (+4.9% and +1.9%, respectively). The opposite is true for Indonesia, which had an increase in water withdrawals but realizes a decrease in consumption (-1%).

Interestingly, hydrogen production itself does not appear to be the root cause for the extreme increases in water consumption, relative to the counterfactual, that are found in some

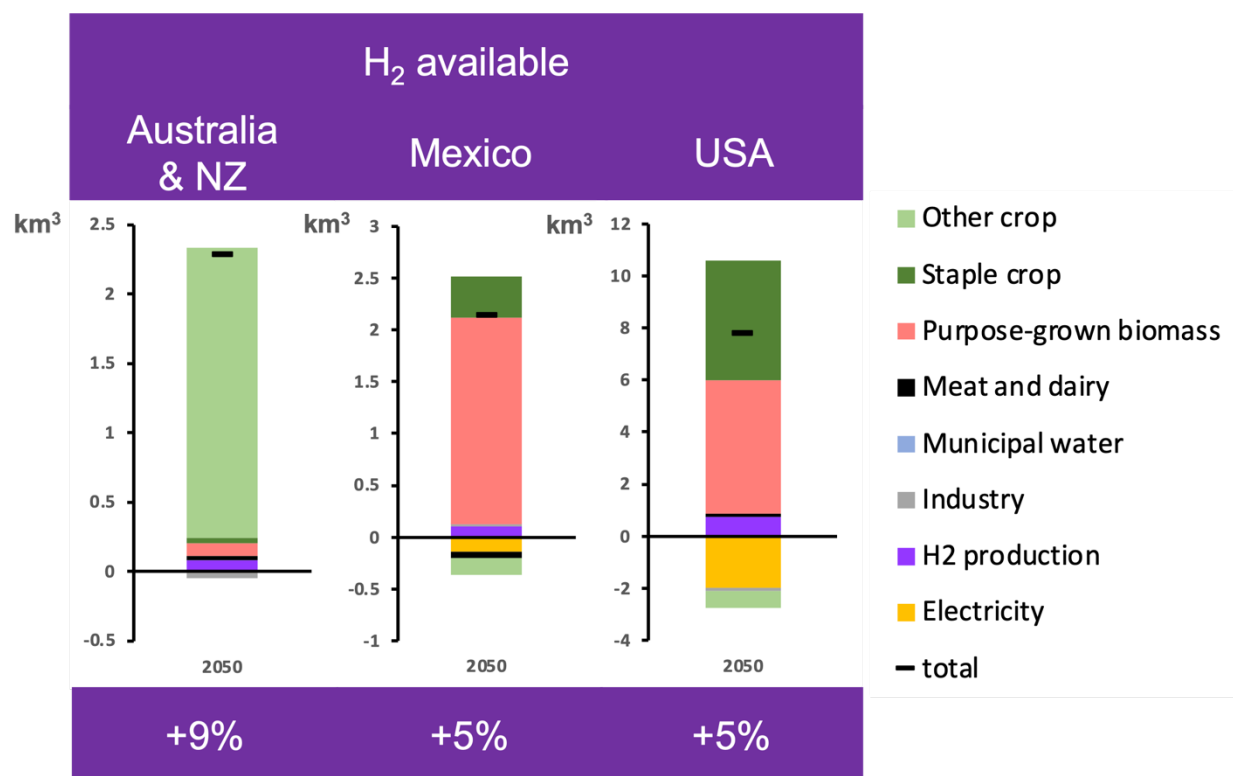


Figure 3.4. Change in water consumption by sector in 2050 for the “H₂ available” scenario. The change is the absolute change compared to the counterfactual where no clean hydrogen is available. The percentages refer to the relative change between scenarios in 2050 for total water consumption and is rounded to the nearest whole percent. Only regions which had greater than or equal to 5% increases in total water consumption are depicted. NZ refers to New Zealand.

regions. Figure 3.4 depicts this change in absolute terms by sector for the three regions in the “H₂ available” scenario that have percent changes greater than or equal to 5%. In each region, hydrogen production itself is only a minor contributor to this increase. Take Australia and New Zealand, for example, which sees the largest positive relative change in water consumption at midcentury. Total consumption increases in the model region by 2.3 km³, but hydrogen production only accounts for 0.08 km³ – or 3.5% of the net growth. Most of the change is due to increased water consumption from crops, which equates to roughly 97% of the net growth in water consumption. A similar finding is illustrated in Mexico and the United States, yet as seen in the figure, the contribution of different crop categories varies by region. The farming of staple

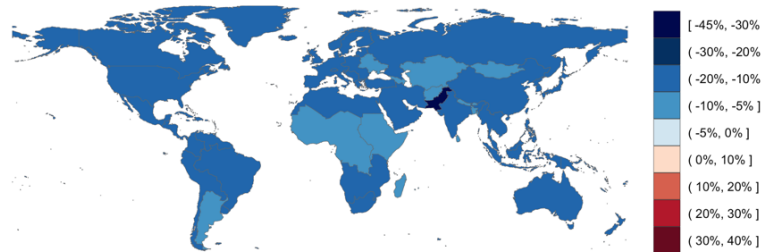
crops plays a much larger proportional role in the net increase of water consumption for Mexico (18.1%) and the United States (58.7%) than in Australia and New Zealand (1.5%). As will be discussed in the subsequent section, this finding is the result of clean hydrogen enabling clean fertilizer production and use within the agricultural sector. This emphasizes the fact that while the availability of hydrogen can increase water demand, this is primarily through an indirect pathway that involves its use rather than its production.

3.C.3. Hydrogen's impact on the staple crops

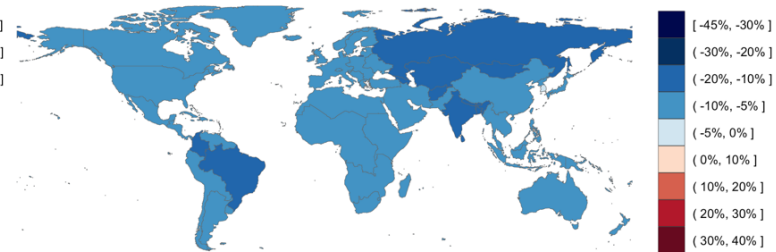
While hydrogen production's relative impact on water systems at the regional level is generally small, the availability of the energy carrier indirectly impacts water systems to a larger extent and its availability similarly has a pronounced influence on staple crops. Panels (A) and (B) of Figures 3.5a and 3.5b show the change in prices for corn, rice, and root tuber for the “H₂ available” scenario (relative to the “No H₂” scenario in 2050). Notably, prices for all staple crops in each region decline with access to clean hydrogen within the economy. However, the effect varies by crop and region. Corn has the largest range in price changes, with the biggest reduction occurring in Pakistan (-37.6%) and the smallest reduction faced by Africa Eastern (-8.6%). The impact range on wheat prices is more concentrated, varying between -19.2% (Pakistan) and -11.8% (Russia).

Rice and root tuber generally have reductions which are not as large in magnitude, with ranges between -13.1% to -4.9% and -10.2% to -1.5%, respectively. Nevertheless, even minor relative reductions in prices (e.g., -1% to -2%) would positively impact consumers. Results are similar across all scenarios (Panel (C) of each figure), with an exception existing for the “H₂

Panel (A): Percentage change in corn prices 2050 for the “H₂ available” scenario compared to the “No H₂” scenario.



Panel (B): Percentage change in rice prices 2050 for the “H₂ available” scenario compared to the “No H₂” scenario.



Panel (C): Results for remaining scenarios.

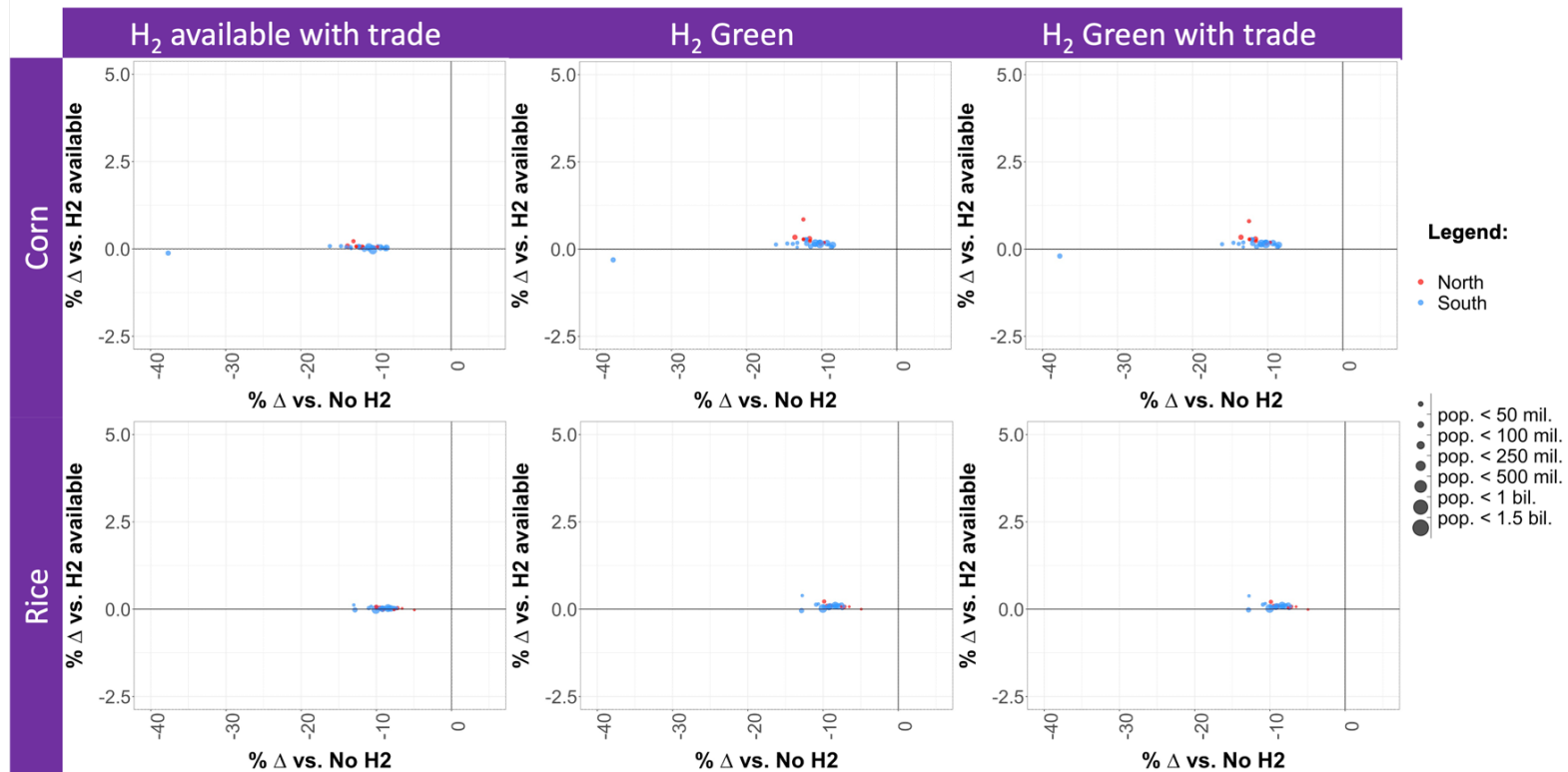
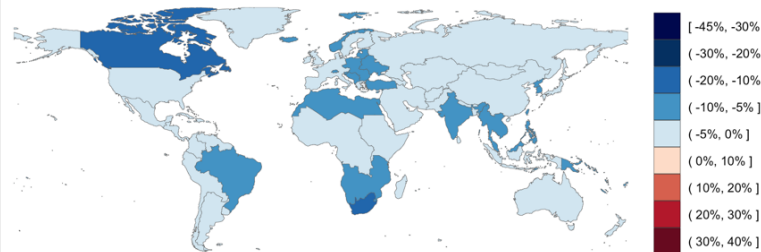


Figure 3.5a. Hydrogen’s impact on staple crop prices by scenario and GCAM region in 2050. Panel (A) portrays the percentage change in corn prices with clean hydrogen availability relative to the counterfactual where no clean hydrogen is available for the “H₂ available” scenario. Panel (B) portrays the same metric for rice prices. Panel (C) shows results for 3 additional scenarios with hydrogen availability. “North” and “South” refer to the Global North and Global South.

Panel (A): Percentage change in root tuber prices 2050 for the “H₂ available” scenario compared to the “No H₂” scenario.



Panel (B): Percentage change in wheat prices 2050 for the “H₂ available” scenario compared to the “No H₂” scenario.



Panel (C): Results for remaining scenarios.

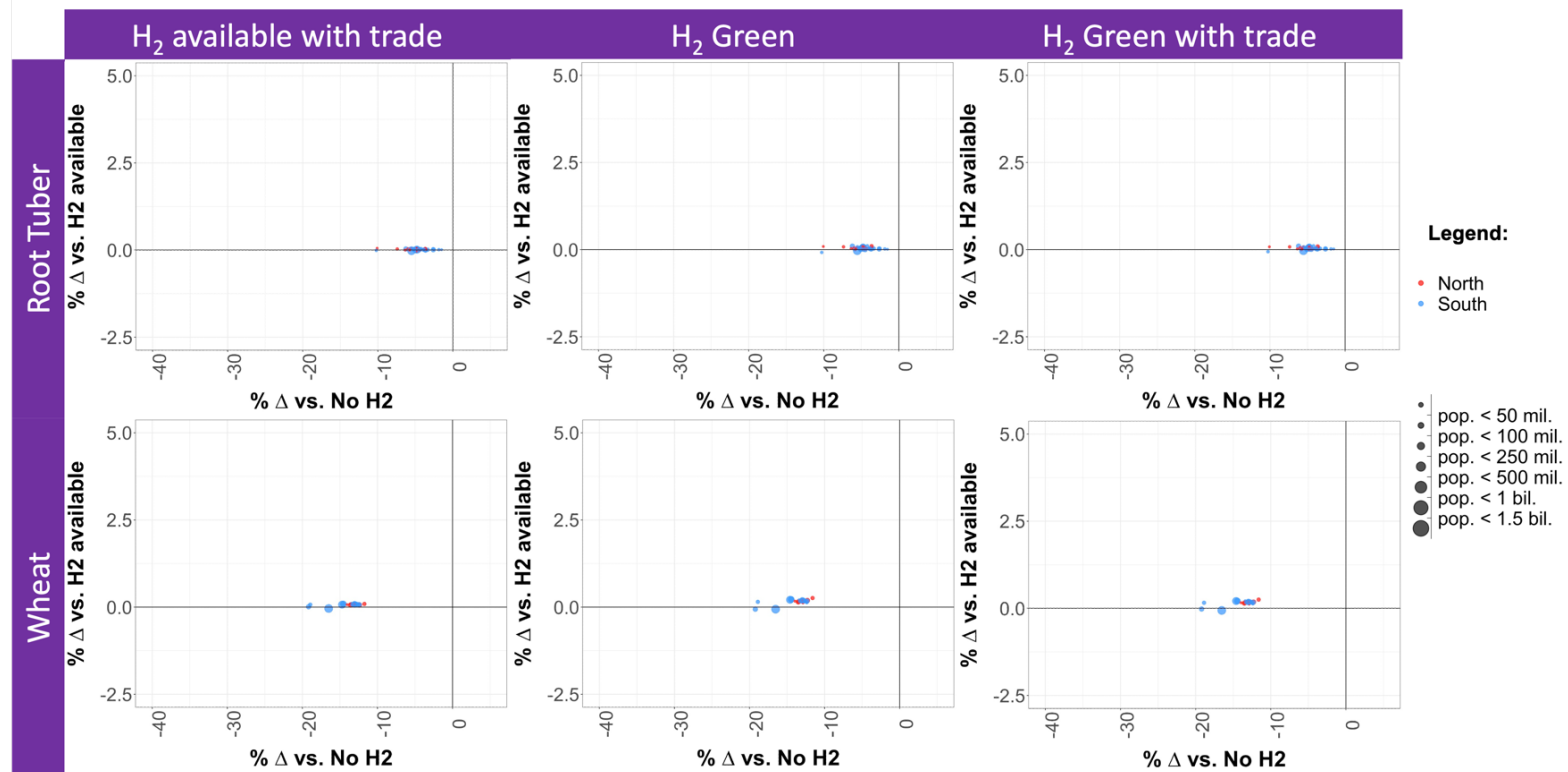


Figure 3.5b. Hydrogen’s impact on staple crop prices by scenario and GCAM region in 2050. Panel (A) portrays the percentage change in corn prices with clean hydrogen availability relative to the counterfactual where no clean hydrogen is available for the “H₂ available” scenario. Panel (B) portrays the same metric for rice prices. Panel (C) shows results for 3 additional scenarios with hydrogen availability. “North” and “South” refer to the Global North and Global South.

High” scenarios. The ambitious level of deployment in these cases requires the model to heavily subsidize the energy carrier in order to reach the exogenously defined “hydrogen economy” scale – which in turn leads to larger crop price reductions than in other scenarios (see Figure B.7 for “H₂ High” scenarios). This implies that hydrogen’s availability under carbon mitigation, whether produced from any means or solely from renewable electrolysis, traded or confined to regional markets, and with varying deployment scales, can facilitate cheaper staple crop prices for consumers.

The mechanism for these crop price reductions is due to large declines in fertilizer prices when clean hydrogen feedstock is accessible. This is sensible, given that fertilizers are an important input to staple crop cultivation. The change in fertilizer prices relative to the counterfactual by region for 2050 can be seen in Figure 3.6. Even the smallest relative price reduction realized for fertilizers in the “H₂ available” scenario is more than 50% (-54% in Taiwan). For the same scenario, fertilizer costs in China even decline by 66% (the largest regional decrease). Comparable results are seen when only green hydrogen is allowed, although the middle 50% of regional reductions has a slightly larger range than the “H₂ available” scenario. In both cases, these findings are not sensitive to the availability of traded hydrogen. On the other hand, an ambitiously high scale of hydrogen deployment (“H₂ High”) sees even more pronounced drops in fertilizer prices compared to the counterfactual. Though, these additional declines should be taken with a grain of salt, given that the model had to subsidize hydrogen production in these cases (as mentioned previously). See Appendix Figure B.8 for fertilizer production results.

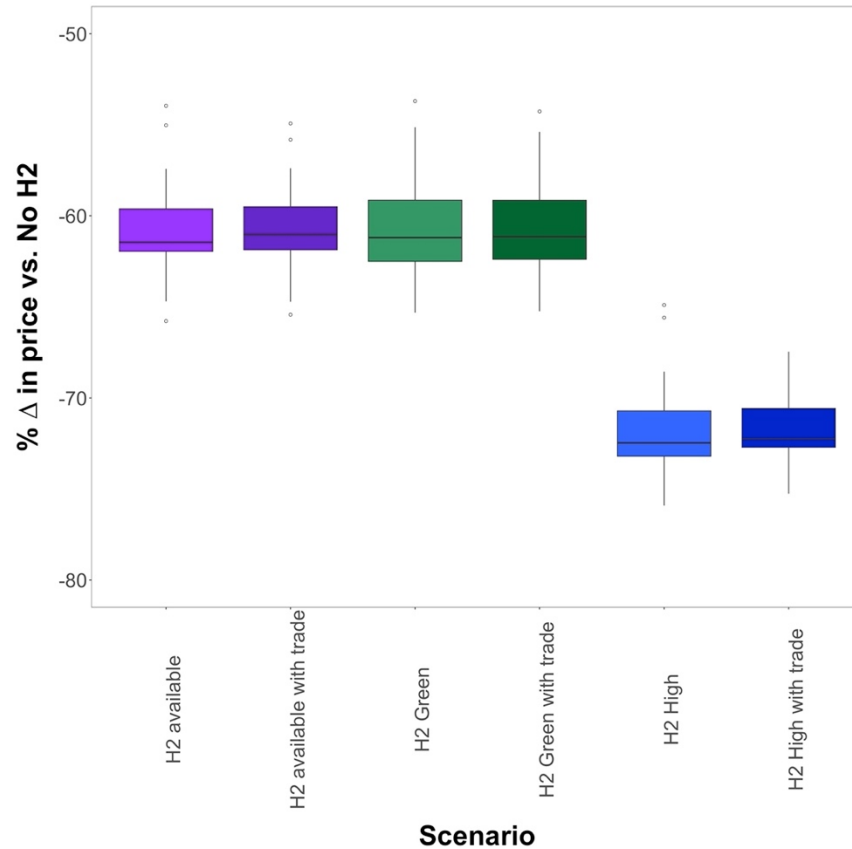


Figure 3.6. Hydrogen’s impact on fertilizer prices by scenario and GCAM region in 2050. The percentage change in prices is relative to the counterfactual where no clean hydrogen is available.

3.D. Discussion

It is highly likely that clean hydrogen will play a role in the future energy system as the global economy progresses towards decarbonization. However, there are concerns that the energy carrier could impact other societal objectives. This research examined two of these areas – specifically, how hydrogen could influence water systems and staple crop markets during an energy transition towards net-zero CO₂ emissions by midcentury. Little investigation in this area has occurred in the past, even though hydrogen’s production, as well as use, could directly and indirectly impact water resources and agricultural markets. The research that has occurred up to this point has only provided a partial view of its potential effects by generally focusing on global change, hydrogen produced from renewable electrolysis, and exogenously stipulated scales of

deployment. Additionally, while the literature has begun to discuss hydrogen's impact on water withdrawals and consumption, rarely does it address both concerns within the same work, rendering comparisons between publications difficult. Further, its influence on crop markets has been even less explored.

This study finds that clean hydrogen production will demand a relatively minor amount of water, if not overly relied upon beyond what is economically efficient in the context of decarbonization. Globally, hydrogen production accounts for less than 0.3% of total water withdrawals and 0.6% of total water consumption at midcentury across all scenarios modeled here. Some regions do exceed this global proportion - but across scenarios and regions the percentage is less than 1.5% for water withdrawals and generally less than 2% for water consumption. While an economically inefficient and ambitious scale of hydrogen deployment (e.g., the “H₂ High” scenarios) results in water consumption between 3% and 4% in some regions, this is still a much lower water requirement than other major sources of demand. These results are qualitatively similar to the minor proportions suggested by the global water consumption and withdrawals assessment of Beswick et al. (2021)³⁰⁹ as well as the country level analysis on water withdrawals by Tonelli et al. (2023).³¹⁰ At the global level, hydrogen availability could also lead to increases in total water withdrawals as well as consumption, but these changes also vary by region. For instance, Australia and New Zealand, the regions with the greatest increase under the “H₂ available” case, saw withdrawals and consumption increase by roughly 9%. Yet, as was shown, this was not the result of hydrogen production but rather the fact that its use led to larger water demand for crop cultivation within the region. Conversely, hydrogen availability also led to reductions in water consumption and withdrawals in some

model regions (e.g., the Middle East and portions of Africa in the “H₂ available” case). This makes clear that clean hydrogen’s impacts will vary regionally, and in some cases may even improve water security.

Still, policymakers looking to reduce the potential impact of hydrogen production on water systems would benefit from an energy transition which uses hydrogen only for economically efficient end uses (i.e., those that are difficult or impossible to directly electrify). It has also been suggested that the water footprint of hydrogen could be further moderated if its production was solely supplied by desalinized water rather than freshwater resources and that doing so would come at only marginal additional cost. Beswick et al. (2021) estimated this would only increase green hydrogen production costs by at most \$0.01 per kg of H₂.³¹¹ Large-scale desalinization is not immune to potential environmental consequences either though, for instance, it can influence the diversity of local marine ecosystems as microorganisms are removed during saltwater withdrawals.³¹² This has led some to suggest a more circular water economy, where hydrogen production could tap into purified wastewater resources. Woods et al. (2022) noted that Australian wastewater could satisfy nearly 100% of the nation’s expected hydrogen production in 2030 and the co-production of oxygen during electrolysis could help satiate a portion of wastewater treatment facilities’ demand for oxygen.³¹³

All of this implies that while economically efficient deployment of hydrogen is unlikely to be associated with major water resource issues, though policymakers should still be conscious of where production facilities are located and what water source is supplied. This is sensible, given that global and regional water availability do not directly imply more localized water

security. A related limitation of this work is that while hydrogen's impact on water withdrawals and consumption were investigated, its influence on water scarcity at the local level was not quantified here. Future research which downscales results from less spatially resolved analysis, such as this work, could help illuminate where hydrogen production may require alternatives to freshwater as well as clarify how hydrogen may improve or worsen water security, and in turn this would facilitate proper governmental planning. Additionally, an understanding of how national hydrogen strategies impact water systems is also warranted, as they may not reflect efficient use of the energy carrier.

In terms of staple crops, this analysis highlights the formidable role clean hydrogen could play in agricultural markets under carbon pricing regimes. While the effect varies by staple crop and region, the prices for all staple crops were reduced with clean hydrogen availability across each region and scenarios considered here. Some of these reductions in price even exceeded 35% (e.g., corn in Pakistan). The mechanism behind these reductions is through declines in nitrogen-based fertilizer costs, which likewise see their prices decrease substantially with access to clean hydrogen feedstock. This finding also makes clear that utilizing clean hydrogen for this conventional application of the energy carrier is an economically efficient choice and can enable more affordable food supplies, thus making an important contribution to food security.^{314, 315}

This is not to say that fertilizer application is without concerns. For example, superfluously applying nitrogen-based fertilizers for long periods of time can acidify soil, their use can result in nitrous oxide (N₂O) emissions, and runoff from croplands where they have been applied can cause eutrophication in bodies of water.³¹⁶ It would behoove policymakers to attempt

to address these problems as well, given that it is highly likely that we will continue to rely on their yield increasing benefits to supply agricultural commodities through midcentury. We do note that one limitation of this work entails a lack of representation for other potentially useful fertilizer substitutes – such as biochar and enhanced rock weathering. Both of these are thought to have yield-increasing properties when applied on agricultural lands.^{317, 318} Still, results from two recent studies that included biochar as an alternative input to crop production implied fertilizers remained viable agricultural inputs. Bergero et al. (2022)’s analysis found low amounts of biochar application through midcentury, although it noted that in the second half of the century nearly 60% of croplands could see biochar application globally when high carbon prices are assumed.³¹⁹ Fuhrman et al. (2023) found biochar application never exceeded 26% of cropland at midcentury for any of GCAM’s 384 land zones when warming was limited to 1.5°C.³²⁰ While biochar and enhanced weathering may help improve yields under some circumstances, fertilizers will likely continue to have a large role in the agricultural sector in the future.

An ancillary limitation of this work is that scenarios were simulated under carbon pricing. While the percentage of water consumption or withdrawals for hydrogen production is unlikely to be as sensitive to alternative policy regimes, the changes induced on water consumption versus a “no clean hydrogen” alternative, as well as the relative impacts on crop prices, may differ from what was found here. One such alternative policy mechanism for facilitating the decarbonization of nitrogen-based fertilizers could entail governmental subsidies for hydrogen producers. If clean hydrogen is to replace conventional and carbon-intensive means of manufacturing the energy carrier, such subsidies would need to at least make low- to zero-carbon

methods of hydrogen production reach cost parity, if not costs that are cheaper than the conventional alternative. In doing so agricultural markets could either see similar or reduced crop prices compared to a no subsidy counterfactual, respectively. Regardless, it is clear that hydrogen is viable mitigation strategy for fertilizer production, that fertilizers will likely continue to help feed global populations through 2050, and that an economically efficient use of the energy carrier is unlikely to be a cause of water stress.

Chapter 4:

Evaluating national hydrogen strategies: Japan and the Republic of Korea^J

^J This chapter is currently in preparation for potential submission to a journal for publication consideration. Contributions are centrally from the author of this dissertation and this publication will include the following co-authors: Leon Clarke, Jay Fuhrman, Nathan Hultman, Jiwon Kwun, Page Kyle, Haewon McJeon, and Paul Wolfram.

4.A. Introduction

Decades of research has shown that hydrogen produced with low- to zero-carbon methods (“clean hydrogen”) has the ability to mitigate climate change inducing greenhouse gas (GHG) emissions in a number of applications that span across the global economy.^{321, 322, 323, 324,}
³²⁵ Recent literature has made clear though that its use would be more impactful if confined to sectors that are difficult or impossible to directly electrify³²⁶, as direct electrification is generally more efficient in terms of costs as well as round-trip energy. Examples of such applications include heavy-duty and long-distance modes of transportation (e.g., marine vessels³²⁷), providing high-temperature heat for industrial processes³²⁸, iron and steel production³²⁹, and fertilizer manufacturing.³³⁰ Targeting such areas does insinuate a more limited role in the energy transition for hydrogen compared to other sources of final energy— namely electricity – but it will nonetheless be critical to achieving carbon neutrality in a cost-effective manner. Wolfram et al. (2024)’s analysis of energy transitions that reach net-zero carbon dioxide (CO₂) in 2050 found that hydrogen (H₂) could reduce the cost of climate change mitigation by 15% to 22% – despite only constituting at most 9% of global final energy.³³¹

Consulting firms and industry groups are also touting massive market potential for hydrogen-based energy and technologies (i.e., hydrogen as well as fuels derived from hydrogen feedstock). The Hydrogen Council estimates a global market size of nearly \$2.5 trillion at midcentury.³³² Deloitte projects the hydrogen market will even eclipse that of liquefied natural gas (LNG) trade by 2030³³³, and PwC and Strategy& have suggested that by 2050 the global export market could approach \$300 billion.³³⁴ It is therefore no surprise that hydrogen has captivated the attention of policymakers resulting in hydrogen strategies or roadmaps in dozens

of nations across the world.^{335, 336, 337, 338, 339, 340, 341, 342, 343, 344, 345, 346, 347, 348, 349, 350, 351, 352, 353, 354, 355, 356, 357, 358, 359, 360}

A number of studies have evaluated national^{361, 362, 363, 364, 365} and regional^{366, 367, 368} decarbonization pathways. The effectiveness of nationally determined contributions (NDCs) towards achieving the aims of the Paris Climate Agreement have likewise received increased scrutiny within the literature.^{369, 370, 371, 372, 373} This is contrasted by the lack of scholarly examination applied to the ever-growing number of national hydrogen strategies and roadmaps. Cheng and Lee (2022) advanced this line of inquiry by classifying national strategies and roadmaps as “green hydrogen now”, “scale first and clean later”, or “zero regulatory stringency.”³⁷⁴ But no examination into whether such strategies are defensible in terms of their contributions to national decarbonization has occurred to the authors’ knowledge, other than Meng et al. (2022)’s analysis of China³⁷⁵, Kar et al. (2023)’s investigation of Australia³⁷⁶, and Gawlik and Mokrzyck (2021)’s examination of Poland.³⁷⁷

Two countries with national hydrogen strategies/roadmaps which are particularly deserving of critical examination are Japan and the Republic of Korea (henceforth referred to as Korea in this work). Both nations plan to heavily rely on hydrogen-based energy for emissions mitigation, amounting to 12 and 5.26 million tonnes (or megatonne, Mt) by 2040 for Japan and Korea, respectively. These supply scales match their expressed desires to be global leaders in the forthcoming “hydrogen economy”. The detailed national plans of these countries similarly state deployment targets across multiple sectors of their economies for many years (Table 4.1), and their situations are made more unique by the fact that they note a potential role for imported

Sector	Country	
	Japan	Korea
Supply	<p>2030: 3 Mt supply³⁷⁸</p> <p>2040: 12 Mt total supply³⁷⁹</p> <p>2050: 20 Mt total supply³⁸⁰</p> <p>*Targets include hydrogen and ammonia.</p>	<p>2030:</p> <ul style="list-style-type: none"> 1.94 Mt total supply³⁸¹ 50% of supply (0.97 Mt) from by-product H₂, electrolysis, or imports³⁸² 50% of supply (0.97 Mt) from H₂ extraction³⁸³ <p>2040:</p> <ul style="list-style-type: none"> 5.26 Mt total supply³⁸⁴ 70% of supply (3.682 Mt) from by-product H₂, electrolysis, or imports³⁸⁵ 30% of supply (1.578 Mt) from H₂ extraction³⁸⁶
Electricity	<p>% of generation - 2030: 1% generation from H₂ & NH₃³⁸⁷</p> <p>Co-firing NH₃ + Coal – 2030: 50% NH₃³⁸⁸</p> <p>Co-firing H₂ + Gas – 2030: 30% H₂³⁸⁹</p>	<p>Fuel cell capacity – 2040: 15 GW (8 GW domestic), cumulative³⁹⁰</p> <p>Generation:</p> <ul style="list-style-type: none"> 2030: 6.1 TWh H₂, 6.9 TWh NH₃ (corresponds to H₂ or NH₃ portion of co-fired generation)³⁹¹ 2036: 47.4 TWh H₂ & NH₃³⁹² <p>% of generation – 2050: 13.8–21.5% generation from H₂ & NH₃ gas turbines³⁹³</p> <p>Co-firing NH₃ + Coal – 2030: 20% NH₃^{394, 395}</p> <p>Co-firing H₂ + Gas:</p> <ul style="list-style-type: none"> 2035: 30% H₂³⁹⁶ 2040: 30-100% H₂³⁹⁷
Transportation	<p>Passenger cars – 2030: 800,000 passenger car-equivalent (~80,000 tonnes/year)³⁹⁸</p> <p>Buses – 2030: 1,200³⁹⁹</p> <p>Sustainable aviation fuels (SAF) - 2030: 10% of aviation fuel⁴⁰⁰</p>	<p>Passenger cars:</p> <ul style="list-style-type: none"> 2025: 100,000, annual production⁴⁰¹ 2040: 5.9 million (2.75 million domestic), cumulative⁴⁰² <p>Taxis – 2040: 120,000 (80,000 domestic), cumulative⁴⁰³</p> <p>Buses - 2040: 60,000 (40,000 domestic), cumulative⁴⁰⁴</p> <p>Trucks - 2040: 120,000 (30,000 domestic), cumulative⁴⁰⁵</p>
Buildings (fuel cells)	2030: 3 million installed units ⁴⁰⁶	2040: 2.1 GW, cumulative ⁴⁰⁷
Final Energy		Hydrogen-derived energy - 2040: ~5% ⁴⁰⁸

Table 4.1. Future national hydrogen-related numerical targets. Mt denotes megatonne (or million tonnes), GW refers to gigawatt, TWh means terawatt hour, and NA signifies not applicable. *While Japan's hydrogen strategy notes that ammonia is included within its 2040 supply target the strategy is less explicit for the remaining years. It is therefore assumed here that ammonia is included within all of Japan's hydrogen supply targets.

hydrogen-based energy even though they can only import via oceanic-based trade. They are also considered crucial markets for nations with hydrogen export ambitions. For instance, Chile's national hydrogen strategy explicitly indicates the country's assumed potential to export billions of dollars' worth of green ammonia (NH₃) and green hydrogen to Korea and Japan by midcentury.⁴⁰⁹

For these reasons Japan and Korea have been selected as cases for this study, which aims to answer the following research question in relation to these nations: *are the prospects for clean hydrogen-based energy sufficient to justify national policymaker expectations and plans?* The investigation will examine their national hydrogen strategies, both in terms of supply (i.e., is the scale of supply over or underestimated by the country targets?) as well as demand (i.e., are the areas that are numerically targeted for hydrogen utilization viable end-use applications?). Although the scholarly understanding of net-zero CO₂ pathways for both nations has been significantly advanced by the works of those such as Oshiro et al. (2024a)⁴¹⁰ and Kim et al. (2022)⁴¹¹, previous research has lacked the detailed technological resolution (in their models and/or results) that is needed to analyze the national hydrogen plans of Japan and Korea. The objective of this research is to fill this gap in the literature by quantitatively assessing their hydrogen strategies under the context of a net-zero emissions transition.

4.B. Methods

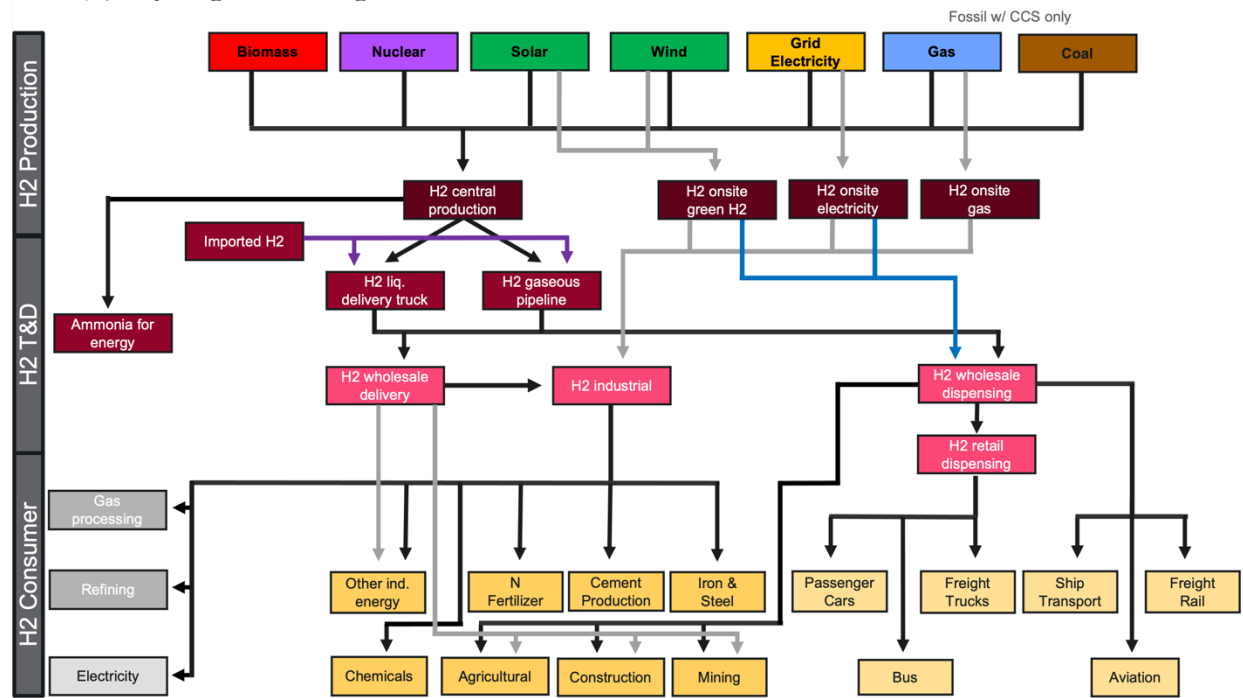
This research utilized the Global Change Analysis Model (GCAM)⁴¹², an open-source partial equilibrium integrated assessment model (IAM), to investigate the national hydrogen strategies of Japan and Korea. GCAM links the economy with energy, water, land, and climate

systems⁴¹³, and both nations are separately represented as two of the 32 economic and energy model regions. Enhancements to the representation of hydrogen-based energy were made to the latest model release (version 7⁴¹⁴) and are detailed in the sections that follow. Simulations running in 5-year timesteps have been conducted through midcentury for this work. The demand for final energy and economic services are driven in GCAM by exogenous assumptions about regional population and gross domestic product (GDP) per capita as well as endogenously computed costs for economic services. The Shared Socio-economic Pathway 2 (SSP2)⁴¹⁵ is the basis for GDP and population assumptions for each simulation considered in this study. Alternative methods of providing a given service compete within each region's energy system and this competition is determined by a logit choice formulation⁴¹⁶ and levelized costs. The latter is defined as the sum of exogenously stipulated non-energy costs (which includes capital as well as operation and maintenance), endogenously calculated energy and/or feedstock input costs, and the CO₂ price imposed on emissions for a given technology when climate policy is enforced.

4.B.1. H₂-based energy supply modeling structure

Figure 4.1 portrays the hydrogen-based energy modeling structure utilized with this study. As seen in Panel (A), hydrogen can be produced within GCAM via fossil fuels coupled with carbon capture and storage (CCS), biomass with or without CCS, and multiple representations of electrolysis. All methods of hydrogen production are available at central supply facilities, which in turn are delivered to consumers by gaseous hydrogen pipelines or liquid hydrogen trucks. Gas with CCS ("blue hydrogen"), grid electrolysis, and renewable electrolysis ("green hydrogen") are also represented in the model as "onsite" technologies, whereas the hydrogen is produced and consumed within the end-use facility. Regional hydrogen

Panel (A): Hydrogen modeling structure.



Panel (B): Ammonia modeling structure.

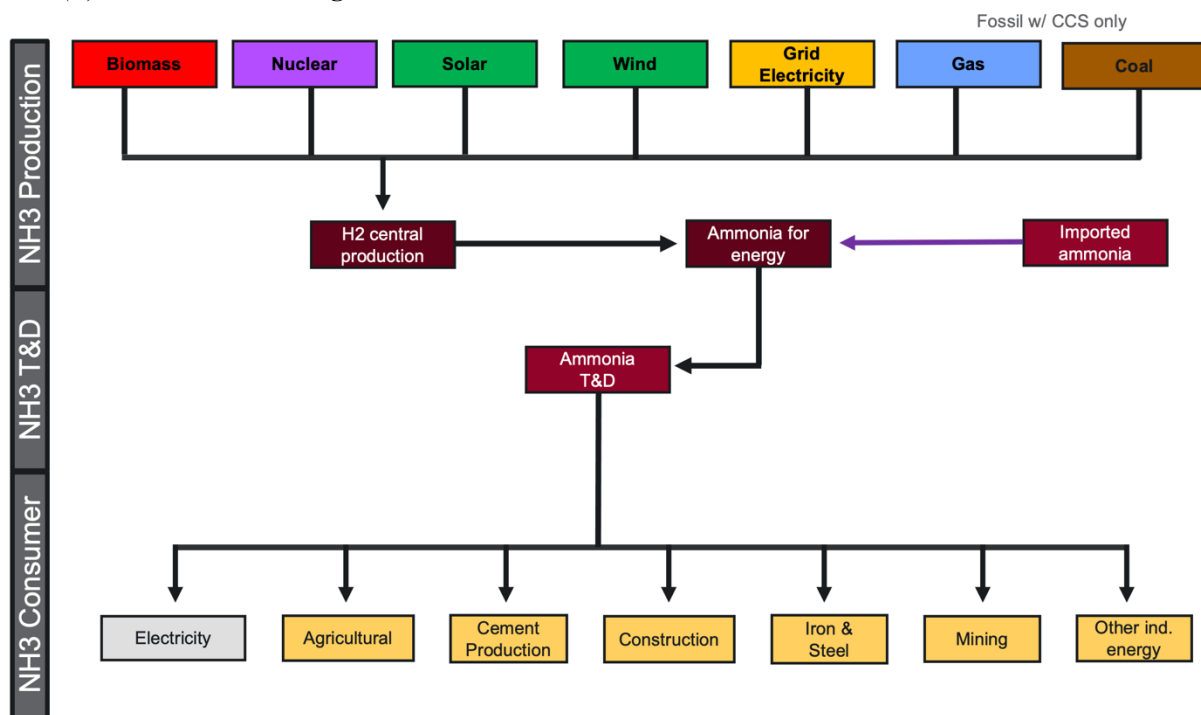


Figure 4.1. Representation of GCAMv7 modeling structure used in this study for hydrogen-based energy supply and demand. Panel (A) portrays the hydrogen modeling structure. Gas processing includes hydrogen feedstock for synthetic methane. Refining includes hydrogen for synthetic liquids (e.g., e-fuels) and bioliquids. Electricity includes firm generation and peaker backup for variable renewable energy. While not depicted here, ammonia for energy, synthetic methane, and synthetic liquids can also be imported. Panel (B) depicts the ammonia modeling structure. T&D refers to transmission and distribution. Electricity includes firm generation only.

supply assumptions are generally harmonized with those developed and detailed in O'Rourke et al. (2023).⁴¹⁷ Two exceptions to this include production assumptions for biomass-based hydrogen and the addition of hydrogen losses during delivery from central production facilities. These modifications are described in GCAM documentation.⁴¹⁸

The ability to use additional forms of hydrogen-derived energy has also been included in this research and their levelized cost as well as input requirements are described in Table 4.2. One such hydrogen energy carrier is ammonia (Figure 4.1, Panel (B)). Centrally produced hydrogen is used as a feedstock and subsequently combined with atmospheric nitrogen to create ammonia via the Haber-Bosch process. Levelized non-energy costs for the air separation unit (ASU), which is used to source nitrogen, and fuel synthesis are based on Dias et al. (2020).⁴¹⁹ A 25% reduction in these costs is assumed to be reached in 2050, and an improvement rate is applied in each model period between 2025 and 2050 to achieve the specified value for midcentury. Stolz et al. (2022)'s assumptions are used for the energy requirements of ammonia production,⁴²⁰ and no improvement is assumed for these values. Ammonia production facilities have the same retirement parameters as hydrogen production (with a maximum lifetime of 40 years and a half-life of 30 years). Before domestic use the ammonia must be delivered to end-use consumers and a representative cost is applied which is based on an ammonia pipeline from the International Energy Agency's (IEA) *The Future of Hydrogen* 2019 report.⁴²¹ The cost is levelized by assuming 100 kilometers (km) of transmission and a 25% improvement in costs from 2030 to 2100, both of which match the analogous assumptions for GCAM's gaseous hydrogen pipeline. The rate of ammonia losses during pipeline delivery at this length is highly

uncertain, and this work utilizes an input coefficient of 1.005 gigajoule (GJ) per 1 GJ of delivered energy (or roughly 0.5% loss rate).

In addition to ammonia for energy, this study includes fuels synthesized from hydrogen and atmospheric CO₂ that is captured by a direct air capture (DAC) unit. Parameters for Fischer-Tropsch derived synthetic liquids are updated for the industrial hydrogen technology detailed in Speizer et al. (2024)⁴²² and GCAM's DAC assumptions are provided in Fuhrman et al. (2021).⁴²³ Specifically, rather than assuming stoichiometric carbon requirements as previously configured, a carbon utilization efficiency of roughly 68% is assumed here. This efficiency is based on Marchese et al. (2021)'s⁴²⁴ parametrization for the technology with the highest carbon utilization rate and is applied to the carbon content of refined liquids in GCAM (19.6 kg of carbon per GJ). Additionally, we added the costs and electricity requirements of the fuel synthesis process. The electricity input assumptions are sourced from Giesen et al. (2014)⁴²⁵ and costs are derived from IEA's *The Future of Hydrogen* 2019 report⁴²⁶, which are levelized by assuming an 85% capacity factor for the refining facility and a 13% fixed charge rate.

Although previous GCAM studies have included hydrogen-derived synthetic liquids (e.g., Speizer et al. (2024) and Fuhrman et al. (2024)⁴²⁷) this analysis extends the model to also include synthetic methane (CH₄) for the first time, to the best of our knowledge. As with synthetic liquids, the process uses DAC to provide atmospheric CO₂ for carbon and industrial hydrogen for feedstock. The methanation process is leveraged to synthesize the gaseous fuel and assumes the same carbon utilization efficiency as was used for synthetic liquids and this is likewise applied to the carbon content of gas in GCAM (14.2 kg of carbon per GJ). The requirements for hydrogen feedstock and electricity for methanation are from Dias et al.

(2020).⁴²⁸ The IEA's *The Future of Hydrogen* 2019 report⁴²⁹ informs the non-energy costs, and these are levelized using the same method as was used for synthetic liquids. Both synthetic liquids and methane are available as energy transformation options beginning in 2030. While GCAM's gas processing sector is not vintaged for any processing method (i.e., does not impose retirement functions or lifetimes on the sector's technologies), the refining sector is vintaged and therefore synthetic liquids assume the same retirement function and lifetime settings as those used for biomass-based Fischer-Tropsch liquids. These synthetic fuels function within the model as any other form of liquid- or gas-based energy. For more information on GCAM's liquid and gas supplies as well as demands, see the model's documentation.⁴³⁰

Hydrogen-derived energy	Levelized non-energy cost (\$2020 / GJ)			Input / Output coefficient (GJ input or kg carbon / GJ hydrogen)		
	Cost component	2025	2050	Input	2025	2050
Ammonia	ASU	1.43	1.08	Electricity (for ASU)	0.026	0.026
	Fuel synthesis	11.40	8.55	H ₂	1.148	1.148
	Transmission & Distribution	0.38	0.35	NH ₃	1.005	1.005
Synthetic liquids	DAC	38.04	20.12	Electricity (for DAC & fuel synthesis)	0.639	0.558
	Fuel synthesis	4.27	2.88	H ₂	1.191	1.191
				Carbon	28.69	28.69
Synthetic methane	DAC	27.56	14.57	Electricity (for DAC & fuel synthesis)	0.473	0.414
	Fuel synthesis	4.08	2.88	H ₂	1.09	1.09
				Carbon	20.789	20.789

Table 4.2. Hydrogen-derived fuel parameters for 2025 and 2050. ASU refers to Air Separation Unit and DAC refers to direct air capture.

Additionally, while hydrogen trade was included in the second research topic of this dissertation, this topic builds on the previous development by including trade of ammonia as well as synthetic liquids and methane. Imports are limited to Japan and Korea, creating a ceiling on

potential imports for the two nations (as no other nations compete with them for foreign hydrogen-based energy). All other regions can export these four forms of energy to the two regions and trade is available within the model beginning in 2030. Given that imports are limited to Japan and Korea, all trade is assumed to be oceanic in nature and in liquid form. It is also assumed that imports from across the world will entail a 10-day voyage on average. For context, a cargo ship leaving Darwin in northern Australia and traveling at an average speed of 22 knots would take more than 5 days to reach Tokyo, Japan.⁴³¹ On the other hand, a cargo ship departing from San Antonio, Chile and traveling at the same speed would take roughly 17 and a half days to reach the same location.⁴³²

Hydrogen liquefaction parameters are based on the IEA's *The Future of Hydrogen* 2019 report.⁴³³ Non-energy costs are levelized by applying a 13% fixed charge rate, resulting in a 2030 value of \$6.81 (2020 USD / GJ). Consistent with the reduction in costs for liquid hydrogen truck delivery within GCAM, an improvement rate is set to achieve 25% lower costs by 2100. The liquefaction process also requires 0.183 GJ of electricity per GJ of H₂. Ammonia likewise needs electricity for liquefaction; however, the requirement is considerably lower than that of hydrogen. Only 0.001 GJ of electricity are used per GJ of NH₃.⁴³⁴ Analogous parameters for synthetic methane match those used for LNG trade in GCAM, as developed within Yarlaga et al. (2024).⁴³⁵ The remaining techno-economic assumptions for hydrogen-based trade (e.g., shipping and losses during delivery) are varied by scenario and described in section 4.B.3. Once imported, hydrogen-based energy is delivered to end users under the same conditions that are applied to domestic resources. An exception to this is that liquid truck delivery of imported hydrogen does not require the assumed cost or energy requirements of liquefaction that are

applied to the domestic hydrogen, given that the import has already been liquefied. Similarly, pipeline delivery of imported hydrogen does not face the compression-related energy requirements that are assumed for domestic hydrogen within Japan or Korea.

4.B.2. Technological representation of H₂-based energy applications

As seen in Figure 4.1 Panel (A), hydrogen-consuming technologies are represented for a number of final energy and secondary energy applications. GCAM version 7 includes hydrogen for stationary and mobile industrial energy needs as well as for industrial processes (e.g., N-fertilizer manufacturing). Hydrogen can also be utilized in the transportation sector for road and non-road (i.e., rail, ship, and aviation) modes of transport. The release version of the model also includes a backup peaker electricity generating unit for variable renewable electricity (VRE) and hydrogen feedstock for bioliquid refining. Techno-economic parameters for these applications are detailed in GCAM documentation^{436, 437} and were previously utilized by Wolfram et al. (2024)⁴³⁸ while analyzing hydrogen's ability to reduce the cost of climate change mitigation as well as within other recent publications.^{439, 440} This work also adds four hydrogen technologies for firm electricity generation. This is allowed as both hydrogen combustion turbines as well as turbines co-firing 50% hydrogen with natural gas. Techno-economic parameters for these technologies match the mono-combustion gas turbine (without CCS) assumptions for GCAM (other than a reduction in gas input requirements which are offset with hydrogen inputs for the co-fired technology). The hydrogen mono-combustion and co-fired turbines are available beginning in 2025.

Multiple ammonia-consuming technologies were also created for this research (Figure 4.1, Panel (B)) and are available beginning in 2030. Several stationary applications for ammonia are created within the industrial sector. Agricultural, construction, mining, cement, and other industrial energy use technologies have the same non-energy costs and energy requirements of the equivalent gas-based technologies. Partial ammonia injection into iron and steel blast furnaces (with and without CCS) have also been considered. Technologies in this sector have their non-energy costs and energy requirements based on the similar hydrogen partial injection blast furnaces. Lastly, 50% co-firing of ammonia with coal in conventional pulverized electricity generating units has been included. These technologies have the same techno-economic parameters as mono-fired coal facilities (other than a reduction in coal energy requirements which are offset with the equivalent amount of ammonia). As for synthetic fuels, they are consumed by conventional liquid- and gas-based technologies in a similar manner to all other refined liquids and processed gas.

4.B.3. Energy transition scenarios

Three potential energy transitions were simulated through midcentury to facilitate the evaluation of Korea's and Japan's national hydrogen strategies (Table 4.3). Each scenario achieves net-zero CO₂ emissions in 2050 for Korea, Japan, and the rest of the world (ROW). Emissions constraints are applied beginning in 2025, with regional values as follows: 1 gigaton (Gt) of CO₂ for Japan, 0.6 Gt of CO₂ for Korea, and 31.9 Gt of CO₂ for ROW. The constraints then linearly decline to the midcentury targets (Figure C.4). The CO₂ objectives are achieved by applying endogenously calculated carbon prices to the carbon emissions from the energy and industrial sectors for each region (i.e., Japan, Korea, and ROW). Carbon emissions from land-use

change (LUC) are not included within these constraints, yet they do face a fraction of the carbon price that is applied to the emissions from the industrial and energy sectors. The fraction that is applied matches the default settings for GCAM version 7. LUC emissions are not included within the emissions constraint, yet their emissions for Japan, Korea, and ROW each are net negative or roughly zero Gt across scenarios in 2050.^K

Scenario Name	Nuclear Power		CCS	H ₂ trade
	Japan	Korea		
H₂ Low	New nuclear allowed beginning in 2030 Constrained to national plan for 2030 only: 21% of electricity generation	Constrained to national plans for 2030 only: 201.7 TWh	Constrained to national plan for 2030 only: Japan: 9 Mt CO ₂ Korea: 11.2 Mt CO ₂	High trade costs & losses, low hydrogen-based energy trade readiness
H₂ Medium	New nuclear allowed beginning in 2030 Constrained to 21% of electricity generation (2030-2050), based on national plan proportion for 2030	Constrained to national plans: - 2030: 201.7 TWh - 2035: 230.7 TWh	Constrained to national plans*: Japan: - 2030: 9 Mt CO ₂ - 2050: 180 Mt CO ₂ Korea: - 2030: 11.2 Mt CO ₂ - 2050: 69.9 Mt CO ₂	Medium trade costs & losses, medium hydrogen-based energy trade readiness
H₂ High	No new nuclear	No new nuclear	No CCS	Low trade costs & losses, high hydrogen-based energy trade readiness

Table 4.3. Scenario design used in this study. CCS refers to carbon capture and storage, TWh refers to terawatt-hour, and Mt refers to megatonne or million tonnes. *Median value of national plan range used where appropriate.

The three modeled cases vary nuclear power and CCS availability as well as assumptions related to hydrogen-based energy trade and are qualitatively defined as follows:

- (1) “*H₂ Low*”: Competitive primary and final energy options are readily available, while H₂-based trade faces challenges.

^K Korea’s LUC emissions are 0.06 Gt in 2050 for the “H₂ High” case. Midcentury LUC emissions which are not net negative round to 0 Gt to the nearest tenth or hundredth decimal place for the remainder of scenarios and regions.

(2) “*H₂ Medium*”: Some limitations on mitigation alternatives are imposed, while challenges to H₂-based trade are reduced.

(3) “*H₂ High*”: Major mitigation alternatives are highly limited and optimistic conditions for H₂-based energy trade are assumed.

For nuclear power, the low case assumes only short-term (2030) restrictions on allowable electricity generation based on national planning^{441, 442, 443}, the medium case constrains the availability of nuclear to long-term national plans, and the high case allows for no new nuclear facilities. Similarly, the CCS scenario component restricts total sequestration to national plan values in 2030, while the medium case constrains total sequestration through midcentury. When national plans provide a range for targeted sequestration the median value is applied to the CCS ceiling.^{444, 445, 446, 447} The “H₂ High” scenario allows for no CCS.

The final scenario component varies hydrogen-based energy trade in terms of shipping cost, losses during delivery, and trade readiness. The shipping costs for liquefied hydrogen (LH₂), ammonia (LNH₃), and synthetic methane (LSM) are tied to GCAM’s LNG shipping cost, which is assumed to be \$0.647 (2020 USD / GJ). The low case assumes shipping LH₂, LNH₃, and LSM will be 150% of the cost for LNG (\$0.971, 2020 USD / GJ), the medium scenario assumes the same shipping cost as LNG, and the high case assumes the shipping cost will be 50% of LNG’s value (\$0.324, 2020 USD / GJ). A similar method is applied to GCAM’s cost of traded oil (\$0.571, 2020 USD / GJ) in order to derive the cost of shipping synthetic liquids: \$0.856 in the “H₂ Low” scenario, \$0.571 for the “H₂ Medium” case, and \$0.285 in the “H₂ High” scenario (all in 2020 USD / GJ).

Regarding losses, a notable percentage of produced hydrogen will subsequently not be delivered due to losses during liquefaction in preparation for export as well as boil-off during shipping. Losses during liquefaction begin with a value that is assumed to be 50% of the losses faced by liquid truck delivery of hydrogen in GCAM, given that these include liquefaction and boil-off. The resulting loss rate is roughly 2.4% and is similar to the medium range found in the literature (~ 2 to 2.2%) by Esquivel-Elizondo et al. (2023).⁴⁴⁸ Boil-off rates are assumed to begin at 1.063% per day, based on Smith et al. (2022).⁴⁴⁹ No improvement in losses is allowed for the “H₂ Low” scenario, while the “H₂ Medium” and “H₂ High” scenarios achieve a midcentury linear reduction in these loss rates of 25% and 50%, respectively. Significantly lower loss rates are seen when hydrogen is transported as liquefied ammonia. Al-Breiki and Bicer (2021)’s estimation for the boil-off rate of LNH₃ was only 0.025% per day⁴⁵⁰, and this forms the initial parameterization for LNH₃ here. While higher than the LNH₃’s boil-off rate, synthetic methane likewise has a boil-off rate that is lower than LH₂. Smith et al. (2022)’s reported rate of 0.0905% per day for a ‘conventional LNG’ ship⁴⁵¹ is used for this work. The scenario specific reduction in loss rates for LH₂ are also applied to the loss rates of LNH₃ and LSM. No losses are assumed during the delivery of synthetic liquids.

Lastly, trade-readiness is considered within this study’s scenario design. Readiness is considered on a non-economic basis and modeled within GCAM with share-weight parameters. Share-weights capture non-levelized cost considerations that can impact competition between technological alternatives (such as preferences and governmental policies). In terms of trade, this could be considered for domestic and foreign conditions. For example, there could be a preference for domestic energy rather than foreign energy, regulations and approvals for import

and export terminals could make trade more difficult to commence than purely economic decision-making would dictate, and potential exporters may favor using their own resources domestically over sending such energy abroad. Share-weight parameters for imported hydrogen-based energy are as follows: for the “H₂ Low” case they begin at 0.1 and linearly converge to non-cost parity (a value of 1) with domestic hydrogen-based energy in 2050; for the “H₂ Medium” scenario the beginning value is set to 0.33 and linearly interpolates to non-cost parity in 2045; and the “H₂ High” scenario starting value is equal to 0.5 and converges linearly to non-cost parity in 2040.

4.C. Results

4.C.1. Hydrogen-based energy supply

Japan’s and Korea’s supply targets for hydrogen-based energy appear difficult to achieve, even if alternative mitigation strategies are highly constrained and optimistic trade conditions exist. Figure 4.2 portrays the regional supply of clean hydrogen and ammonia across scenarios. Hydrogen used as a feedstock for synthetic fuels is included within hydrogen’s values for the figure. This is inconsequential, given that domestic synthetic fuel production is never larger than 0.002 exajoule (EJ) in either region. As seen in the figure, the scale of supply is lower than the targets defined by the national plans in question – for all modeled scenarios and years. The near-term disparity is largest for Korea, who’s goal only considers hydrogen itself. For the most optimistic scenario (“H₂ High”), hydrogen supply only reaches roughly 0.4 Mt in 2030 while the nation’s target for that year is 1.94 Mt (Panel (A)), or approximately 4.8 times larger. The target is even twice that of the 95th percentile of results from scenarios that limit warming to 2°C with a 67% probability or higher within the Intergovernmental Panel on Climate Change’s (IPCC) Sixth

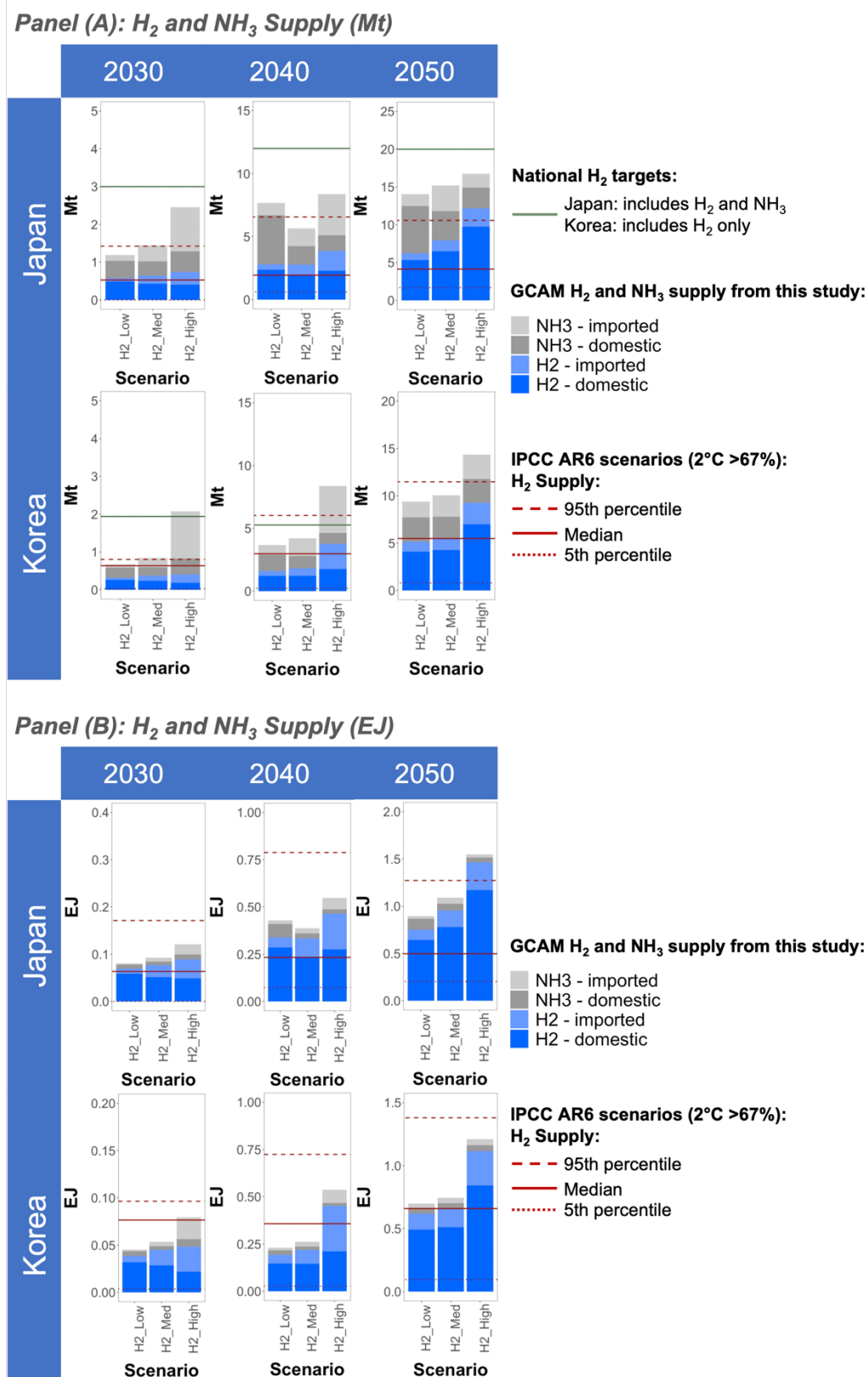


Figure 4.2. H_2 and NH_3 supply by scenario and region. GCAM scenarios include H_2 feedstock for non-biomass synthetic fuels within “ H_2 - domestic”. IPCC AR6 data corresponds to the C1-C3 scenarios.⁴⁵² Mt denotes megatonne (or million tonnes) and EJ refers to exajoule.

Assessment Report (AR6) scenario database (~0.8 Mt). This gap is less extreme for the Korean target of 5.26 Mt of hydrogen in 2040, but it still is noticeably higher than the hydrogen supply found here across scenarios.

This finding is qualitatively similar for Japan, even though the nation's targets include hydrogen as well as ammonia. The scenarios examined here are lower than the 2050 Japanese target (20 Mt) by 3.3 – 6 Mt. This is despite the fact that all cases exhibit hydrogen supply levels that exceed the median values from the IPCC AR6 database for Japan, implying they are somewhat optimistic, and that the “H₂ High” scenario's hydrogen supply surpasses the 95th percentile of the database. The latter was partially enabled by the availability of hydrogen imports, yet it is found that majority of supply for both regions is domestically produced across scenarios by midcentury. For example, in 2050 Korean imports range between 2.7 – 4.8 Mt in 2050 and domestic supply is between 6.6 – 9.5 Mt for the same year. Imports of hydrogen and ammonia amount to a total of 5.2 to 9.1 Mt for both regions. This point is furthered by the fact that imports are only allowed for Japan and Korea in this work. It is possible the amount of foreign hydrogen-based energy available to these two nations could decrease if other regions were able to compete for these forms of foreign energy. Note also that although synthetic fuel imports are not depicted in the figure, their amount for both nations is lower than would be visible within the graphic (< 0.000 EJ through 2050 for both regions, in all cases considered).

Also worth discussing is the differentiation between hydrogen and ammonia supplies. When viewed by weight ammonia appears to be a substantial contributor to satiating hydrogen-based energy supply and at times rivals the scale of hydrogen. Yet this is highly skewed by the

fact that ammonia weighs more per unit of energy than hydrogen. Panel (B) of Figure 4.2 displays the supply in terms of energy. For both regions ammonia deployment is less than that of hydrogen in all years and scenarios. This is true when comparing imported and domestically produced energy, suggesting ammonia may not be as practical of an energy carrier as has been suggested in some studies.⁴⁵³ The differentiation between energy- and weight-based supply likewise highlights the ambiguity that can arise from setting weight-based energy targets that combine different forms of energy that have significantly different masses per unit of energy. If simply achieving such a target was a measure of success, nations such as Japan could prioritize producing and importing heavier sources of energy - and this could come at the expense of total energy supply.

4.C.2. Hydrogen-based energy consumption

Although hydrogen-based energy supply measures on an EJ basis for both nations, these forms of energy constitute a small portion of final energy (FE) in the near term (e.g., <1% of final energy in 2030 across scenarios and regions). While their role in the energy system grows by midcentury, deployment remains limited. In the “H₂ Low” case they represent only 7% - 8% of FE for the two nations. Hydrogen-based energy deployment is also sensitive to what alternative options are available for primary energy (PE) and FE, as well as assumptions about trade (Figure 4.3). When limitations are increasingly imposed on nuclear power generation as well as carbon sequestration, and when more optimistic trade conditions are assumed, the proportion of FE coming from these energy carriers in both regions increases to roughly 9% in the “H₂ Medium” and 12% in the “H₂ High” scenarios. Still, hydrogen, ammonia, and synthetic fuels are unlikely to be dominant sources of energy for end-use consumers. Across cases their use is dwarfed when compared to electricity consumption, which accounts for more than 50% of

final energy across scenarios for Japan and Korea in 2050. In fact, electricity consumption is equivalent to roughly 4.7 to and 5.8 times that of hydrogen and ammonia for the two countries in the same year.

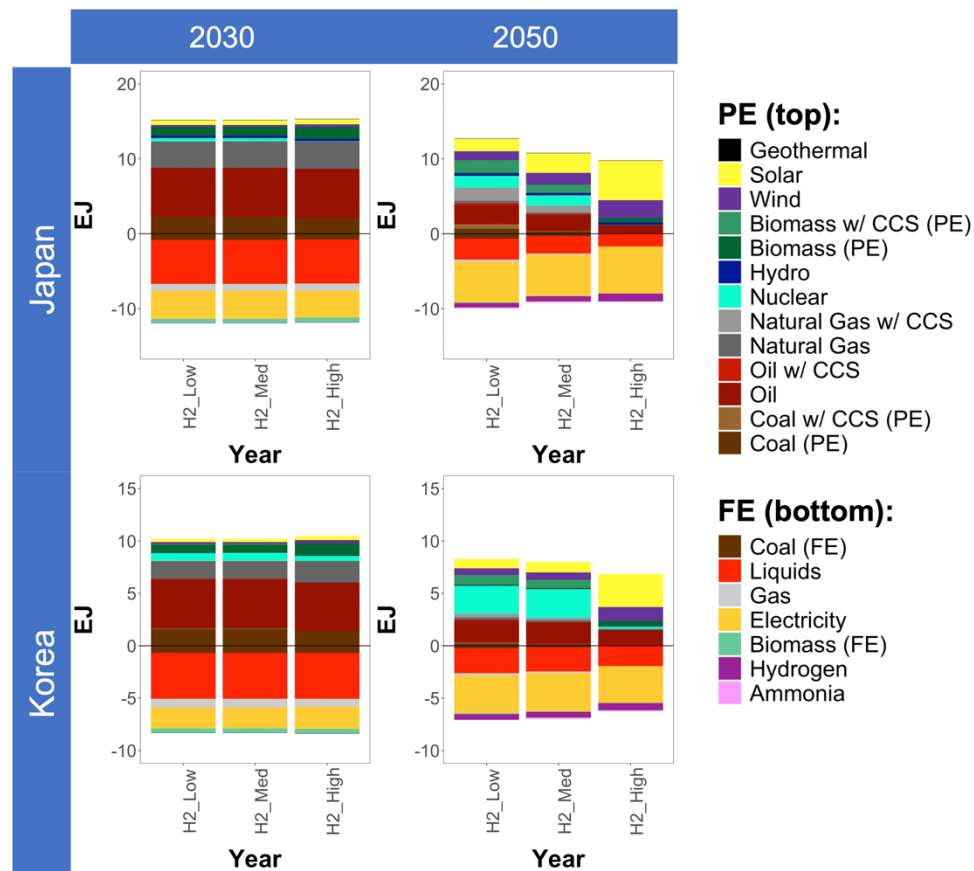


Figure 4.3. Primary energy (PE) and final energy (FE) by scenario. PE is shown in the positive range of each of the four sections of the graph, while FE is shown in the negative range for each section. CCS refers to carbon capture and storage.

Hydrogen-based energy's role in the energy transition may be lesser than other sources of energy, but it will nonetheless fulfill various energy demands in niche applications. Interestingly though, the national plans of Korea and Japan typically concentrate their quantitative deployment targets on hydrogen-based applications that are considered economically inefficient decarbonization strategies. Hydrogen and ammonia consumption by end-use sector for both

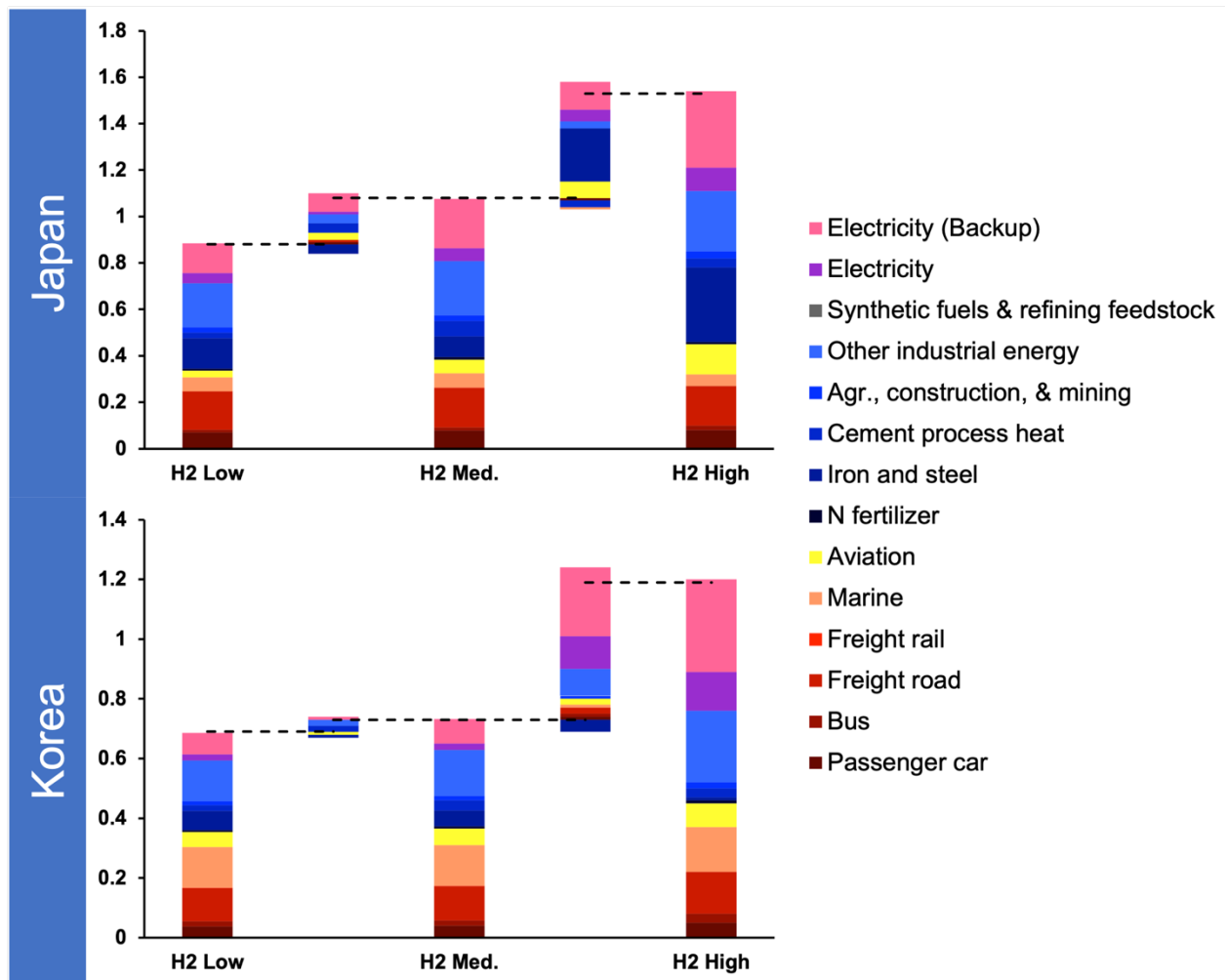


Figure 4.4. H₂ and NH₃ consumption by sector, scenario, and region in 2050. “Other industrial energy use” includes GCAM’s “other industrial energy use” and “chemical energy use” sectors. “Agr.” refers to agricultural.

nations in 2050 is depicted in Figure 4.4. Of note is the heavy emphasis on fuel cell electric vehicles (FCEVs) for passenger cars within the national plans: Japan is planning to have manufactured 0.8 million passenger cars by 2030, and Korea hopes to cumulatively produce 6.02 million passenger cars and taxis by 2040. Despite these goals, this analysis finds FCEVs provide at maximum 15% of passenger car service output (i.e., passenger kilometers) for the two nations in 2050, the year for which this proportion is its greatest (Table 4.4). This is not surprising, as battery electric vehicles (BEVs) are generally considered the appropriate mitigation strategy for this sector⁴⁵⁴, and BEVs are found to satisfy a much larger fraction of the service output in both

countries (e.g., 70% for Korea in the optimistic “H₂ High” scenario). As seen in the figure, passenger FCEVs are also a small portion of total hydrogen demand at midcentury – representing less than 5.5% of total hydrogen consumption for both regions.

The desire to target this application appears to be driven by technological export ambitions for both nations. Within the section of Korea’s national hydrogen roadmap titled “Establishment of the World’s Best Hydrogen Utilization System” it is noted that only 2.83 million of the 6.02 million passenger cars and taxis to be manufactured by 2040 are meant for domestic demand – implying the majority are planned for export. On first glance this may seem to be an appropriate industrial policy, given that Korea and Japan were globally top 10 vehicular exporters by value in 2022, according to the World Trade Organization (WTO).⁴⁵⁵ But it remains unclear how practical such an economic strategy would be, given that the outlook for passenger FCEVs in other markets also seems bleak – only 12% of global service output for passenger cars is provided by FCEVs at midcentury across the scenarios examined here.

A similar peculiarity arises from the fact that these hydrogen strategies quantitatively emphasize deployment for electricity generation. For example, Korea has a midcentury national target of 13.8 – 21.5% of total electricity generation to be provided by hydrogen and ammonia combustion turbines. This contrasts with the 1 – 2% of generation from these sources in the “H₂ Low” and “H₂ Medium” results for 2050 across both countries, and this proportion only rises to 3% (Japan) to 5% (Korea) in the optimistic “H₂ High” case. The magnitude of the Korean electricity target also seems to suggest the energy carrier may provide some form of firm capacity and baseload generation. This is likewise supported by the fact that both nations are also

Sector	Scenario: H2 High							
	Japan				Korea			
	Final energy (EJ)	H ₂ demand (EJ)	% final energy	% service output	Final energy (EJ)	H ₂ demand (EJ)	% final energy	% service output
Industry	4.284	0.650	15.2%	—	3.473	0.317	9.1%	—
Agricultural energy use	0.070	0.014	20.1%	—	0.046	0.009	19.7%	—
Cement	0.040	0.035	87.9%	—	0.034	0.030	87.9%	—
Chemical energy use	0.707	0.070	9.9%	—	0.363	0.054	15.0%	—
Construction energy use	0.044	0.011	24.7%	—	0.019	0.013	69.0%	—
Iron and Steel	0.422	0.320	75.8%	93.3%	0.081	0.013	16.2%	9.5%
Mining energy use	0.010	0.002	17.7%	—	0.006	0.001	21.2%	—
N-fertilizer	0.010	0.009	97.9%	100.0%	0.009	0.009	97.3%	99.9%
Other industrial energy use	1.639	0.189	11.5%	—	1.244	0.187	15.0%	—
Transportation	1.691	0.446	26.4%	—	1.194	0.436	36.5%	—
Passenger Vehicle	0.588	0.083	14.2%	15.5%	0.370	0.046	12.4%	12.2%
Bus	0.030	0.015	50.9%	44.4%	0.057	0.027	46.7%	43.8%
Freight Road	0.666	0.169	25.4%	21.9%	0.345	0.139	40.2%	48.5%
Freight Rail	0.002	0.001	54.4%	22.6%	0.004	0.002	35.2%	23.7%
Marine	0.103	0.051	50.0%	58.7%	0.184	0.147	79.8%	75.9%
Aviation	0.235	0.126	53.6%	60.4%	0.208	0.076	36.5%	38.6%
Electricity	—	0.431	—	2.8%	—	0.436	—	5.2%
Total	—	1.528	—	—	—	1.190	—	—

Table 4.4. H₂ and NH₃ consumption by sector and region in 2050 for the “H₂ High” scenario. “Other industrial energy use” refers to GCAM’s “other industrial energy use” sector. Values are rounded to the nearest thousandth; percentages are rounded to the nearest tenth. Summations across sectors or subtotals may not equal subtotals and the total, respectively, given rounding as well as the fact that sectors which do not consume hydrogen are not portrayed here. Hydrogen feedstock used for refining and ammonia for energy are not portrayed here. See Appendix Tables C.1–C.2 for the remaining scenarios.

planning for the co-firing of hydrogen with natural gas as well as ammonia with coal, in addition to mono-combustion turbines. Yet, most of the electricity generated from hydrogen-based energy across cases has been found to be from hydrogen-only combustion turbines that are providing backup services to VRE. As with the quantitative targets stipulated for passenger car FCEVs, the desire to utilize hydrogen-based energy for power generation may be partially motivated by the aspiration to export hydrogen-consuming technology. For example, the Japanese national plan stresses the need for domestic manufacturing of hydrogen turbines that will be suitable for foreign utilization:

“In the hydrogen power generation sector, co-firing and mono-firing combustors have been developed for small gas turbines, and they have been demonstrated in actual

equipment toward the 2030 carbon neutrality goals. As for large gas turbines, *Japanese companies* have worked to develop 30% co-firing and mono-firing combustors. They *should focus on developing 30% or more co-firing and mono-firing combustors that conforms to overseas gas-fired power standards, such as the EU taxonomy*, and demonstrating them on actual gas turbines.”⁴⁵⁶ [italicized text added for emphasis]

In terms of greenhouse gas (GHG) emissions mitigation, co-firing turbines also seem less practical than mono-combustion, given that co-firing can only reduce a portion of CO₂ emissions (proportionally related to the extent of hydrogen’s fractional input). Additionally, the combustion of ammonia with coal may help reduce CO₂ emissions but could result in increased N₂O emissions, another powerful GHG. It seems more likely that mono-fired hydrogen combustors would only be an appropriate complement to VRE.

The propensity for quantitatively targeting areas that are generally considered inefficient decarbonization strategies is also juxtaposed to the lack of numerical goals for hydrogen-based applications that are more efficient uses of the energy carriers. One such area involves heavy-duty and long-distance modes of transportation, such as freight trucks and ships. Regarding freight trucks, the percent of service output provided by FCEVs at midcentury ranges from 21 – 22% for Japan and 40 – 48% for Korea. The global market for such vehicles also seems to be more promising than passenger vehicles, with FCEVs providing 29% of global service output across scenarios in the same year. While Korea has a national target to produce 30,000 FCEV trucks for domestic use and 90,000 for exports by 2040 (Table 4.1), Japan appears to only qualitatively be discussing this possibility at present and notes of future plans to set numerical goals:

*“We will encourage the transport sector to operate FC trucks (8 metric tons or less) in line with the regulatory requirement and targets. We will develop the plan to set out a conversion target for trucks (over 8 metric tons) from conventional fossil-fuel-powered to hydrogen powered ones and expectations for refueling infrastructure development if those targets are justified by the use of FCVs and associated outlook.”*⁴⁵⁷ [italicized text added for emphasis]

It may be wise to focus attention on this mobile application rather than passenger cars, and this would also align with both countries’ comparative advantage in the global vehicular market.

Perhaps even more promising than road-based transport is the ability to use hydrogen-based energy to power marine vessels. By 2050, hydrogen-powered ships are found to be the dominant technology in the sector across scenarios for Japan, Korea, and globally – providing more than 55% of service output for both nations and the world. In fact, this proportion exceeds 70% regionally and globally in multiple scenarios. Both countries also were top 3 exporters of cargo and passenger ships in 2022, together accounting for roughly 35% of total global exports by value.^{458, 459} Despite this finding and their expertise in the field, neither nation has developed numerical targets for hydrogen-powered ships. However, they have both noted the desire to foster such technology. Korea has even made clear their aim to export such technology (in addition to hydrogen-powered trains and drones), stating that:

*“Commercialization and export projects to be implemented before 2030 through R&D and demonstrations.”*⁴⁶⁰

While such a statement is promising, quantitative goals would help set the expectation that these areas will receive their due attention from both governments, would allow for a measurement-

based approach to assessing related policy effectiveness, and would provide confidence in foreign markets that such technologies will be available for their purchasing.

Industrial applications which are difficult or impossible to directly electrify are likewise promising areas of hydrogen deployment. One such application involves the manufacturing of iron and steel, where hydrogen could be used within a blast furnace or for the direct reduction of iron ore. Under pessimistic conditions for hydrogen deployment (“H₂ Low”), such technologies produce 31% of domestically manufactured iron and steel in Korea in 2050. For the same year Japan sees such technologies approaching half of production in the “H₂ Low” scenario (44%), with the percentage reaching 93% under the “H₂ High” case. The manufacturing of iron and steel is also an important economic sector for Korea and Japan at present, as both nations were top 10 exporters of the commodity by value in 2022, according to the WTO.⁴⁶¹ Globally, hydrogen-based technologies are also found to facilitate 44% of iron and steel production in 2050 across cases, so there may also be the potential for technological exports in this area as well (e.g., blast furnaces and hydrogen direct reduction of iron ore [HDRI] capabilities).

Surprisingly, Korea’s national hydrogen strategy does not mention the words “iron” or “steel”. On the other hand, Japan does detail the need to use hydrogen in the sector and seems to be leaning towards hydrogen blast furnaces rather than HDRI:

“Specifically, in Japan, the technology that is capable of reducing CO₂ emissions by 10% by *injecting hydrogen...into a blast furnace has already been tested* in a test furnace...Now a demonstration project on a large-scale blast furnace for hydrogen reduction ironmaking (COURSE50) is underway... toward commercialization of the

technology by 2030. In addition, the project also focuses on the technologies that would reduce CO₂ emissions by *50% by increasing hydrogen injection into the blast furnace...*and the technologies that directly reduce solid iron ore with hydrogen without using a blast furnace (*direct hydrogen reduction technology*)... *As for the direct reduction ironmaking process, if you construct a new direct reduction furnace, you should preferably construct it in a geographical area where a stable and unexpensive hydrogen supply is available. These kinds of furnaces are likely to be more cost-competitive when they are installed overseas than in Japan.* Furthermore, when hydrogen is used in Japan, those furnaces will inevitably face a significant cost increase compared to the conventional reduction process. The *Japanese steel industry*, which directly or indirectly exports approximately 60% of its production, *may lose its international competitiveness.*”

⁴⁶² [italicized text added for emphasis]

The preference for blast furnaces over HDRI appears to be connected within the Japanese strategy to the notion that the supply of hydrogen will be potentially expensive and unstable. Such conditions could in turn make their nation’s industry less able to compete on the global market. However, this seems somewhat at odds with the desire to use 20 Mt of hydrogen in 2050 in other areas of the economy, as hydrogen being supplied elsewhere would be subject to the same price and stability. Still, neither nation has a numerical goal stipulating an amount or percentage of iron and steel to be made via hydrogen-based technologies. Creating such deployment targets seems pertinent, given the importance of iron and steel to their economies, the potential for technological export, and the economic efficiency of using hydrogen in this domain. Further, ambitions to export iron and steel that is not low carbon in nature may render

Japanese and Korean domestic industries uncompetitive globally in future foreign markets that impose carbon border adjustments.

Lastly, it is also worthy of mentioning the role clean hydrogen will play in nitrogen-based fertilizers. If such fertilizers will continue to be manufactured during the energy transition, the emissions associated with their manufacturing will either need to be directly mitigated via the production of clean hydrogen for feedstock or will have to be offset with negative emissions elsewhere in the economy. Yet, this is perhaps among the lowest hanging fruits available for clean hydrogen deployment. Half or more of all fertilizers produced by mid-century in both nations is provided feedstock from clean hydrogen for the pessimistic “H₂ Low” scenario, and these proportions round to 100% when alternative mitigation technologies are highly constrained and optimistic trade assumptions are assumed (“H₂ High”). However, the word “fertilizer” does not appear in Korea’s hydrogen strategy and is only mentioned once briefly in the Japanese strategy while discussing supply chains for ammonia. While both nations import fertilizers and/or feedstock inputs for their production, they also have domestic fertilizer manufacturing capabilities.⁴⁶³ For example, the U.S. International Trade Administration estimates that the majority of the \$3.1 billion fertilizer market in Japan is domestically produced, with 2020 imports accounting for only \$671 million of this total.⁴⁶⁴ Setting quantitative targets for clean hydrogen feedstock to be used in nitrogen-based fertilizer industries would not only be an economically efficient mitigation policy and use of the energy carrier, but it could also facilitate the growth of domestic hydrogen supply capabilities as well as nurture the potential ability to export hydrogen production technologies (e.g., electrolyzers).

4.D. Discussion

This work has found that the Korean and Japanese national plans for hydrogen-based energy are overly ambitious when compared to an efficient decarbonization strategy. Results indicated that even under conditions which would enable an optimistic ecosystem for clean hydrogen-based energy (i.e., limited mitigation alternatives and optimistic trade assumptions) the scale of deployment was less than that of their national supply targets for all years. Even for the 2030 targets, which are millions of tonnes lower than those set for 2040 and 2050, a massive effort would be required in the next five years to be achievable. For example, it was found that the Korean hydrogen supply goal was 4.8 times as large as the most optimistic scenario simulated here (1.94 Mt vs. 0.4 Mt). Therefore, an insight from this analysis is that perhaps such an effort is not justifiable.

While one could assert imports may alleviate hydrogen supply concerns, this analysis finds lower viability of hydrogen-based trade than is often assumed. While the Hydrogen Council estimates 26 Mt of hydrogen-based energy imports to Korea and Japan at midcentury⁴⁶⁵, only 5.2 to 9.1 Mt in total for both regions occurred within the scenarios simulated here. This difference is even larger when one considers that the weight-based findings from this study are in absolute weight, while the Hydrogen Council's estimate is in "hydrogen-equivalent" weight. This means the gap would widen if the ammonia values reported here were reduced to hydrogen-equivalent weight (since ammonia is heavier than hydrogen per unit of energy^{466, L}). Additionally, imports were only allowed for Japan and Korea in this work – implying additional

^L Kobayashi et al. (2019) note that the lower heating value (LHV) of hydrogen and ammonia are 120 MJ / kg and 18.6 MJ / kg, respectively. Therefore, one MJ of hydrogen has an associated weight of 0.0083 kg, while one MJ of ammonia has a weight of 0.0538 kg.

competition for foreign energy could reduce the amount available for the domestic demand in these two countries.

Across all cases most of the supply was produced domestically by midcentury as well. Together, these findings suggests that if Japan and Korea are to be taken as examples of promising export markets it may be risky for nations to bank on hydrogen-based energy exports as an economic growth strategy. Nations that are specifically pursuing export opportunities to these regions, such as Chile⁴⁶⁷ and Australia⁴⁶⁸, may want to carefully consider their economic options given the import scale to Japan and Korea noted here. A final policy recommendation in terms of hydrogen-based energy supply would be to recenter the focus on energy content, rather than weight. Hydrogen is much lighter per unit of energy than conventional fuels or other hydrogen carriers (e.g., ammonia). Including weight-based goals which lump hydrogen with other hydrogen carriers makes energy policy difficult to analyze as well as judge in terms of the actual amount of energy consumed within a national economy.

Although hydrogen-based energy will help facilitate decarbonization in our path towards a stable climate, plans should target uses which are difficult or impossible to directly electrify rather than economy-wide utilization. This is because there are often cheaper alternative methods of providing a given economic service. This is exemplified by the fact that final energy coming from hydrogen and ammonia was found to be at maximum 12% by midcentury for both countries, paling in comparison to the percentage provided by direct electrification (>50% for the same year). The emphasis on deploying hydrogen-based technology in inefficient applications, e.g., passenger cars and electricity generation, seems connected to the desire to bolster domestic

economic growth via technological exports. For example, Japan notes in their hydrogen strategy that,

“Solid demand in Japan, the mother market, will provide the most reliable arsenal for Japanese companies to compete in the global arena.”⁴⁶⁹

While domestic deployment can help foster industries by providing market entry and “learning by doing”, targeting these areas is an inefficient decarbonization strategy. FCEV’s contribution to passenger car service output tops out at 15% across both nations through midcentury. Even if domestic markets were manipulated to incentivize FCEV deployment, the global share of such cars only reached 12% in 2050 in this work – implying limited export potential. This is generally true for power generation as well, where hydrogen was only found to provide a meaningful role through VRE backup. Hydrogen for baseload generation was found to be uncompetitive, and co-firing 50% hydrogen or ammonia with fossil fuels does not provide sufficient CO₂ emissions mitigation to justify its use for electricity generation. This is consistent with Oshiro and Fujimori (2024b)’s analysis, which found co-firing could support VRE but would only account for roughly 1% of global generation at midcentury.⁴⁷⁰

On the other hand, there are areas of the economy that Japan and Korea could use hydrogen-based energy to simultaneously facilitate a net-zero future while fostering domestic economic growth. For instance, hydrogen seems more likely to assist in the decarbonization of heavy-duty and long-distance transportation than mitigating emissions from passenger vehicles. By midcentury FCEVs could provide roughly a fifth of Japanese truck service output and up to nearly half of the service output for Korea. Both nations have technical expertise in the automotive industry and were top ten exports of vehicular products in 2022. The potential for

exports likewise seems more robust in this market, as FCEVs provided nearly 30% of global freight road output in 2050. Hydrogen-based energy could also power marine vessels. This mode of transportation is even more difficult to directly electrify than trucks and saw a larger portion of its service output provided by hydrogen in this study. In all cases, more than half of the service output was provided by hydrogen-powered ships in both countries as well as worldwide in 2050. Hydrogen-based energy similarly accounted for most of the final energy for Japanese ships in a majority of the net-zero emissions scenarios considered by Oshiro and Fujimori (2024a).⁴⁷¹ Korea and Japan were in the top 3 exporters of passenger and cargo ships in 2022 and could leverage their experience in this area as well. Yet only Korea has a numerical target for trucks and neither has a quantitative goal for marine vessels.

Similarly, both nations were top 10 exporters of iron and steel in 2022 and hydrogen-based technologies were found to be highly competitive in this sector even under pessimistic conditions (e.g., 44% of iron and steel manufacturing at midcentury for Japan). Neither nation has set an output-related goal for iron and steel, even though this seems to be an area worth numerically targeting. It is true that marine vessels and iron and steel facilities may take longer to deploy mitigation technologies than other sources of emissions, given the difficulty of doing so compared to other lower-hanging fruit, but their emissions will require direct mitigation or offsets if the world is to reach net-zero CO₂ in a timely manner. Direct mitigation of these sources also seems likely – for instance, the International Maritime Organization has set a target for “...net-zero GHG emissions by or around, i.e. close to, 2050...”.⁴⁷²

Exactly why these national plans are quantitatively targeting hydrogen-based applications in a suboptimal manner requires additional research. Such a line of inquiry would benefit both the scholarly and policy communities, as it would enable them to suggest a potential pathway for avoiding these pitfalls during future decision making. Based on the national strategies, it has been suggested here that some of these inefficient hydrogen applications might be targeted as a means of bolstering their national economies via technological exports. It could also be the result of path dependence within economic and industrial policymaking. In Japan, for instance, fuel cells were highlighted nearly 20 years ago as an industrial ‘strategic sector’ within their government approved “new economic growth strategy” of 2006.⁴⁷³

The political economies of both nations, as well as an understanding of how their industrial priorities are set and the magnitude of political clout various stakeholders have in this space is likewise warranted. Both countries have a long history of using policy to target specific economic sectors, dating back to 1960s for the automobile industry.^{474, 475} Korea and Japan have even been described as “developmental states” – which involves “...the active and strategic role of the economic bureaucracy to implement economic policies in a close relationship with the corporate sector...” – although, there are differences with the amount of centralization this entailed, and debates exist in the literature regarding the degree to which this labelling still applies.⁴⁷⁶

Regardless, the two countries are clearly pursuing advancement in specific hydrogen-based technologies, and it is possible that close governmental coordination with specific private entities could cause policies to become susceptible to the whims of strong corporations. An

example of how industrial policy has benefited large corporations, conflicting with its original intent, has recently been documented for Korea. Kang and Jo (2021)'s analysis of the Lee Myung-bak administration's green industrial strategy found that "...contrary to the policy aim of promoting small- and medium-sized enterprises (SMEs) and start-ups in a range of clean technology sectors – big business groups in the brown industries emerged as the ultimate winners..." and that "...big business groups amassed structural power and deployed it to shape the green industrial policy in their own favour."⁴⁷⁷ It is possible that stakeholders in the private sector could be influencing Japan and Korea's national hydrogen strategies as well – begging questions, such as, could car manufacturing giants, such as Toyota and Hyundai, be influencing these policies? Therefore, future research should investigate the political economies surrounding the creation of these strategies in order to facilitate more defensible policymaking for the future "hydrogen economy".

In all, this research suggests that national hydrogen plans should focus on difficult or impossible to directly electrify areas of the economy, and that the subsequent scale of targeted supply should be in line with expected demand from these applications. Still, there are limitations to this analysis which should be acknowledged and addressed in future research. To begin, certain potential uses of hydrogen-based energy have not been considered here. One such area would be hydrogen's utilization within buildings. This could occur through combustion or use with fuel cells. Both countries are aiming to use massive amounts of hydrogen in buildings: Japan has a 2030 goal of 3 million fuel cells for building, and the Korean 2040 objective for the sector measures at 2.1 GW of capacity. Yet, direct electrification for building energy requirements seems likely to play a larger role in the sector. Scenarios that limit warming to 2°C

from the IPCC's AR6 scenario database corroborate this notion, with median values suggesting hydrogen will provide at most 1.7% and 0.1% of final energy through 2050 in Korea and Japan respectively (see Appendix Figure C.2). Even the 95th percentiles of these scenarios result in a proportion of < 6.5% for both nations. Jung et al. (2023)'s study focusing on future building energy demand similarly found direct electrification to be a more promising pathway for Korea.⁴⁷⁸ Therefore, it is not believed that including building demand would alter the overall conclusions of this study, and that such applications represent an additional example of an inefficient use of the energy carrier.

It should also be noted that while this work included synthetic fuel production with clean hydrogen and DAC CO₂ feedstock, it did not include pathways for CO₂ captured from other sources to be utilized in fuel synthesis. It is possible that this could be more economically competitive than carbon sourced from the atmosphere, but this remains unclear. But if the carbon is captured from non-biogenic sources, the CO₂ would not be carbon neutral and if combusted it would subsequently require offsets or 100% recapture for storage or reuse. The findings of this analysis as it pertains to Japan and Korea are thought to be insensitive to this technological inclusion given four points: (1) in the most optimistic hydrogen scenario CO₂ could not be sequestered in either region, therefore a net-zero transition would necessitate 100% continual recapture and use of the embodied carbon; or (2) captured carbon would need to be sent abroad; or (3) nature-based offsets would need to offset these emissions; or (4) Japan and Korea would be required to purchase offsets from other nations. The first of these points could be technologically difficult to guarantee and the second could be costly. If natural or foreign offsets were options on the table it is also possible domestic hydrogen deployment could decrease, as

other sources of emissions could be counterbalanced in this fashion. Still, future research could help clarify whether this intuition is true.

Lastly, several other nations have national hydrogen strategies. This methodology could be extended to evaluate their plans and assess whether they are justifiable in the context of decarbonization and domestic economic conditions. Additionally, while hydrogen-based trade to Japan and Korea was limited in these simulations it is possible that other regions of the world may be larger markets for exporters. For example, given the recent issues Europe has had with securing energy supply, future research could elucidate whether hydrogen could help alleviate their energy stress. While this research assumed a 10-day voyage for delivering such exports to Korea and Japan, future studies focusing specifically on global hydrogen-based energy trade should parameterize trade assumptions based on the specific distance between exporters and importers. This should entail both trade costs and losses, which in turn would allow the subsequent results to inform research and policy communities of potentially favorable trade partnerships.

Chapter 5: Conclusion

5.A. Literature contributions and policy implications

5.A.1. Research Topic 1 – Hydrogen’s potential to foster decarbonization

The first portion of this dissertation investigated which hydrogen supply and demand technologies were economically efficient to deploy under global decarbonized energy transitions. Modeled scenarios varied the availability of hydrogen delivery infrastructure, end-use technology costs, and climate policy stringency.^M Results from these simulations revealed several insights about the potential role for hydrogen within the context of climate change mitigation. Regarding supply, it was found that the availability of hydrogen delivery primarily affects the hydrogen production mix rather than the scale of its deployment. Onsite production at the end user was found to be cost-effective – accounting for more than half of production in five of the six core scenarios examined. The largest share of onsite production was from green hydrogen, which is consistent with other recent IAM analyses that have observed the potential role for electrolysis-based hydrogen.⁴⁷⁹

Distributed production of hydrogen was also enabled to a lesser degree by onsite gas with CCS production – yet its use was assumed to be limited to industrial consumers given the scale of production needed to warrant the additional costs of CO₂ capture. It should likewise be noted that while electrolyzers are modular technologies, there are instances where their installation onsite at an end-use facility may not be economically justifiable. For instance, even in situations where fuel cell trucks may be more competitive than their battery electric counterparts having an electrolyzer onsite may not be sensible for all refueling stations. Such may be the case for refueling stations that see few customers daily (e.g., in rural communities that have low

^M See Appendix A (section A.3) for hydrogen production and demand under increased climate policy ambition.

population density and are not located near major highway networks), as the capital costs associated with installing an electrolyzer at their facility may not be financially defensible.

The role of onsite electrolysis is also notable as modular electrolyzers are ‘granular’ technologies (smaller in physical and/or economic scale per unit), and it has been demonstrated that increased granularity can be associated with quicker learning and diffusion timeframes, as well as lower investor risk.⁴⁸⁰ Additionally, the decentralized production of hydrogen avoids hydrogen leakage associated with distribution, thereby enhancing its contribution to GHG emissions mitigation by reducing its indirect climate impact. Onsite production of clean hydrogen could also avoid aspects of the commonly discussed ‘three-sided chicken-and-egg’ problem,⁴⁸¹ or the need to simultaneously foster demand, production, and delivery infrastructure. This is because onsite production balances supply and demand for the energy carrier within the end-use facility.

Moreover, the competitiveness of onsite production highlights the potential for hydrogen to circumvent some of the injustices within our current energy system. Vast pipeline networks may not be a necessary for clean hydrogen’s diffusion, which would benefit traditionally marginalized communities that have often borne the safety and pollution risks of such infrastructures. As discussed in more depth within section 1.A.5 of Chapter 1, onsite production alone will not ensure all environmental injustices are avoided. Storing large quantities of hydrogen or ammonia onsite can leave nearby communities vulnerable to the explosive risk of unintentional fires at such facilities – regardless of whether the hydrogen and ammonia are delivered or produced onsite. Intentionally combusting hydrogen or ammonia for industrial

process heat can similarly make these communities vulnerable to the risks of NO_x air pollution as well.

While delivery will likely be required to connect supply and demand in certain circumstances, this all suggests that policymakers wishing to induce hydrogen's diffusion could target deployment of production technologies (particularly electrolyzers) within hydrogen consuming facilities, and that their location should ideally be a safe distance from population centers where possible. This could be encouraged via subsidies or cost-sharing schemes. Further, deployment could begin more rapidly for onsite production, as there would be no need to wait for delivery infrastructure to materialize. Electrolyzers could also be deployed on an incremental basis given their modularity. Yet it is less clear how current government policies will influence the evolution of clean hydrogen supply. For instance, the United States of America's multibillion dollar program for regional clean hydrogen hubs aims to facilitate the creation of networks which link hydrogen producers and consumers within certain geographical areas of the country.⁴⁸² This strategy even specifically mentions the plan to build hydrogen pipelines (e.g., within the "Gulf Coast Hydrogen Hub") which implies at least some supply will be centralized in nature. On the other hand, the country's clean hydrogen production tax credit is likely to enable onsite electrolysis. This can be seen within the U.S. Department of the Treasury's proposed regulation for the incentive which notes that electrolysis-based producers will be able to utilize the credit for delivered electricity so long as the electrons are created within the same geographical region (spatially correlated) and the hydrogen production involves time-matching with the clean electricity generation (temporally correlated).⁴⁸³ Future research which takes into account

policies such as these would provide more clarity on how governmental schemes may cause hydrogen supply to differ from the results of this dissertation.

Regarding hydrogen demand for final energy applications, results indicated a larger role for hydrogen within the industrial sector rather than the transportation sector for the majority of the core scenarios. Such uses would likely entail providing high-temperature heat as well as facilitating low-carbon manufacturing of steel via hydrogen direct reduction of iron ore (HDRI). Still, its use for providing high-temperature heat through combustion would require attention to NO_x emissions mitigation. Energy policy will be more successful if it not only reduces GHGs but also improves air quality and the combustion of hydrogen (or ammonia) for industrial requirements should face regulated NO_x emissions factors that do not exceed, or are preferably lower than, the combustion emissions factors of the fossil fuels being displaced. Ensuring safe use of hydrogen will also be paramount, which applies to onsite production as well. Hydrogen may also play a role in heavy-duty and long-distances modes of transportation – particularly for marine-based travel. Yet, such a role was found to be more profound after midcentury, or beforehand with increased climate policy ambition. Policymaking communities would benefit from targeting these difficult to directly electrify areas of the economy, rather than promoting its use in all sectors. Results also indicated that hydrogen demand was more sensitive to end-use technology costs than assumptions about delivery availability, implying policymakers will not only need to focus on enabling production technologies but also fostering hydrogen-consuming technologies.

5.A.2. Research Topic 2 – The “hydrogen economy’s” impact on the water-energy-food nexus

Clean hydrogen’s potential impact on hydrological systems and staple crops within the context of a global net-zero CO₂ energy transition was examined in the second portion of this dissertation. Despite the renewed interest in the energy carrier of late, little scholarly examination exists regarding this area of research even though hydrogen’s production, as well as use, could impact water resources and agricultural markets. Previous research has only provided a limited view of its potential effects in these areas; studies analyzing its water impacts have generally focused on global change, green hydrogen, exogenously stipulated scales of deployment, or reported either water consumption or withdrawals. Hydrogen’s potential influence on agriculture has received even less attention, with studies focusing on decarbonizing fertilizer production without a quantitative connection to crop markets.

This research finds that clean hydrogen production is a minimal portion of total water withdrawals and consumption, as long as it is not deployed beyond what is economically efficient. On a global level, its production represents less than 0.3% of total water withdrawals and 0.6% of total water consumption at midcentury across all simulated scenarios. While some model regions do exceed the global proportion, the percentage is generally less than 1.5% for water withdrawals and less than 2% for water consumption across regions and for most scenarios. However, if hydrogen is inefficiently deployed (i.e., the “H₂ High” scenarios) its water consumption would increase – rising to between 3% and 4% in some regions. These results are similar to the minimal water consumption and withdrawals suggested by Beswick et al. (2021)^{s484} global assessment as well as the country level study of water withdrawals by Tonelli

et al. (2023).⁴⁸⁵ Hydrogen availability was also found to lead to increases in total water withdrawals and consumption in some regions compared to the counterfactual where no clean hydrogen was available. For example, the region with the greatest increase under the “H₂ available” case (Australia and New Zealand), saw withdrawals and consumption increase by nearly 9%. Notably though, this was not because of hydrogen production but rather the fact that its availability led to larger water demand for regional crop cultivation. On the other hand, hydrogen availability caused decreases in water consumption and withdrawals in some model regions (e.g., the Middle East and portions of Africa for the “H₂ available” case). This makes clear that clean hydrogen’s impacts will vary regionally, and in some cases may even improve water security.

These results suggest hydrogen’s potential impact on hydrological systems can be minimized if it is only used for economically efficient applications (i.e., those that are difficult or impossible to directly electrify). The literature has also noted that hydrogen’s water impacts could be reduced if its production was solely provided desalinized water. Beswick et al. (2021) estimated this would only marginally increase the costs of producing green hydrogen (at most by \$0.01 per kg of H₂).⁴⁸⁶ However, not all potential locations for hydrogen generation have such water resources (i.e., close access to the ocean) and large-scale desalinization is not immune to potential environmental consequences.⁴⁸⁷ Alternatively, society could build a more circular water economy and supply hydrogen production with purified wastewater. Woods et al. (2022)’s recent analysis found that Australian wastewater could satisfy nearly 100% of the nation’s expected 2030 supply.⁴⁸⁸

This implies that economically efficient hydrogen utilization is unlikely to be associated with major water resource issues, yet policymakers should still be conscious of where production facilities are located and should consider tapping alternatives to freshwater resources. This is sensible, given that water availability at the global or regional level does not imply water security at the localized area of hydrogen production. A related limitation of this work is that while hydrogen's impact on water systems was analyzed in terms of withdrawals and consumption, its influence on local water scarcity was not quantified in this dissertation. Future research should assess whether hydrogen production and use improve or worsen water security at a finer spatial resolution. While also not examined explicitly here, hydrogen supply's water footprint may also benefit from onsite production. This is because less hydrogen would need to be produced for a unit of hydrogen to be consumed at the end use, given losses incurred during its delivery, as well as the avoidance of water which may have been required during the generation of electricity used to compress or liquify hydrogen prior to delivery. Additional research which examines how hydrogen's effect on water systems may differ for distributed and centralized supply is therefore also warranted.

This analysis also contributes to the literature by highlighting the formidable role clean hydrogen could play in agricultural markets under carbon policy. Although the effect varies by crop and region, the prices for all staple crops were reduced with clean hydrogen availability across all regions and simulated scenarios at midcentury. Some of these price reductions even exceeded 35% (e.g., corn in Pakistan). The mechanism behind these reductions is through the substantial decrease in nitrogen-based fertilizer costs when access to clean hydrogen feedstock is available. This finding corroborates the notion that utilizing clean hydrogen for this conventional

application is an economically efficient choice. Further, deploying this mitigation strategy can enable more affordable food supplies, subsequently making an important contribution to future food security.^{489, 490}

This is not to insinuate that the use of fertilizers is without concerns. For instance, their use can result in nitrous oxide (N_2O) emissions, their superfluous application over long periods of time can acidify soil, and runoff from croplands where they have been applied can cause eutrophication in bodies of water.⁴⁹¹ Policymakers should attempt to address these issues, given that it is highly likely that we will continue to rely on the yield increasing benefits of fertilizers to feed society through midcentury.

One limitation of this work is that the scenarios examined were simulated under carbon pricing. While the proportion of water demand for hydrogen production is unlikely to be as sensitive to alternative mitigation policies, the changes to water demand versus a “no clean hydrogen” counterfactual, as well as the impacts on staple crop markets, may differ from the findings of this dissertation. One alternative decarbonization policy regime could involve governmental subsidies for hydrogen production. If low- to zero-carbon hydrogen is to replace conventional and carbon-intensive means of its generation, such subsidies would need to at least make clean methods of production reach cost parity or costs that are lower than the conventional alternatives. In doing so agricultural markets could either see similar or reduced crop prices compared to a no subsidy counterfactual, respectively. Nonetheless, clean hydrogen is a sensible mitigation strategy for the fertilizer industry, fertilizers will likely continue to help feed global

populations into the future, and an economically efficient use of hydrogen is unlikely to be a direct cause of water insecurity.

5.A.3. Research Topic 3 – Evaluating national hydrogen strategies: Japan and the Republic of Korea

The final portion of this dissertation analyzed the Korean and Japanese national hydrogen strategies. It was found that both national plans are expecting supply levels which are overly ambitious when compared to an efficient decarbonization strategy. Even under the most optimistic conditions for clean hydrogen-based energy – where mitigation alternatives were highly limited and optimistic hydrogen trade parameters were assumed – the scale of deployment was less than their national targets for all years. Even for the 2030 targets, which are millions of tonnes lower than those set for 2040 and 2050, a massive effort would be needed in the next few years to be achievable. For example, the Korean hydrogen supply goal was 4.8 times as large as the most optimistic case simulated here (1.94 Mt vs. 0.4 Mt). Therefore, an insight from this analysis is that perhaps such an effort is not defensible.

Although one could postulate that imports may alleviate supply concerns, this study found lower viability of hydrogen-based trade than is often anticipated. While the Hydrogen Council estimates 26 Mt of hydrogen-based energy imports to Korea and Japan in 2050⁴⁹², only a total of 5.2 - 9.1 Mt across both regions occurred within the scenarios simulated here. This difference is magnified if one considers that this dissertation's weight-based findings are in absolute weight, while the Hydrogen Council's projection is in "hydrogen-equivalent" weight. The gap would thus expand if the ammonia values reported here were reduced to hydrogen-

equivalent weight (since ammonia weighs more per unit of energy than hydrogen). Additionally, imports were restricted to Japan and Korea in this work. It is possible that imports to both of these nations could be reduced if other regions were able compete for foreign hydrogen-based energy.

The majority of hydrogen supply was also produced domestically by midcentury across all cases. Together, these findings suggests that if Japan and Korea are to be considered illustrative examples of promising export markets, it may be risky for countries to rely on hydrogen-based energy exports for economic growth. Nations that are pursuing export opportunities to the two countries, such as Chile⁴⁹³ and Australia⁴⁹⁴, may want to consider alternative economic strategies given the scale of imports Japan and Korea realized here. A final minor supply-based recommendation would be to define targets in energy units rather than weight. Hydrogen is lighter per unit of energy than fossil fuels and other hydrogen carriers (e.g., ammonia). Weight-based goals which include multiple forms of hydrogen-based energy make energy policy less transparent and complicate its comparison to alternative sources of energy.

While hydrogen will enable decarbonization, strategies should target uses which are difficult or impossible to directly electrify rather than strive for economy-wide utilization. Similar to the global findings in Chapter 2 of this dissertation, hydrogen and ammonia combined to contribute at maximum 12% of final energy at midcentury for both countries. However, the Korean and Japanese plans often emphasized hydrogen utilization in inefficient applications, e.g., passenger cars and electricity generation. This seems to be linked to the desire to bolster

their domestic economies through technological exports. For example, Japan notes in their hydrogen strategy that,

“Solid demand in Japan, the mother market, will provide the most reliable arsenal for Japanese companies to compete in the global arena.”⁴⁹⁵

Domestic deployment could help foster national firms by providing market entry and subsequently “learning by doing”, but targeting these areas is an inefficient mitigation policy. FCEV’s contribution to passenger car service output was capped at 15% across both nations through midcentury in this dissertation. The potential for FCEV exports also appears to be limited; the global share of service output provided by such cars only reached 12% in the same year.^N This is generally true for electricity generation as well. Hydrogen was only found to provide a meaningful role in this work through VRE backup, as it was not competitive in baseload generation, and co-firing 50% hydrogen or ammonia with fossil fuels did not sufficiently reduce CO₂ emissions to justify deployment. These findings are consistent with Oshiro and Fujimori (2024b)’s recent study, which found co-firing could support VRE but would only provide for approximately 1% of global generation at midcentury.⁴⁹⁶

Fortunately, there are more promising sectors that Japan and Korea could target for hydrogen deployment to simultaneously contribute to efficient emissions mitigation and their domestic economies. For instance, hydrogen is likely to assist in the decarbonization of heavy-duty and long-distance transportation. By midcentury FCEVs could provide a meaningful portion

^N This finding is qualitatively similar to the results from Chapter 2, although there are numerical differences. In Chapter 2 FCEVs contributed a lower percent of global service output for passenger vehicles in the core scenarios examined (at maximum 8.3%, Table 2.2). However, the core scenarios of that analysis reached net-zero CO₂ emissions after midcentury (Figure A.9), whereas the scenarios in Chapter 4 reached net-zero CO₂ emissions in 2050. The results of Chapter 4 are more similar to Chapter 2’s sensitivity cases which limited warming to 1.5°C. For instance, FCEVs provided 12.7% of global service output for passenger cars in the “Pipeline H₂ T&D, High Demand” case which limited warming to 1.5°C (Table A.7).

of truck service output in both nations – representing roughly a fifth in Japan and up to nearly half in Korea. Both nations were top ten exporters of vehicular products in 2022 and there may be a potentially fruitful export market for FCEV trucks as they provided nearly 30% of the sector’s global service output in 2050 for the scenarios simulated here. Hydrogen-based energy could also facilitate emissions mitigation for ships. In all cases, hydrogen-powered ships provided more than 50% of marine service output in both nations and globally in 2050. Oshiro and Fujimori (2024a) similarly found that hydrogen-based energy accounted for the majority of final energy for Japanese ships in most of the energy transition scenarios they considered.⁴⁹⁷ Korea and Japan also have experience in ship manufacturing, as both were in the top 3 exporters of passenger and cargo ships in 2022. Despite these two areas being ripe for their domestic firms and national decarbonization, only Korea quantitatively targets FCEV trucks and neither has a numerical target for ships.

Iron and steel production are similarly efficient areas for these countries to target. Japan and Korea were top 10 exporters of iron and steel in 2022 and hydrogen-based technologies were found to be highly competitive in this sector. For example, even under pessimistic conditions they fulfilled 44% of Japanese iron and steel production in 2050. However, as was the case with marine vessels, neither national plan included an output-related goal for this sector. While ships as well as iron and steel facilities are often considered hard-to-abate areas of the economy, which may result in their emissions being mitigated after other lower-hanging fruit, a net-zero CO₂ future will dictate direct mitigation of their emissions or offsets. It is also highly possible that direct mitigation of these sources will occur – for instance, a target for “...net-zero GHG emissions by or around, i.e. close to, 2050...” has been publicly established for ships by the

International Maritime Organization.⁴⁹⁸ More generally though, this dissertation suggests that national hydrogen plans should focus on sectors which are difficult or impossible to directly electrify and that the scale of targeted supply should be in line with demand projected for such applications. Lastly, while hydrogen-based energy trade may occur to a certain extent, the findings of this research suggest that nations would benefit from not relying on large quantities of imports for domestic energy supply or exports for economic growth.

5.B. Methodological contributions

Several methodological contributions were undertaken by this dissertation, most of which involved enhancements to the modeling representation of hydrogen supply and demand within the Global Change Analysis Model (GCAM). Although a number of hydrogen production technologies existed within the model prior to this work, their parameterization was outdated. Topic 1 updated the existing methods of production with techno-economic assumptions using data from the National Renewable Energy Laboratory's (NREL's) Hydrogen Analysis Production Models (H2A)^{499, 500} and added technological representations for onsite production of green and blue hydrogen using the same data source. The public version of the model also had a simplistic module for hydrogen delivery; this necessitated the construction of multiple means of hydrogen delivery – via liquid hydrogen trucks, gaseous hydrogen pipelines, and blending with natural gas into existing pipeline infrastructures – which were added to the model with the aid of data from Argonne National Laboratory's Hydrogen Delivery Scenario Analysis Model (HDSAM) version 3.1.⁵⁰¹

Topic 3 further improved the modeling structure by including multiple forms of hydrogen-derived energy: synthetic liquids, synthetic methane, and ammonia. While synthetic liquids were previously included within Speizer et al. (2024)⁵⁰² and Fuhrman et al. 2024⁵⁰³, the representation was improved here by including the costs⁵⁰⁴ and electricity requirements⁵⁰⁵ of the fuel synthesis process. Additionally, rather than assuming stoichiometric carbon requirements as previously configured, a carbon utilization efficiency of roughly 68%, based on Marchese et al. (2021)⁵⁰⁶, was assumed here. To the author's knowledge, this is also the first GCAM study to include synthetic methane which is based on assumptions from Dias et al. (2020)⁵⁰⁷ and the IEA (2019).⁵⁰⁸ An ammonia for energy use pathway was also added to GCAM, based on assumptions from Dias et al. (2020)⁵⁰⁹ and Stolz et al. (2022).⁵¹⁰ Lastly, to the author's best knowledge this dissertation includes the first representation of hydrogen-based energy trade within GCAM. Topic 2 included the ability to trade hydrogen and topic 3 allowed for the trade of hydrogen, synthetic liquids as well as methane, and ammonia.

In addition to hydrogen-based energy supply, a number of additional end-use applications were created in GCAM within this dissertation. Topic 1 added several technologies capable of consuming the blended natural gas and hydrogen product: building and industrial heat (i.e., district heat production, residential and commercial space heating, and other building energy needs such as water heating and cooking), process heat for cement manufacturing, and other industrial energy use (process heat and cogeneration). Topic 3 also led to the creation of multiple hydrogen electricity generating units, involving baseload generation from both hydrogen-only and co-fired hydrogen and natural gas combustion turbines. Similarly, the final topic of this dissertation included ammonia and coal co-fired baseload electricity generation, as well as

ammonia-consuming applications in the industrial sector (agricultural, mining, and construction energy use, process heat for cement, iron and steel blast furnaces, and other industrial energy use). Lastly, the final topic of this dissertation provides a methodological example of using an integrated assessment model to evaluate national hydrogen strategies. Together, it is hoped that these model enhancements and applications can be leveraged to facilitate future work in the hydrogen-based literature (e.g., the quantitative evaluation of other national hydrogen strategies).

5.C. Caveats and areas for future research

This dissertation sought to address gaps in the literature for the “hydrogen economy”, however, there are caveats to these findings and there remain many areas that require additional research. Although each research topic involved competing hydrogen against alternative decarbonization strategies, as well as various means of hydrogen production versus each other, in order to endogenously calculate the scale of hydrogen deployment GCAM does not endogenously compute the non-energy costs of technologies. For instance, capital costs are exogenously provided to the model as an input and often entail assumed cost reductions over time. While declines in such costs could be hypothesized to arise from “learning by doing” or from mass manufacturing in the future, it is also possible that non-energy costs for certain technologies could grow over time. This is therefore a caveat for the findings of this dissertation and future research would benefit from integrated assessment models which not only endogenously compete GHG emissions mitigation technologies against each other, but also endogenously compute more of a given technology’s non-energy costs. For instance, such models could create supply and demand parameters for various inputs into a technology which would facilitate their ability to internally compute at least a portion of future capital costs and

provide for more robust results. Results from Wang et al.'s (2024) recent analysis on platinum and hydrogen within China made clear that the metal will be an important enabler of clean hydrogen technologies and that modeling efforts would benefit from representing endogenous markets for platinum.⁵¹¹ Including the critical mineral and metal requirements for alternative mitigation technologies within models as well would therefore provide a greater understanding of hydrogen's competitiveness in the energy transition.

Although this work has cast doubt on the potential for large amounts of globally traded hydrogen-based energy, there are currently actual bottlenecks for energy supply around the world. Russia's invasion of Ukraine has created issues for securing energy in much of Europe. It is possible that such a disruption could call for hydrogen-based energy imports to the region as an alternative to conventional fossil fuels. Several countries are also considering the need to build capacity for hydrogen-based energy exports. Future studies should therefore address the following questions: (1) what are the prospects for hydrogen-based energy trade globally?; (2) what conditions would the scale of such trade be sensitive to?; and (3) what specific form of energy will be traded (e.g., hydrogen, ammonia, or synthetic fuels)? Such research should parameterize trade assumptions based on the specific distance between exporters and importers. This should include both trade costs and losses, which in turn would allow the subsequent results to also inform research and policy communities of potentially favorable trade partnerships.

Open questions also remain regarding hydrogen energy carriers which were not considered here. Methanol and other liquid organic hydrogen carriers (LOHCs) have been gaining attention of late and are considered potentially promising means of delivering hydrogen.

They may even be used directly as a source of energy, rather than converted back to hydrogen upon reaching an end-use facility or importing nation. Additional investigation which competes these LOHCs against the forms hydrogen-based energy considered in this dissertation, as well as alternative mitigation options, is needed to ascertain their value for decarbonization. It should also be noted that while topic 3 included synthetic fuel production with clean hydrogen and DAC CO₂ feedstock, it did not include a pathway for CO₂ captured from other sources to be utilized in fuel synthesis. It is possible that this could be more economically competitive than carbon sourced from the atmosphere. On the other hand, if the carbon is captured from non-biogenic sources the CO₂ would not be carbon neutral – which in turn could reduce its value during the forthcoming energy transition. The source of CO₂ for LOHCs, such as methanol, would likewise influence their potential to contribute to GHG mitigation. The research community should analyze this potential energy transformation application, in addition to LOHCs, in order to clarify whether they are worth governmental backing.

While this work assessed the national hydrogen plans of Japan and Korea, exactly why these national plans are quantitatively targeting hydrogen-based applications in a suboptimal manner requires additional research. Such a line of inquiry would benefit both the scholarly and policy communities, as it would enable them to suggest a potential pathway for avoiding these pitfalls during future decision making. Based on the national strategies, it has been suggested here that some of these inefficient hydrogen applications might be targeted as a means of bolstering their national economies via technological exports. It could also be the result of path dependence within economic and industrial policymaking. In Japan, for instance, fuel cells were

highlighted nearly 20 years ago as an industrial ‘strategic sector’ within their government approved “new economic growth strategy” of 2006.⁵¹²

The political economies of both nations, as well as an understanding of how their industrial priorities are set and the magnitude of political clout various stakeholders have in this space is likewise warranted. Both countries have a long history of using policy to target specific economic sectors, dating back to 1960s for the automobile industry for example.^{513, 514} Korea and Japan have even been described as “developmental states” – which involves “...the active and strategic role of the economic bureaucracy to implement economic policies in a close relationship with the corporate sector...” – although, there are differences with the amount of centralization this entailed, and debates exist in the literature regarding the degree to which this labelling still applies.⁵¹⁵

Regardless, the two countries are clearly pursuing advancement in specific hydrogen-based technologies, and it is possible that close governmental coordination with specific private entities could cause policies to become susceptible to the whims of strong corporations. An example of how industrial policy has benefited large corporations, conflicting with its original intent, has recently been documented for Korea. Kang and Jo (2021)’s analysis of the Lee Myung-bak administration’s green industrial strategy found that “...contrary to the policy aim of promoting small- and medium-sized enterprises (SMEs) and start-ups in a range of clean technology sectors – big business groups in the brown industries emerged as the ultimate winners...” and that “...big business groups amassed structural power and deployed it to shape the green industrial policy in their own favour.”⁵¹⁶ It is possible that stakeholders in the private

sector could be influencing Japan and Korea's national hydrogen strategies as well – begging questions, such as, could car manufacturing giants, such as Toyota and Hyundai, be influencing these policies? Therefore, future research should investigate the political economies surrounding the creation of these strategies in order to facilitate more defensible policymaking for the future “hydrogen economy”.

Further, there are dozens of nations which have yet to have their hydrogen strategies face scholarly evaluation. Public policy is produced within a political system, and therefore can be subject to biases, inefficiencies, as well as other flaws. Governmental evaluations of their own strategies are likewise susceptible to such concerns. There also appears to be a web of actors who have consolidated influence on clean hydrogen's outlook as well as national hydrogen planning. McKinsey & Company is particularly prominent in this space and has for example assisted the Hydrogen Council in developing reports (e.g., their 2017 report titled *Hydrogen Scaling Up: a sustainable pathway for the global energy transition*⁵¹⁷) as well the Chilean government's national hydrogen strategy.⁵¹⁸ This could imply that analytical inputs to non-peer reviewed reports and governmental plans for hydrogen may not be sufficiently independent. Third-party analysis of such policies is therefore necessary for citizens and policymakers to understand the viability of such strategies. The methodology utilized in the third topic of this dissertation could be applied to these nations to determine whether the prospects for hydrogen in their countries are sufficient to justify their own ambitions.

Governmental hydrogen strategies may also impact water and food systems in ways that differ from the findings of this dissertation's second topic. For example, if a nation has plans to

use more hydrogen-based energy that is economically efficient, hydrogen production's water requirements would increase and could be more similar to the impact of the "H₂ High" scenarios from this work. The literature should not only judge whether national hydrogen strategies are sensible for decarbonization, but it should also seek to answer how such plans may impact water and food systems. While this work included results at the water basin level, the research and policy communities would also benefit from analysis with an even finer spatial resolution that assesses how hydrogen production and use might improve or worsen local water security. Lastly, hydrogen and hydrogen-derived energy have the potential to both positively and negatively impact air quality. Clean hydrogen's use with fuel cells would reduce air pollution when displacing fossil fuel combustion, but the combustion of hydrogen and hydrogen-based energy would result in NO_x emissions. Examination into how hydrogen-based energy will impact air quality, and the resulting impact on human health, and any potential environmental justice considerations is therefore needed.

Appendix A: Supplementary information for Chapter 2

A.1. Methodology

A.1.A. Hydrogen production

We allow hydrogen to be produced from the following low-carbon technologies: biomass with or without CCS, fossil fuels with CCS, as well as from multiple electrolysis pathways, including grid electrolysis, dedicated wind and solar electrolysis, and nuclear high temperature electrolysis (HTE). Unabated fossil pathways are not included. Hydrogen can be produced centrally (i.e., at a large-scale facility that subsequently distributes hydrogen to end users) for all methods of production. Alternatively, it can also be produced onsite at the physical location of the end user, but then the production methods are restricted to grid electrolysis, renewable electrolysis (green hydrogen), and natural gas steam methane reforming (SMR) with CCS (blue hydrogen).

Hydrogen production levelized non-energy costs (CAPEX and non-fuel OPEX) and energy requirement assumptions are harmonized with the U.S. Department of Energy's (DOE) National Renewable Energy Laboratory's (NREL) Hydrogen Analysis Production Models (H2A) version 3.2018⁵¹⁹, except for the renewable electricity generation for green hydrogen, nuclear high temperature electrolysis (HTE), and biomass with CCS (discussed in more detail below). H2A's 'current' assumptions were applied to 2015 for model inputs. The H2A models also provide 'future' assumptions for 2040. Improvement rates for levelized non-energy cost and energy requirements were constructed from the two years of H2A data to provide interim year assumptions (2020-2035). After 2040 these improvement rates are continued until a maximum of

10% additional improvement is reached (afterwards costs and efficiency are held constant). See Table A.1 for assumed hydrogen production cost and energy requirements.

Biomass with CCS and future year assumptions for coal with CCS are not provided by H2A version 3.2018. Biomass with CCS assumptions for 2015 were therefore derived by adding the additional costs and energy requirements of CCS. This was done by calculating the ratio between GCAM's power sector's integrated gasification combined cycle (IGCC) with and without CCS biomass technologies and applying these to H2A's biomass without CCS technology. The increased costs and decreased efficiency for biomass with CCS, compared to biomass without CCS, were reduced over time (in line with the difference between costs and efficiencies for GCAM's power sector biomass IGCC technologies. Additional details regarding GCAM's power sector methodology can be found in Muratori et al. (2017).⁵²⁰

Both grid and green hydrogen (for central and onsite production) utilize H2A's data for proton exchange membrane (PEM) electrolyzers, which are considered appropriate for intermittent electricity.⁵²¹ While the electrolyzer costs for green hydrogen are derived from the H2A assumptions, the levelized costs are calculated using the regional capacity factors of their paired renewables. This was done by determining the relationship between capacity factor and electrolyzer non-energy costs using H2A data (for central and distributed electrolysis). These relationships are depicted in Figures A.1 and A.2. Solar panel and wind turbine levelized non-energy costs for green hydrogen production were aligned with GCAM's default power sector assumptions, which are based on NREL's Annual Technology Baseline (ATB) version 2019.⁵²² The representation of onsite green assumes that the hydrogen is produced synchronously with the

Production technology	Levelized non-energy cost (\$2020 / kg of H ₂)		Input / Output coefficient (GJ input / GJ hydrogen)	
	2020	2050	2020	2050
Coal + CCS (central)	1.667	1.332	1.780 (Coal)	1.560 (Coal)
			0.043 (Electricity)	0.038 (Electricity)
Natural Gas + CCS (central)	0.779	0.746	1.367 (Natural Gas)	1.367 (Natural Gas)
			0.020 (Electricity)	0.020 (Electricity)
Natural Gas + CCS (onsite - industrial)	2.645	2.551	1.367 (Natural Gas)	1.367 (Natural Gas)
			0.020 (Electricity)	0.020 (Electricity)
Biomass (central)	1.075	0.872	2.179 (Biomass)	2.090 (Biomass)
			0.045 (Natural Gas)	0.025 (Natural Gas)
			0.029 (Electricity)	0.028 (Electricity)
Biomass + CCS (central)	1.770	1.414	2.606 (Biomass)	2.297 (Biomass)
			0.053 (Natural Gas)	0.026 (Natural Gas)
			0.035 (Electricity)	0.031 (Electricity)
Grid Electrolysis (central)	1.072	0.430	1.601 (Electricity)	1.457 (Electricity)
Grid Electrolysis (onsite: industrial & transport)	1.160	0.442	1.609 (Electricity)	1.458 (Electricity)
Solar Electrolysis (central)	5.059	1.981	1.601 (Electricity)	1.457 (Electricity)
Solar Electrolysis (onsite: industrial & transport)	5.578	2.063	1.609 (Electricity)	1.458 (Electricity)
Onshore Wind Electrolysis (central)	2.753	1.077	1.601 (Electricity)	1.457 (Electricity)
Onshore Wind Electrolysis (onsite: industrial & transport)	3.023	1.117	1.609 (Electricity)	1.458 (Electricity)
Nuclear High Temperature Electrolysis (central)	3.856	3.72	3.189 (Thermal Energy - For Heat and Electricity)	3.189 (Thermal Energy - For Heat and Electricity)

Table A.1. Hydrogen production – costs and energy/feedstock requirements. Levelized non-energy costs refer to the production technology costs per kg of H₂ and do not include the energy/feedstock costs. ‘Input / Output’ coefficients are the inverse of efficiencies and are presented in lower heating values (LHV). The renewable-based hydrogen production costs shown above are based on the capacity factors assumed for the USA. For cost and efficiency assumptions for all model years and regions, see the publication’s supplementary data file.

renewable electricity generation. In this case, electricity is transported between the VRE source and the end user that is producing hydrogen onsite. In contrast, central green hydrogen production is assumed to generate hydrogen at the VRE source (also synchronously), with hydrogen moved to the end user.

Nuclear HTE assumptions are also informed by NREL H2A models, but because there is no 2018 H2A version for this technology, we utilized the 2008 H2A version (version 2.1)⁵²³, the most recent publicly available, and updated the reactor costs using ATB version 2019. The improvement in nuclear HTE costs is also consistent with GCAM's power sector. No improvement in efficiency is assumed. Unlike all other hydrogen production technologies which are allowed to operate after 2020, nuclear HTE is not available until 2030, reflecting the fact that nuclear technologies often require a longer amount of time to construct and to receive governmental approval for operation.

Onsite blue hydrogen is assumed to be available only within industry given the scale required for CO₂ capture and sequestration. This technology is not provided by the H2A models but is created by reducing the assumed size of H2A's central gas SMR + CCS technology to 10% of its designed capacity. Additionally, all hydrogen production technologies have defined lifetimes. Maximum lifetimes are taken from the H2A models. Central production technologies have a 40-year lifetime and 30-year half life, while distributed technologies have a lifetime of 20 years and half life of 15 years.

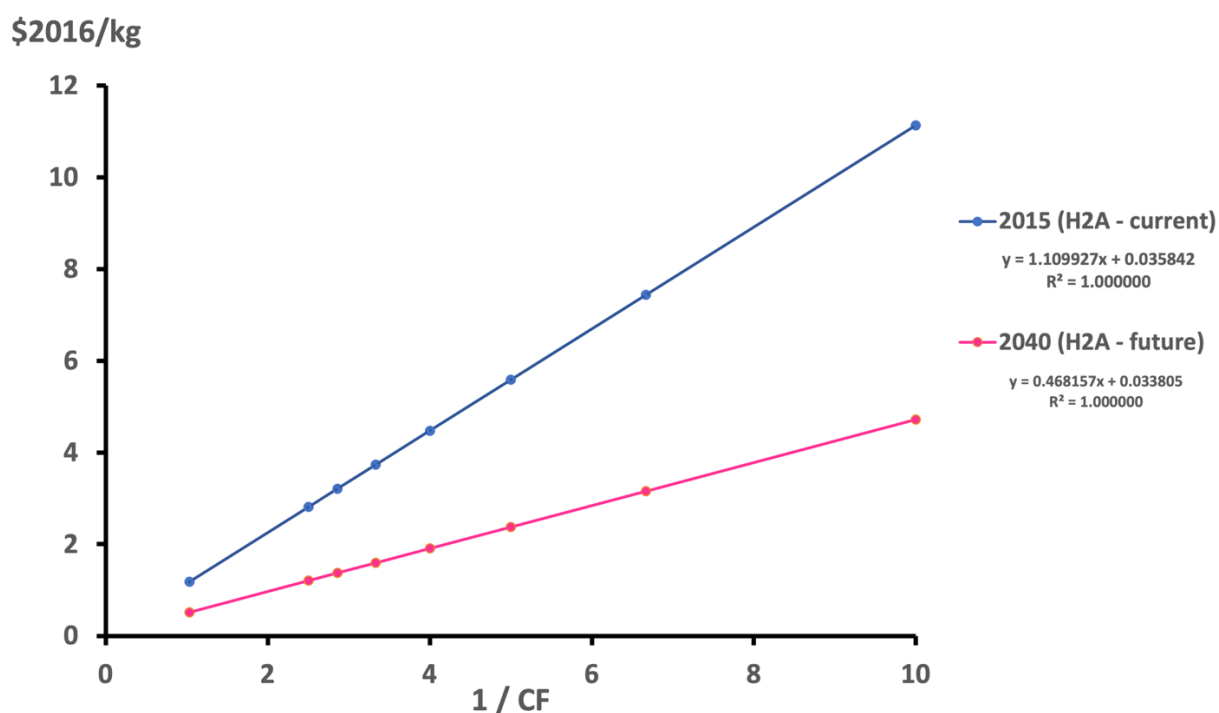


Figure A.1. Levelized electrolyzer non-energy costs as a function of capacity factor for central H₂ production. Based on H2A version 3.2018 central PEM electrolysis production assumptions.

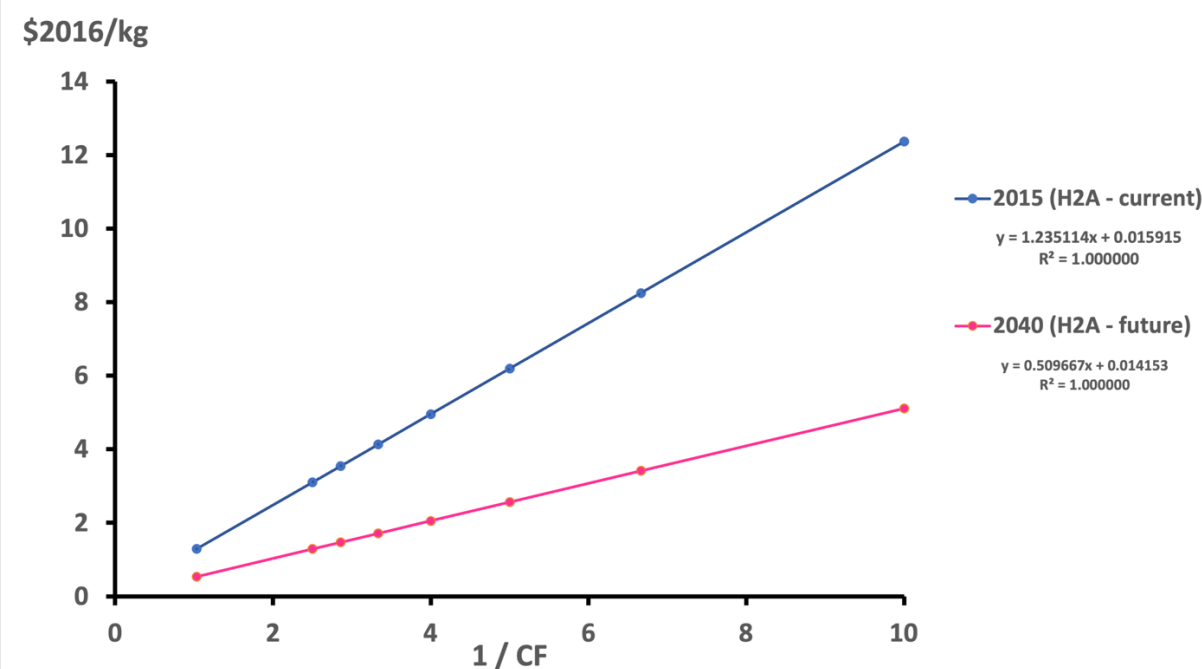


Figure A.2. Levelized electrolyzer non-energy costs as a function of capacity factor for onsite H₂ production. Based on H2A version 3.2018 forecourt PEM electrolysis production assumptions.

In addition to cost and efficiency, technologies in GCAM are calibrated to their historical shares through the “share-weight” parameter. Historically incumbent technologies, such as coal or natural gas, are assigned a unit share-weight of 1, while alternative technologies within a sector have share-weights that reflect whether their historical deployment has been less than or greater than expected given levelized cost competition alone, yielding share-weights that are less than 1 or greater than 1, respectively. Historical share-weights then inform future period energy decisions as past preferences are taken into consideration. This calibration helps avoid unrealistic abrupt fuel-switching in regions and/or sectors where such a change is unlikely, even when considering levelized cost-based competition. However, technologies that have not yet materially deployed have a share-weight of zero in historical years. The speed of a new technology’s penetration is determined by the year in which the new technology reaches a share-weight of 1. This represents when the new technology will be fully integrated into the market with its market share solely based on cost.

Hydrogen production technology share-weights influence the competition between technologies within a given subsector. All hydrogen production technologies, other than CCS technologies, are assumed to have a share-weight of 1 beginning in 2025. CCS technologies are assumed to reach 1 in 2030. The CCS share-weight trajectory is consistent with CCS technology share-weights assumed for other GCAM sectors.

A.1.B. Hydrogen transmission & distribution

In terms of delivering centrally produced hydrogen, we separately represent liquid hydrogen truck and gaseous hydrogen pipeline transmission and distribution. We further include

the blending of hydrogen into the natural gas delivery network as a third method of transporting hydrogen to consumers. A wide range of blend limits have been reported as acceptable within the literature. Timmerberg and Kaltschmitt (2019) found that a range from 2-30% had been published and their study assessing the possibility of exporting green hydrogen from Northern Africa to Central Europe via a blend into the existing natural gas infrastructure used 10% hydrogen.⁵²⁴ The International Energy Agency's 2021 "Net Zero by 2050" study included a blend with a mean of 15% hydrogen globally in 2030,⁵²⁵ while their 2019 "The Future of Hydrogen" report noted that T&D networks as well as certain end uses (boilers and cooking appliances) could tolerate a blend of 20% or larger.⁵²⁶ In the High Demand cases, we model a 20% blend by volume, or roughly a 7% blend by energy content.⁵²⁷ This percentage is within this literature's range and has been previously used as a limit in optimization modeling work by Quarton and Samsatli (2020).⁵²⁸ We also conservatively phase the blend into natural gas distribution networks over time, given that certain end-use technologies currently installed may not be able to handle a blend of 20% hydrogen, such that all new gas technologies in the relevant end-use sectors are consuming the blend by midcentury (see below).

The levelized non-energy cost and efficiency assumptions for hydrogen delivery, found in Table A.2, are based on the U.S. DOE's Argonne National Laboratory's Hydrogen Delivery Scenario Analysis Model (HDSAM) version 3.1.⁵²⁹ Non-energy costs (CAPEX and OPEX) and energy requirements for compression and refrigeration at refueling stations are also included in this study and based on the HDSAM models. Standard HDSAM assumptions were utilized, with modifications made to refueling lifetime (which was set to 20 years). A region selection is required which we defined as Columbus, Ohio given its moderate size and generalizability to

Distribution Method	Levelized Cost (\$2020 / kg of H ₂)			Input / Output Coefficient (GJ in / GJ hydrogen)		
	Cost Component	2020	2050	Input	2020	2050
H ₂ Liquid Truck	H ₂ Liquification for onboard storage	1.893	1.744	Electricity (Liquification / compression for T&D)	0.277	0.225
H ₂ Gaseous Pipeline	Transmission & Distribution	0.918* (2030)	0.845	Electricity (Compression for T&D)	0.017* (2030)	0.017
Central Green H ₂ 400km additional transmission	H ₂ liquid truck (Total cost = non-energy + energy)	0.311	0.281	NA	NA	NA
	H ₂ gaseous pipeline (Total cost = non-energy + energy)	Not Available	0.617	NA	NA	NA
Onsite Green H ₂ delivered electricity	Industry (electricity delivery total cost)	0.485	0.385	NA	NA	NA
	Transportation (electricity delivery total cost)	1.950	1.552	NA	NA	NA
Dispensing (transportation)	Compression & storage (Liquid H ₂ truck delivery)	1.520	1.475	Electricity (Compression & refrigeration - liquid H ₂ truck delivery)	0.016	0.016
	Compression & storage (H ₂ pipeline delivery & onsite production)	2.374	2.228	Electricity (Compression & refrigeration - H ₂ pipeline delivery & onsite production)	0.149	0.149
	Retail dispensing additional T&D (Road transportation)	0.572	0.572	NA	NA	NA
Natural Gas + Hydrogen Blend	Compression	0.067	0.061	Hydrogen	0.070	0.070
				Natural Gas	0.930	0.930

Table A.2. Hydrogen transmission, distribution, and refueling - costs and energy/feedstock requirements. Costs are levelized non-energy costs unless otherwise stated. ‘Input / Output’ coefficients are the inverse of efficiencies and are presented in lower heating values (LHV). Values are rounded to three decimal places. All central production technologies assume 100 km of hydrogen transmission, other than green hydrogen which requires 500 km of transmission. Zero leakage of hydrogen is assumed. Natural gas pipeline costs are not altered to accommodate the 20% hydrogen blend (by volume), but costs for hydrogen compression into natural gas pipelines is included within the model. *Gaseous pipeline H₂ T&D is not available until 2030, so values are presented for this year rather than 2020.

other potential district hydrogen markets. The ‘H2 Market’ type was defined as “Combined Urban/Rural”. Liquid hydrogen truck delivery assumptions assumed dispensing at refueling stations via ‘700 bar gas via pump’ and ‘Medium’ production volume (HDSAM setting ‘Mid’). We assumed ‘700 bar cascade dispensing’ and ‘High’ production volume when generating the gaseous hydrogen pipeline assumptions. Within GCAM, the hydrogen truck representation endogenously selects the drivetrain from the transportation sector’s freight road subsector, and therefore HDSAM assumptions are only leveraged for the necessary liquification for onboard storage component of delivery. Total levelized costs (non-energy and energy) for compressing hydrogen in the natural gas pipelines are generated with the same HDSAM assumptions as gaseous pipeline delivery other than production volume which was set to “medium”.

Hydrogen delivery from central production facilities is assumed to involve 100 km transmission to the end user, except for renewable-based electrolysis. For central green hydrogen production, we assumed 500 km of transmission since the electrolyzers are assumed to be co-located with large wind or solar farms, which are generally sited where the renewable resource quality is highest, not near hydrogen demand centers. The additional amount of transmission is likewise taken from HDSAM models by adding the additional kilometers required for delivery. The first year for hydrogen pipeline delivery in all cases that allow pipeline delivery is 2030, reflecting that it would take multiple years to build out the pipeline network. We represent the cost of moving electricity for our onsite green H₂ production technologies by multiplying the electricity energy requirement to produce a GJ of electrolysis-based hydrogen by the GCAM power sector’s assumptions for delivering electricity to the industrial and transportation sectors.

The cost of delivering electricity to the transportation sector is higher than delivery to the industrial sector, which is why their costs are larger in Table A.2.

We set improvement rates to allow for reductions in non-energy costs for hydrogen delivery and dispensing, given that HDSAM does not include cost variation overtime. For hydrogen delivery by gaseous pipeline, liquification for onboard storage in hydrogen truck T&D, and compression of hydrogen for blending into natural gas delivery networks we assumed a 25% total reduction in non-energy costs by 2100. For refueling centers the assumed non-energy cost decrease is differentiated by the type of hydrogen delivery and location of hydrogen production: 20% non-energy cost improvement by 2100 is assumed for refueling stations with gaseous pipeline delivery or onsite production of hydrogen, while only 10% improvement in cost is assumed for refueling stations with hydrogen delivered in liquid trucks. See Figure A.3 for an example of the levelized cost of hydrogen faced by end-users for select hydrogen production technologies. When delivered hydrogen is available liquid hydrogen trucks have a share-weight value of 1 beginning in 2025 while gaseous hydrogen pipelines have a value of 1 beginning in 2030 (and zero beforehand).

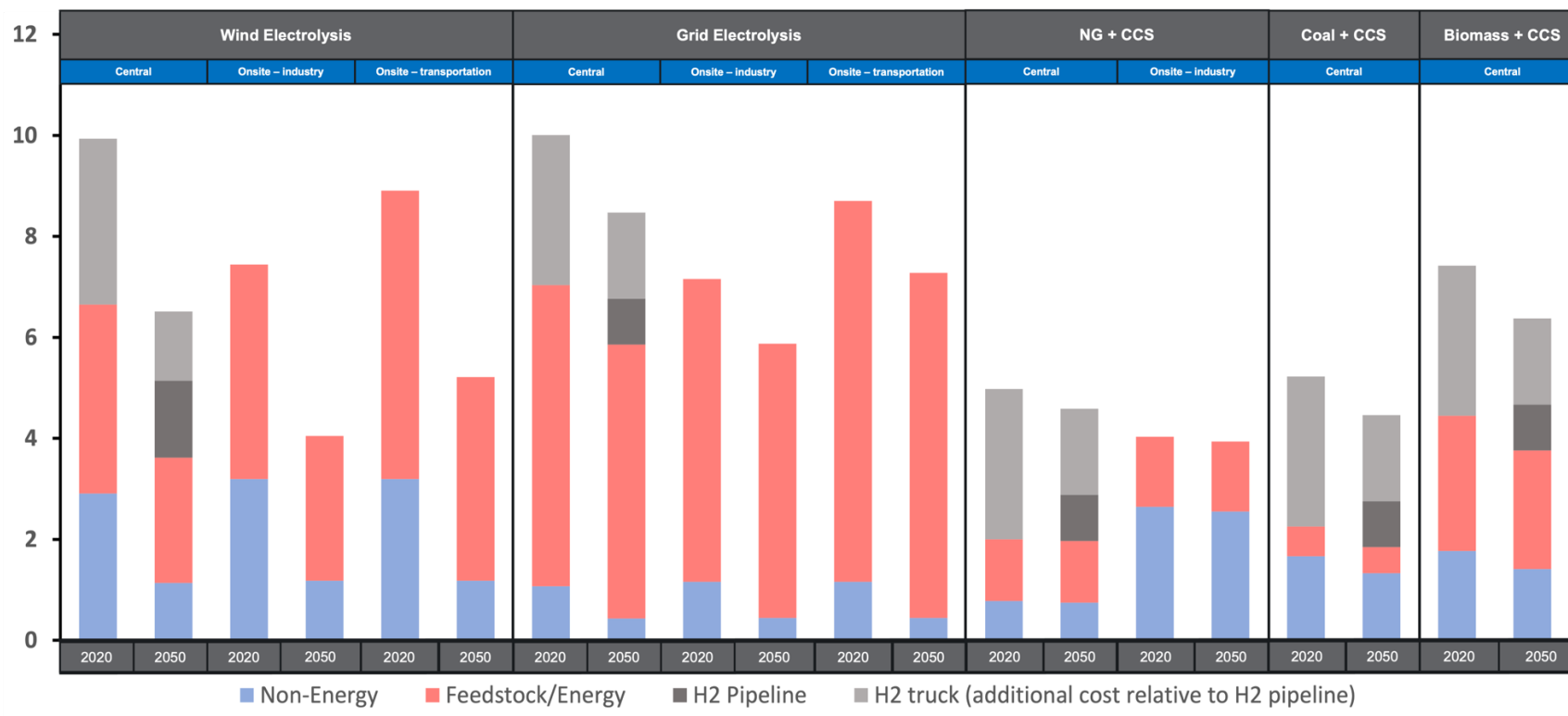


Figure A.3. Levelized cost of hydrogen (LCOH) in \$2020 per kg of H₂. The LCOH for a given production method varies regionally and across scenarios due to differences in the projected prices of delivered energy as well as renewable capacity factors. LCOH values presented here use illustrative delivered energy prices and renewable capacity factors which are within the model’s ranges for these assumptions and projections across regions. Electricity delivered to centralized and industrial grid electrolysis is assumed to cost \$31/GJ, while electricity delivered to onsite production in the transportation sector is assumed to cost \$39/GJ. Natural gas is assumed to cost \$7/GJ for central production facilities and \$8/GJ when delivered to onsite industrial production. Biomass is assumed to cost \$8/GJ. Wind-based electrolysis assumes a 35% capacity factor. “Non-Energy” costs refer to levelized capital and operating expenses. “Feedstock/Energy” costs refer to the costs associated with the feedstock and other energy inputs. The “Feedstock/Energy” cost for electrolysis is primarily the cost of electricity, which is either purchased (e.g., grid electrolysis) or produced onsite (e.g., central wind electrolysis). The total cost of delivering hydrogen via trucks is equal to the sum of costs for “H₂ pipeline” and “H₂ truck (additional cost relative to H₂ pipeline)”. See the publication’s supplementary data file for renewable electrolysis assumptions for all regions and green H₂ technologies.

A.1.C. End-use sector model modifications

Gas-fueled technologies in GCAM's industrial and building sectors are allowed to consume the hydrogen and natural gas blend in 'High Demand' scenarios. These technologies include process heat for cement, other industrial energy use (including cogeneration), building heating, and other building needs not including cooling or energy for water supply (e.g., water heating and cooking). District heat production also was modified to allow for blend consumption. 'High Demand' scenarios also allowed for a 25% cost reduction in hydrogen specific industrial technologies (industrial energy use, industrial cogeneration, process heat for cement), with the reduction achieved between 2020 and 2050.^O

This analysis also included substantial updates to the transportation sector relative to GCAM v5.4, and these updates are now included within the publicly available version of the model (beginning with GCAM v6.0).⁵³⁰ Full information about the assumptions for the transportation sector can be found on JGCRI's GCAM documentation GitHub repository.^P In our 'Reference Demand' scenarios we hold the capital cost of hydrogen-based modes of transportation flat once they are available. In our 'High Demand' cases we allow for cost improvement in these technologies after the first year of availability, with the improvement aligned with the standard cost trajectory assumptions in GCAM v6.0. In end use sectors, share-weights incorporate various non-cost factors related to technologies (e.g., consumer perception of a new technology, ease of permitting, infrastructure availability, other performance attributes,

^O For industrial cogeneration from hydrogen, this 25% reduction is only applied to the portion of the technology which is hydrogen specific (i.e., the hydrogen combustion portion of the technology's non-energy costs, rather than the portion of non-energy costs which involves the electricity generation).

^P Documentation for the transportation sector can be found here: https://jgcric.github.io/gcam-doc/cmp/359-Hydrogen_and_transportation.pdf

etc.). ‘Year of first availability’ as well as the year when hydrogen-powered modes of transport compete with incumbent transportation technologies solely on a basis of levelized costs (i.e., when their technology share-weights reach 1) can be found in Table A.3. All scenarios allow for cost improvement beyond the first year of availability for non-hydrogen powered transportation.

GCAM Mode of Transport	Year of First Availability	Year when Share-weight Reaches 1
Road-based transport	2025	
Minicar		2030
Car		2030
Large Car and Truck		2030
Bus		2050
Light Truck		2050
Medium Truck		2050
Heavy Truck		2050
Freight Rail	2025	2050
Marine transport	2035	
Domestic Ship		2075
International Ship		

Table A.3. GCAM hydrogen-based modes of transport – first year of availability and year when technological share-weight reaches 1. First year of availability corresponds to the first model period in which the given hydrogen-powered mode of transport is available in GCAM (for this study as well as GCAM v6.0). Year when technological share-weight reaches 1 corresponds to the year when competition between hydrogen-powered modes of transport compete with incumbent transportation technologies solely on a basis of levelized costs.

Industrial final energy hydrogen applications attain share-weights of 1 in 2100. While we explored other alternatives for industry, we elected to maintain our default assumption given the aggregate representation of the industrial sector in this version of GCAM. Alternative assumptions about industry could be explored more easily in a version of GCAM with greater industrial disaggregation, which was not available in the core model at the time that this work commenced. While converging the industrial share-weight sooner would likely increase nearer-

term deployment of hydrogen within industry, the significant role for hydrogen within industry is already apparent in the core runs.

A.2. Additional results for the core scenarios

We find that the hydrogen production mix varies depending on whether it is used to meet industrial and transportation demand (Figure A.4), due in part to the assumption that onsite blue hydrogen is not available in transportation. Onsite green hydrogen provides 44-92% of total hydrogen demand in the transportation sector, and any hydrogen demand not fulfilled by onsite green hydrogen is mostly met by central production when available. In contrast, for the industrial sector onsite green hydrogen provides 34-62% of total production, whereas onsite blue hydrogen provides 19-37% of production (or 29-62% and 16-37% including the hydrogen blended with gas, respectively).

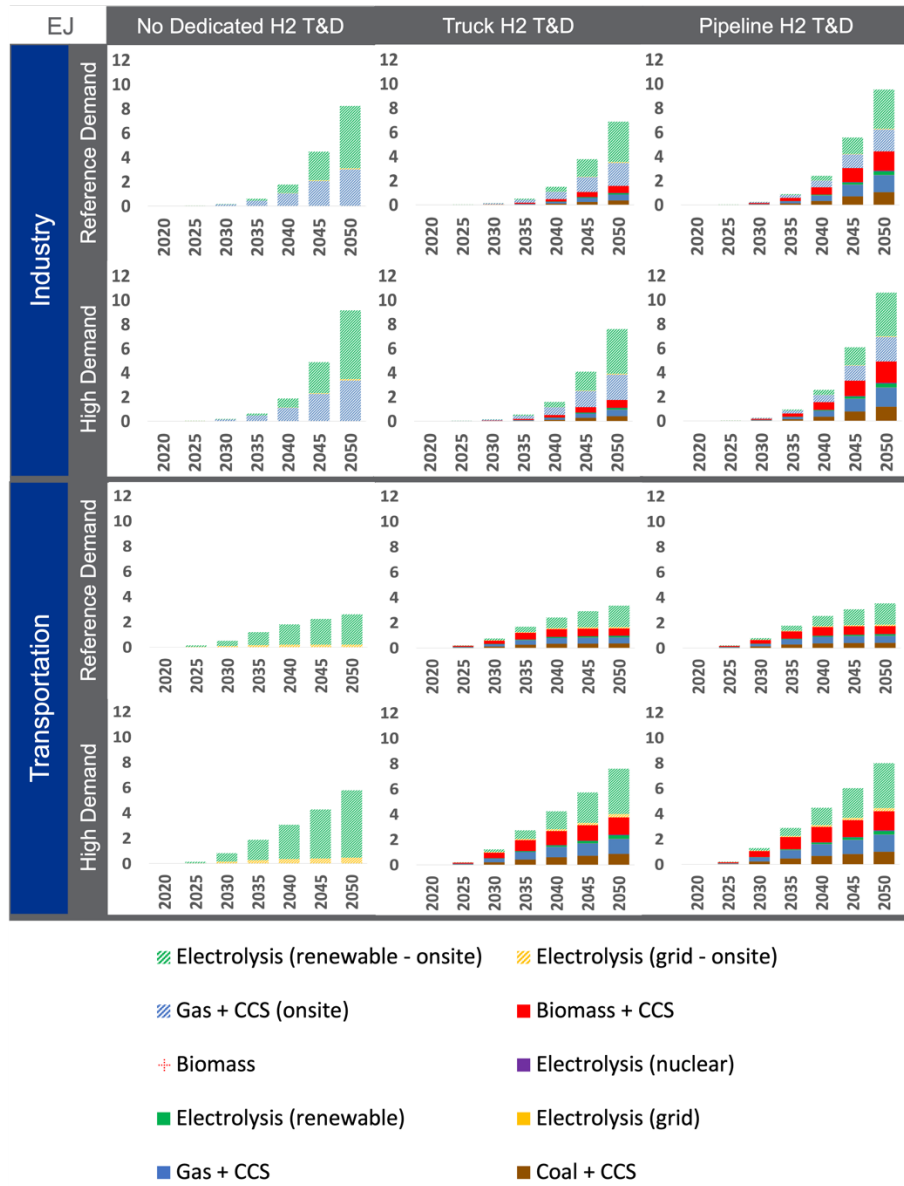
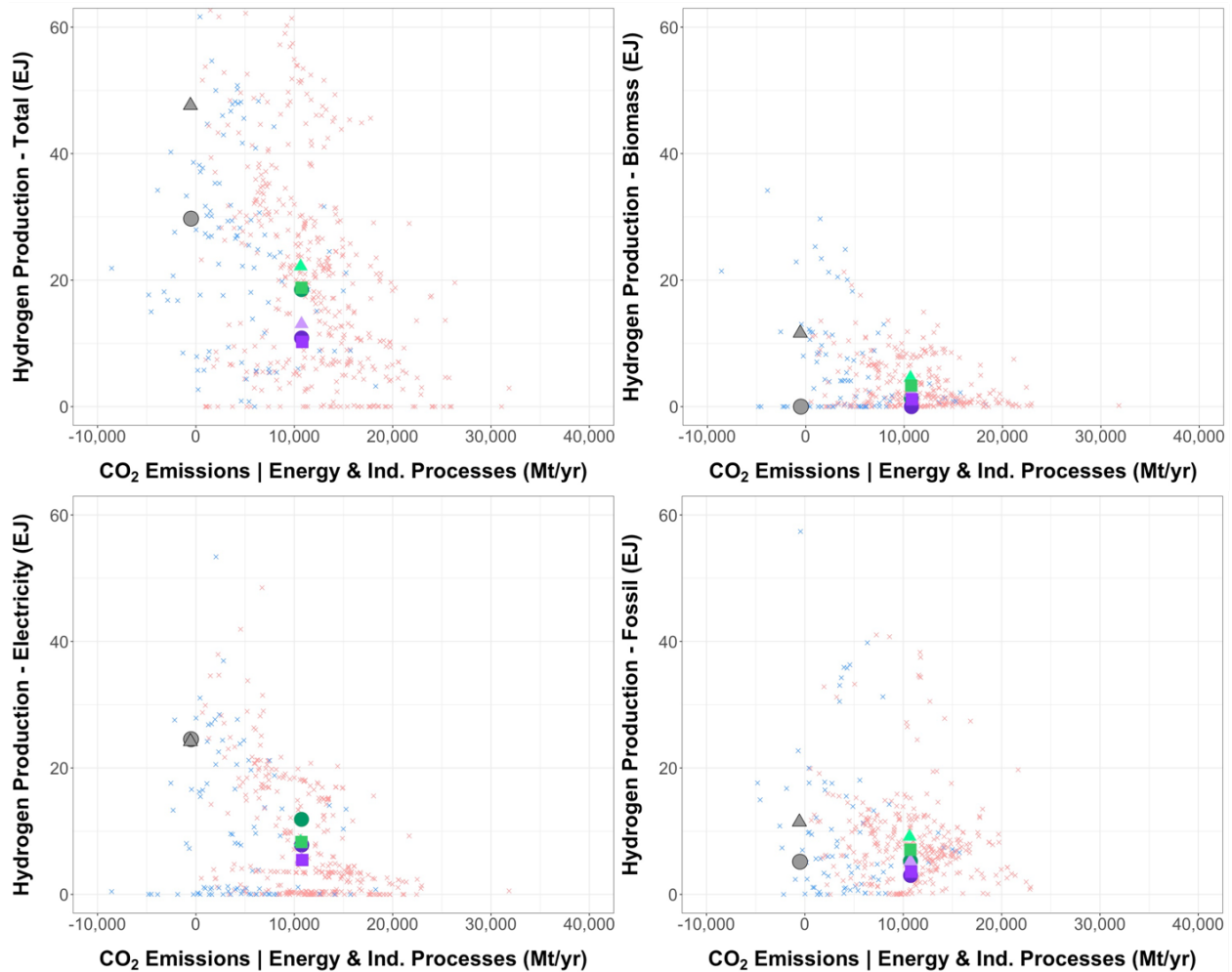


Figure A.4. Global hydrogen (EJ) production by technology and end-use sector through midcentury for the core scenarios. Centrally produced hydrogen is shown using solid colors, whereas onsite production is shown using diagonal hashed colors. Figure does not include hydrogen blended with natural gas for industrial energy use.



IPCC AR6 Database Scenarios:

- × 0°C ≤ 2100 temp. ≤ 1.5°C
- × 1.5°C < 2100 temp. ≤ 2.0°C

GCAM Study Scenarios:

- No Dedicated H2 T&D
- Truck H2 T&D
- ▲ Pipeline H2 T&D
- No Dedicated H2 T&D - High Demand
- Truck H2 T&D - High Demand
- ▲ Pipeline H2 T&D - High Demand

Below 2°C

- No Dedicated H2 T&D
- ▲ Pipeline H2 T&D - High Demand

1.5°C

Figure A.5. Global hydrogen production (EJ) in 2050 – core scenarios and 1.5°C cases vs. IPCC AR6 Scenarios. “Reference Demand” scenarios from this study are portrayed in shades of purple, while “High Demand” scenarios are portrayed in shades of green (however, the 1.5°C sensitivities are all portrayed in grey). IPCC AR6 database scenarios⁵³¹ are sorted by their temperature in 2100 for the variable “AR6 climate diagnostics|Surface Temperature (GSAT)|MAGICCv7.5.3|67.0th Percentile”.

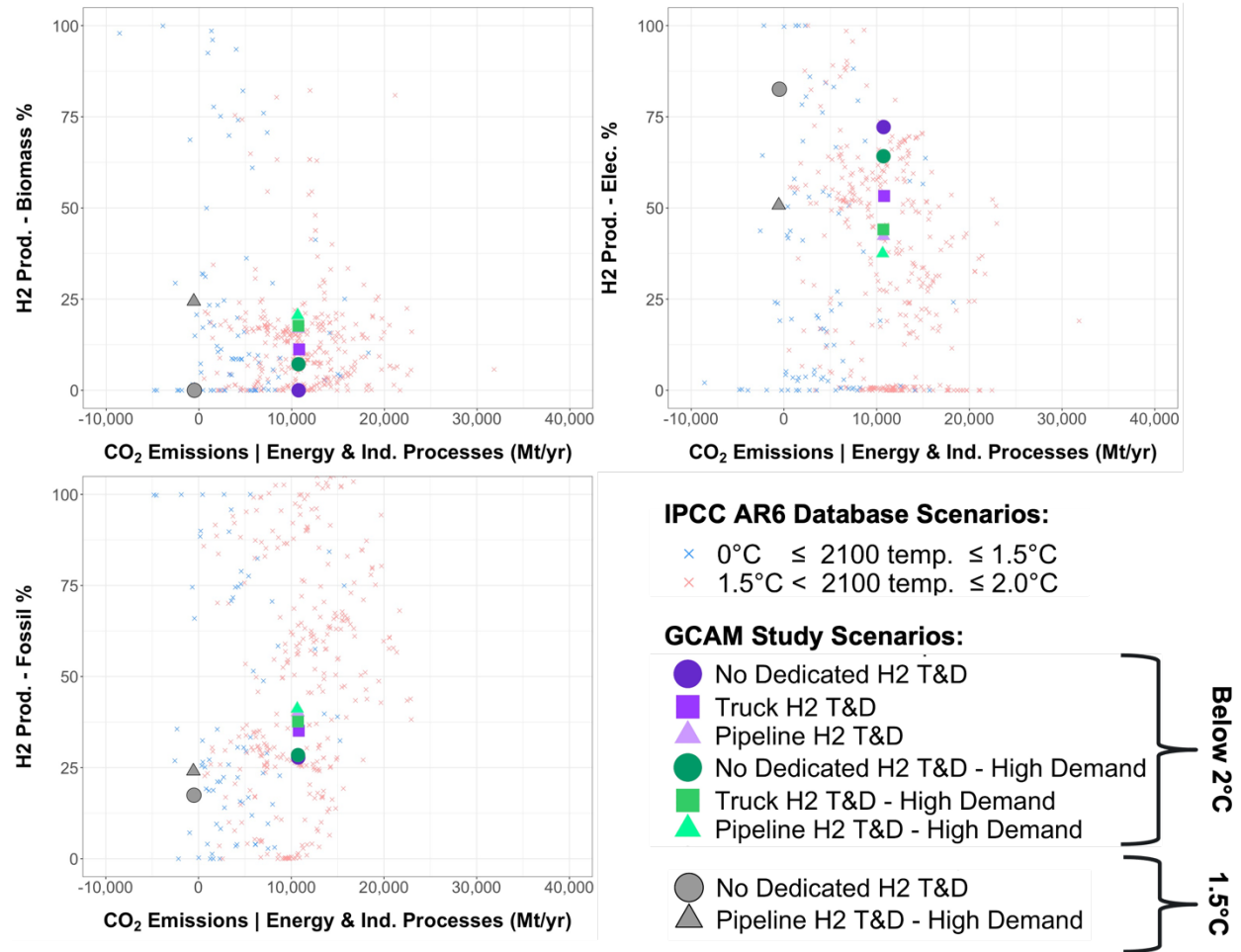


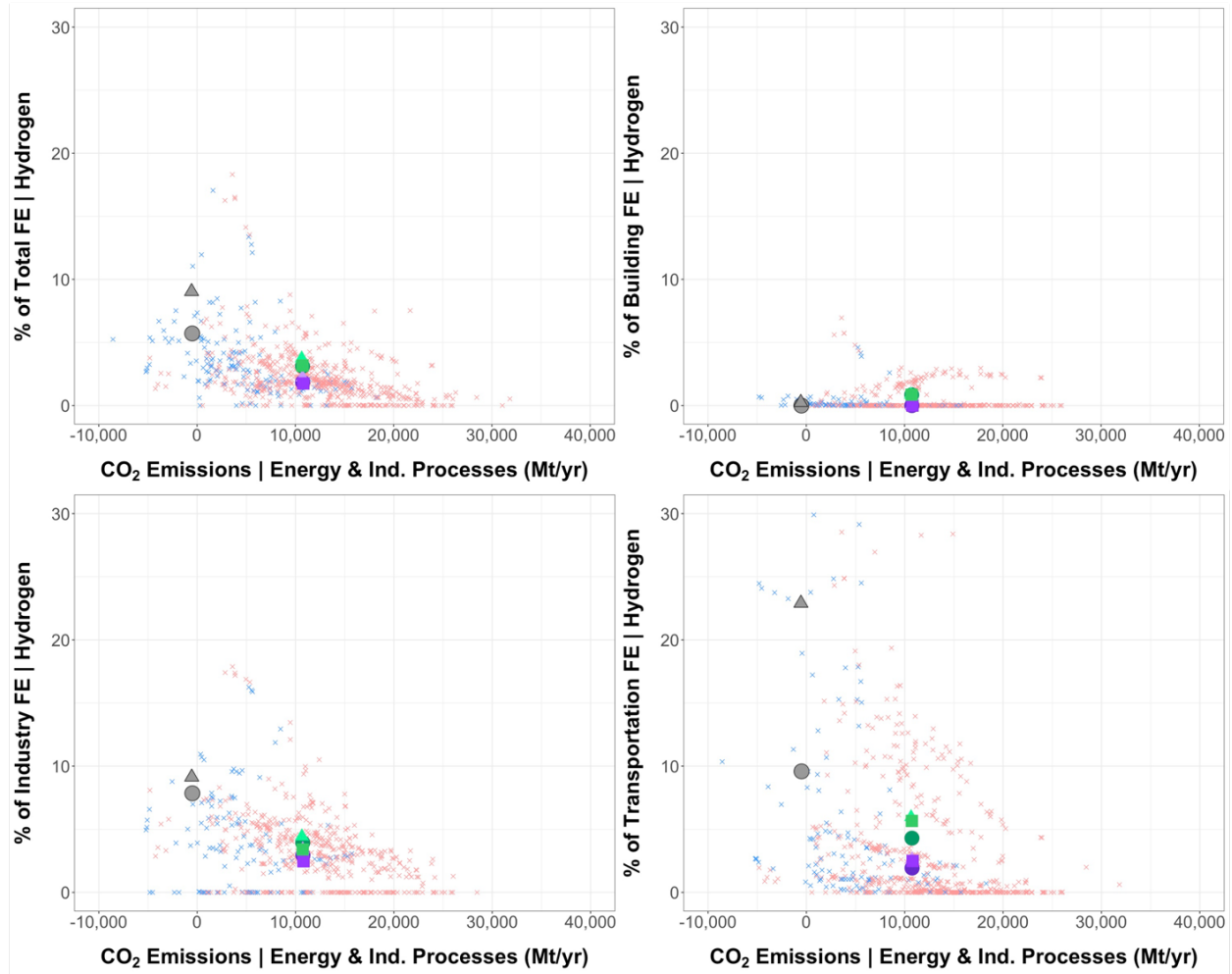
Figure A.6. Percent of global hydrogen production by type in 2050 - main text scenarios and 1.5°C cases vs. IPCC AR6 Scenarios. “Reference Demand” scenarios from this study are portrayed in shades of purple, while “High Demand” scenarios are portrayed in shades of green (however, the 1.5°C sensitivities are all portrayed in grey). IPCC AR6 database scenarios⁵³² are defined by their temperature in 2100 for the variable “AR6 climate diagnostics|Surface Temperature (GSAT)|MAGICCv7.5.3|67.0th Percentile”.

Sector	Scenario:							
	Truck H ₂ T&D, Reference Demand				Pipeline H ₂ T&D, Reference Demand			
	Final energy (EJ)	H ₂ demand (EJ)	% final energy	% service output	Final energy (EJ)	H ₂ demand (EJ)	% final energy	% service output
Industry	278.9	6.9	2.5%	----	279.6	9.5	3.4%	----
Cement	15.3	1.0	6.3%	----	15.3	1.3	8.7%	----
Other industrial energy use	196.3	5.9	3.0%	----	196.9	8.19	4.2%	----
Transportation	134.8	3.4	2.5%	----	134.8	3.5	2.6%	----
Passenger Vehicle	39.0	0.7	1.7%	1.9%	39.0	0.7	1.8%	2.0%
Bus	6.0	0.6	9.9%	22.4%	6.0	0.6	10.0%	22.5%
Freight Road	47.6	1.0	2.2%	2.6%	47.5	1.1	2.4%	2.8%
Freight Rail	3.9	0.8	19.1%	18.2%	3.9	0.8	19.4%	18.5%
Domestic Shipping	2.3	0.1	4.8%	4.9%	2.26	0.1	5.9%	6.1%
International Shipping	13.2	0.2	1.4%	1.8%	13.2	0.2	1.7%	2.1%
Buildings	171.1	0	0%	----	171.1	0	0%	----
Heat	33.2	0	0%	----	33.2	0	0%	----
Other	121.3	0	0%	----	121.3	0	0%	----
Total	584.8	10.2	1.7%	----	585.5	13.1	2.2%	----

Table A.4. Global hydrogen consumption (EJ) by end-use sector in 2050 for remaining Reference Demand scenarios (2°C). Values (EJ and %) are rounded to the nearest tenth if larger than or equal to 0.05 (otherwise values are presented to the nearest hundredth). 'Other industrial energy use' refers to the GCAM sector 'industrial energy use'. The subsector 'Other' within the buildings sector refers to the sum of GCAM's 'residential other' and 'commercial other' subsectors. Subsectors will not sum to the sector total given that there are subsectors which do not consume hydrogen and are thus not reported here (e.g., building cooling, aviation, industrial feedstocks, N fertilizer production, and energy for water supply).

Sector	Scenario:							
	No Dedicated H ₂ T&D, High Demand				Truck H ₂ T&D, High Demand			
	Final energy (EJ)	H ₂ demand (EJ)	% final energy	% service output	Final energy (EJ)	H ₂ demand (EJ)	% final energy	% service output
Industry	280.6	11.1	3.9%	----	280.6	9.5	3.4%	----
Cement	15.3	1.2	8.0%	----	15.3	1.0	6.6%	----
Other industrial energy use	197.8	9.8	5.0%	----	197.8	8.51	4.3%	----
Transportation	134.6	5.8	4.3%	----	134.2	7.6	5.7%	----
Passenger Vehicle	38.6	2.3	6.1%	6.6%	38.5	2.9	7.4%	6.7%
Bus	6.0	0.7	10.8%	24.3%	6.0	0.7	11.0%	24.6%
Freight Road	47.5	1.8	3.8%	4.4%	47.1	2.6	5.5%	6.5%
Freight Rail	3.9	0.7	18.5%	17.6%	4.0	0.8	20.4%	19.4%
Domestic Shipping	2.3	0.05	2.1%	2.2%	2.3	0.2	6.8%	7.1%
International Shipping	13.2	0.2	1.6%	1.9%	13.2	0.5	3.8%	4.7%
Buildings	171.7	1.5	0.9%	----	171.8	1.5	0.9%	----
Heat	33.4	0.9	3%	----	33.5	0.9	3%	----
Other	121.6	0.6	0.5%	----	121.7	0.6	0.5%	----
Total	586.9	18.3	3.1%	----	586.6	18.6	3.2%	----

Table A.5. Global hydrogen consumption (EJ) by end-use sector in 2050 for remaining High Demand scenarios (2°C). Values (EJ and %) are rounded to the nearest tenth if larger than or equal to 0.05 (otherwise values are presented to the nearest hundredth). 'Other industrial energy use' refers to the GCAM sector 'industrial energy use'. The subsector 'Other' within the buildings sector refers to the sum of GCAM's 'residential other' and 'commercial other' subsectors. Subsectors will not sum to the sector total given that there are subsectors which do not consume hydrogen and are thus not reported here (e.g., building cooling, aviation, industrial feedstocks, N fertilizer production, and energy for water supply).



IPCC AR6 Database Scenarios:

- × 0°C ≤ 2100 temp. ≤ 1.5°C
- × 1.5°C < 2100 temp. ≤ 2.0°C

GCAM Study Scenarios:

- No Dedicated H2 T&D
- Truck H2 T&D
- ▲ Pipeline H2 T&D
- No Dedicated H2 T&D - High Demand
- Truck H2 T&D - High Demand
- ▲ Pipeline H2 T&D - High Demand

Below 2°C

- No Dedicated H2 T&D
- ▲ Pipeline H2 T&D - High Demand

1.5°C

Figure A.7. Percentage of global final energy by type in 2050 – main text scenarios and 1.5°C cases vs. IPCC AR6 scenarios. “Reference Demand” scenarios from this study are portrayed in shades of purple, while “High Demand” scenarios are portrayed in shades of green (however, the 1.5°C sensitivities are all portrayed in grey). IPCC AR6 database scenarios⁵³³ are defined by their temperature in 2100 for the variable “AR6 climate diagnostics|Surface Temperature (GSAT)|MAGICCv7.5.3|67.0th Percentile”.

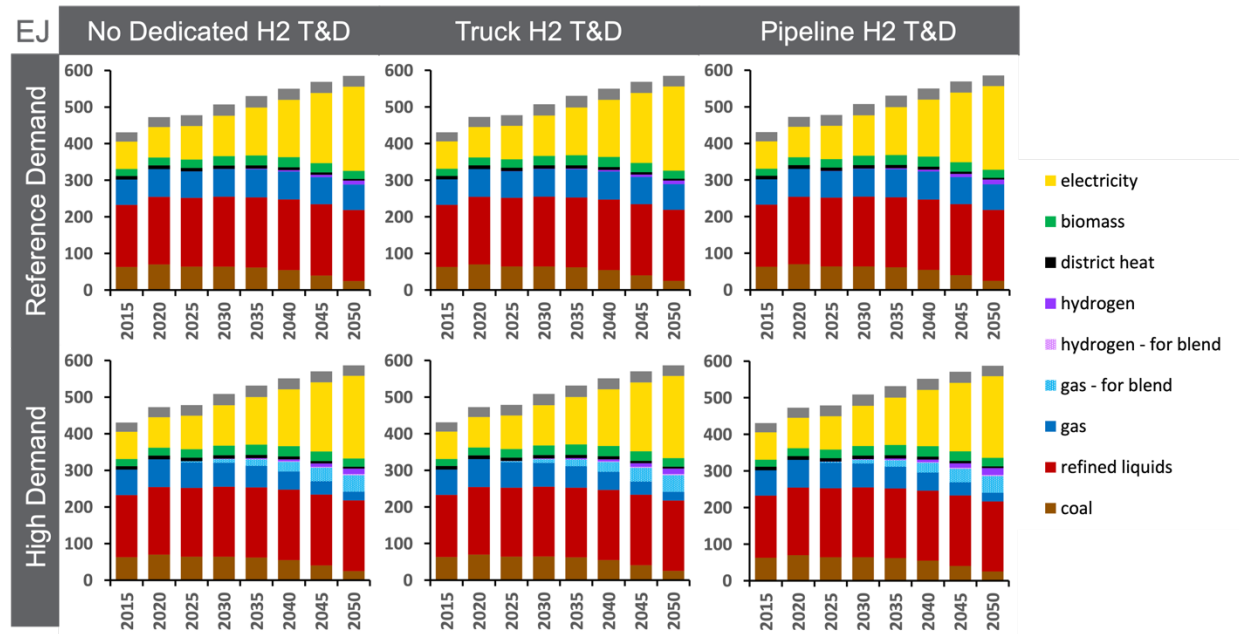


Figure A.8. Total final energy by type in 2050 - core scenarios.

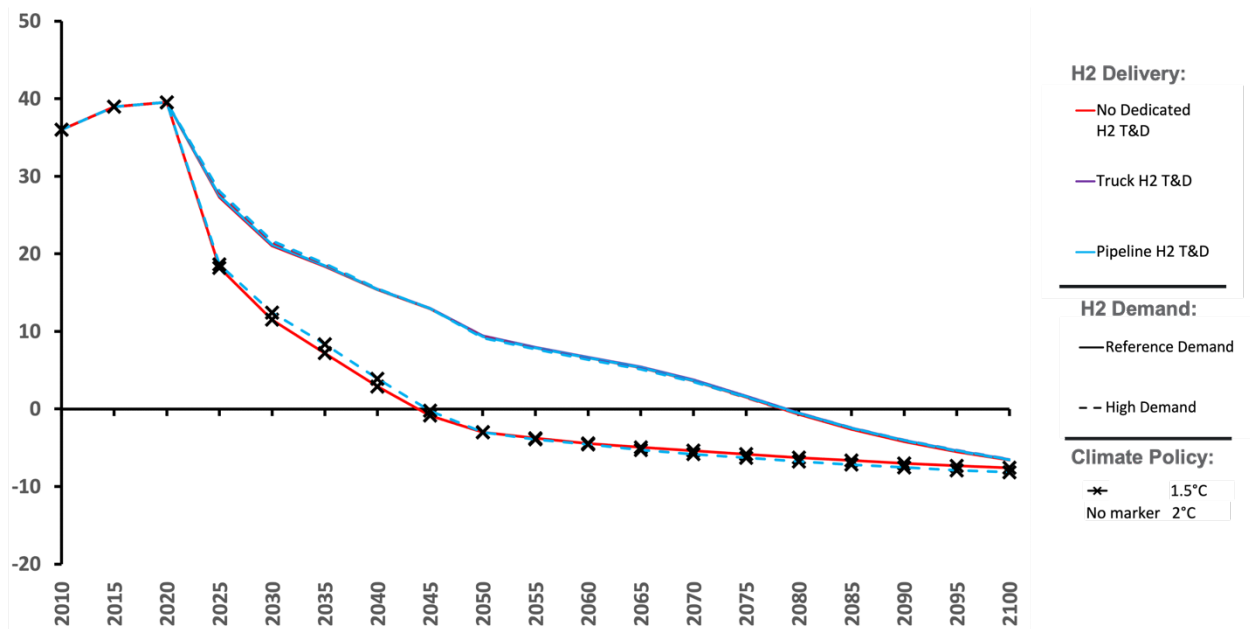


Figure A.9. Global net CO₂ emissions over the century (Gt CO₂) - core scenarios and 1.5°C cases. Net CO₂ emissions include the net emissions from energy and industrial processes as well as land use change.

Scenario		2025	2050
Below 2°C	No Dedicated H ₂ T&D	150	314
	Truck H ₂ T&D	148	310
	Pipeline H ₂ T&D	147	308
	No Dedicated H ₂ T&D, High Demand	144	301
	Truck H ₂ T&D, High Demand	142	297
	Pipeline H ₂ T&D, High Demand	141	295
1.5°C	No Dedicated H ₂ T&D	680	1424
	Pipeline H ₂ T&D, High Demand	608	1274

Table A.6. Carbon prices (2020\$ / t CO₂) - core scenarios and 1.5°C cases. Carbon pricing starts in 2025 and rises 3% annually. Land use change emissions face 10% of this price. Values are rounded to the nearest dollar.

A.2.A. Hydrogen in the second half of the century – below 2°C

Given the relatively modest uptake of hydrogen by midcentury seen in the core scenarios, we extended the analysis to 2100 to investigate how hydrogen’s role may increase over the longer run. The results are inherently more uncertain. Nevertheless, we see important trends. In particular, onsite production of H₂ by renewable electrolysis grows, accounting for a minimum 64% by 2100 across all core scenarios (Figure A.10). This reduces the demand for central production and by the end of the century, scenarios with dedicated hydrogen delivery infrastructure see central production facilities produce at most 28% of total hydrogen globally. As with the near term, we find no substantial difference in total hydrogen supply between the cases where pipelines are available and when no dedicated hydrogen T&D infrastructure exists in the long run (under the same demand assumptions). The High Demand assumptions do increase hydrogen supply, but they also largely maintain the existing proportional mix of production.

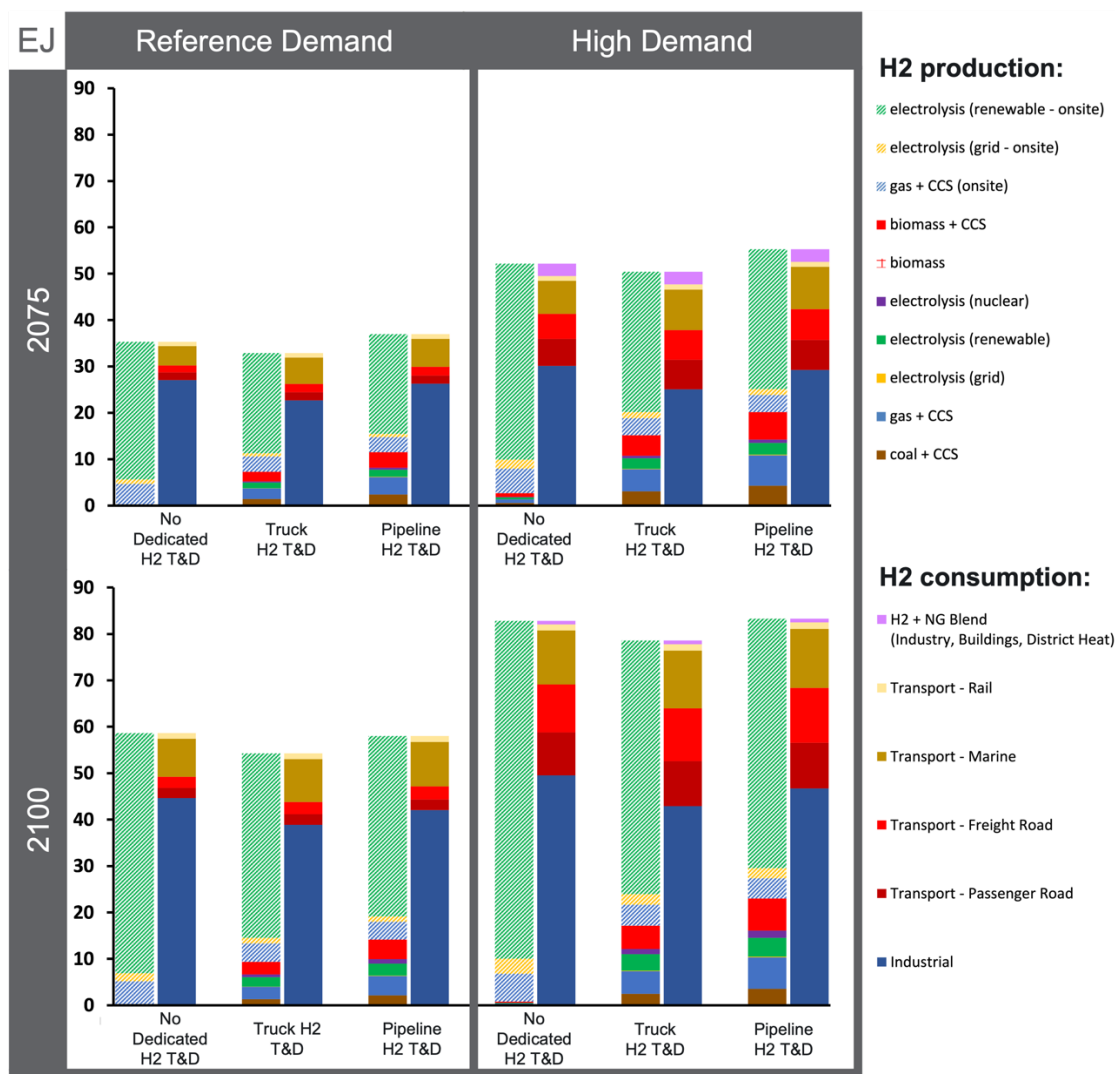


Figure A.10. Global hydrogen production and consumption (EJ) in the long run. Hydrogen production (left stacked bar) and hydrogen consumption (right stacked bar) in 2075 and 2100 for the core scenarios which limit warming below 2°C. Centrally produced hydrogen is shown using solid colors, whereas onsite production is shown using diagonal hashed colors.

In the second half of the century hydrogen's role as a final energy carrier is still modest, meeting just 8 to 12% of total final energy demand in 2100 (54-83 EJ of H₂ consumed). But this represents an expanded contribution to decarbonization relative to midcentury. The industrial sector remains the largest user of hydrogen in the long run, consuming 39- 50 EJ of hydrogen in 2100 (55-76% of total hydrogen consumption, not including H₂ consumed in the form of natural

gas/H₂ blends). While not the dominant provider of final energy for GCAM's industrial energy use sector, hydrogen plays a notable role satiating between 13 and 18% of industrial energy use demand. In fact, by 2100 hydrogen could provide 79% of energy demand for cement without dedicated hydrogen delivery infrastructure and with Reference Demand cost assumptions. For the transportation sector, we find a larger range of potential final energy coming from H₂ across the scenarios (8-20% in 2100). While hydrogen provides 4-20% of final energy for freight trucks by the end of the century, the energy carrier plays a larger role in marine applications. Even with conservative cost assumptions hydrogen provides 65-73% of final energy for international shipping in 2100. Lastly, consistent with the diminished role blended hydrogen and natural gas saw moving from 2030 to 2050, by 2100 hydrogen consumption coming from the blend is found to be minor (1%).

A.3. Sensitivity: limiting warming to 1.5°C

In this section we examine hydrogen production and consumption under scenarios that limit warming to 1.5°C for our two 'bookend' scenarios (Figure A.11). In these scenarios, onsite green hydrogen remains the dominant method of production, providing an even larger share of total production compared to the corresponding 2°C scenarios (45-81% vs. 32-69% in 2050). The percentage and absolute amount of hydrogen production coming from BECCS is also larger when pipeline delivery is available compared to the corresponding 2°C scenarios (11.6 EJ or 24% in 2050 vs. 4.6 EJ or 21%). This is primarily driven by the increased subsidy for BECCS under higher carbon prices (more than 4 times larger in 2050 in the 1.5°C scenarios than in the 2°C scenarios). In addition, hydrogen production accounts for a larger share of total biomass consumption (25% under 1.5°C as compared to 7% under 2°C) for the same scenario and year.

And while the absolute amount of blue hydrogen production increases by 2-3 EJ in the 1.5°C scenarios compared to the corresponding 2°C scenarios, the share of blue hydrogen is lower by 9-10 percentage points. These results are not surprising, as higher carbon prices will favor hydrogen production technologies with a zero or negative carbon intensity.

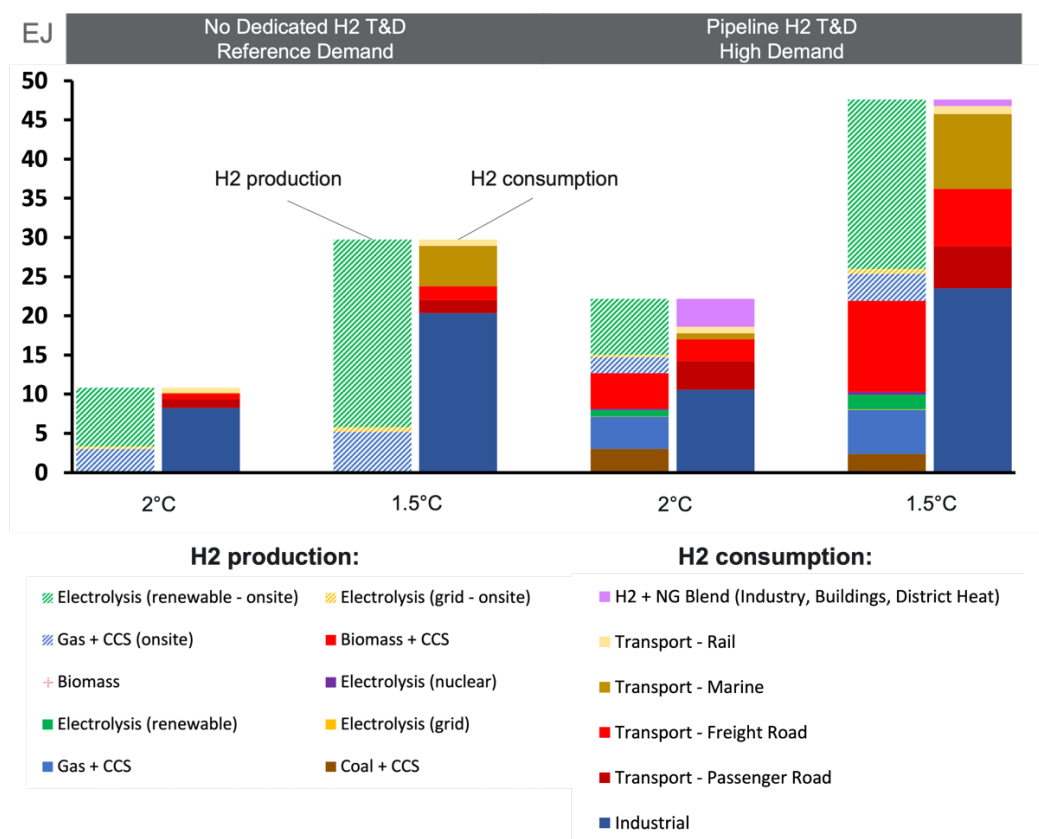


Figure A.11. Hydrogen production and consumption (EJ) in 2050 for two of the core cases for two different climate objectives (1.5°C and 2°C). Centrally produced hydrogen is shown with solid colors, whereas onsite production is shown as diagonal hashed colors.

Total hydrogen consumption in the 1.5°C scenarios (30-48 EJ) is more than twice the amount in the corresponding 2°C scenarios (10-22 EJ) in 2050, as traditional energy carriers are replaced more rapidly with zero-carbon energy carriers. In fact, by midcentury the percentage of

Sector	Scenario:							
	No Dedicated H ₂ T&D, Reference Demand, 1.5°C				Pipeline H ₂ T&D, High Demand, 1.5°C			
	Final energy (EJ)	H ₂ demand (EJ)	% final energy	% service output	Final energy (EJ)	H ₂ demand (EJ)	% final energy	% service output
Industry	259.4	20.4	7.9%		261.7	23.9	9%	
Cement	14.7	8.0	54.3%		14.8	7.7	52.3%	
Other industrial energy use	180.1	12.4	6.9%		182.1	16.2	8.9%	
Transportation	97.7	9.4	9.6%		101.5	23.3	22.9%	
Passenger Vehicle	28.1	0.9	3.3%	2.5%	29.0	4.6	15.7%	12.7%
Bus	4.6	0.7	16.0%	27.9%	4.7	0.8	17.0%	30.1%
Freight Road	35.2	1.8	5.0%	4.6%	35.9	7.3	20.4%	20.3%
Freight Rail	3.1	0.8	25.9%	21.4%	3.4	1.0	29.3%	24.8%
Domestic Shipping	2.0	0.1	5.7%	4.3%	2.3	0.6	8.2%	22.4%
International Shipping	8.7	5.0	57.7%	51.0%	10.0	9.0	90.5%	88.2%
Buildings	163.5	0	0%		163.2	0.4	0.3%	
Heat	32.9	0	0%		32.2	0.3	1.0%	
Other	114.9	0	0%		115.3	0.1	0.1%	
Total	520.5	29.7	5.7%		526.4	47.6	9.0%	

Table A.7. Global hydrogen consumption (EJ) by end-use sector in 2050 for 1.5°C Scenarios. Values (EJ and %) are rounded to the nearest tenth if larger than or equal to 0.05 (otherwise values are presented to the nearest hundredth). 'Other industrial energy use' refers to the GCAM sector 'industrial energy use'. The subsector 'Other' within the buildings sector refers to the sum of GCAM's 'residential other' and 'commercial other' subsectors. Subsectors will not sum to the sector total given that there are subsectors which do not consume hydrogen and are thus not reported here (e.g., building cooling, aviation, industrial feedstocks, N fertilizer production, and energy for water supply).

total final energy from hydrogen increases from roughly 2-4% in the 2°C scenarios to 6-9% in the 1.5°C scenarios. Hydrogen accounts for 10-23% of transportation final energy in the 1.5°C scenarios, which is a substantial increase over the share attained in the 2°C scenarios (2-6%). In fact, consumption from the transportation sector is only slightly smaller (<1 EJ) than that of the industrial sector in the 1.5°C High Demand scenario with pipeline T&D available. Most notably, hydrogen consumption for marine transport under 1.5°C (5.1-9.6 EJ) is now larger than hydrogen consumption for passenger road or freight road. While hydrogen accounts for 48-80%

of marine final energy in 2050, this is primarily hydrogen deployed in international shipping (5-9 EJ) where it accounts for 58-90% of final energy.

Industrial final energy from hydrogen in the 1.5°C scenarios is still a small share of total industrial final energy in 2050 (8-9% including industrial feedstocks), but it is larger than in the 2°C scenarios (2-4%). However, 52-54% of final energy for cement (mostly process heat) is generated using hydrogen in the 1.5°C scenarios, compared to 6-9% in the 2°C scenarios. Lastly, in the 1.5°C scenarios, hydrogen blended with natural gas accounts for less than 2% of hydrogen consumption in 2050, compared to 16-19% in the 2°C scenarios. This is because the higher carbon prices in the 1.5°C scenarios more rapidly drive a transition away from energy carriers that still emit CO₂. For example, at midcentury building heating is more heavily electrified by midcentury in the 1.5°C scenarios (19-20% for the 2°C scenarios vs. 42-45% for the 1.5°C cases).

A.4. Additional sensitivities

A.4.A. Sensitivity: biomass and CCS limited (2°C)

Bioenergy availability could affect hydrogen deployment, both in terms of the production mix (bio gasification for hydrogen production) and in terms of the need for additional carbon free energy carriers - particularly in end uses that may have consumed biomass or bio-derivative products (e.g., bioliquids) if accessible. Additionally, when biomass is coupled with carbon sequestration it can provide a negative source of emissions which would be incentivized by carbon policies. The availability of carbon sequestration also has the potential to impact hydrogen utilization in multiple ways. For one, it could alter the production mix for hydrogen,

particularly since any fossil routes to low-carbon hydrogen require CCS. Additionally, limited ability for carbon sequestration could increase the need for zero-carbon energy carriers in end-use sectors that might otherwise rely on removals via CCS to decarbonize.

Given these reasons, we model two additional scenarios: one with limited bioenergy available and a second with limited bioenergy and limited carbon sequestration. ‘Bio Low’ scenarios here limit primary energy utilization of biomass (other than ‘traditional biomass’^Q) to less than 50 EJ per year, in line with the constraint utilized within McJeon et al. (2021).⁵³⁴ “Bio Low / CCS Low” scenario constrains the amount of globally available carbon sequestration to that of the 25th percentile for scenarios limiting warming to 2°C through the century within the IPCC’s AR6 scenario database⁵³¹, by year. Scenarios are classified according to their temperature for the following variable within the database: "AR6 climate diagnostics | Surface Temperature (GSAT) | MAGICCv7.5.3 | 67.0th Percentile". Table A.8 displays the limitation by model period.

^Q Traditional biomass includes non-modern sources of biomaterial such as agricultural residues, animal dung, and fuelwood. This is in line with the IEA’s “primary solid biomass” energy resource (or ‘product’). More details about traditional biomass within GCAM can be found at http://jgcri.github.io/gcam-doc/supply_energy.html.

Year	25 th Percentile
2020	0
2025	0
2030	194
2035	956
2040	2,001
2045	3,036
2050	4,120
2055	5,332
2060	6,731
2065	7,724
2070	8,612
2075	9,332
2080	9,830
2085	9,938
2090	10,330
2095	10,733
2100	11,017

Table A.8. Carbon sequestration limitation (Mt CO₂ / yr.). Values are based on reporting for the variable “Carbon Sequestration | CCS” within the IPCC AR6 database and are rounded to the nearest whole number.

Each of these scenarios allows for pipeline delivery of hydrogen and utilizes the Reference Demand set of assumptions. The role of biomass is somewhat sensitive to assumptions about biomass and CCS. Specifically, we find that limiting bioenergy (‘Bio Low’) increases total hydrogen production by 4 EJ and expands the role of green and blue hydrogen (Figure A.12). In this case, the benefit of hydrogen as an alternative energy carrier exceeds the cost of constraining one of the H₂ supply options (BECCS H₂). On the other hand, imposing the biomass limitation simultaneously with limited carbon sequestration (the Bio Low + CCS Low scenario) results in roughly the same amount of total hydrogen production, with increased reliance on renewable electrolysis, which then accounts for more than 75% of the production mix. In this scenario, the cost of constraining multiple H₂ options balances the benefit of H₂ as an alternative energy carrier.

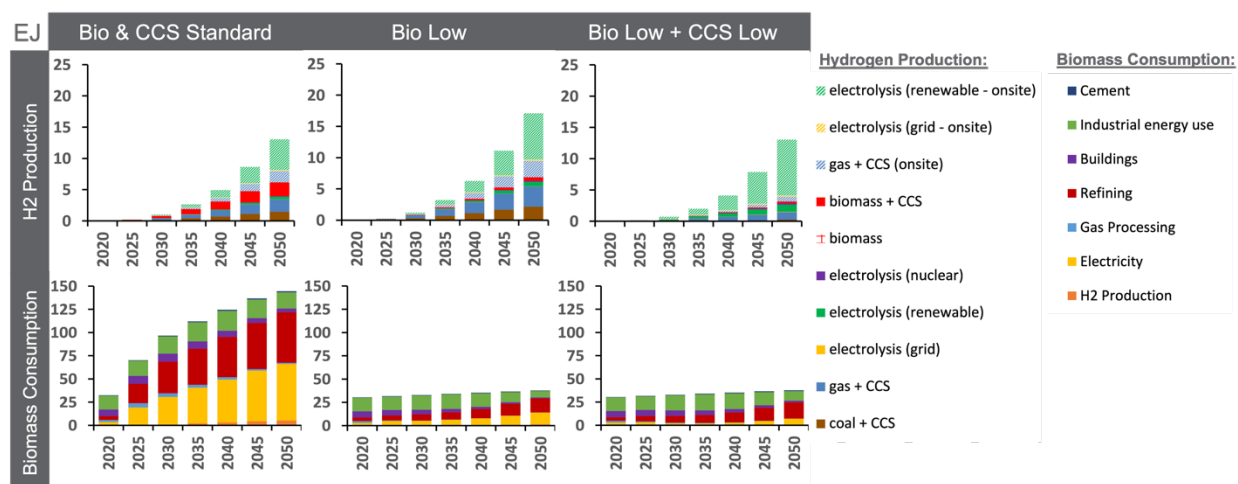


Figure A.12. Global hydrogen production and biomass consumption (EJ). All scenarios in this figure contain the Reference Demand assumptions and allow for pipeline delivery of hydrogen. The “Bio & CCS Standard” scenario refers to the “Pipeline H₂ T&D, Reference Demand” scenario from the standard cases. Centrally produced hydrogen is shown with solid colors, whereas onsite production is shown as diagonal hashed colors.

The broader energy transition assumptions for bioenergy and carbon sequestration availability also impact the consumption of H₂ (Figure A.13). An expansion in hydrogen utilization is found for industry (~3 EJ increase) as well as international shipping (~1 EJ increase) when biomass is limited. While a 1 EJ increase of hydrogen for international shipping may seem trivial, this is equivalent to a rise from 2% to 9% of final energy for this transportation subsector. In terms of industry, a large portion of this gain entails larger deployment of hydrogen for cement process heat - roughly doubling from 1.3 EJ to 2.6 EJ (or from about 9% to about 17% of final energy). The results are perhaps not surprising, given that the combustion of biomass can facilitate industrial process heat demand under decarbonization, and biofuels are also one method of providing a low-carbon fuel for heavy-duty transportation needs. On the other hand, the combined effect of the bioenergy and CCS constraints is not found to impact hydrogen consumption meaningfully.

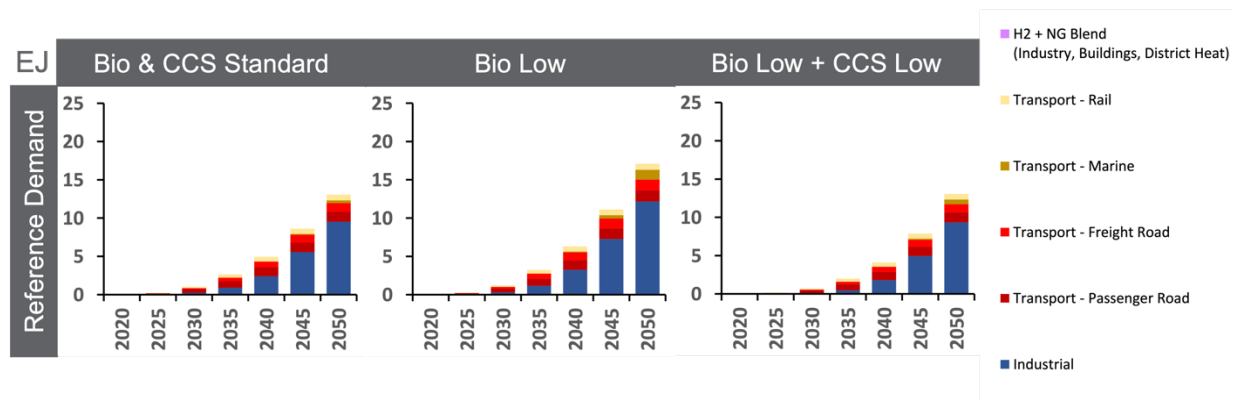


Figure A.13. Global hydrogen consumption (EJ) by end-use sector through midcentury for the Bio and CCS Low scenarios.

A.4.B. Sensitivity: no onsite H₂ production (2°C)

Given that our results suggest a large share of hydrogen could be produced onsite, primarily through renewable electrolysis, we conduct two sensitivities where hydrogen supply is restricted to centralized facilities. Results may also help explain outcomes found in other modeling work where onsite production of hydrogen is not considered (i.e., all hydrogen is delivered and faces the associated costs). Scenarios are simulated under reference and high demand assumptions, with warming limited below 2°C in both cases. Hydrogen transmission by truck or pipeline is available in each of these sensitivity cases as well, so we compare to the main text scenarios with the same climate objective and pipeline availability for illustrative purposes.

As seen in Figure A.14, limiting H₂ production to central facilities is not found to alter the scale of total hydrogen production significantly (e.g., < 1 EJ increase under reference demand assumptions). However, the production mix is considerably different. Without the ability to produce hydrogen at the end user green hydrogen is less competitive – decreasing from 36-41% to 8% of total hydrogen supply at midcentury (across paired scenarios). Production is now mainly based on blue hydrogen and BECCS. The latter of these two sees a large increase in its share compared to the paired counterpart scenarios, and now accounts for roughly a third of total

hydrogen. When onsite production and pipeline T&D were allowed BECCS only contributed 17-21%. Natural gas with CCS's share of total hydrogen supply also increases slightly (from 28-29% to 33-34%). Coal with CCS hydrogen production also nearly doubles when onsite production is restricted for both sensitivities, compared to their counterparts. In terms of demand, we find that this supply side sensitivity does not meaningfully alter hydrogen consumption (Figure A.15).

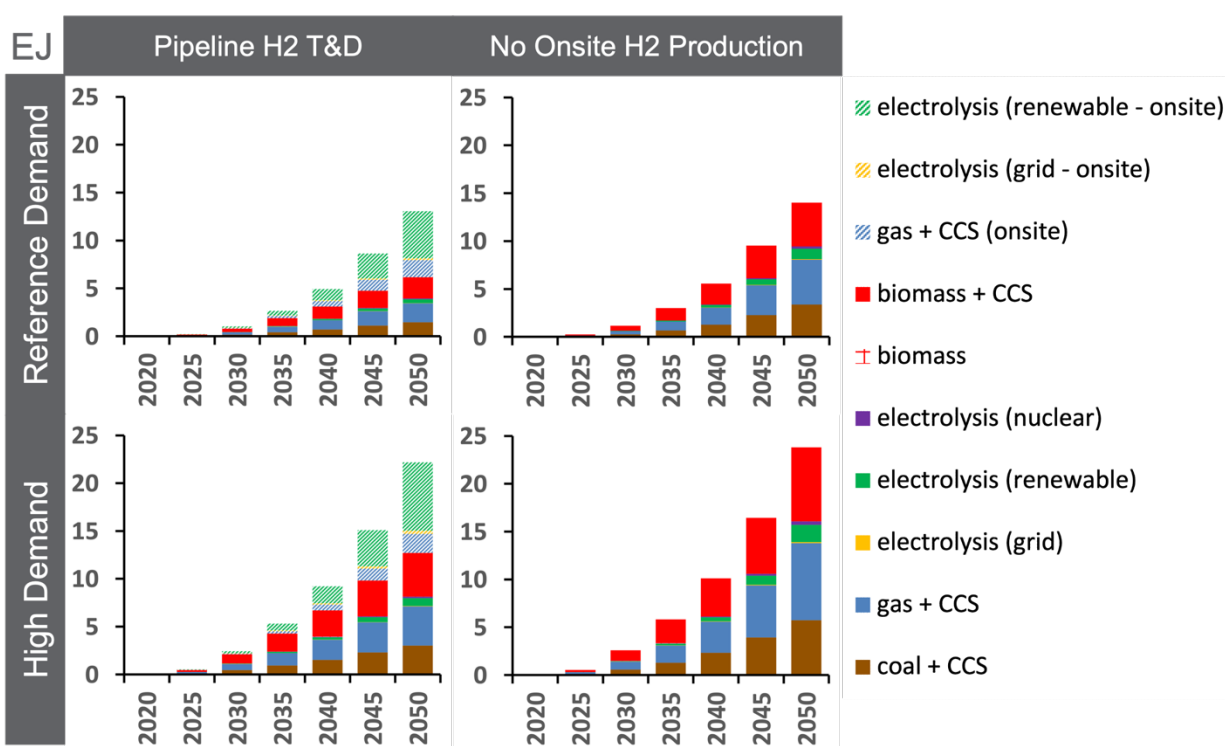


Figure A.14. Global hydrogen production (EJ) - No Onsite H₂ Production scenarios. Centrally produced hydrogen is shown with solid colors, whereas onsite production is shown as diagonal hashed colors.

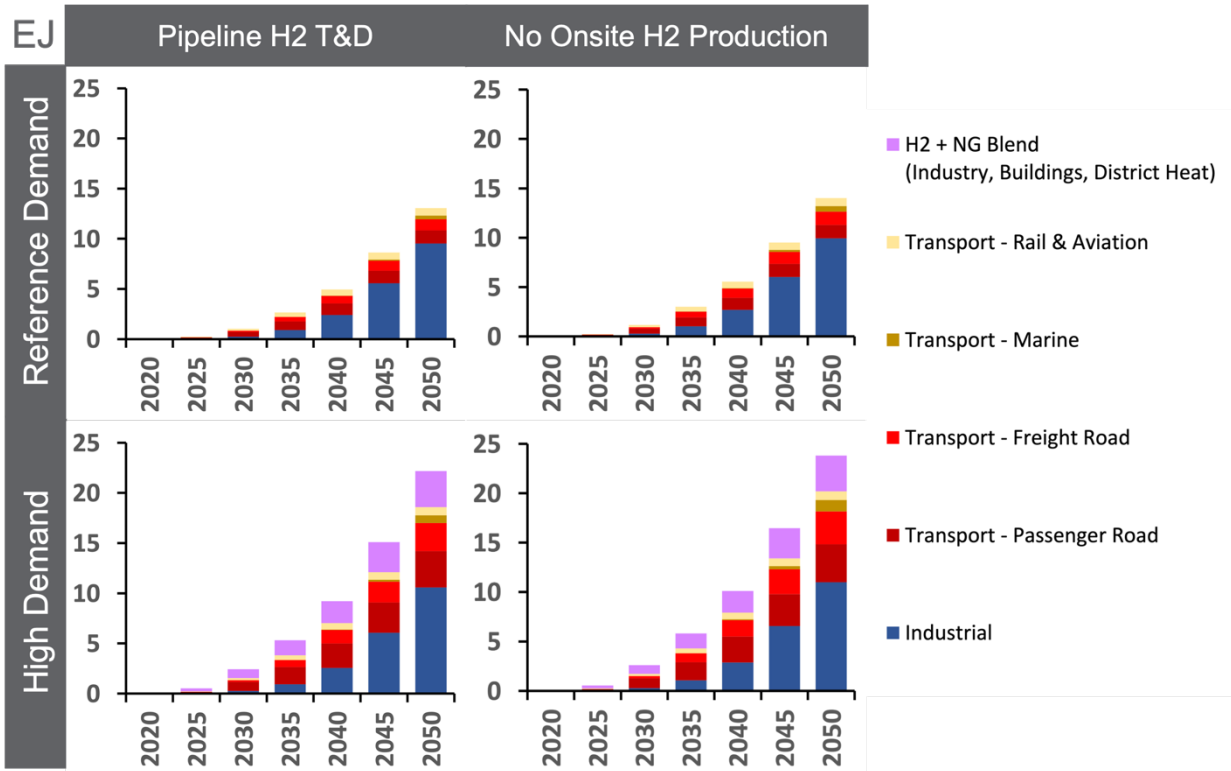


Figure A.15. Global hydrogen consumption by end-use sector (EJ) - No Onsite H₂ Production scenarios. Only the amount of hydrogen within the hydrogen/natural gas blend is included here (pink).

A.4.C. Sensitivity: direct air capture (DAC) available (2°C)

The deployment of facilities that directly capture large amounts of atmospheric CO₂ are not considered within our main text scenarios. One could hypothesize that if such technologies were economically competitive with other mitigation strategies - such as the use of low-carbon hydrogen - that they could reduce the need to deploy alternative decarbonization technologies. Given this possibility, we conduct an additional two sensitivities on our main text bookend scenarios which limit warming below 2°C: (1) *No Dedicated H₂ T&D*, and (2) *Pipeline H₂ T&D, High Demand*.

While not a part of GCAM's default configuration, the model recently included direct air capture (DAC) assumptions for each of the five shared socioeconomic pathways (SSPs). These

are detailed in Fuhrman et al. (2021).⁵³⁵ We utilize GCAM’s SSP2 DAC assumptions, or the “middle-of-the-road” projections, to analyze how the availability of this negative emissions technology impacts hydrogen deployment. Specifically, three types of DAC are considered: (1) high-temperature DAC via natural gas process heat, (2) high-temperature DAC via grid electricity process heat, and (3) low-temperature DAC via electric heat pump.

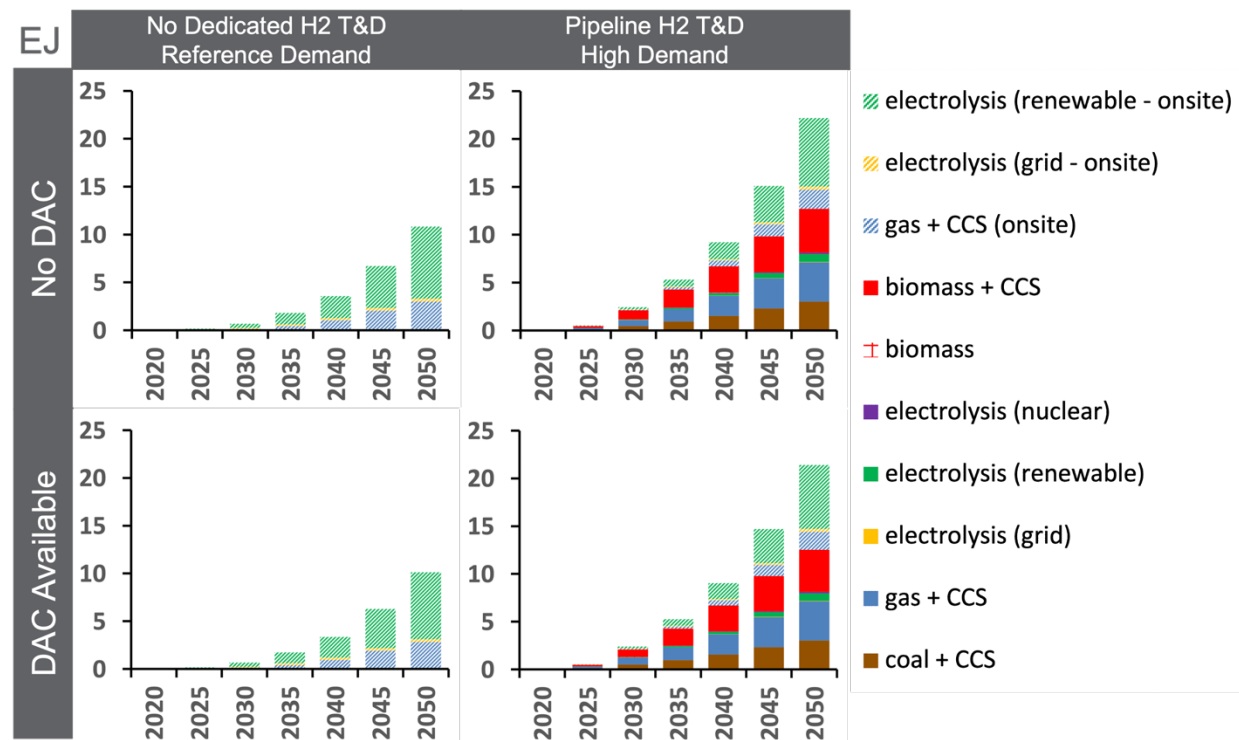


Figure A.16. Global hydrogen production (EJ) - Direct Air Capture (DAC) scenarios. Centrally produced hydrogen is shown with solid colors, whereas onsite production is shown as diagonal hashed colors.

Our results indicate that the availability of DAC doesn’t meaningfully alter the scale or mix of hydrogen production (Figure A.16). H₂ consumption is not altered significantly either (Figure A.17). While these results may change if the ability to couple DAC and H₂ production for the creation of synthetic fuels had been considered, it is still worth noting hydrogen is not sensitive to DAC without carbon capture and utilization (CCU). There is one noticeable change

in the decarbonization trajectory though, as this negative emissions technology allows the economy to delay early climate change mitigation in favor of deeper net negative emissions in the second half of the century (Figure A.18).

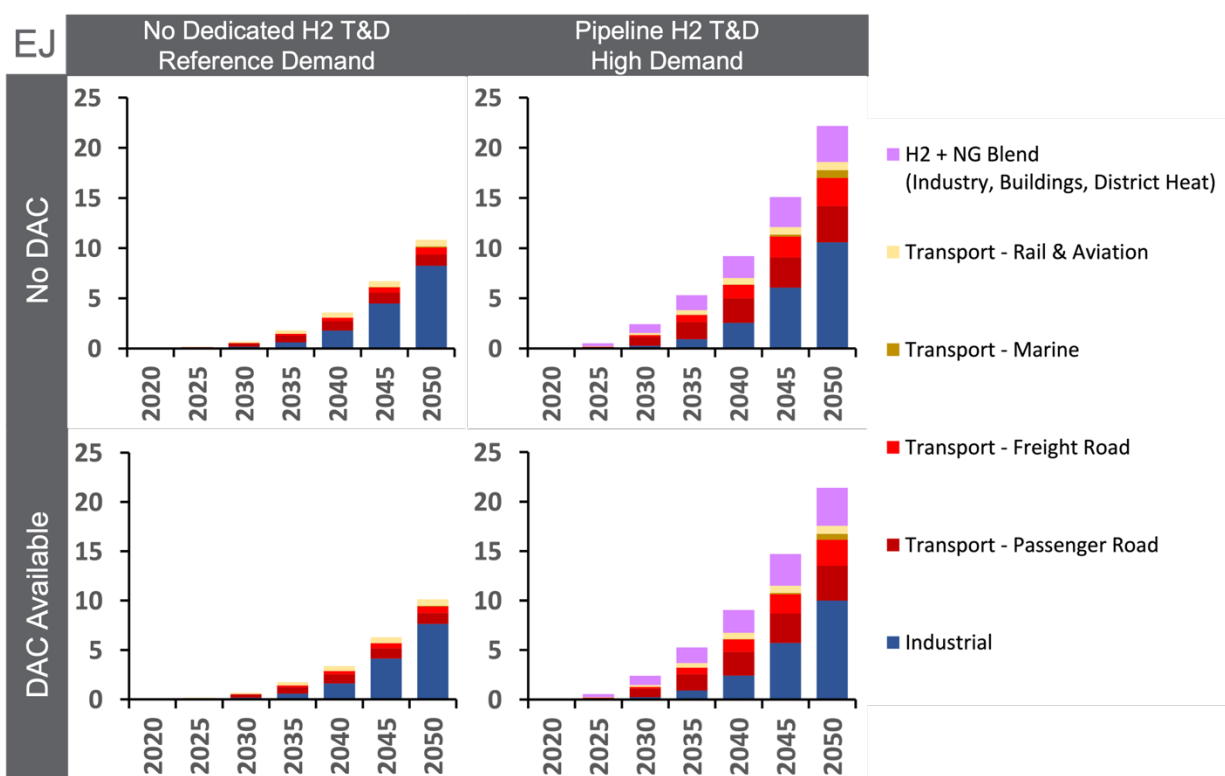


Figure A.17. Global hydrogen consumption by end-use sector (EJ) - Direct Air Capture (DAC) scenarios. Only the amount of hydrogen within the hydrogen/natural gas blend is included here (pink).

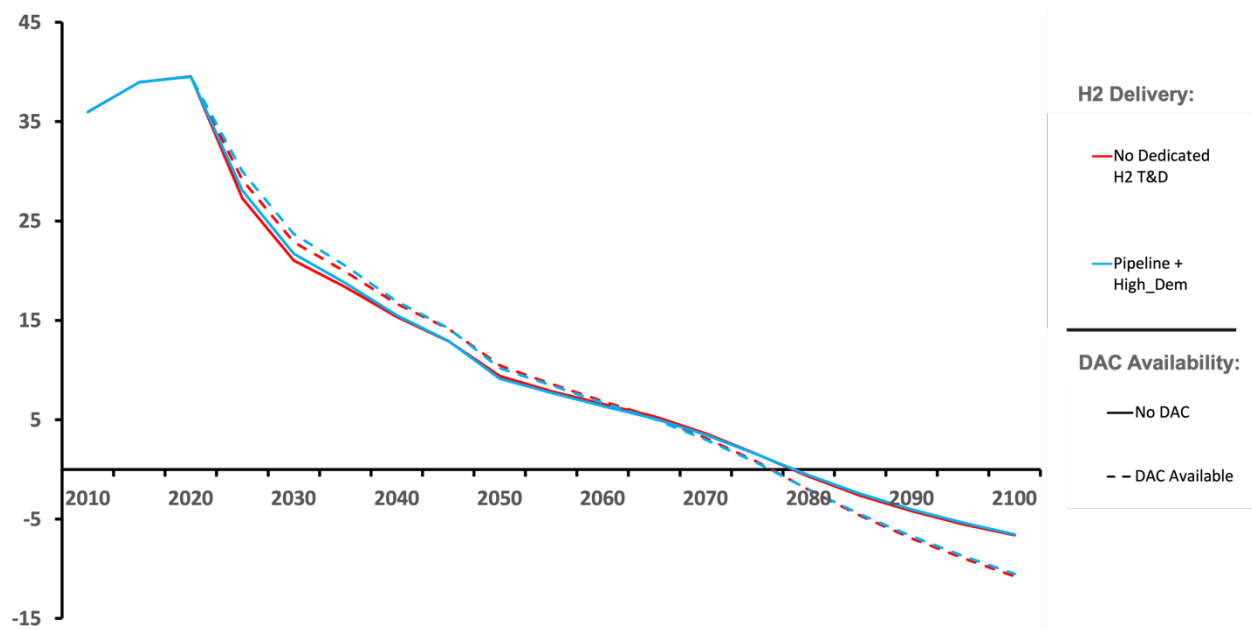


Figure A.18. Global net CO₂ emissions over the century (Gt CO₂) - Direct Air Capture (DAC) scenarios. Net CO₂ emissions include the net emissions from energy and industrial processes as well as land use change.

Appendix B: Supplementary information for Chapter 3

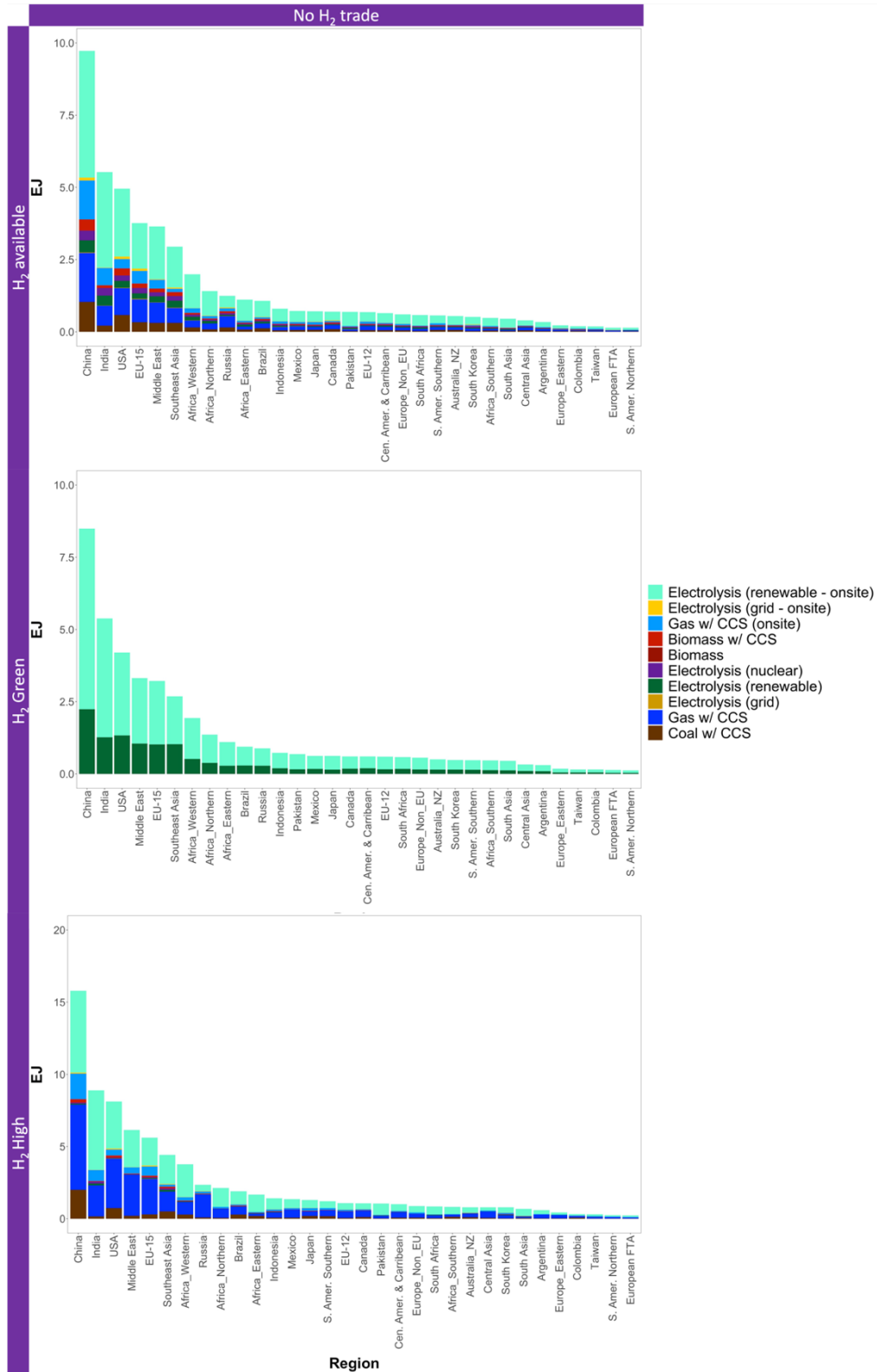


Figure B.1a. Hydrogen production in 2050 by region, technological group, and scenario. Only scenarios without hydrogen trade are portrayed here.

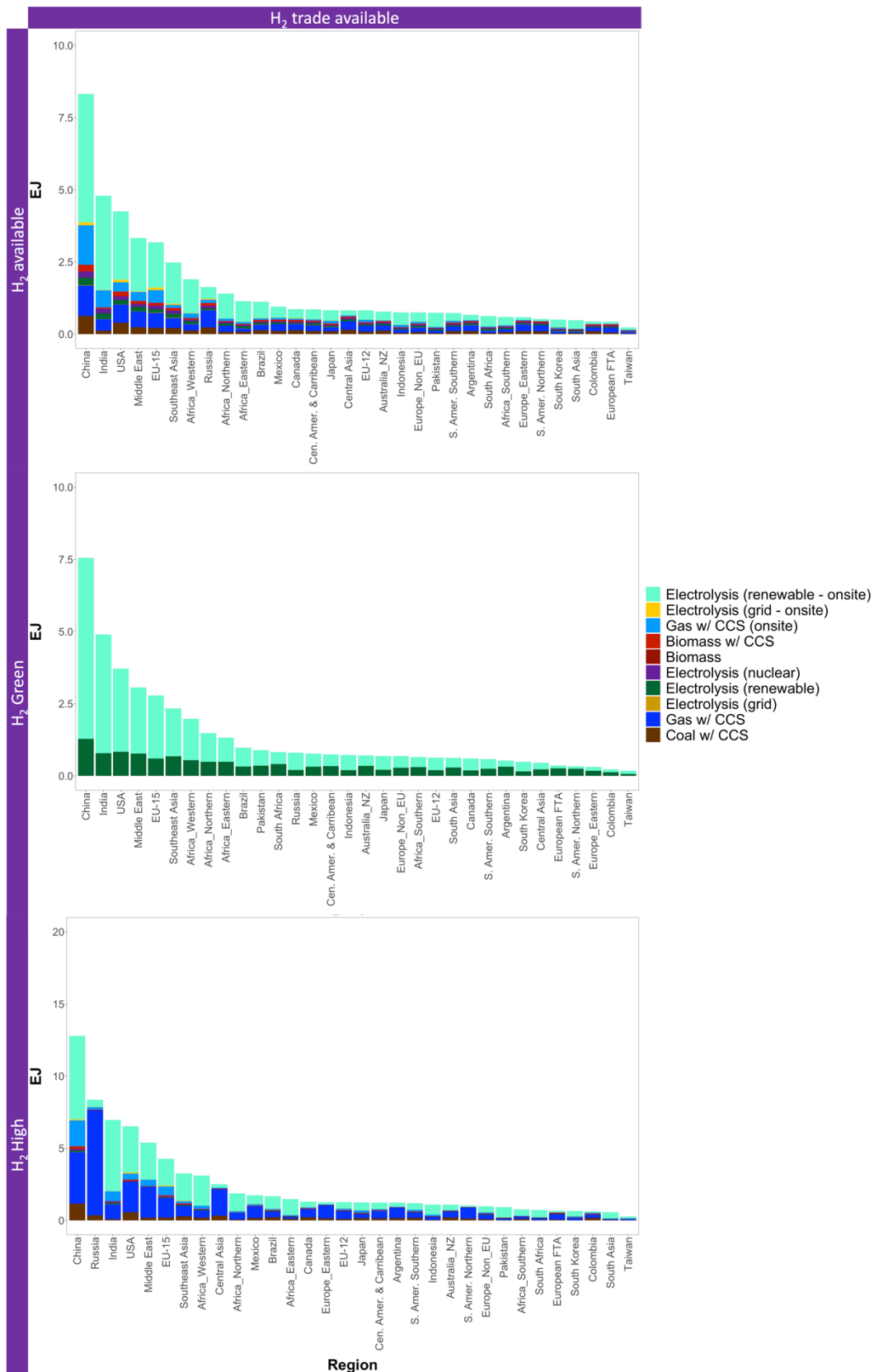


Figure B.1b. Hydrogen production in 2050 by region, technological group, and scenario. Only scenarios with hydrogen trade are portrayed here.

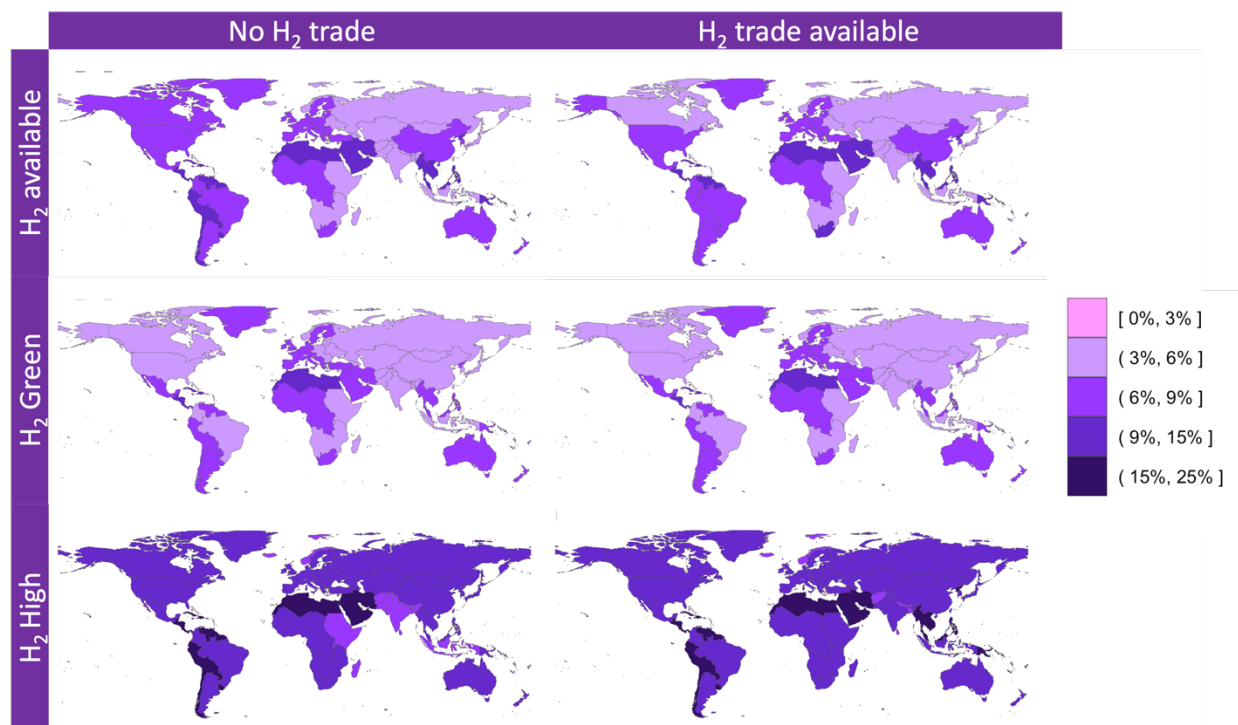


Figure B.3. Percent of final energy provided by clean hydrogen by scenario and model region for 2050.

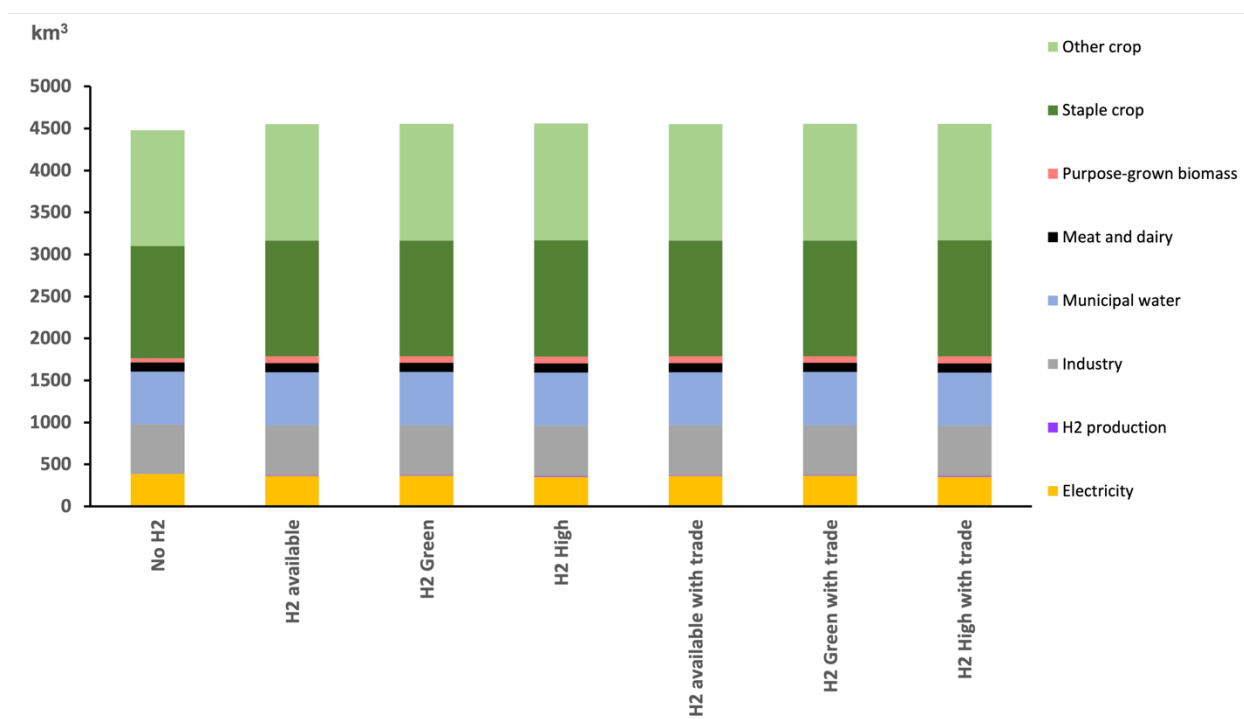


Figure B.4. Global water withdrawals by sector and scenario for 2050.

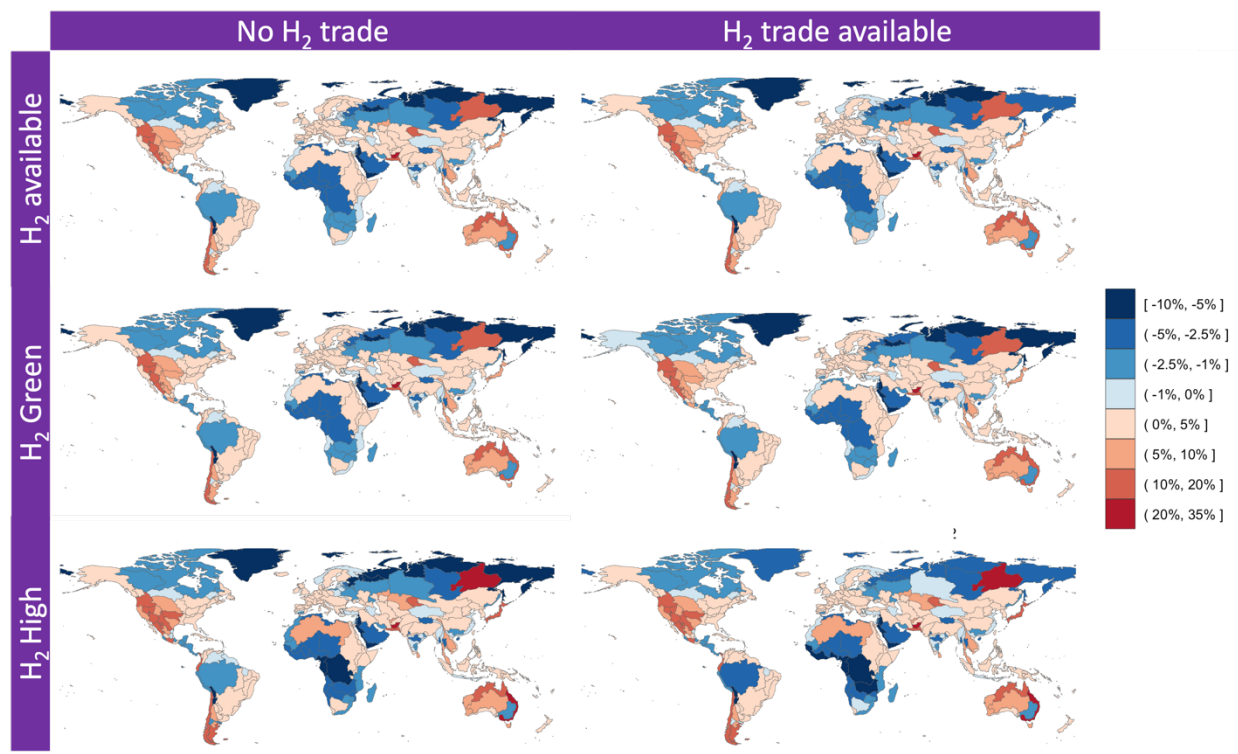


Figure B.5. Percent change in total water withdrawals by scenario and basin in 2050. Percent change is relative to the counterfactual where no clean hydrogen is available.

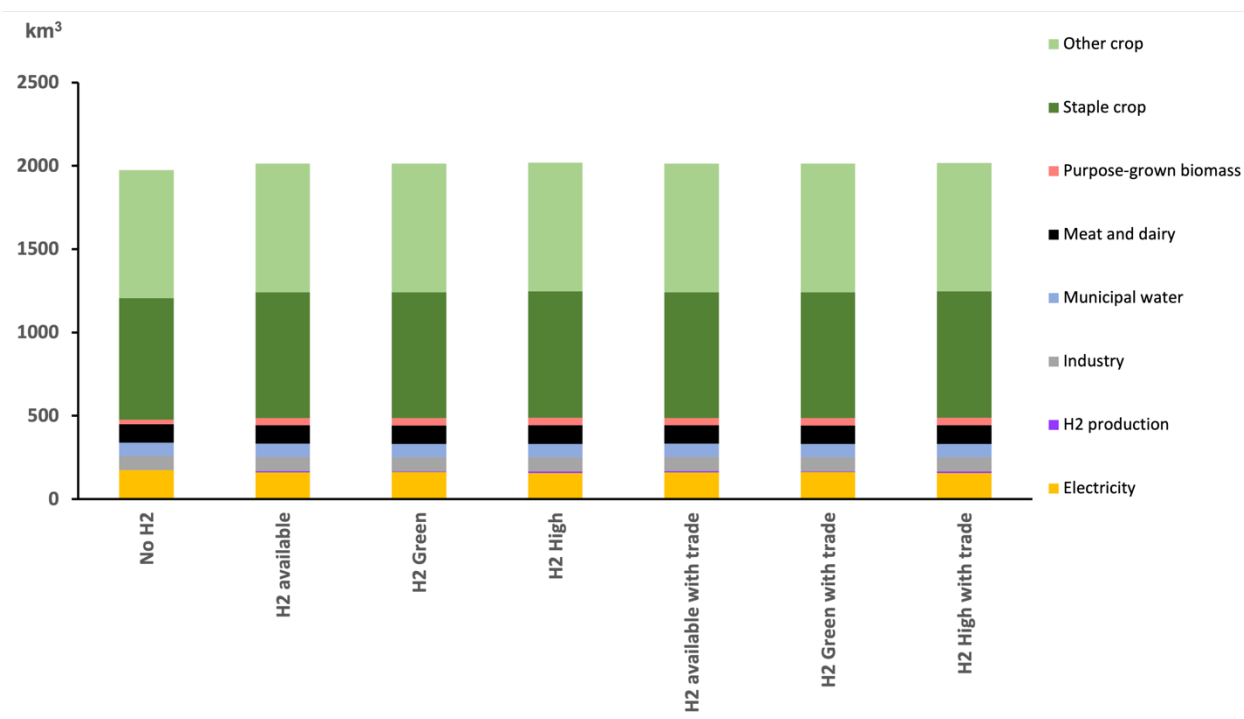


Figure B.6. Global water consumption by sector and scenario for 2050.

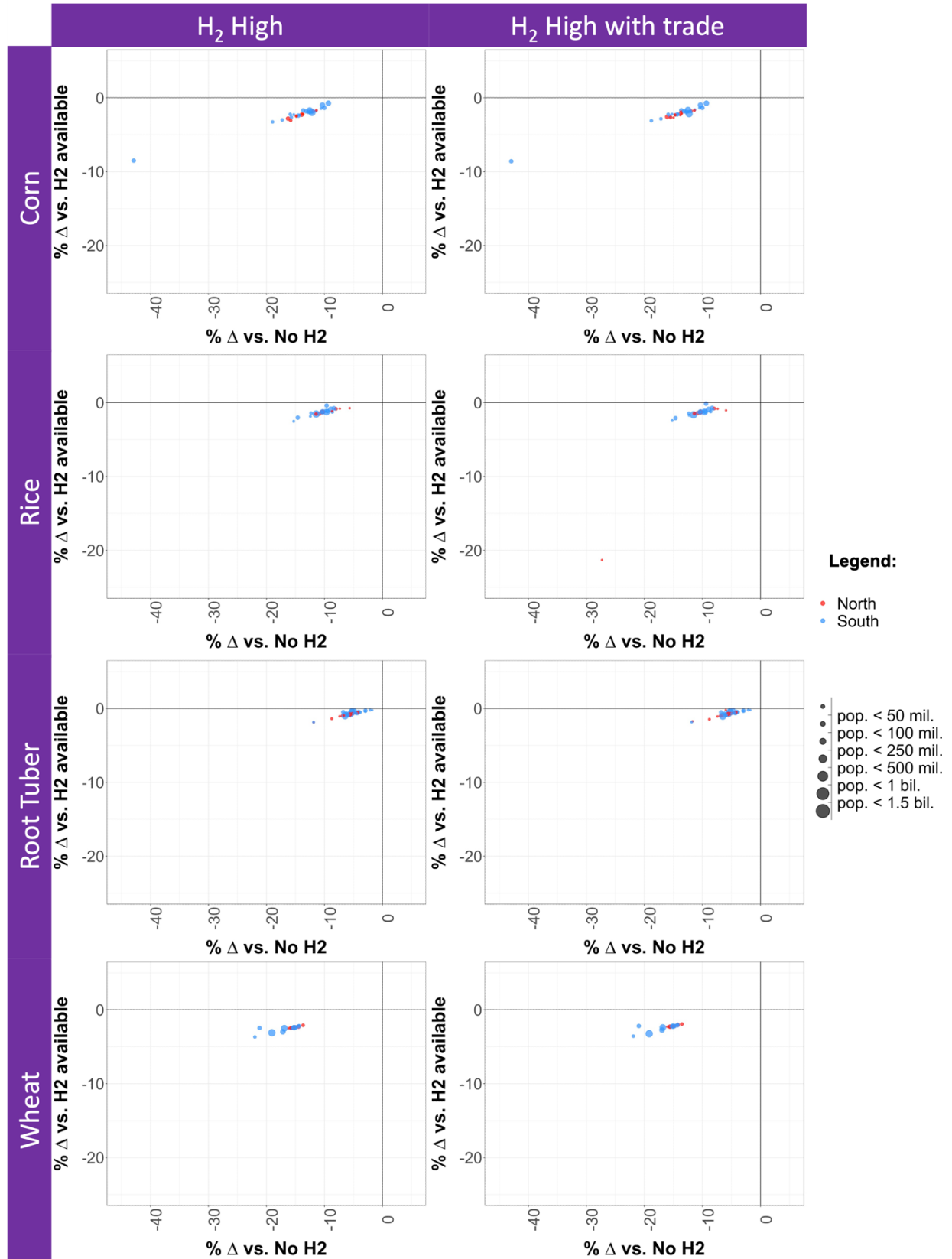


Figure B.7. Hydrogen's impact on staple crop prices for the "H₂ High" scenarios by GCAM region in 2050. "North" and "South" refer to the Global North and Global South.

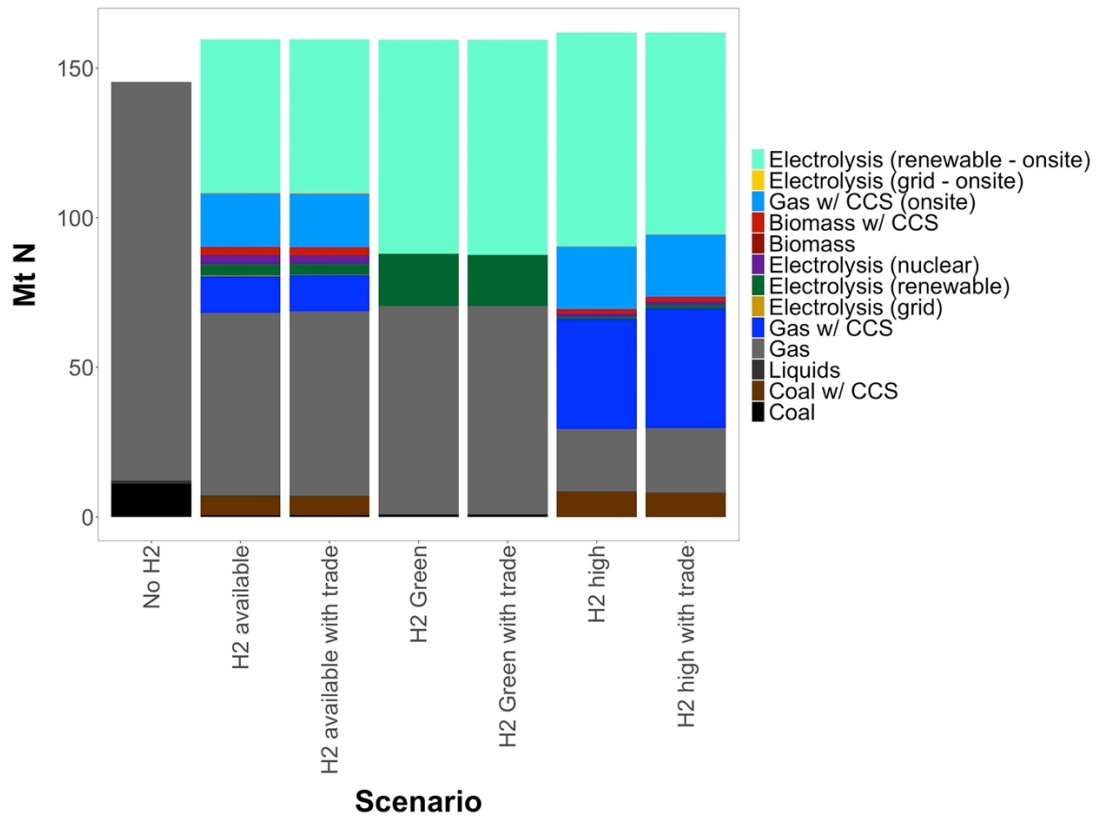


Figure B.8. Global N-fertilizer production by scenario and technology for 2050.

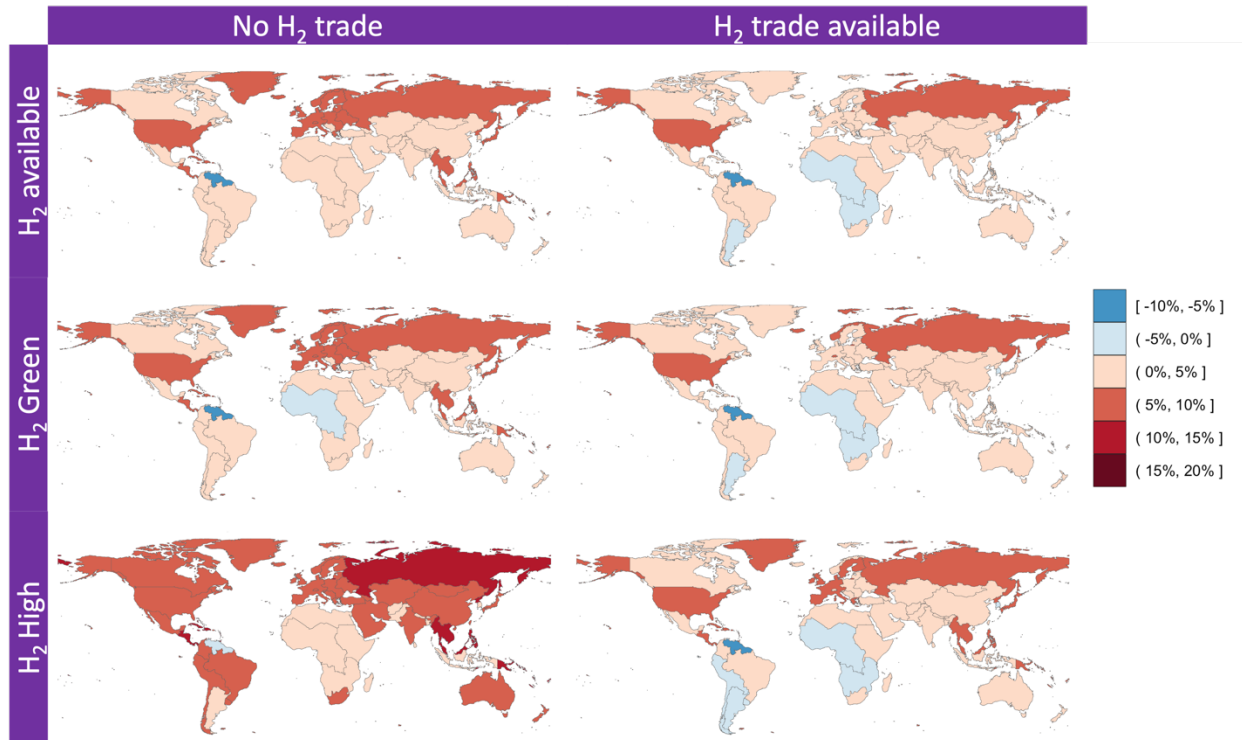


Figure B.9. Total primary energy percent change for 2050, by scenario and GCAM region. The percentage change in total primary energy with clean hydrogen availability is relative to the counterfactual where no clean hydrogen is available.

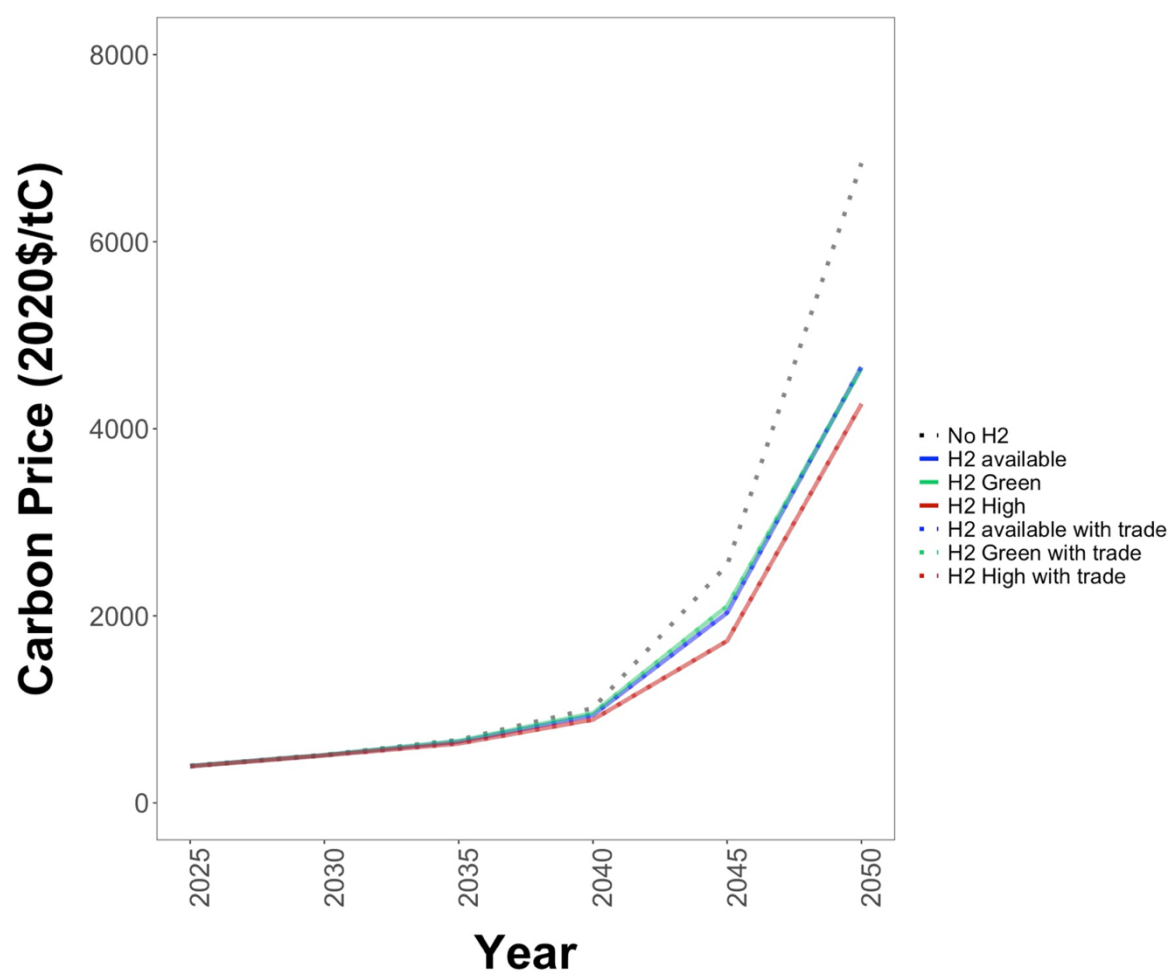


Figure B.10. Global carbon prices by scenario. “tC” refers to tonne of carbon.

Appendix C: Supplementary information for Chapter 4

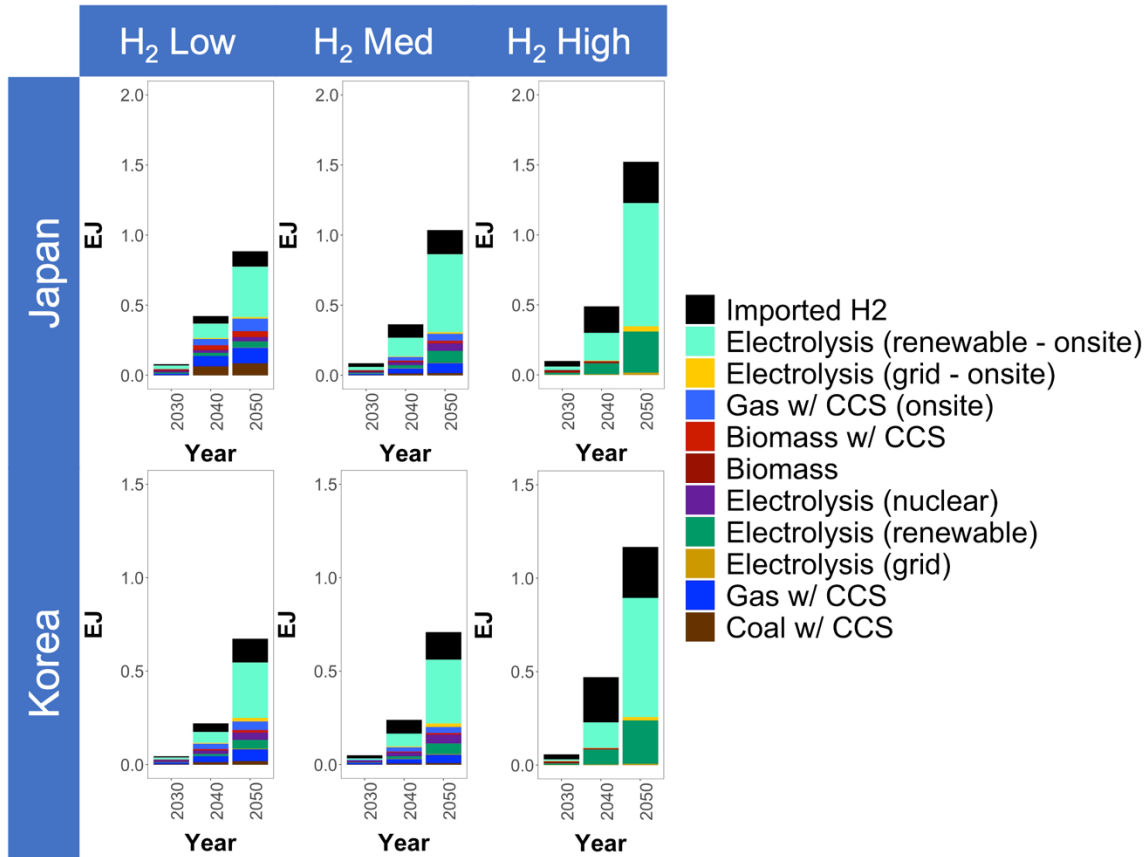


Figure C.1. H₂ supply by scenario and region. Domestic supply includes H₂ used as feedstock within NH₃ and synthetic fuel synthesis. CCS refers to carbon capture and storage.

Sector	Scenario: H2 Low							
	Japan				Korea			
	Final energy (EJ)	H ₂ demand (EJ)	% final energy	% service output	Final energy (EJ)	H ₂ demand (EJ)	% final energy	% service output
Industry	5.135	0.375	7.3%	—	4.178	0.240	5.7%	—
Agricultural energy use	0.079	0.011	14.6%	—	0.048	0.005	10.1%	—
Cement	0.125	0.024	19.5%	—	0.083	0.019	22.8%	—
Chemical energy use	0.752	0.025	3.4%	—	0.402	0.030	7.5%	—
Construction energy use	0.049	0.009	18.0%	—	0.024	0.008	33.5%	—
Iron and Steel	1.079	0.131	12.2%	44.3%	0.525	0.064	12.3%	30.9%
Mining energy use	0.011	0.002	15.6%	—	0.007	0.001	11.1%	—
N-fertilizer	0.021	0.008	37.9%	48.3%	0.013	0.006	50.1%	60.5%
Other industrial energy use	1.631	0.165	10.1%	—	1.295	0.106	8.2%	—
Transportation	1.813	0.337	18.6%	—	1.341	0.354	26.4%	—
Passenger Vehicle	0.655	0.071	10.8%	13.2%	0.419	0.038	9.1%	9.9%
Bus	0.047	0.011	24.2%	36.1%	0.116	0.017	14.7%	29.3%
Freight Road	0.703	0.164	23.4%	21.3%	0.383	0.111	29.0%	39.7%
Freight Rail	0.002	0.001	30.6%	18.3%	0.004	0.001	27.4%	20.4%
Marine	0.104	0.060	57.5%	66.9%	0.183	0.137	74.5%	70.0%
Aviation	0.231	0.030	13.0%	10.3%	0.208	0.050	23.9%	23.1%
Electricity	—	0.172	—	1.3%	—	0.092	—	1.0%
Total	—	0.884	—	—	—	0.685	—	—

Table C.1. H₂ and NH₃ consumption by sector and region in 2050 for the “H₂ Low” scenario. “Other industrial energy use” refers to GCAM’s “other industrial energy use” sector. Values are rounded to the nearest thousandth; percentages are rounded to the nearest tenth. Summations across sectors or subtotals may not equal subtotals and the total, respectively, given rounding as well as the fact that sectors which do not consume hydrogen are not portrayed here. Hydrogen feedstock used for refining and ammonia for energy are not portrayed here.

Sector	Scenario: H2 Medium							
	Japan				Korea			
	Final energy (EJ)	H ₂ demand (EJ)	% final energy	% service output	Final energy (EJ)	H ₂ demand (EJ)	% final energy	% service output
Industry	4.470	0.426	9.5%	—	4.031	0.264	6.6%	—
Agricultural energy use	0.075	0.013	17.5%	—	0.048	0.005	10.7%	—
Cement	0.117	0.068	57.8%	—	0.080	0.034	42.4%	—
Chemical energy use	0.732	0.039	5.4%	—	0.398	0.034	8.6%	—
Construction energy use	0.047	0.010	20.1%	—	0.024	0.009	36.7%	—
Iron and Steel	0.543	0.088	16.3%	47.0%	0.397	0.053	13.4%	28.3%
Mining energy use	0.011	0.002	17.5%	—	0.007	0.001	11.9%	—
N-fertilizer	0.017	0.012	73.2%	81.2%	0.012	0.008	66.7%	75.7%
Other industrial energy use	1.574	0.194	12.3%	—	1.292	0.120	9.3%	—
Transportation	1.746	0.383	21.9%	—	1.324	0.365	27.6%	—
Passenger Vehicle	0.623	0.078	12.6%	14.6%	0.410	0.040	9.8%	10.4%
Bus	0.039	0.013	32.2%	39.8%	0.109	0.018	16.2%	30.6%
Freight Road	0.694	0.171	24.7%	21.9%	0.377	0.114	30.4%	40.9%
Freight Rail	0.002	0.001	35.3%	19.3%	0.004	0.001	29.2%	21.1%
Marine	0.099	0.062	62.0%	71.0%	0.183	0.136	74.3%	69.7%
Aviation	0.219	0.058	26.5%	24.2%	0.213	0.055	26.0%	25.6%
Electricity	—	0.267	—	2.0%	—	0.103	—	1.1%
Total	—	1.075	—	—	—	0.732	—	—

Table C.2. H₂ and NH₃ consumption by sector and region in 2050 for the “H₂ Medium” scenario. “Other industrial energy use” refers to GCAM’s “other industrial energy use” sector. Values are rounded to the nearest thousandth; percentages are rounded to the nearest tenth. Summations across sectors or subtotals may not equal subtotals and the total, respectively, given rounding as well as the fact that sectors which do not consume hydrogen are not portrayed here. Hydrogen feedstock used for refining and ammonia for energy are not portrayed here.

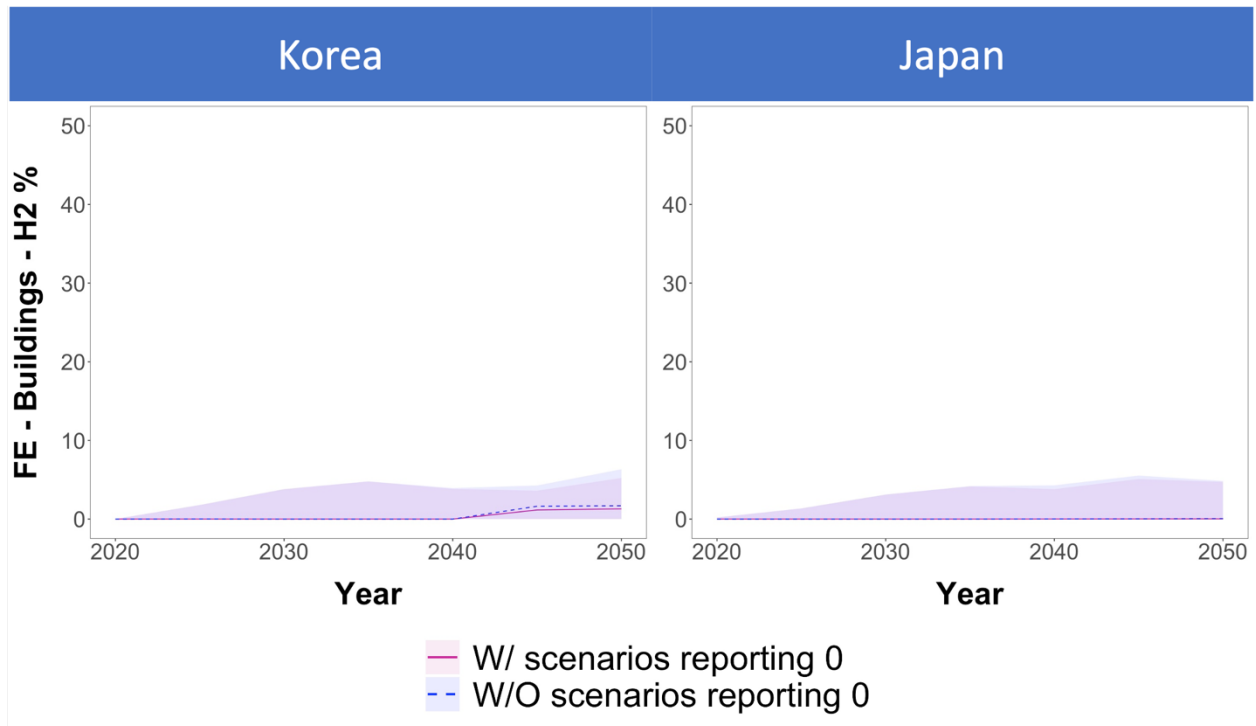


Figure C.2. Percent of final energy from H₂ for buildings within IPCC AR6 scenarios that limit warming to 2°C with >67%. IPCC AR6 data corresponds to the C1-C3 scenarios.⁵³⁶ Solid lines correspond to the median value, while shaded boundaries correspond to the 5th & 95th percentiles. “W/” refers to “with” and “W/O” refers to without, and these are in reference to scenarios which report exactly 0% for the percent of building final energy coming from hydrogen for each year (i.e., 0% from 2020 through 2050).

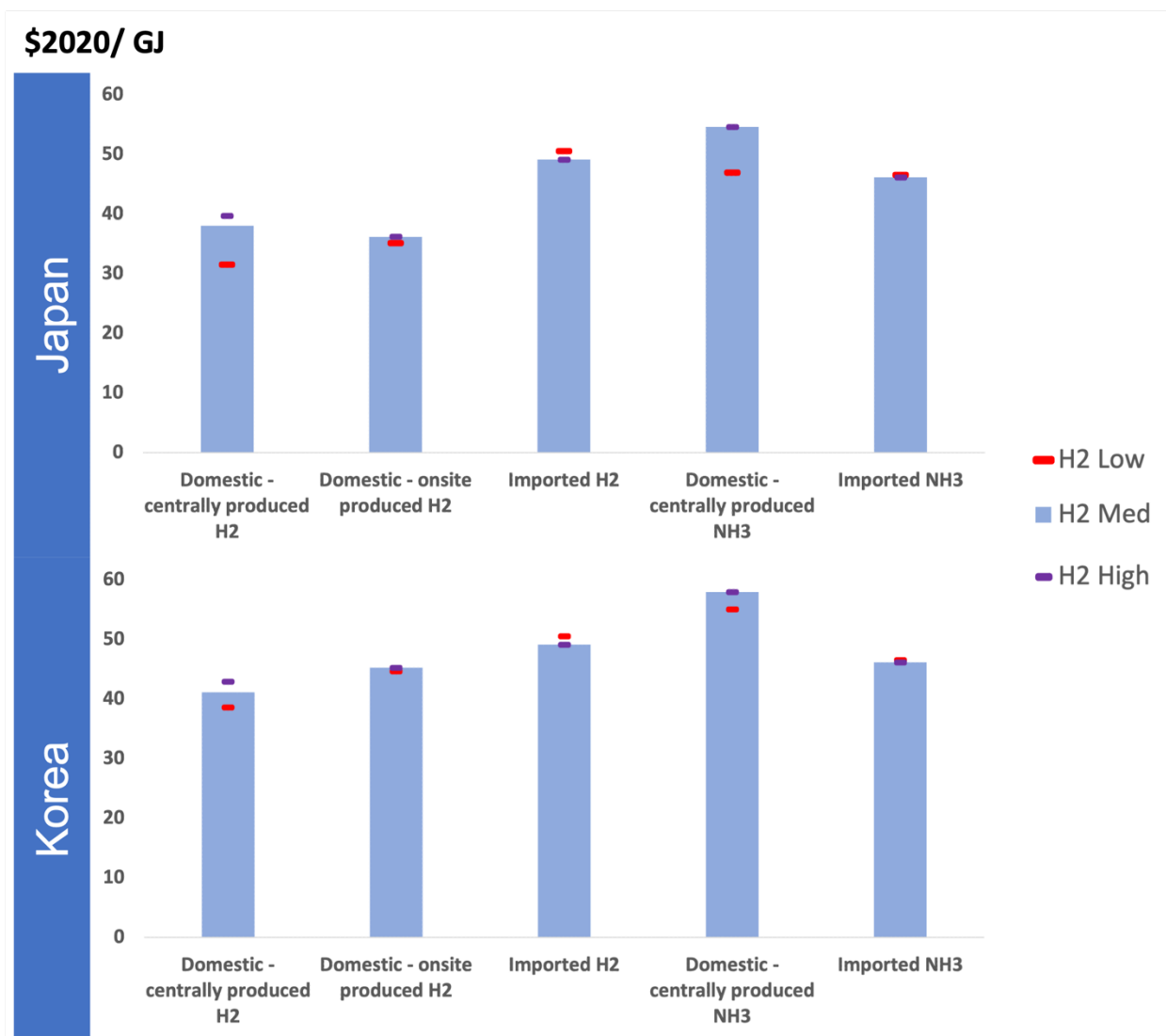


Figure C.3. H₂ and NH₃ supply costs in 2050. No costs for delivery within Korea or Japan are included within the figure. Costs for onsite H₂ production are for the wind-based electrolysis technology for the industrial sector.

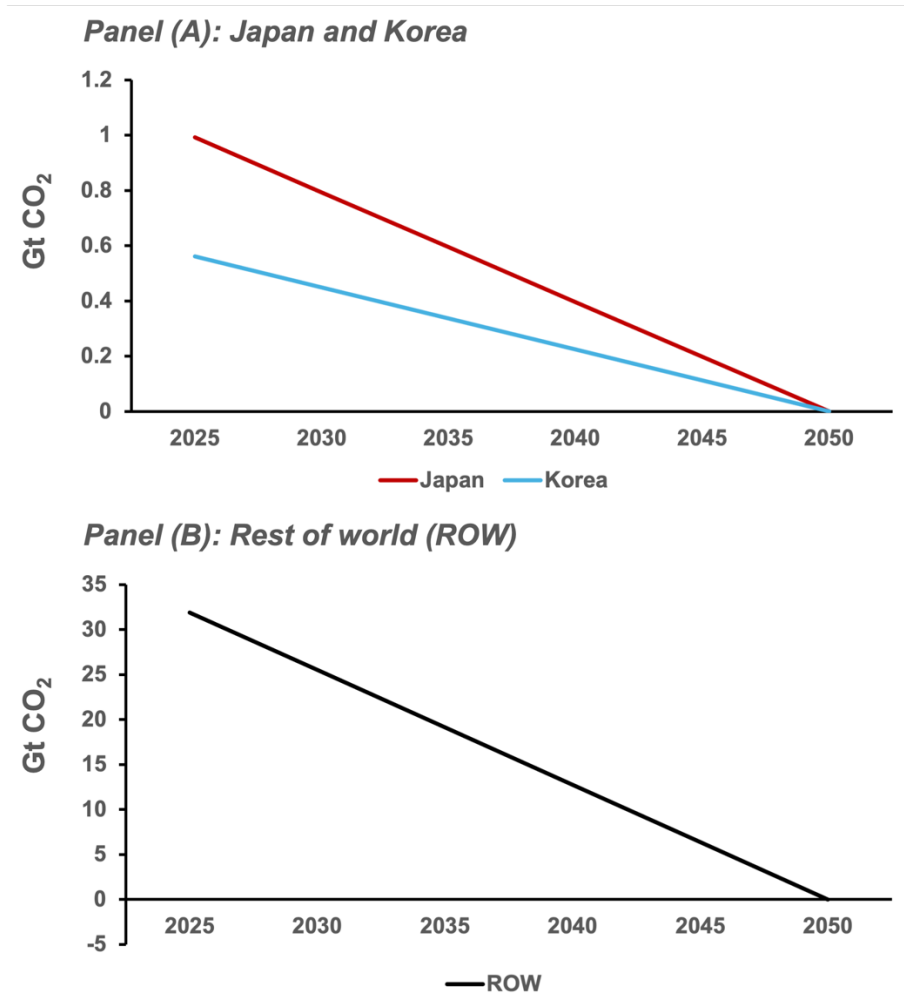


Figure C.4. CO₂ constraints for energy and industrial emissions (by region). “Gt” refers to gigaton.

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