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Challenges toward achieving a successful hydrogen economy in the US: Potential end-use and infrastructure analysis to the year 2100

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ABSTRACT

Fossil fuels continue to exacerbate climate change due to large carbon emissions resulting from their use across a number of sectors. An energy transition away from fossil fuels seems inevitable, and energy sources such as renewables and hydrogen may provide a low carbon alternative for the future energy system, particularly in large emitting nations such as the United States. This research quantifies and maps potential hydrogen fuel distribution pathways for the continental US, reflecting technological changes, barriers to deployment, and end-use-cases from 2020 to 2100, clarifying the potential role of hydrogen in the US energy transition. The methodology consists of two parts, a linear optimization of the global energy system constrained by carbon reduction targets and system cost, followed by a projection of hydrogen infrastructure development. Key findings include the emergence of trade pattern diversification, with a greater variety of end-uses associated with imported fuels and greater annual hydrogen consumption over time. Further, sensitivity analysis identified the influence of complementary technologies including nuclear power and carbon capture and storage technologies. We conclude that hydrogen penetration into the US energy system is economically viable and can contribute toward achieving Paris Agreement and more aggressive carbon reduction targets in the future.

1. Introduction

A transition away from fossil fuels is seemingly inevitable, as nations are driven to address impacts of their energy use on exacerbating climate change. There are a number of options for a low carbon energy transition, including renewables, nuclear power and the use of hydrogen, among others. Many nations are considering the appropriate options for incorporating hydrogen into their future energy system, both as a storage medium and for use in multiple sectors such as energy generation, industry and transportation (McPherson et al., 2018). Japan and Germany represent two nations which are leading the charge toward implementing a hydrogen economy, in spite of having to import hydrogen in the early phase of their transitions (International Renewable Energy Agency, 2022). Some attention has been given to the challenges which will be faced by these nations, and the potential benefits of incorporating hydrogen into their future energy systems (Chaube et al., 2020; Galich and Marz, 2012). Other nations which are likely to export hydrogen, i.e., those rich in fossil fuel or renewable resource also see the emergence of the hydrogen economy as a new economic opportunity, particularly as hydrogen production transitions from grey (fossil based) to blue (fossil + carbon capture) to green (renewable based) hydrogen (Hermesmann and Müller, 2022; International Renewable Energy Agency, 2022).

Building on these potential future dynamics, we recognize a major benefit of hydrogen, its ability to be produced from multiple sources including both fossil fuels and renewable sources (Moreno-Benito et al., 2017). Thus, hydrogen could be incorporated into different stages of a transitioning energy system, easing the adjustment process. During formative stages, hydrogen production will likely utilize cheaper conventional energy sources, gradually converting to renewable sources to become emission free both at the production phase and the time of use. Current barriers preventing such a transition include infrastructure complications, economic feasibility, and non-supportive energy policies.

Fossil fuel use in the energy sector alone is responsible for over 90% of annual anthropogenic carbon dioxide (CO_2) emissions from the United States (US; EPA, 2011). The release of CO_2 and other greenhouse gases (GHG) poses multitudes of risks, and efforts to reduce fossil fuel reliance is increasingly urgent (Change, 2007). Since the 1970's, the

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potential for hydrogen fuel to replace fossil fuels has been investigated as one option for a low carbon transition in the US. Unlike Japan and Germany, whose similarities allow for ease of comparison and analysis, no comprehensive study of the US hydrogen economy cognizant of production, end-use and distribution has been undertaken to establish potential contributions or pitfalls.

The aim of this study is to identify an optimal U.S. hydrogen distribution network through an analysis of policy, technological barriers, and potential end-uses of hydrogen using a global optimization model approach, applied specifically to the US. This study clarifies the key influences of hydrogen storage and distribution methods and its overall impact on achieving carbon reduction targets across multiple sectors. Further, this research fills a gap in existing research through the translation of model and scenario outcomes to a visualization of necessary future hydrogen infrastructure to underpin the emergence of a hydrogen economy in the US.

2. Background and literature review

Here, we investigate existing scholarship on barriers to hydrogen diffusion, potential end-uses, and policies, seeking to identify gaps in the literature, relevant to the US.

2.1. Hydrogen diffusion barriers

High costs and uncertainties associated with the conversion of infrastructure for production, delivery, and storage systems are a major issue (Agnolucci and Mcdowall, 2013). The ambiguity surrounding the desired form of hydrogen (i.e., liquid, gas, or its conversion into other fuels) is partly responsible, requiring a case by case evaluation of infrastructure options (Moreno-Benito et al., 2017).

Pre-existing infrastructure is an important consideration for promoting hydrogen diffusion. One distribution solution undergoing investigation is the blending of hydrogen with natural gas; creating hydrogen enriched natural gas (HENG). Up to 30% hydrogen can be added to natural gas for domestic end-uses with minimal issues (Jones et al., 2018). HENG is also compatible with most domestic applications, and offers a large reduction in initial infrastructure costs, allowing for the gradual introduction of hydrogen without a change in lifestyle [6–7].

2.2. End-use barriers

The need for technological adaptation is a key barrier for HENG, due to safety and performance concerns arising from differences in combustion properties between blends and pure natural gas. Hydrogen injection lowers the Wobbe Index, engendering a reduction in combustion energy output and flame stability, with a potential for flashback (de Vries et al., 2017). The gas grid is essential for many homes, and appliances may become incompatible if HENG cannot meet the safety and performance standards that natural gas provides. A blend of up to 15% hydrogen was found to be acceptable for running a cooktop burner efficiently with no modifications while preventing flashback (Zhao et al., 2019). Another study found that a 25% hydrogen blend could be used without impact upon an oven burner (Jones et al., 2018).

Blending of hydrogen into natural gas transmission pipelines can pose problems with regard to hydrogen embrittlement, ignition safety, and leakage [10,11]. Hydrogen embrittlement is a hydrogen-induced degradation of the mechanical properties of metals and alloys resulting in reduced resistance to component fracture and acceleration of fatigue crack growth (Dadfarnia et al., 2019). Transmission pipelines made of low strength steel with a hydrogen to methane blend up to 20% by volume are likely to operate safely under the given high transmission pressures (Soraghan, 2021). Local distribution pipelines operating at lower pressures are considered to be safe against embrittlement at 20% blends (M.W. Melaina, O. Antonia, 2013). Other piping materials, such as copper or elastomeric polymers, face no major concerns of hydrogen degradation (M.W. Melaina, O. Antonia, 2013).

A systematic effort to establish codes and standards for safe operation of hydrogen components and systems is already underway (Office of Energy Efficiency and Renewable Energy: Hydrogen and Fuel Cell Technologies Office, 2021), and in the area of materials compatibility, research is ongoing (Chandra et al., 2021; Nibur et al., 2010; Pluvinage, 2021) with a number of organizations and professional societies developing codes and standards. A notable example is the development of the B31.12 standard by the American Society of Mechanical Engineers (ASME) on hydrogen piping and pipelines (Code and Piping, 2011).

Industry may be a large user of hydrogen in the future. A study comparing the operation of an industrial gas engine under high specific loads show that just a 10% hydrogen addition to natural gas limits operational ranges. For other industrial devices, benefits such as a leaner fuel to air ratio, improved efficiency and reduced NOx emissions (Korb et al., 2016). Approximately 20% is considered a reasonable limit for most common industrial devices to prevent detonations and flashback risks (De Santoli et al., 2017). Multiple hydrogen blends up to 50% were investigated, identifying that monitoring and consistent adjustment is essential for safe, efficient, and low emission industrial combustion processes (Leicher et al., 2017).

For the transportation sector, a barrier to hydrogen vehicle usage is high costs and inadequate refueling infrastructure. Overcoming these barriers was identified as a key enabler for the hydrogen economy in Japan (Chapman et al., 2020b).

2.3. Storage barriers

Storage needs are also important, with linepack identified as a short-term solution. Hydrogen is maintained within the pipeline system itself when fuel supply exceeds demand and is dependent on demand patterns, flow rate, and pressure. Pure hydrogen linepack in existing pipelines yields approximately 65–71% energy compared to natural gas under the same volumetric conditions (Gondal and Sahir, 2012) (Haeseldonckx, n. d.). Compared to natural gas, linepack flexibility can be as low as 17% for pure hydrogen in high pressure pipelines (80 bar (Quarton and Samsatli, 2020);). A study comparing HENG blend rates to flow rate and linepack showed that a 20% addition of hydrogen reduces relative energy flow by ~5–10%, while a 10% hydrogen addition meant less than a 5% flow reduction (Gondal and Sahir, 2012).

Other options for storage include mechanical, thermal, electrochemical, and chemical options. The most likely large-scale energy storage option comes via chemical storage, utilizing stationary tanks, underground cavities, or hydrogen carriers (Møller et al., 2017). The top four storage options currently in use are high-pressure gaseous hydrogen, liquid hydrogen, liquid organic hydrogen and solid-state hydrogen (Liu et al., 2020). High pressure gas tanks are an efficient and reliable option, and are the preferred storage for vehicles due to relatively high volumetric and gravimetric energy content (Liu et al., 2020). The largest barriers are compression costs and energy losses; liquid hydrogen storage requires extremely low temperatures (−253 C) and is subject to additional energetic and economic barriers to maintain these conditions (Balali and Stegen, 2021).

Solid state storage is promising as it offers greater safety, ease of transport, and a high storage density (Jain et al., 2010). The use of hydrogen absorbing alloy tanks is under development and mostly geared towards vehicles. As this approach matures, it may favor other applications or systems (Mori and Hirose, 2009).

Natural gas currently accounts for over 25% of total US energy consumption, utilizing 2.44 million miles of steel pipeline, with pipe diameters ranging from 4 to 48″, operating at pressures of 42–84 bar. Distribution pipelines range from 1.5 to 8" wide, and pressures ranging mainly from 1.03 to 5.15 bar (M.W. Melaina, O. Antonia, 2013). Transmission pipelines connect larger operations at high pressures, such as treatment plants to compression stations, or to large industrial consumers (Transportation, 2018). In comparison, the distribution service lines connecting homes or commercial buildings are typically smaller and operate at .689 bar (Pipeline Safety Trust, 2015).

While pipelines are an effective mid to long-term transport method, compressed gas trailers and cryogenic liquid tankers may be more suitable for the early stages of hydrogen market development. Capital investment costs for road transport are low, and best suited to short trips and small volumes of hydrogen, likely to act as an interim technology before further pipeline development (Moreno-Benito et al., 2017). Previous research on consolidating distribution requirements utilized a 50-year implementation time span based on a social adoption model in the UK (Moreno-Benito et al., 2017), however, research is lacking on what a multistage process incorporating simultaneous infrastructure approaches would look like for the US.

2.4. Policy, regulatory and incentive barriers

Current US policy appears to be unsupportive to the expansion of the hydrogen economy in several ways. First, there is no national carbon price, which would impose a cost for emitting GHGs. Carbon pricing along with the removal of fossil fuel subsidies could boost hydrogen usage by increasing the costs of using conventional fuels (State Trends Carbon Pricing, 2019, 2019). Some states have independently set carbon prices, such as in California at $15/tCO2; and the establishment of a national price may advance policy and investments in the future. Lack of knowledge on total costs hinders hydrogen policymaking by limiting the creation of essential subsidies and incentives.

An analysis of hydrogen penetration in Europe and China detailed the influence of carbon taxation on increasing hydrogen competitiveness with diesel and gasoline for transportation. Further, HENG usage reduced methane leakages and associated carbon emissions (Tlili et al., 2019). While upfront infrastructure costs are also a major barrier to implementation; establishing support and funding policies will be invaluable in encouraging proactive penetration and competing with incumbent fuel types. A decarbonization review found that the best policy approach toward global hydrogen penetration was carbon pricing with a cap-and-trade regime, placing pressure on industries and encouraging the incorporation of hydrogen or renewables to decarbonize operations (Rissman et al., 2020). In addition to policy, there is a need for safety guidelines and industry standards, i.e., for regulating burning velocities and flashback, which are limiting factors for safe appliance use (de Vries and Levinsky, 2020).

U.S. incentives already in place for hydrogen and other carbon free fuels include 1) The Alternative Fuel Excise Tax Credit of $0.50/gallon, available for vehicles that use renewable fuels, including liquified hydrogen (Alternative Fuels and Advanced Vehicles Data Center, 2014), 2) The Alternative Fuel Infrastructure Tax Credit, offering a 30% tax credit of infrastructure costs up to $30,000 (Alternative Fuels and Advanced Vehicles Data Center, 2014), and 3) the Fuel Cell Motor Vehicle Tax Credit which provides a tax credit of up to $8000 for specific fuel cell vehicles (U.S. Department of Energy (DOE), 2017). Further, incentives which stimulate scenarios which incorporate both transportation and a HENG market will reduce the need for subsidization over time (tractebel, 2017).

In summary, hydrogen fuel has the potential to support US energy needs and transition the nation toward a more sustainable carbon-neutral future. Considering recent scholarship, we seek to identify the most cost effective and practical methods of hydrogen diffusion across various sectors and implementation stages out to 2100 for the US, and to determine the infrastructure required to support the emerging hydrogen economy.

3. Methodology

The methodology for this study consists of two parts: first, a linear optimization of the global energy system is undertaken to determine the potential range of hydrogen penetration and end-uses. Second, a projection of US hydrogen infrastructure requirements including interconnections with bordering nations is undertaken for each time-step of the global energy model outputs.

3.1. Global energy system optimization model

The global energy system optimization model is applied over the period 2000 to 2100 in ten-year timesteps, based on the Dynamic New Earth (DNE) model, using IBM-ILOG CPLEX to estimate the global penetration of hydrogen under carbon, policy and cost constraints (Chapman et al., 2020a). The model, cognizant of primary energy (fossil fuels, nuclear and renewables) and carbon capture and storage, converts these resources into useful secondary energy products including electricity, solid fuels, liquid fuels, gaseous fuels, and chemical feedstocks.

The objective of the model is to determine the lowest cost global energy system (in this study we present costs for the US energy system), while meeting carbon reduction goals in line with both the Paris Agreement targets of an 80% reduction of CO_2 by 2050 and more aggressive targets including carbon-neutrality. The focus of our analysis is on the factors which impact upon hydrogen penetration, including energy policy factors, carbon targets (including post-2050 goals), technology learning curves, and potential end-uses. A base case (detailed below) and multiple future scenarios were analyzed to consider multiple future energy system outcomes.

The global model accounts for 82 nodes across the world, however, in this study, we focus on 6 nodes representative of the four major consumption centers in the US and two contiguously connected nodes of Canada in the north and Mexico in the south. The four nodes in the US represent hydrogen usage regions, identified by the four most populous cities in the US, i.e., New York, Chicago, Houston, and Los Angeles. The nodes interact as energy and resources flow between them allowing for the establishment of a representation of total US energy production and consumption, with a focus on hydrogen. Analyzed nodes and connections are detailed in Fig. 1, including resource production nodes.

The first step in the optimization modeling was the development of the base case, upon which all scenarios were developed and evaluated. Assumptions and constraints are:

i. Hydrogen-city-gas blend ratios between 5% and theoretical maximum value of 30% by volume (Jones et al., 2018), i.e., the injection of hydrogen gas into city gas pipelines, such that hydrogen makes up between 5 and 30% of total gas volume flowing to consumers.
ii. Retirement of gasoline and gasoline-hybrid vehicles by the 2030's (Wappelhorst, 2021).
iii. Hydrogen Fuel Cell Vehicles (HFCV) and Electric Vehicles (EV) assumed to have similar range and passenger capacity, price trends adapted from (McKinsey, 2010).
iv. CCS available for power plants and industry post-2020. CO_2 export is limited to land or pipeline connected nodes.
v. Nuclear power deployment or cessation follows policies outlined by the World Nuclear Association with Fast Breeder Reactors (FBR) becoming available in deploying nations post-2050, and High Temperature Gas-cooled Reactors (HTGR) post-2060 (Association, 2021).
vi. Carbon emissions reduced by 80% compared to 2020 levels by the year 2050, in line with Representative Pathways 2.6 (RCP 2.6) and Paris Agreement 2-degree targets (Erickson and Brase, 2019).
vii. Renewable energy (RE) deployment is constrained by economically feasibility. Actual deployment utilized for 2000–2020 (Ritchie and Roser, 2020). Learning curves derived from (Chiaramonti et al., 2019; Global Wind Energy Council, 2014; Mayer et al., 2015) for post-2020 deployment.

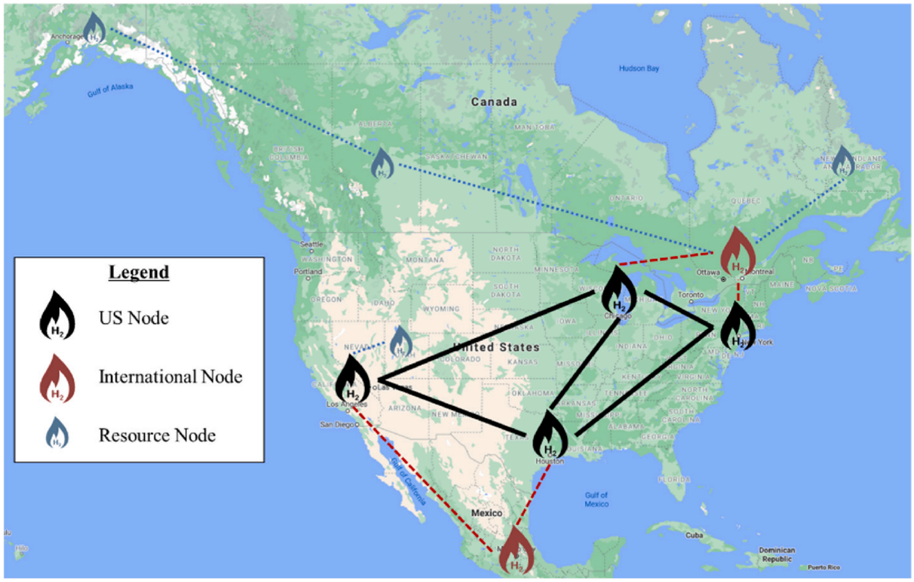

Fig. 1. Node and pipeline connection schematic.

viii. Hydrogen can be generated from fossil fuels (coal, oil and natural gas) and renewable sources including biomass, as well as via high temperature gas cooled nuclear reactors. Conversion of fossil fuels is achieved via gasification for coal and oil, and steam reformation for natural gas. Renewable-based hydrogen utilizes renewable electricity for water electrolysis while biomass is gasified to form hydrogen. End uses for hydrogen include blending with city gas, transportation, electricity generation (co-firing and direct), and as a chemical feedstock.

The development of the base case is followed by scenario driven sensitivity analysis, described in Table 1 to explore policy, technology, and economic impacts on hydrogen penetration in the US and to account for early deployment or any potential delays in deployment of specific technologies, notably CCS and nuclear.

Table 1
Hydrogen penetration sensitivity analysis scenarios, factors and rationales.

Scenario	Sensitivity Analysis Factors	Rationale
Baseline	➢ Hydrogen city-gas blend ratio of 5–30% (5%, 15% and 30% blends analyzed)	➢ Exploring the impact of hydrogen blend ratio on the final quanta of hydrogen introduced into the energy system
Passenger vehicle cost	➢ Varying passenger EV and HFCV vehicle costs from 2030 to 2100 (±5–25%)	➢ Exploring the impact of vehicle subsidizations and cost reduction over time toward a cost-optimal transport sector
Complementary carbon reducing technology	➢ Varying introduction year of CCS from 2020 to 2050 ➢ Varying timeline of nuclear technology deployment	➢ Exploring impacts of delayed CCS introduction due to a lack of public acceptance or support and scale-up timelines ➢ Accounting for nuclear deployment timelines, impacts on hydrogen production and carbon reduction
Post 2050 carbon reduction goals	➢ Increasing required reductions post 2050 to achieve carbon-neutrality by 2060–2100 in both the US and the OECD	➢ In line with recent ambitious national carbon reduction goals

Results of all scenarios are transferred to the infrastructure projection model as detailed below.

3.2. Hydrogen infrastructure projection

Changing hydrogen production and consumption levels and end-uses over time are identified, followed by a mapping of infrastructure requirements.

3.2.1. Hydrogen demand, distribution and end-use visualization

Sankey diagrams were derived from the per node output data of the global energy system optimization model, tracking the movement of hydrogen energy from source to final use-case, including imports and exports. Demand is based on the 30% hydrogen/city-gas blend base case scenario, and utilizes actual 2020, and projected 2050 and 2100 megatons of oil equivalent (MTOE) per year usage of hydrogen products.

Node activities were summarized into two main categories: export or consumption. Export includes any hydrogen transferred to another node via hydrogen liquefaction, toluene hydrogenation, or hydrogen pipeline exports. Import avenues are limited to hydrogen import by land, regasification, and methylcyclohexane (MCH) dehydrogenation. Production is categorized into the following source fuel and process categories: coal, natural gas, oil, biomass, water electrolysis, and high-temperature gas-cooled nuclear reactors (HTGR). The aggregate of the above categories and any imports conclude the total inputs into a single node.

Node outputs include gaseous fuel (hydrogen blended with city-gas), transportation fuel, hydrogen-fueled power (electricity), methane, methanol, Dimethyl ether (DME) and kerosene synthesis. Total outputs include these categories and any exports to other nodes. By separating the total outputs from imports and self-produced fuels by use-case, it is possible to identify which hydrogen fuels are consumed on-site. By comparing flows across 2020, 2050, and 2100, the influence of developing infrastructure and social penetration can be visualized. Residual amounts under a threshold value of 0.001 MTOE are gathered as ‘other consumption’.

3.2.2. Mapping of infrastructure requirements

Mapping was based on data extracted from the optimization model for demand and internode relationships.

The four major US node locations include New York City, New York; Chicago, Illinois; Houston, Texas; and Los Angeles, California, (NYK, CHG, HST, and LOS, respectively). A single node was selected for the bordering countries of Mexico (Mexico City; MXC) and Canada (Montreal; MTL) to represent direct trade connections to the US. Production nodes which export hydrogen to the 4 major US nodes including Calgary, Canada (CLG) and Salt Lake City, USA (SLC) operate beginning in 2050.

2020 mapping builds the foundations of the hydrogen infrastructure system and is derived largely based on automotive fuel consumption, and potential locations for hydrogen fueling stations. Based on this early hydrogen market, initial infrastructure needs include automotive refueling stations centered around heavy demand locations. To quantify hydrogen fueling station distribution, as well as to differentiate between demand for conventional and hydrogen fuels, we compared the presence of conventional fuel stations (Shell et al., 2021) as well as aggregated alternative fuel stations in the US at a 1:63 ratio, representative of the current ratio of hydrogen fuel stations to conventional stations (Jaganmohan, 2021), consolidated for each node. As some areas in the US are further along the hydrogen economy pathway than others, this assumption is a simplification of the current situation (EIA, 2021). Total demand per node is divided by the number of proximate hydrogen stations to calculate the required amount of hydrogen storage per station to meet demand.

To distribute the respective hydrogen fuel storage and distribution stations across node areas, locations were matched with concentrated areas of alternative fuel energy stations to reflect localized demand for similar services. Alternative fuel energy stations include electricity, ethanol, compressed natural gas, propane, biodiesel, liquified natural gas, hydrogen, and others (US Department of Energy, 2014). Lastly, current natural gas compressor stations are selected based on distance from hydrogen fueling stations to act as a transitional component between hydrogen production and compressed storage at stations. Distances were calculated using average road conditions for tube trailer transport of compressed hydrogen, based on simulated traffic for Mondays at 12 p.m. Trailer transport is utilized for the initial stages of infrastructure development as trailers are better suited for short distances and small volume fuel deliveries, as well as having the added benefit of lower initial costs (The National Academy of Engineering, 2004). Natural gas compressor stations were selected as a proxy due to a lack of long-term widespread hydrogen-specific compressor stations across the US, as well as to reflect the potential for hydrogen and natural gas to be compressed and transported in tandem from the same facility.

The 2050 timestep maintains the same nodes, with the addition of export-only nodes, as stated above. Post-2020, as infrastructure investment and demand for hydrogen fuels increases, the main transportation method transitions from tube trailer transport to pipeline delivery (Fuel Cell and Energy Association, 2020). Pipeline delivery co-opts all current, major natural gas pipelines in the US, merging them as a singular framework for all potentially available hydrogen transportation regardless of ownership or other barriers. Within this network, nodes were connected via the most direct route based on export and import connections, as identified in the demand measurements. Only nodes that interacted directly were allocated a specific pipeline route.

To accommodate increasing hydrogen consumption, storage is adjusted from on-site storage at automobile refueling stations to underground storage for both 2050 and 2100 timesteps, as it is readily available across the US in some capacity, commonly used for natural gas. Underground storage sites include existing salt domes, aquifers, and depleted fields with associated working capacities reported in million standard cubic feet (MMcf) per day (EIA, 2014). Storage of hydrogen will occur at 100 bar, at a temperature of 51.9 C (125F), to achieve 0.446lb H_2 per cubic foot of storage. Under these assumptions, 1 MTOE of hydrogen uses 1.48 billion cubic feet of underground storage. The largest storage capacity facilities within node containing states were selected in decreasing volume order until minimum requirements for yearly hydrogen usage per node was met, minimizing intermediary transportation between storage sites and pipeline distribution. Fig. 2 describes the research methodology flow, from the optimization phase using the DNE optimization model through to infrastructure visualization utilizing the 30% gas blend scenario.

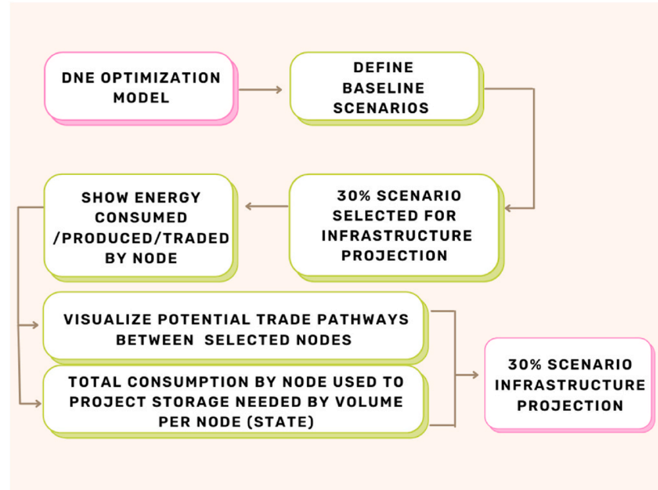

Fig. 2. Research methodology flow chart for visualization of US hydrogen infrastructure.

4. Results and discussion

Results are detailed and discussed, beginning with the global energy system optimization model for the US and interconnected regions, followed by a visualization of hydrogen production and consumption and a projection of hydrogen infrastructure requirements.

4.1. Energy system optimization results

Energy system optimization results are detailed for the baseline scenario, followed by the impacts of scenario-based sensitivity analysis.

4.1.1. Details of the baseline scenario

Fig. 3 details the primary energy supply, system cost, CCS requirements and hydrogen consumption in the US, for the years 2020, 2050 and 2100 to give a cross section of model outcomes for H_2/city-gas blend rates of 5, 15 and 30%.

For each timestep, sources of energy do not change markedly across hydrogen blend levels, however there are some nuanced changes throughout. For example, for 2020, a shift from a 5% hydrogen blend ratio to 30% increases coal's contribution by ~3 MTOE and reduces the contribution of nuclear by approximately the same value. For 2050, increasing the hydrogen blend ratio increases the contribution of oil and nuclear by up to ~8 and ~41 MTOE respectively, and for renewables, PV and wind increase by ~9 and ~14 MTOE respectively. As a result, natural gas' contribution to the energy supply is decreased by up to ~47 MTOE.

In the final year of 2100, increasing the blend of hydrogen in city-gas results in similar outcomes to that of 2050, with methanol production declining as hydrogen usage increases. Over time, oil and coal are reduced significantly, natural gas reduces mildly, and nuclear increases to 2050, before decreasing markedly by 2100. For renewables, hydropower's contribution varies little over time, while biomass, wind and PV all increase, with wind becoming the dominant renewable source by 2100.

For total energy system cost, for the years 2020 and 2100 only very minor variations are detected, irrespective of the hydrogen blend level. For the year 2050 however, the amount of hydrogen is important, and a higher blend level engenders a lower energy system cost, i.e., hydrogen is a cost-effective CO_2 reducing strategy for Paris Agreement targets in the US.

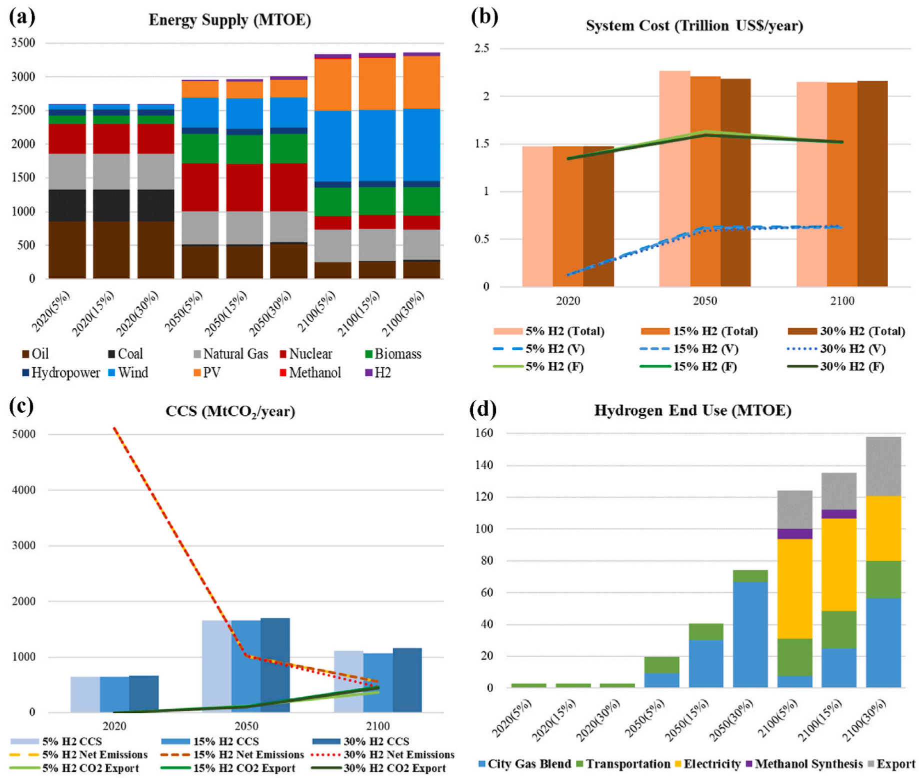

Fig. 3. Baseline Scenario (a) Energy Supply, (b) System Cost: Total, Variable (V) and Fixed(F), (c) CCS, exported and overall emissions, and (d) Hydrogen End-use Outcomes.

Regarding CCS requirements, a 30% blend of hydrogen required the highest levels of CCS in 2020, 2050 and 2100. CCS requirements grow rapidly between 2020 and 2050, peaking at approximately 1700 megatons of CO_2 storage required in the year 2050. In line with increasing RE deployment and hydrogen use, the requirements for CCS in the US reduce to approximately 1150 megatons in 2100. Each of the three blend level scenarios follows an aggressive linear reduction of CO_2 to 2050, and a mild (voluntary) reduction post 2050. While the majority of CO_2 is sequestered in depleted gas wells and aquifers proximate to emissions, approximately 450 megatons is being exported to other nodes for storage by 2100.

In terms of hydrogen penetration and use, in 2020, only a small transportation use-case emerges, predominantly for hydrogen fueled buses. By 2050 the role of the city-gas blend level becomes important with increasing levels of hydrogen penetration dependent on the blend rate. By 2100, other end-uses become economically and environmentally preferable, seeing a large portion of hydrogen being used for electricity generation, transportation, and city-gas. For lower blend levels, excess hydrogen is converted to methanol for use in other industries, while this does not occur for the maximum 30% blend rate.

Finally, export of a portion of locally derived hydrogen occurs by 2100 among US nodes. In the maximum use-case (30% city-gas blend level) hydrogen accounts for approximately 7.6% of US energy consumption across city-gas, transport, electricity generation and chemical feedstock conversion by 2100.

4.1.2. Passenger vehicle, technology deployment policy and carbon target sensitivity analysis

Building on the findings for our baseline scenario, the impact of exogenous factors is tested, including passenger vehicle costs, policy driven parameters of CCS and nuclear power, and more ambitious carbon reduction targets.

4.1.2.1. Passenger vehicles. The baseline scenario assumption for vehicle costs included initially higher cost hydrogen passenger vehicles (based on the Toyota Mirai (Driver, 2020a);) introduced in 2020, with the EV alternative (a compromise between the Tesla Model 3 base, and long-range models (Driver, 2020b);) approximately 3000 dollars less expensive in 2020. Costs for each of these vehicle types converged for the 2040 and 2050 time slices, with EVs maintaining a small price advantage thereafter. In the baseline scenario, EVs account for the majority of vehicles between 2040 and 2070, but from 2080 onwards, HFCVs become more popular, overwhelmingly so by 2100, despite a slightly higher price than the EV alternative. Understanding that future passenger vehicle subsidies or tax breaks may influence purchase prices, we test the sensitivity of EV and HFCV pricing between a range of ±5% ~ 25% as detailed in Table 2.

EV and HFCV passenger vehicle fleet mixes are highly sensitive to price. Increases in the price of one vehicle type, holding other vehicle costs constant excludes them from the future transportation system. In terms of reducing prices, a similar effect is seen, however, while a vehicle price reduction of greater than 20% is required for EVs to emerge as the dominant option in the 2030's, for HFCVs, only a 15% price reduction is required.

In our model, the choice between EV and HFCV is decided based on cost, with small variances enabling one type of vehicle to dominate the transportation sector. Cost alone will not determine end-user's choice of vehicles and considerations such as driver needs, range, cargo carrying capacity and even styling will likely influence these decisions. Also, environmental concerns and refueling infrastructure play a role in

Table 2
Effect of EV and HFCV Price Change on Vehicle Type Penetration between 2020 and 2100.

Sensitivity \ Year	2020	2030	2040	2050	2060	2070	2080	2090	2100
Electric Vehicles									
-5 ~ -15%	×	×	↑	↑	↑	↑	↑	↑	↑
-20 ~ -25%	×	↑	↑	↑	↑	↑	↑	↑	↑
+5 ~ 25%	×	×	↓	↓	↓	↓	↓	↓	↓
Hydrogen Fuel Cell Vehicles									
-5 ~ -10%	×	×	↑	↑	↑	↑	↑	↑	↑
-15 ~ -25%	×	↑	↑	↑	↑	↑	↑	↑	↑
+5 ~ 25%	×	×	↓	↓	↓	↓	↓	↓	↓

vehicle choice (Chapman et al., 2020b), meaning that there is further scope for the diversification of personal transportation options in future modeling efforts.

4.1.2.2. Complementary carbon reducing technologies. In achieving deep CO_2 cuts required by 2050, along with RE and the introduction of hydrogen, CCS and nuclear play a major role. Here we assess the impact on the hydrogen economy and achievement of CO_2 reductions by 1) delaying CCS implementation, and 2) by allowing next generation nuclear power plants (FBR and HTGR) to enter the energy system earlier than was assumed for the base case.

For CCS, the baseline scenario assumes introduction of geological storage of CO_2 by the 2020s, however current lack of public acceptance (Whitmarsh et al., 2019) and the challenges being experienced in scaling up pilot plants to commercial levels means that these timelines may be delayed. Sensitivity analysis assesses the impacts of such delays, as detailed in Fig. 4.

The effect of delaying CCS is influential toward actual CCS use, total system cost, and hydrogen penetration. Restricting CCS reduces CO_2 sequestered, in most cases until the year 2070–2080, where an increase is seen for each scenario, increasing in proportion to the period delayed.

For hydrogen penetration, delaying CCS moderately increases the amount of hydrogen introduced for 10- and 20-year delay options. However, when delaying to the year 2050, we note a higher overall penetration of hydrogen, with a significant spike in the carbon reduction target year (2050). This is explained not only by hydrogens critical role in reducing CO_2 under such a scenario, but also by the economic need to maintain acceptable system cost via the production of methane and dimethyl ether (DME). Results also vary according to end-use-case, with city-gas hydrogen use comparatively lower than the baseline prior to 2050 for a 10- or 20-year delay of CCS but spiking in 2040 in line with a 30-year delay. For transport hydrogen, post-2050, delay scenarios show an increase in usage commensurate with CCS delay length. The impact of delaying CCS on hydrogen-based electricity generation is generally suppressive, except for the 10- and 20-year delay scenarios in the 2080s (end-use-case sensitivity is detailed in Appendix A).

Delaying CCS deployment increases system costs, most notably in the year of delayed introduction, and to a greater magnitude, the longer CCS is delayed.

For Nuclear Power our sensitivity analysis tests the impact of advancing the deployment timeline of Generation III+ and Generation IV type reactors to as early as the 2020s, in line with World Nuclear Association predictions (Zohuri, 2020). Results are detailed in Fig. 5.

Between 2050 and 2080, nuclear output is increased moderately in most scenarios, with only a minor increase in output shown for 2100. For hydrogen penetration and system cost, an increase in nuclear output does not have a significant impact.

Electricity produced from hydrogen is reduced substantially post 2080, while increased deployment of new generation nuclear technologies tends to shift hydrogen use toward transportation (end-use-case sensitivity is detailed in Appendix B).

Overall, the delay of CCS deployment means that hydrogen plays a larger role in reducing energy related carbon emissions, whereas early enabling of next generation nuclear technologies reduces hydrogen's role in electricity generation. Hydrogen's contribution toward the energy sector is relatively insensitive to exogenous impacts, as hydrogen can be utilized flexibly between transportation, city-gas and electricity generation, conducive to long term infrastructure and storage planning.

4.1.2.3. Post 2050 carbon reduction. In line with recent, ambitious declarations of accelerated carbon reduction (The White House, 2021), timelines for achieving a zero-carbon energy supply are brought forward to as early as the year 2060 for both the US and the OECD as detailed in Fig. 6.

For net emissions, each scenario achieves carbon-neutrality in the specified target year (2060–2100), influencing the amount of CO_2 required to be reduced in each time step post-2050. For hydrogen penetration, no radical changes are observed when compared to the base case, with a moderate reduction observed in 2070 (notably for OECD scenarios), and a moderate increase observed in 2080, notably for the US.

Increasing carbon reduction constraints increases system costs, with OECD carbon-neutrality by 2060 the most expensive scenario. By 2100, increased carbon reduction scenario costs converge at approximately 2.3 trillion US dollars, 10% above the Paris Agreement target baseline scenario. Hydrogen end-use impacts include a reduction in hydrogen for city-gas and an increase in transport usage in the early time periods, and an increase in hydrogen exports in 2100. Hydrogen end-use-case sensitivity analysis is detailed in Appendix C.

Hydrogen was expended to meet transport, electricity and city-gas needs, however under certain scenarios, conversion of (mainly imported) hydrogen to chemical feedstocks and value-added products (DME and methanol) was identified. This activity suggests that a financial incentive for the conversion of hydrogen to chemical compounds was required to keep system costs in check and ensure that each energy system scenario could meet its carbon targets at a reasonable cost. DME and methanol were only produced in 5% and 15% hydrogen city-gas blend scenarios.

Both DME and methanol can be used as feedstocks for polymer production, as well as readily storable liquid fuels that can be used as alternatives or in blends with city-gas or LPG for domestic or commercial-scale use (Dincer and Bicer, 2020), and both have been considered for use in fuel cells (Basri and Kamarudin, 2021; Ladewig et al., 2015). These products could both be readily stored and transported for domestic or export purposes, making infrastructure costs low, and based on estimated market prices, would likely be higher value than fossil-fuel-based hydrogen, while less expensive than renewable-based hydrogen in the short-term.

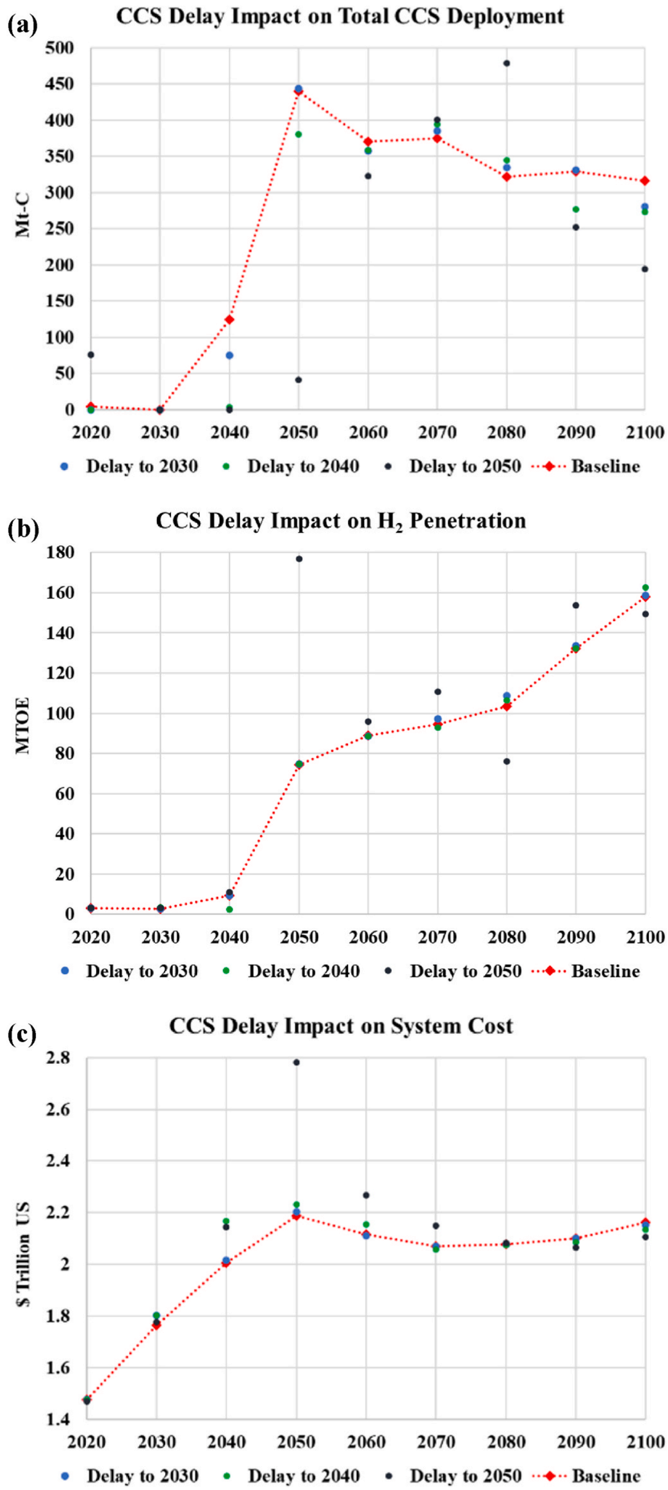

Fig. 4. CCS delay sensitivity analysis for (a) total deployment, (b) H_2 penetration, and (c) system cost.

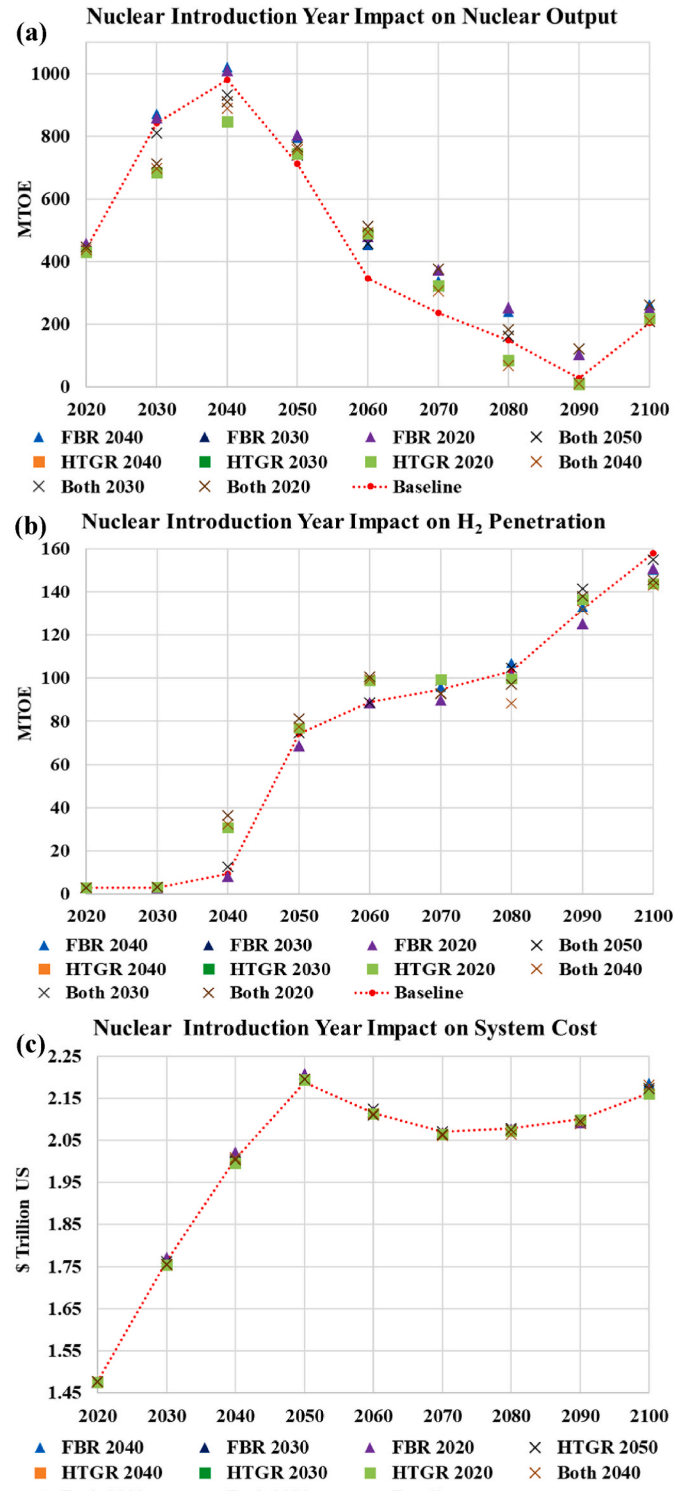

Fig. 5. Nuclear technology introduction year sensitivity analysis for (a) total output, (b) H_2 penetration, and (c) system cost.

4.2. Projection of future US hydrogen infrastructure

Based on optimization model outputs, hydrogen demand, distribution and end-use-cases are visualized, along with a projection of necessary storage media and pipeline interconnectivity for the years 2020, 2050 and 2100.

4.2.1. Visualization of hydrogen demand, distribution and end-uses for US nodes

Results revealed several key characteristics of dominant fuel types in each decade, and potential transitions within the hydrogen economy over time. Fig. 7 details hydrogen flows modeled for the year 2020. Sankey diagrams are organized with producer nodes on the left, flowing to the right toward consumer nodes. Nodes that produce and consume their own fuel stand alone. The furthest right segments designate the

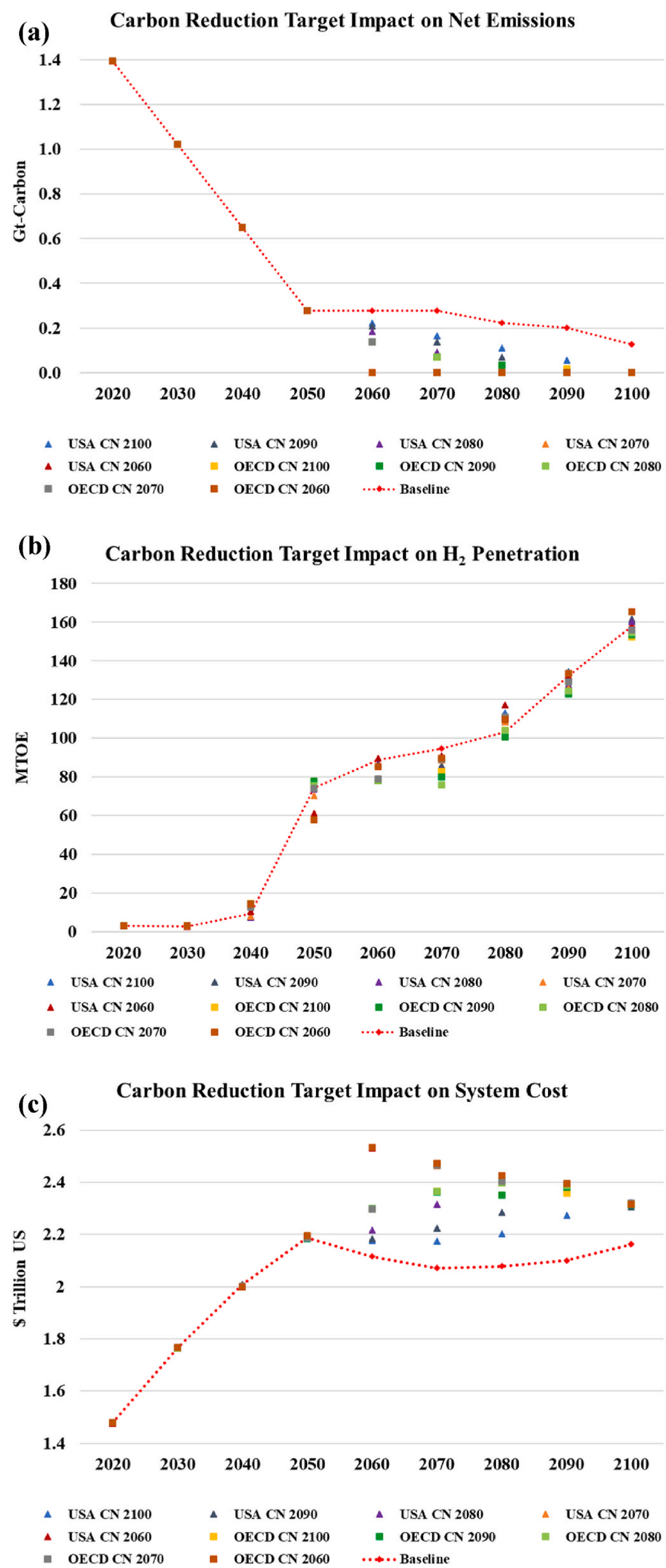

Fig. 6. Carbon reduction target sensitivity analysis for (a) net emissions, (b) H_2 penetration, and (c) system cost.

end-use-cases. Nodes and fuels are organized by color, splitting off dependent on use-case. The dominance of certain colors and weights of pathways represent the dominance of fuel type or usage within the network over the investigated time period.

For 2020, oil is identified as the primary source of hydrogen for all nodes. Hydrogen end-uses are consistent with predictions for initial hydrogen markets, revolving around transportation sector usage; all US nodes utilize 100% of their produced or imported hydrogen for transportation. There are no interactions between nodes, signifying economic isolation for this period. As is currently the case hydrogen is derived from fossil fuel sources, representing the nascent period of hydrogen usage in the US.

There is a distinct shift in the hydrogen network in 2050, as shown in Fig. 8.

Two new primary energy sources emerge, biomass and coal, displacing oil. Imports become the dominant source of hydrogen for all US nodes. Interaction between nodes increases, with connections from external and in-network nodes signifying emerging trade patterns. MTL dominates as the largest in-network exporter both in terms of total exports and the greatest number of export destinations; conversely, MXC has shifted from exporting most of its hydrogen to local production and consumption. NYK and CHG have shifted from minimal or no import, to relying on cheaper international and domestic imports. The main end-use for hydrogen shifts from transportation to city-gas.

2100 further progresses the emerging changes observed in 2050 as shown in Fig. 9.

Coal is phased out, and biomass becomes the primary energy source for all US hydrogen. Production-only nodes are also phased out as the capacities of in-network nodes expand. We also observe a diversification in end-uses, especially from MTL and nodes which import from MTL. City-gas, transportation and export are still major end-use-cases, along with emerging secondary energy synthesis (Methane and DME). MTL maintains its position as the largest producer and total exporter to NYK, CHG, and out of network nodes. LOS and HST on the other hand have increased independence, via self-production and lower import levels. MXC continues to be isolated from network interaction. Over time hydrogen supply, demand and end-use-cases greatly diversify between 2020 and 2100.

End-use transitions for hydrogen across time periods were relatively similar, irrespective of exogenous factors. This finding demonstrates that advantages such as a pre-existing market, such as for LOS, or proximity to a major exporter such as for NYK, does not give a significant advantage toward the realization of a hydrogen economy, notably in early stages. Further, these findings highlight that when hydrogen demand rates vary significantly, preferred production processes, primary energy sources and desired final products are similar across nodes. Based on the consistency of hydrogen economy development across the US, future policy initiatives can be designed to have comparable goals across different regions. Goals for implementing certain levels of infrastructure development, meeting a set percentage of energy consumption from hydrogen, or permitting similar environmental concessions would be reasonable with only slight adjustments needed to match locations. This will make comparing the successes of initiatives more consistent, as locations can be expected to be transitioning through similar primary energy sources and processes to meet their hydrogen economy goals. Indeed, consistency in policy is the gold standard for attaining results and streamlining enforcement of rules and regulations (Allen et al., 2017; Etienne, 2015).

By the year 2100 we observe a divergence of trade patterns, with some nodes becoming more independent, while others become fully dependent on international nodes. Of the US nodes, LOS and HST become mostly self-sufficient; HST imports just 14% of their annual hydrogen needs and LOS ceases importing and exports over half of their produced hydrogen. These nodes have vastly different relationships with hydrogen fuel when compared to NYK, which imports all its hydrogen and has the largest consumption share. CHG also meets 100% of node demand with imports, however their total demand is the lowest of all US nodes in 2100, despite having the greatest demand in the year 2050.

While overall US node hydrogen consumption grew by over 2000% between 2020 and 2100, and over 69% between 2050 and 2100, the

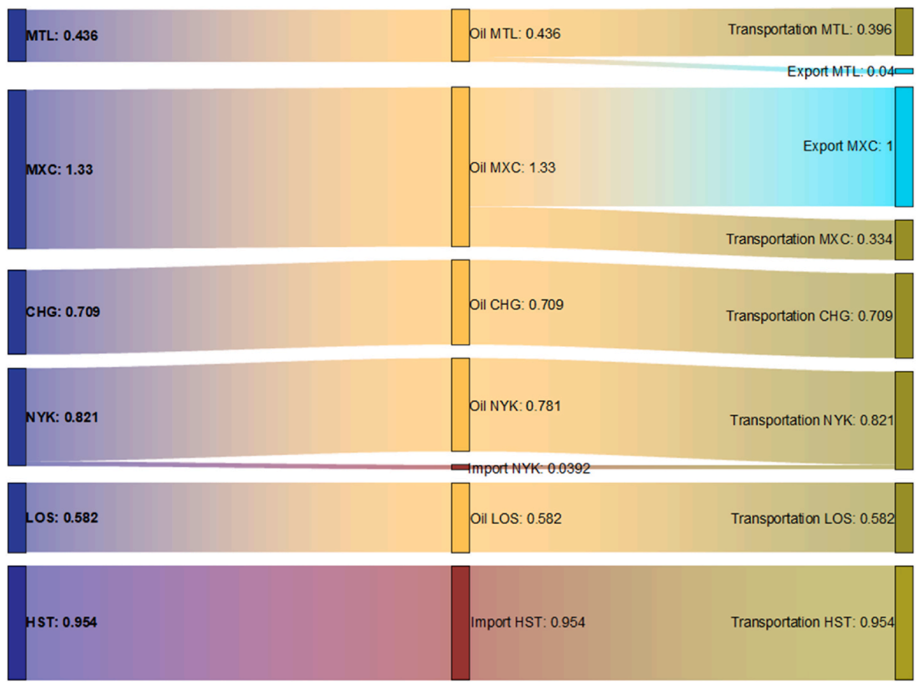

Fig. 7. Modeled hydrogen production, distribution, and utilization for the US in 2020 in (units in MTOE).

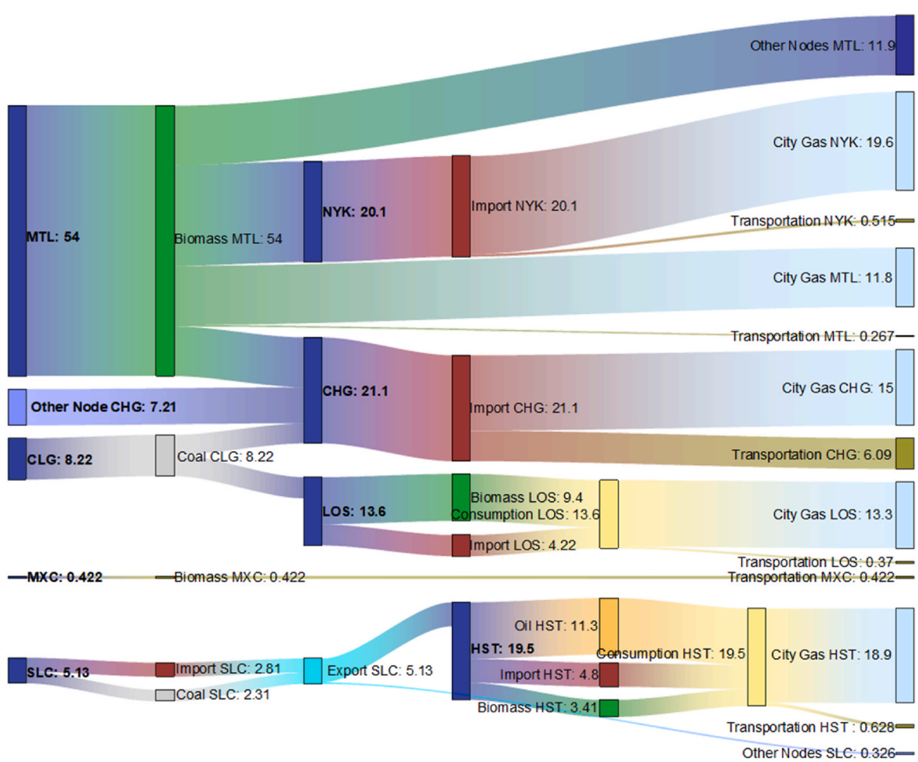

Fig. 8. Modeled hydrogen production, distribution, and utilization for the US in 2050 (units in MTOE).

projected consumption for CHG between 2050 and 2100 decreases by 8.05%. The shrinking hydrogen economy in CHG can be attributed to a shifting energy supply, in which an uptick in nuclear power between 2080 and 2090 outpaces that of hydrogen.

A major difference in how a location with a fully-fledged hydrogen economy utilizes its energy may lie in their level of responsibility for the costs and environmental restrictions surrounding hydrogen production. Without additional expenses outside of the cost of imports, nodes may have more flexibility to partition hydrogen fuel usage into more developing and niche markets, such as NYK delving into electricity production from hydrogen. In comparison, producers must be more selective about distributing available fuels to more established markets (city-gas, transport and exports) in order to ensure national or local energy security, return on investment, and to offset external costs. Practices such as importing hydrogen produced from fossil fuels, purchasing carbon offsets, and other actions displace the burden of abiding by regulatory

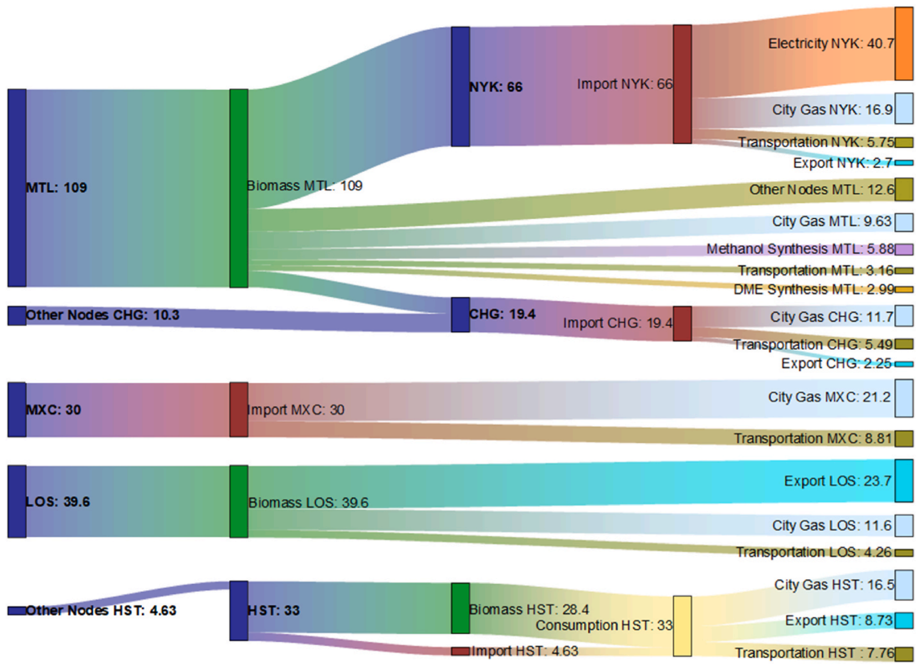

Fig. 9. Modeled hydrogen production, distribution, and utilization for the US in 2100 in (units in MTOE).

requirements and shouldering of external costs. The transition of conventional fuels such as coal or oil to a clean energy commodity (such as hydrogen) which is then imported by other countries is typically seen between the Global South as producers, and the Global North as beneficiaries (Eberle et al., 2019). This concept has been coined 'Carbon Colonialism', whereby countries with the economic wherewithal to purchase carbon credits and utilize other carbon mitigating trade options may continue benefiting from fossil fuels and unsustainable energy processes without appearing unsustainable. In this way, countries with less stringent regulations, or industries that rely on 'dirty' energy sources bear the brunt of poor environmental conditions and external costs. This trade-off is detrimental in the long term, affecting human health, environmental safety, and jeopardizing development (O'Callaghan-Gordo et al., 2016; Pompeu, 2021; Winch and Stepnitz, 2011).

For the US, Canada was the largest provider of hydrogen. Global life-cycle impact-assessment of electricity generation shows that Canada has relatively low external costs and cheaper electricity generation than other G20 countries. Canada has the advantage of having a pre-established RE mix and one of the lowest levels of reliance on fossil fuels (Karkour et al., 2020). Therefore, the Canadian MTL node may

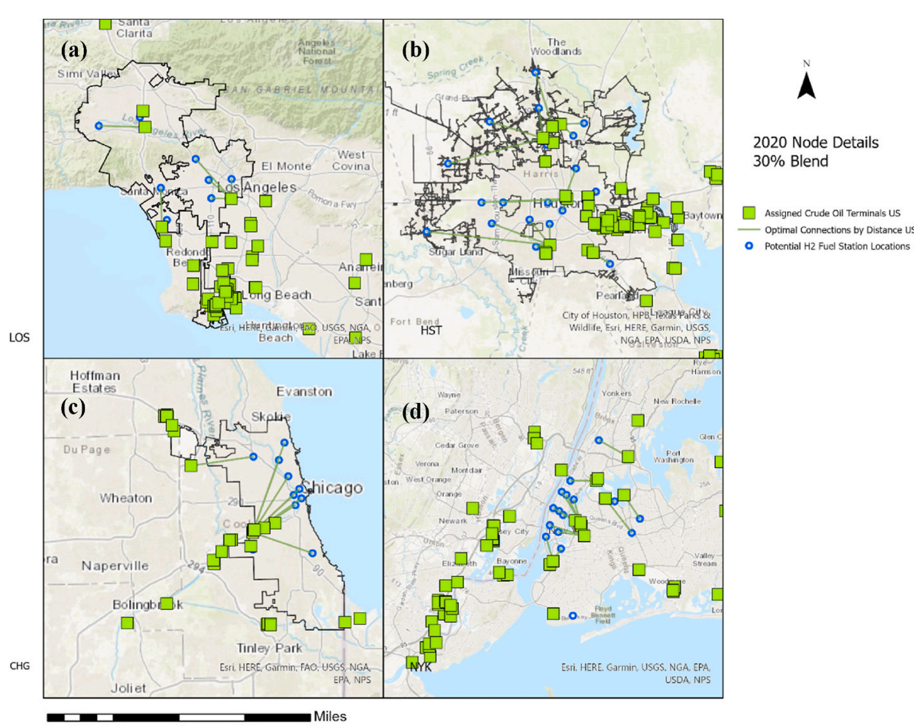

Fig. 10. Hydrogen node infrastructure projection for 2020 for the US nodes of (a) LOS, (b) HST, (c) CHG, and (d) NYK.

represent an export location with below average environmental and external burdens to consider during production. Displacement of external burdens within international energy trade, and its implications on environmental ethics and trade sustainability requires further research, especially for clean energy importers outside of the US.

4.2.2. Hydrogen storage, fueling and distribution infrastructure mapping

Infrastructure projections for 2020 detail the density of potential fueling sites, and the most likely locations as shown in Fig. 10.

Areas with a high density of social and economic activity within node city limits are most likely to have greater concentrations of conventional and alternative fuel stations (primarily electric in 2020). As with conventional fuel stations, most were located along major roadways and intersections. In addition, there were greater concentrations of crude oil terminal facilities around nodes, especially evident around LOS. The Western US has a lower spread of terminals compared to less populous areas of the Midwest and the East Coast, with concentrations of terminals around Los Angeles and San Francisco. Identifying these variations allows for more options when selecting intermediate transport points to compress hydrogen fuel for trailer trucks and when transitioning to pipeline transportation.

2050 initiates pipeline distribution, connecting producer nodes to consumption areas and identifies the shortest transportation pathways as detailed in Fig. 11.

Overlay of storage sites and storage capacities with pipelines show that all pathways pass through one or more zones identified with having 3 or more potential storage sites. A zone is separated by storage type (salt domes, aquifers, and depleted field), and best-case storage areas overlap, diversifying storage options. All nodes except LOS have two or more storage zones within the state. LOS has only 15 storage sites statewide - depleted fields and one aquifer. However, these sites have a combined storage potential that exceeds node demand and are readily accessible, located along the gas pipeline.

2100 represents the final analyzed stage of hydrogen economy integration and outlines specific storage sites within the previously identified underground storage zones as shown in Fig. 12.

LOS, HST, and CHG were able to meet projected 2100 hydrogen demand with just 2 storage facilities each within their state. NYK required 28 facilities, utilizing all available sites within New York and an additional two in neighboring Pennsylvania. Of the US nodes, NYK required the greatest amount of storage at 97.35 billion MMcf/year, coupled with having the least suitable geological features. The pipeline system remains largely the same from 2050 onwards, except for the lack of need for a connecting pipeline between CLG and LOS due to LOS shifting to self-production and consumption of hydrogen. An outline of the hydrogen network for the US in the year 2100, featuring the interconnected pipeline system and underground storage facilities is provided in Appendix D.

Sensitivity analysis of multiple scenarios clarified hydrogen penetration for the US out to 2100 occurring relatively consistently, suggesting that the storage and distribution infrastructure model is appropriate to meet the range of hydrogen penetration estimates.

In terms of infrastructure requirements, differences in storage capacity based on geological conditions and hydrogen demand meant that most nodes were able to meet demand without out-of-state storage. However, in the case of NYK, availability of underground storage facilities is a function of local geological conditions as well as limited land availability. It would be beneficial for the efficiency and stability of state

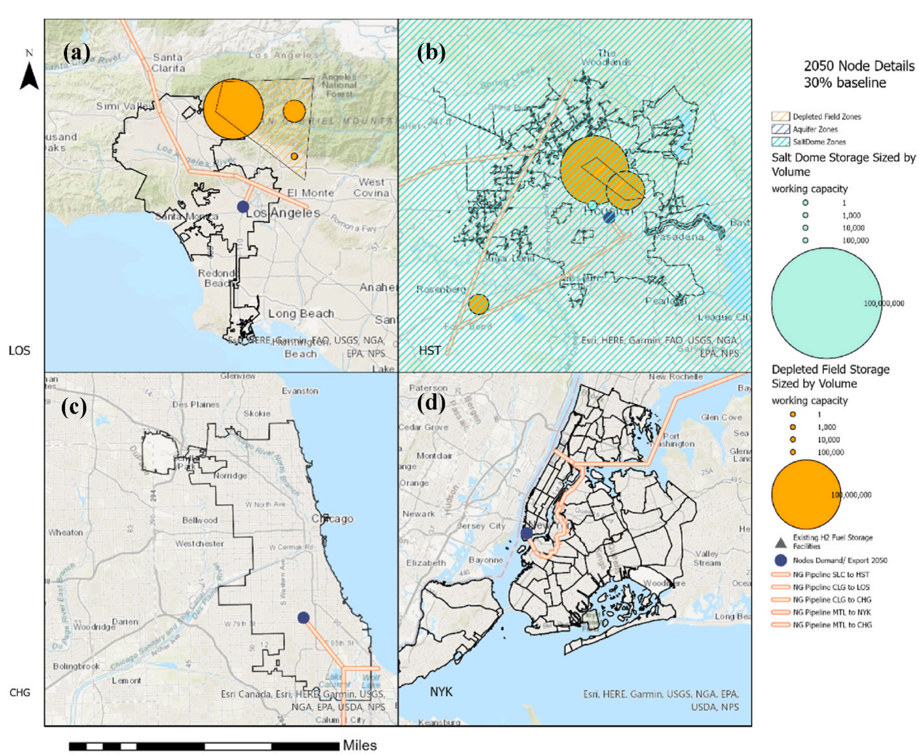

Fig. 11. Hydrogen node infrastructure projection for 2050 for the US nodes of (a) LOS, (b) HST, (c) CHG, and (d) NYK.

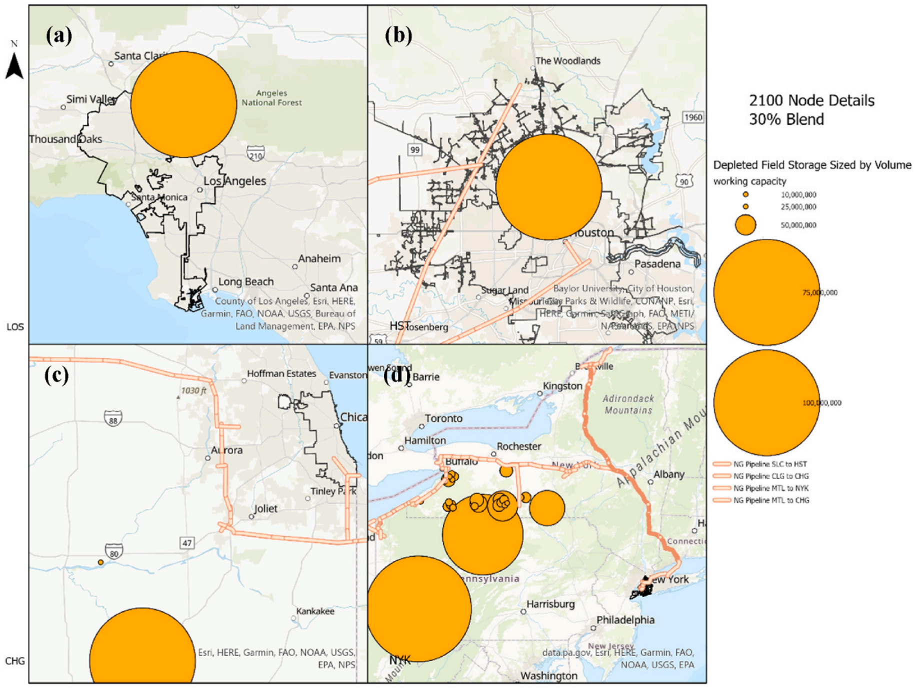

Fig. 12. Hydrogen node infrastructure projection for 2100 for the US nodes of (a) LOS, (b) HST, (c) CHG, and (d) NYK.

energy systems to be able to store hydrogen more proximate to the city center, as lacking the ability to consistently access energy stores during peak usage times or crises could exacerbate supply risks or lead to energy insecurity (Institute, n.d.). For high demand locations with unsuitable distributions or capacities for underground storage, there is a need to consider alternative storage solutions including pipeline storage and pressurized containers. Passive storage from line pack may not be sufficient, however, an expansion into pipe storage is an established and cost-effective solution to contain small amounts of readily accessible fuel (Andersson and Grönkvist, 2019). This practice consists of multiple short sections of pipe, up to 1.4 m in diameter, sealed on both ends and stored underground with pressures consistent with existing natural gas pipelines (100 bar) - 1 km of pipe can store approximately 12 tons of hydrogen in gaseous form (Bünger, 2014).

The option to modify and create caverns to make them suitable for hydrogen storage is a solution currently under investigation that expands upon pre-existing underground storage technologies. The salt caverns identified in our model are naturally occurring, have met various criteria for storage, and are currently fitted and in use for gas storage. A test project for utilizing a man-made underground cavern has been operating successfully as a natural gas storage facility in Sweden with 40,000 m3 of storage capacity. This facility is a lined rock cavern (LRC) and was designed with a steel cylinder lining to act as an impermeable barrier to contain the natural gas, while the surrounding artificial cavern acts as the main load-bearing structure (P.Tengborg, J. Johansson, 2014). The LRC approach allows for much more flexibility in design and placement. While options such as this will increase costs and require additional research to identify and implement, it may represent a sound investment for areas looking to increase total underground storage capacity for the future (P.Tengborg, J.Johansson, 2014).

Another finding of our infrastructure mapping was the inconsistency across pipeline networks. In our model, we utilized any natural gas pipeline as a potential pathway for our network, however, realistically, there will be barriers between overlapping pipelines, such as incompatible pipe material strengths, energy grid separation and corporate issues. Each segment of the pipeline considered in this research is matched with the segment owner. For example, all pipelines within the LOS city limits are owned by Southern California Gas Co (SCGC), however not all pipeline connections from within California or across state lines are owned by SCGC. Further analysis is necessary to discern if pipelines that appear to overlap in our mapping are interconnected and if operators are coordinating transport across pipelines or if they are functioning as separate entities.

5. Conclusions, implications and limitations

Our energy system optimization model, cognizant of energy policy, energy technologies, carbon targets, system costs and the required infrastructure to support this endeavor, explored the potential for the growing contribution of hydrogen to the US energy system, reaching approximately 7.6% of energy needs by the year 2100. This estimate is conservative when compared to analysis provided by pro-hydrogen industry associations which hope to achieve approximately 14% of final energy use in the US from hydrogen by 2050 through industry-government collaboration (Fuel Cell and Energy Association, 2020). On the other hand, the H2@Scale project, conducted utilizing techno-economic analysis by the National Renewable Energy Laboratory estimates hydrogen may account for between 2.6% and 6.4% of primary energy by 2050, more in line with our results (NREL, 2020).

In our analysis, the main uses for hydrogen in the US begin solely with transportation in 2020, growing to include blending with city-gas by 2050, and maturing to include electricity generation, conversion to chemical feedstocks, and exports between national nodes by the year 2100. Hydrogen's predicted role in the US energy system grows in line with an increased role for renewables, reducing energy related carbon emissions. The ability of our model to account for policy, technology, cost and carbon targets make it both novel, and a useful tool for energy system designers and policy makers with a vision to long term energy system development.

While this research identifies a role across multiple sectors for hydrogen in the future US energy system, it is conservative for a number of reasons. Primary among them is the range of technologies available in our model; breakthrough or 'disruptive' technologies including advanced electrolysis do not play a role in our analysis and are likely to increase the overall penetration of hydrogen as costs reduce over time. Potential additional end-use-cases include a larger role for ammonia, steel reformation and the likelihood of hydrogen underpinning freight transportation as these technologies mature. Further, the increasing cost of complementary carbon reducing measures such as nuclear power and CCS, means that their role may diminish over time, providing the potential for an increased role for hydrogen as a cost-effective carbon reducing measure, aligning with more aggressive estimates in the literature of up to approximately 14% by 2050 (Fuel Cell and Energy Association, 2020). The consideration of disruptive technologies could rapidly shift the nature of the US hydrogen production and consumption infrastructure and may also offer a more energy secure future scenario, rather than one which relies on low-cost energy imports.

Bearing these limitations in mind, future work will focus on incorporating disruptive technologies and existing hydrogen roadmaps to capture potential large scale uses of hydrogen. These efforts will likely move away from linear optimization which prioritizes system cost and carbon constraints to an agent-based approach which considers local resources, policies and national priorities.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Sensitivity analysis for CCS delay by hydrogen end-use

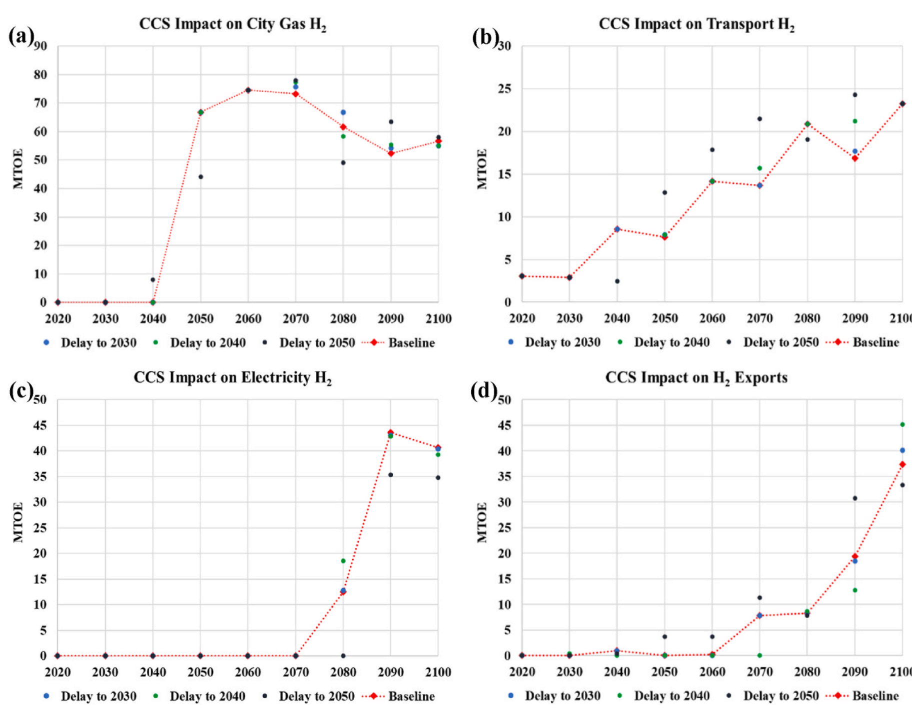

Fig. A1. CCS Delay Impact on (a) City-gas H_2, (b) Transport H_2, (c) Electricity H_2, and (d) H_2 Exports.

Appendix B. Sensitivity analysis for nuclear introduction year by hydrogen end-use

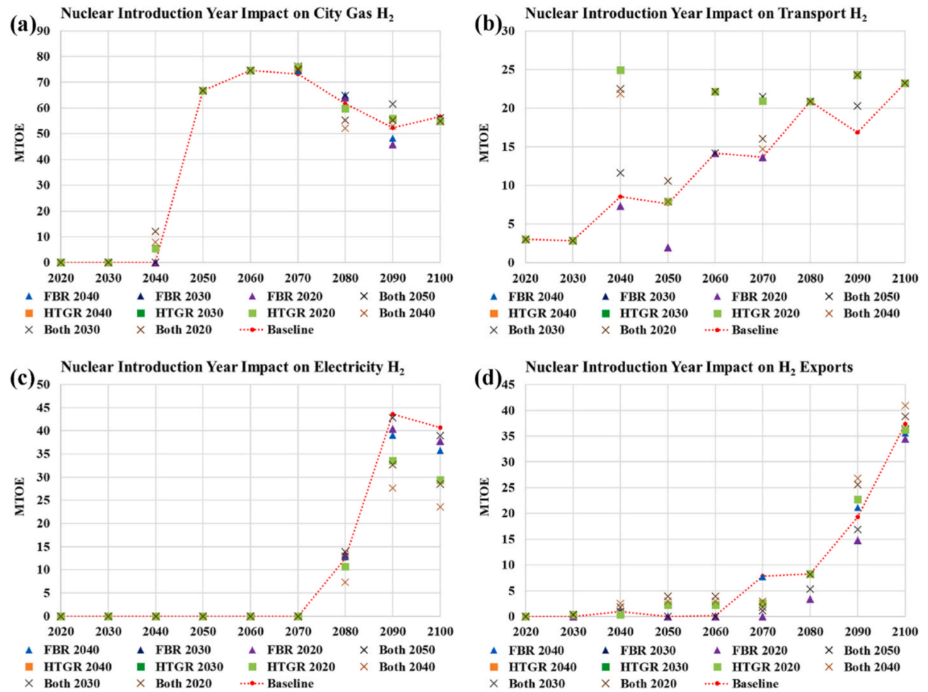

Fig. B1. Nuclear Introduction Year Impact on (a) City-gas H_2, (b) Transport H_2, (c) Electricity H_2, and (d) H_2 Exports.

Appendix C. Sensitivity analysis for carbon reduction targets by hydrogen end-use

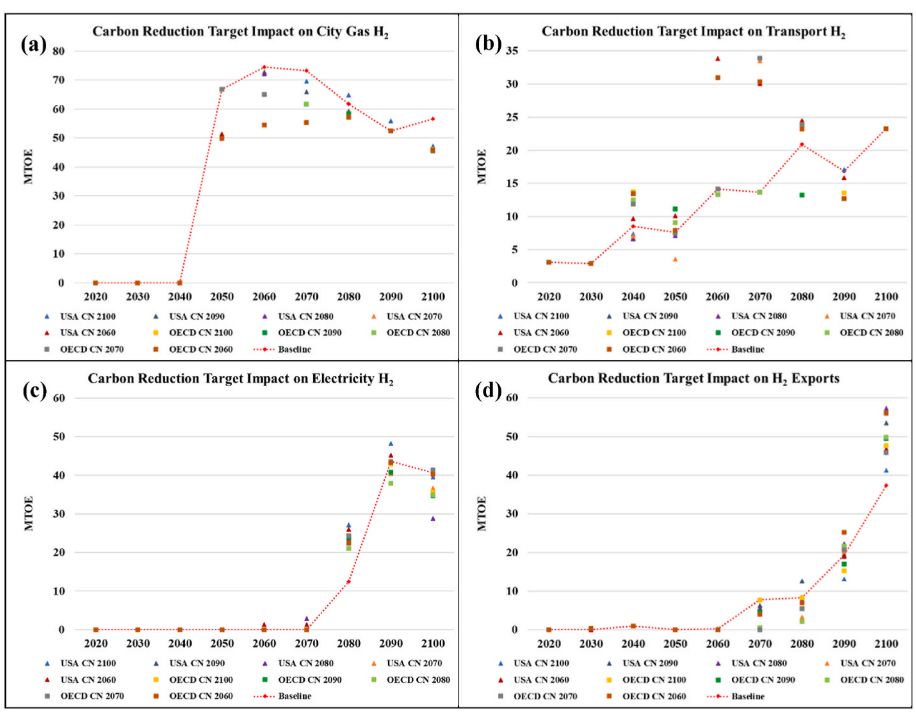

Fig. C1. Carbon Reduction Target Impact on (a) City-gas H_2, (b) Transport H_2, (c) Electricity H_2, and (d) H_2 Exports.

Appendix D. Infrastructure project for the year 2100

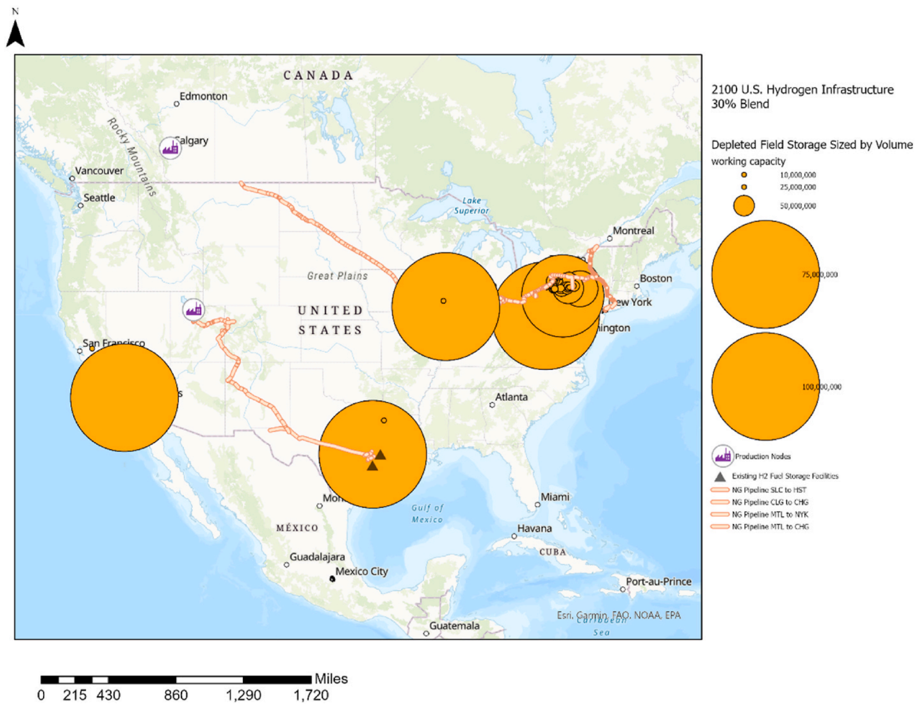

Fig. D1. Hydrogen node storage and pipeline projection for 2100 for the US and interconnected nodes.

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