Industrial H2 Production Cost Assessment for H2 Ventures-United States

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Executive Summary

Hydrogen has experienced substantial growth in popularity in recent decades across the globe. Hydrogen produces little air pollution, thus, allowing for decarbonizing industrial processes where decreasing carbon emissions is a complex task. In this report, we report our main findings on the evolution of LCOE of hydrogen as industrial feedstock. This includes a robust analysis of demand forecasts, policy forecasts, and investment related changes in the future. We create a physical and economic model to simulate various future projections of LCOE estimates and report them in this study. Other results for LCOE estimates from H2A (2019) model by NREL and KPMG (2021) are consistent with our base estimates for green ($3-7/kg), blue ($1.5-4/kg) and grey ($2-4/kg) hydrogen. Our main findings are:

- Hydrogen is likely to continue to be used for oil refining, ammonia production, and methanol production for the chemicals market. In the optimistic forecasts metals refining is an economically viable market.
- Blue hydrogen created from natural gas benefits the most from the tax credits, low price/expected future price of natural gas, and carbon tax-oriented policies to come out as the cheapest production technology at $1.77(2022)-$1.89(2050) in most of the future forecasts.
- As we approach the most pro-green policy scenario, green hydrogen becomes the cheapest technology at $1.62(2022)-~$0.1(2050) which generates huge returns on investment for the shareholders.
- The projections for blue hydrogen are much more stable than the ones for green and grey hydrogen, which have a much bigger confidence interval, as the LCOE for both reacts to extreme policies very strongly.
- According to the IRA, clean hydrogen technology will benefit from a tax reduction on investment or production under several specific provisions. This tax reduction incentive can become even more effective for clean hydrogen expansion given the increasing social cost of carbon (SCC). Our projection concludes that this tax reduction benefit is likely to have a strong and meaningful impact on accelerating the expansion.

Our recommendation to hydrogen ventures would be to invest in natural gas or electric powered blue hydrogen production plant for the most reliable investment. However, if they are feeling optimistic about the policy trajectory of United States they can consider adding electrolyzers to their extant plant and add green hydrogen capacity to the plant to ensure optimum utilization of state benefits for this emerging technology.

Introduction

The United States is of the largest producers and consumers of hydrogen, whose demand accounts for

13% of the total hydrogen demand (Global Hydrogen Review, 2021). However, over 90% of the hydrogen production remains grey (Shearman & Sterling). About 95% of hydrogen (11 MMT) consumed in the United States today serves as a feedstock in industrial processes, such as in the production of ammonia, methanol, and refineries. These industries can gradually transition to low-carbon hydrogen technologies to reduce carbon emissions. There are also emerging applications of hydrogen to decarbonize other industries, such as steel production, cement, and low-carbon fuels for the aviation and marine industries, as well as minor applications in the food industry.[1]

Similarly, to the United States, the European Union is one of the major players in the hydrogen market today. Most hydrogen currently produced in the E.U. is used as industrial feedstock to make other materials due to its chemical rather than energy properties. About 10 million metric tons of hydrogen become feedstock every year, mostly in the refining and chemical production industries. Most of the hydrogen used in these industries currently comes from natural gas (SMR without CCS), and about 95% of the hydrogen produced currently remains grey.[2]

Despite the current leadership in the hydrogen market, the U.S. and E.U. require the coordinated action of national governments to take a lead in the future of energy transformation. The authorities need to continue working on incentives creation for low-carbon hydrogen to displace fossil fuels. They further need to mobilize investment in production and infrastructure, provide strong innovation support to ensure the competitiveness of hydrogen as well as establish appropriate regulatory regimes (Global Hydrogen Review, 2021).

Hydrogen Demand as Industrial Feedstock

United States

Multiple factors can potentially affect the development of the hydrogen market. These include technology advancements, infrastructure development, the performance of related markets (such as natural gas prices), the potential for market accessibility, and other national decisions. Here, we summarize the latest forecasts on hydrogen demand as industrial feedstock in the United States, which are also presented in following figure.[3]

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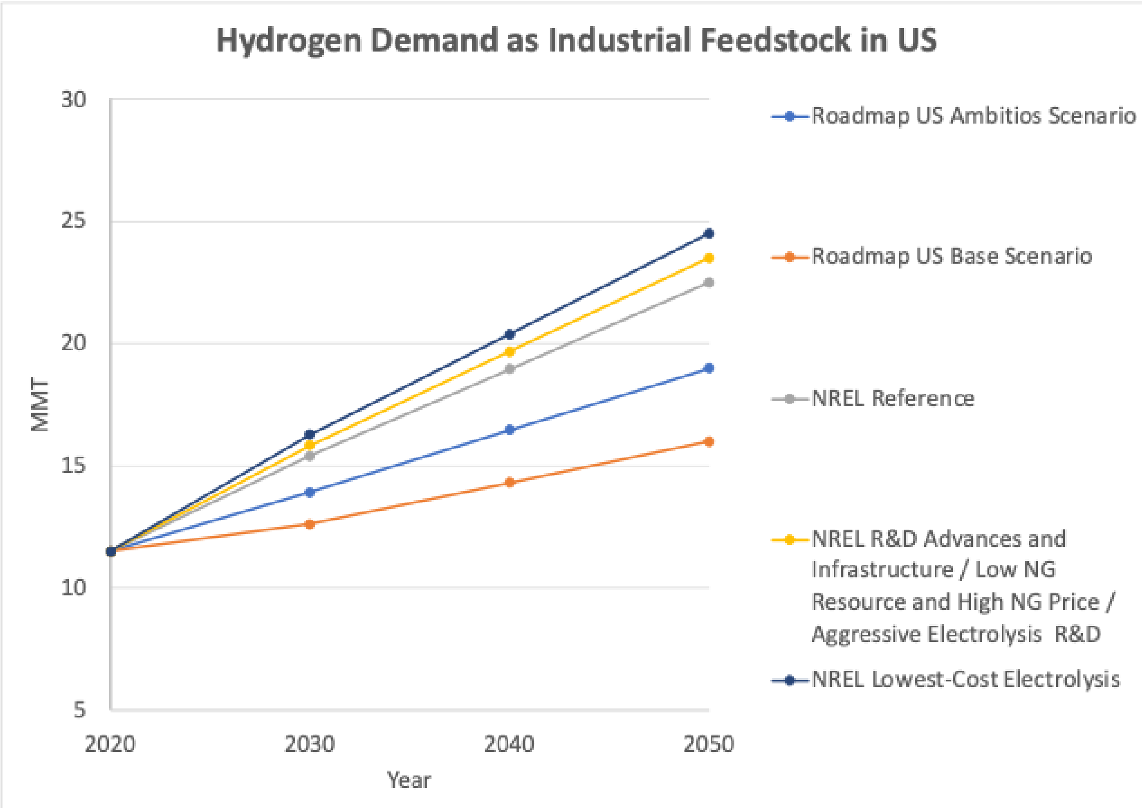
[1] Roadmap to a US Hydrogen Economy report (https://cafcp.org/sites/default/files/Road+Map+to+a+US+Hydrogen+Economy+Full+Report.pdf).

[2] Hydrogen Roadmap for Europe (https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf).

[3] We construct these forecasts based on interpolation of data from 1) Roadmap to a US Hydrogen Economy report (https://cafcp.org/sites/default/files/Road+Map+to+a+US+Hydrogen+Economy+Full+Report.pdf) and 2) NREL's report on "The Technical and Economic Potential of the H2@Scale Concept within the United States" (https://www.nrel.gov/docs/fy21osti/77610.pdf).



In accordance with the US Roadmap, there are 2 primary scenarios for hydrogen industrial demand development:

1. **Roadmap Base Scenario:** Under this scenario, hydrogen demand does not scale significantly from the current levels and reaches 16MMT/yr by 2050. Hydrogen's main use will remain as a feedstock in industrial processes such as ammonia, methanol, and oil refining.
2. **Roadmap Ambitious Scenario:** In this, demand grows at a faster pace and reach around 19 MMT/yr by 2050. In this scenario, the new demand for hydrogen feedstock will be driven by metal refining. In particular, the steel industry which has been historically a major contributor to carbon emissions will be the main driver of hydrogen demand growth. It is expected that steel demand will grow to 120 MMT by 2040. Under the assumption that the industry meets future demand with domestic steel, hydrogen help in reducing carbon emissions for certain types of steel production processes that use reductants. Specifically, around 14 % of steel plants could switch to hydrogen-blend feedstock by 2050, meaning steel production would use roughly 1.4 MMT/year of hydrogen.

NREL (2019) lays out a hydrogen demand forecast which serves as an additional data source on hydrogen demand estimates and allows us to present 3 additional scenarios for hydrogen demand as industrial feedstock:

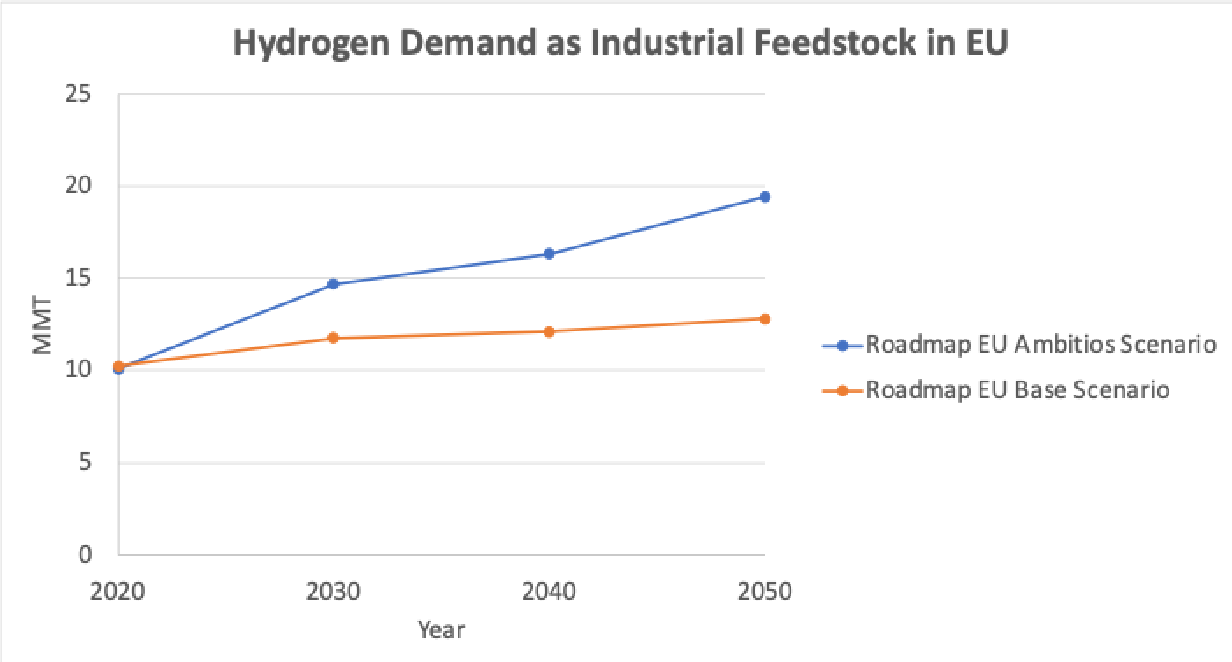
1. **NREL Reference scenario:** This assumes current technology status and strong market competition. All hydrogen in this scenario is produced via SMR of natural gas. The hydrogen demands include current demands plus some growth in biofuels and synthetic methanol production. So, in addition to the current primary markets of oil refining and ammonia production (11 MMT/yr), an additional 9 MMT/yr of hydrogen will go to biofuel production and 2 MMT/yr of demand will go to methanol.
2. **Combined scenario:** NREL R&D Advances and Infrastructure / Low NG Resource and High NG Price / Aggressive Electrolysis R&D.[4] The combined scenario's demand predictions differ from the Reference scenario owing to increased demands for metals refining by 4 MMT/yr, while demand for ammonia decreases by 1 MMT/yr, and the 2 MMT/yr for methanol disappears.
3. **NREL Lowest-Cost Electrolysis scenario**. It assumes optimistic technology development and market structures. The hydrogen demand is largest in this scenario and amounts to roughly 25 MMT/yr. The demand growth is expected due to an increase in ammonia demand.

Overall, both Roadmap and NREL demand forecasts show that hydrogen is likely to continue to be used for oil refining, ammonia production, and methanol production for the chemicals market. In addition, both analyses also indicate that in the optimistic forecasts (Roadmap's Ambitious scenario and NREL Lowest-Cost Electrolysis scenario) metals refining is an economically viable market. Please, refer to the appendix to view the hydrogen demand by sector of industrial application for each scenario.

European Union

Companies in the EU already use hydrogen as an industrial feedstock for oil refining, chemicals, and metal processing. The demand for most hydrogen feedstock applications will continue growing between 1 and 3% a year in the future which makes decarbonizing hydrogen highly relevant. The results from this data review are summarized in the following figure.

[4] This scenario combines 3 different scenarios that vary in underlying assumptions but coincide in predictions for hydrogen demand as industrial feedstock. Specifically, the R&D Advances + Infrastructure scenario assumes expected hydrogen technology development and demand growth. Low NG Resource/High NG Price scenario assumes higher natural gas prices. The aggressive Electrolysis R&D scenario assumes lower low-temperature electrolysis capital costs.



Today, roughly 70% of hydrogen feedstock is produced from natural gas through reforming. The decarbonization of the hydrogen source offers an opportunity to scale up carbon capture and storage and/or electrolysis. It is expected that by 2030, 10% of hydrogen from SMR could feature carbon capture and storage. Furthermore, by 2050, hydrogen for existing feedstock uses could be entirely decarbonized, with more than three-quarters of hydrogen from SMR with carbon capture and storage. In this report, we present 2 scenarios of hydrogen demand developments in the EU.[5]

1. **Base scenario**: In this scenario, all the existing policies continue, but there are no additional steps taken to decarbonize hydrogen production. Following this scenario, the EU fails to reach the 2-degree Celsius global warming target by 2050. The hydrogen production increases only slightly, as compared to the level of 2020, and reaches approximately 13 MMT by 2050.

2. **Ambitious scenario:** In this scenario, the EU uses a hydrogen potential to achieve the 2-degree target and relies significantly on the combined effort of industry, policymakers, and investors. The expected demand for hydrogen as industrial feedstock is projected to be around 19.5 MMT by 2050 in his case. New uses of hydrogen for feedstock, such as steel production will contribute significantly to an additional demand. Specifically, steel production from direct reduced iron will

[5] The forecasts are based on the figures from Hydrogen Roadmap for Europe Report. (https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf).
The conversion from of numerical figures from TWh to MMT was made under the assumption of 100% efficiency.

account for almost 20% of total hydrogen demand by 2050 (4 MMT). Please, see the forecast for each scenario with the breakdown by sector of industrial application in the appendix.

Levelized Cost Of Energy Analysis

Levelized cost of energy (LCOE) is an economic measure of the lifetime costs of energy of the relevant energy resource. This measure takes into account the lifetime investment, operational and maintenance (O&M) costs, as well as feedstock costs, which are then discounted back to the present day. This is normalized against the expected output of the production plant for the resource, which is, in this case, hydrogen. The formula for this is given here:

$$\frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

In this formula, I_t, M_t, F_t, E_t, r, and n represent the future value in year "t" of investment costs, O&M costs, feedstock costs, production estimate of plant, discount rate, total number of years of plant life, respectively. In this model, the O&M and feedstock costs were allowed to increase at the expected rate of inflation for those specific costs. In this section, we discuss the physical and economic model used to develop a realistic LCOE estimate for Hydrogen Ventures in the United States. Detailed assumptions are provided in the appendix. This section summarizes the physical model, followed by the economic model used to generate the LCOE estimates used in this report. The resulting estimates are reported in the results section.

Hydrogen Production Process Modeling

The following sections describe the physical components involved in each hydrogen production technology and related assumptions.

Compression/Storage Costs

After manufacture, H2 must be compressed and stored regardless of the manufacturing method. This adds a capital cost for the compressor/cooler and the storage containers, and an operating cost to supply electricity to compress/cool H2. The capital costs are calculated as 620 \$/(kg H2/day) (Parks 2014). The kWh required per kg of H2 for compressing and cooling are obtained (Cornish 2011), and multiplied by the electricity cost to obtain the operating costs in \$/(kg H2).

Steam Methane Reformation (Blue/Grey Hydrogen)

In steam methane reforming (SMR), methane is reacted with steam to produce hydrogen gas and carbon monoxide. The carbon monoxide is reacted with steam to produce hydrogen and carbon dioxide, using the water shift gas reaction (WSGR). Hydrogen produced via this process is called grey hydrogen, or blue hydrogen if the resulting CO2 is captured.

The process is depicted graphically in figure 3. We calculated the amount of methane (as reagent), methane as fuel to run the reaction, and the amount of water required per kg of hydrogen produced. The amount of methane and water required as reagent was simply calculated from the stoichiometry, with 1 mol of CH4 required per 4 mols of H2, and 2 mol of H2O required per 4 mols of H2. We assumed 1 additional mol of excess H2O per mol of H2O consumed would be used for the reaction and ultimately go to wastewater. This excess fraction can be adjusted to examine the impact of water intensity on final costs, which results in consuming more fuel to heat additional water to the required high temperatures.

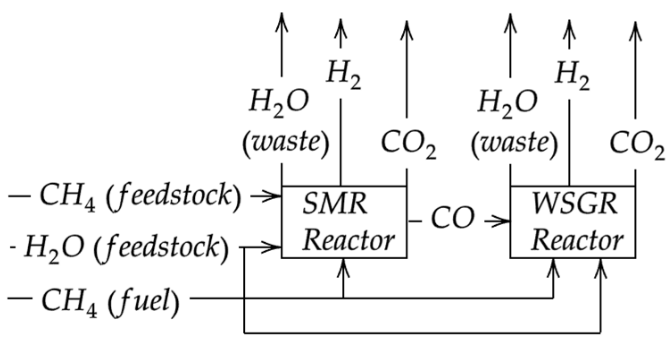


Figure 3. Steam reforming process

Both reactions require heat both due to heat consumed by the reaction (enthalpy) and for heating the reagents to the required temperature (800 C for SMR, and 400 C for WSGR). This includes heat for vaporizing the H2O. The heat required per kg of H2 is calculated, allowing the calculation of CH4 required as fuel. We find that 30% of the CH4 consumed during the entire process is consumed as fuel. The CO2 produced by the WSGR and burning CH4 for fuel is calculated in terms of kg CO2 per kg H2.

Using costs for natural gas from the EIA website (U.S. Natural Gas Prices), industrial water and sewage (Bunch 2017), and carbon capture, we obtain operating costs for each component in terms of $/kg H2 which are added together to give a final operating cost. For the electrified versions, electricity cost was calculated in place of natural gas fuel costs.

For the capital cost, we used the estimate of a grey hydrogen plant consuming 3.7 MMSCFD per day had a capital cost of $35 million. Using our calculated fraction of natural gas consumed as fuel vs consumed as a reagent to calculate the estimated kg of H2 produced per day, this was converted into a capital cost in terms of dollars per kg of H2 produced per day, resulting in a system capital cost of 1550 $/(kg H2/d).

We added capital and operating costs for carbon capture for blue hydrogen. The capital cost required per kg CO2/day consumed was estimated (Panja 2022) and converted to 700 \$/(kg H2/d) by dividing by kg CO2 produced per kg H2 produced. The operating cost of 0.31 \$/(kg CO2) was determined using a similar methodology, and multiplied by (kg CO2)/(kg H2) for each process to calculate \$/kg H2. We assume 90% of emitted carbon is captured.

Electrolysis (Green Hydrogen)

In electrolysis, electricity is consumed to split water into H2 and O2. This process takes electricity and industrial water as input and outputs H2 and sewage.

Using an operating voltage of 2.1 V, the electricity required per kg of H2 is calculated, and hence the electrical operating costs. A higher efficiency electrolyzer corresponds to a lower operating voltage, and a lower efficiency to a higher operating voltage, with a typical range of 1.8-2.4 V. We also calculate the industrial water consumed per kg H2, and assume 1 mol of excess H2O is required and lost as sewage. This excess water can be adjusted to examine the effect of water excess on the cost.

The capital cost of an electrolyzer of 350 \$/kW is used, and the operating voltage and stoichiometry of the reaction is used to convert this into a capital cost of 1370 \$/(kg H2/d).

An electrolyzer's operating cost is sensitive to the varying cost of electricity throughout the day, and therefore we introduce a capacity factor for green hydrogen corresponding to the fraction of the day the system operates during. The lower the capacity factor, the higher the capital costs, as the electrolyzer and compressor must be overbuilt to produce hydrogen at a higher rate during a shorter period of time, so the capital cost is simply divided by the capacity factor. This reduces operating costs, as the cheapest electricity of the day can be used. We also introduce a capacity factor for grey and blue hydrogen for cases where they are not perpetually running, in which case the capital costs of the SMR/WGSR system, carbon capture system, and compressor are divided by the capacity factor.

Economic Model

This section briefly describes some relevant assumptions related to the evaluation of LCOE estimates.

Base case

The base case demand estimate from the previous section was used together with an estimate of the average market capitalization of hydrogen production plants in the US (Market cap, 2022). Using the assumptions of 5% market capitalization a plant with a capacity of producing 750 kg per day is estimated as an input for the physical model for the base case. This gives an estimate for I_t(\$/kg), M_t (\$/kg-year), F_t (\$/kg-day), and carbon produced (ton CO_2/kg H_2) for the given capacity targeted.

The economic model processes the capital expenditure to create estimates for tax liability (IRS, 2022), after accounting for varying depreciation schedules across types of hydrogen production plants. In the base model, the O&M cost assumption of 3% of capital cost expenditures, as provided, is used. This cost assumption is relaxed in the scenario analysis, and O&M costs produced by the physical model are applied to the economic model to test the robustness of LCOE estimates. For the feedstock costs, electricity costs are allowed to decrease at the rate forecasted by EIA (2022). In addition, water/sewage costs are allowed to increase at the interpolated rate calculated using historical data on the industrial cost of water (2022, EIA). The current social cost of carbon at $51/ton CO_2 produced is used to consider a baseline carbon tax impact on the LCOE for all the technologies. In addition, the currently applicable tax credit covered in the policy analysis is applied to green and blue hydrogen which gets a tax credit of $3/kg H_2 produced and $1/kg H_2 produced, respectively.

This process gives a year-by-year total cost expenditure of the industrial hydrogen production plant which is then discounted back to the present value terms and normalized by the present value production capacity of the plant. The plant was assumed to operate until 2050 with an industry-standard discount rate of 2% (Assumptions for H2A, 2022) and year-adjusted inflation rate of 1.9% (EIA, 2022). For the sensitivity analyses, we test the LCOE estimates by varying the cost of electrolyzer, efficiencies, plant utilization rates/capacity factors, and water intensity of hydrogen production influence the cost of producing hydrogen.

Optimistic/Pessimistic Case

Under this case, we test all the pro-green hydrogen policy measures currently active or expected to be applicable in the future, as discussed in the following section on policy analysis. This includes varying the social cost of carbon estimate, the growth rate of this estimate, carbon tax trajectory, natural gas prices, oil reserve exploitation, depreciation schedules etc.

Policy Analysis

Following the growing concerns about climate change, in August 2022, the United States Congress finally passed a groundbreaking law which is known as the Inflation Reduction Act of 2022 (IRA). Despite its apparent mismatch with its name, one of the primary objectives of this law is to facilitate the incumbent administration's aggressive goal of reducing greenhouse gas emissions to 50% below 2005 levels by 2030. (The White House, 2022). This goal is expected to be achieved by incentivizing domestic energy production with novel clean high-tech solutions, including green hydrogen technology. It will benefit from a tax reduction on investment and production under several specific provisions. In this chapter, we will closely look at this law and other relevant federal and state policies which may bring a significant synergy to energy transition by this technology. Furthermore, we will also examine and reflect on the impacts of these policies on our hydrogen technology adoption projection.

Inflation Reduction Act of 2022

Tax Credits Available for Hydrogen Producers through IRA

Life-cycle Emissions (kg CO2e / kg H2)	Investment Tax Credit (%)	Production Tax Credit (2022$/kg H2)
4-2.5	6	0.60
2.5-1.5	7.5	0.75
1.5-0.45	10	1.00
0.45	30	3.00
*kg= kilogram, CO2e= carbon dioxide equivalent, H2= hydrogen *Source: IRA Sec. 45V, Bergman and Krupnick. 2022		

We apply $3/kg for green hydrogen and $1/kg for blue hydrogen pursuant to the IRA provisions. The results are shown in Part 2.

Relevant Federal and State Assistance

Several federal and state policies take a form of assistance. Among them is the Department of Energy (DOE)'s initiative to accelerate the adoption of green hydrogen technology. While the IRA focuses on a standardized tax reduction for green hydrogen production, the DOE's programs in general try to induce public and private stakeholders to advance their R&D on numerous green hydrogen technologies by selective funding. There is no salient tax reduction benefit at the state level either, however, several states are also implementing financial assistance to facilitate regional hydrogen hubs in accordance with the federal government's hydrogen technology agenda. We may also take advantage of these programs to make our proposal more feasible.

Hydrogen Shot and H2@Scale Initiative

Launched in 2021, Hydrogen Shot aims at reducing the cost of clean hydrogen production by 80% to $1 per 1 kilogram in 1 decade. Currently, hydrogen from renewable energy sources costs about $5 per kilogram. (DOE, 2021) The Hydrogen Shot establishes a framework and foundation for clean hydrogen deployment which includes support for demonstration projects. Industries are beginning to implement clean hydrogen to reduce emissions, yet many hurdles remain to deploy it at scale. Supporting collaborative projects among stakeholders to achieve the Hydrogen Shot's 80% cost reduction goal aims to unlock new markets for hydrogen, including steel manufacturing, clean ammonia, energy storage, and heavy-duty trucks.

H2@Scale is DOE's other initiative that brings together stakeholders to advance affordable hydrogen production, transport, storage, and utilization to enable decarbonization and revenue opportunities across multiple sectors. It includes DOE-funded projects and national laboratory-industry co-funded activities to accelerate the early-stage research, development, and demonstration of applicable hydrogen technologies through the private sectors. (DOE, 2021) The DOE announced funding cooperative projects that will complement existing hydrogen-related efforts and support DOE's Hydrogen Shot goal to drive down the cost of clean hydrogen by 80% within the decade. The most recent case is the DOE's announcement of $40 million in funding opportunities in total on August 23, 2022, to further accelerate the research, development, and demonstration of clean hydrogen technologies. (Gibbs and Wu, 2022)

Federal and State Governments' Support for Hydrogen Hubs

DOE formalized its $8 billion financial support for hydrogen hubs, which was endorsed by the Biden administration's Infrastructure Investment and Jobs Act last year, to improve clean hydrogen production, processing, delivery, storage, and end-use. (DOE, 2022) DOE will select proposals that prioritize employment opportunities and address hydrogen feedstocks, end uses, and geographic diversity by May 2023.

Various states and entities in the public and private sectors have come together as a form of a consortium to develop proposals for the regional clean hydrogen hubs program in response to the DOE's agenda. These partnerships may spur investments, result in more local benefits to both public and private stakeholders, and allow individual states to make progress toward achieving their decarbonization goals. (Gibbs and Wu, 2022) For example, New York has signed an agreement with Connecticut, Massachusetts, and New Jersey, and approximately 40 hydrogen ecosystem partners including industry and academia to collaborate and develop plans for a regional hydrogen hub that can facilitate green hydrogen energy innovation and investment to address climate changes. (New York State, 2022) Similarly, Colorado, New Mexico, Utah, and Wyoming have signed an MOU to create the Western Inter-State Hydrogen Hub coalition, in partnership with academic, research, industry, and community partners and stakeholders to develop and submit a proposal for a regional clean hydrogen hub to DOE. (Wyoming Energy Authority, 2022).

Social Cost of Carbon and Hydrogen Technology

The social cost of carbon (SCC) is the marginal cost of the impacts caused by emitting one extra ton of greenhouse gas or its equivalent (carbon dioxide equivalent) on social welfare. (Nordhaus, 2017) In the economic context, it is considered a form of market failure that occurs when producers do not internalize the negative impact of carbon emissions on the environment and human health. The governments try to estimate SCC in order to regulate industries and levy some financial burden in a way that induces agents in the market to internalize it.

Current estimates of SCC vary depending on the time horizon and type of analysis used. The Biden administration announced in February 2021 that it would put the value of SCC back in place with something similar to that of the former Obama administration. The Trump administration set it as $1-7, claiming that carbon dioxide has caused relatively little harm to the economy. Many economists and policy analysts do not support the estimates stipulated by Trump's administration. A recent study by Rennert et al. (2022) has updated the cost range to be between $59-370 depending on different discount rates and other underlying assumptions of the models used. Nevertheless, many would argue that the current estimates of SCC are still underestimated. Thus, potential benefits from carbon emissions reduction may be even larger.

Social Cost of Carbon Estimation

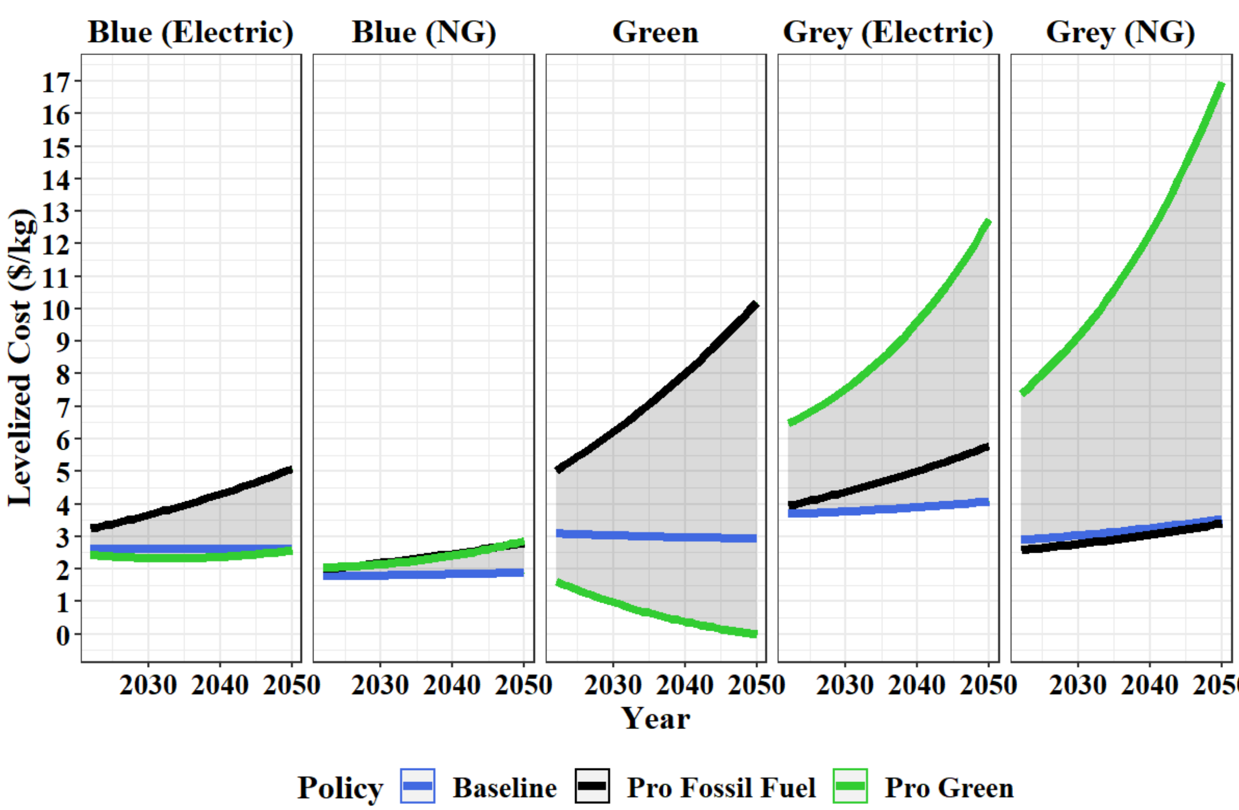
Estimation	Discount Rate (%)			
	1.5	2	2.5	3
US Government, February 2021			$76	$51
US Government, from IRA projection 2022			$78	
Rennert et al. (2022)				
GIVE Sectoral	$308	$185	$118	$80
DICE-2016R	$275	$152	$91	$59
Howard & Sterner	$370	$205	$123	$80
*Source: Federal Government of the United States (2021, 2022), Rennert et al. (2022)				

The well-established SCC cost is $51 (3% discount rate), which was estimated in the former Obama administration and endorsed again by the incumbent Biden administration. This is slightly increased to $78 (2.5% discount rate) which was newly derived from the ground analysis for the IRA legislation in 2022. However, they are milder in comparison with the latest independent research. (Rennert et al.,

2022) We reflect the social cost of carbon in a way that levies an additional tax on production. Under the assumption that later emissions contributing to the temperature increment on top of higher levels of warming make it more difficult to control and adapt, the 1.3-3.9% growth rate of SCC is applied depending on the scenarios. (Anthoff., 2011). We also assume that applying the growth rate of SCC can catch the increment happening in fossil fuel-related prices over time.

Results

For producing grey, blue, and green hydrogen, the LCOE is presented in the following figure. The figure is a result of multiple simulations with varying specification of underlying parameters for future policy scenarios as specified in LCOE section. The green LCOE is driven by electricity costs, which constitute 80%-95% of the total LCOE, whereas capital and natural gas/electricity/tax credit expenditure constitute 60-80% of the grey hydrogen.



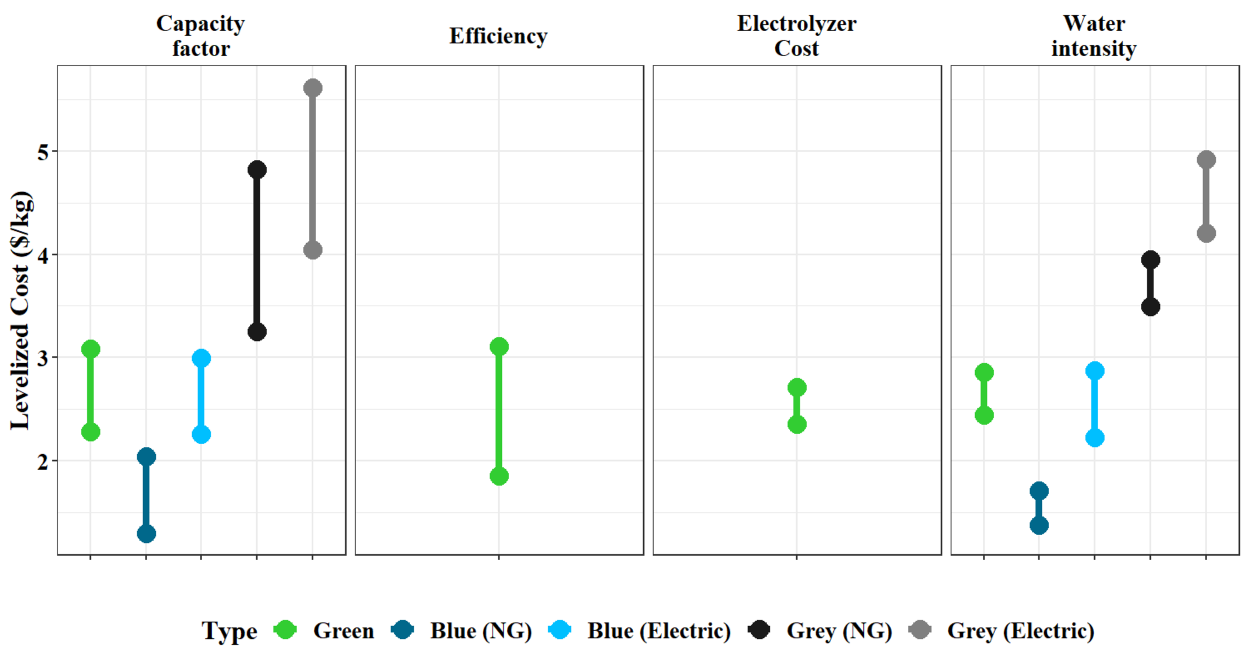
Blue hydrogen created from natural gas benefits the most from the tax credits, low price/expected future price of natural gas, and carbon tax-oriented policies to come out as the cheapest production technology at $1.77(2022)-$1.89(2050) in most of the future forecasts. However, as we approach the most pro-green policy scenario, green hydrogen becomes the cheapest technology at $1.62(2022)-~$0.1(2050) which generates huge returns on investment for the shareholders. This makes sense considering some of the most pro-green scenarios include indefinite continuation of tax credit, electricity cost reduction (as more renewables power the grid), and carbon tax policies.

As shown in the table below, with the current policies and expected future scenarios, the only way grey hydrogen (made with natural gas) becomes a bit viable is under the most pro-fossil fuel scenario, but it is not able to get cheaper than blue hydrogen in most cases. The projections for blue hydrogen are much more stable than the ones for green and grey hydrogen, which have a much bigger confidence interval, as the LCOE for both reacts to extreme policies very strongly.

LCOE ($/kg) (min-max)	Green	Blue (NG)	Blue (Electric)	Grey (NG)	Grey (Electric)
2022	1.62-5.02	1.99-2.03	2.42-3.24	2.57-7.39	3.5-6.47
2050	0.01-10.18	2.8-2.9	2.57-5.08	3.40-16.98	5.79-12.75

Sensitivity analyses

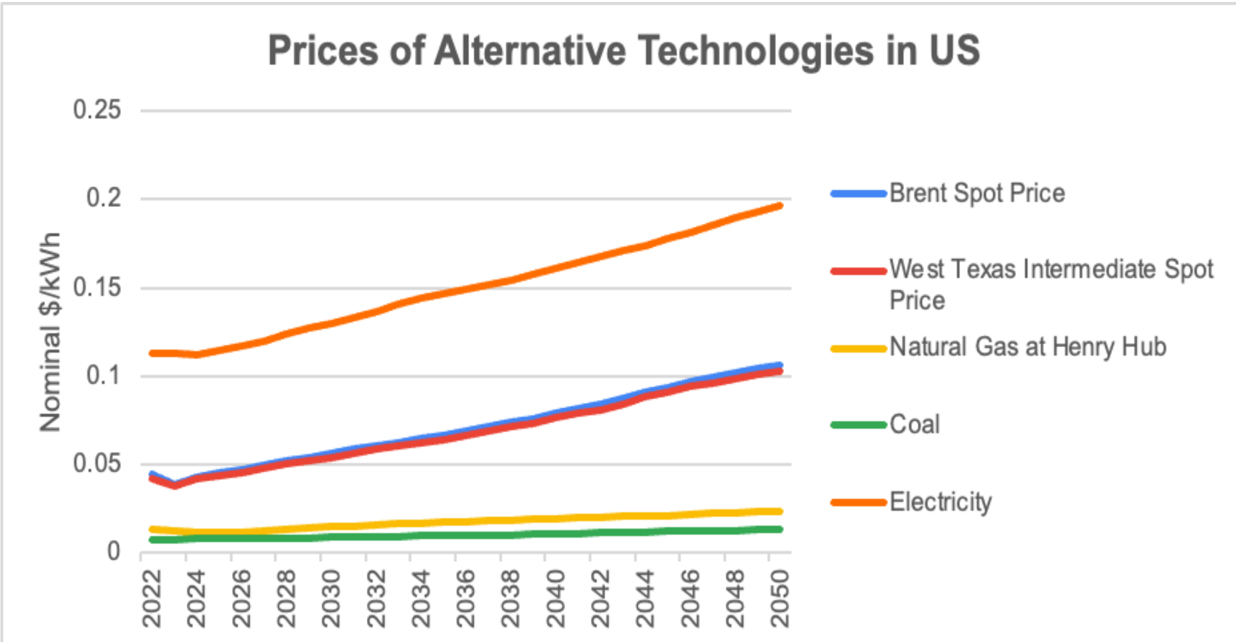
The following figure describes the change in LCOE as a result of varying the cost of electrolyzer, efficiencies, plant utilization rates/capacity factors, and water intensity of hydrogen production. An increase in capacity factor causes a decrease in LCOE for all technologies, with the increase in plant utilization rate causing the highest variation in grey hydrogen (~$1/kg change). Similarly, an increase in electrolyzer efficiency reduces green energy cost and can cause a variation of approximately $1.2/kg change in LCOE. Electrolyzer cost causes only a small change in LCOE because capital investment only forms a small fraction of the cost of green energy. Lastly, water efficiency has a small impact on the overall LCOE for all technologies because industrial water use costs only form a small portion of the overall O&M costs for these technologies.



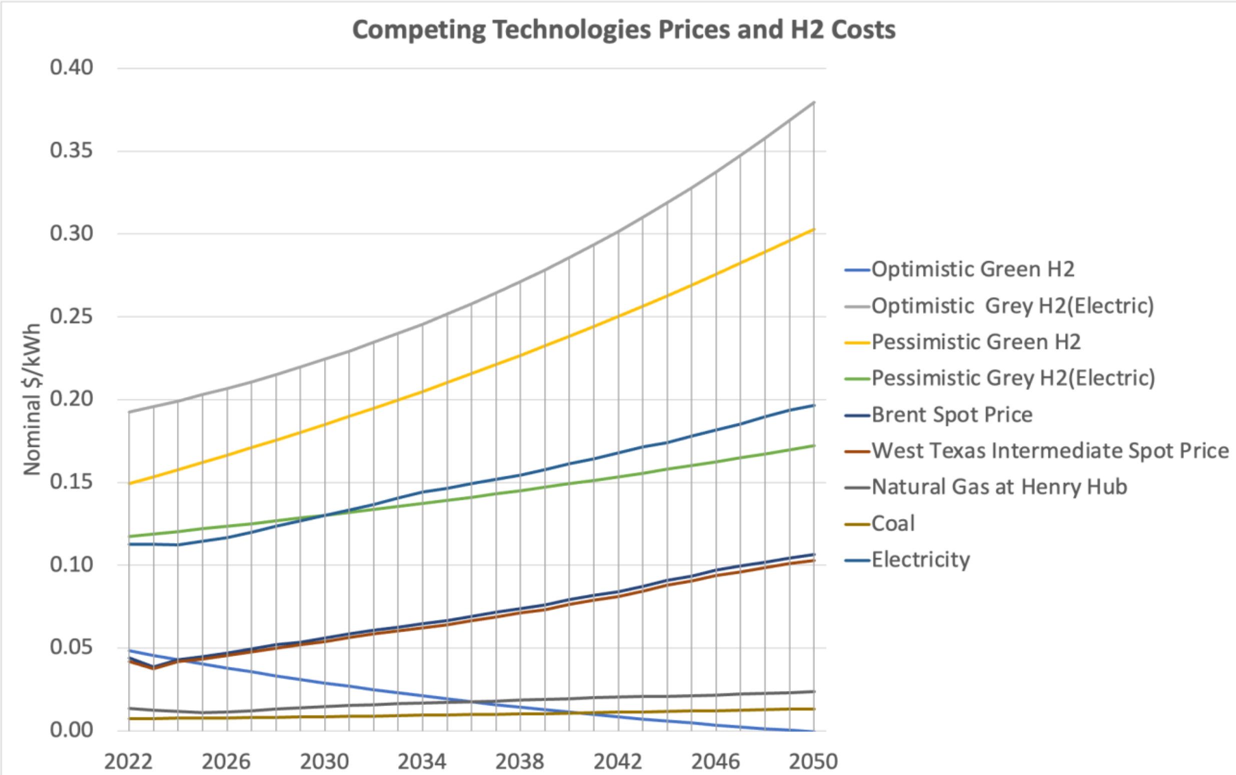
Competing Technologies and Hydrogen Production Costs

This section provides some estimates on competing technologies prices since they play a key role in the adoption of hydrogen gas.[6] The LCOE ($/kg) estimated in this report is converted into hydrogen produced energy cost ($/kWh) for pessimistic and optimistic scenarios for green and grey hydrogen. As can be seen from the following figure, the prices for competing technologies are expected to increase (EIA, 2022), and in some cases double or triple. However, natural gas cost estimates at the moment are comparably low in most cases (~0.01-0.2% growth rate), which is the biggest barrier to entry for hydrogen.

[6] Prices are expressed in nominal dollars. Nominal prices are those that have not been adjusted to remove the effect of changes in the purchasing power of the dollar; they reflect buying power in the year in which the transaction occurred. Data source: "U.S. Energy Information Administration - EIA - Independent Statistics and Analysis." Accessed September 10, 2022. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-aeo2019&cases=ref2019~ref_no_cpp&sourcekey=0.



Green hydrogen does become cost viable under a wide range of policy scenarios as seen in the following figure. However, since the nature of the hydrogen future in the United States is highly dependent on various policy trajectories, it makes it difficult to give a precise estimate of when hydrogen will completely dominate the mainstream industrial fuels market.



Retail price of hydrogen

Retail price of hydrogen is currently driven by the production cost in the United States (KPMG, 2021; NREL, 2022) currently, as demand is too low to drive the market. Most estimates put the retail price of hydrogen between \$2-10/kg H_2, which seems consistent with our analysis of a cost driven estimate. This price is expected to get as low as \$1/kg with various states having set targets of low cost of hydrogen production. Currently, in our analysis, this cost is likely going to be dramatically lowered due to the generous tax credits, depreciation benefits, and carbon tax policies expected over the next few years. These policy fluctuations consistently benefit blue hydrogen which benefits under all policy trajectory in a different way. Considering that with blue hydrogen the feedstock is fairly replaceable between natural gas and electricity, it then becomes even more viable as a clean investment with the best LCOE projections.

Policy Recommendations

The policymakers are currently relying on tax credits to ease the burden of investing in hydrogen technology in the United States. While this is a great idea to kickstart investment in the market, it is not viable for the state to artificially subsidize investment and bear the insurance risk in the long run. Hence, we expect this policy to be limited to a 5-10 year lifespan, given favourable political climate. So the state must look at long term solutions that reduce electricity costs, the main driver of high costs for green hydrogen. This can be achieved through:

- Bringing more renewable powered energy onto the grid like in western interconnection system, which has led to really low (sometimes even negative) electricity costs in states like Washington and Oregon.
- Higher level of decentralization in the electricity market
- Supporting energy storage technology research
- Investment in smart grid technology and electricity transaction markets
- Directly compensating for auxiliary grid benefits in the electricity markets like frequency regulation, blackstart etc. which makes renewable energy much more beneficial to investors

In addition to this, the policymakers should aggressively pursue carbon tax policies informed by the latest social cost of carbon estimates (Social Cost of Carbon, 2022).

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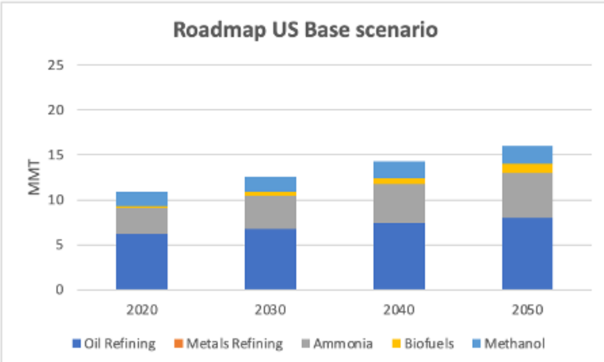
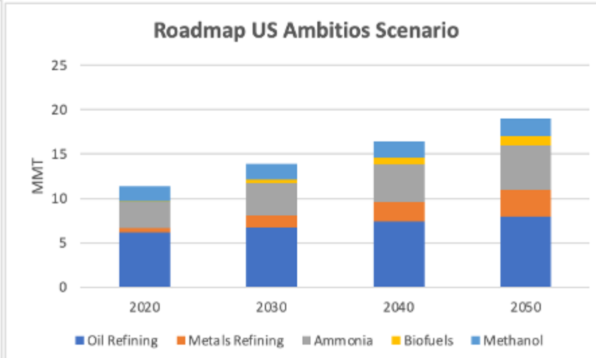
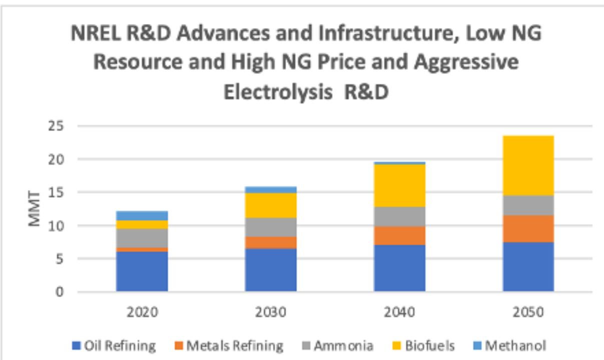
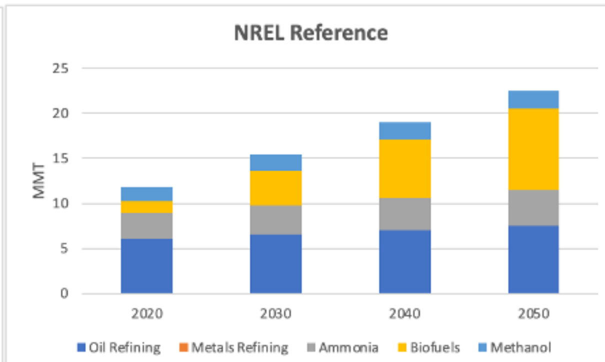
Appendix

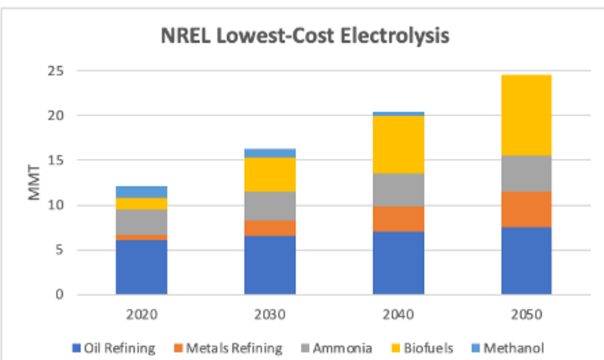
Break Down of Hydrogen Demand by Sector of Industrial Application in the United States



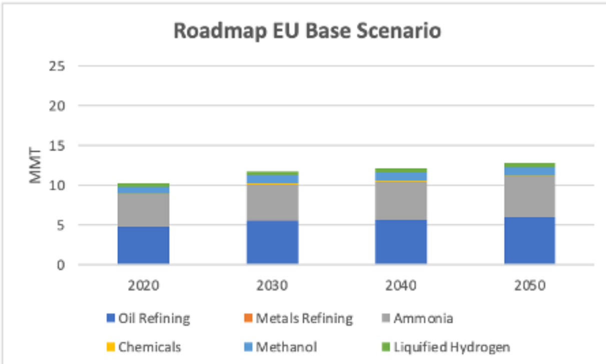


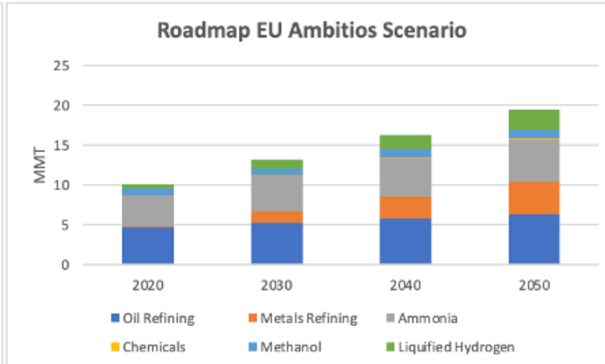






Break Down of Hydrogen Demand by Sector of Industrial Application in the European Union

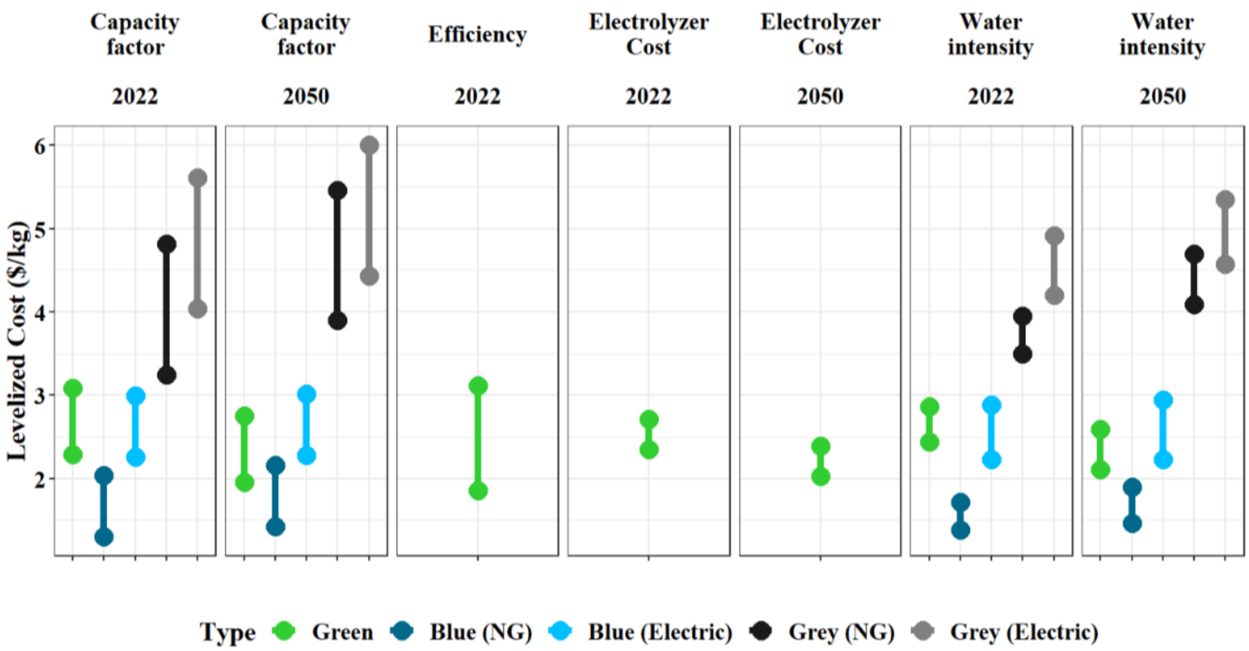




Base Case Assumptions

System Operating lifetime	28
Discount rate	2.00%
Escalation Rates	1.90%
Insurance rate as a fraction of CI_{pv}	2.00%
O&M factor	3%
Federal & state income tax rate	38.9%
MACRs 5-year Depreciation Discount	60.00%
MACRS 20 yr schedule	4%
Energy Cost growth	-0.30%
First year of operation	1
Price Year	0
Water use cost growth	2%
Water drained cost growth	2%
Hydrogen demand market (kg)	15000
Market cap	5%
Energy potential (kWh/kg)	1
Capital investments	3%
Social cost of carbon ($/ton)	51
Natural gas rate growth	0.80%
Increase in SCC	2.60%

Evolution under sensitivity analyses


Capacity factor 2022
Capacity factor 2050
Efficiency 2022
Electrolyzer Cost 2022
Electrolyzer Cost 2050
Water intensity 2022
Water intensity 2050
Levelized Cost ($/kg)
6
5
4
3
2
Type
Green
Blue (NG)
Blue (Electric)
Grey (NG)
Grey (Electric)