Unlocking the Potential of Hydrogen in Intermittent Electricity Systems: A Global Assessment of Levelized Cost of Hydrogen and Low Carbon Industrial Hub Profitability

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ABSTRACT

Recently, numerous countries have announced ambitious hydrogen production targets among clean energy transition objectives, recognizing the potential of hydrogen in decarbonization. However, significant uncertainty remains regarding the cost predictions for hydrogen production and the economic viability of green hydrogen-enabled industrial hubs with higher levels of intermittent renewable energy penetration. This study focuses on assessing the levelized cost of hydrogen generated through polymer electrolyte membrane electrolysis, accounting for regional variations, technology learning, energy intermittency and policy incentives such as those provided by the Inflation Reduction Act. We also evaluate the profitability and market viability of utilizing co-located hydrogen to decarbonize Aluminum and steel production in renewable-powered industrial hubs across various suitable regions worldwide. To accomplish this, we develop a generalizable cost model that identifies the optimal hydrogen production capacity factor and levelized cost of hydrogen under different levels of grid electricity volatility, and construct a regional hour-by-hour prioritized dispatch model to simulate a low-carbon industrial hub primarily powered by wind and solar supported by storage and firming. The results demonstrate that with the regions considered, the levelized cost of hydrogen is consistently high till 2040, but can be reduced to meet the $2/kg production cost target in the coming years through operating capacity optimization and the implementation of policy incentives. Besides, the optimal capacity leading to the lowest levelized cost of hydrogen is negatively correlated with electricity price volatility, highlighting hydrogen's potential as a cost-effective means to absorb fluctuations in grid electricity prices. Moreover, our analysis reveals that for industrial hubs, hydrogen is the most economically viable when integrated with an industry where hydrogen serves both as a material input and as a storage mechanism, as exemplified by green steel manufacturing with the hydrogen-based direct reduced iron-electric arc furnace process. Finally, an analysis on past policies, geopolitical interests, and resource exploitation in developing countries associated with hydrogen highlights additional political and social considerations in hydrogen policymaking from a global development perspective.

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1: Introduction

1.1: Background

1.1.1: A Brief Introduction of Hydrogen

Hydrogen is the simplest and most abundant chemical element in this universe. It exists on the Earth as components of water and organic compounds, from which hydrogen gas can be extracted. Hydrogen gas is primarily used as a feedstock, a catalyst or a hydrogenating agent for chemical production, food and drug production as well as petrochemical and refinery processing (U.S. Department of Energy 2020).

Over time, people have been exploring hydrogen's potential as an energy carrier, which stores and delivers energy produced from other sources. Hydrogen as a fuel has two major benefits: it has the highest energy content per unit of weight and is almost twice as efficient as carbon fuel (Battery University 2020); meanwhile, hydrogen fuel itself has no carbon footprint, as the only by-product of hydrogen is water (Office of Energy Efficiency & Renewable Energy, accessed May 7, 2023). As a result, hydrogen can be a potential replacement of fossil fuel in certain use cases.

Hydrogen can be produced through three processes. The first one is a thermal process, which includes natural gas reforming, coal gasification, biomass gasification, and reforming of renewable liquid fuels. The second one is an electrolytic process, which produces hydrogen through water electrolysis. The third is a solar-driven process, such as photobiological, photoelectrochemical and solar thermochemical processes (Office of Energy Efficiency & Renewable Energy, accessed May 7, 2023).

The overall environmental impact of hydrogen is primarily determined by the carbon emissions during the hydrogen production stage, and therefore in order to receive clean hydrogen, the society need to prioritize less carbon-intense production methods. Hydrogen produced with natural gas, and coal without carbon capture, utilization and storage (CCUS) emits similar amount of carbon dioxide compared with conventional fossil fuel energy sources, but hydrogen produced through electrolysis with renewable powered electricity has negligible life cycle carbon emissions (Ren, Zhou, and Ou 2020). As a result, people classify hydrogen by how its production method:

- Black hydrogen is hydrogen extracted from nature gas using steam-methane reforming (SMR). SMR is an endothermic hydrogen production process, where methane reacts with high-temperature steam (700°C–1,000°C) under 3-25 bar pressure to produce hydrogen, with CO_2 as a byproduct. Black hydrogen can also refer to hydrogen produced by steam reformation from ethanol, propane and gasoline. This is sometimes also called Grey hydrogen.

- Brown hydrogen is hydrogen produced using gasification from fossil fuels, usually coal, under high temperature (480°C –1,650°C) with limited oxygen. The gasification process decomposes the volatile components of an organic substance, and coverts the remaining non-volatile carbon char to syngas. CO_2 is emitted during the process.

- Turquoise hydrogen is hydrogen generated through methane pyrolysis, which is the thermal decomposition of methane under high temperature (480°C –1,650°C). The carbon byproduct of this process is solid carbon instead of CO_2, and therefore it is considered cleaner than black and brown hydrogen.

- Blue hydrogen is black or brown hydrogen with emitted CO_2 sequestered or repurposed with carbon capture, utilization and storage (CCUS) technologies. Therefore, blue hydrogen has overall zero carbon emission.

- White hydrogen is hydrogen produced as a byproduct of industrial processes.

- Green hydrogen is hydrogen produced by electrolysis with energy generated from renewable sources, such as hydropower, wind and solar. Green hydrogen also does not emit CO_2 throughout its life cycle.

- Yellow hydrogen is hydrogen produced via electrolysis using grid electricity, and thus usually has carbon footprint. In some sources, yellow hydrogen refers to hydrogen generated through electrolysis using solar power.

- Pink hydrogen is hydrogen produced via electrolysis using nuclear power, which does not have a carbon footprint (Roeth 2021; National Grid Group, accessed May 7, 2023).

There is yet an international consensus on the typology of hydrogen. The aforementioned “color wheel” is respected more as a convention than a standard, and the color representation of certain hydrogen methods, such as hydrogen produced by electrolysis with grid electricity and with nuclear energy, is subject to dissent.

On February 13, 2023, the European Commission adopted two Delegated Acts as required under Article 27(3) of the *Renewable Energy Directive (2018/2001)* defining what constitutes renewable hydrogen, or green hydrogen, for the European Union. The definition requires that green hydrogen can only be produced from “additional” renewable electricity generated “at the same time and in the same area as their own production” (European Commission, accessed May 7, 2023).

The United States government has not published any official documents classifying hydrogen based on its production method. However, it uses the carbon emission intensity of the hydrogen produced to qualify it with tax credit categories (Inflation Reduction Act 2022). More details can be found in *Section 3.2.11*.

1.1.2: Three Electrolysis Technologies

In order to produce cost-effective clean hydrogen, electrolyzers need to work efficiently with intermittent renewable energy sources such as wind, solar, and hydropower. Starting from 2007, when the feasibility of electrolysis via wind was successfully established by the collaborative effort between the National Renewable Energy Laboratory (NREL) and Xcel Energy, scientists and engineers have been trying to improve electrolyzer technologies in order to increase efficiency, capacity, and compatibility while decreasing capital and operation costs (U.S. Department of Energy 2007). Currently, there are three kinds of electrolyzers: alkaline electrolyzer, polymer electrolyte membrane (PEM) electrolyzer, and solid oxide electrolyzer.

Alkaline electrolysis operates via transport of hydroxide ions (OH^-) from the cathode to the anode of the electrolyte, which is a liquid alkaline solution of sodium or potassium hydroxide and generates hydrogen on the cathode side (Calise et al. 2019). It is the most widely applied among the three electrolysis technologies, because of its low upfront cost, high technology maturity and economic competitiveness. Alkaline electrolyzers requires the lowest capital cost because the materials are relatively inexpensive (Ruth et al. 2017). In addition, as alkaline electrolyzers have been in the market for decades, they have demonstrated long-term operational feasibility and technological reliability (Ruth et al. 2017). Moreover, given that alkaline electrolyzers are able to operate in large-scale capacity units, and can deliver up to 60 kg/h of hydrogen, it exhibits higher economic viability in comparison to the other electrolysis processes (Mayyas & Mann 2018; Dincer & AlZahrani 2018).

However, there are a few limitations of alkaline electrolysis. To begin with, alkaline electrolyzers require low partial load range (20% – 40% minimum load), low operating pressure and low operating current density (~700mA/cm^{-2}) (Ruth et al. 2017; Dinh et al. 2023). The inflexibility in load-following operation limits alkaline electrolysis' potential in green hydrogen production, as many renewable energy sources, such as solar and wind, are subject to intermittency (Ruth et al. 2017). Besides, many current alkaline electrolyzers use asbestos as a separator diaphragm between cathode and anode, a toxic chemical banned by certain countries such as France. Substitute materials are being explored but most of them are still in laboratory stages (Dincer & AlZahrani 2018).

PEM electrolysis generates hydrogen at the cathode with a different process. Water is split into oxygen, hydrogen protons and electrons at the anode, and the hydrogen protons travel via a proton conducting membrane to the cathode, where the protons and electrons re-combine to produce hydrogen. Different from Alkaline electrolyzers, PEM electrolyzers are able to operate under highly dynamic conditions as well as have good partial load range (0 – 10% minimum load), high current densities and high-voltage efficiency, which makes PEM electrolysis a more desired option for green hydrogen production, especially as off-peak energy storage (Kumar & Himabindu 2019; Ruth et al. 2017; Dinh et al. 2023).

There are several drawbacks of PEM electrolysis. PEM requires high-value materials such as platinum, which increases the capital cost of PEM electrolyzers. Besides, PEM electrolyzers may have low durability, an unknown risk as the technology hasn't been in the market for long enough to verify this. Moreover, PEM electrolyzers have smaller production capacities, which limits the amount of hydrogen that can be produced on a daily basis (Kumar & Himabindu 2019; Ruth et al. 2017).

Solid oxide electrolysis is still being tested in the lab and in the market, but it is a promising technology that produces hydrogen with the highest efficiency. With solid oxide electrolysis, water at the cathode forms hydrogen gas and negatively charged oxygen ions, and the oxygen ions pass through the solid ceramic membrane to form oxygen. Solid oxide electrolysis can only be operated under high temperature (700°C – 800°C), which is a big constrain of the deployment of this technology, alongside with its potential low durability and bulky system design. Moreover, due to the lack of market data, the cost reduction prediction of solid oxide electrolyzers in general lacks reliability (Taroco et al. 2011).

1.2: Current Hydrogen Policies

Since its discovery in the 19th century, hydrogen has experienced waves of government attention as a clean energy source, but the industry has never really taken off (Zubrin 2007). In the second half of the 2010s, hydrogen regains tractions from many governments led by Japan, and the development center of hydrogen sets stage in Europe. The first two international organizations established during the most recent wave are in Belgium (Important Projects of Common European Interest, IPCEI, 2015) and Switzerland (Hydrogen Council, 2017). With the announcement of the new *European Industrial Strategy* in March 2020, the European Commission also rolled out the Clean Hydrogen Alliance, a collaboration platform aiming at decarbonizing industry and maintain European industrial leadership.

According to IRENA's Green Hydrogen Policy Report (2020), national strategies of such novel and potentially pivotal technologies are set through four steps: R&D programs, vision documents, roadmaps, and strategies. Between June 2018 and November 2020, 12 countries and regions have published national hydrogen policies, which are the European Union, France, the Netherlands, Norway, Germany, Portugal, Spain, Finland, Australia, Chile, Japan and South Korea (IRENA 2020b). By February 2021, Poland and Italy had published draft strategies, and 11 countries, which are the UK, Austria, China, Estonia, Luxembourg, Morocco, Oman, Paraguay, Russia, Slovakia and Sweden, have strategies in preparation, with the UK planning to announce its hydrogen strategy in Q1 of 2021 (J.P.Morgan CAZENOVE 2021). Meanwhile, South Korea, Japan and Russia have published hydrogen roadmaps, and the European Union, New Zealand, Canada, Portugal and the state of California have published vision documents (IRENA 2020b). By October 2021, over 30 countries in all continents have developed or are the in the process of developing hydrogen strategies (IRENA 2023a).

European Union's Hydrogen Strategy marked a milestone of this round of hydrogen strategy race, especially on green hydrogen. In its hydrogen strategy, EU announced an unprecedented ambitious target of establishing 40 GW of electrolysis capacity in Europe, and another 40 GW in Europe's neighborhood countries that export to the EU, which in total makes up 80% of current announced targets for electrolyzer deployment. Seventy percent of the stated long-term intra-Europe green hydrogen capacity plan has been supported by hydrogen policies of individual countries (J.P.Morgan CAZENOVE 2021). In addition to goal setting, the EU hydrogen strategy also outlines detailed trajectories for technological development, quality and standardizing, economic and market stimulation, finance and investment support, private sector engagement, market regulation, industry sector prioritization, infrastructure construction and integration, and international cooperation (European Commission 2020).

The US hydrogen efforts didn't catch speed until 2020, when 3 policy documents were announced: *Hydrogen Strategy: Enabling A Low-Carbon Economy* by the Office of Fossil Energy, *Integrated Energy Systems: 2020 Roadmap* by the Office of Nuclear Energy, and *The Department of Energy Hydrogen Program Plan*. One potential reason for such a lag was the Trump administration's intentional deemphasis of the development of the clean tech sector. The U.S. hydrogen policy gradually picks up speed with specific development, market, regulatory and investment goals as in the EU hydrogen strategy after Biden's inauguration (U.S. Department of Energy 2020; U.S. Department of Energy, accessed May 7, 2023a). The Inflation Reduction Act (IRA) passed in 2022 provides aggressive tax credits to award hydrogen produced with clean energy sources (Inflation Reduction Act 2022), and on March 15th, 2023, the Biden-Harris administration announces $750 million to address technical challenges of clean hydrogen production that cannot be overcome by scale alone together with U.S. Department of Energy (DOE)'s Hydrogen and Fuel Cell Technologies Office (FHTO) (U.S. Department of Energy, accessed May 7, 2023a; Inflation Reduction Act 2022). Ultimately, U.S. government aims to achieve $1/kg hydrogen within a decade with the support of favorable policies, incentives, and regional clean hydrogen hubs (H2Hubs) (U.S. Department of Energy, accessed May 7, 2023b).

Asia and Australia are "early movers" on hydrogen policy (J.P.Morgan CAZENOVE 2021). In 2017, Japan already adopted a hydrogen strategy, followed by South Korea, New Zealand and Australia in 2019. In addition, instead of setting individual strategies for each country, the Asian strategies formed an interconnecting ecosystem, in which Japan and South Korea focus more on hydrogen demand, usage and technologies with imported hydrogen, and Australia and New Zealand emphasize more on hydrogen production and exporting given their abundant renewable energy resources and carbon capture potentials (J.P.Morgan CAZENOVE 2021). Japan and South Korea are also ambitious on for fuel cell vehicle growth targets. Owning about 40,000 fuel cell passenger cars and 160 refueling stations currently, highest value worldwide, Japan plans to increase these numbers to 200,000 and 320 respectively by 2025, 800,000 and 900 respectively by 2030, and prevail by 2040. South Korea aims to achieve 310 refueling stations by 2025, and 5.26 million hydrogen fuel cell passenger cars and over 2000 refueling stations by 2040, in addition to a hydrogen production target of 3 million tons. China targets at 50,000 fuel cell cars by 2025, and an annual electrolyzer capacity of 0.1-0.2 Mt (IPHE, accessed May 8, 2023).

Other regions, such as the Middle East, North Africa, South America, Canada and Russia, have also rolled out tentative hydrogen development plans, many times with international cooperation and trading incorporated. Saudi Arabia plans to produce hydrogen with nature gas, wind and solar power, the predicted capacity of the latter two are estimated to be 16 GW and 40 GW respectively by 2030. According to Bloomberg's estimation, the market size of hydrogen in Saudi Arabia would reach $700 billion by 2050 (Ratcliffe 2021). North Africa expects to expand its renewable energy output for hydrogen production to 120 GW by 2030, 70 GW among which is wind (van Wijk et al. 2019). Canada produces hydrogen with mainly fossil fuel via SMR and it plans to produce over 20 Mt of low Cl hydrogen annually by 2050 (Canada's Minister of Natural Resources 2020). Russia focuses primarily on producing hydrogen with nuclear power, with the goals of exporting 0.2 Mt of hydrogen to Europe by 2024, and 2 Mt of hydrogen by 2030 with hydrogen produced in its North-Western cluster (St. Petersburg and Leningrad region). Hydrogen produced from the Easter cluster (Sakhalin region) is planned to be exported to the

Asia-Pacific region, and that produced in the Arctic cluster (Siberian Northwest) will be used on autonomous hydrogen power supplies (Frolov & Kalinin 2021). Nevertheless, the war on Ukraine since 2022 may have severely jeopardized Russia's hydrogen plan as the geopolitical landscape between Russia and the European Union has shifted drastically (Patonia 2022).

1.3: Cost of Hydrogen Production

1.3.1: Existing Hydrogen Product Cost Anticipations

In order to make hydrogen competitive in the energy market, cost of hydrogen needs to be below a certain threshold. Several market reports have shown that in many regions, green hydrogen can be below $2/kg after 2030, which along with carbon taxes allows green hydrogen to be market competitive.

The U.S. DOE announces that the target for hydrogen produced with PEM electrolyzers in 2026 is $2/kg, and the ultimate target is $1/kg, set to be achieved by 2031 (U.S. Department of Energy, accessed May 7, 2023b). The recently passed IRA gives US domestic hydrogen producers tax credits based on the greenhouse gas (GHG) intensity of the hydrogen produced, providing up to $3 per kg of hydrogen produced if the GHG emission level is lower than 0.4kg CO_2e/kg H_2 as shown in *Table 1*. This policy lever could potentially lower the hydrogen LCOH with both time limited tax deduction and an increase in overall market supply (U.S. Department of Energy, accessed May 7, 2023b).

CHARACTERISTIC	UNITS	2022 STATUS[C]	2026 TARGETS	ULTIMATE TARGETS
Stack				
Total Platinum Group Metal Content (both electrodes combined) [d]	mg/cm^2	3.0	0.5	0.125
	g/kW	0.8	0.1	0.03
Performance		2.0 A/cm2 @ 1.9 V/cell	3.0 A/cm2 @ 1.8 V/cell	3.0 A/cm2 @ 1.6 V/cell
Electrical Efficiency [e]	kWh/kg H_2 (% LHV)	51 (65%)	48 (69%)	43 (77%)
Average Degradation Rate [f]	mV/kh (%/1,000 h)	4.8 (0.25)	2.3 (0.13)	2.0 (0.13)
Lifetime [g]	Operation h	40,000	80,000	80,000
Capital Cost [h]	$/kW	450	100	50
System				
Energy Efficiency	kWh/kg H_2 (% LHV)	55 (61%)	51 (65%)	46 (72%)
Uninstalled Capital Cost [h]	$/kW	1,000	250	150
H_2 Production Cost [i]	$/kg H_2	>3	2.00	1.00

Table 1 Targets for different parameters for PEM electrolyzers by US DOE

The European Union targets at the cost of green hydrogen being below $2/kg by 2030 (J.P.Morgan CAZENOVE 2021). Canada believes that a production cost of $1.18 – 2.76/kg is achievable (J.P.Morgan CAZENOVE 2021). Australia aims to reduce hydrogen cost to $1.55/kg (J.P.Morgan CAZENOVE 2021). Chile targets at a cost of $1.5/kg (J.P.Morgan CAZENOVE

2021). South Korea, on the higher end due to the need for shipping, believes that a cost of $2.71/kg is viable by 2040 with an annual supply of 3.5 million tons (J.P.Morgan CAZENOVE 2021). The Netherlands does not specify a cost value target for hydrogen, but envisions that the cost of green hydrogen will be competitive against black or brown hydrogen between 2030 – 2035 (J.P.Morgan CAZENOVE 2021).

Industrial players have more bullish prediction on the future cost of hydrogen. Norwegian electrolyzer producer Nel ASA announced in January 2021 that the company would be able to produce green hydrogen at $1.5/kg by 2025. Malaysia oil and gas company Petroliam Nasional Bhd. targets to produce hydrogen at the cost between $1/kg and $2/kg with the country's hydropower and solar power (DiChristopher 2021).

1.3.2: Calculating Cost

The metric used most often to understand the cost competitiveness of generating a certain type of energy is the levelized cost of energy (LCOE) (Musi et al. 2017). LCOE includes all of the costs over an energy system's lifetime (e.g., initial investment, operating costs and other capital costs) divided by the amount of energy output produced over its lifetime. LCOE is the price that the energy must be sold for in order to breakeven on the project (NREL, accessed May 7, 2023). Similarly, the levelized cost of hydrogen (LCOH) is a metric used to compare the different types of hydrogen processing methods. LCOH is estimated using a standard discounted cash flow rate of return methodology to inform the breakeven price of hydrogen (Ramsden, Steward and Zuboy 2009). In addition, some studies use different metrics to quantify the cost of hydrogen. Li et al. (2017) used life cycle cost (LCC) for hydrogen production cost calculation, which considered the cost over the lifetime of a project. Oliva and Garcia (2022) used the annualized cost of hydrogen (ACOH), the production cost of hydrogen with annualized CAPEX and annual OPEX per volume of hydrogen generated, in their study.

Unfortunately, regardless of methods, there is large variation in the reported hydrogen production cost values across literature largely due to differences in the type of hydrogen electrolysis technologies, the choice of electricity sources, and geographic differences. Li et al. (2017) summarized previous techno-economic analysis of electrolysis generated hydrogen and found that the cost of hydrogen ranged from $1.21/kg to $24.0/kg between 2006 and 2015 in a variety of different countries. Their LCC analysis resulted in hydrogen costs less than $1.5/kg in China. Tang, Rehme and Cerin (2022) found that hydrogen in Sweden could cost between 71 and 153 SEK/kg ($6.89/kg – 14.86/kg with exchange rate on March 27, 2023) if generated by off-grid renewables, and between 35 and 72 SEK/kg ($3.4/kg – $6.99/kg) if generated with on-grid electricity. Yang et al. (2023) showed that hydrogen cost can differ by electrolysis technology, lifetime, and current density, and the costs of hydrogen generated in China were between 15.19 and 39.91 RMB/kg ($2.20/kg – $5.77/kg with exchange rate on March 27, 2023) in reference cases and much lower if ohmic losses, electricity prices, catalyst mass, initial potential, end potential, and other relevant costs could be significantly reduced. Glenk and Reichelstein (2019) revealed that hydrogen cost was at least €3.23/kg ($3.57/kg with exchange rate on March 27, 2023) in Germany and at least $3.53/kg in Texas. Findings by Oliva and Garcia (2022) showed that hydrogen cost could be somewhere between $2.2/kg and $4/kg depending on the location of the electrolyzer and the variation of the electricity prices.

Researchers have also performed sensitivity analysis on the factors that could lead to hydrogen cost variation. Analysis by J.P. Morgan demonstrated that the major costs for green hydrogen were electricity price and capital, which were roughly estimated at a price of $30/MWh and $750/kW respectively (J.P. Morgan CAZENOVE 2021). If electricity price could come down to $15/MWh and electrolyzer costs could be reduced to $500/kW, the LCOH could be reduced to approximately $2.2/kg. In addition, the utilization and scale could also affect cost significantly. For instance, one report estimated that a 15% drop of utilization from 50% could increase the LCOH by 16% (J.P.Morgan CAZENOVE 2021). Another study indicated that reducing operating hours to 6200 from 8400 hours a year could save around 3% of LCOH (Mansilla et al. 2013). Jørgensen and Ropenus (2008) learned that reducing operating hours can reduce LCOH in Denmark. Their study revealed that the optimal hydrogen operating hours were lower in cases where the power source exhibited higher volatility due to a high penetration of wind power and lower capital investment (Jørgensen and Ropenus 2008). Furthermore, mixing electricity generation source may also reduce hydrogen production cost. Armijo and Philibert (2020) found that in Chile and Argentina, hybridization of wind and solar power can reduce hydrogen production costs by a few percent thanks to the increase in load factor. Oliva and Garcia (2022) demonstrated that the integration of grid electricity and renewable energy sources contributed to lowering ACOH in Chile, and an electricity market with variable electricity cost based on locational marginal pricing (LMP) could decrease ACOH by up to 10.5%. Moreover, higher automation levels, cheaper raw materials, larger electrolyzer projects and modular construction could all lead to cost reductions (BloombergNEF 2020).

In most of the peer reviewed literatures, the current cost of hydrogen production is higher than what is needed for a hydrogen economy to take place. The enormous variation of hydrogen cost depending on technology, material, location, electricity source, utilization rates, calculation methodology and operating year makes hydrogen cost prediction and cost target setting extremely difficult.

1.3.3: Challenges of Hydrogen Production Cost Prediction

Governments are dependent on reliable hydrogen cost predictions in order to set achievable reduction goals. However, is it not a trivial task to predict the cost of hydrogen in the next decade. Different parameter assumptions and methodologies, uncertainties of technology learning from investment and regulations, changing carbon policy and biases make cost prediction a challenging task. Cost predictions based on inaccurate assumptions may potentially misguide policy decisions.

Different Parameter Assumptions and Methodologies

The cost of hydrogen is highly sensitive to parameter assumption. Capital investment, operations cost, interest rate, discount rate, debt-to-equity ratio, water requirement, electricity cost, labor demand and land cost assumptions all impact the resulting cost of hydrogen production, and meanwhile, there is gap in academia regarding the relative importance of these parameters on the production cost of hydrogen. Jørgensen and Ropenus (2008) observed that many literatures did not include the expenses for construction, property and installation into LCOH calculation. As most researchers agree that CAPEX is an important component to LCOH alongside with operation capacity factor and electricity, CAPEX assumptions ranged from \$25/kg to \$900/kg depending on location, time of construction, availability of data and assumptions made (Jørgensen and Ropenus 2008; Hornby 2021; J.P. Morgan CAZENOVE 2021; Tang, Rehme and Cerin 2022). Oliva and Garcia (2022) declared that water cost was not a major cost and therefore did not include it in the cost calculation. Interest rate, discount rate and debt-to-equity ratio also vary across literatures under different scenario assumptions.

The scope of hydrogen cost analysis also differs from study to study, which makes it difficult to compare LCOH in different regions. For example, studies feature different types of hydrogen production (e.g., central vs. distributed), varying analysis boundaries (e.g., hydrogen production vs. well-to-tank of a hydrogen refueling station) and differ on whether or not they include hydrogen storage and transportation costs in addition to production costs (Viktorssonet et al. 2017; Misra 2022). Many of these studies are also focused on a single region and vary in assumptions around capital and operating costs, electricity price variation, and technology learning over time (Mansilla et al. 2013; Glenk & Reichelstein 2019; Jorgensen et al. 2008; Armijo & Philibert 2020). As a result, a modeling methodology is needed that is able to capture regional variation and test different learning assumptions to allow horizontal comparison across different regions under different development scenarios.

Furthermore, studies examining the optimal operating capacity of electrolyzers and its impact on the lowest LCOH have utilized varying scopes and methodologies. These studies have employed both probabilistic modeling and empirical analyses to gain insights into how the capacity factor of an electrolyzer affects the cost of hydrogen, as well as the potential cost savings achievable through capacity optimization (Jørgensen and Ropenus 2008; Mansilla et al. 2013; Oliva et al. 2023). However, it is important to note that these analyses have been conducted in different geographical regions, during different years, and with different cost calculation methodologies. Consequently, the divergent nature of these factors makes it challenging to draw definitive conclusions regarding the primary causes of variations in optimal capacity factor, the magnitude of cost savings, and how optimal operating hours change over time with technological advancements and learning.

Uncertainties of Technology Learning from Investment and Regulations

With insufficient historical data and changing investment landscape, favorable policies and industry regulations, is it difficult to predict the technology learning rate that impacts the future cost of capital investment.

Technology learning is a concept that captures technological progress and how technology costs fall over time due to this progress. Moore's law is one method to capture this learning where costs are assumed to decrease exponentially with time. This law was first developed for transistors in integrated circuits (IC) in 1965 since the number of transistors was doubling every two years (Jovanovic and Rousseau 2002). Many studies that assess technological progress incorporate Moore's law to understand cost changes over time. For instance, Nagy et al. (2013) evaluated 62 technologies and assessed how well various laws predicted future costs. Their analysis revealed that while Wright's law had the best forecast results with the assumption that cost decreases based on the level of effort invested, Moore's law was the next best in terms of forecasting costs.

Studies of hydrogen production technology learning have been performed for steam methane reforming (SMR), electrolysis, and coal gasification. Schoots et al. (2008) found limited learning in these technologies with a learning rate of 11+/-6% for SMR and 18+/-13% for electrolysis. BloombergNEF (2020) believed that the learning rate was 18% with an error margin of +/-6%. IRENA (2020) has reported that learning rates for hydrogen electrolyzers will be similar to current solar PV in the range of 16-21%, whereas another study found that hydrogen electrolysis with solar thermochemical cycles will have faster learning and therefore more cost reductions than traditional solar photovoltaics (Nicodemus 2018). Further, there are different types of electrolysis technologies including alkaline, PEM, and solid oxide. While alkaline is a mature technology at the commercial scale, PEM and solid oxide are expected to have opportunities for learning and cost reductions over time (Saba et al. 2018). In addition to lower costs from technology improvements, economies of scale are another means for cost reduction in hydrogen technologies. PEM technology research has found that 1,000 units of 1 MW per year results in a 50% cost reduction in stack manufacturing (IRENA 2020a). To achieve cost parity with other energy technologies, hydrogen electrolyzer manufacturers must continue to improve the efficiency of the manufacturing and design process at a large scale (e.g., improve energy efficiency) and increase the lifespan of the technology. Unfortunately, due to the difference in technology and technical complexity, the development paths of other technologies may not be appropriate references to estimate the learning rate of hydrogen electrolysis.

Changing Carbon Policy

Besides, carbon pricing and environmental regulation may also significantly impact the cost competitiveness of emission free hydrogen, but it is usually hard to predict the future carbon pricing in different geographic regions due to changing policy and geopolitical landscapes. Different studies provide a range of carbon prices that could satisfy the cost competitive condition, for instance, J.P. Morgan declares that a carbon price at \$71/t CO_2 and above could make blue hydrogen cheaper than brown or black hydrogen, while that price from BNEF is estimated to be between \$67 and \$109 (J.P.Morgan CAZENOVE 2021). To put these numbers with perspective, the current EU Emission Trading System (ETS) carbon pricing has been fluctuating between 90 and 105€100/t CO2 in the last few months, while many countries do not have a carbon tax or an emission trading system in place (Trading Economics, accessed May 13, 2023; World Bank, accessed May 13, 2023). The targeted carbon prices, therefore, are achievable but expensive, and may be extremely challenging in some regions.

Moreover, in order to make green hydrogen cost competitive against natural gas, a much more aggressive carbon price is probably needed. Currently, natural gas price is significantly cheaper than hydrogen per energy unit produced, and it will still be one-third of hydrogen cost by 2030, \$2.86 - \$9.20/MMBtu and \$6.23 - \$25.10/MMBtu respectively (Tengler, Brandily and Wang 2021). As BNEF concludes, "carbon prices at levels much higher than the one that can be currently observed on the EU ETS would be required for a \$2/kg H_2 to be competitive with the cheapest fossil fuels in use today for industrial applications (BloombergNEF 2020)."

Biases in Predictions

As mentioned earlier, the current cost of hydrogen, especially green hydrogen produced with primarily clean energy, is too high for it to be widely applied in downstream demand use. Hydrogen produced with renewable electrolyzer costs from \$3/kg to \$6.55/kg in Europe, and from around \$6/kg to \$13/kg in the US (European Commission 2020; U.S. Department of Energy 2020). Many predictions are made to justify how these costs can drop to below \$2/kg, but very few of them are backed by sufficient empirical evidence.

Many hydrogen cost predictions are produced by market players that have the incentive to advocate for a more optimistic hydrogen future, which may lead to biased prediction results. Aside from policy documents developed by governments, most of the widely-known hydrogen cost predictions are published by industries that have a stake in developing a hydrogen economy. In consequence, these industry estimates tend to be overly optimistic. For instance, BNEF's 2020 report predicted that the capital cost of hydrogen outside of China could fall from \$1,200 in 2018 to \$600 in 2022. A year later, updated data showed that the capital cost of hydrogen was \$1,000 in 2021, missing the prediction by 67%. This implies a large discrepancy between prediction and reality and should alarm policy makers who rely on predictions for policy making (BloombergNEF 2020; Tengler, Brandily and Wang 2021).

Geographic diversity enhances the complexity of hydrogen cost prediction with differences in labor, construction, water, land and electricity costs. Besides, transportation and storage costs, which can vary significantly depending on distance and transportation method, are often times not included in the overall hydrogen cost analysis. In Japan and South Korea, where hydrogen needs to be imported from other countries in liquified form or in the form of ammonia, the actual cost of hydrogen should include the conversion cost of \$0.9-2.4/kg and transportation cost of \$0.5/kg in addition to the cost of hydrogen production (J.P.Morgan CAZENOVE 2021).

As a result, although many analysts are optimistic about the future cost of green hydrogen, others believe that in the near term, green hydrogen would remain expensive, and therefore won't be widely accessible (J.P.Morgan CAZENOVE 2021). As of now, among the 75 million metric tons (MMT) of global hydrogen annual production, only 4% is produced using electrolysis and the rest is produced from natural gas (47%), coal (27%) or oil as a by product (22%) (IRENA, 2023a). In the United States, among the 10 MMT annual hydrogen production, 99% is generated from fossil fuels, with 95% by SMR from natural gas and 4% via coal gasification. Only 1% is produced from electrolysis (U.S. Department of Energy 2020). In the future, green hydrogen may still not consist a large proportion of total hydrogen produced worldwide. IEA predicts in the *Energy Technology Perspectives 2017* report that by 2050, fossil fuel will still be the primary energy and material source for hydrogen in several hydrogen production regions, with 75% fossil fuel for the United States, 65% for Europe, and 85% for Japan (IEA 2017).

1.4: Sector Coupling: Hydrogen, Storage and Metal Production

The industrial sector is the leading consumer of hydrogen, and therefore demands clean hydrogen for decarbonization, especially for the hard-to-abate sectors where alternative solutions are more expensive, such as heavy industry and seasonal storage (IRENA 2023a; 2023b).

Researchers and industry members are exploring ways of coupling hydrogen with industry to achieve cost-efficient decarbonization goals, as high cost of hydrogen may be offset by its decarbonization potential.

1.4.1: Low Carbon Industry Hubs with Hydrogen

A variety of low carbon industry hubs are planned around the world. Some of them are carbon capture and storage (CCS) focused, and the others are hydrogen based. Many governments have committed financial resources to support carbon capture, utilization and storage (CCUS) technologies for industry hubs. For instance, the Norwagian and UK governments have provided subsidies to stimulate the planning of industry hub decarbonization projects, and the Netherland and Denmark have also committed to support emission reduction targets with carbon removal technologies (Remslie 2021). A variety of CCUS based industry hubs are under planning or during construction, including Northern Lights and the Longship Project in Norway, Net Zero Teeside in UK, Porthos of Rotterdam in the Netherlands, Alberta Carbon Trunk Line (ACTL) in Canada, and more (Remslie 2021; Net Zero Teesside 2023; Porthos 2022; Wolf Midstream, accessed May 5, 2023).

Meanwhile, Australia, US and UK governments have committed resources and policy support for low carbon industry hubs with green hydrogen production. Clean Energy Innovation Park (CEIP) is Australia's first commercial scale green hydrogen supply chain that is connected with Clean Energy Innovation Hub (CEIH) (Kachel 2020). In west Australia, the Western Green Energy Hub is a $100 million project that plans to product 3.5 million tons of green hydrogen and 20 million tons of green ammonia annually (Lewis 2021). In Spain, the Green Hysland aims to deploy a fully functioning hydrogen ecosystem in Mallorca, Spain, the first hydrogen hub in Southern Europe and a demonstration project in Europe on the decarbonization of island economies (GreenHsyland 2022).

In addition, a few regions in the world are planning on creating green steel hubs to develop industry clusters supporting the decarbonization of steel manufacturing. The Middle East and North Africa (MENA) region is identified as one of the key regions because of the availability of high-grade iron ore supply, existing direct reduced iron (DRI) supply and its potential of creating green hydrogen from renewable energy resources (IEEFA, accessed May 5, 2023). In Oman, Jindal Shadeed, Hydrogen Rise and Sohar Port and Freezone (SOHAR) have signed an agreement on potentially construct a green hydrogen plant in Sohar to decarbonize Jindal Shadeed's steel manufacturing (Biogradlija 2022). Moreover, The European Commission has also pledged to support the decarbonization of the steel industry. In the UK, the South Wales Industrial Cluster (SWIC) and Zero Carbon Humber (ZCH) are pioneering the green steel industry hubs (Bone 2023). In Germany, the government has allocated €5 billion on decarbonizing the industrial sector between 2022 and 2024, and over €8 billion on large-scale hydrogen projects across the steel, chemical and transport industries (Bone 2023). The Clean Hydrogen Coastline network in the Netherlands is part of the Important Projects of Common European Interest (IPCEI) program, which involves steel manufactures who try to ensure sufficient hydrogen availability for low carbon steel manufacturing (Bone 2023). In Sweden, steelmaker, iron ore producer and power generator are cooperating under government funding to support its hydrogen ironmaking project (Bone 2023).

1.4.2: Green Steel Production with Hydrogen

Steel manufacturing produces a significant amount of carbon emissions. 73% of the world's steel is produced with the coal-coke based blast furnace-basic oxygen furnace (BF-BOF) route, which is a carbon intense procedure that emits over 1.8 tons of CO2 per ton of steel produced (Shahabuddin, Brooks and Rhamdhani 2023). Overall, the Iron and steel making industry accounts for 8% of the global energy demand and around 7% of the global carbon emission (Hornby and Brooks 2021).

In order to decarbonize the steel manufacturing industry, people have been exploring a variety of alternative technologies. Major decarbonization strategies include decarbonizing the conventional BF-BOF route with CCUS, gas substitutes and improved technologies, developing gas-based technologies to integrate hydrogen, and pursuing plasma and electrolysis-based iron and steelmaking (Shahabuddin, Brooks and Rhamdhani 2023). Among all technologies studied by Shahabuddin et al. (2023), the hydrogen based direct reduced iron with electric arc furnace (H_2-DRI-EAF) is the most promising given its low level of carbon emission and high technology readiness level (TRL) (Shahabuddin, Brooks and Rhamdhani 2023). IEA estimates that the H_2-DRI-EAF technology will reach industry level maturity by 2030 (IEA 2020).

DRI reduces iron directly from in-bearing materials using coal-coke or liquid fuel and gas without converting it into a melting phase. Currently, most DRI uses hydrocarbon-based reductants, among which 76% is natural gas. However, it has the potential to utilize low carbon hydrogen as a reductant to decrease the overall carbon emission intensity of steel. It is anticipated that by 2050, nearly 15% of primary steel produced globally will be through the hydrogen based DRI (IEA 2020). EAF is mostly used for steel making with scrap metal. In the United States, around 70% of steel is produced with scrap metal EAF (Hites 2020). Once technologically ready, the H_2-DRI-EAF steel manufacturing process has the potential to significantly reduce carbon emission by up to 95% with green hydrogen and low carbon electricity sources (Vom Scheidt et al. 2022).

The challenges associated with H_2-DRI-EAF is two folds. First of all, we need to source large quantity of cost-efficient clean energy for the process. Shahabuddin, Brooks and Rhamdhani (2023) indicated that around 104 kg of hydrogen was needed for each ton of steel produced based on the assumption that 54 kg hydrogen is needed to reduce one ton of iron ore (Fe2O3). Vogl, Åhman and Nilsson (2018) has a lower estimation of hydrogen demand, 51 kg hydrogen for each ton of steel output assuming no hydrogen losses in the process. Acquiring large quantity of green hydrogen needed for H_2-DRI-EAF poses technical and economic challenges. Secondly, we need high grade iron ore for H_2-DRI-EAF because low quality iron ore could cause increased gangue materials and incomplete metallization during processing (Shahabuddin, Brooks and Rhamdhani 2023). Nevertheless, the overall quality of iron ore is degrading. According to research, in the last 15 years, the iron content in iron ore has decreased by 3-4%, which could potentially lead to higher processing and higher mining costs as well as heightened resource consumption (Shahabuddin, Brooks and Rhamdhani 2023).

In conclusion, integrating low carbon hydrogen in the steel manufacturing is a promising use of hydrogen to decarbonize the industry. While challenges persist, research has shown enormous potential of green steel produced with the H_2-DRI-EAF process using cost-efficient low carbon hydrogen.

Overall, based on government policies, industry commitments and technology readiness, hydrogen in industrial hubs coupling with other industries may be one viable use case of hydrogen. Additional techno-economic analysis of hydrogen industrial hubs is needed to determine the feasibility and profitability of these hubs.

2: Problem Statement

Under the pressure of global decarbonization, many countries and regions have identified hydrogen as a key component for clean energy transition. Led by developed economies such as the European Union, Australia and Japan, over 30 governments have published hydrogen strategies and road maps to incentivize public and private investments on the R&D and production hydrogen, hoping to reach ambitious hydrogen production cost target in the next few years. However, it remains unclear what the critical hydrogen production cost reduction pathways are, whether it is feasible to achieve government cost targets in time, and what are the best use cases of hydrogen in decarbonizing the industry sector. In this research, we explore the cost of hydrogen and hydrogen use cases in a few regions, taking into consideration of regional variation, technology learning and capacity utilization, and seek answers to the following questions:

1. What will it take for the cost of hydrogen production to reach government targets, if at all?

2. Can coupling hydrogen production with high-energy-demand industries allow more cost-effective hydrogen production with renewable energy sources and provide system-wide profits?

3: Case Study 1: Cost of Hydrogen Production

3.1: Introduction and Motivation

In this case study, we explore the LCOH of hydrogen generated with PEM electrolysis using grid electricity in a variety of regions identified as potential hydrogen hubs in the world.

Despite the availability of numerous reports and academic research papers on the cost of hydrogen, there are certain areas that have not been extensively explored in the literature. These include:

1. Horizontal comparison of hydrogen production costs: There is a lack of comprehensive studies that horizontally compare the cost of hydrogen production using the same technology across different regions worldwide, taking into account regional variables and considering the impact of technology learning over time. Such analyses could provide valuable insights into the factors influencing cost disparities and identify best practices for cost reduction.

2. Empirical analysis of electrolyzer capacity utilization: While there have been investigations into how the utilization of electrolyzer capacity affects the levelized cost of hydrogen (LCOH), empirical studies examining the precise impact and the dynamic nature of optimal capacity utilization and cost savings over time, especially as more intermittent renewable energy sources are integrated to the grid, are limited. A deeper understanding of these aspects could inform operational strategies and aid in optimizing the utilization of electrolyzers for cost-effective hydrogen production.

3. Quantitative analysis of pathways to achieve government cost targets: There is a dearth of quantitative analyses that explicitly explore the pathways for reducing the levelized cost of hydrogen to meet current government cost targets. Additionally, there is a lack of literature that specifically examines the feasibility of meeting the U.S. DOE cost targets for hydrogen production using PEM technology in different regions of the United States. The impact of the Investment Tax Credit (ITC) for clean hydrogen under the IRA on reducing the LCOH has not been extensively studied in the context of various electricity development scenarios.

3.2: Methodology and Data Collection

3.2.1: Choice of Electrolysis Technology

We study hydrogen produced by PEM only in this study. As mentioned in the earlier section, PEM is capable of operating under highly dynamic conditions as well as good partial load range, high current densities and high-voltage efficiency, which makes PEM a more desired option for hydrogen production with intermittent renewable energy sources (Kurmar & Himabindu 2019; Ruth et al. 2017). As we anticipate that the electrolyzer should be able to turn on and off rapidly depending on the grid electricity price, PEM is the most suitable technology for such a use case.

3.2.2: Location Selection

For the global hydrogen pricing comparison, we selected the Middle East, North Africa, Germany, Iceland, China, Australia, Canada, West Texas, California, US Northern Plain, Chile, and India as the target locations. These locations are identified as promising hydrogen hubs in their respective districts. Germany has signed agreements Morocco on developing a sustainable green hydrogen network, and is hoping to import green ammonia from Saudi Arabia starting from 2026 (Blinda 2023; Stickings 2022). Iceland is setting up hydrogen production facilities with its abundant geothermal power (Richter 2021). China is currently developing its own hydrogen policy and has declared its ambitious to build a robust green hydrogen economy (China Daily 2022). Australia is expected to be the second largest net-exporter of low carbon hydrogen by 2030, and the first large scale hydrogen plant is to be built in Pilbara (Arena 2022; Global Australia, accessed May 7, 2023). Canada has recently issued a hydrogen strategy outlining the opportunities and challenges of a clean hydrogen industry in Canada (Hydrogen Strategy for Canada 2022). Texas is branding itself as a hydrogen hub in the West United States with its wealth of solar power in the west desert region (Center for Houston's Future and Greater Houston Partnership 2022; Zuvanich 2023). California has officially announced its intention to create a renewable hydrogen hub (State of California 2022). Chile is one of the major hubs for hydrogen production and the is thought to be among the regions that can produce the lowest cost clean hydrogen thanks to its abundant solar and wind resources (Acosta et al. 2022). Last but not least, the Indian government has approved its National Green Hydrogen Mission with the goal of making India a major producer and supplier of green hydrogen in the world (National Portal of India, accessed May 7, 2023).

We selected Texas for the single location analysis. Wind and solar together produce around 34% of electricity in Texas in the first quarter of 2022, leading the energy markets in the US (Wamsted 2022). Consumers in Texas under the Independent System Operator (ISO) Electric Reliability Council of Texas (ERCOT) are subject to electricity cost variations in the wholesale market, which means that the consumer side electricity prices change on an hourly basis, and during certain hours of a year, electricity users pay significantly higher electricity prices than during the rest of the year depending on demand and renewable energy availability. A more volatile consumer market provides opportunity for electrolyzers to reduce their electricity bills via optimizing their capacity utilization and is more suitable for the capacity factor analysis (see *Section 3.2.9*).

Texas is also an "epicenter" for clean hydrogen production in the Unites States. On the supply side, it has considerable renewable and natural gas resources, both are used for hydrogen production with the former key to clean hydrogen production. On the demand side, it is projected that the demand for clean hydrogen can reach 21Mt by 2050, 6 times the current demand for conventionally produced hydrogen (Center for Houston's Future and Greater Houston Partnership 2022). Texas has formed the HyVelocity hub which is comprised of energy companies and organizations, and it is applying to DOE's Regional Clean Hydrogen Hubs program (H2Hubs) to claim some of the $7 billion allocated by the 2021 Bipartisan Infrastructure Law dedicated to creating a clean energy economy (Zuvanich 2023).

3.2.3: Levelized cost of hydrogen (LCOH)

The goal of this study is to understand the LCOH for varying electricity cost assumptions from now to 2050 to demonstrate future energy scenarios.

LCOH is calculated by dividing the discounted cash flows by discounted hydrogen volumes, as shown with the following formula (Tang, Rehme and Cerin 2022):

$$LCOH = \frac{\Sigma_i \left(\frac{I_i + M_i + O_i - R_i}{(1+r)^i}\right)}{\Sigma_i \left(\frac{E_i}{(1+r)^i}\right)}$$

In the analysis of Tang, Rehme and Cerin (2022), I_i is the investment in year i, M_i is maintenance and service cost in year i, O_i is operational cost in year i, E_i is the hydrogen output in year i in kg, R_i is the revenue in year i, and r is the cost of capital.

In this study, we redistributed the I + M + O into three main cost components: CAPEX, which included capital investment, cost of land purchase, and replacement costs; Electricity cost ("EC"), which is the retail grid electricity price, and OPEX excluding electricity cost ("OPEX"), which includes the cost of process water, labor, interest on working capital, overhead labor and interest of debt on capital investments. In our analysis, we assume that hydrogen is sold at its cost, and therefore no revenue is collected from selling hydrogen Therefore, the formula for LCOH is updated as:

$$LCOH = \frac{\Sigma_i \left(\frac{CAPEX_i + EC_i + OPEX_i}{(1+r)^i}\right)}{\Sigma_i \left(\frac{E_i}{(1+r)^i}\right)}$$

A cost model was developed based on inputs from the National Renewable Energy Laboratory (NREL) H2A models. *Figure 1* shows the flow of the model logic as well as some of the major data sources, including the NREL H2A model, NREL Cambium 2022 Scenarios, Annual Energy Outlook 2021, ERCOT Day-Ahead-Market (DAM) historical data, government reports, and websites that collect specific regional information. Capital investments, electricity price and other operational costs are aggregated into discounted cash flows, and we use them to calculate LCOH together with discounted hydrogen production volumes calculated with production plant parameters. To assess the impacts of different assumptions on the economics of an electrolysis system, the models were adapted to directly incorporate learning factors and scenario details in factor costs. Sensitivity analysis includes an assessment of learning rates, scenario assumptions, and production capacity variation. As production capacity decreases, we identify the optimal capacity factor that enables hydrogen producers to take advantage of periods of low electricity prices.

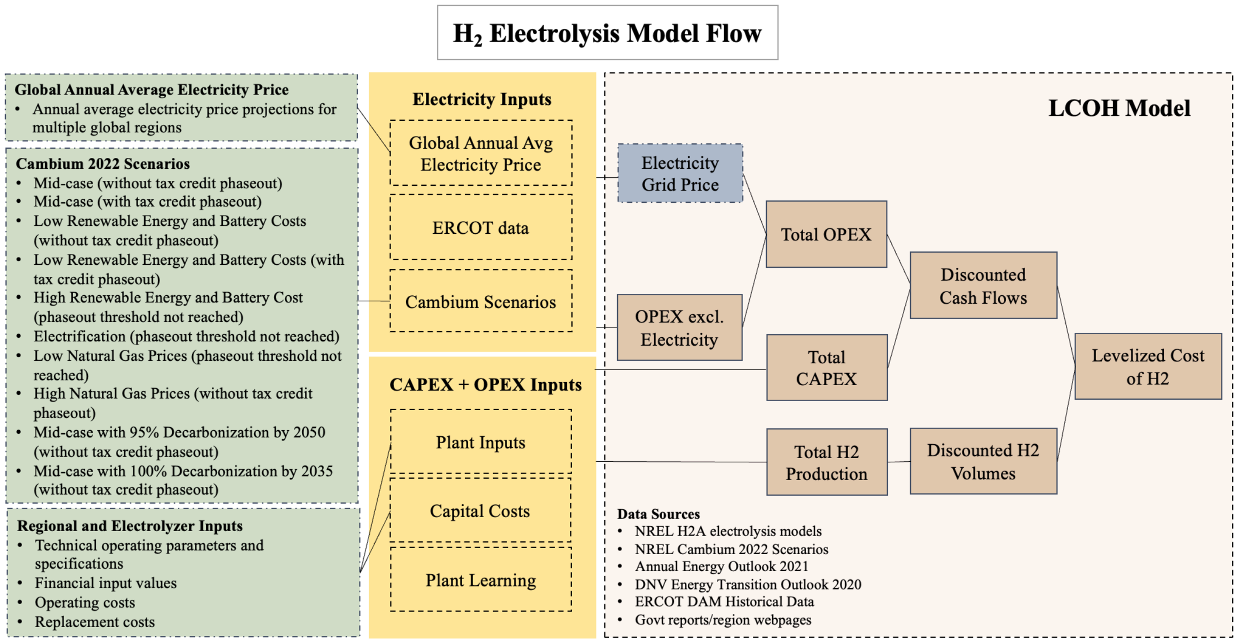


Figure 1: LCOH model flow

3.2.4: Data Collection of CAPEX, OPEX, and CAPEX Multiplier

The CAPEX information of a hydrogen plant is referenced to the NREL H2A model, which provides the investment needed to construct an electrolyzer in the United States with the base year of 2020 (NREL, accessed May 13, 2023). As the CAPEX should be different in different geographic regions as the cost of materials, supply chain efficiency and labor costs are different, we added a CAPEX multiplier to the US value based on geographics. The OPEX assumptions for operating a hydrogen electrolyzer are collected from the NREL H2A model, government reports and other online sources. A list of parameter inputs, their values and data sources can be found in the appendix.

3.2.5: Data Collection of Electricity Pricing

For global hydrogen production cost comparisons, we acquire annual average electricity price projections from 2020 to 2050 of the different regions via Annual Energy Outlook 2021. All electricity prices are wholesale prices, excluding potential transmission, distribution and utility fees and capacity payments and taxes.

For analysis on ERCOT specifically, we collect hourly electricity price information from 2020 to 2050. For 2020, 2021 and 2022, we use ERCOT's historic day-ahead-market (DAM) pricing of settlement point "HB WEST", and from 2024 on, we use the electricity cost information simulated by Cambium, NREL's electricity modeling tool with a range of future scenarios of the U.S. power sector updated annually (Gagnon, Cowiestoll and Schwarz 2023).

ERCOT DAM

ERCOT publishes historic electricity prices of the whole sale market. Both DAM and real-time-market (RTM) prices are publicly available from ERCOT. DAM prices are updated on an hourly basis, and RTM prices are updated every 15 minutes. In this study, we choose to use DAM prices as 85% of the electricity traded in ERCOT is through DAM (ERCOT, accessed May 17, 2022).

Cambium Scenarios for Electricity

Cambium is an electricity modeling tool developed by NREL. It simulates the hourly emission, cost and operational data for a range of scenarios for the U.S. power sector and is intended to be used for long-term decision making. Cambium is developed together with NREL's Standard Scenarios, which has a larger variety of scenarios but does not provide the hourly temporal granularity needed for this study (Gagnon et al. 2022). A detailed list of Cambium scenarios is described in the scenario section.

We use the "total_cost_enduse" from Cambium outputs as the wholesale price in future years. "Total_cost_enduse" is the total short-run marginal cost of the marginal increase in load, capacity expansion (in the case when capital investment is needed to maintain a target planning reserve margin when demand is increased), and staying in compliance with a state's portfolio standard polities, including both renewable portfolio standards (RPS) and clean energy standards (CES), when end demand is increased (Gagnon, Cowiestoll and Schwarz 2023). Since the clearing prices of ERCOT DAM is usually the marginal cost of generating an additional unit of electricity to meet marginal increase in demand, "total_cost_enduse" can be treated as an approximation of the wholesale prices.

Data Gaps and Retail Cost Adder

While ERCOT electricity data is available for years up to 2022, the Cambium 2022 scenarios only exist for 2024, 2026, 2028, 2030, 2035, 2040, 2045 and 2050. Cambium skips the years in between in order to reduce computation burden (Gagnon, Cowiestoll and Schwarz 2023). For any year with no electricity pricing data, we assume that it has the same power market profile as the previous year. For instance, the year 2023 has the same electricity prices as the year 2022, and the years 2031 to 2034 all have the same electricity prices as the year 2030.

An additional $29.4/MWh is added to both ERCOT DAM wholesale prices and the Cambium marginal costs to simulate the actual retail energy price electrolyzers need to pay to purchase grid electricity. This retail cost adder is used by NREL for its own analysis on electricity-consuming resources using Cambium 2022 data, which bridges the gap between wholesale electricity costs and industrial retail rates, taking into consideration costs for distribution capacity, transmission capacity, administrative and general expenses, and other electric sector expenses that is excluded from Cambium's cost analysis (Gagnon et al. 2022).

This retail price adder is not applied to the global hydrogen production cost comparatibe analysis, as the cost of transmission, distribution, utility management, capacity and taxes are different across different regions. Without acquiring more information on the assumptions that goes into the global electricity price projections, we decide to not apply the retail cost adder and treat the global hydrogen comparison as a "minimum cost scenario."

3.2.6: SHAP Analysis

To identify the key factors influencing the levelized cost of hydrogen (LCOH), we conducted a comprehensive SHAP analysis. This analysis enables us to determine the most impactful predictors that significantly contribute to LCOH variations. By understanding these major contributors, policymakers can make informed decisions and devise effective strategies aimed at reducing hydrogen production costs, and subsequently implement targeted measures to achieve cost reduction goals in the realm of hydrogen production.

SHAP stands for "Shapley Additive exPlanations," a tool used to interpret complex machine learning outcomes. SHAP displays each contributor's contribution to an outcome and quantifies how important each contributor is to a model for making predictions. In this study, we use SHAP to gain a better understanding of how different input variables contribute to the resulting LCOH, and which variables have the strongest impacts to support policy making and technology road mapping.

We train a Random Forest Regression model with a variety of CAPEX, OPEX and electricity cost related variables for LCOH prediction. Random Forest Regression is a supervised learning algorithm for regression that deploys ensemble learning, which combines predictions from multiple machine learning algorithms for more accurate predictions in a single model. We feed in the data of *Discount Rate, Interest Rate, Total Worker Hours, Electricity Requirement, Water Requirement, Labor Cost, Electricity Price, Water Cost, Land Cost, Property Tax Rate, Unplanned Replacement Cost, Daily Output,* and *Capital Cost* for all 12 target regions from 2021 to 2040, with in total 240 outcome data points. Detailed description of the aforementioned variables can be found in Appendix. Other variables that contribute to LCOH but do not vary across different regions and over time are not included in the analysis. 20% of the data points are randomly split for model training.

Once the Random Forest Regression model is trained, we apply SHAP to understand the importance and the direction of impact of each variable. Since the most important variables have the largest potential for LCOH reduction, they are the ones policy makers should target at and spend sufficient resources on.

3.2.7: Electricity Price Volatility

Electricity price volatility is calculated in two main ways. The first one is based on the standard deviation, as used by Mauritzen (2010), Rintamäki et al. (2017) and Silva and Horta (2018). The other is by calculating the price velocity, as used by Li and Flynn (2004) to capture people's perception on how fast price changes. Since this study does not focus on people's perception on the speed of change, but rather the objective value of how price points deviate from each other, we calculate the annual standard deviation to indicate the price volatility for the entire year. The equation for price volatility is:

$$V_p = \sqrt{\frac{1}{8760}\, \Sigma_{\mathrm{i=1}}^{8760}\left(P_i - \hat{P}\right)^2}$$

Where V_p is price volatility, P_i is the electricity price at any hour i, and $\hat{P}$ is the annual average electricity price. In this study, we assume that electrolyzer operators are able to perceive the electricity price over the entire year and make generation decisions based on how the hourly electricity pricing is compared with the rest of the electricity price over the entire year, and therefore we use the annual standard deviation to represent price volatility. If a study wants to examine an electrolyzer's behavior assuming decisions are made based on daily electricity price fluctuation only, daily standard deviation should be used instead.

3.2.8: Capacity Factor and Discounted Electricity Price

We define the percentage of time an electrolyzer is operated during a year the "capacity factor." In this study, we assume that the electrolyzers are only operated when electricity prices are the lowest. For example, if the capacity factor is 80%, it implies that the electrolyzer only operates 80% of the time in a year, and all electricity prices within that 80% of the time are lower than those over the remaining 20%. Lowering capacity factor is a way to avoid peek prices in electricity markets where consumers are exposed to electricity price volatilities due to demand increase or generation constraints caused by intermittency.

The average electricity price with a given capacity factor is called "discounted electricity price." To calculate the discounted electricity price, we rank the hourly electricity price over one year from the lowest to the highest, and calculate the average price of the lowest-priced hours during which the electricity is used for hydrogen production according to the capacity factor. The discounted electricity prices are calculated with Python for the 10 Cambium scenarios where hourly electricity prices are available.

3.2.9: Learning

In order to include technological improvement potentials into the LCOH assessment, we incorporate learning into the model. Learning analysis considers lower capital expenditures, higher throughput rates, lower operating expenses and more efficient conversion of fuels to hydrogen and carbon products in the future. To determine learning in capital expenditures, NREL's current and future models are used to estimate learning rates assuming Moore's Law (Jovanovic & Rousseau, 2002).

Learning is applied on the following parameters: electricity demand, water usage, labor productivity and annual hydrogen output. For electricity needs, water usage and labor productivity, improvements happen both incrementally for existing PEM plants and through technology breakthroughs in newly constructed plants. For annual hydrogen output, incremental improvements are calculated via increased production, and technology breakthrough is quantified by decreased capital investment. Different hydrogen production technologies may experience very different learning rates changing the future competitive position of each technology. Learning parameters used in this study can be found in the appendix.

3.2.10: The IRA and GHG Emission Associated with Hydrogen Production

On August 16th, 2022, the Congress passed the Inflation Reduction Act (IRA), which was subsequently signed into law by President Biden. The IRA introduced specific provisions regarding tax credits for clean hydrogen production, which were categorized based on the lifecycle greenhouse gas emissions associated with the produced hydrogen. These tax credits are applicable only to hydrogen generated by facilities located within the United States and owned by taxpayers, provided that the production takes place before January 1st, 2033 (Inflation Reduction Act 2022). The following chart provides a concise summary of the available tax credits for hydrogen producers based on their emission content:

Full value: \$3.00/kg H_2		
GHG Emission Associated with Hydrogen Production	*Percentage of Full Value*	*Tax Credit Received*
>=2.5 $kgCO_2e/kgH_2$ & <4 $kgCO_2e/kgH_2$	20%	\$0.60/kg H_2
>=1.5 $kgCO_2e/kgH_2$ & <2.5 $kgCO_2e/kgH_2$	25%	\$0.75/kg H_2
>=0.45 $kgCO_2e/kgH_2$ & <1.5 $kgCO_2e/kgH_2$	33.40%	\$1.00/kg H_2
<0.45 $kgCO_2e/kgH_2$	100%	\$3.00/kg H_2

Table 2 IRA hydrogen tax credits

In this study, the main GHG emission source of electrolysis-based hydrogen is grid electricity. For the analysis of hydrogen produced in Texas, we calculate the GHG emission content based on the GHG emission associated with every hour of electricity used when the electrolyzer is operating of the 10 different Cambium scenarios. In Cambium's model, the variable "aer_load_co2e" records the average GHG emission rate that is allocated to a region's end-use load in CO_2 equivalent with the unite kg/MWh. This emission rate includes the effects of imported and exported power on GHG emission rate associated to the end users and is the most relevant to the lifecycle GHG emission on which IRA tax credit calculation is based (Gagnon et al. 2023). The correspondent tax credits are treated as negative costs and are integrated in the LCOH calculation.

3.3: Global Hydrogen Production Cost Comparison

3.3.1: Analysis

1. LCOH comparison: we compare LCOH across all 12 global regions from 2023 to 2040 to study how location variations affect LCOH and cost reduction trajectories.
2. Sensitivity analysis on learning rate: we test the results with learning rates of 3.6%, 18% and 31%, which are identified by NREL and Schoots et al. (2008) as possible learning rates for electrolysis, to examine the effect of learning on LCOH reduction.
3. SHAP analysis: we perform Random Forest Regression on all inputs that affects LCOH, and then use the tool SHAP to analysis their predictive power on LCOH to inform their relative importance.

3.3.2: Findings

LCOH Comparison

LCOH of different regions can deviate significantly as a result of different CAPEX, OPEX and electricity price. As *Figure 1a* shows, assuming all electrolyzers are operated at 100% capacity, in 2023, Canada has the lowest LCOH of $3.9/kg, while China's LCOH is 2.3 times higher at $8.83/kg. Although China's CAPEX is the lowest, 0.2 times the baseline CAPEX in the US, its electricity price is among the highest in 2023 at $61/MWh. China's electricity cost is projected to increase before it peaks in 2029, and therefore the LCOH of a 30-year electrolyzer in China would cost significantly more than those in countries with cheaper electricity prices.

Figure 1a and *Figure 1b* display that cost reduction trajectories of these regions are significantly different from each other. With the baseline CAPEX learning rate of 3.6%, Australia-Pilbara shows the most aggressive cost reduction, from $6.86/kg in 2023 to $3.19/kg in 2040, a 54% reduction. This is likely caused by the significant electricity price reduction, from $72/MWh in 2023 to $28/MWh in 2050. In contrast, North Africa shows almost no difference between prices of 2023 and 2040, and its electricity price increased from $39/MWh in 2023 to $54/MWh in 2050, with the lowest electricity price observed in 2029 at $28/MWh. The increase in electricity price compensates the cost reduction gained by CAPEX learning. As a result, the lowest LCOH in 2040 is observed in Australia-Pilbara, and the highest is in India at $6.89/kg.

Similar to what Oliva and Garcia (2023) found, electricity cost comprises the majority of LCOH, ranging from 77% to 98% of LCOH. Over years, percentage of electricity cost in total LCOH increases as CAPEX decreases as a result of technology learning. CAPEX is a much less significant component of hydrogen product cost, comprises 1% - 14% of LCOH.

It is important to notice that although Europe, the Unites States, and many other regions have claimed the target of $2/kg is feasible in the near future, the result from our model with the projected electricity prices and baseline CAPEX learning rate used by NREL's H2A model shows that none of the regions in the world will be able to make this target by 2040 with 100% generation capacity.

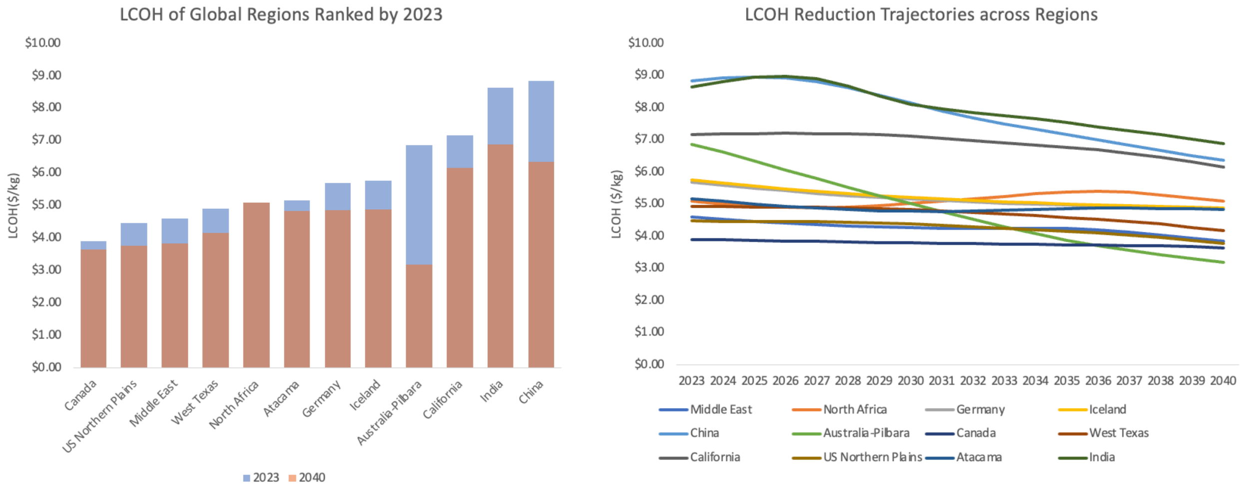


Figure 2 (a) left: LCOH comparison across different regions in 2023 and 2040; (b) right: LCOH reduction projections from 2023 to 2040 in different regions

Sensitivity Analysis on Learning Rate

As discussed in *Section 1.4.2*, various studies in the literature have made different assumptions regarding learning rates. Schoots et al. (2008) argued that the learning rate for electrolyzers can range from 5% to 31%. *Figure 3a* illustrates the resulting LCOH in different regions, considering learning rates of 3.6% (as utilized by NREL's H2A model), 18%, and 31%.

The results show that even with the learning rate of 31%, the LCOHs can still not make the target of \$2/kg by 2040 (*Figure 3a*). The region with the lowest LCOH is Australis-Pilbara at \$2.81/kg. The cost savings range from 0.8% to 12% in different regions when the learning rate increases from 3.6% to 31%. *Figure 3b* compares the cost savings from the increase in learning rate with the percentage of CAPEX in LCOH in 2023, and shows that as the percentage of CAPEX in LCOH increases, increasing learning rate would in general have a stronger impact in reducing LCOH. In regions where electricity cost dominates LCOH, reducing electrolyzer CAPEX has a trivial impact on the resulting LCOH.

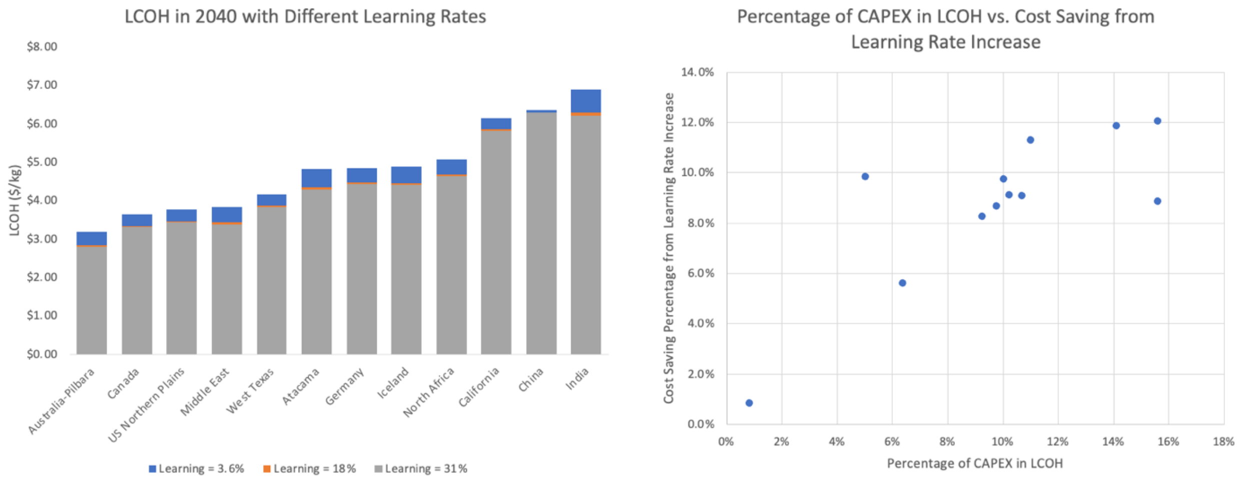


Figure 3 (a) left: LCOH reduction as learning rate increases in different regions; (b) Scatterplot of percentage of CAPEX in LCOH and cost saving percentage from learning increase

SHAP Analysis

Once we achieve all parameter and LCOH data on the 12 regions from 2021 to 2040, we perform Random Forest Regression factors that contributes to LCOH, and then apply SHAP analysis to determine the relative importance of these factors.

Figure 4 is the bar plot of the SHAP analysis. The variables are ordered from the highest to the lowest regarding their predictive power. The values of the bars are mean SHAP values, and therefore the importance ranking does not take into consideration whether the impact is positive or negative. The chart shows that *Electricity Price*, *Water Cost*, *Interest Rate* and *Total Work Hours* are the most impactful variables for LCOH. Both Electricity Price and Water Cost are measured per unit, indicating that the unit prices for electricity and water can be indictive of the value of LCOH. In analysis performed by Oliva and Garcia (2023), water cost is not included in LCOH as it was shown to be low in prior research (Armijo and Philibert 2020). However, SHAP analysis concludes that the regional variation in water cost does have a substantial predictive power in LCOH calculation. Contrary to what researchers previously found, capital investment is not among the factors that have significant predictive power of LCOH (Jørgensen and Ropenus 2008; Mansilla et al. 2013).

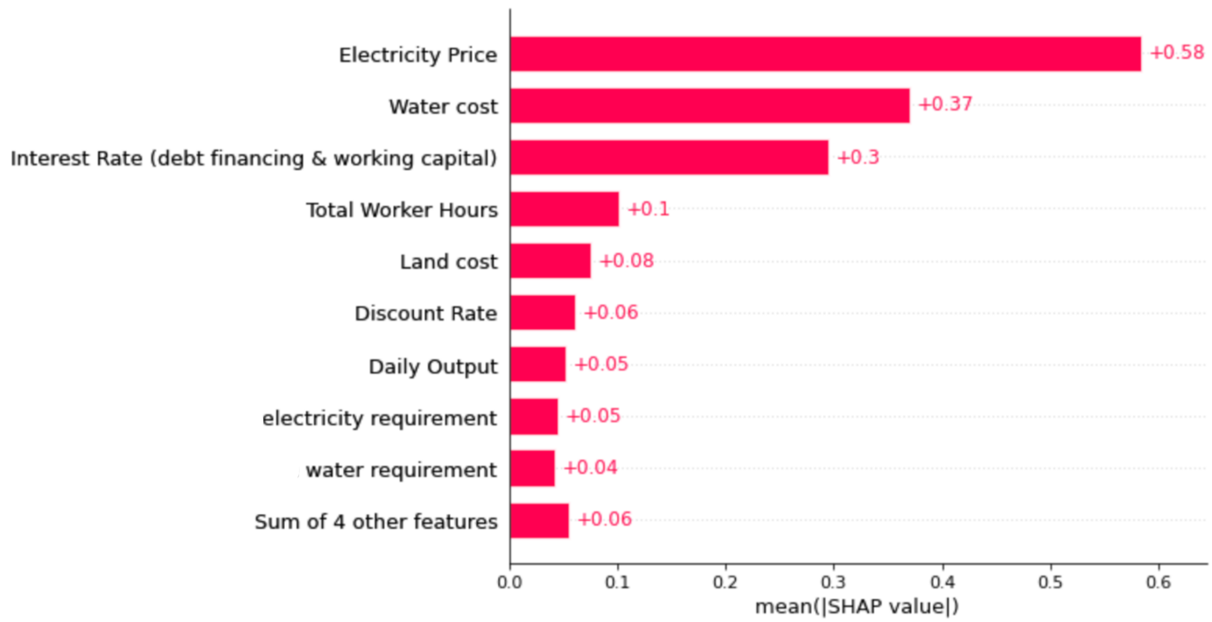


Figure 4 Bar chat of SHAP values

The beeswarm chart (*Figure 5*) provides both an indication of importance and direction of the impact from the variables. *Electricity Price, Interest Rate, Total Work Hours, Discount Rate, Electricity Requirement* and *Water Requirement* all positively predict LCOH, and *Water Cost, Land Cost*, and *Daily Output* negatively predict LCOH. The predictive director of Water Cost and Land Cost is counterintuitive. Higher water cost should lead to more expenses on water usage, and subsequently should lead to higher LCOH. One possible explanation to this phenomenon is that the inflated water cost is indictive of other variables that are associated with low LCOH, such as *Electricity Price*, as *Figure 6* demonstrates. The same explanation applies to why lower *Land Cost* is associated with higher LCOH.

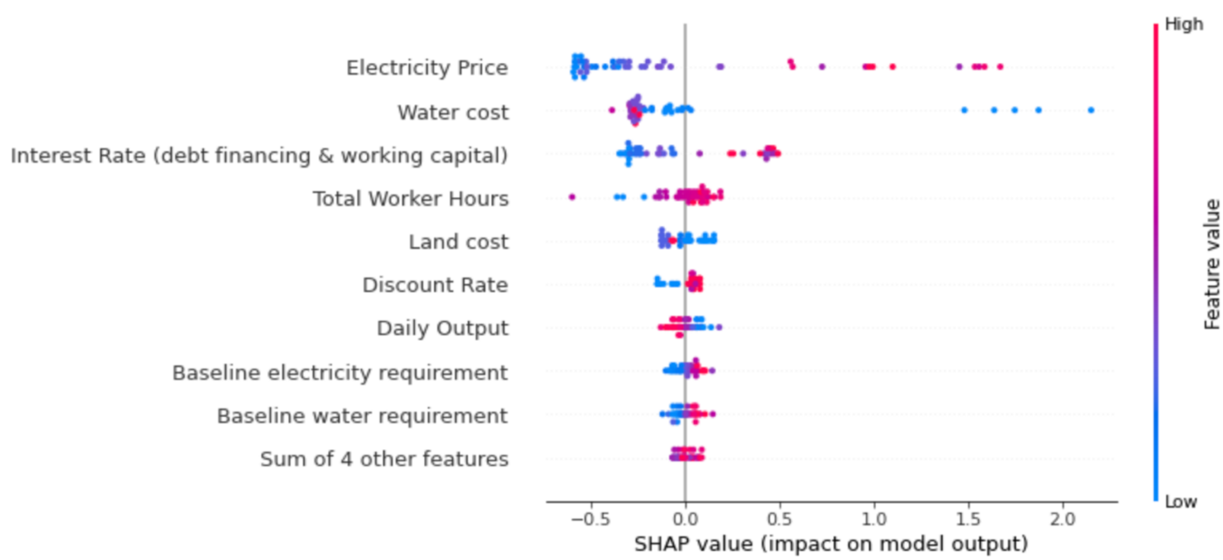


Figure 5 Beeswarm chat of SHAP values

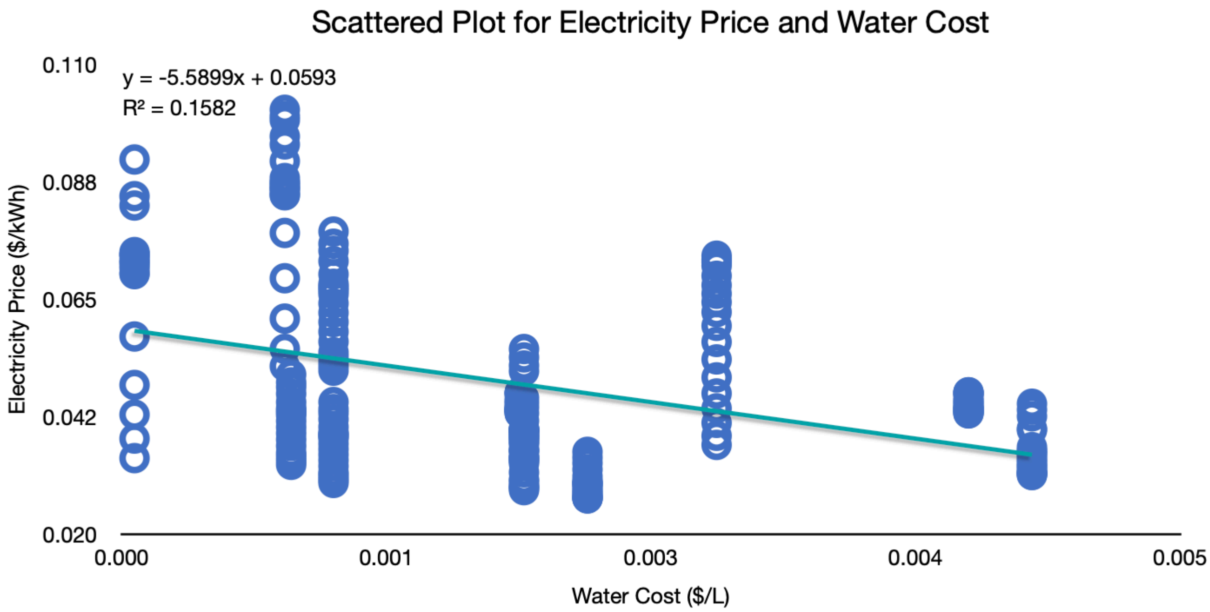


Figure 6 Scatter plot for electricity price and water cost indicating a weak negative correlation between the two variables

The chart below is the waterfall chart shows the main variables that affects the prediction of a single observation, as well as the SHAP values. The sum of all SHAP values equal to the difference between the prediction $f(x) = 4.955$ and the expected value $E[f(x)] = 5.422$.

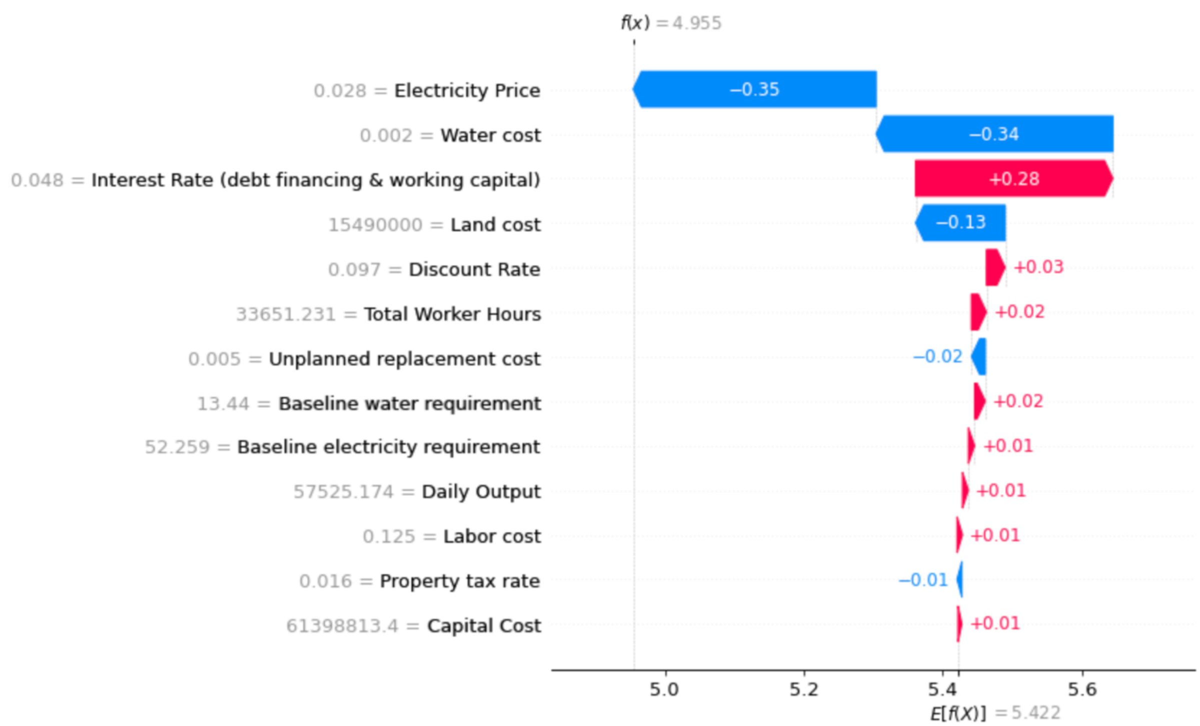


Figure 7 Waterfall chart of SHAP values

3.3.3: Discussion

Through horizontal comparison across different regions identified as hydrogen hubs, the analysis shows that the LCOH of hydrogen produced in different geographic regions can vary significantly. The highest LCOH and the lowest are different by around 2 times both in 2023 and in 2040. A variety of regional parameters contribute to the cost differentiation, among which electricity price is the most prominent differentiator. High electricity cost outweighs other variables and strongly predicts high LCOH.

Previous literature has highlighted the significance of CAPEX in influencing the LCOH. However, the findings of this study challenge the notion that aggressive learning rates, which substantially reduce future CAPEX, will lead to significant reductions in LCOH. This is primarily because CAPEX represents only a small portion of the overall LCOH, and the potential for cost savings through technology learning is positively correlated with the proportion of CAPEX in the LCOH. Furthermore, the SHAP analysis conducted in this study further supports the conclusion that CAPEX does not emerge as a major predictor of LCOH.

The random forest regression and SHAP analysis provides an alternative perspective to the traditional way of understanding variable importance in LCOH. However, there are some drawbacks for the machine learning methodology here. First of all, we have a rather small sample size with a lot of variables. As a result, the error margin is high, and running the analysis multiple times may bring different results. In addition, the LCOH includes the variable values over the entire lifetime of the plant, which is 30 years in this case, but we only input 1 year of value in the random forest regression and SHAP analysis. Consequentially, the parameters and SHAP values obtained through the analysis may not be accurate. Therefore, we need to be cautious when drawing conclusion with the SHAP values, and only use these values as an indication of the degree of importance of these variables.

Last but not least, the analysis shows that the cost of hydrogen production remains relatively expensive in most parts of the world identified as future hydrogen hubs. While some countries show significant cost reduction potential by 2040, mainly as a result of less expensive average electricity price, it is not feasible to achieve the $2/kg hydrogen product cost goal in all of the regions. Furthermore, even after increasing the technology learning rate to 31%, the cost saving can only reach up to 12% of the original LCOH, not enough reduction for the hydrogen cost target. It is important to do further analysis on electricity prices, the most important element LCOH, to explore alternative ways of cost reduction.

3.4: Texas Hydrogen Hub: Scenario-Based Capacity Factor Study for ERCOT

3.4.1: Analysis

1. LCOH at 100% capacity factor: we analyze LCOH with the electricity cost assumptions by the 10 Cambium scenarios to study what composes LCOH, and how LCOHs are different across the 10 scenarios from 2023 to 2040.
2. Capacity Factor Analysis: we lower the capacity factor of the electrolyzers to study whether reduced operating hours can lead to cost reduction, and what are the optimal capacitor factors that could provide the minimum LCOHs in different scenarios.
3. Discounted Electricity Price Analysis: we study how discounted electricity price impacts LCOH in different scenarios, and how they lead to LCOH cost savings.
4. Electricity Price Volatility Analysis: we calculate the electricity price volatility (V_p) of different scenarios and studying the connection between price volatility, optimal capacity factor and minimum LCOH across different scenarios.

3.4.2: Findings

LCOH at 100% Capacity Factor

Assuming a 100% electrolyzer capacity factor, the LCOH primarily consists of electricity costs, accounting for approximately 76% to 85% of the total. The remaining portion comprises CAPEX and OPEX, as consistently observed across different scenarios, as indicated in *Table 3*.

SCENARIOS / YEAR	2023	2026	2031	2040
LOW RE COST	76%	75%	75%	76%
LOW NG COST	76%	76%	76%	77%
LOW RE COST TAX EXP	76%	75%	76%	78%
MID CASE	77%	76%	76%	78%
HIGH ELECTRIFICATION	77%	76%	77%	78%
MID CASE TAX EXP	77%	76%	77%	79%
HIGH NG COST	78%	78%	78%	80%
100% 2035	77%	77%	78%	81%
HIGH RE COST	78%	78%	79%	80%
95% 2050	80%	81%	84%	85%

Table 3 Percentage of electricity cost in LCOH across 10 Cambium scenarios over time

To visually represent the LCOH reduction potential of a PEM electrolyzer from 2023 to 2031 in the Cambium Mid Case scenario, *Figure 8a* presents a waterfall diagram. In this scenario, the LCOH in 2031 ($2.52/kg) is 23% lower than the base year of 2022 ($3.26/kg). The most significant cost reduction is observed in electricity costs ($0.58/kg), followed by CAPEX ($0.11/kg) and OPEX ($0.05/kg). These findings demonstrate the impact of technology learning and decreasing electricity costs on driving down the overall LCOH of hydrogen production.

Figure 8b depicts the trends in the LCOH from 2022 to 2050 across all 10 Cambium scenarios. The data reveals a general trend of LCOH reduction in most scenarios. While certain scenarios exhibit more aggressive reductions in LCOH compared to the Mid Case scenario, a few scenarios indicate an increase in LCOH due to higher average electricity costs.

It is important to note that none of the scenarios examined in this study are able to achieve the ambitious production cost targets set by the U.S. DOE, namely \$2/kg by 2026 and \$1/kg by 2031. Even in the scenario with the lowest cost in 2026, the LCOH remains at \$2.68/kg, which is 34% higher than the target. Similarly, in 2031, the LCOH in the same scenario is \$2.37/kg, representing a substantial 137% increase compared to the DOE's target.

These findings highlight the challenges in achieving the desired cost reductions within the proposed timeframe. Additional efforts and advancements in technology, cost reduction measures, and policy support may be necessary to realize the DOE's ambitious cost targets for hydrogen production.

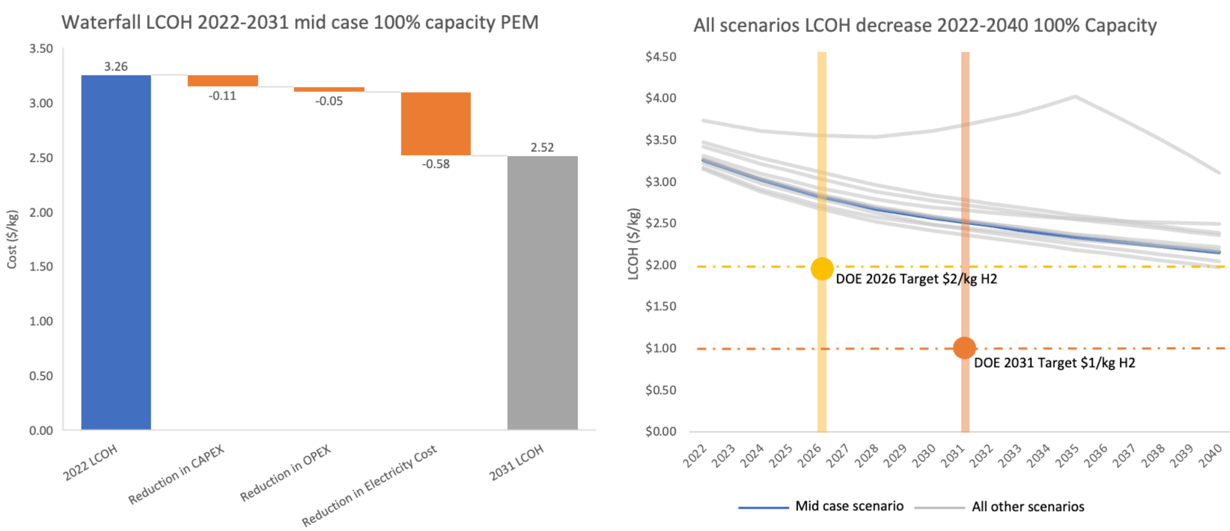


Figure 8 (a) left: Decrease in LCOH from 2022 to 2031 assuming 100% electrolyzer capacity factor in the Cambium Mid Case scenario; (b) right: LCOH reduction across 10 Cambium scenarios assuming 100% electrolyzer capacity factor

Capacity Factor Analysis

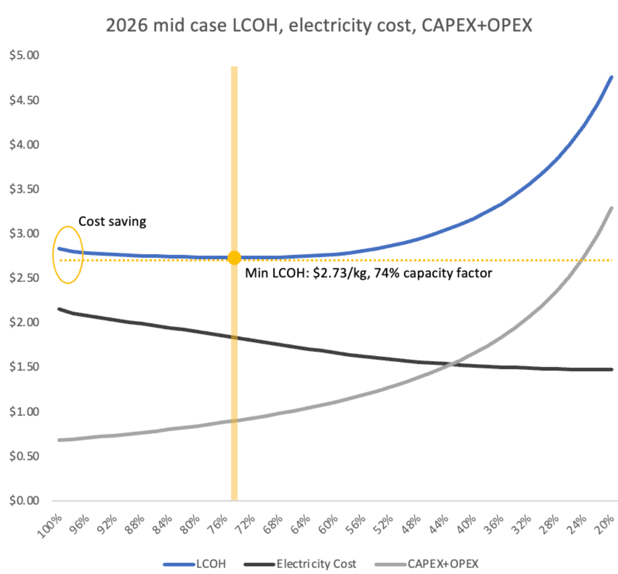
Given the fluctuating retail electricity prices in ERCOT throughout the day, hydrogen generators have the potential to optimize their cost by capitalizing on low-cost electricity during off-peak hours and avoiding high prices during peak hours. In the methodology section, we assume that as the capacity factor decreases, the electrolyzer will prioritize the utilization of the lowest-cost electricity, resulting in an average electricity cost referred to as the "discounted electricity price." Therefore, reducing the operating capacity factor of the electrolyzer can help achieve electricity cost reduction.

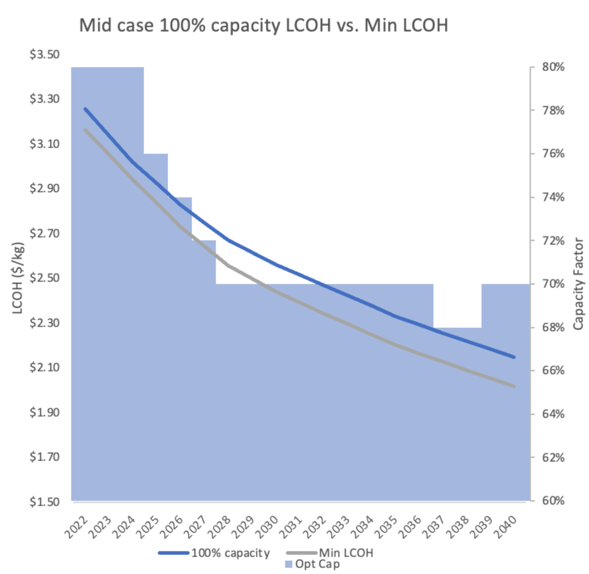
Figure 9a illustrates the decreasing trend of the discounted electricity cost per kilogram of hydrogen generated as the capacity factor decreases in the Mid Case scenario. Simultaneously, the effective cost of CAPEX and OPEX increases with a lower capacity factor. This occurs because a significant portion of CAPEX and OPEX is a sunk cost, and a lower capacity factor leads to a smaller quantity of hydrogen produced, and subsequently higher cost allocated to each kilogram of hydrogen. These two contrasting trends combine to affect the resulting LCOH. Initially, as the capacity factor drops from 100%, the LCOH decreases mainly due to the lower electricity cost. However, as the capacity factor continues to decrease, the LCOH starts to increase again with the rational increase in the allocated CAPEX+OPEX costs. The lowest-cost hydrogen production is achieved at a capacity factor of 74%, resulting in a 3.45% cost saving in the Mid Case scenario in 2026. These findings align with the conclusions of Mansilla et al. (2013).

Figure 9b demonstrates the cost saving potential of optimizing operating capacity factor over time. In the Mid Case scenario, a hydrogen generator can consistently lower production cost by optimizing its capacity factor from 2022 to 2040. Overtime, the amount of cost saving increases as optimal capacity factor decreases.

As CAPEX becomes lower as a result of technology learning, it allows for lower optimal capacity factor as the impact of increased CAPEX becomes relatively smaller than the impact of decreased electricity price. *Figure 9c* shows such a relationship in the Mid Case scenario when both CAPEX and optimal capacity factor both decrease over years. The relationship is not perfectly linear as electricity price and volatility also impacts optimal capacity factor, as described in the *Electricity Price Volatility Analysis*.

Lowering capacity factor make electricity price a less dominant component on LCOH compared to the case with 100% capacity factor. *Figure 9d* shows that when operating with 100% capacity factor in the Mid Case scenario in 2031, electricity cost is over 70% of LCOH, but when capacity factor is reduced to 70%, electricity cost is only around 60% of LCOH. Lower capacity factor gives CAPEX and OPEX more power in determining LCOH.





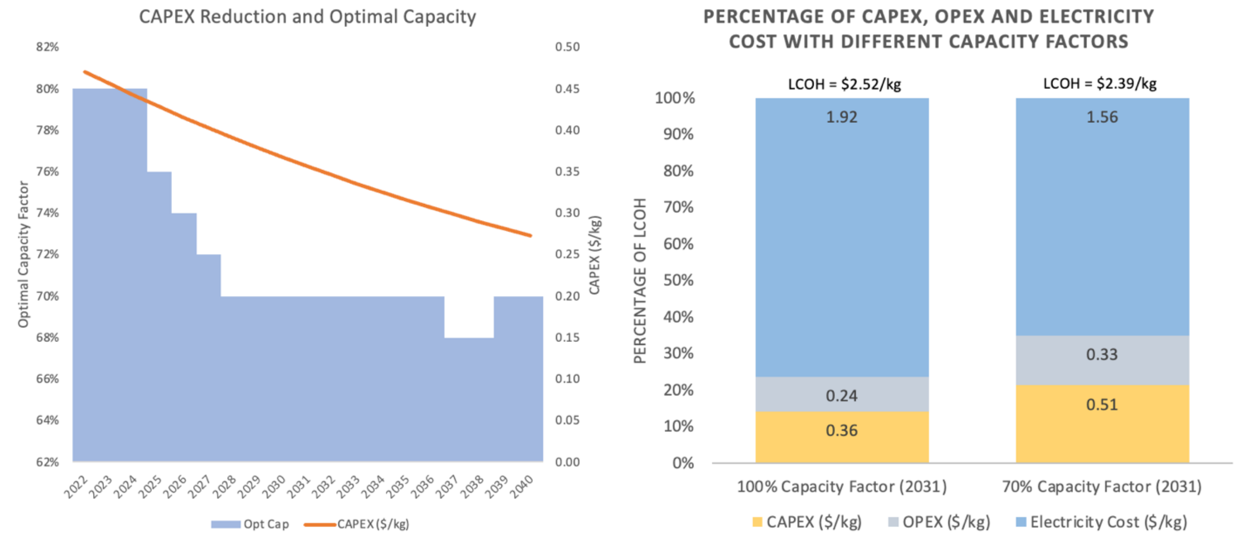


Figure 9 (a) top left: Reducing capacity factor provides cost savings when reduction in electricity price outweighs the increase in CAPEX; (b) top right: In the Mid Case scenario, lowered capacity over time is mainly a result of learning; (c) bottom left: CAPEX and optimal capacity factor in the Mid Case scenario over time; (d) bottom right: Components of LCOH of the Mid Case scenario in 2031 for 100% and 70% capacity factor

Discounted Electricity Price Analysis

Figure 10a presents the temporal evolution of the LCOH across all 10 scenarios from 2022 to 2040. These scenarios showcase substantial disparities both in terms of the LCOH values observed for individual snapshot years and in the trends characterizing the LCOH over time. *Figure 10b*, however, demonstrates that upon optimizing the capacity factor to attain the minimum LCOH, the dissimilarities among the various LCOH values diminish significantly, and all LCOH lines commence a convergence towards lower values.

The convergence of the LCOH with the optimal capacity factor across the examined scenarios can be attributed to the simultaneous reduction and convergence of the discounted electricity price. By reducing the capacity factor, the peak electricity prices prevalent in scenarios characterized by greater electricity price volatility are effectively mitigated. Consequently, the resultant electricity prices exhibit lower levels and greater consistency across scenarios. To provide a comprehensive representation of this notion, we calculated the average electricity price, weighted by the market discount rate, from 2022 to 2050 for both the electricity price at 100% capacity and the discounted electricity price at the optimal capacity factor.

Figure 10c showcases a striking disparity between the average discounted electricity prices at the optimal capacity factors and the average electricity prices at 100% capacity factors. Moreover, the average electricity prices at optimal capacity factors demonstrate a remarkable degree of similarity across the various scenarios examined. Consequently, the electricity cost assumes a diminished role with the LCOH composition, as elucidated in Figure 9d.

Furthermore, Figure 10d shows that despite the increase in annualized CAPEX accompanying the reduction in capacity factor, the larger gains achieved through electricity price reduction contribute to more substantial cost savings in LCOH. In the most extreme scenario, optimization of the capacity factor can yield a noteworthy 20% reduction in LCOH. In the remaining cases, the average reduction in LCOH hovers around 4%. The presented analysis exemplified the potential for capacity factor adjustments to yield considerable cost savings, thereby enhancing the overall economic viability of hydrogen production.

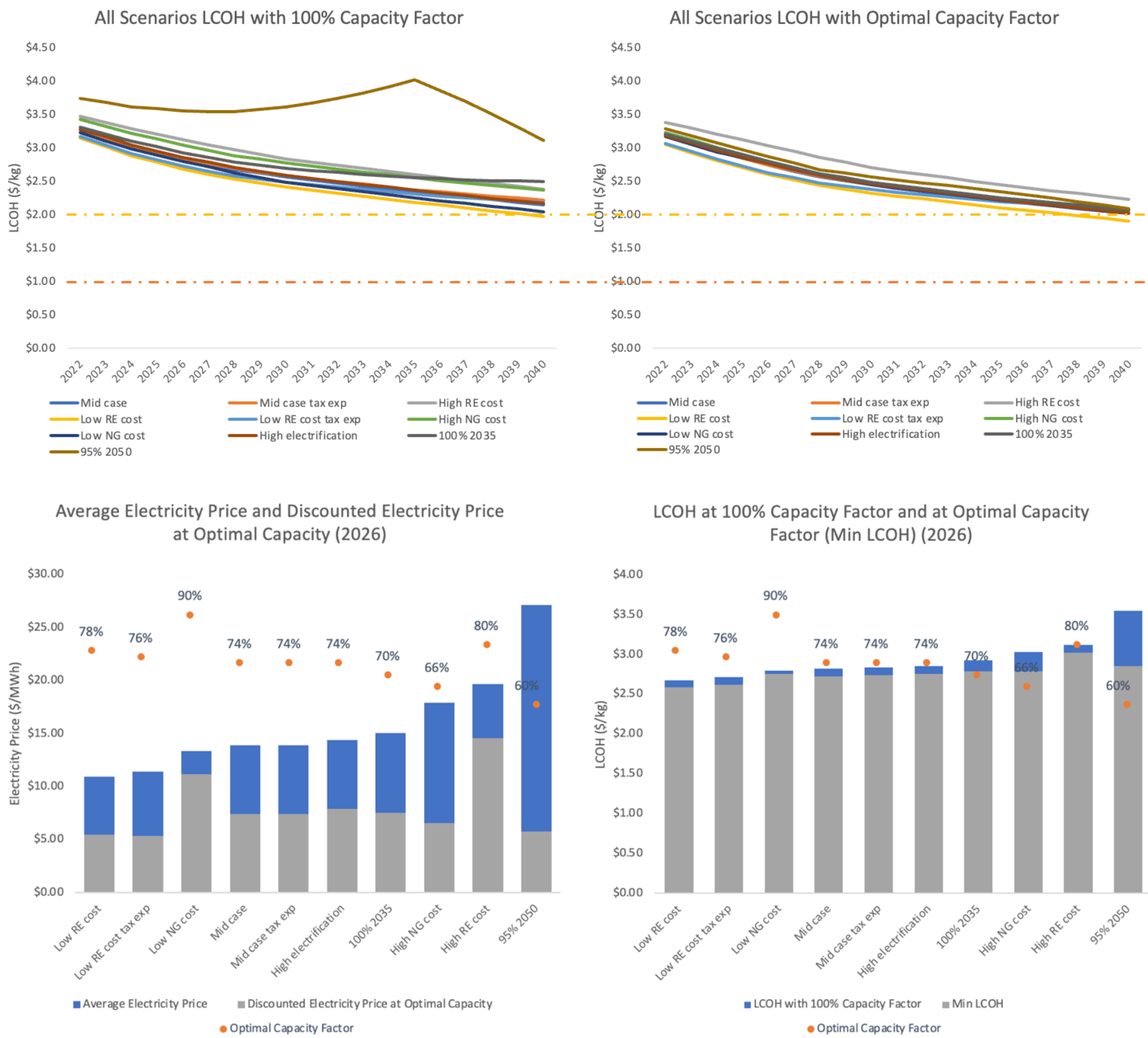


Figure 10 (a) top left: LCOH of all Cambium cases at 100% capacity factor over time; (b) top right: LCOH of all Cambium cases at their optimal capacity factors over time; (c) bottom left: Average electricity price and discounted electricity price at optimal capacity factors for all Cambium scenarios in 2026; (d) bottom right: LCOH at 100% capacity factor and at optimal capacity factors for all Cambium scenarios in 2026

Electricity Price Volatility Analysis

We calculate the annual electricity price volatility (V_p) for all scenarios. Electricity price volatility serves as an indicator of the extent to which electricity prices in a given year deviate from one another. It reflects the magnitude of price fluctuations and the occurrence of price peaks. In the Cambium scenarios, we observed a positive relationship between V_p and average annual electricity price, which implies that the price peaks exert a significant influence on driving up the annual electricity prices. In a broader context, a larger V_p corresponds to a lower optimal capacity factor, as the reduction in discounted electricity price outweighs the associated increase in CAPEX, as depicted in *Figure 11a*. Conversely, *Figure 11b* shows a positive relationship between V_p and LCOH savings, indicating that in scenarios characterized by high volatility in electricity prices, hydrogen generators may achieve more substantial cost savings through the optimization of electrolyzer operating hours and the avoidance of high electricity prices. This finding implies hydrogen's tremendous cost reduction potential in a highly intermittent energy system.

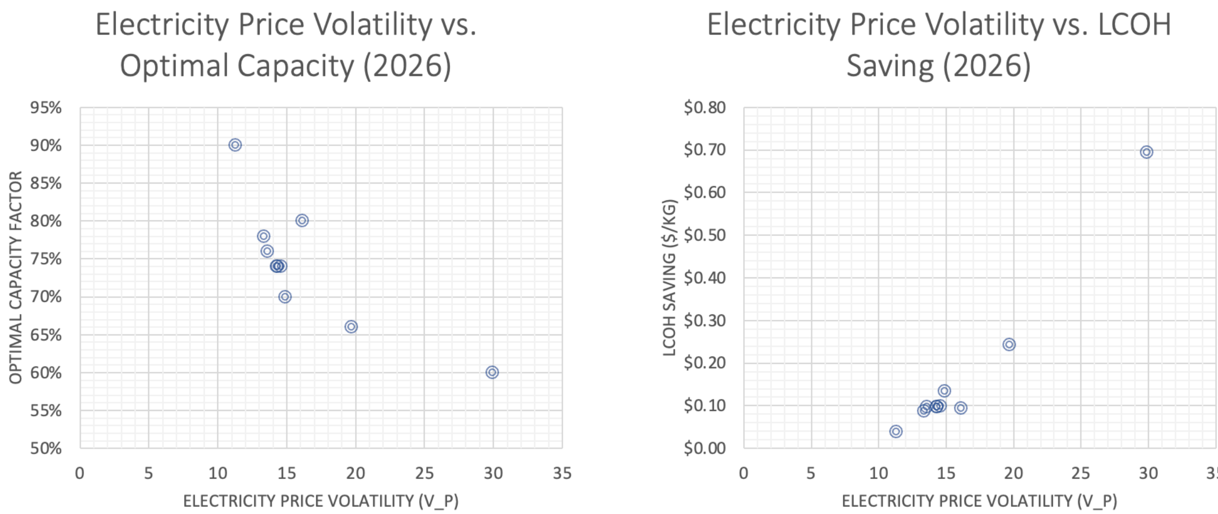


Figure 11 (a) left: Scatter plot of electricity price volatility and optimal capacity factor; (b) right: Scatter plot of electricity price volatility and LCOH saving

3.4.3: Discussion

This analysis highlights the potential cost-saving benefits associated with reducing the operating capacity of an electrolyzer in energy markets characterized by fluctuating energy prices. Across all scenarios examined within EROCT, we observe a reduction in LCOH when the capacity factors are lowered. Optimal capacity factors range from 60% to 90%, with a medium of 74% projected for 2026. These findings align with previous literatures, which has reported optimal capacity factors ranging from over 40% to over 90% depending on the power market structure and the proportion of renewable power in the energy mix.

Overall, lower CAPEX and higher electricity price volatility creates room for selecting lower optimal capacity factors. This conclusion supports the findings of Jørgensen and Ropenus (2008) through a semi-empirical approach. Moreover, our study reveals that this relationship holds over time, with optimal capacity factors generally decrease as a result of the changing CAPEX and electricity price dynamics.

To achieve the lowest hydrogen production costs, a promising strategy involves oversizing the maximum capacity of electrolyzers and reducing the production by 20%-30% to avoid peak electricity prices. Depending on the construction timeline, the developers would benefit from conducting more detailed analyses to determine the optimal capacity factor for their specific region in future years and accordingly size the facilities to minimize hydrogen production costs.

In energy markets characterized by abundant intermittent renewable power and greater electricity price volatility, the cost-saving effect of optimizing capacity factors becomes more pronounced. Consequently, hydrogen electrolyzers located in regions with abundant renewable generation and limited firming technologies, such as battery storage, stand to gain the greatest cost advantage. While intermittent renewable power sources contribute to higher levels of electricity price volatility, hydrogen plants can leverage periods of low-priced electricity to maximize cost savings. Conversely, in energy markets where electricity prices are more regulated, the potential cost benefit is diminished.

It is important to note that none of the 10 scenarios analyzed in this study are able to reach the government target of $2/kg target by 2026. These analyses are based on 3.6% learning rate identified by NREL, which may not be sufficiently aggressive to achieve the demanded CAPEX reduction. Further discussion on learning rates and their impact on LCOH will be presented in the subsequent section.

The 10 Cambium scenarios encompass various assumptions regarding demand, supply, and market dynamics, and the U.S. energy policy decisions. They also offer insights into potential future policy directions. Therefore, it is crucial to consider these distinct assumptions when interpreting the scenario results and view the findings as likely outcomes within the scope of these assumptions, rather than definitive predictions of the future. Nevertheless, certain conclusions can be regarded as more universally applicable, such as the relationship between CAPEX reduction, reduced CAPEX component in LCOH, and the utilization of highly volatile electricity price in energy markets.

3.5: US DOE Hydrogen Product Cost Analysis and IRA

3.5.1: Analysis

1. DOE 2026 Target Feasibility Analysis: we study how to achieve the 2026 hydrogen production cost target by adjusting learning rates and optimizing capacity factors
2. DOE 2031 Target Feasibility Analysis: we study how to achieve the 2031 hydrogen production cost target by adjusting learning rates, optimizing capacity factors and applying the IRA tax credits

3.5.2: Findings

DOE 2026 Target Feasibility Analysis

The US DOE sets the hydrogen product cost target at $2/kg to be achieved by 2026. In addition to the overall cost target, the DOE has established specific targets for total platinum group metal content, performance, electrical efficiency, average degradation rate, lifetime, capital cost, energy efficiency, and uninstalled capital cost (*Table 1*). Within the context of our analysis, the relevant targets are electrical efficiency and capital cost.

We adjust the rate of improvement in electrical efficiency to align with the DOE's 2026 target of 48kWh/kg H_2 to evaluate the feasibility of meeting these targets. Subsequently, we explore the impact of varying the learning rate to assess the required level of aggressiveness for achieving the DOE's capital cost target of $100/kW and the hydrogen production target of $2/kg at a 100% capacity factor.

Analysis presented in *Table 4* reveals that in half of the scenarios examined, the LCOH remains above the $2/kg target even when the learning rate is adjusted to exceed 97%. A 97% learning rate implies a capital cost close to $0/kW by 2026; however, the remaining high electricity costs hinder the reduction of LCOH in these scenarios below the target threshold. Among the scenarios where meeting the DOE production cost target is possible, three of them necessitate highly aggressive learning rates (72%, 79% and 58% respectively), surpassing what is commonly acknowledged as feasible for electrolyzers (Shoots et al. 2008). Additionally, in these three scenarios, the capital cost must also be lower than the DOE target by 2026 to achieve the production cost target, at $39/kW, $34/kW and $55/kW respectively. This implies that even if we successfully meet the DOE's targets for electrical efficiency and capital cost in these scenarios, the production cost target will still remain unattainable due to the persistently high electricity prices.

Figure 12 exhibits the amount of cost reduction achieved by adjusting electricity efficiency and modifying the capital cost learning rate from 3.6% to 72%. This adjustment results in a 30% decrease in LCOH, from $2.83/kg to $2.00/kg. This pattern of cost reduction is observed in other scenarios as well; however, while a few scenarios may meet the $2/kg LCOH target by 2026, a greater number of scenarios fail to do so.

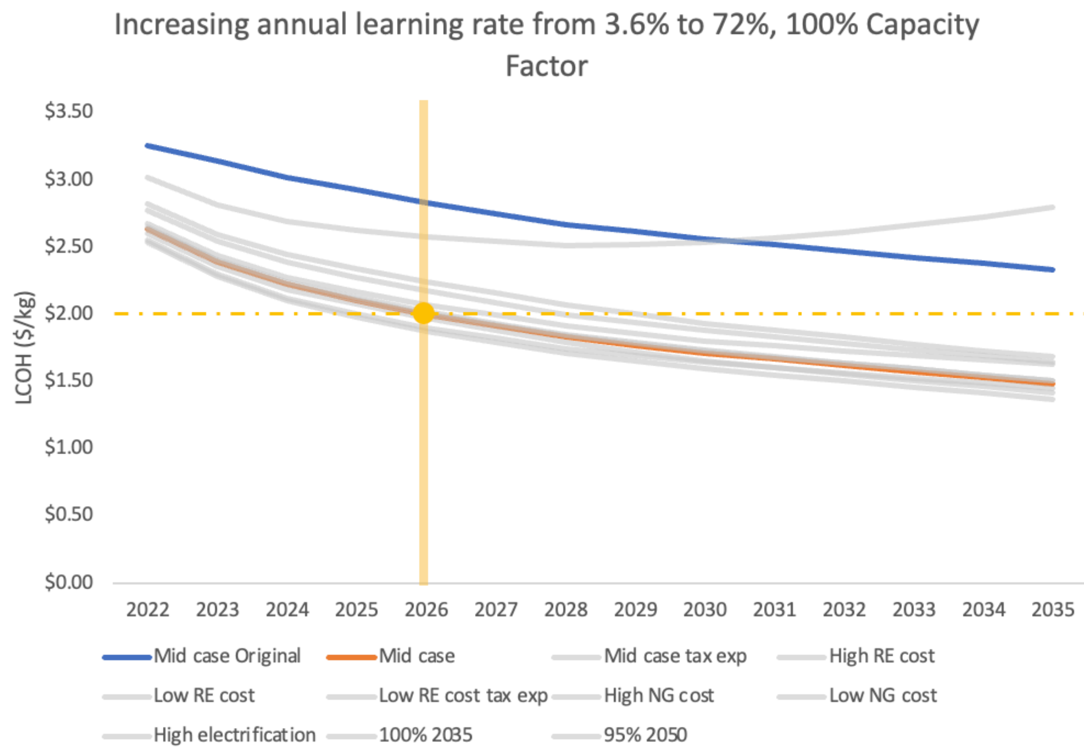


Figure 12 LCOH when increasing learning rate from 3.6% to 72% at 100% capacity factor

Capital cost in 2023		$454/kW
Targeted Capital cost in 2026 by DOE		$100/kW
To attain the $2/kg target by 2026		
	Required Capital Cost in 2026 ($/kW)	**Required Learning Rate**
Mid case	39	72%
Mid case tax exp	34	79%
High RE cost	Won't reach target	NA
Low RE cost	132	32%
Low RE cost tax exp	114	36%
High NG cost	Won't reach target	NA
Low NG cost	55	58%
High electrification	Won't reach target	NA
100% 2035	Won't reach target	NA
95% 2050	Won't reach target	NA

Table 4 Capital cost and learning rate required to attain the $2/kg LCOH target by 2026

Nevertheless, by optimizing the capacity factor, the $2/kg target is much more attainable across all scenarios. As previously discussed, optimizing the capacity factor results in a reduction of LCOH by eliminating production hours when electricity prices are exceedingly high. *Table 5* provides evidence that simply by reducing capacity factor from 100% to 70%, all scenarios are able to achieve the $2/kg production cost target by 2026, with all but 2 scenarios achieving the cost target with a capital cost higher than $100/kW.

To further illustrate the benefits of optimizing the capacitor factor, *Figure 13* presents a compelling visual representation. In the Mid Case scenario, attaining the $2/kg LCOH target by

2026 with a 100% capacity factor requires a learning rate of 72% and an exceptionally low capital cost of $39/kW in 2026. However, by reducing the capacity factor to 70%, the same target can be achieved with a significantly reduced learning rate of 35%. As a high learning rate is technologically more challenging to achieve and requires substantial investment in research and development, this approach proves advantageous. By optimizing the capacity factor, the need for costly technological improvements to achieve low-cost hydrogen is alleviated.

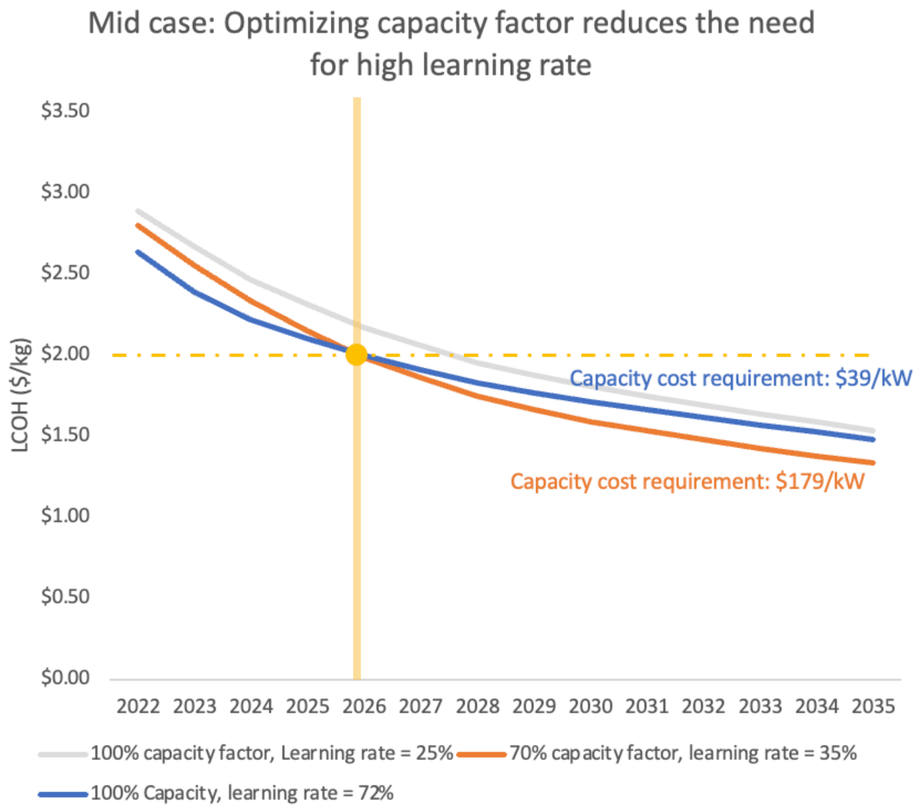


Figure 13 Optimizing capacity factor to reduce the need to high learning rate for the Mid Case scenario

Capital cost in 2023		$454/kW
Targeted Capital cost in 2026		$100/kW
To attain the $2/kg target by 2026		
	Required Capital Cost in 2026 with 100% capacity factor ($/kW)	**Required Capital Cost in 2026 with 70% capacity factor ($/kW)**
Mid case	39	179
Mid case tax exp	34	179
High RE cost	Won't reach target	39
Low RE cost	132	244
Low RE cost tax exp	114	209
High NG cost	Won't reach target	132
Low NG cost	55	132
High electrification	Won't reach target	154
100% 2035	Won't reach target	154
95% 2050	Won't reach target	87

Table 5 Capital cost required to attain the $2/kg LCOH target by 2026 at 100% capacity factor vs. at 70% capacity factor

DOE 2031 Target Feasibility Analysis

We also conduct a comprehensive analysis for the 2031 DOE production cost target of $1/kg. Unfortunately, even after adjusting the learning rate to 97% and lowering the capacity factor to 70%, all resulting LCOH values in 2031 for the 10 scenarios remain higher than the production cost target. Therefore, unless accompanied by additional tax credits or government subsidies, the $1/kg target cannot be feasibly achieved.

In relation to tax credits, the IRA offers incentives to hydrogen producers based on the associated GHG emissions as outlined in the methodology section. The impact of IRA on cost reduction is most notable when the capacity factor is optimized. This is due to the correlation between high electricity prices and a lower proportion of renewable energy in the overall energy mix. By eliminating these periods electricity usage with high carbon intensity, the overall GHG emissions associated with hydrogen production can be reduced, thereby enabling hydrogen to qualify for higher tax credits.

Figure 14 visually depicts the influence of IRA tax credits on LCOH in the Mid Case scenario. When assuming 100% capacity factor, the cost reduction benefit of the IRA is not accessible until 2026 due to the high GHG emission profile within the electricity grid prior to 2026. Nonetheless, upon optimizing the capacity factor, the IRA tax credit benefit becomes available immediately after IRA is enacted, and the amount of tax credit hydrogen producers can claim exceeds the case with 100% operating capacity factor in any given year until the expiration of IRA at the end of 2032. Furthermore, the optimal capacity factor can be lower with the presence of IRA, as the fixed cost component (CAPEX + certain OPEX) is effectively reduced through the application of tax credits and the associated carbon emissions are also lower with earlier-dispatched electricity generated by renewables.

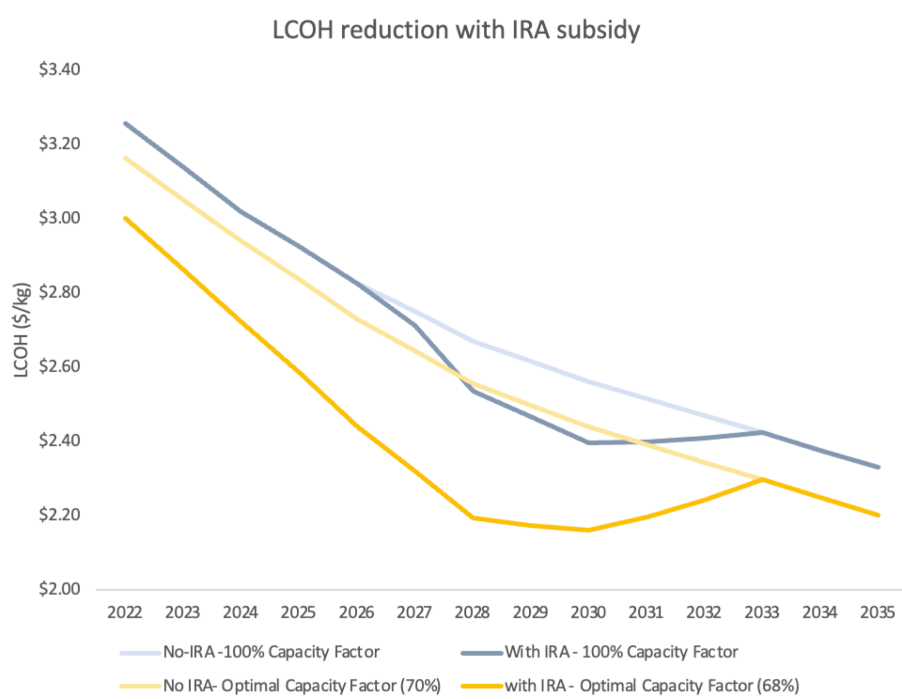


Figure 14 LCOH reduction with IRA tax credit

By implementing the IRA tax credit across all 10 scenarios, we observe that the additional cost reduction brings most scenarios closer to the 2031 cost target. Assuming 97% learning rate and 60% capacity factor (below the previously used 70% because of IRA's impact on optimal capacity factor), two scenarios demonstrate the ability to attain the $1/kg production cost target by 2031. Both scenarios rely on substantial reductions in renewable costs in the future.

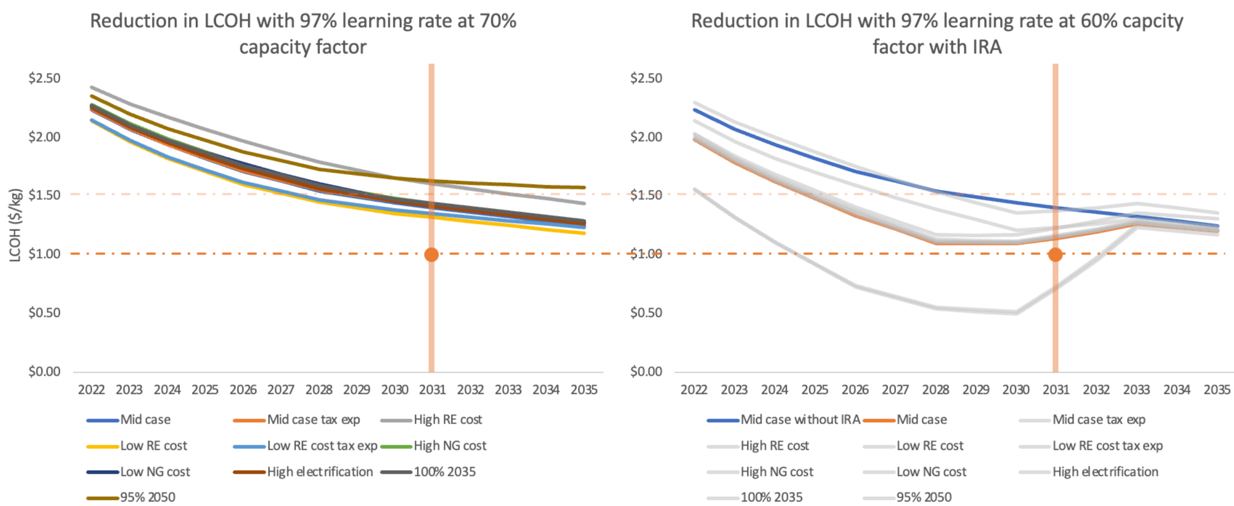


Figure 15 (a) left: Reduction in LCOH with 97% learning rate at 70% capacity factor without IRA; (b) right: Reduction in LCOH with 97% learning rate at 60% capacity factor with IRA

The potential extension of the IRA beyond its current expiration in 2032 could lead to further reductions in LCOH. *Figure 16* illustrates that by extending the IRA to 2035, only three years longer, all but two scenarios would be capable of reaching the $1/kg cost target by 2031, assuming a 97% learning rate and a 60% capacity factor. Furthermore, six of these scenarios could achieve the target even with a capital cost exceeding $100/kW. While a 97% learning rate remains an exceedingly ambitious goal, this analysis suggests that achieving the $1/kg hydrogen target by 2031 is feasible through optimized capacity factors, aggressive CAPEX reductions, and the implementation of tax credits.

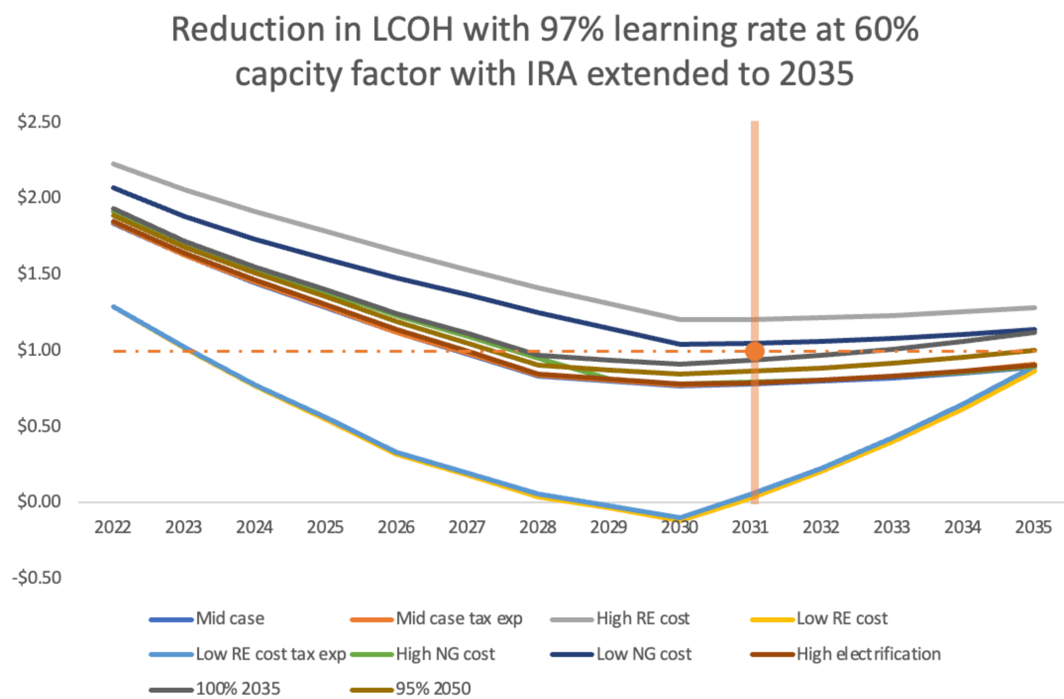


Figure 16 Reduction in LCOH with 97% learning rate at 60% capacity factor with IRA extended to 2035

Capital cost in 2023		$454/kW
Targeted Capital cost in 2031		$50/kW
To hit the $1/kg target by 2031 with IRA extended to 2035		
	Required Capital Cost in 2031 ($/kW)	**Required Learning Rate**
Mid case	111	22%
Mid case tax exp	111	22%
High RE cost	Won't reach target	NA
Low RE cost	434	4%
Low RE cost tax exp	434	4%
High NG cost	111	22%
Low NG cost	Won't reach target	NA
High electrification	111	22%
100% 2035	38	43%
95% 2050	72	29%

Table 6 Capital cost and learning rate required to attain the $1/kg LCOH target by 2031 at 60% capacity factor with extended IRA tax credit

3.5.3: Discussion

This section of the analysis focuses specifically on strategies to achieve the US DOE hydrogen cost targets for PEM electrolyzers. The findings indicate that while it is feasible to attain the $2/kg LCOH target by 2026 through optimized the capacity factors and substantial reductions in capital investments, reaching the $1/kg LCOH target by 2031 is not feasible without the support of favorable government policies. The analysis of the IRA reveals that the current IRA policy provides limited assistance to hydrogen producers in lowering their cost, primarily due to high grid electricity costs. However, extending the duration of the IRA tax credits by 3 years can help alleviate this challenge.

It is important to highlight that the focus of this study is LCOH, which differs from the production cost of hydrogen in any given year. While the production cost of hydrogen in certain years may appear lower, or even negative, it is not sufficient for hydrogen electrolyzer owners to justify a long-term investment, as the annual hydrogen production cost would revert to its original level once the IRA tax credit expires. Therefore, analyzing LCOH is more meaningful and relevant for investor decision-making.

The results also underscore the challenges associated with achieving the hydrogen production cost targets. Even with the $2/kg target, high learning rates are necessary to ensure that the CAPEX can be sufficiently low for low-cost hydrogen production. If hydrogen generators insist on operating their plants at 100% capacity, achieving the LCOH target would require a much lower CAPEX, potentially below $100/kW. Nonetheless, optimizing the capacity factor, or appropriately sizing the hydrogen generation plant and avoiding hydrogen production during periods of high electricity prices, has the potential to obviate the need for aggressive CAPEX reductions.

The persistently high electricity costs across all scenarios present a significant barrier to achieving an LCOH below $1/kg by 2031 without extended tax credits. In light of this challenge, hydrogen generators should actively explore alternative business models to enhance their system's profitability. One such approach is co-locating hydrogen production facilities with renewable generation facilities. By harnessing the synergies between these two sectors, hydrogen generators can benefit from lower electricity costs derived from renewable sources, thus contributing to a reduction in LCOH.

3.6: Summary

The first case study provides a comprehensive analysis of the LCOH of hydrogen produced using PEM electrolyzers in different geographic regions over the next few decades. This comparative study allows for a valuable assessment of various regions and identifies key factors that contribute to cost reduction in order to meet government cost targets.

The findings emphasize the critical role of electricity prices in determining LCOH. Additionally, optimizing the capacity factor of electrolyzers can further contribute to cost reduction. The potential for cost savings through capacity factor optimization is particularly pronounced when electricity price volatility is high and electricity costs account for a significant portion of the LCOH. Although the average reduction in LCOH from capacity factor optimization may be relatively modest (around 4%), its impact becomes more prominent when combined with the IRA tax credit, as low wholesale electricity prices are often associated with lower GHG emissions in the electricity grid. Therefore, hydrogen has considerable potential of utilizing the intermittent power source for cost reduction.

The analysis also highlights the challenges in achieving the general target of $2/kg hydrogen production cost worldwide as it necessitates aggressive reductions in CAPEX and electricity prices. To reach the more ambitious target of $1/kg hydrogen cost in the United States, a near-zero CAPEX and an extended period of IRA tax credits are required. These conclusions are drawn from the Cambium scenarios, which already consider predicted decreases in electricity prices. Considering the low feasibility of achieving the $1/kg hydrogen cost target, investors and developers of hydrogen generation facilities may need to explore alternative avenues for cost reduction, such as industry coupling.

The study acknowledges several limitations:

1. The regional analyses rely on electricity price predictions from third parties. If future electricity prices and volatilities deviate significantly from these predictions, it could affect the resulting LCOH and the validity of the findings.
2. Although the study aims to account for various variables in different regions, it may not capture all potential regional factors that could influence the LCOH of hydrogen production.
3. In the case of horizontal comparisons, the analysis of electricity prices does not include the cost of transmission and distribution. Additionally, for the analysis of specific regions like Texas, the transmission and distribution value is considered fixed, whereas in reality, it may vary depending on factors such as time and location.
4. The granularity of the data from the Cambium scenarios is relatively coarse, with intervals of 2-5 years. Higher-resolution data could potentially lead to different findings.
5. The study relies on hypothetical learning rates, which can be challenging to define accurately for emerging technologies.
6. The analysis focuses solely on hydrogen generated from grid electricity, while in reality, hydrogen electrolyzer owners are exploring different contracting mechanisms with renewable facility owners to minimize the cost of electricity by circumventing utilities. These mechanisms may further reduce average electricity costs but may diminish the cost benefit of reduced capacity factor, depending on the specifics of the contract.
7. The cost of compression, storage and transportation is not included in this study, which can also be significant depending on the time and location.
8. The impact of the demand side responses, stimulated by government policy and reduced cost of hydrogen, is not explored.

4: Case Study 2: Coupling of Hydrogen and Industry

4.1: Introduction and Motivation

In this section, the study aims to fill the gap in economic analysis concerning the profitability of low-carbon industrial hubs that incorporate green hydrogen production and support the decarbonization of other industries. Two specific industrial hub models are examined to explore their overall profitability and optimize their configurations.

The first industrial hub in our model contains hydrogen generation and an Aluminum smelter. There is growing pressure for the Al industry to decarbonize (Hasanbeigi, Springer and Shi 2022*).* Despite recycling efforts, demand for virgin Aluminum remains. After Alumina is extracted from Bauxite ore, a smelting process is needed to convert it into Aluminum. Smelters require a constant, large baseload electricity demand, which may be challenging with a renewable-only industrial hub due to the intermittency of renewable power. Balancing the renewable energy system to meet Aluminum smelter's energy demand involves economic and environmental trade-offs. Oversizing the renewable power generation may lead to excess electricity that goes into waste, while insufficient renewable capacity would necessitate backup conventional power supply and storage investment.

The second model explores the integration of hydrogen generation with steel manufacturing using the H_2-DRI-EAF route. However, there is significant variability in the cost of producing green steel through this process as indicated in current literature. Different studies have assessed the H2-DRI-EAF process and the associated cost of steel production, resulting in varying CAPEX figures ranging from $635/tls to $945/tls (Fischedick et al. 2014; Hornby 2021). In Europe, the CAPEX of DRI + EAF, without considering the CAPEX of the hydrogen electrolyzer, was estimated to be €441/tls (Wortler et al. 2013). Similarly, the operational cost of H2-DRI-EAF also exhibits variations across studies, ranging from $572/tls to $870/tls (Shahabuddin, Brooks and Rhamdhani 2023). These differences can be attributed to varying plant configurations, input assumptions, and regional factors. Additionally, assumptions related to hydrogen consumption and the cost of hydrogen generation contribute to the uncertainty in the cost of producing green steel.

The cost-effectiveness of low-carbon steel produced through the H_2-DRI-EAF route depends on factors such as the green premium and government policies, including subsidies and carbon pricing. Research by Vogl, Åhman and Nilsson (2018) suggests that the carbon price required to make hydrogen-based steel (without scrap content) cost competitive with steel produced using the traditional BF-BOF process was 68 €/tCO_2 for brownfield blast furnace plants and 52 €/tCO_2 for greenfield blast furnace plants. However, other studies have indicated much larger cost differences between the two technologies, ranging from 259 €/tCO_2 to 706 €/tCO_2, primarily due to differing cost and configuration assumptions (Wortler et al. 2013).

Moreover, there is a lack of research on how different renewable power and storage configurations can impact the cost of low carbon steel across different regions. Existing studies typically assume a single electricity source with a constant electricity price. Nevertheless, in a low-carbon industrial hub powered with renewables, the cost of electricity would vary according to the availability of renewable resources, the investment and operation costs of the renewables, the size of the storage system, and technology for storage, and the amount of baseload energy needed.

This study will address these issues with a single model containing consistent data sources with regional variations that is compatible with the previous hydrogen production cost model. Using comparable data inputs and leveraging hydrogen generation assumptions and results from the hydrogen production model, the study conducts profitability analysis of industrial hubs with different configurations, energy mixes, and locations.

4.2: Methodology and Data Collection

4.2.1: Hour-by-Hour Prioritized Dispatch Model with Renewables and Firming

We build a regional hour-by-hour prioritized dispatch model to simulate a low-carbon industrial hub that is primarily powered by wind and solar with the support of storage and firming. The industry hub is consisted of renewable power sources, energy intensive industries, storage mechanisms, and firming technologies. We collect the capacity, CAPEX, OPEX and electricity price information for energy generation and firming technologies, and provide CAPEX, OPEX material needs, power needs, intermittency tolerance (how many hours can the plant go offline due to insufficient power supply without causing prohibitive loss), and sale price information for industrial users in order to evaluate the profitability of the industrial hub as a whole and examine other key indicators, such as the breakeven prices of industrial products (see *Section 4.2.11*), total energy generation, curtailment (the amount of energy generated by the renewable sources but not used) and energy loss (the amount of energy lost due to efficiency reasons), effective electricity prices (total energy cost divided by total consumption), firming demand (the amount of natural gas or grid electricity needed), carbon emission, and optimized energy mix. The model is subject to constraints of the renewable profile in the region, power needs, renewable and storage capacity, the intermittency tolerance of the energy users, and carbon emission allowed by regional policies. The structure of the model is depicted in *Figure 17* with the example of Aluminum smelter and steel plant as industry users.

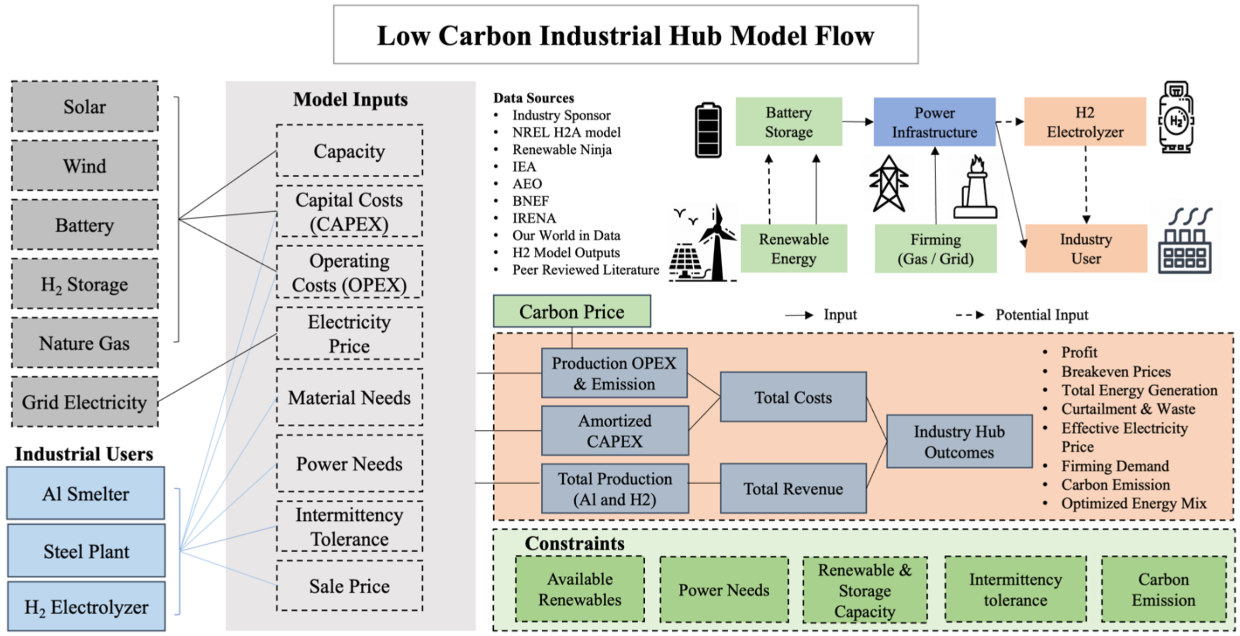


Figure 17 Low carbon industrial hub model flow with structures and detailed components

The industries at the industrial hub are prioritized in a queue based on their intermittency tolerance. The least tolerant industries are the ones that induce prohibitive failure cost if the electricity supply is not sufficient to meet their demand at any hour. At each hour, depending on the amount of renewable power available with given renewable generation profile and renewable capacity, the model makes a decision on whether there is enough electricity to meet the need of the industries according to their position in the queue. If there is excess energy after all industry demands are met, the remaining energy from renewable will be stored in a battery or in the form of hydrogen. If the storage is full, additional energy will be used to supply users that are suitable for intermittent energy inputs, such as hydrogen electrolyzers. If the renewable energy generated at an hour is not sufficient to meet all industry demands, the model will first dispatch storage, and then resort to natural gas plant or grid electricity for firming if there is insufficient storage. If the allowance for natural gas or grid electricity is still not enough for industry demands, a failure cost will be induced. The model logic is described in *Figure 18*.

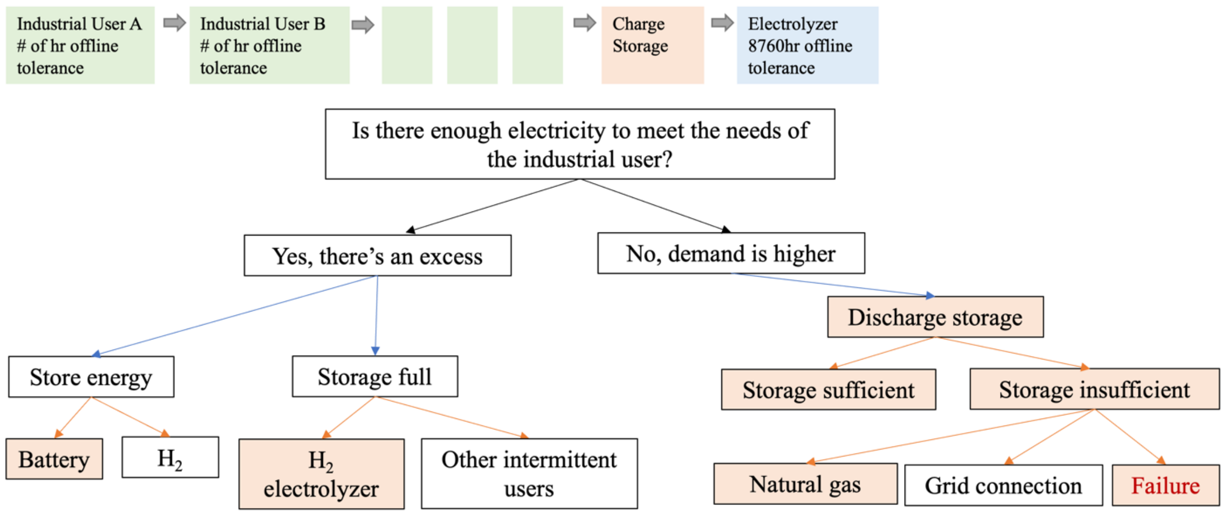


Figure 18 Hour-by-hour prioritization and dispatchment decision tree

4.2.2: Location Selection, Renewable Profile and Year of Analysis

The locations selected are similar to the ones in hydrogen production cost analysis. Some adjustments are made to prioritize locations with more renewable potentials, having constructed low-carbon industry clusters, or are planning on deploying mass renewable or industrial facilities. Within a country or region, we also prioritize locations that have proven large wind and solar generation potentials, such as locations that have already constructed or planned large wind and solar farms. The 14 locations are Australia-Pilbara, UK-Net Zero Teesside (NZT), UK-Zero Carbon Humber (ZCH), Canada-Quebec, Germany-Mecklenburg, California-Kern, Texas-Houston, China-Inner Mongolia, India-Rajasthan, Saudi Arabia, Morocco, Spain-Extremadura and Chile-Atacama. Among the locations, NZT is the first decarbonized industry cluster in the UK, Houston has committed to build hydrogen hubs that support industry developments, and Atacama is a strategic location in Chile for clean energy development.

We use Renewables Ninja to identify the renewable profile for each region (Renewables Ninja, accessed May 17, 2022). Given the latitude and longitude, Renewable Ninja provides the amount of wind and solar power the location receives with 1kW of installed capacity at any hour in a year retrieved from the MERR-a (global) dataset. For solar power, we assume 10% system loss, no tracking, 35° tilt and pole facing. For wind power, we assume a hub height of 80 meters and a turbine model of Vestas V90 2000. The renewable profile data is based on year 2019. Changing any of the parameters above may lead to changes in the resulting renewable profile.

In this study, the industrial hub is in operation in 2030. This is the year when the H_2-DRI-EAF steel manufacturing technology is considered to commercialize, and when many industrial decarbonization pledges are going to be in effect (see *Section 4.2.10*). However, the model has the flexibility to set different operation year in order to study the temporal impact on industrial hub profitability.

4.2.3: Renewable Power Sources

Solar and wind are the only renewable sources in this model. The CAPEX and OPEX of the solar and wind vary according to their locations with a lifetime of 30 years with cost reduction trajectory considered. This model enables users to adjust the capacity of renewable sources individually depending the renewable profiles. Excess energy generated by renewable that is not used or stored are considered to be curtailed.

In this study, we set the capacity of wind and solar the same for simplicity of analysis. Changing the capacity ratio between wind and solar may increase or decrease the system cost depending on the renewable profile in the specific region.

4.2.4: Aluminum Production and Aluminum Pricing

We model an Aluminum smelter of 2,000MW. Aluminum smelters are energy intensive, and can induce huge economic loss if halted due to energy, and therefore it is considered a failure if any hour's electricity support is lower than 80% of the electricity demand. In the industrial hub model, Aluminum smelter only consumes electricity, and all other material needs are included in OPEX as external demand. When battery is used for storage, battery is discharged directly to provide electricity. When hydrogen is used for storage, hydrogen is converted to electricity via a combined-cycle turbine.

Aluminum prices vary across regions and are estimated values based on historical prices and pricing trends. Detailed Aluminum smelter configuration and pricing information is available in the Appendix.

4.2.5: Steel Plant and Steel Pricing

The steel manufacturing technology used in this study is H_2-DRI-EAF. As previously discussed, despite its high cost, H_2-DRI-EAF is the most technologically mature among green steel manufacturing technologies and has the potential to be deployed by 2030. The plant configuration and plant parameters are collected from prior studies on green steel technology and cost comparison as well as the results from the hydrogen cost analysis we perform previously (Hornby 2021; Vogl, Åhman and Nilsson 2018; Shahabuddin, Brooks and Rhamdhani 2023; Wortler et al. 2013).

A steel plant with the H_2-DRI-EAF is constructed with 3 major components: hydrogen generation with a hydrogen electrolyzer, the DRI facility, and the EAF facility. The total steel plant CAPEX includes CAPEX of both the DRI-EAF component and the electrolyzer. The OPEX calculation includes the demand for Iron Ore, limestone, alloys, electrodes, labor, O&M, electricity needed for both hydrogen and DRI-EAF, and some additional expenses. For each ton of steel produced with this process, we need 51kg of hydrogen and 0.814 MWh of additional electricity input. The CAPEX, OPEX and other hydrogen production parameters are from the hydrogen cost analysis and are differentiated by region. In this model, hydrogen is used only as a chemical input in the DRI-EAF process, but not as an energy carrier.

In order to compare the cost of steel made via the H_2-DRI-EAF and via the traditional BF-BOF route, we construct a traditional steel model with CAPEX, OPEX and carbon emission associated with each ton of steel produced. We apply the same CAPEX multiplier that is used for the hydrogen cost model to capture regional variations. This CAPEX multiplier is not applied to the H_2-DRI-EAF model, as we assume for an emerging technology, the capital investment differential is not significant among different regions.

Since BF-BOF is a matured technology and H_2-DRI-EAF is an emerging technology, cost reduction trajectory for either technology is not considered in this model.

4.2.6: Hydrogen Generation and Storage Assumptions

Hydrogen generated from this industrial hub model are all green hydrogen, as the only electricity source for the electrolyzer is wind and solar energy.

As previously discussed, the CAPEX, OPEX and electricity consumption assumptions for a hydrogen electrolyzer is taken from the hydrogen cost model that account for cost reduction from learning over time and regional variation. Since the year of analysis is 2030, we use the electrolyzer cost assumptions modelled for 2030.

We use pressurized containers to store hydrogen. Three different hydrogen storage facilities with pressure levels of 50-80 bar, 350 bar and 700 bar are modeled. Higher pressure level comes with higher electricity demand, CAPEX and OPEX. Hydrogen storage cost reduction potential over time is not considered.

In this study, the size of storage is configured according to the size of electrolyzer, and it is just large enough to store all hydrogen generated from the electrolyzer at its max capacity for any hour. Hydrogen generated but cannot be stored can be sold either at a fixed market price or at its annualized cost, which is the total cost of annualized CAPEX and annual OPEX divided by the total volume of hydrogen generated in a year.

To convert hydrogen back to electricity, we use an open-cycle turbine or a combined-cycle turbine. Combined-cycle turbine has higher efficiency than open-cycle turbine (48% vs. 38%), but also have higher CAPEX and OPEX. Cost reduction potential over time is also not considered.

4.2.7: Battery Storage Assumptions

A 4-hour battery is assumed for this model with a round-trip efficiency of 86%. The CAPEX and OPEX of battery vary according to regions. Battery cost decreases as time goes on.

4.2.8: Gas Plant Assumptions

For gas firming, we model a 30-year-lifetime gas plant with varying CAPEX and OPEX across different regions over time. The gas price in different regions also change depending on the year and the location.

The size of the gas plant is determined by the maximum firming demand at any hour. For example, in the case of a 2,000 MW Aluminum smelter, if at any hour neither renewable power sources nor the storage system is able to supply any power, the gas plant size will need to be 2,000 MW. If the minimum amount of power renewable and storage can provide is 500 MW, than the gas plant size will be 1,500 MW.

4.2.9: Grid Electricity and Carbon Emission

For grid electricity firming, the industrial hub needs to purchase electricity from the market. We use the same electricity market price assumption as the hydrogen cost model for the global regions, and we omit the transmission and distribution cost in this model as well to provide a "least cost" scenario.

The carbon emission intensity of grid electricity in different countries can vary. In this study, we use both the grid emission profile in 2022 and the predicted emission in the sustainable development scenario from IEA in 2030 to study the impact of grid emission, optimal energy mix and associated emission content of metals produced (IEA 2022; Fulghum 2023).

4.2.10: Carbon Emission Sources, Carbon Emission Thresholds and Carbon Price

There are 2 major emission sources from electricity generation in this model, natural gas plant and grid electricity. In addition, we add the upstream emissions, carbon emissions of the mining process on top of the emission of electricity consumed, which is about 0.5t CO_2/t Al and 0.168t CO_2/t Steel (de Berker 2023; Gertsen, accessed May 7, 2023; Haque and Norgate 2015, b615-630). Carbon emission associated with renewable facility construction, plant construction, battery manufacturing, transportation, and other operation activities are not considered in this model.

First Mover Coalition has declared their commitment for Aluminum procurement: "At least 10% (by volume) of all our primary aluminum procured per year will be low-carbon by 2030" (First Movers Coalition, accessed May 16, 2023). Low carbon Aluminum is defined as "emitting <3t of CO_2 per tonne of aluminium produced, including all emissions from cradle to gate." Similarly, First Mover Coalition's procurement commitment for steel is "at least 10% (by volume) of all our steel purchased per year will be near-zero emissions by 2030," which is defined as "emitting <0.4t (with 0% scrap inputs) to <0.1t (with 100% scrap inputs) of CO_2 per tonne of crude steel produced" (First Movers Coalition, Accessed May 16, 2023). In this study, we use 3t CO_2/t Al and 0.4t CO2/t Steel as our carbon emission threshold.

In this study, we calculate the breakeven carbon price, minimum carbon price needed to make low carbon metal and the traditionally produced metal on cost parity. In other words, for instance, if the carbon price in one region is higher than the breakeven price for near zero carbon steel, than a green premium is not needed for the near zero carbon steel to be competitive in a perfect market.

4.2.11: Breakeven Prices

We use the metric of breakeven metal price to compare the cost effectiveness of different industry hub configurations. Breakeven metal price is defined as the lowest price the metal need to sell for in order to avoid negative profit for the industry hub. In formula:

$$BEP_m = \frac{C_t - P_w}{Q}$$

Where BEP_m is the breakeven price for the metal, C_t is the total cost of the industrial hub, P_w is the profit without selling any of the metal produced, and Q is the quantity of the metal produced. For the Aluminum model, Q would be the quantity of Aluminum produced, and in the steel model, Q would be the quantity of Aluminum produced. The higher the breakeven metal price, the less profit the industrial hub can make. If the breakeven metal price is higher than the market price of the metal, the industrial hub would be better off not producing any metal, as the revenue of selling the metal would not be able to cover the cost of production. The profit calculation is:

$$Pro = (P_{mkt} - BEP_m) * Q$$

Where P_{mkt} is the market price of the metal.

We call the difference in breakeven price between the low carbon metal and traditionally produced metal the green premium. In formula:

$$GP = BEP_{lc} - BEP_{trd}$$

Where GP is the green premium, BEP_{lc} is the breakeven price for low carbon metals, and BEP_{trd} is the breakeven price for metals produced with the traditional methods. If $GEP_{lc} < GEP_{trd}$, the green premium would be negative. For example, with high carbon price, we may achieve a negative green premium for hydrogen based low carbon steel.

The breakeven carbon price is the minimum carbon price needed in order to make the low carbon metal cost competitive with the metal produced in the traditional methods. The formula is:

$$\Pr_c = \frac{C_{trd} - C_{lc}}{Q * (CE_{lc} - CE_{trd})}$$

Where $\Pr_c$ is the breakeven carbon price, C_{trd} is the cost of metal produced with the traditional method, C_{lc} is the cost of low carbon metal, Q is the quantity of metal produced, CE_{lc} is the carbon emission per ton of the low carbon metal, and CE_{trd} is the carbon emission of the metal produced with the traditional method. The formula shows that if the low carbon metal has lower production cost than the metal produced with the traditional method, the breakeven carbon price would be negative.

4.3: Low Carbon Industrial Hub with Aluminum Smelter

4.3.1: Analysis

1. Single location analysis of Houston, Texas: analyze the impact of increasing wind/solar capacity, battery size and hydrogen capacity on profitability, breakeven Aluminum price, percentage natural gas firming needed and carbon emission intensity of Aluminum
2. Multi-region analysis: scenario-based analysis on different industrial hub configurations and their impact on low carbon Aluminum breakeven prices and breakeven carbon prices, including:
    a. Sensitivity analysis on electrolyzer CAPEX's impact on breakeven prices
    b. Hydrogen cost analysis and sensitivity analysis on hydrogen selling prices

4.3.2: Findings

Single Location Analysis of Houston, Texas

As outlined in the methodology section, this model simulates an industrial hub powered by wind and solar power with battery or hydrogen storage, supplemented by a natural gas power plant or by grid electricity. This analysis focus on investigating the impact of changing wind/solar capacity, battery size and hydrogen capacity on the profitability of the industrial hub, the resulting breakeven price of Aluminum, the amount of gas firming required, and the carbon intensity of Aluminum.

Figure 19a illustrates the relationship between the increase in wind/solar capacity (from 0 MW to 16,000 MW) and the corresponding changes in breakeven Aluminum price, the percentage of natural gas firming, and carbon emission intensity of Aluminum. Generally, as the renewable power availability increases in the industrial hub, there is a decrease in the dispatch of natural gas power, resulting in lower carbon dioxide emissions. When there is 4,000 MW of each of wind and solar capacity in the system, only 26% of the total electricity consumption is provided by natural gas firming, and the resulting carbon emission intensity is 3.04 tCO_2/tAl, close to the low carbon Aluminum target of 3 tCO_2/tAl set by First Mover Coalition.

However, as the wind/solar capacity increases, the breakeven price of Aluminum also rises. The breakeven Aluminum price represents the minimum market price required to ensure the system remains profitable. A higher breakeven Alunimum price indicates higher system cost due to increased renewable power capital and operational expenditures, as well as decreased utilization of the natural gas plant. The methodology session explained that the size of the natural gas plant is determined by the maximum firming demand at any given hour. Since a gradual increase in renewable capacity does not necessarily decrease the maximum hourly firming demand, the natural gas plant becomes oversized and underutilized.

When the breakeven price matches the market price of Aluminum, the system beaks even by definition. When the breakeven price exceeds the market price, the system incurs a negative profit, indicating an unsuitable industrial hub configuration. *Figure 19a* demonstrates that without storage mechanisms, the maximum wind/solar capacity is around 6,000 MW, as exceeding this capacity results in a net loss for the system. The relationship between the breakeven price and system profitability is depicted in *Figure 19c*.

Next, the analysis explores the impact of battery and hydrogen storage on the breakeven Aluminum price, natural gas firming usage, and associated carbon emission intensity when the wind/solar capacity is fixed at 4,000 MW. *Figure 19b* depicts the scenario where the battery size increases from 0 to 4,000 MWh. The results show that a larger battery size leads to reduced nature gas usage, lower carbon emission intensity of Aluminum, and a higher breakeven Aluminum price. The breakeven Aluminum price increased from $2,459/t to $2,566/t as the battery size increase, while the carbon emission intensity drops from 3.04 tCO_2/tAl to 2.61 tCO_2/tAl. Throughout this process, the breakeven price remains below the market price, ensuring system profitability.

To achieve the same amount of emission reduction at 4,000 MW of wind/solar capacity, the hydrogen generation capacity needs to increase from 0 to 16,000 MW. In this scenario, excess renewable energy is first used to generate hydrogen through a PEM electrolyzer, and then the hydrogen is converted back to electricity using a combined-cycle turbine. Any excess energy that is not stored is sold at a price of $3/kg, which we estimate to be the hydrogen market price ceiling for 2030 based on government commitments and industry reports. *Figure 19d* demonstrates utilizing hydrogen storage for the same emission reduction results in a much higher breakeven Aluminum price, rapidly depleting system profitability. The industrial hub starts generating negative profit when the hydrogen capacity reaches 3,000 MW.

In conclusion, after comparing the different scenarios, it can be inferred that oversizing the wind/solar capacity is the most effective method for reducing carbon emissions. Additionally, coupling the system with an appropriate battery capacity can contribute to further emission reduction without incurring excessive system costs. However, on the contrary, hydrogen storage may not be an efficient approach to emission reduction due to the substantial additional costs it entails.

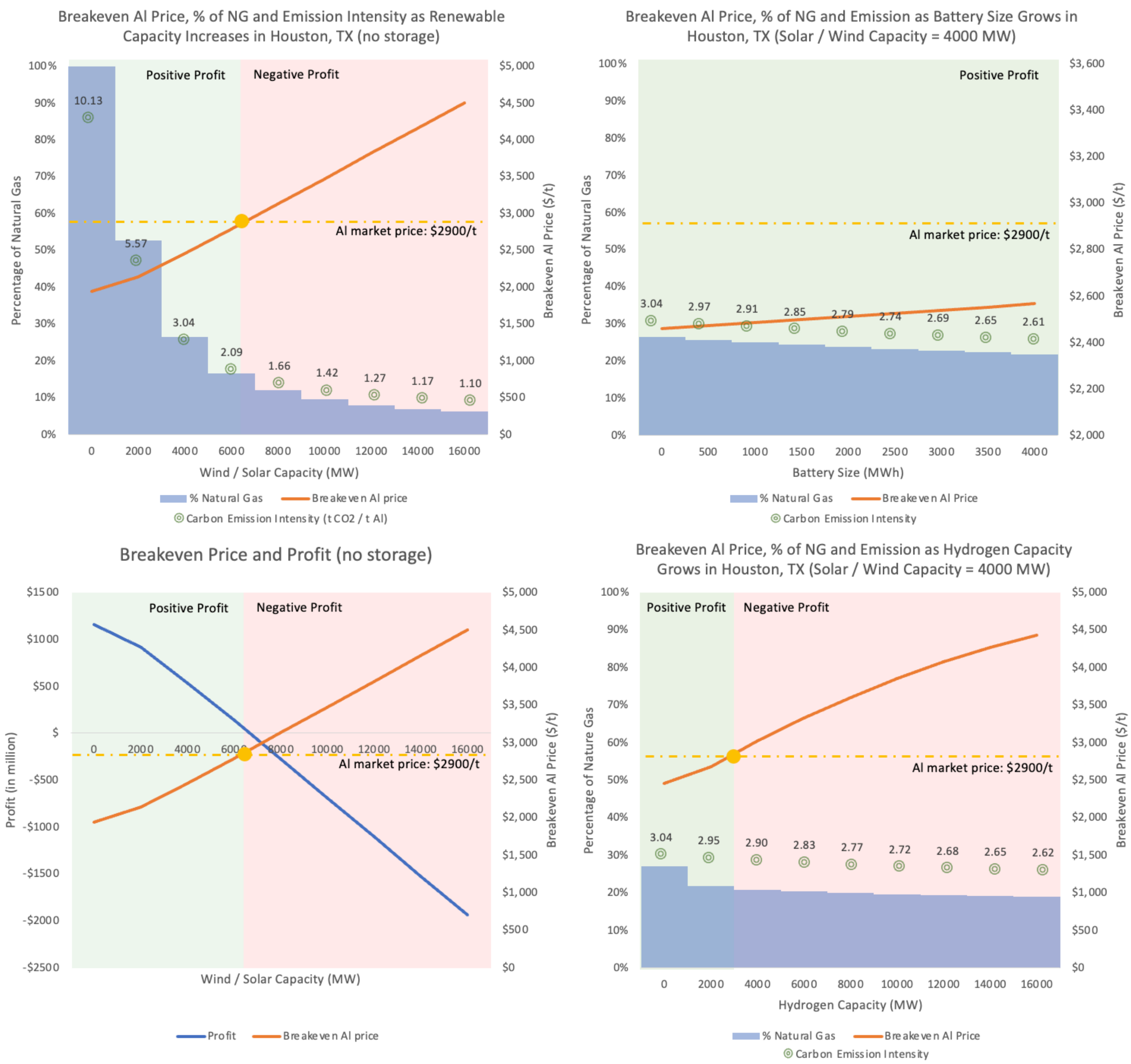


Figure 19 (a) top left: Breakeven Al price, percentage of natural gas usage and carbon emission intensity as renewable capacity increases without storage in Houston, Texas; (b) top right: Breakeven Al price, percentage of natural gas usage and carbon emission intensity as battery size grows with a fixed renewable capacity at 4000 MW for both wind and solar in Houston, Texas; (c) bottom left: Breakeven price and profit comparison in Houston, Texas; (d) bottom right: Breakeven Al price, percentage of natural gas usage and carbon emission intensity as hydrogen capacity grows with a fixed renewable capacity at 4000 MW for both wind and solar in Houston, Texas

Multi-Region Analysis: Scenario Based Analysis on Low Carbon Aluminum Pathways

To analyze the carbon reduction pathways of the Aluminum smelter industrial hub across the identified locations, we have developed five scenarios that yield similar Aluminum carbon emission intensities, as presented in *Table 7*. The Baseline Scenario represents a natural gas-powered hub without any renewables or storage. Scenario 1 incorporates renewable power without storage, supported by natural gas plant for firming. Scenario 2 introduces a 500 MWh battery as a substitute for reduced renewable capacities. In Scenario 3, renewable capacities remain the same as in Scenario 2, but a hydrogen storage system with 4,000 MW of generation power and 84 ton maximum storage capacity is utilized instead of a battery. Scenario 4 is identical to Scenario 3, except that the assumed CAPEX of the hydrogen electrolyzer is 20% of that in Scenario 3. Finally, Scenario 5 represents a system without storage, but instead of firming with natural gas, it relies on Grid Electricity from the year 2022 for firming.

Across all regions, except for the Baseline Scenario, the average emissions are slightly below 3 tCO_2/tAl, demonstrating a low carbon Aluminum production according to the definition set by the First Mover Coalition. Certain degree of regional variation on carbon emission intensity does apply.

	Baseline	Scenario 1	Scenario 2	Scenario 3	Scenario 4*	Scenario 5
Solar Capacity (MW)	0	4,250	4,000	4,000	4,000	3,000
Wind Capacity (MW)***	0	4,250	4,000	4,000	4,000	3,000
Battery Size (MWh)	0	0	500	0	0	0
Hydrogen Electrolyzer (MW)	0	0	0	4,000	4,000	0
Hydrogen Storage Size (t)	0	0	0	84	84	0
Firming Method	Gas	Gas	Gas	Gas	Gas	Grid**
Average Firming Percentage	100%	27%	28%	24%	24%	39%
Average Carbon Emission (tCO_2/tAl)	8.65	2.60	2.66	2.83	2.83	2.80

**Electrolyzer CAPEX is 20% of Scenario 3*
***Grid emission is based on data of year 2022*
****For analysis simplicity, we assume solar and wind have the same capacity in all regions*

Table 7 The scenarios analyzed for the Aluminum production case study

When the industry hub relies solely on natural gas power, the breakeven price of Aluminum remains below its market price in all regions. Nevertheless, as we increase the share of renewable generation in the hub to 4,250 MW for both wind and solar, the breakeven prices of Aluminum experience a sharp increase in most regions. *Figure 20a* illustrates that in regions like Chile-Atacama, Morocco, India-Rajasthan, and Australia-Pilbara, the breakeven cost of Aluminum exceeds the market price. This indicates that industrial hubs in these regions would operate at a loss and would be better off not producing Aluminum at all.

Scenario 2, which incorporates battery storage, allows for smaller renewable capacities. *Figure 20b* demonstrates that the use of battery storage can lead to lower breakeven carbon prices and reduced reliance on natural gas firming. The breakeven carbon price represents the minimum carbon price required for low carbon Aluminum to be competitive with conventionally produced Aluminum in an ideal market. However, the improvement achieved through battery storage is marginal, and the introduction of a carbon price would render more regions unprofitable for such a low carbon industrial hub.

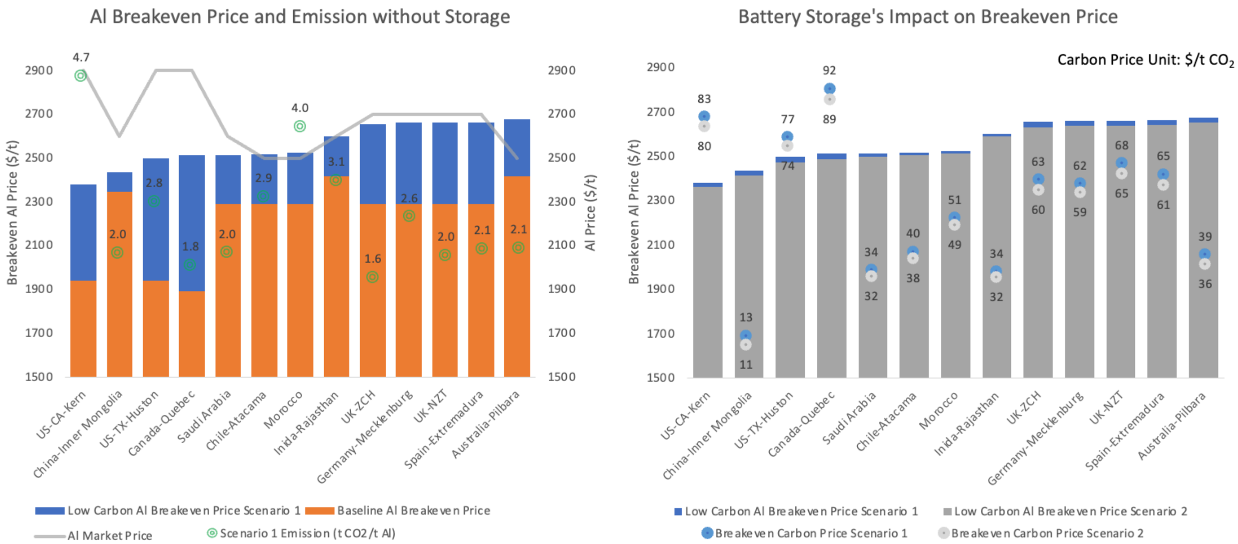


Figure 20 (a) left: Al breakeven prices, market prices and emissions for low carbon Aluminum across all regions for scenario 1; (b) right: Adding a battery storage lowers the breakeven Al price and breakeven carbon price

Scenario 3 and Scenario 4 involve the use of hydrogen storage instead of a battery. Similar to the previous section, in these scenarios, excess renewable energy is first used to generate hydrogen through a PEM electrolyzer, and then the hydrogen is converted back to electricity using a combined-cycle turbine. Any excess energy that is not stored is sold at a price of $3/kg, which we estimate to be the hydrogen market price ceiling for 2030 based on government commitments and industry reports.

Figure 21a illustrates that under both Scenario 3 and Scenario 4, the breakeven prices of Aluminum significantly exceed the market prices of Aluminum in all regions, resulting in non-profitable industrial hubs. In Scenario 4, which assumes lower cost electrolyzers, exhibits lower breakeven Aluminum prices compared to Scenario 3. The breakeven carbon prices of Scenario 4 are between $113/t and $257/t, and those of Scenario 3 are between $130/t and $291/t.

However, if the excess hydrogen generated is sold at its generation cost, the cost advantage of lower-priced electrolyzers disappears. This is because lower electrolyzer CAPEX leads to a lower selling price of hydrogen, which corresponds to the hydrogen production cost, as depicted in *Figure 21d*. The hydrogen production cost ranges from $5/kg to $15/kg, which is higher than the minimum hydrogen generation cost identified in the earlier hydrogen production cost analysis. This increase is due to the low utilization rate of the electrolyzers, as also demonstrated in *Figure 21d*. *Figure 21c* shows that even when hydrogen is sold at cost, the breakeven Aluminum prices remain too high to ensure profitability of the industry hub.

Lastly, Scenario 5 eliminates storage and instead uses grid electricity for firming, based on the 2022 grid electricity emission profile. As shown in *Figure 21b*, Scenario 5 has the lowest breakeven carbon prices, including some negative values. Negative breakeven prices indicate that in these cases, low carbon Aluminum is produced at a lower cost than traditional Aluminum.

Figure 21 (a) top left: Al breakeven prices, market price and carbon emissions for scenario 3 and scenario 4; (b) top right: Impact of an electricity grid on Al decarbonization; (c) bottom left: Al breakeven prices when hydrogen is sold at cost; (d) bottom right: Cost of hydrogen generation and electrolyzer utilization

4.3.3: Discussion

The scenario-based analysis demonstrates that for an industry hub housing an energy-intensive sector with low tolerance for intermittence, such as an Aluminum smelter, the optimal solution is to complement the renewable resources in the hub with grid electricity. Even with the 2022 emission profile, this configuration has already proven to be superior in terms of cost efficiency while meeting the industry's emission targets. In certain locations, the low carbon Aluminum produced can achieve cost parity with conventionally produced Aluminum even without a carbon price. As grid emissions are expected to further decrease with the inclusion of more renewable energy sources, this advantage will become even more pronounced.

However, if the industry hub is situated in remote locations that pose challenges for grid electricity connection without significant transmission and infrastructure costs, the best approach is to increase renewable capacities and pair them with battery storage. This solution works well in areas with abundant renewable resources but can present financial challenges if the renewable generation is insufficient. A carbon price ranging from \$30/t to \$80/t is necessary in most cases to make low carbon Aluminum competitive in the market against Aluminum produced solely from natural gas. While such a carbon price is feasible in many regions, the market price of Aluminum will also increase to account for the carbon price.

In the analysis conducted, hydrogen storage does not emerge as a competitive option. The high cost of hydrogen generation is attributed to low utilization rates of less than 20%, resulting in higher breakeven prices of Aluminum compared to other scenarios, even after an 80% reduction in the CAPEX of the hydrogen electrolyzer. The required carbon prices in these cases are prohibitive, with the highest breakeven carbon price reaching \$257/kg.

The low utilization rate and low round-trip efficiency make hydrogen storage relatively expensive. The current electrical efficiency of PEM water electrolysis is estimated to be up to 77%, while the combined-cycle turbine has an efficiency of 48% (U.S. Department of Energy, accessed May 7, 2023b). Consequently, the round-trip efficiency amounts to 37%, significantly lower than the 86% round-trip efficiency of a battery. Although the hydrogen storage scenario results in the least amount of curtailed energy, significant amount of energy is loss during the conversion processes. Furthermore, while the cost competitiveness of scenarios with hydrogen storage improves when excess hydrogen is sold at its generation cost instead of a hypothetical market price of \$3/kg, it is important to acknowledge that a hydrogen price ranging from \$5/kg to \$15/kg may not be competitive in the hydrogen market in 2030. The DOE has set a target hydrogen production cost of \$1/kg by 2031, and as indicated by earlier analyses, achieving \$2/kg hydrogen by 2030 is feasible. The market price for hydrogen, therefore, should be significantly lower than \$5/kg.

In conclusion, to produce low carbon Aluminum in a renewable-powered industry hub, the most cost-effective approach is to employ grid electricity for firming without storage, while hydrogen storage emerges as the least competitive option.

4.4: Low Carbon Industrial Hub with Steel Manufacturing

4.4.1: Analysis

1. Single location analysis of Houston, Texas: analyze the impact of increasing wind/solar capacity, battery size and hydrogen storage size on profitability, breakeven steel price, percentage firming needed and carbon emission intensity of steel
2. Multi-region analysis: Scenario based analysis on different industrial hub configurations and their impact on green steel breakeven prices and breakeven carbon prices
    a. Sensitivity analysis on electrolyzer CAPEX's impact on breakeven prices
    b. Analysis on the impact of a cleaner grid on optimal industrial hub configuration

4.4.2: Findings

Single Location Analysis of Houston, Texas

In this analysis, we initially compare the profitability of the two firming technologies. Without any storage mechanism, natural gas firming demonstrates higher profitability when the share of renewable power is relatively small. However, as the share of renewable power increases, the profit from natural gas firming declines more steeply compared to grid firming. This decline can be attributed to reduced natural gas plant utilization when renewable power becomes dominant. Since the natural gas plant is sized to meet peak energy demand at any hour, reduced usage renders the investment in the natural gas plant less efficient. In contrast, grid electricity firming, which involves purchasing electricity according to the amount used, experiences a less pronounced decline in profitability as renewable power increases. *Figure 22a* illustrates this relationship.

Moreover, grid electricity firming outperforms natural gas firming in terms of carbon emissions reduction. *Figure 22b* demonstrates that to achieve steel production with carbon emissions below 0.4 tons per ton of steel, grid electricity firming requires a wind/solar capacity of 8,000 MW, whereas natural gas firming necessitates a renewable capacity of over 12,000 MW. Considering the potential increase in the cost of renewable infrastructure as capacity increases, using grid electricity for firming proves to be a more cost-effective option compared to natural gas firming.

Next, we compare the performance of battery and hydrogen storage systems. In the analysis of steel manufacturing, our approach to measuring hydrogen storage size differs slightly from the analysis conducted for aluminum smelters. Instead of focusing on hydrogen production capacity, we define hydrogen storage capacity based on the additional generation capacity required to meet the specific hydrogen demand in the H_2-DRI-EAF process. This additional capacity is expressed as a percentage of what is just sufficient for the required hydrogen amount.

Interestingly, the two storage mechanisms do not differentiate from each other significantly in the context of steel manufacturing. While hydrogen storage is considerably more expensive than battery storage in the case of aluminum smelters, the cost difference between the two storage technologies is only marginal for steel manufacturing, as depicted in *Figure 22c* and *Figure 22d*.

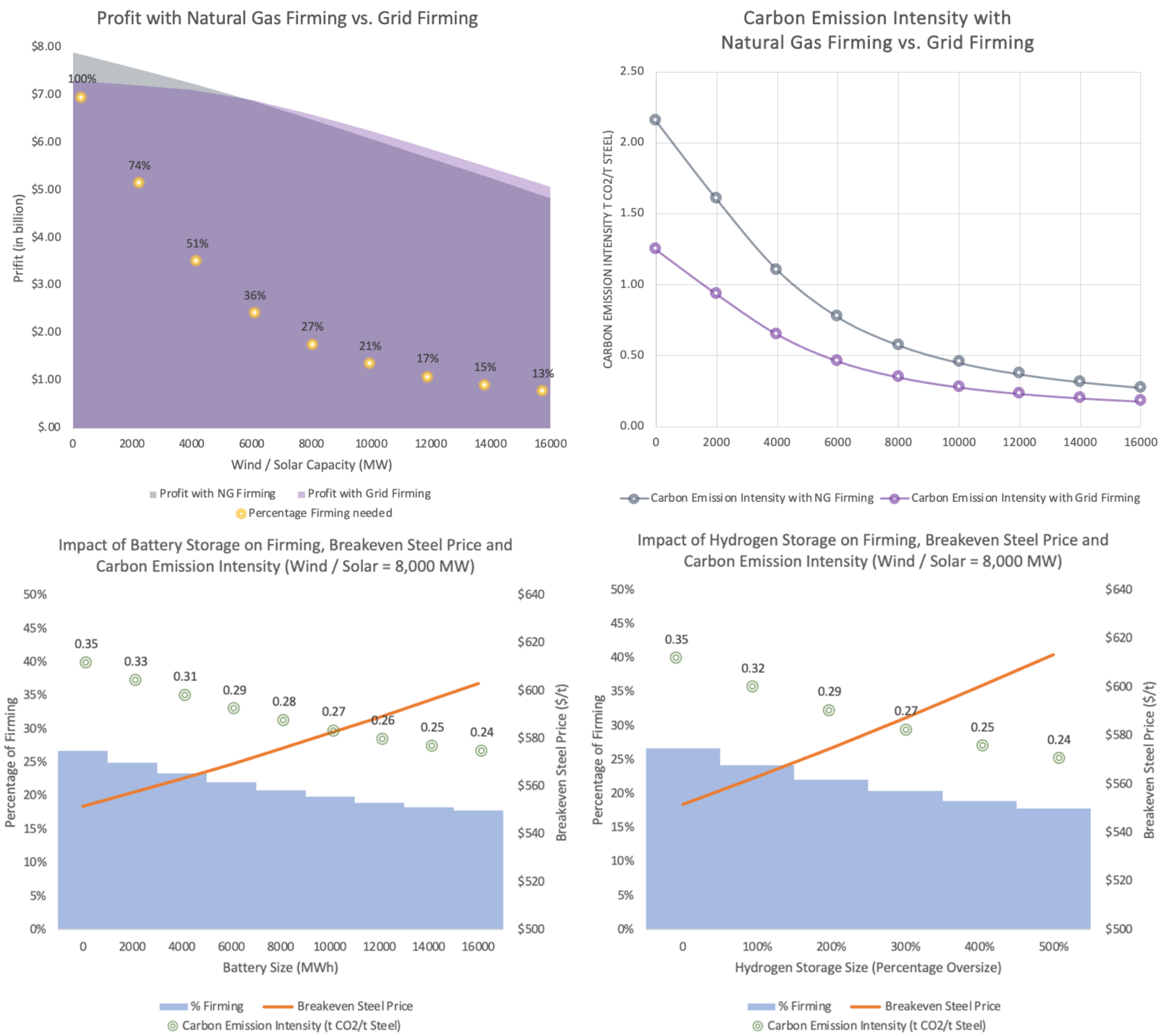


Figure 22 (a) top left: Profit with Natural Gas firming vs. grid electricity firming, and the percentage of firming needed as wind/solar capacities increase; (b) top right: Carbon emission intensity with natural gas firming vs. grid electricity firming as wind/solar capacities increase; (c) bottom left: Impact of battery storage size on firming, breakeven steel price and carbon emission intensity when wind/solar capacities are at 8000 MW; (d) bottom right: Impact of hydrogen storage size on firming, breakeven steel price and carbon emission intensity when wind/solar capacities are at 8000 MW

Multi-region analysis: Scenario Based Analysis on Different Industrial Hub Configurations

To assess the feasibility of green steel production while keeping the average carbon emissions below 0.4 tCO_2/t Steel across all regions, we develop five distinct scenarios. In Scenario 1, no storage is utilized, and renewable capacities are set at 10,000 MW. Scenario 2 allows for the installation of smaller renewable capacities by oversizing the hydrogen generation capacity to be 200% larger than what is necessary for supplying the H_2-DRI-EAF process. In Scenario 3, the hydrogen facility is not oversized, but a 4,000 MWh battery is deployed for storage purposes. Scenario 4 combines the elements of Scenario 2 and 3, incorporating scaled-down battery and hydrogen storage. While scenarios 1 to 4 employ the grid carbon emission profile from 2022, Scenario 5 incorporates the International Energy Agency's prediction of grid carbon emissions under the sustainable development scenario.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Solar Capacity (MW)	10000	8000	8000	8000	3000
Wind Capacity (MW)*	10000	8000	8000	8000	3000
Battery Storage (MWh)	0	0	5000	4000	0
Hydrogen Oversize	0%	200%	0%	100%	0%
Firming Method	2022 Grid	2022 Grid	2022 Grid	2022 Grid	2030 Grid
Average Carbon Emission (tCO_2/t Steel)	0.38	0.37	0.38	0.38	0.36

**For simplicity reason, we assume that solar and wind have the same capacity across all regions*

Table 8 Scenarios for the Industrial Hub Steel Manufacturing Analysis

Figure 23 presents the breakeven price comparison between green steel and brown steel. The breakeven prices for green steel range from 8% - 37% higher than those for brown steel. With the implementation of a carbon price averaging $76 per ton, this price disparity can be effectively mitigated. The carbon emission intensity of green steel exhibits regional variations, but on average, it falls below the threshold set by the First Mover Coalition for defining green steel.

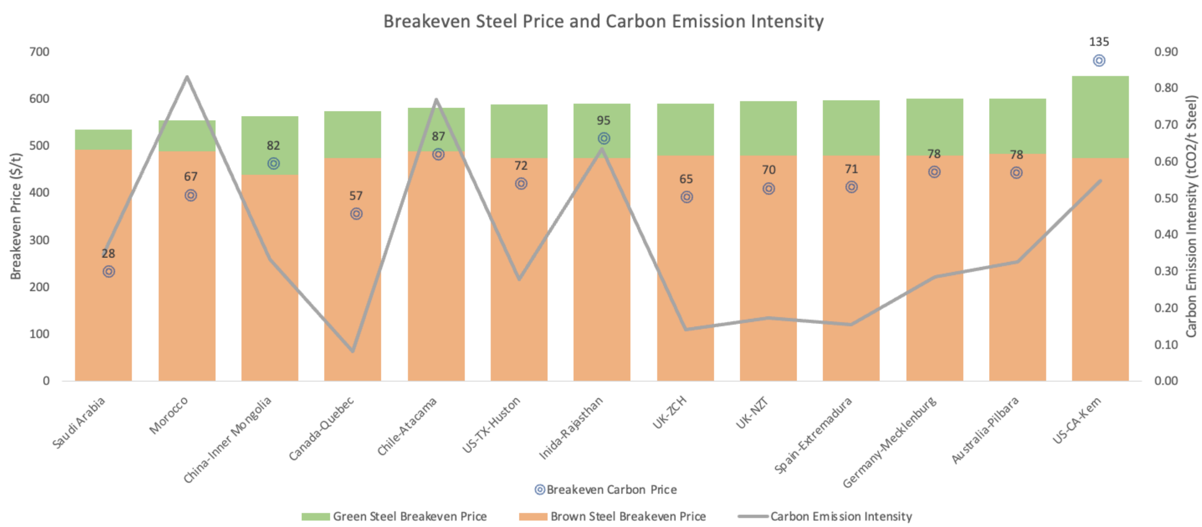


Figure 23 Comparison of green steel and brown steel breakeven prices, breakeven carbon prices and emissions

We subsequently examine how different storage technologies and industrial hub configurations could affect the breakeven prices given the emission constraint. Unlike the case of aluminum production, where battery storage proved significantly more profitable than hydrogen storage, the steel manufacturing model demonstrates similar outcomes for battery storage, hydrogen storage, and the hybrid battery-hydrogen storage. This similarity is evident in *Figure 23a*.

Among the scenarios analyzed, the case involving only battery storage (Scenario 3) yields the lowest average breakeven price for green steel, at $566/t. It is closely followed by the hybrid storage case (Scenario 4) at $580/t, the hydrogen-only case (Scenario 2) at $582/t, and the no storage case (Scenario 1) at $588/t. The resulting average breakeven carbon price falls within the range of $62/t to $76/t, which aligns with previous research and is deemed attainable based on the trajectory of global carbon markets (Vogl, Åhman and Nilsson 2018).

The breakeven prices are significantly lower than the prevailing market price for steel in most regions as *Figure 24a* depicts. However, the current steel prices are considerably higher than the historical levels in many parts of the world, necessitating caution in interpreting the present steel prices are inflated (SteelBenchmaker 2023). However, with the current price inflation, our analysis confirms that the cost of green steel remains significantly lower than the market price, even when considering the breakeven carbon price.

Additionally, we calculate the annualized cost of hydrogen production across these scenarios. Scenario 2, where hydrogen is oversized and serves as the sole storage method, exhibits the lowest annualized hydrogen production cost. The variations in hydrogen production costs can be attributed to changes in effective electricity prices resulting from different industrial hub configurations, curtailment levels, and the amount of grid electricity required. While the average breakeven prices for green steel differ by only 3%, the disparity among annualized hydrogen production costs can reach as high as 26%, as illustrated in *Figure 24b*.

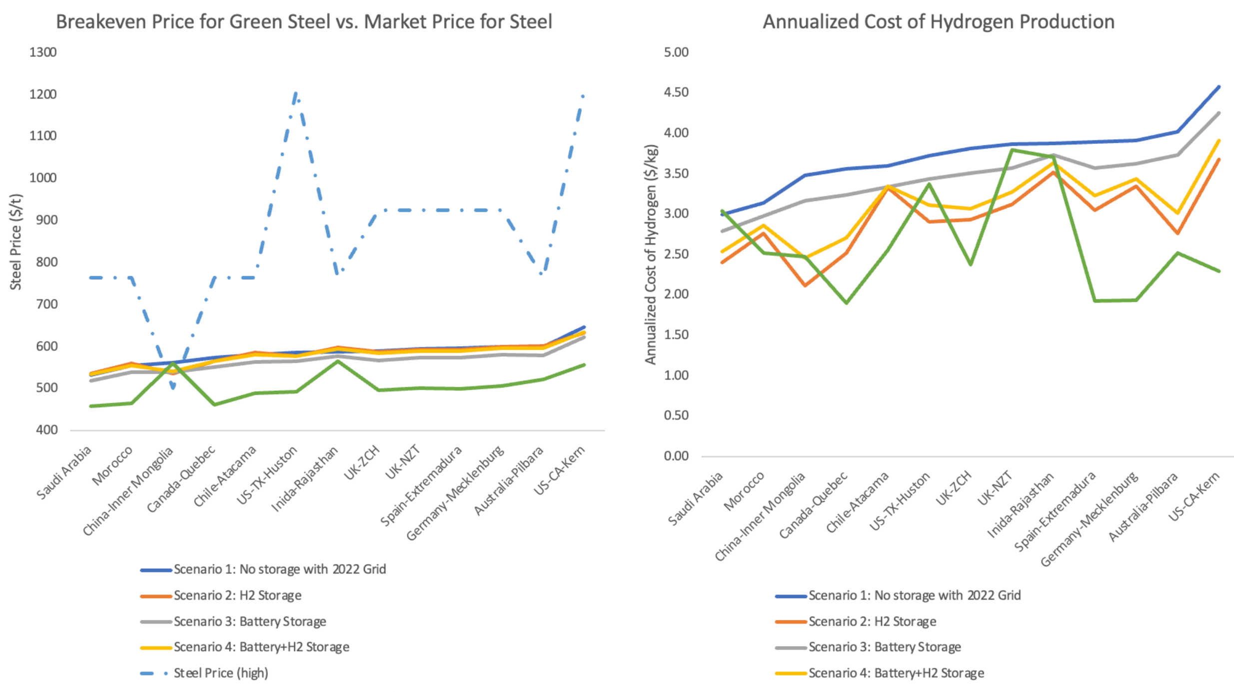


Figure 24 (a) left: Breakeven prices for green steel in all scenarios vs. market prices for steel; (b) right: Annualized cost for hydrogen production in all scenarios

Sensitivity analysis shows that after reducing electrolyzer CAPEX by 80%, the resulting effect on the breakeven green steel price is relatively insignificant. *Figure 25a* illustrates that the CAPEX of electrolyzers is not the most influential factor affecting the breakeven price.

However, a more substantial difference is observed when considering the reduction in grid emissions. *Figure 24b* presents Scenario 5, which is similar to Scenario 1 but assumes a significantly lower grid emission profile. In this scenario, achieving green steel with carbon emissions below 4 tCO_2/t Steel becomes feasible with a smaller renewable capacity of 3,000 MW for both wind and solar. Consequently, the cost of green steel is considerably reduced, leading to a corresponding decrease in the breakeven carbon price. *Figure 25b* demonstrates that the breakeven carbon price can even become negative in this scenario, indicating that green steel production can be more profitable than steel produced through the traditional BF-BOF route.

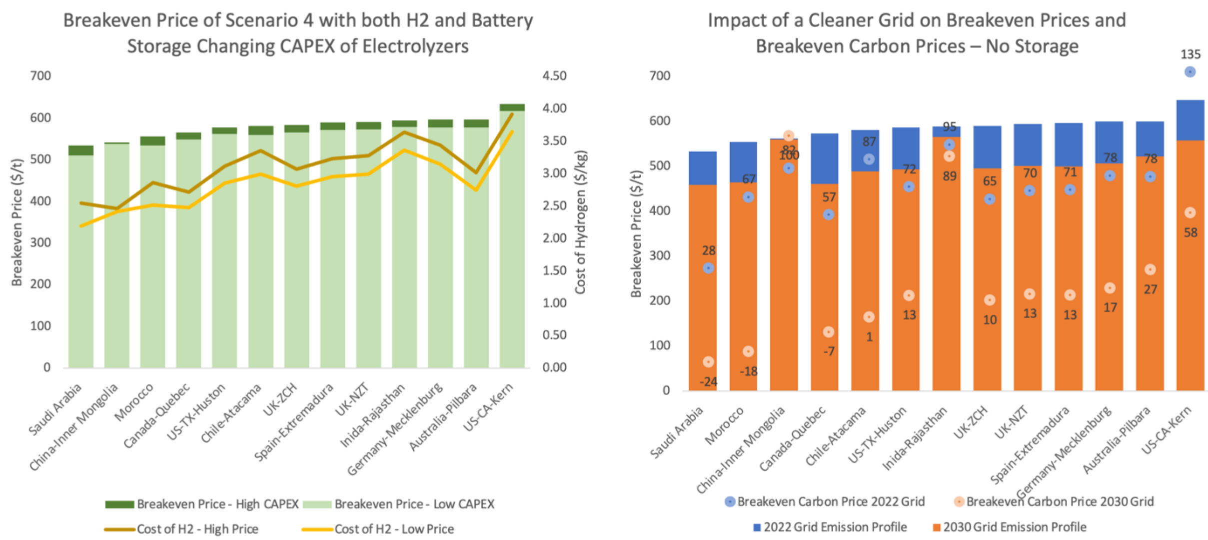


Figure 25 (a) left: Breakeven price of green steel and annualized cost of hydrogen in Scenario 4 with high and low CAPEX of the hydrogen electrolyzer; (b) right: Impact of a cleaner grid on breakeven prices of green steel and breakeven carbon prices without a storage system

4.4.3: Discussion

The analysis on the low carbon industrial hub with Aluminum smelter shows that hydrogen is an uncompetitive storage method compared with battery storage or the use of grid electricity. Nonetheless, the industrial hub with H_2-DRI-EAF shows that hydrogen has about the same performance as battery. While the configuration of the industry hub differs based on the use of hydrogen-only, battery-only or hydrogen-battery hybrid storage system, the overall profitability, as indicated by the breakeven steel price for green steel, remains very similar. In the case of Aluminum, hydrogen is solely used as storage, resulting in lower efficiency rates and utilization under decarbonization constraints. Nevertheless, in steel manufacturing, hydrogen serves as both a storage and a material input, and therefore the utilization rate is much higher. Additionally, given the high hydrogen demand for steel production, hydrogen storage is prioritized for steel production and deprioritized for electricity generation. Without the energy loss of the turbines, the overall efficiency of hydrogen is higher. As a result, hydrogen is more cost-effective when used both as a storage and as a material input, compared to when used solely as storage.

The results also indicate that the carbon price required for green steel to be competitive against brown steel is generally achievable, ranging between \$60/t and \$90/t in most regions. Given that the EU ETS price has already exceeded €100/t, green steel has strong potential to become a cost-competitive product by 2030 in regions where carbon prices remain high. However, in locations with a lower carbon price or without a carbon pricing system, buyers will need to pay a green premium when purchasing green steel.

Furthermore, the steel case highlights the significance of grid decarbonization for industrial decarbonization. By substituting the traditional blast furnace steel production process with electricity-based DRI-EAF using the 2030 grid, the industrial hub can achieve significantly higher profit compared to all storage cases using the 2022 grid. In certain regions, the decarbonized grid could lead to a lower breakeven price for green steel compared to the breakeven price for brown steel, leading to a negative carbon price.

Lastly, regional variation has a major impact on the profitability of the industrial hub as well as the carbon emission intensity of the steel produced. With the same renewable capacities and battery configuration, the breakeven price for green steel can vary by around 20%, and the carbon emission intensity of the steel can differ by up to 9 times. The variations are influenced by regional differences in renewable profiles, CAPEX and OPEX of hydrogen production, grid electricity price, and grid electricity carbon emission intensity. The results indicate that Saudi Arabia, Morocco, China, Canada and Chile are cost competitive locations for green steel production, while Europe, US and Australia would have higher green steel costs. However, lower production costs do not necessarily guarantee higher profits, as the profitability of the industrial hub also depends on the market price for steel, which varies significantly across regions. Despite current inflation, the market prices of steel in Europe, US and Australia have sufficient margins to compensate for higher production costs.

4.5: Summary

Green hydrogen, hydrogen produced from renewable power, holds promise for decarbonizing the metal processing industry. Nevertheless, the economic viability of hydrogen usage in decarbonizing metal processing facilities depends on various factors such as the industrial hub configuration, energy mix, CAPEX, OPEX, renewable energy availability, grid electricity price, grid emissions, and the role of hydrogen in the metal manufacturing process. The study demonstrates that when hydrogen is solely used as storage and requires conversion into electricity through a turbine, it becomes cost-prohibitive for an industrial hub involving another industry with a significant baseload energy requirement, like an Aluminum smelter. Nonetheless, when hydrogen is utilized both as storage and as a material input, as exemplified in a H_2-DRI-EAF steel manufacturing plant, incorporating hydrogen into the production process becomes economically competitive to other industrial hub configurations. Thus, detailed techno-economic analysis is crucial to comprehending whether green hydrogen can contribute effectively to an industrial hub, taking into account the specific use case, industrial hub configuration, energy source, and hydrogen's role.

Moreover, the study reveals that electrification and grid decarbonization have a substaintial impact on the cost of metal production within the constraints of carbon emissions. Substituting natural gas-powered Aluminum smelter with the current grid is sufficient to produce low carbon Aluminum with an emission intensity of under 3t CO2 per ton of Aluminum at the lowest cost, and a future decarbonized grid can further reduce the emission intensity. The grid electricity in

2030 is capable of producing steel with less than 0.4t of CO_2 per ton of steel at significantly lower costs. In both cases, decarbonized electricity grid emerges as the most cost competitive firming technology when compared to battery and hydrogen storage.

However, there are a few limitations to this study. First of all, in both case studies, we only consider one additional industry alongside the hydrogen electrolyzer in the low carbon industrial hub setting. In reality, most industrial hubs would comprise multiple types of industries with varing energy demands, intermittency tolerance and material requirements. Pairing an energy intensive industry with low intermittency tolerance, such as an Aluminum smelter, with a revenue-generating industry with high intermittency tolerance could enhance the overall profitability of the industrial hub.

Secondly, the study assumes the deployment of renewable capacities in a single point for all locations examined, prioritizing the regions with both wind and solar potential. As a result, the renewable profile is highly sensitive to the point location, excluding regions with either low wind speed and high solar radiation, or high wind speed and low solar radiation.

Thirdly, the study assumes identical wind and solar capacities across in all regions. However, considering the varying availability of wind and solar power in these regions, an optimized mix of wind and solar capacity could result in reduced system-wise costs.

Lastly, there may be discrepancy between the CAPEX and OPEX assumptions we use in this analysis and the actual cost values in the industry. While optimized supply chains, long-term bilateral contracts and learning can improve system-wise cost, supply chain disruptions, international conflicts and material scarcity may increase the overall costs. The sensitivity analysis is not included in this study.

5: Additional Consideration of Hydrogen: Past, Geopolitics and Green Colonialism

5.1: A Difficult Path So Far – History of Hydrogen Policies

Approximately two centuries ago, scientists discovered the secret of generating hydrogen from water through electrolysis. In 1834, English scientist Michael Faraday published Faraday's law of electrolysis, and in 1842, Sr. William Robert Grove, a Welsh physical scientist, developed the first fuel cell in history. In 1866, German chemist August Wilhelm von Hofmann invented the Hofmann voltameter for the electrolysis of water. People hoped that the ability to generate energy from water with electricity would make energy "inexhaustible," and as French novelist Jules Verne wrote back in 1874, people envisioned that "water will be the coal of the future" (Zubrin 2007).

However, the hydrogen fuel generated from water electrolysis has not yet replaced coal or other fossil fuels. In fact, throughout the history, we see waves of hydrogen hypes, driven mainly by political, security and environmental demands, that subdued as priorities shifted.

In the 1970s, the oil crisis caused uncertainty about the sustainability and security of an oil economy. The expectation that nuclear power would provide cheap and accessible electricity also went bankrupt as the cost of nuclear did not go down as anticipated. At that juncture, the US and the EU promulgated strong public support for hydrogen R&D programs, and several international collaboration initiatives on hydrogen development were also founded, among them are the International Association for Hydrogen Energy in 1974 and International Journal of Hydrogen Energy in 1976 (Zubrin 2007; Battery University 2020).

In the 1980s, the instance of Chernobyl further induced people's fear on nuclear safety and energy security. In the 1990s, the concern over global warming caused by increasing amount of CO2 emitted from coal and engine combustion raised global awareness on the need to transition to cleaner energy sources (Zubrin 2007). The Canadian federal government began to support hydrogen R&D programs in the 1980s, followed by the Japanese government in the 1990s (IRENA 2020). In 1992, the Clinton administration started to believe that hydrogen may be an alternative for fossil fuels (Waikar 2020).

In the 2000s, after the incident of 9/11, people were further perturbed by the lack of energy independence. As a result, the Bush administration put significant emphasis on the importance of creating a "hydrogen economy," hoping that it could be a solution to the dependence on oil supplied by the Middle East. Over 2,000 organizations were involved in hydrogen fuel cell development from 1999 to 2001, where more than one billion US dollars were raised for fuel cell companies in public stock offerings (Battery University 2020). In 2002, former Energy Secretary Spencer Abraham said:

> "We envision a future economy in which hydrogen is America's clean energy choice – flexible, affordable, safe, domestically produced, used in all sectors of economy, and in all regions of the country… Imagine a world running on hydrogen later in this century: Environmental pollution will no longer be a concern. Every nation will have all the energy it needs available within its borders. Personal transportation will be cheaper to

> operate and easier to maintain. Economic, financial, and intellectual resources devoted today to acquiring adequate energy resources and to handling environmental issues will be turned to other productive tasks for the benefit of the people. Life will get better (Zubrin 2007)."

In 2003, President Bush affirmed on the hydrogen future painted by Spencer Abraham and decleared that, "the first car driven by a child born today could be powered by hydrogen, and pollution-free (U.S. Department of Energy 2004)." He launched a $1.2 billion dollar Hydrogen Fuel Initiative in addition to his FreedomCAR initiative, aiming at making hydrogen fuel cell cars cost-effective for Americans by 2020 (The White House 2003). In the same year, two major international organizations on hydrogen collaboration were founded, which were International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) and International Energy Agency Hydrogen Coordination Group (IEA-HCG). In 2005, the Energy Policy Act was signed into law by President Bush, granting a $3.28 billion R&D fund during the next 5 years for the realization of practical hydrogen fuel cell vehicles by 2020 (U.S. Department of Energy 2005). In 2006, the Advanced Energy Initiative (AEI) was established to support the research effort of the Hydrogen Fuel Initiative (U.S. Department of Energy 2006).

However, the policy enthusiasm towards hydrogen slowed down shortly after. While the US DOE published multiple policy documents between 2002 and 2006, which are *A National Vision of America's Transition to a Hydrogen Economy – to 2030 and Beyond* in February 2002, *The National Hydrogen Energy Roadmap* in November 2002, *Basic Research Needs for the Hydrogen Economy* in February, 2004 by the Office of Science, and *Hydrogen Posture Plan* in December, 2006, it did so only sporadically afterwards, with only two documents published until 2020: *The Department of Energy Hydrogen and Fuel Cells Program Plan* in September 2011 and *Multi-Year Research, Development and Demonstration Plan* updated in 2012 by Office of Energy Efficiency and Renewable Energy.

Comparable policy trends can be found in the European Union (EU). In 2002, the EU founded a high-level working group on hydrogen with 19 stakeholders from academia, industry, the public sector and the private sector, which issued a vision document in 2003 (IRENA 2020). However, the speed of hydrogen development remained slow until the 2018 French hydrogen strategy was issued. In the Netherlands, after the announced *Dutch Clean Hydrogen Strategy: An overview of possibilities for international clean hydrogen cooperation* in 2007, no additional policy document was available until *The Northern Netherlands Hydrogen Investment Plan 2020* was published, which, in essence, was not notably different from the 2007 document (Kingdom of the Netherlands 2007; Kingdom of the Netherlands 2020).

Finance wise, starting from 2011, US significantly withdrew its hydrogen investment, leaving Europe the single largest investor in hydrogen energy research (U.S. Department of Energy 2011). The estimated global hydrogen investment of $724 million in 2018 was almost one-third lower than the peak investment of $1,100 million in 2008 (BloombergNEF 2020).

As a result, the carbon-free hydrogen economy did not arrive as scheduled by 2020. By Oct. 2020, only around 250 MW of electric generation capacity was produced by 108 fuel cell power plants in the Unites States, and Bush's vision that people could drive cost-effective hydrogen fuel cell vehicles by 2020 did not materialize (EIA 2020). Very few hydrogen fuel cell cars are running on the streets, with even fewer refueling stations. The share of hydrogen in Europe's current energy mix was still less than 2% (J.P.Morgan CAZENOVE 2021). Fifteen years after Bush's pursuit of the hydrogen economy and two centuries into the discovery of hydrogen production technologies, the world is still running on fossil fuels. As summarized in the European Union Hydrogen Strategy, "In the past, there have been peaks of interest in hydrogen, but it did not take off (European Commission 2020)." Reichelstein commented on this problem, saying that "The familiar joke has been that hydrogen is the energy platform of the future – and always will be (Waikar 2020)."

5.2: False Predictions on Investment and Cost - a US case study

Examining the failure of US hydrogen industry development between 2003 and 2018, we can conclude that the hydrogen development attempt failed because of the lack of two critical factors: persistent investment and rapid cost reductions.

5.2.1: Government's Overestimation of its Financial Capacity

In order to foster technology development and to close the cost gap between hydrogen and other fuel sources, upfront investment is critical. Upfront investment can enhance the learning effect and scaling effect, the former improving the technological details and operation efficiency through practice, and the latter decreasing the unit cost of production by increasing scale. Among the two, the scaling effect will be the bigger driver of hydrogen cost reduction, unless significant impact from technological breakthroughs appears (Hydrogen Council 2020).

Historical data shows that investments in hydrogen research and development constantly failed expectations. Using the US investment in hydrogen development as an example, in 2006, the federal government requested $289.5 million investment for the Hydrogen Fuel Initiative in the fiscal year of 2007, while only $274 million was appropriated by Congress (U.S. Department of Energy 2006; 2007). The expectation for 2008 was $309 million, while only $281 million was appropriated (U.S. Department of Energy 2008; 2009). In addition, although the Energy Policy Act of 2005 allocated $3.28 billion for hydrogen R&D over 5 fiscal years in addition to the initial $1.2 billion authorized by the Hydrogen Fuel Initiative, only $1.3 billion was spend between 2006 and 2010, 40% of the anticipated investment by the Energy Policy Act. Even 10 years later, for the 15 years between 2005 and 2019, the total amount of investment appropriated by the Congress was $2.78 billion including the special fund allocated to the development of solid oxide electrolyzer, still lower than the amount planned by the Hydrogen Fuel Initiative and the Energy Policy Act (The White House 2003; U.S. Department of Energy 2005 – 2019).

Moreover, a sharp decline in investment took place starting from 2011. Comparing to the annual federal investments between 2005 and 2010, the 2011 to 2019 annual investments were truncated in half, at $139 billion on average (U.S. Department of Energy 2005 – 2019). The United States' lack of hydrogen development investment stalled the technology development and cost reduction progress, and directly impacted the global endeavor towards a hydrogen economy.

Several potential reasons could explain the investment shortfall. First of all, the change of administration might have led to a shift in policy focus, and the new administrations prioritized federal funding to other investment targets. Secondly, after the discovery of shale gas and the subsequent drastic decrease in natural gas price, the US did not see hydrogen as the only solution to strengthen energy security, and therefore withdrew hydrogen-related investments. Last but not least, as will be discussed in the next section, the cost of hydrogen production and hydrogen fuel cell manufacturing did not decrease as fast as anticipated, which shook the government's confidence in continuing making substantial investment in an elusive hydrogen economy.

5.2.2: Government's Underestimation on Hydrogen Cost

Cost is one of the most important factors that determines whether hydrogen fuel can be widely adopted for industrial processes and transportation. In a perfectly competitive market, the use of hydrogen can only be practical if the cost of hydrogen related products is lower than that of its competitors. In other words, cost of hydrogen production will need to be lower than that of natural gas in order for hydrogen to be competitive in electricity generation, and the cost of hydrogen fuel cells will need to be lower than that of battery cells in order for it to be cost-effective in transportation applications.

The cost of green hydrogen production is dominated by electricity cost, capital investment and operational cost. While electricity cost is external, capital investment and operational costs can be reduced by technology development over years. Back in the 2000s, the US DOE announced the goals of keeping hydrogen cost down to below around $3/kg for production and below $30/kW for hydrogen fuel cell manufacturing by 2020, however, neither goal was fulfilled (U.S. Department of Energy 2006; 2009).

Production Cost

At the beginning of the Hydrogen Fuel Initiative, the US DOE made optimistic predictions on hydrogen production cost reduction. In 2005, the US DOE announced a target of reducing the hydrogen production cost to $3 per gallon of gasoline equivalent (gge), or $2.9/kg of hydrogen (U.S. Department of Energy 2005). The target was verified as feasible in 2006 by an independent review, and in 2008, it is considered achievable by 2019 including delivery (U.S. Department of Energy 2006; 2008).

Nevertheless, seeing the cost reduction progress was slower than the early estimation, the DOE adjusted the cost targets up multiple times. In 2010, it is estimated that the levelized cost of hydrogen could come down to between $4.9 - 5.7/gge ($4.8 - 5.6/kg) for distributed hydrogen production at refueling stations including storage and transportation and $2.7 – 3.5/gge ($2.6 – 3.4/kg) at centralized plant without storage and transportation (U.S. Department of Energy 2010). In 2016, this target was adjusted from $2.7 – 3.5/gge up to $4/gge because of the actual cost by then was not that different from the 2012 level, which was between $4.2 – 7.2/gge for the distributed production cost and between $5.8 – 8.5/gge for the central production cost (U.S. Department of Energy 2012; 2016). Until today, the clean hydrogen production cost in the US is still estimated to be between $6 – 13/kg, not improved from the 2012 level, and about 10 times more expensive than natural gas (U.S. Department of Energy 2020).

Fuel Cell Manufacturing Cost

Similarly, the US target for fuel cell manufacturing cost reduction also experienced waves of adjustments. In 2009, after observing significant price decrease from \$275/kW in 2002 to \$69/kW in 2009, DOE predicts that the fuel cell cost will be reduced to \$45/kW by 2010 and \$30/kW by 2015 (U.S. Department of Energy 2009). However, the fuel cell system cost stagnated from 2010 to 2015, lingering around \$55/kW, which made DOE adjust the cost reduction target to \$40/kW by 2020 and \$30/kW ultimately without a schedule (U.S. Department of Energy 2015). In the DOE Hydrogen Program Record published in January 2021, a revisit of fuel cell system cost revealed higher historical fuel cell costs than those indicated in the annual progress review, with the new 2009 durability-adjusted cost of an 80-kW PEM fuel cell system at 100k units/year being \$207/kW instead of \$69/kW as estimated previously, and the 2015 value being \$99/kW instead of \$53/kW. The actual fuel cell cost in 2020 was \$76/kW, almost twice as high as the \$40/kW target, and the \$40/kW target agenda was again pushed back to 2025 (Kleen & Padgett 2021).

In conclusion, historically in the US, the cost reductions of hydrogen production and fuel cell system manufacturing did not meet past predictions, which forced DOE to keep pushing back cost reduction goals.

Sources of Errors

Several reasons may explain why past cost predictions failed. First, the predictions were made with inaccurate data, which displayed lower initial costs and higher than realistic learning curves. This aspect was well reflected by the cost adjustments published by DOE's Program Report, an indication of the inaccuracy of pass assessment and analysis. Second, the predictions were based on the assumption that R&D investments would be consistent, or even increasing over years, which was contradicted by the sharp investment withdrawal in the 2010s. The hydrogen production and fuel cell manufacturing technologies are also novel and unprecedented, and as a result, they are intrinsically difficult to predict because no existing technology development path could serve as a reliable reference. Lastly, the government might not have kept a mutually trusting relationship with the industry, and as a result, while the government misunderstood the industry's ability to reduce cost, the industry also didn't make enough effort after witnessing the government's failure in keeping its investment promises.

In addition to the reasons stated, it is also possible that the US government had known that the investment and cost predictions were overly optimistic, but still chose to accept the unrealistic numbers in order to gain public support. The Hydrogen Fuel Initiative, which painted a promising blueprint of how the US can be energy independent from the Middle East after the 9/11 terrorist attack, also aimed to strengthen confidence in the US power and economy. However, this strategy takes a toll, as the initial false predictions set a high baseline, which was locked in during the years to come, prohibiting any possibilities to adapt and improve until it eventually failed.

5.3: Decarbonization and Geopolitics

In addition to costs, various factors influence global hydrogen policies and the trajectories of hydrogen development. As we consider the future, the pressures of decarbonization and geopolitics will undoubtedly play significant roles in shaping the path forward for hydrogen.

5.3.1: Decarbonization Pressure

First of all, as more and more nations have made pledges to the net-zero goal by 2050, the pressure of decarbonization is high.

Greenhouse Gas (GHG) emission levels induced by human activities have reached historical height in the last few decades. Countries have taken actions to set emission reduction goals in order to reach the 1.5 degree Celsius global temperature increase limit by 2050 as the Paris Agreement requires. In the 2019 UN Climate Summit, 66 countries announced intents to achieve net-zero carbon emissions by 2050, and identified specific reduction pathways to achieve this target (Hydrogen Council 2020). The Biden Administration has committed to reduce GHG emission levels to 50-52% below the 2005 level by 2030, and to decarbonize the entire electricity sector by 2035 (The White House 2021). The EU sets the goal to reduce GHG emissions by at least 55% by 2030, and China has announced that it will peak carbon emission by 2030 and will achieve net zero by 2060 (BBC 2021).

Among all emission sources, energy production contributes 72% of total emissions, in which transportation accounts for 15% of total emissions (Center for Climate and Energy Solutions, accessed Dec 10, 2020). A total of 160 countries have established clean energy commitments to be achieved by 2020 and 2030 (Ross 2016). Within the US, each state has outlined renewable energy standards, for example, Massachusetts intends to achieve 35% Class I renewable energy by 2030 (NCSL 2020). Globally, China aims to achieve at least 20% non-fossil fuel primary energy production by 2030 (Hydrogen Council 2020), and the European Union targets at a 32% share of renewable energy in its energy composition by 2030 (European Commission, accessed May 22, 2021).

The current annual global fossil fuel consumption of 137 thousand terawatt-hours could not be sufficiently reduced without countries aggressively transitioning to cleaner energy sources (Ritchie & Roser 2017). In addition to expanding on renewable and clean electricity sources such as onshore and offshore wind, solar, hydropower, geothermal and unclear power, more ambitious decarbonization efforts need to be made in the industry manufacturing, energy storage and transportation sectors. Hydrogen, an energy-dense fuel source that has the potential to have zero carbon emission, is therefore recognized as one of the ultimate solutions to decarbonization, despite its high cost and unclear market competitiveness.

5.3.2: Geopolitical Interest

The second reason is related to geopolitical interest. Currently, the world's oil and gas markets are dominated by the Middle East, as it has the largest oil reserve, while Russia and the US also play an essential part because of their resource abundancy of oil and natural gas respectively.

This poses an energy security question to the rest of the world, especially prominently to Europe, as the relationship between Europe and the Middle East is further complicated by political and religious conflicts. Moreover, since the war on Ukraine by Russia in February 2022, Europe can no longer rely on low-cost Russian gas. Due to market scarcity and long transportation distance, liquid natural gas (LNG) prices are also prohibitively high, which has driven up household energy costs by between 62.6% and 112.9% and led to sever energy poverty issues (Lawson 2023). Therefore, there is strong incentive for the EU to develop and dominate the hydrogen market in order to change the current energy landscape.

In its hydrogen strategy, the EU aims to achieve the dominant voice of hydrogen in the following two ways. On one hand, the EU plans to set the standard for hydrogen production. To be specific, it plans to “work to introduce a common low-carbon threshold/standard for the promotion of hydrogen production installations based on their full-cycle GHG performance,” “work to introduce a comprehensive terminology and European-wide criteria for the certification of renewable and low-carbon hydrogen” and “strengthen EU leadership in international setting for technical standards, regulations and definitions on hydrogen (European Commission 2020).” These nationalist standard setting attempts would entitle EU with stronger international discourse power and first-mover benefits in hydrogen production and trading.

On the other hand, the EU aims to take the lead in market regulation, integrating it into the existing carbon trading system, by creating “regulation necessary to facilitate a highly-liquid market that supports supply and demand triggers,” developing “a benchmark for Euro dominated transaction” and designing “enabling market rules to the deployment of hydrogen, including removing barriers for efficient hydrogen infrastructure development and ensure access to liquid markets for hydrogen producers and customers and the integrity of the internal gas market, through the upcoming legislative reviews (European Commission 2020).”

Among these goals, the establishment of Euro dominated transaction is of special importance, as it seems to be in parallel with the existing petrodollar system in the current energy market. The petrodollar system stated in 1974 through bilateral agreements with Saudi Arabia, influencing members of the OPEC to standardize the sale of oil in dollars in exchange of US’s military protection of Arab states in the Israeli-Palestinian conflict as well as other worrisome political and military instabilities. The petrodollar system elevated the US dollar to the world’s reserve currency and supplied the US financial market persistent liquidity and foreign capital inflows, despite the comparatively negligible drawback of the “Triffin Dilemma,” when the US is obligated to run deficits to fulfill reserve requirements which hurts global confidence in dollars (Tun 2020). Nevertheless, recently the global energy market is changing landscape with countries threatening to leave the petrodollar system to punish US’s excessive power-play over the oil market. Boosting hydrogen demand and supply, establishing rules and regulations for a hydrogen market and promoting Euro as the trading currency seems to be a reasonable and valid strategy for the EU at this critical time.

Moreover, the more developed parts of the world probably also consider leveraging hydrogen production projects to retain economic power over smaller developing nations. As is reflected by many national strategies and roadmaps, developed countries usually have more aggressive hydrogen import and implementation plans, while the less developed regions, such as the Middle

East, South Africa and South America, would have more ambitious export goals. For example, Saudi Arabia just conducted world's first shipment of blue ammonia to Japan in 2020 and plans to export green hydrogen to Europe in the coming years (Ratcliffe 2020). US gas company Air Product Chemicals is currently involved in a $5 billion electrolysis plant project powered by solar and wind energy in Saudi Arabia, expected to be completed by 2025 (Farmer 2020). North Africa's hydrogen path is closely tied to that of the European Union, aiming to help Europe become fully decarbonized with green hydrogen produced with renewable energy, mainly wind and solar, by 2050 (Bennis 2021). In Brazil, Israeli power producer Energix Energy plans to build the world's largest green hydrogen facility in Cearra, which costs $5.4 billion and will product 0.6Mt of green hydrogen annually from 3.4GW baseload of renewable energy after its construction in 3-4 years (REM 2021). Germany is in conversation with Brazil on pilot project cooperation (Argus Media 2020). Most recently, French independent power producer HDF Energy announced that its $181 million green hydrogen power plant in Namibia will start to produce 142 GWh of annual electricity output from its hydrogen produced from 85 MW of solar panels in 2024 (Reuters 2022).

5.3.3: Green Colonialism

The potential geopolitical consequences and inequalities in the global trade market associated with hydrogen are a cause for concern. The potential strain on resources, exploitation of labor, and political and social instability could exacerbate the challenges faced by underdeveloped nations, despite the financial gains derived from exports.

The resource intensity of green hydrogen production is well understood. According to public data from National Renewable Energy Laboratory (NREL), each kilogram of hydrogen would consume approximately 50 – 70 kWh of electricity with efficiencies ranging from 56% to 73% (National Renewable Energy Laboratory 2004), and 8.9 liter of water (Kroposki et al. 2006). With this information, we can calculate that in order to product 1 million tons (Mt) of hydrogen annually, we will need 50 – 70 Terawatt-hours (TWh) of renewable electricity and 8.9 million tons of water every year. According to International Renewable Energy Agency (IRENA), in order to achieve the goal of less than 1.5 ˚C temperature increase by 2050, 7 – 9 billion tons of water is required. Although this number is 0.25% of current freshwater consumption and a lot less intense compared to agricultural water usage (IRENA 2022), it can still lead to water stress depending on the level of water supply in different geographic regions.

Research has shown that there is a strong dichotomy between the demand centers and supply centers of hydrogen. While the demand centers are concentrated in developed nations, such as Europe, Japan, South Korea, and the US, the supply centers are primarily in developing nations (Bonciu 2021). For many developing countries, this resource intensity could lead to a series of social and humanitarian issues.

From an energy perspective, Bridge et al. (2013) pointed out that the current hydrogen ambition in European had led to a "frantic hydrogen diplomacy" with Sub-Saharan African countries, and the profitability of selling hydrogen may cause the local elites to prioritize using energy for hydrogen production, leaving the population energy deprived. One example is German government's involvement in the expansion of the Inca III dam in the Democratic Republic of

Congo (DRC), one of the least electrified countries in Africa. The German government considers incentivizing the use of hydro power to produce green hydrogen; however, this will not only deprive the necessary power from the ordinary DRC citizens, but also lead to mass relocation under the risk of human rights abuses and corruption (Bridge et al. 2013). The high energy intensity has also posted a strong risk in the adoption of hydrogen for industrial decarbonization, as one of the major steel manufacturers in the U.S. claimed that they were deterred from hydrogen due to its high energy demand.

From a water perspective, many countries may face the issue of competing water usage. Two maps from the IRENA Geopolitics of the Energy Transformation report (2022) show that many of the identified potential hydrogen export countries locate at regions where water stress levels are medium or high, such as some South American, North African, Middle Eastern and Australian regions (See Figure 1 and Figure 2) (IRENA 2022). As desalination cost is rather significant for many developing countries, the hydrogen production industry will likely create difficulties in balancing industrial and residential water usage.

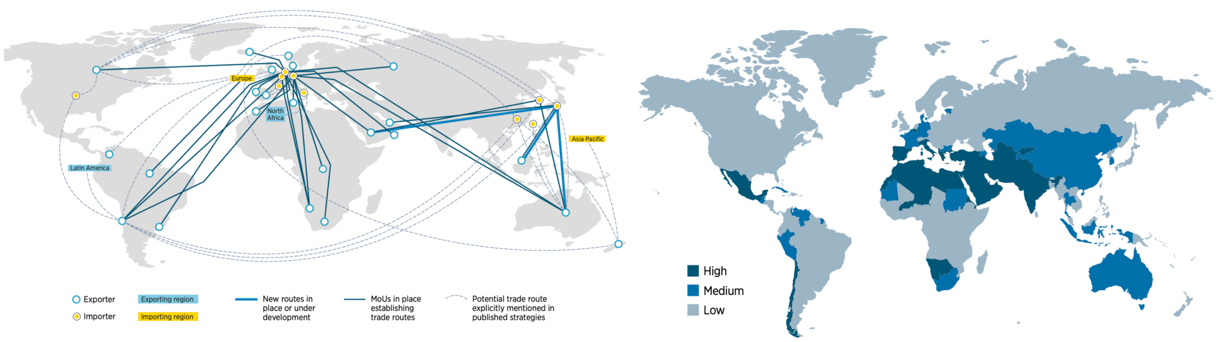


Figure 26 (a) left: Hydrogen explorters and importers; (b) right: Water stress levels

The level of development in hydrogen varies across economies. In terms of technology ownership, it is shown that most of the hydrogen related patents are concentrated in Europe, Japan, South Korea and Unites States (IRENA 2022). Most of the countries that have signed bilateral trade agreements and MOUs for hydrogen exports, such as Namibia, Chile, South Africa, Russia, Canada, Tunisia, UAE, Brunei, Uruguay, Oman, DRC, Morocco, Australia and Saudi Arabia, are not in the aforementioned list (*Geopolitics of the Energy Transformation: The Hydrogen Factor* 2022). Van de Graaf et al. (2020) points out that there is a clear hydrogen technology leadership from the EU, and global competition also makes it difficult for many developing nations to benefit from the global trade relations. The countries owning the technologies may extract more values out of the hydrogen ecosystem, while the countries that exploit their own resources for hydrogen generation may not get much benefit for their own people.

Furthermore, while many countries mentioned above have developed aggressive hydrogen strategies and plans, more nations have not made any progress in hydrogen. The countries that are left behind from the existing hydrogen playground might suffer from a late start, and would experience more economic, trade and geopolitical disadvantage as the industry matures (Bonciu 2021). The geopolitical landscape of hydrogen is novel as hydrogen is a technology that recently attracted global attention; however, it is not completely new as the key players in the hydrogen scene are almost the same as the players in the other major energy technologies.

Many countries seek to reshape the landscape of international trade as hydrogen joins the global energy commodity mix. Van de Graff et al. (2020) discussed both the merits and the drawbacks of such trade relationship reshaping. On the positive side, hydrogen trade may be able help diversify a nation's energy resources, and therefore enhance energy security; on the other hand, the increased "hydrogen diplomacy", bilateral partnerships among countries on hydrogen production and trades, could also bring in new geopolitical challenges. One of them being "green colonialism," defined broadly as when the "the Global North achieves a high standard of living by exploiting the health, labor and land of the Global South (earth.org 2021)." Unfortunately, the green colonialism aspect of hydrogen trade is not sufficiently studied. No literature has been found on this front except for an article by Vijaya Ramachandran (2021), who denounced the idea that green hydrogen should be globally applied, especially to the poorest population, given it possibly was the most complex and expensive energy technology. Analysis by Bridge et al. (2013) on the geopolitics of green hydrogen reveals the large amount of geopolitical and stability threats African countries face, such as the political instabilities and inter-governmental rivalries in Algeria, Morocco, Libya and other North Africa countries. Introducing green hydrogen to countries in turmoil not only threatens hydrogen production and trading, but also complicates local political situations.

The global hydrogen trade also suffers from uncertain demand. Hard-to-predict future hydrogen cost sets a bottleneck on the scale of off-takers. As discussed earlier, the cost of hydrogen production has proven to be slower than planned, and the cost target has been unreliable. As a result, the staggering cost may lead to a slowly developing demand, which could subsequently impact the investment in hydrogen production and the financial risk of the countries that have devoted to a hydrogen economy through production and export.

In general, the existing studies of geopolitics of hydrogen are concentrated with perspective from the developed nations. de Blasio and Pflugmann (2021) created a matrix of examining the export / import potential for a variety of nations depending on their renewable energy resources, renewable freshwater resources and infrastructure potential, but the human factors, such as hydrogen industry's impact on people's living standard, well-being and political and social stability, are not taken into consideration. Furthermore, there is in general a lack of emphasis on the negative consequences, opportunity costs and sacrifices with the global hydrogen production and trade, and therefore the topic of justice and equity is rarely mentioned. Last but not least, as very little data is available given most aspects of the current hydrogen development is new, most projections are made with theoretical analysis, not data-based analysis.

6: Synthesis

Hydrogen produced via electrolysis is a critical element for energy transition in the current world. Because of its low-emission nature and potential to decarbonize the heavy industry and the transportation industry, and serve as long term storage, many countries have included clean hydrogen in their energy strategies. However, in order to objectively evaluate whether hydrogen is an effective method for decarbonization, we need to understand its cost-effectiveness, its economic viability to be combined with heavy industries, and its impacts on international relations and geopolitics.

This study focuses on two key aspects related to hydrogen: the cost of hydrogen production, and the cost-effectiveness of hydrogen when integrated with the industry sector with intermittent renewables as the primary energy sources. We have shown that hydrogen production costs are generally high across all regions studied, and cost reduction faces challenges due to elevated electricity cost. However, in an electricity system with high renewable penetration and high electricity price volatility, hydrogen may achieve considerable cost reduction through capacity factor optimization. In addition, the study reveals that the feasibility of coupling the industry sector with green hydrogen depends on the specific use case, renewable profile, and industrial hub configuration. Regional variation plays a crucial role in determining system costs, and careful optimization of production hours, capacities, and configurations can lead to cost reductions.

These findings have significant policy implications. First of all, given the projected cost of hydrogen in the coming decades, the cost reduction targets set by most governments are overly ambitious. Even with high learning rates on CAPEX, the LCOH in most regions are still higher than \$3/kg if we operate the electrolyzers 100% of the time. The study's SHAP analysis highlights that electricity and water costs significantly impact hydrogen production costs. Therefore, policymakers should prioritize reducing electricity costs and ensuring low-cost water availability alongside technological advancements when formulating hydrogen strategies and development roadmaps.

Secondly, the study demonstrates that reducing the operating hours of electrolyzers can lower the LCOH in a grid characterized by volatile electricity generation costs due to high renewable penetration and a consumer electricity pricing structure reflecting wholesale prices in a competitive energy market. The optimal capacity factor would be further reduced in a future grid with increased power generation intermittency and declining electrolyzer CAPEX. Moreover, optimizing capacity factor could alleviate the pressure of aggressive technology improvements in cost reduction. This conclusion is critical for electrolyzer owners and investors, as the optimal strategy to achieve the most competitive hydrogen cost is through oversizing the capacity and avoiding peak electricity prices. However, challenges remain in implementing this strategy. Identifying "peak price" within a year pose practical difficulties, and capacity reduction leads to inconsistent daily hydrogen output, which may not be acceptable for hydrogen generators that have signed contracts to supply fixed production volumes. Analyzing the optimal capacity factor based on daily price variation may be more suitable for real-life applications. Additionally, not all energy markets the pass-through of wholesale price fluctuations to consumers. In many regions, electricity retailers enter into contracts with consumers, providing a fixed electricity price for a specific duration. Hydrogen producers may also enter into physical or financial Power Purchase Agreements (PPAs) with electricity generators to hedge against electricity price variations during extreme weather events, unplanned outages or unexpected demand surges. In such cases, a reduced capacity factor would only lead to a higher LCOH.

Thirdly, the study highlights that government subsidies have a substantial impact on the LCOH. The application of hydrogen tax credits based on carbon emissions associated with hydrogen production can significantly reduce costs, as demonstrated in the case study of IRA's impact in Texas. Extending the IRA to 2035, only three years beyond the current plan, can make the target of producing hydrogen at $1/kg much more feasible. While significant technological advancements are still necessary, government subsidies can make electrolysis-based hydrogen more cost-competitive, stimulating demand sector growth and leading to a larger market size, increased infrastructure development, and a more mature market. Coupled with other government policies that promote low carbon energy transition, hydrogen may achieve significant progress in advancing the energy transition.

Fourthly, this study highlights the limitations of green hydrogen as pure storage in standalone industrial hubs when the accompanying industry requires high baseload energy and low intermittency. The low utilization rate and round-trip efficiency of hydrogen significantly increases the system-wise cost in a stand-alone hub, and makes the products in the industrial hub less competitive in a perfect market. Nevertheless, when hydrogen is utilized both as a storage and as an input material, it becomes competitive with battery storage thanks to improved utilization rate and efficiency. The result indicates that when designing an industrial hub with green hydrogen production, without considering selling hydrogen to other locations, the composition of the industries in the hub can directly impact the cost-effectiveness of hydrogen and the system. Adding industries with higher intermittency tolerance and establishing connections with other markets can potentially reduce system cost.

Lastly, policymakers need to compare the cost-effectiveness of investing in hydrogen for decarbonization against alternatives like electronification and grid decarbonization. The findings indicate that stand-alone industrial hubs are generally expensive, and connecting them to a decarbonized grid electricity source can reduce the carbon emission intensity of the products while lowering the system-wise cost. Unless an industrial hub has to be constructed in remote regions without connection access to the grid, electrifying industry processes and integrating with a decarbonized grid appear to be the optimal option choice in most regions.

Moreover, the geopolitical analysis of hydrogen reveals that many current hydrogen strategies and investments have clear political intentions and long-lasting impacts on the people. The high resource intensity nature of hydrogen may deprive of local people with electricity and water that could have been used otherwise, and the financial structure of the hydrogen investments may distribute the benefits unfairly among stakeholders. As a result, even though hydrogen can be produced with low cost in some regions because of low-cost resources and labor, it may be socially and ethically challenging to advance these projects. Policymakers and project developers should consider the political and economical impact of hydrogen on the local communities while performing project evaluations.

There are several limitations to this study. To begin with, this study excludes transportation costs of hydrogen, and only considers the minimum storage demand. Incorporating transportation costs and assessing the impact of increased hydrogen storage demand could significantly affect the cost of hydrogen and the feasibility of a hydrogen-based industrial hub. In addition, the study solely focuses on stand-alone systems and does not explore collaborative scenarios involving renewable infrastructures and hydrogen generators in multiple locations. Moreover, while we attempt to incorporate regional variations in locational analysis, it is not comprehensive. Some regional differences rely on assumptions or generic data sources that do not account for specific regional variations within a country or the influence of policies. Consequently, the analysis may lack specificity. Lastly, this analysis does not consider factors such as geopolitics, trade agreements, import/export policies and tariffs, and international investments, which can significantly shape hydrogen strategies of different nations and the future of hydrogen development.

APPENDIX

CAPEX Parameter Assumptions, Learning Rates and Multipliers for Hydrogen Production Cost Analysis

PEM Electrolyzer CAPEX Parameters and Learning

Baseline Capacity	*kg H2/day*	56,500	
Data Basis Year		2020	
Learning Parameters		**Existing Plants**	**New Plants**
Additional Output per year through learning	*%/yr*	0.20%	*see Equipment*
Annual Improvement in Electricity Needs	*%/yr*	-0.40%	-0.80%
Annual Improvement in Water Usage	*%/yr*	-0.15%	-0.30%
Annual Improvement in Labor Productivity	*%/yr*	-0.15%	-0.30%

Equipment		**Investment at Baseline Capacity**	**Scaling Exponent**	**Additional Installaton %**	**Annual Change from Learning**
Stack Capital Cost	*$*	$40,612,000	0.6	12%	-3.6%
Mechanical BoP	*$*	$4,294,000	0.6	0%	-1.9%
Electrical BoP	*$*	$9,729,300	0.6	12%	-0.9%

Equipment Cost Multipliers

Compared with North America costs used as baselines in the tables above

Region	***Equipment Multiplier***
Middle East	1.4
North Africa	1.3
Germany	1.1
Iceland	1.2
China	0.2
Australia-Pilbara	1.2
Canada	1
West Texas	1
California	1
US Northern Plains	1
Atacama	1.3
India	1

OPEX Parameters Assumptions for Hydrogen Production Cost Analysis

Part I

Parameters	*Units*	*Middle East*	*North Africa*	*Germany*	*Iceland*	*China*	*Australia-Pilbara*
Working days/year	days/yr	253	$246	251	247	251	254
Shifts/day	shifts/day	3	3	3	3	3	3
Hours/shift	days/yr	9.6	9.6	8	8	4	7.6
Construction period	years	1	1	1	1	1	1
Project life	years	30	30	30	30	30	30
IRR Required	%	9.7%	9.7%	11.0%	11.0%	8.0%	8.0%
Interest Rate (debt financing & working capital)	%	1%	5%	7%	6%	4%	4%
% Equity Financing	%	40%	40%	40%	40%	40%	40%
Baseline electricity requirement	kWh/kg H2	55.5	55.5	55.5	55.5	55.5	55.5
Baseline water requirement	liters/kg H2	14	14	14	14	14	14
Production Workers	Quantity/shift	5	5	5	5	5	5
Working capital requirement (OPEX)	%	15%	15%	15%	15%	15%	15%
Labor overhead rate	%	20%	20%	20%	20%	20%	20%
Baseline land required	hectares	2	2	2	2	2	2
Property tax rate	%	3%	2%	1%	2%		3%
Unplanned replacement cost	%	1%	1%	1%	1%	1%	1%
Land cost	$/hecatre	3900000	15490000	2225586	36566	76652	4000000
Water cost	$/L	0.0043	0.0019	0.00188	0.004	0.00077	0.00281
Labor cost	$/hr	8	0.125	32	31.96	7.5	27.6

Part II

Parameters	*Units*	*Canada*	*West Texas*	*California*	*US Northern Plains*	*Chile-Atacama*	*India*
Working days/year	days/yr	252	261	261	261	254	300
Shifts/day	shifts/day	3	3	3	3	3	3
Hours/shift	days/yr	8	8	8	8	8.1	8
Construction period	years	1	1	1	1	1	1
Project life	years	30	30	30	30	30	30
IRR Required	%	8.0%	11.0%	11.0%	11.0%	10.1%	10%
Interest Rate (debt financing & working capital)	%	3%	4%	4%	4%	4%	9%
% Equity Financing	%	40%	40%	40%	40%	40%	40%
Baseline electricity requirement	kWh/kg H2	55.5	55.5	55.5	55.5	55.5	55.5
Baseline water requirement	liters/kg H2	14	14	14	14	14	14
Production Workers	Quantity/shift	5	5	5	5	5	5
Working capital requirement (OPEX)	%	15%	15%	15%	15%	15%	15%
Labor overhead rate	%	20%	20%	20%	20%	20%	20%
Baseline land required	hectares	2	2	2	2	2	2
Property tax rate	%	4%	2%	2%	2%	5%	7%
Unplanned replacement cost	%	1%	1%	1%	1%	1%	1%
Land cost	$/hecatre	4000000	7250	125000	125000	20000	14826.31
Water cost	$/L	0.0022	0.0008	0.001	0.001	0.0019	0.00006
Labor cost	$/hr	20.1	36	28	30	2.78	4.4

Cambium Scenarios

We use 10 Cambium scenarios to simulate how electricity prices will change in this study. As described by Gagnon et al. (2023), the scenarios are:

1. Mid-case (without tax credit phaseout): central estimates for inputs such as technology costs, fuel prices, and demand growth. No nascent technologies. Electric sector policies as they existed in September 2022. IRA's PTC and ITC are assumed to not phase out.
2. Mid-case (with tax credit phaseout): the same set of base assumptions as the first scenario, but where IRA's PTC and ITC start phasing out in 2038.
3. Low Renewable Energy and Battery Costs (without tax credit phaseout): the same set of base assumptions as the first scenario, but where renewable energy and battery costs are assumed to be lower. IRA's PTC and ITC are assumed to not phase out.
4. Low Renewable Energy and Battery Costs (with tax credit phaseout): the same set of base assumptions as the first scenario, but where renewable energy and battery costs are assumed to be lower. IRA's PTC and ITC start phasing out in 2033.
5. High Renewable Energy and Battery Costs (phaseout threshold not reached): the same set of base assumptions as the first scenario, but where renewable energy and battery costs are assumed to be high. The emission threshold specified in IRA is not reached in this scenario, and consequentially, the PTC and ITC do not phase out, and there is no corresponding scenario with a phaseout.
6. Electrification (phaseout threshold not reached): the same set of base assumptions as the first scenario, but where demand growth is assumed to average 1.99% from 2022 through 2050, representing higher rates of electrification than the base assumption. The emission threshold specified in IRA is not reached in this scenario, and consequentially, the PTC and ITC do not phase out, and there is no corresponding scenario with a phaseout.
7. Low Natural Gas Prices (phaseout threshold not reached): the same set of base assumptions as the first scenario, but where natural gas prices are assumed to be lower. The emission threshold specified in IRA is not reached in this scenario, and consequentially, the PTC and ITC do not phase out, and there is no corresponding scenario with a phaseout.
8. High Natural Gas Prices (without tax credit phaseout): the same set of base assumptions as the first scenario, but where natural gas prices are assumed to be high. IRA's PTC and ITC are assumed to not phase out.
9. Mid-case with 95% Decarbonization by 2050 (without tax credit phaseout): the same set of base assumptions as the first scenario, but nascent technologies are included and there is a national electricity sector decarbonization constraint that linearly declines to 5% of 2005 emissions on net by 2050. IRA's PTC and ITC are assumed to not phase out.
10. Mid-case with 100% Decarbonization by 2035 (without tax credit phaseout): the same set of base assumptions as the first scenario, but nascent technologies are included and there is a national electricity sector decarbonization constraint that linearly declines to zero on net by 2035. IRA's PTC and ITC are assumed to not phase out.

Variable Inputs for Random Forest Regression and SHAP Analysis

Variable Name	*Description*
Total Worker Hours	Total amount of worker hours needed to operate the electrolyzer for a year (hours/year)
Discount Rate	Market discount rate (%)
Interest Rate (debt financing & Working Capital	Interest rate for debt (60% of the total investment) (%)
Electricity Requirement	The amount of electricity needed to produce each kilogram of hydrogen. The value is subject to learning (kWh/kgH_2)
Water Requirement	The amount of water required to produce each kilogram of hydrogen. The value is subject to learning (Liters/kgH_2)
Property Tax Rate	Tax rate for land and space rental (%)
Unplanned Replacement Cost	Replacement cost that as a percentage of the initial capital investment (%)
Land Cost	Land cost ($/hectare)
Water Cost	Water cost ($/Liter)
Labor Cost	Labor cost ($/hour)
Daily Output	Amount of hydrogen being produced every day (kg/day)
Electricity Price	Electricity price charged by the grid ($/kWh)
Capital Cost	Initiation capital investment to the hydrogen electrolyzer ($)

Aluminum and Steel Parameters

Aluminum and Steel Market Prices by Region

Region	***Aluminum Price ($/t)***	***Steel Price ($/t)***
Australia-Pilbara	2,500	765
UK-NZT	2,700	765
UK-ZCH	2,700	501
Canada-Quebec	2,900	765
Germany-Mecklenburg	2,700	765
US-CA-Kern	2,900	1,211
US-TX-Huston	2,900	1,211
China-Inner Mongolia	2,600	926
Inida-Rajasthan	2,600	926
Saudi Arabia	2,600	926
Morocco	2,500	926
Spain-Extremadura	2,700	765
Chile-Atacama	2,500	1.211

Aluminum Production Parameters

Parameter	*Value*	*Unit*
Aluminum Smelter CAPEX	276.02	$/t
Aluminum Smelter OPEX	1,448.68	$/t
Energy Consumption	14.5	MWh/t
Power Demand	2,000	MW
Lifetime	10	years

Steel Production Parameters

Parameter	*Value*	*Unit*
Hydrogen Demand for 1t of Steel	51	kg/t
Steel Production Capacity	10,000,000	t/yr
Energy Demand for DRI + EAF	0.814	MWh/t
CAPEX for DRI + EAF	414	€t
Iron Ore (62%)	100	€/t
Limestone	100	€/t
Limestone Demand	50	Lbs/tls
Alloys	1777	€/t
Alloy Demand	11	kg/tls
Electrodes	4	€/t
Electrode Demand	2	kg/tls
Labor	53.2	€/t
O&M	3	% of CAPEX
Lifetime	20	years

Regional Variations for the Industrial Hub Model

Facility Costs for Solar, Wind, Battery, and Natural Gas Power Plants (Year 2030)

	Solar		***Wind***		***Battery***		***Natural Gas***	
Region	**CAPEX ($/MW)**	**OPEX ($/MW/yr)**	**CAPEX ($/MW)**	**OPEX ($/MW/yr)**	**CAPEX ($/MW)**	**OPEX ($/MW/yr)**	**CAPEX ($/MW)**	**OPEX ($/MW/yr)**
Australia-Pilbara	634,693	16,000	1,100,736	43,000	387,310	0	945,087	17,800
UK-NZT	634,693	16,000	1,188,608	43,000	387,313	0	945,087	17,800
UK-ZCH	634,693	16,000	1,188,608	43,000	387,313	0	945,087	17,800
Canada-Quebec	634,693	16,000	1,100,737	43,000	387,310	0	945,087	17,800
Germany-Mecklenburg	634,693	16,000	1,188,608	43,000	387,313	0	945,087	17,800
US-CA-Kern	634,693	16,000	1,100,737	43,000	387,310	0	945,087	17,800
US-TX-Huston	634,693	16,000	1,100,737	43,000	387,310	0	945,087	17,800
China-Inner Mongolia	442,271	16,000	799,221	43,000	232,534	0	472,543	17,800
Inida-Rajasthan	398,556	16,000	814,373	43,000	387,311	0	945,087	17,800
Saudi Arabia	398,556	16,000	814,373	43,000	387,311	0	945,087	17,800
Morocco	398,556	16,000	814,373	43,000	387,311	0	945,087	17,800
Spain-Extremadura	634,693	16,000	1,188,608	43,000	387,313	0	945,087	17,800
Chile-Atacama	398,556	16,000	814,373	43,000	387,311	0	945,087	17,800

Natural Gas and Electricity Prices and GHG Emissions by Regions

Region	***Natural Gas Price (2030) ($/MMbtu)***	***Natural Gas GHG Emissions (tCO_2e/MWh)***	***Electricity Price (2030) ($/kWh)***	***Electricity GHG Emissions (2022) (tCO_2e/MWh)***	***Electricity GHG Emissions (2030) (tCO_2e/MWh)***
Australia-Pilbara	9.17	0.570	0.064	0.531	0.205
UK-NZT	7.63	0.484	0.043	0.268	0.072
UK-ZCH	7.63	0.484	0.043	0.268	0.072
Canada-Quebec	2.87	0.562	0.029	0.128	0.049
Germany-Mecklenburg	7.63	0.563	0.043	0.386	0.072
US-CA-Kern	3.47	0.660	0.064	0.379	0.163
US-TX-Huston	3.47	0.664	0.042	0.379	0.163
China-Inner Mongolia	9.17	0.562	0.100	0.544	0.340
Inida-Rajasthan	9.17	0.562	0.074	0.637	0.350
Saudi Arabia	7.63	0.562	0.032	0.571	0.221
Morocco	7.63	0.562	0.029	0.610	0.236
Spain-Extremadura	7.63	0.513	0.043	0.217	0.072
Chile-Atacama	7.63	0.562	0.035	0.417	0.161

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