INVESTING IN A U.S. HYDROGEN FUTURE

Paving the Way for a Clean Hydrogen Economy

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Executive Summary

Hydrogen is poised to play a large role in the decarbonization of several high-footprint industries, such as steel, ammonia, and petrochemical refining. While several countries in Europe have put forth plans and strategies to grow a hydrogen economy, the United States is only more recently showing a bipartisan interest in capturing the benefits of this technology. Hydrogen Ventures can take advantage of being an early investor in this movement. However, given the diversity in natural resources, demand, political drivers and public perceptions, Hydrogen Ventures must develop an investment strategy that considers these variables.

To characterize some of the variables mentioned above, a k-cluster analysis was employed. This mapping exercise showcases the impact of stakeholder decisions regarding importance of each variable, while enforcing the diversity of infrastructure and natural resources across the United States. Additionally, given the options in terms of hydrogen hub engineering design, levelized costs were determined for a combination of hubs – whose locations and designs were selected considering the political drivers, public perceptions and natural resources.

We recommend that Hydrogen Ventures develop a diversified portfolio of investments in both blue and green hydrogen. There are public perception hurdles that will have to be employed both at a state and federal level, policy interventions to optimize the expansion of hydrogen corridors, and industry interests that will impact the long-term adoption of hydrogen. While the expected U.S. demand is uncertain, there is an expected growth within the industrial sectors from 9.5 MMt/yr to 23.1 MMT/yr, providing a slow growth over the course of 30 years. However, this growth could be accelerated by additional federal incentives, as well as the uptake of hydrogen as either a transportation fuel or as a residential application. Though Hydrogen Ventures is specifically interested in industry applications, the alternatives could provide a cyclical growth in demand that would also impact industry.

By taking a holistic approach to understanding the hydrogen economy in the United States – from a siting study, to a levelized cost analysis, to a review of the evolving regulatory policies and public perceptions – Hydrogen Ventures may optimize their investment strategy to minimize risk while capitalizing on opportunities in this emerging market.

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Introduction

Hydrogen is garnering global attention as a potential player in the clean energy transition; it is imperative to consider how hydrogen, an important industrial feedstock, also needs to transition to clean production methods. Hydrogen Ventures has been at the vanguard of hydrogen investments in Europe and, given the potential for hydrogen production and demand in the United States, would stand to benefit from strategic early investments in clean hydrogen in this new market.

In early 2022, the U.S. Department of Energy announced a $9.5 billion initiative aimed at funding regional hydrogen networks, also referred to as hydrogen hubs (U.S. Department of Energy). The objective of hydrogen hubs is to address a large infrastructure challenge by bringing producers and end-use consumers in proximity to each other. Figure 1 shows a simple illustration of what a hydrogen hub might look like. In this figure, different production methods and energy sources are shown on the left, and various end uses and applications on the right.

There are numerous ways to produce hydrogen, but only two methods are currently considered to be "clean." The different production methods are referred to by colors, though they all output the same final product: hydrogen. Blue hydrogen uses a process called steam methane reformation (SMR) to extract hydrogen from natural gas; the carbon dioxide generated in the production process is captured and injected into deep geologic formations through a process referred to as carbon capture and sequestration (CCS). This is opposed to gray hydrogen, which does not utilize CCS and instead emits the CO_2 to the atmosphere after the hydrogen is extracted from the fossil fuel (Saha). Green hydrogen, on the other hand, employs fresh water as a feedstock and renewable energy for electricity generation, and, through a process called electrolysis, produces hydrogen and oxygen as outputs (Saha). A third potentially clean hydrogen production method is pink hydrogen; the process uses electrolysis (like green hydrogen), but the electricity is generated via nuclear energy (National Grid). While we provide a brief discussion of pink hydrogen in our policy analysis, we will focus the discussion in this paper on blue and green hydrogen given the current environment.

While hydrogen has the potential to be used in the transportation sector (through fuel cell technology) and for residential heating applications, this paper will focus on the segment of hydrogen specifically employed in industry applications.

Hydrogen is an essential feedstock for many industrial processes around the world, with the largest global demand coming from petrochemical refining, chemical production, and metals processing, specifically iron and steel (International Energy Agency). Because hydrogen is an integral part of these processes, decarbonizing its production is crucial for the decarbonization of industry. Building a clean hydrogen economy in the U.S. is an important part of this decarbonization plan. The recently passed Inflation Reduction Act provides specific tax credit incentives for clean hydrogen production, as well as hydrogen as a fuel and other demand related provisions (KS Law).

We recommend that Hydrogen Ventures take the following factors into account for long-term investment planning in the U.S.:

- Expected U.S. demand for hydrogen as a feedstock,
- Expected geographic distribution of hydrogen hubs in the U.S.,

- Levelized costs of producing hydrogen through different methods,
- Potential policy support and/or hurdles, and
- Consideration of critical issues surrounding a hydrogen hub economy's successful launch (e.g., public perception, regulatory legislation).

The following sections expand on these recommendations and provide best-estimates of future hydrogen expectations.

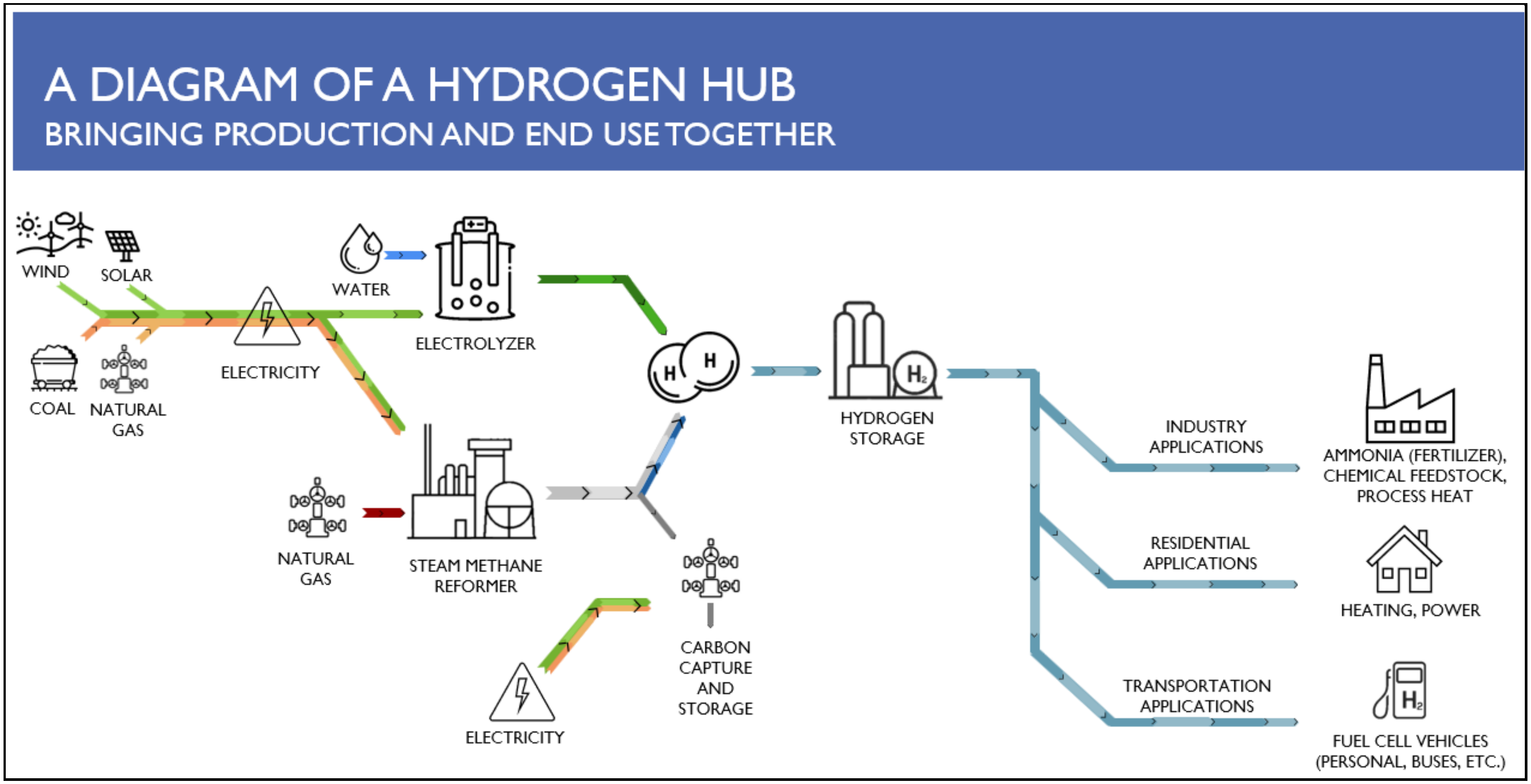

Figure 1 Hypothetical hydrogen hub design (Iacob).

Industrial Hydrogen Demand

Before assessing the potential costs and expected profitability of hydrogen, it is important to understand the sources of industrial demand for hydrogen. In this section, we look at current and projected sources of demand for hydrogen as an industrial feedstock.

United States Hydrogen Demand

In many areas of the country, there has been a focus on hydrogen either as a transportation fuel or for use in electric and industrial heating. However, around 10 MMT/yr of hydrogen demand currently comes from industrial processes that use hydrogen as a feedstock – primarily petrochemical refining and ammonia production (Ruth, Jadun and Gilroy). Furthermore, increased investment in industrial retrofits and downward pressure on hydrogen prices could encourage other industries to incorporate hydrogen as a feedstock substitute. One sector with substantial potential for hydrogen substitution are iron and steelmaking, where hydrogen can be used as a reducing agent for iron in place of natural gas.

According to National Renewable Energy Laboratory (NREL), in 2017, most U.S. hydrogen demand was driven by the petrochemical industry, where oil refineries demanded 5.9 MMT/yr of hydrogen (Ruth, Jadun and Gilroy). The same report estimates that hydrogen demand within the sector is expected to rise to 7.5MMT/yr by 2050, an increase of 27%. Since oil refining is reliant on hydrogen as a primary feedstock, its demand for hydrogen is relatively inelastic and could support prices up to $3.00/kg for hydrogen without affecting demand. Meanwhile, ammonia production accounted for 2.5 MMT/yr of hydrogen demand in 2017, where on average hydrogen prices also stayed around $3.00/kg. Ammonia demand could increase to 3.6 MMT/yr in 2050, contingent on the price of hydrogen falling to $2.00/kg within the time period; otherwise, it would remain relatively level.

Along with existing industrial hydrogen uses, other industries are testing processes that may enable partial conversion of existing feedstocks to hydrogen as a pathway towards decarbonization. Existing iron and steel plants may be able to replace as much as 30% of natural gas inputs with hydrogen, which would generate 4 MMT/yr of hydrogen demand in 2050. It is also estimated that, if there is radical change in the primary production method for crude iron that allows for use of 100% hydrogen, the iron and steel industry could provide at maximum 12 MMT/yr of hydrogen demand by 2050. The 4 MMT/yr scenario would require hydrogen prices of around $1.70/kg to compete with using only natural gas as feedstock, while hydrogen prices of around $0.80/kg would be necessary to approach the 12 MMT/yr maximum.

European Hydrogen Demand

In 2021, industrial hydrogen demand in the European Union (EU) and UK was approximately 9.1 MMt/year, primarily for chemical and refining industries (D'hont). In addition to these, hydrogen demand is projected to increase across several other sectors as well, including transportation and industrial heat processes (Wang, Jens and Mavins) (D'hont). All sources show an increase in hydrogen demand between now and 2050, with notable variations in total magnitude and grouping of applications, as shown in Table A. This variability underlines the long-term uncertainties associated with hydrogen economies, as both political and industry drivers need to align for long-term planning. However, regardless of the projections being used, the U.S. demand is smaller than the expectations in Europe – a reflection of Europe’s foresight in hydrogen investments.

Summary of Hydrogen Demand

The following table summarizes estimated hydrogen demand growth as a feedstock for the U.S., as well as two estimates for European demand growth. The amount of demand realizable will depend on the cost to produce hydrogen. Specifically in planning for long-term U.S. demand, assuming hydrogen prices remain stable at $3/kg, demand is expected to increase by 5.6 MMt/yr. However, if hydrogen prices fall to $1.70/kg, demand could increase by up to 6.7 MMt/yr. At a price of $0.80/kg, dramatic industry change would enable up to 14.7 MMt/yr of new hydrogen demand by 2050, requiring over double the amount of hydrogen production currently available in the U.S. This indicates a healthy investment opportunity for Hydrogen Ventures.

Table 1. Estimated demand for hydrogen as an industrial feedstock in the U.S. and Europe. U.S. estimates are the maximum potential demand from fuels & refining, chemical, and iron and steel applications; European demand estimates also include industrial demand.

	U.S. (Ruth, Jadun and Gilroy)	EU + UK (Wang, Jens and Mavins)	EU (D'hont)
2020	9.5 MMt/yr	-	-
2030	-	8.9 MMt/yr	31.7 MMt/yr
2040	-	26 MMt/yr	78 MMt/yr
2050	23.1 MMt/yr	36.4 MMt/yr	102.5 MMt/yr

Prices and Competing Feedstocks

Prices

NREL estimated that in 2017, hydrogen was priced at around $3/kg with most industrial demand coming from ammonia production and petroleum refining (Ruth, Jadun and Gilroy). Meanwhile, McKinsey estimates that grey hydrogen cost about $1.50/kg to produce in 2020 (Hydrogen Council, McKinsey & Company). Notably, the current industrial users of hydrogen cannot replace it as a feedstock and are thus largely captive to the price of hydrogen in the short term. However, increased investments in blue and green production may drive prices down as the market becomes more competitive. Further, to open iron and steelmaking as a new industrial market for hydrogen, prices would have to decrease even more substantially.

Competing Fuels and Feedstock

The ability to price hydrogen profitably partially depends on the prices of competing alternatives. If hydrogen can be priced lower than alternative technologies, industrial customers are more likely to move away from their current feedstock and energy sources and, when relevant, more willing to invest in retrofits and additional infrastructure required to use hydrogen as an input. The paragraphs below estimate the prices of current inputs within three key industrial sectors where hydrogen substitution is viable and compares these estimates with the projected levelized costs of hydrogen.

Petrochemicals

Currently, hydrogen is essential to efficient petroleum refining—it is required to perform hydrocracking, which converts heavier fuels into lighter fuels (Harrison). However, due to the importance of hydrogen in the refining process and the relatively tight margins in the sector, many refineries invest in on-site hydrogen production to ensure stable supply at more predictable prices. Sustained high hydrogen prices in the retail market may encourage more refiners to develop on-site production, which would decrease the available market for third-party hydrogen producers.

Ammonia Production

Currently, most ammonia production worldwide requires hydrogen as a feedstock, meaning the subsector is a promising source of sustained industrial hydrogen demand. While there are alternative technologies being developed that could directly produce ammonia via a solid electrolyte (Brown), these technologies are unproven and their potential is currently only theoretical, making short-term disruption unlikely. As technologies mature, they might produce ammonia more cheaply and efficiently without using hydrogen, but this would likely only be possible in the long-term time horizon.

Iron and Steel

There are currently two dominant methods for making steel from iron ore, each with potential for hydrogen substitution. Basic oxygen furnace (BOF) production currently relies on coke as a reducing agent to purify iron ore, where this coke can be partially substituted with hydrogen or biomass. Meanwhile, direct reduced iron–electric arc furnace (DRI-EAF) production primarily relies on natural gas to produce DRI but can partially substitute with biogas or hydrogen.

McKinsey estimates that, in 2030, the price of natural gas will be $4.59/MMBTU and the price of biogas will be $13.3/MMBTU (Hydrogen Council, McKinsey & Company), suggesting that biogas is unlikely to replace natural gas at the current trajectory. In electric arc furnace production, the ability of hydrogen to displace natural gas as a reductant will require substantial declines in hydrogen costs and would be highly sensitive to changes in natural gas prices.

Projected Levelized Costs of Hydrogen

Cost analyses on hydrogen production are dependent on the size and feedstocks used for the hydrogen hub. However, while hydrogen can be estimated on a general level, hub distribution will rely more on existing infrastructure (production, transportation, storage) as well as the distribution of the demand.

Geographic Distribution of U.S. Hydrogen Demand

Planning for U.S.-centered investments requires an understanding of how a hydrogen economy may integrate across the country, given the different sources available for hydrogen production. In this case, a mapping tool was created to show how different siting considerations affect overall development. ArcGIS includes a tool that allows for user-specific inputs that reflect the relative importance of different variables to display “ideal” locations for projects. In this case, we focused on existing power plant production capacities (as a proxy for regional natural resources), existing hydrogen demand (taking into account current existing demand may also reflect non-industry uses), existing inter- and intra-state natural gas pipeline systems, future hydrogen demand (assuming population may provide a proxy for distribution of future demand across the country), and current underground storage capacity (to reflect potential underground storage for either hydrogen or carbon capture and sequestration).

The maps below showcase each of these five variables' distribution across the United States. The work in this segment is reproduced from Iacob, unpublished manuscript.

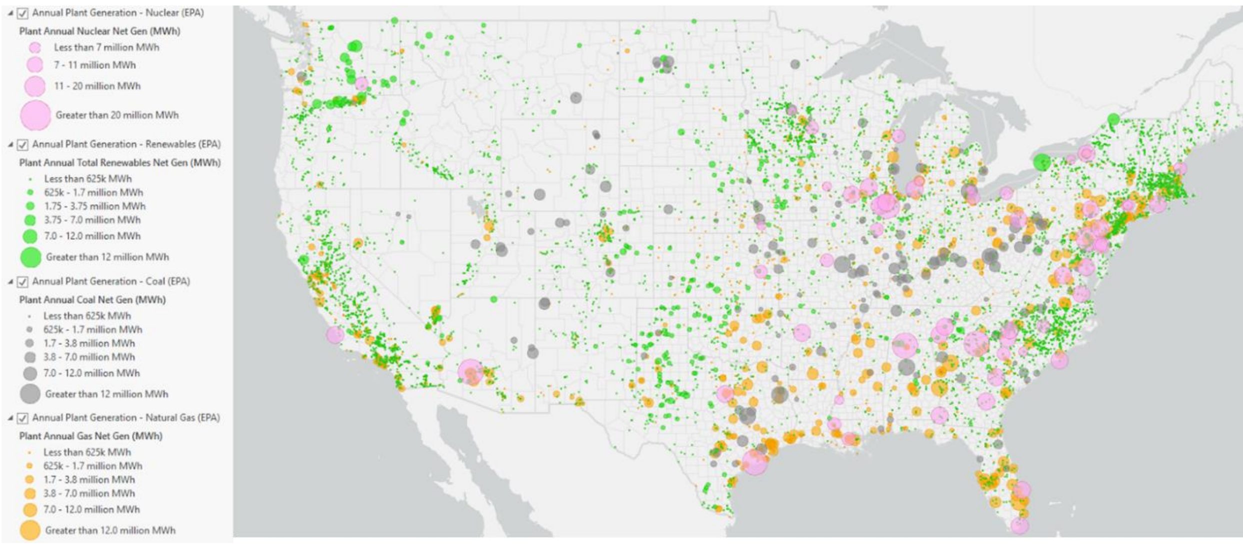

Figure 2. Map showing U.S. Power Plant Net Generation by Primary Source (U.S. EPA).

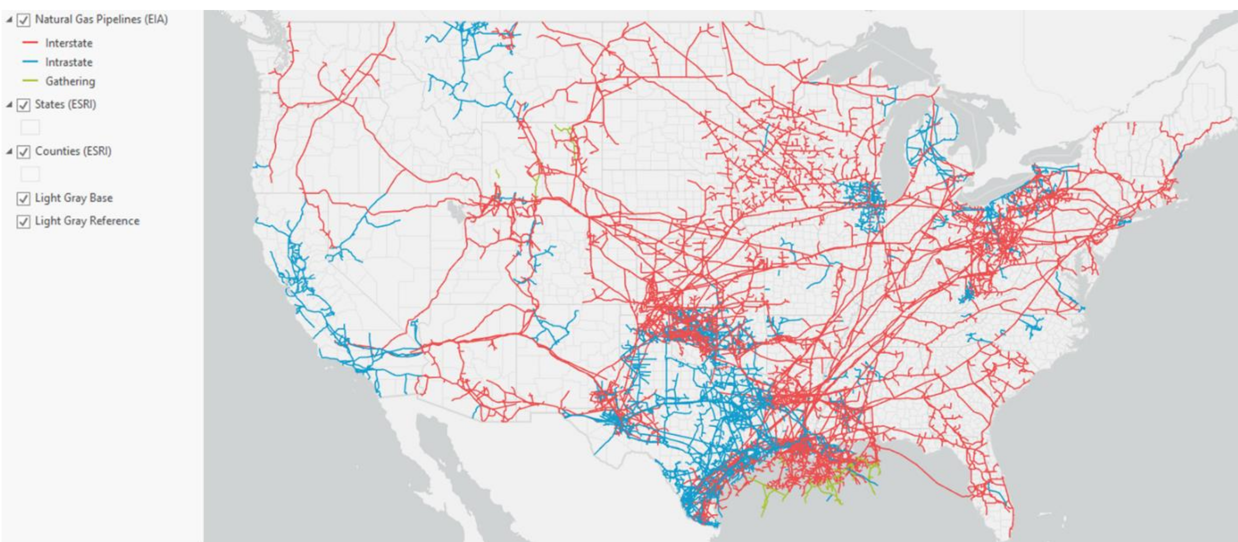

Figure 3. Map Showing Intra- and Interstate Natural Gas Pipelines (Energy Information Administration).

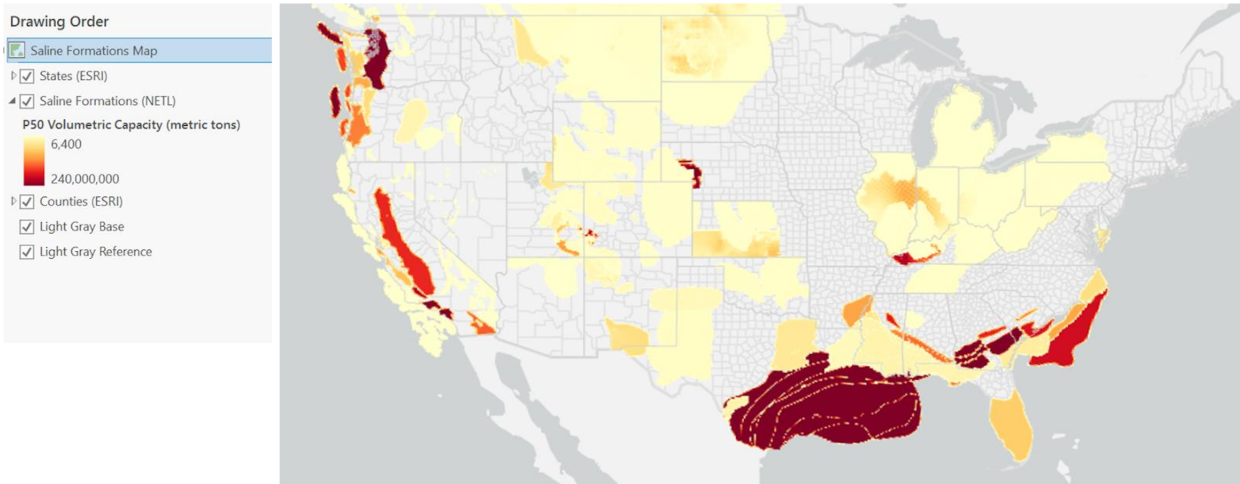

Figure 4. Map Showing Saline Formations and Volumetric Capacities (Goodman, Hakala and Bromhal).

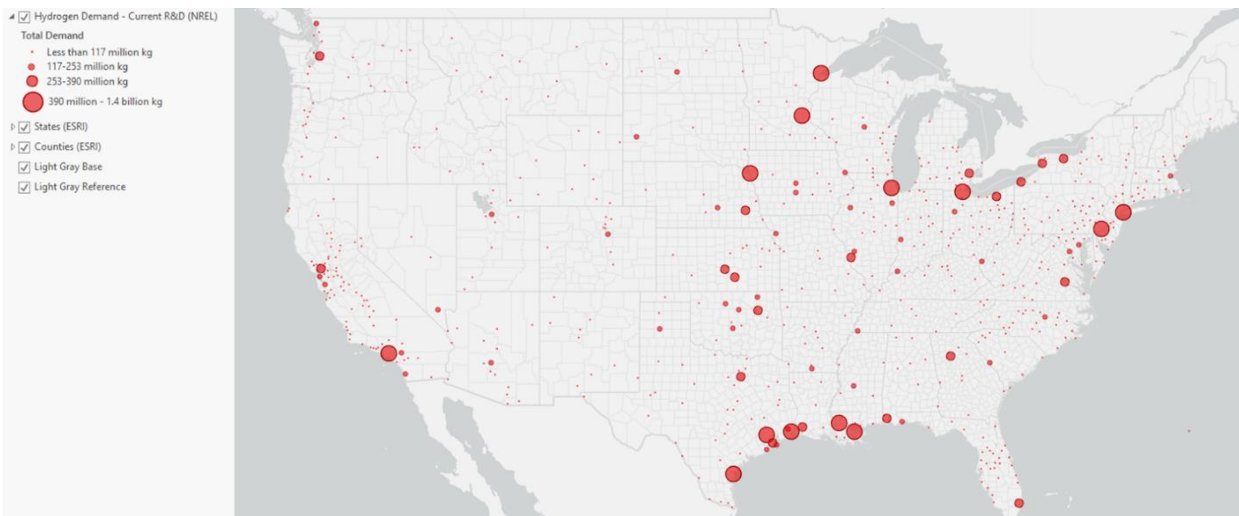

Figure 5. Map Showing Current Hydrogen Demand (NREL).

k-cluster Analysis

Siting is one of the first decisions project managers need to make for a hydrogen hub. In this paper, a mapping tool was created to find the impact different variables may have on "ideal" locations across the United States. ArcGIS Pro provides a specialized mapping tool that combines multivariate k-means clustering as a method of determining clusters in the data points provided. The tool used in this study – the multivariate clustering tool – uses "unsupervised machine learning methods to determine natural clusters in [the] data." The multivariate clustering tool aims to find clusters "where all the features within each cluster are as similar as possible, and all the clusters themselves are as different as possible." (ArcGIS) The data sets used for this portion included: current hydrogen demand from the National Renewable Energy Lab, natural gas inter- and intrastate pipelines for the U.S. from Living Atlas, NATCARB saline formations and their volumetric capacities, current U.S. population from ESRI, and power plant net generation values (U.S. EPA).

Sensitivity analyses on k-means cluster analyses were performed to reflect a decision maker's drivers and key characteristics; in the two images below, we show the difference between using all five characteristics to pick a location, versus selecting three characteristics. In both cases, the characteristics are weighted equally. The first map shows the impact population has on siting (e.g., most major U.S. cities are shown in red dots below).

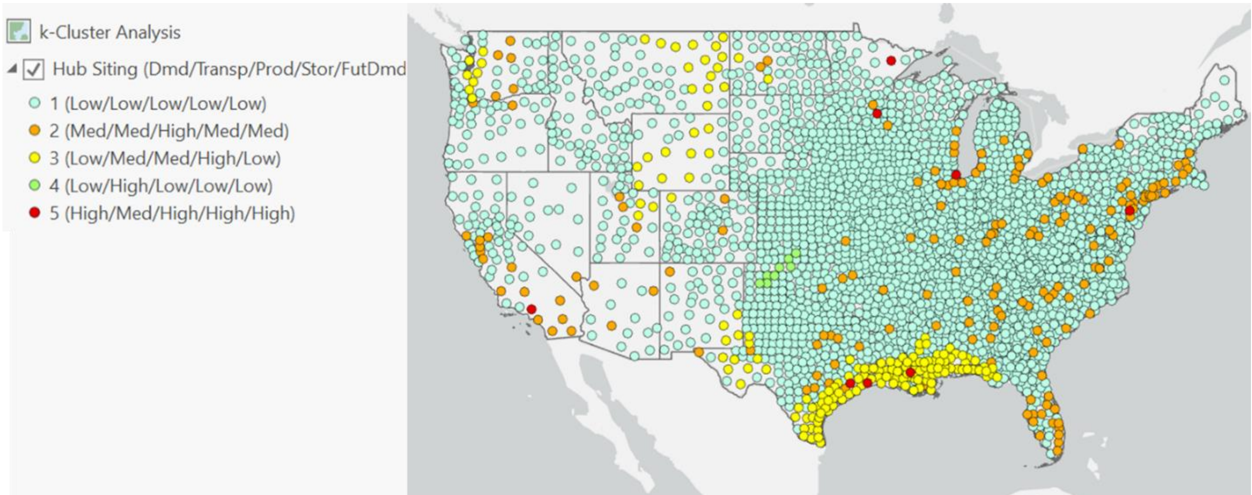

Figure 6. k-cluster Analysis of Hub Locations (Current Demand/Transportation Infrastructure/Production Capacity/Storage Capacity/Future Demand) (Iacob).

To test the hypothesis that demand may be overvalued in siting analysis, we re-ran the mapping tool removing current and future demand values. As can be seen below, focusing primarily on existing infrastructure also skews the results because of the large saline formation volumetric capabilities along the Gulf Coast, as well as the cluster of red dots in the Wyoming-Montana region - a likely result of the long miles of intra- and inter-state natural gas pipelines on a per-county basis.

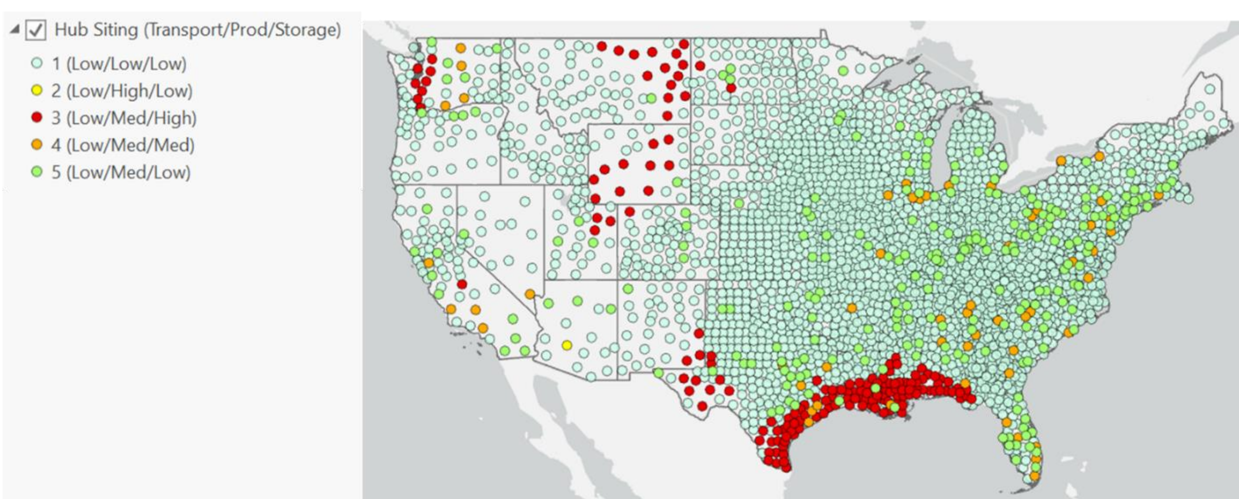

Figure 7. k-Cluster Analysis of Hub Locations (Transportation Infrastructure/Production Capacity/Storage Capacity) (Iacob).

Additional discussion of k-cluster analysis can be found in Appendix 1.

Using the k-cluster analysis, we planned our levelized costs around a 6-hub design, where we expect to have 3 large regional hubs (2 along the Gulf Coast, 1 in Utah/SoCal) and 3 small regional hubs (1 each in the Pacific Northwest, Ohio River Valley, and Florida).

H2A: Hydrogen Analysis Models Projected Costs

NREL has multiple hydrogen analysis models that provide real levelized values per kg of hydrogen. In our models, we assumed several inputs based on existing technical operating parameters, as shown in the tables below. Given the variation in existing production methods and the existing natural resources and political drivers across different regions of the country (see Figure 2, discussion on Policy Implications), the table below summarizes the projected levelized costs for the planned 6-hub design.

Table 2. Levelized Costs per kg H2.

	Gulf Coast Hub #1	Gulf Coast Hub #2	Utah/SoCal	Pacific Northwest	Ohio River Valley	Florida
Hub Size	Large	Large	Large	Small	Small	Small
Hydrogen Production	SMR w/CCS	SMR w/CCS	SMR w/o CCS	Electrolysis	SMR	SMR
Operating Capacity Factor	90%	90%	90%	86%	86%	86%
Plant Design Capacity (kg H2/day)	483,000	966,000	483,000	3,000	6,000	4,000
Plant Output (kg H2/year)	158,700,000	317,300,000	158,700,000	942,000	1,883,000	1,256,000
Start-Up Year	2030	2030	2030	2030	2030	2030
CAPEX (million USD)	\$808.8	\$1,157	\$283.7	\$4.379	\$1.409	\$1.409
OPEX (million USD/yearly)	\$194.0	\$350.9	\$112.9	\$2.410	\$1.600	\$1.090
Levelized Cost per kg H2	\$2.03	\$1.81	\$1.24	\$4.90	\$1.27	\$1.32
	\$1.83 (with \$20 per metric ton CO2 45Q credit)	\$1.61 (with \$20 per metric ton CO2 45Q credit)		\$1.90 (with 45U credit)		

Sensitivities were performed for these calculations to show which parameters have the largest overall impact in the levelized cost calculations. The figures below show the tornado chart (with a 5% deviation), waterfall chart and risk analysis for the proposed Ohio River Valley hub. The associated tornado charts and bar charts for the other hubs are included in Appendix 3.

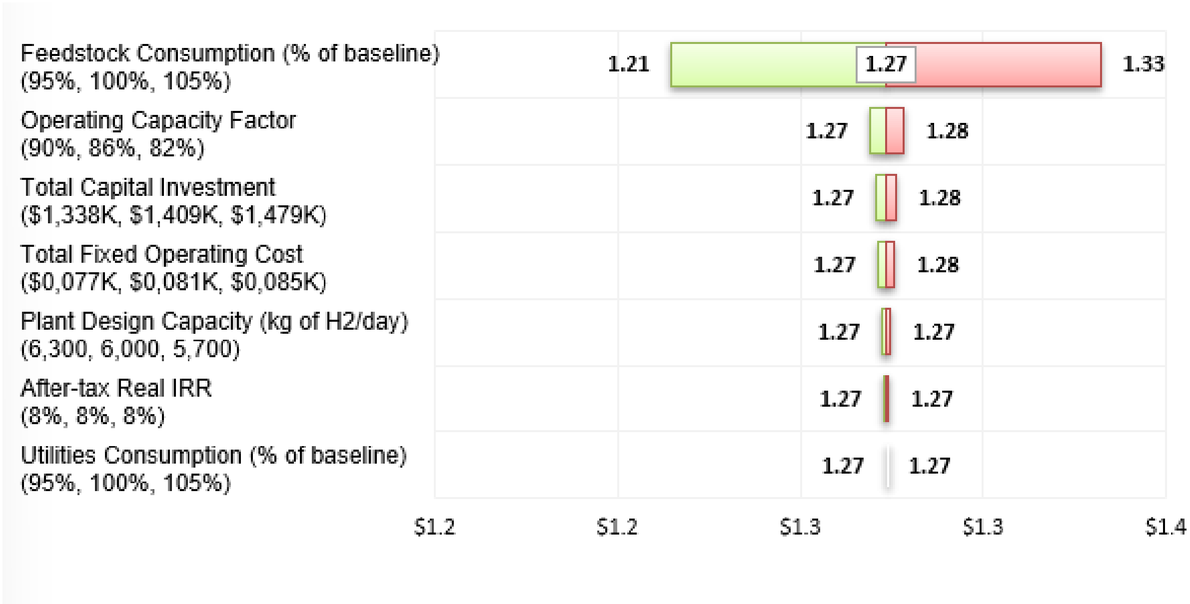

Figure 8. Tornado Plot for Levelized Cost (Ohio River Valley Hypothetical Hub).

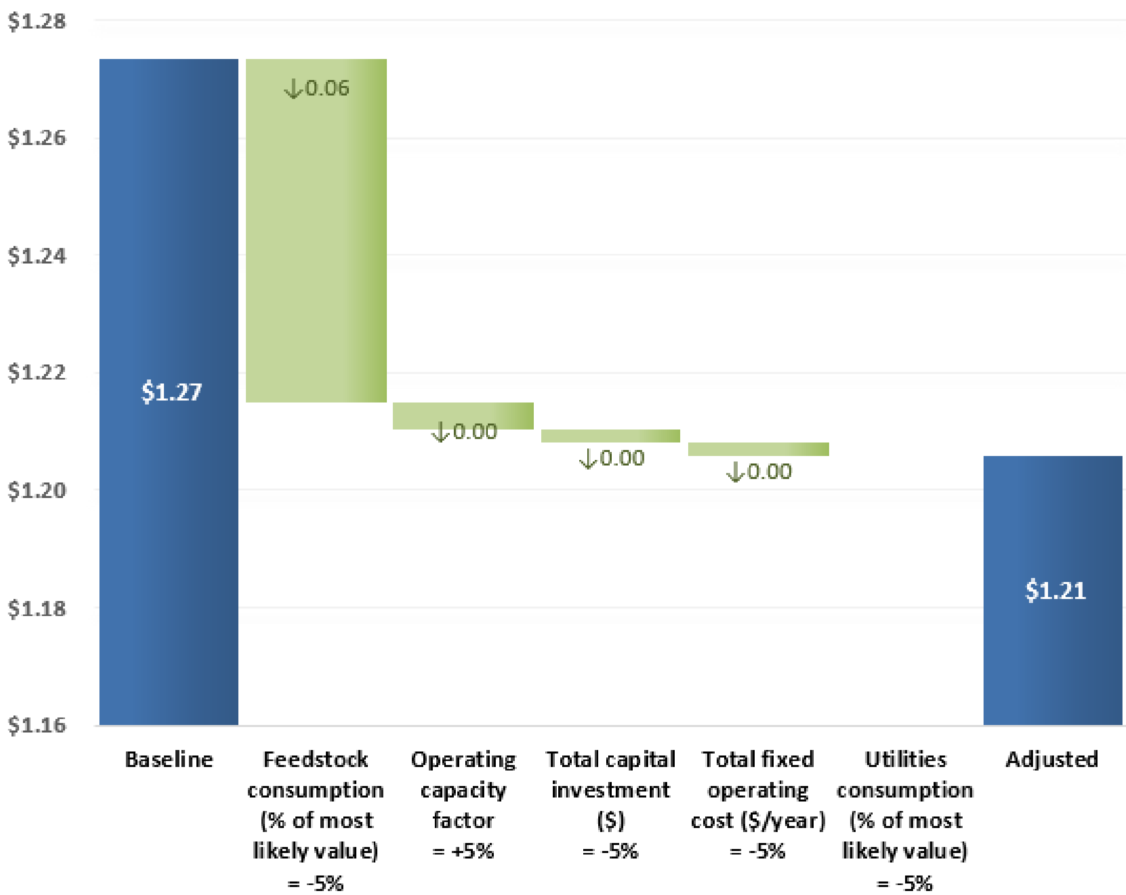

Figure 9. Waterfall Chart for Levelized Cost (Ohio River Valley Hypothetical Hub).

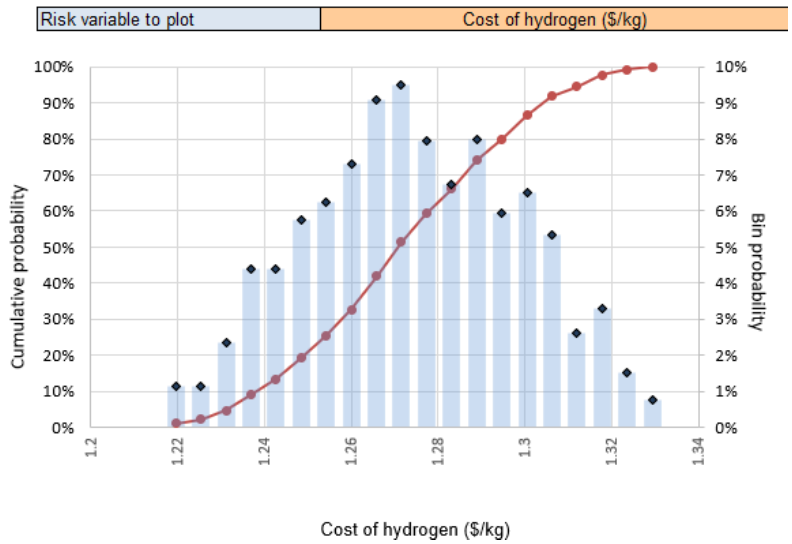

Figure 10. Cumulative Probability of Hydrogen Cost (Ohio River Valley Hypothetical Hub).

The takeaway from this analysis is that the feedstock consumptions have the largest impact on the levelized costs, which indicates both a necessity for de-risking feedstock pricing where possible, as well as understanding the importance of developing hubs based on regional advantages. The outlier in levelized costs is the green hydrogen hub proposed for the Pacific Northwest. However, with the 45V incentives, this price would be more competitive with the other types of hubs. Overall, the levelized costs per kg of hydrogen are comparable, although the CAPEX and OPEX values are quite varied. In this case, we would advise Hydrogen Ventures to consider their internal strategic goals and values in determining which types of hubs to invest in.

Policy Environment

The policy of the U.S. government is favorably inclined to the production of hydrogen gas as a vector for decarbonization, especially in the industrial and power sectors. The August 2022 signing of the Inflation Reduction Act of 2022 (IRA) builds upon a host of long-standing and recently expanded grants, loans, and tax incentives intended to speed the development and deployment of hydrogen infrastructure. That is not to say that federal policy is “feedstock-neutral” – especially in the case of the IRA, there are clear policy preferences for clean- or zero-carbon hydrogen. Additionally, federal policy to date has largely focused on hydrogen production, leaving considerable uncertainty about the strength and potential growth in market demand.

Hydrogen Production Policy Incentives

45U Production Tax Credit for Clean Hydrogen

The most significant incentive for hydrogen production is codified in Section 45U of the Internal Revenue Code in the form of a production tax credit (PTC). For 10 years following the start of a facility’s service, 45U awards tax credits according to the lifecycle carbon intensity of the hydrogen produced, with a maximum credit of $0.60 USD/kg for hydrogen with fewer than 0.45 kg/CO2e per kg. Section 45U incentivizes early-movers and those who meet prevailing wage during the construction and future modification of the hydrogen facility – projects that begin shortly following the issuance of guidance by the U.S. Department of Labor on prevailing wage and apprenticeships and adhere to the guidance qualify for five times the original credit amount. For example, a facility synthesizing hydrogen at a rate of 0.45 kg/CO2e or less and abides by prevailing wage and apprenticeship requirements is eligible for $3.00 USD/kg so long as construction begins within 60 days of guidance from the Department of Labor. On the other hand, a facility that abides by the same requirements and which produces hydrogen at an emissions rate of 4 kg/CO2e per kg hydrogen earns just $0.60 USD/kg.

Notably, most blue hydrogen facilities are not eligible for 45U; facilities that qualify for 45Q credits on captured and sequestered carbon dioxide are explicitly prohibited from clean hydrogen credits. A sufficiently small (<500,000 metric tons of sequestered CO2) blue hydrogen facility would qualify for 45U, although a process at that scale would be limited to less than 75,000 kg/H2 a year. These same exemptions do not apply to facilities that qualify for renewable electricity production credits (I.R.C. § 45) or the nuclear power production credit (I.R.C. § 45U), making a strong case for green and pink hydrogen.

As shown in the levelized cost section (Table 2), the 45U incentive would make the green hydrogen hub competitive with the similarly sized blue hubs – for the first ten years. However, when the ten years have passed, the price point would likely return to the higher levelized costs. Depending on extensions of these incentives, the price point of green hydrogen may never be fully competitive on a small scale hydrogen hub.

Hydrogen Hubs Competitive Grant Program

Prior to the signing of the Inflation Reduction Act, the greatest policy commitment to the expansion of domestic hydrogen production arrived in the form of a competitive grant program within the 2021 Bipartisan Infrastructure Law. Administered by the U.S. Department of Energy, the program will award $8 billion USD between four or more applicants representing a coalition of public and private entities to kick-start hydrogen production, transportation, and application in strategic areas of the country.

The Regional Clean Hydrogen Hub program takes a multidimensional approach to kick-starting hydrogen production by mandating extraordinary diversity across the project types, scope, and geography of the selected projects. The BIL requires a diversity of feedstock and end-uses among the selected hubs: at least one project must synthesize hydrogen from fossil fuels, at least one from renewable electricity, and at least one from nuclear energy. Likewise, at minimum one project is required to leverage hydrogen for power generation, another for industrial applications, one must demonstrate hydrogen in residential and commercial heating, and one project must use hydrogen in transportation. U.S. DOE is also required to select at least two projects with abundant natural gas reserves. The application process is expected to open by October 2022.

Hydrogen Demand-Side Policy Incentives

Demand-facing policy incentives have largely focused on hydrogen as a fuel source for transportation. Since the mid-2000s, federal policy has classified hydrogen as an alternative vehicle fuel, granting taxpayers a credit of $0.50 USD per gallon of fuel equivalent and waiving federal fuel taxes entirely for some entities like local governments. The IRA modified tax credits for individuals purchasing fuel cell vehicles to include used cars, although only vehicles whose final assembly takes place in the U.S. are eligible for tax credits after August 16, 2022.

Considerable progress needs to be made in the deployment of hydrogen transportation and distribution infrastructure to fully leverage these incentives. The U.S. Department of Transportation is currently reviewing proposals for alternative fuel corridors along highways and will have the authority to issue loans and $2.5 billion USD in grants to refueling infrastructure projects along these corridors by mid-NNovember2022. Refueling properties that equipment for alternative fuels may also be eligible for a tax credit of $100,000 USD if they adhere to prevailing wage requirements and are not sited in urban areas.

Given the limited penetration of hydrogen fuel cells into the production vehicle market, incentives directed to transportation applications threatens to limit hydrogen demand to a limited number of sites such as ports with relatively fixed demand. Robust and growing demand will be key to the long-term viability of hydrogen production, and there is considerable latitude for policy action to encourage hydrogen applications in the industrial and power sectors. For example, while blending natural gas and hydrogen for power production or industrial heat is likely to only have a small effect on total carbon emissions, incentivizing blending at even small concentrations could have a drastic impact on regional hydrogen demand and spur a cycle increase in production.

State-Level Policies

As is the case for demand-side policy incentives, the focus of state-level policymaking on hydrogen has largely concentrated on hydrogen vehicles. Of these, California is perhaps the most successful example with approximately 7,500 privately-owned hydrogen vehicles, 56 refueling stations providing service to light- and heavy-duty vehicles and an additional 35 in permitting or under construction. Some states have expanded their focus to include hydrogen production, however. For example, in 2019, Washington enacted a law to authorize public utility districts to produce and sell renewable hydrogen using off-peak power from hydroelectric plants. In response to the announcement of the Regional Hydrogen Hubs grant program, states agencies and agency-aligned organizations have or are conducting reviews of state policy with the aim of accelerating hydrogen infrastructure deployment.

Other Considerations

Class VI Primacy

The production of low-carbon hydrogen from natural gas requires, definitionally, the application of carbon capture technology and permanent geologic storage. A consideration of clean hydrogen feasibility would therefore be incomplete without a brief examination of the most significant regulatory barrier to CCUS projects – Class VI permitting.

The permanent, geologic sequestration of CO_2 involves the subsurface injection of the gas into a permeable layer of rock hundreds or thousands of meters below Earth's surface – a process that has been deeply understood and exploited as a means of producing petroleum (known as Enhanced Oil Recovery or EOR) since 1972. Since 2010, however, geologic carbon sequestration has required the application for and receipt of a Class VI injection well permit – a permit unique to permanent carbon storage and required for any project seeking 45Q tax credits. Administered by the U.S. Environmental Protection Agency, Class VI permits have been uniquely challenging to obtain: of the over 700,000 injection wells permitted by the EPA, only two have been Class VI.

While increasing attention has been paid to reforming the federal permitting process, the staff, resources, and leadership needed at EPA to accelerate and streamline Class VI permitting are unlikely to materialize in time for project leaders to assure investors of their eligibility for the maximum 45U tax credit. For these and other reasons, Wyoming and North Dakota have already secured primary enforcement authority, or "primacy," over the Class VI permitting process, giving appointed state agencies the power to review applications and issue permits while upholding EPA standards and requirements. Several other states are studying the question of primacy or are in pre-approval. While state primacy is not a guarantee of a fast and efficient permitting process, it may signal a favorable statewide attitude towards CCS and hydrogen projects and the possibility of additional, future regulatory and policy incentives.

Regulation of Hydrogen Infrastructure

No federal agency has been legally charged with the regulation of hydrogen infrastructure. While preliminary discussions of permitting reform indicate that the Federal Energy Regulatory Commission will ultimately be charged with oversight duties, existing hydrogen pipelines presently fall under the authority of the Pipeline and Hazardous Material Administration (PHMSA), an agency within the U.S. Department of Transportation. PHMSA's mandate is limited to the direction of "minimum safety requirements for pipeline facilities and the transportation of gas" (49 Code of Federal Regulations Part 192.1).

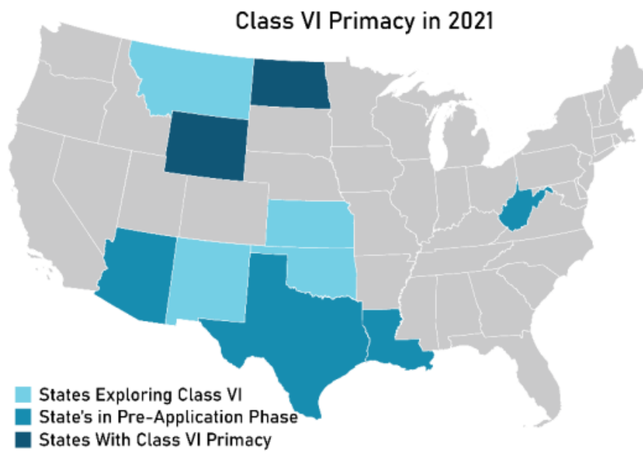

Figure 11. Map Showing Class VI Primacy Across United States, Carbon Capture Coalition, 2021.

Public Perception & Local Governance

Public acceptance is a critical factor in the adoption and long-term success of a major capital investment, such as a hydrogen hub. In the case of a new technology, the public's lack of understanding may pose an additional hurdle to public acceptance. Policy design will have to account for the potential "public alarm, chiefly on safety (i.e. associations with the Hindenburg disaster)" (Roche et al, 2010), as well as the "low hydrogen awareness" (Nnaemeka V. Emodi). Several studies have been carried out in Europe and Japan that show lower awareness is generally associated with lower acceptance, though civic pride provides an opportunity for positive feelings toward the technology (Diego Iribarren) (Huijts) (Rob Flynn) (Kyoko Ono). Given the federal government's interest in this technology, a concerted effort will have to be made to communicate the expected benefits, safety assessments, retraining efforts, and infrastructure developments associated with these hubs. As alluded earlier, different regions of the country have varying political drivers, as well as natural resources. For example, based on a phone call with a Blue-Green Alliance employee, engagements with stakeholders from the Pacific Northwest were limited to green hydrogen production, given the negative perceptions toward blue hydrogen's association with the fossil fuel industry (Anonymous). On the other hand, several seminars conducted in the Southwestern Pennsylvania region showed a more open attitude toward blue hydrogen hub development in the region, alluding to the additional jobs, the expected fossil fuel industry support, and the influx of jobs (Iacob).

Policy Analysis

Despite groundbreaking tax incentives, loans, and grant programs designed to spur the production of clean hydrogen, federal policy environment is only half-formed when it comes to this emerging industry. While great regulatory uncertainty persists, especially at the federal level, on questions of carbon management and hydrogen transportation infrastructure, first movers will be rewarded with valuable production tax credits if they manage to begin construction quickly.

Conclusions and Recommendations

As discussed at the outset, the hydrogen market in the United States will be affected by several factors, including the natural resource, political drivers, policy implications, public perceptions, and existing infrastructure. Given the small market currently, along with the large interest shown around the world in decarbonizing industries through hydrogen uptake, there are large uncertainties regarding overall hydrogen market in the U.S. over the next several decades. Rather than focusing on understanding individual industries' internal drivers or predicting long-term policy interventions, we focused on presenting a high-level overview of primary factors that will affect investments. Thereafter, we provide an analysis of levelized costs for various sizes and designs of hydrogen hubs. Lastly, we delineate the current policy landscape within which Hydrogen Ventures needs to operate when entering the U.S. market.

According to our study, the expected hydrogen demand is uncertain not only in the United States, but in Europe as well. Since Hydrogen Ventures is currently in the European market and might have internal strategies to counter the long-term market size uncertainties abroad, the United States growth and uptake may not be as large of a factor for investment as other variables. Most importantly in developing a strategy is understanding what financial and infrastructure hurdles may exist in this market.

Using a k-cluster analysis, we identified several potential sites that could provide long-term investment options for Hydrogen Ventures. Understanding the internal drivers within the company would cull the list further; however, given the current infrastructure layout and Hydrogen Ventures' interest in clean hydrogen, we proposed a 6-hub analysis to provide a holistic overview of expected levelized costs. In the analysis, we show the ranges in pricing that Hydrogen Ventures may expect both for smaller hubs (as may be needed for the regions with smaller initial demand and storage potential), as well as for large hubs (as may be seen in areas that are currently the majority of U.S. demand and in regions of exceptionally large saline formations).

Using the levelized cost analysis, siting study, and current policy landscape, we recommend that Hydrogen Ventures invest in several hydrogen hubs across the country, that cover both large and small scale demand centers, as well as both blue and green hydrogen designs. We also recommend that Hydrogen Ventures follow state and federal regulations closely regarding both tax incentives, as well as Class VI primacy regulations, as they will affect the long-term investment returns. Lastly, we recommend that Hydrogen Ventures engage with local stakeholders to address local public perceptions, concerns and misunderstandings. A strong engagement and support from the public could drive a higher uptake and acceptance of hydrogen, leading to a more promising long-term hydrogen demand outlook.

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Appendices

Appendix 1: k-Cluster Analysis

To perform a k-means cluster analysis, the five characteristics are first standardized to be on similar scales. For all the data points within each characteristic, the respective mean was subtracted and then the new value divided by the respective standard deviation. This resulted in a new set of ranges for the five characteristics that were of comparable scales.

	Demand (Hydrogen Demand)	Transportation (Pipeline Length)	Production (Plant Net Generation)	Storage (Saline Formation Capacity)	Future Demand (Population)
1	Low	Low	Low	Low	Low
2	Medium	Medium	High	Medium	Medium
3	Low	Medium	Medium	High	Low
4	Low	High	Low	Low	Low
5	High	Medium	High	High	High

Figure 12. Cluster interpretation based on five-factor multivariate analysis (Iacob)

Appendix 2: Hydrogen Production Incentives in the Inflation Reduction Act

I.R.C. § 45U(b) “Applicable Amount” establishes a production tax credit for each kilogram of hydrogen based on total lifecycle emissions per kg of H_2 for 10 years, starting when the facility is placed into service.

12 cents/kg: lifecycle emissions 2.5-4 kg CO_2e per kg of H_2
15 cents/kg: lifecycle emissions 1.5-2.5 kg CO_2e/kg of H_2
20 cents/kg: lifecycle emissions 0.45-1.5 kg CO_2e/kg H_2
60 cents/kg: lifecycle emissions <0.45 kg CO_2e/kg H_2

Appendix 3: Tornado Charts, Waterfall Charts and Cumulative Probability Charts for Proposed Hypothetical Hubs

Gulf Coast Hub #1: Large SMR Hydrogen Hub with CCS - 483,000 kg H2/day (no incentives)

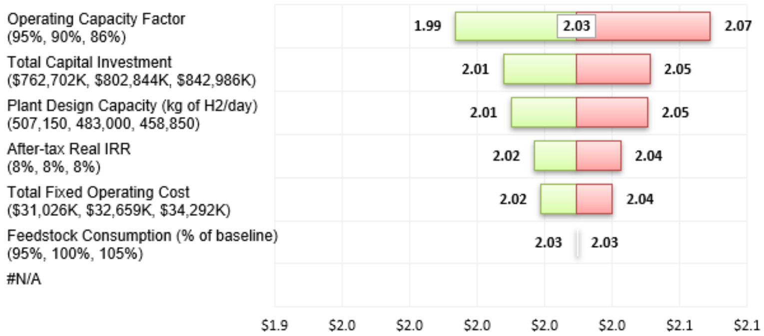

Figure 13. Tornado Plot for Hypothetical Gulf Coast Hydrogen Hub #1 with CCS (no incentives)

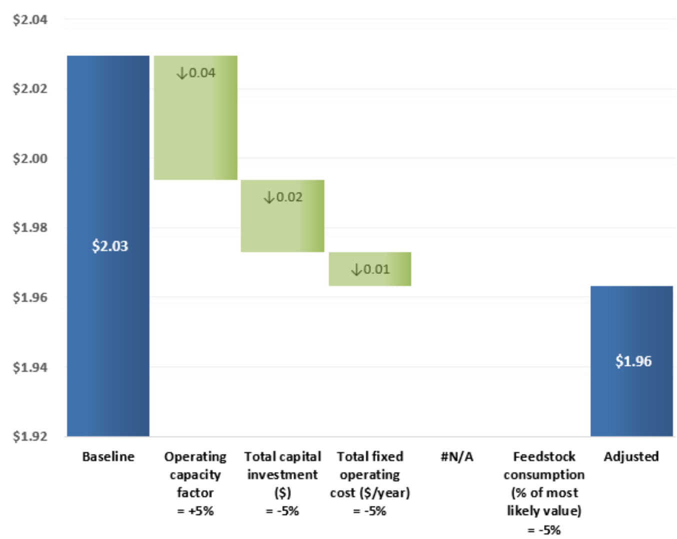

Figure 14. Waterfall Chart for Hypothetical Hydrogen Hub #1 (no incentives)

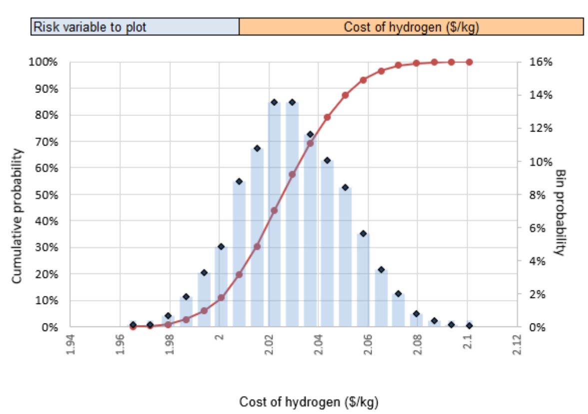

Figure 15. Cumulative probability of hydrogen cost for Gulf Coast Hydrogen Hub #1 (no incentives)

Gulf Coast Hub #1: Large SMR Hydrogen Hub with CCS - 483,000 kg H2/day (45Q credit)

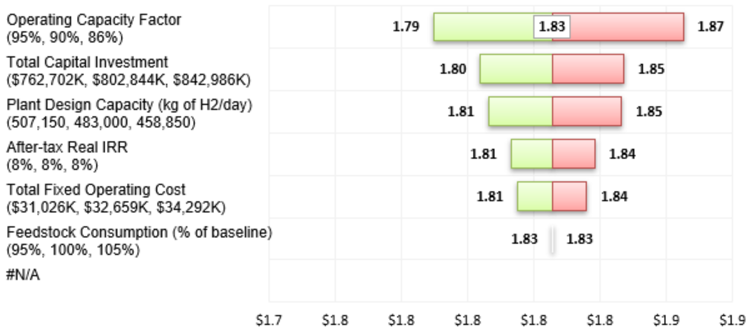

Figure 16. Tornado Plot for Hypothetical Gulf Coast Hydrogen Hub #1 with CCS (with $20 45Q tax credit)

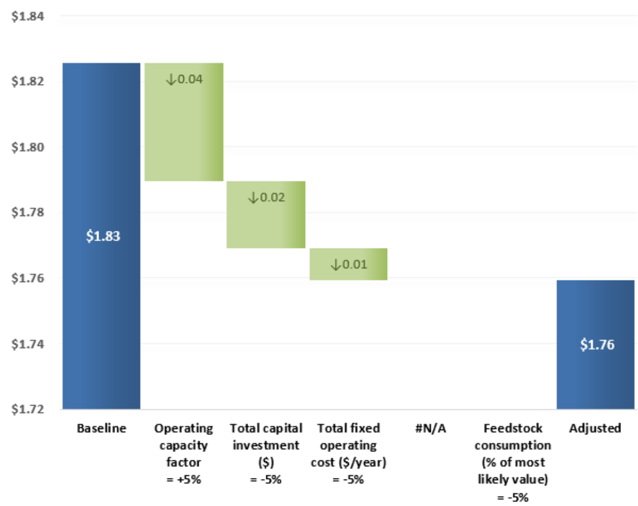

Figure 17. Waterfall Chart for Hypothetical Hydrogen Hub #1 with CCS (with $20 45Q tax credit)

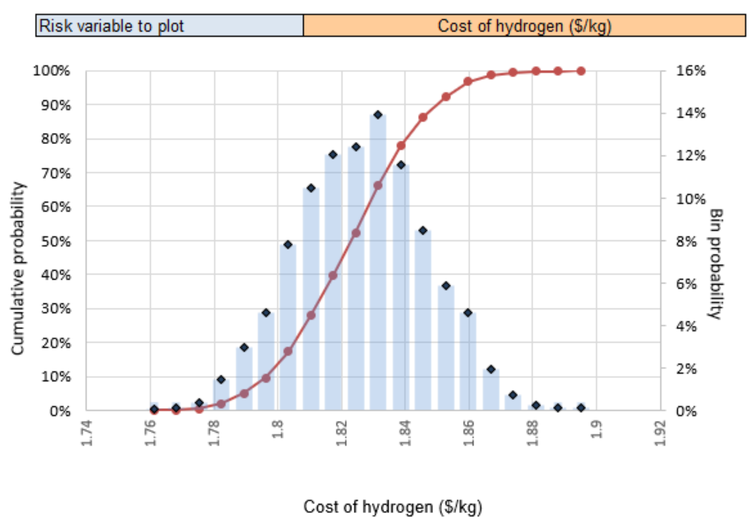

Figure 18. Cumulative probability of hydrogen cost for Gulf Coast Hydrogen Hub #1 with CCS (with $20 45Q tax incentive)

Gulf Coast Hub #2: Large SMR Hydrogen Hub with CCS – 966,000 kg H2/day (no incentives)

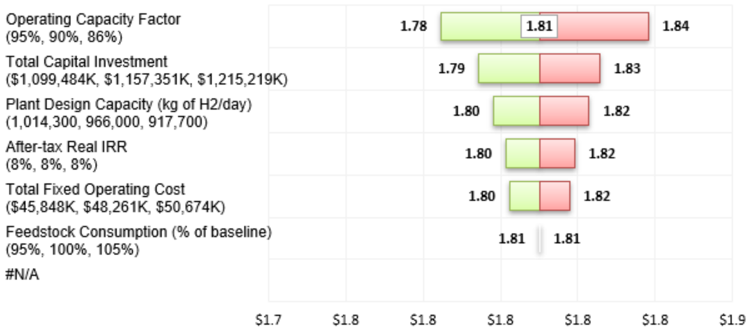

Figure 19. Tornado Plot for Gulf Coast Hydrogen Hub #2 with CCS

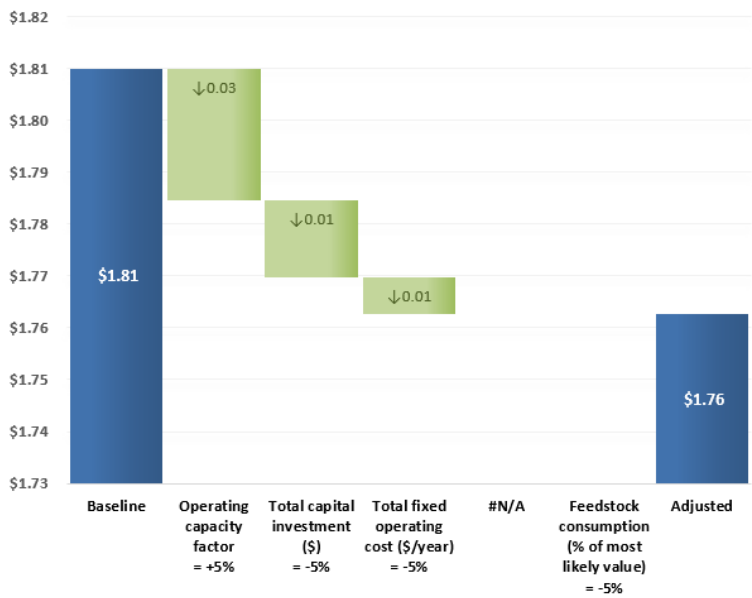

Figure 20. Waterfall Chart for Gulf Coast Hydrogen Hub #2 with CCS

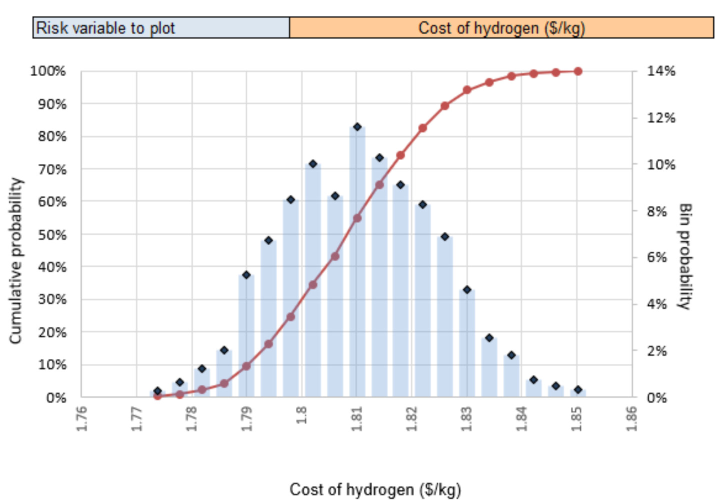

Figure 21. Cumulative probability of levelized cost of hydrogen for Gulf Coast Hydrogen Hub #2 with CCS

Utah/SoCal: Large SMR Hydrogen Hub without CCS

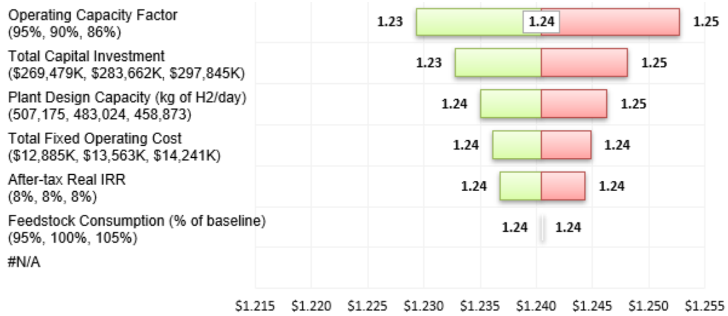

Figure 22. Tornado Plot for Utah/SoCal Hydrogen Hub without CCS

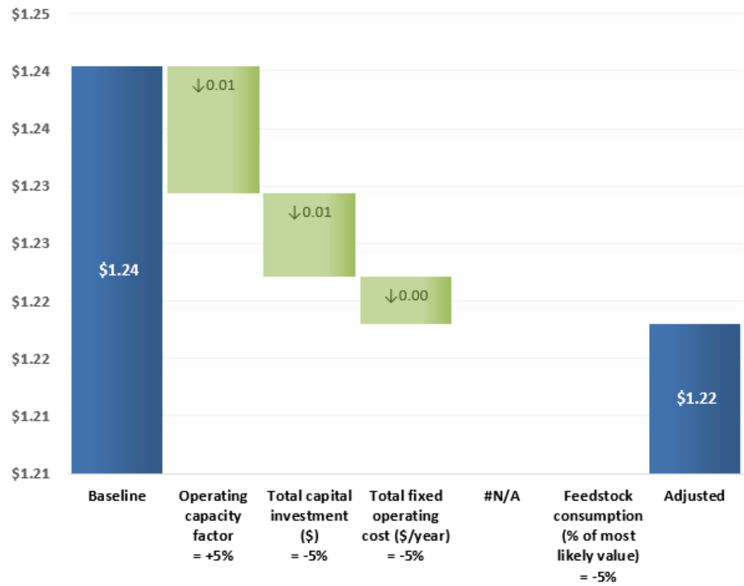

Figure 23. Waterfall Chart for Utah/SoCal Hydrogen Hub without CCS

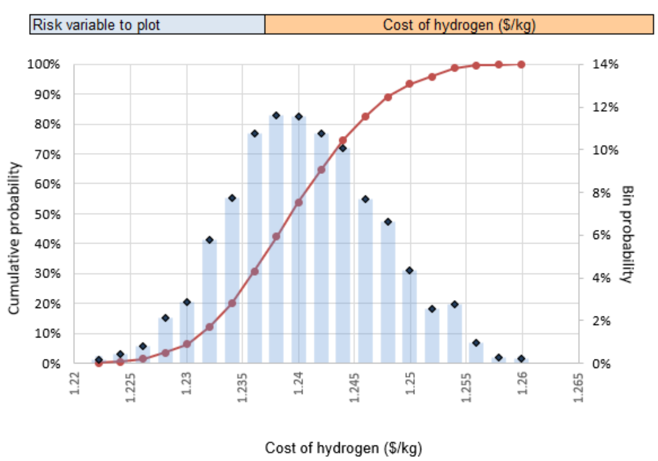

Figure 24. Cumulative probability of levelized cost of hydrogen for Utah/SoCal Hydrogen Hub without CCS

Pacific Northwest: Small Electrolysis Hydrogen Hub

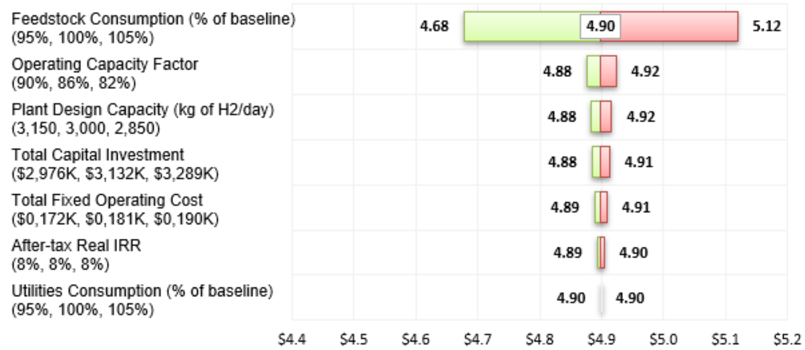

Figure 25. Tornado Plot for Hypothetical Pacific Northwest Hydrogen Hub Levelized Cost

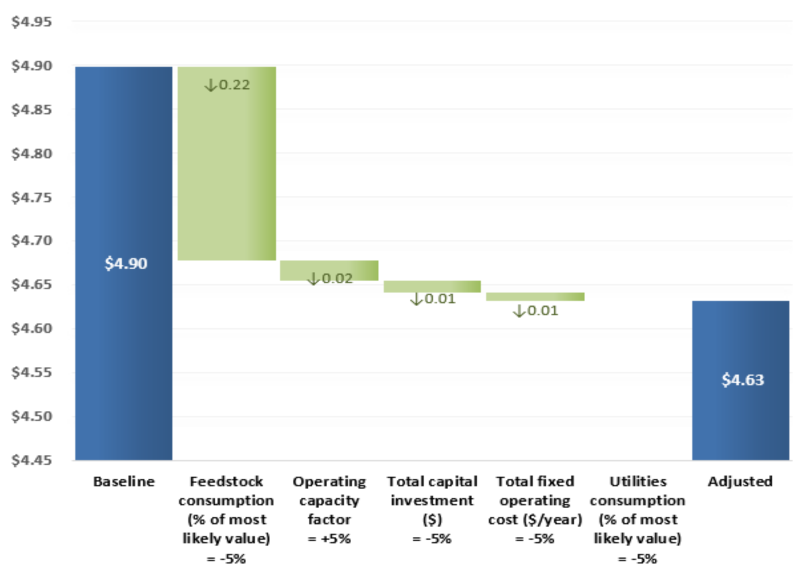

Figure 26. Waterfall Chart for Hypothetical Pacific Northwest Hydrogen Hub

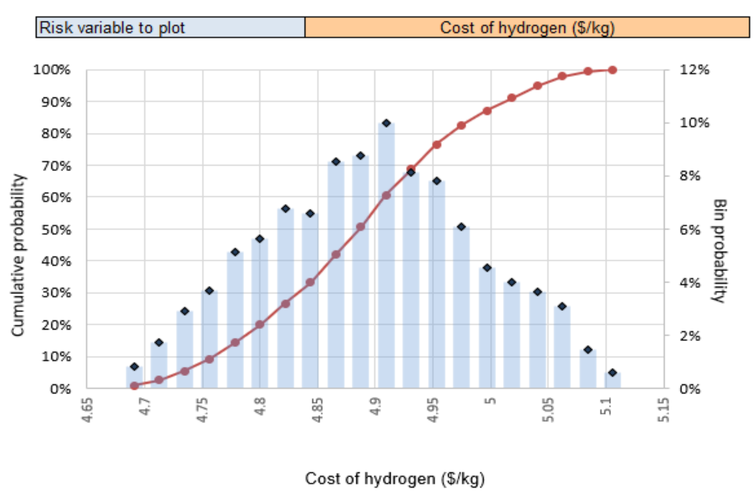

Figure 27. Cumulative probability of Levelized Cost of Hydrogen for Hypothetical Pacific Northwest Hydrogen Hub

Florida: Small SMR Hydrogen Hub

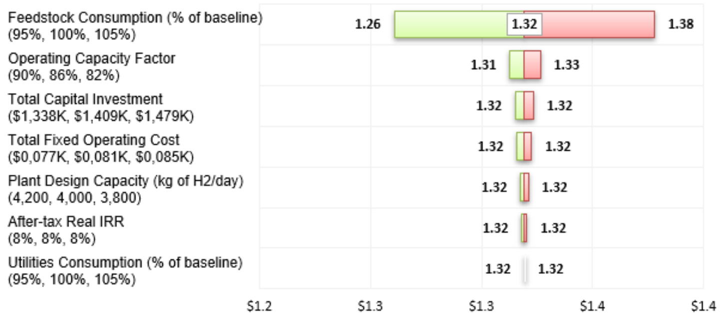

Figure 28. Tornado Plot for Hypothetical Florida Hydrogen Hub Levelized Cost

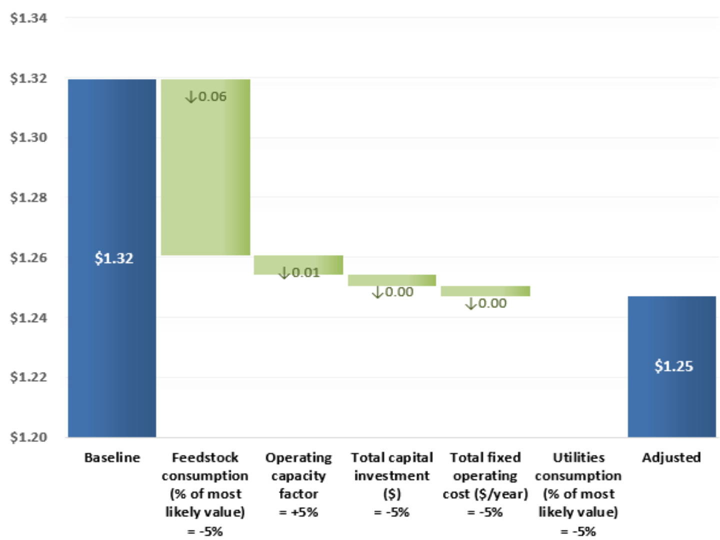

Figure 29. Waterfall Chart for Hypothetical Florida Hydrogen Hub

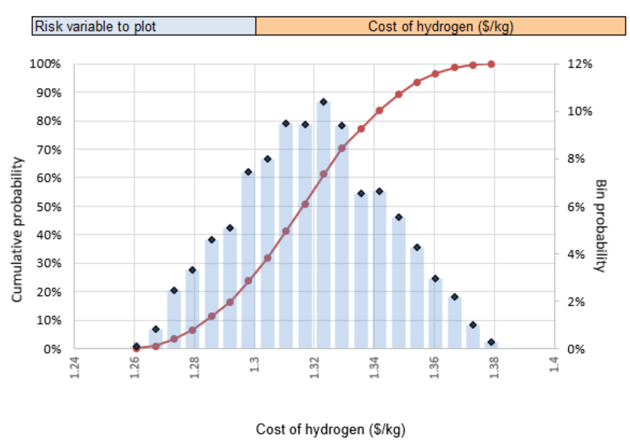

Figure 30. Cumulative Probability of Hydrogen Cost for Hypothetical Florida Hydrogen Hub