International Hydrogen Ramp-up Programme – H_2Uppp

Techno-economic feasibility of exporting green hydrogen from Northwestern Mexico to California

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List of Abbreviations

CAPEX	Capital Expenditures
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
EZ	Electrolysis
FC	Fuel Cell
FCEV	Fuel Cell Electric Vehicle
FLH	Full Load Hours
GH_2	Green Hydrogen
GHG	Greenhouse Gases
H_2	Hydrogen
HD	Heavy Duty (Vehicles)
HRS	Hydrogen Refueling Station
kg	Kilogram
Kton	Kiloton
kWh	Kilowatt-hour
LCOE	Levelized Cost of Energy
LCOH	Levelized Cost of Hydrogen
LD	Light Duty (Vehicles)
LH_2	Liquid Hydrogen
LOHC	Liquid Organic Hydrogen Carrier
MM	Million
MSW	Municipal Solid Waste
$MTRH_2$	Metric Ton of Renewable Hydrogen
MW	Megawatts
NG	Natural Gas
NH_3	Ammonia
OPEX	Operational Expenditures
PV	Photovoltaic solar energy
RH_2	Renewable Hydrogen
SMR	Steam Methane Reforming (for hydrogen production)
TMY	Typical Meteorological Year
TPD	Tons per day
USD	US Dollars

Executive Summary

The state of California has long been a leader in decarbonizing its energy consumption, and in promoting and adopting renewable hydrogen in the transport sector. With its ambitious decarbonization targets of achieving climate neutrality by 2045 and many programs to support the development of hydrogen infrastructure and demand in the transport sector, the potential demand for green hydrogen is set to increase significantly in the near and medium term. At the same time, the Golden State faces many challenges in scaling up quickly the production and distribution of this low-carbon energy carrier.

Meanwhile, Mexico offers great opportunities for the production of green hydrogen, which can be produced at relatively low costs thanks to the excellent solar and wind resources in the northwest of the country and could benefit from addressing pressing needs in the fast-developing U.S. hydrogen supply chain.

In this report, the current and future demand scenarios for the low-carbon energy carrier in California were assessed and the potential for the state to supply its projected needs from local renewable energy sources and potential barriers in achieving these goals were evaluated. The cost of exporting green hydrogen through various means (new and repurposed gas pipelines, compressed tube trailers and ammonia) was estimated from three states in Northwestern Mexico (Baja California, Sonora and Chihuahua) and the competitiveness of this exported Mexican hydrogen was evaluated based on with the willingness to pay from different industries in California. The report concludes by assessing the role that Mexico could play in the development of this new, fast-growing industry in California, either through the export of green hydrogen and power or as a partner that can leverage its local manufacturing base.

The findings show that even though the levelized costs of producing green hydrogen (LCOH[1]) in Mexico (1.88 and 1.71 USD/kg from wind by 2035 and 2045, respectively, in Baja California) are slightly lower than in California (2.13 and 1.84 USD/kg from wind in 2035 and 2045), it cannot compete directly with IRA-subsidized[2] Californian green hydrogen, or with that coming from other U.S. neighboring states. While the techno-economic potential of California to install wind and solar farms is nine times larger than its projected long-term demand, there are many barriers that will likely impede a sufficiently fast deployment, including bottlenecks in project interconnections, slow permitting, and resistance from local organizations and communities. Mexico could complement California's own renewable hydrogen production (1) in case California cannot scale its renewable energies and infrastructure fast enough to meet demand (in this case it could import hydrogen even though it is not directly competitive) and (2) in case imported green hydrogen could be delivered at lower cost than local production, over distances preferably under 500-700 km, which is within reach of the San Diego and Los Angeles areas. Should green hydrogen shortages occur in California, Mexico could fill the gaps, even at higher costs, especially for the transport sector, where the willingness to pay is the highest among the demand sectors.

When it comes to getting the Mexican green hydrogen to demand centers in California, the cost of transporting it through dedicated pipelines is high (2.74 USD/kgH_2) for small scale production (for a 100 MW electrolyzer —requiring an 8-inch pipeline— over 500km), but more attractive for larger scale production (0.24 USD/kgH_2 for a 1,700 MW electrolyzer capacity, over a 16-inch pipeline, over the same distance). Using retrofitted natural gas pipelines would reduce these transport costs by around 80%, though there are currently no signs that Mexico will reduce or eventually halt its natural gas imports from the U.S.

By 2035, transporting hydrogen from a 100 MW electrolyzer in northern Baja California (a region selected for its excellent wind resource) to San Diego (about 500km) can be done in liquid form over trucks for a cost of 2.76 USD/kgH_2, followed

[1] LCOH: Levelized Cost of Hydrogen

[2] IRA: Inflation Reduction Act can provide incentives of up to 3 USD/kg for hydrogen produced with emissions below 0.45 kgCO_2/kgH_2 through Production Tax Credits (PTC).

by the option of transporting it over compressed tube trailers for a cost of 3.2 USD/kg. In both cases these transportation costs make small-scale Mexican green hydrogen uncompetitive with renewable hydrogen produced and subsidized in the U.S.

By 2045 - when IRA subsidies no longer apply - the Mexican states of Baja California, Sonora and Chihuahua could produce green hydrogen, and transport it over existing refurbished (natural gas) pipelines to deliver it in California at prices that are within the expected (though unproven) ranges of willingness to pay (between 2.0 and 6.0 USD/kg of H_2). For this to occur, natural gas should no longer flow from the U.S. to Mexico, which is a scenario that has currently no political backing, but certainly a possibility if Mexican climate policies eventually align with the Paris Agreement.

For large quantities of green hydrogen, using existing ammonia (storage) infrastructure available at the Mexican port of Guaymas (Sonora) and LA, assuming an LCOH of 2 USD/kgH_2 –realistic for solar hydrogen from the state of Sonora by 2045— the delivered costs of ammonia to LA would be approximately 934 USD/tNH_3 which could be competitive with grey hydrogen depending on the price of natural gas and possible carbon taxes.

Instead of exporting hydrogen or its derivatives directly, Mexico could export renewable electricity to the U.S. where it can be used for producing green hydrogen and receive the IRA subsidies. Electricity can be exported by (1) being connected directly to a substation across the northern border (and therefore building the transmission infrastructure - this should be viable for short distances under 1.5 km); (2) by making use of the Mexican and U.S. grids and paying the regulated transport costs; or (3) by generating from projects that have an export permit under the Mexican LSPEE[3] law, and that pay the same regulated transport costs as new projects since 2020. These options would add 0.85 USD/kgH_2 to the LCOH at the electrolyzer gate and would not be competitive against U.S. generated renewable power and hydrogen that can benefit from renewable energy PTC[4], but this option however could be feasible if barriers in the U.S. slow down the deployment.

Aside from abundant renewable resources, Mexico also has a great manufacturing base and a competitive workforce, that can provide critical supplies to the highly strained hydrogen-related supply chains, from electrolyzers, fuel-cells, and fuel-cell vehicles' components to electrical equipment, including transformers. Both countries share an interest to pursue and increase cooperation in the areas of research, innovation, industrial planning and policy making, and it is recommended to facilitate these exchanges through further joint research and international cooperation.

[3] Law of the Public Service of Electric Power, which allowed...

[4] PTC are also available for renewable power generation in the U.S. under provision 45Y, which can account for up to 26 USD/MWh of tax credits for 10 years.

1 Hydrogen market and demand in California

1.1 The role of hydrogen in California

This section presents a summary of the status and policy landscape for hydrogen in the state of California. This includes hydrogen deployment, government programs and incentives, and key stakeholders from the hydrogen industry.

1.1.1 Current hydrogen deployment in California

The state of California is the United States' leader in renewable hydrogen deployment, embracing it as a key vector for decarbonizing the transportation and energy sectors. California is a global leader in launching and scaling the light-duty Fuel Cell Electric Vehicles (FCEV) sector, with 57 retail hydrogen fueling stations in operation as of June 2023 (USDOE, 2023), with another 113 under development (H2FCP, 2023). As of May 2023, 15,912 Fuel Cell cars had been sold in the country (H2FCP, 2023), with this number expected to rise to 65,600 FCEV by 2028 (California Air Resources Board, 2022). Hydrogen applications in California also extend to marine and rail transport, as well as off-road applications, such as forklifts and construction equipment, which together account for nearly 20% total fuel use in the state (UC Irvine Advanced Power and Energy Program, 2020).

Nevertheless, the hydrogen ecosystem in California is still mostly defined by the more traditional applications in the industry and energy sectors, with fuel refining and ammonia production still being the biggest sources of demand in the state (UC Irvine Advanced Power and Energy Program, 2020). Consequently, key players from both, the public and the private sector, acknowledging renewable hydrogen's potential to help decarbonize the economy, have joined forces in a statewide alliance called ARCHES (Alliance for Renewable Clean Hydrogen Energy Systems) to apply for the $8 billion hydrogen hub program funded through President's Biden Bipartisan Infrastructure Law (Transport Topics, 2022) and aim to support the development of the renewable hydrogen ecosystem in the state.

1.1.2 Programs and incentives for renewable hydrogen in California

California's leadership in renewable hydrogen has been backed by the state's public policy in terms of both goals and incentives, mainly for clean transportation. Some of the most relevant programs and policies are summarized below (US DOE, 2022a) (US DOE, 2022b).

California's Low Carbon Fuel Standard

The California Low Carbon Fuel Standard (LCFS) is a regulation established by the California Air Resources Board (CARB) with the purpose of reducing the carbon intensity of fuels used in the transportation sector compared to conventional petroleum-based fuels, such as gasoline and diesel (CARB, 2021). It operates under a credit system in which petroleum-based fuels generate negative credits, while cleaner fuels such as natural gas, biofuels, electricity, and hydrogen can choose to generate positive credits. In the case of hydrogen projects, hydrogen production for fuel cell vehicles and renewable hydrogen for the production of e-fuels are both eligible for credits (CARB, 2021).

Zero Emission Vehicle (ZEV) Promotion Plan

All California state agencies must support and facilitate the commercialization of ZEVs in California. Additionally, the Air Resources Board, the Energy Commission (CEC), the Public Utilities Commission (CPUC), and other relevant state agencies must work with the private sector towards achieving ZEV commercialization and deployment targets. These include:

- By 2025, there will be 1.5 million ZEVs in California and clean, efficient vehicles will displace 1.5 billion gallons of petroleum fuels annually.
- By 2025, there will be 200 hydrogen fueling stations and 250,000 electric vehicle (EV) chargers in California, including 10,000 direct current fast chargers.
- By 2030, there will be 5 million ZEVs on the road in California.

- By 2050, greenhouse gas emissions from the transportation sector will be 80% lower than 1990 levels.

Plug-In Hybrid and Zero Emission Light-Duty Vehicle Rebates

The Clean Vehicle Rebate Project offers rebates for the purchase or lease of qualified vehicles, which include light-duty electric vehicles (EVs), fuel cell electric vehicles (FCEVs), and plug-in hybrid electric vehicles (PHEVs) that the California Air Resources Board (CARB) has approved or certified. The rebates are for up to $4,500 in the case of FCEVs.

Grants for Alternative Fuel Vehicles (AFV) purchase and infrastructure

The Motor Vehicle Registration Fee Program in California provides funding for projects aimed at reducing air pollution from on- and off-road vehicles. Eligible projects include purchasing AFVs and developing alternative fueling infrastructure (such as FCEV and HRS, respectively).

Alternative Fuel and Vehicle Incentives

The California Energy Commission administers the Clean Transportation Program to provide financial incentives for businesses, vehicle and technology manufacturers, workforce training partners, fleet owners, consumers, and academic institutions, with the aim of developing and deploying alternative and renewable fuels and advanced transportation technologies. Funding areas include hydrogen vehicles and refueling infrastructure.

Alternative Fuel Vehicle (AFV) Parking Incentive Programs

The California Department of General Services (DGS) and the California Department of Transportation (Caltrans) must develop and implement Alternative Fuel Vehicle parking incentive programs in public parking facilities operated by the DGS, with 50 or more parking spaces and park-and-ride lots owned and operated by Caltrans. The incentives must provide meaningful and tangible benefits to drivers, such as preferential spaces, reduced fees, and fueling infrastructure.

Light-, Medium- and Heavy-Duty Zero Emission Vehicle (ZEV) Sales Requirement

All sales of new light-duty passenger vehicles in California must be ZEVs or plug-in hybrid electric vehicles (PHEVs) by 2035, increasing gradually from 35% in 2026. Similarly, all new medium- and heavy-duty vehicles sold in California are required to be ZEV by 2045. ZEVs include battery-electric and fuel cell electric vehicles.

State Agency Low Carbon Fuel Use Requirement

At least 3% of the aggregate amount of bulk transportation fuel purchased by the state government must be from very low carbon transportation fuel sources. The required amount of very low carbon transportation fuel purchased will increase by 1% each year, until January 1, 2024.

It is also important to note that, as per Senate Bill 1075, 2022, the California Air Resources Board (CARB), in collaboration with other state agencies, must complete an **evaluation on the deployment, development, and use of hydrogen in the state**, to be published by June 1, 2024. This evaluation shall include:

- Policy recommendations regarding the use of hydrogen to help achieve California's climate, energy, and air quality goals, as well as to overcome market barriers.
- Strategies to support hydrogen infrastructure through the whole value chain (production, processing, delivery, storage, and end-use applications)
- An assessment of different forms of hydrogen that could contribute to decarbonization, especially in the electric and transportation sectors.
- An estimate of GHG emissions reductions and air quality improvements through the deployment of hydrogen
- Policy recommendations for permitting processes related to the transmission and distribution of hydrogen.

1.1.3 Inflation Reduction Act incentives for low-carbon hydrogen in the U.S.

In addition to the hydrogen hubs program mentioned in the Bipartisan Infrastructure Law, in August 2022, the U.S. government approved the Inflation Reduction Act (IRA), which represents an unprecedented investment towards clean energy and energy transition in the country. As part of a robust incentive package, it provides economic benefits to low-emission hydrogen producers in the form of Production Tax Credits (PTCs), or investments in hydrogen production projects through Investment Tax Credits (ITCs). These incentives can provide benefits to low-emission hydrogen production in the United States for up to 30% of the initial investment in the project (ITC) or providing a PTC of up to 3 USD per kilogram of hydrogen produced for 10 years, with project developers having the possibility of choosing between one or the other. To be eligible for these credits, hydrogen must be produced with an emission intensity of less than 0.45 $kgCO_2e/kgH_2$, and the projects must comply with certain requirements related to employment conditions (prevailing wages) and job creation. This subsidy applies to low-emission hydrogen projects in the U.S. that begin construction before 2033, regardless of their final use or application. The IRA also introduces new technologies to be eligible for PTC and ITC, including fuel cells and certain projects are also eligible for 'bonus credits' – meaning the ITC increases from 30% to 40% - if they meet certain provisions, like being within an energy community[5] and a low-income census tract, and using a minimum domestic content[6]. The IRA incentives are therefore expected to provide **a significant boost to low-carbon hydrogen production in California.**

1.1.4 Key players in the hydrogen value chain in California

Key players in the hydrogen value chain in California include members of hydrogen working groups and associations in the state, international companies with hydrogen developments with presence in California, and representative companies in different sectors through the hydrogen value chain. The list of stakeholders identified includes companies in the Oil & Gas, Electricity & Renewables sectors; Original Equipment Manufacturers (OEMs); engineering, procurement, and construction firms (EPC); heavy and light industry players; and government and public agencies. They were grouped based on what segment of the hydrogen value chain they belong to and are presented in Figure 1, Figure 2 and Figure 3.

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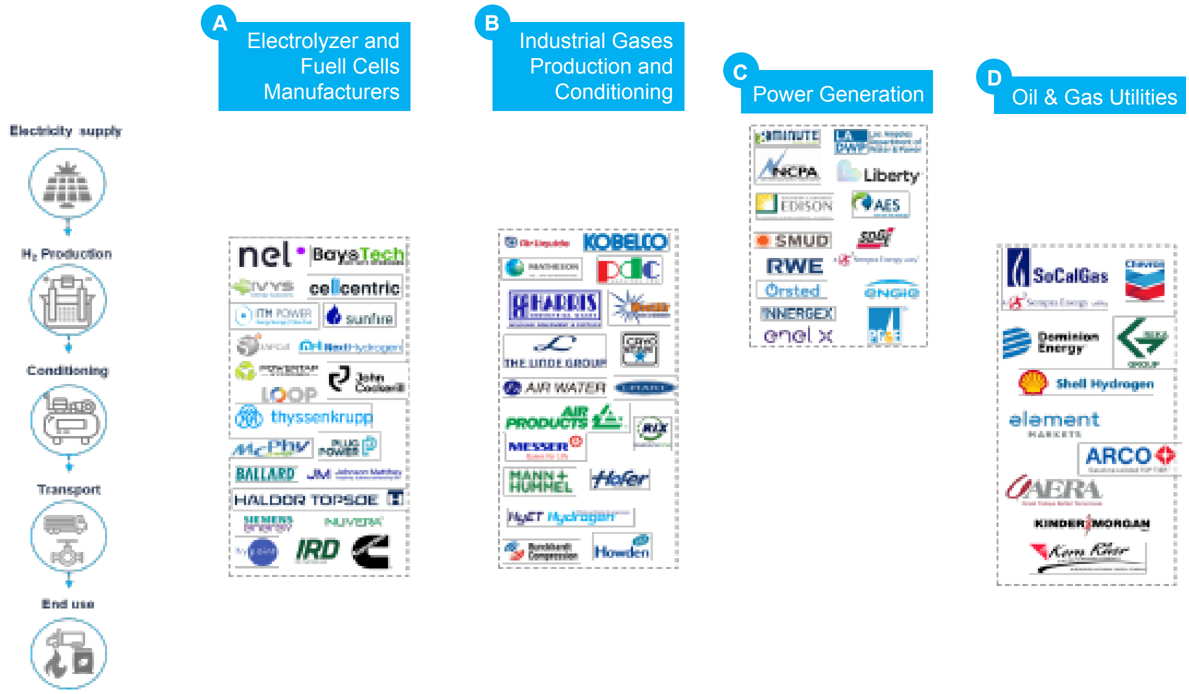
[5] An energy community is an area that has a closed coal mine or coal-fired generating station or had significant employment related to the extraction, processing, transport or storage of coal, oil or natural gas and meets certain unemployment levels.

[6] The domestic content provision encourages project developers to source materials in the United States. Domestic content is defined as any steel, iron or manufactured product which is a component of a renewable energy facility that was produced in the United States.

Figure 1. Key players along the hydrogen value chain in California – Part 1.



Source: Hinicio (2022)

Figure 2. Key players along the hydrogen value chain in California – Part 2.

Source: Hinicio (2022)

Figure 3. Key players along the hydrogen value chain in California – Part 3.

Source: Hinicio (2022)

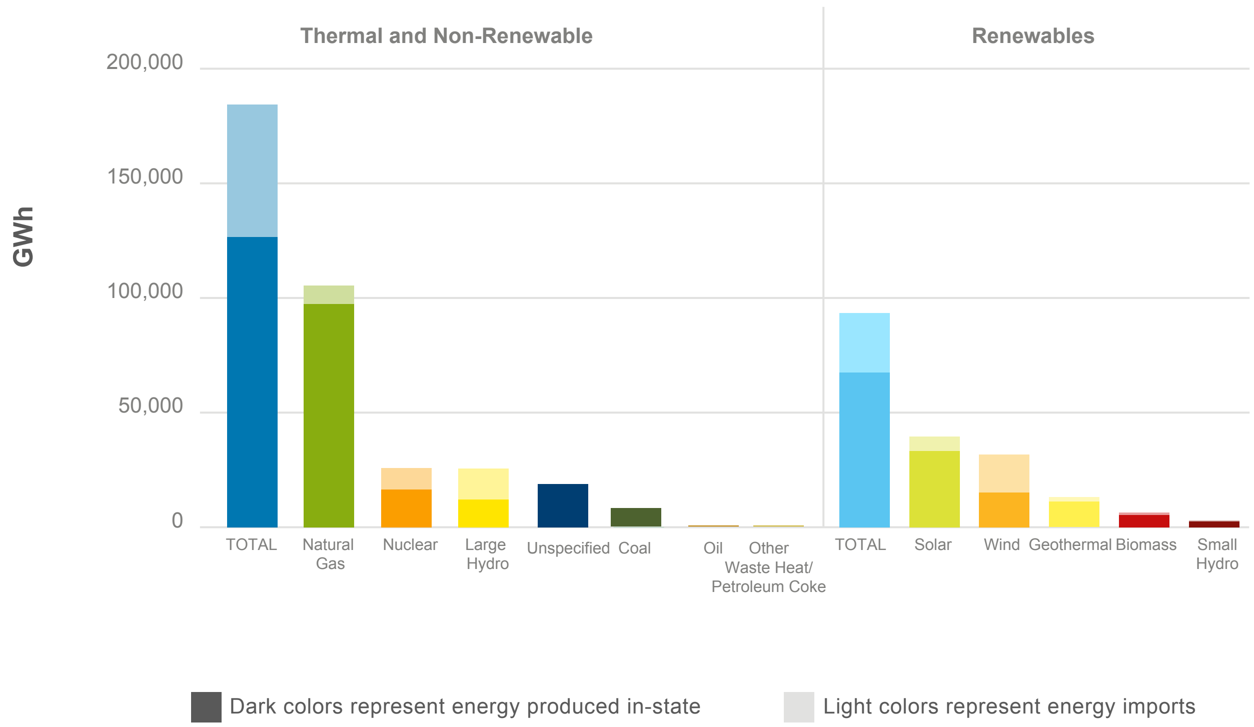
1.2 California's current energy and hydrogen demand

1.2.1 Current energy demand in California

California is the most populous state and has the largest economy in the United States. Consequently, it has the second highest electricity consumption in the country, only behind Texas, reaching a total of 277,764 GWh in 2021 (Alves, Bruna, 2022) (California Energy Comission, 2022b). California is also rich in energy resources and it is the second largest producer, after Texas, of renewable electricity generation. It is the national leader in power production from solar, geothermal, and biomass with a total of 49,757 GWh generated in-state in 2021, which represents about 18% of total generation (U.S. Energy Information Administration, 2022).

Total renewable electricity consumption in California, comprising biomass, geothermal, small hydro, solar and wind sources reached 93,333 GWh (33.6%) in 2021. From this figure, 67,461 GWh were generated in-state, while the remaining 25,872 GWh came from imports (California Energy Comission, 2022b). Figure 4 shows the complete distribution of electricity consumption by source in California in 2021, also indicating whether the energy was produced in-state or was imported. Table 1 presents all the information in detail.

Figure 4. Electricity consumption by energy source in California in 2021.



Source: Hinicio based on (California Energy Comission, 2022b).

Table 1. Electricity consumption in California by energy source (2021).

Energy Source	In-state	Northwest imports	Southwest imports	Total Imports	Total	% of total
Thermal and Non-Renewables (Total)	126.666	21.017	36.748	57.764	184.431	66%
Natural Gas	97.431	45	7.880	7.925	105.356	38%
Nuclear	16.477	524	8.756	9.281	25.758	9%
Large Hydro	12.036	12.042	1.578	13.620	25.656	9%
Unspecified	-	8.156	10.731	18.887	18.887	7%
Coal	303	181	7.788	7.969	8.272	3%
Oil	37	-	-	-	37	0%
Other (Waste Heat / Petroleum Coke)	382	68	15	83	465	0%
Renewables (Total)	67.461	11.555	14.317	25.872	93.333	34%
Solar	33.260	220	5.979	6.199	39.458	14%
Wind	15.173	9.976	6.405	16.381	31.555	11%
Geothermal	11.116	192	1.906	2.098	13.214	5%
Biomass	5.381	864	26	890	6.271	2%
Small Hydro	2.531	304	1	304	2.835	1%
Total	194.127	32.572	51.064	83.636	277.764	100%

Source: Hinicio based on (California Energy Comission, 2022b).

1.2.2 Current hydrogen demand and production capacity in California

Current hydrogen demand in California is approximately 2,000 kton/year and corresponds predominantly to fuel refining, which adds up to 1,798 kton/year, or roughly 90% of the total (Gilani & Sanchez, 2020). Meanwhile, hydrogen consumption for FCEV stands at around 5,400 kg H_2/day, or 2 kton/year approximately. Hydrogen is mostly produced via Steam Methane Reforming (SMR), except for hydrogen for transport, where nearly 36% corresponds to renewable hydrogen (H2B2, 2020).

The refineries in the area of Los Angeles are the current largest hydrogen demand centers, with over one million barrels of oil refined per day, as can be seen in Table 2 below.

Table 2. Total capacity of crude oil refined in the Los Angeles area.

Refinery	Location	Capacity (Barrels per day)
Marathon Petroleum	Carson / Wilmington	363,000
PBF Energy	Torrance	166,000
Chevron	El Segundo	269,000
Valero	Wilmington	85,000
World Energy*	Paramount	50,000*
Phillips 66	Wilmington	139,000
Los Angeles Area Refineries	Total	1,022,000

Source: (California Energy Comission, 2022a).

Regarding hydrogen production in California, the two biggest players by far are industrial gas companies and refineries themselves, with gas companies producing around 767 kton/year (equivalent to approximately 38% of California's total demand) and refineries producing 1,051 kton/year (around 53% of the state's total demand) (Gilani & Sanchez, 2020). Table 3 and Table 4 show the production capacities of these two sectors by source and location in California.

Table 3. Hydrogen production capacity from industrial gas companies in California in 2019.

Producer	Location	Technology	H_2 production capacity (tons/year)	Industry
Praxair	Richmond	SMR	228,687	Oil Refining
	Ontario	SMR	10,555	Multiple
	Ontario	SMR	7,276	
Air Products	Wilmington	RFG SMR	140,730	Oil Refining
	Carson	SMR	87,956	
	Martinez	SMR	77,402	
	Martinez	SMR	30,785	
	Sacramento	SMR	2,023	Multiple
	Sacramento	SMR	Unknown	Food
Air Liquide	Rodeo	SMR	105,547	Oil Refining
	El Segundo	SMR	75,643	
Total			766,604	

Source: (Gilani & Sanchez, 2020).

Table 4. Hydrogen production capacity from refineries in California in 2019.

Company	Location	H_2 production capacity (tons/year)
Chevron USA Inc.	Richmond	284,262
	El Segundo	66,328
Phillips 66 Company	Rodeo	19,812
	Wilmington	90,447
San Joaquin Refining Co. Inc.	Bakersfield	3,446
Shell Oil Products USA	Martinez	166,250
Tesoro Refining & Marketing	Martinez	74,942
	Carson	103,368
Torrance Refining Co.	Torrance	125,764
Valero Refining Co. California	Benicia	116,289
Total		1,050,908

Source: (Gilani & Sanchez, 2020).

1.3 California's future energy and hydrogen demand

The future of energy demand in California is largely shaped by the state's commitment to carbon neutrality by 2045 (Executive Order B-55-18, 2018), requiring major efforts to diversify its energy matrix, not only by incorporating renewable energies into its power mix, but also by decarbonizing the fuels and raw materials used for transportation, agriculture, refinery, and thermal processes.

California's future energy demand will therefore have to be met by cleaner generation, including renewable hydrogen for its hard to abate sectors like transport, refining and fertilizers.

1.3.1 Future energy demand in California

The Californian Energy Commission developed a series of long-term forecasts for 2045 based on the goal of achieving carbon neutrality through three different pathways: High Electrification, High Biofuels, and High Hydrogen (Californian Energy Commission, 2019). A model was used to provide load forecasts for those three scenarios in 2045. The High Electrification scenario is chosen as the default because it provides a decarbonization pathway with low costs and commercially available technologies. Energy efficiency and baseline consumption are assumed to be the same in all three scenarios.

Details on the energy consumption distribution for the three mentioned pathways are shown on the tables below:

Table 5. CEC High Biofuels Pathway Load Forecast (GWh).

RESOLVE Scenario Setting	2020	2022	2026	2030	2045
Baseline Power Consumption	239,966	246,638	257,559	265,707	286,572
Electric Vehicles	1,110	1,946	5,862	11,099	30,485
Other Transport Electrification	1,198	1,734	3,596	6,615	26,852
Building Electrification	-	-	255	3,023	35,104
Hydrogen Production (GWh)	203	331	611	579	986
Energy Efficiency	(5,930)	(10,186)	(19,550)	(27,940)	(46,390)
Total	236,547	240,463	248,333	259,083	333,609

Source: (Californian Energy Commission, 2019)

Table 6. CEC High Electrification Pathway Load Forecast (GWh).

RESOLVE Scenario Setting	2020	2022	2026	2030	2045
Baseline Consumption	239,966	246,638	257,559	265,707	286,572
Electric Vehicles	1,110	1,947	5,838	11,442	38,427
Other Transport Electrification	1,198	1,734	3,596	6,617	28,209
Building Electrification	-	-	255	3,023	35,104
Hydrogen Production	276	499	1,563	4,476	31,913
Energy Efficiency	(5,930)	(10,186)	(19,550)	(27,940)	(46,390)
Total	236,620	240,632	249,261	263,325	373,835

Source: (Californian Energy Commission, 2019)

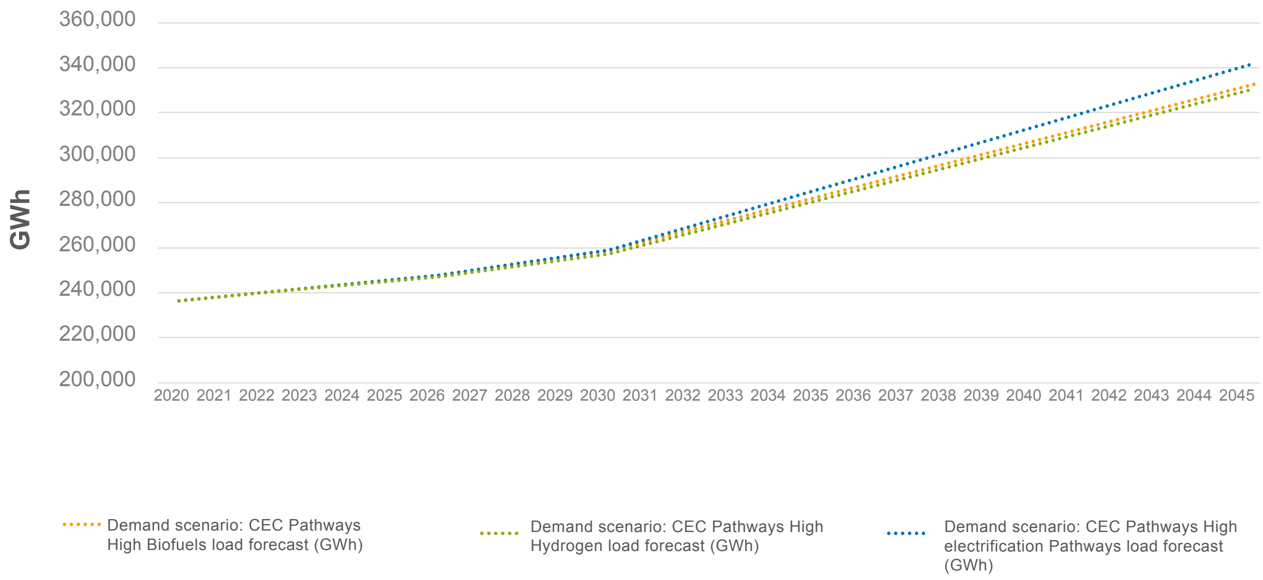
Table 7. CEC Pathways High Hydrogen Load Forecast (GWh)

RESOLVE Scenario Setting	2020	2022	2026	2030	2045
Baseline Consumption	239,966	246,638	257,559	265,707	286,572
Electric Vehicles	1,110	1,947	5,838	11,442	38,427
Other Transport Electrification	1,127	1,590	3,054	5,107	17,013
Building Electrification	-	-	255	3,023	35,104
Hydrogen Production	279	506	1,578	4,559	89,226
Energy Efficiency	(5,930)	(10,186)	(19,550)	(27,940)	(46,390)
Total	244,502	252,703	270,310	291,868	468,387

Source: (Californian Energy Commission, 2019)

A graphical comparison between the three scenarios is shown in the Figure 5.

Figure 5. Future energy demand scenarios in California.



Source: (Californian Energy Commission, 2019)

1.3.2 Future hydrogen demand in California

The Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California, prepared by The University of California Irvine Advanced Power and Energy Program for the California Energy Commission, presents a series of future high-, medium-, and low- renewable hydrogen demand scenarios for selected applications (UC Irvine Advanced Power and Energy Program, 2020). However, these scenarios are not in line with the stated objective of achieving net zero by 2045. Therefore, all hydrogen demand in California was mapped out, in order to present a more complete picture of renewable hydrogen's potential in the state. For this reason, a series of hydrogen demand projections were carried out, based on the total energy demand in the state, and by identifying all sectors in which renewable hydrogen could potentially participate. UC Irvine's renewable hydrogen projections are presented fist in order to compare them with the projections carried out.

1.3.2.1 UC Irvine's renewable hydrogen demand scenarios

UC Irvine's renewable hydrogen demand scenarios were based on the following set of assumptions (Table 8).

Table 8. Assumptions for the Renewable Hydrogen Demand Scenarios in California

Renewable H_2 application	High-scenario	Mid-scenario	Low-scenario
Light-duty vehicles (LDV)	• 1 million FCEVs by 2030 • 50% penetration by 2050	• 500,000 FCEVs by 2030 • 35% penetration by 2050	• 250,000 FCEVs by 2030 • 20% penetration by 2050
Medium-duty vehicles (MDV), heavy-duty (HDV) and other	Hydrogen serves 50% of MDV/HDV renewable diesel demand and 20% of other non-LDV Hydrogen is 33% renewable in 2025, ramped to 100% by 2050	Midpoint between high and low scenarios	20% of fuel is renewable, (same as LDV), half of which is filled by hydrogen. Hydrogen is 33% renewable in 2025, ramped to 100% by 2050
Petroleum refining	100% decarbonized H_2 by 2050 on linear ramp, beginning 2025	50% of high case	No RH_2 demand in low case
Power generation and storage additions	Geothermal and storage hold half the added capacity	50% of high case	No RH_2 demand in low case
Process and heat	10% of current natural gas demand in 2050 with H_2 blending beginning in 2025	50% of high case	No RH_2 demand in low case
Ammonia production	100% decarbonized H_2 by 2030	15% of high case	No RH_2 demand in low case

Source: (UC Irvine Advanced Power and Energy Program, 2020).

Based on the results obtained in their study, it is possible to put together estimates for California's renewable hydrogen demand in 2025, 2035 and 2045, which are presented in Figure 6, Figure 7, and Figure 8.

Figure 6. Renewable hydrogen demand in California by 2025.

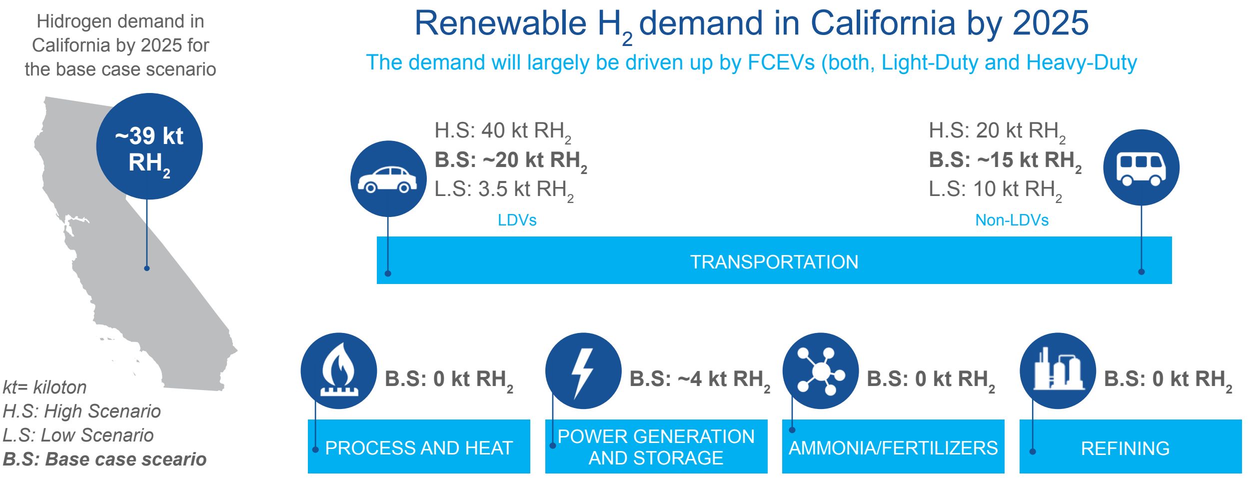


Figure 7. Renewable hydrogen demand in California by 2035.

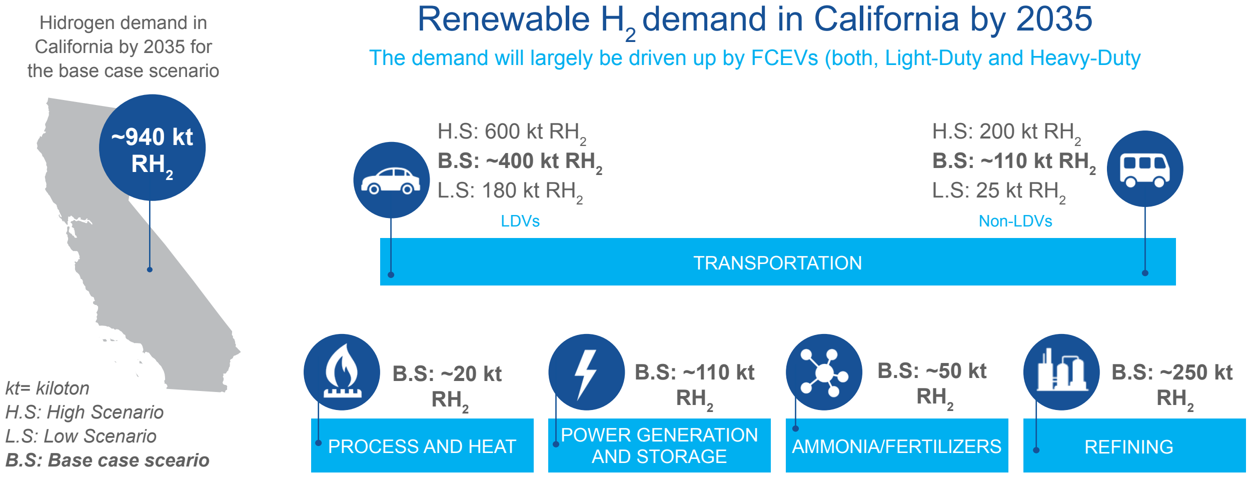
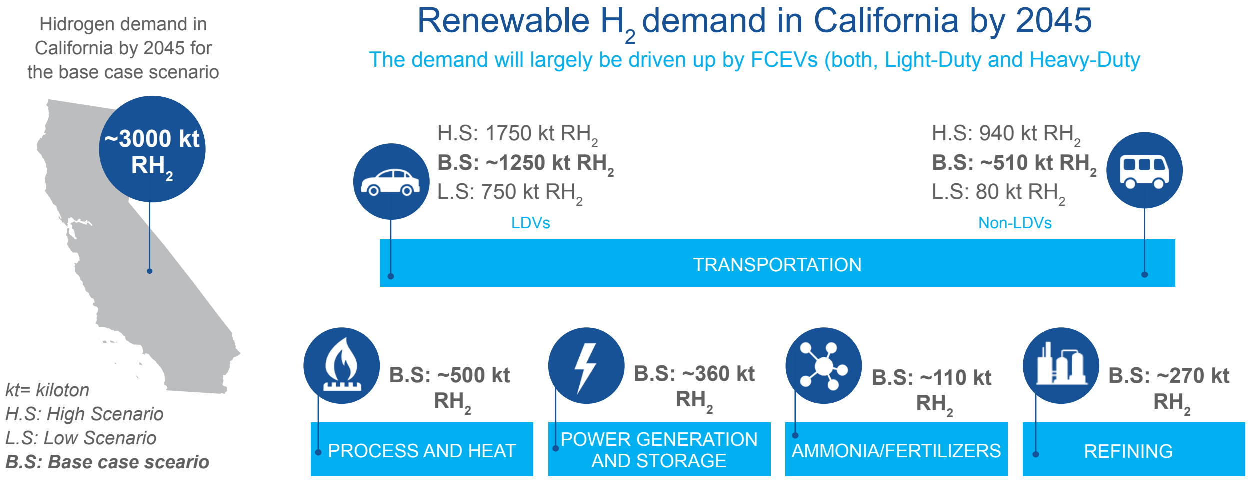


Figure 8. Renewable hydrogen demand in California by 2045.

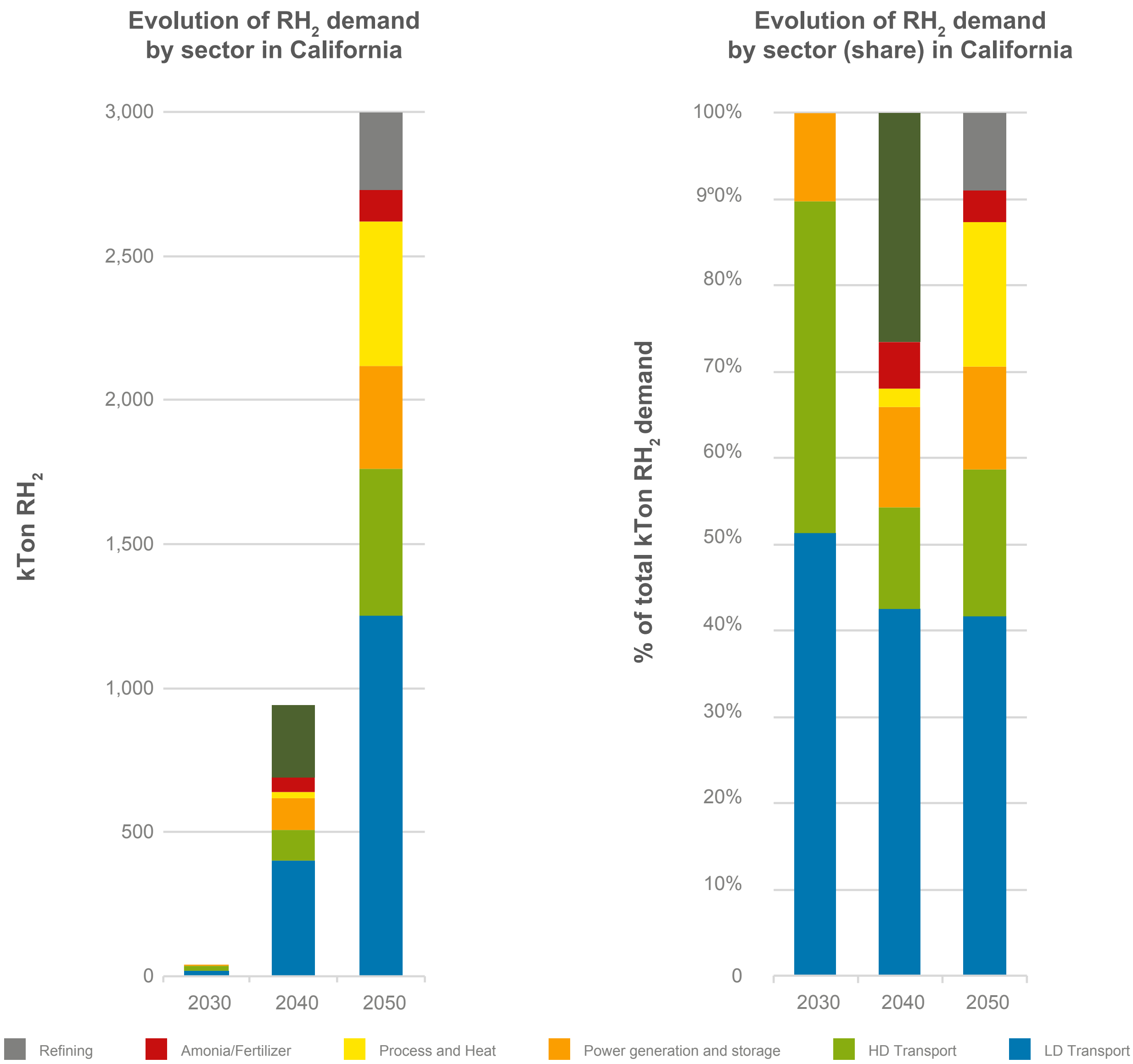


Source (6,7,8): Hinicio based on (UC Irvine Advanced Power and Energy Program, 2020).

Evolution of the Renewable Hydrogen Demand in California (UC Irvine Projections)

Figure 9, presented below, shows the evolution of renewable hydrogen demand in California by sector in the 2020-, 2030- and 2050-time horizons in terms of both net demand and as a share of total demand, according to the UC Irvine projections.

Figure 9. Evolution of the renewable hydrogen demand in California by sector in 2020, 2030 and 2040.



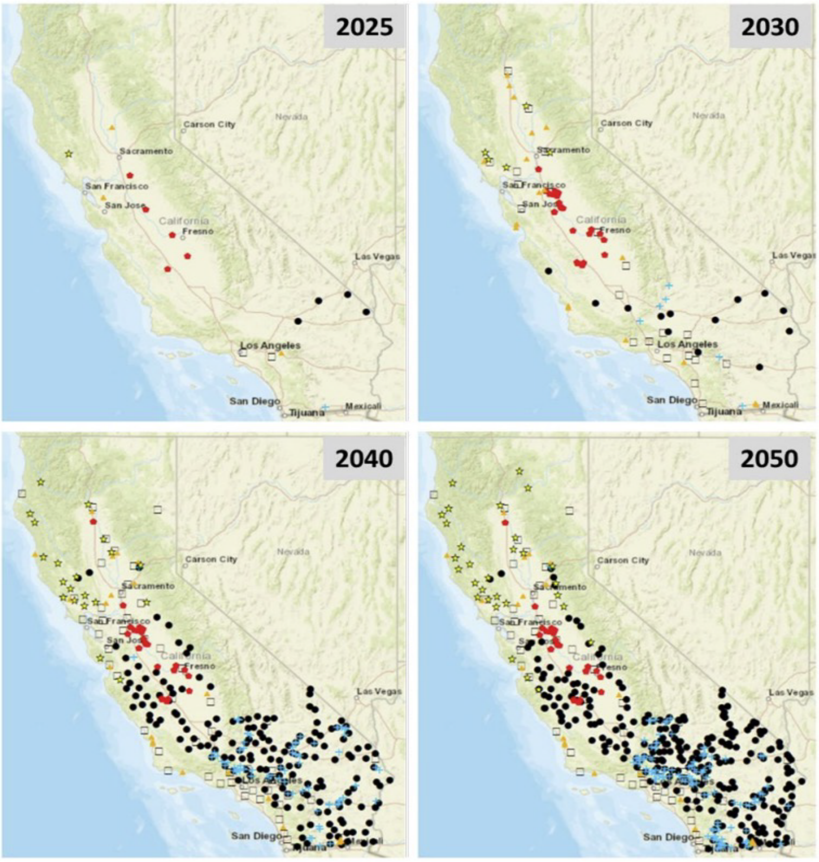
Source: Hinicio based on (UC Irvine Advanced Power and Energy Program, 2020).

These projections show that Light-Duty transport is expected to be California's biggest source of RH_2 demand in the near and long term, while Heavy-Duty transport is expected to start strongly too but will then be caught up by emergent hydrogen demand from power generation and storage, as well as commercial, industrial, and residential uses (process and heat). Renewable hydrogen will also be used to supply the demand for ammonia production and fuel refining, with the latter falling off towards 2050, as the use of fossil fuels in the state starts to decline.

Technological buildout of renewable hydrogen production in California

UC Irvine also presented a projection of the spatial buildout of hydrogen production in California per technology. The result is presented in Figure 10.

Figure 10. Spatial buildout projection of hydrogen production in California by type of technology.



Technology Count by Year	2025	2030	2040	2050
Solar-powered electrolysis	4	13	169	265
Wind-powered electrolysis	1	6	72	113
Thermochemical conversion of bio-mass	1	5	20	30
SMR of dairy-derived biogas	5	24	28	28
SMR of organic MSW-derived biogas*	3	19	21	21
SMR	2	21	51	51

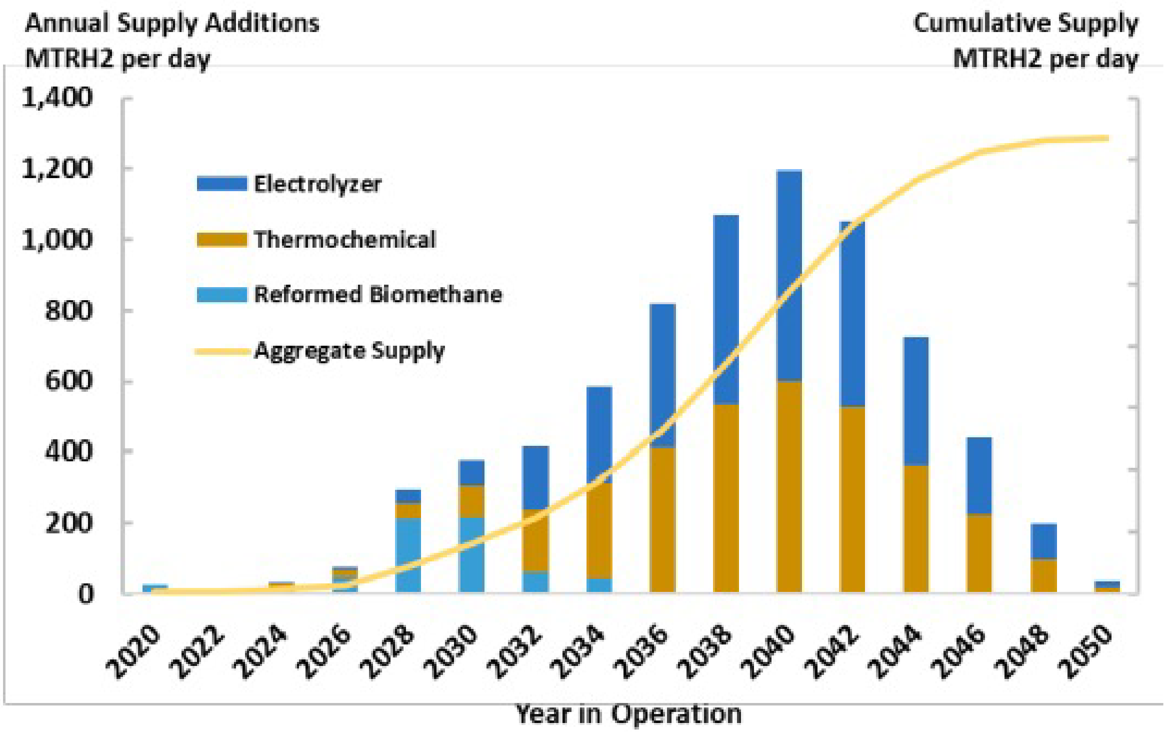
*MSW: Municipal Solid Waste

Source: (UC Irvine Advanced Power and Energy Program, 2020).

The buildout scenario shows a significant push to increase California's hydrogen production capacity with various technologies and from different energy sources. Electrolysis powered with solar energy is projected to provide the largest share of production plants in the state towards 2050, becoming dominant from 2030 onwards. Electrolysis powered with wind energy is projected to have the second highest number of production plants, starting from 2040. There will also be a notable increase in the number of plants using thermochemical conversion of biomass, as well as biogas from dairy and organic municipal solid waste. Lastly, the production of hydrogen via SMR will also be relevant, in combination with carbon capture systems to reduce GHG emissions.

By considering the spatial buildout of hydrogen production facilities, as well as the typical performance of each technology, UC Irvine's projections yielded the following results for the contribution of each renewable source to California's hydrogen demand from 2020 to 2050 (UC Irvine Advanced Power and Energy Program, 2020).

Figure 11. Share of California's renewable hydrogen demand supplied per each production technology.



Source: (UC Irvine Advanced Power and Energy Program, 2020).

1.3.2.2 Projected renewable hydrogen demand scenarios

The renewable hydrogen demand projections are based on the total energy demand in California. Both high and low demand scenarios were developed. To determine the share of each renewable hydrogen production technology, the distribution estimated by UC Irvine (Figure) was considered.

The share of electrolytic hydrogen was presented in a separate graph to provide more detailed insights and consider the crucial role of electrolytic hydrogen, considering that the other renewable hydrogen production methods such as biogas reforming and thermochemical conversion of biomass, have important limitations. Biogas reforming will be limited by feedstock supply constraints, while thermochemical conversion of biomass has a much higher carbon intensity than electrolysis and biogas reforming. Additionally, the technological improvement trajectories of both biogas reforming and thermochemical conversion of biomass are expected to be less substantial than those for electrolysis (UC Irvine Advanced Power and Energy Program, 2020).

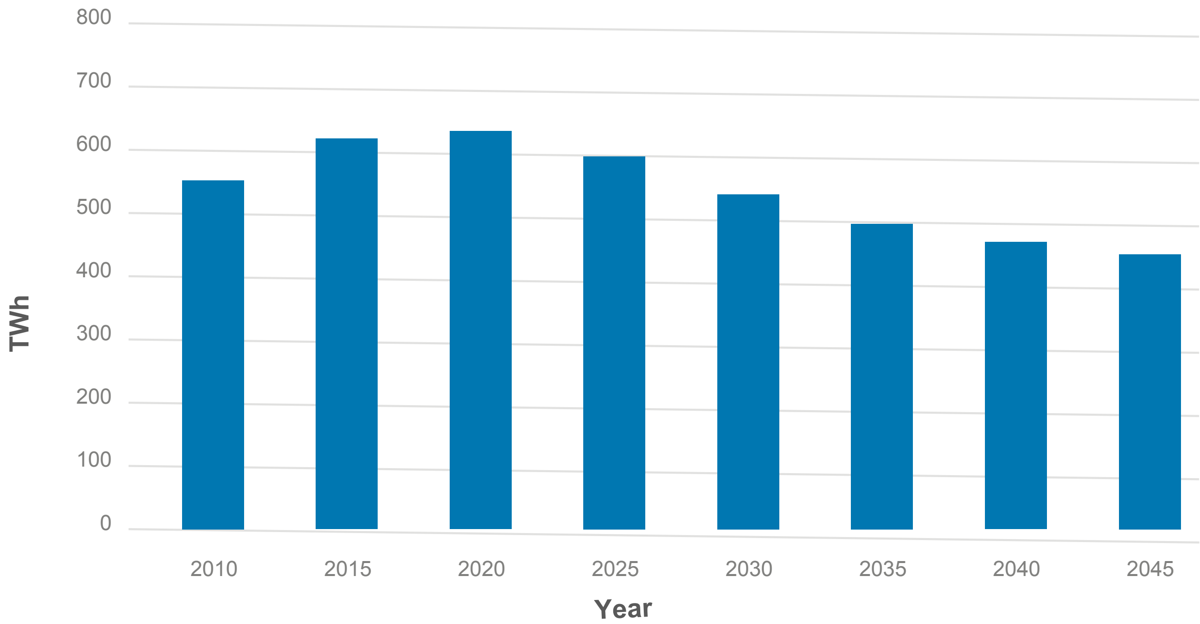
With these considerations in mind, the resulting hydrogen demand projections are presented below, together with their respective assumptions.

On-road transport (cars, buses and trucks)

ETransport decarbonization can be achieved through a variety of means, such as promoting the use of electric vehicles, investing in public transportation, and improving the efficiency of existing vehicles. In California, there are several initiatives and projects aimed at reducing transportation-related carbon emissions. For instance, the state has set a goal to achieve carbon neutrality in the transportation sector by 2045. This goal will demand significant investments in clean energy infrastructure and technology, as well as changes in the way people and goods are transported.

Four scenarios are proposed to achieve the state's decarbonization targets by 2045 (UC Institute of Transportation Studies, 2021). Considering the Business-as-Usual conditions it would not be possible to achieve a net zero scenario. Figure 12 shows the total transport fuel energy consumption projections in California.

Figure 12. Transport Fuel Energy consumption projections in California – Business as Usual scenario. Considering: H_2, electricity, CNG/RNG, LNG, BBD, diesel, BBG, gasoline.

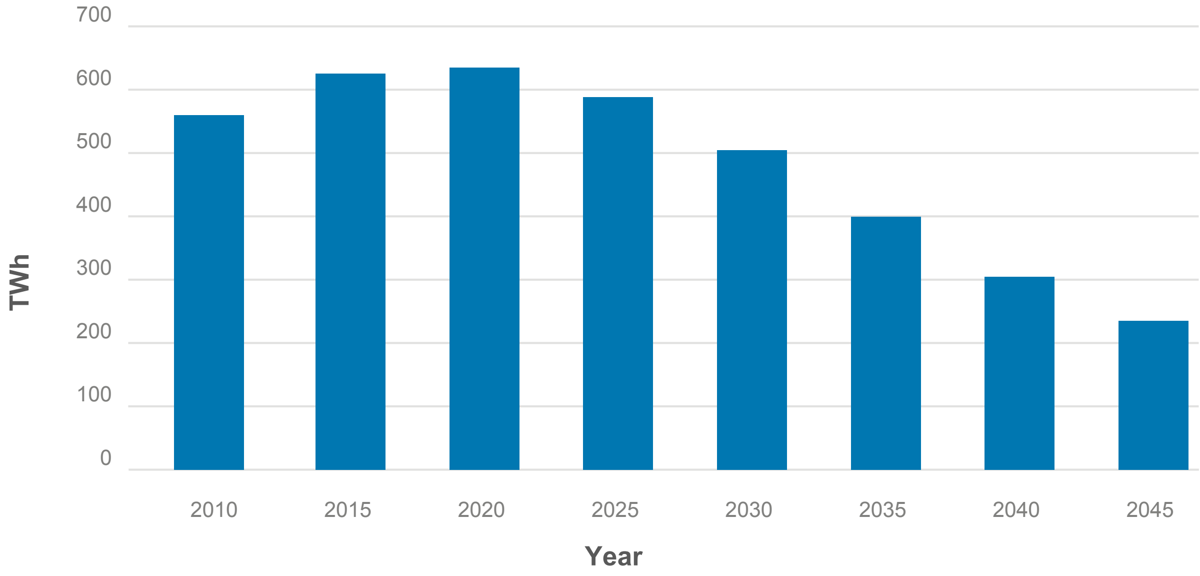


Source: (UC Institute of Transportation Studies, 2021).

The energy reduction for the next decades, as seen in Figure 12, are explained by new and more efficient technologies. Those new technologies demand new energy resources such as electricity, hydrogen, CNG/RNG (Compressed/Renewable natural gas), LNG (Liquefied Natural Gas), BBD (bio-based diesel), and BBG (bio-based gasoline).

Under the projections of the BaU scenario, it would not be possible to decarbonize the transportation sector in California entirely, therefore a central scenario that achieves carbon neutrality by 2045 is proposed. This scenario is called the "Low Carbon scenario" (LC1) and is considered the baseline scenario to achieve transport decarbonization in California. Figure 13 shows the required transport energy consumption projections in California to achieve carbon neutrality.

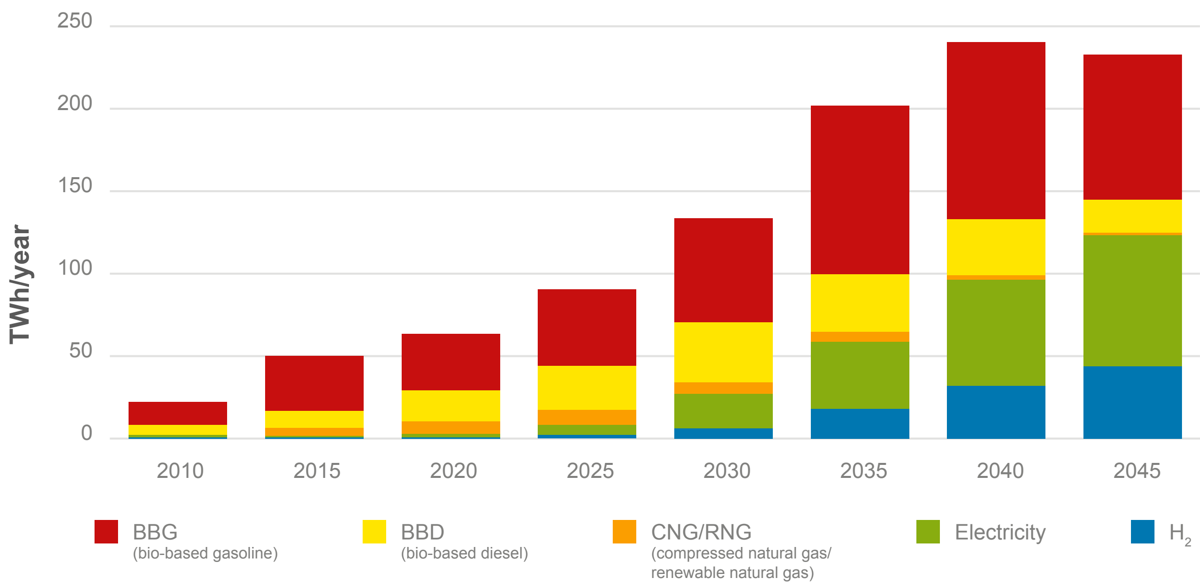
Figure 13. Transport Energy consumption projections in California – LC1 scenario



Source: (UC Institute of Transportation Studies, 2021).

The LC1 scenario requires a contribution from non-petroleum fuels shown in Figure 14:

Figure 14. Transport energy consumption by non-petroleum Fuels - LC1 scenario.



Source: (UC Institute of Transportation Studies, 2021).

LC1 describes a transition where mostly zero-emission vehicles (ZEVs) are sold for LDVs and trucks by 2030 (for LDVs ZEV 50%, and trucks 30%). By 2040, zero emission LDVs and trucks would represent 100% of sales. Zero emission buses are mandated to achieve a sales fraction of 100% by 2030.

ZEVs include battery electric vehicles, plug-in hybrid electric vehicles, and fuel cell electric vehicles. The shares of these ZEVs have been determined through a combination of modeling and expert judgement. Based on these assumptions, three scenarios have been developed:

- High ZEV" (HZ) scenario: accelerated uptake of LD and HD ZEVs
- "High Fuel Cell (HFC) scenario, with more FCEVs and fewer BEVs among HD and LD vehicles
- "High Liquid Fuels" (HLF) scenario, with slower ZEV uptake and thus more liquid fuels (such as biofuels) use through 2045.

The key assumptions considered for each of these are presented in Table 9.

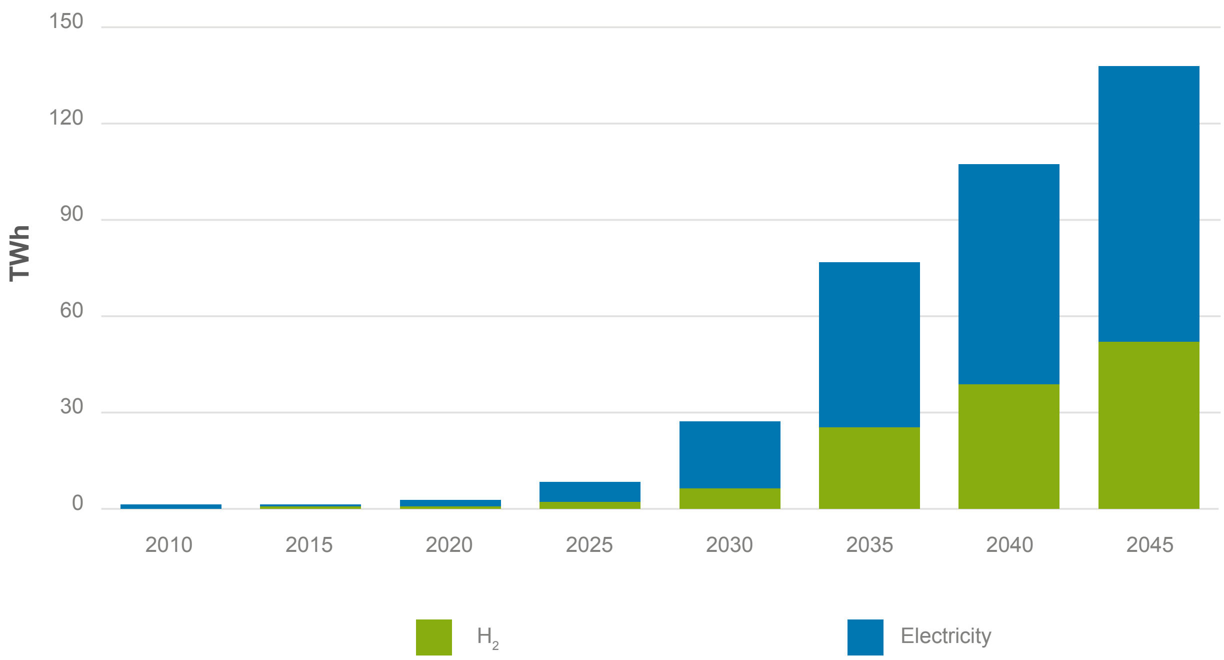
Table 9. ZEV side case scenarios comparison

	LDV (ZEV sales hit 100% by)	Trucks (ZEV sales hit 100% by)	Fuels (100% low- carbon fuels by)
LCI	2040	2040	2045
High ZEV (HZ)	2035	2035	2045 (but less needed)
High Fuel-cell (HFC)	2040 (lower BEV)	2040 (lower BEV)	2045 (same as LC1)
High Liquid Fuel (HLF)	2045	2045 (except 2050 for long haul trucks)	2045 (/But more needed)

Source: (UC Institute of Transportation Studies, 2021).

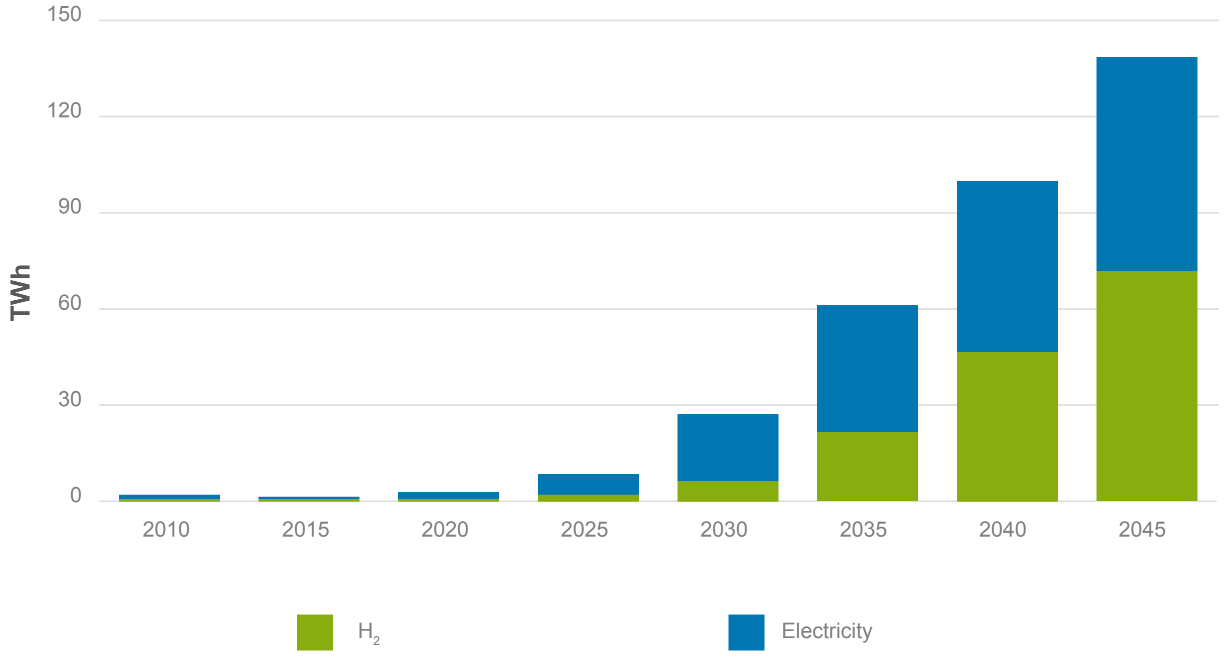
As in the LC1 scenario, energy demand projections were made for each scenario. The hydrogen and electricity demand that would be needed to decarbonize the transport sector are shown below.

Figure 15. Renewable hydrogen and electricity demand projection for transportation in California - HZ scenario.



Source: Hinicio based on (UC Institute of Transportation Studies, 2021).

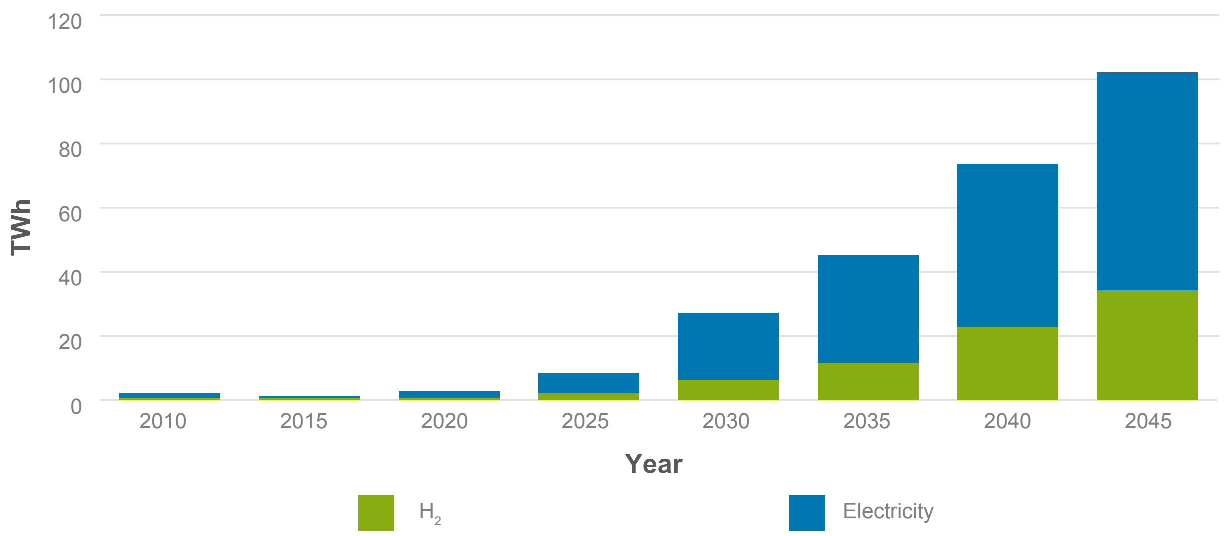
Figure 16. Renewable hydrogen and electricity demand projection for transportation in California - HFC scenario.



This scenario will be used after in the high-hydrogen demand scenarios proposed by the consulting team.

Source: Hinicio based on (UC Institute of Transportation Studies, 2021).

Figure 17. Renewable hydrogen and electricity demand projection for transportation in California - HLF scenario.



This scenario will be used after in the high-hydrogen demand scenarios proposed by the consulting team.

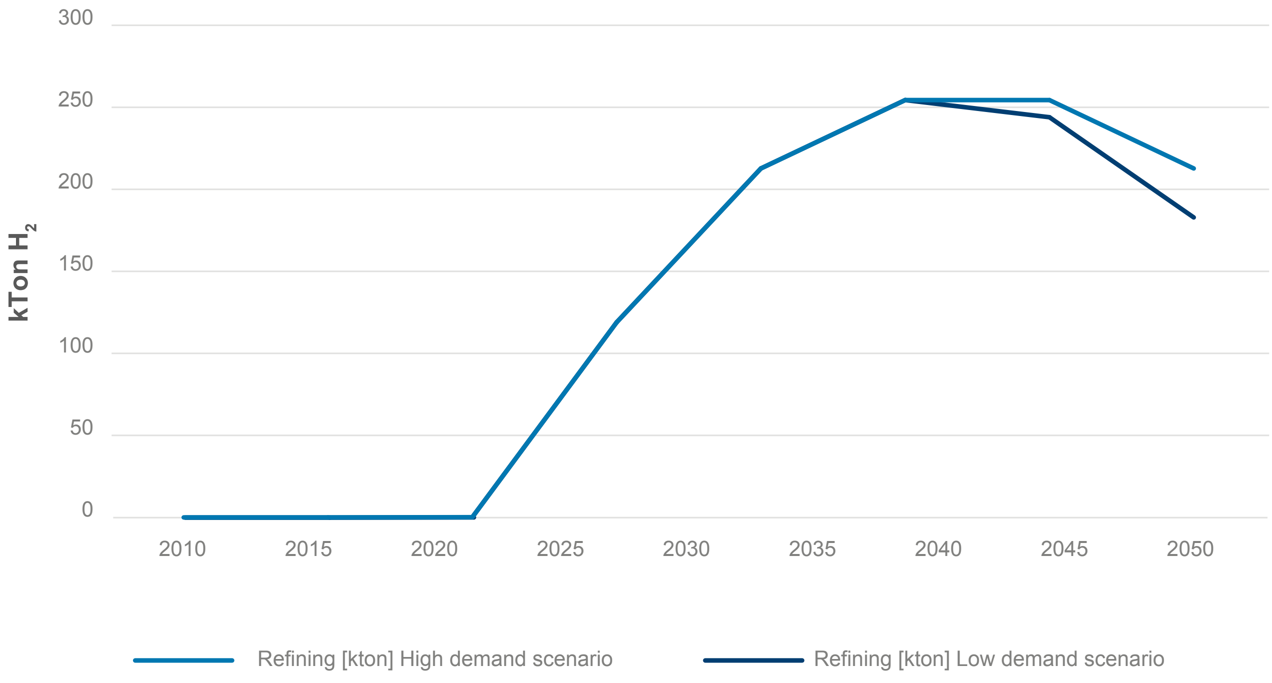
Source: Hinicio based on (UC Institute of Transportation Studies, 2021).

Refining

Decarbonization of hydrogen used for refining has already started in countries like Germany and Colombia. For California, assumptions based on (California Energy Comission, 2020) were considered:

- 100% of hydrogen consumed for refining in California will be renewable by 2050.
- The adoption of renewable hydrogen in the refining sector would begin in 2025, due to the expected cost reductions and the beginning of pilot projects.
- The overall demand for petroleum decreases, reaching between 10% and 20% of current demand by 2050 (the range difference is represented through a low demand and a high demand scenario).

Figure 18. Renewable hydrogen demand projections for refining



Source: Hinicio based on (UC Irvine Advanced Power and Energy Program, 2020).

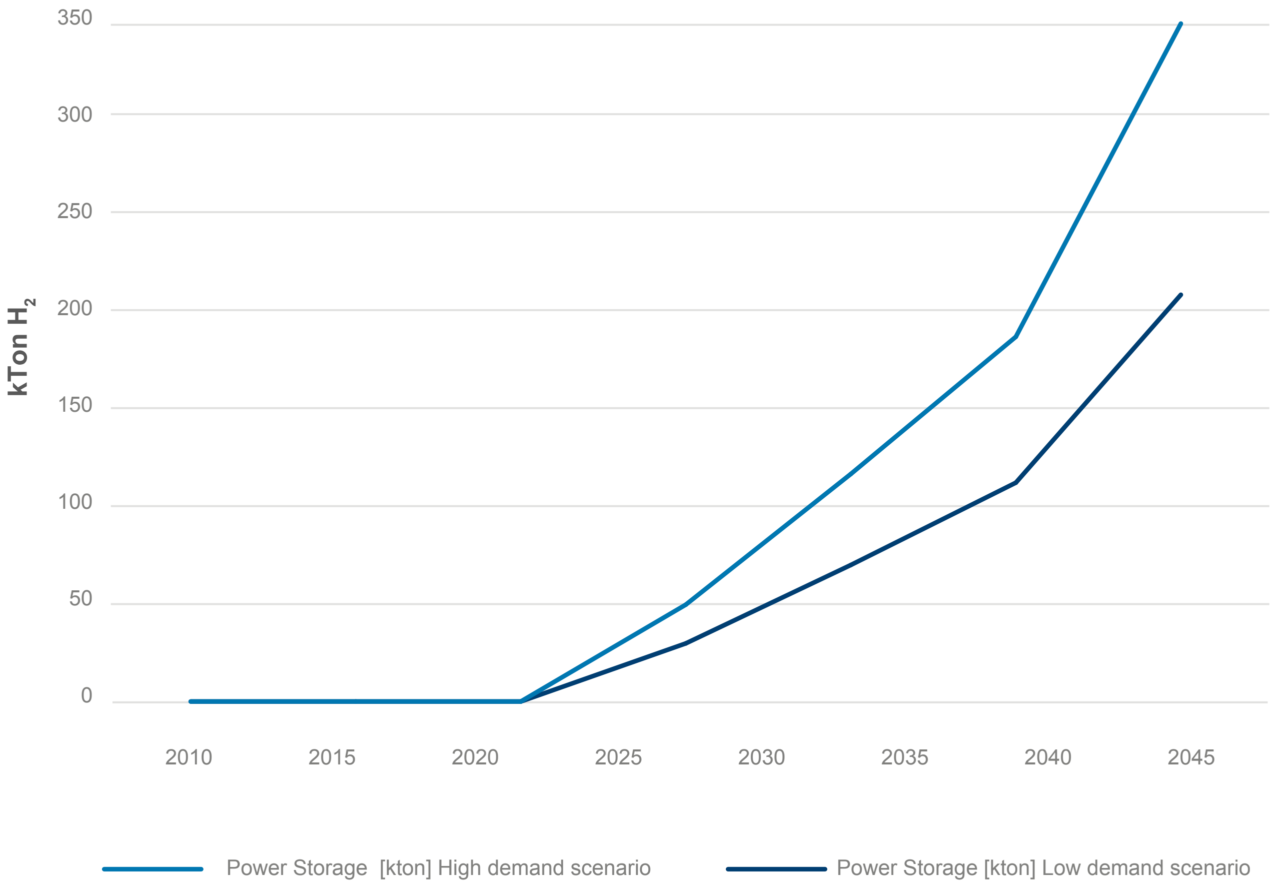
Power generation

As the penetration of variable renewable energy sources increases, it becomes important to develop storage capacity for excess energy to avoid curtailments. When renewable energy sources are producing more energy than is needed, that excess energy can be stored as hydrogen for later use, either as a fuel in existing but adapted gas turbines (short-medium term) or through fuel cells (medium-longer term).

Hydrogen is typically stored in high-pressure tanks or in metal hydride storage systems. Although the energy balance of storing power in the form of hydrogen is relatively poor (as compared to other storage options like batteries), hydrogen can be used for storing large quantities of energy over longer periods of time and is therefore more suitable for seasonal and weekly storage. For example, surplus energy generated during the summer can be stored in geological formations, and later used during the winter.

To reflect the potential of hydrogen for storing purposes, two scenarios were developed: one with 50% (high demand) and other with 30% (low demand) penetration of the base-case storage discharge capacity forecasted by the RESOLVE resource planning model, which is an optimization model that dispatches existing resources and adds new ones over time, in order to serve load at the least cost (PUC, 2020).

Figure 19. Renewable hydrogen demand projections for power generation.



The scenarios depend on the progression of technology costs among the alternative technologies (fuel cells or advanced hydrogen turbines), batteries, pumped hydro, geothermal, being all those technologies part of the RESOLVE´s planning model solution.

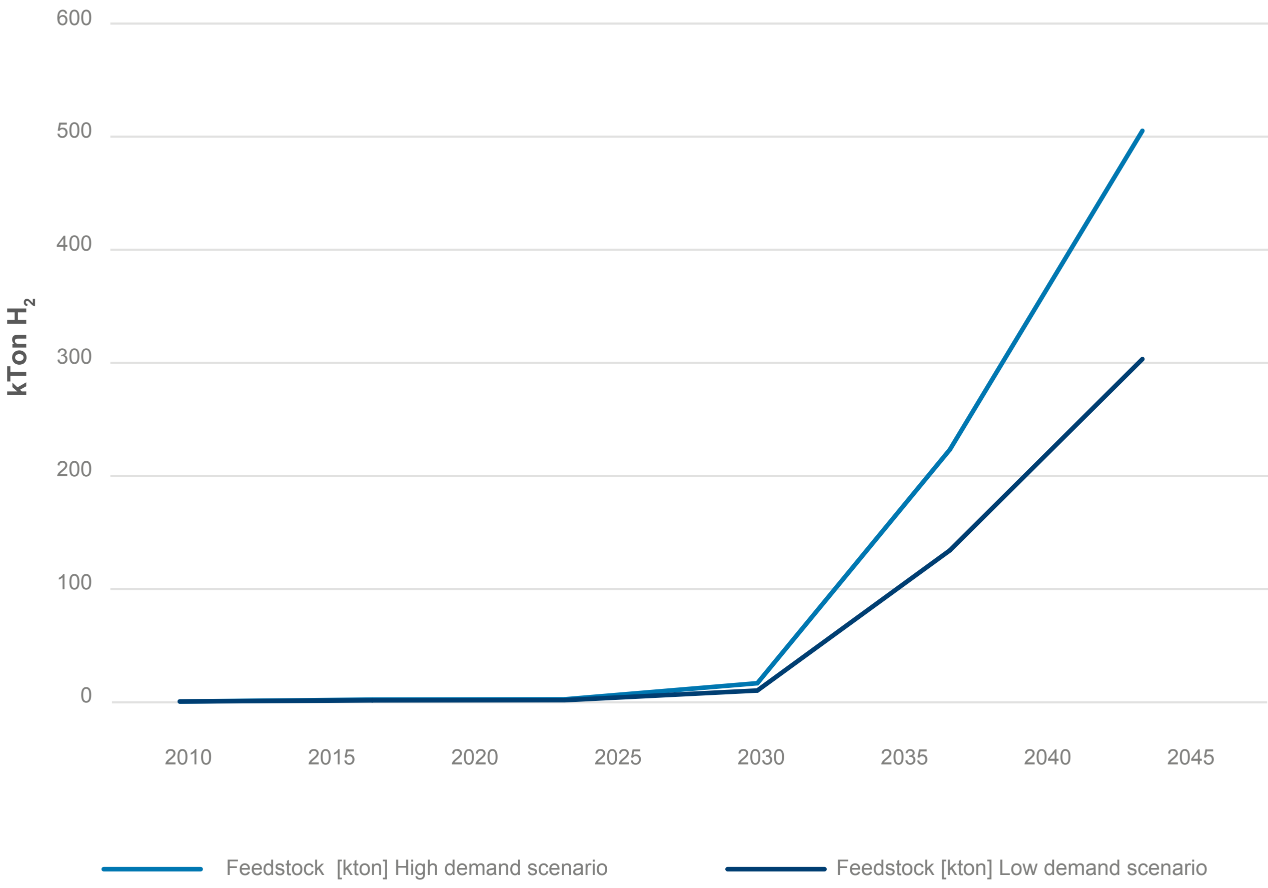
Source: Hinicio based on (UC Irvine Advanced Power and Energy Program, 2020).

Commercial, industrial, and residential uses (process and heat)

Green hydrogen can be used in a variety of industrial processes, though it is not expected to contribute significantly in California in the short term (UC Irvine Advanced Power and Energy Program, 2020) and (UC DAVIS ITS, 2023). However, if prices for renewable hydrogen fall below 2.2USD/KgH_2, it could be used as a blend stock for natural gas or as an outright replacement in certain applications. Pilot projects using pure hydrogen are already underway in Europe, and initial conversions to dedicated hydrogen distribution networks are targeted for implementation in the late 2020s. Taking this into account, two scenarios for hydrogen demand in process and heat uses have been developed: one considering an 85% (high demand) and other considering a 50% (low demand) replacement of the total natural gas consumed in the state. These scenarios assume that, starting in 2030, the transition to dedicated hydrogen networks will grow to 10% of the current natural gas demand in California, reaching 100% by 2050.

The construction of dedicated pipelines and other projects for hydrogen transportation are likely to happen gradually. Due to the uncertainty of the timing and size of each project, a smooth curve is used to represent the overall demand growth for hydrogen in processes and heat uses.

Figure 20. Renewable hydrogen demand projections for commercial, industrial and residential uses



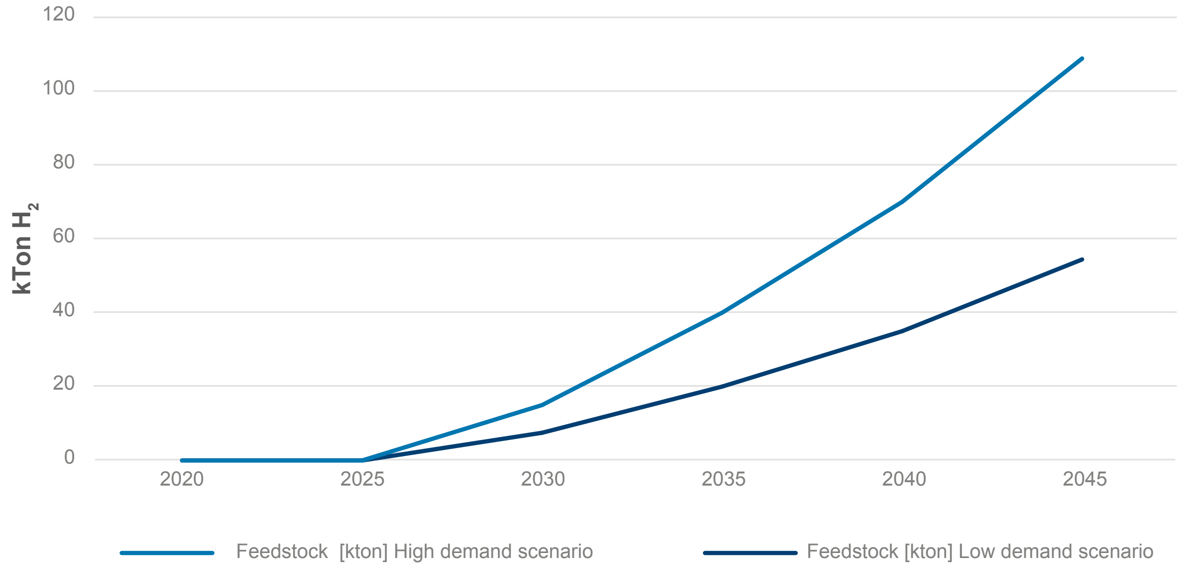
Source: Hinicio based on (UC Irvine Advanced Power and Energy Program, 2020).

Ammonia

Currently, U.S. hydrogen demand for ammonia production is estimated to be 2.5 Mton, 88% of which is used for fertilizers. This number is expected to increase to 3.3 Mton by 2050 and remains flat thereafter (Elgowainy, 2019). A UC Davis assessment estimated that the use of nitrogen fertilizer in California ranged from 650,000 to 950,000 tons in the early 2000s and is projected to be around 1 million tons currently (Tomich, 2014). If all of this came from ammonia, the hydrogen requirement would be about 190 kton. Data from the U.S. Department of Agriculture shows that roughly 15% of ammonia for fertilizers is used in the form of anhydrous NH_3, with the remainder used in the form of other fertilizers, like urea.

Transitioning to zero-carbon-ammonia is feasible at a reasonable cost by midcentury (Ammonia Energy Association, 2019).The potential cost reduction for renewable hydrogen supports this perspective. This analysis assumes that the production of renewable hydrogen demand for fertilizers production in the state will grow to an estimated 110 kton H_2 per year for the high demand scenario and 54 kton H_2 per year for the low demand scenario by 2045. The increase in the renewable ammonia fraction is expected to show gradual changes as more facilities are added, but because of the uncertainty in facility size and deployment timing, a smooth curve was used to represent the overall growth demand from this hydrogen final use.

Figure 21. Renewable hydrogen demand projections for ammonia production



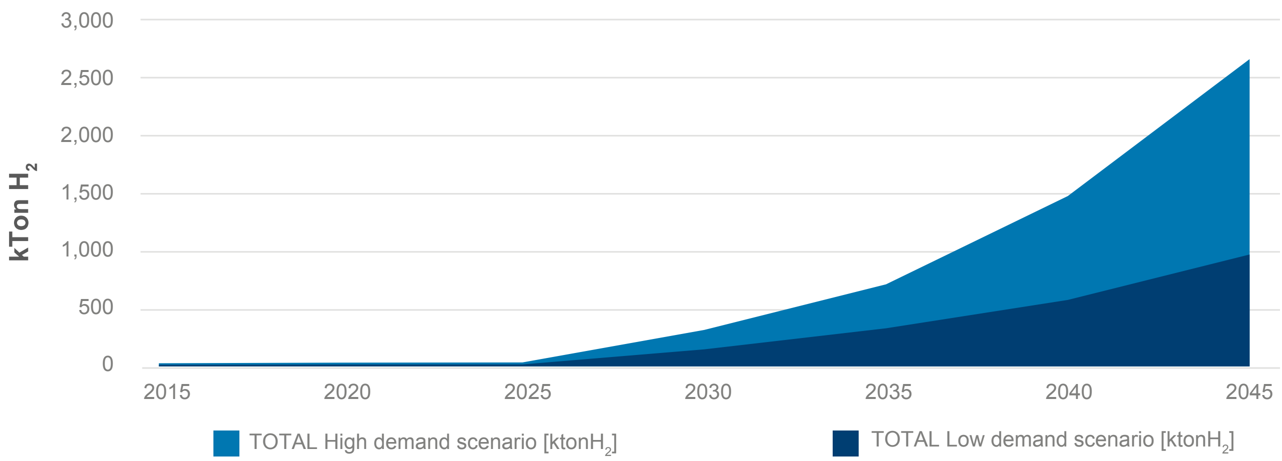
Source: Self elaborated, based on (UC Irvine Advanced Power and Energy Program, 2020).

After considering the potential hydrogen demand from all sectors, a set of synthesized high and low demand scenarios were built. The high demand scenario reaches a total of 2,630 ktonH$_2$ by 2045. This demand begins to grow in mid-2025, driven primarily by the transport sector. The first million tons per year of renewable hydrogen in California would be reached in 2037, 12 years after mid-2025, but in just 5 more years (2042), the demand would be doubled, reaching 2 Mton and indicating a significant acceleration in hydrogen deployment to come in the decade of the 2040s. In the low demand scenario, the first yearly megaton of renewable hydrogen consumption would be reached by 2040.

The results for the complete renewable hydrogen demand and the subset of electrolytic-only hydrogen demand are presented next:

1. Total renewable hydrogen demand

Figure 22. Total renewable hydrogen demand projections.

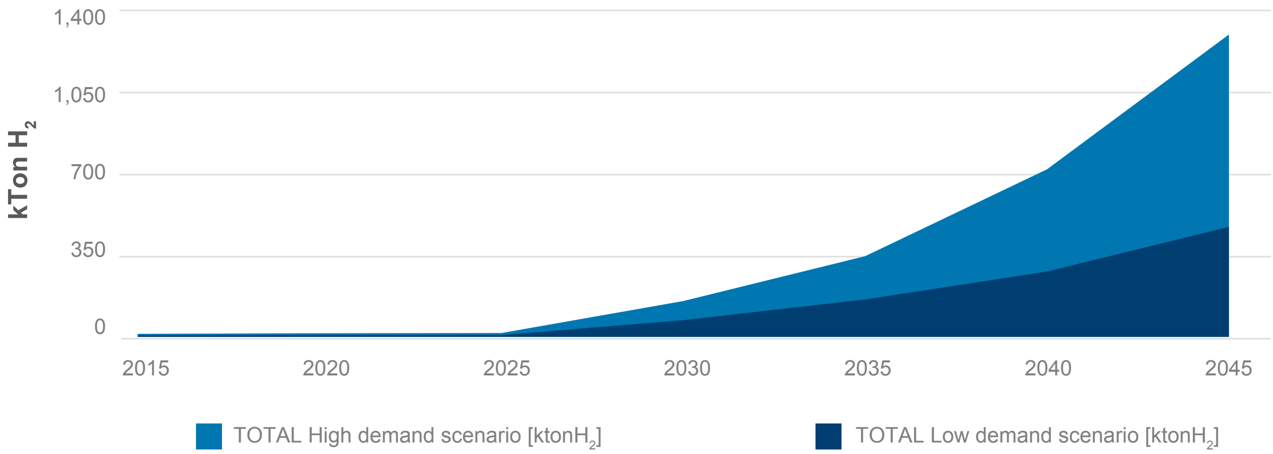


Source: Hincio based on (UC Irvine Advanced Power and Energy Program, 2020).

2. Electrolytic-only hydrogen demand

It is expected that until mid-2030 the production of renewable hydrogen from electrolysis will comprise less than 20% of the renewable hydrogen demand in the state, with biogas reforming and thermochemical conversion playing a major role. The expected drop in the cost of electrolyzers and renewable energy, allows to estimate an increase in the share of electrolytic hydrogen until reaching approximately 50% of this demand by 2050.

Figure 23. Total electrolytic hydrogen demand projections.



Source: Hinicio based on (UC Institute of Transportation Studies, 2021).

1.4 Hydrogen production potential in California

California is already a leader in the production of hydrogen, with several large-scale hydrogen production facilities located in the state (see section 1.2.2). These facilities use a variety of technologies to produce hydrogen, including steam methane reforming and electrolysis. Steam methane reforming involves using natural gas to produce hydrogen, while electrolysis involves using electricity to split water into hydrogen and oxygen. These two methods are the most used in the state nowadays, but in the coming years, renewable hydrogen production technologies are expected to diversify, incorporating:

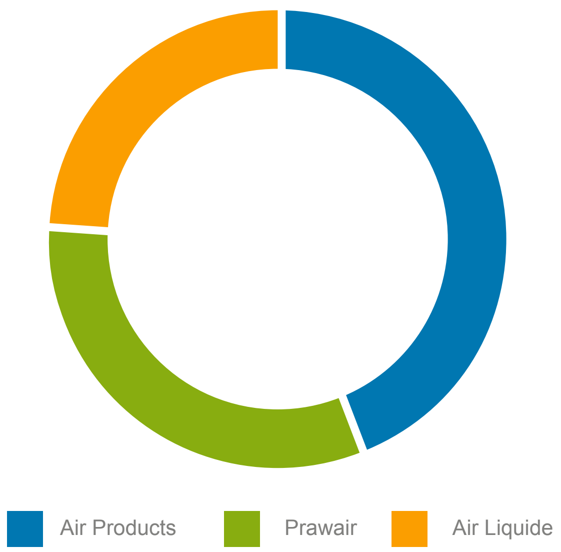
Anaerobic digestion with reformation: Decomposition of organic material through a series of anaerobic reactions to create methane and CO_2, followed by reformation of methane to produce hydrogen.

Thermochemical conversion: Use of high temperatures and, in some cases, pressure to create a hydrogen-rich gas from biomass.

It is also worth noting that the total hydrogen production potential in a specific location can differ depending on a variety of factors, such as the availability of natural gas and water, the amount of renewable energy available for electrolysis, and the overall demand for hydrogen. For instance, the current infrastructure and deployed hydrogen supply chain in California is mainly related to the oil industry, which uses hydrogen to remove sulfur content that is naturally contained in oil to refine fuels. Hydrogen used by refineries is largely being supplied by industrial gas companies (IGCs) that primarily use Steam Methane Reforming (SMR) of natural gas to produce hydrogen.

The IGCs are responsible roughly of the 40% of the total hydrogen demand in California, distributed as follows:

Figure 24. Installed hydrogen capacity distribution by IGCs in California.



Source: Source: Hinicio based on (Berkeley, 2020).

Although all the installed capacity of just over 1 Mton/year comes exclusively from SMR processes, proposed plants for renewable hydrogen production have been announced, and most of them will be using electrolysis. Those projects are intended to align industries, such as refineries, with the decarbonization goals of the state. In the following sections, the renewable hydrogen production potential will be analyzed, considering different sources and technologies to produce it.

1.4.1 Potential availability of renewable energies

There are several potential constraints to deploying solar and wind energy in California. One major constraint is the availability of land for installing solar panels or wind turbines. There can also be logistical challenges associated with integrating renewable energy sources into the existing power grid, and there are regulatory hurdles to overcome as well.

For estimating the techno-economic potential of renewable energies in California, we consider 11 restrictions to land availability to deploy solar and wind energy, and their respective buffer areas. Table 10 shows these restrictions used to determine the land availability for solar and wind systems.

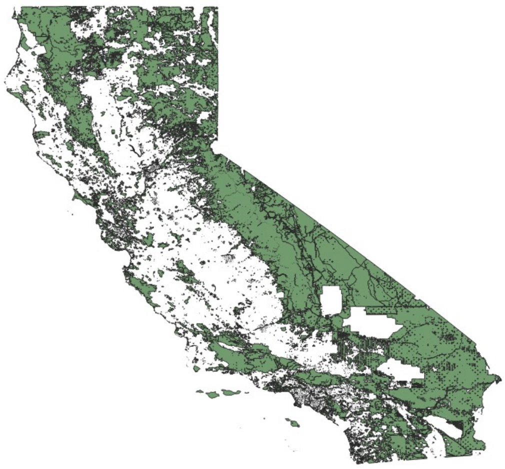
Table 10. Restrictions to build Solar and Wind production plants in California.

Constraint	Buffer distance Solar energy [m]	Buffer distance Wind energy [m]	References
Protected Natural Areas	1000	1000	(GIZ, 2021)
Airports	200	5000	(Samsatli et al., 2016)
Easements	100	1000	(EPM, 2019)
Highways	200	200	(Samsatli et al., 2016)
Major rivers	200	300	(MDPI, 2018)
Major Lakes and Reservoirs	200	300	(MDPI, 2018)
Cities	200	1000	(MDPI, 2018)
Rail network	200	200	(Samsatli et al., 2016)
Natural gas pipelines infrastructure	200	239	(ICFMFA, 2018)
Transmission lines	2.3	15	(VIRIDI, 2022)
Military zones	200	200	(GIZ, 2021)

Source: Hinicio

All these restrictions are mapped below to provide a better understanding of the potential that California has to develop renewable energy infrastructure, either for renewable electricity or for hydrogen production sites.

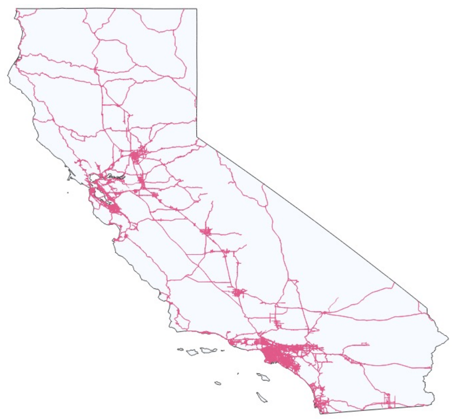
Protected Natural Areas



Airports

Easements

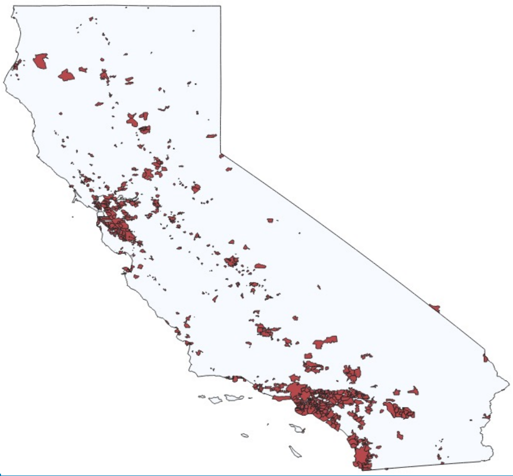
Highways



Major rivers

Major Lakes and Reservoirs

Cities

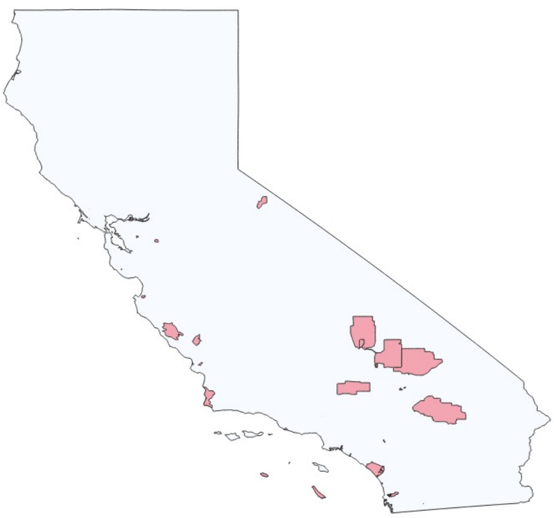


Rail network

Natural gas pipelines infrastructure

Transmission lines

Military



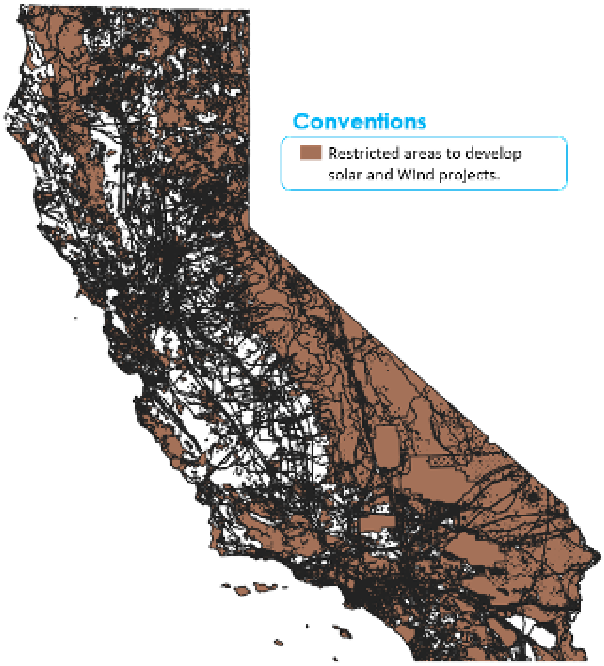
Elevation

There are several reasons why it might not be appropriate to build solar and wind systems in areas with any of the restrictions mentioned above. These may include impacts on the following subjects:

- **Wildlife**: Solar and wind systems can have an impact on local wildlife, including birds and other animals. For example, large wind turbines can pose a collision risk for birds, and the bright lights on solar panels can disturb the natural behavior of nocturnal animals.
- **Landscape**: Solar and wind systems can also have an impact on the natural landscape. Large wind turbines, for example, can be visually intrusive and may alter the natural beauty of an area.
- **Environment**: The construction of solar and wind systems can also have environmental impacts. For example, the installation of solar panels may require the removal of vegetation and the construction of roads, which can lead to soil erosion and other environmental issues.
- **Protected natural areas**: It is important to minimize the impacts on the environment and wildlife. Building solar and wind systems may not achieve this, and alternative energy sources might need to be considered.
- **Aviation safety**: Solar and wind systems can have an impact on aviation safety. Large wind turbines, for example, can pose a collision risk for aircraft, and the reflection of sunlight off solar panels can create visual distractions for pilots.
- **Air traffic control**: Solar and wind systems can also interfere with air traffic control systems. For example, the reflection of sunlight off solar panels can interfere with radars, and the spinning blades of wind turbines can create radar shadows that make it difficult to detect aircraft.
- **High levels of air pollution**: Cities are often located in areas with severe air pollution and other forms of environmental degradation. Building large solar and wind systems in these areas could potentially contribute to pollution during the construction, waste disposal and management stages, as well as other forms of environmental damage.
- **Population density**: Cities are typically more densely populated than rural areas, and large solar and wind systems can take up a significant amount of space. This could lead to conflicts with other land uses, such as housing, transportation, and recreation.
- **Financial feasibility**: Building large solar and wind systems in cities can be more expensive than building them in rural areas, since urban land is typically more expensive. Consequently, it can be more difficult to obtain the necessary permits and clearances to build them in urban areas.
- **Transport infrastructure**: In general, it is often heavily used by people and vehicles, and the presence of large solar and wind systems could potentially create safety hazards. For example, if a solar panel or wind turbine were to break or malfunction near a highway, it could cause accidents or other safety issues. Furthermore, these areas often have a high level of noise and other forms of pollution, and the construction and operation of large solar and wind systems could potentially contribute to this type of pollution, causing multiple negative impacts on the surrounding environment and wildlife.
- **Zoning laws**: Urban areas are often subject to strict regulations and zoning laws, so it can be difficult to obtain the necessary permits and approvals to build large solar and wind systems.
- **Other potential hazards**: Overall, while it is technically possible to build solar and wind systems near highways, rail networks, major rivers, major lakes, transmission lines, natural gas pipelines, and military zones, it is generally not recommended due to the potential safety, environmental, and regulatory challenges.

Figure 25 shows the union of all the aforementioned restrictions in California. The areas in which the deployment of solar and/or photovoltaic generation infrastructure would not be feasible are shown in brown.

Figure 25. Restricted areas to develop solar and Wind projects in California.



Source: Hinicio

The levelized cost of energy (LCOE) is a measure of the overall cost of generating electricity from a particular energy source, considering the initial capital investment, operation and maintenance costs, as well as the total amount of energy (in this case electricity) generated over the lifetime of the project.

LCOE are calculated for non-excluded areas in California, considering solar irradiation and wind speeds, using the following formula:

Equation 1. Equation 1. *LCOE* formula.

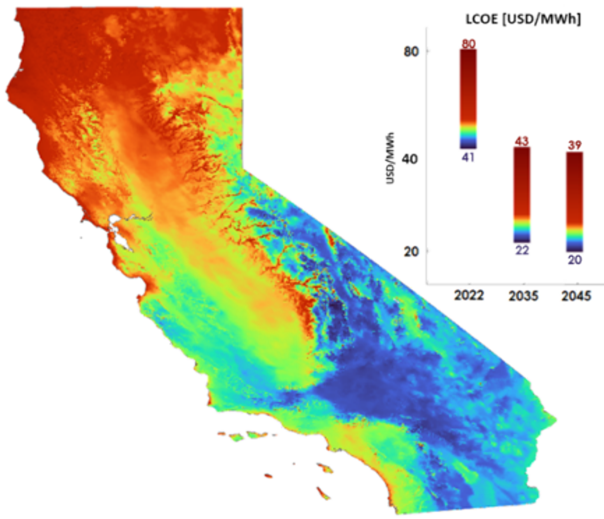
$$LCOE = \frac{CAPEX + \sum_1^t \frac{OPEX_t}{(1+r)^t}}{\sum_1^t \frac{Energy\ produced_t}{(1+r)^t}}$$

Where:
CAPEX: Capital expenditures including contingencies
OPEX: Operational expenditures
r: Discount rate
t: Project´s lifetime

In California, the LCOE of solar and wind energy has been steadily decreasing over the years, making them increasingly competitive with traditional fossil fuel sources.

Figure 26 and Figure 27 show LCOE costs for potential wind and solar projects respectively. Detailed assumptions on CAPEX and OPEX for each technology are presented in Annex 1. The analysis considered expected learning and associated cost-reduction over the periods to 2035 and 2045.

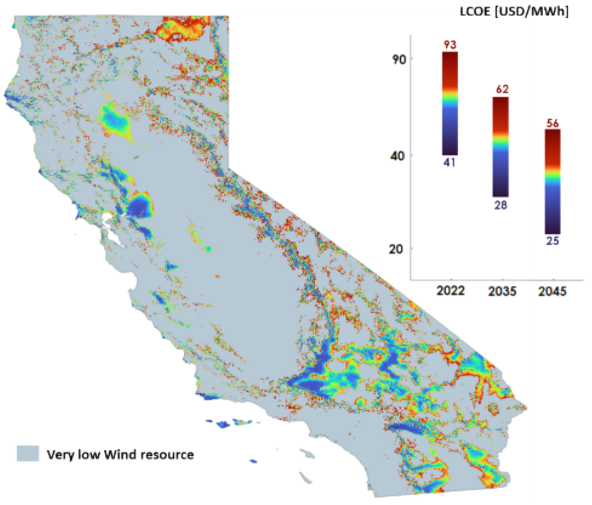
Figure 26. Solar Levelized Cost of Energy spatial distribution (*LCOE*).



Source: Hinicio

The LCOE of solar energy is expected to decrease by approximately 50% between 2022 and 2045. This reduction would happen faster in the medium term (2022-2035) than over the long term (up to 2045). This is because the more mature a technology becomes, the harder it is to make it more efficient (diminishing returns come with increased total installed capacity).

Figure 27. Wind Levelized Cost of Energy spatial distribution (LCOE).



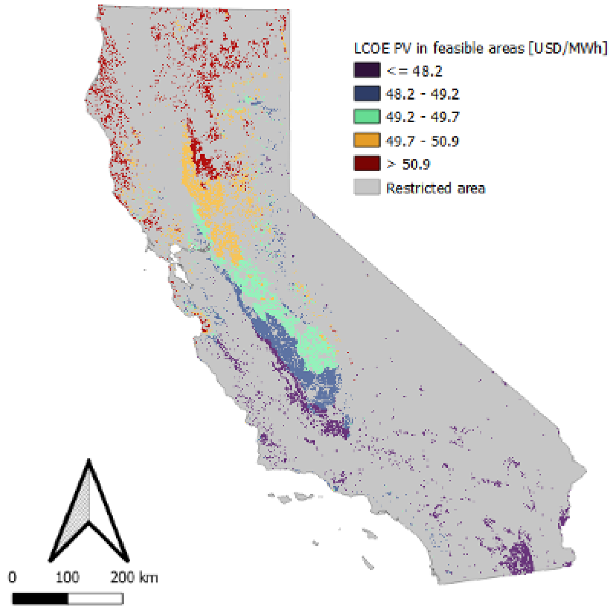
Source: Hinicio

As for the wind projects, the LCOE is expected to decrease by 34% between 2022 and 2035 and by 10% between 2035 and 2045.

It is also expected that by the late 2020s, solar power will become cheaper than onshore wind power by roughly 6.5 USD/MWh. This solar cost advantage is expected to increase to approximately 10 USD/MWh towards the decade of the 2030's and to persist in the long term.

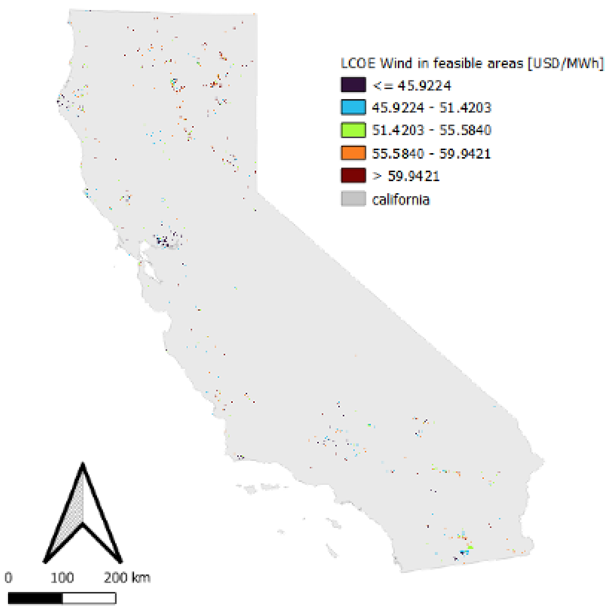
Considering cost (LCOE) and the restrictions shown in Table 10, the most attractive locations for renewable projects are selected. Figure 28 and Figure 29 show the feasible areas for solar and wind.

Figure 28. LCOE of PV energy in areas available lands in California.



Source: Hinicio

Figure 29. LCOE of Wind energy in areas available lands in California.



Source: Hinicio

1.4.2 Renewable hydrogen production potential

Besides renewable electricity, the availability of feedstock for the various renewable hydrogen production pathways is a key input to the final delivered cost and ultimate quantities that can be produced.

Organic materials (biomass): Organic materials availability is an important factor in the state's efforts to increase the use of renewable energy and reduce its reliance on fossil fuels. Organic materials that are commonly used as feedstocks in California include agriculture residues, energy crops, food waste, forest residue, manure, municipal solid waste (MSW), and trees.

Each type of organic material can be used in a preferred pathway to produce hydrogen. Table 11 shows the processes through which the various feedstocks are transformed to renewable hydrogen.

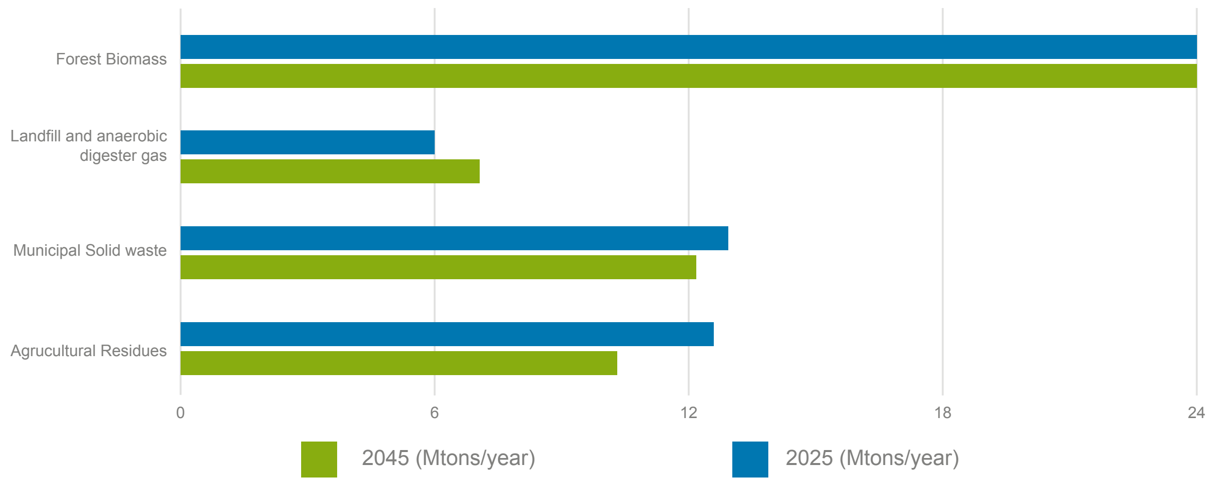
Table 11. Conversion process to produce renewable hydrogen from different organic feedstocks.

Feedstock	Conversion process
Forest, Agricultural Residue, Woody MSW	Thermochemical
Energy Crops	Thermochemical
High-Moisture Organic MSW	Anaerobic Digestion & Biomethane reforming

Sources: (Baker, 2019)

The total biomass available in California for 2025 and 2045 is estimated to be 54 million tons per year and 56 million tons per year, respectively (Baker, 2019). Figure 30 shows the projected availability of feedstocks by source and by year:

Figure 30. Biomass availability in California (2025-2045)

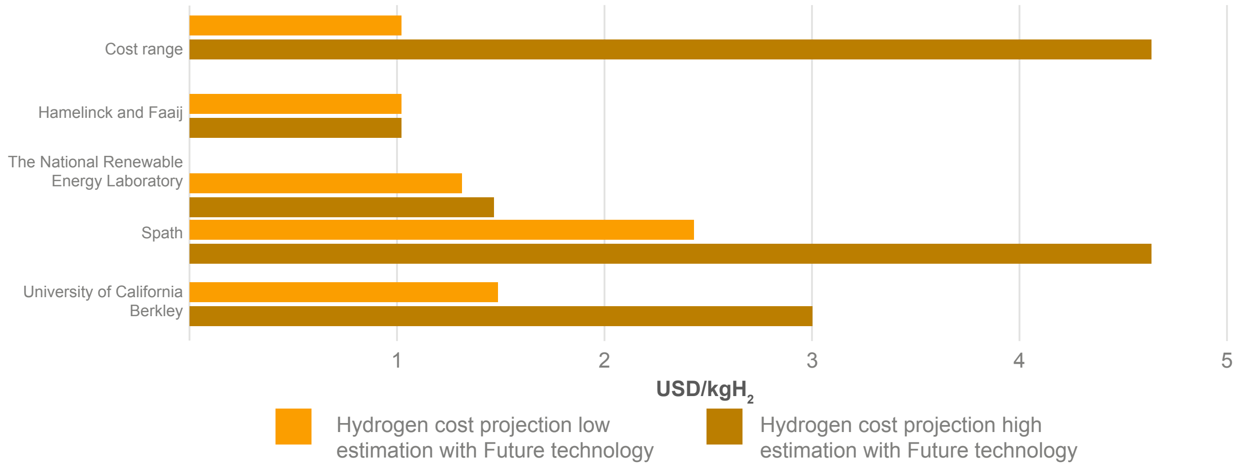


Sources: (Baker, 2019)

According to the University of California-Berkeley (Berkeley, 2020), if all available and applicable biomass is utilized to produce hydrogen, 3,800 kton of renewable hydrogen could be produced annually in California. On the other hand, previous studies about the role of biomass to develop the hydrogen economy in California have estimated a potential production of 335 PJ (Parker, Ogden, & Fan, 2009), equivalent to 2,340 kton of hydrogen, with municipal solid waste being the largest resource available in the state.

Since few commercial-scale biomass hydrogen production facilities exist today, decision-makers rely on engineering-economic studies based on technology modeling and expert opinion. For instance, a comprehensive study of hydrogen from the National Academy estimates the 'current' technology production cost of hydrogen is at \$4.63/kg and will be dropping down to \$2.21/kg with 'future' technologies (NRC, 2004). Other reference costs for the production of renewable hydrogen from biomass are shown in Figure 31.

Figure 31. Range of hydrogen cost from organic materials in California.

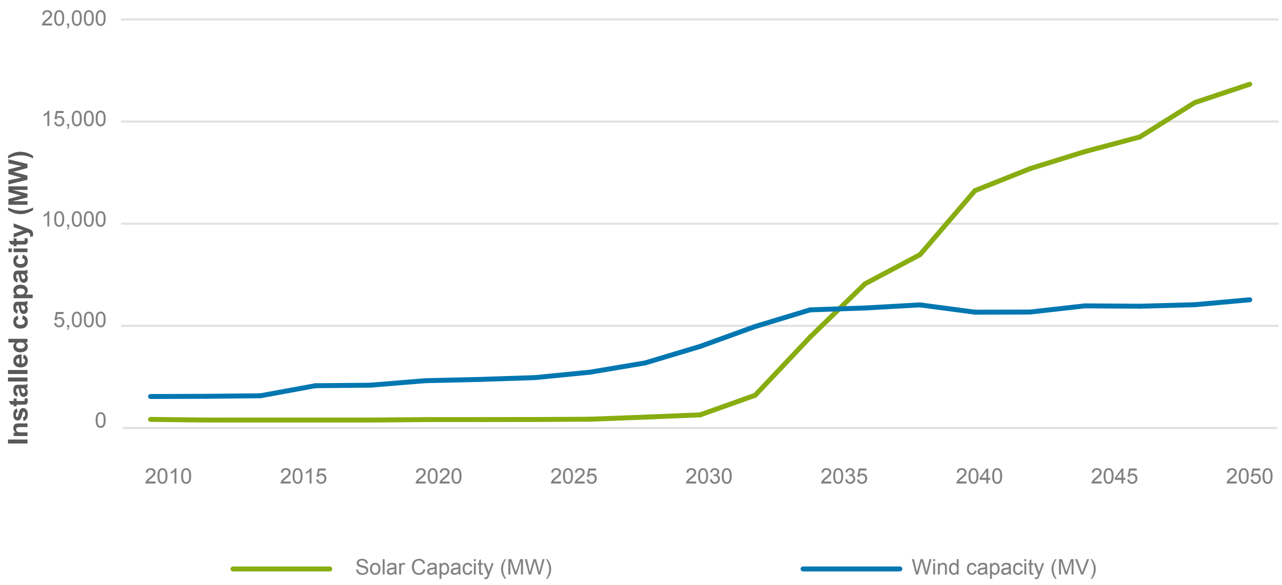


Sources: (Baker, 2019), (NRC, 2004), (Spath, 2003), (Hamelinck, 2006).

Renewable electricity

According to the California Energy Commission, as of 2021, California generates approximately 50% of its electricity from renewable sources such as solar, wind, and hydropower (CAE, 2021), with solar and wind accounting for 23 GW of installed capacity in 2021 (CEM, Data on Renewable Energy Markets and Resources, 2021). The state has set a goal of reaching 100% zero carbon electricity by 2045 and has implemented policies to encourage the growth of renewable energy generation. During the last few years, solar and wind energy have been protagonists of the energy transition in the USA, and California is no exception.

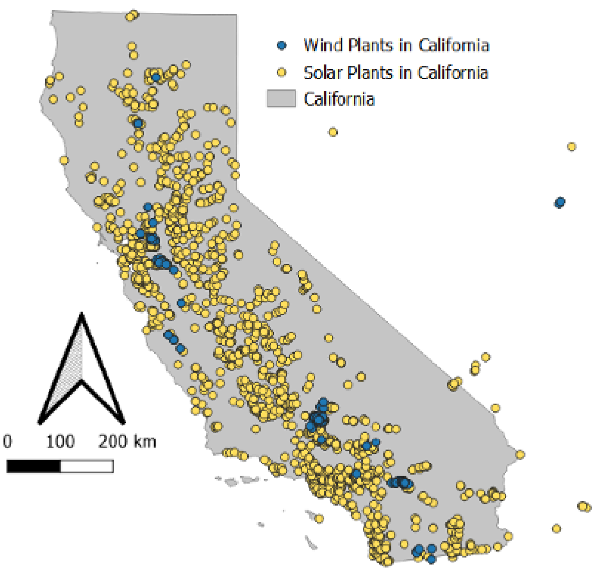
Figure 32. Solar and wind installed capacity in California.



Source: (CEM & California Energy Comission, 2021)

Renewable power plants have been distributed throughout California. Although there are areas with a higher concentration of projects, without considering the restricted areas already mentioned in Figure 25, the solar and wind generation projects run from north to south across the state, with a greater presence of solar facilities, as can be seen in Figure 33.

Figure 33. Solar and wind projects in California.



Source: Renewable Ninja

In the next section, the potential for producing electrolytic hydrogen from renewable energy (solar and wind) is analyzed. For this purpose, the assumptions described in Annex 1 regarding the development cost of this technology, and the restrictions for its deployment, are considered.

1.4.3 Electrolytic hydrogen production potential

Electrolytic hydrogen has been identified as a potentially important source of clean energy. California, with its abundant renewable energy resources and ambitious clean energy goals, is well-positioned to take advantage of the potential of electrolytic hydrogen production. In fact, the California Fuel Cell Partnership has stated that “California is uniquely suited to lead the nation in the deployment of hydrogen infrastructure and fuel cell electric vehicles, given the state’s strong commitment to reduce greenhouse gas emissions, advanced technology sector, and abundant renewable energy resources.” (California Fuel Cell Partnership, 2020). Additionally, the California Energy Commission has identified hydrogen production via electrolysis as a key technology for meeting the state’s clean energy goals, stating that it has “the potential to significantly reduce greenhouse gas emissions and improve air quality” (CEM, California Energy Commission, 2019).

Due to its dependence on the availability of renewable resources, an estimate of the electrolytic hydrogen production potential must be based on the availability of its primary resources. For this reason, the proposed methodology considers the selection of feasible land to produce renewable energy (solar and wind) carried out during section 1.4.1 to calculate the optimal Levelized Cost of Hydrogen (LCOH) that can be achieved under the considerations presented in Annex 1.

Methodology: The generation of renewable energy from photovoltaic panels and wind turbines was considered, contemplating its large-scale deployment on available land and production costs.

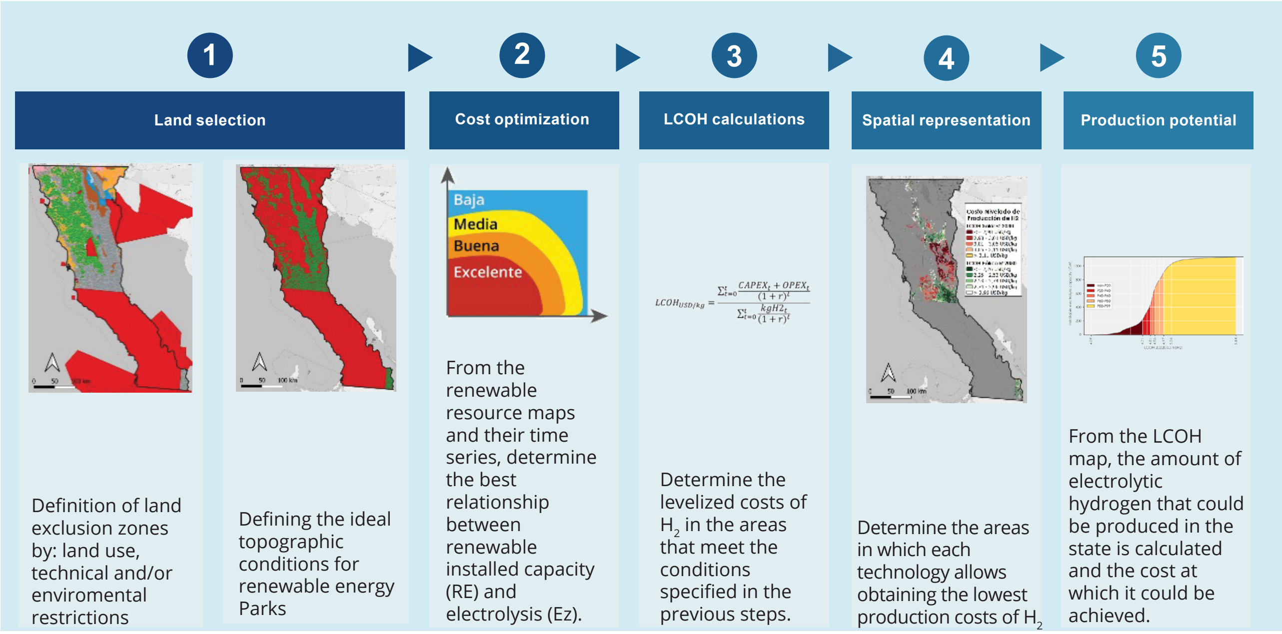
The methodology consists of five stages:

1. **Land selection:** Exclusion of areas within the state due to technical, environmental and land occupation restrictions. The exclusion zones were based on scientific literature from similar studies and previous studies carried out in the North American context (see Figure 25). In addition, areas that do not meet suitable topographic conditions, depending on the renewable technology to be installed, are also excluded (the application of this restriction was shown in Table 10 and Figure 25).
2. **Cost optimization:** Use of the exclusion layers obtained in the previous step with the renewable resource maps and application of technical-economic models (Figure 26 and Figure 27) to determine the best configuration of renewable energy and electrolysis capacity.
3. **LCOH calculation:** Determining hydrogen generation costs for all the eligible territory within the state.

4. **Spatial representation:** LCOH calculation on the state map, considering exclusively the regions where renewable capacity and electrolysis can effectively be installed.

5. **Production Potential:** From the LCOH map, the amount of electrolytic hydrogen that could be produced in the state is calculated, as well as the cost at which it could be achieved.

Figure 34. Methodology to estimate the LCOH and the potential amount of electrolytic hydrogen.



Based on the renewable potential identified according to the type of resource and its geospatial mapping in California, the LCOH and the annual potential production of electrolytic hydrogen throughout the state were calculated. For the LCOH, the following assumptions were considered:

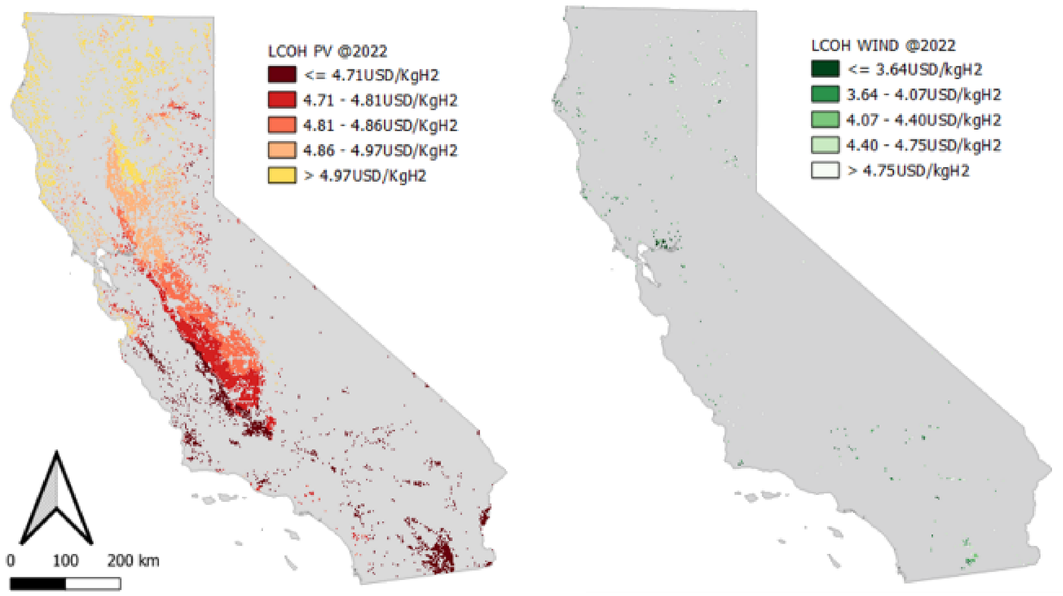
- Capacity factors for solar and wind were extracted from the ESMAP **GlobalSolarAtlas**[7] and **GlobalWindAtlas**[8] tools.
- Renewable energy plants are assumed not to be connected to the grid, so excess renewable energy cannot be sold and is curtailed. Being able to being able to sell those surpluses could reduce production costs.
- Hydrogen production is done *in-situ*. This means that is, the levelized cost of hydrogen corresponds to hydrogen obtained at the outlet of the electrolyzer and does not include storage or transport costs.
- An analysis was carried out to determine the optimal dimensions for the renewable energy capacity (RE) compared to the electrolysis capacity (Ez) for the conditions of California. A ratio of 1.4 to 1 (MWRE/MWEz) was obtained for the case of solar energy and a 2 to 1 ratio (MWRE/MWEz) for the case of wind energy.
- The analysis was carried out for the years 2022, 2035 and 2045, using the cost assumptions presented in Annex 1.

The calculations were made assuming a project lifetime of 30 years, a discount rate of 8% and a change of the electrolysis stack every 16 years for a cost of 20% of the original equipment in year 0. The results are shown in Figure 35.

[7] Global Solar Atlas 2.0, a free web-based application, is developed and managed by Solargis s.r.o. on behalf of the World Bank Group, using data from Solargis, with funding provided by the Energy Sector Management Assistance Program (ESMAP). For more information: https://globalsolaratlas.info

[8] Global Wind Atlas 3.0, is a free web-based application developed and managed by the Technical University of Denmark (DTU). The Global Wind Atlas 3.0 is published in collaboration with the World Bank group, using data provided by Vortex, and financing by ESMAP. For more information: https://globalwindatlas.info

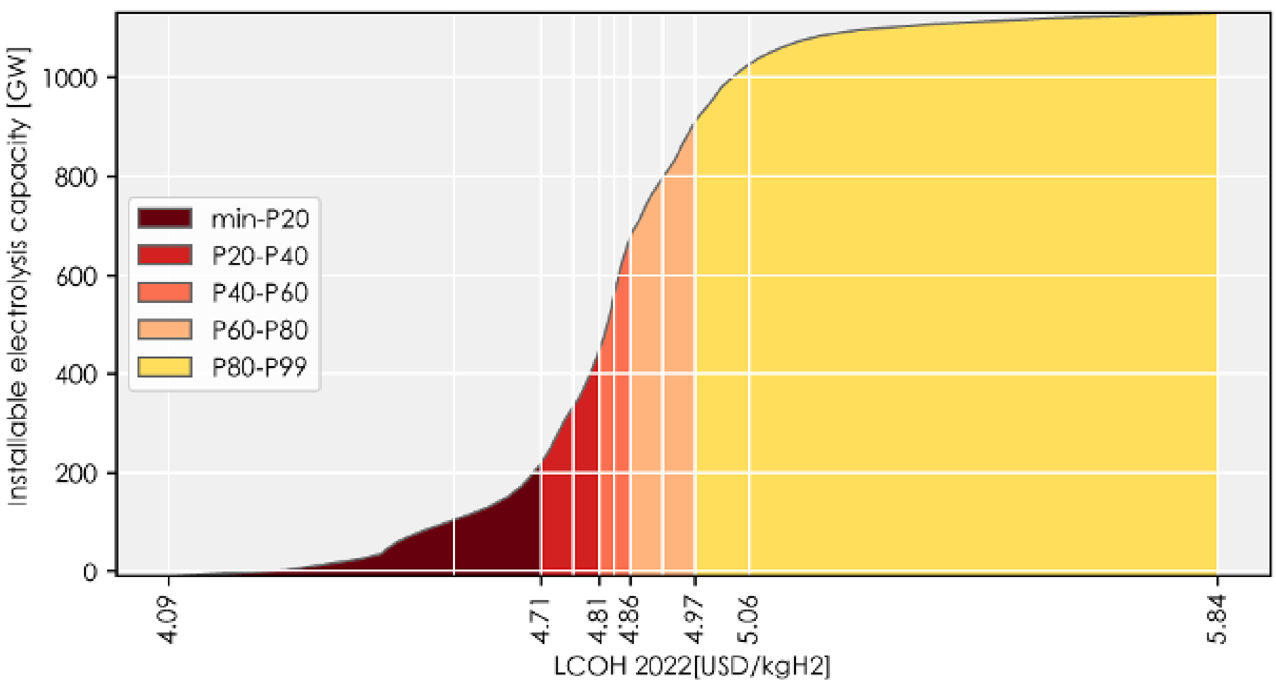
Figure 35. Solar and Wind LCOH available in California in 2022.



Source: (Hinicio, 2022).

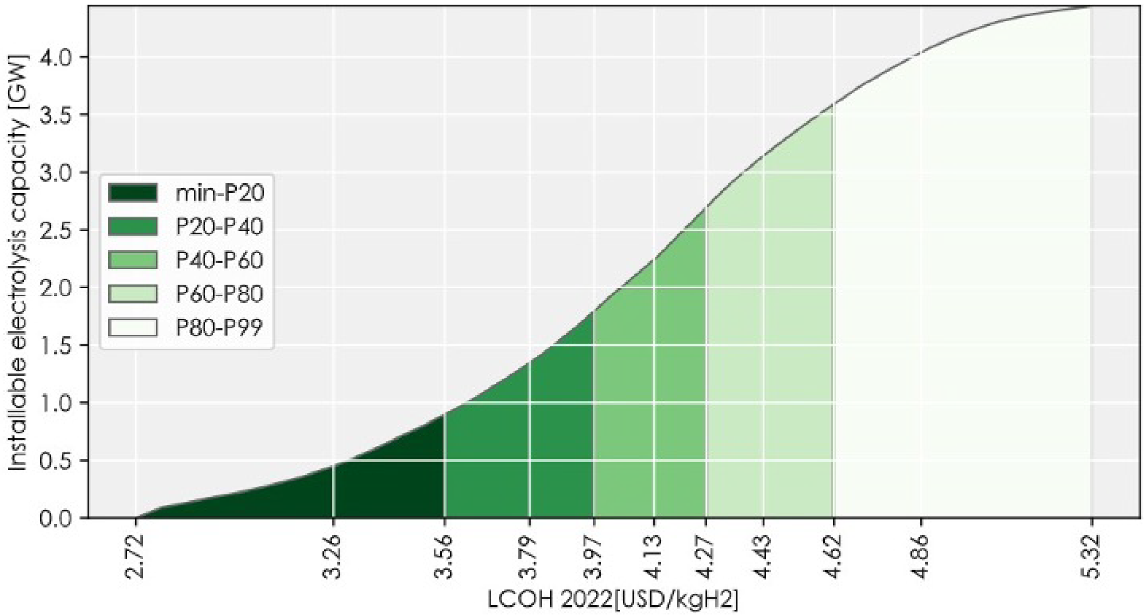
Figure 35 shows the result of step 4 (described in Figure 34), where the spatial distribution of LCOH in the state of California was calculated. The production potential of the state is shown through a supply curve, that shows the amount of green hydrogen that can be produced vs its cost. Figure 36 and Figure 37 show these curves for solar and wind powered green hydrogen respectively and the quintiles correspond to those shown in Figure 35.

Figure 36. Hydrogen production installable capacity in California from solar energy according to its LCOH in 2022.



Source: (Hinicio, 2022)

Figure 37. Hydrogen production installable capacity in California from wind energy according to its LCOH in 2022.



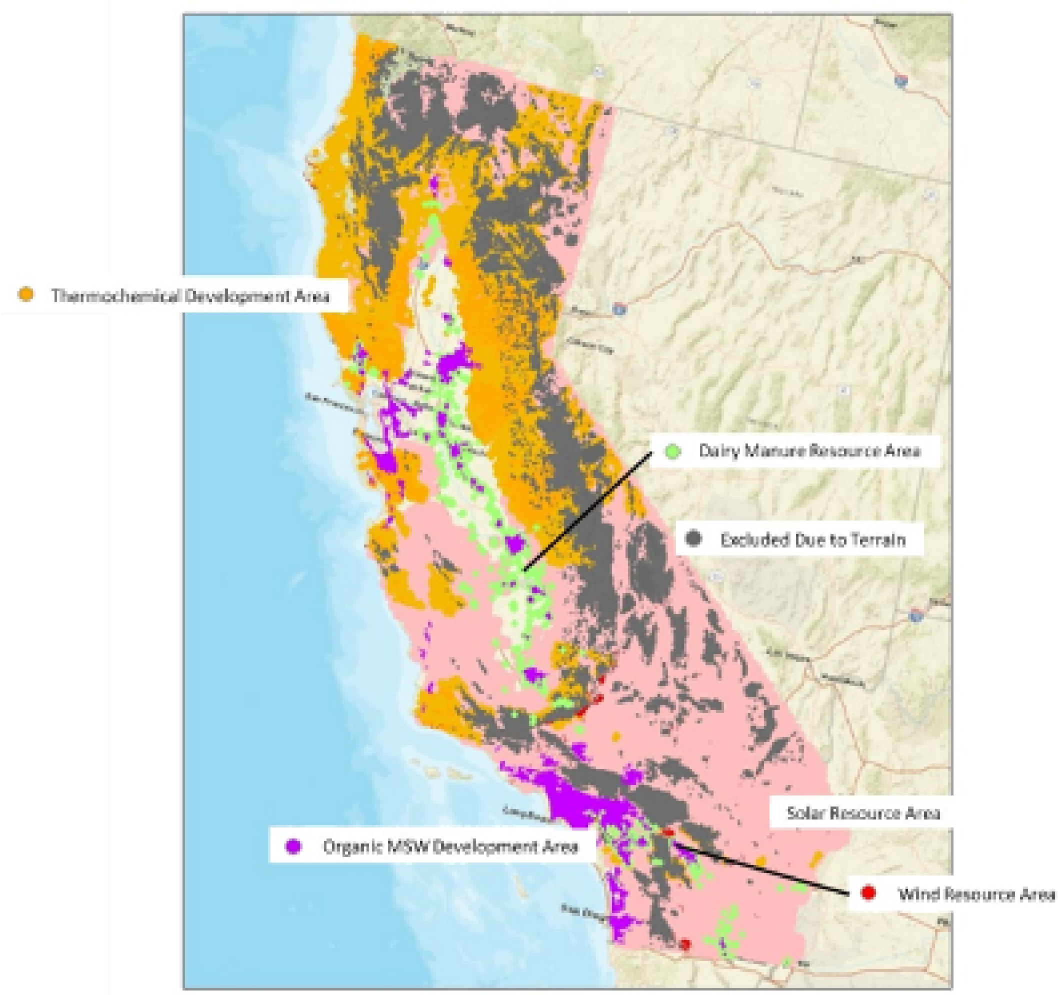
Source: (Hinicio, 2022)

1.4.4 LCOH in regions with the greatest potential for renewable hydrogen production in California

This section shows the most suitable areas for producing hydrogen in greater detail, based on the availability of renewable resources and the cost at which hydrogen could be produced.

- **From organic materials:** The distribution of resources from which hydrogen could be produced has already been identified previously by other authors (Berkeley, 2020). In principle, the availability of the raw material is distributed throughout the whole state, with each of the resources being more densely available in some areas than others. For example, the forestry, agricultural and woody residues are located mostly to the north of the state, while the organic MSW areas surround large cities. On the other hand, in the center of the state, where large areas of cultivation and animal husbandry are located, there is a higher availability of dairy manure.

Figure 38. Primary Resource Areas for Renewable Hydrogen Production and Conversion.

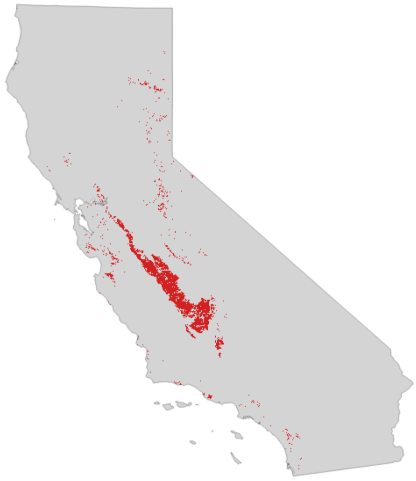


Source: (Berkeley, 2020)

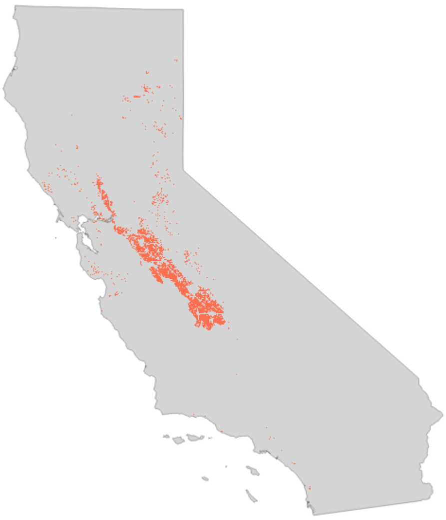
- **From renewable electricity:** Figure 35 shows the best areas to produce electrolytic hydrogen based on its LCOH. In this section, the maps are split, so that the areas with the best economic benefits in the production of hydrogen in California can be identified. Furthermore, a map with water resources is shown as a reference to locate hydrogen production projects using the two main resources needed for renewable electrolysis.

1st place, according to LCOH (Solar P20)

2nd place, according to LCOH (Solar P20-P40)



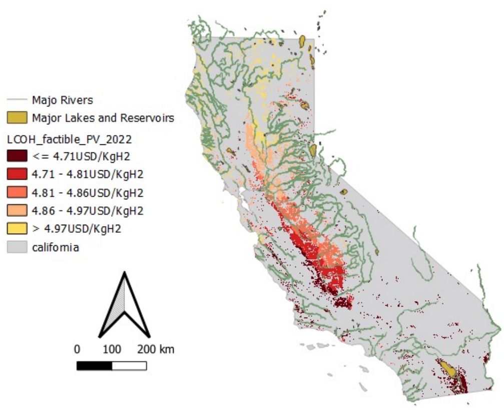
3rd place, according to LCOH (Solar P40-P60)



4th place, according to LCOH (Solar P60-P80)

5th place, according to LCOH (Solar P40-P60)

Contrast of the best resource to produce renewable hydrogen and the water resources in California



The distribution of the best places for hydrogen production from renewable resources comprises various areas throughout the entire state. It is important to note that the production of renewable hydrogen from organic material and renewable energies must compete for space or that these can be produced in a complementary way in spaces where both resources are technically and economically feasible to produce. In the last case, it will be necessary to evaluate complementarities in the productive processes and decide on the resource (mix) to be used.

The production of renewable hydrogen will also compete against other economic activities for the space and resources of the state like, agriculture, grid-connected renewable energy, and state infrastructure.

1.4.5 Competitiveness of renewable hydrogen in California

Since hydrogen policy is driven mainly by supporting production, the real demand for renewable hydrogen will be determined by its competitiveness with the conventional energy alternatives in each sector (see section 1.3.2). Renewable hydrogen competitiveness has been of prior interest to some institutions such as the DOE and the University of California at Irvine. Some benchmarks have been drawn up, which are used to determine the competitiveness in each of the sectors over time (Irvine, 2020). The benchmark for each of the sectors can be found in Table 12.

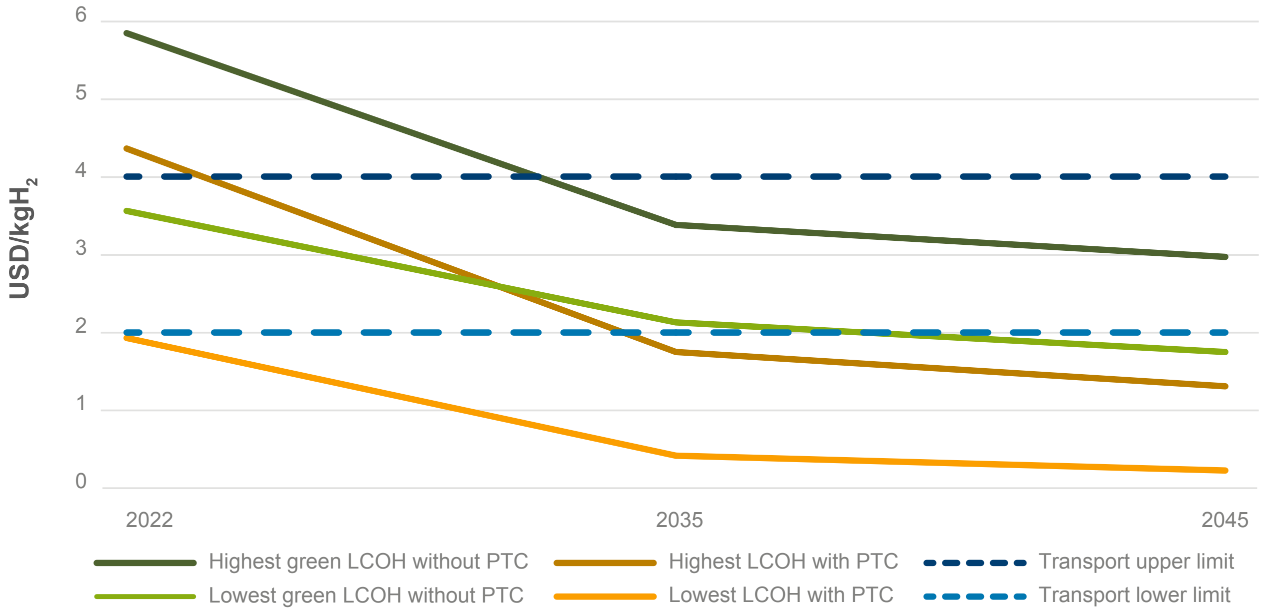
Table 12. Representative Costs for Renewable hydrogen substitutes.

	Target range by sector	
Sector	**Lower limit [USD/kgH_2]**	**Upper limit [USD/kgH_2]**
Transport	2	4
Refining	2.2	3.4
Fertilizer	2.2	3.4
Generation/ Storage	2	3
Industrial, Commercial, and Residential Thermal and Process	3	6

Source: (Irvine, 2020)

As can be seen from Table 12, for each sector a lower limit and an upper limit have been estimated The ranges are wide, mainly due to the variability of the price in the competing fossil fuel alternative (gasoline and diesel for transport, natural gas for refining, fertilizer, and the industrial applications), as well as possible carbon taxes which would add an extra cost for burning fossil fuels without carbon capture. These limits show the costs at which renewable hydrogen should be produced (and delivered) to be competitive. The figures below show these lower and upper levels of competitiveness as horizontal dotted lines and the highest and lowest LCOH of renewable hydrogen for each year. In the early years, the most competitive costs come from wind resources, while from 2035 onwards solar provides the lowest LCOH. The blue lines show the costs without PTC while the green lines show the costs with the maximum PTC of 3 USD/kgH_2. Further details of the LCOH calculations can be found in Annexes 1 and 2. **Note that the PTC is 3 USD/kgH_2 during the first ten years of the project only, which means that when the LCOH is calculated, this subsidy gets diluted over the lifetime of the project, and therefore the difference between the 'with PTC' and 'Without PTC' values is smaller than 3 USD/kgH_2.**

Figure 39. Competitiveness of green hydrogen in the transport sector.



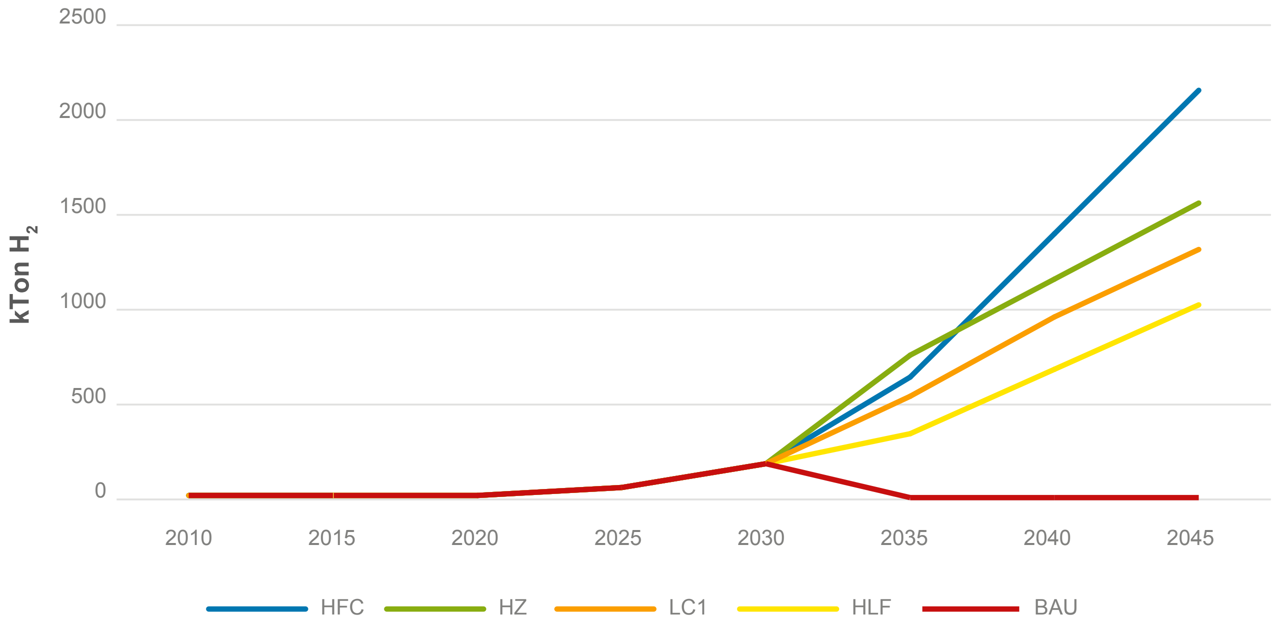
Source: Hinicio based on (Irvine, 2020) & (Californian Energy Commission, 2019).

The benchmark for the transport sector considers the substitution of diesel and/or gasoline. This sector already has objectives to replace those fuels at costs of hydrogen dispensed between 10-12 USD/kgH_2, (after compression and recovering investments in refueling equipment) which would require the hydrogen delivered to the refueling station to be priced between 2 and 4 USD/kgH_2. These objectives are shared by different institutions such as the DOE, interviewed experts, and the University of California – Irvine (Irvine, 2020).

For the upper limit, the projections show that green hydrogen would be competitive by 2032 (without PTC), regardless of the resource used for its production. However, the lower limit is only reached by 2039.

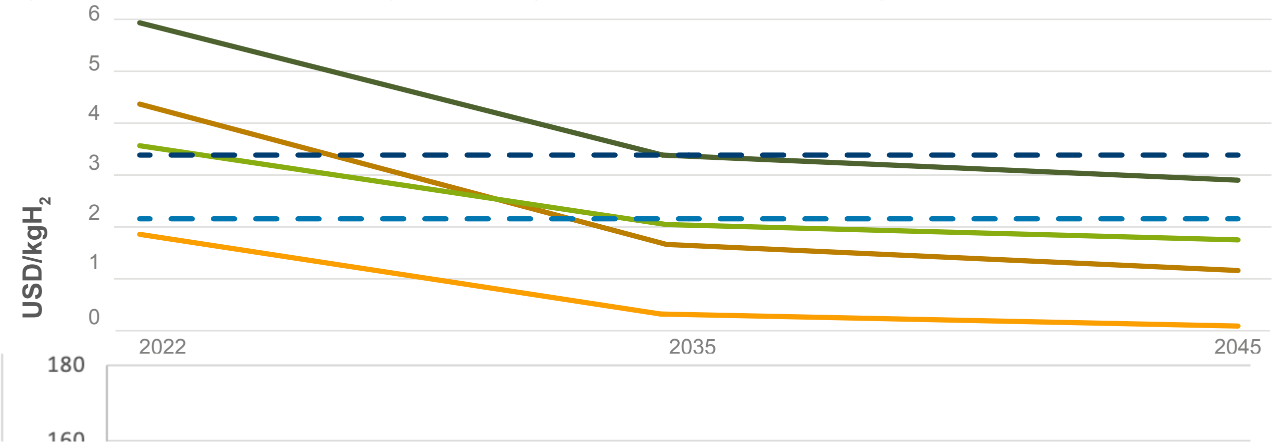
According to the University of California and its report "Driving California's Transportation Emission to Zero" (UC Institute of Transportation Studies, 2021), different energy carries would be part of the solution to achieve the decarbonization of the transport system. Hydrogen would be playing an important role regarding its competitiveness as it was shown in the previous figure, but also depending on the scenario considered. For instance, the University of California has proposed five scenarios (BaU: Business-as-Usual; LC1: Low Carbon; HZ: High Zero Emission Vehicle; HFC: High Fuel Cell; HLF: High Liquid Fuel), each one with its own assumptions for hydrogen penetration in this sector. Figure 40 shows the forecasted hydrogen demand for each scenario.

Figure 40. Energy demand according to five transport scenarios by (UC Institute of Transportation Studies, 2021).



The scenarios show consistency with the benchmark analysis of Figure 39, considering the competitiveness of hydrogen in the sector. It should be noted that even though all the scenarios show an accelerated adoption from the 2030s (decade of parity shown in Figure 39), each one of them evolves differently, there are even scenarios where hydrogen has a small participation by 2045 due to the dominance of other types of fuels such as bioethanol.

Figure 41. Competitiveness of green hydrogen as a feedstock for refining and ammonia production.

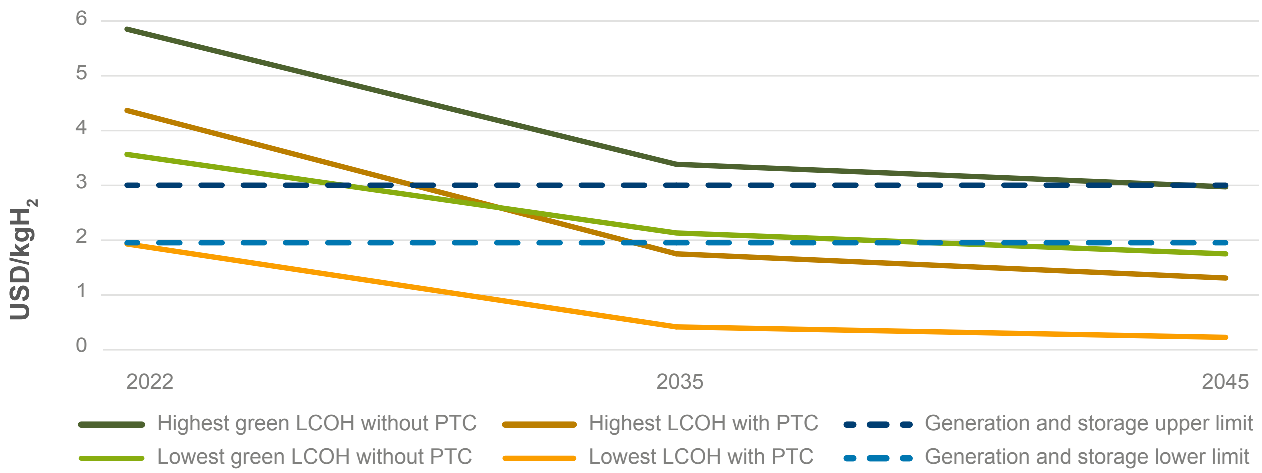


Source: Hinicio based on (Irvine, 2020) & (Californian Energy Commission, 2019).

The limits defined in the refining industry correspond to the cost range at which the kilogram of gray hydrogen is expected to be produced, considering a carbon tax between 20 and 100 USD/tonCO_2. The higher the carbon tax, the earlier the parity of costs with renewable hydrogen will be. For example, if the upper limit of Figure 41 is observed, it is possible to say that for any hydrogen source, cost parity would be achieved by 2035.

For ammonia production, the use of gray hydrogen is considered as a feedstock considering the previously mentioned carbon tax range. Under these conditions, and without PTC, ammonia production from renewable hydrogen should be competitive compared to the higher limit by the mid 2030's, using the most competitive wind or solar resources or even organic material for its production.

Figure 42. Competitiveness of green hydrogen with power and storage.

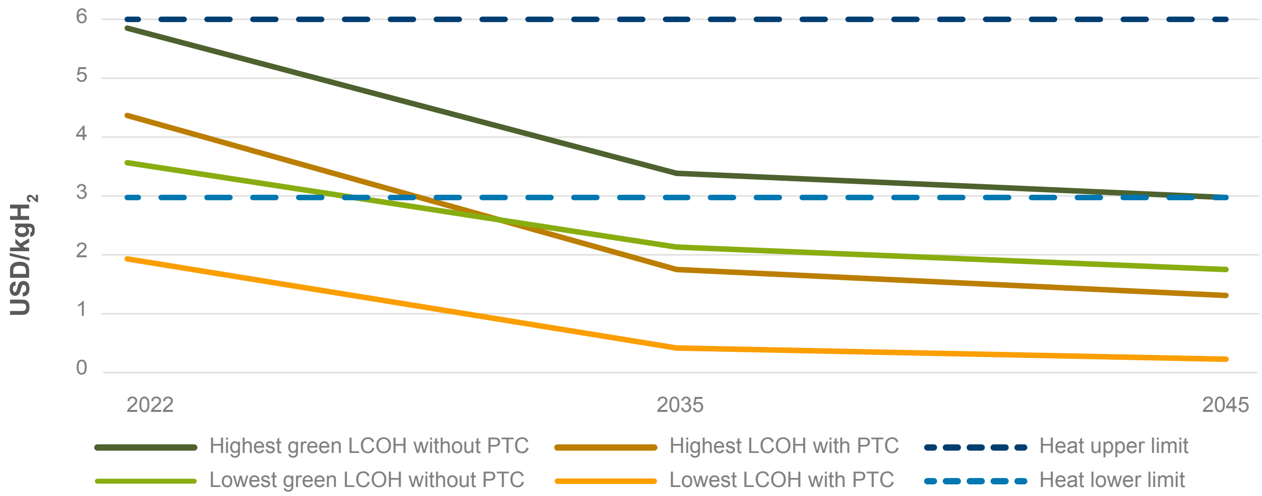


Source: Hinicio based on (Irvine, 2020) & (Californian Energy Commission, 2019).

Considering the ranges that must be reached in electricity generation and storage, it is assumed that the resource to be replaced would be biomethane with a price range between $15 -25 USD/MMBtu, assuming it is a fuel substitute to be used in gas turbines for power generation.

Without PTC, green hydrogen would be competitive before 2035 against biomethane, if biomethane costs remain high. Otherwise, renewable hydrogen's competitiveness would take more than 15 years to be reached. Considering the historical spot price in California, cost parity could be achieved before 2035, but it is possible that measures adopted by the Californian market and the introduction of cheaper energy sources will manage to reduce market price, displacing the hydrogen cost parity until the 2040s.

Figure 43. Competitiveness of green hydrogen with industrial, commercial and residential heat.



Source: Hinicio based on (Irvine, 2020) & (Californian Energy Commission, 2019).

The range to be reached by green hydrogen for heat in industry, commerce and residential use considers the cost of energy between 140 - 200 USD/MWh equivalent, assuming the cost of biomethane at $15 - $25/MMBtu, plus $10/MMBtu for transport and distribution of renewable hydrogen or renewable natural gas. Figure 43 shows that without PTC, could be competitive by 2028, while the lower limit could be reached by 2040.

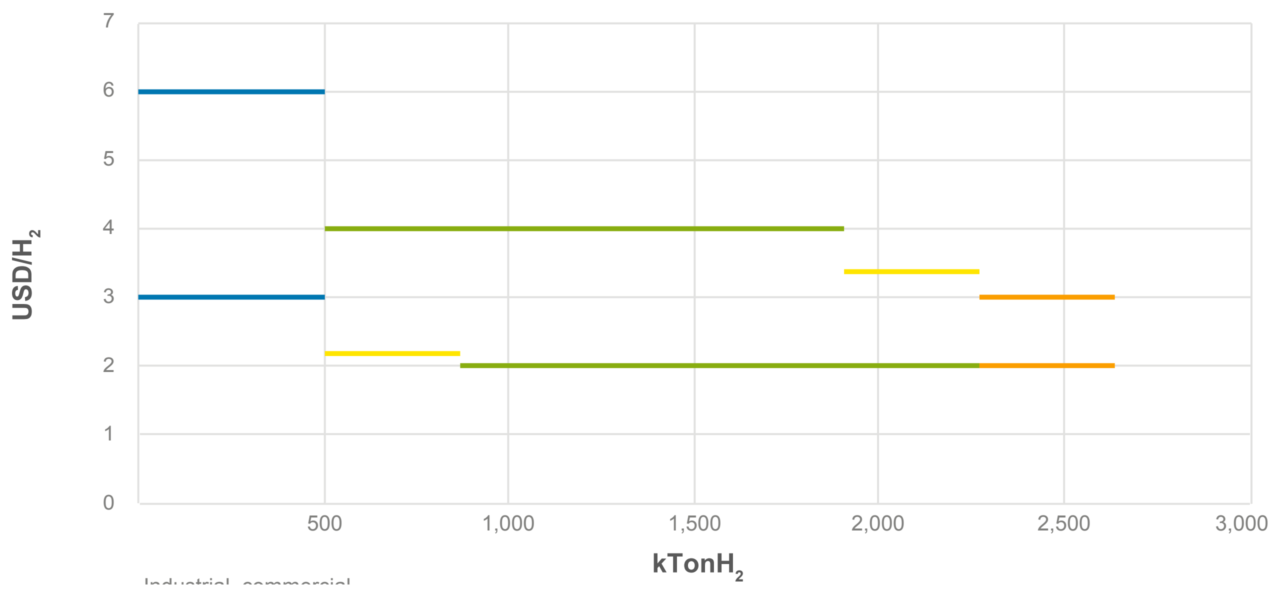
The PTC subsidies would allow green hydrogen to reach cost parity in all segments by 2034 if lower taxes and restrictive measures for fossil fuels are assumed.

Results are more promising when considering the upper limits, for all segments, even the worst renewable resources (P99), could reach competitiveness before 2028. For these projections, only the incentives for hydrogen production have been considered, but incentives for the production of renewable energy can be added to these, having an even greater impact on the competitiveness of renewable hydrogen in California, with the possibility of reaching negative LCOHs.

The willingness to pay varies by industry, since they use different fuels and sometimes longer supply chains (for example in the transport sector). It is important to note that these are estimates that remain untested in practice. When making fuel shifts, other considerations related to storage, technology availability, competence of personnel etc. could mean that real willingness to pay may be different.

Taking the lower and upper limits from the previous figures, together with the demand for each sector, the willingness to pay by industry and the market share that could be absorbed as a function of LCOH is obtained. This also allows us to determine the possible competitiveness of Mexican hydrogen and its ability to meet a part of California's demand. The following figure shows the estimated market size and willingness to pay for the analyzed industries.

Figure 44. Estimated market size (2045, high demand scenario in California) vs willingness to pay.



Source: Hinicio based on (Irvine, 2020) & (Californian Energy Commission, 2019).

Figure 44 shows that hydrogen delivered at under 6 USD/kg could start to compete (with biogas) in the industrial and heat sectors. At a cost below 4 USD/kg it can start to compete in the transport sector, while hydrogen at costs of 2 USD/kg should be able to supply 100% of California's hydrogen demand by 2045. Therefore by 2045 Mexico should deliver hydrogen at between 2 and 6 USD/kg at most to be able to meet possible willingness to pay, but it also needs to compete with locally produced renewable hydrogen.

1.5 Assessment of California's capacity to meet its renewable hydrogen demand

The need to develop more infrastructure to produce electricity and hydrogen can lead to competition for existing resources in the state. Such competition would take place in a context where California must face challenges with transmission lines, increased energy and food demand and climate change among others.

The energy context in California is challenging, with the security of supply being threatened by several blackouts in recent years due to a variety of factors. One major factor is the increasing demand for electricity in the state, which has outstripped the supply available from traditional power sources. This has led to an increased reliance on renewable energy sources, such as solar and wind power, that are highly variable. Additionally, the state's aging infrastructure, including transmission lines and power plants, has also been a contributing factor. Finally, wildfires that have become more frequent and severe due to climate change have damaged infrastructure and disrupted the power supply.

Despite this, the California government persists in its goals of becoming carbon neutral by 2045, and sectors that cannot be decarbonized through electrification and renewable energy will require renewable hydrogen. This requires the development of additional infrastructure, as hydrogen must be produced, transported and distributed.

Although California already has significant hydrogen demand, the potential new uses of decarbonized hydrogen would imply a growth of up to 125 times by 2045.

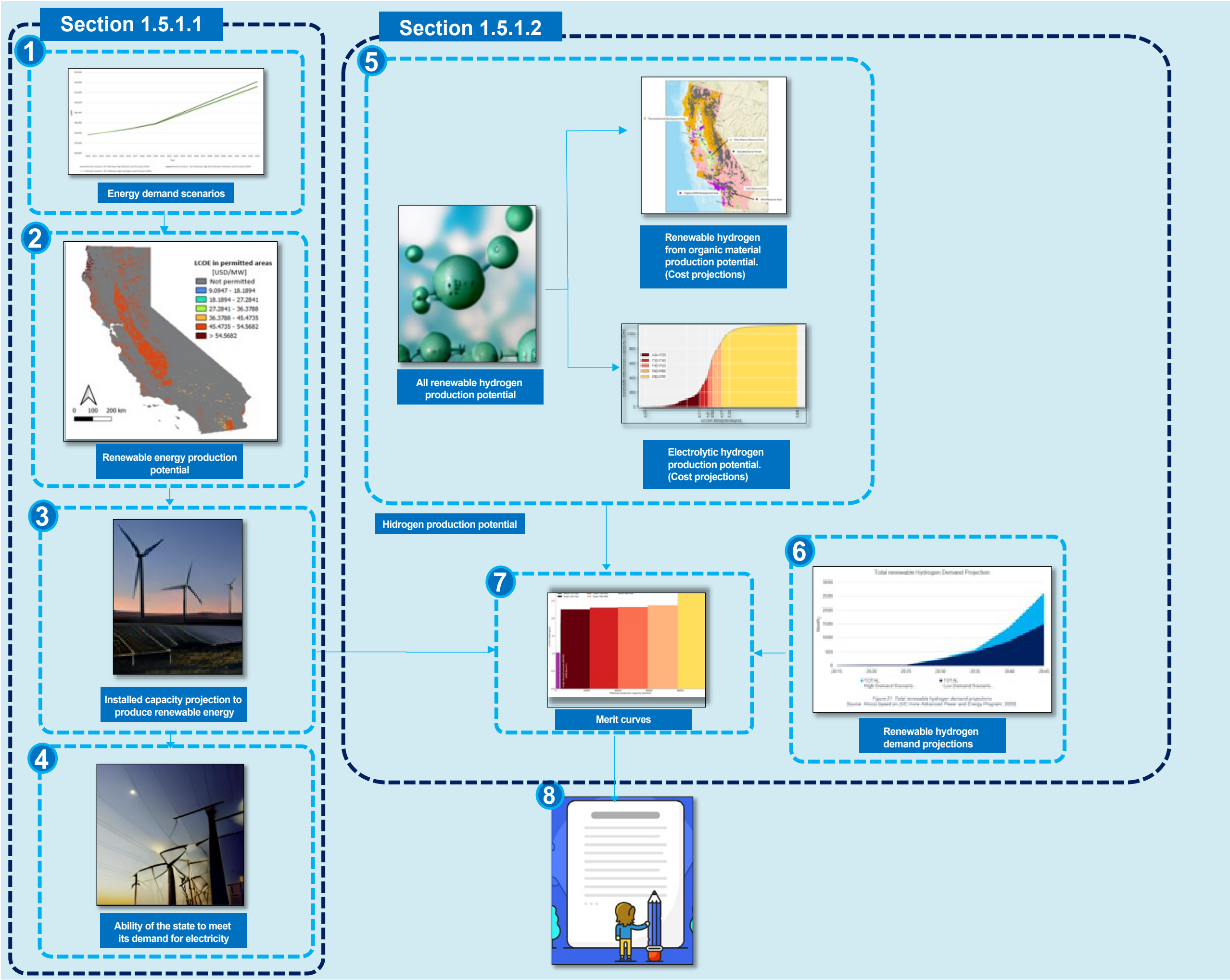
After having estimated hydrogen demand scenarios and hydrogen production potential, we can estimate California's ability to cover its own energy needs.

1.5.1 California's capacity to meet its renewable hydrogen and electricity demand

Based on the electricity demand scenarios shown in Table 5, Table 6, Table 7, and the demand scenarios for green hydrogen analyzed in section 1.3.2, in this section we present the capacity that California would have to install for meeting both the demand for renewable electricity and for green hydrogen.

Figure 45 describes the methodology for analyzing California's ability to meet its demand for renewable hydrogen and electricity. The methodology consists of 8 steps, which are divided into two sections. The first section analyzes the state's electricity demand and its capacity to meet that demand with renewable energy. The second section uses the results from the first section and the hydrogen demand projections to examine California's capabilities for meeting its hydrogen demand under different scenarios. The analysis is conducted using merit curves, which help to determine the cost and amount of renewable energy that will be needed to meet the demand under different scenarios.

Figure 45. Methodology to assess California's ability to meet its renewable hydrogen and electricity demand.



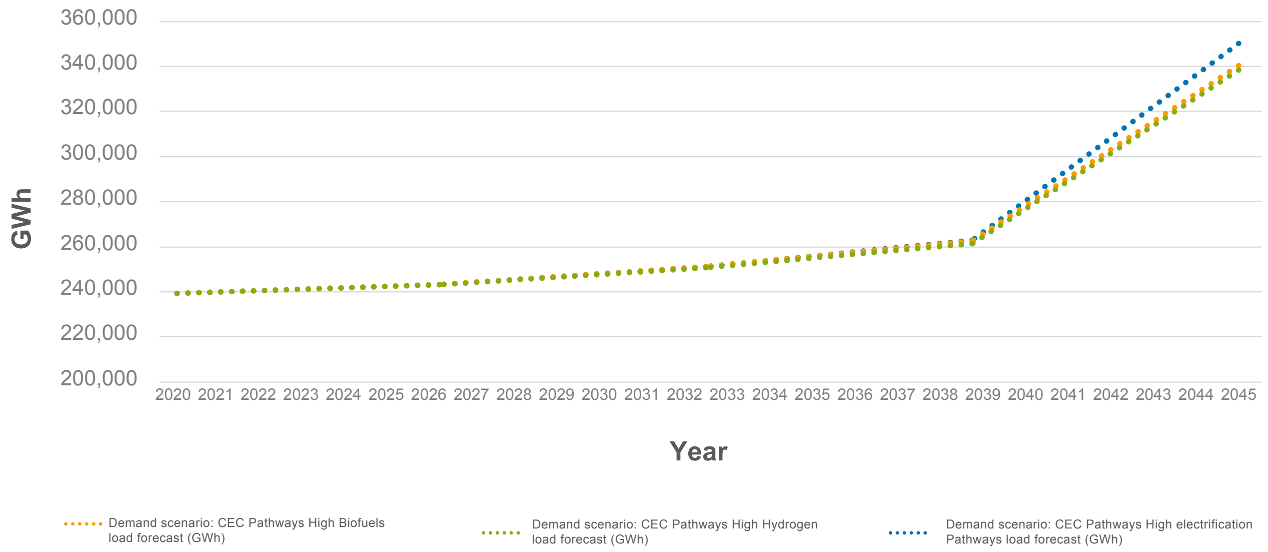
Source: Hinicio

1.5.1.1 Renewable capacity to attend the demand projections on the state

Most of the information required to study the renewable capacity to attend the electricity demand projections in California has already been presented in previous sections. The next 4 steps allow to determine if the renewable potential in California and its ability to deploy solar and wind systems would be enough to cover its demand and zero carbon target by 2045.

1. **Energy demand scenarios:** In section 1.3.1, three energy demand scenarios have been presented (Table 5, Table 6 and Table 7). The main difference between the scenarios is the way California would electrify its transport. Figure 46 shows these demand scenarios.

Figure 46. Electricity Demand scenarios in California.

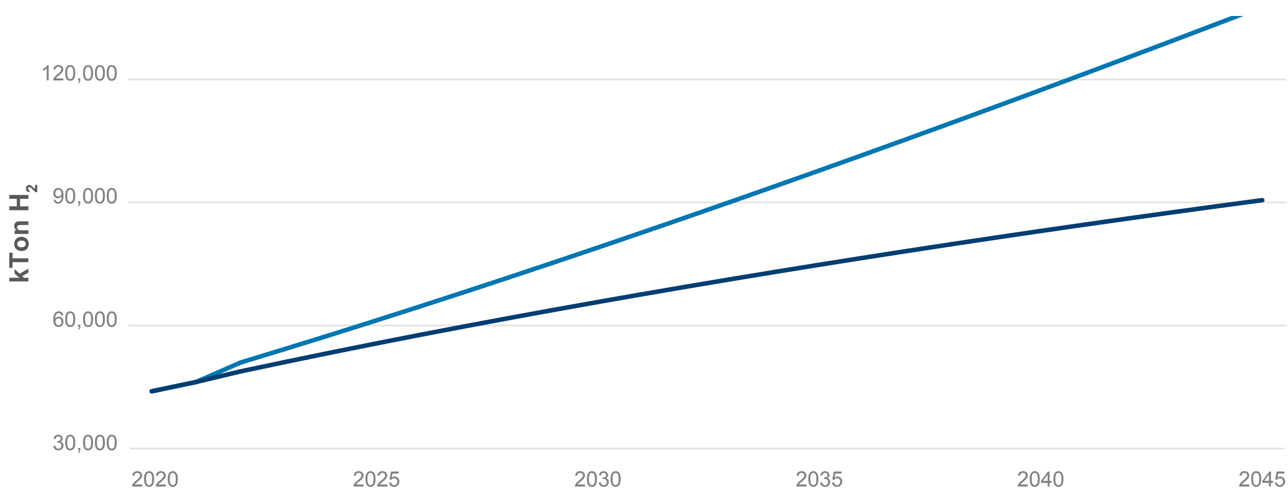


Source: (Californian Energy Commission, 2019).

2. **Renewable energy production potential:** After the analysis made in section 1.3.3, all the restrictions and renewable resources in California have been considered to calculate the total renewable energy production potential from solar and wind resources. Load factors for each technology, as well as historical data from the authorities in the state were also used. The results show that there is roughly 3,100 TWh per year of renewable energy production potential in California.

3. **Installed capacity projection to produce renewable energy:** The historical solar and wind generation capacity of California (see Figure 32) were used to project, with a 30% range of uncertainty, the potential for energy production from wind and solar. Figure 47 shows this growth with both a high and low share of renewable energies.

Figure 47. Renewable energy production projection from solar and wind in California.



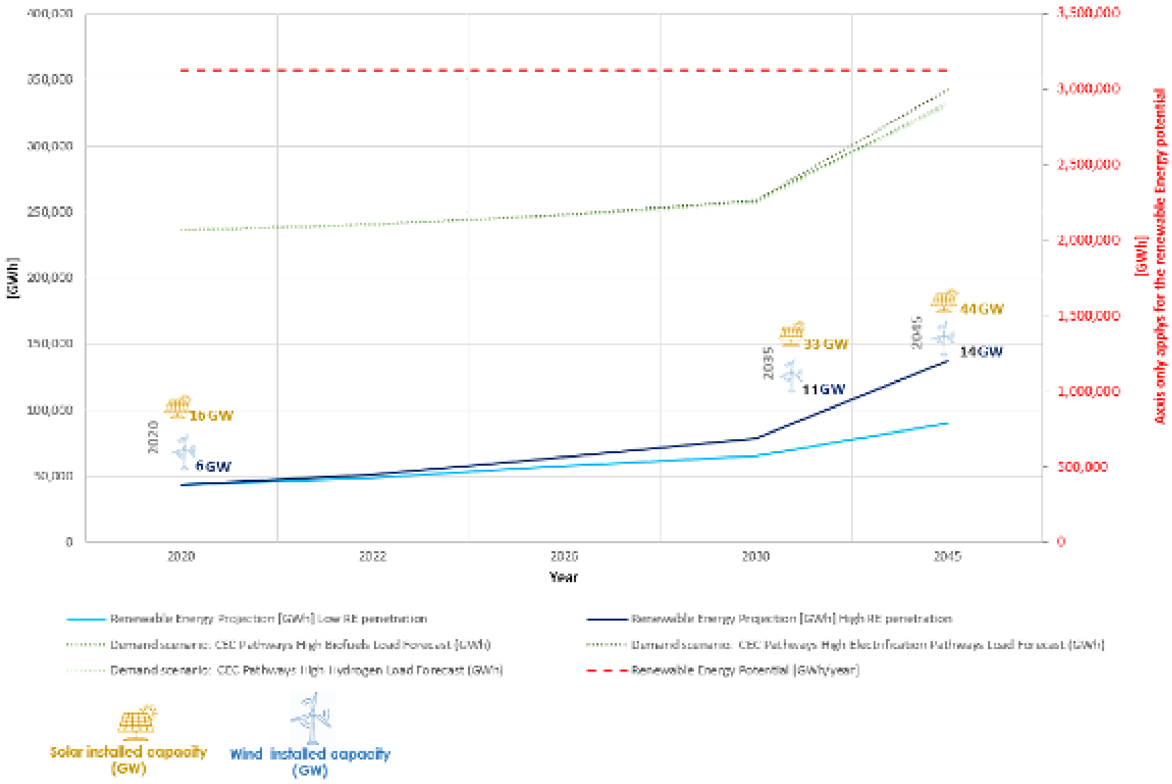
Source: Hinicio based on (CEM & California Energy Comission, 2021)

4. **Ability of the state to meet its demand for electricity:** California's ability to supply its own energy demand from the use of renewable energy (solar and wind) was analyzed with the projections shown in the previous steps. The renewable production potential is greater than any of the demand scenarios studied by 2045 (9 times greater). However, not all the potential can be used in the short or medium term, due to different restrictions such as transmission lines capacity, the deployment speed for solar and wind farms, problems with environmental permits, among others.

Furthermore, it is essential to consider the historical data with which California has been developing its renewable generation systems. Through this information, installed capacity that California would reach by 2045 was forecasted, considering both an adoption rate with a faster adoption of renewables and another with a slowdown in the development of new projects.

Figure 48 summarizes these projections to put the renewable production potential and the expected electricity demand in California into perspective.

Figure 48. Renewable production potential vs. energy demand, and renewable energy production projection from solar and wind in California.



Source: Hinicio based on (CEM & California Energy Comission, 2021), (Irvine, 2020) , (Californian Energy Commission, 2019).

From Figure 48, we can draw the following conclusions:

- The potential for renewable energy production (solar and wind) in California is approximately 9 times greater than the expected demand for electricity in all the scenarios considered.
- The electricity demand is expected to grow at a higher rate than the state's current ability to deploy photovoltaic and/or wind power plants (RE would represent between 26 % and 40 % of the total energy supply in California by 2045, according to state plans).

- If the growth rate trend of renewable capacity installation continues as it has been historically, the state would not be able to cover all its demand with solar and wind energy by 2045.
- There are other alternatives for California to meet its own energy needs. Among others, different sources from government entities mention importing electricity from neighboring states, keeping nuclear plants running longer than originally planned, and expanding the thermal generation capacity with natural gas (CES, 2021) (EIA, 2019).
- The installed solar capacity will have to increase 2.75 times between 2020 and 2045 in order to reach the high renewable share projections in the state.
- Similarly, installed wind energy capacity needs to increase approximately 2.33 times between 2020 and 2045.

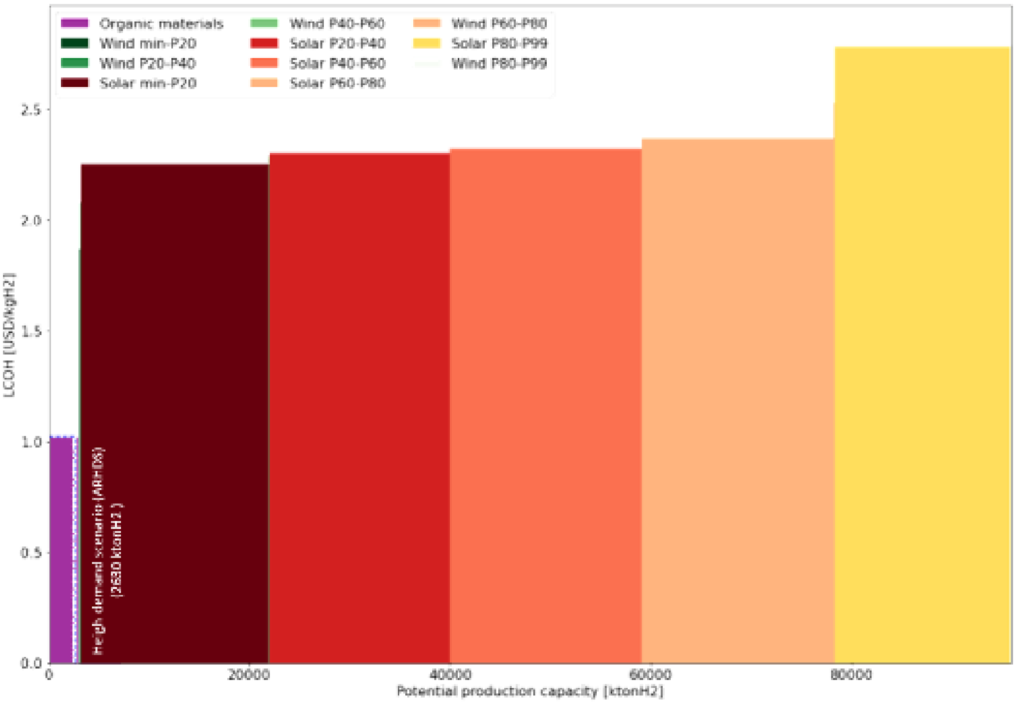
In the following section, these results are used to analyze how California could meet the hydrogen demand projections, with electrolysis fed by renewable electricity.

1.5.1.2 Renewable hydrogen merit curve to attend the hydrogen demand projections on the state.

Based on the demand projections shown in Figure 22 and Figure 23, the resources with which the state of California would be able to supply these demands are analyzed through means of the merit order curve.

Merit curves: Two merit curves are proposed for 2045 (year with the highest demand of the time horizon considered). The **first merit curve** considers the **hydrogen production potential** calculated in section 1.4 and compares it with the demand scenario. This way, the capacity that different technologies would have to meet the demand for hydrogen in 2045 was determined under free market conditions.

Figure 49. Merit curve to supply renewable hydrogen demand in California in 2045, considering all technologies to produce renewable hydrogen in California.



Source: Hinicio.

Under these conditions, the production of hydrogen from organic material would be able to supply the demand in the highest of the scenarios projected to 2045. However, the restrictions of this technology must be considered, among them:

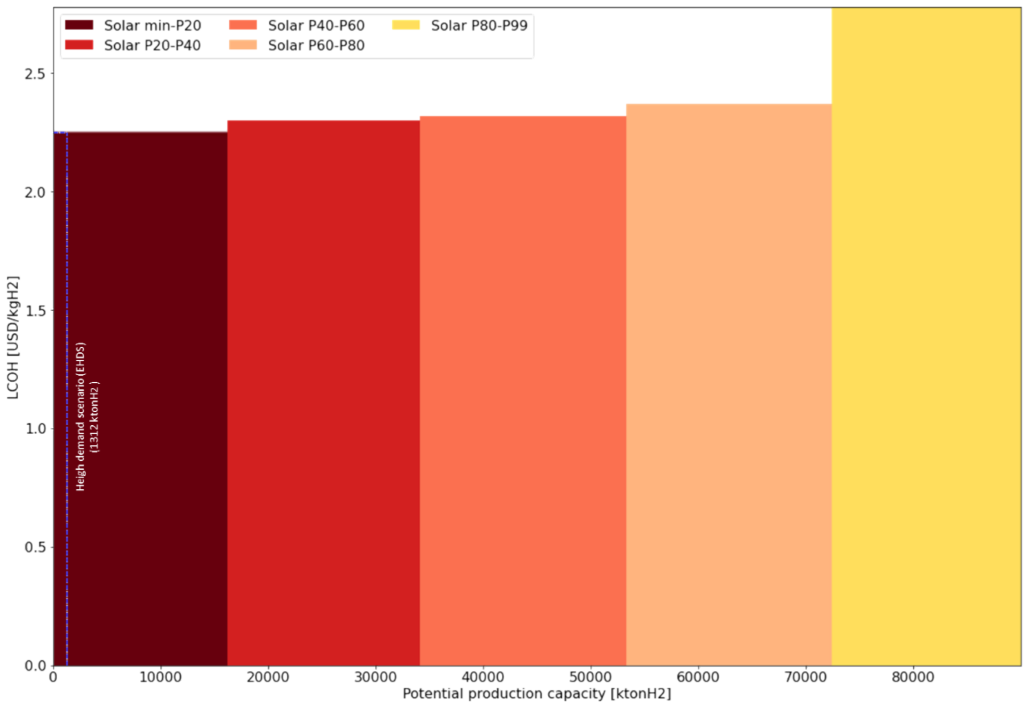
- Biogas reforming will be limited by feedstock supply constraints.
- Thermochemical conversion of biomass has a much higher carbon intensity than electrolysis and biogas reforming, meaning that it would possibly need to be paired with CCS systems in order to allow California to reach higher GHG emissions reductions (according to estimation of the consulting team, CCS could add between 5% and 15 % to the total blue hydrogen cost).
- The technological improvement trajectories of biogas reforming and thermochemical conversion of biomass are expected to be less substantial than that of electrolysis.

Due to the above-mentioned limitations on the production of hydrogen from organic material, there is uncertainty about the exploitation of this type of hydrogen. However, just to give a perspective of what could happen, the largest demand estimated in section 1.3.2 would require 85% of the total hydrogen potential production from organic material.

On the other hand, the estimates shown in Figure 11 indicate that approximately half of the demand for renewable hydrogen in California would be satisfied from organic material, which represents a use of less than 85% of the total potential. The rest of the demand for renewable hydrogen would be met by electrolytic hydrogen.

The **second merit curve** only considers the high demand scenario for 2045 (EHDS). As this scenario considers only the hydrogen that would be produced from renewable energies (electrolysis fed with solar and wind energy). Additionally, in this merit curve, the reduction of renewable resources will be considered, due to the use of these resources for electricity production (calculated in the previous section).

Figure 50. Merit curve to supply electrolytic hydrogen demand in California in 2045, considering the EHDS high demand scenario and only solar and wind as renewable resources.



Source: Hinicio.

Considering these two merit curves, the state's ability to supply the different demand scenarios proposed in the previous sections is put into perspective. After analyzing the state's ability to meet demand projections, it becomes clear that even competing with other technologies and decarbonizing the state's electrical grid, California has sufficient resources to satisfy its energy demands, achieving its decarbonization target by 2045. However, there are important barriers that will limit California's full potential. These limitations are discussed further in section 1.6 .

1.5.2 California's renewable hydrogen potential imports demand

The previous sections show that based on the techno-economic potential, California has sufficient resources to satisfy its own energy demands and to achieve its decarbonization target by 2045. However, the state currently imports over 9% of its power demand, showing that neighboring states can generate power more competitively at certain moments, and the same could be true for its future renewable hydrogen demand. In this sense, imports of green hydrogen from Mexico could complement the states' own production (1) in case the barriers to deploying renewable end hydrogen capabilities mean the scaling-up is not fast enough to meet demand (in this case it could import hydrogen even though it is not directly competitive) and (2) in case imported green hydrogen could be delivered at lower cost than local production.

1.6 Barriers to the development of renewable energy projects in California

There are many barriers that can hinder the development of solar photovoltaic and wind generation projects in California, which are key for producing green hydrogen, while others are more specific to the production and use of hydrogen.

Barriers to the deployment of renewable energy and hydrogen projects include, but are not limited to the following:

a. **Permitting** procedures are slow in California, and in the USA in general, which imply time and costs to the project. Permitting was identified as "the single biggest obstacle to building the infrastructure of the future" by a diverse coalition of energy players, in their letter to Congress, asking for legal action (Coalition Letter on Permitting Reform, 2023). A lack of local approval capacity is delaying the construction of solar PV plants as the Bureau of Land Management scrambles to increase **staff count** and process priority projects (Reuters, 2023).
b. Bottlenecks in **interconnection** to **power grids** are leading to certain project developers to consider operating in island configuration (i.e., not connected to the grid, but directly feeding their power to an adjacent electrolysis plant). Working in island mode means that the electrolyzer will run at a low capacity factor (when wind or solar is not generating) and does not allow selling excess power to the grid, meaning suboptimal project performance. Most of the U.S. electric grid was built in the 1960s and 1970s. Today, over 70% of the U.S. electricity grid is more than 25 years old (CNBC, 2023). A study by Berkely Lab calculated that more than 1,300 GW of solar, storage, and wind projects are currently in interconnection queues (Berkeley Lab, 2022)
c. **Availability of suitable land**. Solar and wind projects require large extensions of land and finding suitable locations that are close to transmission lines and have minimal environmental impacts can be challenging. Furthermore, developers must also pay **federal royalty fees**, known as megawatt capacity fees, so land costs are sometimes "far higher than fair market value" in areas such as California's Riverside, San Bernardino and San Diego counties (Reuters, 2023).
d. Solar and wind projects often face **opposition from local residents** or environmental groups, which can delay or prevent their development (NIMBY effect). Some environment NGOs are also very worried about the GHG balance of hydrogen production (see sustainability concerns in the next point) and are creating resistance with the public to hydrogen projects.
e. Uncertainties regarding **specifics of sustainability requirements.** The three sustainability principles that are required of green

hydrogen projects are additionality (making sure renewable power capacity is built to feed electrolyzers, and that no renewable power is taken from the current electricity demand), deliverability (making sure the renewable power can be physically delivered to the electrolyzer, i.e. they are on the same grid) and time-matching (making sure the renewable power is generated at the same time it is actually used). The US Department of Treasury is expected to publish guidance on these definitions and requirements during 2023, addressing the uncertainty, but the requirements could remain barriers for investments, depending on how they are defined.

Though renewable energy projects are relatively fast to install (usually several months) compared to conventional power plants, the development cycle can be much longer. Every individual project has four pillars on which it succeeds:

- Revenue streams (PPAs)
- Interconnection
- Site control
- Permitting

Development pipelines, tend to include (in order of declining risk): early-stage assets, later-stage assets and “NTP[9]-ready” assets. The portfolio shrinks as projects move from the early-stage to NTP-ready phase, and developers looking to sell their pipelines often provide their views on the pull-through rate for projects in their pipelines. A pull-through rate has to do with finding offtake agreements. The offtake agreement, often a power-purchase agreement (PPA), is the centerpiece of a solar or wind project. Sales cycles for unsolicited PPAs last anywhere **from three months to three years**. (Hodge, 2019)

Interconnection may be hampered by congestion on the grid and depends on other projects that are competing for capacity. One option for green hydrogen projects is to simply operate in isolation of the grid, which means they cannot arbitrage power prices, but frees them from the interconnexion costs and delay.

Access to water may be limited. Though there may be enough water available based on historical data, the availability may be reduced over the lifetime of a project (20-30 years) and local priorities may interfere with a green hydrogen project.

A location that may be attractive for its renewable resources (wind or solar irradiation) may be far removed from demand centers and **developing hydrogen transport and distribution infrastructure** will run into similar barriers as for a renewable project, though these typically cross many county barriers and are therefore more complex.

Sometimes resistance can come from **county-level governments.** In June 2022, Gov. Gavin Newsom pressured lawmakers to approve an energy plan that aimed to expedite and streamline construction of new clean energy facilities. The law includes a controversial clause that lets developers bypass local permitting and instead turn to the California Energy Commission for fast-track approval. This has led to some resistance from local governments and populations who feel excluded from the process (Calmatters, 2022).

There have also been reports of specific fear of hydrogen, for its potential leaks and explosion risks. A lot of education of the public is still needed in this regard.

[9] Notice to Proceed

2 Cost scenarios of transporting green hydrogen from Northwestern Mexico to California through pipelines

In this chapter, scenarios are developed to assess the costs and competitiveness of cross-board green hydrogen transport by pipeline. First, some attractive locations in Mexico to produce green hydrogen with solar and wind resources are described, and then the potential costs of building new pipelines for exporting at different scales is assessed, as well as the costs for repurposing existing natural gas infrastructure.

2.1 Green hydrogen production costs (LCOH) in northwestern Mexico.

2.1.1 Sonora

The state of Sonora has high solar irradiation, and there are ongoing plans for investing heavily in exploiting this resource, as part of the 'Plan Sonora'. While the plan hasn't been officially released[10], based on public information and press conferences at the federal and state levels, the plan is set in the context of the energy transition and highlights the role of lithium mining, and achieving electromobility and decarbonization of the state's industrial activity. It considers the development of five photovoltaic power plants such as the one designed by the Federal Electricity Commission (CFE) in Puerto Peñasco (1,000 MW, to be delivered in 2028), in which the government of the State of Sonora could participate with a 46% investment. These plants seek to supply **domestic and export electricity markets**, with the latter focusing on the south of the United States (Energía a Debate, 2023). Based on the current power demand and transmission projections for the region, it is estimated that the construction of these projects would lead to a **surplus photovoltaic capacity of about 7 GW.**

Mexico's Ministry of Foreign Affairs stated that the clean energy component of the Sonora Plan will require around **48 billion dollars between now and 2030** (Expansion, 2022).

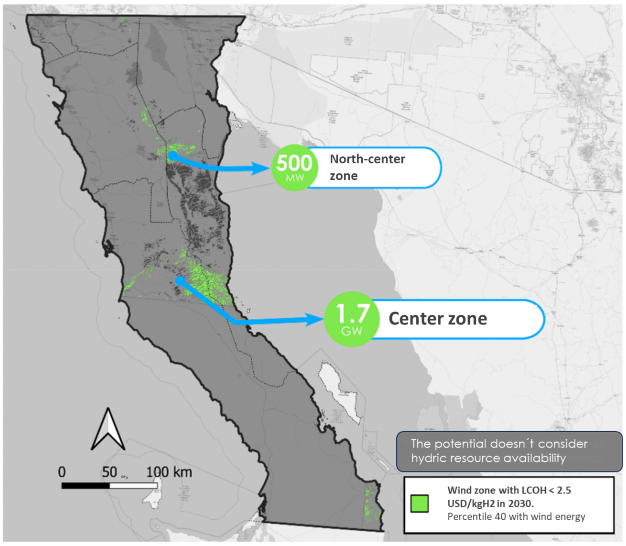
As an indication of the scale at which green hydrogen could be exported from Sonora (to California), using the estimated 7 GW of surplus solar power (at an average cost of 890 USD/kWp between 2023 and 2030), this would allow for the production of **525 kton of green hydrogen per year** by 2030 at an LCOH between 2.9 and 3.1 USD/kg.

2.1.2 Baja California

The state of Baja California has a large technical potential for producing green hydrogen. It is estimated that the state could install about 54 GW of electrolysis in the state fed exclusively by wind power, that would produce green hydrogen at an LCOH of under 3.0 USD/kg (GIZ, 2023).

Pipeline transportation costs from the North Central Zone and Central Zone regions were computed. It was estimated that 500 MW and 1.7 GW respectively of green hydrogen can be produced in this state at a cost of less than 2.5 USD/kg and correspond to the 40th percentile of the total potential capacity. These zones and potentials are shown in Figure 51.

Figure 51. Theoretical electrolysis potential from solar PV power in 2030 in the state of Baja California.



Source: Hinicio 2023

[10] The official 'Plan Sonora' is being prepared by the Sustainable Development Council of Sonora (CODESO) and is expected to be issued in the near future.

2.1.3 Chihuahua

The state of Chihuahua has an important capacity of installed pv solar power. The state government has set a goal of generating 35% of its electricity from renewable sources by 2030. Overall, Chihuahua has made significant progress in developing its renewable energy sector, with a growing number of solar energy projects currently in operation and under development.

It is estimated that the state could install about 10 GW of electrolysis in the state - fed exclusively by solar power - that would produce green hydrogen at an LCOH of under 3.16 USD/kg (GIZ, 2023).

2.2 Hydrogen transportation cost from northwestern Mexico to California with new pipelines

In its latest Energy Technology Perspectives (IEA, 2023), the International Energy Agency mentions that “It is likely that, where feasible, onshore or offshore pipelines will be preferred: it is the most efficient and least costly way to transport hydrogen up to a distance of 2,000-2,500 km for capacities below 600 ktpa (kilotons per year) in 2030 in the NZE [Net Zero Emissions by 2050] Scenario”.

To calculate the levelized cost of transportation (LCOT) for moving compressed hydrogen in a pipeline the costs of two stages was considered:

- the first stage consists of conditioning the hydrogen with a compressor to reach 100 bar;
- the second stage consists of building and operating the pipeline infrastructure, including its operation and maintenance.

Conditioning:

CAPEX and OPEX cost, including electricity cost, of the compression equipment were considered. The compressor was sized considering the peak production of a 100 MW electrolyzer, which would produce 23 tons of hydrogen per day or about 8,400 tons per year.

Pipeline

The cost of building and operating the pipeline is calculated using a CAPEX per kilometer and OPEX.

Delivery is considered in San Diego, Los Angeles – Riverside, San Francisco – San José – Sacramento and production in northwestern Mexico, with one injection point in each of the following states: Baja California, Chihuahua and Sonora. The production zones were chosen according to the following criteria: relative proximity to California, high availability of renewable resources, availability of land that is not occupied by urban areas and experience with development of renewable energy projects.

For the distance between production and consumption areas, the road distance between the two points was used as a reference as it is a conservative approximation, and it allows a fair comparison between pipeline and those involving road transport, using the same distances (see also chapter 3). The maps of the routes considered for each production zone are shown below:

Figure 52. Trajectory of theoretical pipeline connecting Baja California, Sonora and Chihuahua to San Diego, Riverside, Los Angeles and the Bay Area.

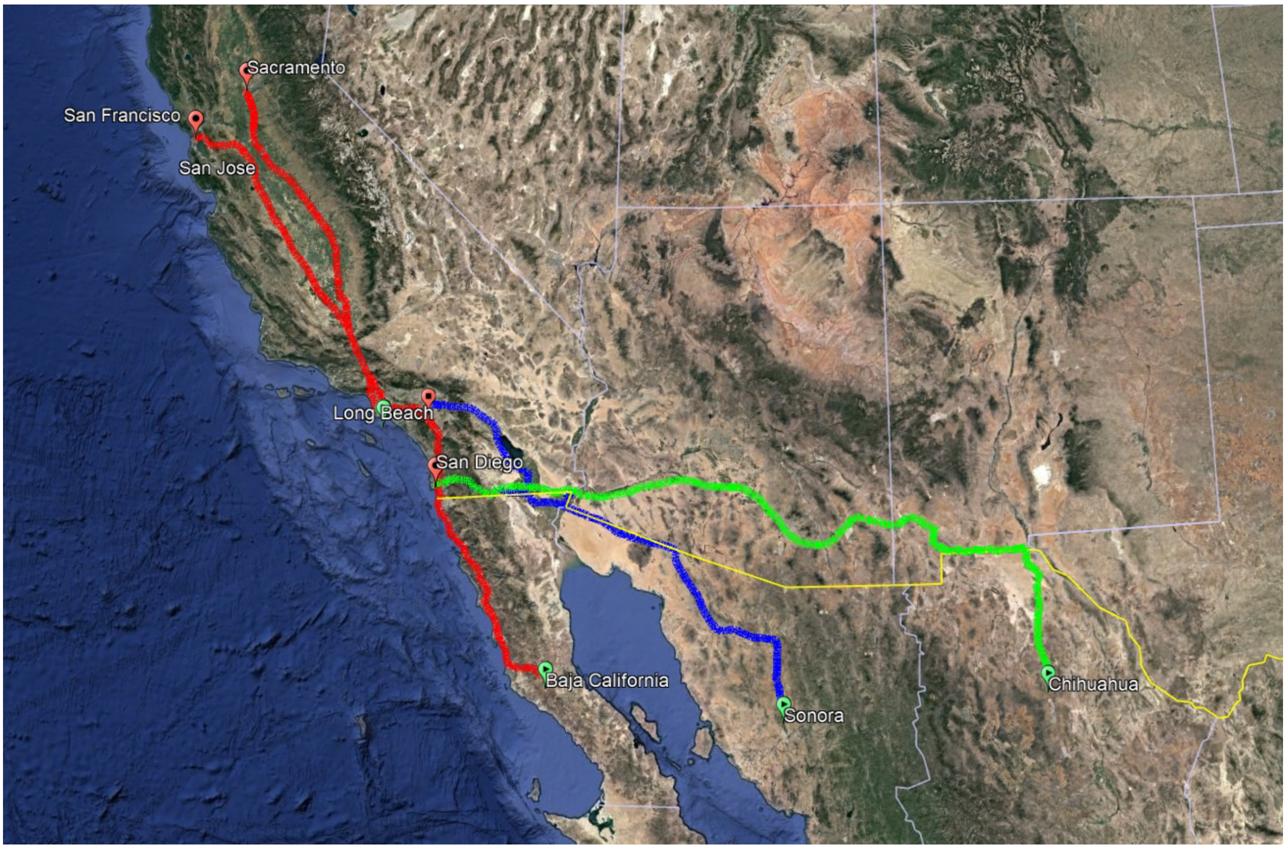


Table 13. Distance matrix of green hydrogen production sites in Mexico to potential demand hubs in California.

Destination \ Origin	Unit	Baja California	Sonora	Chihuahua
San Diego				
Distance	km	500	870	1400
LCOT Pipeline	USD/kg H_2	2.74	4.74	7.59
Los Ángeles				
Distance	km	700	1050	1500
LCOT	USD/kg H_2	3.82	5.7	8.14
Riverside				
Distance	km	660	1000	1400
LCOT	USD/kg H_2	3.6	5.43	7.59
San Francisco				
Distance	km	1320	1670	2100
LCOT	USD/kg H_2	7.16	9.05	11.37

San José				
Distance	km	1250	1600	2040
LCOT	USD/kg H_2	6.79	8.67	11.05
Sacramento				
Distance	km	1320	1670	2100
LCOT	USD/kg H_2	7.16	9.05	11.37

The following is the disaggregated cost of production and transportation of hydrogen from Baja California to San Diego (500km), considering the cost of production in 2030.

Figure 53. Cost build-up of green hydrogen produced Baja California transported to San Diego in 2030

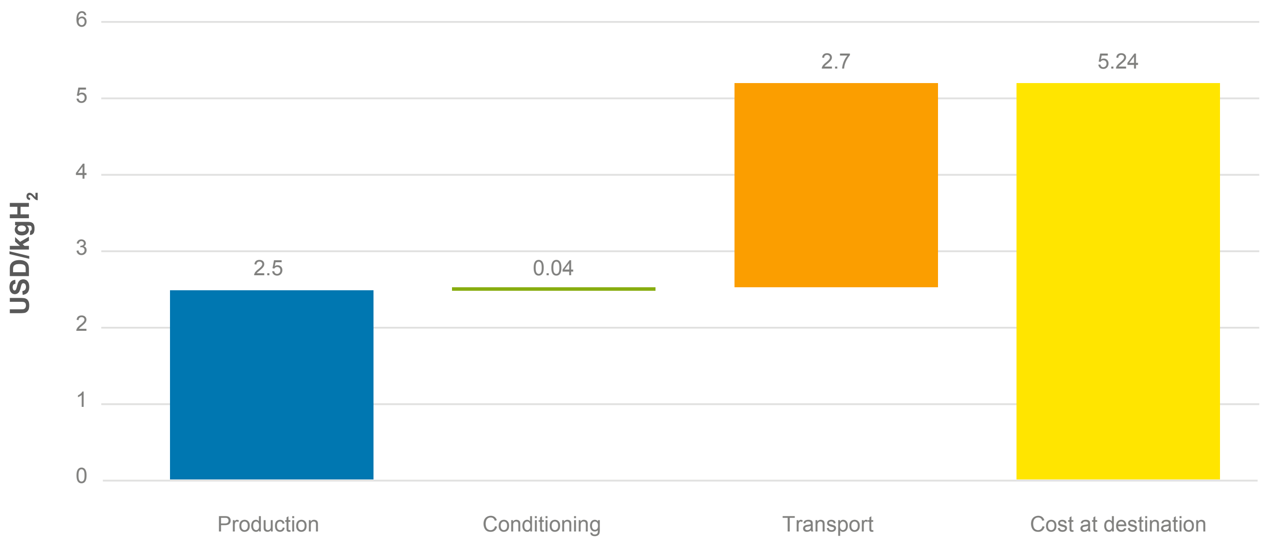


Figure 54. Projected Levelized Cost of Transport (LCOT) through pipeline from Baja California to various destinations in California in 2030

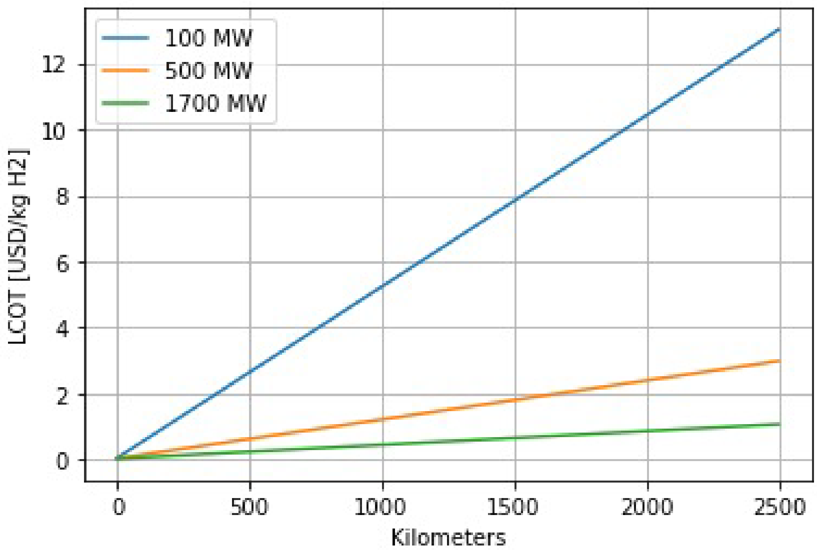


Table 14. Transportation cost for different production scales

Region	Distances	100 MW 8 in	500 MW 10 in	1700 MW 16 in
San Diego				
LCOT	500	2.74	0.65	0.24
Los Ángeles				
LCOT	700	3.82	0.89	0.33
Riverside				
LCOT	660	3.6	0.84	0.31
San Francisco				
LCOT	1320	7.16	1.65	0.6
San José				
LCOT	1250	6.79	1.56	0.57
Sacramento				
LCOT	1320	7.16	1.65	0.6

As shown in Figure 54, the cost for transporting compressed hydrogen over a pipeline from Baja California to California ranges from 2.7 USD/kgH_2 (to San Diego) to 7.2 USD/kgH_2 (to San Francisco). It should be noted that the behavior shown is gradually increasing as the total distance traveled increases. These values correspond to a fixed production of 23 tons of hydrogen per day. It is possible to reduce the cost of transport by increasing the scale of hydrogen transported, thanks to the economy of scale generated in larger pipelines that are cheaper per kilogram and in higher occupancy rates.

2.3 Cost scenarios for transporting hydrogen from northwestern Mexico to California with existing pipelines

Where natural gas pipelines exist, they can be repurposed for hydrogen transport, which could avoid decommissioning them before the end of their technical lifetime and reduce new material needs, reducing costs significantly. Blending hydrogen into natural gas streams could be an interim strategy to kick-start hydrogen production before demand is high enough to justify investing in dedicated hydrogen pipelines. Existing infrastructure needs to be assessed on an individual basis to determine whether it is suitable for repurposing and what modifications are required.

2.3.1 Repurposing

The suitability of a pipeline for repurposing and the technical modifications required depend on its design and operational parameters, including the type of steel, the age and condition of the line, welding and operating pressure. The economic case for repurposing depends on proximity of the pipeline to both the sources and destinations of the hydrogen, with relatively large volumes of minimum market uptake, and market factors like the cost of building new hydrogen pipelines or other alternative means of transport (IEA, 2023).

Repurposing gas networks will require an adjustment of the compression strategy, often including compressor replacements and a thorough inspection of the pipeline and the integrity of its components. Plus, there will be relatively simple measures, such as replacing valves and other leak-prone parts, and reconfiguring or replacing gas meters (IEA, 2022).

New compressors will be needed for repurposed transmission systems as well as more powerful turbines or motors, as the volumetric flow of hydrogen is up to three-times higher than for natural gas for the same pressure drop along the pipeline. As a result, for a hydrogen pipeline the **maximum energy capacity could be up to 80-90% of that of a natural gas pipeline.** Depending on the size of the original pipeline and the demand for hydrogen, pressure can be optimized to limit the cost of compressors at initial stages. For example, for a new 48-inch (80 bar) pipeline, compressor power is a significant expense. Operating the pipeline at 75% of its design capacity, the compression power and the subsequent electricity consumption would be around 45% lower, sufficient to lower the overall transmission costs (IEA, 2022).

It is estimated that repurposing natural gas pipelines to transport hydrogen could cut investment costs by 50-90% relative to building new lines (IEA, 2022) and (IRENA, 2022).

There are currently two natural gas pipelines that cross the border of Mexico with California, which according to the California Energy Commission, have a diameter between 1 and 12 inches. If we assume that these have a diameter of 12 inches, they could each transport a maximum of 267 tons of hydrogen per day adding up to a combined 534 ton per day, or over 190 kton per year.

Figure 55. LCOT vs distance for new vs retrofitted 12” pipelines.

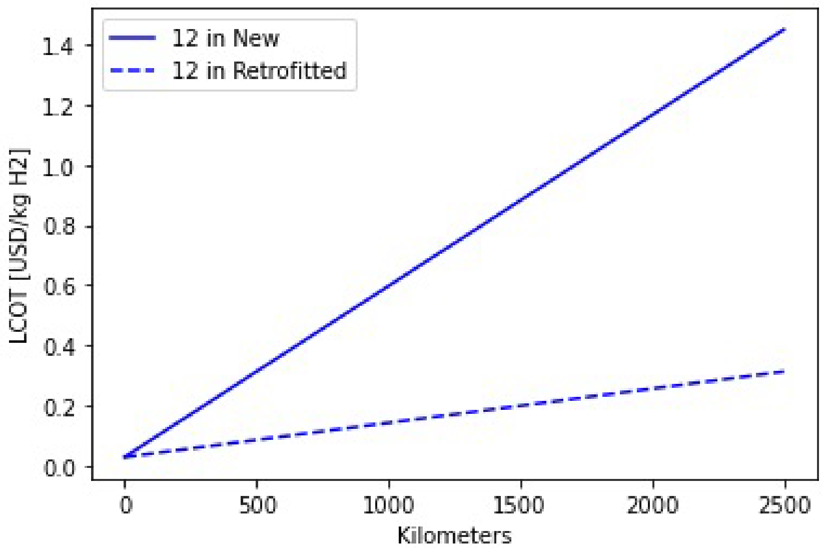


Table 15. Transportation cost for new and reconditioned 12” pipelines.

Region	Distance	12 in New	12 in Retrofitted
San Diego			
LCOT	500	0.31	0.08
Los Ángeles			
LCOT	700	0.42	0.11
Riverside			
LCOT	660	0.4	0.1
San Francisco			

LCOT	1320	0.77	0.18
San José			
LCOT	1250	0.73	0.17
Sacramento			
LCOT	1320	0.77	0.18

Figure 56. Levelized cost of transport vs volume transported in reconditioned pipelines.

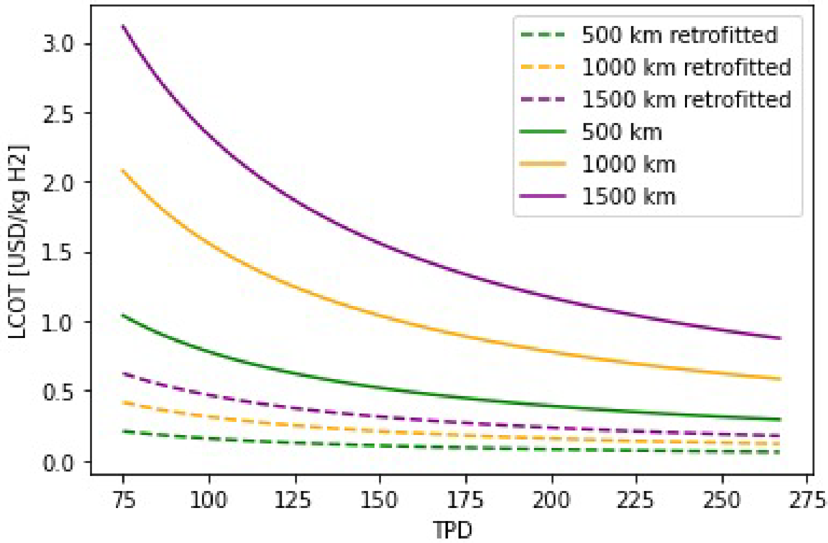


Figure 58 shows how the relative cost of transport through pipeline benefits from scaling (the higher the capacity, the lower the cost per kg).

2.3.2 Blending

Some research indicates that integrating blended hydrogen into natural gas transmission networks is feasible at levels of around 5- 10% with relatively minor upgrading. In distribution networks, with polymer-based pipelines blending, shares of up to about 20% would not require significant changes in the infrastructure, although the gas chromatographs would need to be adapted. While a 20% threshold in the distribution grids will require some upgrading, such as retrofitting the compressors, it seems to be the technical upper limit, above which significant investment may be needed, in particular for some downstream installations and end-use equipment (IEA, 2022).

The CO_2 benefit is small, equivalent to about a third of the blending fraction (i.e. a blending target of 20% by volume only leads to about 7% lower CO_2 emissions). It increases the gas price, as relatively cheap hydrogen of USD 3/kgH_2 is still about 10 times higher than the typical natural gas price in the United States (assuming 2.5 USD/ MMBtu). This results in an equivalent GHG mitigation cost that can exceed USD 500/tCO_2 (IRENA, 2022).

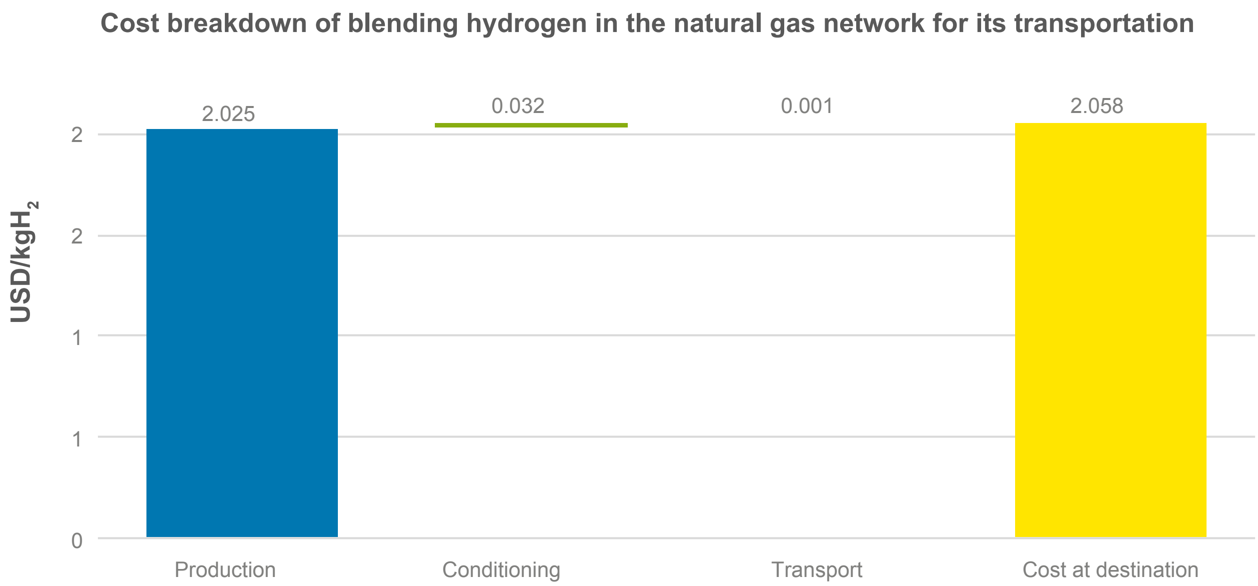
To understand the situation between Mexico and California, a model was developed based on existing natural gas infrastructure between both countries to reflect how a blending case could work. The Rosarito Mainline gas pipeline was used as an example. This system was originally put into service in August 2002 to supply natural gas from the United States to several power plants and industrial customers in the Baja California market in Mexico. The system is a 30-inch diameter pipeline with a length of approximately 225 km and a design transport capacity of 534 million cubic feet per day (MMcfd).

On the one hand, 20% of this capacity will be considered for transporting hydrogen through blending, which is supported by the literature as the maximum optimal percentage that can be transported without requiring mayor infrastructure intervention. This together with the decarbonization efforts of the countries could lead to gas pipelines having unused capacity by the year 2045. This means that 20% is equivalent to 106.8 million cubic feet per day, which is equivalent to 3.02 million cubic meters or 257 tons per day.

On the other hand, it was assumed that there are no costs related to CAPEX, and OPEX corresponds to 20% of the total, this is because 20% of the volumetric capacity is being used. To estimate this, it was based on 1% of the total CAPEX of a new 30-inch pipeline would cost.

The previous calculation yields a result of 0.033 USD/kg for transportation, and below are the itemized cost breakdowns.

Figure 57. Cost breakdown for blending

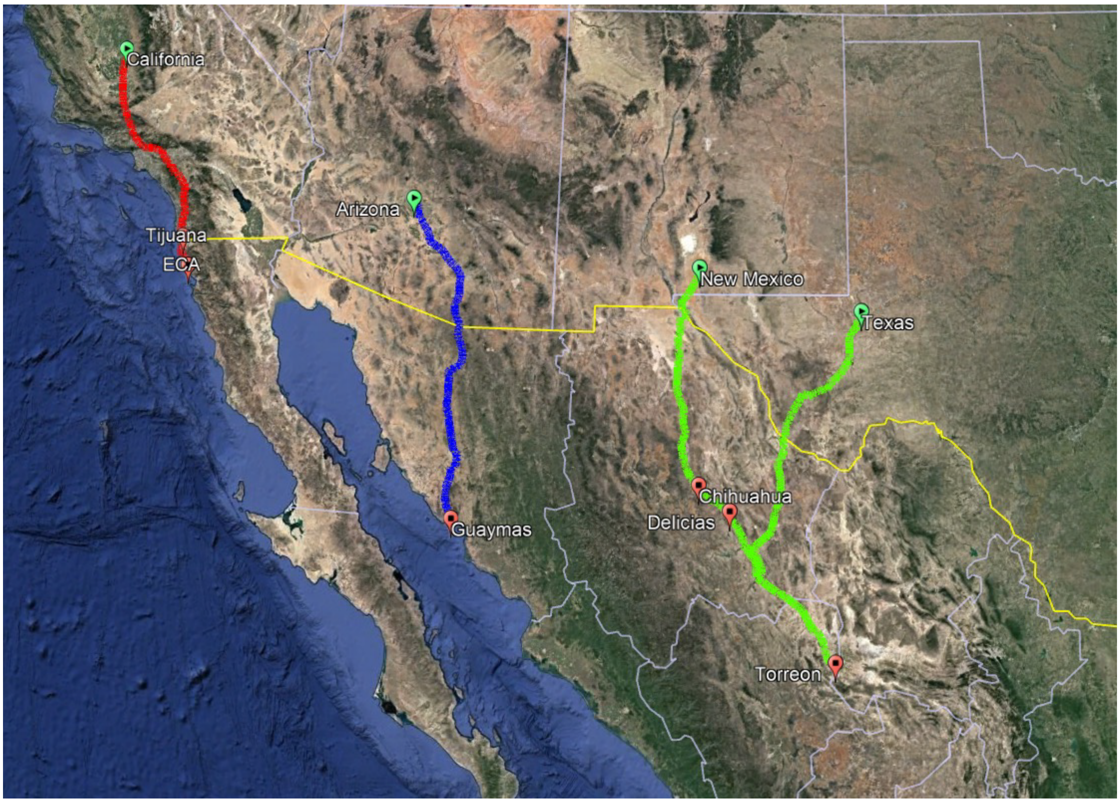


The above analysis does not consider any separation after the hydrogen enters the pipeline system, so the end use could only be for heat generation. While it has been discovered that projects are being developed to recover hydrogen after blending, this is still in the development stage and the associated costs at an industrial level are unknown, one example is the project being developed jointly by SoCalGas and HyET, which seeks to separate hydrogen from natural gas using a proton exchange membrane. To make a better comparison of the cost of hydrogen through this medium, which is considered only for heat, the leveled cost of hydrogen is provided in energy units; 0.017 USD/MJ

2.4 Cost scenarios of transporting hydrogen from US border states to Mexico

To obtain the cost of transporting hydrogen from California, we used the same methodology as in the previous section. The results are shown below, as well as the routes considered.

Figure 58. Map of potential pipeline transport from California to ECA,Tijuana (red), from Arizona to Guaymas, Sonora (Blue) and from New Mexico and Texas to Chihuahua and Torreon (green)



2.4.1 California (LA)-Tijuana- ECA,

Table 16 shows the distance of potential demand hubs in Baja California: Tijuana and ECA (Energía Costa Azul) terminal in Ensenada, from southern California.

Table 16. Distance matrix of green hydrogen production sites in California to potential demand hubs in Baja California.

Region	Unit	California
Tijuana		
Distance	km	450
LCOT Pipeline	USD/kg H_2	2.47
ECA		
Distance	km	530
LCOT	USD/kg H_2	2.9

2.4.2 Arizona (Phoenix/Tucson) – Nogales – Hermosillo – Guayamas

Table 17 shows the distance of potential demand hubs in Mexican state of Sonora (Nogales, Hermosillo and Guaymas) from a region in California with good solar resource (and low LCOH).

Table 17. Distance matrix of green hydrogen production sites in Arizona to potential demand hubs in Sonora

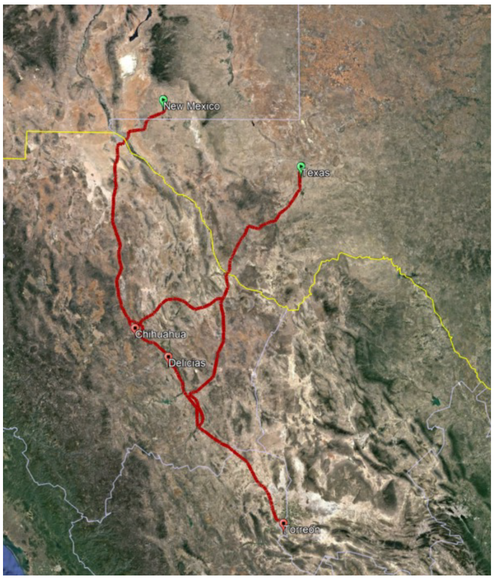
Region	Unit	Phoenix	Tucson
Nogales			
Distance	km	370	120
LCOT Pipeline	USD/kg H_2	2.04	0.69
Hermosillo			
Distance	km	650	400
LCOT	USD/kg H_2	3.55	2.2
Guaymas			
Distance	km	780	530
LCOT	USD/kg H_2	4.25	2.9

2.4.3 New Mexico or West TX – Chihuahua – Delicias – Torreón

Table 18. Distance matrix of green hydrogen production sites in Texas and New Mexico to potential demand hubs in Chihuahua.

Region	Unit	New Mexico	Texas
Chihuahua			
Distance	km	490	510
LCOT Pipeline	USD/kg H_2	2.69	2.79
Delicias			
Distance	km	580	590
LCOT	USD/kg H_2	3.17	3.23
Torreón			
Distance	km	960	830
LCOT	USD/kg H_2	5.22	4.52

Figure 59. Map of pipeline for transport from New Mexico and Texas to Mexico.



2.5 Minimum viable scale required for transporting hydrogen through pipelines

Figure 60. Cost of transporting hydrogen though an 8-inch pipeline.

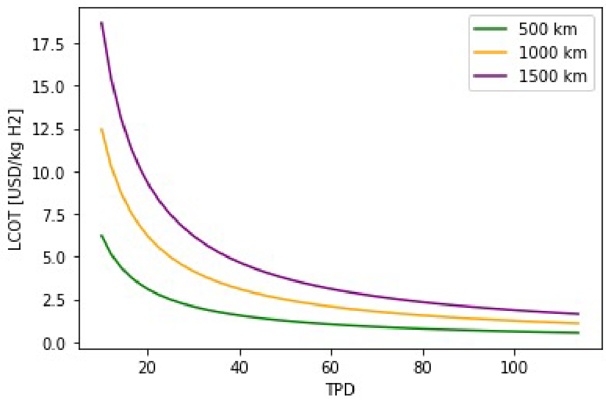


Figure 62 shows the levelized cost of transporting 1 kg of hydrogen through an 8-inch pipeline over distances from 500 to 1,500 km. As the pipeline throughput is increased (by increasing pressure), the relative costs decrease, until the pipeline reaches its limit of 110 ton/day.

Figure 61. Cost of pipeline transport changes as the diameter of pipelines increases.

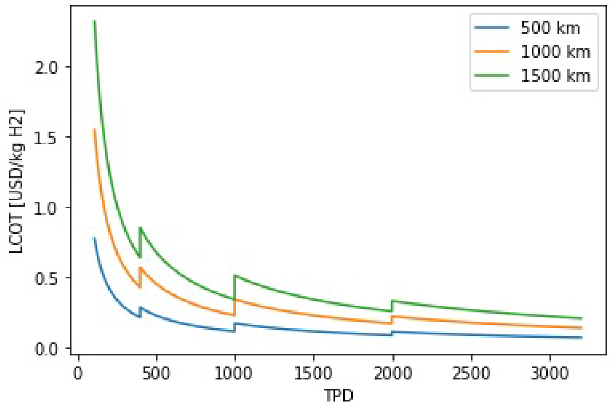


Figure 63 shows how the levelized cost of transporting a kg of hydrogen changes depending on the required throughput: it decreases as a particular pipeline is being optimized (increased throughput through higher pressure), but when the pipeline reaches its pressure and throughput limit, a larger pipeline must be used, which explains the bumps.

3 Alternative transport technologies and pathways for exporting hydrogen from Northwestern Mexico to California

3.1 Export through alternative technologies

In this chapter, two alternatives are explored for transporting green hydrogen from northwestern Mexico to California over the road: (1) through compressed road transport (tube trailers) and (2) through liquefied road transport.

3.1.1 Compressed road transport

Trucks that haul gaseous hydrogen are called tube trailers. Gaseous hydrogen is compressed to pressures of 180 bar (~2,600 psig) or higher into long cylinders that are stacked on a trailer that the truck hauls. This gives the appearance of long tubes, hence the name tube trailer.

Tube trailers are currently limited to pressures of 250 bar by U.S. Department of Transportation (DOT) regulations, but exemptions have been granted to enable operation at higher pressures (e.g., 500 bar or higher). Steel tube trailers are most commonly employed and carry approximately 380 kg onboard; their carrying capacity is limited by the weight of the steel tubes. Recently, composite storage vessels have been developed that have capacities of 560–900 kg of hydrogen per trailer. Such tube trailers are currently being used to deliver compressed natural gas in other countries (DOE, 2022).

Cost components

There are three main cost components to transporting hydrogen in tube trailers:

1. **Conditioning**, which includes the cost of compression at 350 bar that was calculated for the peak demand delivered by a 100 MW electrolyzer.
2. **Storage**. In our calculations this was sized for storing one day's production in vessels.
3. **Transportation**. The size of the fleet needed to transport the production was considered, and time and distance traveled costs were considered in addition to the OPEX.

3.1.2 Liquified road transport

The energy sector has vast experience in producing, transporting, and storing LNG; however, the lower boiling point of hydrogen (-253 °C) compared to natural gas (-162 °C) requires different technologies. The transport of hydrogen in the form of liquid hydrogen (LH_2) may be attractive for users requiring high purity hydrogen. Hydrogen liquefaction and storage are mature technologies that have been used for decades, mostly for space applications and petrochemicals; however, at relatively modest levels compared with the LNG industry.

Hydrogen liquefaction is a reasonably well-established process, with a globally installed liquefaction capacity of around 500 ton per day (tpd). Most large hydrogen liquefaction plants were constructed for the US NASA during the 1950-1970 period, and the largest plant in the world with a capacity of 34 tpd is still in operation. During the last two decades only smaller plants of around 5-10 tpd were built, and a few plants of around 30 tpd have been built in the United States since 2020 to satisfy rising demand in the transport sector. Korea is constructing the largest hydrogen liquefaction facility in the world with a capacity of 90 tpd to start operations in 2023, mainly to serve the transport sector (IEA 2022).

There are three main cost components to liquefy hydrogen transport with cryogenic tanker trucks:

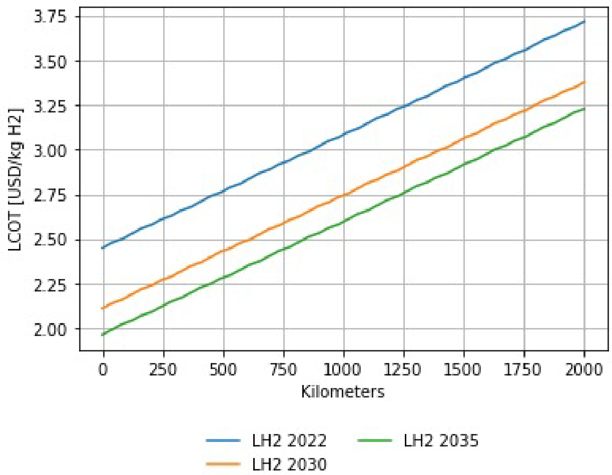
1. Conditioning- Energy and OPEX for cooling to cryogenic temperatures for a 100 MW electrolyzer.
2. Storage. For this scenario it was sized for one day's capacity.
3. Transportation. Fleet size and distance were considered for each scenario.

More details on the assumptions of CAPEX and OPEX can be found in Annex 2.

With the implementation of this technology, we can see a significant reduction in the capital expenditure (capex) for the liquefaction plant over time, leading to cost savings until the year 2035. After that, the cost is expected to remain stable.

Using these assumptions (and more detailed assumptions provided in Annex 2), factoring in the technology's lifespan, maintenance requirements, and expected operational costs, we calculated the levelized cost of transport (LCOT) per kg of hydrogen. The results are shown in the figure below.

Figure 62. Projected Levelized Cost of Transport (LCOT) through LH_2 trucks.



3.2 Hydrogen export from seaports

With more than 11,000 km of coasts, Mexico imports and exports a great amount of goods through its ports, covering commodities for all industries, and hydrogen wouldn't be an exception. Nevertheless, exporting hydrogen would imply infrastructural adaptations to the port to be used for these ends, considering that the hydrogen value chain has not been developed in the country.

There are 4 main ports in the northwestern region of Mexico: Ensenada, Guaymas, Topolobampo and Mazatlán. For its proximity to the state of California, the possibility to export hydrogen through the port of Ensenada, the biggest and most important port in the region is analyzed.

The port of Ensenada comprises an area of around 338 ha (about 835 acres), counting with shipyards, fishing and touristic areas, bulk and minerals section, and a large commercial area with designated patios and warehouses. Industry in the region is characterized by agriculture, mining, and commerce sectors, therefore the port of Ensenada's infrastructure is focused mainly on exports and imports for these business areas.

In contrast, regions of Mexico where the main industrial sectors revolve around oil and its derived compounds do count with ports prepared with infrastructure for fluids and chemicals trade. For instance, the port of Coatzacoalcos, located in southern Veracruz, is one of the areas with the most activity of exploration and exploitation of oil reserves in the Gulf of Mexico. This port consists of 352 hectares of land and water, and four of its piers count with infrastructure for ammonia shipping with a combined maximum storage capacity of 180,000 tons.

The only port in the northwestern region of Mexico with relevant amount of infrastructure for ammonia is the port of Guaymas. The fertilizer division of PEMEX counts with storage and shipping facilities on one side the port, including a considerable number of tanks, pipelines and a vessel terminal of its own, fully equipped to manage liquid bulk.

Another option reported is the port of Topolobampo, situated 322 km from the entrance of the Gulf of California, although its ammonia storage capacity is unknown.

Considerations for shipping hydrogen to California

1. Shipping ammonia rather than pure hydrogen

   The International Renewable Energy Agency (IRENA), the German think tank Agora Energiewende, and energy analyst Wood Mackenzie all agree that shipping hydrogen derivative ammonia (NH_3) rather than pure H_2 would be more cost-effective. The first reason being that ammonia, at its standard liquid form at -33°C packs 59% more energy than liquid hydrogen, which must be compressed and super-cooled down to -253°C, consuming a lot more energy.

   Additionally, transforming hydrogen into ammonia is almost 15 times cheaper than liquifying it (LH_2), considering the same price of green hydrogen. Likewise, it is a lot more costly and technically difficult to maintain LH_2's temperature over long trips, and a percentage of these extremely cold liquids will inevitably warm up to the point where they transform into gas, a process known as "boil-off" in the industry. Liquid hydrogen ships tend to rely on insulation, while ammonia carriers are usually completely refrigerated, lowering losses from boil-off when shipping NH_3.

2. Routes and destinations

The closest destination from Ensenada to California would be to the port of San Diego. Nevertheless, this port does not count with infrastructure for liquid bulk imports, rather focusing on fishing, tourism, and traditional cargo.

The next significant destination along the American West Coast would be San Pedro Bay, 260 km from Ensenada, where both Los Angeles and Long Beach ports are located, comprising the busiest commercial ports in North America. As the gateway to Asia, these mega-ports involve trading activities of all kinds and products, with liquid bulk not being an exception.

Vopak, a company dedicated to imports, exports and distribution of petroleum products, chemicals, and biofuels, has presence both in the Los Angeles and Long Beach ports. The combined capacity of these two Vopak terminals is 137 tanks, with a total storage capacity of 434,777 m3, with a large share for ammonia storage. In addition, the company is developing new infrastructure and exploring opportunities to import or export low-carbon or renewable hydrogen products (ammonia, liquified hydrogen, and liquid organic hydrogen carriers-LOHC). This shows that actors at the ports of Los Angeles and Long Beach are active in the ammonia and chemicals trade and are looking forward to integrating infrastructure to receive new renewable alternatives, such as hydrogen.

3. Costs for shipping ammonia from Mexico to California

In a scenario where green hydrogen produced in Sonora were to be shipped to California in the form of ammonia, we consider the costs of green hydrogen, ammonia production and shipping. Storage is assumed to be provided by the ports with existing infrastructure.

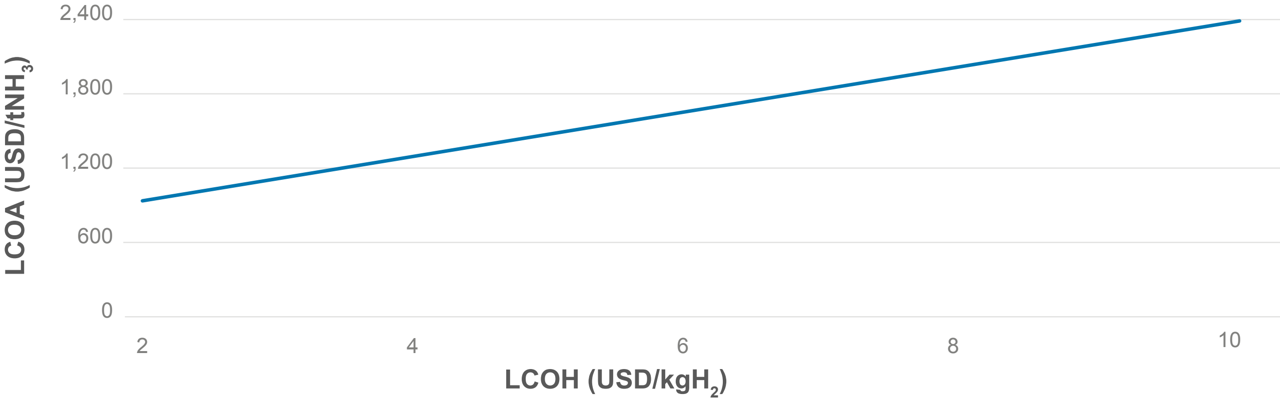
The cost buildup considers CAPEX of ammonia production of 124 USD/tNH_3 to process hydrogen generated in Sonora (525 kton/year)[11], and an OPEX of 21.4 USD/tNH_3. Additionally, the LCOE for the northern part of Mexico was contemplated to operate the Haber-Bosch process. Sources and further details on assumptions can be found in Annex 1.

As for shipping, the typical ammonia vessel carries 60,000 tons of NH_3, and costs rely between 40-60 USD/tNH_3 for short distances (less than 10,000 km). In this case the longest route possible is around 2,000 km, from Guaymas to LA, going around the Baja California Peninsula for which a shipping cost of 40 USD/tNH_3 was considered.

Figure 65 presents the resulting costs of delivering ammonia (levelized cost of ammonia -LCOA) to California vs the LCOH of hydrogen produced near the port. For an LCOH of 2 USD/kgH_2, (realistic value for solar hydrogen from the state of Sonora by 2045) the delivered costs would be approximately 934 USD/tNH_3. From 2042 - when PTC is no longer applicable - Mexican green ammonia prices could be more competitive than gray ammonia (from natural gas).

[11] This is a maximum hydrogen production scenario, where all the currently estimated 7 GW of excess solar capacity from the Pan Sonora would be used for producing green hydrogen. This is not a likely scenario, but an upper limit.

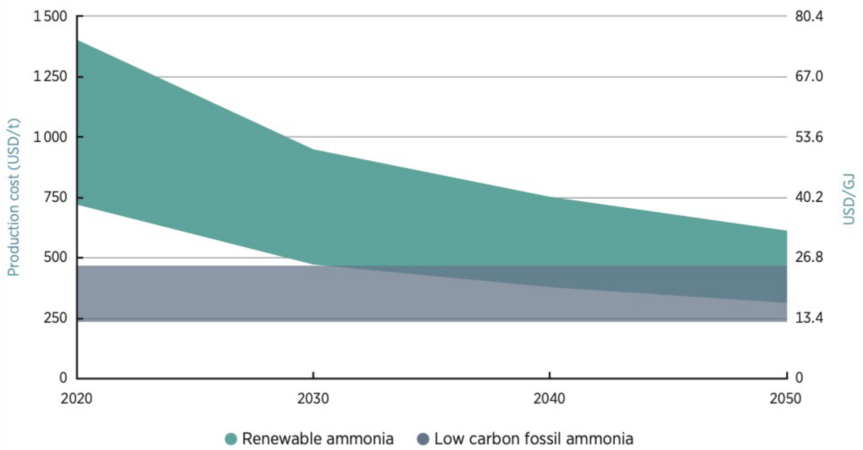
Figure 63. Levelized cost of ammonia delivered to California vs LCOH of hydrogen produced in Mexico in 2045



(Developed with data from Hinicio's and Valera-Medina, 2020, Techno-Economic Challenges of Green Ammonia as an Energy Vector).

According to IRENA's Innovation Outlook on Renewable Ammonia (2022), low-carbon fossil ammonia prices currently vary in a range between 250-500 USD/tNH_3, while green ammonia prices begin at 750 USD/tNH_3 and rise to 1400 USD/tNH_3 (Figure 66). However, these costs are expected to lower during the following decade, reaching the first point of parity in 2032. The decrease in green ammonia production costs is due to technological developments and the widespread availability of renewable energy.

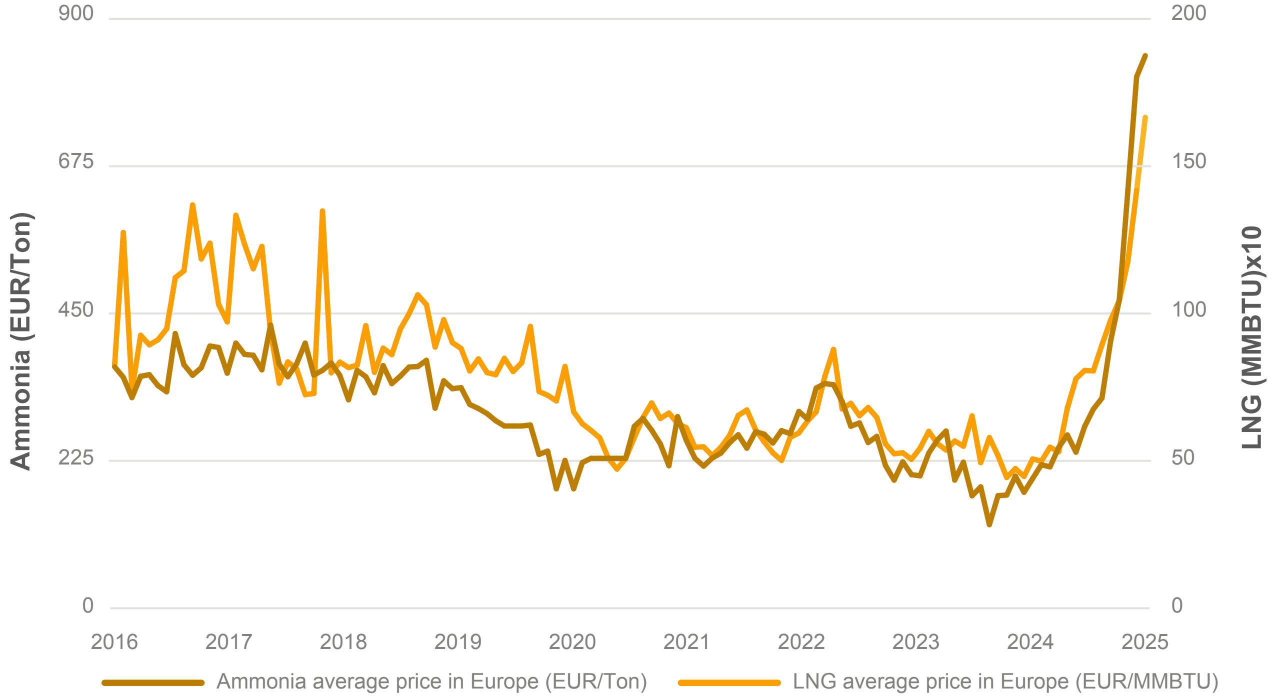
Figure 64. Current and future production costs of renewable ammonia, compared with production cost range for low-carbon fossil ammonia (USD 2-10/GJ).



(IRENA, 2022)

Recently, renewable ammonia prices have gotten more competitive compared to traditional fossil ammonia due to sudden increases in natural gas prices, which are directly correlated as can be appreciated in Figure 67. Geopolitical conflicts in the region have a significant impact on natural gas prices in Europe, which were pushed to prices over 800 EUR/tNH_3 in early 2022, in the wake of Russia's invasion of Ukraine.

Figure 65. Ammonia prices in comparison with LNG prices in Europe.



Source: IRENA

Note: LNG prices are shown on a different scale to show its correlation with ammonia prices.

3.3 Results – LCOT for transporting hydrogen to California

Table 19 shows the costs of transporting 1kg of green hydrogen produced in three locations in Mexico to six destinations in California using compressed and liquified forms over the road for the scale of a 100 MW electrolyzer. As it can be seen, the liquified option is always cheaper than the compressed cost at this scale, and ranges from 2.76 USD/kg for the 500 km from the north of Baja California to San Diego, up to 3.29 to northern California (San Francisco).

Table 19. Levelized cost of transporting hydrogen from 3 locations in Mexico to California over the road for the year 2035.

Region	Unit	Baja California	Sonora	Chihuahua
San Diego				
Distance	km	500	870	1400
LCOT Compressed	USD/kg H_2	3.2	5.18	7.96
LCOT Liquified	USD/kg H_2	2.76	3	3.34
Los Ángeles				
Distance	km	700	1050	1500
LCOT Compressed	USD/kg H_2	4.26	6.13	8.5
LCOT Liquified	USD/kg H_2	2.89	3.11	3.4

Riverside				
Distance	km	660	1000	1400
LCOT Compressed	USD/kg H_2	4.06	5.87	7.96
LCOT Liquified		2.87	3.09	3.34
San Francisco				
Distance	km	1320	1670	2100
LCOT Compressed	USD/kg H_2	7.56	9.4	11.69
LCOT Liquified	USD/kg H_2	3.29	3.5	3.78
San José				
Distance	km	1250	1600	2040
LCOT Compressed	USD/kg H_2	7.19	9.02	11.37
LCOT Liquified		3.24	3.46	3.74
Sacramento				
Distance	km	1320	1670	2100
LCOT Compressed	USD/kg H_2	7.56	9.4	11.69
LCOT Liquified		3.29	3.5	3.74

Figure 66. Comparison of transport options from Baja California to California.

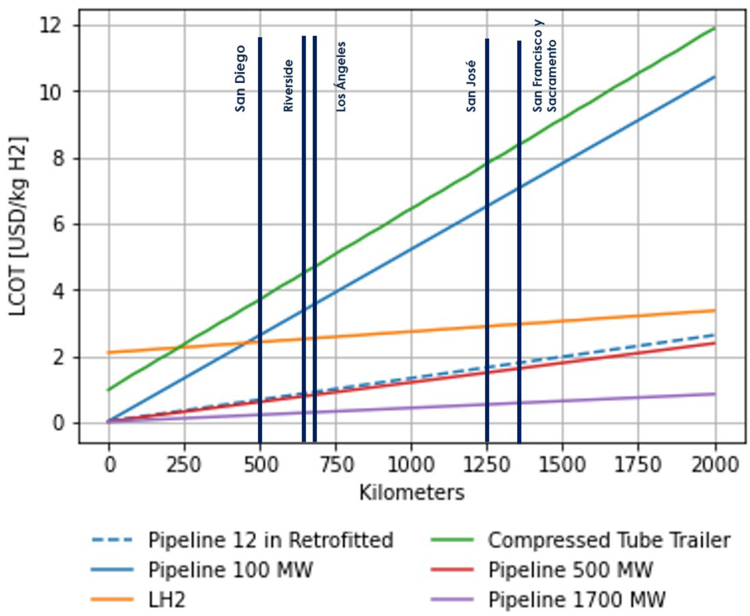


Figure 68 shows a comparison of costs of three transport options over different distances and scales, it can be observed that as hydrogen transported volumes increase, the use of pipelines becomes more competitive than liquid hydrogen, retrofitting is also a more competitive option.

Figure 69 and Figure 70 show the cost buildup for delivering 1kg of green hydrogen produced at an LCOH of 2.5 USD/kg over a distance of 1,000 km through compressed and liquified trucks respectively. We can see that the additional cost of conditioning for liquid transport is largely compensated by the lower transport costs, due to the higher density of transporting hydrogen in liquid form.

Figure 67. Cost buildup hydrogen delivered over 1000 km in liquid form (truck).

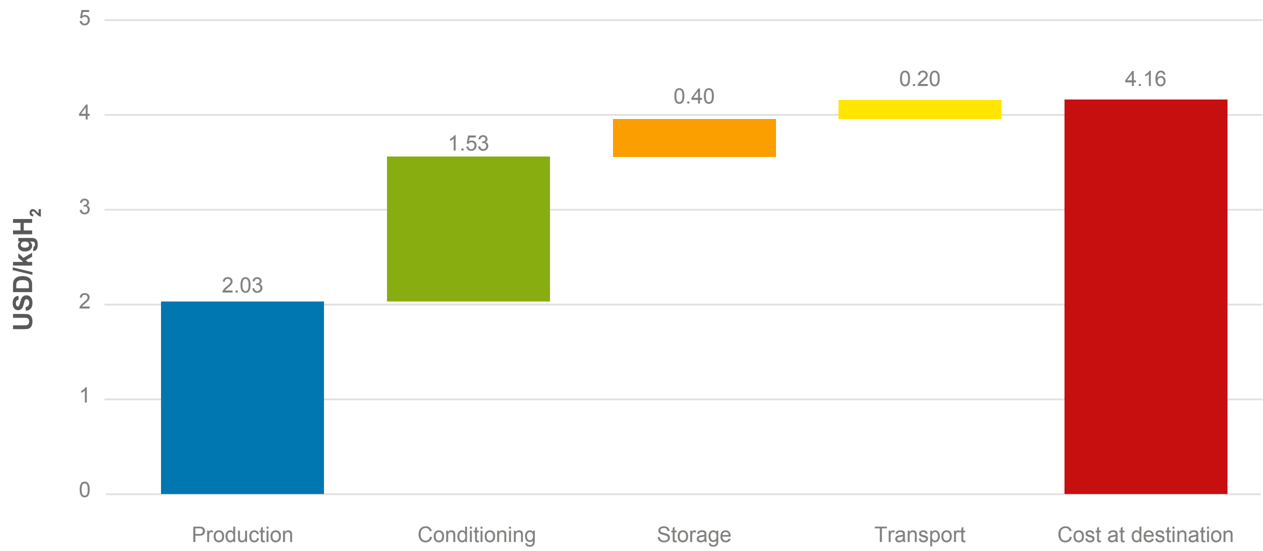
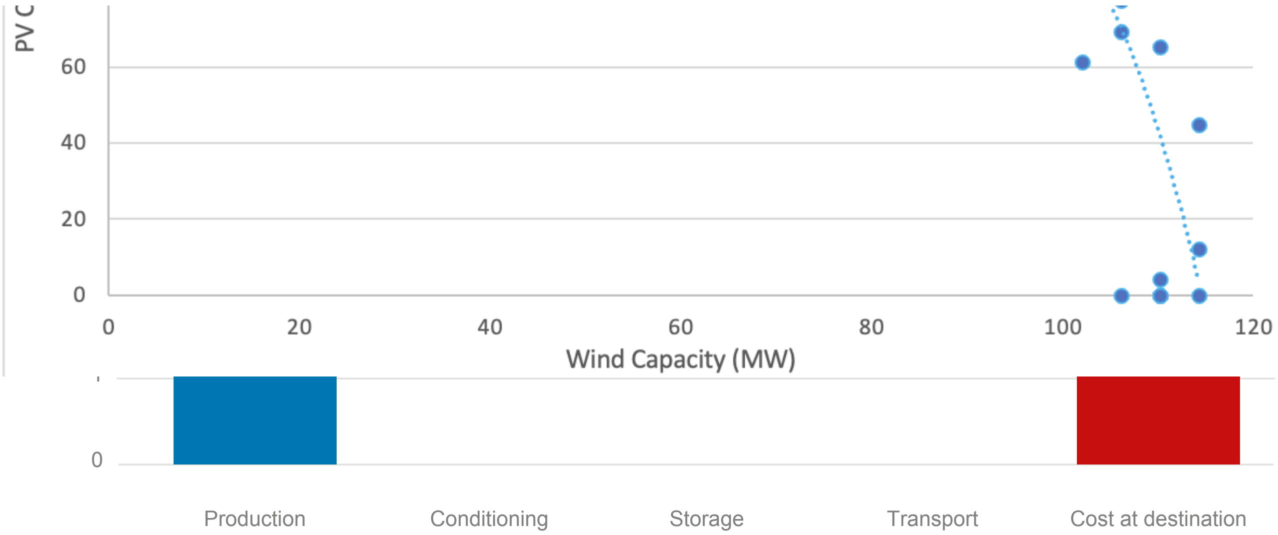


Figure 68. Cost buildup of delivering 1kg of hydrogen in compressed form at 1,000 km.



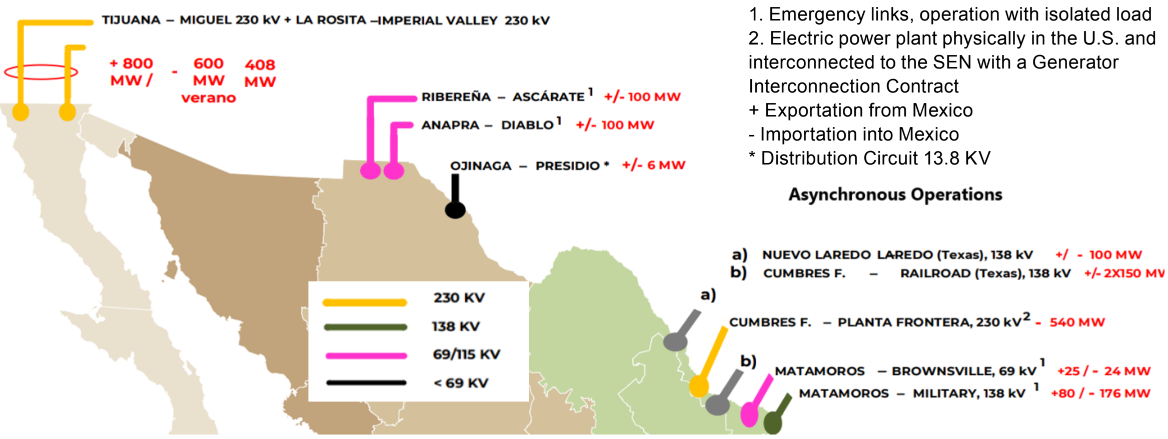
3.4 Export of electricity for hydrogen production in California

Electricity trading between the United States and Mexico is very modest, with U.S. imports from Mexico representing roughly 0.6% of electricity consumption in the U.S. border States of Arizona, California, New Mexico, and Texas. Mexican imports from the U.S. representing less than 2% of

Mexican consumption[12]. The primary reason for the low level of U.S.-Mexico trade in electricity is that the electrical systems of the two countries are only integrated with limited exceptions (McNeece, Irastorza, & Martin, 2022) as shown in Figure 71.

In the report A Call for Deeper Integration Between the Electrical Systems of the United States and Mexico (McNeece, Irastorza, & Martin, 2022) it is argued that "the move toward increased use of renewable energy in both countries, together with related grid reliability challenges and extreme weather risks presented by climate change, support increased electrical integration between the two countries". Arguments in favor of integration include the fact that geographical diversity can help smooth out the intermittency of renewables, reduce renewable curtailments, and lower electricity prices. Geographical diversity will also provide reliability benefits and eventually, a reduced need for reserve capacity. A further and deeper integration, coupled with increased development of renewables, could mitigate Mexican dependence on imported hydrocarbons.

Figure 69. Electric transmission border crossings between Mexico and USA.



Source: (McNeece, Irastorza, & Martin, 2022) citing S&P Market Intelligence, PRODESEN 2019 and Nera Analysis.

At the Major Economies Forum on Energy and Climate (June 17), the Mexican Government committed to a decalogue of actions against climate change, including creation of solar parks on the border between Mexico and the U.S. (see also Plan Sonora described in section 2.1), as well as the construction of energy transmission networks that would allow export of electricity to California and other U.S. states (Bloomberglinea, 2022).

3.4.1 Three modalities for exporting Mexican electricity to the US

A Mexico-based power generator has three main options for exporting (part of) its power to a US-based client.

1. A direct interconnection to a cross-border substation (this is the case of Sempra's Cimarron wind farm located in BC and interconnected in San Diego).
2. An interconnection to the Mexican SEN making transactions through the available capacity at the transmission border crossing.
3. If it is a legacy project[13] with an export permit.

On the Mexican side, the generator requires a permit in any of these modalities. If the generation is connected directly to a Gen-Tie, it needs what is called a Presidential Permit in the US for the infrastructure to cross the border. Depending on the jurisdiction in the US, other types of permits may also be required.

[12] U.S. imports of electricity from Mexico in 2021 were 5,026 GWh, while exports to Mexico in that year were 3,788 GWh. (IEA, 2023)

[13] Legacy projects (also known as 'proyectos legados' in Spanish, which are regulated under the old LSPEE law)

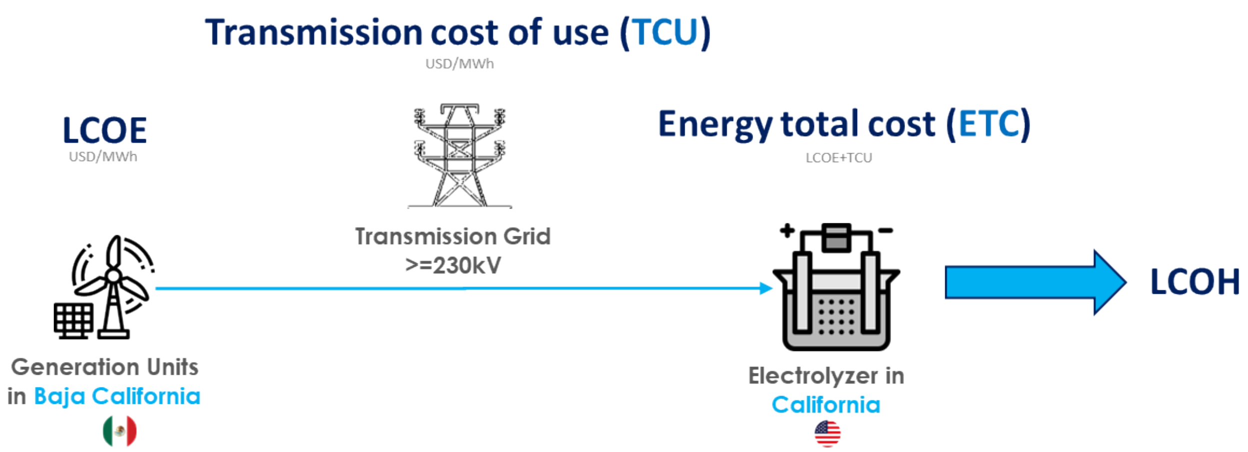
Note that a Mexico-based renewable power generator **cannot benefit from the PTC while physically in Mexico**. However, under California's Renewable Portfolio Standard (RPS), renewable energy projects located in Mexico near the border will satisfy California utilities' RPS obligations if those projects are connected to the California grid with a dedicated cross-border transmission line that is not connected to the Mexican grid[14].

The North American Energy Reliability Corporation (NERC) – the body responsible for overseeing the reliable operation of the interconnected electric grid for the U.S. – foresees energy shortfall risks and extreme weather risks in California, Southwestern U.S. and Texas into the future (NERC, 2022).

The California transmission grid is already linked and synchronized with the grid of Baja California, within the regulatory framework of the Western Electricity Coordinating Council (WECC), as shown in Figure 71 (McNeece, Irastorza, & Martin, 2022). The transmission link between the two grids is rated at 800 MW northbound and 600 MW southbound. However, Baja California's grid is not currently linked with the rest of the Mexican electrical system, the National Interconnected System (SIN), though plans for a transmission line from Sonora have recently been announced (El Universal, 2023).

The potential LCOH that could be achieved from producing electricity in Mexico and transmitting it under the aforementioned schemes was estimated. Figure 72 shows a diagram describing this interconnection.

Figure 70. Scheme for hydrogen production with generators in Mexico and electrolyzer in USA.



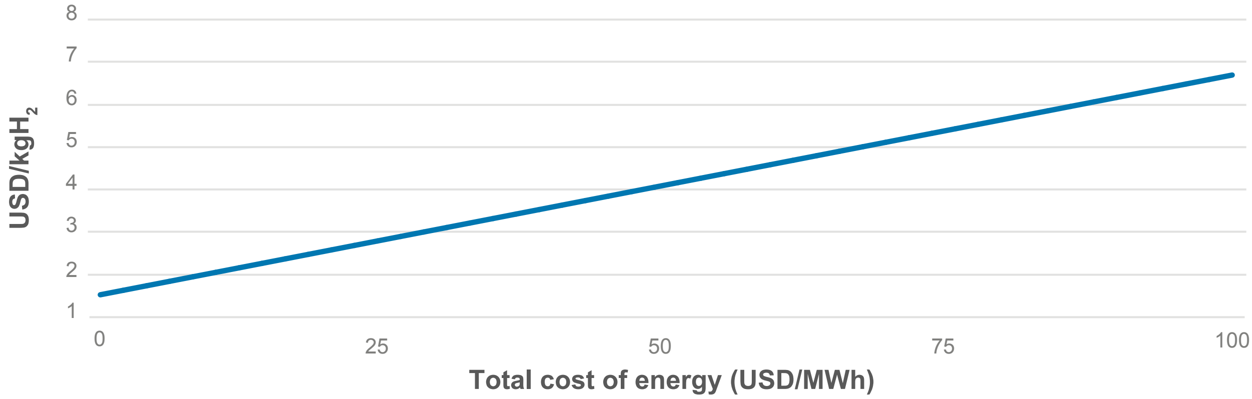
Source (HINICIO, 2022).

To determine the LCOH in California for the three transmission schemes, the following methodology is employed:

1. The LCOH is defined as a function of the Energy total cost (ETC). Energy total cost is defined as the LCOE + the transmission cost of use (TCU), where the TCU depends on the scheme to transmit the electricity. Figure 73 shows a curve representing the relationship between the TCU and ETC.

[14] On the eligibility of a foreign project to meet RPS requirements, see California Public Resources Code § 25741(a)(2)(A). See also California Public Utilities Code § 399.11(e)(1) and (2) (generating resources located outside of California that are able to supply RPS eligible electricity to California end-use customers shall be treated identically to generating resources located within the state)

Figure 71. LCOH as a function of the energy total cost in 2022.



Source (HINICIO, 2022).

The LCOH for this estimation is the one obtained for this document (refer to Annex 2 for more details) for 2022. The mathematical function according to the results is as follows:

Equation 2. Equation 2. LCOH as a function of the energy total cost.

$$\textbf{LCOH} = 0.052 * (\textbf{ETC}) + 1.5086$$

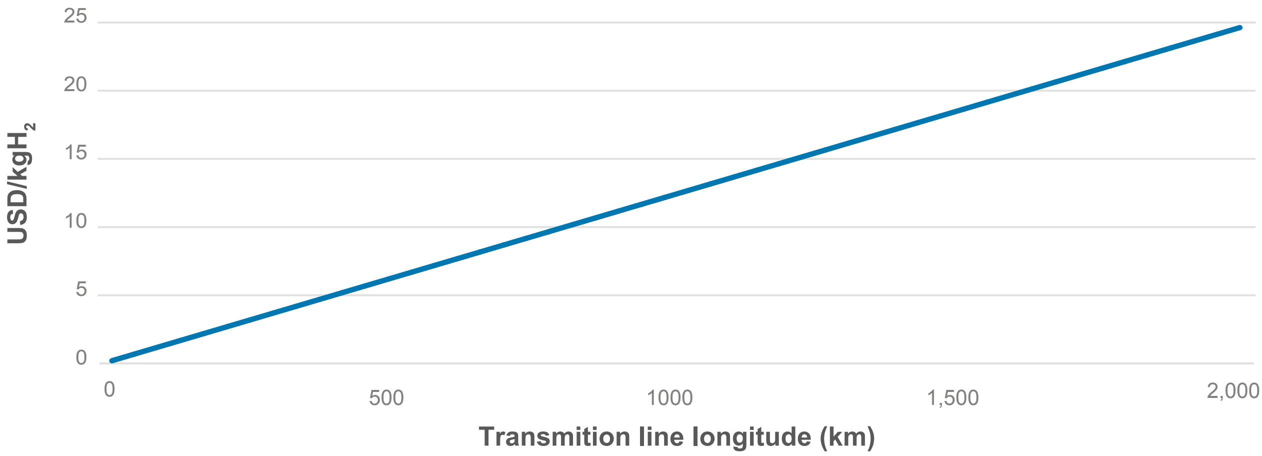
Considering a split between the LCOE and the TCU, the resulting equation is:

Equation 3. Equation 3. LCOH as a function of the energy total cost (split between LCOE and TCU).

$$\textbf{LCOH} = 0.052 * (\textbf{LCOE} + \textbf{TCU}) + 1.5086$$

2. Therefore, an equation of the LCOE as a function of the TCU was obtained. The TCU as a function of the different schemes in which the transmission cost can be considered is detailed next:
   a. A direct interconnection to a cross-border substation. In this modality, TCU is defined as a function of the transmission line length. This variable is the most relevant when calculating the CAPEX needed to build a new transmission line between Mexico and the substations in the U.S.A. It was calculated considering a transmission line of 600 MWVA at 230kV to feed an electrolyzer located in the U.S.A. The results are shown as follows:

Figure 72. Cost of transmitting a MWh vs distance for a 230kV transmission line



The resulting equation is:

Equation 4. Equation 4. TCU as a function of the distance

$$\textbf{TCU} = 12.4 * \textbf{Distance} + 0.0017$$

Where Distance is given in kilometers.

Therefore, the LCOH as a function of the LCOE and distance of transmission lines becomes:

Equation 5. Equation 5. LCOH as a function of the LCOE and transmission line longitude.

$$\textbf{LCOH} = 0.052 * \textbf{LCOE} + 0.64 * \textbf{Distance} + 1.50$$

b. An interconnection to the Mexican SEN making transactions through the available capacity at the transmission border crossing. **TCU** is considered as 16.39 USD/MWh (CPUC, 2022) because of historical transmission fee cost to transport energy in the California Independent System Operator's (CAISO) control area.
c. It can be a legacy project[15] with an export permit. **TCU** is considered as 16.39 USD/MWh because of historical transmission fee cost to transport energy in the California Independent System Operator's (CAISO) control area.

For modality b and c, the LCOH could be calculated as:

Equation 6. Equation 6. LCOH as a function of the LCOE and the historical transmission cost fees.

$$\textbf{LCOH} = 0.052 * \textbf{LCOE} + 0.85 + 1.50$$

From the equations shown, 0.85 USD/kgH_2 is the cost added to the LCOH for interconnecting a project to the transmission line system that connects Mexico and EEUU.

From Equation 5 and Equation 6, it can be concluded that a dedicated transmission line to the transport renewable energy from Mexico to the United States to feed an electrolyzer, **would be economically feasible if the line were less than 1.3 km.** Otherwise, it is convenient to transmit electricity using theexisting infrastructure connecting both countries.

Interconnecting a renewable power plant to the Mexican SEN and using the cross-border transmission capacity would therefore be the most economically feasible scheme, assuming the cost of use of 16.39 USD/MWh. This allows to estimate that the cost component for transmitting electricity, which increases the LCOH approximately between 25% and 30%, depending on where the electrolyzer and the renewable resources are located.

As a conclusion, it can be said that the production of renewable energy in Mexico for its subsequent use in the United States is technically viable, especially if existing networks and existing regulations for such purposes are used. However, the additional costs of transmitting electrical power make it more competitive to produce power and hydrogen in the United States. Producing the renewable electricity in Mexico and consuming it in the USA, would incur in an increase of the green hydrogen costs of up to 30%. Such a scenario would only be desirable in the case that California would not have the area to deploy the renewable generation infrastructure, however it could also compromise California's transmission network, which is already overloaded.

[15] Legacy projects are power projects that are regulated by the old 'ley del servicio público de la energía eléctrica' LSPEE.

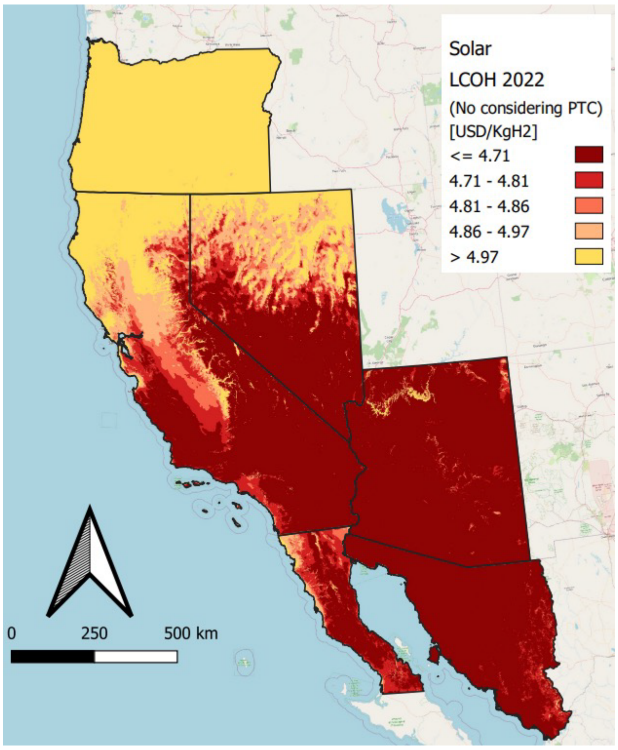
4 Cost comparison of exporting green hydrogen from Mexico to California vs locally produced hydrogen

A high-level estimation of LCOH's and transport cost from neighboring states (Arizona, Nevada, Oregon, Utah and/or other relevant states) was performed to evaluate the competitiveness of exports from north-western Mexico against them.

4.1 Competitiveness of green hydrogen from neighboring US states

Potential LCOH's in Oregon, Nevada and Arizona are compared using the same quintile's used to analyze California's resource to contrast the competitiveness of each one. As the next figure shows, the LCOH distribution from solar resources is comparable between California, Nevada and Arizona since Oregon does not have a good solar resource compared to the rest of the analyzed states.

Figure 73. LCOH – solar comparison in the U.S. states and Mexico – No considering PTC.

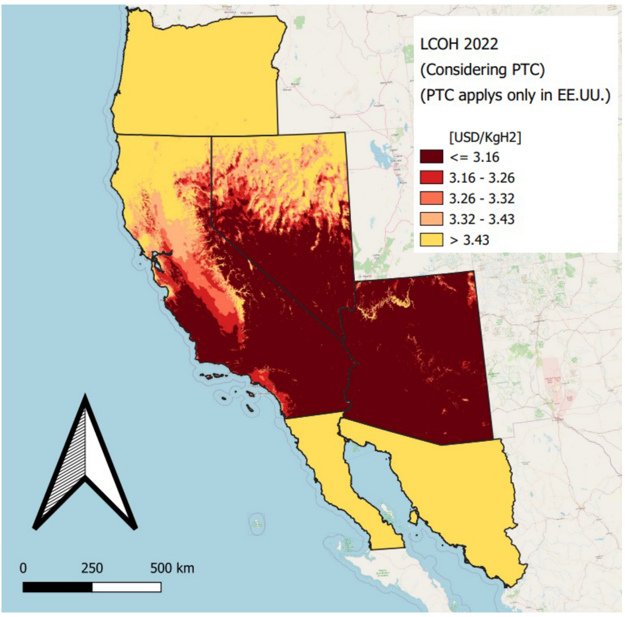


Note: Quintiles have been used in the rest of the state to facilitate comparison of resources.
Source: (Hinicio, 2022)

Baja California and Sonora's potential LCOH was evaluated using the same methodology to compare both countries. Sonora and Baja California could compete against California, Nevada and Arizona, before transport costs (exports/transport information is shown in section 4.3) and under equal conditions (not considering PTC), Mexico could produce competitive green hydrogen when considering LCOHs.

However, when IRA's incentives come into play, they make green hydrogen from neighboring US states more competitive. Using 2022 data the effects that this would have on cost competitiveness between the two countries is observed. As seen in Figure 76 the Mexican states shown would be displaced from the top quintile, as well as Oregon, with at least a difference of around 0.27USD/kg between the states with the best resources in the U.S. and Baja California and Sonora.

Figure 74. LCOH – solar comparison in the U.S. states and Mexico –Considering PTC in EE.UU. States.

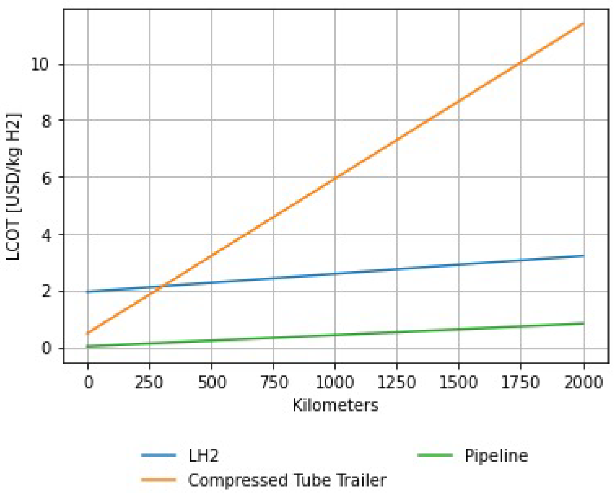


Note: California quintiles have been used in the rest of the state to facilitate comparison of resources.
Source: (Hinicio, 2022).

Analyses for 2035 and 2045 can be found in Annex 2, showing that the difference between the upper and lower quintile is reduced to 0.14 and 0.15 USD/kgH_2 respectively using the solar resource that is the most abundant resource in this region. Without PTC, Oregon is the only state neighboring California that would not be competitive in terms of its LCOH, while competitiveness of Mexican states occurs exclusively in conditions without PTC.

Wind resource powered electrolysis was also analyzed considering the PTC. In this case Oregon has the lowest LCOH's due to a better distribution of its wind resources, compared to the other U.S. states. In Mexico, Sonora has the best wind resource in the northwest of the state, with an LCOH between 2.70 and 4.27 USD/KgH_2, while Baja California has a few good wind sites close to the border.

Figure 75. LCOH – wind comparison in U.S. states and Mexico –Considering PTC.



Note: California quintiles have been used in the rest of the state to facilitate comparison of resources.
Source: (Hinicio, 2022).

It can be concluded that the PTC will create an advantage for the U.S., making it more competitive to produce electrolytic hydrogen in neighboring U.S. states than in Mexico to capitalize on the Californian market. Cost competitiveness could then accelerate the deployment of green hydrogen industry in California and its neighboring U.S. states.

While Baja California and Sonora currently do not have incentives for green hydrogen production, it is possible to obtain LCOH comparable to those in the U.S. It is expected that the PTC fosters a collaborative economy within the U.S. states, between those with greater and lesser demand for hydrogen, but not a potential export demand to Mexico, as long as Mexico has the capacity to develop its own infrastructure for the production, transmission, storage and distribution of green hydrogen.

4.2 Competitiveness and potential scale of Mexican hydrogen export

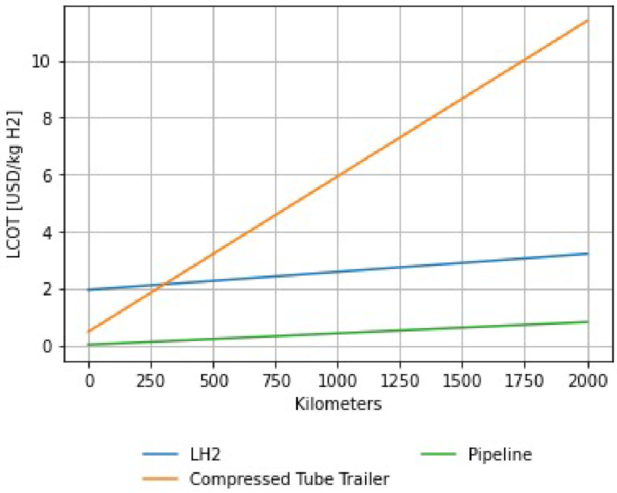
This section presents the most favorable scenario for the transportation cost of hydrogen considering pipelines, tube trailers, and liquid hydrogen trucks for the year 2045, assuming the maximum feasible transport capacity from Baja California, and excluding the PTC.

It is assumed that the hydrogen is produced in Baja California and transported exclusively by ground to its final destination. The maximum feasible transport capacity is assumed, and for 2045, the most favorable scenario is developed, considering the largest feasible electrolyzer scale, lowest technology costs, and the potential for using idle/stranded capacity in gas pipelines that may arise in the future. This means that the hydrogen transportation infrastructure must be capable of handling large volumes of hydrogen.

For pipelines, the cost depends on the length of the pipeline, construction and operational costs. For tube trailers, the cost depends on the number of trailers needed, the distance to the destination, and any associated costs. For liquid hydrogen trucks, the cost depends on the number of trucks needed, the distance to the destination, and any associated costs.

The most favorable case for the transportation of hydrogen in 2045 is the use of pipelines, this is mainly due to the low transportation cost and the fact that pipelines can handle large hydrogen volumes. The use of tube trailers and liquid hydrogen trucks is also technically possible, but their cost is relatively higher than pipelines when considering such high volumes. Liquid hydrogen trucks face challenges related to the evaporation of hydrogen, which can result in additional costs.

Figure 76. Comparison of transport options from Baja California in 2045 for a 1700 MW electrolizer



4.3 Share of California's green hydrogen demand that could be met by Mexican exports

As seen in sections 1.5.1.2 and 1.5.2, California's renewable resources are technically sufficient to meet any of the demand scenarios studied. However, the state can face possible setbacks that could incur the need to resort to energy resources in the states close to California, both in the U.S. and Mexico.

To analyze the import possibilities in greater detail and considering that the transportation sector would be the sector with both the largest demand as well as the highest willingness to pay in California, below are some tables where the costs of local production of electrolytic hydrogen in California are compared with the production costs of Mexican hydrogen, considering different modes of transportation. Since the costs of transporting hydrogen from Sonora and Chihuahua are not compensated by lower LCOH with respect to Baja California, only exports from this state were considered in this section. To build Table 20 and Table 21, the following facts were considered:

1. San Diego, Los Angeles, Riverside, San Francisco, San José and Sacramento were selected as demand locations.
2. Pipeline, LH_2 and Compressed H_2 were selected as transport means.
3. In Table 20, LCOT is calculated using the same referential point in Baja California (in the middle of the state) as shown in Figure 64.
4. In Table 21, LCOT is calculated using Manchón Blanco (north of Baja California) as referential point in Baja California. Manchón Blanco is a region in north of Baja California with great solar and wind resources. If hydrogen land transport will take place between EE.UU. and Mexico, it would be feasible to implement production plants there.
5. LCOH at the electrolyzer is defined as the lower LCOH available in Baja California.
6. No subsidies were considered by 2045 in California.

Table 20. LCOH comparison for California Vs. center of Baja California in 2045.

Region	Unit	LCOT	LCOH at electrolyzer output (In Baja California)	LCOH at point of delivery	
San Diego					
Distance	km	500			
LCOT Pipeline	USD/kg H_2	0.23	2.05	2.28	
LCOT LH_2	USD/kg H_2	2.27	2.05	4.32	Benchmark (USD/kgH_2) 2.25
LCOT Compress	USD/kg H_2	3.21	2.05	5.26	
Los Ángeles					
Distance	km	700			

LCOT Pipeline	USD/kg H_2	0.31	2.05	2.36	Benchmark (USD/kgH_2) 2.25
LCOT LH_2	USD/kg H_2	2.4	2.05	4.45	
LCOT Compress	USD/kg H_2	4.3	2.05	6.35	
Riverside					
Distance	km	660	2.05		
LCOT Pipeline	USD/kg H_2	0.29	2.05	2.34	Benchmark (USD/kgH_2) 2.25
LCOT LH_2	USD/kg H_2	2.37	2.05	4.42	
LCOT Compress	USD/kg H_2	4.08	2.05	6.13	
San Francisco					
Distance	km	1320	2.05		
LCOT Pipeline	USD/kg H_2	0.55	2.05	2.6	Benchmark (USD/kgH_2) 2.32
LCOT LH_2	USD/kg H_2	2.78	2.05	4.83	
LCOT Compress	USD/kg H_2	7.67	2.05	9.72	
San José					
Distance	km	1250	2.05		
LCOT Pipeline	USD/kg H_2	0.53	2.05	2.58	Benchmark (USD/kgH_2) 2.32
LCOT LH_2	USD/kg H_2	2.74	2.05	4.79	
LCOT Compress	USD/kg H_2	7.3	2.05	9.35	
Sacramento					
Distance	km	1320	2.05		
LCOT Pipeline	USD/kg H_2	0.55	2.05	2.6	Benchmark (USD/kgH_2) 2.37
LCOT LH_2	USD/kg H_2	2.78	2.05	4.83	
LCOT Compress	USD/kg H_2	7.67	2.05	9.72	

The results of the previous tables show that Mexican hydrogen produced in the middle of Baja California could hardly compete in most of the cities analyzed, which coincide precisely with the most important cities in the state of California with greater probability of absorbing the demand for sustainable transport in the period analyzed. The LCOH of hydrogen produced in the middle of Baja California could be up to 12% more expensive than the production close to the consumption centers in the state of California, which is why it was necessary to consider more favorable production conditions for Mexico where it could be considered in the north of the country, as it was done in Table 21.

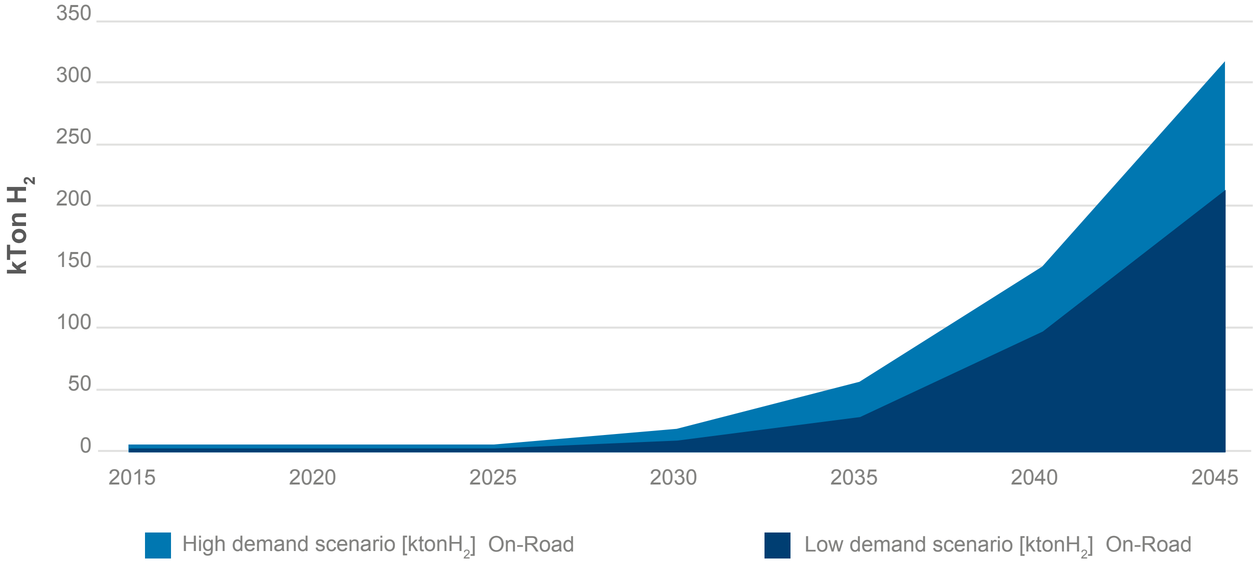
Table 21. LCOH comparison for the transport sector (California Vs. North of Baja California) in 2045.

Region	Unit	LCOT	LCOH at electrolyzer output (In Baja California)	LCOH at point of delivery	
San Diego					
Distance	km	100			
LCOT Pipeline	USD/kg H_2	0.07	2.05	2.12	Benchmark (USD/kgH_2) 2.25
LCOT LH_2	USD/kg H_2	2.01	2.05	4.06	
LCOT Compress	USD/kg H_2	1.03	2.05	3.08	
Los Ángeles					
Distance	km	170			
LCOT Pipeline	USD/kg H_2	0.09	2.05	2.14	Benchmark (USD/kgH_2) 2.25
LCOT LH_2	USD/kg H_2	2.06	2.05	4.10	
LCOT Compress	USD/kg H_2	1.41	2.05	3.46	
Riverside					
Distance	km	130			
LCOT Pipeline	USD/kg H_2	0.08	2.05	2.13	Benchmark (USD/kgH_2) 2.25
LCOT LH_2	USD/kg H_2	2.03	2.05	4.08	
LCOT Compress	USD/kg H_2	1.19	2.05	3.24	
San Francisco					
Distance	km	500			
LCOT Pipeline	USD/kg H_2	0.23	2.05	2.27	Benchmark (USD/kgH_2) 2.32
LCOT LH_2	USD/kg H_2	2.27	2.05	4.31	
LCOT Compress	USD/kg H_2	3.21	2.05	5.25	
San José					
Distance	km	460			
LCOT Pipeline	USD/kg H_2	0.21	2.05	2.26	Benchmark (USD/kgH_2) 2.32
LCOT LH_2	USD/kg H_2	2.24	2.05	4.29	
LCOT Compress	USD/kg H_2	2.99	2.05	5.04	
Sacramento					
Distance	km	500			
LCOT Pipeline	USD/kg H_2	0.23	2.05	2.27	Benchmark (USD/kgH_2) 2.37
LCOT LH_2	USD/kg H_2	2.27	2.05	4.31	
LCOT Compress	USD/kg H_2	3.21	2.05	5.25	

The results of Table 21 show that production centers closer to the Californian border, taking advantage of solar resources and pipeline transportation, are determining factors for the competitiveness of Mexican green hydrogen. Under these conditions, Mexican hydrogen could be up to 6% cheaper than local production in California, which is why it is possible to consider that part of the Californian market could be served by Mexican production.

The closer the production centers are, the lower the transportation costs would be and, consequently, the more competitive Mexican hydrogen would be. If the development of the infrastructure occurs under the considerations raised, it is expected that in the long-term Mexico will be able to address part of the demand for hydrogen in California, especially in the transportation sector, where it could supply a significant share. Figure 79 shows a high and low scenario for the Mexican exports to attend the hydrogen demand in the transport sector in California.

Figure 77. Exports scenarios from North of Mexico to California (selected cities) to be used in the transport sector.



In the event that California, for the different reasons discussed in this document, cannot develop its hydrogen production infrastructure to meet its own demand, Mexico would have opportunities to sell electrolytic hydrogen. Considering a scenario in which Mexico strategically establishes a value chain for hydrogen production, it can be considered that annually between 100 ktonH_2 and 350 ktonH_2 can be sold from Baja California to California by 2045.

5 Conclusions, opportunities and recommendations

California's commitment to carbon neutrality by 2045 requires major efforts to diversify its energy matrix, including an important role for green hydrogen in the transport, refining, industry, and power generation sectors. The base case analyzed is that demand for green hydrogen could reach about 940 kton per year by 2035 and 3 million tons per year by 2045. Based on the availability of land and both solar and wind resources, California should be able to generate enough renewable energy to power locally produced green hydrogen. However, many barriers – mainly linked to slow permitting procedures and resistance from local communities – could hamper the fast growth of the industry in the state, and California will likely continue to import power from neighboring states (on both sides of the border) and is planning to import hydrogen from neighboring U.S. states. Unless projects developed in Mexico become eligible for subsidies to compete with the IRA producer tax credits of 3 USD/kg, Mexico will not be able to compete directly with green hydrogen produced in the U.S. However, Mexico could export competitive renewable power from the northwestern states of Baja California, Sonora, and Chihuahua to power hydrogen production in California, where it would benefit from the IRA subsidies. Should IRA subsidies be capped or limited in any other way, Mexico could produce and transport competitive hydrogen near the US border, provided the distances are relatively short (under 500km), with high-volume pipeline transport being the most competitive, or tube trailers for smaller volumes.

Uncertainties remain as to what the different sectors are really willing to pay for green hydrogen once it becomes available. The current willingness to pay estimates are based on energy content, but it remains to be seen if end users are willing to make the switch, which requires important investments and barriers that go beyond the fuel price. The current lack of a transparent market and pricing add to this uncertainty.

5.1 U.S. hydrogen supply chain challenges and opportunities for Mexico

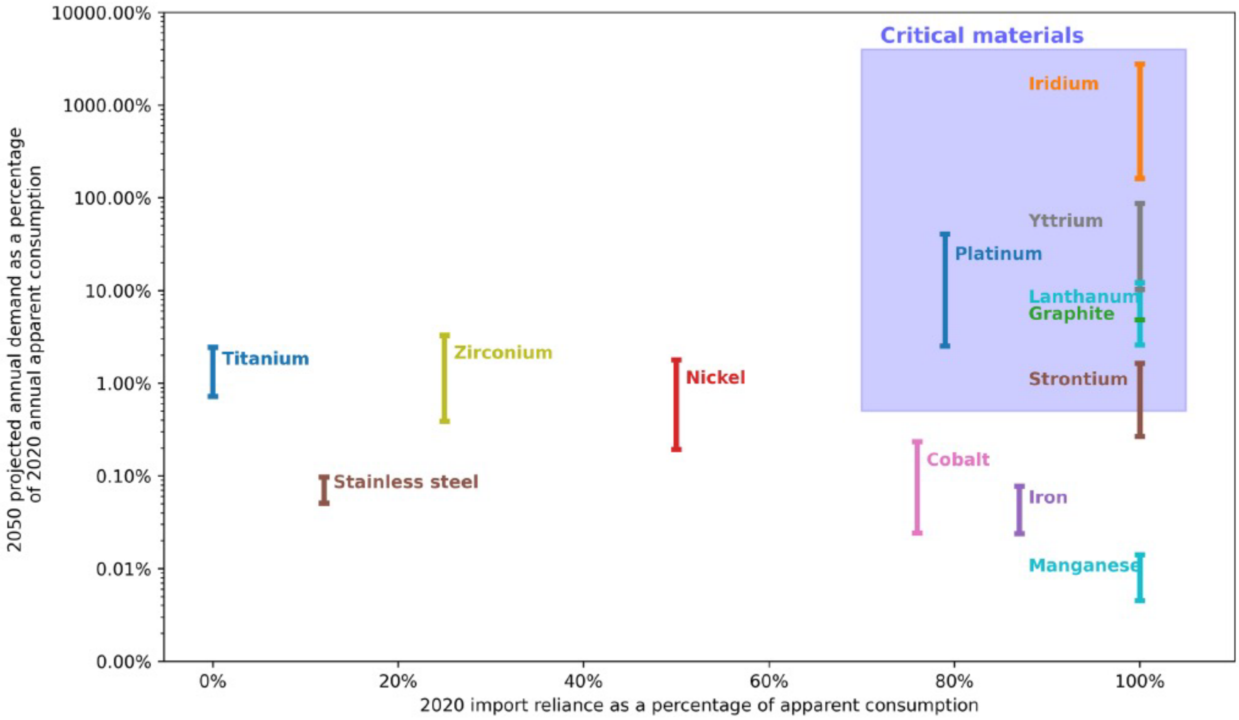
To meet the U.S. national objectives of around 100 Mton of renewable hydrogen by 2050, it is estimated that the electrolyzer capacity should grow from 0.17 GW today, to 1,000 GW by 2050 and the fuel cell capacity will need to grow to over 50 GW over the same period (USDOE, 2022a). This enormous growth comes with significant challenges for the United States related to raw material availability; manufacturing capacity; dependence on foreign supplies; worker training; global trade practices; research and data analysis. Consulted experts signalled existing and likely future bottlenecks in the availability of certain components in many areas, ranging from hydrogen refuelling stations to transformers.

In response to Executive Order 14017, "America's Supply Chains," the DOE produced a report titled 'America's Strategy to Secure the Supply Chain for a Robust Clean Energy Transition' (USDOE, 2022b), accompanied by several issue-specific deep dive assessments, including one on Water Electrolyzers and Fuel Cells Supply Chain (US DOE, 2022a) as well as electric grid (including transformers), energy storage, solar photovoltaic and wind, which are all relevant to the deployment of green hydrogen technologies. In the report on electrolyzers and fuel cells (US DOE, 2022a), the authors identified several weaknesses in the US supply chain for these technologies:

- The U.S. manufacturing capacity may not be sufficient to meet growing demand;
- High reliance on imports of key materials especially platinum, iridium, and graphite;
- High manufacturing cost for fuel cell/ electrolyzer components and lack of high-throughput assembly processes;
- Strong competition from Chinese and European markets.

Regarding to future **materials** demand and availability in the U.S., the same report identifies the most critical materials – i.e., materials whose demand is projected to increase, and which are currently imported into the United States at high percentages – to be Iridium, Yttrium, Platinum, Lanthanum, Graphite and Strontium.

Figure 78. Projected material demand as a percentage of annual U.S. consumption and U.S. import reliance for key fuel cell and electrolyzer materials.



Source: (US DOE, 2022a)

Mexico is a major producer of **Strontium** (together with Spain) (USGS, 2013) and a potential producer of platinum (UNAM, 2013) and other **rare earth elements** (Mineriaenlinea, 2023).

Moreover, the subsidies provided by the IRA (producer tax credit and investment tax credits – PTC and ITC) require a minimum percentage of components to be domestic content, that begins from 45% for projects that start construction before 2025 and increases to 55% for projects starting after 2027. This leaves significant room for imported components, including those manufactured in Mexico. For IRA subsidies on the purchase of electric and fuel cell vehicles (Clean Vehicle Credit of $7,500 per vehicle), the vehicle must meet standards for North American assembly, **which includes construction in Mexico**.

Mexico is well positioned to **benefit from the nearshoring**[16] trend that has started in the last couple of years and will likely continue. The Interamerican Development Bank (IADB, 2022) identified 'quick wins' in additional exports of goods from Mexico to the U.S. of around 30 billion USD in the coming years as part of this nearshoring trend and the recent announcement of Tesla's 1 billion dollar investment in a 'megafactory' in Nuevo Leon (that could reach 10 billion USD over the next 10 years) is another example of how nearshoring can benefit Mexican industry (Porras, 2023).

There will however also be **strong competition** from other countries to get a share from the large IRA subsidies, in particular from China, which is already a leader in renewable energy and electrolyzer fabrication. Besides China, the European Union has recently announced policy that competes with the

[16] Nearshoring is a recent trend that aims to mitigate the risks induced by the opposite trend of offshoring (that started in the 60s and 70s) by bringing back manufacturing capacity closer to the demand centers, thereby reducing supply chain risks that were made evident during the COVID-19 pandemic.

IRA for hydrogen technology, but also aims to help European companies to compete in the U.S. market.

Another risk for Mexico is the possibility that the U.S. could implement a **carbon border tax**. The EU has already implemented such a protectionist measure through its Carbon Border Adjustment Mechanism which covers imports of hydrogen (Euractiv, 2023).

5.2 Opportunities for Cooperation

Most of the consulted experts agree that cooperation between Mexico and California (or with the U.S. in general) would be beneficial for addressing challenges in the supply chain, including in aligning needs and capabilities of the industrial base, in training a qualified workforce and in sharing (policy) experience.

The U.S. Department of Energy (USDOE, 2022b) recommends "establishing and funding an initiative for expanding clean technology manufacturing capacity globally to achieve the dramatic scale-up in manufacturing of key climate and clean energy equipment associated with meeting net-zero commitments.". It went on to recommend the following specific actions:

- Leverage bilateral and multilateral energy dialogues to promote the expansion of like-minded sourcing and manufacturing capacity;
- The creation of research partnerships between labs and foreign academic institutions in support of a net zero manufacturing accelerator network;
- The development of relevant workforce capacity;
- The formation of multi-party pilot projects to demonstrate and move toward deployment of carbon neutral clean technology sourcing and manufacturing capacity and;
- The expansion of technical assistance in partner countries to facilitate development of clean technology supply chain and manufacturing capacity.

Stanford University will lead a large project funded by a DOE grant, that includes a component of analyzing **cross-border electricity exchange** with Mexico. It will be worthwhile for Mexican renewable energy sector to keep abreast of this project and its findings, as there are likely opportunities for exporting renewable power to California.

In May 2023, during the launch of the North American Ministerial Committee on Economic Competitiveness (NAMCEC), the leaders of the three North American countries declared their commitment to "deepen [their] economic cooperation, create the quality jobs of the future, promote investment, spur innovation, and strengthen the resilience of [their] economies". The objectives of NAMCEC are to "align efforts at the cabinet-level to strengthen regional competitiveness and productivity in industries of the future including semiconductors, **clean energy, critical minerals,** biomanufacturing, and information and communications technology". To advance these opportunities, the United States, Mexico, and Canada committed to "establish biannual dialogues among officials" in order to "enhance North America's status as a trusted supplier of semiconductor technologies while cultivating domestic expertise and supporting the transition to both a digital and green global economy (White House - NAMCEC, 2023)

Mexico could benefit from joining the **International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE)**. This organization was created by the U.S. Department of Energy and the U.S. Department of Transportation in 2003 to foster **international cooperation** through **working groups** on hydrogen and fuel cell R&D, common codes and standards, and information sharing on infrastructure development. Each of its 23 member countries and the European Commission has committed to accelerate the development of hydrogen and fuel cell technologies to enhance the security and efficiency of their energy systems, to help address environmental objectives, and to grow the economy. If and when Mexico makes such commitments on a national level, it should be able to join this organization and benefit from knowledge, expertise and cooperation facilitated by the platform.

Though this has not been studied in detail yet, Mexico's geology (salt caverns) could provide storage capacity for hydrogen that could be used in the U.S.

5.3 Funding opportunities for cooperation and participating in the U.S. hydrogen supply chain

To address some of the challenges mentioned above, several U.S. programs exist that could be of relevance to Mexican players:

The DOE Loan Program's Office (LPO) title XVII and Advanced Technology Vehicles Manufacturing (ATVM) programs support various clean energy industry products and components in renewable energy sectors, including clean hydrogen and storage, and in advanced technology vehicle supply chains, including batteries, electric motors, and their respective components.

The Export Import Bank of the United States (EXIM) and the Development Finance Corporation (DFC) both support eligible companies to invest in securing American supply chains abroad. EXIM is launching a new Office of Global Finance Development to enhance its business development capabilities and engage U.S. firms capable of expanding exports of transformational products.

The Build Back Better World (B3W) initiative, launched in 2021 by G7 countries, supports projects that simultaneously advance energy supply chain resiliency and B3W's principles for quality and sustainable infrastructure.

Furthermore, in its Strategy to Secure the Supply Chain for a Robust Clean Energy Transition (US-DOE, 2022b) the DOE made some recommendations for executive actions, that could be relevant for Mexico:

- "Increase Federal government financial support to eligible U.S. companies investing in or exporting to foreign countries to secure supply chain inputs that fill challenging domestic gaps and support growth of other domestic segments of the supply chain.
- "Establish and fund an initiative for expanding clean technology manufacturing capacity globally to achieve the dramatic scale-up in manufacturing of key climate and clean energy equipment associated with meeting net-zero commitments."
- "Accelerate and expand financing and project development tools and incentives to assist eligible companies investing in resource-rich countries"
- "Prioritize support for materials mining and processing projects, with a particular focus on projects that feed growth of other supply chain segments in the United States that currently have unmet demand for inputs that cannot be met through domestic avenues at scale or at sufficient pace as identified by DOE supply chain analyses."

5.4 Funding Opportunities for green hydrogen in Mexico

The **International Hydrogen Ramp-Up Program (H_2-Uppp)** accompanies and supports the booming green hydrogen (H_2) market and power-to-X (PtX) applications in selected developing and emerging countries, of which Mexico is one. Unlike other hydrogen-related promotion initiatives, H_2-Uppp aims at the development of early-stage green hydrogen projects. The program is commissioned by the German Federal Ministry of Economics and Climate Protection.

https://www.giz.de/en/worldwide/107567.html

The program can also be helpful in applying for funding under the Developpp program from the German Federal Ministry of Economic Cooperation and Development.

Annex 1: Techno-economic assumptions and data

Assumptions are divided by technology block (renewable resource, hydrogen production and energy transport) and general assumptions for the project evaluation.

General Assumptions

Except where specified, the general assumptions to evaluate projects at different places will be used.

General assumptions reflect the project economic evaluation and are presented in Table -1 for California and Table -2 for Mexico. The techno-economic evaluation will be performed in nominal terms and only focus on costs (i.e., not analyzing any sales or market price).

Table I. General assumptions for California

Parameter	Unit	Value
Evaluation	-	Nominal terms
Inflation	%/year	2%
Discount rate	%	12%
Project lifetime	years	30

Table II. General assumptions for Mexico

Parameter	Unit	Value
Evaluation	-	Nominal terms
Inflation	%/year	4%
Discount rate	%	10%
Project lifetime	years	30

USA Tax Credit

During August 2022, the United States of America published several benefits in the form of Production Tax Credits (PTC) and Investment Tax Credits (ITC) for green hydrogen production that is produced projects located and paying taxes in the USA, as part of the Inflation Reduction Act (IRA). These subsidies can significantly reduce production costs of green hydrogen in California, but some are conditional on several requirements being met. We will take them into account through the scenarios shown below, in their comparison with green hydrogen exported from Mexico.

Table III. USA Production Tax Credits

	Scenario		
Parameter	Conservative	Base case	Aggressive
Hydrogen tax credit (PTC) USD/kgH_2	0	3	3.6
RE before 2033 tax credit (RE PTC) USD/MWh	0	26	32
RE 2034 tax credit (RE PTC) USD/MWh	0	20	24
RE 2035 tax credit (RE PTC) USD/MWh	0	13	15
RE 2036 and after-tax credit (RE PTC) USD/MWh	0	0	0

Note that the PTC for both hydrogen and Renewable Energy is only valid during the first 10 years after construction. In case of Renewable PTC, the subsidy begins to decrease if the construction starts after 2033 and reaches 0 USD/MWh when construction starts after 2036 (according to the Summary of Investment Tax Credit (ITC) and Production Tax Credit (PTC) Values Over Time – USA Department of Energy (DOE)).

Renewable Energy Assumptions

Renewable energy technology will focus on Solar photovoltaic (PV) and Wind turbines (Wind) to supply electricity to the electrolyzer. The economic data for both technologies are listed in the Table . The cost projection is according to the year of purchasing the equipment and all costs are expressed in terms of real 2022 USD.

Cost reductions in the future are reflected in lower CAPEX (USD per installed capacity), which include owner costs, and OPEX (operation and maintenance cost and indirect costs). Due to their commercial availability and proven track record, the contingency for both technologies is low, at 3% of CAPEX.

For wind turbines, the values were obtained from NREL's Annual Technology Baseline (ATB) for 2022, which provides the projected costs of the technology. For the solar photovoltaic resource, we calculated from the capital cost decrease projections, using as reference the initial value that NREL considers for 2020.

Table IV. Renewable energy economics

	Solar PV			Wind		
Parameter/Year	2022	2035	2045	2022	2035	2045
System CAPEX [USD/kW]	890	481	436	1360	908	813
System yearly OPEX [% of Capex]	2%	2%	2%	3%	3%	3%
Contingency [% of CAPEX]	3%	3%	3%	3%	3%	3%

The technical information (such as hourly generation and yearly plant factors) is extracted from public databases and tools such as Renewables Ninja[17].

To reflect the uncertainties of the forecasted CAPEX for renewable technologies, **sensitivities** regarding this parameter will be considered. In particular, the CAPEX will be adjusted **between -20% to +20%** from the default assumption.

Hydrogen production

The electrolyzer is the plant that converts electricity from any kind to hydrogen. Its cost is described by a specific CAPEX, expressed in USD per installed kW of electrical power and yearly OPEX is assumed proportional to this cost. Largescale electrolyzer projects (100 MW scale) are still under development and therefore the uncertainty regarding this technology is higher than renewable energy. This leads to considering a Contingency of 20% for the first years and 10% from 2045. The efficiency of electrolyzers is also expected to increase, consuming less electricity to produce the same amount of hydrogen for newer models. Based on current market trends and technological developments, we are choosing alkaline electrolyzer technology, for its flexibility and cost profile. The current cost of these electrolyzers is assumed to be around 650 USD/kWe, according to public data (Global Hydrogen Review 2022 – IEA September 2022) and Hinicio private projects database. These costs are for USA and LatAm markets (Asian markets can be quite different, but not relevant here). The annual cost reduction is assumed to be 5 % until 2030, 2 % between 2030 and 2040, and 1% after 2040, considering the maturity of the market.

[17] Renewables.ninja, a free access hourly power output simulation tool for wind and solar PV developed by researchers from ETH Zurich and Imperial College London.

Table V. Electrolyzer economics

Parameter	2022	2035	2045
System CAPEX [USD/kWe]	650	390	350
Efficiency [kWh/KgH_2]	52	50	49
System yearly OPEX [% of Capex]	3%	3%	3%
Contingency [% of CAPEX]	20%	15%	10%

The cost reduction is adjusted to 10% until 2030, 3% from 2030 up to 2040 and 2% after 2040, to reflect the more optimistic 'Net Zero scenario' from the IEA. We consider electrolyzer efficiency to vary with -5% to +5% from the base case.

Ammonia Production

A basic calculation of the levelized cost of ammonia (LCOA) was carried out in the study, as part of the exploration of hydrogen export through shipping.

The LCOA calculated is composed of ammonia production CAPEX and OPEX, levelized cost of hydrogen (LCOH) and levelized cost of energy (LCOE). The ammonia production and LCOE values come for the internal Hinicio project database, while the LCOH was taken from the calculations carried out in this study.

The following table presents the parameters taken into account, as well as the values utilized in the calculation of the LCOA.

Table VI. Parameters used for LCOA calculation

Parameter	Value	Unit
NH_3 production CAPEX	**124**	**USD/tNH_3**
NH_3 production OPEX	**21.4**	**USD/tNH_3**
	2.02	USD/kgH_2
LCOH	**21.4**	**USD/tNH_3**
	16.39	USD/MWh
LCOE	**432.95**	**USD/tNH_3**

Electricity

To compare the costs of green hydrogen produced and delivered to the different regions, we consider transport of energy in the form of electricity as well as hydrogen from the production area to its destination. Considering that both areas will be accessible by land, and are reasonably close, only land transport will be considered.

Electricity will be assumed to be transported by high-voltage transmission lines, to allow for renewable energy from Mexico to be consumed by electrolyzers in the USA. For the transport of hydrogen, we assume transport in liquid state via trucks and in the gaseous state via trucks and pipelines.

To avoid using the public electricity grid, we assume electricity from Mexico will be transported using a private dedicated transmission line, up to the substation that either connects either to the SIN (Main Mexican grid) or directly to CAISO US power grid. To allow the use of this electricity at the destination, an additional substation must be considered. Equipment (transmission line and substation) cost have been analyzed from the published cost of equipment of the Chilean electrical grid.[18]

[18] https://infotecnica.coordinador.cl/

Table VII. Electrical transmission economics

Parameter	Value
System CAPEX [kUSD/km/MVA]	0.5
Voltage [kV]	230
System yearly OPEX [% of Capex]	2%

Table VIII. Electrical substation economics

Parameter	Value
System CAPEX [USD/ kVA]	50
Voltage [kV]	230
System yearly OPEX [% of Capex]	2%

Transportation costs

Cost of transportation is calculated for the base flow of a 100 MW electrolyzer as well as for an increased capacity from 200 MW and up to 1 GW of electrolyzer.

Hydrogen Pipeline

The pipeline transportation and conditioning system is sized for transporting the production of at least a 100 MW electrolyzer. After obtaining the diameter, the corresponding capex value, which does not include Right-of-Way were obtained from the "DOE Technical Targets for Hydrogen Delivery" and using the estimations for the year 2020 target of 695 kUSD/mile. The compressor was based on the methodology proposed in "The Techno-Economics of Hydrogen Compression" the first step was to size the compressor for hydrogen production from a 100 MW electrolyzer and then used the formulas; TIC = UC*IF, 3,083.3* kW^SF, where Scale Factor (SF) = 0.8335; IF = 2.0. it should be noted that the result is given in Canadian dollars and the exchange rate of 0.73 US$/C870S$ was used.

For both cases, constant investment values were used, since these are mature technologies.

Table IX. Pipeline economics

Parameter	Value
System CAPEX [MUSD/km]	0.44
Nominal diameter [in]	8
System yearly OPEX [% of Capex]	1
Delivery pressure [barg]	30
Linepacking pressure [barg]	100

Source: DOE Technical Targets for Hydrogen Delivery, NA.

Table X. Compressor economics

Parameter	Value
Compressor efficiency [%]	0.9
Isentropic efficiency [%]	0.7

Parameter	Value
Compressor capacity [kW]	1400
Capex Compressor [kUSD]	1.9
System yearly OPEX [% of Capex]	5%

Source: Transition Accelerator - The Techno-Economics of Hydrogen Compression, 2021.

Liquid Hydrogen

For exporting hydrogen in liquid form, the process requires a liquefaction plant at the Electrolyzer site to perform this conversion. Then, additional liquid hydrogen storage and a regasification facility are also needed at the destination to regasify the liquid hydrogen back to its gaseous form.

Table XI. Liquefaction Plant

Parameter	Value 2025	Value 2030	Value 2035
System CAPEX [USD/ kg H_2/hr]	60,480	47,964	42,600
System yearly OPEX [% of Capex]	2%	2%	2%
Elec. Consump [kWh/ kg H_2]	13	13	13

Table XII. LH_2 Storage

Parameter	Value
System CAPEX [USD/ton LH_2]	152,000
System yearly OPEX [% of Capex]	3%
Dissipation rate	0,03

Table XIII. Regasification

Parameter	Value
System CAPEX [USD/kg H_2/hr]	1,140
System yearly OPEX [% of Capex]	0.04
Energy consumption [kWh/kg H_2]	0.6

Source: HINICIO´s estimation based on: 1. BNEF: Hydrogen Economy Outlook the Economics of transport & Delivery, 2020.

Truck Transport

For short distances, it is usual for hydrogen to be distributed with trucks, as most hydrogen is transported today. In order to calculate the cost of transportation by this means, it is necessary to know the TCO (Total Cost of Ownership), a metric that represents both CAPEX and OPEX in a transportation system throughout its useful life. The TCO together with the characteristics of the tube trailers will allow calculating the cost of ground transportation of hydrogen.

The project size and the transporting distance are the main parameters to consider in assessing hydrogen transport costs – IRENA

Table XIV. Truck transport data

Parameter	Value
System CAPEX [USD/kg H_2/hr]	706,160
OPEX Maintenance [USD/year]	20,132
OPEX Tires [USD]	4,620
OPEX Labor [USD]	147,200
Capacity [KgH_2]	728
Pressure [Bar]	350

Source: HINICIO´s estimation based on: **1.** BNEF: Hydrogen Economy Outlook the Economics of transport & Delivery, 2020. **2.** Study on the potential for implementation of hydrogen technologies and their utilization in the Energy Community,2021. **3.** Hydrogen supply and transportation using liquid organic hydrogen carriers (HYSTOC), 2018. **4.** Introduction to the Hydrogen Market in California, 2020.

Ammonia Shipping

Ammonia shipping costs were collected from the IEA report "The Role of Low-Carbon Fuels in the Clean Energy Transitions of the Power Sector" (2022). The values utilized were for ammonia shipping for short distances (less than 10,000 km), which vary between 40 and 60 USD/tNH_3. For the calculations, the value of 40 USD/tNH_3 was utilized, considering that the distance between any port in northwestern Mexico and the port of Los Angeles is less than 3,000 km.

Annex 2: Other calculations and deep dive

LCOH Calculation

In order to determine the competitiveness of green hydrogen in different economic sectors where it is can be used, it is necessary to determine the moment in which hydrogen achieves cost parity regarding to fuels it aims to replace, such as diesel, gasoline, natural gas, among others. Therefore, the LCOH is calculated, which is equivalent to LCOE, but for the production of H_2.

The LCOH takes into account the CAPEX and OPEX throughout the life cycle of a project for the hydrogen production, discounted to its net present value.

The LCOH calculation has three main components: Cost of Electricity (LCOE), Cost of Operation (OPEX), and Investment Costs (CAPEX). For this reason, the methodology to find the parity of hydrogen costs regarding to traditional energy source used in each industry starts from determining these three components (see Equation 1).

Renewable energy technology will focus on Solar photovoltaic (PV) and Wind turbines (Wind) to supply electricity to the electrolyzer. The economic data for both technologies are listed in Annex 2. Cost projections are aligned with the year that the equipment is purchased, and all costs are expressed in terms of real 2022 USD.

Cost reductions in the future are reflected in lower CAPEX (USD per installed capacity), which include owner costs, and OPEX (operation and maintenance and other indirect costs). Due to their commercial availability and proven track record, the contingency for both technologies is low, at 3% of CAPEX.

For wind turbines, the values were obtained from NREL's Annual Technology Baseline (ATB) for 2022, which provides the projected costs of the technology. For the solar photovoltaic resource, the capital cost decrease projections were calculated using the initial value that NREL considers for 2020 as reference.

$$LCOH_{USD/kg} = \frac{\sum_0^t \frac{CAPEX_t + OPEX_t}{(1+r)^t}}{\sum_0^t \frac{KgH_{2t}}{(1+r)^t}}$$

Where:
CAPEX: Capital expenditures including incidental expenses.
OPEX: Operational expenditure (Energy, Water).
t: Years of operation.
r: Discount rate.
KgH2: Produces hydrogen annually.

Methodology

The methodology used for the calculation of the LCOH in the different parts of California consists of two parts:

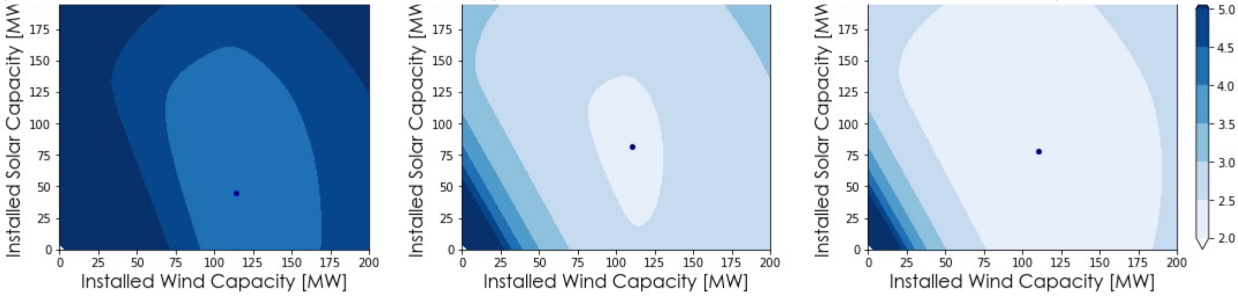
The first one, is to determine the LCOE form historical hourly data of solar and wind resources from "Renewables Ninja[19]", with a production profile constructed for a typical meteorological year (TMY). Then, a mixed production plant is sized to supply energy to a 100 MW electrolyzer that generates hydrogen with an efficiency for each period listed in the Assumption Book. If for a given hour there is an excess of energy, this energy is discharged.

This process includes an iterative calculation considering a capacity for each technology between 0 and 200 MW. Then the plants are optimized to minimize the Levelized cost of Hydrogen and, therefore, for each location, we obtained an LCOH with the size of the corresponding solar and wind farm that

[19] Renewables Ninja is a web tool developed by Imperial College London and ETH Zürich that shows the estimated amount of energy that could be generated by wind or solar farms at any location in the world. It is available at the website https://www.renewables.ninja/

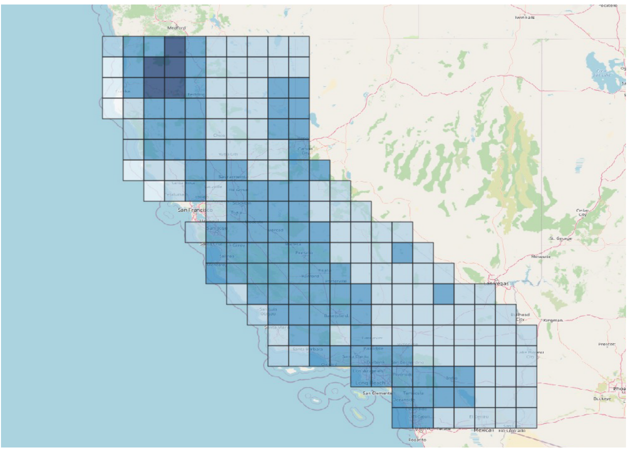
minimized costs. To accomplish this, each mix is characterized by its CAPEX and OPEX depending on the installed capacity and date from the Assumption Book for the three periods: 2022, 2035 and 2045. Figure illustrates, for a particular geographic coordinate, the behavior of the LCOH as a function of the energy mix and how the cost of production is decreasing over the years due to the lower cost of technology. In each heatmap a blue dot indicates which energy mix minimizes the LCOH.

Figure 79. LCOH as a function of the energy mix in 2022 (left), 2035 (middle) and 2045 (right).



The same sizing process is performed throughout the state of California, with 50 kilometers between points, because the Renewable Ninja tool utilized is limited to the geographic granularity of measurements it can deliver. This works to determine which zones are most attractive from a cost-effective point of view. Figure shows the minimum value in each zone for 2022.

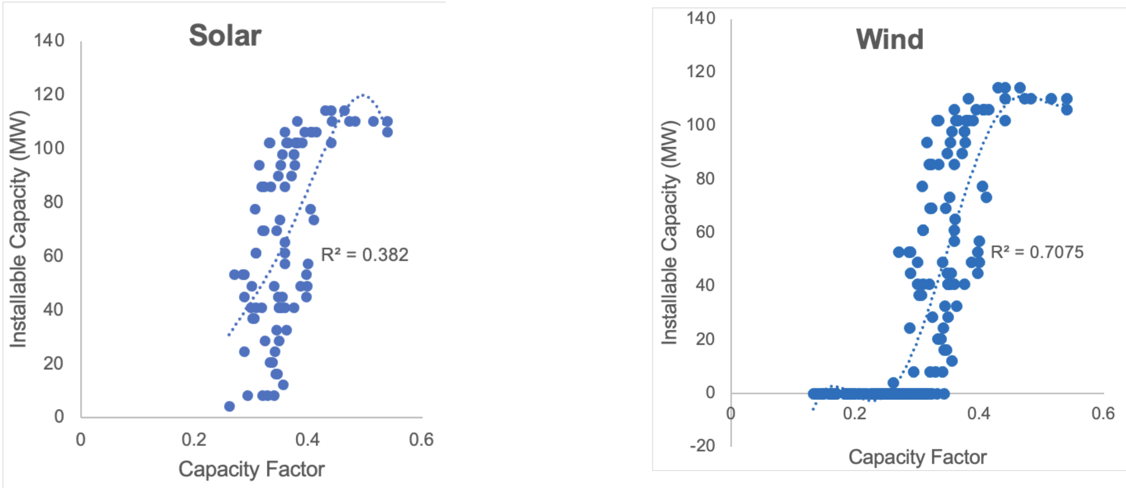
Figure 80. Minimum LCOH in a 50 km grid in California in 2022.



The second part consists in determining the LCOH for a higher granularity, since the previous methodology is limited to the size of the renewable resource samples of the Renewable Ninja resource. For more detailed geographic information, the annual average capacity factor is used, which is available with more sensitivity, but it omits the hourly variations generated. Therefore, the size of power generation plants tends to be underestimated. To fix that, we use the relationship that exists in the state between the capacity factors and the size of the plants.

It was found that the wind factor has a higher weighting in the final result of the energy mix than the solar factor, i.e. that when faced with a high wind resource and a high solar resource, the model prioritizes a higher wind capacity. This can be seen in Figure , where the relationships between capacity factor and installable capacity are shown. Thus, the first part consists of obtaining the installable wind power capacity as a function of the wind factor.

Figure 81. Relation between capacity factor and installed capacity for solar and wind energy.

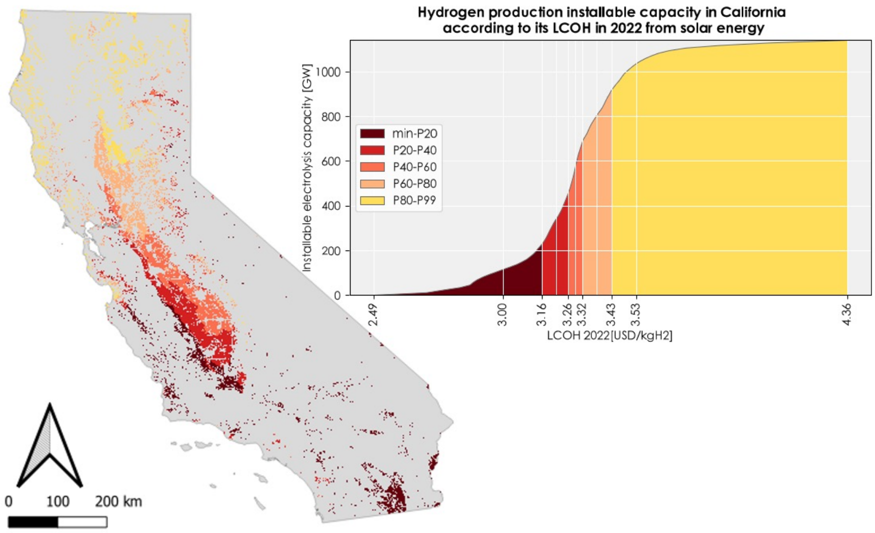


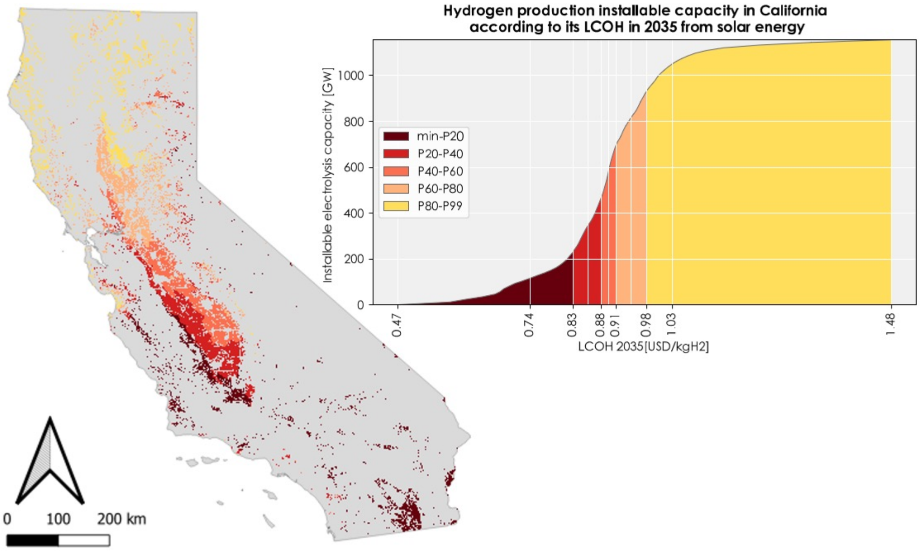
Source:Hinicio

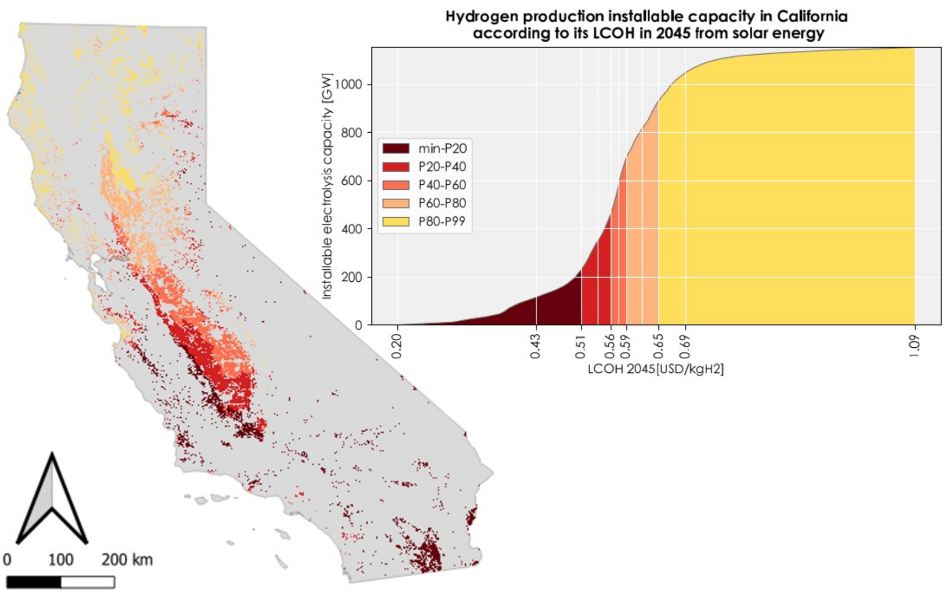
Since the calculation was made considering a fixed electrolyzer size of 100 MW, it is natural that a higher installed capacity of one renewable source limits the other. This can be seen in Figure . In the same way as before, a regression was obtained between the ratio of wind and solar installed capacity, so that after having obtained the wind capacity, this formula is used to calculate the solar installed capacity as well.

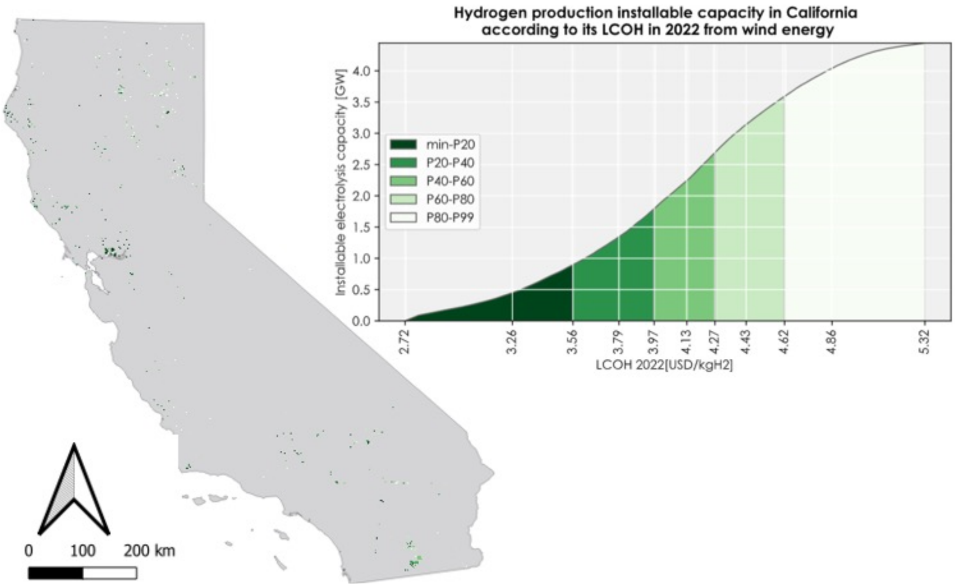
Figure 82. Relation between installed capacity of solar and wind energy, considering a fixed electrolyzer size of 100 MW.

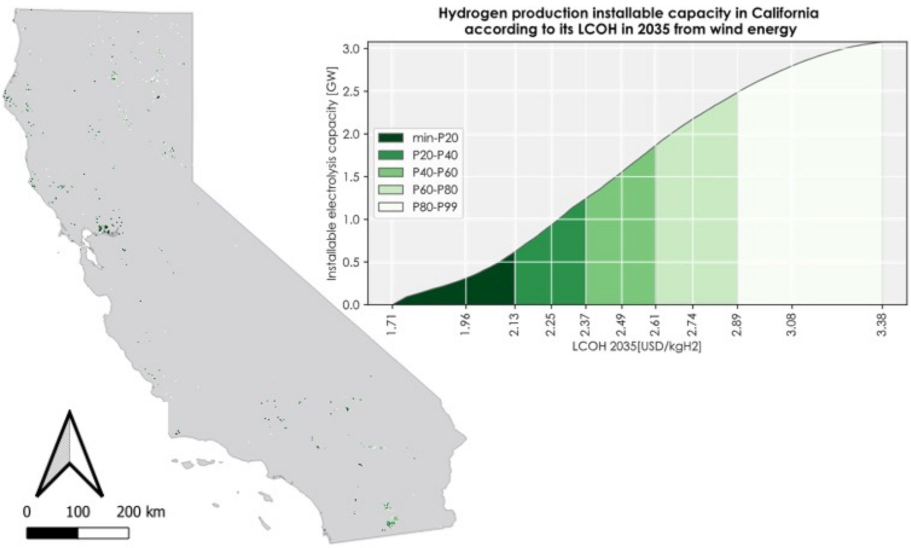
LCOH Results (not considering PTC)

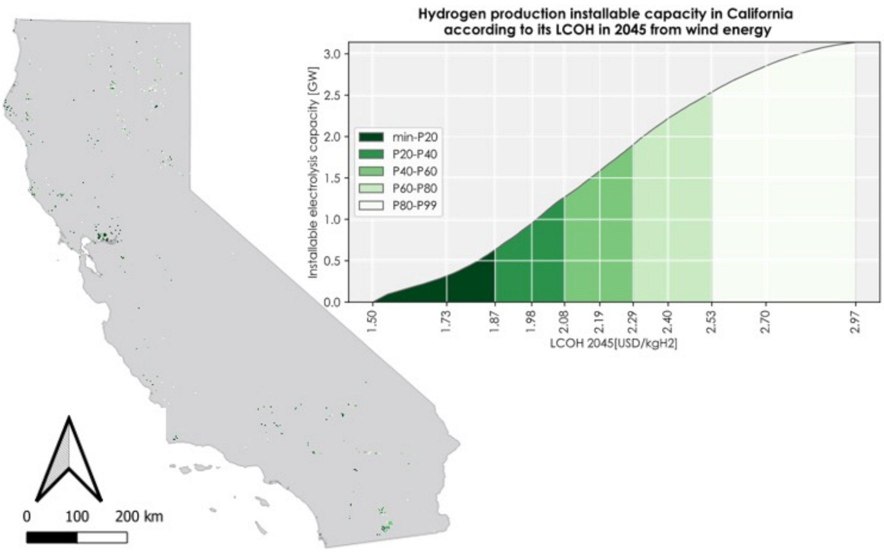




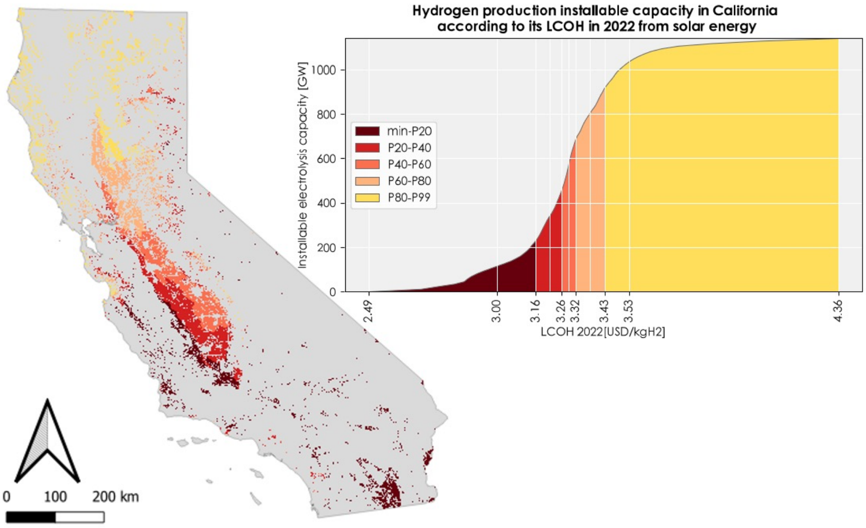


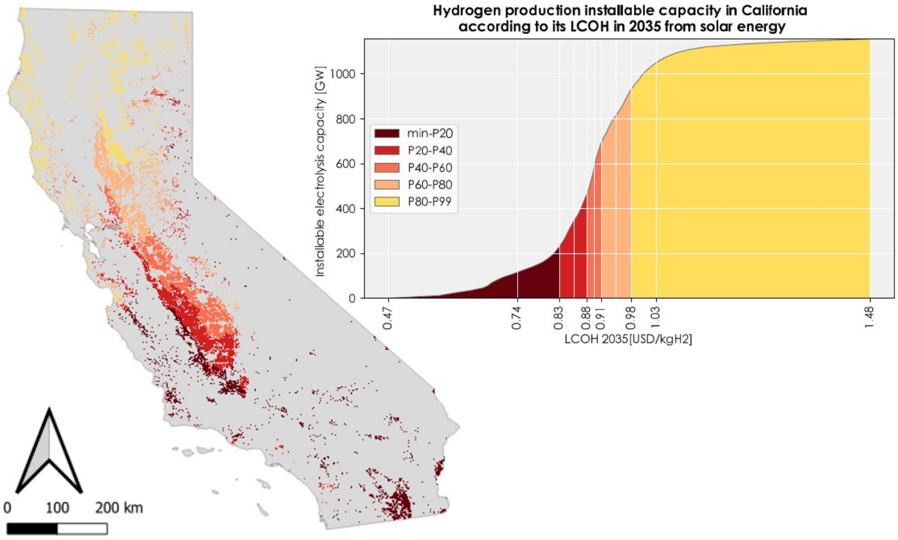

Hydrogen production installable capacity in California
according to its LCOH in 2022 from wind energy
Installable electrolysis capacity [GW]
min-P20
P20-P40
P40-P60
P60-P80
P80-P99
2.72
3.26
3.56
3.79
3.97
4.13
4.27
4.43
4.62
4.86
5.32
LCOH 2022[USD/kgH2]
0
100
200 km

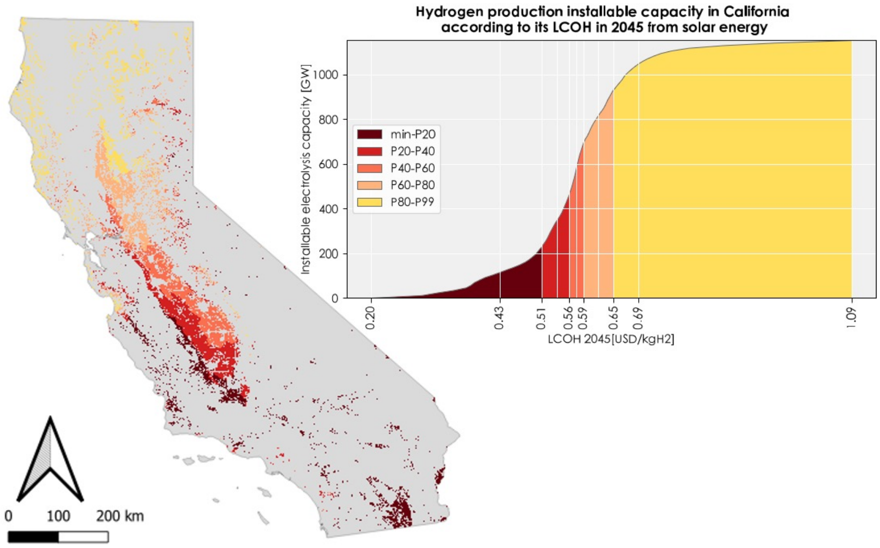

Hydrogen production installable capacity in California
according to its LCOH in 2035 from wind energy
Installable electrolysis capacity [GW]
min-P20
P20-P40
P40-P60
P60-P80
P80-P99
1.71
1.96
2.13
2.25
2.37
2.49
2.61
2.74
2.89
3.08
3.38
LCOH 2035[USD/kgH2]
0
100
200 km

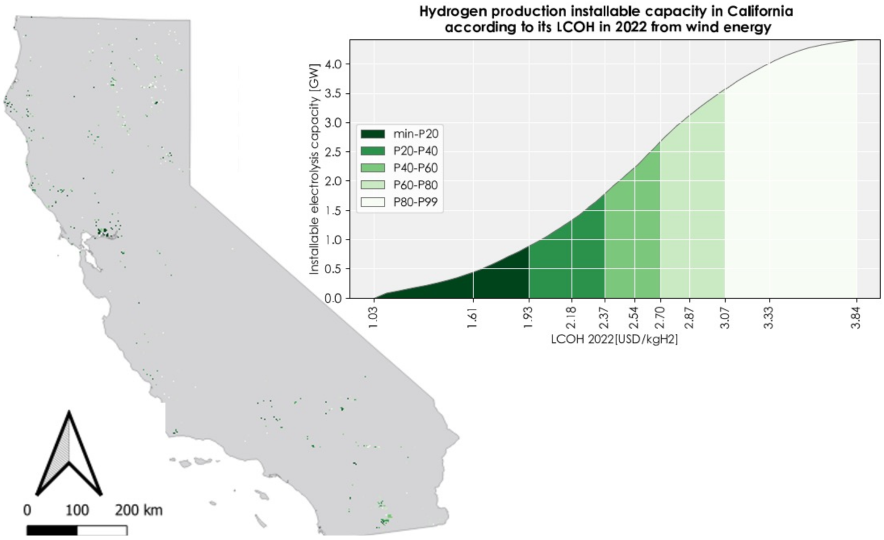

Hydrogen production installable capacity in California
according to its LCOH in 2045 from wind energy
Installable electrolysis capacity [GW]
min-P20
P20-P40
P40-P60
P60-P80
P80-P99
1.50
1.73
1.87
1.98
2.08
2.19
2.29
2.40
2.53
2.70
2.97
LCOH 2045[USD/kgH2]
0
100
200 km

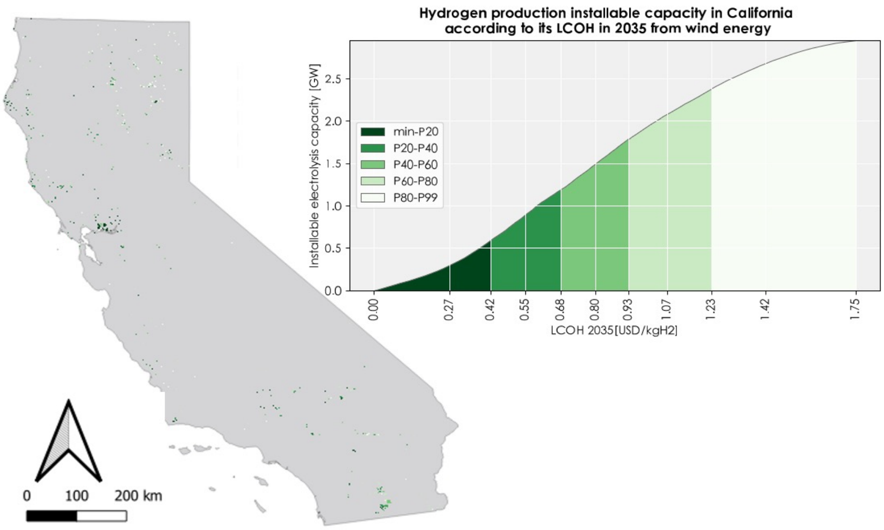
LCOH Results (considering PTC)

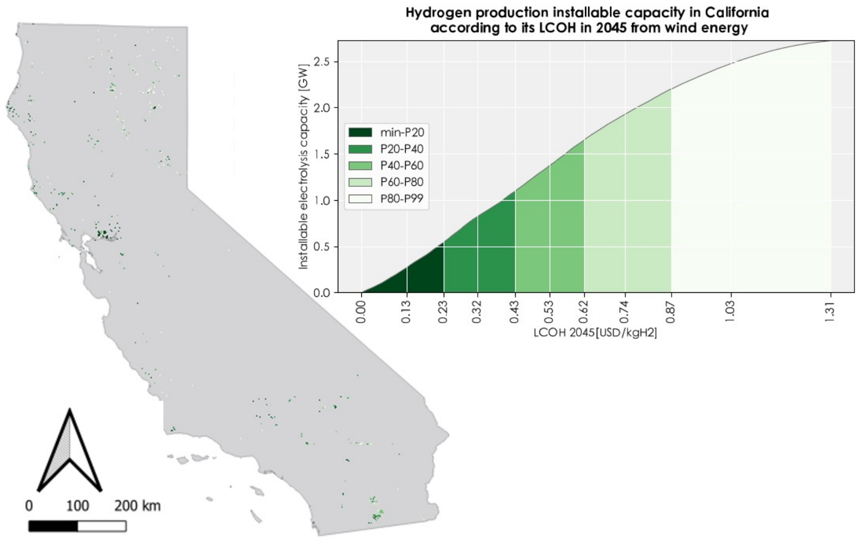




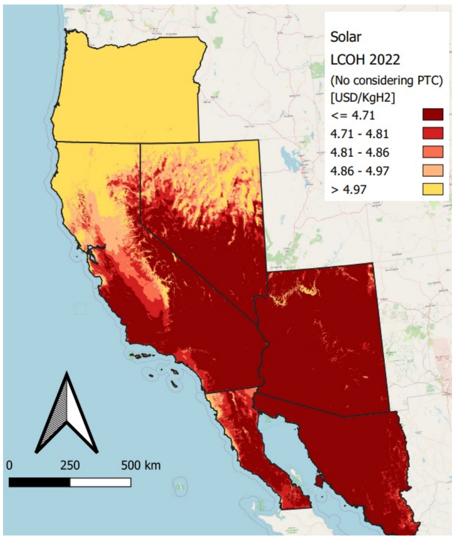


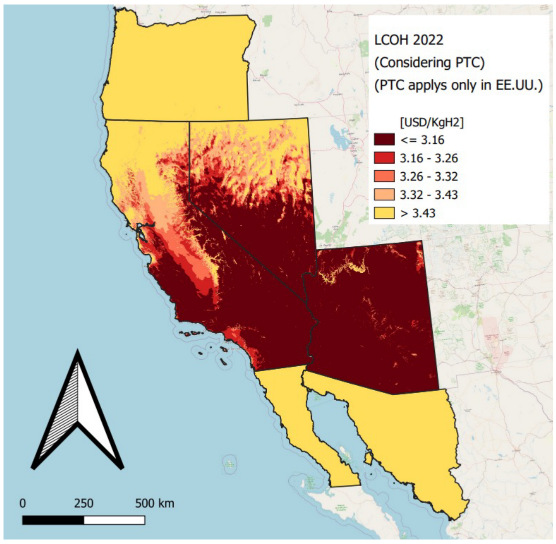

Hydrogen production installable capacity in California
according to its LCOH in 2022 from wind energy
Installable electrolysis capacity [GW]
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
min-P20
P20-P40
P40-P60
P60-P80
P80-P99
1.03
1.61
1.93
2.18
2.37
2.54
2.70
2.87
3.07
3.33
3.84
LCOH 2022[USD/kgH2]
0
100
200 km

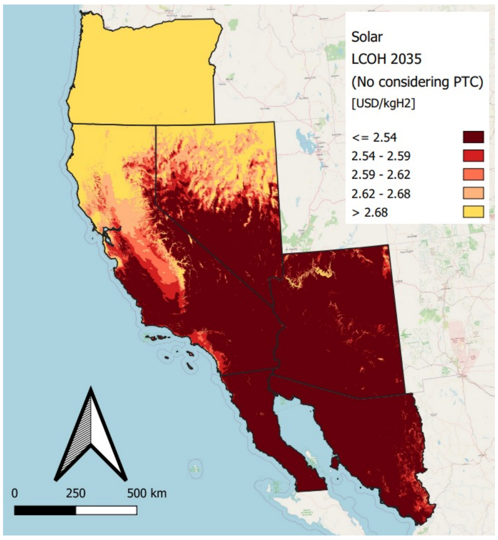

Hydrogen production installable capacity in California
according to its LCOH in 2035 from wind energy
Installable electrolysis capacity [GW]
0.0
0.5
1.0
1.5
2.0
2.5
min-P20
P20-P40
P40-P60
P60-P80
P80-P99
0.00
0.27
0.42
0.55
0.68
0.80
0.93
1.07
1.23
1.42
1.75
LCOH 2035[USD/kgH2]
0
100
200 km

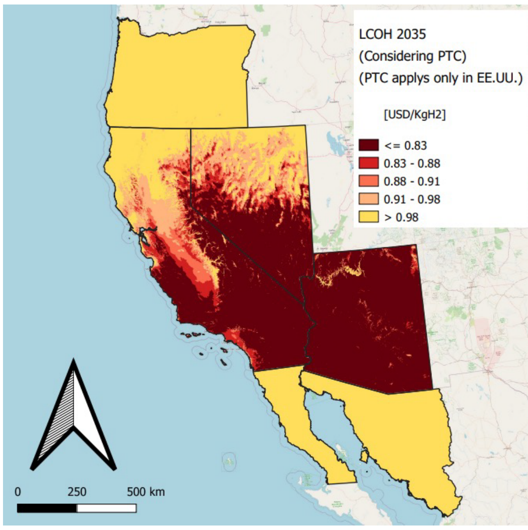

Hydrogen production installable capacity in California
according to its LCOH in 2045 from wind energy
Installable electrolysis capacity [GW]
0.0
0.5
1.0
1.5
2.0
2.5
min-P20
P20-P40
P40-P60
P60-P80
P80-P99
0.00
0.13
0.23
0.32
0.43
0.53
0.62
0.74
0.87
1.03
1.31
LCOH 2045[USD/kgH2]
0
100
200 km

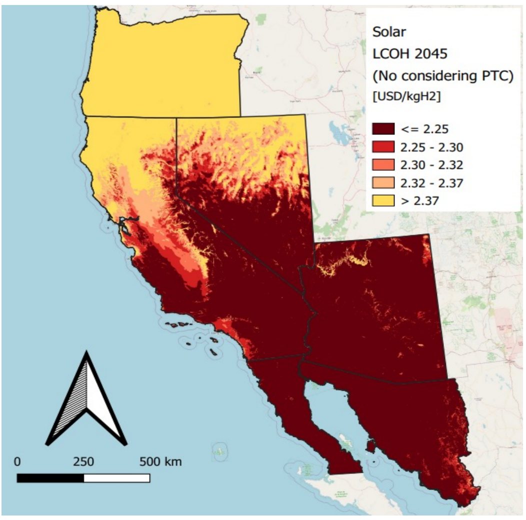
Competitiveness of green hydrogen from neighboring US states.

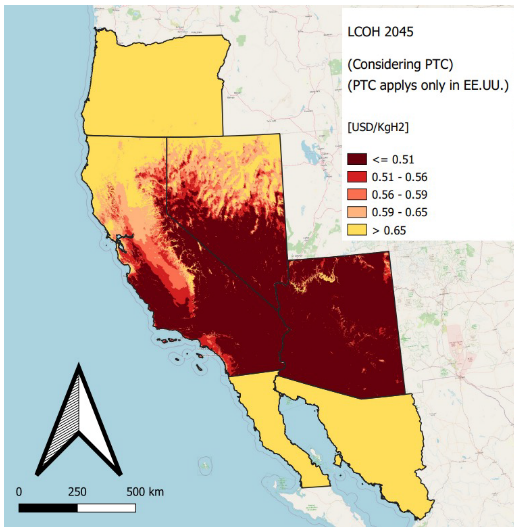








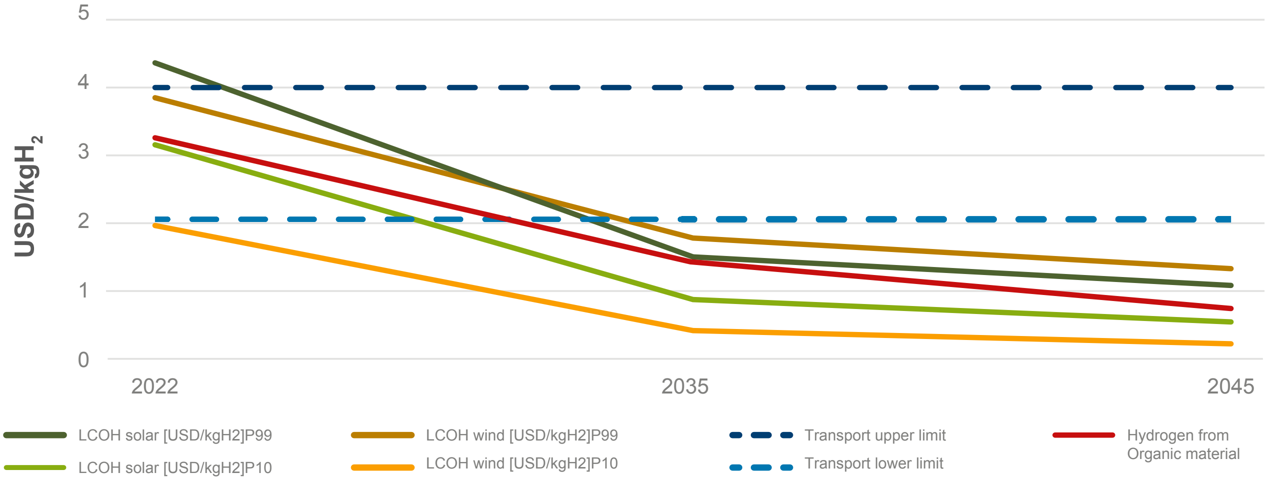




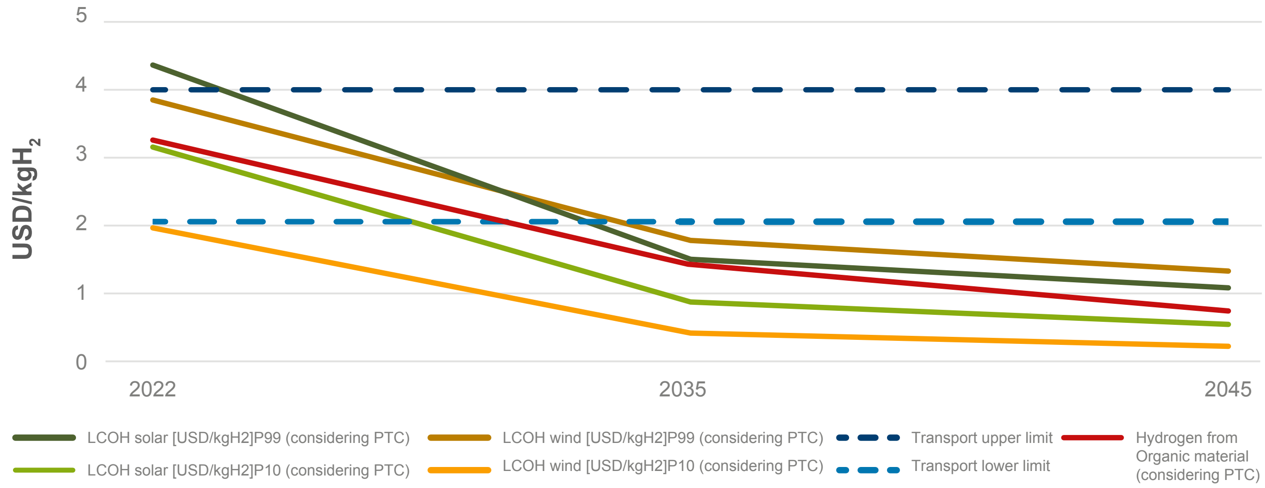
Competitiveness green and renewable LCOH in California vs sectors

The following graphs show

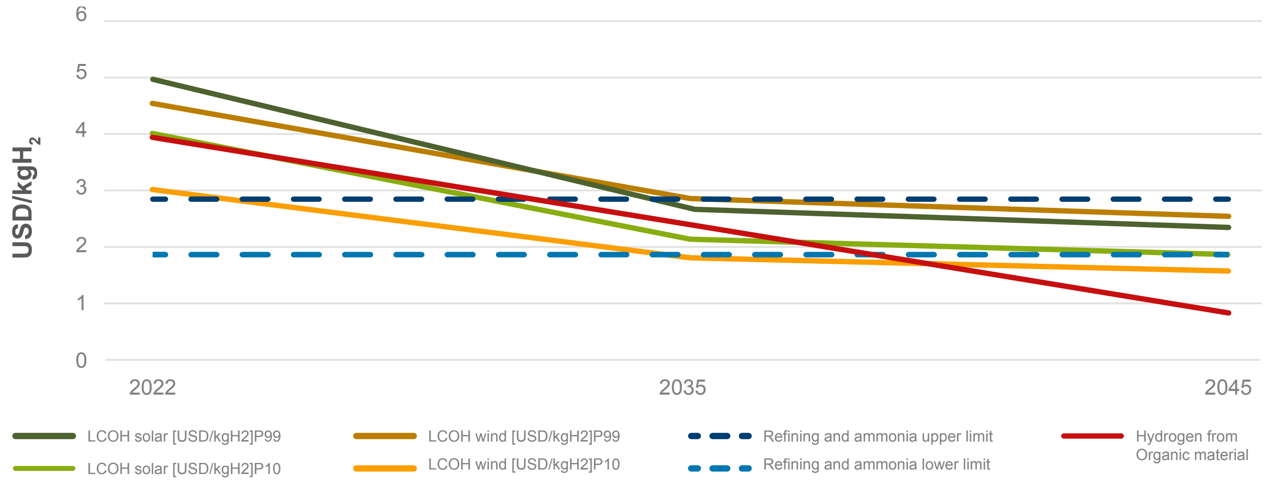
Competitiveness renewable hydrogen in transport sector without PTC



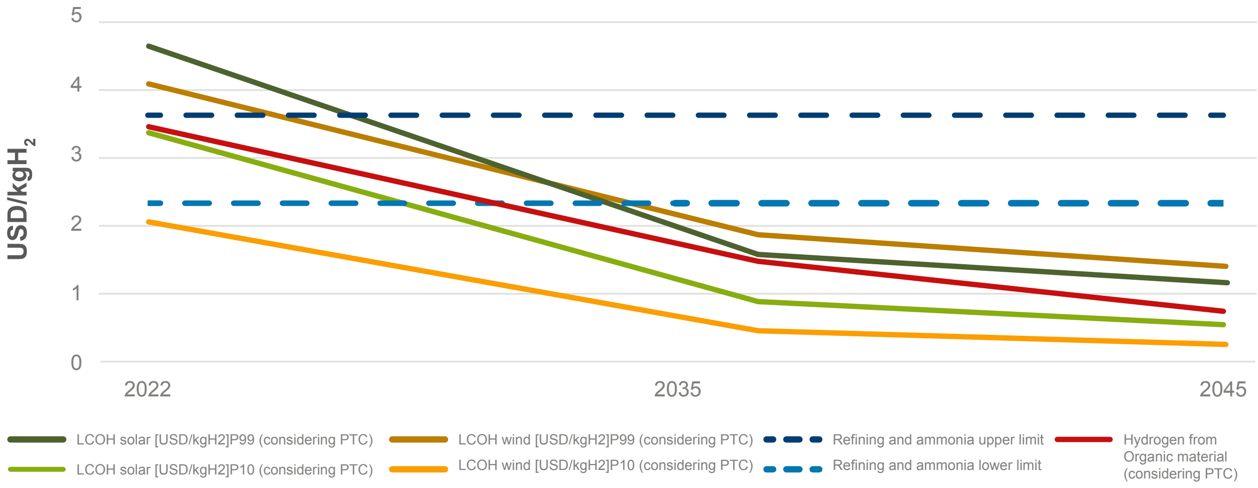
Competitiveness renewable hydrogen in transport sector with PTC



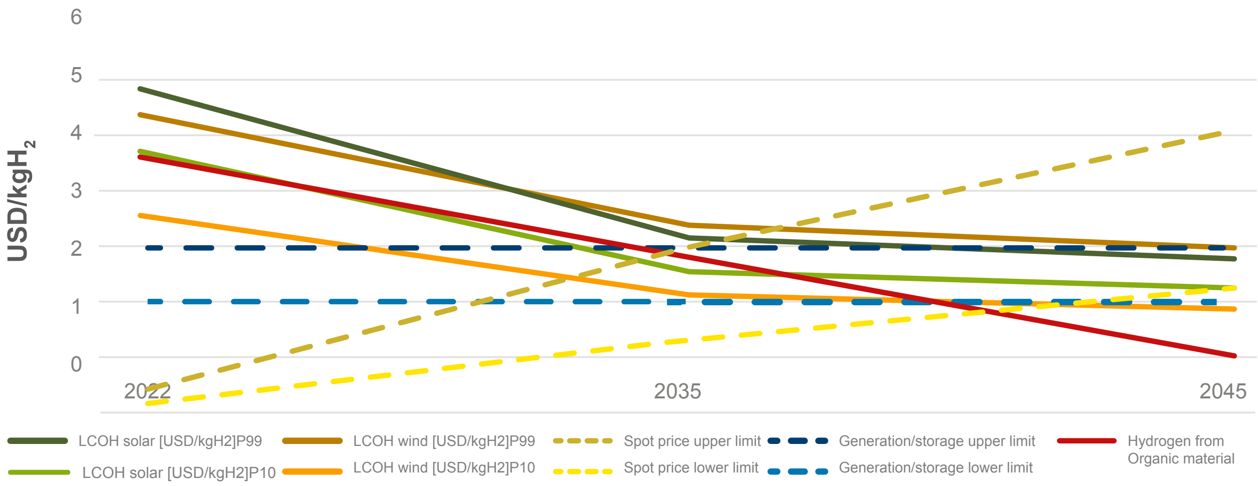
Competitiveness renewable hydrogen in the refining and ammonia sector without PTC



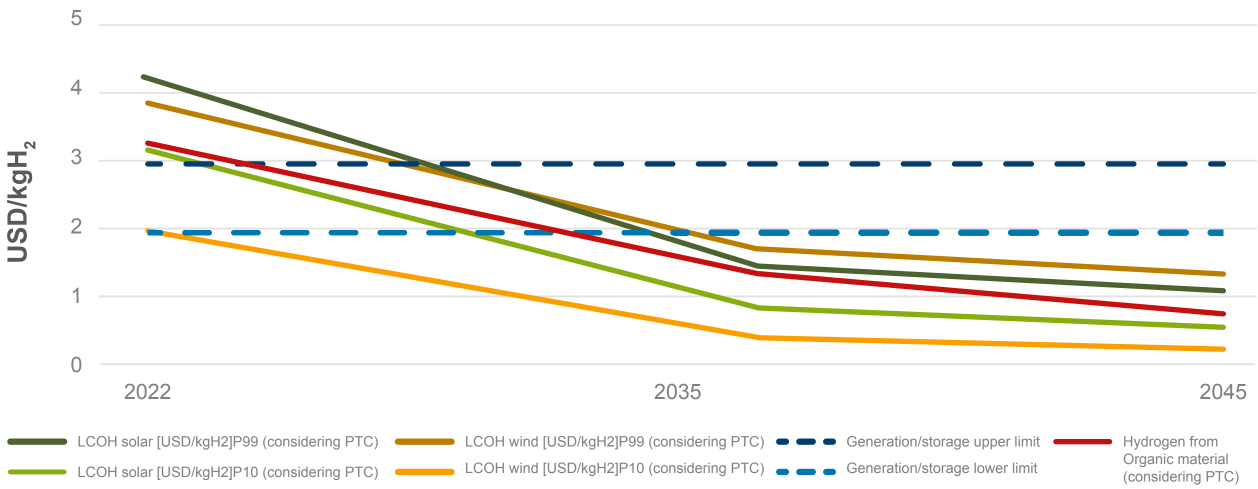
Competitiveness renewable hydrogen in the refining and ammonia sector with PTC



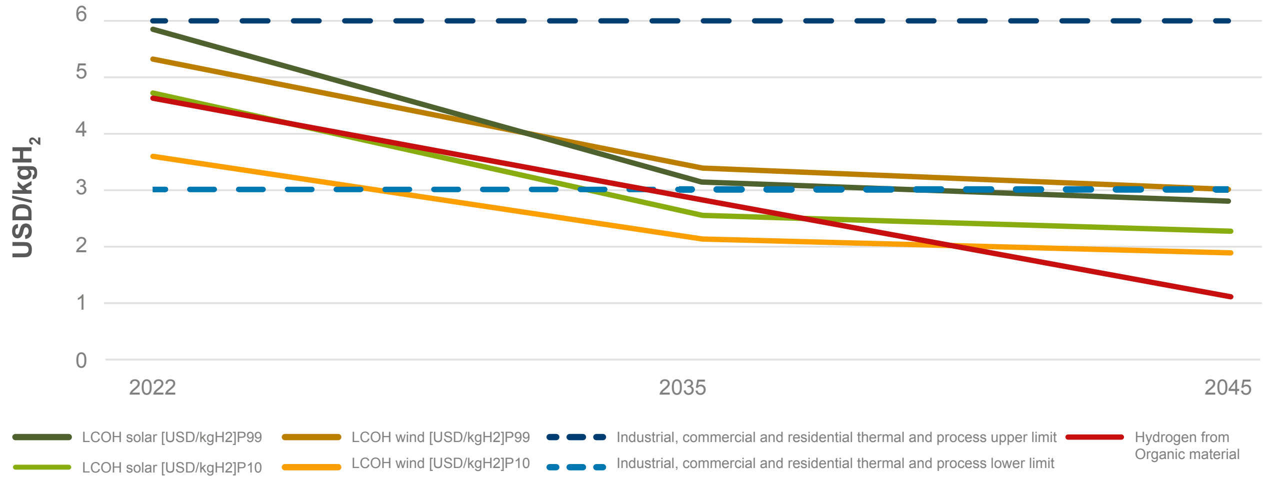
Competitiveness renewable hydrogen in energy and storage sector without PTC



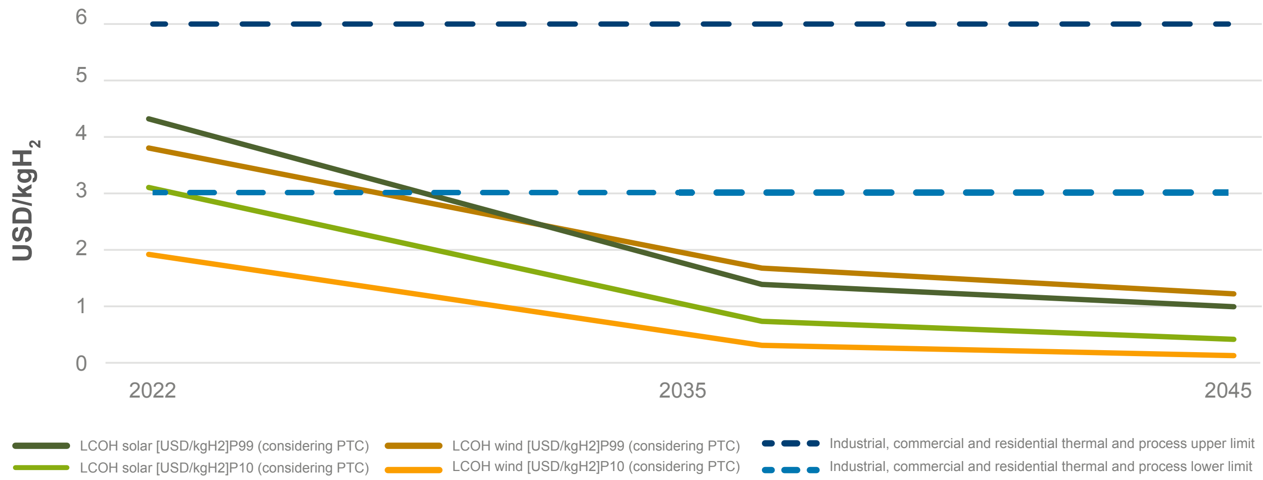
Competitiveness renewable hydrogen in energy and storage sector with PTC



Competitiveness renewable hydrogen in commercial, industrial and residential heat without PTC



Competitiveness renewable hydrogen in commercial, industrial and residential heat with PTC



Annex 3: Fact Sheet Summary - Key Deliverables for the 2023 North American Leaders' Summit

The North American Leaders' Summit (NALS), sometimes called the Three Amigos Summit in the popular press, is the trilateral summit between the **prime minister of Canada**, the **president of Mexico**, and the **president of the United States**. The summits were initially held as part of the Security and Prosperity Partnership of North America (SPP), a continent-level dialogue between the three countries established in 2005, and continued after SPP became inactive in 2009 (White House, 2007).

On January 1st, 2023, during a series of talks taking place in Mexico City; President Biden, President Obrador, and prime minister Trudeau used NALS to drive North America's economic competitiveness and promote inclusive growth and prosperity.

The three countries agreed to deepen economic cooperation, promote investment, and reinforce competitiveness, innovation, and resilience. The three leaders committed to combatting the climate crisis by:

- Committing to reduce methane emissions from the solid waste and wastewater sector by at least 15% by 2030 from 2020 levels and deepen collaboration on waste and agriculture methane measurement and mitigation, including achieving the Global Methane Pledge through trilateral cooperation on methane and black carbon emissions.
- Developing a Food Loss and Waste Reduction Action Plan by the end of 2025 outlining efforts to cut food loss and waste in half by 2030.
- Sharing information between our countries on best practices to electrify and decarbonize public buses through the cooperative development of a Joint Transit Decarbonization Toolkit.
- Developing a plan for operating standards and the installation of EV chargers along international borders to ensure a seamless EV charging transition from country to country.
- Committing to trilateral cooperation to meet a joint commitment to conserve 30 percent of the world's land and ocean area by 2030 and to advance Indigenous-led conservation.
- Developing a **North American clean hydrogen market**, including potential cooperation on research and development, safety codes and standards, c**ross-border hydrogen clusters, green freight corridors**, and integrated **maritime operations** (White House, 2023).

These declarations open the door to international cooperation between the three North American countries, in which green hydrogen would play a relevant role. During the event, the semiconductor industry was also a key point. The maximum value within international cooperation will be found in the synergies achieved by apparently distant industries that can complement each other to provide a significantly greater value to the economic development of the region.

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The International Hydrogen Ramp-up Programme (H_2Uppp) of the German Federal Ministry for EconomicAffairs and Climate Action (BMWK) promotes projects and market development for green hydrogen in selected developing and emerging countries as part of the National Hydrogen Strategy.