Assessing Uruguay's green hydrogen potential: A comprehensive analysis of electricity and hydrogen sector optimization until 2050

Evaluación del potencial de hidrógeno verde en Uruguay: Un análisis integral de la optimización de los sectores de electricidad e hidrógeno hasta el 2050

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Resumen

Uruguay se posiciona como potencial exportador de hidrógeno verde y derivados, según lo descrito en la hoja de ruta. El objetivo principal de este estudio es explorar cómo reacciona el sistema eléctrico del país a los objetivos delineados en la hoja de ruta. Otro objetivo es analizar cómo podría desarrollarse el sector del hidrógeno verde basado en el precio de mercado del hidrógeno. Se propone una metodología para distribuir los costos entre ambos sectores. El análisis revela que cada escenario presenta desarrollos muy diferentes de los sistemas energéticos en Uruguay. Son necesarias expansiones sustanciales en las capacidades de energía renovable, particularmente fotovoltaica y eólica, para apoyar una economía del hidrógeno. Los escenarios impulsados por el mercado, especialmente con precios más altos del hidrógeno, muestran aumentos significativos en las capacidades de los electrolizadores. La viabilidad económica de la producción de hidrógeno a precios más altos sugiere que las exportaciones de hidrógeno podrían convertirse en un negocio rentable para Uruguay.

PALABRAS CLAVE: Hidrógeno, Modelo de sistema energético, Optimización, Coste nivelado de la electricidad, Coste nivelado del hidrógeno, Uruguay.

Abstract

Uruguay is setting out to become a leading exporter of green hydrogen and its derivatives, as described by the hydrogen roadmap. The primary aim of this study is to explore how the country's electricity system reacts to the goals outlined there. Another aim is to analyze how the green hydrogen sector could develop based on the market price for hydrogen. A methodology for distributing the costs among both sectors is proposed. The analysis reveals that very different pictures are painted in each of the scenarios, leading to completely different developments of the energy systems in Uruguay, substantial expansions in renewable energy capacities, particularly photovoltaic and wind power, are necessary to support a hydrogen economy. The market-driven scenarios, especially at higher hydrogen prices, show significant scale-ups in electrolyzer capacities. The economic viability of hydrogen production at higher price points suggests that hydrogen exports could become a profitable venture for Uruguay.

KEYWORDS: Hydrogen, Energy system model, Optimization, Levelized cost of electricity, Levelized cost of hydrogen, Uruguay.

1. INTRODUCTION

The increasing global focus on green hydrogen as an essential energy carrier reflects a widespread commitment to decarbonizing energy systems, particularly in sectors where direct electrification is impractical (IRENA, 2022). To meet the temperature goals set by the Paris Agreement (United Nations, 2015), achieving significant emission reductions across all economic sectors is essential. This requires decarbonizing energy, advancing electrification, increasing the share of renewable energies, and improving energy efficiency. Green hydrogen, produced from renewable sources via water electrolysis, stands out as a clean energy vector (Kumar & Lim, 2022; Stolten & Emonts, 2016) with a high energy-to-weight ratio (Chi & Yu, 2018). Its production process, which relies on solar, wind, or hydroelectric power, positions it as an environmentally friendly and sustainable option (BP, 2022; Kumar & Lim, 2022; Sánchez Delgado, 2019). With zero greenhouse gas emissions, green hydrogen holds significant potential as a substitute for fossil fuels (Kumar & Himabindu, 2019; Laguna-Bercero, 2012), particularly in "hard-to-abate" sectors. For example, Hydrogen can be utilized in fuel cells to regenerate electricity, power cellular radio bases in remote locations, or drive fuel cell electric vehicles, among other applications. It also has the potential to replace natural gas in various heat-dependent processes. Hydrogen can also play a critical role in reducing iron oxide (iron ore) to produce iron (Direct Reduction Iron, or DRI) and steel, eliminating the need for fossil fuels in one of the most challenging industrial processes to decarbonize.

Uruguay, with its advantageous geographic location and robust renewable energy infrastructure, is well-positioned to leverage green hydrogen production for export and to foster the development of new industries (International Energy Agency, 2019, 2022, Appendix A; Ministerio de Industria, Energía y Minería, 2023a). The country has formulated its strategy, embodied by the "Green Hydrogen Roadmap in Uruguay"(Ministerio de Industria, Energía y Minería, 2023b), to cultivate a domestic market for green hydrogen and position itself as a prominent exporter of this renewable energy resource. In the Roadmap it is recognized that Uruguay's potential for renewable energy production far exceeds the future needs of its electricity system. Uruguay's stability, transparent legal framework, and a strong reputation for honoring contracts and commitments make it an appealing destination for large-scale projects in green hydrogen and related fields. Uruguay is uniquely positioned to combine hydrogen with biogenic carbon dioxide (CO2) to produce green methanol. This methanol can be converted into synthetic gasoline, gas, oil, or jet fuel. Uruguay can create new energy sources that fully replace conventional fossil fuels by harnessing renewable resources to produce green hydrogen and utilizing agro-industrial waste. In the short term, Uruguay aims to develop a domestic market for green hydrogen and its derivatives, focusing on heavy and long-distance transportation and green fertilizer production. The national hydrogen roadmap projects that the costs of renewable energy in Uruguay by 2030 would enable green hydrogen production at values between 1.2 and 1.4 USD/kgH2 in the western region and between 1.3 and 1.5 USD/kgH2 in the eastern region. These competitive costs position Uruguay as a strong contender in the export market for hydrogen derivatives. In the long term, Uruguay will explore the potential for offshore green hydrogen production to further enhance its export capabilities (Ministerio de Industria, Energía y Minería, 2023b).

1.1. Literature review

The roadmap is not the first study that investigated Uruguay's hydrogen potential and costs for producing hydrogen in the country.

(Corengia et al., 2020) present a case study where they establish a simulation-based sizing of grid-connected electrolyzer plants for the case of Uruguay. Their limiting factor is the available surplus electricity from the grid; the only service that the electrolyzer would provide to the electricity system is peak shaving. They concluded that the produced hydrogen is too expensive compared to traditional fuels and that the utilization of the electrolyzer plants is too low.

(Corengia & Torres, 2022) propose a design that involves selecting power sources, electrolyzer types and sizes, and energy storage devices for hydrogen production in Uruguay at various scales. The study highlights solid oxide electrolyzers as promising, with alkaline electrolysis preferred over proton exchange membrane electrolysis among current market options. It emphasizes the importance of complementarity in energy sources and challenges the idea of producing hydrogen solely to use energy surplus and avoid curtailment.

(Ibagon et al., 2023) developed a model to optimize the capacity of renewable energy facilities, electrolyzers, storage systems, and hydrogen transport methods to minimize hydrogen costs in Uruguay. It analyzed the impact of hydrogen demand scale and technological maturity (2022 vs. 2030) on production costs and the supply chain. For medium and small demands, conversion, processing, transport, and storage costs are similar to energy costs. For larger demands, the cost of renewable energy represents the most relevant cost and pipelines are the most cost-effective for transporting compressed gas, while trucks are preferred for smaller demands. For medium demand, longer distances favor liquid organic hydrogen carriers by truck, and shorter distances favor trucks for compressed gas. The study predicts that advancements in technology will reduce hydrogen production costs from 3.5 USD/kg in 2022 to 2.3USD/kg by 2030.

The study from (Bouzas et al., 2024) examines hydrogen production costs in Uruguay, focusing on the impact of various techno-economic parameters. It highlights that electricity costs are a major driver of hydrogen production costs, especially when low capacity factors make electrolyzer CAPEX and OPEX more significant. Water costs are found to be negligible. The Weighted Average Cost of Capital (WACC) also has a substantial influence, particularly in scenarios with lower full load hours where electrolyzer investment costs dominate. Overall, WACC significantly impacts investment-based costs.

Previous studies on hydrogen production in Uruguay have focused on identifying optimal renewable locations and estimating production and transportation costs to centers like Montevideo. However, they haven't explored integration with the existing electricity system, interactions with current infrastructure, or the potential synergies of an integrated hydrogen and electricity system. This paper aims to address these gaps by assessing how hydrogen production can be integrated with the electricity system, evaluating infrastructure interactions, and determining incentives for expansion. It also provides the levelized costs of electricity and hydrogen within such integrated systems.

2. METHODOLOGY AND MODEL DESCRIPTION

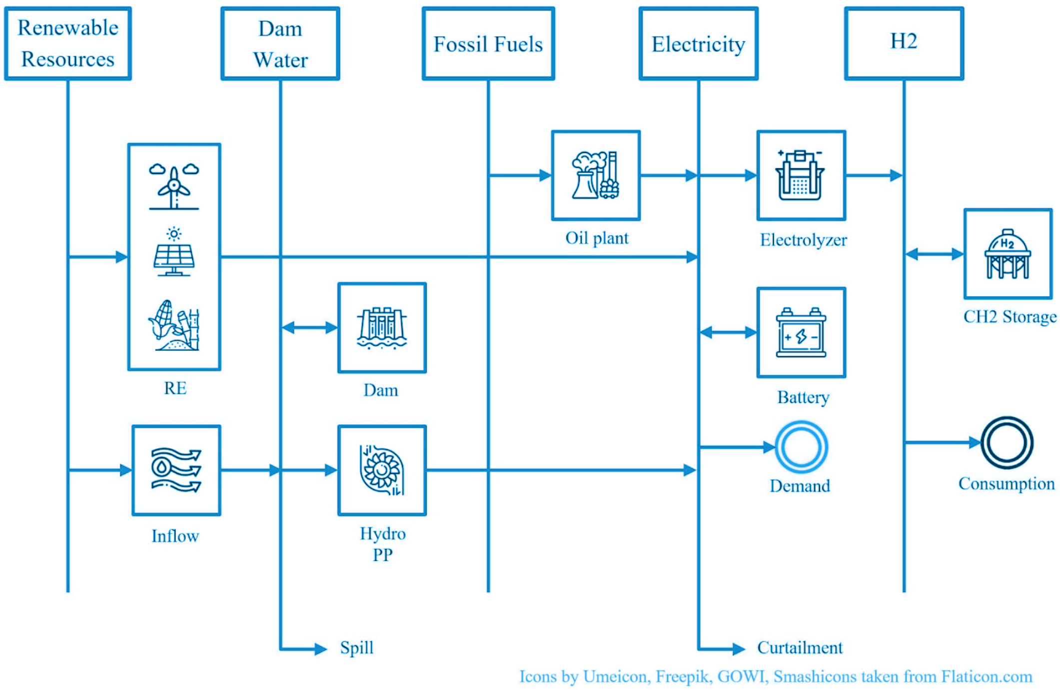
This study employs a linear programming energy system optimization model called urbs (Dorfner, 2016; Dorfner et al., 2019). The software allows the optimization of multi-commodity energy systems. It incorporates inter-temporal planning to analyze development pathways, consisting of a "perfect foresight" model, which means all future variables are defined from the beginning. The model minimizes the total costs of the system, all while fulfilling the given commodity demands. For further information about the mathematical background or the tool in general, check the documentation (Dorfner, 2023). The model in this study encompasses the existing Uruguayan electrical system alongside planned expansions, optimizing the system expansion and operation for electricity generation and hydrogen production. The analysis is an inter-temporal approach that spans multiple reference years, including 2021, 2025, 2030, 2040, and 2050, providing a comprehensive outlook on the evolution of Uruguay's electricity and hydrogen landscape. Uruguay is modeled as a single node in this model, so the costs and respective energy losses of any transmission or distribution lines within the country are not considered. In this section, we will examine the specific assumptions, models, and data utilized throughout the study.

2.1. Reference Energy System

The creation of the energy model requires the creation and definition of different input data and parameters. All the interactions between different technologies and commodities can be visualized and understood through a reference energy system. The reference system for this case can be seen in Figure 1.

In the case of Uruguay, there are different available technologies to generate electricity, from intermittent or non-conventional renewable energies, there are present solar and wind energy, to be more specific, we can find the following technologies: Open field PV, Rooftop PV, Wind onshore Level I, Wind Onshore Level II, and Wind Offshore. For each of them we have a determined potential and generation time series, the specifics are discussed in below section 2.3. All of these have a temporal generation time series as input, and their output is electricity. More traditional renewable energies such as biomass and hydro have the advantage of being flexible when they generate electricity. For biomass, yearly energy potential is the limit. For hydro, the dam can be used to store the water coming from an inflow time-series. This stored water can either be directed to its powerplant to generate electricity or be spilled. The last technology available for electricity production is the Oil plant, which consumes oil for which there is a specific cost associated and generates electricity but also direct CO2 emissions. The domestic demand then consumes electricity; this demand has to be fulfilled every single hour. The electricity could then be stored in batteries, so generation can be shifted in time. Electricity is also an input for hydrogen production using electrolyzers. This produced hydrogen to fulfill the specific demand or to sell hydrogen for a specific price. The produced hydrogen can be stored in a compressed hydrogen storage and then released for use at another time. In addition to storing, there is the possibility of curtailing electricity, which means getting rid of overproduction when this is the cost-optimal solution.

Figure 1 Reference Energy system for urbs model for Uruguay



2.2. Demands

Uruguay, like any other country, assumes an increase in its economic growth and, therefore, its electricity consumption. The Ministry of Energy and Mining has scenarios and projections of the electricity demand of the national interconnected system (SIN) until 2040 (Ministerio de Industria, Energía y Minería, 2018). 'For this study the Baseline scenario ("Tendencial") was used, where there are no significant changes in the demand distribution by sector from 2018 onwards. The growth rate from the last years was then extrapolated to calculate the expected demand for 2050. The respective values can be seen in Table 1.

Table 1. Yearly electricity demand of the National Interconnected System (SIN)

Year	2021	2025	2030	2040	2050
Yearly Electricity Demand [GWh]	11,078	12,190	13,525	16,747	20,608

All these calculations refer to the total yearly electricity demand. The hourly profile is taken from the electricity market operator (ADME, 2024) for the year 2021 is used as a base to disaggregate future yearly demand into hourly values. In the case of hydrogen demand, the roadmap (Ministerio de Industria, Energía y Minería, 2023b) gives information in terms of electrolyzer capacity, market size, and one singular value for the yearly production of 2040 of one million tons H2, corresponding to 9 GW of electrolyzer capacity. With this last value, we can derive that for each GW of electrolyzer, they are assuming 111.111 kg of hydrogen a year, and this ratio is used for all the other years. Since the roadmap goes until 2040, but the time scope of this study is until 2050, some assumptions were required to calculate the 2050 value; we went for a conservative approach of an electrolyzer capacity and demand increase of 20%, which results in 1.2 million tons for 2050. The respective original and calculated electrolyzer capacities and demands can be seen in Table 2.

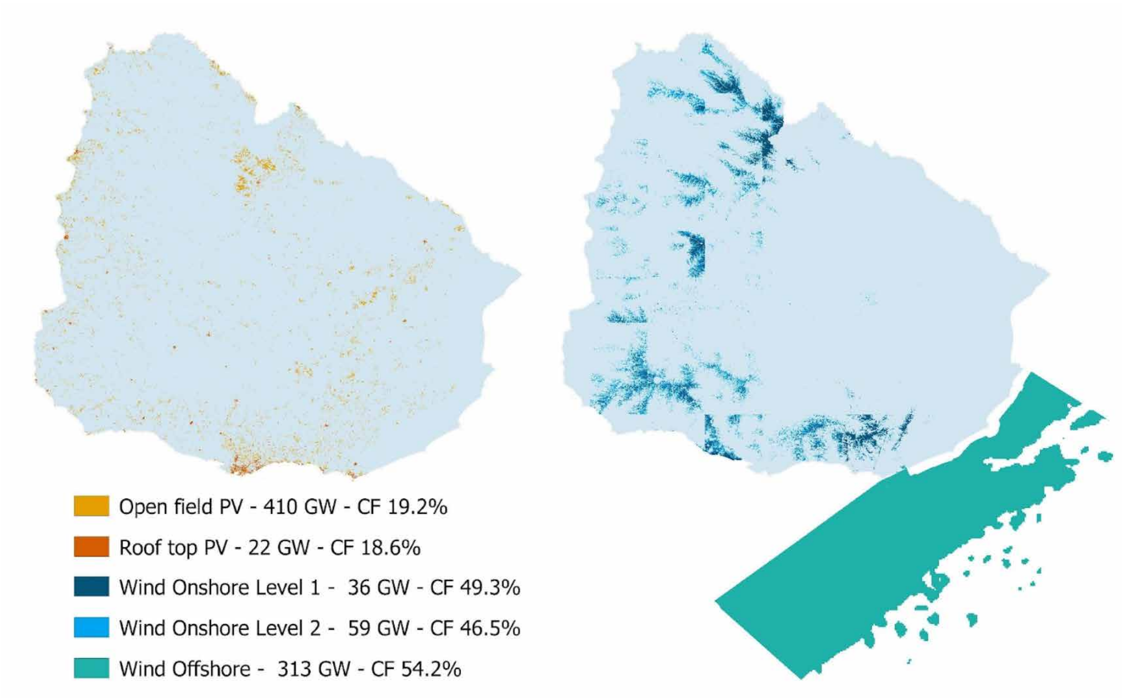
Table 2. Specified electrolyzer capacities and estimated hydrogen demands. Based on: (Ministerio de Industria, Energía y Minería, 2023b)

	2025	2030	2040	2050
Electrolyzer Capacity [GW]	0.1	0.6	9	10.8
Hydrogen demand [kton H2/year]	11.11	66.66	1000	1200

2.3. Renewable Potentials

The renewable potential analysis is carried out using the open-source tool pyGRETA (Kais Siala et al., 2022). The tool performs customizable land use eligibility analysis based on 38 different criteria (Ryberg et al., 2018) at a high spatial resolution of 250m x 250m to estimate the available locations and total potential of solar and onshore wind technologies of a given region. The tool also analyses exclusive economic zones up until a seabed depth of 50m to calculate the fixed offshore wind potential. In addition to potential calculation, the tool also reads historical weather data from MERRA-2 (Global Modeling and Assimilation Office (GMAO), 2015b, 2015a) and Global wind atlas (Global Wind Atlas 3.0, 2022) to calculate the hourly capacity factors of all possible locations. The detailed methodology is described in sources (Kais Siala et al., 2022) and (AUTHOR, 2024). Figure 2 shows the results of this analysis. The map on the left shows the locations of open field and roof top PV potentials and the map on the right shows the locations of onshore and offshore wind potentials considered in the energy model of Uruguay. The capacity factors for solar PV technologies are very similar across Uruguay as it is mostly latitude dependent. So, the total potential of 410 GW for Open field PV and 22 GW of Rooftop PV is considered to have the same hourly capacity factor time series. For wind technologies, the capacity factors are highly dependent on the location's geography and are different across the country. So even though the total onshore wind potential of Uruguay is much higher, only the highest two levels of locations are considered with 49.3% and 46.5% capacity factors, respectively. For simplicity within the model, the capacity factor of 54.2% taken from an average location is assumed for the offshore region. It should be noted that the capacity factors of this magnitude for wind technologies are one of the highest in the whole world, which makes them cost-competitive compared to PV technologies despite drastic cost reductions projected in the future for PV. See below section 2.4.

Figure 2. Renewable Energy Potentials from pyGRETA for Uruguay. Legend: Technology Potential Yearly Capacity Factor



2.4. Technoeconomic Data

The urbs model requires various techno-economic data inputs, including CAPEX and OPEX for all technologies, fuel costs, and broader economic parameters such as the Weighted Average Cost of Capital (WACC) and discount rates for long-term investments. For the technology-specific data, we intentionally minimized the number of different sources used. By relying on a limited set of sources, we ensured that the assumptions and methodologies applied across technologies are consistent, making comparisons between them fairer and uniform. This approach reduces the risk of discrepancies that could arise from using data with varying underlying assumptions, thereby enabling a more balanced evaluation of the different technologies. Investment and operational costs vary significantly across regions, particularly Latin America. To estimate the specific costs for Uruguay, we employed the methodology introduced by the Inter-American Development Bank in their report on optimizing the Latin American electrical system (Inter-American Development Bank & Paredes, 2017).

Table 3. Sources for the Country and Temporal-specific Input Techno-economic data

Technology	Techno-economic Data	Source
Power plants	Investment costs, Operational Costs, Efficiency, Fuel Costs	Brazil Net Zero Emissions by 2050. (International Energy Agency, 2022)
	Lifetime	(NREL (National Renewable Energy Laboratory), 2023)
	Country Cost factor	(Inter-American Development Bank & Paredes, 2017)
Electrolyzers	Investment costs, Operational Costs, Lifetime	≥100MW EPRI Low Range including STACK+ BOP. (EPRI, 2023)
	Efficiency	Efficiency Assumptions based on (IRENA, 2020)
Batteries	Investment costs, Operational Costs, Efficiency, Lifetime	Advanced Scenario. (NREL (National Renewable Energy Laboratory), 2023)
Hydrogen Storage	Compressor (Investment costs, Operational Costs, Efficiency, Lifetime)	(Wang et al., 2012)
	Container (Investment costs, Operational Costs, Efficiency, Lifetime)	(Ibagon et al., 2023)

This approach involves recalculating investment and fuel costs for each country in the region, by using specific factors per technology and fuel. In our case we use Brazil as a baseline and recalculated the factors. For all technologies, we utilized the Net Zero 2050 scenario values, using Brazil as the baseline. The only exception was Rooftop PV, for which we selected techno-economic data from Europe instead of Brazil, due to the significantly lower costs reported for Brazil. According to market reports, such as the recent ones from Wood Mackenzie (Mackenzie, 2023, 2024), the current range for rooftop PV in Brazil is between 1200 to 1500 USD/kW, which aligns more closely with the European starting point of 1120 USD/kW in 2021. The Table 3 summarizes the matching of different data sources used to create the country-specific and year-specific input data.

As previously mentioned, key economic parameters still need to be defined. Studies by (Steinbach & Staniaszek, 2015), (García-Gusano et al., 2016), and the (OECD, 2021), have specifically examined the role of discount rates and the Weighted Average Cost of Capital (WACC) in energy system models, highlighting their influence on long-term investment outcomes. The WACC is crucial for assessing investments, representing the cost of capital in a region and sector, while the social discount rate reflects the time value of money and opportunity cost of capital. Lower discount rates favor renewable energy, while higher rates favor fossil fuels. Due to economic uncertainty in Latin America, adopting a default WACC is inappropriate. Therefore, a region-specific WACC for Uruguay was defined using an approach proposed in the PTX Business Opportunity Analyser tool (Oeko-Institut, 2023), where country-specific Equity Risk Premiums (Damodaran, 2024) are used, resulting in a WACC of 7.38%, compared to the 5% in Uruguay's Hydrogen Roadmap. The WACC will be applied uniformly across all timeframes due to the lack of a reliable projection method. The study also adopted an average social discount rate of 3.894% for South America, based on recommendations for Latin American countries (Moore et al., 2020).

This methodology creates a relevant and adaptable database for the region.

Based on the techno-economic data discussed in this section and the estimated capacity factors for different renewables from above section 2.3, the Levelized cost of Electricity from Open-field PV will decrease considerably from 48 USD/MWh in 2020 to 22 USD/MWh in 2050. For onshore wind, the decrease is from 29-31 USD/MWh in 2020 to only 25-27 USD/MWh in 2050. For offshore wind, LCOE decreases from 101 USD/MWh in 2020 to 41 USD/MWh.

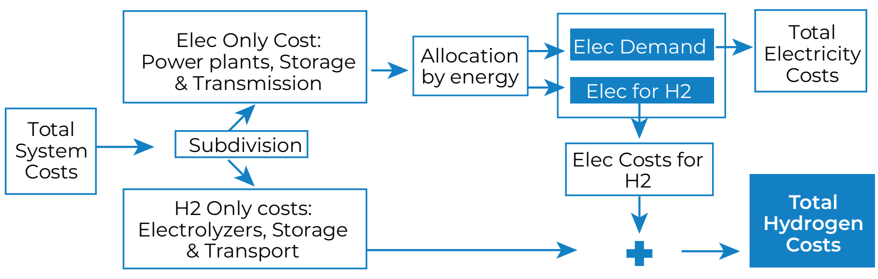
2.5. Levelized cost of Electricity and Hydrogen

To calculate the levelized cost of electricity and hydrogen, we consider their interrelation, as the electrical infrastructure is affected by hydrogen production. Using the urbs framework, our objective is to minimize total global costs for both electricity generation and hydrogen production. To be able to assign the costs between these two products we will use a methodology and approach commonly used in life cycle analysis called subdivision and complemented by allocation, the graphical description of the process can be seen in Figure 3.

Subdivision tries to assign inputs, flows, or, in our case, costs to the singular products. The second approach, allocation, distributes the effects and impacts of a system equitably based on specific characteristics of the co-products. For the subdivision step, the investment, fix, and fuel costs to produce electricity, as well as batteries and their costs, are assigned to electricity generation, and the costs only related to hydrogen such as costs for electrolyzers and H2-Storage are assigned to hydrogen production. For the allocation step, we take into account that the total electricity that gets produced is used as a direct electricity demand and also used in the electrolyzer, so the total electricity generation costs, are allocated between the electricity demand and hydrogen production, this costs of the electricity used for H2 production get summed to the costs which were only related to H2 and this constitutes our total hydrogen costs.

This method ensures a fair distribution of investment and operational costs, recognizing that higher hydrogen demand requires additional investment in the electrical system but may also enable greater integration of low-cost renewable energies. This approach is suitable because our model optimizes the overall system costs, ensuring fair cost and benefit assignment given the interrelated nature of electricity and hydrogen production.

Figure 3. Methodology used for the cost distribution among the products, commodities or sectors



2.6. Scenario definition

To analyze the energy model and system optimization for hydrogen production and electricity generation in Uruguay, which aims to produce and export hydrogen, three distinct scenarios were developed:

Baseline Scenario (Only Electricity): This scenario represents the expected evolution of the energy system without implementing a hydrogen economy. It serves as a reference point, illustrating the system's behavior under current policies and technologies focused solely on electricity supply. The model simulates the current trajectory of the energy system, highlighting potential challenges and limitations in meeting future electricity demands without hydrogen integration.

National Hydrogen Roadmap Implementation (H2 Roadmap): This scenario models the implementation of the country's national hydrogen roadmap. Specific goals for hydrogen production and utilization are set for each year, reflecting the government's strategic plan to integrate hydrogen into the national energy mix. The roadmap includes targets for hydrogen production capacities, and infrastructure development. The model evaluates the roadmap's targets, assessing the required capacities, investments, and resulting costs.

Market-Driven Hydrogen Production (1 to 3 USD/kg H2): In this set of scenarios, a price signal for hydrogen is introduced, allowing the model to determine the optimal production and export quantities based on profitability. The model assesses whether hydrogen production is economically viable and adjusts the production levels accordingly. Various price points are considered, which are kept constant throughout the analysis period to evaluate their impact on the global energy system. The model explores the economic dynamics of hydrogen production, considering various price signals and their influence on production decisions and export potential.

3. RESULTS AND DISCUSSION

The results show notable expansion within the electricity sector, driven by the increased demand necessitated by hydrogen production. The study thoroughly evaluates the generation matrix, Hydrogen production quantities, and their corresponding levelized costs. The information from all figures can also be found in the supplementary material.

Figure 4. Installed Capacities for electricity generation per scenario and year.

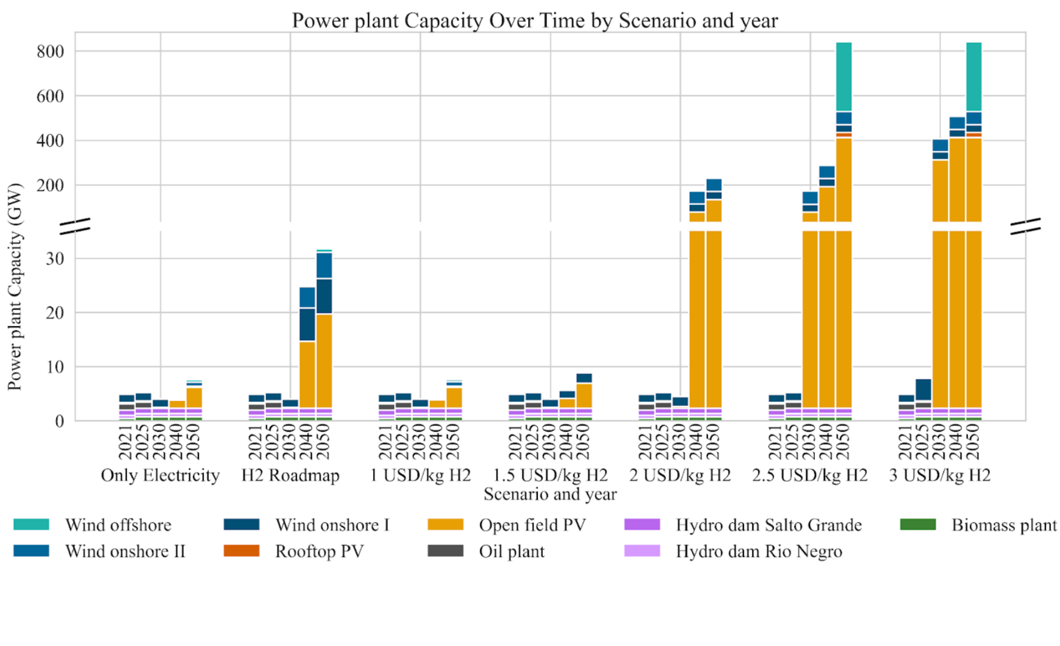
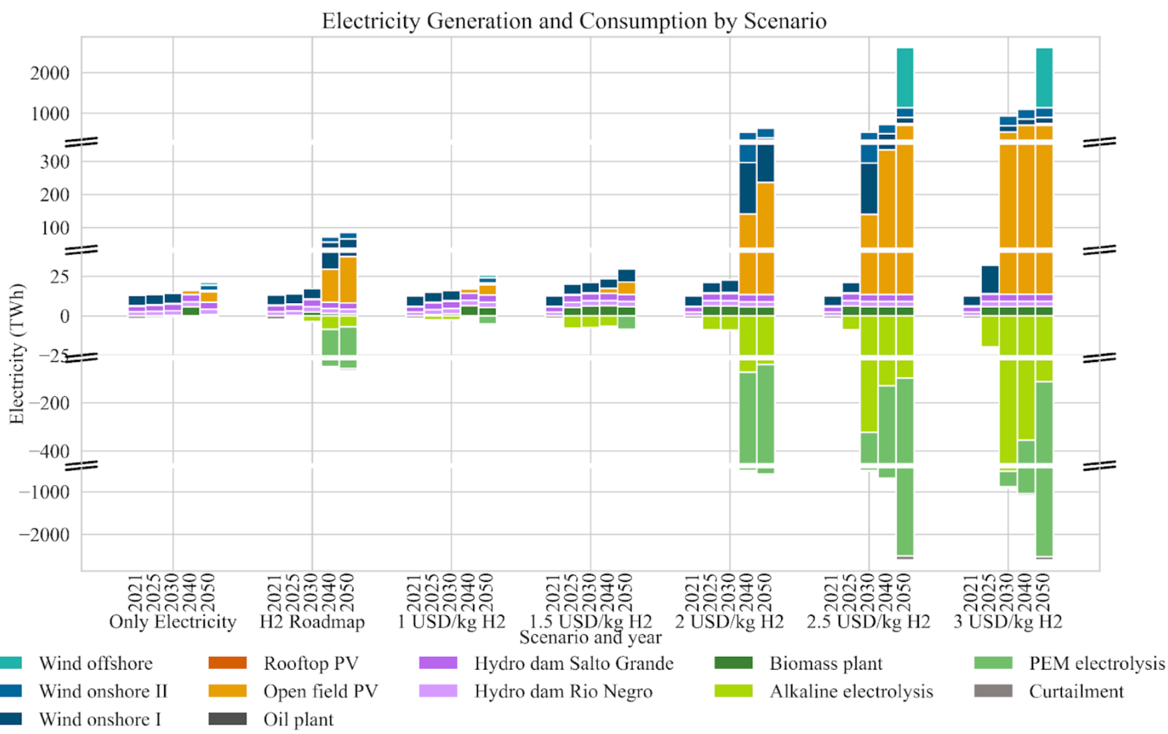


Figure 4 illustrates the installed capacities, and Figure 5 the electricity generation and consumption per scenario and year. In the only electricity scenario, there is minimal expansion up to 2025 and 2030, with the only changes being the addition of an already planned biomass plant and the decommissioning of the oil plant. Hydropower plants provide enough flexibility to meet electricity needs despite lower capacity. By 2040, significant changes occur as existing renewable energy plants end their life. Photovoltaic (PV) capacity increases significantly by 2040 and 2050. On the contrary, onshore wind capacity will decrease, while offshore wind will see new installations by 2050.

Regarding electricity generation and consumption, in all scenarios, the year 2021 shows minimal differences in technology and curtailment, with the electricity mix remaining relatively stable. Approximately 44% of electricity comes from hydropower, 50% from onshore wind, 2.6% from biomass, and the remainder from PV. However, at least 11.8% of generated electricity is curtailed in 2021.

In the electricity-only scenario, there are no significant changes in subsequent years. By 2040, new large-scale renewables are not expected with the decommissioning of existing renewable energy sources, so biomass must provide around 5 TWh of electricity. In 2050, with a larger expansion and diversification of renewables, biomass returns to operating as a peak power plant.

Figure 5. Electricity generation and consumption per scenario and year.

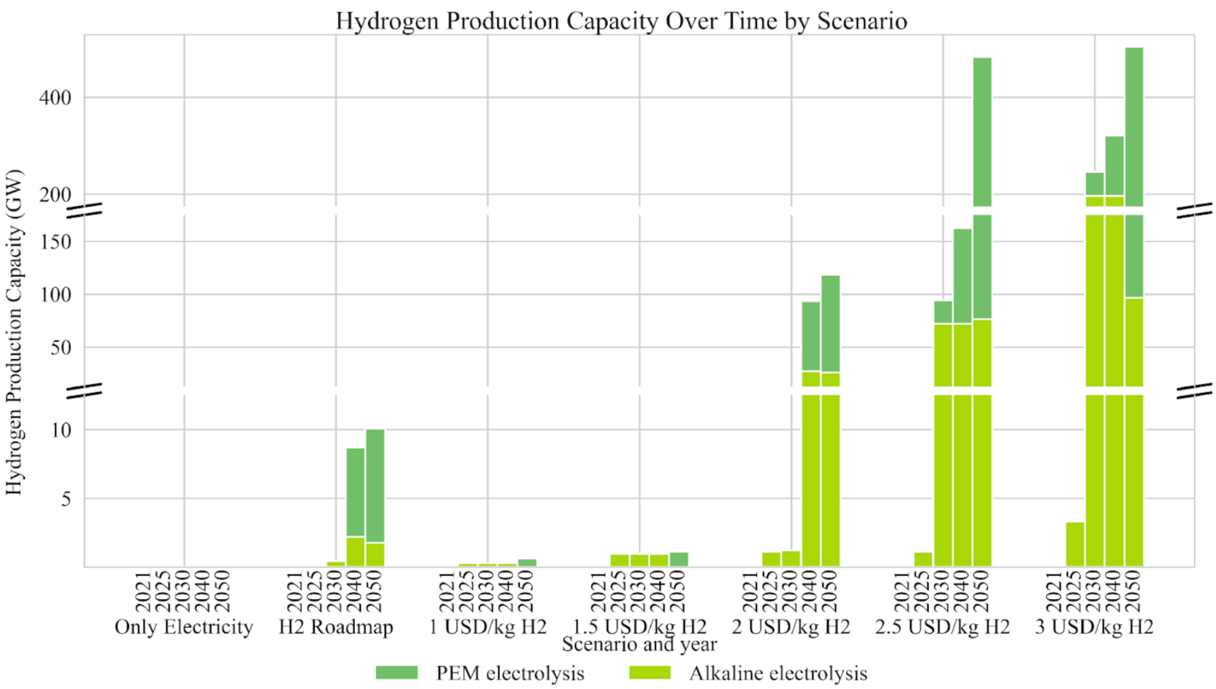


In the hydrogen roadmap implementation scenario, the installed capacity for 2021, 2025, and 2030 mirrors the electricity-only scenario, with existing renewable energies and planned expansions being sufficient for the early stages. By 2040, significant hydrogen demand and depreciated renewables necessitate substantial expansion, with PV, onshore wind, and offshore wind capacities increasing by 2040 and 2050. This scenario requires in total 22.4 GW of renewables by 2040, exceeding the 18 GW new RE target in the official roadmap. The new installations contrast sharply with the existing capacity and expected evolution.

The hydrogen roadmap scenario is quite similar to the electricity-only scenario in 2025 regarding electricity generation and consumption, with some curtailment replaced by hydrogen production. By 2030, curtailment is fully replaced by hydrogen production, and biomass plants operate supply electricity for electrolyzer. In 2040 and 2050, the expansion of renewables, supported by flexibility measures, allows direct operation of electrolyzers. However, 23% of electricity is curtailed in 2040 and 29% in 2050.

For the market-driven hydrogen production scenarios, results vary widely based on the given hydrogen prices. In the initial years (2021 and 2025), installed capacities remain similar to the only electricity scenario, except for the 3 USD/kg H2 scenario, which sees additional onshore wind by 2025. By 2030, higher price scenarios (2.5 and 3 USD/kg H2) show significant PV and onshore wind capacity expansions. From 2040 onwards, scenarios diverge more. The 1 USD/kg H2 remains similar to the electricity scenario, while the 2 USD/kg H2 fully exploits onshore wind potential and adds 75 GW of PV by 2050. Higher price scenarios (2.5 and 3 USD/kg H2) achieve maximum potential for PV and wind offshore by 2050.

Figure 6. Electrolyzer capacity through the years and scenarios



As a perspective, the Table 4 shows the produced hydrogen per year and scenario. The orders of magnitude among scenarios are not comparable; they show the magnitude of the possible market that Uruguay could have under favorable conditions. In lower price scenarios (1 and 1.5 USD/kg H2), in the first years, hydrogen production is driven by the full utilization of existing power plants, specifically the biomass plant. In 2040, the increase in the electricity demand and the decommissioning of older PV and wind plants will lead to a reduction of available surplus electricity and, therefore, a reduction in hydrogen production in the 1 USD scenario and a slight reduction in the 1.5 USD scenario. In 2050, due to price reductions, it is worthwhile to further expand renewable energies, and hydrogen production will increase again. Electric generation and hydrogen production grow significantly for the higher price scenarios (2, 2.5, and 3 USD/kg H2).

Some curtailment remains, but most electricity produced is used for hydrogen production. This shift means that electricity demand becomes a secondary service, with the primary goal being hydrogen production. According to our model, this would be profitable for the country, but the actual implications for infrastructure, including electricity and hydrogen transport, as well as river transport, maritime, and port infrastructure, are not considered.

Table 4. Hydrogen production quantities in the different scenarios and years.

Hydrogen production quantities [kton H2/ year]						
Year	**H2 Roadmap**	**1 USD/ kg H2**	**1.5 USD/ kg H2**	**2 USD/ kg H2**	**2.5 USD/ kg H2**	**3 USD/ kg H2**
2025	11.1	46.4	143.0	161.8	161.8	361.4
2030	66.8	46.3	137.1	167.4	9,496.3	16,724.1
2040	1,038.8	16.1	123.6	10,302.0	14,062.3	21,003.9
2050	1,256.7	111.0	188.2	12,688.5	54,759.5	55,108.3

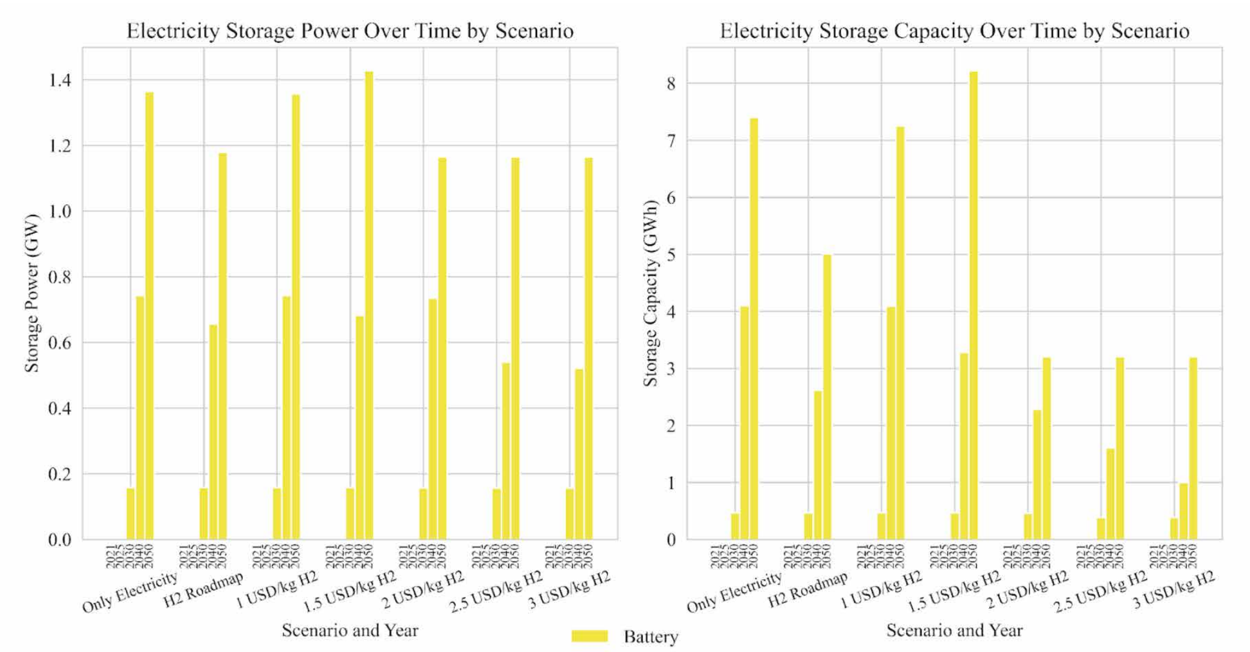
Regarding the hydrogen production system, Figure 6 shows the required electrolyzer capacity expansion across different scenarios. The roadmap scenario differs to the values given in the official hydrogen roadmap, for 2025 approximately 70 MW of electrolyzer are required, in comparison to the 100 MW reported, in 2040 0.43 GW vs 0.6 GW, in 2040 8.69 GW vs 9 GW. These differences can be explained by the difference in the utilization of the electrolyzers; here, they are operated for more hours, so for the same hydrogen demand, you require less electrolyzer capacity. In the Hydrogen roadmap, most projects are assumed as off-grid systems, whether they are fully Wind, PV or PV+Wind operated, and therefore with lower utilization hours.

In market price scenarios, varying hydrogen prices lead to different scales of electrolyzer capacity expansion. The 1 USD/kg H2 scenario maintains modest growth with around 290.6 MW of alkaline electrolyzers until 2040. As prices increase, significant expansions occur. The 2 USD/kg H2 scenario reaches about 27.2 GW by 2040 and 118.5 GW by 2050. The 2.5 USD/kg H2 scenario sees even more growth, with capacities reaching around 113 GW by 2040 and 482.4 GW by 2050. The highest price scenario of 3 USD/kg H2 shows exponential growth, achieving around 320.9 GW by 2040 and 503.8 GW by 2050, illustrating potential massive scale-up under favorable economic conditions.

Technological changes occur over time, with alkaline electrolyzers initially dominant. By 2040, PEM electrolyzers become competitive due to increased efficiency, and by 2050, new installations are about 80% PEM and 20% alkaline for scenarios with capacities above 2 GW.

Regarding the installed battery capacity and power, the Figure 7 shows the results. Battery expansion becomes necessary by 2030 in all scenarios, with hydro dams providing flexibility until then. A synergy between the electrical system and hydrogen production reduces power capacity needs in scenarios with significant hydrogen production. Storage capacity is notably reduced in the H2 roadmap and extreme hydrogen scenarios (2, 2.5, and 3 USD/kg H2), especially by 2050.

Figure 7. Battery capacity and power according to the scenario and year

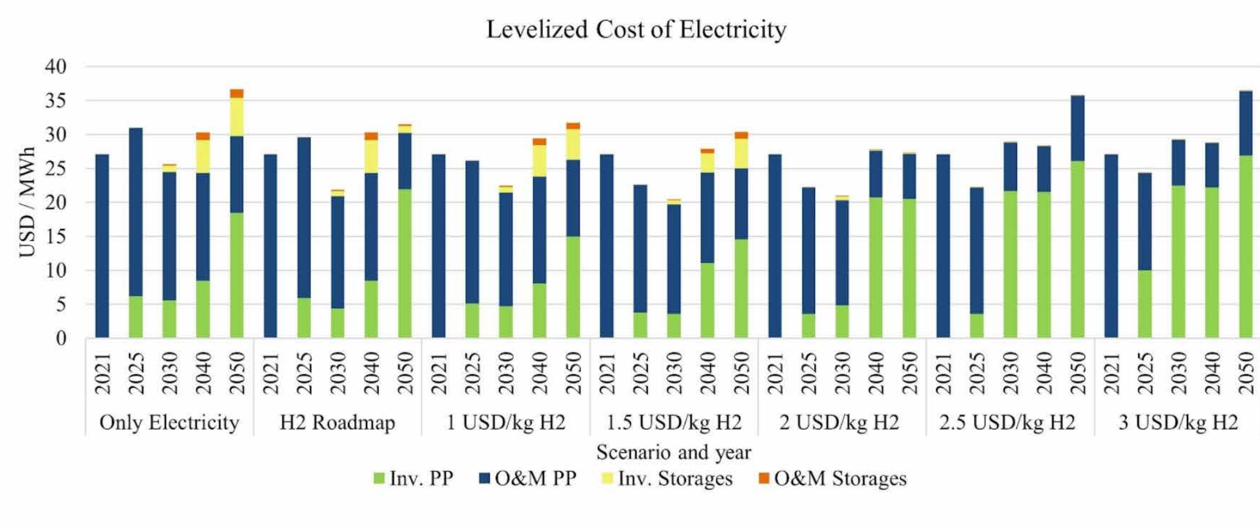


Another technology that delivers flexibility to the system are hydrogen tanks for H2 storage, with significant expansions in the H2 roadmap scenario. By 2050, hydrogen tanks are about 50% of installed electrolyzer capacities but below 7.5% of yearly hydrogen demand. The H2 roadmap scenario requires hydrogen tanks due to constant yearly hydrogen demand, necessitating storage to shift hydrogen delivery to low production hours. In market price scenarios, hydrogen is sold directly once produced, eliminating the need for production shifting.

3.1. LCOE

Figure 8 presents the LCOE for each year and scenario; it shows a shift from operation and maintenance cost-based to investment cost-based systems due to renewable energy expansion. LCOE reacts to investment decisions, which can either increase or decrease it, depending on the utilization of new capacity, as seen in 2025 in the different scenarios. In the “Only electricity” and “H2 Roadmap” scenarios, LCOE increases because the new biomass plant isn’t used, while in other scenarios, it reduces overall costs by producing useful electricity. Having huge flexible hydrogen production (scenarios 2, 2.5, and 3 USD/kg H2) decreases the need for battery flexibility. For example, in the “Only electricity” scenario, batteries account for about 6 USD/MWh in LCOE in 2040 and 2050. The LCOE for the “Only electricity” scenario tends to be higher due to the fact there is no other sector or product to share them with, and all capacity expansion costs are solely to electricity. This means that integrating and expanding the system based on hydrogen market prices benefits the country and electricity consumers, promoting renewable energy expansion and lowering LCOE. The only exception is in 2030, where significant capacity expansions in the 2.5 and 3 USD/kg H2 scenarios cause higher LCOEs. Despite different power plant expansions, LCOE remains relatively stable, indicating cost-optimal decisions.

Figure 8. Levelized cost of electricity, by cost categories. Inv: investment. PP: power plants. O&M: Operation and maintenance, including fuel

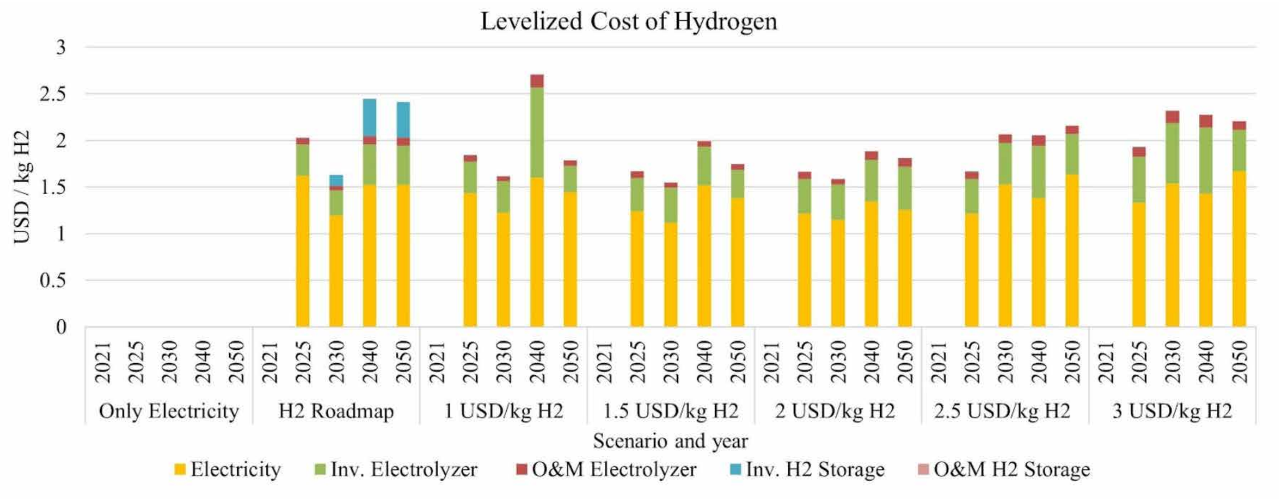


3.2. LCOH

Figure 9 shows the LCOH divided into different cost categories for various scenarios and years. The most significant costs in the LCOH come from the electricity used for hydrogen production, making LCOH closely related to LCOE and reflecting its changes over time. LCOH also depends on the capacity expansion of the hydrogen system, including electrolyzer and hydrogen tank capacities. Due to the modeling assumptions hydrogen storage is only required in the H2 roadmap scenario, adding costs in 2030, 2040, and 2050 in line with storage costs reported in the roadmap (Ministerio de Industria, Energía y Minería, 2023b).

The “H2 Roadmap” scenario indicates that a scale mismatch in the early years (2025 and 2030) can cause higher LCOH due to underutilized electricity systems. In 2040, a significant demand increase leads to a peak in costs driven by storage and electrolyzer investments. In the 1 and 1.5 USD scenarios, LCOHs are above market prices, but the model optimizes total costs by expanding electrolyzers to use otherwise curtailed electricity. This results in higher costs in 2040 due to reduced surplus electricity and limited infrastructure use. For higher price scenarios (2, 2.5, and 3 USD), LCOHs are below market prices, leading to large expansions and high production quantities. Overall, LCOHs tend to decrease over time, with increases during expansion years. Despite different development scenarios for Uruguay’s electricity and hydrogen systems until 2050, LCOH remains relatively homogeneous, following similar trends.

Figure 9. Levelized cost of hydrogen, by cost categories. Inv: investment. O&M: Operation and maintenance, including fuel costs.



4. RESULTS AND DISCUSSION

This work presents a methodology for assigning and distributing costs for a system with co-production of two or more commodities; this methodology can be applied to any energy system that analyzes sector coupling. We also present a comprehensive methodology for deriving all input data, such as demands, year-specific and country-specific CAPEX and OPEX, and economic factors, such as WACC and discount rates. The study presents different scenarios for optimizing Uruguay's electricity and hydrogen systems. Each scenario demonstrates distinct pathways for the evolution of the energy system, highlighting the potential impacts of integrating hydrogen production on installed capacities, electricity generation, and consumption patterns.

The research highlights the strategic role of hydropower and the necessity of battery storage in maintaining grid stability and enhancing system efficiency, particularly to support renewable energy expansions in photovoltaic and wind power.

The research also emphasizes the potential economic benefits of the hydrogen roadmap, including reduced electricity costs for domestic consumers and the promotion of renewable energy sources with costs. The findings suggest that, under favorable market conditions, hydrogen production could significantly contribute to Uruguay's economy, positioning the country as a major hydrogen exporter.

Recommendations for policymakers and stakeholders include investing in renewable energy capacities and hydrogen production, storage, and transportation infrastructure; developing robust market conditions and incentives for integrated renewable energy investments and electrolyzer capacities; exploring the implications for river, maritime, and port infrastructure to handle hydrogen transport and export; and investigating advancements in electrolyzer technologies and flexibility measures to enhance system efficiency and reduce costs.

In conclusion, this study provides valuable insights into optimizing Uruguay's electricity and hydrogen systems, demonstrating the transformative potential of integrating hydrogen production into the national energy mix. The research offers a roadmap for policymakers and stakeholders to navigate the energy transition, emphasizing the importance of strategic planning, infrastructure investment, and supportive policies to realize the full potential of hydrogen as a key component of Uruguay's sustainable energy future.

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