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Green Hydrogen Production to Mitigate Renewable Energy Curtailment in the Greek Grid

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Abstract

The continuous increase in Renewable Energy Sources (RES) in Greece's electricity system has led to growing energy curtailment due to limited grid capacity, especially in high-production regions. According to recent data, more than 200 GWh of clean energy was curtailed in a single quarter in 2024, highlighting the urgent need for effective storage solutions. Curtailment represents a growing system level challenge, but it also creates an opportunity to convert surplus renewable electricity into green hydrogen through electrolysis. This study quantifies the hydrogen production potential of curtailed RES electricity in four Greek regions, Peloponnese, Crete, Thrace, and Western Macedonia, and evaluates alternative storage pathways under harmonized techno-economic assumptions. A scenario-based framework is developed using regional RES capacity, curtailment estimates, electrolyzer efficiency, hydrogen conversion factors, and indicative storage cost ranges. The analysis compares pressurized tank storage, underground storage, and hybrid configurations, while also estimating avoided CO_2 emissions from the substitution of grey hydrogen. The results indicate substantial regional variation. The Peloponnese exhibits the highest annual hydrogen potential, followed by Crete, Thrace, and Western Macedonia, while each region presents different infrastructure constraints and deployment roles. Mainland regions with access to geological storage show lower indicative hydrogen costs than island systems, where storage and export constraints increase costs. The findings show that curtailed renewable electricity can function as a low-carbon feedstock for hydrogen production in Greece, supporting grid flexibility, regional decarbonization, and the gradual development of hydrogen hubs under differentiated regional strategies.

Keywords: green hydrogen; renewable energy curtailment; electrolysis; energy storage; Greece; sustainability

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1. Introduction

In recent years, the Greek economy has experienced significant growth in the renewable energy sector, reshaping the national energy landscape. Driven by the objectives of the European Green Deal [1], the REPowerEU Plan [2], and Greece's National Energy and Climate Plan (NECP) [3], the share of solar and wind power in the electricity mix has grown significantly. Greece benefits from one of the highest solar irradiation levels in Europe, with average global horizontal irradiance (GHI) ranging from 1400 to 1600 kWh/m^2/year in most regions [4]. This solar potential, combined with strong onshore and offshore wind resources, has made the country a frontrunner in the expansion of RES capacity. By the

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end of 2024, Greece had installed 9.6 GW of solar photovoltaics (PV) and 5.4 GW of wind power, representing nearly 60% of the total electricity generation capacity [5].

A report from the environmental think tank Green Tank indicates that Greece achieved a new milestone in clean energy production last year, with outputs from renewable energy sources and large hydroelectric plants reaching the highest levels observed in a decade. This development underscores Greece's ongoing commitment to renewable energy, the goal of attaining carbon neutrality by 2050, and its aspirations to establish itself as a green energy hub for Southeastern Europe [6]. The recently revised National Energy and Climate Plan outlines Greece's objectives to reduce greenhouse gas emissions by 58% over the next five years, and by 80% by the end of the following decade, and to achieve complete carbon neutrality, along with energy independence, by 2050. The updated plan for the period from 2025 to 2050 anticipates an increase in the share of renewable energy sources in electricity production, which currently stands at approximately 57%, to 75% by 2030 and to 95.6% by 2035.

The renewable energy sector represents a significant example of investment in new fixed productive capital within Greek territory. These investments have already yielded measurable results in the electricity generation mix.

According to data from the Greek Independent Power Transmission Operator (IPTO or ADMIE) S.A., a total of 25.2 TWh of electricity was generated from renewable sources on the interconnected grid, excluding large hydroelectric sources. This figure represents more than double the production level of 2019, which was 12.2 TWh, and indicates an average annual growth rate of 15.6%. The significant increase in renewable energy capacity, alongside the implementation of a policy aimed at achieving total decarbonization by 2028, has resulted in a substantial transformation of the electricity generation mix.

However, this remarkable progress has also introduced operational challenges. Chief among them is the issue of renewable energy curtailment, whereby excess electricity generation cannot be absorbed by the grid. Curtailment arises from transmission bottlenecks, insufficient storage, and market design constraints [7]. In Greece, curtailment has become particularly significant, with the Independent Power Transmission Operator (IPTO) reporting that more than 200 GWh of renewable electricity was curtailed in the first quarter of 2024 alone [7]. Seasonal variability exacerbates the issue, with higher curtailment in spring and autumn, when production from PV and wind is high but demand is relatively low. In contrast, curtailment is lower in summer and winter due to stronger consumption patterns.

Curtailment occurs when electricity generation exceeds the grid's capacity to transmit it, a fundamental challenge in power systems with high penetration of variable renewable energy. This is particularly acute in isolated island systems, such as Crete, and in peninsular regions with high-RES potential but limited transmission infrastructure, such as the Peloponnese and Thrace, as consistently documented in operator reports [8,9]. The problem is also emerging in Western Macedonia, a region undergoing a profound economic transformation guided by the national decarbonization strategy [10]. As the country's historic lignite heartland, its thermal power plants are being phased out. While this has freed up significant grid capacity, the region's Just Transition Development Plan anticipates a massive influx of new solar PV projects aiming to utilize this very infrastructure [11]. This rapid build-out is predicted to recreate congestion issues within years, a prospect detailed in the nation's grid development plan, making proactive storage planning essential [8].

This wasted energy represents both an economic loss and a missed opportunity for reducing carbon emissions. Instead of being discarded, curtailed electricity can be transformed into green hydrogen via water electrolysis. Green hydrogen has emerged as

a pivotal solution to this challenge. This hydrogen can then be stored for long periods and utilized across various sectors: industry, transport, heating, or for reconversion to electricity during periods of high demand and low-RES generation [12]. This approach is consistent with current EU and national hydrogen policy frameworks. The European Union's Hydrogen Strategy envisions the installation of 40 GW of electrolyzers by 2030 [13], while Greece's own National Hydrogen Strategy outlines a framework for pilot projects, infrastructure development, and market creation [14]. The International Energy Agency (IEA) emphasizes that green hydrogen will be a critical vector for decarbonizing "hard-to-abate" sectors, such as steelmaking, chemicals, and heavy transport [15]. Similarly, the Greek Hydrogen Strategy (2023) positions hydrogen as a cornerstone of the transition to climate neutrality, aiming for large-scale deployment by 2050 [15].

The potential for hydrogen production from curtailed RES is particularly relevant in Greece, given the spatial concentration of renewable resources. Four regions stand out: Peloponnese, Crete, Thrace, and Western Macedonia, as illustrated in Figure 1.

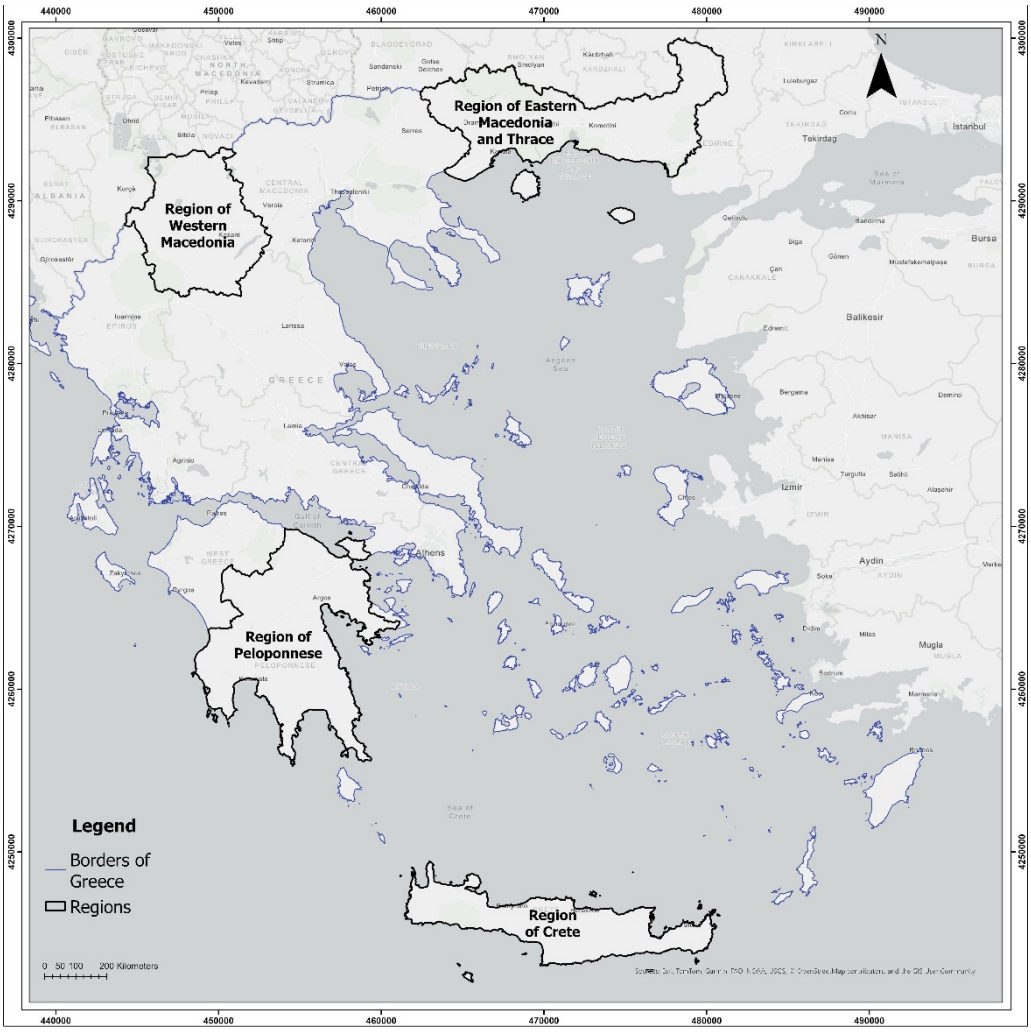


Figure 1. Map of the regions (Source: Authors, 2025).

These areas combine high-RES penetration with frequent curtailment events, making them promising candidates for hydrogen hubs. Each region also exhibits unique socio-economic and infrastructural characteristics. For example, Western Macedonia is undergoing a major transition away from lignite-based electricity generation, with the construction of the country's largest PV park in Kozani (200 MW capacity) [16], while Crete

has long faced grid isolation problems and seasonal curtailment of wind and solar power. An example of a large-scale PV installation in the Kozani region is presented in Figure 2.

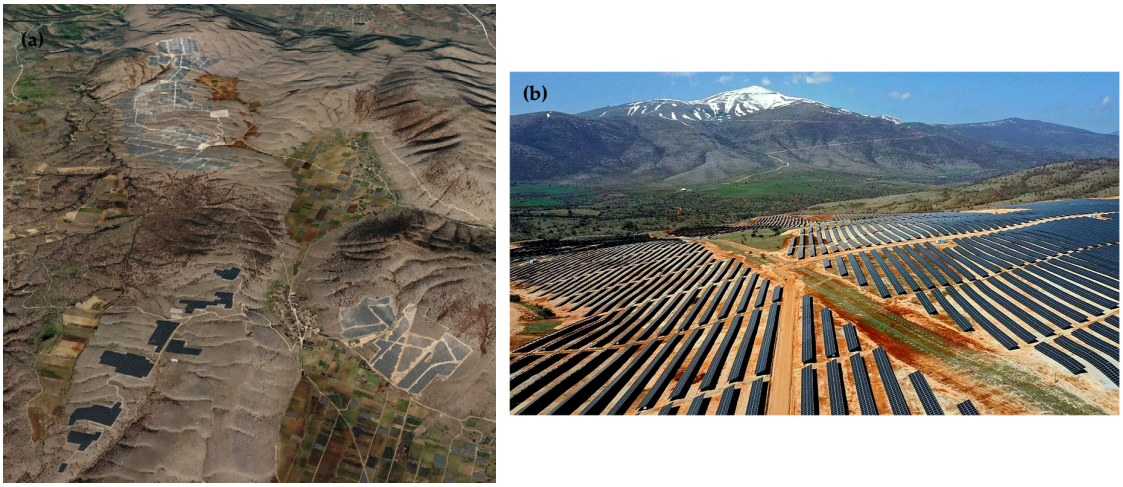


Figure 2. (**a**) Google Earth satellite view of the PV power plant in Kozani. (**b**) Photograph captured by the authors of the PV power plant in Kozani. (Source: Google Earth imagery, photo by the authors.)

From a systemic perspective, curtailed energy can be reconceptualized as a resource rather than a problem. This aligns with the principles of the circular economy, where waste streams are revalorized to create new value [17]. Converting excess electricity into hydrogen can increase the flexibility and resilience of the Greek grid, reduce dependency on imported fossil fuels, and contribute to the EU's long-term decarbonization pathway. Furthermore, the possibility of exporting hydrogen or derivatives (such as ammonia) positions Greece as a potential clean energy hub for the wider Eastern Mediterranean region [18].

Hydrogen integrates seamlessly with renewable energy systems, sequestering excess generation from wind, solar, and other variable sources. When renewable energy sources produce more electricity than the grid needs, that excess can be diverted to hydrogen production instead of being wasted. Later, when production from renewable sources declines, such as during periods of low wind or limited sunlight, the stored hydrogen can be used to fill the gap [19]. Figure 3 presents a graphic depicting various forms of hydrogen production and utilization.

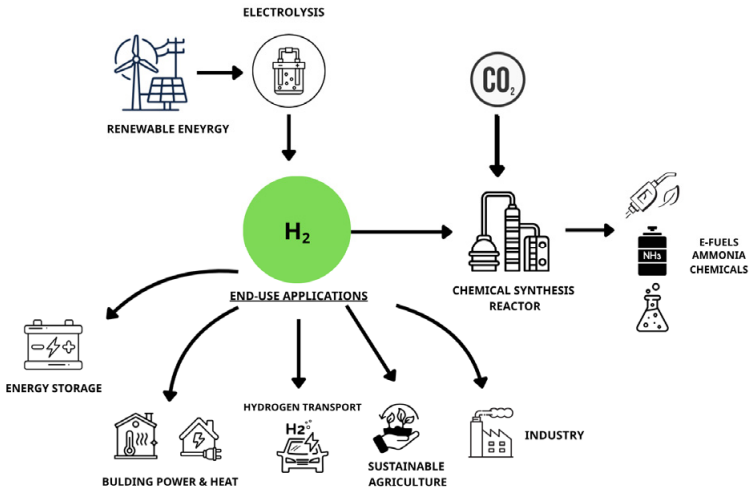


Figure 3. A graphic depicting various forms of hydrogen production and utilization (Source: Authors, 2026).

This approach aligns perfectly with strategic goals at multiple levels. The European Union's Hydrogen Strategy envisions the installation of 40 GW of electrolyzers by 2030 [13], while Greece's own National Hydrogen Strategy outlines a framework for pilot projects, infrastructure development, and market creation [14].

This study addresses that gap by evaluating the potential to convert curtailed renewable electricity into green hydrogen in four key Greek regions: the Peloponnese, Crete, Thrace, and Western Macedonia. The analysis combines regional curtailment estimates with harmonized assumptions on electrolyzer efficiency, hydrogen conversion, storage configurations, and avoided CO_2 emissions. The objectives are to quantify the annual hydrogen production potential from curtailed RES electricity in each region, to compare alternative storage pathways and their indicative techno-economic implications, and third, to assess the distinct regional roles that these areas could play in the development of hydrogen hubs in Greece. In doing so, the paper provides a comparative regional perspective on how curtailed renewable electricity can be integrated into emerging hydrogen strategies.

2. Materials and Methods

2.1. Data Sources

This study draws on a combination of national, European, and international data sources to evaluate the potential for producing green hydrogen from curtailed renewable energy in Greece.

The primary datasets used in this study draw from several authoritative sources [20]. IPTO's monthly operational reports provide detailed figures on curtailed renewable electricity, with more than 200 GWh of RES production curtailed in the first quarter of 2024 [7]. Complementary information is available through Hellenic RES Operator (DAPEEP), whose renewable curtailment and settlement reports offer additional insight into system-level constraints [21]. The National Energy and Climate Plan (NECP) establishes the official framework for Greek energy policy and projects that installed PV capacity will reach 13.5 GW by 2030 [10]. Regional energy demand data from Eurostat and the Hellenic Statistical Authority (ELSTAT) enable direct comparisons between renewable generation and consumption profiles across Greece [22,23]. Global benchmarks for electrolyzer efficiency (60–70%), hydrogen conversion factors (33.3 kWh/kg H_2), and CO_2 emission intensities were derived from recent IRENA and IEA publications [24,25]. Hydrogen energy content is expressed on a lower heating value (LHV) basis (33.3 kWh/kg), unless otherwise stated. Recent academic work, including studies such as Vigkos & Kosmopoulos (2025) on solar potential in Greece [5], research by Ganter A. et al. [26], and additional literature on renewable curtailment, provides context for current trends in RES deployment and grid congestion. Hourly load and RES generation data for the corresponding regions and time periods were obtained from ENTSO-E [27]. Finally, techno-economic parameters, including electrolyzer efficiency (kWh/kg-H_2), CAPEX (€/kW), OPEX as a percentage of CAPEX, component lifetimes, and storage costs for both pressurized gaseous storage (200–500 bar) and prospective underground salt caverns, were sourced from recent IEA and IRENA reports as well as relevant academic studies. These data sources were combined to construct a scenario-based framework for quantifying hydrogen production potential from curtailed RES electricity.

To ensure consistency across regions, the analysis applies a common set of assumptions for electricity to hydrogen conversion, emissions displacement, and indicative storage performance. Regional curtailment values were combined with harmonized conversion parameters to allow direct comparison between Peloponnese, Crete, Thrace, and Western Macedonia. This approach does not aim to reproduce plant-level dispatch behavior, but

rather to provide a transparent and regionally comparable estimate of hydrogen production potential under representative techno-economic conditions.

2.2. Analytical Framework

The analytical framework is based on a sequence of simplified but transparent calculations linking curtailed renewable electricity to hydrogen production, avoided CO_2 emissions, and indicative storage requirements. First, annual curtailed electricity was estimated either directly from reported values or by applying representative curtailment shares to annual regional RES generation. Second, hydrogen-equivalent energy was calculated using an electrolyzer efficiency of 65% (LHV basis), adopted here as a representative value within the 60–70% performance range commonly reported in recent IEA and IRENA publications for commercial alkaline and PEM electrolysis systems. Curtailment percentages are based on reported ranges in high-renewable regions (typically 5–12%) and are applied as representative values for each case study. Where direct regional data were not available, mid-range values were adopted to ensure consistency across the analysis. Third, hydrogen mass was derived using the lower heating value conversion factor of 33.3 kWh/kg H_2. Finally, avoided CO_2 emissions were estimated assuming substitution of grey hydrogen with an average emissions intensity of 10 kg CO_2 per kg H_2.

For pressurized storage, indicative hydrogen storage volume was calculated assuming a representative density of approximately 22 kg H_2/m^3 at 350 bar. For collocated electrolysis concepts, such as the Kozani case study, a simplified electrolyzer sizing heuristic was also applied using a 25% utilization factor to approximate the electrolyzer capacity required to absorb annual curtailed electricity under clustered curtailment conditions. A utilization factor of 25% is assumed for collocated electrolyzers, reflecting the intermittent nature of curtailed renewable energy, particularly under midday-heavy curtailment patterns typical of PV-dominated systems. This value is consistent with literature ranges for curtailed-energy-driven hydrogen production systems, where utilization is significantly lower than nominal capacity due to temporal mismatch between generation and demand. Reported values typically range between 20 and 40%, depending on regional generation profiles and grid constraints [24].

The analysis follows a deterministic framework based on representative values for key parameters (e.g., curtailment rates, electrolyzer efficiency, and utilization). While this approach enables transparent and comparable results across regions, it does not capture temporal variability or operational uncertainty. Therefore, the results should be interpreted as first-order estimates rather than precise system simulations.

2.3. Storage Ways

At its core, hydrogen energy storage involves producing hydrogen gas, typically through electrolysis, where water is split into hydrogen and oxygen using renewable electricity, and storing it for later use. This stored hydrogen can then be converted into electricity via fuel cells or turbines or used directly as a clean fuel for industrial processes, heating, and transportation. As part of the renewable energy system, hydrogen acts as a flexible and scalable energy carrier that complements other storage technologies [28].

Green hydrogen can be stored as compressed gas, liquid hydrogen (cryogenic), or within solid materials. Common methods include high-pressure gas tanks for short-term storage, double-walled cryogenic tanks for liquid storage, and chemical storage in materials like metal hydrides or carriers like ammonia for longer durations. Large-scale, long-term storage can be achieved by injecting hydrogen gas into underground salt caverns [19].

The most common physical storage methods are the Compressed Gas and the Liquid Hydrogen methods. In the Compressed Gas Method, the hydrogen is stored at high pressures (350–700 bar) in tanks, often cylindrical or spherical for stationary applications. This is a mature technology suitable for short- to medium-term storage [29]. At the Liquid Hydrogen Method, the hydrogen is cooled to cryogenic temperatures (−252.8 °C) to become liquid. This requires specialized, double-walled, vacuum-insulated tanks and is suitable for applications with high volume needs [18].

Each hydrogen storage pathway presents distinct advantages and limitations. Compressed gas storage is technologically mature, modular, and suitable for short- to medium-term applications. However, it is associated with higher storage costs and lower volumetric energy density. Liquid hydrogen storage enables higher energy density but requires cryogenic conditions and additional energy input, increasing system complexity. In contrast, underground storage options, such as salt caverns, offer the lowest cost for large-scale and long-term storage, although their deployment is constrained by geological availability and requires significant upfront investment. Therefore, the selection of storage pathways depends on the scale, location, and intended use within the energy system. Figure 4 presents a typical liquid hydrogen storage tank system with double-gasket insulation and dual sealing configuration.

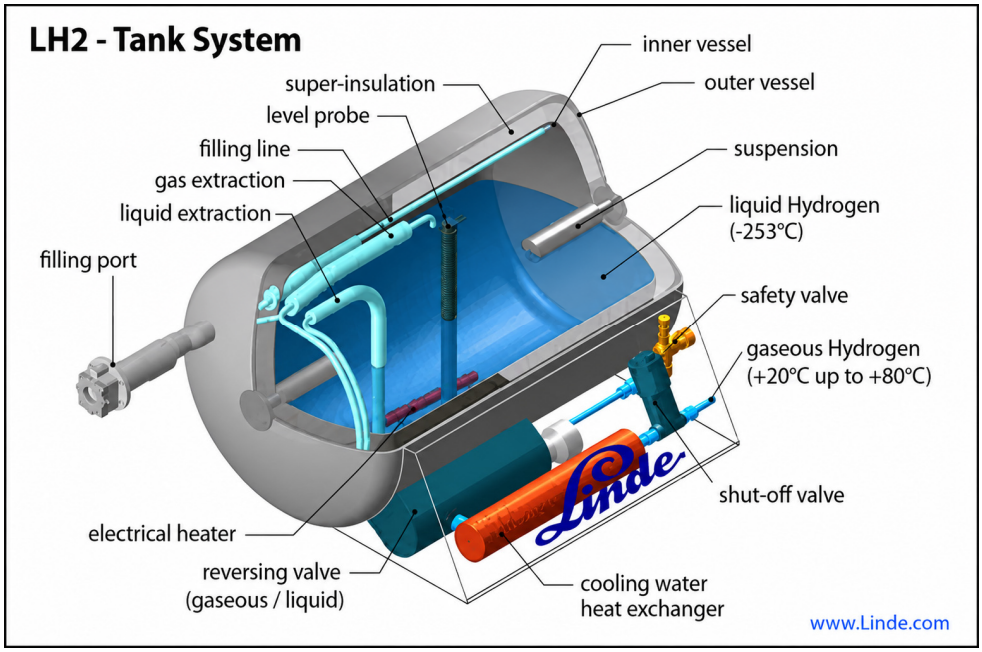


Figure 4. Liquid hydrogen storage tank system, horizontal mounted with double gasket and dual seal [30].

Pressurized hydrogen tanks represent the most mature and modular storage option, suitable for short-term applications and for deployment near renewable energy parks, industrial facilities or transport hubs. Their key advantages include technological readiness, fast response times and scalability from pilot to commercial scale. However, they remain limited by the relatively high storage costs—typically estimated in the range of €2–4/kg H_2, and by spatial requirements, which make them unsuitable for seasonal-scale storage compared to geological alternatives. Despite these limitations, pressurized hydrogen tanks have already been commercialized in hydrogen refueling depots, with Germany and Japan operating on-site storage facilities ranging between 1000 and 5000 m^3, demonstrating their feasibility for mobility and distributed energy applications [31].

Large-Scale & Long-Term Storage

In the Underground Salt Caverns the hydrogen gas can be injected into large, naturally occurring underground salt formations, creating a cost-effective solution for storing large quantities of energy for long durations [32]. Figure 5 presents the HYBRIT pilot rock cavern hydrogen storage facility in Luleå, Sweden.



Figure 5. Rock cavern hydrogen gas storage facility; HYBRIT's pilot facility at Svartöberget in Luleå, Sweden. (Source: SAB, LKAB & Vattenfall).

Underground storage of hydrogen, typically in salt caverns, aquifers, or depleted hydrocarbon fields, is widely recognized as the lowest-cost large-scale option, with estimated costs ranging from 0.5 to 1 €/kg H_2 [32] and seasonal storage capacities that may reach several hundred gigawatt-hours per cavern. Despite these advantages, the deployment of underground storage is strongly dependent on local geology and requires extensive surveying, characterization, and permitting before commercial use is possible. In the Greek context, promising opportunities are found in Northern Greece, particularly in Thrace and Western Macedonia, where sedimentary basins and depleted gas fields could provide suitable candidates for underground hydrogen storage [33].

Unlike batteries, which are generally designed for short-term energy storage lasting from hours to many days, hydrogen is excellent for storing energy over weeks or indeed months. This seasonal storehouse capability enables renewable energy produced in the summer to be stored for use during periods of lower demand and lower renewable energy availability.

Hydrogen can also be reconverted into electricity via fuel cells or turbines, enabling long-term and seasonal energy storage within renewable energy systems. This capability makes hydrogen a key flexibility option for balancing variable renewable energy generation and demand. In addition, recent studies highlight ongoing developments in hydrogen production and material-based systems that support the broader hydrogen value chain and its role in energy transition pathways [34].

The hydrogen storehouse is also largely scalable, able to meet the requirements of artificial installations, indigenous grids, or indeed entire nations. Large underground swab grottoes, for example, can store vast quantities of hydrogen at low cost, offering a practical result for long-term, large-scale energy adaptability. This scalability makes hydrogen a critical enabler of public and cross-border renewable energy strategies [29].

Overall, the feasibility of hydrogen storage pathways depends strongly on regional characteristics. Pressurized hydrogen tanks are technically mature and suitable for distributed and short-term applications, particularly near renewable generation sites and mobility hubs. In contrast, underground storage options such as salt caverns offer significantly lower costs at large scale but are highly dependent on local geological conditions. In the Greek context, such options are primarily relevant for mainland regions such as Thrace and Western Macedonia, while island systems like Crete are more constrained and rely on alternative storage or export pathways.

Hydrogen storage options also involve clear trade-offs between cost, storage duration, and system complexity. Compressed storage is suitable for short- to medium-term applications but involves higher costs, while underground storage offers cost-effective long-duration capacity but is constrained by geological availability. Hydrogen carriers such as ammonia or LOHCs enable long-distance transport and long-term storage but introduce additional conversion steps and efficiency losses.

3. Results

Before examining each region in detail, it is useful to emphasize that the four case studies represent different configurations of renewable development and system constraints within Greece. The Peloponnese reflects a high-generation mainland region with transmission bottlenecks, Crete represents an island system with persistent balancing challenges, Thrace combines moderate curtailment with strong corridor and export potential, and Western Macedonia reflects a post-lignite transition region where hydrogen could be linked to industrial restructuring. For this reason, the regional analysis is not intended only to quantify hydrogen output, but also to compare how geography, infrastructure, and storage options shape the role of hydrogen across distinct parts of the Greek energy system. The same analytical framework is consistently applied across all regions. Therefore, the detailed calculation steps are described once, and only key regional inputs and results are presented in the following subsections.

For clarity and comparative purposes, the key regional parameters and hydrogen production estimates are summarized in Table 1.

Table 1. Comparative summary of renewable energy generation, curtailment assumptions, and estimated hydrogen production potential across the four studied regions in Greece.

Region	RES Generation (TWh)	Curtailment (%)	Curtailed Energy (GWh)	H_2 Potential (t/year)	Key Constraint
Peloponnese	~4.5	6%	~270	~5270	Grid bottlenecks
Crete	~1.8	10%	~180	~3510	Island system
Thrace	~2.2	6%	~132	~2575	Transmission/export
Western Macedonia	~0.9	8%	~72	~1405	Transition region

3.1. Peloponnese

The Peloponnese peninsula represents one of Greece's most important renewable energy regions, with abundant solar radiation and favorable wind conditions. The Peloponnese has consistently ranked among the top Greek regions for photovoltaic (PV) deployment due to high levels of global horizontal irradiance (GHI), averaging 1500–1600 kWh/m^2/year [35]. This solar potential has attracted significant investment in both utility-scale and distributed PV systems, complemented by large onshore wind farms.

However, despite its renewable wealth, the Peloponnese faces frequent electricity curtailments due to limited transmission capacity toward Central Greece and Attica, the country's largest demand centers. IPTO (2024) notes that curtailment events are especially severe in spring and autumn, when high-RES output coincides with lower local electricity demand [8].

Installed Renewable Capacity

As of 2024, the Peloponnese hosts approximately 1.5 GW of PV capacity and 1.2 GW of wind farms, accounting for more than 15% of Greece's total RES capacity [5,7]. With an average PV yield of 1450 kWh/kWp per year [5], the region's solar installations produce roughly:

$$1,500,000 \text{ kWp} \times 1450 \text{ kWh/kWp/year} = 2.18 \text{ TWh/year}$$

Wind generation adds an estimated 2.5–3 TWh/year under typical capacity factors of 25–30% [13]. Combined, this represents more than 4.5 TWh of annual renewable electricity generation, a volume comparable to 12% of Greece's total electricity consumption in 2023 [7]. Figure 6 presents the annual renewable energy generation in the Peloponnese region for 2024.

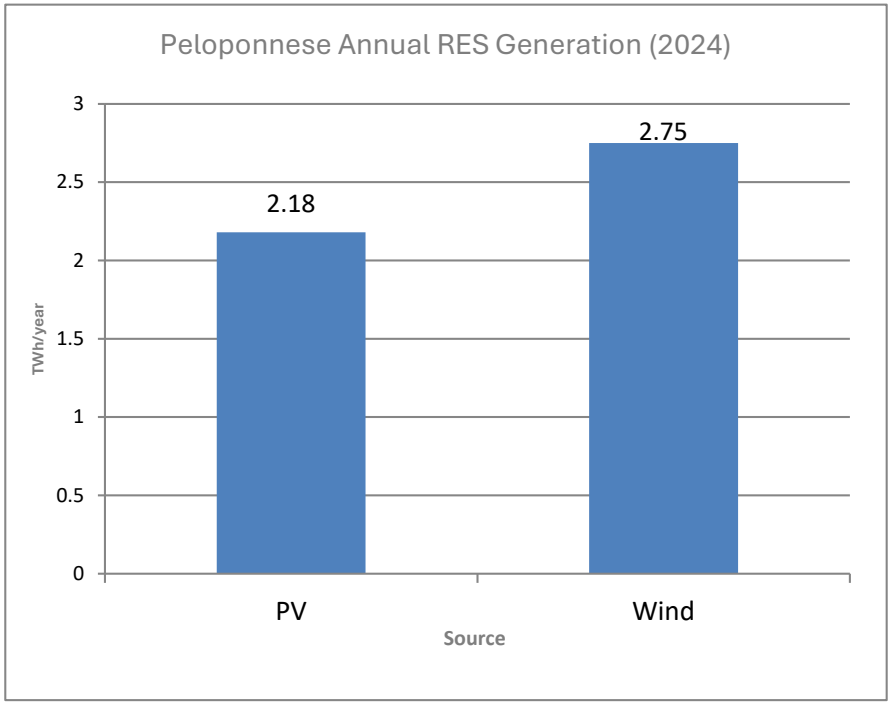


Figure 6. Peloponnese Annual RES Generation.

The distribution between PV and wind indicates the degree of renewable diversification in the region, which directly affects the temporal profile of curtailment and the stability of hydrogen production.

Curtailment Levels

Curtailment in the Peloponnese is disproportionately high due to grid bottlenecks. The region can experience curtailment levels of 5–8% of annual renewable production [7]. Applying a mid-value of 6% to the estimated 4.5 TWh annual RES output, curtailed energy is approximately:

$$4500 \text{ GWh} \times 0.06 = 270 \text{ GWh/year}$$

This figure is consistent with the national-level curtailment (~800 GWh/year) reported by IPTO [8], suggesting that the Peloponnese alone accounts for roughly one-third of Greece's curtailed renewable electricity. The annual renewable electricity generation and curtailment distribution for the Peloponnese region is presented in Figure 7.

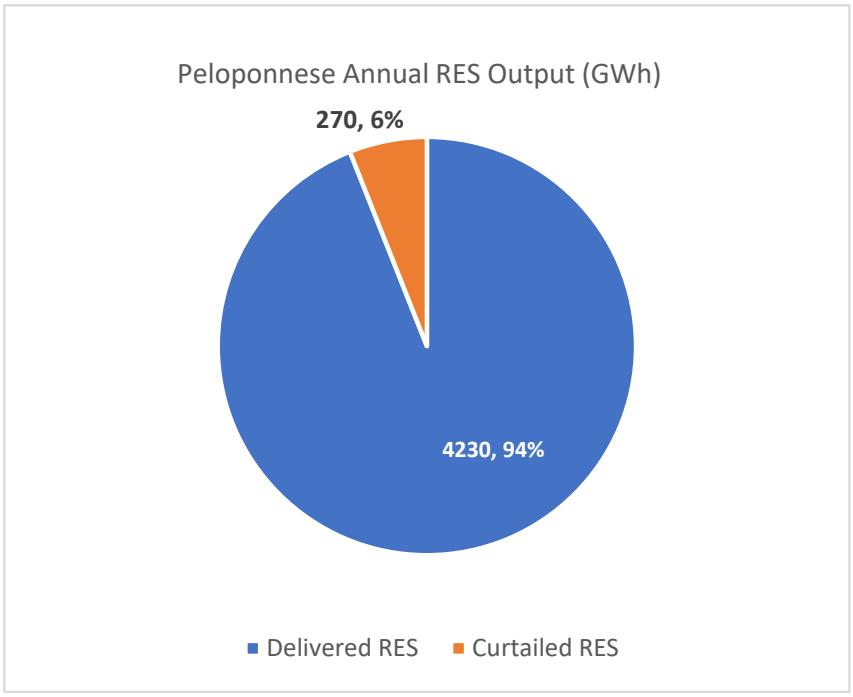


Figure 7. Annual renewable electricity generation in the Peloponnese under a mid-case curtailment scenario (6% of total RES output).

The level of curtailment reflects the magnitude of unused renewable energy, highlighting the available potential for hydrogen production as a flexibility solution.

Hydrogen Production Potential

Redirecting 270 GWh of curtailed electricity to electrolysis could produce green hydrogen. Assuming 65% electrolyzer efficiency [15], the hydrogen-equivalent energy yield is:

$$270\ \text{GWh} \times 0.65 = 175.5\ \text{GWh}\ (\text{H}_2\ \text{energy})$$

Converted to hydrogen mass using 33.3 kWh/kg H_2 [18]:

$$175,500,000\ \text{kWh} \div 33.3\ \text{kWh/kg} = 5270\ \text{tons of}\ \text{H}_2/\text{year}$$

CO_2 Avoidance

If this green hydrogen substitutes grey hydrogen (average 10 kg CO_2 per kg H_2 [24]), annual avoided emissions would be:

$$5270 \times 10 = 52,700\ \text{tons of}\ \text{CO}_2/\text{year}$$

The overall calculation framework for hydrogen production potential and associated CO_2 avoidance is presented in Figure 8.

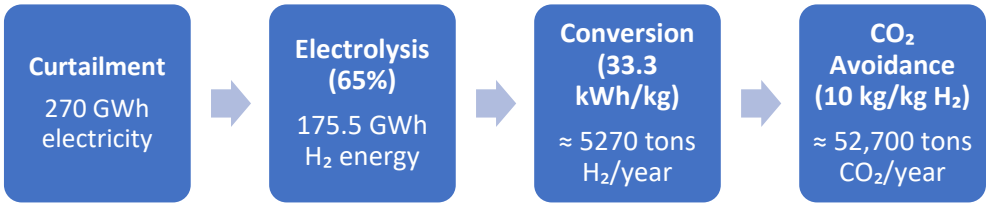


Figure 8. Calculation chain of hydrogen production and CO_2 avoidance in the Peloponnese.

Hydrogen presents a wide range of promising applications across key sectors. In the transport sector, the establishment of hydrogen refueling hubs along the Patras–Athens corridor could support heavy-duty vehicles such as trucks and buses, with each ton of hydrogen capable of powering approximately 50 fuel-cell buses for one day [7]. In industry, green hydrogen could replace fossil-based hydrogen currently used in small chemical industries in Corinthia and Patras. Finally, regarding grid balancing, the reinjection of hydrogen into the electricity system during summer demand peaks could enhance reliability, especially given the high penetration of photovoltaic generation.

Storage Options in the Peloponnese

Curtailment in the Peloponnese is driven by midday PV peaks and transmission bottlenecks toward Central/Northern Greece, especially in spring and autumn [6,7]. Because events are clustered, a mix of short-term buffering and bulk/seasonal storage is optimal.

Pressurized Hydrogen Tanks (Daily Weekly): The system is designed to capture midday curtailment, smooth day-to-day variability, and supply clean fuel for local mobility needs such as buses and trucks. For illustration, if the Peloponnese curtailed approximately 100 GWh per year, consistent with Greece-wide curtailment shares and seasonal patterns reported by IPTO and the relevant literature [7,8], this volume can serve as a baseline for estimating the required electrolyzer capacity, storage needs, and resulting hydrogen output.

H_2 energy at 65% electrolysis efficiency [36]:

$$100\ \text{GWh} \times 0.65 = 65\ \text{GWh}\ H_2/\text{y}$$

H_2 mass at 33.3 kWh/kg [24]:

$$65,000,000\ \text{kWh} \div 33.3 = 1952\ \text{tH/y}$$

Tank volume at ~350 bar (~22 kg H_2/m^3) (DOE/IRENA ranges) [24,34]:

$$1,952,000\ \text{kg} \div 22\ \text{kg}\ H_2/m^3 = 88,700\ m^3$$

The implication is going to be that this is too large for a single site but practical as distributed storage across several hubs (e.g., co-located at major PV nodes and logistics depots). This option is fast to deploy and modular, making it particularly suitable for use as transport fuel. However, it requires higher compression costs and is not suitable for long-term or seasonal energy storage.

Underground Storage (Seasonal): This option serves as a bulk, low-cost seasonal storage solution, using salt caverns or depleted gas fields, to pool curtailed energy from multiple PV and wind clusters. Its feasibility depends on detailed geological screening, though European experience demonstrates that individual caverns can provide storage capacities of several hundred GWh in regions with favorable formations [7]. At large scale, this approach offers the lowest cost per kWh of stored energy; however, it requires suitable geology, thorough subsurface characterization, and comprehensive permitting procedures.

Hybrid Setup: This configuration combines distributed pressurized hydrogen tanks, which capture daily curtailment and supply refueling services, with regional underground storage that provides seasonal balancing capacity [37]. Such architecture is well suited to the Peloponnese, given its high photovoltaic penetration, recurrent curtailment patterns, strategic ports, and highway corridors that facilitate hydrogen logistics, and the presence of potential industrial offtakers, including food and agro-processing industries.

Overall, the Peloponnese combines the highest quantitative hydrogen potential with favorable conditions for hybrid storage deployment, making it the strongest candidate for early large-scale mainland implementation.

3.2. Crete

Crete is the largest island in Greece and one of the most dynamic regions for renewable energy development. With strong wind potential, high solar irradiation, and until recently an isolated grid, Crete has historically faced some of the highest levels of renewable curtailment in the country. For decades, the island operated as an autonomous electrical system, with only small-scale submarine cables connecting it to the mainland. This created frequent imbalances between production and demand, forcing the grid operator to curtail significant volumes of wind and solar power [6,7].

Installed Renewable Capacity

By 2024, Crete had installed approximately 450 MW of wind power and 350 MW of PV capacity [3]. The island's global horizontal irradiance (GHI) averages 1600 kWh/m^2/year, making it one of the sunniest regions in Europe [35].

Using a typical PV yield of 1500 kWh/kWp/year, the annual solar electricity production is:

$$350,000 \text{ kWp} \times 1500 \text{ kWh/kWp/year} = 525 \text{ GWh/year}$$

With average wind turbine capacity factors of 30–35%, the island's wind fleet generates approximately 1.2–1.4 TWh annually [13]. In total, Crete produces ~1.7–1.9 TWh of renewable energy per year, covering 80–90% of the island's energy demand [22,23].

Figure 9 presents the annual renewable energy generation in the Crete region.

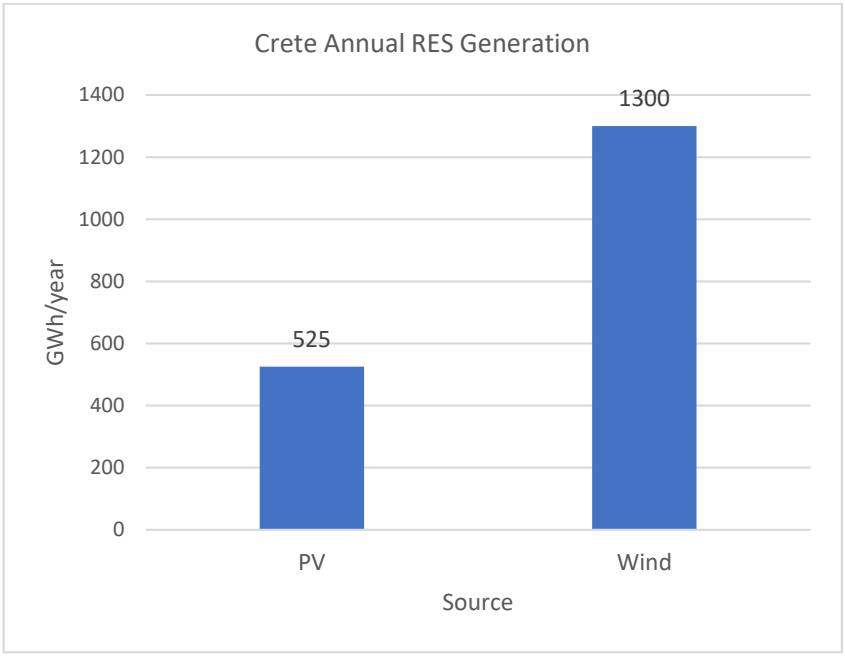


Figure 9. Crete Annual RES Generation.

Curtailment Levels

Curtailment has historically been severe due to the island's isolation. Estimated curtailment levels on Crete are at 8–12% of annual renewable production [13]. Assuming a mid-value of 10% applied to an average of 1.8 TWh annual RES output, curtailed energy is:

$$180 \text{ GWh/year}$$

The Crete–Attica interconnection (completed 2022–2023) has begun to reduce curtailment, yet it remains a persistent issue, particularly in spring and autumn when demand is lower and RES production is high.

The annual renewable electricity generation and curtailment distribution for the Crete region is presented in Figure 10.

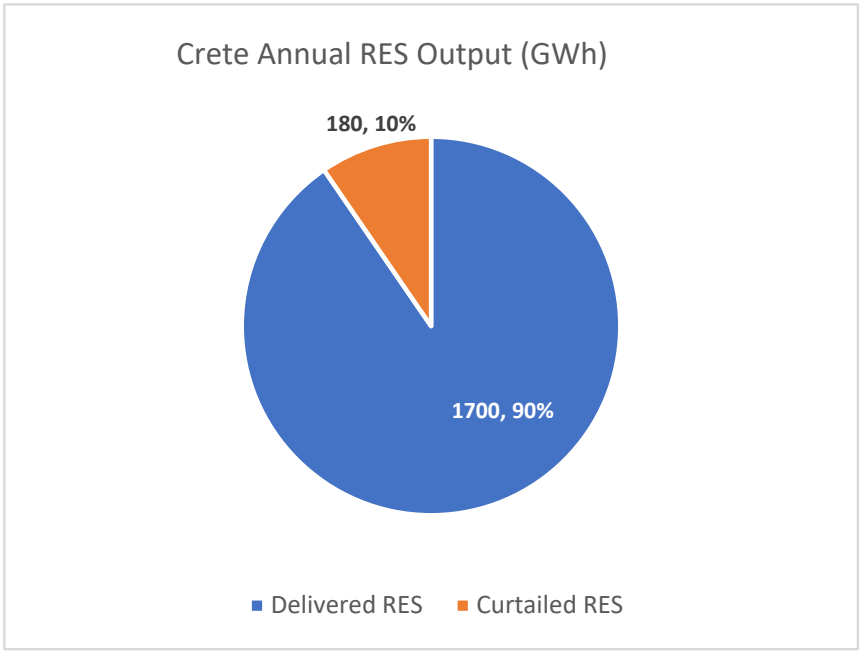


Figure 10. Annual renewable electricity generation in Crete under a mid-case curtailment scenario (10% of total RES output).

Hydrogen Production Potential

If 180 GWh of curtailed electricity is redirected to electrolysis, and assuming 65% electrolyzer efficiency [38], the hydrogen-equivalent yield is:

$$117 \text{ GWh } (H_2 \text{ energy})$$

Converted into hydrogen mass [39]: 3510 tons of H_2/year.

CO_2 Avoidance

If this hydrogen replaces grey hydrogen, which typically emits ~10 kg CO_2 per kg H_2 [40], annual avoided emissions are:

$$35,100 \text{ tons of } CO_2/\text{year}$$

The overall calculation framework for hydrogen production potential and associated CO_2 avoidance is presented in Figure 11.

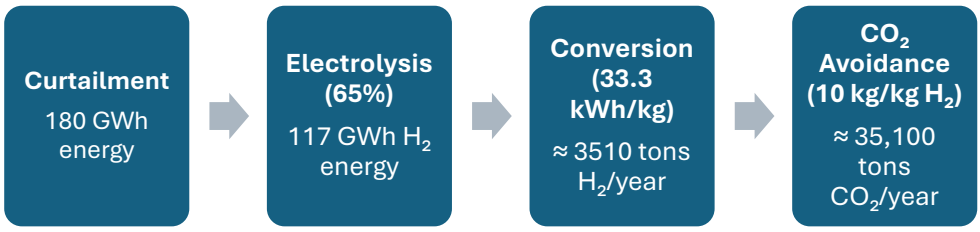


Figure 11. Flow chart of hydrogen production and CO_2 avoidance in the Crete.

Crete offers several promising pathways for hydrogen deployment. In the transport sector, the island's extensive tourism-related mobility, buses, taxis, and ferries, positions it as an early adopter, with hydrogen-powered ferries already being piloted on other European islands, indicating strong transferability to the Cretan context. Although heavy industry is limited, sectors such as food processing, cold storage, and logistics could integrate hydrogen to reduce their dependence on diesel and lower operational emissions. Moreover, given Crete's exceptionally high solar penetration, hydrogen-to-power facilities, using turbines or fuel cells, could provide seasonal balancing, reinjecting electricity into the grid during peak summer demand when air-conditioning loads are at their highest, thereby enhancing system stability.

Crete's combination of abundant RES, persistent curtailment, and high energy demand makes it an ideal candidate for hydrogen pilot projects. As an island with limited fossil fuel resources, Crete also offers a compelling showcase for energy autonomy and sector coupling through hydrogen. A successful hydrogen strategy here could serve as a blueprint for other European islands under the EU's Clean Energy for EU Islands initiative.

Pressurized Hydrogen Tanks (On-Island, Daily–Weekly):

Using the Crete scenario, we estimate an annual hydrogen output of 3510 t derived from 180 GWh of curtailed electricity at 65% conversion efficiency [24,36]. At a storage density of ~22 kg/m^3 for 350-bar tanks [24,41], this corresponds to approximately 159,500 m^3 of required storage volume.

$$3,510,000 \text{ kg} \div 22 \text{ kg} = 159,500 \text{ m}^3$$

These volumes indicate that high-pressure tanks are feasible primarily as distributed, multi-site storage, located at the airport, port, and bus depots, to support tourism-driven mobility applications such as buses, ferries, and logistics fleets. The approach enables fast deployment and is well suited for fueling hubs, though spatial limitations and cost escalation constrain large-scale expansion.

Underground Storage (Limited On-Island Prospects)

Crete's geological conditions make the development of large underground hydrogen storage structures, such as salt caverns, highly unlikely, while depleted hydrocarbon reservoirs would require intensive appraisal to confirm viability. As a practical alternative, Crete can be treated as a production and near-term consumption site, serving transport and backup power needs, while exporting hydrogen or derivatives to the mainland for seasonal-scale storage.

Conversion-Based Storage for Export (Off-Island Seasonal)

Chemical carriers such as ammonia (NH_3) and liquid organic hydrogen carriers (LOHC) represent established options for bulk hydrogen storage and export, particularly suitable for islands where space and geology constrain large-scale physical storage [36,41]. In this pathway, hydrogen is converted into NH_3 (or LOHC) and shipped to major mainland hubs such as Piraeus/Attica or Western Macedonia, where underground storage or industrial consumption is available. Although this adds conversion losses and in-

creases CAPEX, it circumvents Crete's physical constraints and leverages Greece's maritime logistics capabilities.

From a comparative perspective, Crete represents a distinct hydrogen case in which strong renewable availability and persistent curtailment support production potential, but long-term deployment depends more heavily on distributed storage and export-oriented conversion pathways than in mainland regions.

3.3. Thrace

Thrace, located in northeastern Greece, is strategically positioned near industrial zones, cross-border transport corridors, and interconnections with Bulgaria and Turkey. This geographic advantage, combined with its high wind and solar potential, makes Thrace a prime candidate for renewable energy expansion and the development of a hydrogen hub.

Installed Renewable Capacity

By 2024, Thrace was estimated to have 600 MW of wind capacity and 300 MW of PV installations, reflecting growing investments in both technologies [12,13]. The region benefits from strong coastal and mountainous wind resources, with average capacity factors of 30–35%, and solar yields of ~1400–1500 kWh/kWp/year [14,32].

This translates into an approximate annual production of:

- PV electricity: $300,000\ \text{kWp} \times 1450\ \text{kWh/kWp/year} = 435\ \text{GWh/year}$;
- Wind electricity: $600\ \text{MW} \times 8760\ \text{h/year} \times 0.3 = 1735\ \text{GWh/year}$.

Total renewable generation is therefore around 2.2 TWh/year, significantly exceeding local demand in some periods. Figure 12 presents the annual renewable energy generation in the Thrace region.

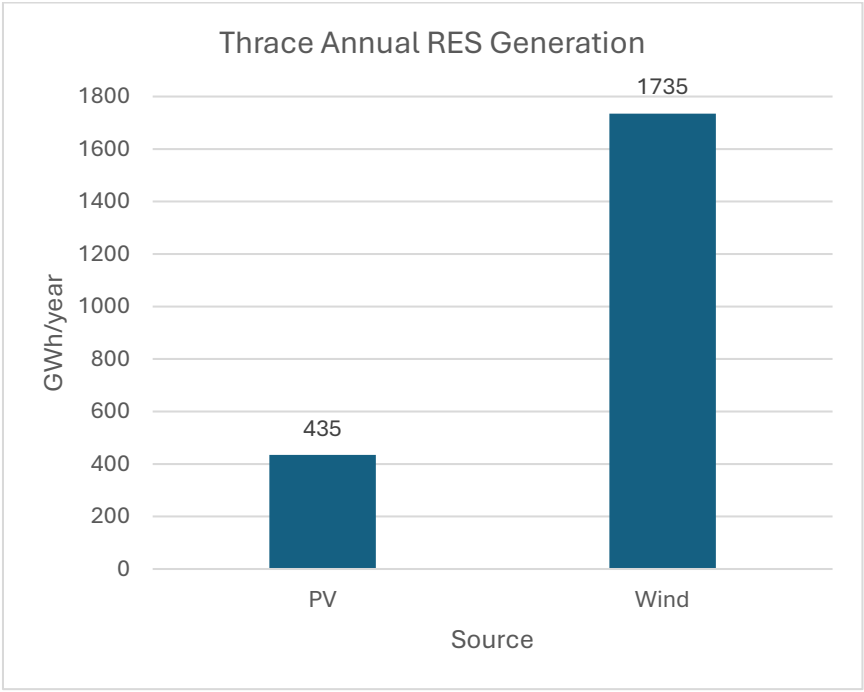


Figure 12. Thrace Annual RES Generation.

Curtailment Levels

Due to transmission bottlenecks and grid balancing challenges, Thrace also experiences RES curtailments. Curtailment is estimated at 5–8% of annual output [13,14]. Using a mid-value of 6%: 2200 GWh × 0.06 = 132 GWh/year curtailed.

The annual renewable electricity generation and curtailment distribution for the Thrace region is presented in Figure 13.

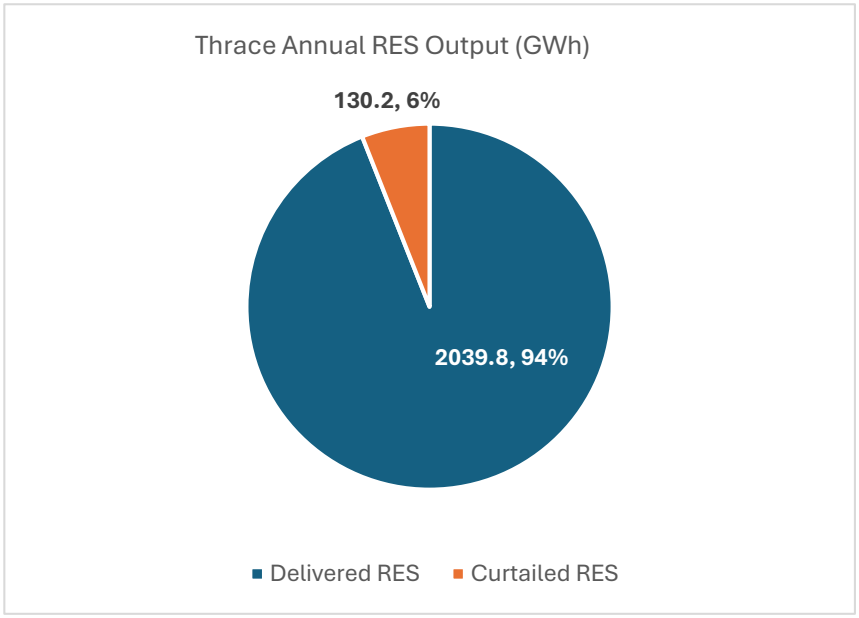


Figure 13. Annual renewable electricity generation in the Thrace under a mid-case curtailment scenario (6% of total RES output).

Hydrogen Production Potential

If the curtailed 132 GWh is directed to electrolysis at 65% efficiency [38]:

$$85.8 \text{ GWh } (H_2 \text{ energy})$$

Converted into hydrogen mass [42]:

$$2575 \text{ tons of } H_2/\text{year}$$

CO_2 Avoidance

If this replaces grey hydrogen (10 kg CO_2/kg H_2) [43]:

$$25,750 \text{ tons } CO_2/\text{year avoided}$$

The overall calculation framework for hydrogen production potential and associated CO_2 avoidance is presented in Figure 14.

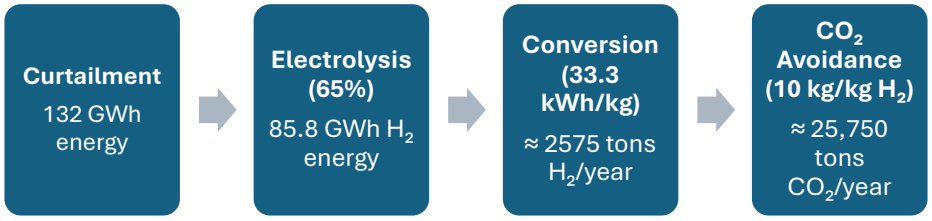


Figure 14. Flow chart of hydrogen production and CO_2 avoidance in the Thrace.

Potential Applications

Thrace's proximity to industrial facilities and cross-border trade routes makes it an ideal location for hydrogen supply chains. Hydrogen could be exported northward to Bulgaria and Romania.

- Transport: Hydrogen could decarbonize freight and heavy-duty trucks along the Egnatia Odos highway, a major east–west corridor.
- Grid Reinjection: Hydrogen-to-power could complement RES and reduce curtailments in peak periods.

Thrace's mix of strong wind, growing PV, and strategic geography supports its role as a regional hydrogen hub, potentially serving both domestic and export markets.

Storage Options in Thrace

Thrace's curtailed energy potential of 132 GWh/year translates into approximately 2575 tons of hydrogen per year, assuming 65% electrolysis efficiency and the standard 33.3 kWh/kg H_2 conversion factor [24,33]. While the absolute quantity is modest compared to national demand, the strategic location of Thrace makes it highly attractive for developing storage and logistics infrastructure. The region's proximity to cross-border corridors (Bulgaria, Turkey) and to existing gas pipelines and interconnectors positions Thrace as a potential hydrogen export gateway for Southeast Europe.

Pressurized Hydrogen Tanks

Calculation of storage volume: Annual hydrogen production potential: 2575 t H_2/year = 2,575,000 kg. At 350 bar compression, the density of H_2 is ~22 kg/m^3 [24,39]. Required storage volume:

$$\frac{2,575,000 \text{ kg}}{22 \text{ kg/m}^3} = 117,000 \text{ m}^3.$$

This volume is not practical as a single storage site, but it is highly feasible when distributed across multiple pressurized storage depots. For example, ten refueling depots along the Egnatia Odos highway (spanning Thrace to Epirus) would each need ~11,700 m^3 of tank capacity. This scale is consistent with hydrogen refueling stations already deployed in Germany and Japan, where typical storage capacities are in the 1000–5000 m^3 range [24].

Thrace presents strong potential for hydrogen deployment, particularly along the Egnatia Odos corridor, where hydrogen can support heavy transport and logistics operations. A distributed network of storage and refueling sites can act as a buffer for daily peak loads, absorbing surplus electricity from local photovoltaic and wind farms during midday and meeting mobility demand during evening and nighttime hours. Such an approach enables the development of a decentralized infrastructure that minimizes the need for long-distance hydrogen transport in the short term, while strengthening regional energy flexibility and supporting the decarbonization of freight mobility.

Underground Storage

While pressurized tanks are effective for daily/weekly needs, large-scale seasonal storage requires geological options.

Geological potential: Northern Greece is located close to areas with depleted hydrocarbon fields and saline aquifers, which are considered viable for hydrogen storage [7]. Although specific Greek assessments are limited, analogs from the Balkans and Central Europe suggest that caves or aquifers could hold hundreds of GWh of hydrogen energy.

System role: By concentrating the curtailed energy from Thrace and Eastern Macedonia, an underground site could act as a seasonal regulator. For example, the curtailed energy of 132 GWh/year in Thrace could be aggregated with nearby curtailed energy to justify a single medium-scale cave (capacity ~500 GWh).

Business case: With Thrace's location close to the Kipi (Greece-Turkey) and Sidirokastro (Greece–Bulgaria) interconnections, the stored hydrogen could be exported to the north and east. This would align with the EU's Hydrogen Trunk Initiative, which envisages cross-border hydrogen pipelines in the region [44].

Hybrid with Pipeline Line-Pack

As hydrogen transmission networks expand, pipeline line-pack can operate as a complementary storage mechanism alongside geological options. Line-pack stores additional hydrogen by increasing the pressure within pipelines, effectively transforming the transmission network into a distributed short-term storage asset [24].

In the short term, this mechanism can absorb fluctuations over hours to days, smoothing demand variations along the corridor.

Over the long term, line-pack functions in parallel with underground storage, where caverns manage seasonal imbalances while pipelines provide operational balancing. Thrace is particularly well positioned for this hybrid approach: as a cross-border energy corridor, it is a strong candidate for early hydrogen pipeline deployment, and securing rights-of-way now ensures seamless integration into future hydrogen networks.

Thrace combines moderate hydrogen production potential with exceptionally high strategic value for Greece and the wider region. Its geographic position enables it to function as an export hub, facilitating hydrogen flows toward Bulgaria, Romania, and Turkey and strengthening Greece's role in the emerging regional hydrogen economy. At the same time, hydrogen can support energy-intensive industries in Northern Greece, such as cement production and metallurgy, reducing dependence on imported grey hydrogen and enhancing industrial competitiveness. Thrace's infrastructure prospects also align with EU-level planning, fitting directly within the ENTSO-E and ENTSOG hydrogen corridor concepts for Southeastern Europe [44]. Although the region does not exhibit the highest curtailment volumes nationally, its unique combination of storage, export, and logistics advantages makes it a critical enabler of hydrogen system integration.

Taken together, Thrace combines moderate hydrogen production volumes with disproportionately high strategic importance, particularly for logistics, cross-border transport, and future hydrogen corridor integration.

3.4. Western Macedonia

Western Macedonia has historically been Greece's lignite heartland, supplying most of the country's coal-fired electricity. However, the ongoing lignite phase-out and the EU's Just Transition Mechanism are transforming the region into a hub for clean energy investments [8]. One of the most emblematic projects is the Kozani PV park, the largest in Greece and among the largest in Europe, with an installed capacity of 200 MW [12]. This flagship project symbolizes Western Macedonia's transition from lignite to renewable energy sources.

Installed Renewable Capacity

By 2024, Western Macedonia hosted 200 MW Kozani PV park (operational since 2022), producing roughly:

$$200,000\ \text{kWp} \times 1400\ \text{kWh/kWp/year} = 280\ \text{GWh/year}$$

An additional 400 MW of smaller PV projects and 150 MW of wind power will contribute to the region's diversification [12,14].

Total annual renewable production is estimated at ~900 GWh/year.

Curtailment Levels

With the rapid addition of PV, curtailments have emerged as a significant issue. IPTO reports show frequent cutbacks in Western Macedonia, particularly in spring and autumn [14]. Assuming 8% annual curtailment:

$$72 \text{ GWh/year curtailed}$$

Hydrogen Production Potential

If the curtailed 72 GWh is utilized for electrolysis at 65% efficiency [38]:

$$46.8 \text{ GWh } (H_2 \text{ energy})$$

Converted into hydrogen mass [42]:

$$1405 \text{ tons of } H_2/\text{year}$$

CO_2 Avoidance

If this replaces grey hydrogen (10 kg CO_2/kg H_2) [43]:

$$14,050 \text{ tons } CO_2/\text{year avoided}$$

Western Macedonia offers multiple pathways for hydrogen deployment, closely aligned with its ongoing transition and industrial redevelopment strategy. In the industrial sector, green hydrogen could gradually replace fossil fuels in district heating networks, cement production, and potentially in emerging hydrogen-based chemical processes. The region's major highways and logistics corridors also create strong opportunities for hydrogen refueling stations serving trucks and buses that connect Northern Greece with the broader Balkan region. Additionally, hydrogen-to-power units could reinforce grid stability, with the Kozani PV park providing an ideal testbed for demonstrating integrated RES hydrogen systems and validating hybrid operational models for large-scale renewable penetration.

Western Macedonia is undergoing a just energy transition, and shifting from lignite mining to clean energy is the region's renewable potential, while hydrogen can provide both energy storage and new industrial opportunities. Its symbolic role as a pioneer in lignite-to-hydrogen makes Western Macedonia a critical region for Greece's long-term energy strategy.

In summary, Western Macedonia should be interpreted less as the region with the highest hydrogen volume and more as a transition-oriented demonstration space where curtailed RES, industrial restructuring, and hydrogen deployment can be linked within a just transition framework.

Kozani PV Park: Curtailment & Green Hydrogen Case Study
Baseline inputs:

- Installed capacity (Kozani): ≈200 MW (200,000 kWp). Large PV plant in Kozani, operational since 2022 [3].
- Annual PV yield: 1400 kWh/kWp/year (continental Greece range, anchored by recent regional irradiance work) [35].
- Annual generation (no curtailment):

$$200,000 \text{ kWp} \times 1400 \text{ kWhkWp}\backslash\text{cdotpyear} = 280 \text{ GWh/year}$$

Curtailment rate (scenario range): 5–12%. We used a central case of 8% based on regional patterns reported by the system operator and peer-reviewed curtailment analysis

for Greece; park-level disaggregated curtailment is not publicly reported; hence, we apply regional rates to the asset as a transparent scenario [7].

- Electrolyzer efficiency (LHV): 65% (typical for modern alkaline/PEM, consistent with IEA) [38].
- Energy-to-mass conversion: 33.3 kWh/kg H_2 (LHV) [42].
- Grey hydrogen benchmark: ~10 kg CO_2/kg H_2 (production-phase emissions to be displaced) [43].
- Electrolyze sizing heuristic: curtailment is midday-heavy; assume 25% utilization factor for a collocated electrolyze to "catch" curtailed windows (simple rule-of-thumb consistent with diurnal PV profiles).

Curtailment and Hydrogen Yield-Three Scenarios

Table 2 presents the estimated hydrogen production potential and associated CO_2 avoidance under three representative curtailment scenarios (5%, 8%, and 12%). The results demonstrate that increasing renewable energy curtailment directly increases the available hydrogen production potential, ranging from 273 to 656 t/y of H_2. The table also highlights the corresponding avoided CO_2 emissions and average curtailed power levels for each scenario.

Table 2. Hydrogen production and CO_2 avoidance estimates under different curtailment scenarios.

Scenario (Annual Curtailment)	Curtailed Energy (GWh/y)	H_2 Energy (GWh/y) at 65%	H_2 (t/y)	CO_2 Avoided (t/y) *	Avg. Curtailed Power (MW)
Low (5%)	14	9.1	273	2733	1.6
Central (8%)	22.4	14.56	437	4372	2.56
High (12%)	33.6	21.84	656	6559	3.84

* Using 10 kg CO_2 avoided per kg of green H_2 that replaces grey H_2 [24].

How each number is derived (example: central 8%):

- Curtailed energy: 280 GWh $\times$ 0.08 = 22.4 GWh/y.
- Hydrogen energy: 22.4 GWh $\times$ 0.65 = 14.56 GWh/y [25].
- Hydrogen mass: $14,560,000 \text{ kWh} \div 33.3 \frac{\text{kWh}}{\text{kg}} = 437,237 \text{ kg} \approx 437 \text{ t/y}$ [18].
- CO_2 avoided: $437 \text{ t } H_2\text{/y} \times 10 \frac{\text{t } CO_2}{\text{t}H_2} = 4372 \text{ t } CO_2\text{/y}$ [24].
- Average curtailed power: 22.4 GWh $\div$ 8760 h = 2.56 MW

Note on park-level data: The exact curtailment for a specific unit is rarely published. Therefore, regional curtailment ranges observed by the operator (5–12%) are applied for Kozani as scenarios, according to the Greek curtailment literature and the IPTO report on seasonal curtailments [5]. This keeps the method simple, transparent and reproducible.

What electrolyzer size captures this curtailment? (simple sizing)

Assuming curtailment clusters around midday, a collocated electrolyzer works with low annual utilization (we use 25% as a conservative rule). The minimum electrolyzer power P_{elec} that can digest the annual curtailed energy E_c is:

$$P_{elec} = \frac{E_c}{UF \times 8760 \text{ h}}$$

- 5% case (14 GWh): $P_{elec} = \frac{14{,}000 \text{ MWh}}{0.25 \times 8760} = 6.4$ MW.
- 8% case (22.4 GWh): $P_{elec} = \frac{22{,}400 \text{ MWh}}{0.25 \times 8760} = 10.2$ MW.
- 12% case (33.6 GWh): $P_{elec} = \frac{33{,}600 \text{ MWh}}{0.25 \times 8760} = 15.3$ MW.

The electrolyzer sizing represents an equivalent annual capacity based on the average availability of curtailed energy. In practice, curtailment events are temporally clustered

(e.g., midday peaks in PV-dominated systems), and therefore peak capacity requirements may be higher than the average value estimated here.

These sizes absorb most curtailment without oversizing. If curtailment duration is shorter/higher in magnitude (e.g., fewer hours but more intense), a slightly larger electrolyze (e.g., 12–18 MW) provides headroom.

Water and Oxygen co-products (central case, 8%)

- Process water (electrolysis needs ≈9 L/kg H_2) [18]:

$$437,000 \text{ kg } H_2 \times 9 \text{ L/kg} = 3935 \text{ m}^3/\text{y}$$

- Oxygen by-product (≈8 kg O_2/kg H_2 stoichiometry):

$$437 \text{ t } H_2/\text{y} \times 8 = 3498 \text{ t}O_2/\text{y}$$

(can serve local industry/health services).

Western Macedonia is uniquely positioned for hydrogen deployment due to its existing transmission infrastructure and land availability inherited from the lignite era. Grid substations and established rights-of-way provide strong interconnection capacity, while co-locating electrolysis behind the meter can reduce feeder loading and directly convert curtailment into a valuable product stream [2,5]. The region's just-transition plans also anticipate new industrial activity, creating opportunities to utilize both hydrogen and oxygen streams locally, for example in logistics fleets, district heating blends, and small-scale chemical applications, while surplus hydrogen can be transported by truck to nearby demand centers. Moreover, the same straightforward 5–12% curtailment-to-hydrogen conversion logic applies to other large PV sites across Greece, making techno-economic due-diligence transparent and easily replicable nationwide.

A regional comparison of hydrogen production potential from curtailed RES electricity is presented in Figure 15.

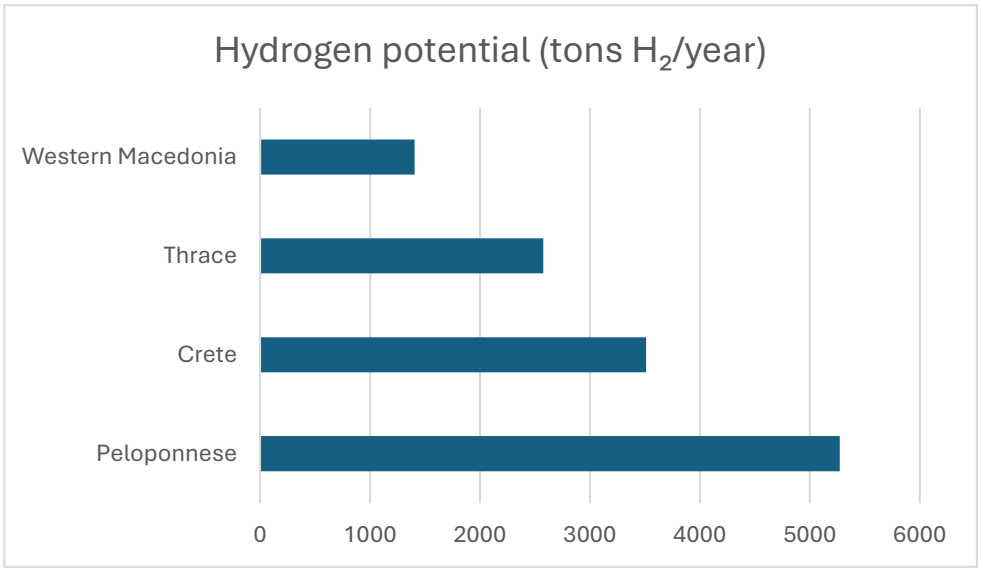


Figure 15. Comparison of green hydrogen production potential from curtailed RES electricity in four Greek regions.

3.5. Cost Considerations

The cost of producing green hydrogen depends primarily on three drivers: the cost of electricity input, the capital cost and utilization factor of electrolyzers, and the cost of storage, compression, or conversion.

Recent international assessments indicate that in Europe, the levelized cost of renewable hydrogen currently ranges between €4 and 8/kg H_2, reflecting electrolyser capital costs of €1600–2000/kW for commercial PEM and alkaline systems and electricity prices of €40–60/MWh [45]. When curtailed renewable electricity is used, the marginal electricity cost can approach zero, but electrolyser underutilization raises the effective cost per kilogram. Several recent studies show that curtailment-driven hydrogen could achieve costs of €3.5–5.5/kg H_2 under mid-range utilization scenarios, provided that electrolyzers are optimally sized to capture curtailment windows [24,44]. Storage and conversion add further costs. Pressurized tanks typically add €2–3/kg H_2 (≈€500–1000/kg H_2 capacity), while underground salt cavern storage remains cheaper at <€1/kWh of stored energy, but is only feasible where geology allows [18]. Conversion to ammonia or LOHCs for transport and export adds an additional €1–2/kg H_2 [46].

For Greece, where curtailment shares of 5–12% are observed in high-PV regions, collocated electrolyzers at curtailed sites such as Kozani or the Peloponnese could absorb surplus electricity and produce hydrogen at competitive costs in the €3.5–5.0/kg H_2 range by 2030. Achieving the lower bound will depend on continued reductions in electrolyzer CAPEX, utilization gains, and access to EU support mechanisms. This range is consistent with the EU Hydrogen Strategy's cost-reduction targets for renewable hydrogen.

Table 3 compares the estimated levelized cost of hydrogen (LCOH) across Greece's main renewable-rich regions under different storage pathways. The results show that collocated electrolyzers in the Peloponnese and Kozani can achieve the most competitive costs, around €3.5–4.5/kg H_2 with cavern storage, owing to higher curtailment and thus better utilization. Thrace and Western Macedonia occupy an intermediate range (€4.0–5.0/kg H_2), supported by the potential for underground storage in nearby formations. In contrast, Crete remains more expensive (€5.5–7.0/kg H_2) due to lower utilization and the additional costs of conversion to ammonia or LOHC for export. These findings highlight that while regional variability is significant, curtailment-based hydrogen production in Greece can approach the EU's cost-competitiveness targets for 2030 when optimal storage options are available.

Table 3. Estimated Levelized Cost of Hydrogen (LCOH) from curtailed RES by region and storage type (€/kg H_2).

Region	Utilization Factor	LCOH with Tanks (€/kg)	LCOH with Cavern/Carrier (€/kg)	Notes
Peloponnese	25%	5.5–6.5	3.5–4.5	High curtailment; strong PV & wind
Crete	22%	7.0–8.0	5.5–7.0	Extra cost for NH_3/LOHC export
Thrace	24%	5.7–6.7	3.7–4.7	Corridor + cavern potential lowers bulk cost
Western Macedonia	20%	6.0–7.0	4.0–5.0	Transition hub, cavern storage plausible
Kozani PV Park (sub-case)	25%	5.5–6.5	3.5–4.5	Flagship case study within Western Macedonia

Higher LCOH values in Crete are primarily driven by system isolation and limited infrastructure, while lower costs in Peloponnese and Western Macedonia reflect higher curtailment volumes and more favorable integration conditions.

Figure 16 compares the levelized cost of hydrogen (LCOH) across the examined Greek regions under different storage configurations.

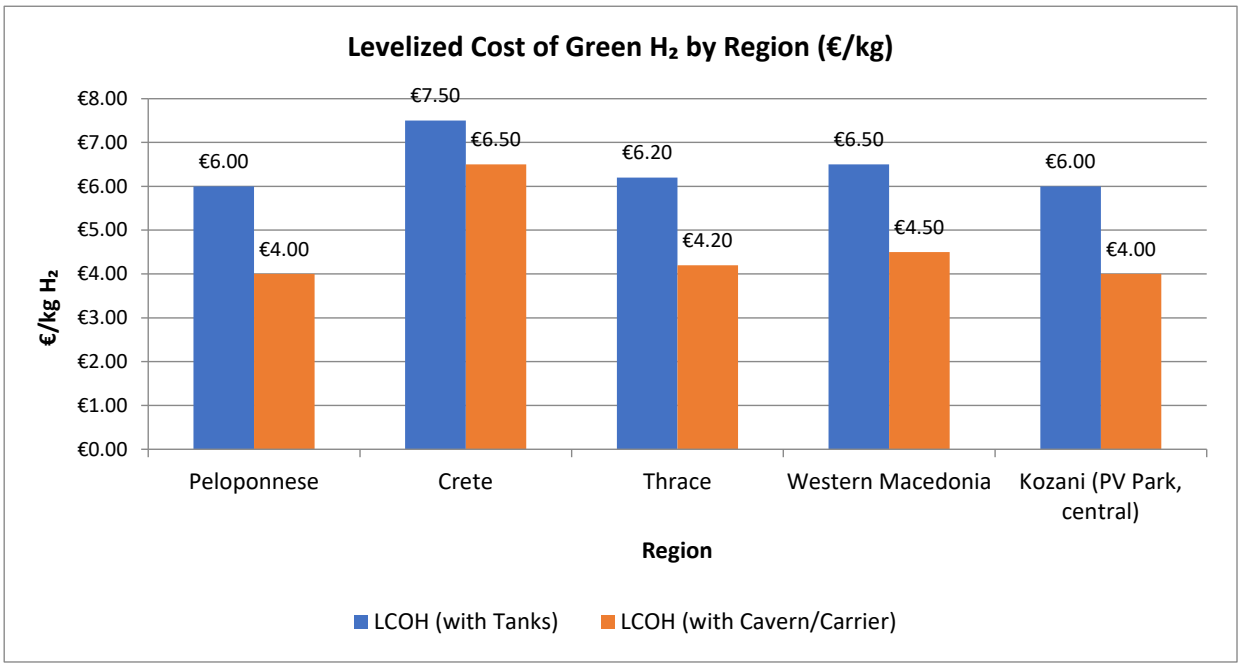


Figure 16. Levelized cost of hydrogen (LCOH) by region in Greece, comparing daily–weekly storage in pressurized tanks versus seasonal cavern/carrier storage.

The variation in hydrogen production cost reflects regional differences in resource availability, infrastructure, and system constraints, influencing the economic feasibility of deployment.

Across Peloponnese, Crete, Thrace, and Western Macedonia, annual curtailed energy ranges from 70 GWh (Western Macedonia, Kozani case) to 270 GWh (Peloponnese). When redirected to electrolysis, these curtailed volumes could yield between 2500 and 5300 tons of green hydrogen per year per region, displacing 25,000–53,000 tons of CO_2 annually, assuming replacement of grey hydrogen.

Across Greece's regions, hydrogen potential varies in scale but offers complementary strengths. The Peloponnese emerges as the most promising area, with more than 4.5 TWh of renewable generation, recurrent curtailments, and a hydrogen production potential exceeding 5200 tons per year. Crete also demonstrates substantial curtailed volumes, around 180 GWh annually, even after recent interconnections, enabling roughly 3500 tons of hydrogen per year suitable for transport and tourism-related applications. Thrace, while exhibiting moderate curtailed energy levels (~132 GWh), holds exceptional strategic value due to its position along major cross-border energy corridors, making it an ideal export hub for Southeast Europe. Finally, Western Macedonia, exemplified by the Kozani PV park with approximately 72 GWh of curtailed energy, stands out as a symbolic pilot region where Greece's lignite-to-hydrogen transition can be demonstrated and scaled.

Cost analysis (Table 3) indicates that hydrogen production from curtailed RES can achieve competitive Levelized Costs of Hydrogen (LCOH) in the range of €3.5–5.0/kg for mainland regions with cavern storage potential. Crete remains more expensive (€5.5–7.0/kg) due to additional conversion costs for export.

In addition to production and storage costs, hydrogen transportation represents a non-negligible component of the overall system cost. Depending on the transport mode, including compressed gas trucking, pipelines, or conversion to carriers such as ammonia (NH_3) or liquid organic hydrogen carriers (LOHCs), transportation costs can add approximately €1–2/kg H_2. These costs are particularly relevant for geographically constrained regions such as islands, where hydrogen export to mainland consumption or storage hubs may be required.

Overall, the results highlight that Greece's curtailed RES can serve as a cost-effective and low-carbon feedstock for hydrogen production, transforming an operational challenge into a strategic opportunity for the energy transition.

Taken together, the results indicate that regional hydrogen potential in Greece is not determined solely by the magnitude of curtailed electricity, but also by the interaction between curtailment patterns, storage feasibility, and regional infrastructure conditions. The Peloponnese exhibits the largest hydrogen production potential due to its high renewable output and recurrent curtailment. Crete shows substantial potential despite higher storage and export constraints. Thrace combines moderate hydrogen volumes with strong strategic value for corridor-based deployment, while Western Macedonia offers lower absolute volumes but high relevance as a just-transition demonstration region. This comparative perspective suggests that a differentiated regional strategy is more appropriate than a single national hydrogen deployment model.

4. Discussion

While green hydrogen is widely recognized as a low-carbon energy carrier, the environmental footprint of electrolysis systems should also be considered. Electrolyzer operation requires water input (approximately 9 L per kg of H_2 produced), as well as materials such as critical metals used in system components. Although these impacts are significantly lower than those associated with fossil-based hydrogen production, a full life-cycle perspective is important for a comprehensive sustainability assessment.

The differences observed between regions are not only quantitative but also structural, reflecting variations in renewable energy availability, grid infrastructure, geographic characteristics, and system integration potential. These factors directly influence both the feasibility and the role of hydrogen deployment in each region. For example, regions with high curtailment and strong grid constraints (e.g., Peloponnese) are more suitable for large-scale hydrogen production, while geographically isolated systems (e.g., Crete) require more localized and flexible solutions. Similarly, regions with strategic location advantages (e.g., Thrace) can support hydrogen export pathways, whereas transition regions such as Western Macedonia can leverage hydrogen as part of broader economic restructuring efforts.

The results show that curtailed renewable electricity can provide a meaningful feedstock for green hydrogen production in Greece, but the scale and practical relevance of this opportunity vary substantially across regions. In quantitative terms, the Peloponnese exhibits the highest hydrogen potential, followed by Crete, Thrace, and Western Macedonia. However, the comparative value of each region is not captured by hydrogen output alone. Storage availability, infrastructure maturity, grid constraints, and potential end uses strongly influence the feasibility of regional hydrogen deployment. Accordingly, the findings support a differentiated interpretation of hydrogen development in Greece, in which regions contribute through distinct but complementary roles rather than through a uniform national model.

This comparative analysis shows that curtailed renewable electricity in Greece can serve as a strategic feedstock for green hydrogen production. The results suggest that the

Peloponnese has the largest hydrogen potential overall (~5270 t H_2/y). Crete has a lot of hydrogen potential, but it is currently constrained by recent links (~3510 t H_2/y). Western Macedonia is a symbolic hub for the move from lignite to hydrogen because it has less hydrogen (~1405 t H_2/y). Thrace, on the other hand, has a moderate amount of potential (~2575 t H_2/y), yet it is particularly important as a hydrogen corridor between countries.

Recent studies demonstrate that the cost of generating hydrogen and how easy it is to scale up rely a lot on the market and how successfully curtailment is employed. Georgopoulos et al. [47] show that regulatory incentives and active trading in Greece can lower the cost of hydrogen by about €1.2/kg. This shows how important it is to develop policies well. Ganter et al. [26] similarly demonstrate that utilizing limited wind and solar resources for hydrogen production significantly enhances economic viability throughout Europe, hence validating the methodology employed herein. This alignment is very essential for Greece because the levels of RES are just 5% to 12% in places with a lot of PVs.

Localized techno-economic evaluations support these conclusions. Koutalidis et al. (2025) [48] say that adding hydrogen into Greek gas lines will cost between €2.14 and €5.0 per kilogram. This illustrates that there are still ways to get hydrogen that are competitive, even when infrastructure is limited. This makes it more probable that electrolyzers will be put in places with a lot of curtailment, like Kozani or the Peloponnese, where there is good connectivity to the grid and a lot of RES.

The largest challenge is still storage. According to Hydrogen Europe (2024) [45], Europe will need roughly 45 TWh of hydrogen storage by 2030 to meet the REPowerEU goals. This is a lot more than what is already planned. This means that cheap subterranean storage is better in Greek areas with favorable geology, like Thrace and Western Macedonia. But islands like Crete must employ more expensive pressure tanks. Franco (2025) [49] says that green hydrogen needs more than simply infrastructure to grow. It also needs a supply chain that is ready, cautious positioning, and a realistic view of how much energy will be lost during conversion.

The findings indicate that Greece's constrained renewable energy resources may facilitate the establishment of a hydrogen sector that is both competitive and strategically significant. The outcomes are contingent upon the degree of regional disparity. The Peloponnese and Kozani are suitable for large pilot efforts, Crete is ideal for a hybrid local/export approach, and Thrace is appropriate for cross-border corridors. The ability of Greece to leverage curtailed energy for a just transition hinges on definitive regulations, investment in storage infrastructure, and strategies to integrate with the EU's hydrogen backbone.

From a policy perspective, the results suggest that hydrogen deployment in Greece should be regionally sequenced. Mainland areas with higher curtailment volumes and potential access to geological storage, such as the Peloponnese and Western Macedonia, are better suited for early large-scale demonstration and integration with industrial demand. By contrast, island systems such as Crete are more likely to require distributed storage and export-oriented pathways, while corridor regions such as Thrace are well positioned for transport applications and cross-border infrastructure development. In this sense, curtailed electricity should not be interpreted solely as a system inefficiency, but as a spatially differentiated resource whose value depends on the availability of conversion, storage, and end-use infrastructure.

The regional roles of hydrogen in Greece can be summarized as follows:

- Peloponnese: Large-scale hydrogen production and grid balancing.
- Crete: Island energy autonomy and export-oriented hydrogen pathways.
- Thrace: Cross-border hydrogen transport and export corridor.
- Western Macedonia: Just transition hub linking hydrogen with industrial restructuring.

5. Limitations and Future Work

This study offers an initial comparative assessment of the hydrogen production potential from renewable energy sources that have been curtailed in important Greek regions. However, certain limitations must be acknowledged. The curtailment data came from reports by regional and national agencies that used broad estimates (5–12%) rather than data from specific facilities. This limitation complicates the assessment of energy reductions in some locations, such as the Kozani PV park. The model for the operating efficiency of electrolyzer efficiency was based on traditional assumptions of 65% efficiency and a 25% utilization factor. Efficiency and operating standards vary depending on the technology and scale. The research on storage alternatives was based on examples from the global literature due to the limited research on the effectiveness of the geology of Greece for large-scale underground hydrogen storage. Ultimately, it is difficult to determine the cost due to the rapidly evolving costs associated with the electrolyzer efficiency capital expenditure, financing mechanisms, and European Union funding procedures.

Future initiatives should address these limitations using more sophisticated models and pilot programs. The Independent Transmission Operator of Electricity (IPTO) offers high-resolution curtailment data that can be integrated with dynamic electrolyzer efficiency simulations to determine optimal sizing and monitor hourly fluctuations. Geological surveys in Western Macedonia and Thrace are necessary to establish the viability of exploiting salt caves or aquifers for underground hydrogen storage, a critical factor for cost competitiveness. To validate the feasibility of underground hydrogen storage in regions such as Western Macedonia and Thrace, detailed geological investigations are required. These include subsurface characterization through seismic surveys, assessment of reservoir properties (porosity, permeability, caprock integrity), and evaluation of existing depleted gas fields or saline aquifers. Such analyses are essential to determine storage capacity, safety, and long-term operational viability. In addition, demonstration projects such as the installation of 10–20 MW electrolyzers at the Kozani photovoltaic park or the construction of hydrogen refueling stations along the Patras–Athens corridor would provide empirical data on operational efficiency, economic impact, and integration compatibility. Finally, follow-up research should explore interconnections between various industries and mechanisms for transporting products to foreign nations. This could include integrating hydrogen into natural gas networks, establishing ammonia-based power pipelines for islands such as Crete, and constructing pipelines extending across borders to Bulgaria and Turkey. Greece's goal of the European Basic Hydrogen Cycle would be consistent with all of this.

Fuel Cell Electric Vehicles (FCEVs) have emerged as a strategically important pathway for Europe's decarbonization and industrial competitiveness, particularly in vehicle segments where Battery Electric Vehicles (BEVs) face operational and supply-chain limitations. According to recent analyses [50], hydrogen mobility supports longer driving ranges, rapid refueling under five minutes, and superior performance in heavy-duty and long-distance transport, where BEV charging times and battery mass constraints limit deployment. Updated European fleet data shows that FCEVs remain a niche market today but demonstrate strong growth potential, especially in logistics and commercial fleets [51]. Furthermore, Europe's hydrogen vehicle strategy underscores a critical geopolitical advantage: unlike BEVs, whose core battery supply chain is dominated by Chinese manufacturers, FCEVs rely on European technological strengths in fuel cells, electrolyzers, and heavy-duty vehicle engineering [52]. This provides the EU with a unique opportunity to strengthen industrial sovereignty, diversify transport energy systems, and maintain competitiveness in global mobility markets.

Despite these limitations, the present framework provides a transparent first-order comparison of regional curtailed RES to hydrogen potential under harmonized assumptions.

Its main contribution lies in offering a regionally differentiated basis for future work that can incorporate higher-resolution curtailment data, dynamic electrolyzer operation, location-specific storage constraints, and more detailed infrastructure cost modeling. In that sense, the study can be seen as a comparative screening framework for identifying where more detailed hydrogen feasibility studies in Greece are most justified.

6. Conclusions

The potential of Greece's reduced renewable electricity as a fuel for the generation of green hydrogen was evaluated in this study. The findings show that annual curtailed volumes can be substantial, ranging from around 72 GWh in Western Macedonia to about 270 GWh in the Peloponnese, by examining four important regions: the Peloponnese, Crete, Thrace, and Western Macedonia (including a case study on the Kozani PV park). By rerouting this reduced energy to electrolysis, each region could produce 1400–5300 tons of hydrogen annually, which would eliminate 14,000–53,000 tons of CO_2 annually if gray hydrogen were substituted.

The cost research showed that hydrogen created from curtailed power can be competitive. In places where cavern storage is viable, the Levelized Costs of Hydrogen (LCOH) are between €3.5 and €5.0 per kilogram. This fits with the EU's goal of cutting expenses. Because it costs more to convert and ship Crete, it is still more expensive (about €5.5–7.0/kg). This highlights how crucial it is to have distinct hydrogen plans for different areas.

From a comparative perspective, the Peloponnese emerges as the most favorable region for large-scale hydrogen production due to its high renewable energy output and recurrent curtailment levels. Thrace, although exhibiting moderate hydrogen volumes, holds significant strategic value as a cross-border energy corridor with strong export potential. Crete represents a distinct case, where hydrogen deployment is driven by system isolation and relies on distributed storage and export-oriented pathways. Western Macedonia plays a critical role as a transition region, linking renewable energy development with industrial restructuring, as part of the EU's Just Transition framework, which supports regions transitioning away from fossil fuel-based economies.

This study indicates that hydrogen can assist in cutting down on the amount of renewable energy that is wasted and help decarbonize some areas. Hydrogen production could be useful for transportation and industries in Kozani and the Peloponnese. Crete needs a mix of tourism and exports. Hydrogen meshes with Greece's status as a cross-border energy hub in Thrace.

In general, limited renewable energy is not a problem but a chance to make a strategic move. Greece can turn curtailed electricity into green hydrogen if it has the right storage, regulatory backing, and infrastructural integration. This will help Greece's energy transition and the EU Hydrogen Strategy as a whole.

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