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Maximizing the use of hydrogen as energy vector to cover the final energy demand for stand-alone systems, application and sensitivity analysis for the Canary Archipelago by 2040

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ABSTRACT

Fossil fuel-based economies must undergo a deep transition for complete decarbonization. To this end, it is widely recognized that all economies must move towards the electrification of energy end uses. Even though there is a part that cannot be electrified, at least at affordable costs; clear examples are heavy road transport, maritime and air transport, and some industrial processes. As a result of the limitations of electrification in certain energy end uses, the potential use of hydrogen as an alternative energy carrier has been examined in recent decades. Hydrogen is seen as a viable option for the medium to long term. Specifically, efforts are being made in the case of the Canary Islands to move towards a carbon-free energy mix. In fact, the aim is to advance the economy decarbonization by 10 years over the date foreseen for both Europe and the rest of Spain. To this end, the HOMER program has been used to analyze the possibility of producing the necessary hydrogen in a scenario applied to the Canary Islands in which the uses of this energy vector have been maximized. This research considers two possible scenarios, together with a sensitivity analysis under the different uncertain conditions associated with the used technologies. The results have been the estimation of hydrogen production costs for high demands, about 230,000 tH_2/year, in 2040 for an isolated archipelago under two totally different generation scenarios. The first scenario is totally renewable, while the other is based on nuclear generation by means of high-temperature SMRs. The results show, that it would be possible to produce at a cost in the range of 1 €/kgH_2 using nuclear technology and around 4 €/kgH_2 using renewables, with uncertainty cost ranges of around 40%, i.e. costs between 0.85-1.48 and 3.29–4.99 € kgH_2 respectively.

1. Introduction

World energy demand has been growing uninterruptedly in recent decades (International Energy Agency, 2021). The COVID-19 pandemic temporarily slowed this trend which, in all probability, will return to the old path when the current pandemic situation is overcome. A very high percentage of the world's primary energy generation, about 80%, is produced using fossil fuels (International Energy Agency, 2021); this situation entails a double problem, on the one hand, the depletion of these fossil fuels, in the medium term would endanger the continuity of electricity supply (bp and Energy Outlook 2022 edition, 2022). And a second problem, even more, serious and in the short term, is the continued use of these fossil fuels, which causes an unacceptable increase in the current trend of greenhouse gas emissions (Whiting et al., 2017; Capellán-Pérez et al., 2014).

At present, electricity generation is also based on the use of fossil fuels, in fact, about two-thirds of electricity is generated using fossil fuels. As a consequence, it is responsible for approximately 35% of the total CO_2 emissions of the energy sector (Jiang and Guan, 2016). This situation is even more pronounced on many islands, where mainly due to their small size and isolated location the fossil fuel-based percentage becomes even larger. On islands, the generation sources are necessary to ensure a high reliability level of power supply, since usually there is no possibility of connecting to a larger grid, then reliable sources such as

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fossil generation sources (fuel oil plants, combined cycle gas plants, etc.) must be used.

The transition to GHG-free energy sources is necessary to meet the goals of net-zero emissions in electricity generation by 2050 (Henriques and Borowiecki, 2017; Berna-Escriche et al., 2021); but this use must be made with economic competitiveness in mind. Focused on these purposes, the present study presents the combined use of small modular reactors (SMRs), in conjunction with renewable sources to be able to cover the hydrogen demands (Locatelli et al., 2018; Zarei, 2019; OECD NEA, 2021). Using highly variable renewable energy sources, such as wind and solar photo-voltaic (solar PV), can be challenging when it comes to matching electricity generation and demand (Capros et al., 2018; Sun et al., 2016). Therefore, it is necessary to combine them with more reliable generation sources and/or storage technologies, so that demand can be met with guarantees and at affordable costs. These reliability problems become even more pronounced in isolated regions, such as islands, where the energy system must be self-sufficient and have a reliable generation source and/or considerable energy storage capacity. On islands, the system, in most cases, operates independently and needs to be 100% self-sufficient. In addition, in order to achieve the future goal of zero greenhouse gas emissions, it is necessary to eliminate fossil fuels in all areas of the economy. It is, therefore, necessary to develop techniques to assess the feasibility of the combined use of different carbon-free technologies. The use of renewable energies with nuclear energy (Sun et al., 2016; Dellano-Paz et al., 2015; Zaman and el Moemen, 2017), together with storage technologies (Cîrstea et al., 2018; Huber et al., 2014), can be a very good possibility to achieve these goals. It is probably the best option in the case of isolated locations where the system must be self-sufficient precisely because of this isolation.

Another very important aspect to consider in order to achieve the objective of decarbonization of the economy is the electrification of the economy, i.e., all those energy uses that can be electrified at an affordable cost must be electrified (Deloitte, 2020). This electrification will entail a significant increase in electricity demand, which will lead to a significant increase in demand in the coming years. This makes the already complicated design of a totally renewable system even more complicated, since several studies speak of an increase of up to close to 100% of the current electricity demand if this process of electrification of the economy is carried out (Deloitte, 2018, 2020). Moreover, it is not enough to electrify to the maximum, but for those energy end uses that cannot be electrified an alternative must be offered so that fossil fuels are totally eliminated from the economy. In particular, these uses are mainly some transport (e.g. heavy vehicles, maritime and aviation) and certain industrial processes (basically those demanding high heat). The option that currently has most likely to succeed is the use of a new energy vector, hydrogen is placed as the best option, so that those non-electrifiable energy end-uses employ this element as fuel (IEA, 2019). But not only hydrogen could be used as an energy vector applied in non-electrifiable uses, but it could be used as a storage vector, aiming to refeed the grid when needed (Hurtubia and Sauma, 2021). Here the use of high-temperature nuclear reactors is a very suitable option, as it is expected to allow the production of hydrogen at a competitive cost in the near future (Locatelli et al., 2018), since the high-temperature heat can be used to produce the water electrolysis through the use of solid oxide electrolyzer cells (SOEC). One of the disadvantages of nuclear reactors, in general, is that they have almost no load-following capacity, since this is done by applying negative reactivity to lower the power, but since most of the costs of nuclear generation are fixed, this reduction of power does not almost affect the total operating costs of the plant, i.e., less energy is generated but the total cost is almost the same. In other words, the electricity produced becomes more expensive. Also, it must be considered that the use of these reactors as following demand could damage the fuel, so it is recommendable to operate these reactors at a power constant level as much as possible. For this reason, in recent years the idea of load following is being discussed, but with cogeneration. This concept of load-following consists of being able to satisfy the fluctuations of the demand of the electrical market and, at the same time, to avoid the economic penalty of the adjustment of the power of the reactor, by using the excesses of energy in cogeneration or even tri-generation (Locatelli et al., 2018; Technical and Economic Aspects of, 2011; Locatelli et al., 2015). In this setup, the nuclear power plant would continuously produce electricity at its full capacity, maintaining constant conditions in the primary circuit. Cogeneration would be carried out with the production of electric power or hydrogen depending on the existing demand. That is, during high-load hours the nuclear thermal energy is fully converted into electricity for the grid, while during low-demand hours the excess thermal energy would be used for hydrogen production.

Most Generation III nuclear reactors are competitive with other sources of baseload electricity, such as gas and coal, in terms of cost. However, due to their size, time, investment and process complexity, classical nuclear power plants have strong installation disadvantages. Additionally, many of these reactors have a power output that is to high to be used in off-grid areas. A typical nuclear power plant has approximately a very high electricity generation capacity, ranging from 1 to 1.6 GWe (IEA/NEA, 2020). However, over the last few years, several new reactor designs with much lower power ratings are being developed; these designs are called small modular reactors (SMRs). More than 70 different concepts are currently under study (OECD NEA, 2021), of which about 25 are evolutions of existing pressurized water reactors (PWRs). Many of these are high-temperature gas-cooled reactors (HTGRs), fast neutron spectra, and molten salt designs. In general, most SMR designs consist of integrated reactors, which means that the pressurizer, steam generator, nuclear core and, in many designs, the recirculation pumps are enclosed, i.e., the entire primary circuit is sealed with the pressure vessel.

Currently, three hydrogen production technologies exist, alkaline electrolysis (AEL), proton exchange membrane (PEM) and solid oxide electrolysis cells (SOEC) (IEA, 2019). AEL is the most established and widely used technology, having been employed for hydrogen production in the fertilizer and chlorine industries since the 1920s. Alkaline electrolyzers are capable of operating at a range of capacities, from a minimum of 10% up to their full design capacity. In the past, alkaline electrolyzers with a capacity of up to 165 MWe were used, but in the 1970s they were phased out as natural gas and steam methane reforming for hydrogen production took off. AEL has relatively low capital costs compared to other electrolyzer technologies due to the fact that it does not require the use of precious materials. PEM technology is the most developed technology today, General Electric introduced PEM electrolyzer systems in the 1960s as a solution to the operational issues that alkaline electrolyzers faced. They are known for their small size and their capability to produce highly compressed hydrogen for decentralized production and storage at refueling stations. It can operate at pressure levels of 30–60 bar without the need for an additional compressor, and some systems can reach pressure levels of 100–200 bar. These systems offer flexible operation and are suitable for a variety of applications. The electrolyzer's operating range extends from zero load to 160% of its design capacity. This means that it is possible to operate the electrolyzer at an overload for an extended period of time if the plant and power electronics have been designed to allow for it. The disadvantages are that they require expensive electrode catalysts, such as platinum and iridium, as well as expensive membrane materials. Additionally, the current lifetime of these electrolyzers is shorter than that of alkaline electrolyzers. Their total costs are higher than those of AELs and their deployment is lower. While SOECs use ceramics as an electrolyte and have a low material cost. It operates at high temperatures and with a high degree of electrical efficiency. Since they use steam for electrolysis, this technology requires a heat source and consequently is best suited for use in combination with high-temperature nuclear plants (SGTR or VHTR type reactors).

This work proposes the analysis and comparison of two on-site hydrogen generation scenarios with zero emissions, both capable of covering the maximum demand foreseen for the Canary Islands Archipelago for the year 2040. The scenarios analyzed are based on the one hand, on renewable energy production systems (a scenario proposed by the own Canary Island government, which is based on solar PV and wind generations (Tecnológico de Canarias, 2022a)) and, on the other hand, a scenario based on nuclear generation with high-temperature reactors. For this purpose, the different contributions of the possible hydrogen consumption of the Canary Archipelago for the year 2040 have been estimated. The characteristics of each generation source have been considered. Specifically, for renewable generation, the available wind and solar resources have also been analyzed to consider their effect on energy generation. As a result, the energy available from each source used has been estimated. On the other side, the most appropriate technologies for hydrogen production for each generation resource have also been analyzed. In other words, it has been considered the characteristics of the energy generation systems along with the hydrogen production system used, so that their performance, costs, and other characteristics of each of them have been contemplated. So, the final result is the estimation of the cost of hydrogen production by renewable energies and its comparison with a production system based on nuclear production by means of high-temperature reactors of the modular type (SMRs).

To carry out the mentioned objectives the study has been organized as follows: the general hydrogen perspectives along with the particularities of the Canary Islands have been described in section 2; The different technologies needed for hydrogen production are analyzed in section 3; the methodology followed and the analyzed scenarios have been described in section 4; the major results of the conducted simulations are presented in section 5. While section 6 is dedicated to the display of the major conclusions and their discussion.

2. The hydrogen

2.1. Past, current, and future perspectives

Significant amounts of hydrogen have been produced for more than a century, although almost all of it was produced from fossil fuels, resulting in the emissions of large amounts of greenhouse gases (GHG). However, several recent studies focus on the production of hydrogen through the electrolysis of water, although this process is much more energy-demanding. However, it is intended to use electricity generated by renewable sources, usually from the inevitable surplus of renewable generation due to the inherent oversizing of the facilities caused by their intrinsic variability also the use of high-temperature hydrolysis in the future from HTGR should be considered because of its higher efficiency to produce hydrogen. This hydrogen obtained from renewable sources is often referred to as "green hydrogen" or "renewable hydrogen". Whereas hydrogen produced from nuclear power is often referred to as pink, purple or red. Even though, the lifecycle GHG emissions of all subsystems involved in the production of hydrogen from nuclear power are even lower than those emitted from renewables (UNECE - United Nations Economic Commission for Europe, 2022; IAEA, 2022). Fig. 1 shows a diagram of the hydrogen production process without using fossil resources.

Different processes are available for water electrolysis at varying degrees of maturity, with the more established options having appreciable efficiencies, such that current commercial electrolyzers (in particular alkaline electrolysis/AEL and proton exchange membrane/PEM systems) are around 60%, with relatively low degradations and high lifetimes (degradation of 1.5 and 2.5% per year, lifetimes between 55-120 and 60–100 thousand operating hours respectively for AEL and PEM), which is approximately 10–15 years of operation (Burton et al., 2021). Regarding future estimates of green hydrogen production costs, these are approximately between 1.5 and 6 €/kgH_2 depending mainly on the part of the world and the evolution over the next years of the different technologies (a $/€ exchange rate of 1 to 1 has been

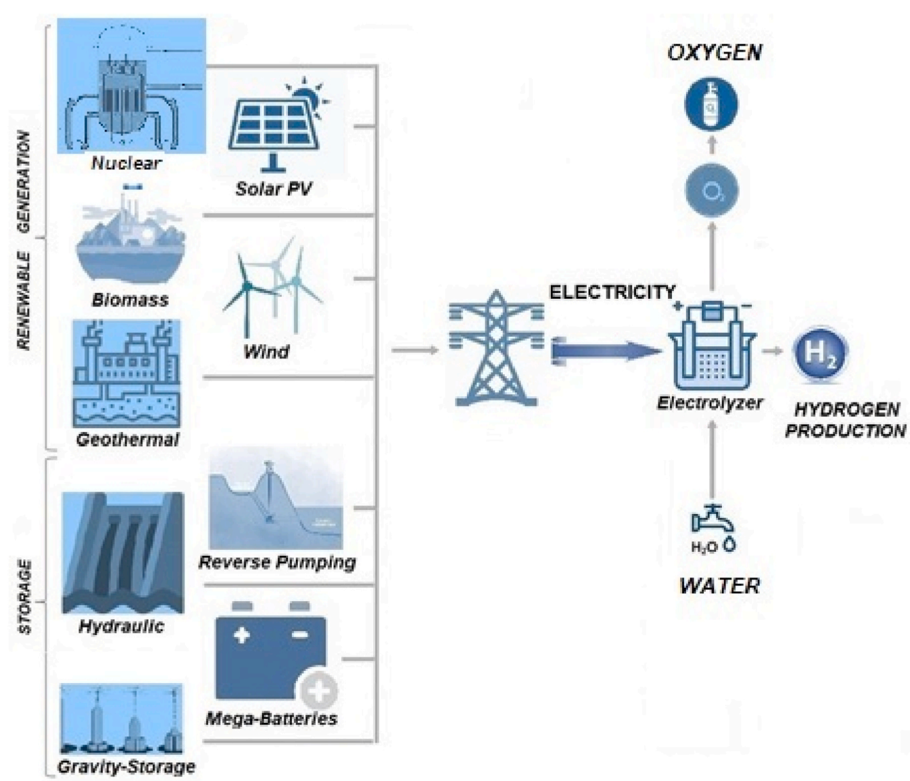

Fig. 1. *Possible Ways to "Clean" Hydrogen Production from carbon-free electric generation. (Based on (Berna-Escriche et al., 2022a,b)).*

considered). In the case of Europe, long-term costs are expected to be around 3 €/kgH_2 (IEA, 2019). However, optimistic forecasts for the far future say that the minimum costs of hydrogen production from renewable energy sources are expected to be about 1.5 €/kg and even below 1 €/kg in some regions by the 2050s (Brändle et al., 2021).

An aspect to consider in water electrolysis processes is the importance of water consumption. With 18 kgs of water, 2 kgs of H_2 are produced, but significant amounts of Oxygen are produced as a by-product (for each kilogram produced of H_2, approximately 8 kgs of O_2 are produced). This oxygen produced during electrolysis could be recovered and stored in pressure vessels for later use in processes that require O_2, such as sanitary applications, welding, oxy-fuel, replacing air in the aeration of wastewater, among other uses. This could be a value-added benefit of implementing electrolysis, along with the cost reduction of H_2 production (Mohammadpour et al., 2021).

Another option to produce H_2 could be the use of heat and electricity from HTGR (High-Temperature Gas-cooled Reactor) for advanced low-carbon hydrogen production methods, that is, through high-temperature steam electrolysis (HTSE) or thermochemical cycles. These methods are still being developed or are in the demonstration phase, but they are expected to reach higher energy efficiency for hydrogen production than current low-temperature electrolysis processes, which only require electricity. In the longer term, an evolution of these HTGR reactors, and the development of Very High-Temperature Reactor technology (VHTR), which is expected to generate at core outlet temperatures of more than 950 °C (Locatelli et al., 2018). The VHTRs are expected to provide helium at more than 900 °C for industrial processes, which would further increase the efficiency and competitiveness of hydrogen production using this heat along with electricity. Therefore, the use of high-temperature SMRs together with integrated SOEC hydrogen production technology would be a very suitable solution for centralized and decentralized hydrogen production. Ideally, a VHTR with an outlet temperature of 900–1000 °C and a capacity of 250–300 MWe is suitable for this integration (Lee et al., 2022), while nuclear reactors of 1–1.5 GWe would be appropriate for centralized hydrogen production. Even though, the current tendency of generation is towards the distributed generation in most cases (OECD NEA, 2021).

According to the information provided in different research sources, when a total electrification scenario of the economy has to be analyzed, there are several major groups of contributions to the final energy demand (Deloitte, 2018, 2020; Bataille et al., 2021). From all these groups, as mentioned above, there are some that are difficult to electrify, or even in a more or less distant future it may be more appropriate to use another energy vector instead of electricity. In this sense, the work analyzes the use of hydrogen as a potential energy vector to cover these consumptions, trying to maximize its use. It is important to consider that these "non-electrifiable" final energy consumptions are particularly in the transportation sector (such as heavy vehicles, marine and aviation) and from some industrial sectors (Bataille et al., 2021; Bach et al., 2020), having also been considered the use of hydrogen as a storage system, so that it can be used later to produce electricity again (Tecnológico de Canarias, 2022a). Later, the state of the art of some of these possible applications of hydrogen will be described in more detail.

To fully decarbonize heavy road transport, there are at least two possible viable solutions. On the one hand, there is the electric truck, while on the other hand, there is the hydrogen fuel cell, although both still need further development. In recent years there have been pilot projects using both electric and hydrogen technologies, such as the electric Tesla Semi or the hydrogen Nikola One and Two. However, it is believed that hydrogen will eventually become the dominant fuel for heavy vehicle transport, or at least the combination of electricity and hydrogen will be successful, according to previous research (Whiting et al., 2017).

In inter-island shipping, it is likely that routes with a fixed path between two ports with a distance of less than about 100 km could be electrified. There are currently several international examples of ferries that operate or will operate in the near future on a regular basis with this technology. There are numerous projects, such as the "Europas Seaways" ferry, which is intended to be powered by a 23 MW fuel cell and to connect Copenhagen with Oslo on a round trip of approximately 48 h (EURACTIV, 2021). Recently there have been studies of the use of hydrogen-powered transport vessels also powered by such fuel through the use of gas turbines (Alkhaledi et al., 2022). As for the Canary Islands, about 85% of inter-island ferry trips are less than 100 km in distance, so they could potentially be powered by electricity. But despite this, hydrogen could provide a solution for long distances and/or routes where greater flexibility in refueling is desired (Tecnológico de Canarias, 2022a).

In the short or medium term, air transport does not have emission-free solutions due to important technical limitations, mainly related to the higher power-to-weight ratio required for this purpose. This is particularly affected by the restrictions on the weight of the batteries in electric airplanes and on the weight and/or volume of fuel tanks in hydrogen airplanes. But despite this, hydrogen is also postulated as a strong candidate to decarbonize the air transport sector, but the design of hydrogen aircraft is not being considered; rather, the most realistic options involve the use of this element to produce other synthetic fuels and, in particular, synthetic kerosene. In fact, the first production plant for synthetic kerosene (e-fuel), which is intended to provide environmentally friendly fuel for the aviation sector, will begin production in Germany. This plant will produce a very small quantity, but its aim is to show the feasibility of the technology (Tecnológico de Canarias, 2022a).

Numerous projects for the production and use of green hydrogen are currently being developed in Spain and Europe. In Spain, several large electric utilities and construction companies, such as Iberdrola, Acciona and Enagas, are betting on hydrogen. For example, Iberdrola is working on the start-up of its Puertollano plant (Iberdrola), Acciona and Enagas, together with Cemex, Redexis, the Institute for Energy Diversification and Saving (IDAE) and the Balearic Government, are promoting the "Power to Green Hydrogen Mallorca" project (Acciona). Even in the Canary Islands, there are two projects related to Hydrogen that have been executed, namely the RES2H2 and HYDROHIBRID projects (both located at the research complex of the Instituto Tecnológico de Canarias, ITC, in Gran Canaria) (Tecnológico de Canarias, 2022a). Additionally, other facilities are in different degrees of development, such the one of Enagas and the DISA Group are promoting the production, distribution and commercialization of green hydrogen through the project "Canary Renewable Hydrogen Hub Cluster" to contribute to the progressive decarbonization of the Archipelago, a project that brings together 20 institutions, including companies and public bodies (de Canarias).

2.2. Hydrogen demand of the Canary Islands by 2040

There is a strategy in the Canary Islands to analyze all possible energy generation sources and vectors to reach the ambitious objective of having zero emissions of GHGs (Green House Gases) by 2040. In this line, hydrogen is an energy vector that must be enhanced, the amount of hydrogen that would be required in a scenario of total decarbonization in the Canary Islands is analyzed in great detail (Tecnológico de Canarias, 2022a). This analysis is aligned with the rest of the energy links in the archipelago, as well as with the generation method needed to meet this demand.

In reference to the different fields of hydrogen application, the one that is currently closest to profitability is land mobility. Even though it is true that the electric vehicle already offers an interesting solution for light vehicles, in the case of buses or trucks it does not seem to be the most suitable solution from the operational point of view (charging times, range and battery sizes). The second technological option which is close to economic profitability is re-electrification. The most interesting cases are those in which the supply is totally isolated from the public grid and the use of diesel generators are required for electricity supply. These cases tend to occur, especially in places close to or within

Protected Natural Spaces, which is one of the reasons why they are not connected to the public grid, a situation which takes place quite often in the Canary Archipelago, since mainly 4 national parks, 146 Protected Natural Spaces (ENP), 66 Important Bird Areas (IBA) and 53 Special Protection Areas for Birds (ZEPA) are located in the islands (Tecnológico de Canarias, 2022b). Then, wind farms and photovoltaic plants can generate electricity that could be converted into hydrogen for storage and transportation, using it, when necessary, in fuel cells or in gas engines/turbines, without this implying a drastic change in the management of these sites. It should be highlighted that re-electrification itself can be used as a method of energy storage, using fuel cells and hydrogen engines to provide energy and power services in the system.

Another use that could be close to being profitable would be the use of hydrogen in stationary applications for large consumers in which heat demands have an important weight in the final energy demand. The maritime mobility sector is another candidate that also opens up new development opportunities for the use of hydrogen. This application has the problem of the enormous space required to contain the high quantities of hydrogen demanded, which poses a serious storage problem. The possibility of liquefying hydrogen to reduce the space occupied involves reaching temperatures of −253 °C with the difficulties that this entails, both technical and profitability. An alternative that would make more sense is the synthesis of other fuels that could be converted to the liquid phase at a lower cost, for the maritime sector the main candidate is ammonia.

Hydrogen could also be used as a fuel for inter-island air transportation, although not directly but to subsequently obtain liquid fuels and, in particular, synthetic kerosene through the Fischer-Tropsch process. Given that the use of hydrogen as such presents a priori insurmountable obstacles due to its low "energy density". It must be said that this alternative is the most complex of the possible alternatives presented. Although its complexity is at the same level as its necessity, since air transport in islands constitutes an important part of the GHG emissions. This solution has a certain similarity with ammonia, although in this case hydrogen is combined with carbon dioxide, captured from processes such as biogas production or from the effluents of industries that currently emit it as a result of their activities.

For the demands which need re-electrification, hydrogen can be converted to electrical energy through the use of fuel cells whose operation consists of reversing the electrolysis process; that is, they extract oxygen from the air and, by combining it with the hydrogen produced, generate an electrical current and water. In this process, 50% of the energy generated by fuel cells is electrical while the other 50% is thermal. Therefore, this technology can also satisfy thermal demands and even both combined (electrical and thermal demands) through the process known as Combined Heat and Power (CHP). Re-electrification of hydrogen is also possible by using engines or gas turbines specially prepared for the combustion of this fuel. The efficiency of the process is lower than would be obtained with a fuel cell (between 20 and 40% depending on whether it is a turbine or an engine and its size). But this system achieves a higher power and is probably more suitable for those uses that also demand a significant amount of heat.

In line with the description of the different hydrogen use options presented above, the situation projected for the year 2040 based on the studies carried out by the own Canary Islands government (Tecnológico de Canarias, 2022a) is detailed below. This scenario assumes complete decarbonization through the use of hydrogen for heavy road transport (vehicles over 3500 kg), inter-island maritime and air transport with the production of synthesis fuels. In the electricity sector, the inclusion of hydrogen as a large-scale storage system on islands where other more competitive alternatives, such as reverse pumping, are not possible has also been assessed. Finally, a part of the demand associated with industrial applications and renewable cogeneration in the tourism sector is also added. The values of these contributions, disaggregated by islands, are shown in Table 1.

The H_2 demand data shown in the previous table, requires slightly more than $2{\cdot}10^6$ m^3 of water (for every 2 kgs of H_2 produced, 18 kg of water are needed for the electrolysis process). While the total water consumption of the Canary Islands is about $1.5{\cdot}10^8$ m^3 (INE - National Institute of Statistics, 2022), then the hydrolysis requirements represent an increase in water demand of just over 1%. Given the scarcity of water resources on the islands, the most reasonable option would be to obtain it through desalination. Then, the additional desalination capacity requires an initial investment of approximately 15–25 M€ and has annual O&M costs of about 3–5 M€, which means around 1.5 € per m^3 of water (REE, 2019; Eke et al., 2020).

3. Electric generation and hydrogen production

In recent years, hydrogen use is increasing, being used as an energy carrier for a variety of applications, instead of electricity. Given that there are some energy uses in which electricity clearly presents disadvantages, especially those applications where high temperatures or in general heat is demanded, or uses in which high power/weight ratios are required, such as in certain industrial uses with high heat or temperature demands, heavy road, maritime or air transport. Therefore, there are certain "non-electrifiable" energy uses and others where it is not clear which one is the most suitable energy vector. Almost the only explored option to produce green hydrogen is through water electrolysis from the electricity surpluses which come from renewable power plants (Berna-Escriche et al., 2022a,b). In this case, the usual production processes would be alkaline electrolysis (AEL) and proton exchange membrane (PEM) electrolysis. Both technologies are mature enough, mainly alkaline electrolysis which is being employed for natural gas and steam methane reforming since the 1920s, while PEM has been used since the 1960s to overcome some operational problems of alkaline electrolysis. But, as mentioned previously, another option which is being explored recently, is the use of very high-temperature reactors (VHTR) to produce hydrogen through the use of solid oxide electrolysis cells (SOEC), a technology that has not yet been commercialized. This technology operates at high temperatures and with a high degree of electrical efficiency, since they use high-temperature steam to promote the electrolysis process (IEA, 2019).

3.1. Electrolyzer technologies

Currently, only a small fraction (less than 0.1%) of hydrogen production is derived from water electrolysis, while the efficiency of the different electrolyzer systems ranges from approximately 50%–80% depending on the technology type and load factor. Three leading

Table 1
Hydrogen forecasted demand broken down by subsectors and islands by 2040, expressed in tH_2/year (Based on estimations of (Tecnológico de Canarias, 2022a)).

	Tenerife	Gran Canaria	Lanzarote	Fuerteventura	La Palma	La Gomera	El Hierro	Total Use
Heavy Road Transport	49,695	60,505	14,979	8157	3825	1735	1485	140,381
Inter-Island Maritime Transport	27,521	32,173	0	0	0	0	0	59,693
Inter-Island Air Transport	3035	3274	1701	1508	859	172	395	10,944
Industrial and Tourism Sector	3649	2925	792	689	247	67	45	8414
Re-Electrification	0	0	4482	4482	0	0	0	8964
Total Islands	83,901	98,876	21,954	14,836	4931	1974	1925	228,396

technologies used for water electrolysis are currently in use, i.e. alkaline electrolysis (AEL), proton exchange membrane electrolysis (PEM), and solid oxide electrolysis cells (SOECs). Table 2 shows the current and long-term major technical and economic characteristics of these technologies based on the predictions of IEA and other important sources (IEA, 2019; Buttler and Spliethoff, 2018).

Alkaline electrolysis is a mature technology that has been used since the 1920s, particularly for hydrogen production in the fertilizer and chlorine industries. It can operate at load levels ranging from a minimum of 10% up to full design capacity. One of its main advantages is its relatively low capital costs compared to other electrolyzer technologies, as no precious materials are used.

PEM electrolyzer systems utilize pure water as the electrolyte solution, which eliminates the need for the recovery and recycling of potassium hydroxide electrolyte solution. Their compact size can make them more appealing for its use in densely populated urban areas compared to alkaline electrolyzers. PEM systems have the potential to produce highly compressed hydrogen for decentralized production and storage at refueling stations (30–60 bar without the need for an additional compressor). Its operating range can go from zero loads to 160% of the design capacity.

SOECs operate at high temperatures and with a high degree of electrical efficiency. Since this electrolyzer use ceramics as an electrolyte and have a low material cost. A SOEC electrolyzer has the ability to operate in reverse mode as a fuel cell, converting hydrogen to electricity. This means that, in combination with hydrogen storage facilities, it can provide balancing services to the grid. Unlike alkaline and PEM electrolyzers, this capability allows the SOEC electrolyzer to offer these services. Since this technology uses steam for electrolysis (HTSE), it needs a heat source, which can be through nuclear power plants, solar thermal, or geothermal heat systems. This technology would be the most promising due to its great advantages in producing hydrogen in an economical, sustainable and efficient way.

3.2. Hydrogen production through renewable sources

Green or renewable hydrogen is produced through the use of electrolyzers using electricity from renewable sources. This renewable energy would be generated by wind and/or solar photovoltaic in the case of the Canary Islands, as it would be in most of the possible analyses in the different sites. Nowadays, renewable generation sources mature enough to cover large demands are wind and solar PV. In addition, particularly in the case of the Canary Islands, there are excellent conditions for their optimal exploitation, presenting high irradiations as well as excellent wind conditions with high and quite steady values (Berna-Escriche et al., 2021; Vargas-Salgado et al., 2022). These energy sources have an intrinsic problem, as they are non-manageable sources, there is the need to store them in periods of generation excesses, feeding them back into the grid in periods of shortages. Consequently, since hydrogen can be stored, the extensive use of hydrogen can contribute to solving this management problem.

3.2.1. The Spanish and canarian hydrogen production scenario

The Spanish Hydrogen Roadmap foresees (ministerio para la transición ecológica, 2022) the installation of 4 GW of electrolyzer power by 2030 and a minimum contribution of 25% of renewable hydrogen with respect to the total consumed in the industry that year. It also envisages a fleet of at least 150–200 buses, 5000–7500 hydrogen-powered light and heavy-duty vehicles, and at least 100–150 public access hydrogen-generators for refueling. In short, it is expected that this technology will have reached a sufficient level of maturity to allow large-scale deployment by 2030. In line with the above, the aim of the Canary Islands' green hydrogen strategy is to analyze, in as much detail as possible, the amount of hydrogen that would be required in a scenario of total decarbonization, aligned with the rest of the energy links in the archipelago, as well as the means of generation needed to meet this demand.

According to Monitor Deloitte's estimates, the generation mix of the Canary Islands proposes a system made up of approximately 75% solar PV generation and the remaining 25% wind power (Deloitte, 2020). The reason for this weighting is that solar generation has a better fit with storage than wind, since it has a more predictable production, which allows the necessary storage to be sized more precisely. Solar production is concentrated at specific times of the day and facilitates daily day-night charge-discharge cycles. On the other hand, wind generation can experience extended periods of low production that require increased storage capacity, together with periods of several days of high production that can overwhelm the storage system and generates spills. According to the report, a 75% wind - 25% solar generation mix would require more than twice as much storage capacity to meet 100% of demand as a 25% wind - 75% solar mix. Then the majority weight of solar generation would inevitably come together with an adequate demand management that would align electricity consumption with the generation profile (solar) and reduce the need for storage to manage the large peak of the central day hours. According to the authors of the report, there could be a potential for demand management towards central hours of the day of 20–30% of daily consumption, mainly through the displacement of electric vehicle recharging and consumption in the building sector (domestic hot water and household appliances). However, if not only electricity is taken into account as an energy carrier, but also hydrogen, the situation may change.

In the aforementioned sense, other studies show estimates in the opposite direction, for example, than the previously mentioned report of the Canary Islands government (Tecnológico de Canarias, 2022a). This study focuses on favoring hydrogen as the energy vector of choice over electricity (total electrification of the economy) as almost the only solution to address the challenge of eliminating greenhouse gas emissions in the energy sector. In this report, despite the advantages of solar PV generation, mainly due to its greater predictability and lower storage requirements, its advantages over wind are not so evident. Given that, on the contrary, in solar PV generation, there is an inevitable existence of a large peak in the central hours of the day (as shown in Fig. 2). This peak becomes difficult to absorb by any system and even more if a hydrogen production system is planned (strong oversizing of the

Table 2
Three main electrolyzer technologies characteristics (Based on estimations of (IEA, 2019; Buttler and Spliethoff, 2018)*).*

	Alkaline		PEM		SOECs	
	Nowadays	Long Term	Nowadays	Long Term	Nowadays	Long Term
Electrical Efficiency (%)	63–70	70–80	56–60	67–74	74–81	77–90
Operating Pressure (bar)	1–30		30–80		1	
Operating Temperature (°C)	60–80		50–80		650–1000	
Operating Hours (thousand hours)	60–90	100–150	30–90	100–150	10–30	75–100
Load Range (% of nominal load)	10–110		0–160		20–100	
CAPEX ($/kW$_e$)	500–1400	200–700	1100–1800	200–900	800–2800	500–1000

Notes: LHV = lower heating value. For SOEC, the electrical efficiency for steam generation is not included; CAPEX represents system costs, including power electronics, gas conditioning and balance of plant; CAPEX ranges reflect different system sizes and uncertainties in future estimates.

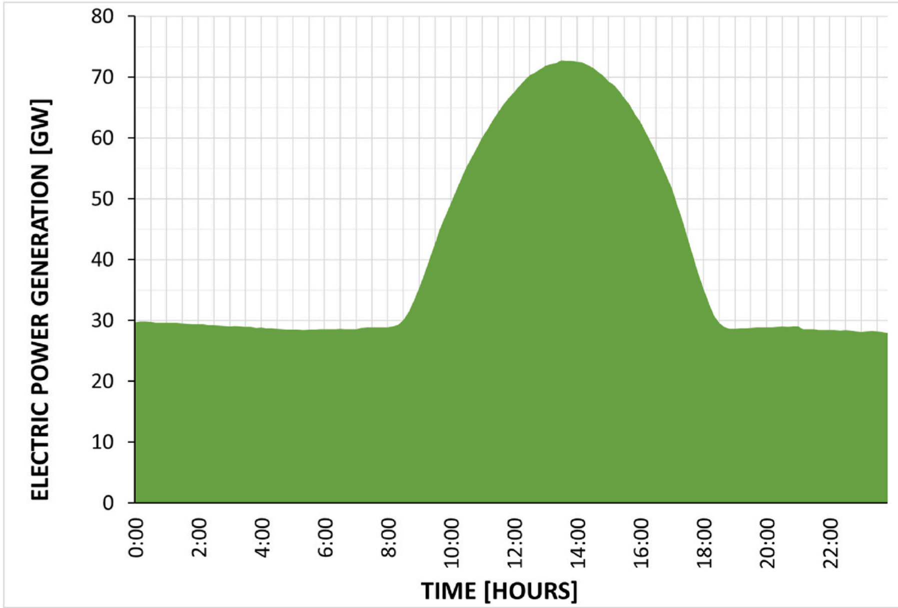

Fig. 2. *Forecasted electric generation curve of a renewable system with 60-40% solar PV and wind energy for Spain by 2040. (Estimations based on* (Berna-Escriche et al., 2021)).

electrolyzers to absorb the strong peak). In addition, the privileged location of the Canary Islands, which have very constant and strong winds, especially in several areas of the sea, makes that wind production have very high capacity factors. As mentioned above, the Canary Islands Government's green hydrogen strategy report (Tecnológico de Canarias, 2022a) estimates hydrogen production based on a generation mix composed of wind and solar photovoltaic as generation sources to produce the forecasted demand for hydrogen (Table 1). Then, the supposed electricity generation of both systems is 12.31 and 4.07 TWh per year for the wind and solar PV technologies respectively, which means a total generation of 16.38 TWh per year. Considering capacity factors of 0.6 and 0.27 for the wind and solar PV systems (typical figures for the Canary Archipelago (Rivera-Durán et al., 2023)), then the installed power needed to generate the demanded electricity would be around 2000 MW for each one of the two generation systems.

According to the information provided by the above-mentioned report on the green hydrogen strategy of the Canary Islands (Tecnológico de Canarias, 2022a), it would be necessary to install a total power up to 2177 MW in electrolyzers, distributed among 51 production centers, to meet the expected hydrogen demand in 2040. Electrolyzers which will be able to reach the demanded average production capacity of around 230,000 tH_2/year (supposing an operation time of around 75%), although if the electrolyzers were operated at 100% the production could almost rise to 300,000 tH_2/year.

3.2.2. Renewable generation

Renewable generation in the Canary Islands has very good prospects due to the excellent conditions to take advantage of both solar and wind resources. The sunshine in the Canary Islands is the highest in Spain and the wind conditions are also very favorable for wind power generation, especially offshore. The estimation of the solar resource has been carried out using NASA's POWER Data Access Viewer (NASA, 2022). In which the hourly solar data are obtained from satellite observations added to the surface solar irradiance information from NASA's Global Energy and Water Exchange Project (GEWEX)/Surface Radiation Budget (SRB) Release 3 and NASA's CERES Fast Longwave And Shortwave Radiative project (FLASHFlux). As for the wind resource, the magnitude of the wind resource was assessed using the POWER wind global data access viewer developed by NASA (NASA, 2022). This database bases its wind measurements on the Modern Era Retrospective-Analysis for Research and Applications (MERRA-2) assimilation model products of the Goddard Global Modeling and Assimilation Office (GMAO) and the GEOS 5.12.4 near-real-time products of the Advanced Processing Instrument Teams (FP-IT) of the GMAO. In the first instance, the last 10 years were sampled to obtain average hourly values for both resources, but this averaging makes the variability of the resource strongly attenuated, so it was finally decided to use the hourly values of the year 2019, since this year presents similar values in terms of solar irradiance and wind to the rest of the years analyzed.

Regarding the solar resource, the annual values of potential global horizontal irradiance are 1826 ES H/year (equivalent hours of sunshine), which can be increased to 2442 ES H/year through the use of solar trackers. The data described are those used in the current research, so it is assumed that this irradiance is maintained until the year 2040. Table 3 provides a summary of the information implemented in the solar photovoltaic installation. Given the conditioning factors of the islands, mainly the large surface area occupied by protected areas, together with the strong dependence on tourism, make the installation of large surfaces of solar farms, with the consequent visual pollution, not advisable. For this reason, the best option has been considered to be the exclusive installation of self-consumption for solar generation. Table 4 shows a breakdown by islands of the surface areas and installable power in the different types of constructions.

Regarding the wind source, an analysis of the most suitable sites for the different islands has been carried out, and a view of the average wind speed of the archipelago is shown in Fig. 3. As shown, wind generators can be installed in many suitable locations, of both onshore and offshore

Table 3
Inputs used for the PV system (Trina Solar, 2022).

Lifetime (years)	25
Derating factor (%)	90
Tracking system	No tracking
Solar panel	Vertex 550+
Temperature coefficient of power (%/°C)	−0.38
Peak Power (W)	550
Nominal operating cell temperature (°C)	45
Efficiency of the panel at standard conditions (%)	21.1
Cost (€/kW)	1300
O&M cost (per 1 MW peak power) (€/year)	3500

Table 4
Self-consumption data of Solar PV (Based on estimations of (Tecnológico de Canarias, 2021a)).

Island	Total Roof (km^2)	Maximum Occupancy	Available Roof (km^2)	Maximum Installable Power (MW)
Tenerife	71	0.70	50	5000
Gran Canaria	53	0.70	37	3700
Fuerteventura	15.7	0.69	10.9	1091
Lanzarote	13.9	0.65	9	940
La Palma	5.3	0.70	3.7	366
La Gomera	1.5	0.67	1	100
El Hierro	1.2	0.67	0.8	83.5
Total	161.6	0.68	112.4	11,280.5

technologies. As commented earlier, in this study, it has been considered that the best option was the use of offshore technology from the land occupation side. This technology is much more expensive but given its higher production (more stable and higher average wind speeds at marine sites) and from the aforementioned criterion of land occupation, it has been considered the best option. A summary of the datasheet of the selected wind generator is shown in Table 5.

3.3. Hydrogen production through nuclear energy

3.3.1. The small modular reactors (SMRs)

Nuclear reactors are an attractive energy source due to their high reliability, zero emissions of pollutants, and very low cost of electricity production. This high reliability is achieved through a high-capacity factor (nearly 100%) and very low operational requirements (such as the plant typically only refuels once every two years approximately). To ensure a smooth process, the plant has typically secured contracts in advance and keeps some of the fresh fuel on site.

However traditional reactors have several drawbacks, such as their large size, together with their difficulty of load regulation (even if possible, there would be practically no cost savings, since almost all costs in the power plant are fixed costs, which would simply increase the price per kWh of electricity produced) and their long time to start-up, meaning that they currently present major problems for their installation (Wrigley et al., 2021).

Therefore, a strong current trend is in the opposite direction, downsizing. But this raises the problem of the economy of scale, i.e., an increase in the unit cost of production due precisely to their small size. To counteract these “diseconomies of scale” and to be able to improve competitiveness, the business case for SMR designers relies on the economies of series or mass production, which is based on five key factors for cost reduction: simplification of design, standardization, modularization, maximization of manufacturing time in the factory and consequent minimization of on-site construction (Maronati et al., 2018; Mignacca and Locatelli, 2020; NEA and OECD, 2021; Lovering and McBride, 2020).

There are currently about 70 pre-designs of SMRs, but in order for series production to compensate for the “diseconomy of scale”, only a few designs must arrive to their final production stage in order to establish a sufficiently large market. Among these conceptual SMR designs, the most mature are evolutionary variants of Generation II, III and III+ of light water reactors (LWR-SMRs). This means that they are evolutions of reactors currently being operated worldwide, benefiting from many decades of operational and regulatory experience. These designs represent approximately half of the SMR designs under development. While the other 50% are fourth-generation reactors (Gen IV SMRs) that incorporate alternative coolants (i.e., liquid metals, gases or molten salts), advanced fuel and innovative system configurations. Although Gen IV-based designs do not have the same levels of operational and regulatory experience as LWRs, and more research is still needed in some areas, they are also benefiting from previous extensive research history on which developers and regulators can build (Maronati et al., 2018; Mignacca and Locatelli, 2020; NEA and OECD, 2021; Lovering and McBride, 2020).

The High-Temperature Reactors.

All nuclear reactors would be suitable for electricity generation and from that for hydrogen production. But among the possible new SMR designs, the ones that seem most suitable for hydrogen production are those operating at high temperatures (OECD NEA, 2021). Of the different hydrogen production processes, the one that is likely to achieve the highest efficiencies in the near or distant future is the SOEC electrolyzer, as shown in Table 2. However, not only this high-temperature steam electrolysis (HTSE) process is under study, but there are also promising results for thermochemical cycles. All these technologies increase their performance as the temperature increases, requiring less electricity for hydrogen production. The amount of electricity needed for electrolysis is strongly dependent on the temperature. At 2500 °C the process of thermolysis allows water to split into hydrogen and oxygen

Table 5
Datasheet of the wind turbine (ENERCON, 2022).

Wind generator	Enercon E−126
Rated power (MW)	7.58
Rotor diameter (m)	127
Height to the hub (m)	135 m
Total height (m)	197 m
Lifetime (years)	25
Cost of system (M€/turbine)	17.9
M€/MW	2.39
O&M cost (M€/year)	3.5

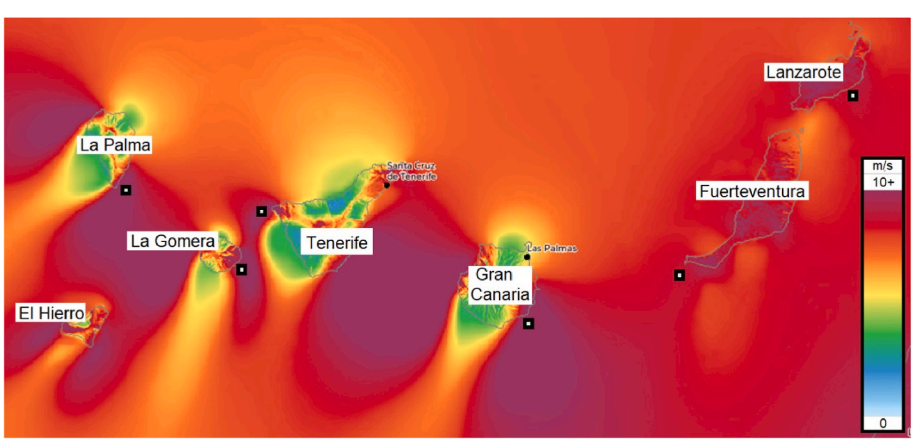

Fig. 3. *The offshore wind resource and optimum wind farm site in the Canary Islands (NASA, 2022).*

(Xing and Hino), but at lower temperatures, the energy input is a combination of electricity and heat (Fig. 4). For instance, the electrical and thermal energy inputs for the HTSE at 900 °C (a typical value) are respectively 1.97 [kWhe/Nm^3] and 0.93 [kWht/Nm^3]. These electric requirements can even be reduced through the use of thermochemical water-splitting processes, since the decomposition of a water molecule into hydrogen and oxygen is favored by one or more cyclic thermally driven chemical reactions, which require lower reaction temperatures in comparison to direct water-splitting. Many cycles have been proposed over the last decades such as Hybrid Sulfur (HyS)), Ispra Mark 13, Cu–Cl and Hybrid Ca–Br among many others (Xing and Hino).

The Generation IV design that meets this high-temperature operation condition is the high-temperature gas-cooled reactor (HTGR). This reactor technology is cooled by helium and moderated by graphite, using the proven ceramic-coated particle fuel. It currently has a projected capacity to provide a stable heat supply at a temperature of around 550 °C and could in the future be a practical option for decarbonizing industrial heat sectors, while contributing to the security of supply through the diversification of energy sources. The ease or difficulty of using HTGRs in different industrial sectors is mainly determined by the operating temperature of the process, the system compatibility of the process and the amount of energy demand of the plant in question. Focusing on process operating temperature and system compatibility, there are several processes that would be suitable for these designs at current temperatures, such as district heating applications, seawater desalination, bitumen recovery from oil sands, etc. Replacing existing fossil fuel-fired steam boilers and CHP plants with HTGR in CHP mode could swiftly decarbonize certain applications. However, incorporating HTGRs into additional applications would be implemented at a later stage (OECD NEA, 2022).

But beyond these more proximate HTGR heat application opportunities, HTGR heat can be utilized for the conventional process of hydrogen and ammonia production through natural gas reforming. However, the contribution of this technique to the reduction of CO_2 emissions would be restricted to 15–30% as natural gas would still be utilized as feedstock for H_2 production. Therefore, while emissions would be decreased as hydrogen and ammonia replace fossil fuels in the industrial and transportation sectors, very significant amounts of carbon emissions will still remain. Complete decarbonization of hydrogen and ammonia production can be achieved by using the heat and electricity from HTGR in advanced low-carbon hydrogen production methods, such as HTSE or thermochemical cycles. Although these processes are currently under development or in the demonstration phase, they are expected to achieve higher energy efficiency for hydrogen production than current low-temperature electrolysis processes, which only require electricity. In the longer term, an evolution of these HGTR reactors, the development of very high-temperature reactor technology (VHTR),

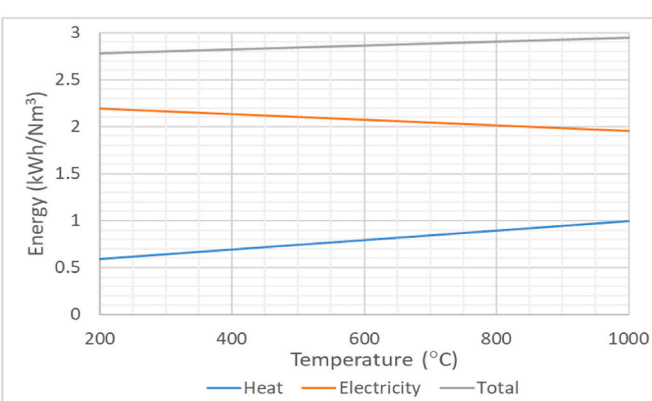

Fig. 4. *Energy Demand for high-temperature steam electrolysis. (Estimations based on* (Balta et al., 2016)).

which is expected to generate at core outlet temperatures of more than 950 °C (Locatelli et al., 2018). Therefore, the use of high-temperature SMRs together with integrated SOEC hydrogen production technology would be a very suitable solution for decentralized hydrogen production, or even the development of some thermochemical process to improve the efficiency of water vapor dissociation. Ideally, a very high-temperature reactor (VHTR) with an outlet temperature of 900–1000 °C and a capacity of 250–300 MWe is suitable for this integration (Lee et al., 2022). While nuclear reactors of 1–1.5 GWe would be appropriate for centralized hydrogen production, even though in many cases, the current tendency of generation is towards the distributed generation. Particularly, in the case of islands and especially in the case of the Canary Islands, the electric and hydrogen demands would be below the generation capacity of a big-scale nuclear reactor (Berna-Escriche et al., 2022a,b; Vargas-Salgado et al., 2022).

Concentrating on SMR designs, several types are at different stages of development. For instance, High-Temperature Reactor-Pebble Module (HTR-PM) is in operation in China, this reactor is partially based on the HTR-10 prototype reactor (Zhang et al., 2016). The HTR-PM has two reactors of 250 MWt each, connected to a steam turbine able to generate 210 MWe and with an outlet coolant temperature of 750 °C. Another promising design is the Gas Turbine High-Temperature Reactor 300 (GTHTR300) (Sato et al., 2014), which has been designed by JAEA, the original objective of this reactor was to produce both electricity using a gas turbine and hydrogen using a thermochemical water splitting method (IS process method). The upgraded design of the GTHTR300 has a thermal power output of 600 MWt with an electrical generation efficiency of 50.4% (302.4 MWe) and a coolant outlet temperature of 950 °C, being 2.87 c€/kWh the power generation cost at 90% of load factor (1.04 capital costs, 0.74 operation and maintenance costs, 1.09 fuel costs) (Yan et al., 2016). Currently, there are other conceptual designs under study such as the GT-MHR of 285 MWe, MHR-100 of 25–87 MWe and the MHR-T of 205.5 MWe (4 modules) all developed by the Russian nuclear engineering company OKBM Afrikantof, there is another GT-MHR design of 50 MWe developed by General Electrics and Framatome along with some other projects around the world (OECD NEA, 2021).

In relation to the reduced generation costs mentioned above, reaching the ones of large reactor designs, say that these important costs reduction of serial construction may provide lessons from many other industries over the last decades, such as in aircraft or shipbuilding industries. Another favorable point of SMRs is the reduced land occupation of this technology, then, all the needed modules could be placed in one or two sites of the most consuming islands (Tenerife and/or Gran Canaria). The cost reductions will be motivated by design simplification, standardization, replication, modularization, harmonization, and factory-based construction (OECD NEA, 2021; OECD NEA, 2020).

4. Scenario approaches and applied methodology

In this section, an overview of potential scenarios that may arise during the production hydrogen via zero-emission (GHG) technologies is provided, along with a discussion of the methodology to be developed. Subsequently, the two scenarios that are most likely to be implemented in the future have been selected. The primary focus and innovation of the paper lie in comparing the performance of H_2 production based on the technology deployed.

The first scenario is the use of mature water electrolysis technologies using electricity to break the water molecule, i.e. AEL or PEM technologies. The electricity required for these H_2 production technologies could be generated from renewable energy sources. Or in its case, any other technology with zero GHG, in the case of the Canary Islands, solar PV and wind generation are the most likely technologies to be considered. The second option would be the use of newer water hydrolysis technologies, such as high-temperature steam electrolysis processes (mainly SOEC) or thermochemical cycles (such as HyS, Cu–Cl, Hybrid

Ca–Br). As mentioned before, electricity and steam are needed to implement either of these last two options. So, future high-temperature reactor designs, both modular (SMR) and conventional plants, are expected to be very suitable for this use, additionally. Add in this second option that, since steam production has a much higher efficiency than electricity generation, a priori leads to a possible cost reduction.

Another possible option could have been the use of solar-based technologies able to reach the high demanded temperatures, i.e. the use of concentrating power technologies. Basically, it can be done by means of four different configurations: the parabolic trough, the linear Fresnel reflector, the solar tower and the parabolic dish. But the large-scale application of these technologies in the Canary Islands is unfeasible, especially given the high landscape pollution produced by the large extensions required and given the large number of protected areas of the islands and not only this, but they are a place eminently dedicated to the tourism sector. For this reason, only the possibility of the two technologies described above has been considered.

Therefore, these two scenarios have been analyzed, the production of H_2 by electrolysis of water from renewable generation and from generation by high-temperature SMRs. The first one is based on the scenario proposed by the own Canary Government through the Instituto Tecnológico de Canarias (Tecnológico de Canarias, 2022a), while the second one has been defined to cover the hydrogen demand estimated in this report but through the use of nuclear energy and high-temperature electrolysis technologies. Additionally, sensitivity analysis of costs, characteristics and performance of the different scenarios and subsystems in each of them will also be carried out, aiming to not only estimate the capabilities of the proposed scenarios but their possible variation ranges.

Then, to implement these two scenarios, the HOMER software (Hybrid Optimization of Multiple Energy Resources) has been used. The code is being widely employed during recent years by the scientific community to compare and analyze the different systems tested, finally reaching the optimal energy mix. The computer program was developed by National Renewable Energy Laboratory (NREL) (NREL HOMER ENERGY, 2020a). The code estimates optimal system size, investment, LCOE and payback by varying the characteristics of different energy sources. In fact, it mainly uses an economic criterion, so it determines the optimal size of the system aiming to reach the minimum values of the previously mentioned economic variables. This code is widely used by the scientific community to make energy production predictions and consequently choose the best option to implement, these calculations can be carried out using different generation sources. In that sense, HOMER allows implementing all kind of hybrid systems, for instance, it is possible to define almost any energy source (solar PV, wind, nuclear, carbon, gas, biomass, geothermal, etc.), along with storage systems (through batteries) and is also able to consider electric and hydrogen loads, all of them for stand-alone and grid-connected systems (Berna-Escriche et al., 2021; Vargas-Salgado et al., 2022; Qiblawey et al., 2022).

The basis of the methodology consists of obtaining from reliable sources the input data required by the HOMER software (NREL HOMER ENERGY, 2020b). From these data the code is able to analyze the proposed system, reaching the optimized size of the electric generation and H_2 production systems to cover the hydrogen demand. A project lifetime of 25 years has been established for the financial analysis. A schematic view of the major input and outputs of the HOMER code is shown in Fig. 5. Among the different inputs required for the code to perform the simulations, it could be mentioned the energy demand to be covered (in the current case, the H_2 to be produced), technical information and costs of the generation systems (in this case solar PV, wind, and SMRs) and H_2 production systems (PEMs, SOECs, Cu–Cl cycles, etc.). A summary of the major data of the H_2 system are shown in Table 6. Furthermore, other required inputs are the energy resources of every power system (the solar PV and wind resources available in the Canary Archipelago and information about the implemented nuclear reactor) and the financial information, such the annual interest rate, or the project lifetime, among other data. As a result, the code provides the economical optimal solution for the particular conditions of the scenario under study (LCOE, initial capital, NPC, payback, and internal rate of return (IRR), etc.) as well as the details of the configuration chosen.

5. Results

As previously mentioned, two hydrogen production scenarios have

Table 6
Major characteristics of the analyzed scenarios.

Scenario	Renewable (solar PV & Wind)	VHTR
Demand (tH_2/year)	228,396	
Production technology	PEM	SOEC
Electrical Efficiency (%)	70.5 (67–74)	83.5 (77–90)
Operating Hours (thousand hours)	125 (100–150)	87.5 (75–100)
Load Range (% of nominal load)	0–160	10–100
CAPEX (k€/MW_e)	550 (200–900)	750 (500–1000)

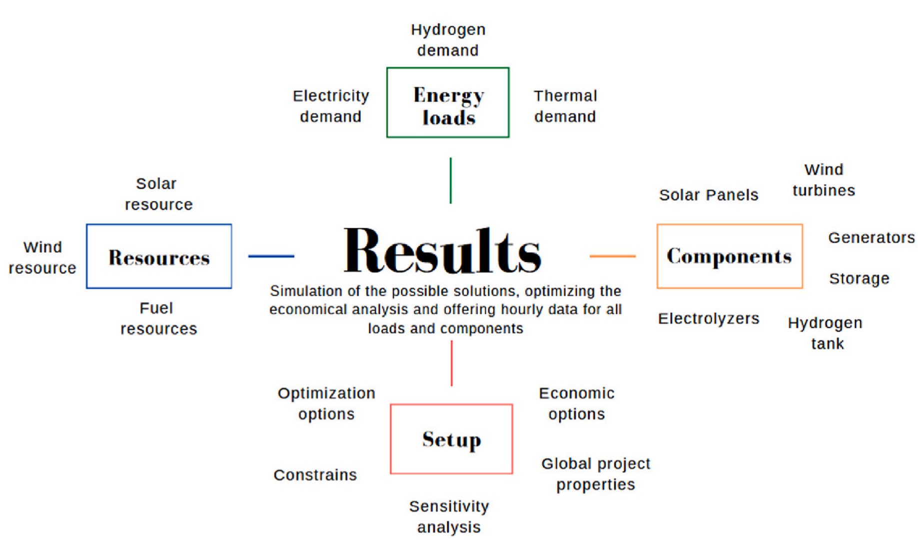

Fig. 5. Overview of the major inputs and outputs of the HOMER software.

been simulated to maximize the use of hydrogen in the final energy consumption in the Canary Islands. The first one is based on renewable energies and the second one is based on the use of modular reactors of high-temperature. This results section will show the main economic and technical aspects associated with these simulations, as well as a sensitivity analysis of the different conditioning factors that can affect both the final hydrogen production and its cost. For this purpose, this section has been divided into two subsections, one in which the aspects related to the two base scenarios are developed and another section where the sensitivity analysis of these scenarios is developed.

5.1. The base scenarios

The renewable scenario is based on the Canary Islands Government's green hydrogen strategy report (Tecnológico de Canarias, 2022a). This report estimates the hydrogen production based on a generation mix composed exclusively of wind and solar PV as generation sources to produce their forecasted demand of hydrogen (Table 1) with a maximization of the hydrogen consumptions. The forecasted value is 228,396 tH_2 per year, amount which increases the water demand of the islands by 5500 m^3/day because of the electrolyzer requirements. The final energy demands covered with hydrogen have been maximized, since all consumptions that have good perspectives on hydrogen as a fuel have been considered. This scenario has been reproduced and the major results are displayed in Table 7. It would be necessary to install total powers of 1745, 2152.5 and 2177 MW for the solar PV, wind and electrolyzer subsystems to be able to cover the forecasted hydrogen demand. This coupled system of electric generation and hydrogen production leads to a final hydrogen production cost of 4.1 €/kgH_2.

While considering the other scenario, hydrogen production by means of SMR reactors, the system has required 1814.4 and 1450 MW for the installed power of the SMRs and the SOEC-type electrolyzer, respectively. In this case, the reactors have an optimal operation at full load producing exclusively electricity or heat. The selected reactors can work in cogeneration, producing 1 tH_2/hour and 50 MWe, which means a much lower hydrogen production performance (Yan et al., 2016). Therefore, the simulated system consists of the installation of six SMRs, four of which are used to produce the electricity necessary for the electrolysis of water using SOEC technologies, one for the production of the heat necessary for this electrolysis, and the remaining one is kept as a backup. This last reactor is used either when any of the others must be refueled or shut down on a scheduled basis or in any other situation, then the objective is to have as a whole system a capacity factor of 100%. With these considerations, hydrogen production of $3.36 \cdot 10^5$ tH_2/year will be reached, thus, there are hydrogen excesses of $1.08 \cdot 10^5$ tH_2/year. Then, to feed the electrolyzer, a water supply of 8250 m^3/day is required. The system leads to a final hydrogen production cost of 1.18 €/kgH_2, even if not selling the excess hydrogen, the system would have a cost of 1.73 €/kgH_2. These significant surpluses could be exported either by means of hydrogen carrier ships or even a submarine pipeline connected to the Moroccan coast to export these excesses, given that it is less than 100 km away in its closest part to the island of Fuerteventura. In fact, due to the reduced cost of production, it could even be considered duplicating the system, which would be even more competitive, given the need to have only one SMR module as backup, i.e. a total of eleven SMRs. Table 8 shows the summary of the major lifetime economic costs of the two analyzed scenarios.

In relation to the costs of both hydrogen production systems, it can be seen that generation exclusively by means of renewable energies has a cost of approximately 2.5 times higher than that of production by means of nuclear energy, despite being able to produce almost 50% more H_2, which makes the production costs almost 4 times higher with the renewable system. Most of this cost comes from the wind system, so it would be possible to optimize renewable generation through the increase of solar PV use. Although it would lead to the increase of the huge generation peak of the central day hours, which subsequently lead to the oversizing of the electrolysis system to be capable of absorbing part of this energy. Several attempts have been carried out and the cost reductions have not been quite significant. Consequently, only the results of the optimized system proposed by the own Canary Island government (Tecnológico de Canarias, 2022a) is shown in the current study. Going into detail on the costs of the subsystems of renewable energy generation, as shown in Table 8, the higher cost comes from the wind subsystem, both capital and operation and maintenance of wind turbines represent about 80% of the total cost. The systems associated with solar PV generation and water electrolysis account for almost equal parts of the remaining 20%. In the case of nuclear power generation, the costs are distributed in proportions of approximately 75% and 25% in the nuclear and electrolyzer installations, respectively. The costs of nuclear facilities are split almost equally between capital costs, and operation and maintenance (fuel costs included). While the capital cost of the electrolysis subsystem accounts for almost 50% of their total cost, while the replacement costs of this equipment account for almost 30% (given their shorter lifetime than the reactors need to be replaced), leaving the remaining 20% or so for their O&M.

Another aspect to consider regarding the coupling of the hydrogen production/demand balance is that hydrogen consumptions are fairly

Table 7
Summary of the major technical characteristics of the two analyzed scenarios.

Scenario	Renewable (solar PV & Wind)	VHTR
Generation System		
Installed Power (MWe)	1745/2152.5[a]	1814.4[b]
Unit Cost (k€/MWe)	1300/2390	2051
O&M Cost (k€/MWe·year)	3.5/261	84[c]
Generation (TWh/year)	4.28/9.54	10.60/ 5.26[d]
Electric Wastages (%)	7.59	–
Electrolyzer		
Water demand (m^3/day)	5500	8250
Production technology	PEM	SOEC
Installed Power (MW)	2177	1450
Electrical Efficiency (%)	70.5	83.5
Operating Hours (thousand hours)	125	87.5
Load Range (% of nominal load)	0–160	10–100
Unit Cost (k€/MWe)	550	750
O&M Cost (k€/MWe)	10.4	14.18[e]
Replacement Cost (k€/MWe)	191	515
Hydrogen Production		
Production (tH_2/year)	228,396	336,463
LCOE (€/kg H_2)	4.10	1.18

[a] Installed power of solar PV and wind resources.
[b] Electrical power of the 6 SMRs installed, four produce electricity, one produces heat and the remaining one is used as a backup system.
[c] O&M includes the fuel cost.
[d] Electrical and thermal production respectively.
[e] O&M costs of the VHTR also includes the fuel costs.

Table 8
Summary of the major lifetime economic costs of the two analyzed scenarios.

Systems	Capital cost (M€)	Replacement cost (M€)	O&M (M€)	Total (M€)
Renewable Scenario				
Wind	4836	–	14,015	18,851
Solar PV	2269	–	96	2365
Electrolyzer[a]	1217	415	666	2298
Whole System	8322	415	14,777	23,514
SMR Scenario				
Nuclear	3720	–	3818	7538
Electrolyzer[a]	1118	746	664	2528
Whole System	4838	746	4482	10,066

[a] Includes the costs of the desalination plant (CAPEX 20 and 30 M€ for the renewable and SMR scenarios respectively, and 0.08 €/m^3year).

constant throughout the year. As seen in Table 1, most of the consumption comes from heavy road transport, which shows very little seasonality, but not only the majority contribution, but also the remaining ones, maritime and air transport and industrial consumption, do not show seasonality either (Tecnológico de Canarias, 2021b). Therefore, there would be a very flat hydrogen demand curve throughout the year, which would fit perfectly with the production of hydrogen with nuclear, since the reactors are working at their maximum power all days of the year. While in a renewable generation system, there would exist marked variations throughout the year. Fig. 6 presents the hydrogen production for a typical day of summer and winter. As can be seen in the figure, in the summer months production is much higher than in winter ones. As shown in Fig. 6 the peak production is similar in both cases, since the power of the electrolyzers determines this value. However on a typical summer day (Fig. 6a), the electrolyzers operate at full load for a significantly much longer time than on a typical winter day (Fig. 6b), mainly due to the higher midday peak power generation driven by solar PV energy in the summer months. In fact, on some winter days, the electrolyzers do not run at full load at any time. Additionally, on average, winds tend to be stronger in summer than in winter, a situation that further increases wind production on most summer days. Consequently, the end result is a daily hydrogen production of up to approximately 50% more in summer than in winter, for instance, daily production of around 850 tons of hydrogen on the July 26, 2019 versus the production of 550 on the 6th of January.

Therefore, if the additional costs of the increase in the reservoir capacity required in the renewable scenario were to be taken into account, an extra increase in the cost of storage compared to SMRs would have to be considered. However, this storage estimate, together with the different calculations associated with hydrogen transport and distribution, has been considered outside the scope of this work. Therefore, only the costs related to hydrogen production through renewable and nuclear sources have been estimated in this work, showing an important difference in the final production costs in favor of hydrogen production through nuclear technology.

One aspect to comment on is that in the current study hydrogen demand has been considered separately from electricity demand. In reality, this will not be the case, so for the renewable energy generation scenarios, as far as possible, H_2 generation would be carried out in the periods of time in which there are electricity surpluses, which would undoubtedly affect the cost analysis. The end result would be the use of a significant part of the electricity excess, with the consequent reduction of costs. But these excesses are usually concentrated almost entirely in the central hours of the day, since those systems usually has a big contribution of solar PV generation. Additionally, there would exist other possible peaks caused by excesses produced by wind generation, but these will have much lower absolute importance since they will occur less frequently. The result of the existence of these large generation peaks concentrated in a few hours, motivates to reach a balance between the extra cost of oversizing the hydrogen production system to be able to absorb these excesses of energy and the oversizing of the generation system itself, thereby increasing the excesses. In any case, the accuracy of the presented calculations would be appreciable, since the cost reduction of the partial use of electricity surpluses would be compensated by the oversizing of the hydrolysis production subsystem. In the case of the nuclear power generation system, this analysis of hydrogen generation shows fewer differences compared to the overall study. Since only the analyses should be carried out to determine at which times all of the SMR generation is dedicated to electricity generation and at which times a part of it is derived to the direct use of the heat produced to be used together with the necessary electricity in the processes of high-temperature steam electrolysis or thermochemical electrolysis. The comparison of the current analysis with those of the integrated hydrogen/electricity demand will be left for future studies, along with the study of a system composed of renewable and nuclear generation to cover both demands.

5.2. Sensitivity analysis

In the previous section, the calculations of the two scenarios have been carried out based on the "average" values of cost forecasts and technical characteristics of the different technologies for the year 2040. In general, the uncertainties in the capital costs, O&M and replacement, if necessary, have been considered. But specifically in the case of electrolysis installations, uncertainties in some of their technical aspects have also been considered, specifically efficiency and service life. The technologies to be used, both PEM and SOEC, are not at a high degree of maturity, which means that there are greater uncertainties in their future performance. SOEC technologies, in particular, are the least developed and are not yet in commercial operation. Table 9 shows the main inputs and outputs that have been implemented in the renewable scenario, so two new sub-scenarios have been obtained, one with the most favorable forecasts for production and the other with the most unfavorable forecasts. The same analysis has been performed for the nuclear scenario (Table 10).

As shown in Table 9, there is a variation in the H_2 costs of more than 1.5 €/kgH_2 (from 3.29 to 4.99 €/kgH_2) with the consideration of possible uncertainties in electricity generation technologies plus hydrogen production technologies between the optimistic and pessimistic scenarios. Percentage-wise, the greatest uncertainties are related to hydrolyzers, both in their technical and economic aspects. While for hydrogen production from electricity/steam through nuclear technologies this variability is reduced to just over 0.5 €/kgH_2 (0.85–1.48 €/kgH_2), although the latter variability is somewhat higher in percentage terms (35 vs. 43% approximately). It should also be noted that even if the surplus hydrogen could not be sold, the production cost would still be very competitive, between 1.14 and 2.34 €/kgH_2. As can be seen in both previously mentioned tables, the electrolysis process is the one

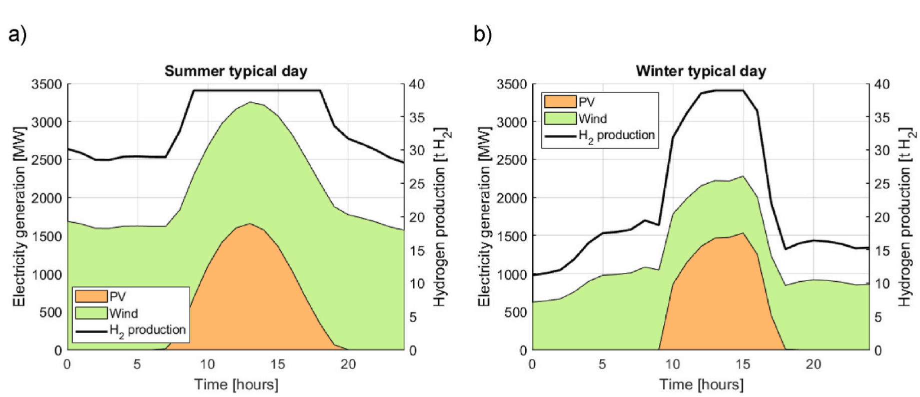

Fig. 6. Seasonality of hydrogen production in the full renewable generation scenario for a typical day of: a) Summer (July 26, 2019; b) Winter (January 6, 2019).

Table 9
Summary of the input uncertainty together with the output variability for the renewable scenario.

Scenario	Optimistic Scenario	Pessimistic Scenario
Inputs Uncertainty		
Solar PV System (k€/MWe)	975	1625
Solar PV O&M Cost (k€/MWe·year)	2.45	4,55
Wind System (k€/MWe)	2022	2472
Wind O&M Cost (k€/MWe·year)	234.9	287.1
Electrolyzer System (k€/MWe)	200	900
Replacement (k€/MWe)	3.78	17
O&M Cost (k€/MWe·year)	69.45	312.5
Electrolyzer Electrical Efficiency (%)	74	67
Electrolyzer Operating Hours (thousand hours)	150	100
Desalination Plant Cost (M€)	15	25
Desalination Plant O&M (€/m^3 year)	0.06	0.10
Outputs Variability		
Power Solar PV System (MWe)	1745	1745
Power Wind System (MWe)	2062.5	2190
Power Electrolyzer System (MWe)	2030	2530
Generation (TWh/year)	13.42	14.00
Electric Wastages (%)	9.22	3.86
Cost Solar PV System (M€)	1774	2956
Cost Wind System (M€)	16,256	21,097
Cost Electrolyzer System (M€)	764	4531
Total System Costs (M€)	18,794	28,584
LCOE (€/kg H_2)	3.29	4.99

Table 10
Summary of the input uncertainty together with the output variability for the nuclear scenario.

Scenario	Optimistic Scenario	Pessimistic Scenario
Inputs Uncertainty		
Nuclear System (k€/MWe)	1367	2735
Electrolyzer System (k€/MWe)	500	1000
O&M Cost (k€/MWe)	9.45	18.91
Replacement Cost (k€/MWe)	343.3	686.7
Electrolyzer Electrical Efficiency (%)	90	77
Electrolyzer Operating Hours (thousand hours)	100	75
Desalination Plant Cost (M€)	22.5	37.5
Desalination Plant O&M (€/m^3 year)	0.06	0.10
Outputs Variability		
Power Electrolyzer System (MWe)	1450	1450
Cost Nuclear System (M€)	5025	10,050
Cost Electrolyzer System (M€)	1530	3403
Total System Costs (M€)	6555	13,453
Hydrogen Production (tons)	362,655	310,271
LCOE (€/kg H_2)	0.85	1.48

with the greatest variability, given that in both cases these technologies are not currently in an advanced commercialization process, especially SOEC technologies. Therefore, there are wide ranges in the costs of the installations (capital, O&M, and replacement), as well as in their technical characteristics (fundamentally efficiencies and lifetimes).

When considering the uncertainties in the electrolyzer performances, the amount of hydrogen capable of being produced by each system has been varied. So, in the renewable case, where the installation had been dimensioned to produce just the required amount of H_2, the power of the electricity production installations and the electrolyzers used had to be changed, specifically, the installed power of the wind turbines and the electrolysis installation had to be varied to compensate for the increase or decrease in the performance of the latter installation. In the nuclear case, as mentioned above, the reactors must be working at full load and taking full advantage of their electrical and thermal performance (exclusive use of a reactor to produce electricity or heat). Therefore, the system is oversized, so the effect of these uncertainties causes costs to vary and excesses to vary, but in all cases, there is a surplus of hydrogen.

6. Discussion

The phase-out of GHG emissions is a key aspect of energy systems; in this study, the maximization of hydrogen as an energy vector is analyzed. So, for its production, a comparison between two systems with zero GHG emissions has been carried out, taking into account the forecasted hydrogen demand of the Canary Islands by 2040. One system is based on renewable energies (solar PV and wind), while the other is based on one of the latest design of generation modular reactors (SMRs of the VHTR type). These islands are located in the Atlantic Ocean, so their location makes it advisable to have maximum energy independence from the outside. But, at present, almost all energy consumption are based on the use of fossil fuels. So, they are far from being self-sufficient, as they have to receive a continuous flow of fuel (mainly oil and gas) almost every day, coupled with high levels of GHG emissions caused by the extreme use of fossil fuels. This situation is planned to be changed by the year 2040 in all the extra-peninsular territories of Spain, since there are government plans in that direction for the complete elimination of GHG emissions. As part of this decarbonization of the economy, along with favoring the electrification of energy end-uses, there is also the more than likely need to maximize hydrogen end-uses.

Consequently, for the total decarbonization of the economy, it is widely recognized that the economy must be electrified, but there are several final energy uses for which this electrification is not possible, or at least it is not economically profitable. For this reason, the possibility of using hydrogen as an energy carrier has been analyzed during the last years. So, the use of hydrogen is being studied in those uses where it presents advantages over the use of electricity. In this line, as part of this decarbonization of the economy, this document analyzes how to cover the energy needs in the case of maximizing the use of hydrogen as an energy vector in all those uses in which there are currently good prospects in terms of the suitability of the hydrogen use. All this has been applied to the Canary Islands, which will have a population of around 2.5 million people by 2040 and according to in-depth studies carried out by the Canary Islands Institute (a public company of the Canary Islands government) have estimated a hydrogen demand for 2040 of approximately 230,000 t/H_2 per year for a scenario where the final energy use of hydrogen has been maximized (Tecnológico de Canarias, 2022a). This hydrogen amount represents a very high production, which requires detailed planning. The exclusive use of renewable generation sources to supply the electrolyzers and thus produce hydrogen from clean energies is proposed in the above mentioned study. This scenario has been replicated, reaching results very similar to those proposed in the study. Going one step further, a scenario based on SMR reactors has been simulated to generate the electricity and heat (use of SOEC-type electrolyzers) needed to produce hydrogen.

The key points that can be drawn after comparing both scenarios and performing an uncertainty analysis associated with different variables (related both to costs and to the technological characteristics of the different subsystems required for hydrogen production of both analyzed scenarios) are the following.

- Renewable generation leads to much higher hydrogen production costs than nuclear production, in particular through the use of high-temperature modular reactors. Being almost 4 times higher, from around 1.2 €/kgH_2 to almost 4.1 €/kgH_2.
- Regarding the performance of both systems, it should be noted that renewable generation is more flexible, in the sense that the system can be sized for the required demand (always with the uncertainty inherent to renewable resources), while the nuclear system does not have that flexibility. But on the other hand, nuclear production is much more competitive, so even without using the excesses caused by this lack of flexibility, it is much more competitive than a renewable generation. Additionally, nuclear production is almost

completely predictable (except for unexpected shutdowns, but a reactor is always maintained as backup in the current study) while renewable strongly depends on the weather conditions, so large production variations can take place.
- In electricity generation associated with renewable sources, the challenge is to take advantage of the resources in such a way that the full demand for hydrogen can be covered at all times. Wind power generation poses the problem of difficulty in predicting the wind, with the possibility of prolonged periods of low or no speed (although off-shore generation in the Canary Islands has very high and constant wind speeds). While solar PV power, although more predictable (with a scarcity of cloudy days in the islands), presents the problem of extremely high production in the central day hours. So, in both cases, the hydrogen production system should be oversized, the first to cover the wind variability and the second to cover the nighttime and absorb the peak of the central hours of the day. Therefore, a compromise solution must be reached between the two subsystems of electricity generation and hydrogen production.
- In renewable generation there is also a problem of seasonality in the production. Therefore during the summer months, there is a higher electricity production of both wind and solar PV generation systems. As a consequence, it would be necessary to oversize the hydrogen storage systems, so that the excesses/defects of production could be managed in order to have the demand covered during the whole period.
- In the nuclear scenario, there is a constant hydrogen production, which fits very well with the hydrogen demand curve, since all hydrogen uses are not very seasonal (transport uses consume almost all the demanded hydrogen), so that it can be assumed that they are constant throughout the year.
- It should be noted that as a by-product of the hydrogen production system, the production of O_2 represents a higher amount in mass. So that, it could be recovered for the different uses in which it could be required.
- As for hydrogen production technologies, the electrolyzers used in the renewable scenario (PEM technology) are at a much higher maturity stage than the ones used in nuclear generation (SOEC technology for the HVTRs). However, in the long-term predictions, the performance is expected to be significantly higher in this second technology, although with higher capital and O&M cost and possibly with a shorter lifetime. However, the total costs per unit of installed power and hydrogen produced are quite similar in both cases.
- In the renewable scenario, the investment bulk goes to power generation (over 90%), while in the nuclear scenario, it represents a significantly lower proportion (around 75%). Of this 90%, a large part comes from the wind subsystem, given its higher capital and O&M costs compared to the solar PV subsystem. These costs could have been reduced by using on-shore generation technologies, but in the Canary Islands there are many restrictions (mainly because of protected areas and tourism), so it was decided to use exclusively off-shore production.

In the two scenarios, the unavoidable uncertainties associated with calculations based on long-term forecasts have been analyzed. It has been analyzed the sensitivity to different variables of the systems, particularly those associated with costs and, especially for the less mature systems and those associated with technical characteristics. This sensitivity analysis has shown that there is a relatively large range in the final production costs in both cases, with a variation range of around 40%. However, under all of them, nuclear production achieves much lower costs.

7. Conclusions

This study compares two scenarios for hydrogen production, one based on renewable energy sources and the other on high-temperature modular reactors. The analysis focuses on the costs and performance of the different subsystems required for hydrogen production in each scenario. An uncertainty analysis has also been performed to identify the variables related to costs and technological characteristics that have the most significant impact on the results.

The economic study shows that nuclear production leads to much lower hydrogen production costs, at around 1.2 €/kgH_2, while renewable generation is almost 4 times higher, at 4.1 €/kgH_2. Generally, nuclear production is more competitive and predictable than renewable generation, which has offered superior flexibility. However, renewable generation requires oversizing the hydrogen production system to cover wind variability and nighttime and absorb peak central hours of solar PV power. In addition, the seasonality inherent in renewable generation represents a challenge, which requires oversizing the hydrogen storage system to manage the excesses or deficits of production. In contrast, the nuclear scenario has a constant hydrogen production that fits well with the almost constant hydrogen demand throughout the year.

The analysis of the hydrogen production technologies shows that the electrolyzers used in the renewable scenario are more mature than the ones used in the nuclear generation. However, in the long-term predictions, the performance is expected to be significantly higher in the second technology, although with higher capital and operating costs, and possibly with a shorter lifetime. Nevertheless, the total costs per unit of installed power and hydrogen produced are quite similar in both cases.

Finally, this study includes a sensitivity analysis to test the robustness of the results under different scenarios. The sensitivity analysis shows that there is a relatively large range in the final production costs, with a variation of around 40%. However, under all scenarios, nuclear production achieves much lower costs than renewable generation. The study concludes that a compromise solution is required between the two subsystems of electricity generation and hydrogen production to optimize the costs and performance of the hydrogen production system.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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