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Green Hydrogen Hub Development: A Case Study of Galway's Path to a Hydrogen-Powered Future

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Abstract

With the need to reach zero emissions by 2050, hydrogen is expected to play a significant role as a low-carbon energy carrier in decarbonised economies. Nowadays, the supply chain for green hydrogen is still limited, with only a few pilot projects using it.

The creation of some hydrogen valleys and Ireland's vast wind potential could be used to produce hydrogen, and other electrofuels, for the decarbonisation of some of the hardest-to-abate sectors of the energy system as industry, transport, and power generation.

This project aims to investigate the potential of green hydrogen production to meet the growing hydrogen demand in Galway in the future.

To begin with, the study quantifies the future energy balance and estimates the hydrogen demand of the region, considering hydrogen use in each sector based on factors such as government policies, market dynamics and technological advances. This forms the foundation for the subsequent investigation.

A techno-economic analysis is conducted to compare three green hydrogen production methods: grid-connected using electricity from operational renewable energy assets through a Power Purchase Agreement, buying electricity from the wholesale market only when greenhouse gas emission intensity is below the regulation threshold and off-grid electrolysis.

The ultimate goal is to identify the optimum scenario for demand metering and lower levelized cost of hydrogen (LCOH) for each decade from 2030 to 2050, analysing different renewable sites that could be identified as hydrogen hubs.

It was shown that the most cost-effective method of producing green hydrogen is generally an off-grid scenario that relies on wind power.

The LCOH for 2030 varies from €8.5-€13.5/kgH2, remaining very high due to the storage needed to supply a constant demand over time. For 2040, the LCOH ranges from €7.9-€4.7/kgH2, with the electricity supply identified in an offshore wind farm. Using liquid hydrogen to store large quantities of hydrogen becomes cost-effective. Results show that hydrogen produced on an offshore platform, stored underground in a depleted gas field, and supplied to the natural gas grid through the existing infrastructure has an LCOH of €4.3/kgH2 in 2050. To achieve an affordable LCOH, it is essential to have an ample supply of renewable energy, implement an economical storage method, and establish an effective transport system.

Nomenclature

Alkaline	**AWE**	Kilowatt hour	**kWh**
Boil-off gas	**BOG**	Levelised cost of electricity, €/MWh	**LCOE**
Capacity factor, %	**CF**	Levelised cost of hydrogen, €/kg	**LCOH**
Capital expenditure, €	**CAPEX**	Lifetime, years	**n**
Carbon dioxide	**CO_2**	Liquid hydrogen	**LH2**
Carbon intensity, kgCO2/MWh	**CI**	Mount Lucas Wind Farm	**MLWF**
Climate Action Plan 2023	**CAP23**	Natural gas	**NG**
Diameter	**D**	Offshore Renewable Energy	**ORE**
Efficiency	**η**	Operating Expenditure, €	**OPEX**
Emission intensity, kgCO2/MWh	**EI**	Photovoltaic	**PV**
European Union	**EU**	Power Purchase Agreement	**PPA**
Fuel Cell Electric Vehicle	**FCEV**	Proton exchange membrane	**PEM**
Galway Hydrogen Hub	**GH2**	Renewable Energy Directive	**RED II**
Galway Wind Park	**GWP**	Renewable Energy System	**RES**
Greenhouse Gas	**GHG**	Republic of Ireland	**ROI**
Heavy fuel oil	**HFO**	Sustainable aviation fuels	**SAF**
High Voltage Direct Current	**HVDC**	Sustainable Energy Authority of Ireland	**SEAI**
Hydrogen	**H_2**	Techno-economic analysis	**TEA**
Hydrogen Refuelling Station	**HRS**	Wholesale electricity market	**WEM**
Kilotonnes of equivalent oil	**ktoe**		

1. Introduction

The energy sector contributes significantly to greenhouse gas emissions, accounting for about 75% of them. This makes it crucial to address climate change, one of humanity's greatest challenges. To limit the long-term rise in global temperatures to 1.5°C, reducing global carbon dioxide emissions to zero by 2050 is essential.

Achieving this goal requires a complete transformation in the way we produce, transport, and consume energy.

In decarbonised economies, hydrogen is expected to serve as a significant low-carbon energy carrier and feedstock.

In the pathway towards achieving net zero emissions (NZE), the initial focus for hydrogen utilisation is on replacing existing fossil energy uses with low-carbon hydrogen. The sectors targeted for hydrogen adoption include industry, transport, and power generation[1].

On a global scale, the use of hydrogen is projected to expand from less than 90 million tons (Mt) in 2020 to over 200 Mt in 2030, reaching the 500 Mt threshold in the next 20 years. [2]

The proportion of low-carbon hydrogen in the overall hydrogen supply is expected to increase from 10% in 2020 to 70% in 2030 (Figure 1).

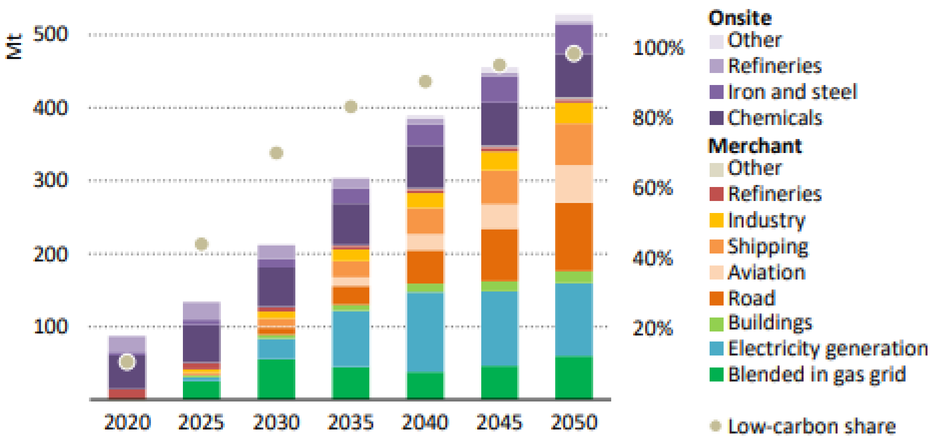

Figure 1: The use of hydrogen and hydrogen-based fuels on a global scale in achieving a Net Zero Emissions goal.[2]

Nowadays, hydrogen production is mainly dependent on fossil resources, which causes considerable environmental harm. An alternative to this is the process of water electrolysis, which when coupled with renewable energy sources, generates green hydrogen with low greenhouse gas emissions.

Islands with high-capacity factors of wind and photovoltaic electricity generators, low population densities, and scarce local demand have huge potential as hydrogen export hubs. Large-scale hydrogen production can lead to their economic development. [3]

However, it is essential to carry out a techno-economic and environmental life cycle analysis to evaluate potential hydrogen production clusters in such favourable locations.

1.1 Green Hydrogen

Green hydrogen refers to hydrogen that is produced through water electrolysis using electricity from renewable energy sources. This method of production ensures that no carbon dioxide (CO_2) emissions are generated during the process. Other processes based on bioresources conversion can generate also green hydrogen but will not be considered in the following analysis developed within this thesis. Green hydrogen is crucial in the transition towards a more sustainable energy and transport system. Despite its immense potential, it currently only accounts for a small percentage (4%) of total hydrogen production due to the high costs involved. [4], [5]

One of the most important challenges for the widespread production of green hydrogen is its economic viability. To be economically attractive, green hydrogen must achieve cost parity with grey hydrogen (produced from fossil fuels) in sectors that already use hydrogen, and with fossil fuels in sectors that have not yet made the transition to decarbonized solutions. [6]

However, current green hydrogen production and transportation technologies are still relatively expensive. Improvements in the performance and efficiency of hydrogen production technologies, such as electrolysis, can help reduce the costs associated with green hydrogen production.

As technology advances and economies of scale are realized, the costs of producing and transporting green hydrogen are expected to decrease, making it a more attractive option for a wide range of applications.

1.1.1 The Levelized Cost of Hydrogen

When evaluating the economic feasibility of hydrogen production, the main measure used is the levelized cost of hydrogen (LCOH).

The LCOH is the total cost of building and operating a hydrogen production facility, expressed as the cost per energy unit of hydrogen produced (€/kg). The cost includes all relevant expenses, such as those for capital, operation, fuel, and financing. The levelized cost of hydrogen production technology is the ratio of the total costs of a generic plant to the total amount of hydrogen expected to be produced over the life of the plant. Both costs are expressed in terms of net present value, which means that future costs and outputs are discounted against current costs and outputs. The cost of financing is applied as a discount rate, and revenue streams available to producers (such as hydrogen sales) are not considered in the levelized cost estimates. [7]

The electricity cost accounts for up to 40%–57% of the levelized cost of hydrogen [4], so Figure 2 below displays the estimated costs of operating a PEM electrolysis plant over time, taking into account different operating modes such as grid connection, dedicated power from offshore wind farms, and curtailed power. The analysis assumed a 30-year lifespan for the plant and a size of 10 MW during the online years of 2020 to 2050, with electrical conversion efficiencies ranging from 72% in 2020 to 82% for a plant that comes online in 2050. [8]

Data are taken for Western Europe considering production technology costs and specifications but excluding the ones related to hydrogen compression, storage, transmission, distribution, and end-use.

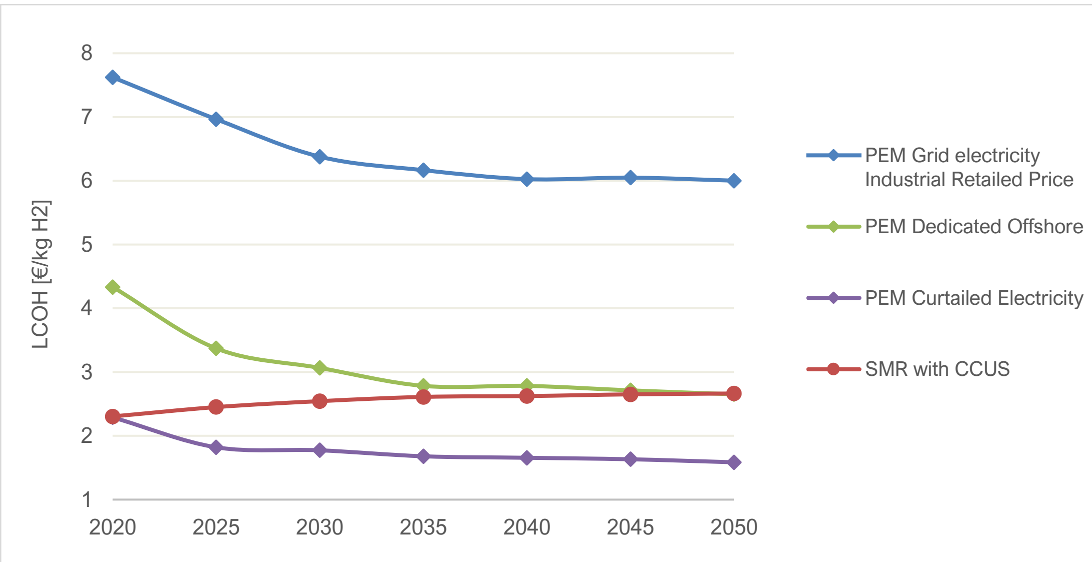

Figure 2: Comparison of LCOH estimates in water electrolysis fed by different types of electricity [8].

When grid electricity is used for electrolysis plants, the levelized cost of hydrogen tends to be higher because it includes all associated costs. If electrolysis plants were exempt from these costs, connecting to the grid would become a more appealing option. However, choosing a dedicated offshore connection reduces the LCOH but increases the fixed cost elements due to lower load factors.

Starting from 2025, PEM electrolysis using only curtailed electricity could become cost-competitive with respect to steam-reforming methane with CCUS. This technology has a rather stable trend over time with a slight increase toward 2050 due to the higher cost of carbon imposed by the EU Emissions Trading System (EU ETS). [9]

It is important to consider that curtailment, which refers to the reduction of electricity generation due to oversupply, is expected to be limited by 2030, depending on the development of the power sector. Additionally, electrolysers will have to compete with other technologies and flexible solutions like demand response, storage, and interconnection. [1] [10]

This competition may result in either less electricity being available for electrolysers or increased prices for curtailed electricity.

1.2 Ireland's Hydrogen Potential

Ireland is the third largest island in Europe, with an area of 84,421 km^2 and a population of 6.93 million people. With a coastline stretching 7,524 km and unique island geography, Ireland is an ideal location for the deployment of renewable energy, particularly onshore and offshore wind power, which is now being deployed on a gigawatt scale across the island. Despite the border, the island's electricity and gas transmission networks are operated as a single entity, with existing and planned infrastructure connecting the north and south of the island. Ireland is making progress toward a comprehensive renewable energy system, with a 36.8% share of energy from renewable sources in gross electricity consumption in 2022. [11]

1.2.1 The Wind Resource

By 2030, the goal is to generate 80% of electricity from renewable sources. The Climate Action Plan 2023 (CAP23) outlines the amount of renewable generation required to meet this goal, as well as targets for reducing carbon dioxide emissions. CAP23 mandates that Ireland must connect 9 GW of onshore, 5 GW of offshore wind, and 8 GW of solar photovoltaic generation.

Additionally, 2 GW of offshore wind generation is specifically designated for hydrogen production [12], [13]

If all the announced renewable energy capacity is developed, Ireland is expected to generate up to 42.7 TWh of renewable electricity annually by 2030 [14]. However, this poses significant technical challenges for the Irish electricity grid. Managing the variable supply to match demand will be difficult and there may be times when there is more renewable electricity supply than demand, requiring curtailment or other solutions. Grid congestion may also restrict power allocation.

To overcome challenges, green hydrogen can store energy: a hydrogen supply network can complement the electricity one by using onshore and offshore wind resources. Green hydrogen technology aids in the deployment of variable renewable generation, it extends emission reductions beyond the electricity sector and mitigates issues of variability and storage associated with high levels of wind and solar PV penetration. [10], [15]

One approach is to directly connect wind turbines to electrolysis systems, effectively converting wind farms into dedicated hydrogen production systems. This integration would alleviate the strain on the electricity grid. By 2050, electrolysis is projected to consume 20% of the global electricity supply, with green hydrogen and its derivatives accounting for 8-10% of final energy use. [2], [16]

Given Ireland's abundance of wind energy resources and limited fossil fuel reserves, the use of hydrogen technologies is likely to be even more significant in the country.

Figure 3 shows LCOH from dedicated floating offshore (red), bottom-fixed offshore (green), and onshore wind farms (purple) in the 30 years to 2050. Upper and lower bounds indicate a combination of the more and less favourable financial and technological parameters for each strategy. The data were taken and revised for the Irish case from a study by Wiser et al. [17], who conducted a self-administered online survey in 2020 to establish LCOH estimates for 2025, 2035, and 2050.

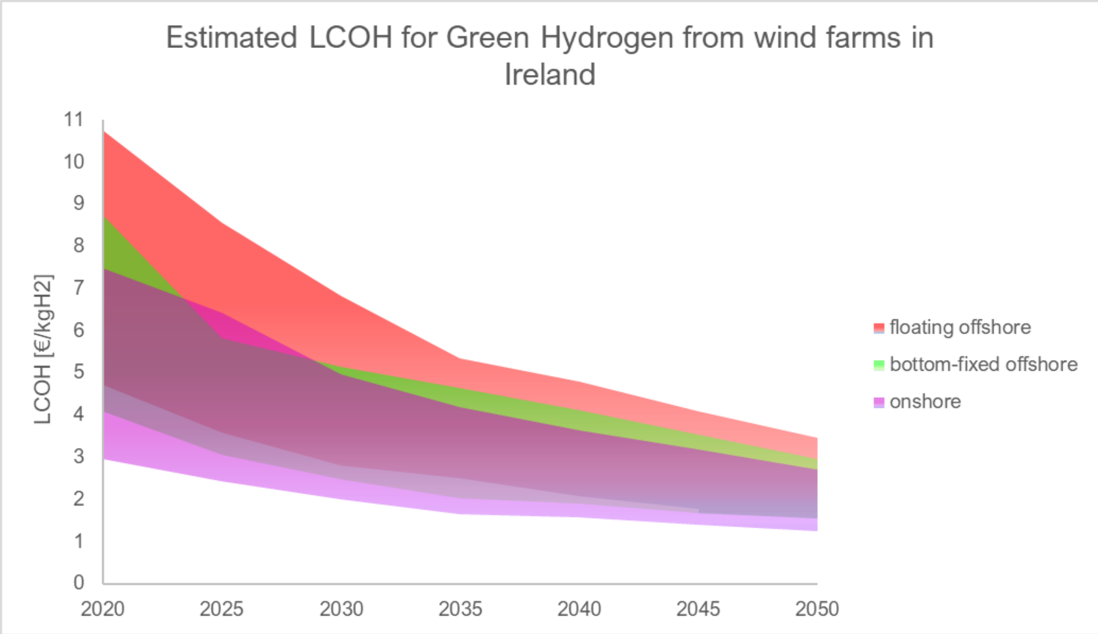

Figure 3: LCOH estimates of floating, bottom -fixed and onshore wind power production.

From many previous studies [17], [18], both fixed and floating offshore wind have higher capacity factors than onshore wind, despite that their levelized cost of energy (LCOE) is higher and cannot compensate for hydrogen production at a lower LCOH than onshore wind. Onshore wind remains the most cost-effective option due to its maturity and lower capital expenditure (CAPEX).

However, the figure also shows that LCOE alone is not sufficient to determine hydrogen production suitability: although the floating offshore wind has more than twice the LCOE of onshore wind in 2025, the higher capacity factors reduce the LCOH difference to about 50%. The initial costs of floating offshore wind are higher, but the higher efficiency and capacity utilization contribute to a relatively smaller disparity in the overall cost of hydrogen production. Therefore, by 2050 the three different modes of wind production converge to values around 1.5 €/kg, making them very competitive with each other and with fossil fuels.

This cost convergence establishes Ireland as a promising location for hydrogen production, as the country has abundant wind energy resources. The cost competitiveness of hydrogen production, combined with the government's commitment to decarbonization and the potential for renewable electricity generation, supports the country's potential to become a hydrogen hub and exporter, as pointed out in the research of Noussan et al. [19]

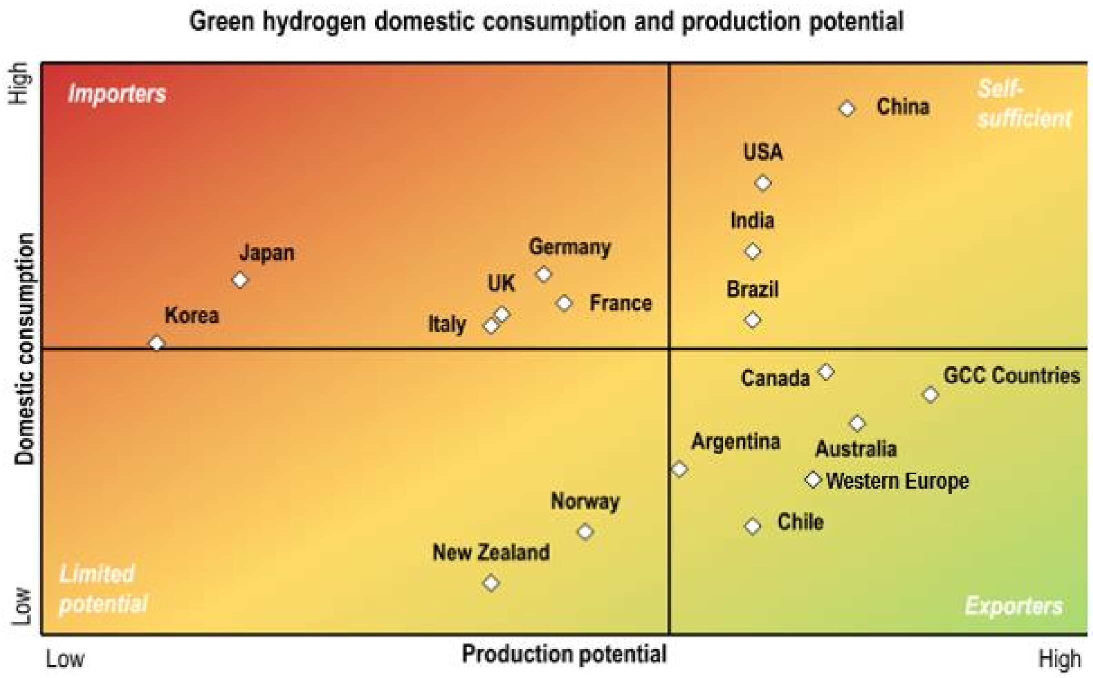

Figure 4: Ireland has the potential to contribute to the hydrogen trade due to its location, but domestic consumption and renewable production must also be considered in national strategies. [19]

1.2.2 Wind Farm

Ireland is a global leader in the use of wind energy, ranking second worldwide in 2020 after Denmark. Exactly in 2020, there was a curtailment of 11.4% in wind electricity due to the limitations of the power grid design. This resulted in a loss of 1,448 GWh. [20] To avoid wastage, excess electricity generation could be utilized to produce green hydrogen instead of being curtailed. This solution could assist Ireland in achieving its emission reduction goals and contribute to the expansion of wind farms in the country.

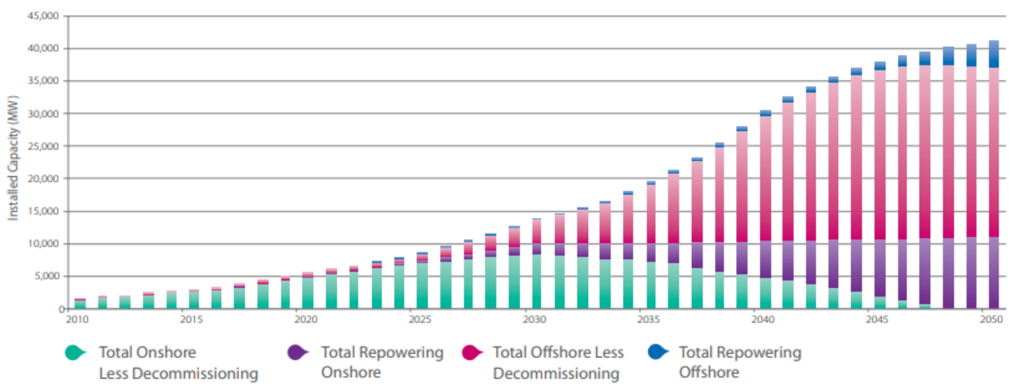

Figure 5: Cumulative capacity with repowering of onshore and offshore wind power plants to 2050 [21]

As SEAI reported, by 2050, the combined capacity of onshore and offshore wind installations is expected to increase due to the process of repowering. This will result in a cumulative increase in capacity. If Ireland's policies and infrastructure continue to improve, it could generate 11-16 GW of onshore wind and 30 GW of offshore wind by 2050, and repowering both typologies could add over 15 GW by 2050. Maintaining and repairing the turbines will be crucial for a sustainable industry, as the wind markets grow.

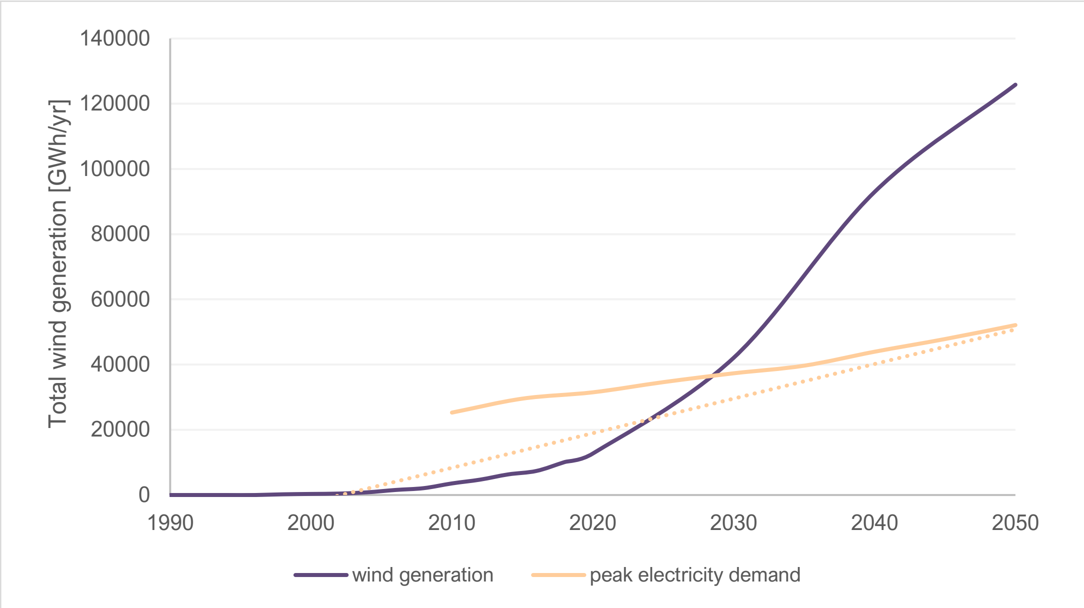

Figure 6: Comparison of Ireland's annual electricity demand and wind power generation from 1990 to 2050.

As Figure 6 shows, by 2030, Ireland could produce more electricity than it needs to meet its domestic demand. Data were taken and processed from reports produced by the IEA [22] and SEAI. [21]

This offers an opportunity to use the surplus electricity in several directions, contributing to a more sustainable and environmentally friendly energy transition. There are several beneficial ways to use surplus electricity. In addition to the production of green hydrogen, the excess electricity can also be exported to neighbouring countries through electricity interconnections, strengthening energy relations and encouraging the sharing of renewable energy. Industries can benefit from this surplus to power energy-intensive manufacturing processes, reducing their carbon emissions and making them more sustainable. Additionally, excess electricity can be utilized to power electric heat pumps for heating buildings, replacing the use of fossil fuels and reducing CO_2 emissions in the heating sector. Surplus electricity can support the development of energy storage technologies, such as batteries and long-term storage systems, improving the management and flexibility of the electricity grid. Lastly, excess electricity can be used to support agricultural activities and food production, such as for irrigation, refrigeration, and processing.[23]

This concept can be applied in general to all energy sources, but in the Irish case, it is related to the wind source.

1.2.3 Hydrogen valleys through Europe: SH2AMROCK– Brief Project Overview

Current geopolitical tensions worldwide, but especially at the European level, have underscored the urgent need for safe, clean and reliable energy solutions. As already pointed out, hydrogen and hydrogen-derived fuels are recognized as key solutions to address this challenge, increasing the integration of renewables through sectoral coupling, and leading to greater penetration of renewables in hard-to-abate areas. [24]

To facilitate the development of green hydrogen sectors, the concept of hydrogen valleys, or local and regional hydrogen ecosystems, has emerged. These valleys involve co-locating hydrogen production, transport and end-use to optimize economies of scale and minimize the levelized cost of hydrogen. They are strategically concentrated to maximize economic and environmental efficiency and become centres of expertise and collaboration for the development of hydrogen-related technologies and represent an innovative model for sustainable energy supply.

The exploitation of local resources is one of the main features: these locations are selected based on the availability of renewable natural resources, such as wind, sunlight, or water resources, which can be harnessed for the generation of renewable energy needed to produce hydrogen through processes such as water electrolysis.

In addition, hydrogen valleys promote collaboration among different stakeholders, including renewable energy producers, hydrogen production companies, end users, and research institutions. This collaboration can lead to synergies that improve the overall efficiency of hydrogen supply chains. For these reasons, these kinds of projects have attracted attention in the future because they represent an innovative way to address energy and environmental challenges. They offer an opportunity to create sustainable energy ecosystems, reducing dependence on fossil fuels and contributing to global efforts to mitigate climate change. In addition, hydrogen valleys have the potential to create new economic opportunities, promoting job creation in hydrogen-related industries and stimulating technology development locally and globally.

Two noteworthy projects, BIG HIT [25] and GREEN HYSLAND [26], have demonstrated the successful creation of hydrogen valleys in the Orkney Islands and Mallorca, respectively.

HEAVENN [27], another demonstration project in the Netherlands linked to significant hydrogen demand, is a relevant example of decarbonizing existing energy demand and catalysing the reduction of fossil fuels in mobility and heating.

A short resume of the three projects is proposed below:

- BIG HIT (Building Innovative Green H2 systems in an Isolated Territory) is a five-year demonstration project located in the Orkney Islands, UK. With a budget of €10.9 million and 12 partners from across Europe [25], BIG HIT was the first of Europe's so-called "hydrogen valleys." The Orkney Islands, characterised by a high percentage of annual energy reductions (over 30%), use hydrogen to capture excess energy and reduce emissions, generating added value for the local economy. The hydrogen produced on the two islands, as seen in Figure 7 is then stored and transported by ship to the utilisation hub in Kirkwall where there is an HRS.

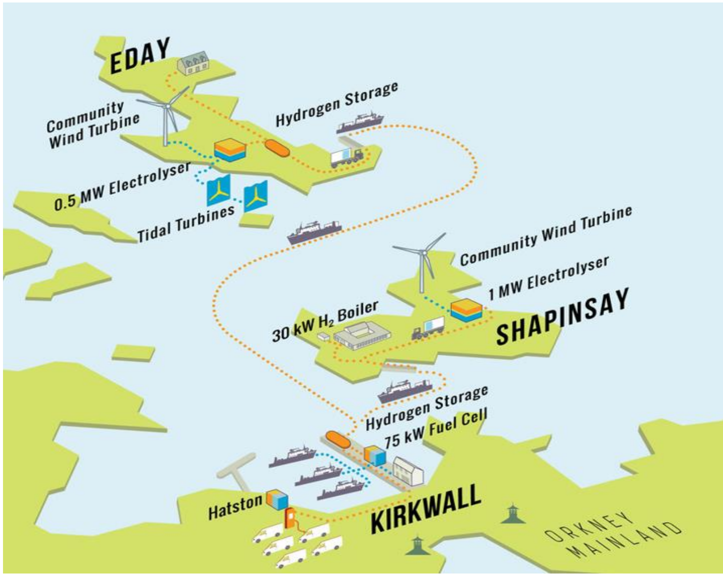

Figure 7: Electricity generated from renewable sources on the islands of Eday and Shapinsay is used to power electrolysers that produce hydrogen through the process of water electrolysis. [25]

- GREEN HYSLAND is a large-scale hydrogen valley project located in Mallorca, a Spanish island with considerable difficulties in the electricity grid. The project extends the BIG HIT methodology to achieve a broad integration of green hydrogen production from solar PV. [26]

- HEAVENN (H2 Energy Applications in Valley Environments for Northern Netherlands) is a project with more than 30 partners and a total budget of €83 million [27]. Located in the

Netherlands, HEAVENN is focused on creating a hydrogen valley in the Northern Netherlands region. The Netherlands has one of the highest hydrogen demands in all of Europe, exceeding 50 TWh annually: this hydrogen valley aims to decarbonize this existing energy demand and act as a catalyst for fossil fuel mitigation in the mobility and heating sectors. The project demonstrates how to implement a hydrogen hub in the context of established local industries, to integrate green hydrogen into key sectors such as mobility and heating.

$SH_2AMROCK$

The projects reported have demonstrated the entire hydrogen value chain, highlighted opportunities for sector coupling to address local dispatch issues, and applied hydrogen in the mobility, industry, and energy sectors, in line with Ireland's needs. It, while not a small island like Orkney or Majorca, also faces challenges related to dispatching down its growing renewable energy portfolio due to a limited electricity grid.

By combining the lessons and inspiration from these three projects, $SH_2AMROCK$ aims to achieve large-scale deployment of hydrogen fuel cell production, distribution, and applications.

The $SH_2AMROCK$ project is a bold undertaking to transform Ireland's energy landscape and lead the way in decarbonization efforts. The project's main focus is to utilize hydrogen's potential in creating a comprehensive ecosystem that includes the production, distribution, and utilization of green hydrogen.

One of the main objectives is to establish Ireland's first multi-modal hydrogen transport hub that targets the transportation sector instead of industrial clusters. This sector is a major contributor to emissions, and the project aims to decarbonize it by promoting hydrogen mobility as a zero-emission alternative.

$SH_2AMROCK$'s ultimate goal is to promote decarbonization across various applications, especially in the transport sector, by using green hydrogen as a main energy carrier. The project aims to achieve sector targets set by Ireland's Climate Action Plan by introducing green hydrogen into zero-emission transport applications like road, maritime, and aviation.

During this research, the project varied its design so that other possible production and storage poles were considered with the aim of meeting the city's hydrogen demand over time.

1.3 Aims, Objectives and Novelty

This Master Thesis project aims to investigate the potential of green hydrogen production to meet Galway's growing demand in the future.

The study starts by determining the region's energy requirements, laying the groundwork for the subsequent analysis in which the hydrogen demand for Galway is calculated. Assumptions were made about hydrogen use in each sector based on factors such as government policies, market dynamics and technological advances.

Initially, this study was to be related to the project in its initial form, the original layout of which was to be built in the Port of Galway. The initial project consisted of a 5 MW electrolyser connected to the grid through renewable energy assets (Galway Wind Park) via a Power Purchase Agreement.

During the months some complications arose so investors and partners decided to redesign the project and move it from Galway. It will be located in Mount Lucas. Here, a revised plan envisages a 4 MW electrolyser installed directly on the Mount Lucas Wind Park site, which will allocate 2 MW exclusively to Galway's hydrogen needs.

As this research is purely academic and not for commercial purposes, it was decided to analyse both of these possible hubs in order to outline and investigate their main differences.

In addition to the two primary projects, the research incorporates the integration of other renewable energy sources into the analysis. These include three offshore wind sites, Sceirde Rocks (comprehensive of 450 MW) in Connemara and the Atlantic Offshore Renewable Energy 1 and 2 (of 4.2 GW and 3.75 GW respectively), as well as the Ballymoneen solar farm that will account 100 MW installed.

A comprehensive techno-economic analysis will be undertaken to evaluate and compare three distinct production methods for hydrogen generation.

- Grid-connected configuration, where the electrolyser procures electricity from the wholesale electricity market, dynamically adjusting its purchases based on the GHG emission intensity of the grid that must be below the RED II threshold, to prioritize greener electricity sourcing. Although this method offers an easy way to exploit green electricity, it requires some constraints in order to guarantee completely green hydrogen production.

- Renewable energy grid integration: this approach is realized through a Power Purchase Agreement (PPA). This ensures a reliable source of renewable electricity, making it a green way to produce hydrogen.
- Off-grid electrolysis approach, wherein direct connections with nearby Renewable Energy Sources (RES) are established, minimising transmission losses, and ensuring access to clean energy.

The investigation seeks to elucidate the advantages and disadvantages of housing the electrolyser within the city and connecting it to the existing grid versus deploying an off-grid configuration at the various renewable energy sites. Furthermore, this analysis takes into account the prevailing policies outlined in the Irish Hydrogen strategy.

The research plan is being carried out in two phases. The first phase aims to investigate whether the combination of these renewable energy sources can effectively meet Galway's hydrogen demand. Next, the study delves into a cost-benefit analysis of each scenario, intending to determine which combination of renewable energy sources best aligns with the overall goal of meeting Galway's needs sustainably and cost-effectively, comparing the LCOH and the greenhouse gas (GHG) emissions intensity of hydrogen production for each pathway.

1.4 Literature Review

Thus far, comprehensive techno-economic analyses have been carried out to identify critical aspects and explore various characteristics of hydrogen development concerning the decarbonization agenda.

A thorough examination has been conducted on the various technologies involved in producing, transporting, and utilising hydrogen as an energy source, considering the associated costs and environmental impacts. The analyses have also highlighted the existing technological challenges, as well as government initiatives aimed at advancing the hydrogen industry.

As regions such as Galway seek to embrace this sustainable energy solution, understanding the techno-economic landscape and evaluating various production methodologies become imperative. This literature review synthesises existing research to provide insights into the challenges and opportunities associated with green hydrogen production, particularly regarding previously defined objectives.

The levelised cost of hydrogen is the primary parameter used to evaluate the economic aspects of hydrogen production, which can be significantly influenced by the cost of electricity, capacity factor, and capital cost of the electrolyser [28].

The North Sea and the Irish Sea, which have consistently high wind speeds, are particularly attractive for offshore hydrogen production. Studies by Singlitico et al. [29] and McDonagh et al. [30] offer useful insights into the factors that impact the levelised cost of hydrogen for various production methods. Singlitico et al. compared onshore, offshore, and in-turbine electrolysis and determined that an LCOH of 2.40 €/kg could be achieved in 2030 for hydrogen production from offshore wind in the North Sea. McDonagh et al. analysed several electricity and hydrogen production scenarios for a 504 MW offshore wind farm in the Irish Sea in 2030 and concluded that dedicated hydrogen production could achieve an LCOH of 3.77 €/kg.

In conclusion, using off-grid wind power, a lower levelised cost of electricity (LCOE) and a higher capacity factor of the wind resource result in a lower LCOH. Exploring the potential of sites such as Sceirde Rocks and Atlantic ORE 1 and 2, as outlined in the research plan, aligns with global efforts to harness various offshore renewable resources for green hydrogen production.

The sustainability and environmental impact of hydrogen production depend heavily on the integration of various renewable energy sources. In light of the increasing number of approved solar photovoltaic projects in Ireland, this thesis examines the potential for one solar PV park to serve as a hydrogen production.

Research conducted by Gunawan et al. [31] has shown that the LCOH varies across regions based on solar resource availability. The study analysed the potential for large-scale hydrogen production from solar energy in Libya, intending to export to Italy through the current natural gas export pipeline. With liquid hydrogen for storage, an LCOH of €2.81/kg is projected for the year 2030.

When it comes to hydrogen production projects, the choice between a grid-connected or off-grid electrolysis configuration is crucial. The researches cited above indicate that off-grid electrolysis can have significant advantages in areas with abundant wind or solar resources. Additionally, using the electricity grid for electrolysis instead of relying solely on renewable sources can increase capacity factors and reduce the capital costs of the electrolyser [32]. This approach may also localise production closer to demand and eliminate distribution costs.

Various strategies for electrolysers to participate in electricity markets have been explored, Nguyen et al. [33] discovered that for a 10-100 MW system, LCOH can range from 2.40 €/kg to 6.20 €/kg for flat-rate and wholesale pricing mechanisms.

Assessing the advantages and disadvantages of these configurations in the context of Galway's energy landscape will be essential to devising an optimal production strategy.

The development process of the research benefited from the collaboration with the research group of NUI Galway, known as the Energy Systems Integration Group (Erin) whose contribution has been fundamental in guiding and supporting the progress of this Master Thesis project. Meetings and discussions with researchers in this group have contributed significantly to defining key areas of investigation and understanding of the specific challenges and opportunities related to the production of green hydrogen in the Galway region.

In particular, the academic works produced by Gunawan et al.[34] and Moran et al. [35] have constituted a valuable source of inspiration and support for this thesis, allowing a more in-depth assessment of the techno-economic implications of the different green hydrogen production options.

Most of the techno-economic analysis (TEA) studies indeed typically focus on isolated aspects of the hydrogen supply chain [30], [36]. The two authors cited above, however, adopted a comprehensive approach, exploring various facets of hydrogen supply chains, particularly in the context of Ireland.

Hydrogen production was modelled by Gunawan et al. [34] at each wind farm on the island of Ireland, leveraging historical hourly wind data. Three distinct electrolyser operating modes were examined: 1) reduced and constrained electricity, 2) utilisation of available wind energy, and 3) full-capacity operation using mixed-source grid electricity when necessary. The capacity of the electrolyser was systematically optimized in each mode to minimize the levelised cost of hydrogen. The results of these in-depth analyses indicated the potential to achieve a range of LCOH from €6-20 per kg/H_2 depending on the electrolyser's capacity factor.

The paper by Moran et al. [35] aims to address the lack of a flexible techno-economic modelling tool for hourly hydrogen production, storage, and distribution for specified hourly demand, which can be applied to a variety of regional scenarios or case studies. The developed tool utilizes a full year of hourly data for renewable energy availability and dispatch (the sum of curtailment and constraint), wholesale electricity market prices, hydrogen demand, as well as other user-defined inputs, and sizes the electrolyser capacity to minimize costs. The model is applied to some case studies for Ireland and Northern Ireland. For the scenarios analysed, the overall LCOH ranges from €2.75-3.95 per kgH_2. Higher costs for scenarios without access to geological storage indicate the importance of cost-effective storage to enable flexible hydrogen production to reduce electricity costs while consistently meeting a set demand.

The significant variation in the levelised costs of hydrogen across all these studies suggests that there is still much research to be done for green hydrogen production and cost determination. It appears that the LCOH varies widely depending on the input parameters of each individual project, the location, and the corresponding availability of renewable energy, as well as the characteristics of the production site. Therefore, it is important to conduct a comprehensive analysis to fully understand and predict the potential scenarios for the cost of hydrogen produced at the various sites investigated in this research.

1.5 Thesis outline

This thesis is structured in such a way that the reader follows a logical progression to facilitate understanding.

The introductory chapter provides the background of the research, as well as some basic goals and objectives that the project hoped to achieve, and also develops further details by reviewing the most recent literature published on the topic.

Chapter two describes the methods used to collect energy balance information and calculate hydrogen demand for Galway City. Chapter three presents the main aspects of the techno-economic analysis (its methods and mathematical models) used to conduct the analysis. All model assumptions and input values are included.

Chapter four will present the scenarios, the results of which will be presented in chapter five according to the different case studies. Finally, chapter six will include the conclusions reached.

2. Energy Data collection and estimation

This research aims to size and assess the costs of future hydrogen production and storage based on estimated hydrogen demand. The absence of an existing hydrogen market in Ireland means that there is much uncertainty about the size and timing of future hydrogen demand.

To investigate potential hubs to meet the demand required by Galway and its County, the analysis process began with an in-depth examination of the current energy balance, with a focus on the use of different energy carriers in the various sectors. The objective was to compare the evolution of the energy consumption landscape from the current to the future situation for 2030, 2040 and 2050.

The timing of hydrogen demand and its magnitude in many potential end uses is uncertain, and SEAI reports that hydrogen use in the future would appear to be zero even in the long term.

Therefore, in the second part of the study, an attempt was made to size the estimated hydrogen demand in three different decarbonisation stages: Missing Targets, Meeting Targets and Exceeding Targets, as described below. Assumptions were made about hydrogen use in each sector based on factors such as government policies and technological advances.

All calculations/modelling were completed using Microsoft Excel.

2.1 Galway Energy Balance

The data used in this study was initially obtained from the Energy Data Portal provided by SEAI for the entire Republic of Ireland, following the High WEM (Wholesale Electricity Market) scenario is intended to reflect what would happen based only on the measures in place by the end of 2021, without any additional measures being implemented in later years.

This choice was dictated by a desire to explore the future impact of increased growth in both the electricity market and overall energy demand, considering the increasing exploitation of data centres and transport across the country, and maintaining a conservative view of the data, especially since future forecasts are never robust.

2.1.1 Current Total Final Consumption

Irish Sustainable Energy Authority (SEAI) [37] divide primary and final energy. In primary energy, the total amount of energy used is considered. It includes both the final energy used directly by the users, but also the energy input in the transformation processes (electricity generation from all sources in the energy mix and also losses such as transmission and distribution).

Final energy refers only to the one that is directly consumed by the end user. This includes all the energy that is supplied for various activities such as industrial production, transportation of people and goods, and daily needs such as heating and cooking.

Total final energy consumption can be measured in kilotonnes of oil equivalent (ktoe) for easy comparison and analysis of energy consumption data across different regions, sectors, and periods. Using a consistent unit of measurement helps understand complex data involving multiple energy carriers and sources, including oil, gas, coal, and renewables, taking into account their energy content and efficiency. This helps assess the overall energy mix and the relative contribution of each source to total consumption.

This data has been adapted and scaled to the Galway city population to make it more relevant to the local context.

For some sectors, more accurate data from the Galway Energy Master Plan [38], published in July 2023, was used where necessary. It made further adjustments to meet the specific needs of the different energy carriers within the city, identifying emerging sectors and clusters. All data taken from this report were converted from MWh to ktoe to make them comparable with those with the SEAI ones.

The sector details that emerged from the analysis allowed activities to be broken down by Galway, associating them with specific MWh consumption.

The sectoral micro-analysis, especially in the case of transport, is of fundamental importance for the subsequent calculation of hydrogen demand, allowing the identification of specific energy needs and opportunities for the integration of sustainable solutions.

As far as macro-divisions are concerned, detailed fuel consumption was also obtained by consulting data available from SEAI and subsequently adapted from fuel consumption information where data were available.

This approach provided a detailed and comprehensive view of energy consumption at the local level, laying the foundation for the focus on hydrogen demand in Galway City then was added to these graphs.

2.1.2 Future Projections

Since the SEAI portal provides data until 2035, the forecasts for energy consumption up to 2040 and 2050 have been developed considering various assumptions and methodological approaches. Firstly, concerning sectoral consumption in agriculture and fisheries, households, industry, services, and transportation, it was assumed to maintain the growth trend observed between 2030 and 2035 (+5.7% considering the High WEM demand scenario) and extend it for the following five years until 2040 and then to 2050. This approach is based on the continuity of observed trends in the past and also considers the expected demographic growth for the entire Ireland, which is approximately +6% over a five-year period starting in 2020 according to the demographic projections provided by the government [39].

It is important to recognise that people do not consume energy directly, but rather the services and products made possible by energy, such as mobility, heating and cooking. The demand for these services is influenced by economic activity, population growth and technological advances. Over the past 30 years, Ireland's energy needs have increased by more than 50%, closely following the 40% increase in population and these could be easily reported also to the main cities in the country.

On the other hand, regarding the different energy carriers, including coal, electricity, gas, hydrogen, non-renewable waste, oil, peat, and renewables, a slight slowdown in the growth trend towards a plateau after 2030 was anticipated. This is because it follows the hypothesis that, once emission reduction targets and the increase in the share of renewables are achieved by 2030, there will be a gradual decrease in the use of fossil fuels and a proportional increase in electricity, renewable sources, and hydrogen. This approach considers energy policies aimed at reducing environmental impact and promoting a transition to a more sustainable energy system in the long term.

The associated percentage of consumption for each fuel were reported in Table 1 and they are comparable with the growth (or decrease) trends present in the study conducted by MaREI "Our Climate Neutral Future: Zero by 50" [40]

Table 1: Associated consumption percentage of each fuel in Galway City.

	% of consumption			
Fuel type	**2019**	**2030**	**2040**	**2050**
Coal	2	1	1	0
Electricity	36	43	52	54
Gas	16	10	7	5
Hydrogen	0	1	3	5
Oil	41	28	15	11
Peat	2	1	0	0
Renewables	3	16	22	25

Figure 8 shows the breakdown of fuel consumption projections for Galway City, revealing a gradual decrease in fossil fuels as renewables, electricity, and hydrogen take the lead.

Within the heading "Renewables" are collected solar thermal, renewable waste, biomass, biogas, bioethanol, biodiesel and ambient heat. They are properly thermal renewable energy sources. This term is used to distinguish these renewable energy sources from others that primarily produce electricity, such as wind and solar photovoltaics. Renewable thermal sources use natural or biological heat to generate thermal energy instead of electricity. For example, solar thermal energy harnesses the sun's heat to heat water or fluids, while biogas and biomass can be used to produce heat for heating or steam production in industrial processes.

The chart starts from 2019 and is impacted by the COVID-19 pandemic, which has significantly affected the global energy sector. During lockdowns, energy consumption was reduced due to decreased economic activity, leading to a stationary total consumption throughout this decade. However, it has also catalysed the shift towards cleaner and renewable energy sources, partly because of reduced fossil fuel demand and partly due to government policies that promote a post-pandemic "green recovery".

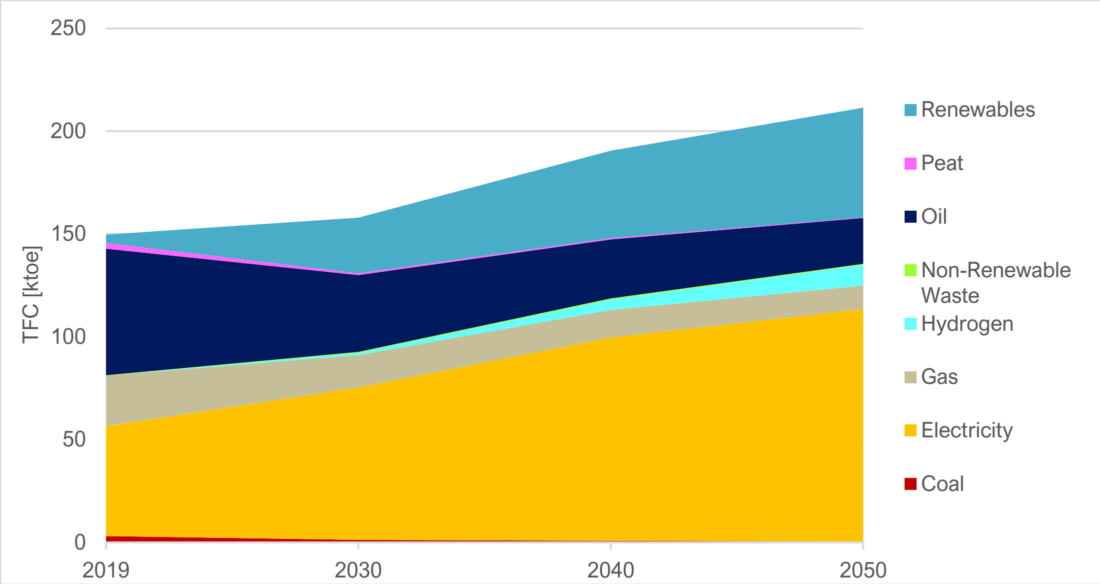

Figure 8: Projected total final consumption for Galway by Fuels.

2.2 Hydrogen Demand Projections

The introduction of renewable hydrogen in the Irish context, as in the rest of Europe, is intended to focus on sectors that present particular challenges in terms of decarbonisation. These are sectors where conventional energy efficiency improvements and direct electrification are not feasible or are economically unviable solutions. Consequently, the deployment of renewable hydrogen is expected to begin in the sectors most difficult to decarbonise, with a primary focus on meeting the EU's binding 2030 targets [41].

In particular, the first sectors expected to embrace this transition are heavy transport, followed by industry and flexible power generation. The aviation and maritime transport sectors will emerge as end-users of hydrogen and its derivatives in large quantities, but they are expected to require further time for development and integration due to the inherent complexities of these sectors.

From a comprehensive analysis of the current and future energy balance, the expected use of hydrogen in the Galway City context also appears to be predominantly concentrated in the industrial and transport sectors.

Therefore, for the sake of clarity, a subsequent classification was made, dividing transport into heavy-duty vehicles, buses and coaches, and shipping. As of 2040, an examination of the role of hydrogen in power generation was also included in this categorisation, in addition to its use for industrial heating and some aviation testing.

A further category was introduced to include a small surplus or reserve in the hydrogen refuelling station (HRS) and from 2050 the export of excess pure hydrogen and e-fuel produced. There are currently few producers of Sustainable Aviation Fuels (SAFs) in Ireland, but they are mentioned in the latest National Hydrogen strategy [41]. Policy initiatives aiming at a high rate of offshore wind energy by 2030 support the domestic production of SAFs.

Each of these categories will be described in more detail later when we detail each of the inputs used in the demand calculation.

The percentages of hydrogen use (as well as the associated tonnes) are estimates based on the sources cited. They are reports on technological developments of hydrogen technologies being used in various sectors or on European/national policies that have set a certain hydrogen share based on usage. These figures on the future cannot be certain, but they are intended to give a projection as closely aligned with reality as possible.

Sectoral demand projections have been generated for the years 2030, 2040, and 2050, predicated upon three imaginary distinct decarbonization trajectories, that take into account a pessimistic trend, one in line with development expectations and one particularly optimistic.

These trajectories may be summarised as follows:

1. "Missing" scenario
2. "Meeting" scenario
3. "Exceeding" scenario

In the first pathway, the climate and decarbonisation targets are assumed to be missed by a considerable margin, due to the failure to accelerate the necessary policies and investments.

In the second pathway, the climate and energy targets for 2030 to 2050 are met and the Irish energy system is carbon negative by 2050. In the final pathway, decarbonisation exceeds climate and energy targets, with large volumes of energy exports from the island by 2050.

Given the short timeframe between now and 2030, it is unlikely that this pathway will be achieved in that timeframe, and the same argument can be made for the Meeting pathway.

However, it is useful to consider the reality of what needs to be done to achieve the targets against the reality of current actions. The more ambitious pathways also help realise the challenges and opportunities over a longer time frame, up to 2040 and 2050. For each pathway, the demand for hydrogen on the island of Ireland is estimated for the years 2030, 2040 and 2050.

The following section provides an overview of the hydrogen demand data used in this thesis. It includes details on the methods used to acquire the data, as well as any conversions done to make it usable. The data has been collected from a variety of sources, including public, private, and semi-state companies, through both primary and secondary sources.

2.2.1 Heavy goods vehicles

It is assumed that hydrogen fuel cell trucks will play a leading role in the heavier-weight class segment (> 15 tonnes) rather than in the lighter-weight class segment (3.5 to 15 tonnes). To establish a baseline figure for heavy road freight transport consumption, we refer to the one taken from the Galway Energy Master Plan [38]. The percentage of hydrogen usage for 2030, 2040, and 2050 is determined by both the historical growth profile of trucks in Ireland, and government policies like the Climate Action Plan, and EU CO_2 emission performance standards for new heavy-duty vehicles which impose hydrogen use rates in the sector. [13], [42].

Table 2: Percentage of hydrogen use in HGVs [13], [42].

Assumed percentage of hydrogen heavy-duty trucks in Galway			
	missing	meeting	exceeding
2030	1%	2%	5%
2040	7%	10%	15%
2050	17%	20%	25%

For trucks, a penetration rate of hydrogen fuel cell trucks is assumed as a percentage of the total consumption relative to heavy-duty trucks in Galway for each scenario (Table 2).

2.2.2 Buses and Coaches

Bus Éireann is one of three subsidiaries owned by CIÉ and is the operator of many public buses within the city of Galway. Concerning public transport such as buses and coaches, to calculate the percentage of hydrogen consumption, the consumption associated with all public passenger transport services has been taken as the basis, then a small portion of electricity consumption has been subtracted as Bus Éireann uses hybrid vehicles that are unlikely to be converted to hydrogen buses [38].

The breakdown of buses is based on data from Bus Éireann and the Central Statistical Office (CSO) and includes three categories: Urban, Regional and Intercity.

In order to achieve the targets, it is important to focus on the decarbonisation of city bus fleets, which can mainly be achieved through electrification. Intercity and regional/commuter buses that cannot be electrified are likely to remain diesel or be converted to low-emission alternatives.

In the Missing scenario for 2030, hydrogen is likely to play a negligible role in the decarbonisation of buses and coaches. However, with the introduction of hydrogen-powered bus prototypes planned for 2024 and the interest shown by Bus Éireann, some intercity routes could be decarbonised using hydrogen, contributing to around 2% of zero emissions in Galway.

For Meeting one, Bus Éireann already has some hybrid buses in its city fleet, so we can assume that about 10% of the remaining buses will be hydrogen-powered, together with some coaches that will make up another 5% of the fleet.

As far as the Exceeding Scenario is concerned, a 10% increase in fuel cell buses is expected compared to the Meeting Scenario.

In 2040, the Missing one equal to the Meeting for 2030 is likely to occur due to the plateau reached after the first policy-driven decarbonisation efforts. For the Meeting Scenario, which aims to reach the CIÉ target of making all city bus fleets zero-emission by 2035, it is expected that most city buses will be electric, but some may require hydrogen. Also, the majority of intercity buses and some regional/commuter buses will be decarbonised through hydrogen. Furthermore, it is expected that 35% of the total Public Passenger Services will be powered by hydrogen.

In 2050, all buses and coaches will be zero-emission in the Meeting Scenario, with 45% of the total powered by hydrogen. For the Missing Scenario, the number of fuel cell buses will be obtained by linear interpolation between the 2040 and 2050 meeting figures. Finally, for the Exceeding 2050 Scenario, higher penetration of hydrogen-powered buses and coaches in the zero-emission fleet is assumed, at 55% of the total.

These assumptions are based on various sources, including the Climate Action Plan 2023, National Sustainable Mobility Policy, and CIÉ Group Sustainability Annual Review 2023 [13], [43], [44]. These sources either directly report hydrogen usage rates, the number of fuel cell buses that are expected in the future, or the technology development targets that can be foreseen for the sector.

2.2.3 Industry

For the industrial sector, estimates of hydrogen demand in each scenario are based on data from the National Heat Study conducted by SEAI [45].

This study aims to provide a rigorous and comprehensive analysis of the options to reduce CO_2 emissions associated with heating in Ireland in all industrial sectors using gas or other fossil fuels for thermal energy generation.

The cited study presents an output in Excel in which the final energy demand per fuel (the same fuels presented above for the energy balance) was calculated in TWh from 2020 to 2050 with a division by sectors.

The value in TWh for hydrogen use was taken for the industrial sector alone over the years and from the total consumption expected the various percentages were calculated.

The Missing, Meeting and Exceeding scenarios for each year are based on the low, medium and high hydrogen demand estimates derived from the three different decarbonisation pathways outlined in the aforementioned study and reported below.

These are descriptions of different transition scenarios towards low-carbon practices:

- Baseline/Missing: represents the continuation of current practices with limited adoption of new technologies or fuel switching. It assumes that all sectors continue to rely on carbon-intensive practices, with minimal deployment of heat networks and new technologies. The policies implemented are in line with those outlined in the CAP 2019 and do not reach net zero by 2050.
- Balanced: envisages a gradual transition with a mix of low-carbon technologies, such as electricity, bioderived gas and green hydrogen. It aims to strike a balance between sustainability goals and economic feasibility, progressively moving towards decarbonisation.
- Decarbonised gas: focuses on the transition to green hydrogen, carbon capture, utilisation and storage (CCUS) infrastructure or bioderived gas. The transition to these new fuels for domestic and commercial use is encouraged to reduce carbon intensity.

However, it should be kept in mind that in all scenarios, the role of hydrogen in the industry ranges from use in a limited number of niche applications to widespread adoption for medium and high-temperature heating.

Below the graph shows the percentage of green hydrogen use within the industrial sector from which the tonnes required annually were then calculated.

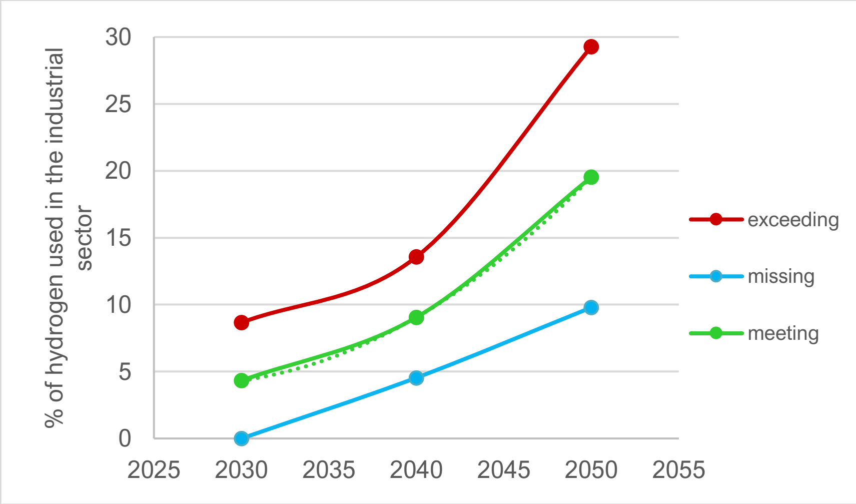

Figure 9: Industrial use of hydrogen trend over the years.

2.2.4 Power Generation

For 2030, it is assumed that hydrogen will not be used for power generation. However, starting from 2040, the analysis will include the hydrogen demand required by the Tynagh power station, with a capacity of 386 MW, the primary electricity generator in County Galway.

It is hypothesized that the new generations of gas turbines will operate with a capacity factor of 20%, considering the electricity system to be almost emission-free. Therefore, 20% of the electricity production will come from turbines fuelled by hydrogen, based on the 80% RES electricity system in Ireland outlined by Deane and Mehigan [46]. This decarbonized fuel is used in gas generation during periods of low wind speed.

The turbine burns a mixture of hydrogen permitted by the nitrous oxide control system and the specifications of each turbine.

The mass flowrate in tonnes per hour required by a power plant of this capacity for each percentage of hydrogen blend was provided by Mogorosi Thuso Booth from his work within the Erin research group assessing the techno-economic feasibility of using hydrogen as a fuel for combined cycle gas turbines to produce electricity in Ireland. This study is still being finalised and has therefore not yet been published.

Table 3: Hydrogen mass required in Tynagh power plant over the years.

	2040			2050		
	Missing	Meeting	Exceeding	Missing	Meeting	Exceeding
% of hydrogen blend to gas turbines	2.5	5	7.5	10	12.5	15
t/h H2 required	0.18	0.36	0.54	0.72	0.9	1.08
t/yr	315.36	630.72	946.08	1261.44	1576.8	1892.16

2.2.5 Shipping

Hydrogen-derived fuels like liquefied hydrogen, ammonia, and methanol are expected to be essential for large-scale shipping in the maritime sector. These low-carbon synthetic fuels can significantly contribute to reducing emissions in the industry. The 'Fit for 55' FuelEU Maritime regulations set emissions reduction targets for the maritime sector, with hydrogen-derived fuels expected to play a vital role in achieving these goals.

In the maritime sector, Aran Island Ferries stands as the primary transportation company servicing the three Aran Islands and the mainland. Due to the absence of direct fuel consumption data, all information was sourced from a secondary reference.

According to the report providing the data, ferries depart from Rossaveal to the islands twice daily (morning and afternoon) from September to May, totalling four trips. Additionally, a third service operates exclusively during June, July, and August, resulting in six trips from Rossaveal to Inishmore, the biggest island. However, according to the Aran Islands Ferries website, the number of trips can increase to nine per day (round trips) during July and August.

The approximate annual energy consumption for the ferry is estimated at 17,219 MWh [47], which also encompasses the energy consumption of ferries operating from Doolin to Inishmore and Inishmaan. This figure is comparable to the previously calculated navigation consumption for Galway, amounting to 16,782 MWh annually, thereby suggesting its validity.

For the Meeting Targets scenario, the FuelEU Maritime regulation posited that 18%, 36%, and 54% [48]of the marine transport fuel demand will be met by e-fuels by 2030, 2040, and 2050, respectively. Despite the aspiration to replace a portion of the total Heavy Fuel Oil (HFO) consumption in the ports of Ireland with H2-derived fuels, the relatively consistent growth trend stems from the absence of hydrogen-derived fuels production hubs within the ROI.

2.2.6 Aviation

The aviation sector in Ireland heavily relies on imported fossil fuels, contributing significantly to emissions. Sustainable Aviation Fuels (SAFs) present a promising solution for decarbonizing the industry. However, due to limited bio-based resources, alternative methods for SAFs production, such as e-methanol or e-kerosene, are being explored. To facilitate e-SAF production, a dependable source of green carbon dioxide is crucial. Although the utilization of renewable hydrogen and carbon dioxide holds potential for e-SAF production in Ireland, the absence of a national production hub currently necessitates a more conservative approach.

Regarding air transport in Galway, Aer Arann Islands operates between Inishmore, Inshmaan, and the mainland, from Connemara Airport, located 36 km far from Galway City. From November to February, there are approximately 1-2 round-trip flights per day to each island. During the peak season from June to August, the frequency increases to up to 8 round-trip flights daily. Since direct data from the Aer Arann Islands was unavailable, information was sourced from secondary references. An average annual consumption of 1131 MWh [47] of aviation gasoline for flights between 2013 and 2017 was utilized for analysis.

The European RefuelEU Aviation agreement sets targets for the share of SAFs in the EU aviation sector, including a minimum of 2% SAF by 2025, 6% by 2030, and 70% by 2050. Additionally, the direct use of hydrogen in aviation is under development, with Airbus pioneering commercial aircraft designed for hydrogen propulsion [49].

In our analysis, a conservative approach was adopted for hydrogen utilization in aviation, with a projected 6% uptake starting from the 2040 meeting scenario. This decision is based on the assumption that international aviation will be prioritized before domestic aviation, resulting in a technology lag of approximately 10 years. Subsequently, a 32% utilization rate was applied for 2050, considering that smaller airports are less likely to experience significant technological advancements compared to international airports. These percentages were then applied to the calculated consumption for domestic air transport in Galway.

2.2.7 Others

It is predicted that by 2030, 10% of the transport demand for heavy goods vehicles, buses, and coaches will be allocated to constructing hydrogen refuelling stations (HRS). This extra capacity can be useful for handling sudden surges in demand or for meeting potential increases in demand over time without the need for significant modifications to the existing infrastructure. This approach is followed for the meeting scenario and is maintained in the following years.

From Meeting 2040 onwards, it is assumed that also 1% of private cars will be powered by hydrogen, given that electric cars are becoming more popular as a low-carbon transport option and may be preferred for cost reasons. The tonnes associated are derived from the consumption for Road Private Car in Galway [38].

Renewable hydrogen produced from electricity can be used to create ammonia using the Haber-Bosch process, which can then be used to produce urea-based fertilizers. An additional quota was then calculated to consider the production of ammonia for use within the chemical industry and to create agricultural fertilisers.

Table 4 shows the percentages of fertilizer demand that can be met by urea derived from renewable hydrogen for each scenario. These fertiliser statistics data were obtained from Central Statistics Office and the Department of Agriculture, Environment, and Rural Affairs [50], [51]. As shown, the percentages start from 2040 because it is necessary to first establish an ammonia production near Galway, and there are currently no projects for such production hubs. The percentages are understood as additional shares only of production for the maritime demand as e-ammonia is classified as an e-fuel.

Table 4: Percentage of hydrogen-based fertilizers [50], [51].

Assumed percentage of fertilizers produced by renewable ammonia in Galway			
	missing	meeting	exceeding
2030	0%	0%	0%
2040	0%	12.5%	25%
2050	12.5%	25%	50%

An additional quota was included to account for the export of hydrogen and e-fuels. It is estimated that from 2050 onwards a part of the total production will be exported. The main objectives of the National Hydrogen Strategy are to prioritise decarbonisation and ensure energy security. However, there are also further opportunities for expansion of export markets.

Ireland has abundant renewable resources that can be harnessed to produce renewable hydrogen above domestic demand in the long term. As several European nations will require a sustained share of renewable hydrogen imports to meet their decarbonisation targets, it is assumed that Ireland will contribute with 2% of the production for other sectors for the 'meeting' scenario and 5% for the 'exceeding' scenario in 2050, according to projections by the National Hydrogen Strategy [41].

2.3 End Considerations

In the Appendix in Figure 39, the energy balance comparison over the years is displayed in detail for each sector.

Today, Ireland's energy system is heavily dependent on oil, a trend reflected in the energy balance of Galway City itself. Oil accounts for the largest share of final energy consumption, at 41% in 2019, about half of the other fuel types combined. Significant volumes of oil are mainly attributed to transport and domestic heating, but the service sector and agriculture also contribute to its increase. However, it must be recognised that the electricity consumption of 36% is a good figure that underlines the city's advanced development from a technological point of view thanks to the virtuosity and research in the field of sustainability provided by the two university centres.

Looking ahead to 2030, emission reductions in the transport sector will require progress in the blending of sustainable bioliquids (bioethanol and biodiesel) and the adoption of electric vehicles, especially in private vehicles. Furthermore, an increasing use of identified renewable sources such as solar thermal and ambient heat in the residential and service sector and on the other hand the use of renewable waste, biomass and biogas within industries is crucial for reducing emissions.

By 2050, the electricity system is expected to become the backbone of Ireland's energy system, with renewables as the primary energy source. The energy mix is therefore expected to be almost completely fossil fuel-free, with most transport and heating modes predominantly electrified. Bioenergy will play a significant role in difficult-to-decarbonise sectors such as industrial heat and heavy transport, along with the use of hydrogen as an energy carrier. Hydrogen production will be based on renewable electricity, underlining its importance in achieving decarbonisation targets.

In this future scenario, electricity is set to become the dominant energy carrier, accounting for almost 54% of final energy consumption, in contrast to its 36% share today, replacing oil as the backbone of the energy system.

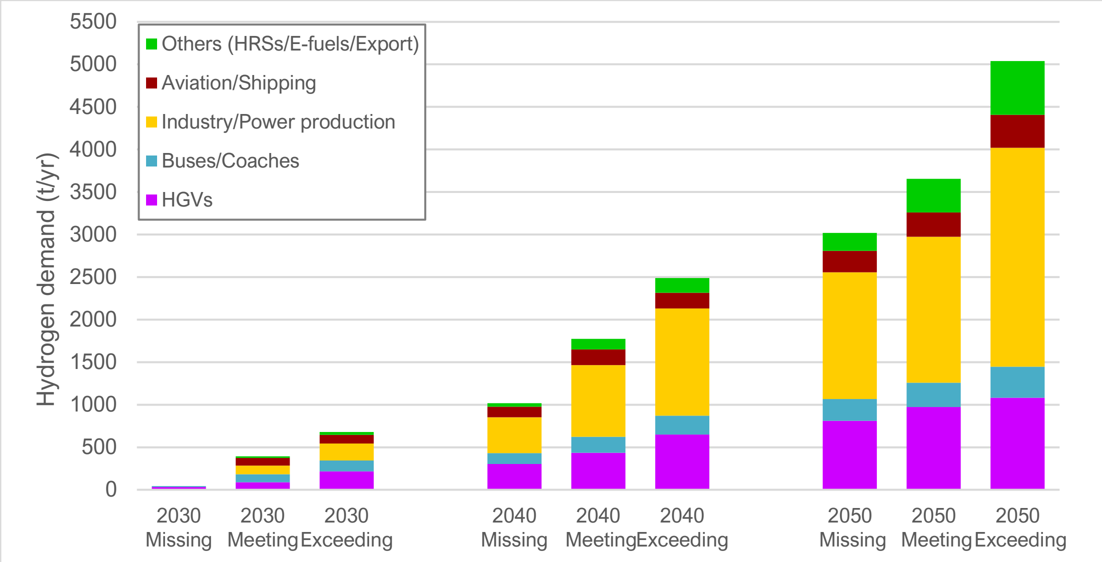

Figure 10: County Galway sectoral hydrogen demand scenarios.

Regarding the hydrogen demand, in 2030, the total hydrogen demand for County Galway varies significantly, ranging from 56 tons in the Missing Targets Scenario to 679 tons in the Exceeding Targets Scenario, as shown in Figure 10. In the Missing Scenario, only a small number of heavy hydrogen trucks and buses are present due to the ongoing development of these technologies. In the Meeting Scenario, HGVs, buses, industry, and maritime transport all settle around 90-100 tons. In the industry, hydrogen is mainly used in bitumen plants for heating purposes (supply for high-temperature heating and other processing needs). Moreover, the targets focus on decarbonizing urban bus fleets, leading to the development of hydrogen technologies in that sector. The same trend is visible in the Exceeding Scenario.

By 2040, hydrogen demand will increase significantly, ranging from 1020 tons to 2490 tons. Electricity generation is now the dominant domestic end-use for hydrogen, with the Tynaghd power plant using hydrogen as a decarbonized fuel in gas-fired generation during periods of low wind speeds, representing almost 50% of total demand in all scenarios for 2040. The rest of the demand consists mainly of hydrogen used in road transport, and industry, with a small share for aviation and shipping fuel production, fertilizers, and another relatively small quantity used in buses and coaches.

By 2050, hydrogen demand is projected to further increase, reaching between 3020 and 5040 tons. Electricity generation, especially when wind and solar resources are limited, remains the primary end-use sector for all three scenarios. For other sectors, the previous trend is expected to continue, with an export share driven by production surplus relative to local demand, leveraging abundant wind resources.

Table 5: Summary table containing the tonnes of hydrogen used within the various sectors in County Galway.

		HGVs	Buses/ Coaches	Industry/Power production	Aviation/ Shipping	Others	Total
	references	[13], [42]	[13], [43], [44]	[41], [45]	[48], [49]	[41], [50], [51]	
2030 missing	tons	43.29	12.65	0.00	0.00	0.00	56
	use %	1%	2%				
2030 meeting		86.57	94.89	100.81	91.25	18.15	392
		2%	15%	4.5%	18%	10%	
2030 exceeding		216.43	126.51	201.62	100.80	34.29	680
		5%	25%	9.8%	20%	10%	
2040 missing		303.00	126.51	421.06	126.00	42.95	1020
		7%	15%	4.3%	25%	10%	
2040 meeting		432.85	189.77	841.54	184.50	124.59	1773
		10%	30%	9%	6%, 36%	10%, 12.5%	
2040 exceeding		649.28	221.40	1262.01	184.50	172.46	2490
		15%	35%	19.5%	6%, 36%	10%, 25%	
2050 missing		811.60	256.13	1489.37	251.99	209.04	3018
		17%	40%	8.6%	6%, 50%	10%, 25%	
2050 meeting		973.92	284.66	1716.19	284.42	396.18	3655
		20%	45%	13.6%	32%, 54%	10%, 25%, 2%	
2050 exceeding		1082.13	363.73	2573.73	388.65	631.62	5040
		25%	55%	29.3%	32%, 75%	10%, 50%, 5%	

Table 5 (that refers to Figure 10) contains hydrogen consumption data for each sector. Please note that these values were calculated from the percentages given by the regulations, development targets and policies associated with each technology cited above.

Some sectors have been merged during the analysis for convenience, so that in some columns you will find more than one indication of usage percentages. In any case, a more detailed description for each sector can be found in Chapter 2.2 and the resulting subsections. Please note that to find the demand in tonnes of hydrogen, these percentages were applied to the sectoral consumption resulting from the city's energy balance described in Chapter 2.1 and visible in Figure 40 in the Appendix.

It should be noted that these are only estimates, since no firm data is available for the future, and these three decarbonisation trajectories were defined, which take into account a pessimistic trend, one in line with development expectations and one particularly optimistic precisely to maintain a more conservative approach to the analysis.

3. Techno-economic analysis

This chapter aims to describe the methodology used for the part concerning the techno-economic analysis (TEA). All the TEA inputs will be outlined, focusing on the different technologies and then the equations and choices made to implement the model will be described.

The modelled systems, such as the electrolyser, the production, the storage and the transport system, will be illustrated. Finally, an overview of the scenarios studied is given.

The computational analyses and modelling procedures were executed utilizing Microsoft Excel and Matlab software tools.

3.1 System boundaries (overview of the supply chain)

The following is a detailed overview of the system boundaries of a hydrogen hub that has been thoroughly studied. The hub comprises a hydrogen supply chain that includes hydrogen production and storage systems, as well as a distribution network that delivers the hydrogen to the intended end-use application. You can refer to Figure 11 for a visual representation of the system.

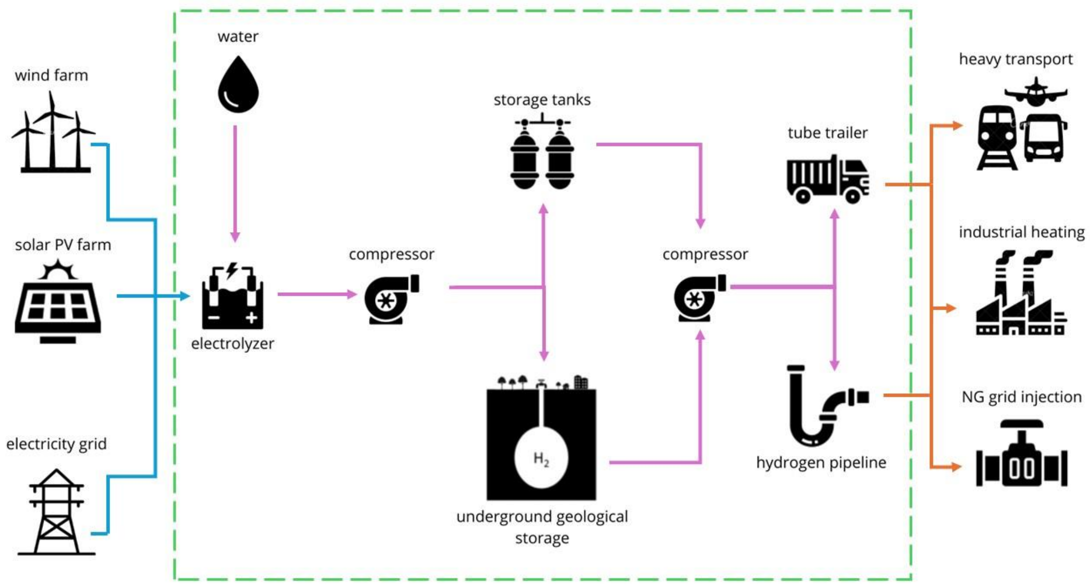

Figure 11: An overview of the hydrogen supply chain hubs and the modelling system boundary.

3.1.1 Production Methods Outline

The techno-economic analysis is conducted to compare three different production methods. For each of them, it is assumed that energy from renewable sources is supplied at its levelized cost following two possible scenarios: the best case where the LCOE is lowest or the worst case where it is highest depending on both CAPEX and OPEX changes over time.

Off-grid

The off-grid electrolysis involves the production and storage of hydrogen near a source of electricity, such as a wind or solar farm. The hydrogen is then distributed through a tube trailer or pipeline, depending on the distance and volume of production, to end-users in sectors that are hard to decarbonize, as previously explained in Chapter 2. This method benefits from the proximity to RES, resulting in enhanced efficiency, cost reduction and easier scalability.

RES associated through PPA

The second case is through a financial agreement between the RES generator and the generating system, such as a power purchase agreement (PPA).

A Power Purchase Agreement (PPA) is a contract between an electricity generator and a customer, which is usually a government, utility, or company. PPAs are time-dependent and during this period, the power purchaser buys energy at a pre-negotiated price. These contracts are crucial in financing independently owned electricity generators, particularly those that produce renewable energy. The sale of electricity under a PPA can take place at different physical points of the electrical grid, as agreed upon by both parties in the contract. It is common to sell the electricity directly where the generator connects to the grid, known as a "busbar" sale [52]. Alternatively, the PPA can specify another delivery point agreed upon by both parties, as in the case under analysis, in which a specific electricity substation, directly located at the hub site, is connected to the national grid, and powered by a PPA.

Grid-connected

In addition, a grid-connected electrolysis system has been studied with feeding from the national electricity grid. It is assumed that grid electricity can be purchased at a wholesale market price set at hourly intervals. The electrolyser only uses electricity when the GHG emission intensity is below a certain threshold set by the Renewable Energy Directive (RED

II). Therefore, electrolyzers' operating strategies and related capacity factors are also variable and changing over time depending on the evolution of electricity generation mix.

The RED II defines criteria for the sustainability and GHG emission of bioliquids used for transport. It also sets EU rules for renewable hydrogen in a low-carbon economy. If hydrogen production is located in a bidding zone with an emission intensity of electricity below 65 gCO2/kWh, it can be considered renewable [53].

3.1.2 General Outlook of the System Components and Distribution Process

Production

Water electrolysers are devices designed to utilize electricity to split water molecules into hydrogen and oxygen gases. Currently, there are several different types of water electrolyser technologies available. Among them, four technologies show significant promise for future technical applications: alkaline (AWE), proton exchange membrane (PEM), solid oxide electrolyser cells (SOEC), and anion exchange membrane (AEM).

Alkaline and PEM technologies are already widely used and represent the majority of the installed capacity today, they are now at the commercial stage. On the other hand, SOEC and AEM technologies are still in the early stages of research and development but show potential for enhanced performance and efficiency.

Alkaline electrolysers offer a slightly higher efficiency when compared to PEM electrolysers[54]. However, AWEs come with a lower investment cost and have a simple system design. It is worth noting that water needs to be purified and product gases must be dried before utilization and this adds more complexity to the process. AWEs operate at a lower current density, requiring more space. Additionally, it is important to balance the pressure between the anode and cathode to prevent any explosion caused by the interpenetration of oxygen and hydrogen.

PEM electrolysers, on the other hand, are currently less efficient and more expensive than alkaline electrolysers. However, further research could enable them to achieve similar performance. PEM electrolysers have a smaller physical footprint, occupying 20-25% less space, making them ideal for dynamic operation when connected to the electricity grid [54]. They offer a fast response and lower degradation and are easy to integrate, with high conversion efficiency. The small size of the electrolysis cell makes it easier to couple with wind energy and photovoltaics, making it a potential option for the future. However, the scarcity of iridium, a rare and expensive element used as a catalyst, can potentially affect the production of PEM electrolysers. This high demand for iridium in various industries can lead to supply constraints and increased costs, making it challenging for widespread adoption and scalability.

Table 6 provides an overview of the main technological aspects of these water electrolyser options.

Table 6: Water electrolysis technologies present to date. Adapted from [54], [55]

		AWE	PEM	SOEC	AEM
	Development status	**Commercial**	**Commercial**	**Demonstration**	**Under research**
Operating conditions	Temperature (°C)	40-90	20-80	550-850	40-60
	Pressure (bar)	30	<70	1	<35
Cost parameters	CAPEX (system) (USD/kW)	600	1000	>2000	
	Lifetime (hours)	50 000	60 000	20 000	5000
	Efficiency %	50-70	40-60		
Flexibility	Load range	15-100%	0-160%	30-125%	5-100%
	Start-up	1-10 min	1 sec-5 min		
	Ramp up/down	0.2-20% per second	1000% per second		
	Shutdown	1-10 min	seconds		

Several possible scenarios for hydrogen production with a long-term perspective were investigated during the development of this research. PEM technology was selected for the entire study. Its fast-response ramp-up and down capability and wide dynamic range of operation make it the most suited technology for coupling with RES. The PEM is also a compact, reliable and low-maintenance solution for off-grid operations, which will be analysed in some scenarios presented later.

The electrolyser capacity was sized according to the metering of the hydrogen demand for each scenario.

The production system also consists of a power supply, water pump, water treatment, safety devices, heat exchanger, gas separators and dryers, and compressors. The compressors are used to pressurise the hydrogen gas to the necessary storage pressure, depending on the storage method.

Storage

The costs associated with hydrogen storage exhibit significant variation depending on the technology employed and the capacity required. Moreover, the appropriateness of a specific technology is contingent upon various factors, including the intended end-use application, the presence of existing infrastructure, and the local accessibility of suitable underground rock formations, particularly in the case of geological hydrogen storage.

Within the scope of this investigation, hydrogen that is generated is stored in different ways: in tanks that can be either compressed or liquid or additionally, in a geological storage facility that is located in an underground decommissioned natural gas reservoir off the northwest coast of County Mayo, in the Atlantic Ocean.

Compressed hydrogen is produced using a well-established technology that is similar to the one used for natural gas. The hydrogen is compressed up to 300 bar, which requires a significant amount of specific work. The capital cost of a compressor is dependent on the work it needs to do, which is based on the inlet pressure, outlet pressure, and flow rate [54]. Capital costs may differ depending on the rated power and operating pressure. For pressure vessels, the cost decreases as the stored mass increases.

Liquid hydrogen (LH_2) requires significant costs for liquefaction due to the cryogenic cycle required to reach -253°C. The tanks used for liquid hydrogen are low-pressure but have high capital costs due to the insulation performance needed to prevent the boiling off.

The management of boil-off gas (BOG) is a critical aspect of LH_2 storage: factors such as wall material, insulation quality, and vessel surface-to-volume ratio influence the percentage of liquid hydrogen entering the gas phase over time. Unlike other cryogenic liquids, LH_2 experiences more severe BOG issues due to its extremely low storage temperatures. BOG losses can range from 0.4% per day for smaller cryogenic tanks to 0.06% for larger tanks [56]. Managing BOG is crucial for large-scale LH_2 storage and transport to address economic and safety considerations associated with land-based tanks and sea-borne vessels.

As the volume of the tanks increases, the cost slightly decreases. Furthermore, the advantage of larger tanks is that they have less leakage due to the smaller surface area per unit volume.

Geological storage sites offer significant advantages over above-ground facilities, particularly in terms of storage capacity. Depleted oil and gas fields and saline aquifers generally have larger storage capacities compared to tanks. The discharge time of a storage site is crucial for efficient hydrogen storage. Depleted gas fields have greater capacity and slower response times, making them more suitable for seasonal variations [57].

During cyclic storage, a certain volume of gas must be injected to maintain a minimum pressure in the geological container. This allows for adequate production rates during the withdrawal season and is known as cushion gas. Hydrogen can be used as cushion gas to keep the overall hydrogen concentration as pure as possible.

The utilization of existing natural gas fields, in Ireland, has emerged as a strategic focus for future assessments. These fields have proven sealed reservoirs capable of holding gas for geological periods, presenting a promising option to mitigate risks associated with leakage.

Transport

The need for hydrogen delivery infrastructure arises only when the hydrogen is produced in the off-grid cases in a central or semi-central location, which is not in the vicinity of end-users. Before being distributed by tube trailer or dedicated pipeline to its end-use application or natural gas grid injection point, the hydrogen is compressed or expanded if necessary.

The distribution of hydrogen currently relies on a specific infrastructure consisting of pipelines that serve larger demands, as well as tankers and tube trailers for smaller ones. For significant and consistent demand, a dedicated pipeline is utilized: in the case of offshore production, both submarine pipelines and existing refurbished natural gas pipelines were investigated for a pure hydrogen flowrate.

3.2 TEA tool description

The tool used was developed by the Energy Systems Integration Group (Erin) at the National University of Ireland (NUI Galway) [35].

The model is designed to take in data on wind, solar, and electricity market prices as well as the emission intensity of the grid. It is an Excel spreadsheet-based tool that allows the user to manually size an electrolyser to meet a given annual hydrogen demand, it also allows the user to prioritize the operation of the electrolyser or the export of electricity to the grid, depending on the specific scenarios. The capacity factor of the electrolyser is affected by the different electricity sources, the relative size of the RES electricity source and the electrolyser, and the mode of operation.

The user can manually size the appropriate hydrogen storage to meet a specification reliably. The tool calculates the levelized cost of hydrogen (LCOH), which includes the capital

(CAPEX) and operational (OPEX) components of hydrogen production and storage. It also calculates the greenhouse gas intensity (GHG) for the hydrogen produced.

Table 7: Hourly data inputs for the hydrogen hub analysis tool

Hourly Data Inputs	
Hydrogen demand	tons/h
Available Wind production	MWh
Available Solar production	MWh
Wholesale electricity prices	€/MWh
Grid emissions Intensity	kgCO2/MWh

Table 7 shows the different types of hourly data used by the model and the associated technical, economic, and environmental data. The LCOH is the key element of the modelling, as it is used as the basis for component sizing. The LCOH is the sum of the levelized costs of production ($LCOH_P$), storage ($LCOH_S$), and transport ($LCOH_T$). Each of these is calculated using their specific formula, while equation (1) represents the total discounted cost of hydrogen production, storage, and distribution, respectively, over the lifetime of the system, in units of €/kg.

The supply chain has different components, each with its associated costs. These costs are divided into the initial capital expenditure (CAPEX) and the annual operating expenditure (OPEX). The CAPEX is a one-time cost and is usually the most challenging aspect of the project's construction. The OPEX includes maintenance and electricity costs and covers the expenses associated with the maintenance and operation of the project throughout its lifetime. It is also worth noting that the model assumes a discount rate of 6% over the 20-year economic lifetime [34].

$$LCOH_{tot} = LCOH_P + LCOH_S + LCOH_T \tag{1}$$

$$LCOH_P = \frac{CAPEX_P + (OPEX_P)^n}{(H_{2P})^n} \tag{2}$$

$$LCOH_S = \frac{CAPEX_S + (OPEX_S)^n}{(H_{2P})^n} \tag{3}$$

$$LCOH_T = \frac{CAPEX_T + (OPEX_T)^n}{(H_{2P})^n} \tag{4}$$

Where H_{2P} represent the quantity of hydrogen that is produced, and n is the number of years of operation.

3.2.1 Economic Input Technology Data

Production

To calculate the production system's CAPEX, OPEX and, subsequently, the $LCOH_P$, the cost of the electrolyser, compressor, and associated equipment are included in the CAPEX.

The specific CAPEX of the electrolyser was calculated ad hoc according to its size, following the cost curves produced for 1, 10 and 100 MW electrolysers in an optimistic and pessimistic scenario from some different sources. Then it was entered into the tool for both best-case and worst-case scenarios. The above-mentioned data are visible in Figure 12.

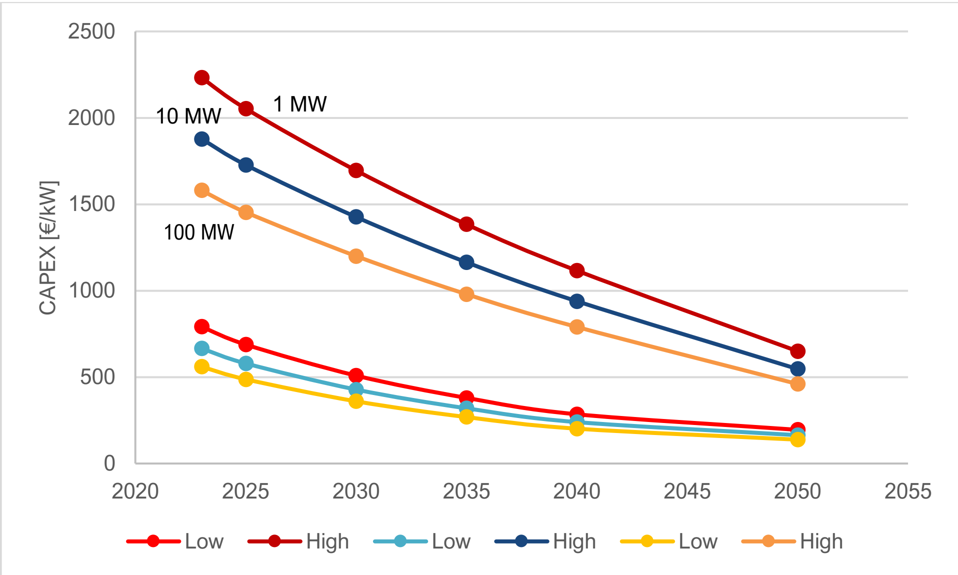

Figure 12: Electrolyser CAPEX curve cost based on size, scenario and decade. Adapted from [28], [34].

The economic parameters for the hydrogen production part are described by Gunawan et al. [34] and it's already implemented in the model. The CAPEX of the compressor, and also the main equipment and other components are functions of the electrolyser's capacity. The OPEX includes fixed costs such as operating and maintaining the electrolyser, compressor, and associated equipment. For further discussion of the equations, please refer to the study above-mentioned.

Variable costs like electricity and water are also included. The amount and cost of electricity, as well as the overall cost of producing hydrogen, depends on the operating schedule of the electrolysers. Table 8 presents the different assumptions regarding the costs of electricity from various sources. Green indicates the most optimistic and lowest levelized cost of electricity for the future, while red represents the worst-case scenario. The references for onshore and offshore wind technologies are specifically taken for Ireland from a study conducted by Janssen et al. [36].

Table 8: Electricity cost assumptions.

Electricity cost	IRENA [58], [59]	[36]
	€/MWh	€/MWh
Onshore wind		
2030	27,9	22,5
	37,2	31,8
Solar PV		
2030	18,6	
	74,4	
Offshore wind		
2040 fixed	37,2	41
	74,4	78,2
2050 floating	27,9	39
	65,1	76,2

Storage

The $LCOH_S$ is calculated by considering the CAPEX and OPEX for storage, which are determined based on the size and technology of the storage facility. Technical parameters and specific costs for storing compressed hydrogen are modelled using data from Tietze et al. [60]. Long-term target prices for liquid tanks of 3500 m^3 have been reported at USD 3.3 million in [61] resulting in €13/kg for this capacity, and the LH_2 storage has been calculated based on this, taking into account also the boil-off rate per day.

Costs for hydrogen storage were calculated for four specific reservoirs representing four different storage types (depleted reservoir, aquifer, washed salt cavern and excavated cavern). For each storage type, a base case was developed and the sensitivity of the cost of service to various technical and economic parameters was examined. Figure 13 is a graphical summary of the calculated base-case service costs for hydrogen gas storage, the label associated with each column indicates the annual storage in tons that each type can tolerate.

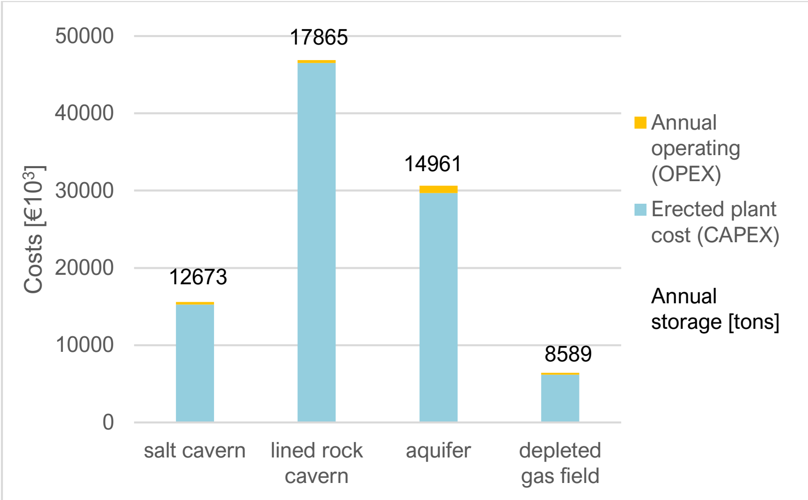

Figure 13: Base-case costs of service for storing hydrogen in four types of reservoirs. Adapted from [62].

Finally, the costs associated with using depleted gas fields for storage were chosen since the west coast area of Ireland has no salt aquifers or salt caverns to exploit in this regard.

The tool's model was implemented using the latest technology studies, which required modifying some equations and data. The details of the equations used to calculate the storage costs and their references are presented in Table 9.

Table 9: Economic parameters for hydrogen storage infrastructure

Economic Parameters for Hydrogen Storage			**ref**
CAPEX			
Compressed Tanks	C_{CS}	$\left(e^{\frac{1}{a\cdot\log_{10} m_s + b}}\right)\cdot m_s$	[60]
Liquid Tanks	C_{CS}	$\lvert(m_s - m_r)\rvert \cdot sf + C_s$	[60]
Depleted gas field	C_{CS}	$C_s \cdot m_p$	
OPEX			
Storage	C_{OS}	2% C_{CS}	

CAPEX in €, OPEX in €/year.
m_s represents the useful mass stored, while m_p is the total hydrogen produced and m_r the reference mass stored. C_s is the specific CAPEX in €/kg associated with the different technologies and sf is a scale factor of 0.67 taken from [63].
The values for variables a and b have been calculated using linear regression and are shown below.

	a	b
Compressed tanks	0.008426016	0.365964663

Distribution

The transport model calculates the cost of distributing hydrogen produced through a tubular trailer or dedicated pipeline, based on the amount of hydrogen, distribution distance, and method of distribution.

A tube trailer is a specialized vehicle designed to carry compressed hydrogen gas. These trailers are equipped with a series of high-pressure cylinders or tubes that store the compressed hydrogen. The tubes are usually made of materials such as composite materials or high-strength alloys to withstand the pressure. In the case of distribution via a tubular trailer, the same *Transportation Sub model* as described by Gunawan et al. [34], already inside the tool is used.

The cost analysis included several parameters such as tube trailer pressure, maximum hydrogen load, trailer fill/unfill time, vessel and trailer CAPEX and operation and maintenance cost per km, these data are taken from the review prepared by Reddi et al. [56].

In Figure 14, it is observed that when the pressure with which the hydrogen is transported and the maximum load increase, the CAPEX per trailer also increases.

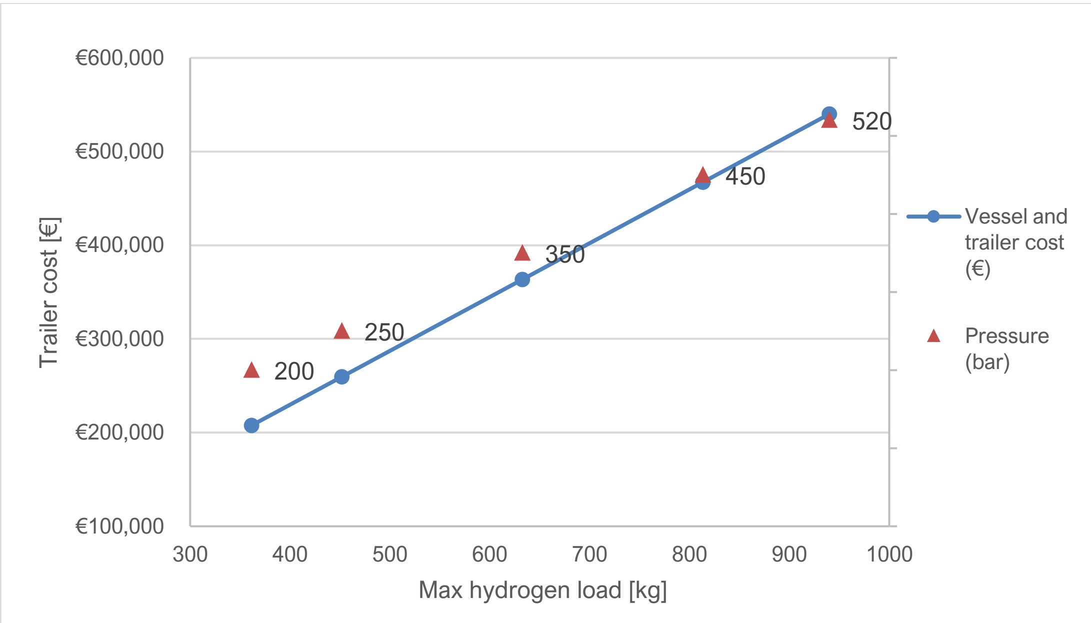

Figure 14: Fitting curve that relates the Hydrogen Payload and associated Trailer Costs also considering the operating pressure of the vessels.

Within the analysis, the final transport costs are calculated considering the entire fleet, based on the number of trucks required. Furthermore, some fixed costs were added from the tractor model: for all scenarios involving compressed or liquified tube trailers, it was chosen as a Fuel

Cell Electric Vehicle (FCEV). FCEV is a type of electric vehicle that uses a fuel cell to generate electricity on board, which is then used to power an electric motor.

The tractor unit is the part of the tube trailer that includes the vehicle's engine, cab, and other components necessary for driving. In the context of FCEVs, the tractor unit is likely to be a hydrogen-powered fuel cell electric truck. This means that the tractor unit itself uses a hydrogen fuel cell to generate electricity on board, which powers the vehicle's electric motor.

FCEVs have the advantage of quick refuelling times and longer driving ranges compared to some battery-electric vehicles. Hydrogen can be stored and transported more easily than electricity, making tube trailers a practical means of delivering hydrogen to different locations.

Some data from the study conducted by Basma et al. [64] are summarised in Table 10.

Table 10: Costs independent of trailer type

Parameter	Value	Units
Fuel for tube trailer tractor unit	FCEV (2030)	
Tractor CAPEX	150.000	€/tractor
Tractor CAPEX (minus resale at 20% value)	120.000	€/tractor
Tractor CAPEX (annualised, minus resale)	24.000	€/yr/tractor
Fuel consumption	3,29	kWh/km/truck
Fuel price	0,20	€/kWh/truck
Fuel price per km	0,66	€/km/truck
Fuel GHG emissions	263	gCO2/kWh/truck
Drivers per truck (4x 6-hr shifts)	4	employees/truck
Other employees per truck	1,1	employees/truck
Employee salary	40.000	€/yr/employee

A comparison was conducted to determine whether electricity or hydrogen would be the best carrier for transporting energy from an offshore wind farm to the shore.

To calculate the necessary pipeline diameter for offshore hydrogen distribution through submarine pipelines, a Matlab code was developed. The code used a concatenation of various equations, following the same calculation method as Singlitico et al. [29].

As for electricity, the submarine HVDC cables and onshore substations costs were taken into consideration within the system boundaries as part of the electrolyser equipment. Although renewable energy sources were not analysed, the Matlab model included the cost of necessary infrastructure, such as submarine HVDC and onshore substation, through curve fitting following the work of Härtel et al. [65].

In one scenario, the potential to utilize current natural gas pipelines was explored. The reuse potential for offshore hydrogen production is significant, particularly if the hydrogen is injected directly into a depleted natural gas reservoir. This reservoir is connected to the national gas grid through an infrastructure that can be converted to transport 100% hydrogen.

The expenses associated with offshore pipelines include intelligent pigging, rock drainage, and valve inspections. This study estimates the OPEX for a trunk line to be between € 4,000 and € 6,000/km [66].

Table 11: Economic parameters for hydrogen and electricity distribution infrastructure

Economic Parameters for Distribution			unit	ref
CAPEX				
HVDC cables	C_{CD}	$ET \cdot L_{HS} \cdot \left(\frac{P_{HVDC}}{P_{MAX}}\right)$	$	[29]
Onshore substation	C_{CD}	$101 \cdot P_{HVDC} + \frac{P_{HVDC}}{P_{MAX}} \cdot 61.6$	$	[29]
Offshore Pipeline	C_{CD}	$\left[\begin{matrix}1.75 \cdot (0.314 + 0.574 \cdot 10^{-3} \cdot D) \\ +(1.7 \cdot 10^{-6} \cdot D^2)\end{matrix}\right] \cdot 10^6 \cdot L_{HS}$	$	[29]
OPEX				
HVDC cables	C_{OD}	2% C_{CD}	€/yr	
Pipeline	C_{OD}	2% C_{CD}	€/yr	
Existing NG Pipeline	C_{OD}	$5000 \cdot L_{HS}$	€/yr	[66]

Where ET is the economic target for HVDC cables in $/km, L_{HS} is the distance from the shore, P_{HVDC} is the power of the HVDC transmission lines and P_{MAX} is considered as the maximum capacity of the farm and D is pipeline diameter.

NB: The calculations for the CAPEX need to be converted into € using the conversion rate between USD and Euro.

Hourly Data Sources

Hourly data on electricity market prices and carbon emissions were obtained from a comprehensive simulation of the Irish electricity system for the year 2030 by Deane et al. [46].

This simulation involved an Irish electricity system that relies on 80% renewable sources and generates hour-by-hour market prices and emission intensity data.

To generate hourly wind and solar PV data for each scenario, the online data generation tool renewableninja (RN) [67] was used, which leverages historical wind speed and solar radiation data to produce hourly production profiles for farms. The same meteorological year (1982) used by Deane et al. was utilized to generate the production profile for the wind farm to provide consistency and clarity to all the research.

The estimation of hydrogen demand is based on the annual amount of hydrogen required to replace existing fossil fuels in the end-use sector, accounting for efficiency differences where applicable, as described in Chapter 2.2 section “Hydrogen Demand Projections”.

The study assumed that the hydrogen demand would remain constant throughout the year as it was difficult to model the hourly demand for the future. This was due to the unavailability of the hourly or monthly profile of consumption data for the current energy carriers used in County Galway.

The model is designed to solve for hourly demand; hence, the latter was calculated by dividing the estimated total annual hydrogen demand by the number of hours in a year.

Emissions calculation

The environmental performance of a green hydrogen hub is a critical factor for its viability.

The calculation of hydrogen's carbon intensity is derived from the carbon intensity of the electricity utilized during electrolysis and compression. For renewable energy, a zero-carbon intensity is assumed, whereas for grid electricity, the carbon intensity fluctuates based on the instantaneous generation mix.

In the model, one year of hourly data was considered for the carbon intensity of grid electricity, and the average figure was then calculated.

As part of the study, the annual electricity grid CO_2 emissions (tons/year) are calculated using equation (5) and then the hydrogen GHG emissions intensity by dividing the total emissions by the annual hydrogen production.

$$m_{CO2}^{produced} = \left(EI_g \cdot el_g\right) \cdot 10^3 \tag{5}$$

Where EI_g is the emission intensity of the grid and is the average of the hourly grid emissions intensity (kgCO2/MWh) associated with grid electricity to electrolyser taken hourly according to the 65 kgCO2/MWh limit control. And el_g is the total electricity consumed (MWh).

Annual transportation GHG emissions, in tCO2/year, are calculated according to equation (6).

$$m_{CO2}^{transport} = (fc \cdot FE \cdot d \cdot n_t) \cdot 10^6 \tag{6}$$

The fuel consumption in kWh/km/truck is represented by fc, FE is the fuel GHG emissions in gCO2/kWh/truck specific to the FCEV utilisation case, d is the distance travelled by each truck in a year to transport the hydrogen from the hub to the end users and n_t is the number of trucks required in any specific case.

The distance per trailer travelled has been calculated from the total number of trailers filled each hour times the distance to the end user, considering both the outward and return journey.

Other emissions associated with hydrogen production, such as life-cycle emissions from the production or construction of the wind farm or hydrogen production facility are not considered.

3.3 Chapter Summary

Several methodologies were involved in the realisation of this research paper. The general perspectives of the system components and the distribution process were described in this section, followed by the techno-economic model for calculating the LCOH. It was important to collect, from a series of studies conducted by professionals in the field, the primary data to be included in the model. This was done so that the results developed would be as accurate and usable as possible.

4. Scenario development

To demonstrate the aims and objectives of this thesis, the model was applied to some case studies on the island of Ireland, specifically in County Galway.

Despite the lack of a concentration of heavy industry or significant demand for hydrogen, Galway City boasts the presence of two universities that contribute significantly to the city's development through innovative ideas and academic research. This presence can foster economic growth, and technological and cultural innovation, and create opportunities for collaboration between academia and industry that could potentially facilitate the use of hydrogen to decarbonise end-uses in transport, heat and power.

The hypothetical regional hydrogen hubs analysed in the case studies are assumed to commence operations in 2030, 2040, and 2050. These hubs have the potential to cater to the hydrogen demand required by the city through various strategies.

When modelling a hydrogen hub, the region's unique characteristics are taken into consideration. Firstly, existing or potential future sources of electricity, including wind, solar, and grid power, are identified. Secondly, the region's potential future hydrogen demand, as studied in Chapter 2.2, is determined for each decade based on different end-use applications and national decarbonization targets. To connect production to demand, storage, and distribution options are identified.

The different input parameters have been summarised in Table 12.

Table 12: Description of scenario parameters and their possible values.

Parameters	Possible Options	Notes
Year of commencement of roll-out	• 2030 • 2040 • 2050	The SH2AMROCK base project means that the earliest possible hydrogen deployment will be around 2028 (more consistently in 2030), with the target of reaching net zero by 2050.
Electricity source for electrolysis	• Electricity grid • Onshore wind (GWP, MLWF) • Offshore wind (Atlantic ORE 1,2, Sceirde Rocks) • Solar PV (Ballymoneen)	The Galway Wind Park was the project's initial supplier, which is now set in Mount Lucas. The next potential resource to tap into is the bottom fixed Sceirde Rocks wind farm in Connemara and from the offshore floating wind of the Atlantic ORE 1 and 2 located both on the west coast of Ireland. In addition, one solar PV project in the county is due to come online by 2030.
Electrolyser size	scaled on the electrolysis strategy and the metering of the demand required	Commercially available electrolysers start at 2 MW. 50 MW units in advanced planning stages across Europe representing larger future electrolysers.
Strategy for electrolyser operation	• Excess electricity/ Dispatch down (Electricity first, then hydrogen) • dedicated H2 production strategy (Hydrogen first, then electricity)	To maximize hydrogen production, it is necessary to operate continuously, but that requires a constant supply of electricity. Co-production sites for both electricity and hydrogen have two proposed strategies. These strategies prioritize the production of either hydrogen or electricity. If only hydrogen is produced, no electricity is exported.
Hydrogen storage type	• Compressed tanks (gas or liquid form) • Underground geological storage	Gas cylinders are common for small-scale hydrogen roll-out. Also, the possibility of liquid storage is investigated. The use of existing natural gas fields in Ireland for hydrogen storage should also be a focus of future assessments.
LCOE case projection	• Best case (lower cost) • Worst case (higher cost)	
Electrolyser type	• connected to the grid through PPA • using only grid electricity bought from the wholesale electricity market • off-grid	Grid electrolysis can produce hydrogen in an easier way but less sustainably. To reduce this risk, the European Commission has developed criteria for renewable grid electrolysis. These include having a power purchase agreement with a renewable electricity source, being in the same bidding zone as the renewable source and having a time difference of no more than one month between the renewable electricity and the hydrogen produced. Alternatively, hydrogen from grid electrolysis can be considered renewable if produced in an electricity system with an emission intensity below 65 gCO2/kWh.

4.1 Use-Case Scenario Description

The relevant information for each scenario is summarised in Table 16, reported in the Appendix at the end of this work. Included are electrolysis size and strategy, electricity provider, storage method, distribution distance and method of distribution.

Furthermore, all the renewable energy source (RES) locations were identified taking into account the government-established renewable projects in the County Galway area that can be used for the production of green hydrogen.

All scenarios are based on the assumption that demand will be met for the specific decade. In this regard, only the demand outlined above in the Meeting scenarios for 2030, 2040, and 2050 (Chapter 2.3) was taken into account resulting in eleven identified scenarios that will be described in this section.

4.1.1 Scenarios at 2030 timeline

This section describes the possible hubs, located in different locations and based on different sources. They were analysed based on the assumption of meeting a demand of 392 tonnes by 2030.

For each of them, the size of the electrolyser was determined based on the demand, following the previous analysis, to ensure appropriate sizing based on the different electrolysing strategies and sources.

Flexible grid-connected

In this specific scenario, the hub is located at Galway Port, which is where the intended end-users for the next decade have been identified. The investigation is underway to examine the potential for a hydrogen hub as an alteration of the Galway Hydrogen Hub (GH2) Project.

The electrolyser is connected to the national electricity grid through the existing substation. To supply electricity from the Galway electricity network to the proposed GH2 site, a new underground cable is suggested, which will connect to a new 38 kV substation located adjacent to the site. ESB (Electricity Supply Board the main energy provider in Ireland) has assessed the network in the area and identified the most appropriate grid connection point to be at the northern junction, approximately 50 meters from the Trimms Lane 38kV substation [68].

In this case, the electrolyser sources its power directly from the wholesale electricity market. However, it follows a carefully designed approach that only utilizes electricity with an emission intensity below 65 gCO_2/kWh to power the electrolyser.

The data used are derived from the comprehensive study conducted by Deane and Mehigan [46]. By utilizing hourly values for wind (onshore and offshore combined) and all Island market prices, along with the emission intensity data for a 2030 80% RES-E power system in Ireland, the analysis of hydrogen production was conducted.

The hydrogen produced is compressed from 30 to 300 bar and stored in aboveground gas cylinders, assuming full capacity, before being dispensed to public and private vehicles (including buses, trucks, and boats) at the Hydrogen Refuelling Station (HRS). These applications will be interlinked by connecting infrastructure which, however, being around 100 m (as depicted in Figure 15) is not considered within the analysis.

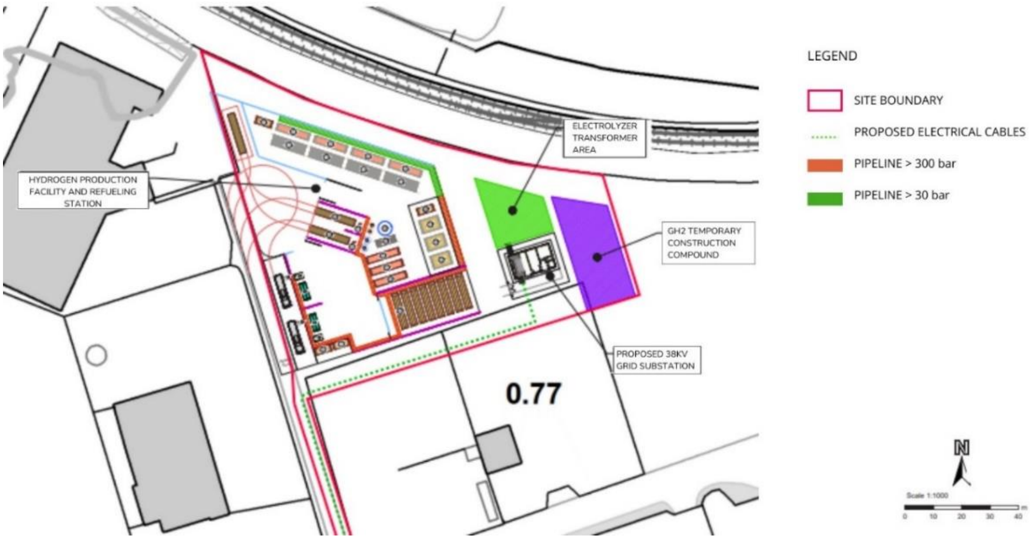

Figure 15: Hypothetical site layout. Adapted from [68].

Grid-connected through Power Purchase Agreement

The same site layout presented above is considered in this case in which at the substation only green electricity produced by the Galway Wind Park, with a capacity of 174 MW, is supplied. The electrolyser is powered by renewable energy through a Power Purchase Agreement with the RES, backed up by a guarantee of origin. Siemens SWT 3.0 101 was the turbine model inserted into the computation into RN: this is the real model installed into the wind farm.

To analyse two different scenarios based on PPA, the entire farm capacity was scaled to the size of the electrolyser, with only a few turbines involved in the dedicated production of hydrogen through a specific PPA.

Starting on January 1st, 2030, hydrogen will need to be produced during the same one-hour period as electricity from renewable sources. Hence, the hourly wind power profile was obtained from the RES site. Before this, a monthly correlation was applied. This difference in terms of the supply of the electrolyser was investigated to understand which is the most cost-effective.

However, since the tool is hourly based, the monthly condition was modelled by taking into account the average monthly power output applied then for each hour of the day throughout the year, resulting in a lower but more comprehensive profile.

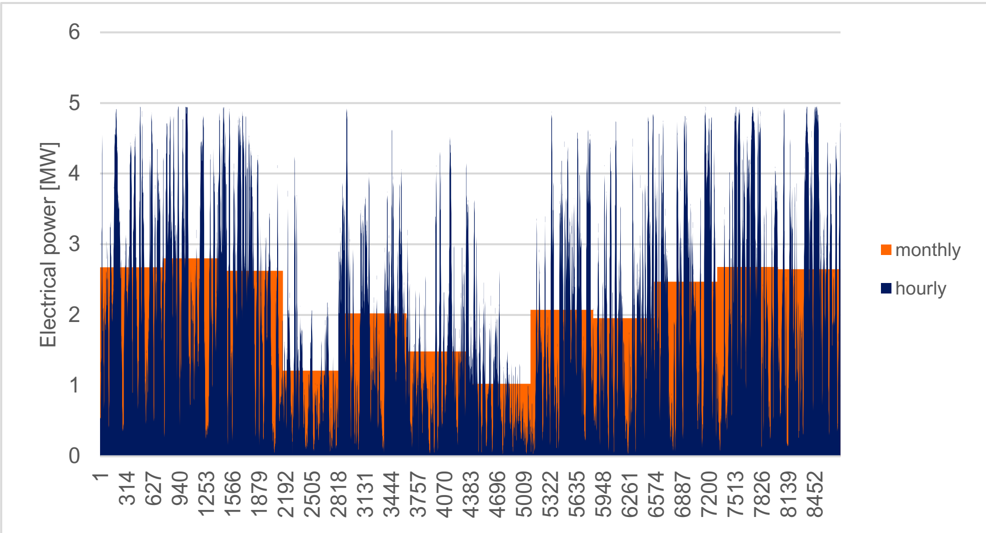

Figure 16: Scaled Galway Wind Park power output profile used in the analysis.

Onshore wind farm

For the first off-grid scenario, production by electrolysis directly on the site of the Mount Lucas wind farm was investigated. It consists of 28 Siemens SWT 3.0 101 turbines with a total installed capacity of 84 MW.

The project involves the construction of a 4 MW pilot-scale hydrogen electrolysis plant, 2 of which will be dedicated to meet Galway's demand. The project has received planning permission from Offaly County Council and will begin production in 2025.

Given the absence of information regarding the electrolysis approach and considering the significant differences in plant and electrolyser capacities, it was decided to explore the possibility of utilizing the wind power facility to generate electricity during the day for grid injection, while at night-time, when there is less demand from the community, to transform it into hydrogen.

Wind electricity is most frequently dispatched down during periods of low demand, such as at night, when overall electricity consumption tends to be lower. But other factors can also influence this choice.

In regions with high levels of renewable energy penetration, wind power may be curtailed more frequently during periods of low demand to avoid overloading the grid with excess energy.

For this reason, the electrolyser only works during the night hours (defined in this case as off-peak) from 11 pm to 8 am, to avoid the dispatch down of the wind power.

In this special condition, a 2 MW electrolyser was not big enough to meet the demand of the city of Galway, so it was scaled up to 6 MW to encounter it.

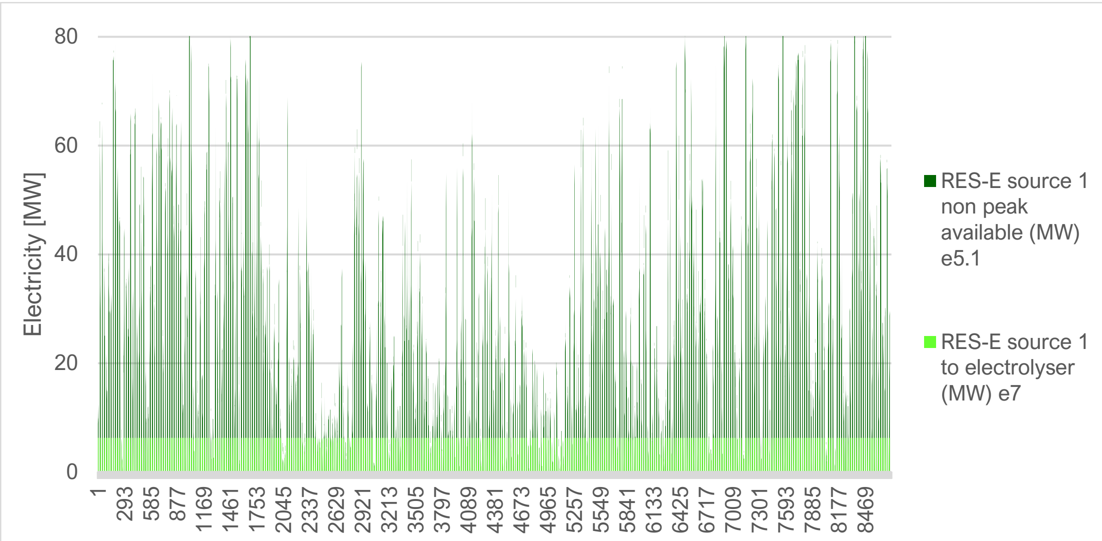

Figure 17: Mount Lucas wind farm available electricity and electrolyser power input. The analysis does not consider the economics of selling electricity to the grid.

The production and storage hub is directly at the RES site. Off-grid electrolysis benefits from proximity to RES, resulting in enhanced efficiency, cost reduction, and scalability, but at the same time, transport costs must be included when analysing scenarios such as these.

The Mount Lucas wind farm is located 151 km away from Galway City. To transport hydrogen overland, compressed tube trailers were considered as terrestrial transportation method, being compatible with the storage method (compressed tanks).

Solar Photovoltaic farm

This case revolves around an examination of the proposed PV site in Ballymoneen, Co. Galway - a 100 MW photovoltaic solar power project. The plan includes a 5-year construction period and permission to build a Solar PV Energy and Battery Storage system. While the solar farm is intended to operate for 35 years, for the purposes of this study, a consistent economic lifespan of 20 years was used across all scenarios to ensure clarity and consistency.

The plant production data was taken for 100 MW installed on RN using CM-SAF SARAH (that has higher accuracy for Europe) as dataset taking as base year 2015, which after doing some research on PVGis, seems to be quite average for the Country in terms of solar radiation.

The tilt and azimuth angles have been optimised up to 40° and 180° and 14% losses as on PVGis were considered.

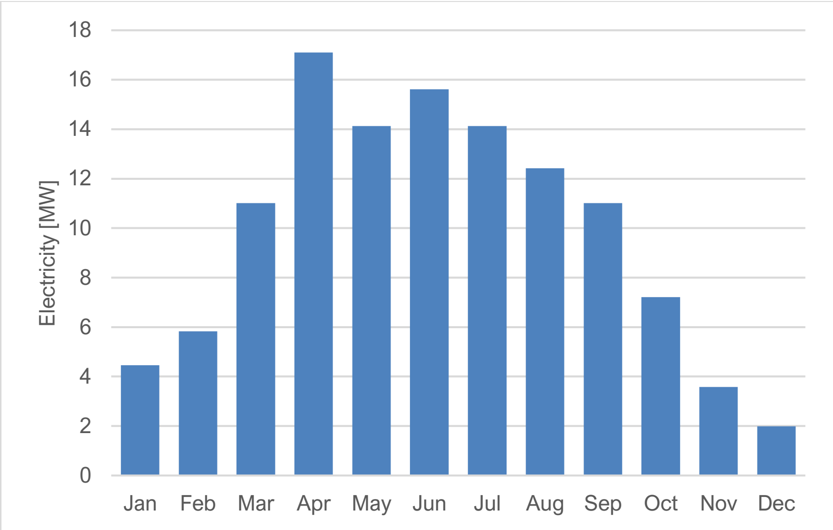

Figure 18: Solar PV monthly mean electricity production.

Solar PV in Ireland faces a real problem due to the nation's low irradiation, resulting in a low capacity factor of around 6%. The calculated RES capacity factor, using:

$$CF = \frac{actual\ energy\ pruduction\ [MWh]}{RES\ installed\ capacity\ [MW]\cdot time\ [h]} \tag{7}$$

For this photovoltaic system, it is only 10% and as can be seen in Figure 18 the monthly average of electricity produced is quite low.

This means that the entire capacity must be utilised in a dedicated way to produce hydrogen to supply a 5 MW electrolyser to meet the hydrogen demand.

It is widely acknowledged that solar PV is a renewable energy source with high levels of intermittency. Therefore, a reliable storage system is essential for effective production. With 2030 on the horizon, compressed gas tanks are the preferred storage method due to their mature technology. In the end, as this hub is situated 17 km from Galway, compressed tube trailers are necessary for transporting hydrogen to the city's end-users.

4.1.2 Exploring 2040 Scenarios

For this decade, only one offshore renewable facility has been taken into consideration: the Sceirde Rocks wind farm. The feasibility of establishing a potential production and storage hub either on the coast or directly offshore was explored, with an analysis conducted on the variances between utilizing electricity or hydrogen as an energy carrier from the farm to the shore.

Once again, the sizing of the electrolyser was determined to align with the assumption of meeting a demand of 1773 tonnes per year by 2040, ensuring appropriate sizing following the various electrolysis strategies.

Bottom fixed offshore wind

Only one renewable plant was considered within the analyses for 2040. The Sceirde Rocks wind farm, located about 25 km from the port of Rossaveel, with a capacity of 450 MW, is a bottom-fixed offshore wind farm. The site configuration is visible in Figure 19.

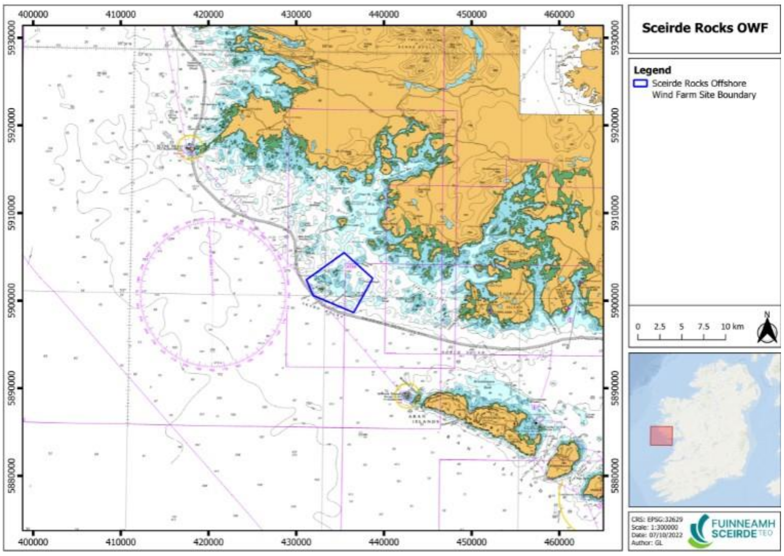

Figure 19: Sceirde Rocks site location [69]

The possibility of locating a potential production and storage hub in Rossaveel stems from an earlier study that identified it as a possible location for the construction of turbines [70].

The difference between using electricity or hydrogen as an energy carrier from the farm to the shore was studied after the study of Ibrahim et al. [71], in which the advantages and disadvantages of a Centralised Onshore Electrolysis and an Offshore one were depicted. The two typologies are visible in Figure 20.

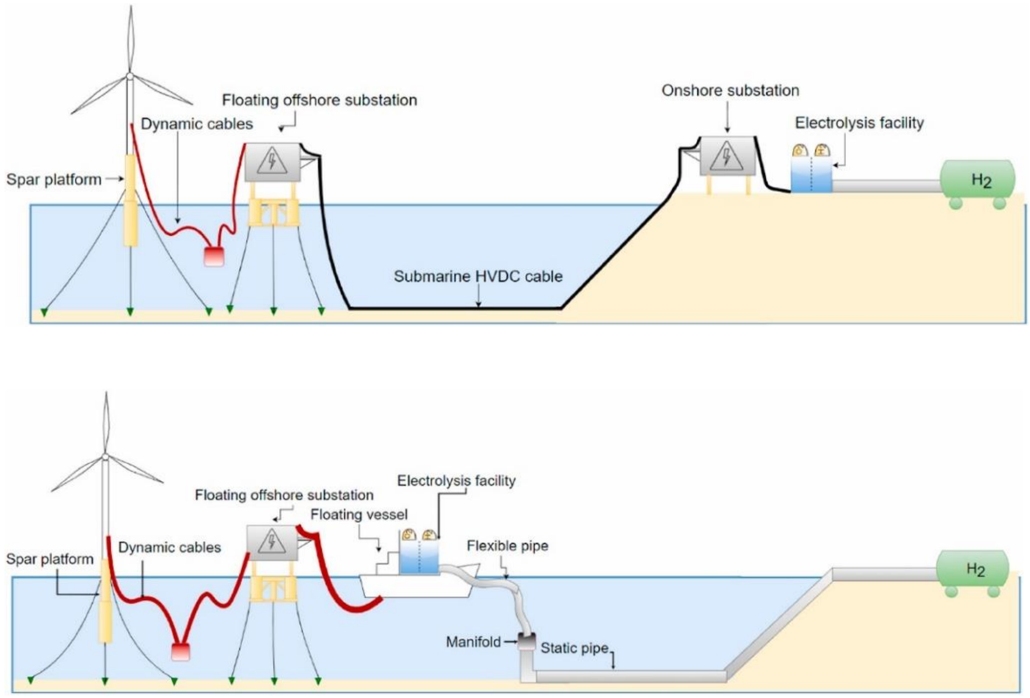

Figure 20: Onshore and centralised offshore electrolysis typologies [71].

Centralized Onshore Electrolysis presents advantages such as easier installation and lower initial costs, benefiting from the stability of onshore environments. However, challenges arise in scaling up operations and dealing with the high costs associated with submarine High Voltage Direct Current (HVDC) transmission, particularly for large farms located at considerable distances from the shore. The expense of HVDC converters and energy losses during electrical transmission further add complexity to the economic viability and overall efficiency of onshore electrolysis projects. Careful consideration of these factors is crucial for successful planning and implementation.

On the other hand, Offshore Electrolysis relates to hydrogen pipelines that are cost-efficient for large farms and long distances and it is competitive at deep-water floating sites. However, it has to face the requirement of a large offshore platform to accommodate the electrolyser with water purification facilities and all the power control and storage systems. These increase a lot the CAPEX of the production part.

To understand how these differences impact the final LCOH, these two types were studied, and some modifications were implemented in the tool based on the energy vector utilized:

- Electricity: The costs of submarine HVDC cables and onshore substations are considered into the system boundaries as electrolyser equipment. Onshore electrolysis is performed in Rossaveel Port, located 25 km away from the wind farm. LH_2 storage tanks are located there, and then hydrogen is transported through the liquefied tube to Galway.

- Hydrogen: It is transported after offshore electrolysis via a submarine pipeline directly to Galway, located 50 km from the plant (platform and seawater desalination costs are considered as electrolyser facilities).

In the case of HVDC transmission, the generated electricity is collected on the hub, on which the alternating current (AC) is converted to HVDC through voltage converters. The rated power of the HVDC cable and the onshore substation P_{HVDC}, used in equations in Table 11, is the total power of the group of turbines involved in the analysis: could be 25 MW or 450 MW of the entire farm.

Indeed, two different electrolysis strategies were studied:

- the first case is dedicated H2 production the wind farm scaled on the electrolyser size of 25 MW (only 3 turbines considered).
- the second is all 450 MW farm related to a 27 MW electrolyser taking electricity only at night-time from 11 pm to 8 am, given the substantial differences in plant and electrolyser capacity.

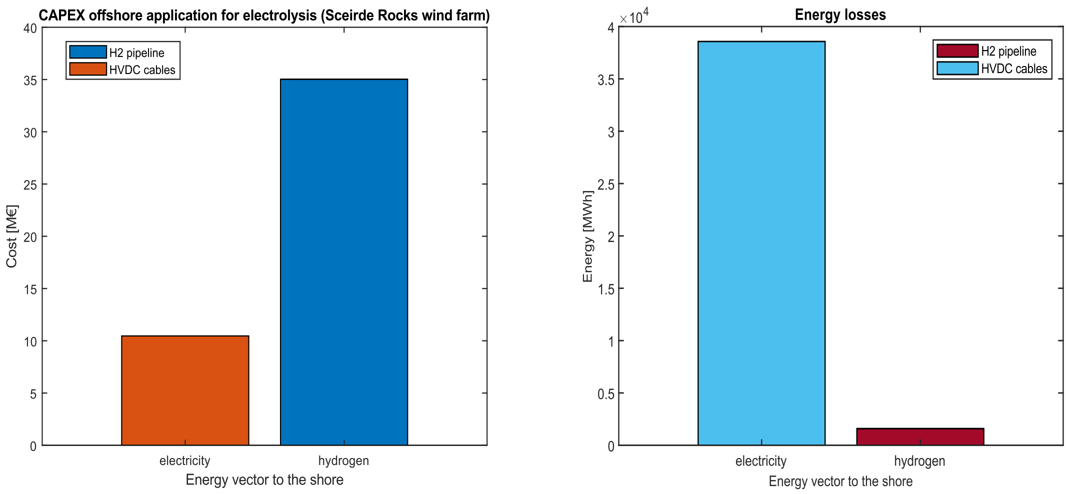

Figure 21: Comparison between the cost of utilising different energy vectors.

Figure 21, produced by the analysis of the 450 MW farm, points out that submarine HVDC cables cost less in the case of a short distance from the coast and for a farm with a capacity of this size than building a dedicated pipeline.

On the other hand, if one considers the losses in terms of derived energy (computed in MWh/year), in the case of electricity transport via HVDC cables the losses are two orders of magnitude bigger than in the case of pipeline transport.

The equations utilised for this calculation are:

$$E_{loss} = E_{electr} \cdot (\eta_{st} \cdot N_{HVDC} + \eta_{hs} \cdot L_{HS}) \tag{8}$$

$$H_{loss} = L \cdot L_{HS} \cdot LCV \tag{9}$$

Where E_{electr} is the total energy production of the specific farm over a year in MWh, L_{HS} is the distance from the shore, N_{HVDC} is the number of the substation, equal to 2; η_{HS} is the energy loss per km assumed to be 0.0035%, η_{ST} is the energy loss at the conversion station equal to 1% [29], and LHV is the Low Heating Value of hydrogen of 33.3 kWh/kgH_2.

These scenarios include the evaluation of green offshore hydrogen production from an electrolyser (PEM) installed on fixed offshore structures, as the wind farm under analysis is bottom-fixed.

The weight and cost estimates are based on information provided by the study conducted by Wood Norway, in the form of equipment weights and surface requirements necessary to allow offshore green hydrogen production, as well as an assumed water depth of 70 metres, same as the bathymetry in the Sceirde Rocks site location.

The needed jacket and topside structures required to allow for production have been estimated. The cost of the platform for electrolysis, desalination and compression is 3 M$/MW of PEM electrolyser power installed [72]. Operating expenses (OPEX) were not considered as part of the estimate, so it was defined as 2% of CAPEX for the other facilities.

The study examined the storage of liquid hydrogen and the transportation through liquified tube trailers, assuming that by 2040, liquid tanker technology will have reached maturity. While LH_2 storage is cheaper than compressed tanks, it presents unique challenges.

Hydrogen must be cooled to below -253°C at atmospheric pressure, requiring significant energy and cost. Liquefaction, which accounts for about one-third of the total energy content of liquefied hydrogen, and the storage of liquid hydrogen in vacuum-lined stainless steel tanks present difficulties, as heat loss through the tank walls leads to vaporisation or boil-off as explained at the beginning of the chapter.

Through the analysis, it was noted that by changing only the type of storage, the amount of hydrogen decreased in the case of liquid hydrogen. This is explained by the fact that the biggest difference between the methods is the amount of electricity required during the compression/liquefaction phase. In the case of LH_2, a higher energy consumption of about 12 kWh/kgH_2 must be considered instead of 2 kWh/kg as in the case of compressed tanks.

On the other hand, the capacity of liquid tankers, around 4 tonnes, is 5-6 times that of composite pipe trailers and 15-20 times that of steel pipe trailers used for compressed hydrogen gas [56].

4.1.3 Towards 2050: Mapping the Future of Hydrogen Hubs

For the last decade, key criteria for site selection included water depths suitable for floating wind technology, appropriate wind resources/speed, favourable seabed morphology, avoidance of heavy maritime traffic, proximity and accessibility of deepwater harbours, and exclusion from Special Areas of Conservation (SAC), Special Protection Areas (SPA) or marine protected areas.

Two floating offshore wind projects already established by the government have been identified as meeting these criteria and for being the first in front of the Galway coastline, and the second due to its proximity to the Corrib natural gas field. It will be exhausted by 2050 so it was decided to consider it for geological underground storage.

For the year 2050, there is a demand of 3655 tons that needs to be met. The size of the electrolyser has been carefully determined, as in previous assessments, for the two resources under analysis to match the demand requirements. This ensures that the sizing is optimal, taking into account various electrolysis strategies.

The Atlantic Offshore Renewable Energy 2 Project.
It concerns a floating offshore wind farm located off the west coast of Ireland, off County Galway. The offshore park is located approximately 100 km from the City and will have a capacity of approximately 3.75 GW [73].

For this scenario both offshore electrolysis and onshore one as explained above were investigated: the distance to the city is therefore the same for both the case of hydrogen pipelines and the case of electricity transport via HVDC cables.

In Figure 22 below, however, it can be seen that for a wind farm with a capacity greater than 1 GW, such as this one, it is more convenient to transport hydrogen directly, given the lower capital costs associated with transport.

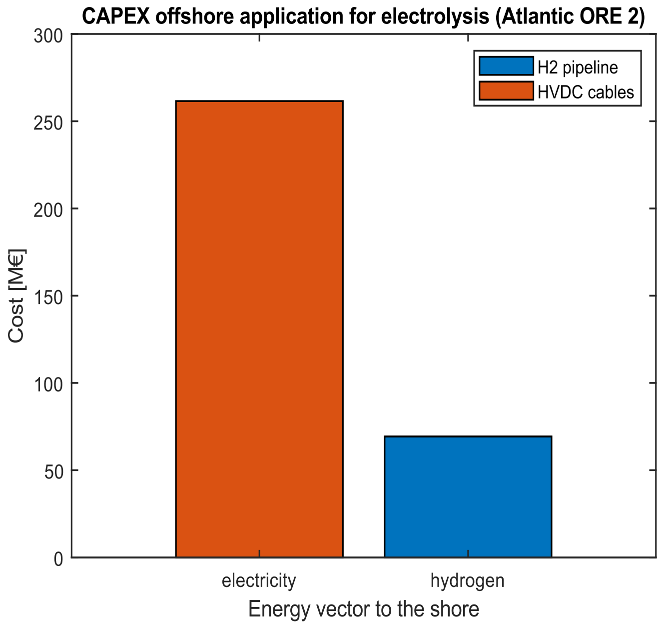

Figure 22: Comparison between investment cost required for the two energy vectors.

The onshore electrolysis scenario in the case of exploiting the wind farm at its maximum capacity is therefore outside the scope of the analysis since it would be too costly.

The two cases considered are therefore offshore electrolysis with floating platform and dedicated hydrogen pipeline for all farm at night with 50MW electrolyser and scaled plant on 30MW electrolyser for dedicated production.

When an electrolysis plant is located offshore on a floating platform, several considerations need to be taken into account. The choice of the floating platform depends on an on-site assessment, considering factors such as depth and ocean weather conditions.

The plant consists of electrolysers, cooling units, seawater desalination units, a hydrogen storage system, and a battery system for backup power supply.

Compressed tanks were chosen as the storage method to be placed on the floating platform. The design of the storage capacity should be made following technological advancements and the availability of space on the platform, considering the weight of the different facilities.

Alternatively, floating vessels used also in the offshore oil and gas industry, could also be used depending on system configuration variables.

However, the addition of a floating facility contributes significantly to the capital expenditure which in this case has been identified to be around €0.6/MW, estimates from manufacturers [74].

The Atlantic Offshore Renewable Energy 1 project.

It concerns a floating offshore wind farm located off the west coast of Ireland, mainly in County Mayo and to a lesser extent in Galway. The site selection process involved a comprehensive multi-criteria analysis of national constraints, which led to the identification of potential development areas within and outside the 12 nautical mile limit, resulting in a two-stage development [73].

Phase 2 envisages a capacity of about 4.2 GW and is the one interested in the analysis.

A 50 MW electrolyser operating only overnight is sufficient to meet Galway's hydrogen demand. It is placed on an offshore platform with the water purification system, the compression station and other facilities required as described above.

Due to the plant's proximity to the natural gas extraction site, it was considered as underground geological storage.

Corrib, located in the Slyne Basin off the west coast of County Mayo, features a reservoir discovered in 1996 and sealed by Triassic halite, which commenced production in 2015. Despite being in decline, the field may become a potential candidate for hydrogen storage in approximately 10 years if additional gas volumes are not tied in.

The hydrogen storage potential of depleted gas fields is determined by the mass of hydrogen that can occupy pore space once filled with recoverable natural gas. Calculations indicate an estimated total energy storage capacity of around 75 TWh. Factoring in cushion gas requirements, assuming a 50% need, yields maximum working gas capacity estimates of 38 TWh equal to 1515 tons, considering the utilization of all reservoir units [57].

A maximum injection flow rate of 980.55 kg/h [62] is allowed for this kind of geological storage so all these constraints were implemented inside the tool in order to provide consistency to the work.

Clearly, the capacity of this underground storage is far greater than the production and storage for the city alone, which is why all limits regarding pressures, capacity, maximum throughput and throughout are respected.

This assessment highlights the potential of repurposing a depleted gas field for hydrogen storage and using an existing natural gas pipeline (long about 90 km) to transport it to the shore at the first injection point, as seen in Figure 23. Then the national gas grid is directly connected to Galway in which the end-users are clustered so hydrogen could be easily transported, but the grid injection facilities and methodology are beyond the scope of this work.

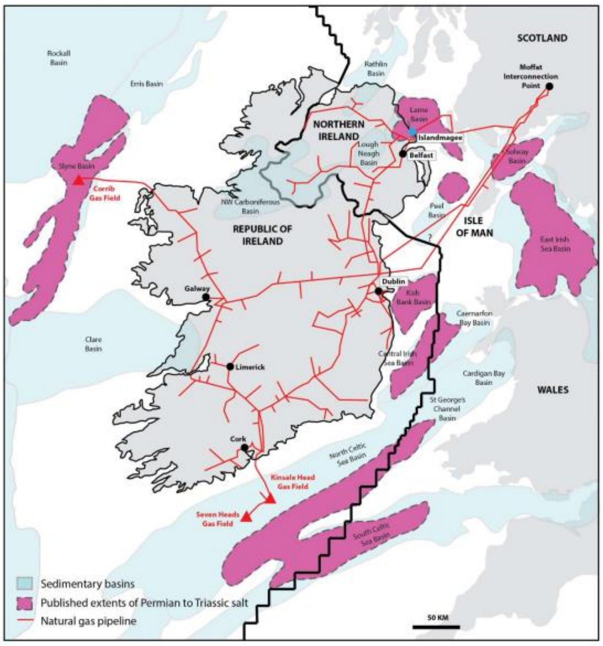

Figure 23: Map of Ireland indicating major gas transmission lines, sedimentary basins, and the locations of Kinsale Head and Corrib gas fields as storage facilities [57]

4.2 Chapter Summary

In this section, several production scenarios were described in detail and the map in Figure 41 depicts all the hubs examined.

After a deep examination of the characteristics and the variable inputs chosen for each hub, the results produced by the scenario analysis will be compared and discussed in detail in the next chapter.

5. Results and Discussion

In this chapter, the results obtained from the techno-economic model for the various scenarios outlined in the previous chapter will be represented graphically, implementing a comparison for each decade. A discussion of the significance of these results considering the functioning of the various components within the system boundaries will also be presented.

5.1 Analysis of 2030 Scenarios Outcomes

The levelised cost of hydrogen can be broken down into production, storage, and transport costs, which are represented by different colours in Figure 24. Investment costs are shown in darker shades, while operating and maintenance costs are displayed in lighter shades. The production cost includes the CAPEX of the electrolyser and compressor/liquefier, along with the cost of necessary electricity as an OPEX.

It can be seen from the graph that the component with the greatest impact on the LCOH is storage. Both storage size and the specific cost of storage have significant effects on LCOH: for all the scenarios in 2030, as described above, the storage method chosen was compressed tanks. Comparing Figure 24 and Figure 25, is noticeable that the capital costs for storage are directly proportional to the amount of hydrogen that needs to be stored, and thus the size of the storage needed.

Storage requirements are influenced by the need to balance the variable output of the electrolyser with the constant demand for hydrogen. When the electrolyser operates at a lower capacity factor, there might be a need for larger storage capacities to ensure a continuous and reliable supply of hydrogen.

The capacity factor of the electrolyser (CF_E) is affected by the intermittency of the energy source supplying power to the electrolyser. In the case of renewable sources with a low capacity factor, not considerable or not constantly available, the electrolyser may operate at a lower capacity, which impacts the amount of hydrogen produced.

The graph shows that the higher the percentage associated with CF_E, the lower the cost associated with storage.

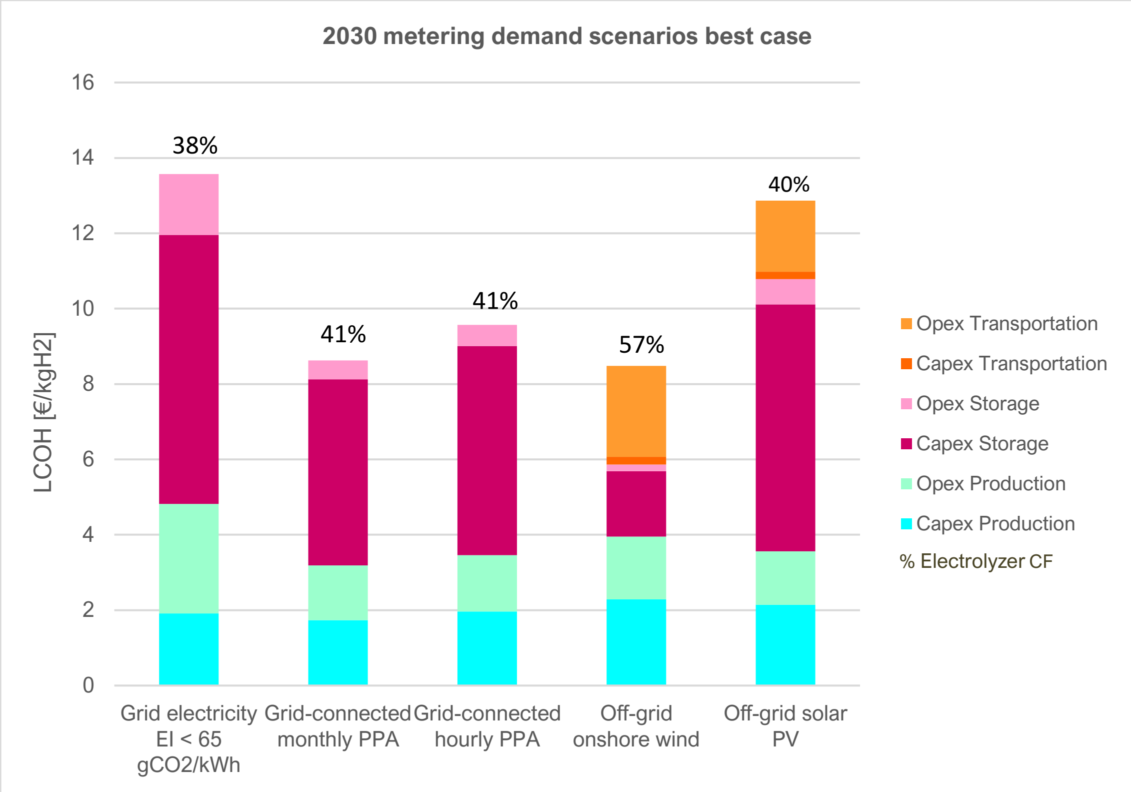

Figure 24: Breakdown of the levelized cost of hydrogen for various hydrogen production scenarios in 2030.

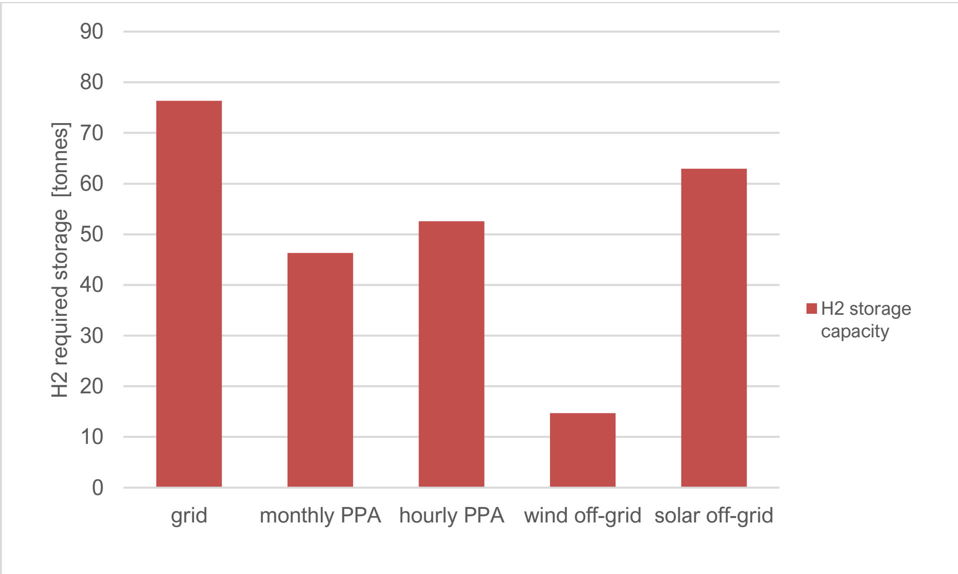

Figure 25: Storage capacity required in each scenario.

By 2030, the maturity of compressed tank technology will not yet be mature enough for an effective capital cost reduction to occur. The requirement of storage was considered in the analysis given the assumption of constant demand, but a less cost-impactful choice might be to deliver hydrogen to end-users only when production is active, thus without the need for storage.

But in the end, considering that in none of the cases is there any real dedicated production (apart from solar PV which, however, cannot be taken as a case study for the country for the reasons described above), the prices are still within the assumed cost curves for this period.

What is also emphasised by the diagram is that the different methods seen each have certain advantages and disadvantages.

Grid-connected electrolysis within the city has pros that include the utilization of existing infrastructure and reducing the need for additional investments. The location flexibility of electrolysis plants also makes it easier to integrate with existing industrial plants or hydrogen distribution networks. However, its cons involve dependence on grid stability which can reduce generation efficiency during disruptions such as power outages or voltage fluctuations.

On the other hand, there is off-grid electrolysis directly at the site of the renewable energy source. Its pros include optimised resource utilisation, greater energy independence, and modular implementation potential. However, its cons involve transport requirements, where hydrogen needs to be transported from remote production sites to end-users, increasing costs.

5.1.1 Grid electricity

The non-constant and highly intermittent hydrogen production from the electrolyser, despite the supply of energy directly from the grid, can be attributed to several factors.

The wind energy sources on which the model is based show an inherent intermittency due to variations in weather patterns. This intermittency leads to fluctuations in electricity generation, resulting in an inconsistent supply of low-emission electricity to power the electrolyser.

Although the system on which the analysis is based is 80% renewable (and the majority leveraged on wind farm generation), the electricity available with a specific emission intensity below 65 gCO_2/kWh is not consistent for there to be constant hydrogen production over time.

It is well known that in Ireland, as in many other regions, wind power production varies significantly throughout the year. During the winter months, there are usually windier weather conditions, with higher wind speeds. During these periods, wind power production tends to be higher. On the other hand, during the summer months, conditions may be less windy, leading to a decrease in wind energy production.

Exactly for this reason, given the long periods when the electrolyser is not working (even months at a time, as can be seen from the power input graph), one strategy could be to switch off the electrolyser during these periods when electricity production from wind power is low.

Also, there is a need to store large quantities of hydrogen in the high-production periods and then release them over time in such a way that the supply and demand curves are exactly equal and are constantly satisfied. Conversely, in the case of non-full storage, but for example with a capacity of two days, the LCOH is lowered to less than half because the $LCOH_S$ is reduced by 96% (from 7.68 €/kg in the case of full capacity to 0.28 €/kg in the case of two days), but the system is not able to satisfy constant demand.

In the end, even though this scenario presents the simplest implementation possibility, without additional infrastructure or logistical costs, it results in the highest LCOH due to this intermittent production.

Figure 26 shows the cumulative development of production versus demand, electrolyser power input and storage development over the year. As can be seen, when the electrolyser has a particularly loaded profile, which generates constant production, the storage fills up. Conversely, when production is low, the storage drains to meet demand.

In the storage graph, you can see how the actual storage curve overlaps with the idealised curve. The tool was modelled to choose between full capacity or two days of capacity. If full storage is chosen, the two curves overlap so that the black remains below the blue. If, on the other hand, a two-day storage capacity is chosen, the blue curve remains below the black curve following a different trend.

This behaviour will also be visible for all subsequent figures since it was decided throughout the study to analyse the various storage technologies at full capacity, which is necessary to ensure that the end-user supply curve is identical to demand and does not instead follow the pure production profile.

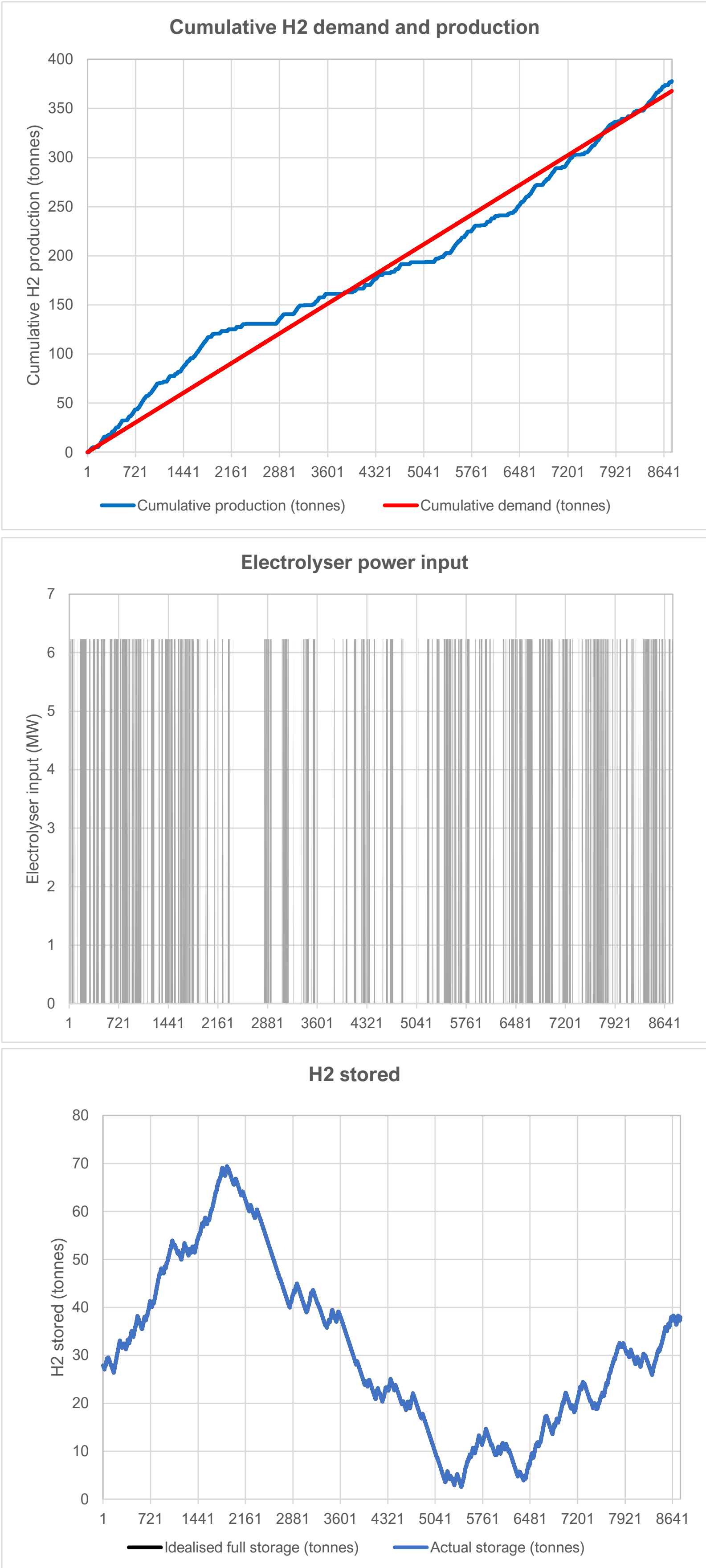

Figure 26: Hydrogen production and storage distribution in case of grid-connected scenario.

5.1.2 Grid connected through PPA

The difference between the production of hydrogen through an electrolyser supplied by a monthly power purchase agreement (PPA) and an hourly PPA from a wind farm lies in the terms of the agreements and the corresponding variability of the power supply.

With a monthly PPA, the supply of electricity from the wind farm to the electrolyser is contracted on a monthly basis. This means that the electrolyser receives a predetermined amount of electricity for hydrogen production each month. Regardless of fluctuations in wind power production in each month, the monthly PPA provides a fixed volume of electricity to the electrolyser. However, this may lead to a variability of production in each month if wind power production varies significantly.

In an hourly PPA, the electricity supply from the wind farm to the electrolyser is contracted on an hourly basis, resulting in a more granular electricity supply. The electrolyser receives electricity from the wind farm in hourly increments, reflecting the actual variations in wind power production throughout the day.

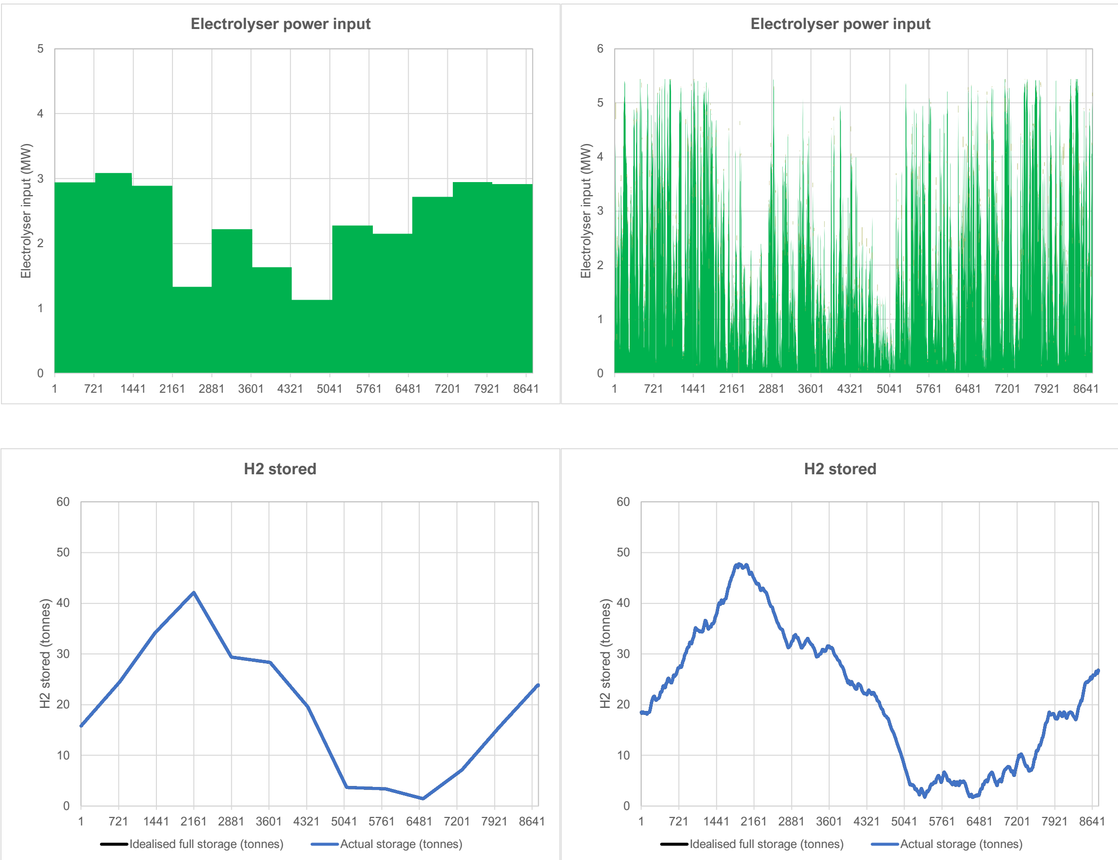

Figure 27: Comparison between monthly and hourly PPA. Electrolyser power input and hydrogen stored.

From Figure 27, it can be seen that while the power input following the hourly PPA has higher peaks, the output of the monthly PPA is more consistent, possibly allowing an electrolyser of only 3 MW instead of 5, which is smaller and still allows demand to be met with a CF of 75%.

The cost also for the 3 MW electrolyser remains about the same and the need for 46 tonnes of storage remains. In the case of monthly PPA, it is lower in fact than the storage required for the hourly one precisely because of the lower intermittency of production.

The greater storage capacity required in the case of hourly PPA slightly raises the cost of storage and of the total LCOH, but in any case, the two cases do not present such substantial differences (8.62 €/kg versus 9.57 €/kg), indicating that the policies do not change the final costs in an impactful manner.

5.1.3 Off-grid onshore wind

Night is the period when the dispatching of wind power is most common due to lower demand.

For this reason, it was imagined that the electrolyser would only be supplied by taking the wind generation that occurs between 11 pm and 8 am.

This leads to a more constant production time, which as can be seen in Figure 28 is only slightly lower than the demand towards the end of the year. This leads to the benefit of having storage with a much lower capacity than in the other cases, thus resulting in the lowest-cost scenario.

A potential solution that is not only cost-effective but also eliminates the need for a large storage area in the city harbour would be to establish a hub at the Mount Lucas wind farm. Assuming the use of compressed tanks with a height of about 25.5 meters, capable of storing 100 m^3 of hydrogen, a minimum storage area of 73.2 m^2 would be needed for the first three scenarios if the hub were to be located within the Port of Galway. In contrast, a storage area of only 23.8 m^2 would be required if the hub were installed at Mount Lucas. This comparison was made possible by examining the specifications of the gas-phase storage vessels that are currently being manufactured and commercialised by Baglioni (baglionispa.com) and calculating the base area of the cylinder required, through the proper equations.

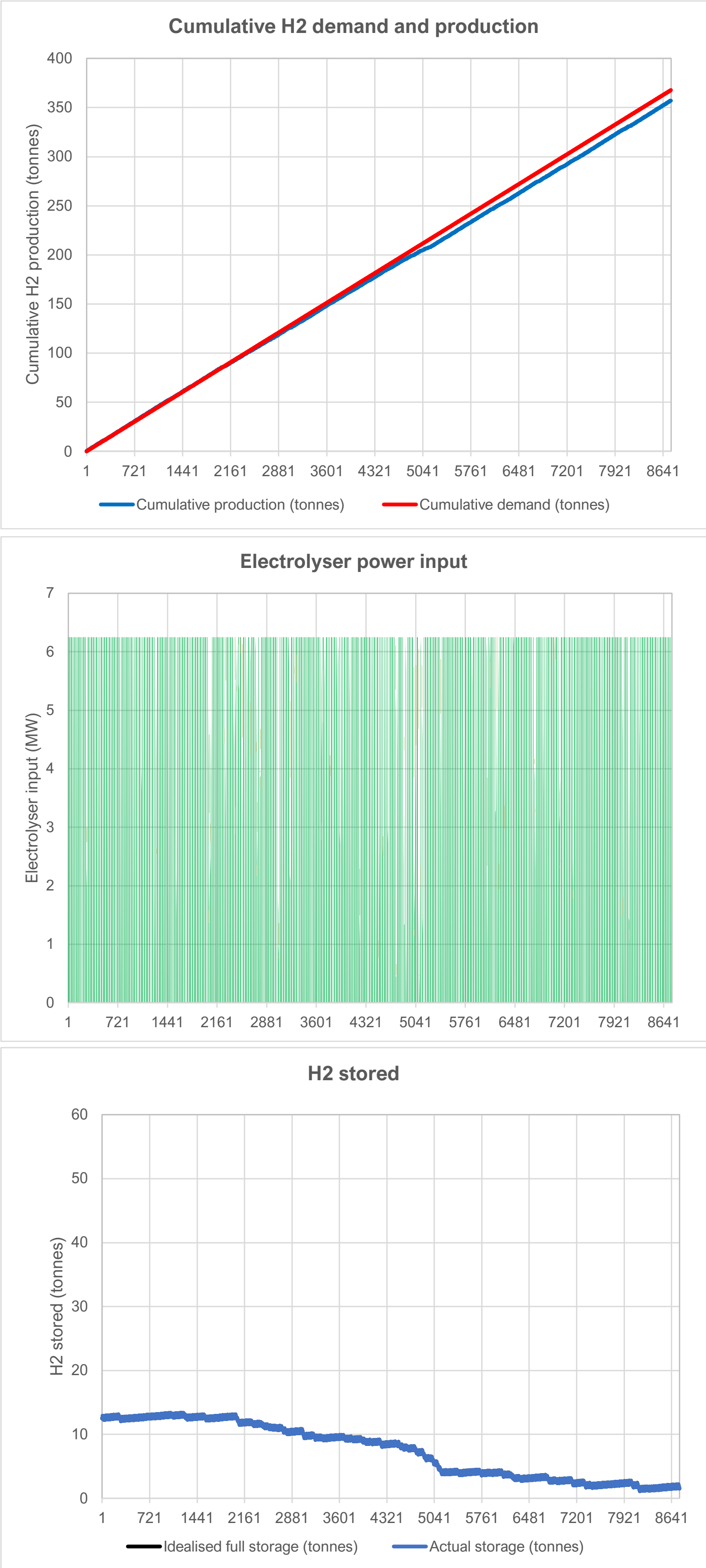

Figure 28: Hydrogen production and storage distribution. Off-grid scenario.

5.1.4 Off-grid solar PV

For this case study the LCOH is 12.87 €/kg of which the major contribution is due to the storage which accounts for 6.55 €/kg.

The hydrogen storage curve of an electrolyser powered by photovoltaic solar energy can provide valuable insights into the seasonal variations in solar energy production as represented in Figure 29.

The minimum and maximum storage points in February and October respectively indicate the corresponding changes in solar irradiation. During the winter months with low solar irradiation, solar PV production is reduced, resulting in minimal hydrogen storage. Conversely, during the summer or high irradiation periods, solar PV production is maximum, and the electrolyser can generate a substantial amount of hydrogen, leading to increased storage.

The seasonal variation in solar energy production, which follows a goniometric curve with the maximum in the summer months, and the minimum during winter, is directly correlated with the changes in hydrogen storage over the year.

As outlined in Chapter 4.1.1, the solar PV capacity factor in Ireland is low due to the country's low irradiation levels. This has a significant impact on the cost of hydrogen production, as storage becomes necessary. With a capacity factor of only 10% for this particular site, the actual energy output is limited compared to the installed capacity. As a result, the solar PV system generates electricity for only a small portion of the time, resulting in lower overall energy production than systems located in regions with higher irradiation levels.

Because of the low energy production, the entire installed capacity must be dedicated to hydrogen production to meet the demand for a 5 MW electrolyser. To ensure a constant supply of hydrogen to end-users despite the intermittent nature of solar PV generation, storage solutions become vital, increasing the overall cost of hydrogen production. Large-scale storage systems can be expensive to install and maintain, further contributing to the final cost of hydrogen production.

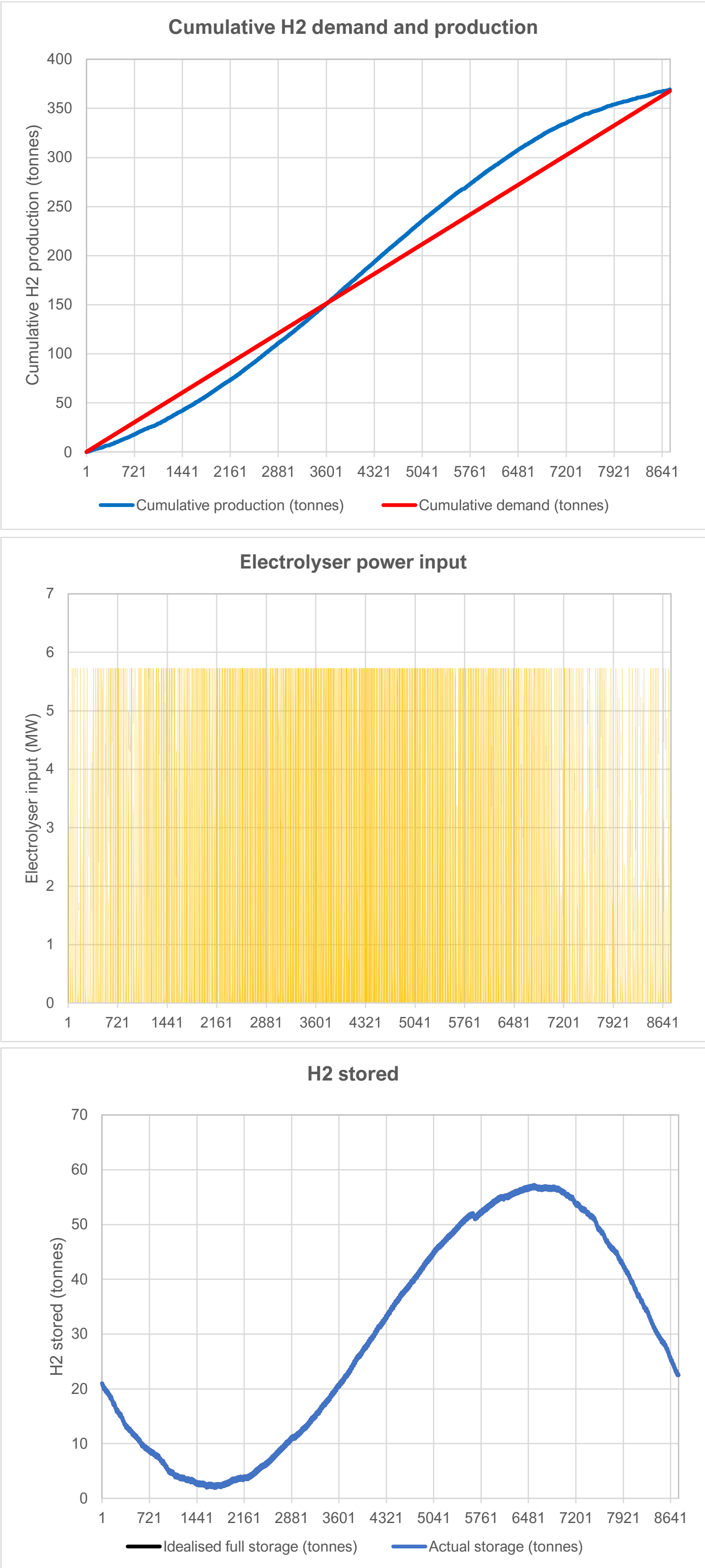

Figure 29: Hydrogen production and storage distribution solar PV scenario.

5.1.5 End Considerations

Best/worst case comparison

When analysing the three scenarios with the lowest LCOH, in Table 13 the best case is associated with the worst case, meaning the highest electricity price and specific electrolyser CAPEX. This emphasizes the critical role these costs play in determining the final levelized cost of hydrogen.

The cost of electricity directly affects the operating costs of hydrogen production by electrolysis, while the specific capital expenditure of the electrolyser represents the initial investment required to purchase and install the equipment. A lower specific CAPEX for the electrolyser reduces the cost of the initial investment, leading to lower overall hydrogen production costs. Conversely, a higher specific CAPEX results in higher production costs over the life of the electrolyser.

The significant difference of about 4 €/kg in LCOH between the two cases highlights the substantial impact these cost factors have on the economic feasibility of hydrogen production.

The difference between electricity prices and electrolyser capital costs is a crucial factor in the economics of hydrogen production. Even small changes in these parameters can significantly impact the overall cost of hydrogen.

This underscores the importance for stakeholders to fully understand and manage the risks associated with such fluctuations when making investment decisions. Policymakers and industry leaders must also take into account the implications of these factors on the scalability and deployment of hydrogen production infrastructure. Encouraging the adoption of renewable energy, promoting innovation and economies of scale to reduce electrolyser costs, and establishing stable regulatory frameworks can all play a vital role in supporting the development of a cost-competitive hydrogen economy.

Table 13: Best and worst case comparison impacting on LCOH.

	Grid-connected monthly PPA (Galway Wind Park 174MW scaled)	***Grid-connected hourly PPA (Galway Wind Park 174MW scaled)***	***Off-grid (Mount Lucas wind farm 84MW)***	
Worst	12.72	13.68	13.49	*€/kg*
Best	8.62	9.57	8.48	*€/kg*

Emissions produced

According to Figure 30, the carbon intensity of the hydrogen produced in the first case is notably higher than the others. This disparity is attributed to the reliance of this scenario on grid electricity. Nonetheless, to classify the hydrogen as "green," the model was designed to solely utilize electricity emitting less than 65 kgCO2/MWh.

In contrast, scenarios powered by purely renewable sources are inherently zero carbon.

All scenarios produce hydrogen with an intensity below the RED II limit for low-carbon hydrogen, which is 3.38 kgCO2/kgH2 [53].

These findings underscore the complex interplay of various factors in determining the environmental impact of a hydrogen hub, including the carbon intensity of the electricity used for electrolysis, and the emissions associated with transportation.

Particularly in off-grid scenarios far from end-users where transportation emissions, including those from FCEVs, contribute to the overall carbon footprint proportionally to the distance.

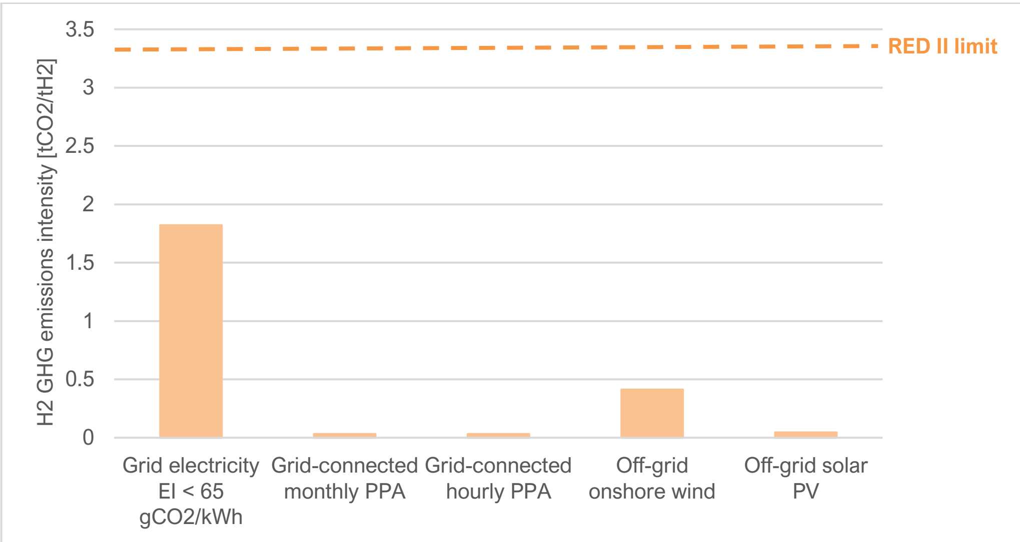

Figure 30: Specific carbon intensity of the hydrogen produced for each 2030 scenarios.

5.2 Analysis of 2040 Scenarios Outcomes

The cost of electricity is a significant factor influencing the overall cost of electrolysis and thus the final levelized cost of hydrogen. Elevated electricity prices lead to increased energy expenses for electrolysis, which raises the total cost of hydrogen production.

Electrolysis by definition is a process that divides water into hydrogen and oxygen using electricity. The expense structure of electrolysis is heavily influenced by the cost of electricity, which accounts for a significant portion of the total operating costs as can be seen in Figure 31.

Electrolysis is frequently promoted as a crucial technology for green hydrogen production, using renewable energy sources like solar or wind power. The feasibility of hydrogen production through electrolysis is dependent on the cost of renewable electricity compared to regular fossil fuel-based electricity. Lower prices of electricity from renewable sources improve the economic potential of electrolysis, making green hydrogen more competitive in the market.

Since electricity costs make up a significant part of electrolysis costs, changes in electricity prices have a direct impact on LCOH. Higher electricity prices result in higher LCOH values, which makes hydrogen production less cost-effective.

In the specific case of bottom-fixed offshore wind as a source of electricity in Ireland, where electricity prices are expected to vary between 40€/MWh and 80€/MWh by 2040, these variations will significantly affect the cost of hydrogen production through electrolysis. Lower electricity prices reduce the energy costs of electrolysis, resulting in lower LCOH values and increased competitiveness of hydrogen produced by electrolysis.

As can be seen in one such case in Figure 31, it reaches a value of €4.68/kg, making it only slightly higher than the price of oil.

In particular, the final hydrogen production costs for the best case are comparable and in line with other studies on green hydrogen from offshore sources. [17], [18]

Conversely, higher electricity prices would increase the operating costs of electrolysis, leading to higher LCOH values and potentially affecting the economic viability of hydrogen production projects.

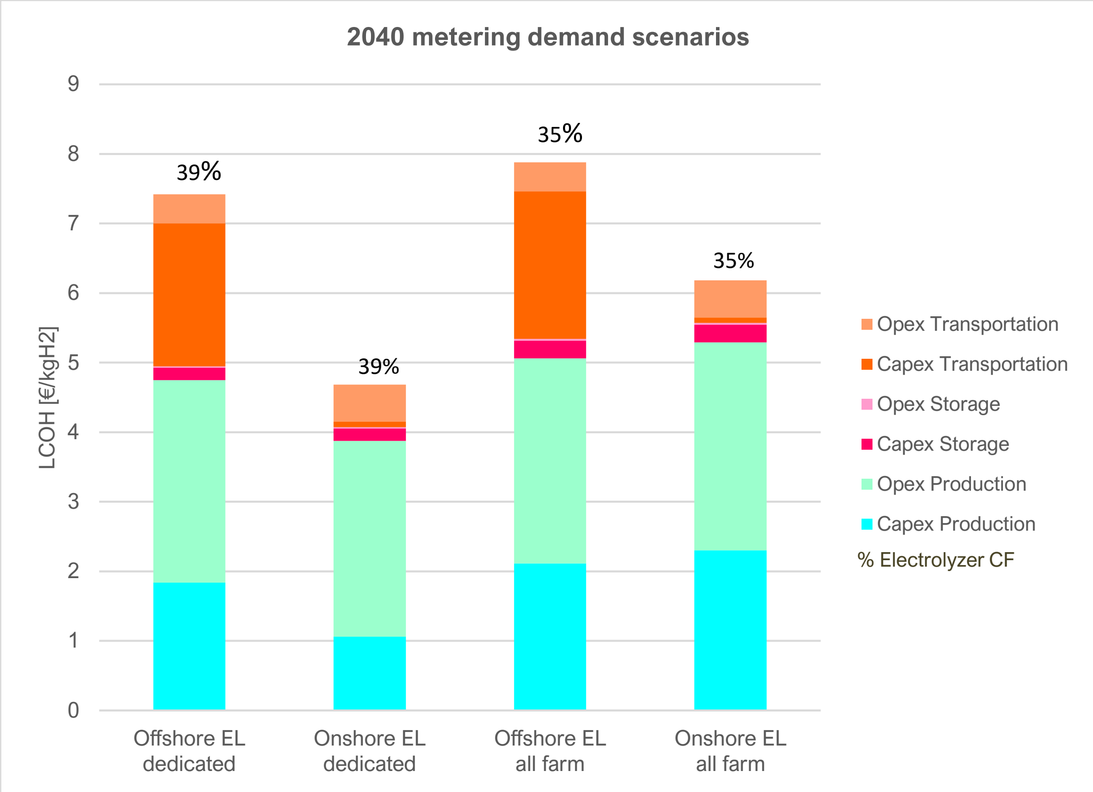

Figure 31: LCOH breakdown for various hydrogen production scenarios for 2040.

When considering the storage of large quantities of hydrogen, several factors come into play when comparing liquid hydrogen tanks and high-pressure tanks for compressed hydrogen.

In general, liquid hydrogen tanks are more economical for storing large quantities of hydrogen: in the case of dedicated production where 250 tonnes need to be stored the specific storage CAPEX is around €12/kg while for the all-farm scenario where the H2 storage capacity is of 54 tonnes the specific investment cost increases to €77/kg due to the scale factor whereby smaller tanks require a higher capital expenditure.

In the end, however, the percentage associated with the storage costs within the final LCOH can be purchased due to the different quantity that needs to be stored and, as can be seen from the figure, the contribution of storage is very small compared to the 2030 cases.

The reason for this is that liquid hydrogen tanks operate at lower pressures, and do not demand the same level of structural reinforcement and safety measures as high-pressure tanks. Additionally, liquid hydrogen has a greater volumetric energy density than compressed hydrogen gas, making it possible to store larger amounts of hydrogen in a given volume of storage tanks.

However, while liquid hydrogen may offer benefits in terms of transportation due to its higher energy density, it necessitates the use of specialized cryogenic infrastructure and tanker trucks, which can add to the overall cost of transportation.

In the case of offshore electrolysis, the installation of an underwater hydrogen pipeline that can transport liquid hydrogen affects LCOH by almost €2/kgH2.

5.2.1 Dedicated H2 production

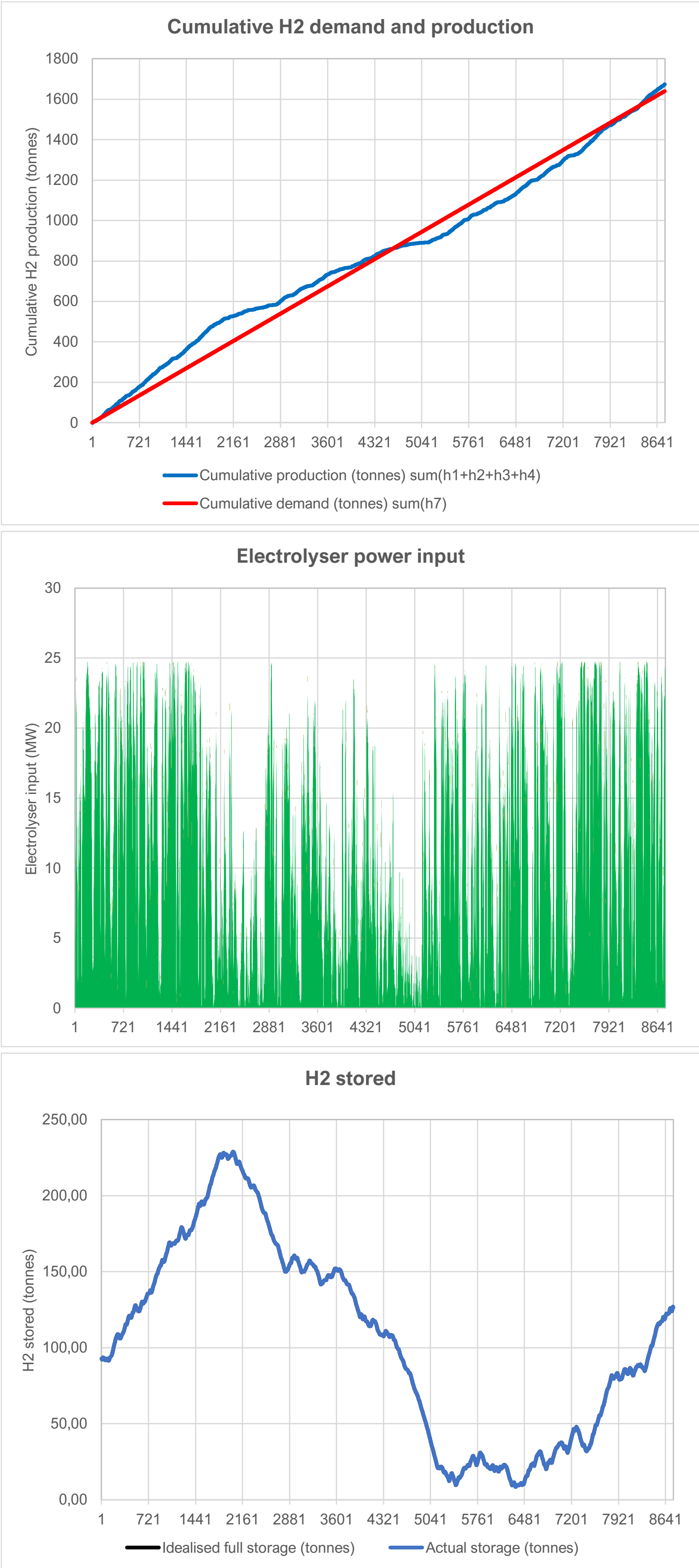

Figure 32: Hydrogen production and storage distribution Sceirde Rocks dedicated.

While studying dedicated production, where the wind power plant is scaled to the needs of the electrolyser (reducing the capacity from 450 MW to 25 MW and dedicating only three turbines exclusively to hydrogen production), the production profile follows the availability of wind according to seasonality, as displayed in Figure 32. As the wind system is scaled to completely fill the electrolyser, hydrogen storage is very high. During the early months of the year, when wind availability is high, the power input of the electrolyser is almost fully utilised to produce hydrogen, thus filling the storage. However, during the summer months, when wind availability decreases, the power input of the electrolyser decreases accordingly, causing a decrease in hydrogen production and a consequent reduction in storage filling. This seasonal, scaled-up production profile is characteristic of dedicated hydrogen production systems that rely on wind power as the primary source.

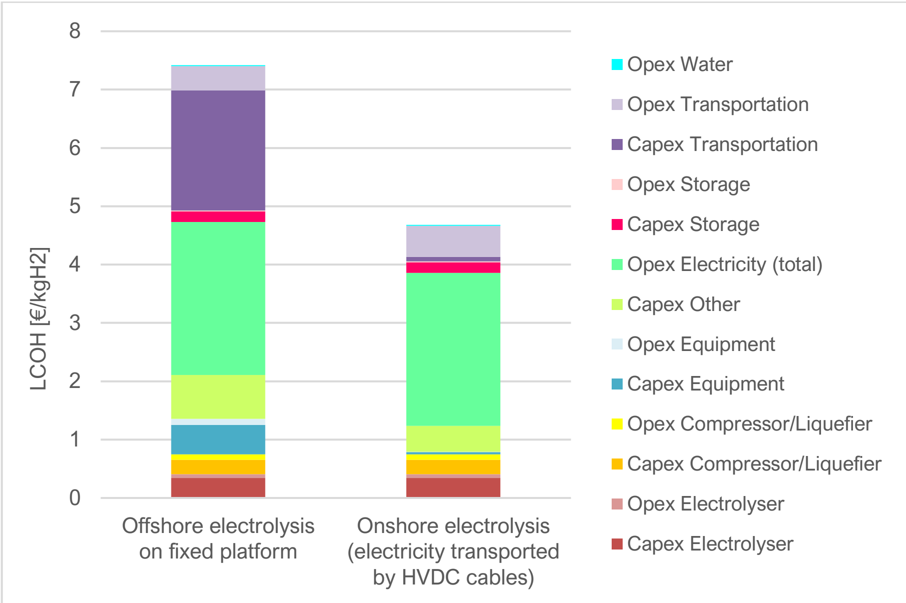

Figure 33: Detailed breakdown of the cost for dedicated hydrogen production of Sceirde Rocks.

Comparing the two cases of offshore and onshore electrolysis in Figure 33, significant differences in overall costs emerge. In both cases, the costs for the electrolyser, liquefaction, storage and electricity are equivalent. However, offshore electrolysis results in a higher LCOH due to the additional costs associated with transporting hydrogen via subsea pipelines, as well as the need for a fixed offshore platform, which affects equipment costs significantly. Furthermore, the need for a fixed offshore platform introduces additional costs associated with its installation, maintenance and operation over time. On the other hand, in the case of onshore electrolysis, higher operating costs (OPEX) arise concerning the transport of liquefied hydrogen by trailer. These higher operating costs arise from the need to use trailers for the onshore transport of liquefied hydrogen, which entails higher maintenance and operating costs than subsea transport methods.

5.2.2 Night time H2 Generation

This overnight production approach using the entire capacity of the wind farm seems to guarantee more constant production with a higher capacity factor. These data suggest that the best strategy to optimise hydrogen production from all farm during off-peak hours would therefore be to directly switch off the electrolyser during the day.

As can be seen in Figure 34, the production and demand curves are almost perfectly overlapping, as a result, less storage capacity is required, which saves useful space if storage has to be installed directly on the offshore platform.

It can be seen, for example, that in the case where the electrolyser is 27MW, the maximum power input is around 34MW. This is because an additional percentage for compression/liquefaction and transportation of 24% is taken into account in this case.

Adding a percentage for hydrogen compression, liquefaction and transportation is a common practice when evaluating power requirements for the electrolyser. This approach takes into account the additional energy consumption required to produce, process and transport the hydrogen to the point of final use. In this way, a more accurate estimate of the overall energy requirement of the hydrogen production system is obtained.

This percentage calculated from the specific electricity consumption for the electrolyser, compression, liquefaction and transport is a reasonable estimate to account for these additional processes. However, it is important to note that it varies depending on the specifics of the plant, the technologies used and the operating conditions.

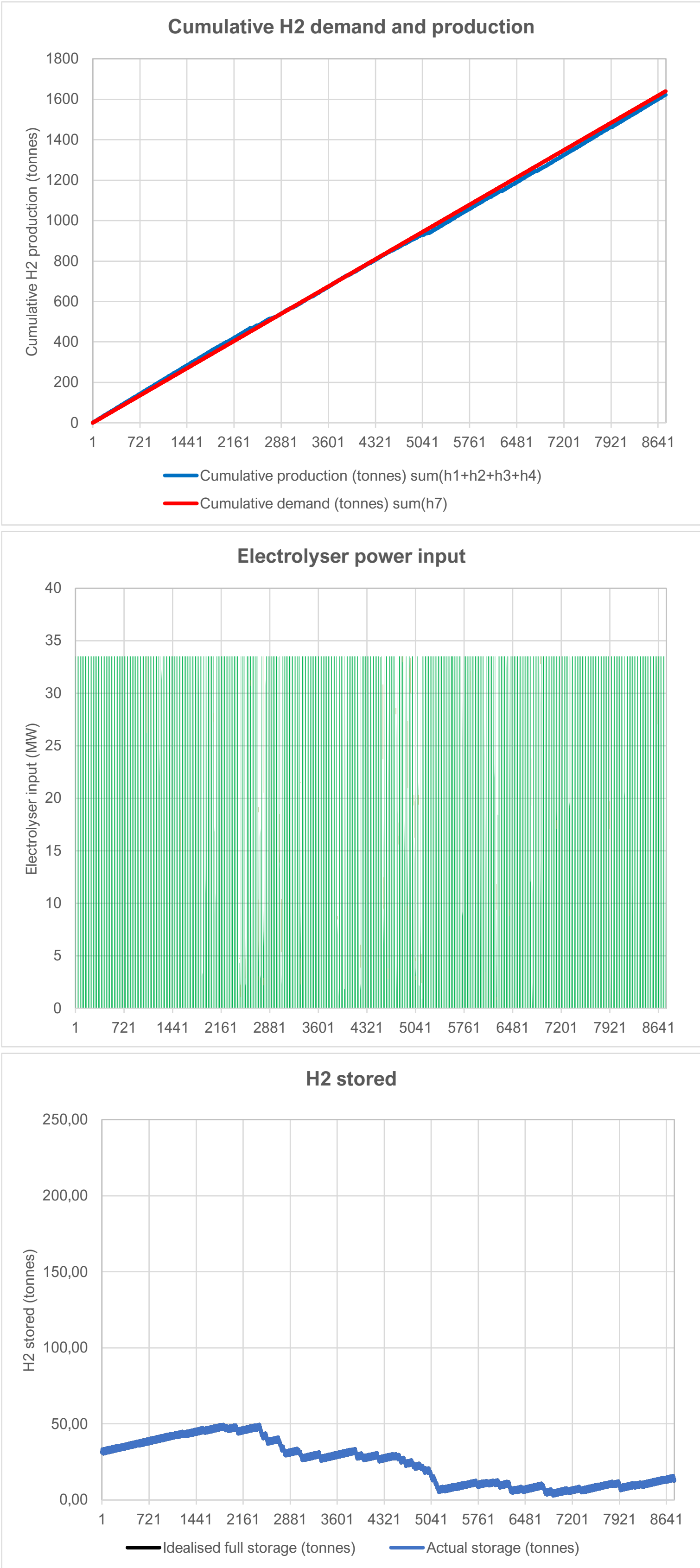

Figure 34: Hydrogen production and storage for Sceirde Rocks all farm at night time.

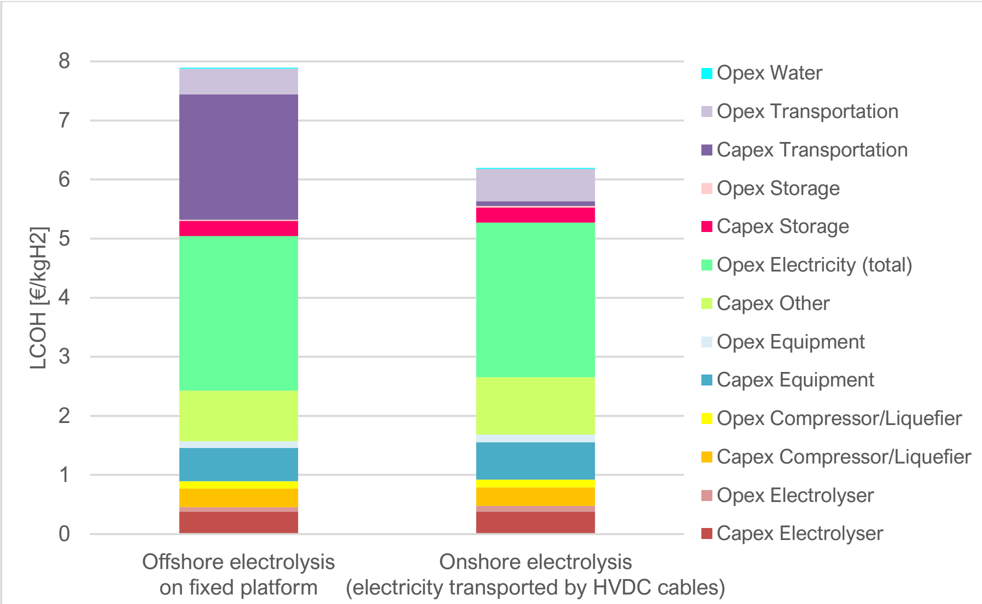

Figure 35: Detailed breakdown of the cost for all farm hydrogen production Sceirde Rocks.

While the offshore electrolysis case has comparable costs to the previous case (comparing Figure 34 and Figure 35), for onshore electrolysis in the case where the 27 MW electrolyser receives electricity only during the night, using the entire capacity of the wind farm, there is an increase in costs compared to the previous scenario of dedicated hydrogen production, where only a few turbines (total 25 MW) are used to power the electrolyser.

This cost increase is mainly due to the higher cost of HVDC cables and the onshore substation for electricity conversion when the entire plant capacity is considered, compared to transporting only the electricity produced by a few turbines. In this scenario, equipment costs exceed those associated with offshore hydrogen production via a dedicated platform.

On the other hand, the costs of the production plant vary only slightly, as the electrolyser increases from 25 to 27 MW, but this does not significantly affect the overall costs.

5.3 Analysis of 2050 Scenarios Outcomes

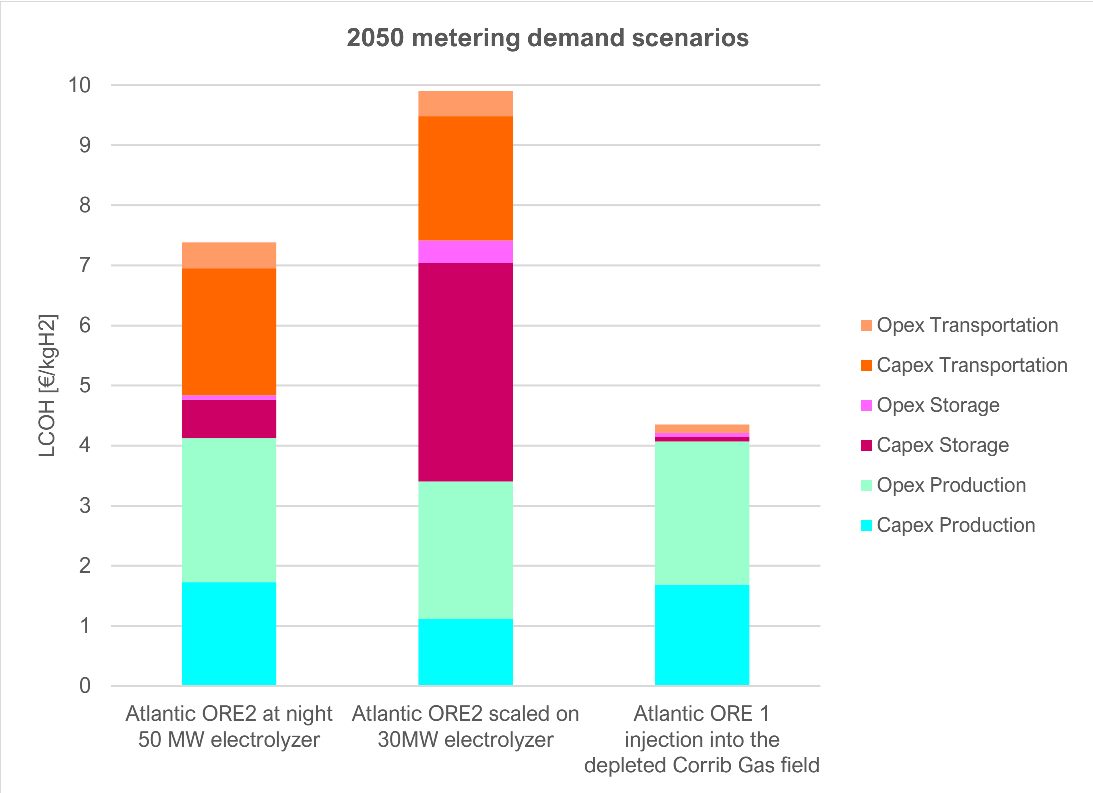

Figure 36: LCOH breakdown for various hydrogen production scenarios in 2050.

Upon analysing the graph in Figure 36 it becomes evident that the price of electricity will continue to have a significant impact on the LCOH even in 2050, particularly in the case of floating wind where it remains high in both the best and worst-case scenarios (that is not reported graphically).

Another point is that since they are all offshore production methods, the production CAPEX is also quite high due to the need for a platform to place the electrolyser, compressor, and storage.

Notably, in the second case, the initial investment for storage alone accounts for one-third of the final cost.

Table 14: Interesting TEA output.

		Atlantic ORE2 scaled on 30MW electrolyser	Atlantic ORE2 at night 50 MW electrolyser	Atlantic ORE1 at night 50 MW electrolyser
Total electricity consumed	MWh	175933.17	170491.76	166520.06
Annual water consumption	m3/year	49488.04	48346.92	47762.42
H2 storage capacity	tonnes	344.29	53.95	101.10

Total electricity consumed and annual water consumption for producing and storing green hydrogen from renewable sources, such as offshore wind, are related to several factors that can influence these figures.

The efficiency of the electrolyser, which converts electricity and water into hydrogen and oxygen, has a significant impact on the amount of electricity consumed and water used in the process. In all cases, the capacity factor of the electrolyser is around 30/40%. In the two overnight production cases, the power input profile is more constant with a CF of 37%, so the total electricity required to meet demand is also lower.

The hydrogen compression process and its storage may require additional energy and water for cooling and treatment of the hydrogen. The energy required for compression in the case of compressed hydrogen tanks at 300 bar is greater than in the case of storage within the depleted gas field where hydrogen is injected at approximately 120 bar.

However, thanks to the choice of comparable technologies, the numbers in Table 14 do not differ much, except for the amount of hydrogen that needs to be stored and the chosen method that greatly influences the final LCOH.

The following sub-sections will delve into a detailed breakdown of costs.

5.3.1 Atlantic ORE 2

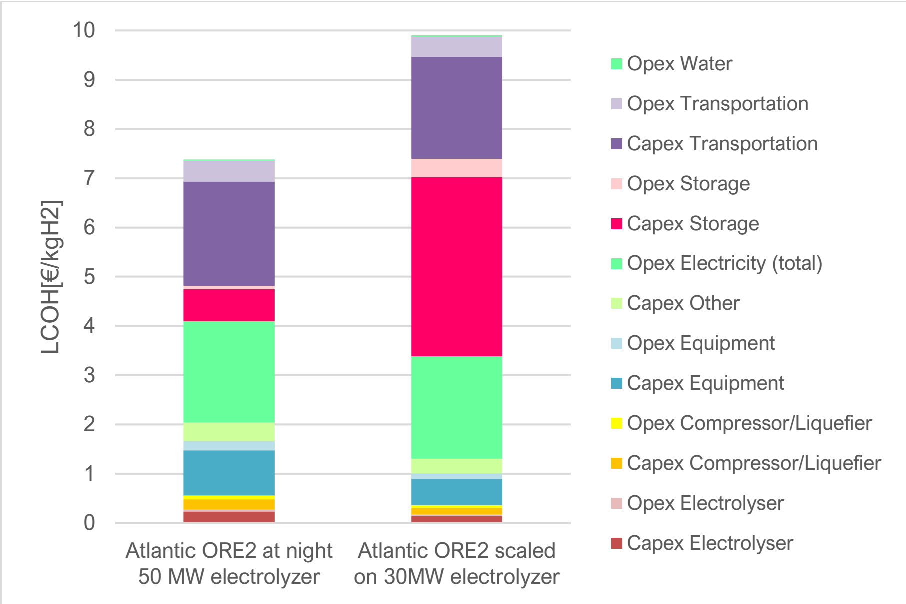

Figure 37: Detailed breakdown of the cost for hydrogen production Atlantic ORE 2.

The cost of electricity plays a crucial role in determining the economic competitiveness of hydrogen production, especially when using offshore wind technologies as in this case.

The initial investment for installing dedicated platforms to position the electrolyser, compressor and hydrogen storage is proportional to the size of the electrolyser. It is higher in the case of a 50MW electrolyser.

The production, electrolyser power input and storage profiles are comparable to those presented above for related cases, so are not shown graphically.

The cost of storage in the case of dedicated production is very high since a large quantity of hydrogen must be stored due to the intermittency of production. The selected method (compressed tanks) has a high specific CAPEX so increasing the quantity also increases proportionally.

Therefore, the choice of using compressed tanks as storage is not the best, since in addition to the high cost, they would require a very bulky and heavy infrastructure to be placed above the offshore platform.

The alternative solution of storing hydrogen in the form of LH_2 would result in a substantial reduction in both the associated cost and the volume of space required, but one must consider the fact that the plant and electrolyser must be scaled back to a higher capacity to compensate the amount of electricity used for liquefaction.

5.3.2 Atlantic ORE 1

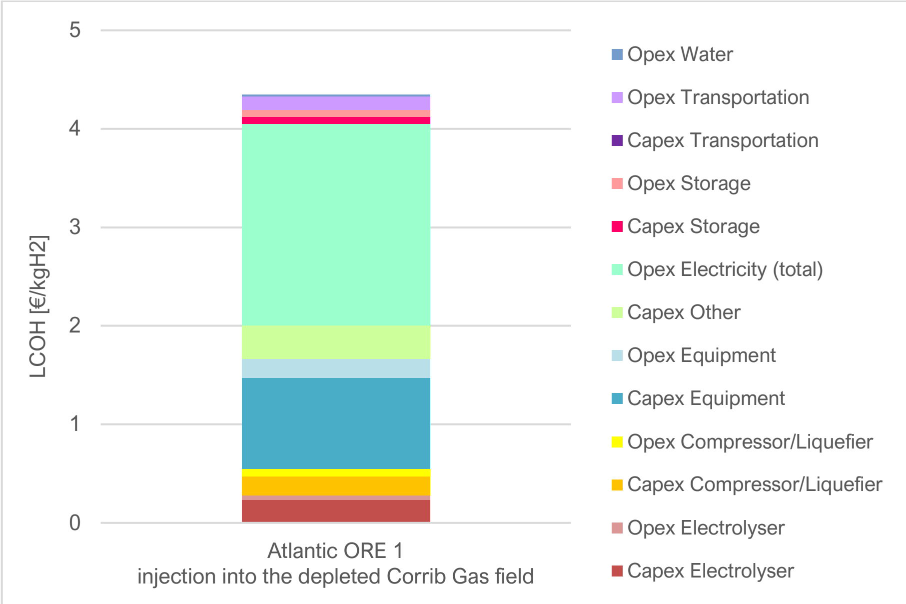

Figure 38: Detailed breakdown of the cost for all farm hydrogen production Atlantic ORE 1.

As described earlier in Chapter 4.1.3 in this scenario, a 50 MW electrolyser is placed on an offshore platform together with water desalinisation system and compressor station. These components make up roughly half of the LCOH, which is also heavily influenced by the cost of the renewable source of electricity required for the process.

The Corrib gas field provides an excellent storage method with minimal associated costs, and production and storage adhere to all physical limits of reservoir utilisation. Hydrogen is transported to Galway via an existing natural gas pipeline, which incurs only operating and maintenance costs without any initial investment costs.

Although there is no dedicated hydrogen production, RES is utilised for both hydrogen production during the night and electricity during the day. Therefore, the LCOH may not be as low as expected for 2050, but it is still in line with projections from other studies. This price makes green hydrogen a competitive alternative to other fossil fuels, especially considering the price increase they will experience to address climate change.

5.4 Chapter Summary

The graphical results obtained within this project are presented above. Different scenarios with different production, storage and transport methods were calculated and discussed, all of which met the required hydrogen demand for each decade.
A value of around 4€/kg for green hydrogen could be considered affordable, especially when compared to the current and forecast future costs of fossil fuels and grey hydrogen. If the right conditions are met, this value of LCOH or even lower can be achieved, but this depends on the availability of enough wind energy to power the electrolyser in a sufficient and effective manner, a cheap storage method and effective transport that does not require too many infrastructure and maintenance costs.

6. Conclusions

This master thesis project aims to assess the feasibility of green hydrogen production in meeting Galway's future energy needs. During periods of high-power generation, the many wind farms in Ireland often have to shut down operations as the grid is at maximum capacity and cannot absorb additional amounts of electricity without overloading. By limiting this power, both economic and carbon abatement benefits are lost. This renewable energy can then be used to produce a new energy carrier: green hydrogen.

The study starts by analysing the energy requirements of the region, moving on to the calculation of Galway's hydrogen demand.

The TEA tool was applied to several 'hydrogen hub' case studies in the County Galway area, where eleven scenarios were modelled for 2030, 2040 and 2050.

The two main projects for the creation of SH_2AMROCK, Ireland's first hydrogen valley aiming at the production, storage and distribution of green hydrogen, are compared. Initially, the project was to be located within the Galway harbour, now it is planned to be located in Mount Lucas, directly within the wind farm.

The research integrates other renewable energy sources and conducts a comprehensive techno-economic analysis of three hydrogen generation methods: grid-connected configuration, grid integration of renewable energy and off-grid electrolysis. The investigation assesses the advantages and disadvantages of hosting the electrolyser within the city versus off-grid configuration at various renewable energy sites, considering the policies outlined in the Irish hydrogen strategy.

The research aims to determine the most sustainable and cost-effective combination of renewable energy sources to meet Galway's hydrogen needs, considering factors such as the levelised cost of hydrogen and greenhouse gas emission intensity, which are the main outputs of the analysis.

Table 15: Optimum scenarios for each decade.

Year	Technology	LCOH [€/kgH2]	Electrolyser size [MW]	Electrolyser strategy	Storage method	Distance to the end user [km]	Transport method
2030	Onshore wind	8,48	6	off-peak electricity H2 production only at night time (23/8)	compressed tanks	151	compressed tube trailer
2040	Bottom fixed offshore wind	4,68	25	dedicated H2 production: wind farm scaled on the electrolyser size and onshore electrolysis	liquid tanks	39	liquid tube trailer
2050	Floating wind	4,35	50	off-peak electricity H2 production only at night time (23/8)	geological underground storage	90	existing NG pipeline

In this project, it was shown that the most cost-effective method of producing green hydrogen is generally an off-grid scenario that relies on wind power. Depending on the reference year, wind power technology varies, and the electrolysation strategy exploits either the generation of only part of the turbines, which are then dedicated exclusively to hydrogen production, or the utilisation of the entire plant capacity, but only taking electricity at night, when consumer demand is lowest.

The LCOH for 2030 varies from 8.48-13.52€/kgH2, this is due to the prohibitive cost of compressed hydrogen storage needed in the case of intermittent production during the year present in most of the scenarios analysed. The highest cost is associated with the grid-connected case for which results show that green hydrogen could be produced directly from grid electricity bought from the wholesale market imposing a control on the emission intensity value of the electricity allowing the definition of green hydrogen. This limitation, however, imposes intermittent production with the consequent need to store hydrogen in times of surplus to meet demand when production is stagnant or scarce. However, an advantage of this option is having the production and storage hub directly next to the end-users.

Conversely, for the more performant case, the need to transport hydrogen from the production site right at Mount Lucas to Galway impacts the final LCOH by increasing the cost by 2.5€/kgH2. These considerations provide insight into how locating a wind farm closer to the city that can be utilised according to the strategies analysed in this research would enable the production of green hydrogen at a lower and competitive cost as early as 2030 compared to other fossil fuels.

For 2040, the LCOH ranges from 7.89-4.68€/kgH2, with the electricity supply being identified in an offshore wind farm. Two scenarios were analysed: production and storage hub located on an offshore platform or on the coast (the former requiring a pipeline to transport hydrogen to the city and the latter a subsea HVDC cable infrastructure to transport the electricity to the onshore electrolyser). Two different electrolysis strategies were also considered whereby only off-peak electricity is taken from the entire farm and production occurs only at night time (23/8) or dedicated production with the wind farm scaled on the electrolyser size. Using liquid hydrogen to store large quantities of hydrogen becomes cost-effective.

Using the entire capacity of the wind farm for onshore electrolysis during the night increases costs compared to using only a few turbines. The cost increase is due to the higher cost of HVDC cables and the onshore substation for electricity conversion when the entire plant capacity is considered.

In the case of dedicated production, the two cases of offshore and onshore electrolysis, have significant differences in overall costs. Offshore electrolysis results in higher costs due to the need for subsea pipelines for hydrogen transportation and fixed offshore platforms, which increase equipment, installation, maintenance, and operation costs.

Results show that hydrogen produced on an offshore platform, stored underground in a depleted gas field, and supplied to the natural gas grid through the existing infrastructure has an LCOH of €4.38/kgH2 in 2050.

The Corrib gas field provides an excellent storage method with minimal associated costs, hydrogen is transported to Galway via an existing pipeline, which incurs only operational and maintenance costs with no upfront investment costs. Although there is no dedicated hydrogen production, renewable energy is used for both hydrogen production during the night and electricity during the day. Therefore, the LCOH may not be as low as might be expected by 2050, but it is still in line with projections of other studies.

Achieving a levelised cost of affordable hydrogen depends on several key conditions being met. First, there must be an ample supply of renewable energy to constantly power the electrolyser. Furthermore, it is essential to implement an economical storage method to ensure the efficient utilisation of the hydrogen generated. Furthermore, it is essential to establish an effective transport system that minimises infrastructure and maintenance costs. By meeting these requirements, it becomes feasible to achieve a competitive LCOH, making green hydrogen a viable and sustainable energy option for the future. However, it is imperative to comprehensively address these challenges to realise the full potential of hydrogen production.

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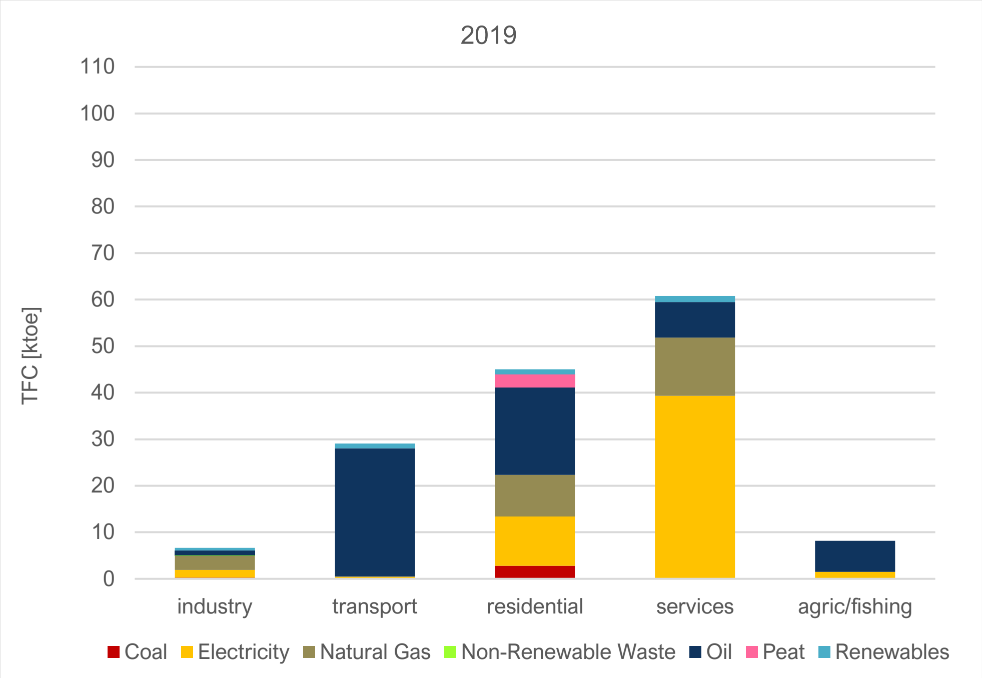
Appendix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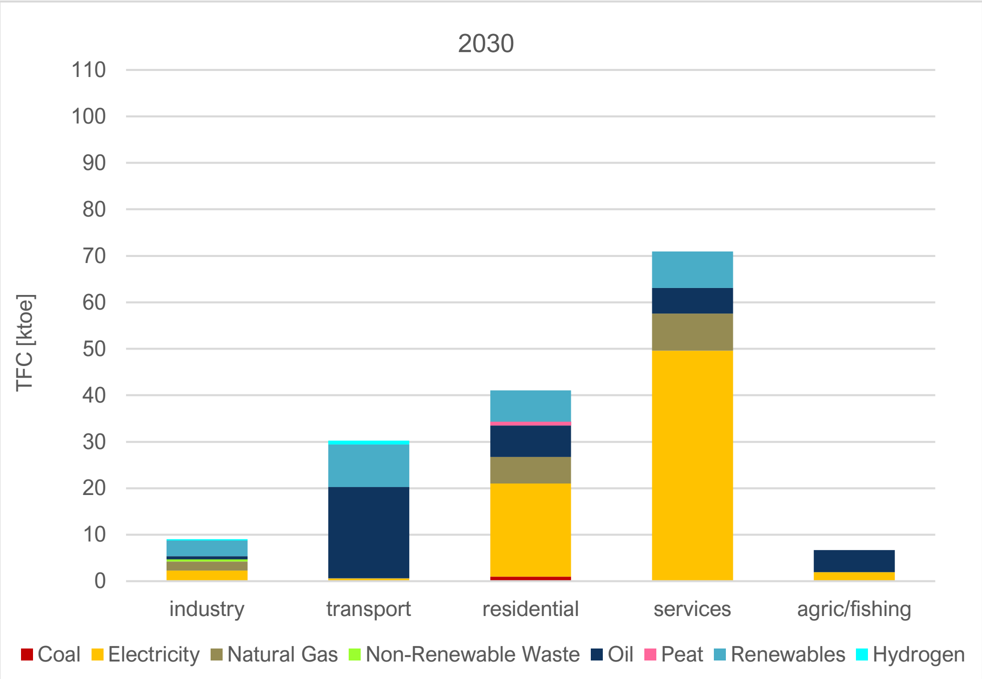
Renewables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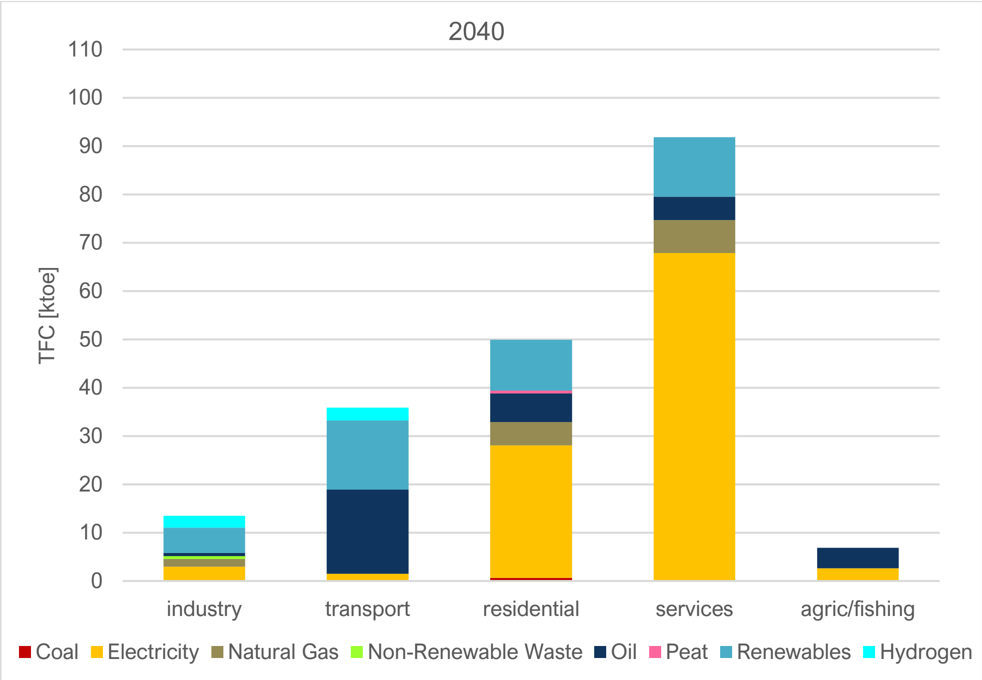

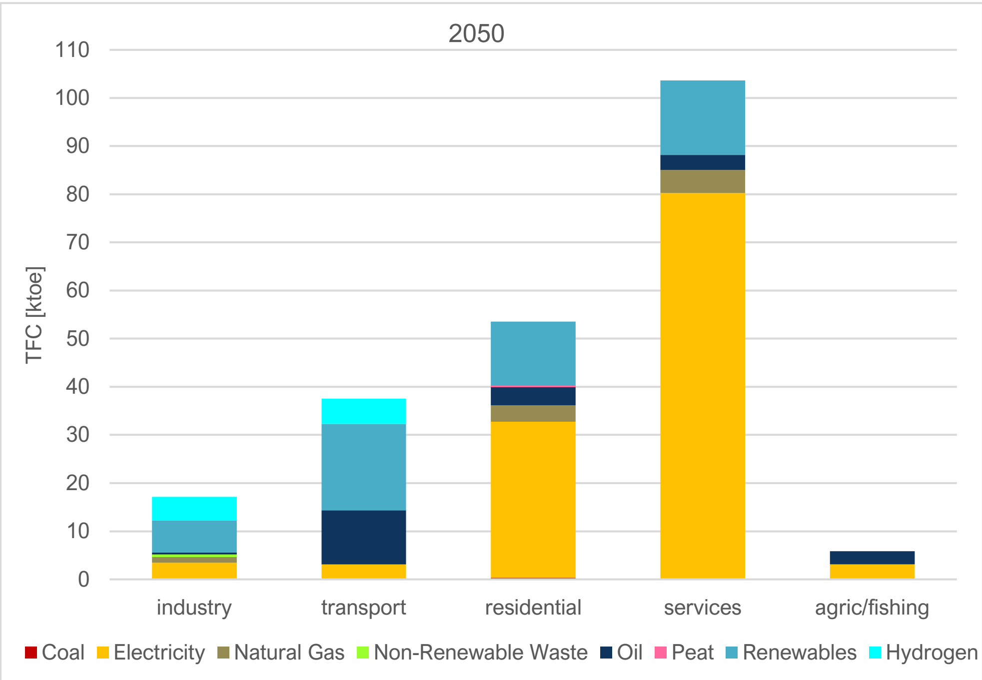

Figure 39: Energy mix comparison within Galway City consumption projections.

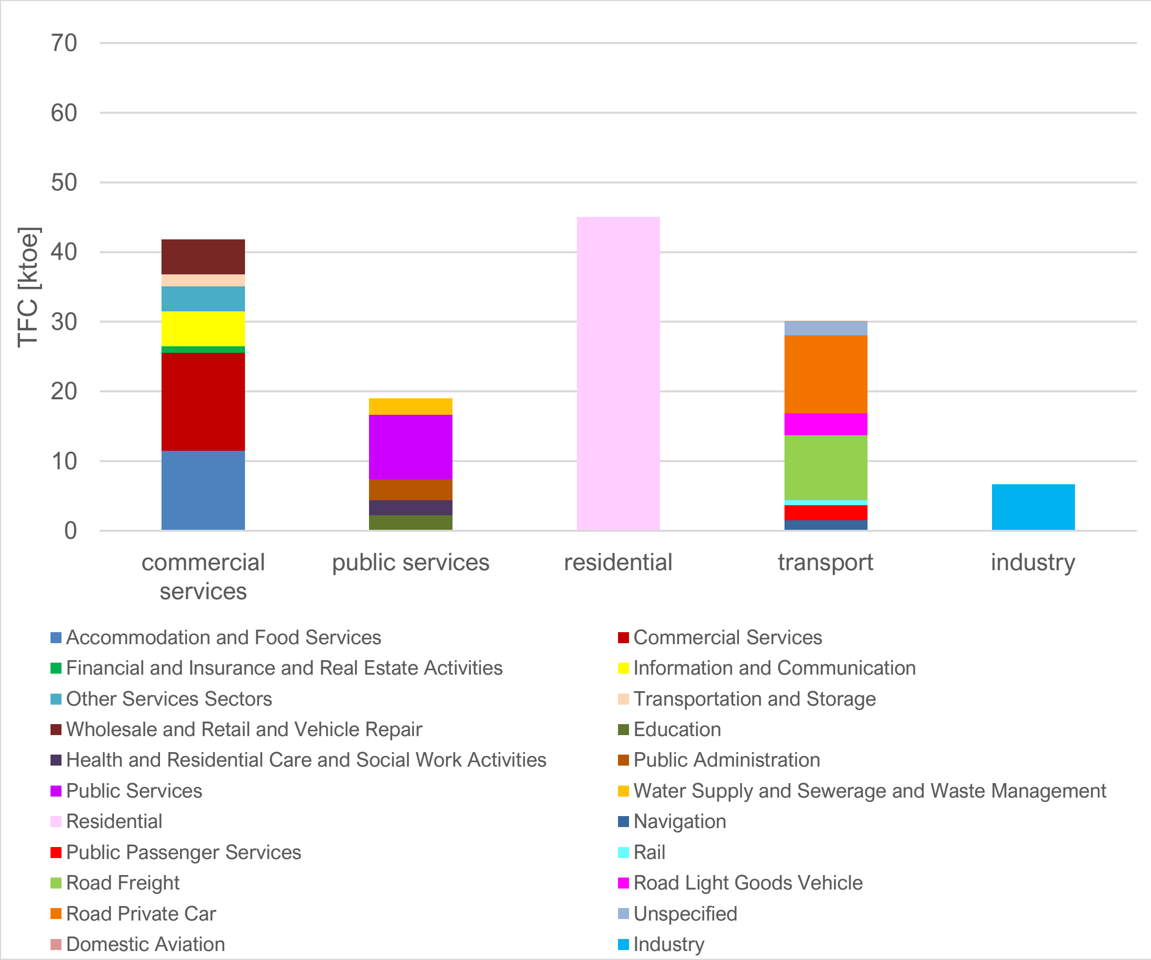

Figure 40: Subdivision of the total final consumption into specific sectors in Galway.

Table 16: Summary of relevant information of the eleven scenarios modelled.

n°	Scenario	Year	Electrolyser capacity [MW]	H2 storage method	Distance to end user [km]	H2 transport method	Electricity provider	Electrolyzer strategy
1	Grid electricity EI < 65 gCO2/kWh	2030	5	compressed tanks	0	none	wholesale electricity market	GHG emission intensity control
2	Grid-connected monthly PPA	2030	5	compressed tanks	0	none	onshore wind farm (Galway Wind Park 174 MW)	dedicated scaled
3	Grid-connected hourly PPA	2030	5	compressed tanks	0	none	onshore wind farm (Galway Wind Park 174 MW)	dedicated scaled
4	Off-grid	2030	6	compressed tanks	151	compressed tube trailer	onshore wind farm (Mount Lucas Wind Farm 84 MW)	off-peak electricity H2 production only at night time (23/8)
5	Off-grid	2030	5	compressed tanks	70	compressed tube trailer	solar PV farm (Ballymoneen Solar 100 MW)	dedicated H2 production
6	Off-grid	2040	25	liquid H2 storage	38	liquified tube trailer	bottom fixed offshore wind (Sceirde Rocks 450 MW scaled on 25 MW electrolyzer)	dedicated hydrogen ONSHORE ELECTROLYSIS in Rossaveel (HVDC cables for electricity needed)
7	Off-grid	2040	25	liquid H2 storage	50	hydrogen pipeline	bottom fixed offshore wind (Sceirde Rocks 450 MW scaled on 25 MW electrolyzer)	dedicated hydrogen OFFSHORE ELECTROLYSIS (requires platform and desalination unit)
8	Off-grid	2040	27	liquid H2 storage	38	liquified tube trailer	all 450 MW Sceirde Rocks provide electricity only at night time (23/8)	both electricity and hydrogen production ONSHORE ELECTROLYSIS
9	Off-grid	2040	27	liquid H2 storage	50	hydrogen pipeline	all 450 MW Sceirde Rocks provide electricity only at night time (23/8)	both electricity and hydrogen production OFFSHORE ELECTROLYSIS
10	Off-grid	2050	30	compressed tanks	100	hydrogen pipeline	floating wind (Atlantic ORE2 3.75 GW scaled on 30 MW electrolyzer)	dedicated hydrogen ONSHORE ELECTROLYSIS (in Galway) HVDC cables needed
11	Off-grid	2050	50	undeground storage (depleted Corrib gas field)	90	existing NG pipeline	floating wind (Atlantic ORE1 4.2 GW provide electricity only at night time)	both electricity and hydrogen production OFFSHORE ELECTROLYSIS

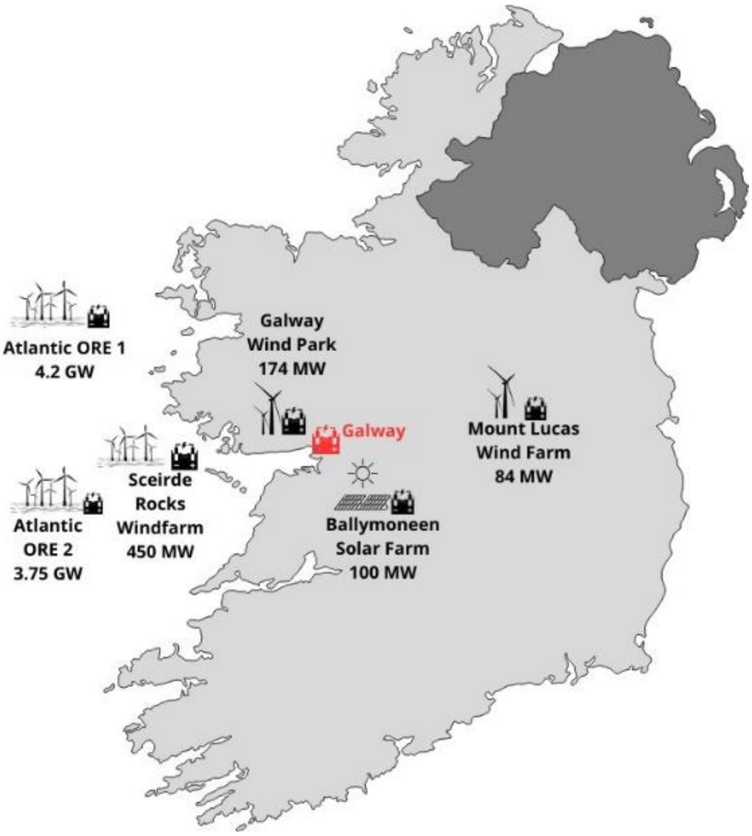

Figure 41: Map of the Republic of Ireland showing the locations of the hydrogen hub case studies.