Challenges and opportunities in future hydrogen supply chain design and operation: A techno-economic analysis

Challenges and opportunities in future hydrogen supply chain design and operation: A techno-economic analysis

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Abstract

Hydrogen is seen as a key tool for achieving energy system decarbonisation. The opportunities it represents for clean industry and energy security are widely understood, as evidenced by its inclusion in two hallmark pieces of clean energy legislation: the EU Green Deal, and the US Government's Inflation Reduction Act. Despite this, many of the challenges to be overcome in developing a clean hydrogen industry are not yet deeply understood. There remains much uncertainty about how policy can best enable the rapid scale-up required of the industry to deliver on ambitious climate targets. The work described in this thesis aims to investigate the challenges and opportunities of the burgeoning clean hydrogen industry through comprehensive techno-economic analysis of hydrogen production, storage, and supply, with a particular focus on the island of Ireland. The work identifies that hydrogen storage has not been adequately considered in much of the analysis of hydrogen supply chains, and key implications for hydrogen cost and emissions footprint therefore not discovered. Calculated levelised cost of renewable hydrogen in 2030 varies from €3.90-12.40/kgH_2 depending on storage technology. In addition, the work highlights how grid-connected hydrogen production can operate flexibly based on market prices, producing low-cost, low-carbon hydrogen. A levelised cost of €2.05/kg for 2030 can be achieved, with carbon intensities lower than 1 gCO_2/gH_2 for grid-connected electrolysis in an 80% renewable power system. The sheer scale of investment and relatively short timelines required to deploy hydrogen infrastructure on the island of Ireland to meet climate targets are also outlined. Estimated hydrogen demand in Ireland in 2050 ranges from 36 TWh to 116 TWh. For context, natural gas consumption in the Republic of Ireland was 51 TWh in 2021. These findings underline the key considerations faced by project developers and policymakers alike in realising hydrogen's role in decarbonisation. The challenges faced by hydrogen storage must be overcome through innovation and forward-thinking policy, whilst policy is also crucial in enabling system integration to ensure hydrogen plays a role in achieving clean, affordable, and secure energy for all.

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- C. Moran, P. Deane, S. Yousefian, R.F.D. Monaghan, The hydrogen storage challenge: Does storage method and size affect the cost and operational flexibility of hydrogen supply chains?, Int. J. Hydrogen Energy. (2023). https://doi.org/10.1016/j.ijhydene.2023.06.269.
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Conference Presentations

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- C. Moran, P. Javadi, F.B. Bozzolo Lueckel, S. Yousefian, R.F.D. Monaghan, How much hydrogen could Ireland produce from offshore wind? Poster - Wind Energy Ireland Conference 2022, Dublin, Ireland.
- C. Moran, P. Deane, S. Yousefian, R.F.D. Monaghan, How flexible is hydrogen really? Why storage matters, European Hydrogen Energy Conference 2022, Madrid, Spain.
- C. Moran, S. Yousefian, R.F.D. Monaghan, Hydrogen in the 2050 energy system: A techno-economic analysis, INFORMS Annual Meeting 2022, Indianapolis, USA.
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- F.B. Bozzolo Lueckel, C. Moran, Arjun Bopaiah, P. Deane, M. Lynch, R.F.D. Monaghan, Flexible Grid Hydrogen Production: Beyond The Colours Taxonomy, Offshore Energy and Storage Symposium 2023, St, Julians, Malta.
- C. Moran, F.B. Bozzolo Lueckel, Arjun Bopaiah, P. Deane, M. Lynch, R.F.D. Monaghan, Grid-connected or off-grid hydrogen production? Implications on cost and emissions, Hydrogen Ireland Conference 2023, Belfast, Northern Ireland.
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- Hydrogen – Exploring Opportunities in the Northern Ireland Energy Transition, report for the NI Department for the Economy produced in collaboration with Dublin City University and HyEnergy Consultancy, March 2021.
- Lough Ree Hydrogen Feasibility Study, analysis and presentation to Midlands Regional Transition Team in conjunction with FDT Consulting Engineers as part of the Lough Ree Technology Cluster Study, May 2021.
- Is hydrogen the clean energy fuel of the future? RTÉ Brainstorm Article, January 2022.
- University of Galway's response to the Irish Government's Hydrogen Strategy consultation, September 2022.
- Quarterly HyLIGHT Partner Meetings 2022 - 2023.
- Department of the Taoiseach's Energy Summit on Energy Security, July 2023.
- SEAI Connecting Energy Research and Policy Seminar Series, November 2023.

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Declaration of Work

I, Cian Moran, hereby declare that this thesis is entirely my own work and that I have not obtained a degree in this University, or elsewhere, on the basis of this work. All sources used have been acknowledged and referenced in the text.

Chapter 1: Introduction

We are now at the inflection point in an unprecedented time in human history, and indeed the history of the planet. Human activity, namely the burning of fossil fuels and unsustainable land use, has caused the climate of the planet to change beyond anything observed in humanity's time on earth. Multiple tipping points threaten to push the climate beyond the point of no return with dire consequences for all life on earth. In the midst of such staggering change to our climate, there also lies an opportunity for societal change as monumental as the agricultural or industrial revolutions. There is incredible potential for humanity to transform its energy and food systems to allow all of humanity to thrive in cooperation with climate and nature.

The transformation of the energy system has well and truly begun, with renewable electricity set to be the dominant form of electricity generation globally by 2025, overtaking coal [1]. Wind and solar are now the cheapest forms of power generation in many regions of the world [2]. In addition to this, governments around the world continue to set increasingly ambitious climate and decarbonisation policies. Building on the foundation of the Paris Agreement from 2015, where 196 nations signed up to limit global warming to 1.5°C, and accelerated by the global energy crisis arising from the Russian invasion of Ukraine, policy packages such as the EU Green Deal and Inflation Reduction Act (IRA) in the Unites States represent step changes in government climate and energy policy [3]. The European Union has now committed to being the first climate neutral continent by 2050 with a target for 55% emissions reduction by 2030 [4]. As part of the IRA, the US Government will provide $369 billion in investment for the development of renewable energy projects and related technologies [5]. Closer to home, when the Irish Government announced a target of 51% emissions reductions by 2030, it was one of the most ambitious emissions reduction targets for any country ever [6]. The Climate Action Plan sets out how to achieve this, with ambitious targets for renewables deployment by 2030; 9 GW of onshore wind, 5 GW of offshore wind, and 8 GW of solar [7].

Comprehensive decarbonisation, however, will require far more than the widespread acceleration of renewable electricity, which is of course a central pillar. At present, only 22% of Ireland's energy is used in the form of electricity, with the remainder provided by predominantly oil, gas, and other fossil fuels for the transportation of people and goods and heating for homes, businesses, and industry [8]. Significant improvements in energy efficiency, from technology to consumption behaviour and the development of a circular economy represent a huge opportunity for active decarbonisation, as does the electrification of transport

and heat through electric vehicles and heat pumps, allowing newly built renewables to decarbonise end-uses previously reliant on liquid or gaseous, polluting fuels. Though progress has been frustratingly slow for many, as evidenced by the continued protests and activism against climate change and fossil fuels, and the increasingly evident impacts of climate change around the world, much of the path to decarbonisation is somewhat clear: Accelerate deployment of renewable electricity, improve energy efficiency, and electrify heat and transport.

Achieving 100% decarbonisation of our energy systems will require new technologies, many of which are largely unproven at scale. Sectors of the economy, dubbed 'harder-to-abate', such as chemicals, industry, and heavy transport, are not easily decarbonised by the aforementioned means. These will require new and innovative solutions to fully decarbonise, some of which may not yet be known. There is a consensus that biofuels, such as biodiesel can play a key role in the 'harder-to-abate' sectors or even a transitional role as a 'drop-in' replacement for fossil fuels for end-uses which can eventually be electrified. Biofuels vary significantly in feedstock and form, and can be produced from dry or wet biomass. There is now an understanding that biofuels should not compete with food or contribute to habitat and biodiversity loss through land-use change, but instead should be derived from waste products such as forestry residues or human and animal wastes. As a result, there is a limit to the sustainable resource for biofuel production, meaning biofuels cannot be produced in sufficient quantities to fully decarbonise the 'harder-to-abate' sectors alone.

Other solutions include carbon capture and storage (CCS) which could be deployed at existing sources of carbon emissions such as power plants and industry. However, the technology is as yet unproven at scale and experts warn that the promise of future large-scale CCS must not be used as an excuse to continue pollution and slow down the implementation of existing decarbonisation measures.

The use of hydrogen as a clean energy vector has been long touted as an alternative to fossil fuels. Hydrogen, when burned, produces no carbon dioxide emissions. However, existing hydrogen usage today, primarily as a feedstock for the production of chemicals such as ammonia and methanol, is supplied by hydrogen produced from fossil fuels, and contributes to 2% of global carbon dioxide emissions [9]. There are alternative, more sustainable production methods. For instance, hydrogen can also be produced by using electricity to split water into hydrogen and oxygen by electrolysis. It can also be produced from biomass via gasification or

anaerobic digestion and separation. Many hydrogen production pathways exist, and are often categorised by colour. Hydrogen produced from fossil fuels is often referred to as ‘grey’ or ‘black’ hydrogen, whilst if most of the emissions are captured using CCS, it is called ‘blue’ hydrogen. Hydrogen from renewable electricity has been called ‘green’ hydrogen. However, none of these colours are based on the carbon emissions associated with production, which can vary significantly from case to case. For ‘green’ hydrogen specifically, there is much debate around the definition of ‘green’ as it pertains to subsidies and policy.

Perhaps the key to hydrogen’s potential as a solution is the possibility for it to be stored safely and cost effectively at large-scale for long periods. Hydrogen can be produced from renewable electricity at times of high generation, stored for months to years and used to supply a variety of potential end-uses not suitable for electrification. Such end-uses include heavy road transport, shipping, aviation, industrial processes, high-temperature heat, and backup power generation for both on-site and grid scale.

It is clear governments now see a role for hydrogen in the future energy system, as evidenced by ambitious targets and policy relating to hydrogen production and use. As part of REPowerEU the European Union has set a target for 10 million tonnes of domestic clean hydrogen production by 2030 as well as 10 million tonnes of imports [10]. Mandatory targets for hydrogen usage in transport and industry have also been set. Renewable hydrogen derived fuels, referred to as renewable fuels of non-biological origin (RFNBOs) must supply 1.2% of aviation fuel and 42% of existing industrial hydrogen consumption must be renewable by 2030 [11,12]. As part of the Inflation Reduction Act (IRA), the United States has set aside $8 billion in funding for the development of regional hydrogen hubs, offering subsidies of up to $3/kg of hydrogen produced depending on carbon dioxide intensity criteria. As part of its National Hydrogen Strategy, the Irish government has announced that it will set up a Hydrogen Demonstrator Fund to help fund small-scale renewable hydrogen projects prior to 2030 [13].

The focus on small-scale projects is due to a number of reasons. Firstly, there is very little existing hydrogen usage in Ireland, with the vast majority of hydrogen production and consumption taking place at Whitegate Oil Refinery in Cork. This amounts to approximately 1,500 tonnes [14]. As such, demand for renewable hydrogen in Ireland is likely to come from new end-uses such as the harder-to-abate sectors mentioned above. This will require the development of brand new infrastructure. Therefore, it is sensible to develop smaller projects first, and use the learnings and skills gained from these to scale up the industry. Secondly, the

cost of renewable hydrogen, and associated technology such electrolysers, fuel cells and vehicles are currently very expensive compared to fossil fuels and other clean energy technologies such as battery electric vehicles (BEVs). As a result, high levels of subsidy are required to ensure these projects are affordable. However, as more and larger projects are built in the coming years, and manufacturing of hydrogen technologies scale up, cost are predicted to fall significantly. Thirdly, there is still much uncertainty around the role hydrogen will play in some sectors. For instance, in heavy road transport, it is not known how much of the heavy duty trucking fleet can be electrified. Some argue there is no need for hydrogen, whilst other studies show a role for hydrogen for heavier, longer distance trucks [15]. Therefore, the Irish government is eager to avoid funding larger projects which may become stranded assets if a role for hydrogen does not materialise in a certain sector. Having said this, there is a clear understanding of the huge opportunity afforded to Ireland by a renewable hydrogen industry. The island's offshore wind resource is vast, with an estimated 70 GW of technical potential for floating offshore wind in the Atlantic. This far exceeds any predicted future renewable capacity requirement for a zero carbon electricity system (estimated at 29 GW by Mehigan and Deane [17]), and due to the isolated nature of the island's electricity grid, it is unlikely that interconnection to Britain and Europe could sufficiently facilitate the export of this wind energy. As such, there is an opportunity to use this excess wind power to produce hydrogen. This hydrogen could be exported by pipeline or ship or used to produce other electrofuels – fuels derived from electricity – such as e-jet fuel, or even high-value products such as steel and fertiliser.

As mentioned previously, any hydrogen industry in Ireland would require the development of new infrastructure to allow the sustainable production, storage, and secure supply of hydrogen to suitable end-uses. The level of infrastructure required is potentially monumental, requiring the build out of wind and solar capacity dedicated to hydrogen, large-scale electrolysis, underground storage, hydrogen pipelines, refuelling stations, and power plants. It is likely that time and money can be saved by utilising existing infrastructure where possible by retrofitting, such as existing gas pipelines and power plants. To adequately plan investments in such large-scale and widespread infrastructure, it is crucial to have some estimation of the scale, type, and even location of the infrastructure needed.

It is necessary to analyse future hydrogen supply chains based on potential for production, storage, and demand, to identify challenges and opportunities for the hydrogen industry, as

well as the scale of infrastructure that may be required. The aim of this work, therefore, is to analyse the challenges and opportunities for a hydrogen industry in Ireland to enable a zero carbon energy system. More specifically, the objectives of the work are:

1. To develop a comprehensive techno-economic analysis (TEA) tool for hydrogen supply chains and regional hubs.
2. To use this tool to identify key technical and economic considerations for hydrogen supply chains and systems.
3. To use the learnings from the modelling work carried out to design, analyse, and interrogate a future island-wide hydrogen system.

1.1 Overview of Thesis Layout

As shown in Figure, this thesis is based on three journal papers – two published and one accepted for publication – and a white paper in preparation. Chapter 2: "*A flexible techno-economic tool for regional hydrogen hubs – A case study for Ireland*" follows this introduction and is the first journal paper, which was published in the International Journal of Hydrogen Energy in April 2023. This is followed by Chapter 3: "*The hydrogen storage challenge: Does storage method and size affect the cost and operational flexibility of hydrogen supply chains?*", which was published in the International Journal of Hydrogen Energy in July 2023 as part of a Special Issue of papers from the 2022 European Hydrogen Energy Conference, at which this work was presented. Chapter 4: "*Flexible Grid Hydrogen Production: Beyond the Colours Taxonomy*", has been accepted for publication in IET Renewable Power Generation, as a selected paper from the Offshore Energy and Storage Symposium 2023. Its publication schedule has been delayed by 4 months by the editor. In Chapter 5, the work of an all-island hydrogen modelling study that is being prepared for publication as a white paper is described. In Chapter 6, the results and findings from Chapters 2 through 5 are discussed in the broader context. Finally, in Chapter 7, the conclusions of the work are outlined, and limitations and future work discussed.

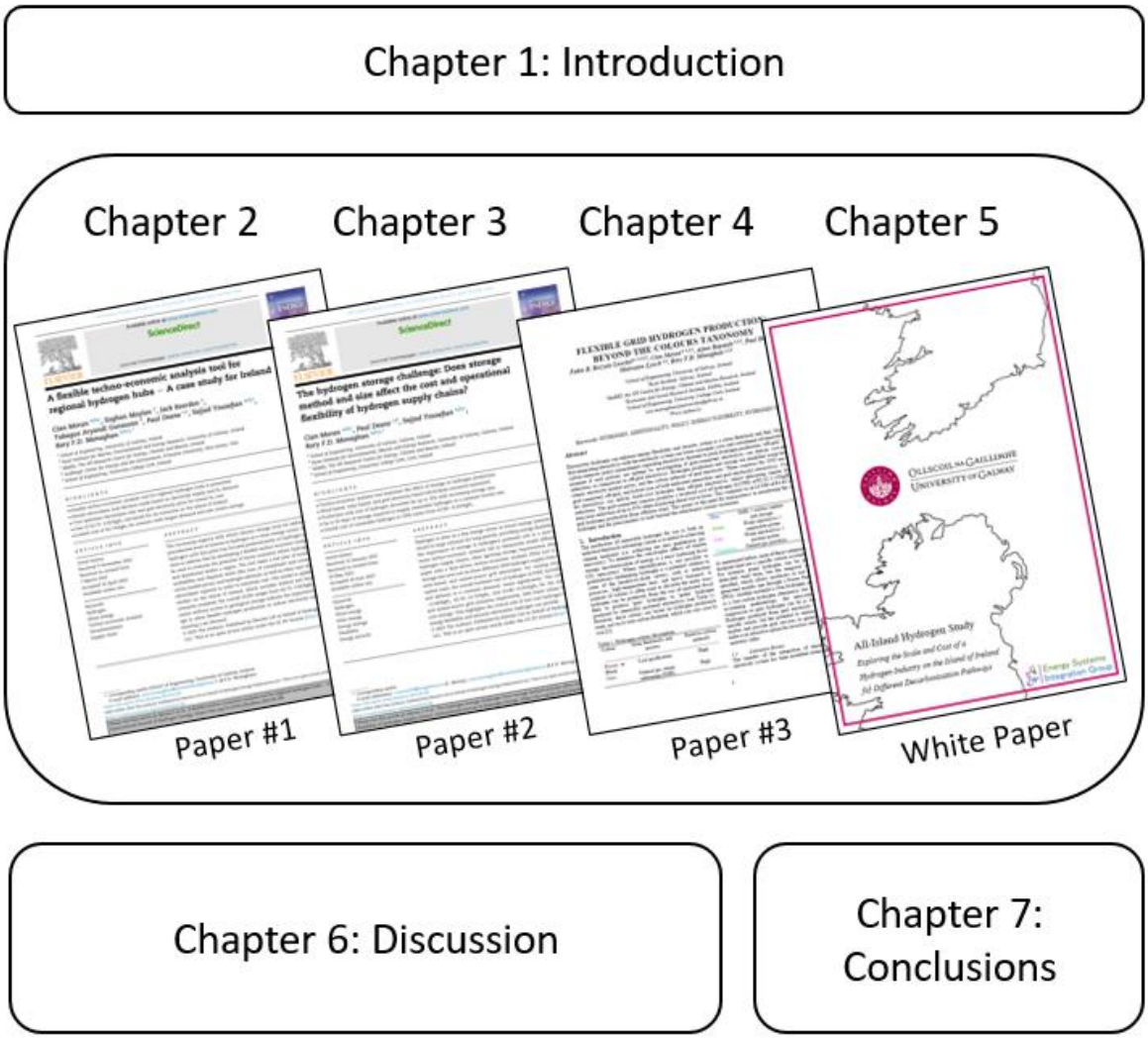

Figure 1: Diagram of thesis layout.

In Chapter 2, the first journal paper describes the TEA tool developed for regional hydrogen supply chains or hubs and applies it to a number of specific case studies on the island of Ireland. This tool allows for the comprehensive modelling of hydrogen production, storage and distribution to the end-user based on hourly renewables output, electricity market prices, and hydrogen demand. The work identifies some key parameters that influence the cost of hydrogen delivered such as the cost of electricity and the cost and size of hydrogen storage. The latter is the focus of Chapter 3, where the effect of hydrogen storage on overall hydrogen costs and the operational flexibility of hydrogen production are examined in detail in a journal paper. The key finding of this work identifies the possibility of prohibitively high costs for 100% renewable or 'green' hydrogen depending on the storage technology. In Chapter 4, the third journal paper examines the usage of grid electricity for hydrogen production and its effect on cost and emissions for both low- and high-cost hydrogen storage options. The identification of

a trade-off between cost and emissions for high-cost storage suggests further consideration is necessary in determining rules for renewable hydrogen production. The work implies rules could be based on actual emissions and not colours, advocating for full transparency and short-term flexibility to enable cost-effective decarbonisation. Based on the TEA tools developed as part of the three journal papers, Chapter 5 sizes and costs an island-wide hydrogen system for Ireland for 2030 and 2050. Based on estimates of hydrogen demand, the scale of wind, solar, electrolysis, and storage capacities required for dedicated hydrogen production are optimised and an average levelised cost of hydrogen (LCOH) is calculated. This is carried out for a range of scenarios from 'Missing Climate Targets' to 'Exceeding Climate Targets'. Thus, key numbers for the scale and cost of the hydrogen infrastructure required for a zero carbon energy system are estimated. Barriers to deployment as well as crucial technical considerations and their consequences on cost and emissions are also highlighted, with many pointing to the need for further research. Future work can help to develop a greater understanding of the challenges and opportunities faced in enabling hydrogen's role in energy system decarbonisation.

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Chapter 2: A flexible techno-economic analysis tool for regional hydrogen hubs – A case study for Ireland (Journal Article #1)

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Abstract

The increasing urgency with which climate change must be addressed has led to an unprecedented level of interest in hydrogen as a clean energy carrier. Much of the analysis of hydrogen until this point has focused predominantly on hydrogen production. This paper aims to address this by developing a flexible techno-economic analysis (TEA) tool that can be used to evaluate the potential of future scenarios where hydrogen is produced, stored, and distributed within a region. . The tool takes a full year of hourly data for renewables availability and dispatch down (the sum of curtailment and constraint), wholesale electricity market prices, and hydrogen demand, as well as other user-defined inputs, and sizes electrolyser capacity in order to minimise cost. The model is applied to a number of case studies on the island of Ireland, which includes Ireland and Northern Ireland. For the scenarios analysed, the overall LCOH ranges from €2.75 - 3.95/kgH_2. Higher costs for scenarios without access to geological storage indicate the importance of cost-effective storage to allow flexible hydrogen production to reduce electricity costs whilst consistently meeting a set demand.

Keywords

Hydrogen, wind energy, techno-economic analysis, decarbonisation, supply chain

Highlights

- Flexible techno-economic analysis tool for regional hydrogen hubs is presented
- Hourly electrolyser load decision made based on electricity supply and H_2 demand
- Tool optimises electrolyser size and grid electricity price for lowest H_2 cost
- Cost of €2.75 – 3.95/kgH_2 calculated for six scenarios on the island of Ireland
- Lowest cost of €2.75/kgH_2 for scenario with largest demand and salt cavern storage

Nomenclature

Abbreviations			
AGI	Above ground installation	*MBP*	Maximum bid price, €/MWh
ALK	Alkaline	*MPL*	Minimum partial load, %
C	Total cost, €	*MW*	Megawatt
c	Specific cost, €/kWh	*MWh*	Megawatt hour
CAPEX	Capital expenditure, €	*N*	Number
CF	Capacity factor, %	*NI*	Northern Ireland
CNG	Compressed natural gas	O_2	Oxygen
CO_2	Carbon dioxide	*OPEX*	Operating Expenditure, €
D	Diameter	*P*	Rated Power/Capacity, kW
DD	Dispatch down	*p*	Pressure
h	Hour	*PEM*	Proton exchange membrane
H_2	Hydrogen	*PV*	Present value
HFO	Heavy fuel oil	*ROI*	Republic of Ireland
kg	Kilogram	*SLGN*	Sligo Local Gas Network
km	Kilometre	*t*	tonnes
kV	Kilovolt	*TCO*	Total cost of ownership
kW	Kilowatt	*TEA*	Techno-economic analysis
kWh	Kilowatt hour	*VRE*	Variable renewable electricity
LCOE	Levelised cost of electricity, €/MWh	EF	Emissions factor, $kgCO_2/MWh$
LCOH	Levelised cost of hydrogen, €/kg	CI	Carbon intensity, $kgCO_2/MWh$
m^3	Metres cubed		

Subscripts and superscripts

avg	Average	*ME*	Main equipment
C	Capital (cost)	*O*	Operation and maintenance
Comp	Compressor	*OFW*	Offshore wind
D	Distribution	*ONW*	Onshore wind
DD	Dispatch down	*Oth*	Other
E	Electrolyser	*P*	Production
e	Electrical	*S*	Storage
EMU	Energy management unit	*SOL*	Solar
Eng	Engineering	*TT*	Tube Trailer
f	Fuel	*W*	Water
IC	Interconnection		

Greek symbols

η	Efficiency
τ	Lifetime, years

2.1 Introduction

Fossil fuels account for 84% of global energy demand [1], with energy contributing to 73% global greenhouse gas emissions [2]. Large-scale deployment of wind and solar power have helped to decarbonise electricity but the heat and transport sectors remain heavily reliant on liquid and gaseous fossil fuels. Whilst electrification through heat pumps and battery electric vehicles can decarbonise domestic heating and light-duty passenger vehicles, respectively, the solutions to the harder-to-abate sectors of heavy transport and high-temperature heat are less clear. With wind and solar PV now amongst the cheapest methods of electricity generation, there is potential to use this renewable electricity to produce green hydrogen via electrolysis. This hydrogen can then be stored and distributed as a liquid or a gas for use in some harder-to-abate sectors and for seasonal or strategic energy storage.

2.1.1 Literature Review

The techno-economic analysis (TEA) of hydrogen production from wind [3–6], solar [7–9], and mixed source grid electricity [10–13] has been extensively carried out in the literature for different time scales and locations around the world. The primary metric for the economic evaluation of hydrogen production is levelised cost of hydrogen (LCOH). It is heavily affected by the cost of electricity, capacity factor, and capital cost for the electrolyser [14]. Using off-grid wind power, a lower levelised cost of electricity (LCOE) and a higher capacity factor of the wind resource lead to lower LCOH. As a result, LCOH from offshore wind varies from 3.20 €/kg to 8.00 €/kg for different countries in Europe for the year 2020 [15]. Offshore areas with consistently high wind speeds such as the North Sea and the Irish Sea are of particular interest. Singlitico et al. [4] evaluated the cost of hydrogen production in the North Sea from offshore wind and compared onshore, offshore, and in-turbine electrolysis, finding that an LCOH of 2.40 €/kg in 2030 could be realised. For the Irish Sea, McDonagh et al. [3] investigated multiple scenarios for electricity and hydrogen production from a 504 MW offshore wind farm in 2030, deducing that an LCOH of 3.77 €/kg is achievable for dedicated hydrogen production.

For off-grid hydrogen production from solar, the capital cost of the electrolyser has a more significant effect on LCOH due to the lower capacity factor of solar power in comparison to wind [15]. For 2020, LCOH from solar varies significantly across Europe, from 3.50 €/kg in Portugal to 15.00 €/kg in Norway. As with areas of consistently high winds, areas of high solar potential are of particular interest for hydrogen production. Gunawan et al. [16] analysed the

potential for large-scale hydrogen production from solar power in Libya, with the aim of export to Italy through hydrogen blending in the existing natural gas export pipeline. With liquid hydrogen storage, an LCOH of 2.81 €/kg is calculated for the year 2030. Other regions with high solar resource have been analysed as potential hydrogen production locations, including the Atacama Desert in Chile. According to Gallardo et al. [17], an LCOH of as low as 1.67 USD/kg is possible for the region by 2025.

Combining wind and solar for hydrogen production can increase the electrolyser capacity factor and lower LCOH in some locations such as Germany [15]. Locations with a high resource of both wind and solar have great potential for low-cost hydrogen production. Work by Kakavand et al. [18] identified three locations in Iran with high combined wind and solar resource and evaluated the cost of hydrogen for ammonia production via electrolysis and Haber-Bosch. The minimum LCOH calculated varies from 2.94 – 3.32 USD/kg for current technology costs. Raab et al. [19] calculated LCOH values in the range of 4 – 6 €/kg for the year 2020 at five locations around the world with suitably high wind and/or solar resource whilst also examining the effect of supplementing the renewable generation with small amounts of grid electricity.

The use of grid electricity for electrolysis in place of dedicated renewables is also of interest. It enables higher capacity factors than variable renewable electricity (VRE) only systems, thus amortising electrolyser capital costs to a greater extent [13]. It can also serve to locate production closer to demand, reducing or eliminating distribution costs. Many different strategies for the participation of electrolysers in electricity markets have been investigated, including the provision of grid services by Matute et a. [20]. Nguyen et al. [10] found that for a 10 to 100 MW system, LCOH varies from 2.40 €/kg to 6.20 €/kg for flat-rate and wholesale market pricing mechanisms for 8 locations in Canada, California, and Germany. This is equivalent to 7.2 to 18.6 c/kWh. For comparison, the average price of natural gas in August 2022 was 23 c/kWh on the European market and 3 c/kWh in the USA [21].

Hydrogen storage [22–25] and distribution [26–28] costs vary considerably depending on technology and capacity. In addition to this, the suitability of a particular technology depends on several factors, such as the end-use application, existing infrastructure, and the local availability of suitable underground rock formations in the case of geological hydrogen storage.

Many of the TEA studies have considered only one aspect of the supply chain in isolation [3,5-11,15,19]. However, previous studies by some of the current authors [29–31] investigated

multiple aspects of hydrogen supply chains, specifically production, distribution, and dispensing. Hydrogen production was modelled at every wind farm on the island of Ireland using historical hourly wind data [29]. This study examined three different electrolyser operating modes: 1) curtailed and constrained electricity, 2) available wind power, and 3) full capacity operation using mixed source grid electricity when required. For each mode, electrolyser capacity was optimised to minimise LCOH. GIS mapping software was utilised to calculate the cost of distributing the hydrogen to a gas grid injection point [29] or city bus network [30] via tube trailers.

The supply chain was designed to utilise the most suitable wind farms based on their combined LCOH production and distribution. Lastly, the dispensed hydrogen cost for buses [30] and mining trucks [31] was investigated. This consists of the capital and operational costs of the hydrogen refuelling infrastructure, which is sized based on the hourly refuelling schedule of the vehicles. The results indicated that an overall LCOH of €5-10/kg can be achieved in 2030. This cost is competitive compared to diesel for city bus fleets under certain carbon tax scenarios. Multiple aspects of the hydrogen supply chain were modelled in detail. However, the inclusion of the storage capacity required to match hydrogen supply and demand was not considered. The work also assumes an average price for electricity, not considering the temporal nature of electricity market prices. In an alternative approach, McDonagh et al. [13] investigated the effect on the capacity factor and cost by setting a maximum hourly price at which electricity is purchased for hydrogen production for methane synthesis.

Although some studies have conducted nationwide modelling and optimisation of hydrogen supply chains [32–34], none, to the best of the author's knowledge, have built a techno-economic modelling tool of hourly hydrogen production, storage, and distribution for specified hourly demand, which can be applied to variety of regional scenarios or case studies.

2.1.2 Objectives, novelty, and sections of report

The objectives of this work are to (1) build a flexible techno-economic model of electrolytic hydrogen production, storage, and distribution that sizes production based on the available electricity and hydrogen demand of a region, (2) to apply this model to a number of future 'hydrogen hub' case study scenarios on the island of Ireland, each with its own unique characteristics, in order to evaluate their economic potential, and (3) to investigate how

different technical and economic aspects of the supply chain influence each other and the overall cost of hydrogen delivered.

The novelty of the work lies in the functionality of the model. The techno-economics of hydrogen production, storage, and distribution are modelled based on the availability of electricity for electrolysis and the hourly hydrogen demand that must be met. The model can be applied to a variety of scenarios and can integrate multiple electricity sources to minimise electricity costs. The electrolyser and other components are sized in order to minimise the LCOH delivered to the end user as in the work of Gunawan et al. [29]. In addition to this, if the electrolyser is connected to the electricity grid, it optimises the maximum bid price (MBP) at which electricity is purchased, similar to the method of McDonagh et al. [13]. Integrating these modelling techniques allows for investigation into the use of multiple electricity sources for electrolysis to reduce costs. The modelling of hourly storage to ensure variable hydrogen production can meet a consistent demand is another novel feature of the tool.

The methods used to achieve the previously outlined objectives are described in Section 2.2, which follows this introduction. Firstly, what constitutes a hydrogen supply chain or hub is clearly set out and described in detail, and the scope of the modelling work is outlined. Then, the workings and assumptions of the techno-economic model are explained before the hydrogen hub case studies to which the model is applied are described. Following the Methodology section, the results of the modelling are presented and discussed in Section 2.3, before conclusions are drawn and areas for future work are suggested in Section 2.4.

2.2 Methodology

Firstly, an overview of the hydrogen supply chain structure, the developed system and its boundaries are described in subsection 2.2.1. Secondly, the techno-economic model and the details of its underlying calculations are described in subsections 2.2.2 to 2.2.5. Finally, the case study hydrogen hubs to which the model is applied are described in subsection 2.2.6.

2.2.1 Overview of Supply Chain Structure and System Description

In this study, a hydrogen hub refers to an electrolytic hydrogen supply chain consisting of hydrogen production and storage systems, and distribution to the end-use application as shown in Figure 1.

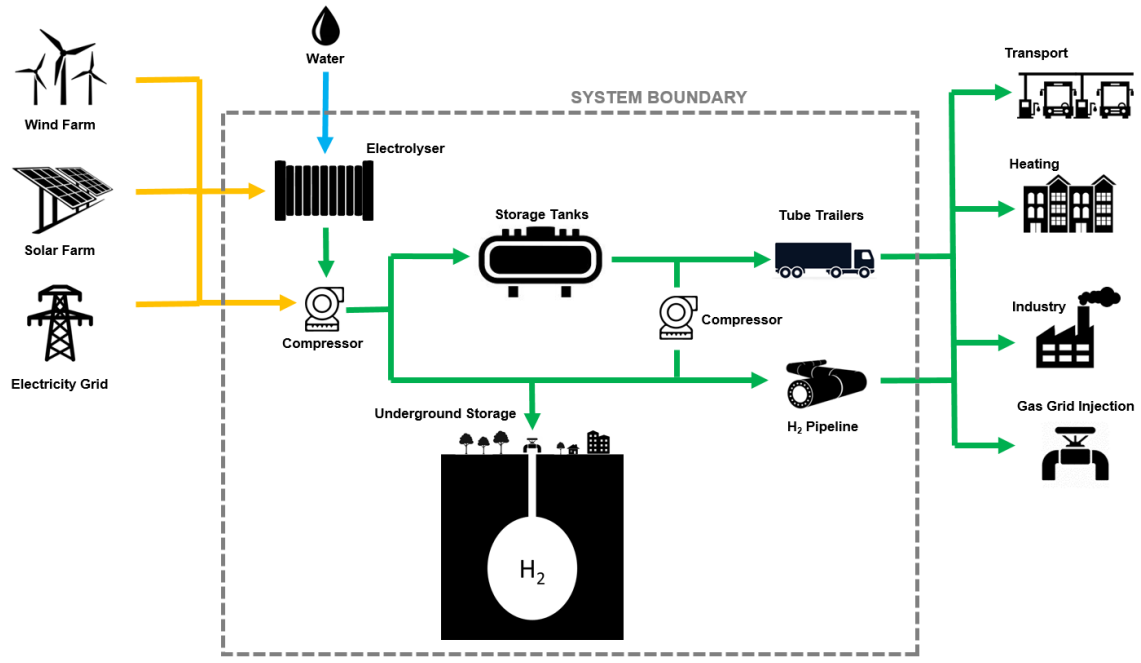

Figure 1: Potential hydrogen supply chain routes or hubs and the system boundary of the modelling.

Both the hydrogen production system and hydrogen storage system are located at or nearby a source of electricity such as a wind or solar farm or an electrical grid connection. Hydrogen is distributed by tube trailer or dedicated hydrogen pipeline depending on production volume and distribution distance. The hydrogen is delivered to an end-user in a hard-to-abate sector such as trucks or high temperature industrial heat. In the case where wind or solar power is used for electrolysis, the production system has a direct connection to the wind or solar farm or is located sufficiently nearby on the electrical grid to be able to use its VRE. It is assumed that the power is provided at its levelised cost. In this case, the VRE generator and hydrogen production system are under the same ownership/are the same entity. This may also be the case by means of a financial agreement between the VRE generator and the production system such as a power purchase agreement (PPA). If the system is connected to the electrical grid, it is assumed that grid electricity can be purchased at a wholesale market price set at hourly time intervals. VRE generation can be constrained due to local electricity network congestion, or curtailed due to technical limitations of the whole electricity system. Collectively, this is referred to as dispatch down and is a growing problem for electrical grids with high penetration

of VRE. For example in 2020, 12% of the wind power generated in Ireland and Northern Ireland was dispatched down [35]. It is assumed that this electricity is available at a discounted rate if dispatch down is available to the system from either a direct connection to a VRE generator or the electrical grid.

The production system consists of an alkaline (ALK) or proton exchange membrane (PEM) electrolyser, which uses the electricity to split water into hydrogen (H_2) and oxygen (O_2), as well as a power supply, water pump, water treatment, safety devices, heat exchanger, demisters, 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.

In this study, the hydrogen produced is stored in aboveground compressed tanks or an underground salt cavern storage facility. Aboveground tank storage is suited to smaller scale hydrogen hubs (less than 10 tonnes of hydrogen storage) whilst salt caverns are used for large-scale hydrogen storage [24]. The hydrogen is then compressed or expanded if necessary before being distributed by tube trailer or dedicated pipeline to its end-use application or natural gas grid injection point. These end-use applications include hydrogen refuelling stations for trucks, buses, and trains, high-temperature industrial heat, commercial space heating, and natural gas consumers. The techno-economics of providing hydrogen for end-use applications via hydrogen refuelling stations and grid injection facilities is beyond the scope of this work.

2.2.2 Description of Techno-Economic Analysis (TEA) Tool

The tool calculates technical, economic, and environmental parameters, including optimal electrolyser capacity, the LCOH, and the equivalent CO_2 emissions avoided through the use of hydrogen instead of fossil fuels. Figure 2 shows the data flowchart of the tool for the calculation of the LCOH.

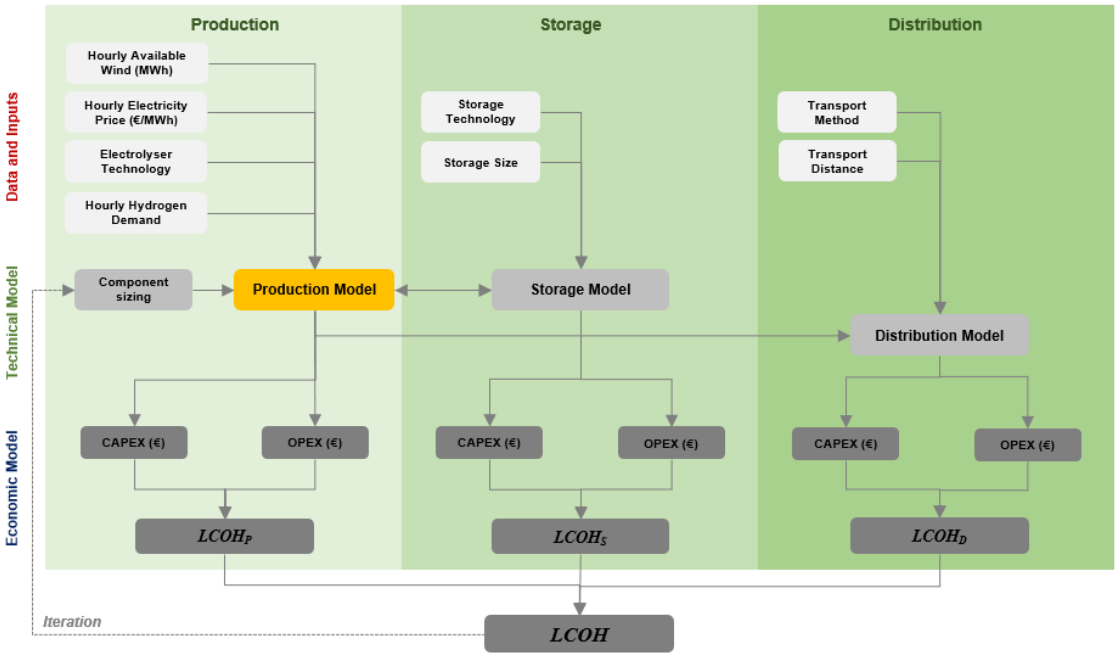

Figure 2: Techno-economic analysis tool data flowchart for LCOH calculation.

The model takes hourly wind, solar, and electricity market price data as inputs, as well as the hourly demand profile for hydrogen over a full year. Based on user-defined storage size, the model makes an hourly decision whether to operate the electrolyser at full load, partial load, or shut down, aiming to maximise the use of VRE, dispatch down, or cheap electricity to meet hydrogen demand. The user-defined inputs to the model are shown and categorised in Table 1.

Table 1: User-defined inputs for flexible hydrogen hub modelling tool.

User-Defined Inputs	*Units/Notes*
Demand	
End-use	Trucks, Buses, Trains, Industrial Heat, Natural Gas Consumers
Total Annual Demand	kg
Electrolyser	
Technology	ALK or PEM
Efficiency*	%
Electricity	
Source	Wind, Solar, Grid, Dispatch Down (or any combination)
Priority	Cost or Renewables
Average Grid Price**	€/MWh
CO_2 Intensity of Grid Electricity	$kgCO_2$/MWh
Available Wind Location	Onshore/Offshore if applicable
Available Wind Capacity	MW
LCOE Wind*	€/MWh
Available Solar Capacity	MW
LCOE Solar*	€/MWh
Dispatch Down Cost	€/MWh
Storage	
Quantity	Number of days of hydrogen demand
Type	Compressed Tanks, Buried Pipes, Lined Rock Cavern, Salt Cavern
Distribution	
Method	Tube Trailers, Dedicated Hydrogen Pipeline (Onshore/Offshore)
Distance	km
Economic	
Construction Time	Years
Project Lifetime	Years
Discount Rate	%
Base Year	2024 or 2030
Electrolyser Specific CAPEX*	€/kW
Compressor Specific CAPEX*	€/kW Electrolysis
Storage Specific CAPEX*	€/kg usable hydrogen
Water Cost*	€/m^3

*Optional inputs (assumptions included in model)
**Only required if hourly wholesale market prices are not available

Some inputs are not required as assumptions for these parameters have been included in the model. The different types of hourly data used by the model and its technical, economic, and environmental outputs are shown in Table 2.

Table 2: Hourly data inputs and technical, economic, and environmental outputs for the flexible hydrogen hub analysis tool.

Hourly Data Inputs	
Available Wind Output	MWh
Available Solar Output	MWh
Dispatch Down	MWh
Wholesale Electricity Prices	€/MWh
Hydrogen Demand	kg
Outputs	
Technical	
Optimal Electrolyser Capacity	MW_e
Optimal Maximum Bid Price	€/MWh
Capacity Factor	%
Economic	
LCOH Production, Storage, Distribution	€/kg H_2
Environmental	
Emissions	tCO_2 equivalent/year
Emissions Avoided	tCO_2 equivalent/year

Of these, the LCOH is the key focus of the modelling, as it is used as the basis for component sizing. As shown by Equation 1, the LCOH is the sum of the levelised costs of production ($LCOH_P$), storage ($LCOH_S$), and distribution ($LCOH_D$). Each of these is calculated using Equations 2-4, and represents the total discounted present cost of producing, storing, and distributing hydrogen, respectively, over the lifetime of the system, in units of €/kg. The costs for each aspect of the supply chain and its components are broken down into initial capital expenditure (CAPEX), and annual operational expenditure (OPEX), including maintenance and electricity costs. For the purpose of this work, a discount rate of 6% is assumed as well as an economic lifetime of 23 years, the first 3 of which are designated for construction of the hydrogen hub. The discount rate of 6% aligns with similar studies carried out for the same location and timeframe [3,29]. As part of the flexibility of the model, these economic parameters can easily be changed by a user if required when investigating a particular hydrogen hub. There are a number of other user-defined inputs, as detailed in Table 1.

$$LCOH = LCOH_P + LCOH_S + LCOH_D \quad (1)$$

Where LCOH is levelised cost of hydrogen, P is production, S is storage, and D is distribution.

$$LCOH_P = \frac{PV\ CAPEX_P + PV\ OPEX_P^{\tau}}{PV\ H_{2_P}^{\tau}} \quad (2)$$

Where PV is present value, CAPEX is capital expenditure, OPEX is operational expenditure, τ is lifetime, H_2 is quantity of hydrogen, and P is production.

$$LCOH_S = \frac{PV\ CAPEX_S + PV\ OPEX_S^{\tau}}{PV\ H_{2_P}^{\tau}} \quad (3)$$

Where PV is present value, CAPEX is capital expenditure, OPEX is operational expenditure, τ is lifetime, H_2 is quantity of hydrogen, and S is storage.

$$LCOH_D = \frac{PV\ CAPEX_D + PV\ OPEX_D^{\tau}}{PV\ H_{2_P}^{\tau}} \quad (4)$$

Where PV is present value, CAPEX is capital expenditure, OPEX is operational expenditure, τ is lifetime, H_2 is quantity of hydrogen, and D is distribution.

As shown in Figure 2, the model can be broken down into three separate submodels for production, storage, and distribution. Depending on the characteristics of the specific hydrogen hub being modelled, the production model takes available hourly wind and solar data, electricity prices, and dispatch down data. Based on the hourly hydrogen demand that must be met, it makes an hourly decision on whether the electrolyser should operate at full load, partial-load, or shut down. The technical parameters of the electrolyser assumed for the 2030 analysis are shown in Table 3.

Table 3: Electrolyser technical parameters for 2030.

Technical Parameters 2030		**PEM**	**ALK**		ref
Electrolyser Efficiency	η	66.6	69.4	%	[36]
Electrolyser Outlet Pressure	p_{WE}	30	30	bar	[36]
Minimum Partial Load	MPL	5	5	%	[14]

The production model also interacts with the storage model to take the level of hydrogen storage into account. The details of this hourly decision model are described in the subsection 2.2.5. From the electrolysers operating schedule, the quantity and cost of electricity, and subsequently the quantity of hydrogen produced over a year is calculated. The assumptions for electricity costs of different sources are shown in Table 4.

Table 4: Electricity cost assumptions for 2030.

Electricity Costs 2030				ref
Onshore Wind LCOE	c_{ONW}	34	€/MWh	[37]
Offshore Wind LCOE	c_{OFW}	59	€/MWh	[37]
Solar LCOE	c_{SOL}	42	€/MWh	[38]
Dispatch Down	c_{DD}	0	€/MWh	

The CAPEX and OPEX for the production system, and then the $LCOH_P$ are calculated. The CAPEX includes the cost of the electrolyser, compressor, and the associated equipment as described by Gunawan et al. [29]. OPEX includes fixed costs such as operation and maintenance costs of the electrolyser, compressor, and associated equipment as well as potential electrolyser stack replacements. Variable costs such as electricity and water are also included. Details of the equations used to calculate production related costs and their respective references are presented in Table 5.

Table 5: Economic parameters for electrolyser and other system equipment for 2030.

Economic Parameters 2030			ref
CAPEX			
PEM Electrolyser*	C_{CE}	1185.69 x $P_E^{0.925}$	[29,36,39]
ALK Electrolyser*	C_{CE}	948.55 x $P_E^{0.925}$	[29,36,39]
Compressor(s)**	C_{CComp}	4948 x $P_E^{0.66}$	[40]
Main Equipment	C_{ME}	$C_E + C_C$	
Energy mgmt unit	C_{EMU}	0.1 x C_{ME}	[40]
Interconnection	C_{IC}	0.2 x C_{ME}	[40]
Engineering	C_{Eng}	0.15 x C_{ME}	[40]
Other	C_{Oth}	1.5652 x $P_E^{-0.154}$ x C_{ME}	[40]
OPEX			
PEM Electrolyser***	C_{OE}	(349.8 x $P_E^{-0.305}$) x P_E	[29,36,39]
ALK Electrolyser***	C_{OE}	(266.52 x $P_E^{-0.305}$) x P_E	[29,36,39]
Compressor(s)	C_{OComp}	0.02 x C_C	[40]
Water Cost	c_W	2.38	[41]

CAPEX in €, OPEX in €/year, water cost in €/m^3.

*up to an electrolyser capacity of 100 MW. For electrolyser capacities greater than this, there is no change in specific CAPEX

**up to a capacity of 400 kg/h. For greater capacities, there is no change in specific CAPEX

***includes potential stack replacement

The $LCOH_S$ is calculated in a similar manner, with CAPEX and OPEX for the storage calculated based on the storage size and technology. Assumptions for the technical parameters and specific costs of hydrogen storage in compressed tanks are taken from Gunawan et al [29], whilst those for buried pipes, lined rock cavern, and salt cavern storage are based on work by Papadias et al [42]. These are detailed in the Appendices.

The transport model calculates the cost of distributing the hydrogen produced by tube trailer or dedicated pipeline, as defined by the model user, based on the quantity of hydrogen,

distribution distance, and distribution method. For distribution by tube trailer, the same model described in Gunawan et al is used [29]. For onshore dedicated hydrogen pipeline distribution, the model uses the same calculation as Baufume et al [43] and for offshore hydrogen pipeline distribution, that of Singlitico et al [4]. These formulae are also detailed in the Appendices. If required, a second compression stage is included to bring the hydrogen up to the distribution pressure. For distribution by dedicated hydrogen pipeline, the size and location of recompression stations on the network is not specified but is included in the cost calculation on a per kilometre basis.

2.2.3 Optimal System Configuration

The techno-economic analysis tool considers two variables when calculating the optimal system configuration. These variables are electrolyser capacity and the maximum bid price (MBP) if the hydrogen hub has a grid connection. The model iterates through different values of the two variables calculating the LCOH for a number of different combinations. From this, it ascertains the minimum possible LCOH and the corresponding optimal electrolyser capacity and MBP. The model checks a number of operating criteria to ensure the system configuration is a valid one. These criteria are that the system meets the annual hydrogen demand, has adequate hydrogen storage capacity, and has a capacity factor less than or equal to 92% to allow a minimum of 8% downtime for maintenance. If any system configuration of size and MBP does not meet all three of these criteria, the calculated LCOH is returned as invalid. Only valid LCOH values are considered when finding the optimal electrolyser capacity and MBP.

2.2.4 Emissions Calculation

A crucial aspect of any hydrogen hubs potential is its environmental performance. The tool calculates the equivalent CO_2 emissions associated with hydrogen production, where only the emissions associated with the carbon intensity of the electricity (CI) used to produce the hydrogen are considered. As part of this calculation the carbon intensity of the hydrogen produced is also found. The tool also calculates the equivalent net CO_2 emissions avoided of the hub from the use of hydrogen in place of fossil fuels. These are calculated using Equations 5-7.

$$m_{CO_2}^{produced} = \left(\frac{CI_{avg}}{\eta}\right) * m_{H_2} \quad (5)$$

Where $m_{CO_2}^{produced}$ is the equivalent mass of CO_2 emissions per year associated with hydrogen production, CI_{avg} is the average carbon intensity of the electricity used for electrolysis, η is the efficiency of the electrolyser, and m_{H_2} is the mass of hydrogen produced per year.

$$m_{CO_2}^{gross\ avoided} = EF_{ff} * E_{ff} \quad (6)$$

Where $m_{CO_2}^{avoided}$ is the equivalent mass of CO_2 emissions per year avoided due to the displacement of fossil fuels, EF_{ff} is the emissions factor of the fossil fuel displaced, and E_{ff} is the quantity of fossil fuel energy displaced.

$$m_{CO_2}^{net\ savings} = m_{CO_2}^{avoided} - m_{CO_2}^{produced} \quad (7)$$

Where $m_{CO_2}^{net\ savings}$ is the net equivalent mass of CO_2 emissions avoided per year from the hydrogen hub.

For the fossil fuel emissions avoided, only the tailpipe or combustion emission factors are considered, which are 204.7, 263.9, and 273.6 kgCO2/MWh for natural gas, diesel, and heavy fuel oil respectively [44]. The greater fuel efficiency of hydrogen trucks and buses over internal combustion engine vehicles is also accounted for. The tool also calculates a new metric: the specific net emissions avoided. This is calculated using Equation 8.

$$m_{CO_2}^{spec\ net\ savings} = \frac{m_{CO_2}^{net\ savings}}{m_{H_2}} \quad (8)$$

Where $m_{CO_2}^{spec\ net\ savings}$ is the specific net emissions avoided. A more comprehensive environmental performance assessment which accounts for emissions from the full supply chain is a priority for future versions of the model. This would include any hydrogen losses due to leakage as hydrogen is itself a greenhouse gas.

2.2.5 Hourly Electrolyser Load Decision

As mentioned previously, the production model makes an hourly decision to run the electrolyser at full load, partial load, or to shut down, based on hourly data inputs to the model: VRE availability (wind or solar), wholesale electricity market price, dispatch down availability, and hydrogen demand. The flowchart in Figure 3 shows the decision process followed.

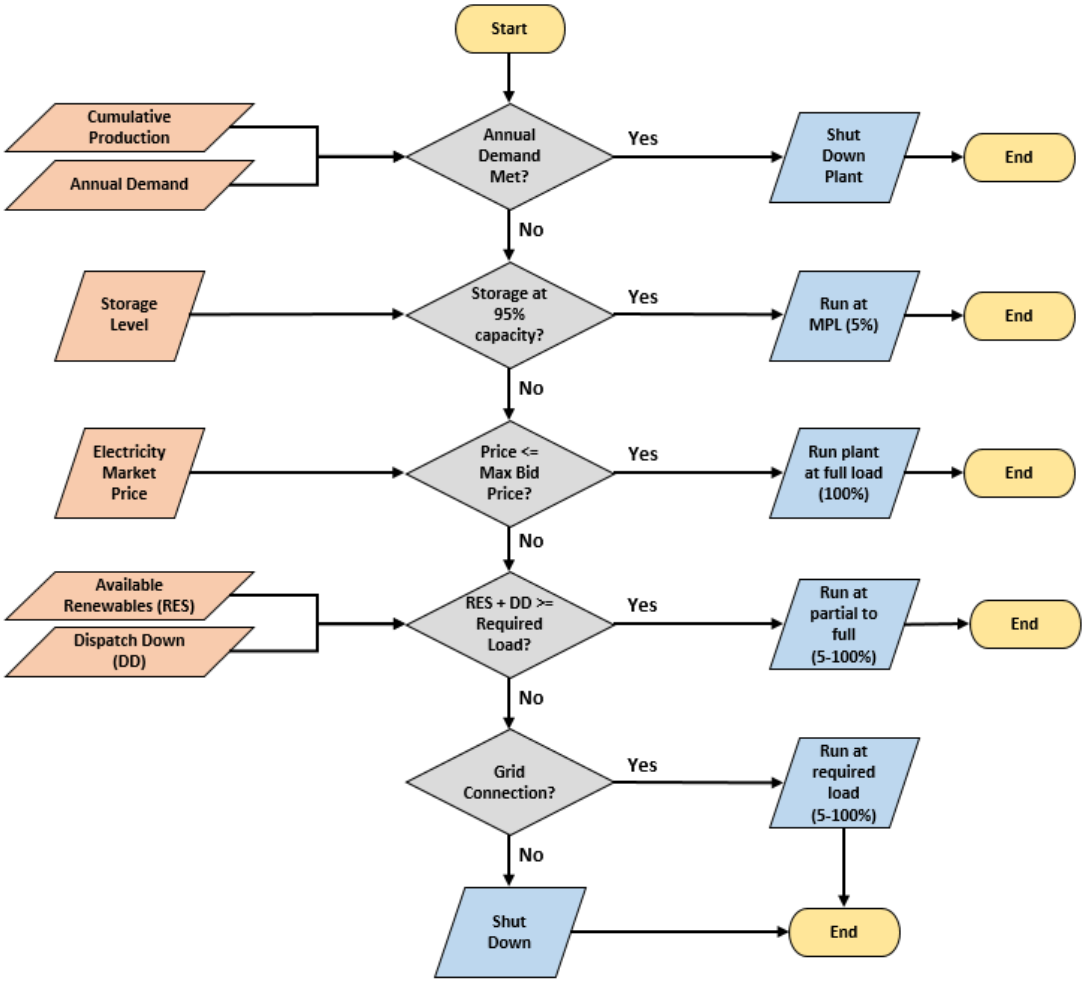

Figure 3: Hourly electrolyser load decision process flowchart.

The decision aims to maximise the use of VRE, cheap or otherwise wasted (dispatch down) electricity, for hydrogen production whilst also ensuring that the hourly demand for hydrogen is met. This aspect of the production model also interacts with the storage model to ensure that storage limits are not exceeded. If storage is full, the electrolyser will run at minimum partial load (MPL), even if there is an availability of VRE, dispatch down, or cheap grid electricity.

The decision flowchart in Figure 3 shows the step by step process of the hourly decision process. Firstly, the model checks to see if the annual demand for hydrogen has already been met by production. If it has, the electrolyser shuts down and no longer produces hydrogen as there is no demand for it. Secondly the model checks if the storage level is nearly full. If the storage level is at 95% of capacity or greater, the electrolyser runs at MPL.

Then, if connected to the electricity grid, the model checks if the electricity market price for that hour is less than the maximum bid price, which can be user-defined or optimised by the model. If the market price is less than the MBP, the electrolyser runs at full capacity.

For each hour, the model calculates the minimum required load that the electrolyser must run at to meet demand, and is equal to a value between 0-100%. The model then checks to see if the quantity of VRE and dispatch down electricity available is sufficient to meet this load requirement. If so, the electrolyser runs at partial or full load, using as much VRE or dispatch down electricity as possible.

It is worth noting that if there is some VRE availability and the market price is less than or equal to the maximum bid price, the system will prioritise VRE and dispatch down or cheaper grid electricity depending on a user-defined preference. If the user prioritises VRE, the system uses the available VRE, only purchasing grid electricity to top up if needed. If the user prioritises cost, the system will use whichever source of electricity is the cheapest. This means that if the market price is cheaper than the LCOE of the available VRE, the system purchases grid electricity over VRE. The purpose of this feature of the model is to allow the user to evaluate different scenarios where the sources of electricity may be part of or separate to the hydrogen hub. If the source(s) of VRE are owned by the same company or organisation as the hydrogen hub, VRE is likely be used for electrolysis when available. However, if separate to the hydrogen hub, the owner/operator of the hydrogen hub may opt to use the cheapest source of electricity available at any given hour.

If the level of VRE and dispatch down electricity is insufficient to meet the load requirement, but the system is connected to the electrical grid, it will purchase grid electricity from the wholesale market, regardless of price, to meet it. If the system does not have a grid connection, it is unable to produce hydrogen to meet the demand and is therefore an invalid system configuration.

2.2.6 Description of Case Study: Island of Ireland

To demonstrate the novelty and utility of the model, it is applied to some case studies on the island of Ireland. Ireland has high levels of VRE in its electricity mix, with some regions experiencing dispatch down figures in excess of 25% for certain months of the year [35]. With

VRE capacity set to grow in line with ambitious targets from both the Irish and UK governments, there is significant potential to produce hydrogen in such a high VRE system. Whilst it does not have a heavy industrial base or considerable existing hydrogen demand, the island has modern gas and electricity networks which could facilitate the use of hydrogen to decarbonise end-uses in transport, heat, and power.

The case studies analysed are hypothetical regional hydrogen hubs assumed to begin their lifetime in 2030. When modelling a hydrogen hub, the region's unique characteristics are examined. Firstly, the existing or potential future sources of electricity, including wind, solar, and grid, are identified. Secondly the regions potential future demand for hydrogen from a number of different end-use applications is investigated. For instance, a large existing diesel road haulage fleet could be replaced by fuel cell electric trucks or hydrogen could be blended into the natural gas network. Then to link production to demand, the options for storage and distribution are identified. The hubs examined are depicted on the map in Figure 4 and the relevant information of each scenario is summarised in Table 6. This includes electrolysis technology, storage size and method, distribution distance and method, end-use application, and total hydrogen demand.

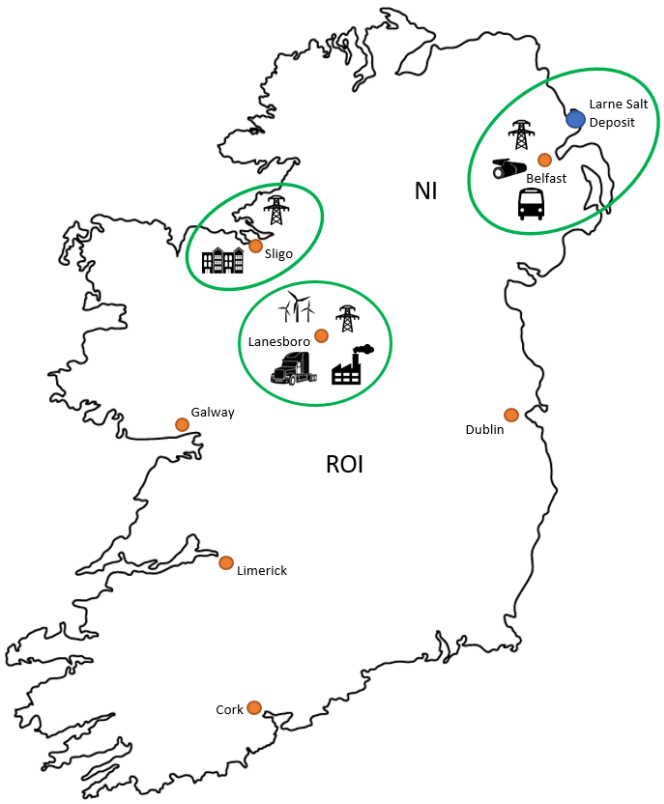

Figure 4: Map of the Republic of Ireland (ROI) and Northern Ireland (NI) showing the locations of the hydrogen hub case studies.

Table 6: Summary of relevant information of the six scenarios modelled.

	Hydrogen Hub	Electricity	Electrolysis Tech	Storage	Transport	End-Use	H_2 Demand (Tonnes)
1	Lough Ree	58 MW Wind, Grid, DD	PEM	Tanks, 1 day	Tube Trailers, 40 km	50 Trucks	400
2	Lough Ree	58 MW Wind, Grid, DD	PEM	Tanks, 1 day	Tube Trailers, 30 km	Industrial Heat	1,780
3	Lough Ree	58 MW Wind, Grid, DD	PEM	Tanks, 1 day	H_2 Pipeline, 45 km	Natural Gas Consumers (20% by vol.)	21,000
4	Belfast	Grid, DD	ALK	Salt Cavern, 10 days	H_2 Pipeline, 30 km	350 Trucks, 210 Buses, 8 Trains	3,970
5	Belfast	Grid, DD	ALK	Salt Cavern, 10 days	N/A	Natural Gas Consumers (20% by vol.)	9,720
6	Sligo	Grid, DD	PEM	Tanks, 1 day	Tube Trailers, 20km	Local Gas Network (Industry)	1,880

2.2.6 a Lough Ree

The first hydrogen hub modelled is located in the Lough Ree area, in the Midlands of Ireland. The region is home to a recently decommissioned peat burning power station in Lanesboro, Sliabh Bawn Wind Farm, with a capacity of 58 MW, and a number of different potential hydrogen end-users, including road haulage fleets and heavy industry. The largest town in the region, Athlone, is home to industry, transport fleets, and the natural gas network.

For the 2030 hydrogen hub, it is assumed that the production system is located on the site of the decommissioned power plant, using its existing electrical substation. The 58 MW, operational wind farm at Sliabh Bawn, is connected to this substation. Therefore, it is assumed

that any wind power produced is available for electrolysis if needed. The system can also purchase grid electricity in the wholesale electricity market. The hydrogen produced is compressed and stored in aboveground tanks with a capacity of one day of hydrogen demand.

Three different end-use scenarios are examined for this hydrogen hub, as depicted in Table 6. In the first, the hydrogen is produced by PEM electrolysis on the site of the decommissioned power plant in Lanesboro and distributed by tube trailer to a refuelling station in Athlone to fuel 50 hydrogen trucks. PEM electrolysis is chosen for its quick response time, allowing it to follow the variable output of a wind farm [36]. Tube trailers are again the method of distribution for the second scenario, this time delivering the hydrogen to a number of large industrial energy users in the area. Hydrogen is combusted in boilers to provide high-temperature heat, in place of 50% of their current heavy fuel oil usage. Lastly, in the third scenario for this hydrogen hub, the hydrogen produced is piped via a dedicated hydrogen pipeline to a natural gas grid injection facility. It will be blended into the high-pressure natural gas transmission network in volumes of up to 20%. This is the current assumed limit for safe hydrogen blending in high-pressure transmission networks [45].

2.2.6 b Belfast

The second region the model was applied to was Northern Ireland (NI), specifically the area surrounding its capital, Belfast. NI shares electricity and natural gas networks with Ireland and is connected with Scotland by natural gas and electrical interconnectors. NI itself has a high penetration of renewable electricity generation at 44% [46], with the same figure for Scotland and Ireland at 61% [47] and 42% [48], respectively. This abundance of available renewable energy in NI from indigenous and surrounding areas makes it a key area of interest for hydrogen production. Currently, much of this energy goes to waste as a result of dispatch down, with 14.8% [35] of the wind energy produced in NI in 2020 not being used [35]. This figure is likely to grow as wind capacity increases over the next decade, with a government target of a 70% renewable electricity system by 2030 [49]. There is also considerable underground salt deposit formation in the area at Larne. This could be utilised for large scale hydrogen storage in salt caverns. The city of Belfast is home to a number of different transport fleets suitable for hydrogen, such as buses, trucks, and trains.

For both the hydrogen hub scenarios modelled for the Belfast area, the production system is located at Larne, near both the electricity and natural gas networks. The system has no direct connection to VRE but instead purchases grid electricity from the wholesale market. It is

assumed that up to 10 days of hydrogen demand can be stored in salt caverns nearby. The hydrogen is produced by ALK electrolysis and is then either distributed to Belfast via a dedicated hydrogen pipeline to fuel a fleet of 350 trucks, 210 buses, and 8 trains or injected directly into the high-pressure natural gas transmission network in blends of up to 20% by volume. ALK electrolysis is chosen due to the larger scale of hydrogen production required in comparison to the Lough Ree hub and the fact that the electrolyser is not required to follow the output of a specific wind farm or farms.

2.2.6 c Sligo

The final hydrogen hub analysed was located in Sligo, in the Northwest of Ireland. Sligo is the largest town in Ireland without a natural gas grid connection. As a result, investigation is underway to examine the potential for an isolated local gas network as part of the Sligo Local Gas Network (SLGN) Project [50]. It is proposed that this network would initially be supplied by compressed natural gas (CNG) distributed by truck from the nearest above ground installation (AGI) on the national natural gas network, with a view to transition to local sources of biomethane or hydrogen in the medium to long term. The network would provide gas primarily to industrial and commercial sites for on-site heating and combined heat and power generation. The Sligo region has a large installed wind capacity which suffers from a disproportionate amount of dispatch down due to congestion on the local electrical grid.

The proposed 2030 hydrogen hub modelled as part of this work aims to reduce the issue of dispatch down in the area whilst investigating the potential for hydrogen to supply the SLGN. As a result, the production system is located at a 220 kV electrical substation at Srananagh, which is in the vicinity of a number of wind farms. The hydrogen is produced by PEM electrolysis, and it is assumed that the system purchases grid electricity in the wholesale electricity market, as well as utilising dispatch down when available. Aboveground tanks provide storage capacity for one day of hydrogen demand. The hydrogen is then distributed by tube trailer to an injection point in the SLGN, where it is used to meet 100% of the network's demand.

2.2.7 Hourly Data

For electricity market prices, hourly data was obtained from detailed simulation of the 2030 Irish electricity system carried out by Deane et al. [51]. The work simulated a 70% renewable Irish electricity system, producing hour by hour generation and market price data. This data

was also used to calculate national dispatch down availability for 2030. For the hourly wind data, the online data generating tool renewablesninja.com [52] was used to generate hourly wind farm output profiles based on historical wind speed data. In order for the hourly data to match up, the same weather year of 1982 which was used by Deane et al, was used to generate the wind farm output profile.

Hydrogen demand is estimated based on the annual quantity of hydrogen required to replace the existing fossil fuel in the end-use sector, taking into account any differences in efficiency where applicable. For this study, demand is assumed to be constant throughout the year. The model is built for hourly demand resolution, so the hourly demand is calculated by dividing the total annual hydrogen demand estimate by the number of hours in a year.

2.3 Results and Discussion

In this section, the technical, economic, and environmental output results from the TEA tool for the three different hydrogen hub locations are presented and discussed. The operating profile of the optimally sized electrolyser for scenario 2 is presented and discussed in subsection 2.3.1. In subsection 2.3.2 the LCOH and optimal system configurations for each scenario are shown. Finally, the environmental outputs of the TEA tool for each scenario are presented in subsection 2.3.3.

2.3.1 Technical Outputs – Operating Profile of Electrolyser

The operating profile of the electrolyser for Scenario 2 the first 10 days of the year is shown in Figure 5, as well as the profile of available wind power and dispatch down electricity.

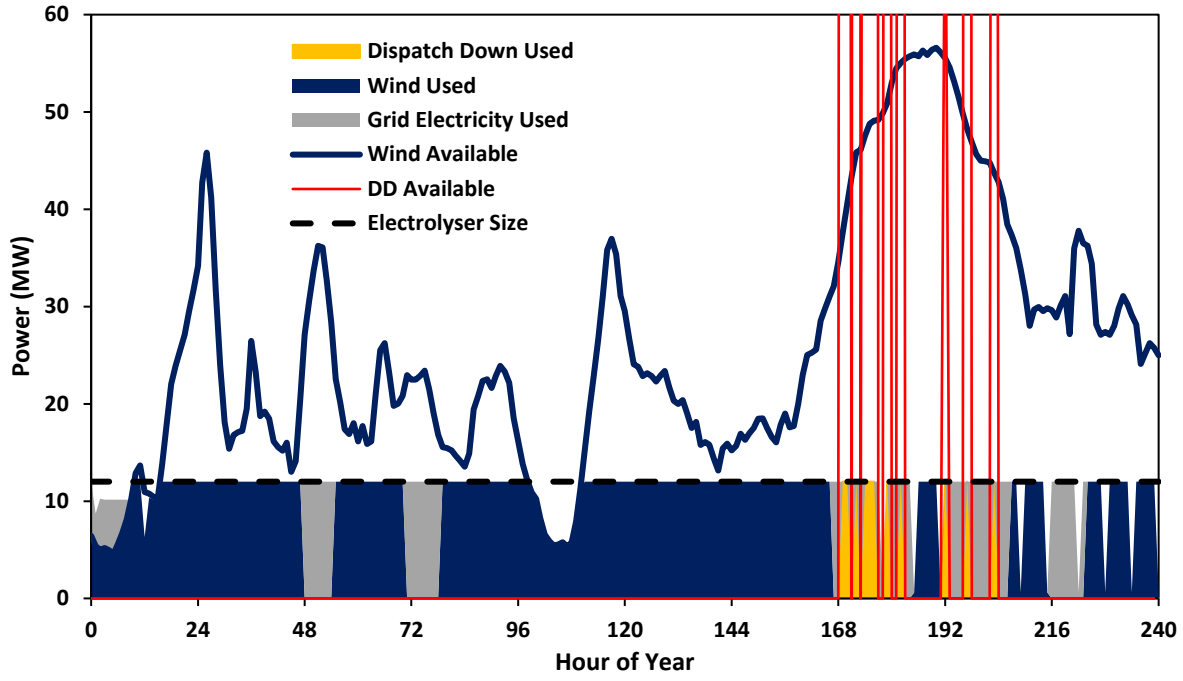

Figure 5: Operating profile of electrolyser for Scenario 2, Lough Ree over a period of 10 days.

In the first day of operation the electrolyser must top-up the available renewables with grid electricity to ensure that demand is met. On days 3 and 4 the electrolyser purchases grid electricity for a period, despite the availability of renewables. This is because the electrolyser will use the cheapest electricity available and for these periods, the wholesale market price has dropped below the cost of the available wind power. The electrolyser uses electricity that would otherwise be dispatched down on days 8 and 9, taking advantage of this low-cost source of electricity when it occurs. Over the course of the 10 days, it can be seen that the electrolyser uses mostly renewable or dispatch down energy, only purchasing grid electricity when necessary to ensure supply to demand, or to take advantage of low market prices. As the capacity of the electrolyser is smaller than that of the wind farm, much of the available wind power is not used by the electrolyser. This excess electricity may be sold to the electricity grid but this is beyond the scope of this analysis. However, were the wind farm or even the full electricity system to be included in the scope of the work, optimizing electrolyser operation for LCOH may not be economically or environmentally efficient. For example, at times of high electricity demand and wholesale prices, it is likely a wind farm would choose to export electricity to the grid instead of selling it at levelised cost for electrolysis. Grid export of VRE is likely to be prioritised over its use for electrolysis for this reason. This is a key consideration for future work.

2.3.2 Economic Outputs and Optimal System Configuration

2.3.2 a Lough Ree

Table 7 shows the optimal system configuration variables (electrolyser capacity and MBP) and LCOH for the six hydrogen hub scenarios modelled.

Table 7: Results of modelling for the six hydrogen hub scenarios analysed.

Scenario	Location	H_2 Demand (t)	Electrolyser Capacity (MW_e)	Max Bid Price (€/MWh)	Electrolyser Capacity Factor	LCOH
1	Lough Ree	400	2.5	30	92%	€3.50
2	Lough Ree	1,780	12	45	85%	€3.00
3	Lough Ree	21,000	138	70	87%	€3.40
4	Belfast	4,000	52	55	42%	€3.15
5	Belfast	9,700	126	55	42%	€2.75
6	Sligo	1,875	12	75	89%	€3.95

Focusing firstly on the Lough Ree hydrogen hub (scenarios 1 to 3), the different electrolyser capacities match their respective scenarios hydrogen demand requirement. The increase in MBP with electrolyser capacity reflects the need to 'top-up' the available VRE with more grid electricity to meet this higher demand. In relation to LCOH, Figure 6 shows that the contribution of electricity costs is greatest for Scenario 3, the demand with the largest electrolyser capacity.

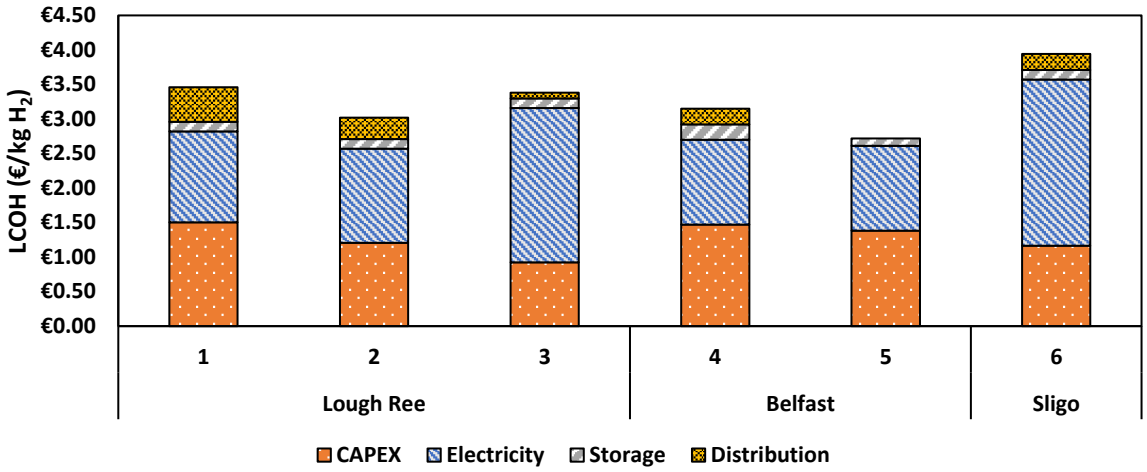

Figure 6: Levelised cost of hydrogen (LCOH) for the six scenarios modelled.

This is due to its need to purchase more grid electricity than the other scenarios. 78% of the electricity for electrolysis is supplied by the grid, compared to 18% and 25% for Scenarios 1 and 2 respectively, as shown in Figure 7.

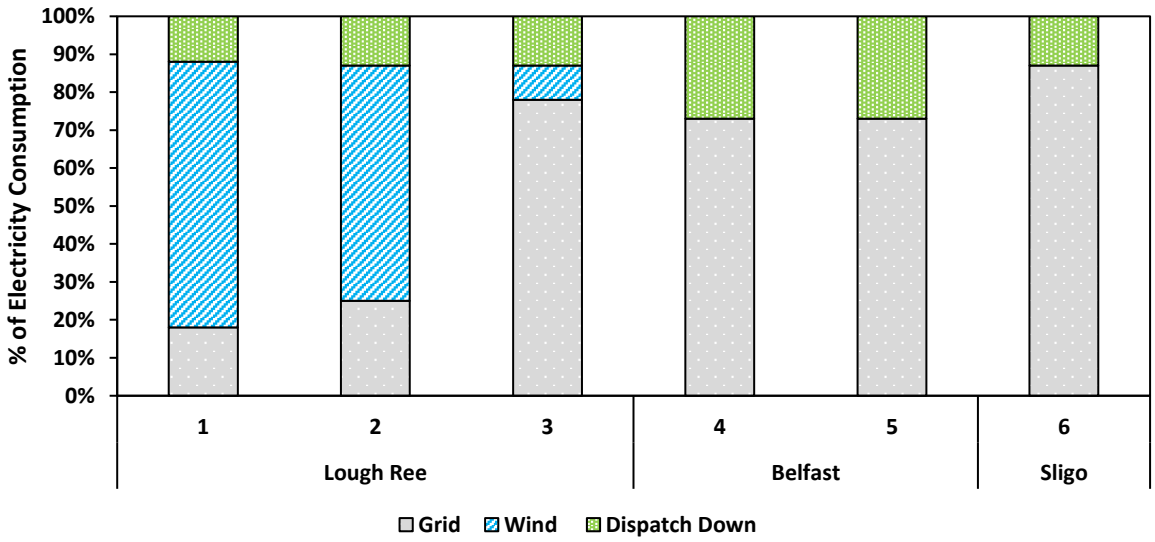

Figure 7: Percentage of electricity consumption from grid, wind, and dispatch down electricity for each scenario.

The contribution of capital costs (CAPEX) to the LCOH decreases with increasing electrolyser capacity due to economies of scale, as well as increasing electricity costs. The LCOH Storage remains the same for all three scenarios as the storage capacity for all three is one day of hydrogen demand in compressed tanks. The contribution of distribution costs to the LCOH is smallest for Scenario 3 where hydrogen is distributed via dedicated pipeline. For Scenarios 1 and 2, hydrogen is distributed via tube trailer as the cost of dedicated pipelines is prohibitive

in these cases, due to smaller annual hydrogen production quantities. Of the Lough Ree scenarios, the lowest LCOH is calculated for Scenario 2. This Scenario takes advantage of economies of scale for electrolysers whilst also making use of available VRE nearby to reduce electricity costs.

High capacity factors (>=85%) for all three Lough Ree scenarios are as a result of the need to meet consistent hydrogen demand with limited storage capacity. Looking at Scenario 1 specifically, Figure 8 shows the range of values of $LCOH_P$, $LCOH_S$, and $LCOH_D$ for electrolyser capacities from 1 to 10 MW_e.

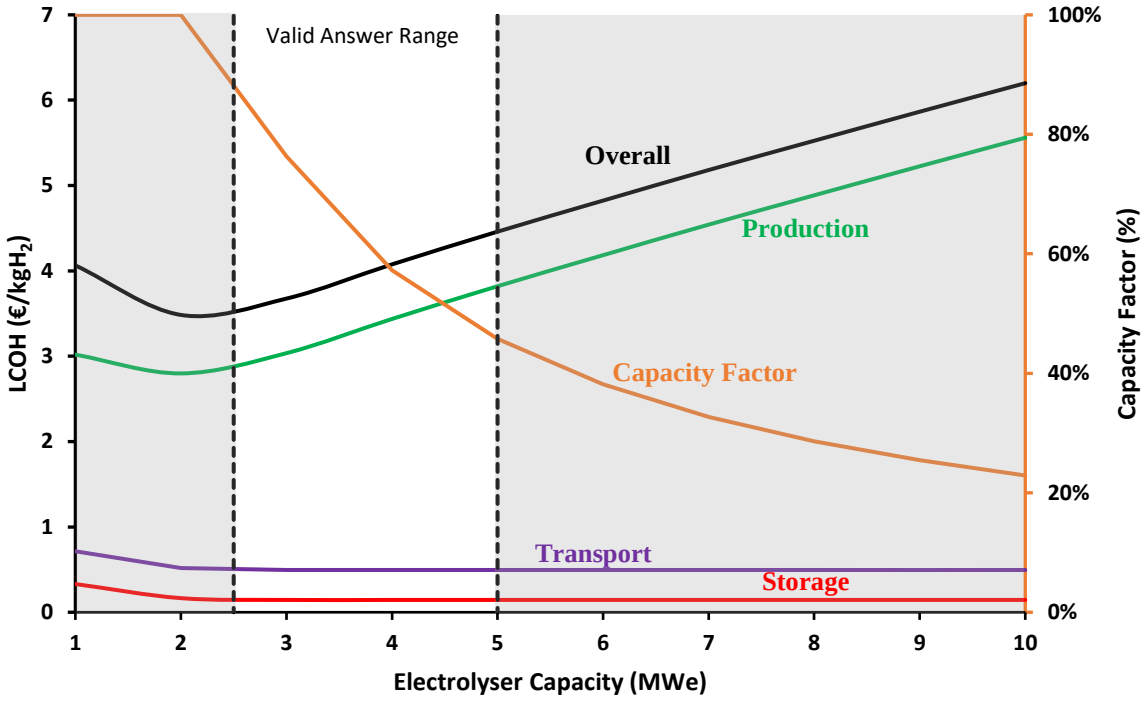

Figure 8: $LCOH_P$, $LCOH_S$, $LCOH_D$, overall LCOH, and electrolyser capacity factor (CF) vs electrolyser capacity for Lough Ree Hydrogen Hub Scenario 1.

The range of valid answers is quite narrow, from 2.5 to 5 MW_e. This is due to two main reasons. Firstly, electrolyser capacities less than 2.5 MW are unable to produce enough hydrogen to meet annual demand whilst also allowing adequate downtime for maintenance. Secondly, due to the limited storage capacity of 1 day of hydrogen demand, electrolyser capacities greater than 5 MW are unable to operate more flexibly and at a lower capacity factor, thus producing too much hydrogen and exceeding storage capacity.

The effect of electrolyser capacity on the $LCOH_P$ can also be seen. Initially, for electrolyser capacities up to 2 MW, the $LCOH_P$ decreases slightly, and then begins to increase steadily out

to 10 MW. The initial decrease is due to economies of scale in electrolyser costs, whilst the steady increase is due to a reduction in capacity factor as electrolyser capacity increases. Despite the increase in electrolyser capacity, the annual hydrogen demand to be met for the scenario does not change, so the larger system configurations still produce the same quantity of hydrogen, just by operating at a lower capacity factor (as shown in Figure 8). The $LCOH_S$ and $LCOH_D$ are relatively unaffected by changes in electrolyser capacity as the storage capacity, as well as the quantity and distance of hydrogen distribution, do not change.

The Sliabh Bawn Wind Farm has a capacity of 58 MW and produces over 180,000 MWh of electricity annually according to our modelling. Only 20,000 MWh per year are needed to produce enough hydrogen from the 2.5 MW electrolyser. However, due to the limited storage capacity of 1 day, it was still required to purchase 18% of its electricity from the grid to meet demand. Whilst 12% of the electricity used by the electrolyser in this scenario would have been otherwise dispatched down, the need to purchase a significant amount of grid electricity despite an abundance of nearby VRE calls the benefit of this hydrogen hub to the electricity system into question. This highlights the importance of storage to enable flexible operation of electrolysers for the benefit of the electricity system. The storage capacity for the Lough Ree Scenarios was limited to one day as greater compressed tank storage capacity added considerable expense to the overall LCOH. The restrictive effect this has on electrolyser operation could in fact exacerbate the issue of dispatch down rather than remedy it. This is an area for further study.

2.3.2 b Belfast

As for the Lough Ree hydrogen hub, for both Belfast scenarios the electrolyser is sized to meet the required hydrogen demand. As scenarios 4 and 5 participate in the same wholesale electricity market without any direct VRE connection, both also have the same MBP and capacity factor. This capacity factor of 42% is much lower than those for the Lough Ree scenarios. This is due to the assumed availability of large-scale hydrogen storage in the Larne salt deposits at a much lower specific cost to compressed hydrogen tanks. 10 days of hydrogen storage is assumed for the Belfast scenarios, allowing larger electrolysers to operate more flexibly and only produce hydrogen when grid electricity is cheap or dispatch down is available. This hydrogen can then be stored for use when electricity prices are higher and the electrolyser runs at MPL or shuts down. For both Scenario 4 and 5, 27% of the electricity used for electrolysis would otherwise have been dispatched down.

Figure 6 shows that the contribution of electricity costs for both Belfast scenarios is very similar, with the difference in overall LCOH resulting from lower specific CAPEX and storage costs due to economies of scale, as well as the absence of any distribution costs for Scenario 5, as the hydrogen is produced, stored, and injected into the natural gas grid on-site. The effect of MBP on LCOH for a different electrolyser capacities is shown in Figure 9.

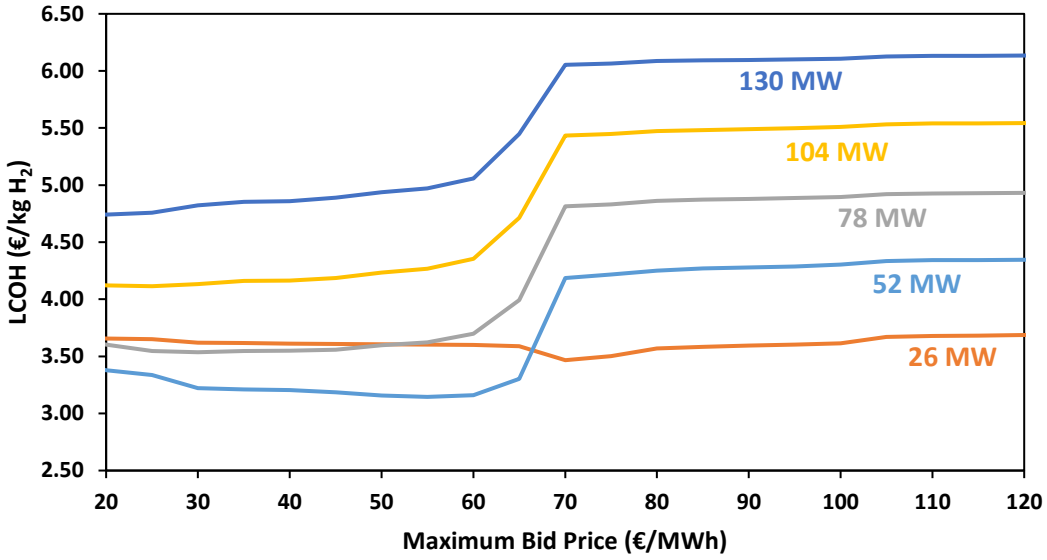

Figure 9: LCOH vs Maximum Bid Price (MBP) for different electrolyser capacities for the Belfast Hydrogen Hub (Scenario 4).

For an increase in MBP from €55/MWh to €110/MWh, there is an increase of 38% in the LCOH for an electrolyser capacity of 52 MW. This again outlines the effect of electricity costs on the overall cost of hydrogen. The steep increase in LCOH from a MBP of €60/MWh to €70/MWh for four of the five electrolyser capacities is due to the fact that this is the most common decade for electricity market prices. There is no such increase for an electrolyser capacity of 26 MW. The MBP has little effect on its operation as it must often run regardless of bid price to produce enough hydrogen to meet demand. LCOH increases with electrolyser capacity for all capacities above 52 MW. As demand for hydrogen is fixed for this scenario, increasing electrolyser capacity beyond 52 MW leads to lower capacity factors and higher CAPEX with no decrease in electricity costs per kilogram of hydrogen produced.

2.3.2 c Sligo

It is most relevant to compare the LCOH of the final scenario modelled (Sligo) to Scenario 2 (Lough Ree) in Figure 6 as the electrolyser capacity for both scenarios is 12 MW_e. The main discernible difference in LCOH between the two scenarios is in relation to electricity costs.

The source of electricity for Scenario 6 is grid electricity (87%) in addition to dispatch down electricity from the region (13%), whereas Scenario 2 is supplied by predominantly VRE (75%) which is not only cleaner, but also cheaper than grid electricity in 2030.

2.3.2 d Comparison of Hydrogen Hubs

Overall, the scenario with the lowest LCOH is scenario 5 in Belfast, due to both its lack of distribution costs, cheap storage, and the ability of the electrolyser to operate flexibly as a result of this storage, thus taking advantage of low electricity market prices. However, the most expensive LCOH, scenario 6 in Sligo, is also grid connected, participating in the exact same market. However, this scenario is limited to one day of compressed tanks storage and therefore could not utilise the same level of storage as the NI scenarios. This means the electrolyser has to operate consistently throughout the year, often buying expensive grid electricity to meet demand for hydrogen. The extent to which storage cost and size effects the operating schedule and LCOH is worthy of further investigation.

2.3.2 e Comparison to Other Fuel Options

The cost of hydrogen from Scenario 5 is competitive with the projected values of both heavy fuel oil (HFO) and diesel in 2030 [53], excluding VAT but accounting for a carbon tax of €80/tCO_2 [54] as shown in Figure 10.

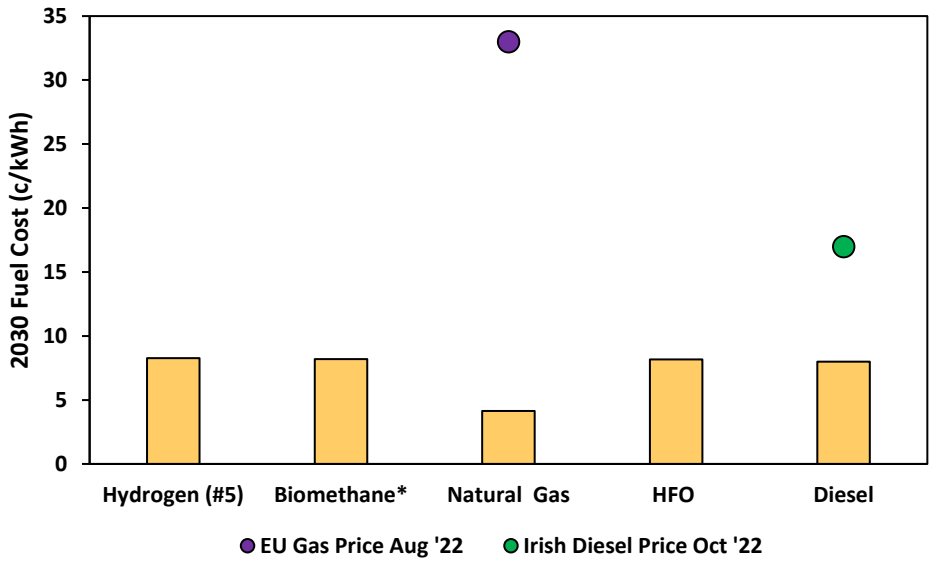

Figure 10: Bar chart of projected 2030 costs for different fuels. 2030 fossil fuel costs excluding VAT but including carbon tax of €80/tCO_2. Recent high prices for fossil fuels are also depicted (excluding VAT). *Biomethane costs for today not 2030.

This does not account for the superior efficiency of fuel cell vehicles over combustion engines for mobility applications. Natural gas however, is still significantly cheaper than hydrogen, based on historical prices [53]. Having said this, the high natural gas price of over 30 c/kWh in August 2022 outlines the inherent volatility of fossil fuel prices due to supply and demand imbalances, as well as the influence of geopolitics. This highlights the unreliability of any predictions or estimates for fossil fuels prices in 2030. For biomethane production in Ireland for injection into the gas grid, Keogh et al. calculated a minimum current LCOE of 8.2 c/kWh including the cost CNG filling station construction [55].

Whilst it can be useful to consider fuel costs when comparing hydrogen to other fuels, total cost of ownership (TCO) is a more comprehensive method of economic comparison of different decarbonisation options for a particular application. This is beyond the scope of this work but is an area for further study.

2.3.3 Environmental Outputs

2.3.3 a Lough Ree

In Figure 11 it can be seen that the third scenario has the greater value for emissions avoided per annum of the three Lough Ree scenarios. This is due to the fact that a much larger quantity of hydrogen is produced in this scenario, which offsets natural gas use.

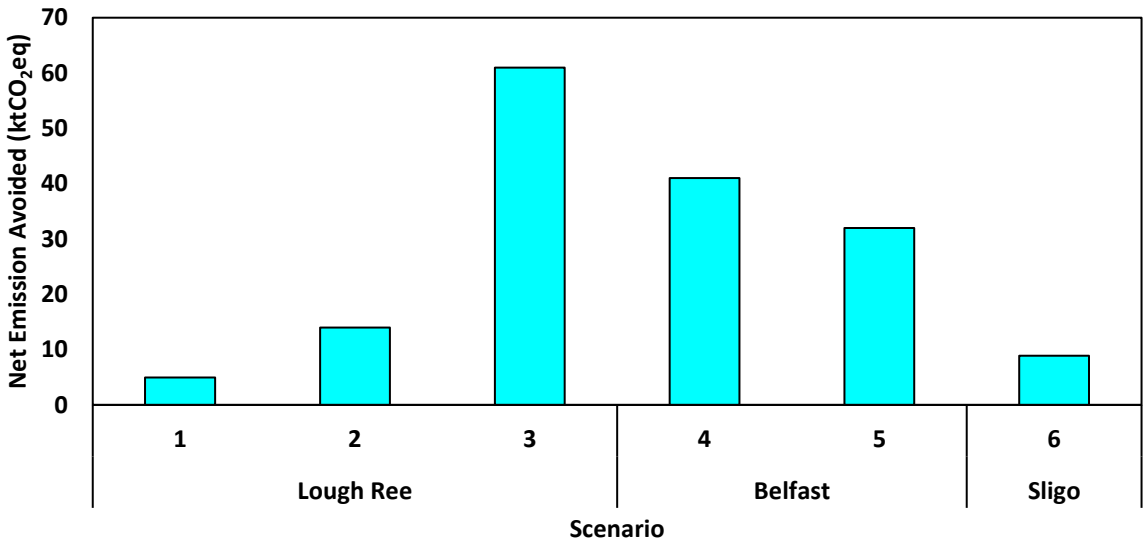

Figure 11: Net emissions avoided per year for each of the scenarios modelled.

However, as shown in Figure 12, the carbon intensity of the hydrogen produced in Scenario 3 is much greater than that of the first two.

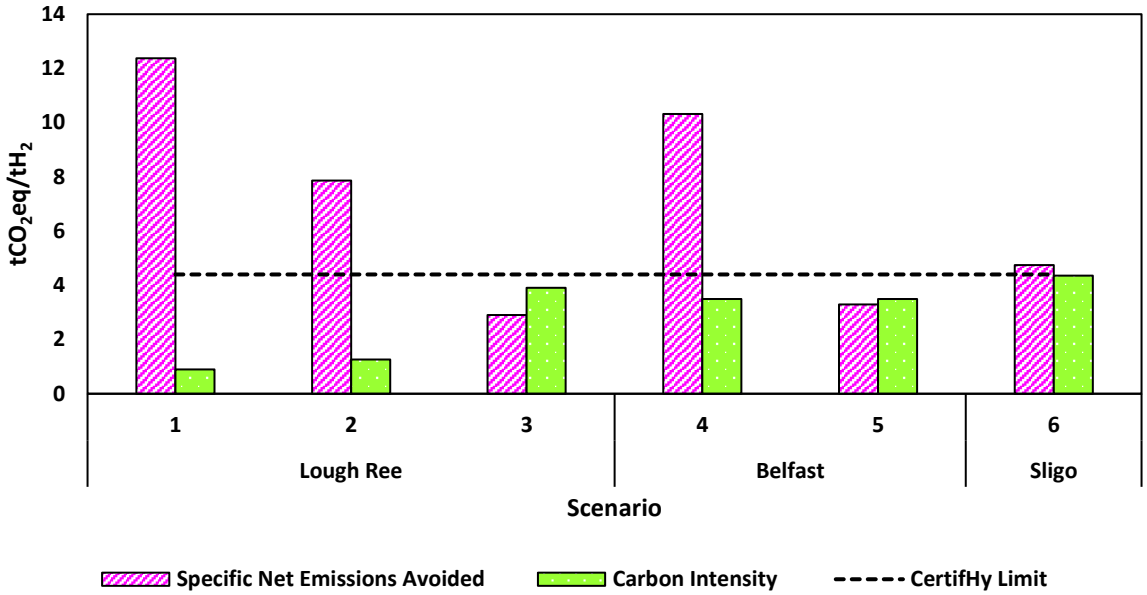

Figure 12: Specific net emissions avoided and carbon intensity of the hydrogen produced for each of the scenarios analysed.

This is because of this scenarios greater reliance on grid electricity, as mentioned before. In Figure 12, the specific net emissions avoided per tonne of hydrogen produced for each scenario is also shown. The first scenario has the highest value of the three here. This is because of three things. Firstly, the hydrogen produced in this scenario has the lowest carbon intensity. Secondly, it is displacing diesel use for trucks, which has a higher carbon emissions factor than natural gas, but slightly lower than that of heavy fuel oil. Lastly, hydrogen fuel cell trucks are more efficient than their diesel counterparts [31], meaning less hydrogen is needed to offset a larger amount of diesel by energy.

From these results, it can be seen that the environmental performance of a hydrogen hub is influenced by a number of factors, including; quantity of hydrogen produced, the carbon intensity of the electricity used for electrolysis, and both the type of fossil fuel displaced and its mode of use.

2.3.3 b Belfast

Unlike the Lough Ree scenarios, the scenario with the smaller electrolyser capacity and lower annual hydrogen production volume delivers greater emissions savings when comparing both Belfast scenarios (4 and 5), as shown in Figure 11. This is because the hydrogen produced in Scenario 4 displaces diesel use in transport, which, as mentioned previously, has a higher

emissions factor than the natural gas displaced in Scenario 5. The greater environmental performance of Scenario 4 is further highlighted by its higher specific net emissions avoided, which is almost 4 times that of scenario 5, as shown in Figure 12. Both scenarios produce hydrogen with a carbon intensity of 3.5 $kgCO_2/kgH_2$, within the CertifHy limit for low-carbon hydrogen of 4.37 $kgCO_2/kgH_2$ [56].

2.3.3 c Sligo

As a result of its use of grid electricity, Scenario 6 also avoids less emissions than Scenario 2, which has the same electrolyser capacity and produces a similar quantity of hydrogen. Though the emissions intensity of the hydrogen produced in Scenario 6 is nearly four times that of Scenario 2 (see Figure 12), it still qualifies as 'low-carbon' hydrogen.

2.3.3 d Comparison of Hydrogen Hubs

The scenario with the largest emissions avoided is Scenario 3 in Lough Ree. This is predominantly due to the fact that its electrolyser capacity and annual hydrogen production are the largest of all the scenarios. It also utilises wind power from the 58 MW Sliabh Bawn wind farm nearby, reducing the carbon intensity of the electricity used, and thus the hydrogen produced. When examining the specific net emissions avoided, the results are quite different, scenarios that use more VRE (Scenario 1), and which decarbonise more carbon intensive end-uses such diesel trucks (Scenarios 1 and 4), deliver greater emissions avoided per tonne of hydrogen delivery. None of the scenarios produce 100% green hydrogen, as at least some grid electricity is used for each. Intuitively, the scenarios which use the most VRE, produce hydrogen with the lowest carbon intensity (Scenarios 1 and 2). Having said this, all the scenarios modelled produce 'low-carbon' hydrogen with a carbon intensity below the CertifHy limit of 4.37 $kgCO_2/kgH_2$. This is due to the assumed reduction in the carbon intensity of grid electricity by 2030 ($100gCO_2/kWh$[57]). An area for future work could be the inclusion of hourly values for the carbon intensity of grid electricity to more accurately calculate the carbon intensity of the electricity used for electrolysis.

2.4 Conclusions

For this work, a flexible TEA tool for electrolytic hydrogen production, storage, and distribution that sizes production based on available electricity and estimated hydrogen demand of a region was built. The main inputs to the model are electricity market prices, VRE and dispatch down availability, and estimated hydrogen demand, all at an hourly resolution for one full year. The tool sizes the electrolyser capacity based on these and other user defined inputs. The main outputs of the model are LCOH, which is the sum of the levelised costs of production ($LCOH_P$), storage ($LCOH_S$ and distribution ($LCOH_D$), and the emissions avoided due to the use of hydrogen in place of fossil fuels for a particular end use. The techno-economics of providing hydrogen for end-use applications via hydrogen refuelling stations and grid injection facilities is beyond the scope of this work but is an important area for future study.

The TEA tool was applied to a number of 'hydrogen hub' case studies on the island of Ireland for the year 2030. Six different hydrogen hub scenarios were modelled in the Lough Ree area, Belfast, and Sligo.

Results show that low-carbon hydrogen could be produced from grid electricity bought from the wholesale market, stored underground in salt caverns, and supplied to the natural gas grid for blending on-site for an LCOH of €2.75/kg H_2 in NI in 2030. For the three Lough Ree hubs modelled, supplied by a 58 MW wind farm and topped up with grid electricity when required, the LCOH varied from €3.00-3.50/kg/H_2. For scenario 1, an electrolyser capacity of 2.5 MW still requires the use of grid electricity in order to meet a constant hydrogen demand, despite the availability of 58 MW of wind capacity nearby. This is a consequence of the 1 day storage limit for the Lough Ree hydrogen hubs due to the prohibitive cost of compressed tank storage. The final scenario modelled in Sligo delivers hydrogen for an LCOH of €3.95/kgH_2. This is considerably higher than the LCOH for both Belfast scenarios, despite also purchasing electricity from the wholesale electricity market. Again, this is due to the prohibitive cost of compressed hydrogen storage and the resulting limitation of 1 day of storage capacity, as opposed to 10 days for the NI scenarios. Larger storage capacity allows more flexible hydrogen production which can take advantage of available VRE, dispatch down, and/or cheaper wholesale prices at certain hours of the year. This leads to lower electricity costs, which explains the difference in LCOH across the scenarios. The scenarios with the lowest electricity costs are those with access to cheaper electricity, whether it is from direct VRE sources, dispatch down, or the wholesale electricity market. The effect of storage size and cost on the

flexibility of hydrogen production to utilize variable or low-cost electricity is worthy of further examination.

The scenario that delivered the most emissions avoided was the third Lough Ree scenario, avoiding over 60 thousand tonnes of equivalent carbon dioxide emissions each year. This is because it is also the scenario that produced the most hydrogen. When considering the most emissions avoided in relation to the quantity of hydrogen produced, the best performing scenario is the first Lough Ree scenario. Although it produces the least amount of hydrogen per annum, it has the greatest share of VRE in its electricity supply, and delivered its hydrogen to a carbon intensive end-use in diesel trucks. None of the scenarios produced fully renewable green hydrogen, due to the requirement to use grid electricity to meet demand, but all produced hydrogen considered is 'low-carbon'. As mentioned previously, the use of hourly carbon intensity data for the grid electricity used would give a more accurate carbon footprint metric and could be included in future work.

The TEA tool developed is a versatile tool that can be applied to any regional hydrogen hub or supply chain. The use of the tool for a number of case studies on the island of Ireland has identified the influence of storage capacity and costs on the techno-economic and environmental performance of hydrogen supply chains as a key area for future study. Hydrogen production must also complement the electricity system. It may often be more favourable for a wind farm to sell their electricity in the market than to produce hydrogen. As a result, although the wind farm may be producing electricity, this electricity may not always be available to the electrolyser, as our analysis assumes. In addition to this, the use of grid electricity, some of which will still be supplied by natural gas in 2030, to produce hydrogen for natural gas grid blending is somewhat inefficient, both energetically and environmentally. It may however, be necessary for some time to ensure economic viability. Having said this there is huge scope for grid-connected electrolysers to act as flexible demand and to participate in grid services markets [58]. How both VRE and grid-connected electrolysers can best utilise renewable electricity, contribute to electricity system stability, and decarbonise some of the most carbon intensive sectors of the energy system requires further investigation.

2.5 Acknowledgements

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2.6 Conflicts of Interest

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

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2.8 Supplementary Material

Table 8: Economic parameters for hydrogen storage infrastructure in 2030.

Economic Parameters for Hydrogen Storage 2030			ref
CAPEX			
Compressed Tanks	C_{CS}	470 x m_S	[39]
Underground Storage	C_{CS}	$\left[e^{a\left(\ln\left(\frac{m_S}{1000}\right)\right)^2} - b\left(\ln\left(\frac{m_S}{1000}\right)\right) + c\right] m_s$	[42]
OPEX			
Storage	C_{OS}	2% x C_{CS}	[39,42]

CAPEX in €, OPEX in €/year.
Values for a, b, and c for each underground storage method shown in Table 9 below.

Table 9: Values for a, b, and c for underground storage capital cost calculation [42].

Storage Method	**a**	**b**	**c**
Buried pipe	0.001798354	0.042016435	6.43774627
Lined Rock Cavern	0.110313069	1.771290644	10.89261757
Salt Cavern	0.085855232	1.549202319	9.868379508

Table 10: Economic parameters for hydrogen distribution infrastructure 2030.

Economic Parameters for Hydrogen Distribution 2030			unit	ref
CAPEX				
Tube Trailer	C_{CD}	232,000 x N_{TT}	€	[29]
Onshore Pipeline	C_{CD}	(2,200,000 x D^2) + (860,500 x D) + 247,500	€/km	[43]
Offshore Pipeline	C_{CD}	[1.75 x (0.314 + 0.574 x 10^{-3} x D) + (1.7 x10^{-6} x D^2)] x 10^6	€/km	[4]
OPEX				
Tube Trailer	C_{OD}	1.9	€/km	[29]
Pipeline	C_{OD}	2% x C_{CD}	€/yr	[4]

Where N_{TT} is the number of tube trailers required and D is pipeline diameter.

Table 11: Technical parameters for hydrogen storage and distribution infrastructure 2030.

Technical Parameters for Hydrogen Storage and Distribution 2030		ref
Operating Pressures (bar)		
Compressed Tank	300	[39]
Buried Pipe	100	[42]
Lined Rock Cavern	200	[42]
Salt Cavern	120	[42]
Tube Trailer	300	[59]
Pipeline	80	[60]
Other		
Tube Trailer Capacity, kg	500	[39]
Pipeline Gas Velocity, m/s	15	[60]
Pipeline Gas Density, kg/m^3	7.9	[60]

Chapter 3: The hydrogen storage challenge: Does storage method and size affect the cost and operational flexibility of hydrogen supply chains? (Journal Article #2)

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Author Contributions

Cian Moran: Conceptualisation, Methodology, Software, Data Curation, Formal Analysis, Investigation, Writing – Original Draft, Writing – Review and Editing, Visualisation. **Paul Deane:** Resources, Writing – Review and Editing. **Sajjad Yousefian:** Conceptualisation, Writing – Review and Editing, Supervision. **Rory F.D. Monaghan:** Conceptualisation, Methodology, Resources, Writing – Review and Editing, Supervision, Funding Acquisition.

Abstract

Hydrogen is seen as a key energy vector in future energy systems due to its ability to be stored in large volumes for long periods, providing energy flexibility and security. Despite the importance of storage in hydrogen's potential role in a zero-carbon energy system, many techno-economic analyses fail to adequately model different storage methods in hydrogen supply chains, often ignoring storage requirements altogether. Therefore, this paper uses a data-driven techno-economic analysis (TEA) tool to examine the effect of storage size and cost on three different 2030 hydrogen supply chain scenarios: wind-based, solar-based, and mixed-source grid electrolysis. For varying storage sizes and specific capital costs, the overall levelised cost of hydrogen (LCOH), including production, storage, and delivery to a constant demand, varies significantly. The LCOH ranges from €3.90-12.40/kgH_2, €5.50-12.75/kgH_2, and €2.80-15.65/kgH_2 for the wind-based, solar-based, and mixed-source grid scenarios respectively, with lower values for scenarios with low-cost storage. This highlights the critical role of low-cost hydrogen storage in realising the energy flexibility and security electrolytic hydrogen can provide.

Keywords

Hydrogen, wind energy, solar energy, energy storage, flexibility, energy security

Highlights

- Techno-economic analysis tool examines the effect of storage on hydrogen production
- Wind-based, solar-based, and grid electricity-based electrolysis scenarios examined
- Production only cost of hydrogen decreases by up to 35% with increasing storage size
- Up to 56 days of storage required to supply renewable hydrogen at a constant hourly rate
- Overall cost of renewable hydrogen in 2030 varies from €2.80-15.65/kgH_2

3.1 Introduction

The use of hydrogen as an energy vector is seen by many as crucial in achieving a climate neutral energy system, as it can decarbonise hard-to-abate sectors whilst also providing energy flexibility and security when stored in large volumes over long time periods. As part of the European Green Deal, the EU aims to be climate neutral by 2050, with an intermediate target of 55% net reduction in greenhouse gas (GHG) emissions by 2030 [1]. In addition to ambitious targets for the deployment of wind and solar capacity, contributing to a total renewable generation capacity of 1236 GW, the European Commission, through the REPowerEU plan, has set targets of 10 million tonnes of renewable hydrogen production in the EU and 10 million tonnes of hydrogen imports by 2030 [2]. This hydrogen is primarily to be used to decarbonise existing hydrogen production, as well as for heavy industry and transport, where direct electrification may be challenging or infeasible. One of the reasons why hydrogen could play a key role in future energy systems is because of the possibility of flexible production from variable renewable electricity (VRE) coupled with its potential for long-term storage in large quantities in underground geological formations [3].

3.1.1 Literature Review

To understand the costs associated with providing hydrogen to hard-to-decarbonise end-uses, techno-economic analysis (TEA) of future hydrogen production and supply chains has been widely used [4–10]. Janssen et al. calculated the levelised cost of hydrogen production ($LCOH_P$) from off-grid renewables for 30 countries in Europe from 2020 to 2050 [11]. For hydrogen production from onshore wind, Ireland was one of the cheapest locations, with an $LCOH_P$ of less than €2/kgH_2 for the year 2030. This compares to a range of €5-10/kgH_2 calculated by Gunawan et al. for hydrogen production at existing onshore wind farms in Ireland, which included distribution costs to supply city bus fleets [5]. For hydrogen production from solar, Janssen et al. calculated that Spain and Portugal were two of the lowest cost locations in 2030 with $LCOH_P$ values of €3.16/kgH_2 and €2.66/kgH_2 respectively. This compares to estimates for 2021 by Hydrogen Europe of €2.90-4.30/kgH_2 for Spain and €2.90-3.50/kgH_2 for Portugal [12]. The use of grid electricity for electrolysis can result in higher capacity factors than VRE only systems, lowering hydrogen production costs [13]. According to numerous modelling studies, there are many systems benefits to the integration of electrolysis with the electricity sector [14–16]. The addition of flexible demand such as electrolysers to the electricity system can reduce the total cost of electricity to consumers and

lower levels of VRE curtailment [13,15]. Raab et al. investigated the effect of using grid electricity in addition to VRE for hydrogen production for five locations around the world [10]. Including sufficient compressed hydrogen storage at 250 bar in aboveground tanks to meet a constant hydrogen demand, a techno-economic analysis was carried out to size each aspect of the supply chain for a minimum levelised cost of hydrogen (LCOH). Future costs are in the range of €2.5 – 4/kgH_2 for the five locations, which were selected based on their high combined wind and solar potential. In previous work by the present authors, a comprehensive TEA tool for modelling regional hydrogen supply chains was built, which included an hourly storage sub-model [17]. Electrolyser size and maximum grid bid price were calculated to minimise LCOH for several different scenarios on the island of Ireland, which incorporates Ireland and Northern Ireland. Results varied in the range of €2.75 – 4/kgH_2 for the year 2030, with scenarios with access to large-scale underground storage having lower overall costs. This finding echoes that of Nguyen et al. (2019) [8], yet many TEA studies do not give sufficient consideration to the storage aspect of hydrogen supply chains.

Due to its potentially high costs, it is essential to include temporal storage modelling as part of any comprehensive TEA work related to hydrogen supply. Whilst hydrogen production from renewables is inherently variable, demand for hydrogen in many end-use applications such as heavy industry and transport is often, if not entirely constant, consistent and predictable. Storage is required to match these differing supply and demand profiles.

Table 1 summarises some of the relevant TEA literature, displaying the electricity source and location of hydrogen production, and whether temporal modelling of production, storage, and demand is carried out.

Table 1: Summary of relevant hydrogen supply chain TEA literature.

Electricity Source	Location	Temporal Modelling			Storage Scenarios Modelled			Ref
		Production	*Storage*	*Demand*	*Different storage sizes?*	*Different storage methods & costs?*	*Parameter study?*	
Onshore Wind, Grid	Ireland	Yes	No	No	N/A	N/A	N/A	Gunawan et al. (2020)
Offshore Wind	Ireland	Yes	No	No	N/A	N/A	N/A	McDonagh et al. (2020)
Offshore Wind	North Sea	Yes	No	No	N/A	N/A	N/A	Singlitico et al. (2021)
Wind (Onshore and Offshore), Solar	Europe	Yes	No	No	N/A	N/A	N/A	Janssen et al. (2022)
Onshore Wind	Iran	Yes	No	No	N/A	N/A	N/A	Rezaei et al. (2021)
Offshore Wind	Portugal	Yes	No	No	N/A	N/A	N/A	Lucas et al. (2022)
Solar	California	Yes	No	No	N/A	N/A	N/A	Mastropasqua et al. (2019)
Grid	Spain	Yes	No	No	N/A	N/A	N/A	Matute et al. (2019)
Solar PPA	Spain	Yes	No	No	N/A	N/A	N/A	Matute et al. (2022)
Onshore Wind, Grid	Ireland	Yes	No	Yes	N/A	N/A	N/A	Gunawan et al. (2020)
Onshore Wind, Solar, Grid	Chile, Saudi Arabia, Spain, Australia	Yes	Yes	Yes	No	No	No	Raab et al. (2022)
Grid	California	Yes	Yes	Yes	Yes	No	No	Zhang et al. (2020)
Onshore Wind, Solar (Microgrid)	Mexico	Yes	Yes	Yes	Yes	Yes	No	de la Cruz-Soto et al. (2022)
Grid	Canada, Germany, California	Yes	Yes	Yes	Yes	Yes	No	Nguyen et al. (2019)
Onshore Wind, Grid	Ireland	Yes	Yes	Yes	Yes	Yes	No	Moran et al. (2023)
Onshore Wind, Solar, Grid	Ireland, Spain	Yes	Yes	Yes	Yes	Yes	Yes	Present Work

In much of the literature, variation in storage levels over time are not calculated or examined to adequately size storage to match supply and demand. Often, an arbitrary storage quantity is chosen to calculate costs [4–6,18–20] rather than sized or limited appropriately based on temporal variation in hydrogen production. In these cases, the sufficiency of the storage size chosen is not investigated. In some cases, storage is not accounted for at all [7,11,21,22].

It is also important to consider different types of hydrogen storage. Table 1 also outlines if the previous literature has considered multiple hydrogen storage sizes or methods across its

modelling scenarios. In addition to the aboveground tanks considered by Raab et al., there are multiple methods of hydrogen storage, with specific capital costs varying from €7 per kg usable hydrogen storage capacity for underground geological storage in some cases to €1,040 per kg for compressed hydrogen tanks in others [23,24]. Usable storage capacity accounts for the need for some gas to remain in the storage medium to provide a minimum pressure for gas withdrawal. Suitable storage options will vary from case to case, especially for underground storage, as this is dependent on the availability of suitable geological formations locally. Despite this, many studies consider only one method, and therefore one cost, of storage. In the works of Raab et al. and Zhang et al. hydrogen storage is modelled but only aboveground compressed hydrogen tanks are considered. The work of de la Cruz-Soto et al. carried out a TEA of a hydrogen storage system for a wind and solar-based microgrid, including a sensitivity analysis of hydrogen storage costs [25]. However, only costs in the range of aboveground compressed hydrogen tank storage were considered. Nguyen et al. completed a TEA of mixed-source grid-connected electrolysis in a number of electricity systems with different electricity pricing mechanisms and hydrogen storage options [8]. The scenarios with the lowest LCOH were located in Ontario, Canada, where the electrolyser participated in the wholesale electricity market and had access to large-scale, low-cost underground hydrogen storage. Similar results were found for scenarios in Northern Ireland in previous work by the present authors, as mentioned above. However, variation in storage size and cost for each modelling scenario via a parameter study or sensitivity analysis was not included. Therefore, the problem is twofold. Not only has the role of hydrogen storage been neglected in much of the TEA literature to date, but its effect on the techno-economics of hydrogen supply chains has not been explicitly or sufficiently investigated by means of a comprehensive parameter study or sensitivity analysis, as shown by the second to last column in Table 1.

3.1.2 Objectives, Novelty, and Sections of the Paper

The overall aim of this paper, therefore, is to examine the effect of storage size and cost on the overall techno-economic and environmental performance of hydrogen supply chains. The specific objectives of this paper are to 1) examine the effect of storage size on the levelised cost of hydrogen production ($LCOH_P$) for three different hydrogen production scenarios (wind-based, solar-based, and 100% grid electricity), 2) examine the effect of varying storage size and specific cost of hydrogen storage on the overall LCOH (production, storage, and distribution), 3) evaluate the effect of storage size on the capability of the electrolyser to

flexibly utilize VRE or cheap market electricity, and 4) to examine the effect of storage size on the carbon intensity of the hydrogen produced.

The novelty of this work is its focus on the techno-economics of hydrogen storage and how they significantly affect the techno-economic and environmental performance of hydrogen supply. This work uses a generic storage model to carry out a parameter study whereby a range of values are input for storage size and specific cost so that their effect on cost, operational flexibility, and carbon emissions of a hydrogen supply chain. Also, the examination of three distinct scenarios of hydrogen production from wind, solar, and mixed-source grid electricity for multiple storage criteria is in and of itself a novel work.

Following this introduction is Section 3.2, where the methodology used to carry out the work is described. An overview is given of the TEA tool used, and the three hydrogen supply chain scenarios are described. In Section 3.3, the results of the analysis are presented and discussed, and Section 3.4 details the conclusions of the paper and discusses potential areas of future work.

3.2 Methodology

The methodology used to carry out the analysis is described in this section. Firstly, a hydrogen hub is defined, and an overview of the hydrogen hub TEA tool used for this study is given in subsection 3.2.1. The case study scenarios for the work are then described in subsection 3.2.2.

3.2.1 Overview of Hydrogen Hub TEA Tool

An electrolytic hydrogen supply chain with hydrogen production, storage, distribution, and use located in one region is sometimes referred to as a hydrogen hub. Figure 1 shows the many potential configurations of a hydrogen hub and the system boundary of the TEA tool used for this analysis.

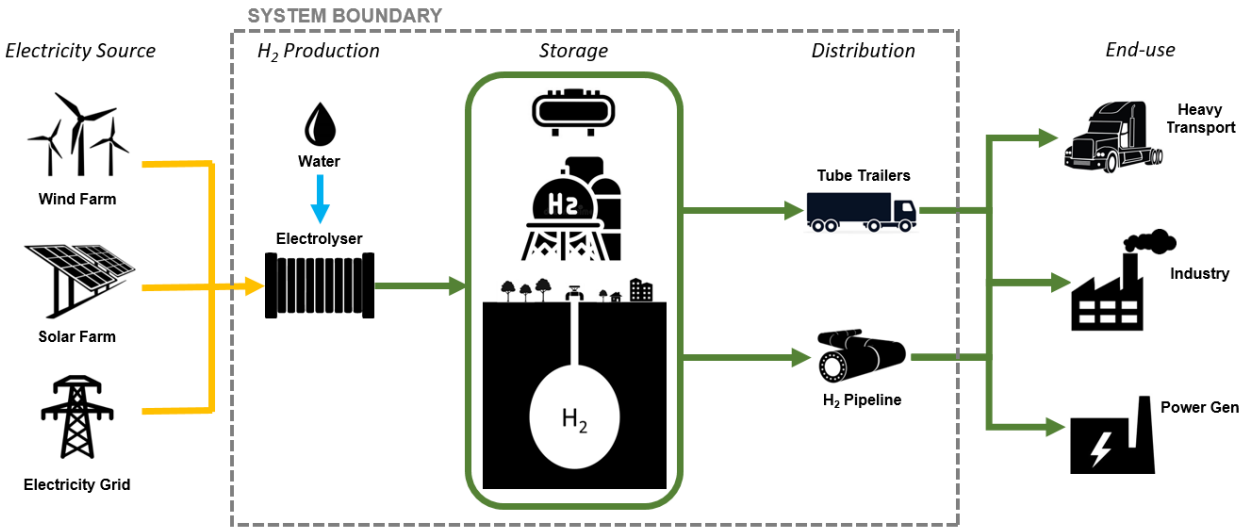

Figure 1: Potential hydrogen hub configurations and TEA tool system boundary.

The TEA tool used is based on previous work by the present authors and is described in detail in a previous paper [17], but a brief description is given below. As shown in Figure 2, the tool can take hourly data for multiple sources of electricity, as well as hourly data for hydrogen demand, and calculates a number of techno-economic and environmental outputs based on user-defined inputs including electrolyser technology, distribution method, and distribution distance. For this analysis, a generic storage sub-model is used to examine a range of values for storage size and cost.

As mentioned above, there are many methods of hydrogen storage, each varying in cost and scale. These include hydrogen storage as a compressed gas in aboveground tanks, buried pipes, and underground geological formations [26,27], liquid hydrogen storage in cryogenic tanks [28], and hydrogen storage in other chemicals such as ammonia and LOHCs (liquid organic hydrogen carriers) [29]. Hydrogen can also be stored in solid form through a variety of technologies such as metal hydrides, but these are at a low technology readiness level (TRL) [30]. For hydrogen storage in aboveground tanks, storage pressures vary from 30 to over 1,000 bar depending on tank technology [31]. Capital costs for aboveground tanks also vary according to literature, with a specific capital cost as high as 1,040 €/kg hydrogen storage capacity [24], in comparison to the Clean Hydrogen Partnership Key Performance Indicator figure of 350 €/kgH_2 [32]. This is due to cost variations across the four types of compressed hydrogen storage tanks currently available, as detailed by Hassan et al. [31], and differing assumptions in potential future cost reductions. For hydrogen storage in underground salt caverns, specific capital costs can be as low as €7/kgH_2 storage capacity [33]. Hydrogen storage

in salt caverns is mature with operational sites in the USA and UK [34] and projects of up to 8,052 GWh hydrogen proposed [35]. It would not be feasible to store such a large quantity of hydrogen in aboveground tanks due to space limitations. Aboveground compressed hydrogen tanks are most suited to storage of hydrogen in quantities of less than 10 tonnes (0.33 GWh). However, salt cavern storage is dependent on the availability of suitable underground formations and is therefore often not an option for many hydrogen projects. A number of other barriers to large scale underground hydrogen storage exist today, such as a lack of uniform regulations, codes and standards, public perception, and in some cases, technical limitations. Salt caverns are also only cost-effective for storage capacities greater than 100 tonnes [26]. This represents a challenge for smaller scale hydrogen projects seeking access to low-cost storage, even if salt deposits are available locally.

Instead of specifying a particular storage method or technology, this work consists of a parameter study examining the two main techno-economic variables relating to hydrogen storage. These variables, the specific cost of hydrogen storage (€/kg of usable hydrogen storage capacity) and storage size (mass equivalent to a defined number of days of hydrogen demand) are iterated for a range of values, as shown in Figure 2.

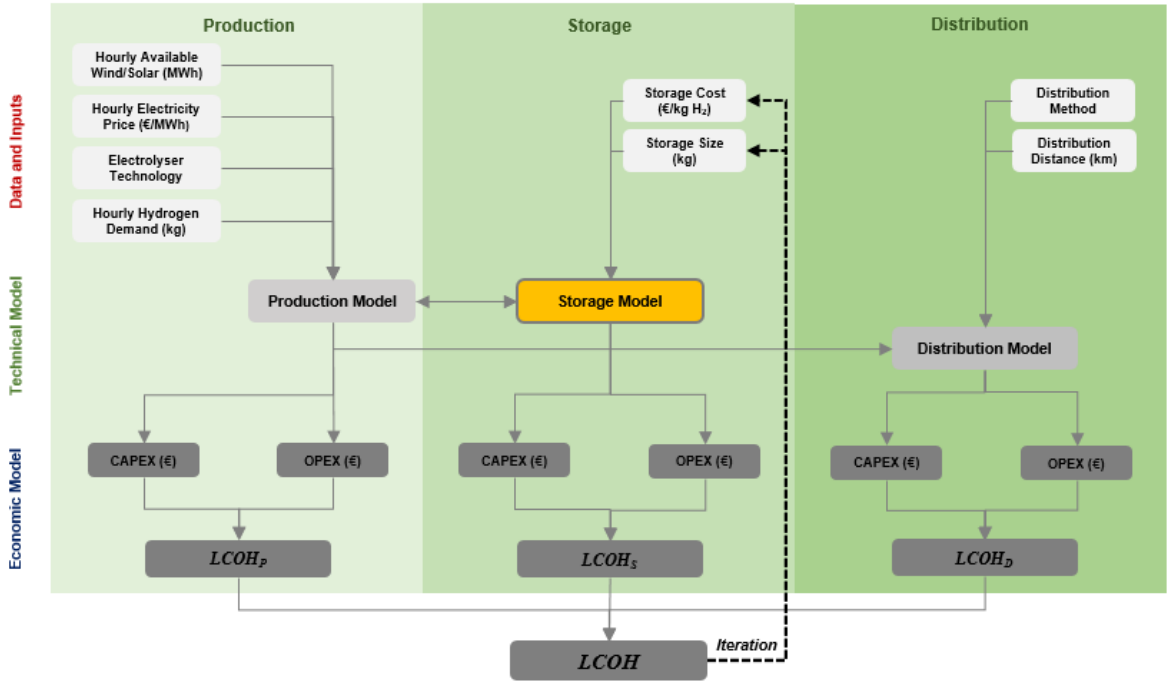

Figure 2: Flow diagram of hydrogen hub TEA tool.

Hydrogen production, storage, and distribution are included within the system boundary, but VRE generation is not. Thus, the capital cost of new VRE capacity is not used to calculate LCOH. Instead VRE is purchased at an assumed levelised cost. Mixed-source grid electricity is bought from the hourly wholesale market. The hydrogen production model interacts with the storage model, deciding each hour how much electricity the electrolyser consumes, aiming to use VRE or cheap electricity when available, whilst ensuring hydrogen demand is met and storage limits are not exceeded. The capital expenditure (CAPEX) and operational expenditure (OPEX) associated with hydrogen production are calculated, including the costs of the electrolyser, balance of plant, and compressor. Electricity costs are included in the OPEX. The calculated CAPEX and OPEX values are then used to calculate the $LCOH_P$. A detailed description of the relevant cost assumptions is described by Moran et al.[17].

In the storage model, the CAPEX is calculated by multiplying the specific cost of storage by the storage size. Annual OPEX is assumed to be 2% of the total CAPEX [4]. From these figures, the $LCOH_S$ is calculated. For specific storage costs, the input values range from €10/kg of hydrogen storage capacity, which is similar to specific costs for underground geological storage, to €500/kg which is similar to specific costs for storage in aboveground compressed hydrogen tanks [26,36]. The range for storage size begins at the mass required to meet 2 days of hydrogen demand, up to the maximum storage size that could be utilized in each scenario. This is calculated by incrementally increasing storage size until the additional storage capacity is not utilized by the hub. All other aspects of the hydrogen hub are fixed for each scenario, including electrolyser size and VRE capacity, which are sized so that theoretically there is sufficient electricity for electrolysis to supply the annual hydrogen demand.

The distribution model calculates the CAPEX and OPEX based on the distribution method (tube trailer or pipeline) and distance. For this analysis, these are both fixed across all scenarios. The $LCOH_D$ is then calculated based on the CAPEX and OPEX of distribution. Details of the cost assumptions related to distribution are given in Moran et al. [17]. The overall LCOH is the sum of the $LCOH_P$, $LCOH_S$, and $LCOH_D$. The cost of end-user equipment such as hydrogen boilers or vehicles is not included within the scope of the TEA tool.

In addition to LCOH, the emissions associated with hydrogen production are calculated from the carbon intensity of the electricity consumed. Thus, the carbon intensity of the hydrogen can also be derived. This calculation is detailed in Moran et al.[17].

3.2.2 Description of Case Study Scenarios

The TEA tool is applied to three different hydrogen production scenarios for the year 2030 summarised in Table 2.

Table 2: Summary of scenarios analysed.

Primary Electricity Source	Location	VRE Capacity (MW_e)	Electrolyser Size (MW_e)	Electrolyser Capacity Factor
Wind	Galway, Ireland	138	138	42%
Solar	Andalucía, Spain	240	240	24%
Mixed-Source Grid	Ireland	N/A	150	38%

The first two locations are chosen for their high VRE resource potential, and Ireland is chosen as the location for the mixed-source grid scenario as the Irish government has an ambitious target for 80% renewable energy penetration in the electricity system by 2030 [37]. All three scenarios are sized to meet an annual demand of 10,000 tonnes. This is equivalent to the demand of about 1,250 40-tonne trucks powered by hydrogen fuel cells. The demand is fixed to offer a fair comparison of results across scenarios. The potential for such demand in each of the case study regions is not quantified and is considered beyond the scope of the work. The hydrogen is assumed to be required, and therefore delivered at a constant hourly rate via a 100-km dedicated hydrogen pipeline. Although the profile of hydrogen demand is likely to vary depending on the end-use, many applications will require a constant supply on an hourly, daily, or weekly basis. For example, many industries have a 24-hour production schedule, and public transport fleets run to fixed daily schedules all year round. In the case where hydrogen is to be subsequently used to produce an electrofuel such as ammonia, methanol, or e-jet fuel, these processes favour stationary operation, requiring a constant supply of hydrogen [10]. In any case, the aim of this work is to examine the influence of storage when acting as a buffer between hydrogen supply, which is variable, and demand, which is likely to be more consistent. The constant demand assumption therefore acts as a straightforward reference case on which to base the analysis. For both the wind and solar scenarios, the renewables and electrolyser capacity are matched so that all of the VRE can, in theory, be used for electrolysis. This work examines the effect of storage size on the technical possibility of full VRE utilization; to ascertain if this is indeed realistic. Hence, the wind and solar-based scenarios can also use mixed-source grid electricity if required. Whilst the wind or solar generation may be provided

to the electrolyser via a power purchase agreement (PPA), it is assumed that the grid electricity used in addition to this is not available via a PPA as hourly temporal and spatial matching is required for PPAs for hydrogen production from 2030 onwards, the timeframe studied here. Instead, an hourly wholesale price and the average carbon intensity of grid electricity is assumed for any non-VRE consumption. This may affect the ability of a hydrogen producer to avail of subsidies for renewable hydrogen.

Hourly wind and solar generation data is generated using renewablesninja [38], an online tool which can calculate wind and solar profiles for any location in the world using models based on historical wind speed and solar irradiance data. The locations used were Galway, Ireland for the wind-based scenario, and Andalucía, Spain for the solar-based scenario. For mixed-source grid electricity, 2030 hourly market prices are taken from future energy system simulation modelling carried out by Deane and Mehigan [39]. That work simulated hourly generation and market prices for the Irish electricity system in 2030 using PLEXOS. The same modelling was also carried out by Deane and Mehigan for the Spanish electricity system in 2030 and the resulting market price data used for the solar-based hydrogen production scenario. The same weather year is used to create the VRE profiles as that used for the 2030 electricity system simulation. The electrolyser size of 150 MW for the grid-based electrolysis scenario is chosen as it is the system size with the lowest $LCOH_P$ (which does not include storage costs) that produces enough hydrogen to meet demand, assuming unconstrained or limitless storage capacity.

3.3 Results and Discussion

In this section the results of the analysis are presented and discussed. Firstly, the relationship between $LCOH_P$ and storage size is outlined in subsection 3.3.1. Secondly, in subsection 3.3.2, the effect of storage size on the flexibility of hydrogen production is shown and discussed. Then, the effect of storage size and specific cost on overall LCOH, including for storage and transport, is examined in subsection 3.3.3. Lastly, the relationship between the carbon intensity of the hydrogen and storage size is shown in subsection 3.3.4.

3.3.1 Production Cost vs Storage Size

The reduction in $LCOH_P$ versus storage size (in days of hydrogen demand) for all three scenarios is depicted in Figure 3.

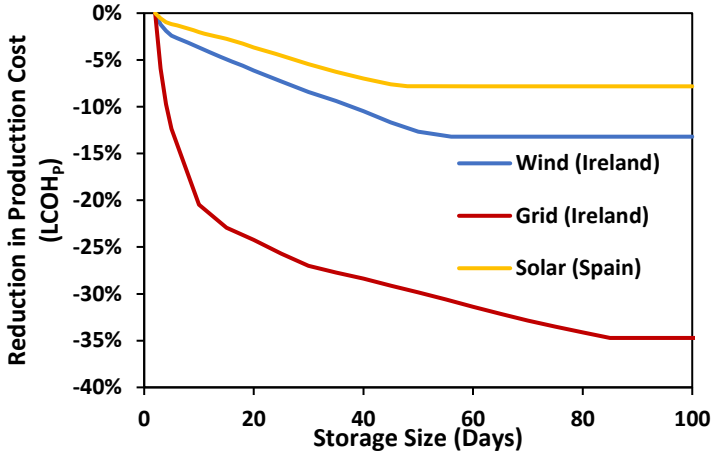

Figure 3: Reduction in levelised cost of hydrogen production ($LCOH_P$) with storage size for the three scenarios modelled.

As storage size increases, $LCOH_P$ is reduced, most significantly in the case of mixed-source grid-based electrolysis. By increasing storage size, the $LCOH_P$ is reduced by 8%, 13%, and 35% for solar, wind, and grid-based electrolysis, respectively, for storage sizes of at least 48, 56, and 85 days of storage. The reduction in cost with storage size is due to the fact that if storage is full at any given time and demand has been met, the electrolyser must shut down, even if there is an availability of VRE (for the wind and solar scenarios) or market prices for grid electricity are low (for the grid-based scenario). This loss of energy must be made up for at another time by buying mixed-source grid electricity when storage is low and electricity market prices are higher, to ensure hydrogen demand is met. This occurs less often as storage size increases, until storage size is sufficient to fully utilize VRE generation (for the wind and solar scenarios) or low market prices (for the grid-based scenario). It is important to note that $LCOH_P$ does not include the cost of hydrogen storage or distribution, which will be examined later.

3.3.2 VRE Wasted and Grid Import vs Storage Size

Wind or solar power that is unused by the electrolyser due to operational limitations such as exceeding storage limits is hereafter referred to as 'VRE Wasted'. The VRE wasted and the grid electricity imported as a percentage of total electricity consumption of the electrolyser versus storage size for the wind and solar-based scenarios are shown in Figure 4 and Figure 5.

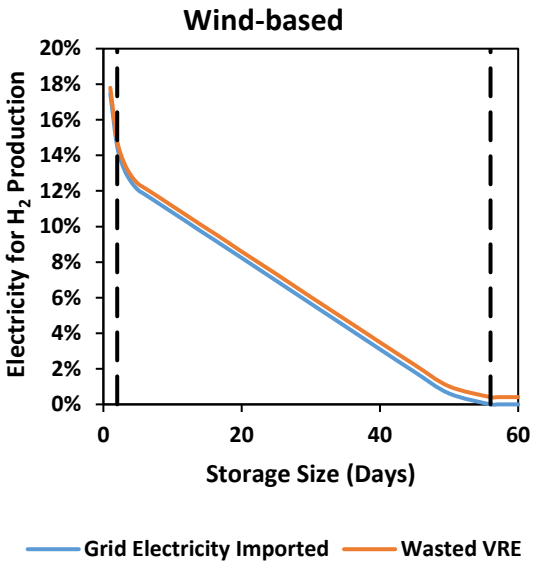

Figure 4: VRE wasted and grid electricity imported versus storage size for the wind-based electrolysis scenario.

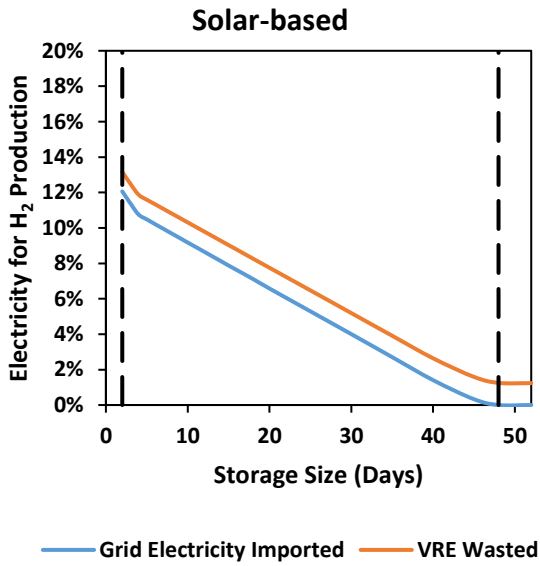

Figure 5: VRE wasted and grid electricity imported versus storage size for the solar-based electrolysis scenario.

As storage size increases, the quantities of VRE wasted and grid electricity imported decrease. This is for the same reason that $LCOH_P$ decreases, as described in subsection 3.3.1. For smaller storage sizes, storage fills up more often, resulting in more VRE being unutilized, and more grid power being imported to make up for this deficit. The quantity of VRE wasted is slightly greater than the grid electricity imported. This is due to the fact that some VRE is also wasted when there is insufficient VRE to run the electrolyser at minimum partial load, sometimes referred to as 'hot standby' or 'idle load'. The electrolyser shuts down completely and the insufficient VRE that is available is unused. No grid import is required for storage sizes of 56 days for wind and 48 days for solar, corresponding to the storage size for minimum $LCOH_P$. 48 days of hydrogen storage in this case is equal to over 1,300 tonnes. With these quantities of storage, and based on the particular weather year analysed (1982), hydrogen production could be off-grid, i.e. not connected to the main electricity network, for these scenarios. In practice, extra storage would likely be required to ensure security of supply in low-wind years.

Developers of some projects may opt to oversize VRE capacity compared to electrolyser capacity in order to increase capacity factor without the need for grid imports. Some VRE would be curtailed in this case but this may be economically acceptable for many projects, but for the purpose of this analysis VRE generation and the electrolyser are fixed at the same capacity.

These results are particularly relevant in the context of the EU Delegated Act adopted in February 2023 that sets out rules for the production of renewable liquid and gaseous fuels of non-biological origin, which includes hydrogen and its derivatives [40]. These rules require that to be considered renewable, hydrogen production must follow renewables output on an hour-by-hour basis from 2030. In this case, any hydrogen produced using electricity imported from the grid would not be considered renewable. However, the results herein indicate that the use of grid electricity may be required to ensure security of hydrogen supply to end-users.

3.3.3 The Impact of Storage Size and Specific Cost on Overall Cost

The overall LCOH, which is the sum of production ($LCOH_P$), storage ($LCOH_S$), and distribution ($LCOH_D$) costs, for a range of different specific storage costs, as a function of storage size is shown in Figures 6-8, for all three scenarios. The low value in the range of specific storage is similar to costs for salt cavern storage at large-scale, whilst the high value corresponds to aboveground compressed hydrogen tanks.

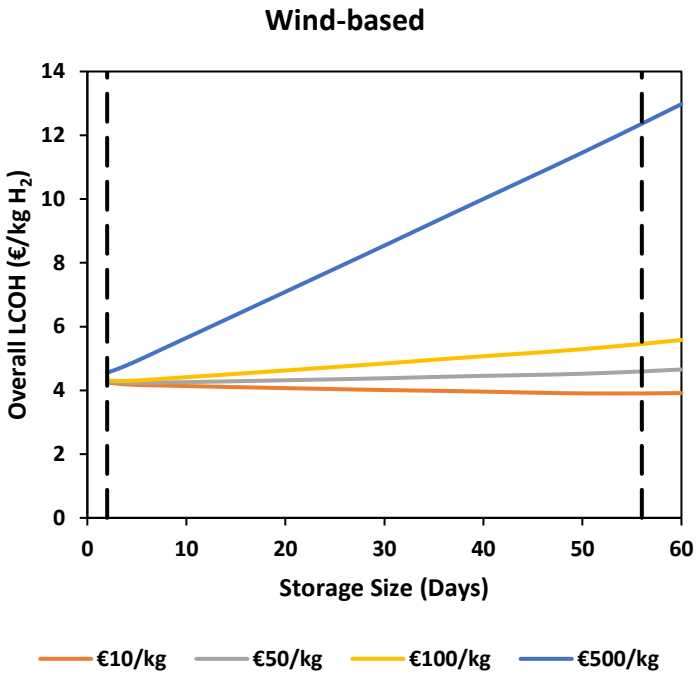

Figure 6: Levelised cost of hydrogen (LCOH) versus storage size for different specific costs of hydrogen storage for wind-based electrolysis in Ireland.

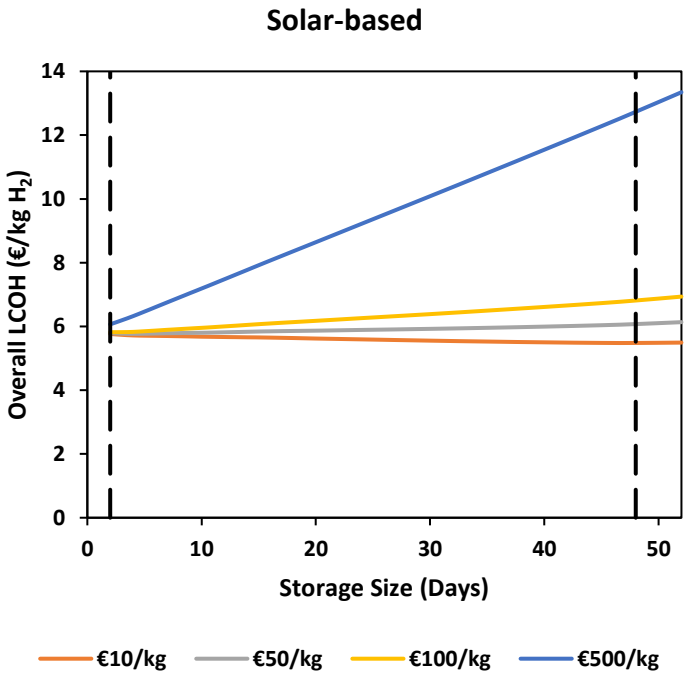

Figure 7: Levelised cost of hydrogen (LCOH) versus storage size for different specific costs of hydrogen storage for solar-based electrolysis in Spain.

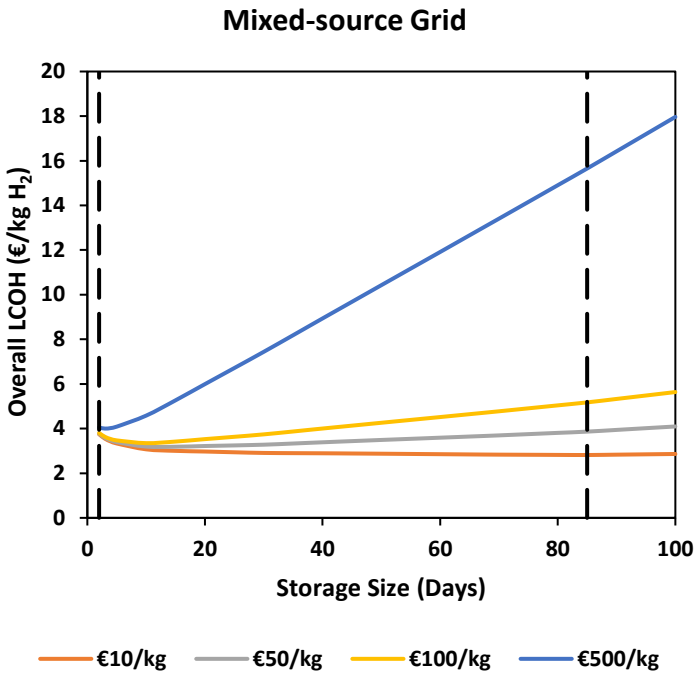

Figure 8: Levelised cost of hydrogen (LCOH) versus storage size for different specific costs of hydrogen storage for grid-based electrolysis in Ireland.

It is clear that both storage size and the specific cost of storage have significant effects on LCOH. For one day of hydrogen storage capacity for the wind-based scenario the cost varies from €4.25/kgH_2 to €4.55/ kgH_2 for the range of specific storage costs (€10/kg to €500/kg usable hydrogen storage capacity). For 56 days of storage, which is optimal for $LCOH_P$, the lower range LCOH value decreases by 8% to 3.90/kgH_2 while the higher range value increases by 170% to €12.40/kgH_2. A similar trend is observed for the solar-based and grid-based electrolysis scenarios.

The effect of storage cost on electrolyser operation and overall LCOH is significant. If storage costs are low, more storage allows for flexible electrolyser operation, taking advantage of periods of high VRE or low electricity market prices, storing the hydrogen produced for consumption at a later time. However, if storage costs are higher, the extra capital cost of storage is not sufficiently offset by flexible operation and resulting lower electricity costs. This highlights the importance of the storage method when designing hydrogen supply chains. For large scale hydrogen storage in underground geological formations, salt cavern storage is mature whilst storage in depleted gas fields and aquifers has been proposed but remains unproven at scale [26]. The availability of suitable underground storage is location dependent, and due to upfront capital costs and long lead times, is only cost-effective at large scale. Due to these factors, low-cost geological storage is unlikely to be a possibility for many first mover

hydrogen projects. In this case, hydrogen storage in compressed tanks may be the only suitable option. High capital costs, in addition to space restrictions and health and safety regulations, may result in lower storage sizes for such projects. In such cases grid electricity is likely to be required for electrolysis to ensure security of supply. However, according to the proposed rules from the European Commission, any hydrogen produced from grid electricity would be ineligible for subsidy as it is not considered renewable.

3.3.4 Carbon Intensity vs Storage Size

The carbon intensity described herein is based only on the carbon dioxide equivalent emissions from the electricity used for hydrogen production and excludes all other emissions in the hydrogen supply chain, for example the emissions associated with the manufacturing of components, or construction of the hydrogen production facility or hydrogen pipelines. Wind and solar electricity is assumed to have a carbon intensity of zero. Mixed-source grid electricity used exclusively (grid-based scenario), or in addition to VRE (wind-based and solar-based scenarios) to ensure hydrogen demand is met, is assumed to have the average carbon intensity of the electricity grid, regardless of which hour of the year it is purchased. In Figures 9-11, the carbon intensity of the hydrogen produced versus storage size is shown for each of the scenarios for two different average carbon intensities for mixed-source grid electricity, one similar to today's carbon intensity and one for 2030. The EU CertifHy low-carbon threshold is also shown for reference [41].

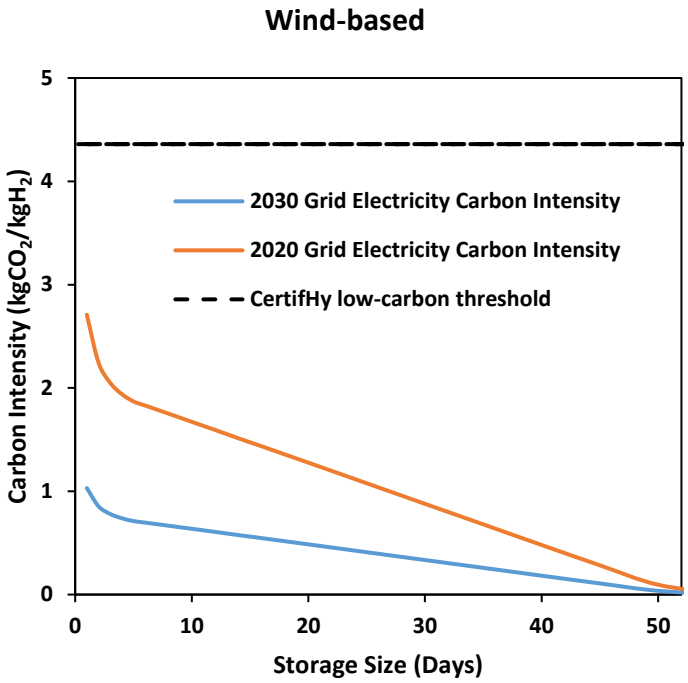

Figure 9: Carbon Intensity of hydrogen produced versus storage size for grid electricity carbon intensity for 2020 (310 gCO_2/kWh) and 2030 (118 gCO_2/kWh) for the wind-based scenario [39,42]. The CertifHy low-carbon threshold is also depicted.

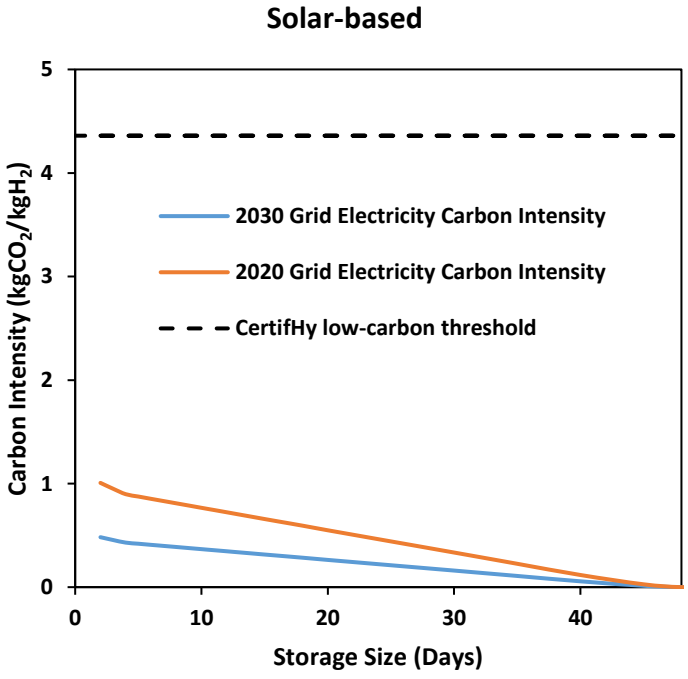

Figure 10: Carbon Intensity of hydrogen produced versus storage size for grid electricity carbon intensity for 2020 (167 gCO_2/kWh) and 2030 (80 gCO_2/kWh) for the solar-based scenario [43]. The CertifHy low-carbon threshold is also depicted.

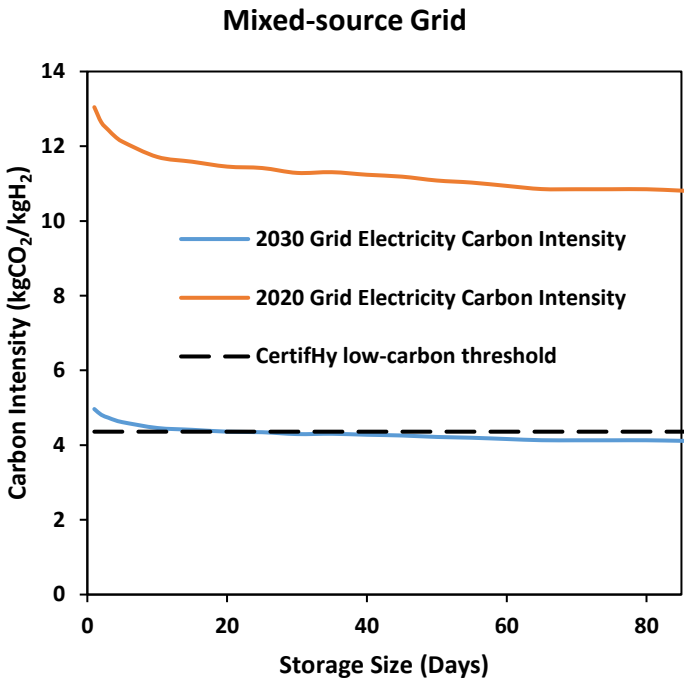

Figure 11: Carbon Intensity of hydrogen produced versus storage size for grid electricity carbon intensity for today (310 gCO_2/kWh) and 2030 (118 gCO_2/kWh) for the mixed source grid-based scenario. The CertifHy low-carbon threshold is also depicted.

For the wind- and solar-based electrolysis scenarios, the hydrogen produced is 'low-carbon' according to the CertifHy standard for all storage sizes, today and in 2030. This is because, despite the need to import mixed-source grid electricity, most of the electricity used for electrolysis is VRE. In the wind-based scenario, with one day of storage, 84% of the electricity consumed is VRE. However, the hydrogen is only 100% renewable and adheres to the widely understood definition of 'green hydrogen' for storage sizes of at least 56 and 48 days for wind and solar-based electrolysis respectively. Carbon intensity increases with storage size as more VRE can be used for electrolysis, and less grid power is imported. In the grid-based scenario, the carbon intensity of hydrogen decreases slightly with storage size. This is because more storage allows for the purchase of greater amounts of zero cost electricity, which is available when there is an excess of renewables on the system that would otherwise be wasted. This electricity is assumed to a have a carbon intensity of zero. Having said this, hydrogen production in the grid-based scenario is only low carbon for storage sizes greater than 20 days in 2030. This indicates that the viability of using mixed-source grid electricity for electrolysis is very dependent on the carbon intensity of a regions electricity system. It is also important to note that an average carbon intensity for grid electricity is used for the calculation, but carbon intensity can vary over time depending on weather conditions and associated VRE generation.

Using hourly values of grid electricity carbon intensity is likely to affect results and has been identified as an area for future work.

3.4 Conclusions

As there is a large variation in cost and scale of different hydrogen storage methods, this work investigates the effect of storage size and specific cost on the techno-economic and environmental performance of hydrogen supply chains. Firstly, the effect of storage size on $LCOH_P$ is investigated for wind-based, solar-based, and mixed-source grid-based electrolysis scenarios using a data-driven techno-economic analysis tool. It is found that larger storage sizes result in lower hydrogen production costs ($LCOH_P$), not including the cost of hydrogen storage and distribution. This is because greater storage capacity allows the electrolyser to take advantage of periods of high VRE and/or low electricity market prices to produce and store hydrogen for delivery at times of lower VRE and higher electricity prices. Secondly, the effect of variation in the size and specific cost of hydrogen storage on the overall LCOH, including production, storage, and distribution is examined. For low-cost storage in the range of specific capital costs for large-scale salt cavern storage, more storage corresponds to a lower overall LCOH for all three scenarios. However, for specific capital costs corresponding to aboveground compressed hydrogen tanks, the opposite is the case. Greater storage capacity increases the overall LCOH as the reduction in production costs is nullified by significantly larger storage costs. Thirdly, the effect of storage size on the operational flexibility of the electrolyser is determined. For lower storage sizes, the electrolyser is unable to take full advantage of periods of high VRE resulting in the wastage of VRE in both the wind-based and solar-based scenarios. The electrolyser must instead import more expensive mixed-source grid electricity at times of low VRE to meet the constant hydrogen demand, as storage is insufficient. For the grid-based scenario, lower storage sizes prevent the electrolyser from taking full advantage of periods of low electricity prices as storage capacity fills up quicker and the electrolyser must shot down. As in the wind and solar-based scenarios, electricity must be bought at times of higher prices to meet hydrogen demand as storage is insufficient. To summarise, lower storage sizes restrict the ability of the electrolyser to operate flexibly and take advantage of times of high VRE and/or low prices. Lastly, the effect of storage size on the carbon intensity of the hydrogen produced is explored. Across all scenarios, larger storage sizes

result in lower carbon intensities of hydrogen. For the wind and solar-based scenarios hydrogen produced across all storage sizes examined have a carbon intensity below the CertifHy low-carbon threshold, but storage sizes of 56 and 48 days respectively, are required for zero carbon hydrogen production. Only the emissions associated with the electricity for hydrogen production are included and average values for the carbon intensity of mixed-source grid electricity are used. Inclusion of supply chain emissions and the use of hourly carbon intensity data for grid electricity are key areas for future work.

These results underline the importance of storage when assessing or designing potential hydrogen supply chains or hubs. Geological storage is dependent on the availability of suitable underground geological formations and is thus location dependent. Lead times for construction of such large-scale projects are also significant due to existing barriers such as a lack of uniform regulations and social perception. This points to the importance of finding suitable sites and developing cost-effective large-scale storage as soon as possible, in parallel to developing uniform standards and improving public engagement. A hydrogen network is likely necessary to connect production and demand to these storage sites. In the short-term, many projects may not have the location, time, or scale required for cost-effective geological storage. Such projects may need to operate less flexibly, using mixed-source grid electricity to reduce storage requirements and lower costs. In these cases, there is a trade-off between cost and emissions and a balance must be struck to enable cost-effective emissions savings.

The effect of both VRE and grid-based electrolysis on the energy system is a key area for future work. Parameters such as LCOH do not account for system effects, energy security, or the benefit of flexibility and storage to the energy system. As electrolysis capacity grows, its effect on the electricity system and market, as well as the wider energy system, is inevitable. Hydrogen can contribute to a clean, flexible, and secure energy system but the development of cost-effective, large-scale hydrogen storage is essential in realising this.

3.5 Acknowledgements

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3.6 Conflicts of Interest

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

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Chapter 4: Flexible Grid Hydrogen Production: Beyond The Colours Taxonomy (Journal Article #3)

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Abstract

Electrolytic hydrogen can enhance energy flexibility and security, acting as a clean feedstock and fuel. Modelling has shown that integrating electrolysis with the electricity system can lower consumer costs and curtailment of renewable energy, yet strict carbon intensity policy requirements regarding electrolysis threaten to push hydrogen production 'off-grid'. This work aims to examine if such policies are optimal by investigating if grid-connected electrolysis can deliver cost-effective emissions reductions in comparison to off-grid electrolysis. Hydrogen production and storage are modelled using hourly data for wind output, electricity market prices, and the carbon intensity of grid electricity. Three scenarios for 2030 are analysed: Flexible grid-connected, off-grid, and hybrid (use of both dedicated renewables and grid electricity) electrolysis. Using grid electricity for electrolysis can deliver lower-cost hydrogen than off-grid electrolysis, whilst delivering similar levels of emissions reductions. The grid-connected scenario produces a levelised cost of hydrogen (LCOH) of €2.05-3.10/kgH2 in 2030, with an emissions reduction of up to 95% when displacing diesel use in buses. This compares to an LCOH of €4.40-11.60/kgH2 for off-grid hydrogen production from offshore wind. However, when displacing natural gas, emissions reductions in the grid-connected scenario are substantially lower, with increased emissions in some cases and costs much higher than natural gas. This highlights the importance of considering the end-use of hydrogen, the need for transparency in monitoring carbon intensity and for policymakers to look beyond the reductionist colours taxonomy in designing hydrogen policy.

Keywords

Hydrogen, Additionality, Policy, Energy Flexibility, Hydrogen Storage

4.1 Introduction

The production of renewable hydrogen for use as both an industrial feedstock and energy carrier is essential to achieving climate neutrality (i.e. achieving net zero greenhouse gas emissions). To minimise the catastrophic effects of climate change, decarbonisation of energy is a must (reducing fossil CO_2 emissions). Where electrification is not possible or prohibitively challenging, hydrogen is a potential solution to some of the hardest-to-abate sectors, such as industrial processes, high-temperature heat, and heavy transport. A rainbow of colours is often used to describe the many ways hydrogen can be produced, from the use of unabated fossil fuels to produce 'grey' hydrogen, to 'green' hydrogen produced by renewably powered electrolysis (see Table 1). However, these colours are based on hydrogen production route, not on its true carbon footprint, which can vary case by case [1].

Table 1: Description of hydrogen production colours.

Colour	Main feedstocks and process	Relative carbon intensity
Brown or Black	Coal gasification	High
Grey	Natural gas steam reforming (SMR)	High
Blue	SMR + carbon capture and storage	Reduced
Green	Water electrolysis + renewable power	Zero
Pink	Water electrolysis + nuclear power	Zero
Turquoise	Natural gas pyrolysis	Zero

As mentioned before, none of these categories ensure a carbon footprint limit nor a specific carbon accounting methodology. For instance, green hydrogen can be produced using a dedicated wind farm, but the temporal correlation is not specified, which allows producers to use renewable power generated months ago through a Power Purchase Agreement (PPA). Another example is blue hydrogen, proposed by many as a low-carbon hydrogen alternative, but depending on the accounting methodology, the emissions reduction in comparison to grey hydrogen can be as low as 9-12% [2]. Hydrogen produced from grid electricity does not have a specific colour, but the potential to interact with the power market and provide grid services

to generate extra revenue make it an attractive option for investors and electricity system operators alike.

4.1.1 Literature Review

The benefits of the integration of electrolysis with the electricity system has been modelled extensively [3–5]. The use of grid electricity for hydrogen production can lower production costs [6], whilst modelling has shown the benefits to the electricity system of sector coupling with hydrogen such as increased variable renewable generation and a reduction in the levelised cost of energy [3]. Despite this, proposed EU rules around hydrogen production require additional renewables capacity to be built for electrolysis whose output must be followed on an hour-by-hour basis from 2030, essentially separating hydrogen production from electricity systems and markets. Conversely, the EU low-carbon hydrogen regulation, CertifHy, rules are more flexible, allowing carbon intensity to be calculated as an average annual figure. The EUs Renewable Energy Directive (RED) II requires hourly resolution and UK's Low Carbon Hydrogen Standard a 30-minute resolution. At time of writing, the rules for the US Inflation Reduction Act hydrogen subsidies are yet to be finalised. Table 2 compares these hydrogen production policies.

Table 2: Low-carbon hydrogen policy landscape [1].

Regulation	GHG emission threshold ($kgCO_2/kgH_2$)	Temporal resolution 2030
UK	2.4	30 minutes
RED II	3.38	Hourly
US	4	Not yet specified
CertifHy	4.37	Annual

Several papers have considered the use of mixed-source grid electricity for hydrogen production [6–10]. Raab et al. [6] studied hydrogen production with grid participation in different locations with high renewable generation potential. One of the major conclusions of the work was that with even just 1.7% of the electricity provided by the grid, the levelised cost of hydrogen (LCOH) decreased 20% when compared to fully off-grid hydrogen production systems. Other studies added grid connection to the electrolyser operation, but in most of those, no investment optimization was considered (system CAPEX & OPEX) [8,9] or no dedicated renewable generation was connected to the electrolyser [10], which did not allow a comparison

to flexible grid-connected hydrogen production. Furthermore, no carbon accounting was considered in the grid electricity used, hence no impact on the emissions of the system was reported on those studies. Only Scolaro & Kittner [7] considered carbon abatement costs, but their supply chain configuration also allowed for the sale of electricity to the grid instead of use for hydrogen production. The hydrogen produced could be sold or used to produce electricity for grid export, and as such, could not be considered dedicated hydrogen production to supply a set demand.

On a systems level, hydrogen production from grid electricity is only beneficial if the rapid deployment of renewable power happens at the same time [11,12]. This quick development of new renewable generating capacity is essential to decarbonise the power and energy market but does not necessitate the exclusion of the hydrogen industry. Clean energy technologies such as heat pumps and electric vehicles that contribute to growing demand for electricity can be charged with grid electricity. However, according to additionality rules proposed as part of EU policy, grid-connected hydrogen production cannot, unless an average of 90% of grid electricity is produced from renewable sources in the previous calendar year. By adding carbon emissions caps on the energy sector or aggressively tackling the GHG emissions from the power sector, hydrogen can be deployed quickly with less risk [13]. Besides, hydrogen production from electrolysis adds a non-restrictive shiftable demand to the power market becoming a strong demand response asset [4].

As shown before, literature has addressed the benefits of including flexible grid operation electrolysers on an energy system level, reporting effects on the market and carbon emissions. On the other side, the hydrogen production system-level studies that have considered the flexible use of grid electricity for dedicated hydrogen production do not consider the emissions associated with the use of non-fully renewable electricity. In this paper, the carbon emissions and economic performance of both flexible grid-connected and off-grid hydrogen production are thoroughly examined.

4.1.2 Aims and Objectives of Paper

This paper aims to investigate if strict green hydrogen production policies such as additionality are necessary or even desirable by analysing a range of hydrogen supply chain scenarios.

The specific objectives of the paper are as follows:

- To examine the effect of capacity factor on the carbon intensity (CI) of grid-connected hydrogen production.
- To investigate the relationship between capacity factor and LCOH for a variety of hydrogen production scenarios for both low-cost (salt caverns) and high-cost storage (gaseous tank storage).
- To compare cost and emissions reduction potential across all of the scenarios analysed considering two different end-uses: 1) Displacing diesel use in buses with hydrogen-fuelled fuel cell electric buses (FCEBs), and 2) Displacing natural gas consumption with hydrogen.

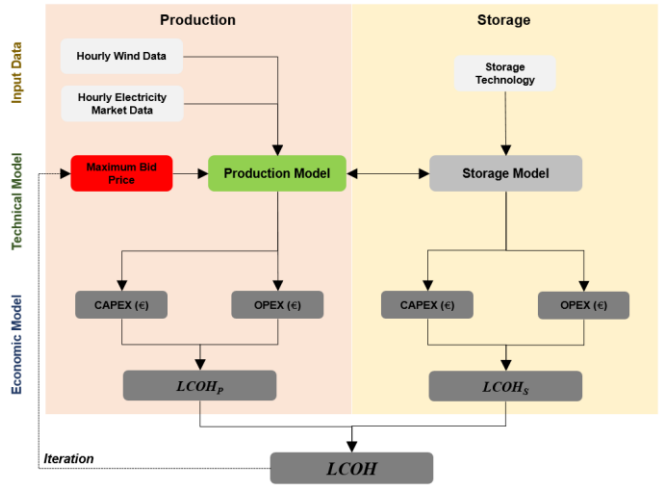
This paper is structured as follows; a methodology shows the modelling approach considered for the analysis as well as the scenarios selected for each case. The results of the analysis are then presented and discussed, before the work, its key findings, and their implications are summarised in the conclusions section.

4.2 Methodology

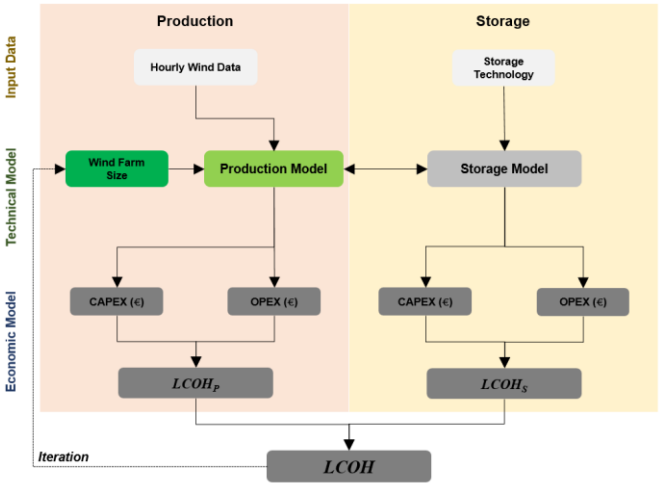
This section describes the methodology used to achieve the above objectives. Firstly, an overview of the techno-economic analysis tool used is given. Secondly, the scenarios modelled are described in detail.

4.2.1 Model Overview

The work uses a detailed techno-economic analysis (TEA) tool for hydrogen supply based on the work of Moran et al.[14,15]. The tool uses hourly renewables data, as well as hourly electricity market price and carbon intensity data, to calculate the LCOH and CI of hydrogen supply. The flowcharts in Figure 1 give an overview of the workings of the tool.



(A)



(B)

Figure 1: Flowchart of TEA tool for (A) grid-connected and (B) off-grid hydrogen production.

4.2.1 a Model Inputs and Cost Assumptions

The inputs to the tool are one full year of hourly renewable electricity output, grid electricity market prices and emissions intensity, as well as a number of user-defined parameters, such as electrolyser size and mode of operation (e.g. grid-connected or off-grid), and storage technology. As shown in Figure 1, capital (CAPEX) and operational (OPEX) costs are calculated for both hydrogen production and storage. The primary CAPEX and OPEX assumptions are shown in Table 3 and include the electrolyser, compressors, and storage. Storage requirements are sized based on the need to supply hydrogen to meet a constant hourly demand, regardless of how the electrolyser operates. Other costs such as energy management unit, engineering, and water are included as per Gunawan et al.[16]. The cost of hydrogen distribution or dispensing is not included in the current work.

Table 3: CAPEX and OPEX assumptions for hydrogen production and storage.

Parameter	Value	Unit	Ref
Electrolyser CAPEX	400	€/kW	[17]
Electrolyser OPEX	8	€/kW/yr	[18]
Compressor CAPEX	171	€/kW	[18]
Compressor OPEX	2%	CAPEX/yr	[18]
Underground storage CAPEX	10	€/kgH_2	[19]
Underground storage OPEX	2%	CAPEX/yr	[19]
Hydrogen tanks CAPEX	470	€/kgH_2	[20]
Hydrogen tanks OPEX	2%	CAPEX/yr	[20]

4.2.1 b Levelised Cost of Hydrogen (LCOH)

The levelised cost of hydrogen production ($LCOH_P$) and levelised cost of hydrogen storage ($LCOH_S$) are then calculated and added to give the overall LCOH (Equations 1-3). The LCOH is equal to the present value of the total cost of hydrogen production and storage over the lifetime of the plant divided by the present value of the total quantity of hydrogen produced. It represents the minimum breakeven selling price of hydrogen, not accounting for taxes, grid fees, or profit margin.

$$LCOH = LCOH_P + LCOH_S \tag{9}$$

Where LCOH is levelised cost of hydrogen, P is production, and S is storage.

$$LCOH_P = \frac{PV\ CAPEX_P + PV\ OPEX_P^{\tau}}{PV\ H_{2_P}^{\tau}} \tag{10}$$

Where PV is present value, CAPEX is capital expenditure, OPEX is operational expenditure, τ is lifetime, H_2 is quantity of hydrogen, and P is production.

$$LCOH_S = \frac{PV\ CAPEX_S + PV\ OPEX_S^{\tau}}{PV\ H_{2_P}^{\tau}} \tag{11}$$

Where PV is present value, CAPEX is capital expenditure, OPEX is operational expenditure, τ is lifetime, H_2 is quantity of hydrogen, and S is storage.

4.2.1 c Carbon Intensity of Hydrogen Production

The carbon intensity of the hydrogen produced is calculated based on the carbon intensity of the electricity used for electrolysis and compression, as shown in Equation 4. The carbon intensity of renewable power is assumed to be zero, whilst the carbon intensity of grid electricity varies depending on the instantaneous generation mix. The model can take one year of hourly data for the carbon intensity of grid electricity and calculates an annual average carbon intensity of hydrogen production. Other emissions associated with hydrogen production such as life-cycle emissions from the manufacture or construction of the wind farm or hydrogen production plant are not considered.

$$CI = \frac{\sum_0^y CI_e^h \cdot e_h}{H_{2_P}^{\ y}} \qquad (12)$$

Where CI is carbon intensity, H_{2p} is quantity of hydrogen produced, e is electricity consumed, h is each hour of operation, and y is the number of hours of the representative year.

4.2.1 d Variation of Capacity Factor

The model can be used to analyse hydrogen production from multiple sources of electricity. For any given hour, if renewable electricity is available, the model assumes as much of it as possible will be used for electrolysis. If the electrolyser is connected to the grid, it is assumed that the electrolyser can purchase electricity from the hourly wholesale market. A maximum bid price (MBP), which can be defined by the user, sets the maximum price at which electricity is purchased for hydrogen production. For this study, the MBP is used to vary the capacity factor and examine its effect on outputs such as LCOH and CI. As shown in Figure 1(A), the model iterates through values of MBP from 0 to 185 €/MWh. This in turn varies the capacity factor for the grid-connected scenarios. If the electrolyser is not connected to the grid (i.e. off-grid), the model iterates through different wind farm capacities as shown in Figure 1(B), thus varying the capacity factor of the electrolyser of a fixed size.

4.2.1 e Comparison to Fossil Fuel Use Case

To compare the hydrogen produced to other fuels, the model calculates the percentage difference in fuel cost and emissions based on assumptions for a particular end use. For this study, the use of hydrogen in fuel cell electric buses (FCEBs) in place of diesel buses and the displacement of natural gas usage in industrial heat and power generation are chosen as reference cases. There are many potential use cases for hydrogen as a fuel, but FCEBs represent

a viable short-term demand for hydrogen outside of existing hydrogen usage [21]. Since one of the aims of this study is to show decarbonisation potential, battery electric buses were not considered in the comparison with FCEB. This is due to the very likely deployment of both types of zero-emissions technologies in the transport sector due to the complementary capabilities of both technologies [21]. The difference in fuel costs and emissions are calculated on a per km basis. Assumptions for fuel efficiency, emissions, and cost are shown in Table 4.

Table 4: Assumptions for hydrogen and diesel buses.

	Hydrogen	**Diesel**	Unit	Ref
Specific Fuel Consumption	0.071 kg	0.24 l	/km	[17,22]
CO_2 Emissions	Calculated	1,320	g/km	[23]
Fuel Cost	Calculated	1.90	€/l	[24]

In addition to the diesel bus case, fuel cost and emissions are compared to natural gas. Renewable hydrogen can displace existing natural gas used for industrial heat and power generation. The difference in fuel costs and emissions are calculated on a per kWh basis using lower heating values (LHVs) for hydrogen and natural gas. The cost of natural gas is assumed to be 8.37 c/kWh based on the average price to commercial users in Ireland for the first six months of 2022 [25]. This is of course impacted by factors including the Russian invasion of Ukraine, but is substantially lower than the record high European wholesale prices observed in late 2022 [26]. Natural gas prices are likely to remain unstable, making estimates for future prices challenging. The emissions factor of natural gas is assumed to be 204 gCO_2/kWh, based on combustion emissions only [27].

4.2.2 Scenario Description

As part of this study, three hydrogen supply scenarios for 2030 are analysed: Flexible grid-connected, off-grid, and hybrid (use of both dedicated renewables and mixed-source grid electricity) electrolysis (see Figure 2). All scenarios are modelled using the TEA tool described above.

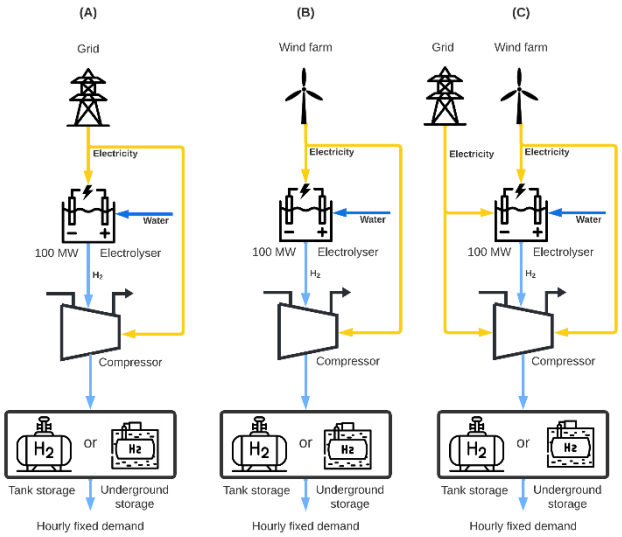


Figure 2: Hydrogen supply chain diagram for (A) flexible grid scenario, (B) off-grid scenario, and (C) hybrid scenario.

Using hourly wind data from windatlas.xyz [28], and simulated hourly wholesale electricity prices and emissions for a 2030 80% RES-E power system in Ireland from Deane and Mehigan [29], LCOH and CI are calculated for a range of capacity factors for a 100-MW_e alkaline electrolyser located on the island of Ireland. Table 5 summarises the key techno-economic assumptions.

Table 5: Techno-economic parameter assumptions.

Parameter	Value	unit	ref
Electrolyser Size	100	MW	
Electrolyser Efficiency	69	%	[17]
LCOE Offshore Wind	65	€/MWh	[30]
Cost of Grid Electricity	Hourly Data 80% RES-E	€/MWh	[29]
Carbon Intensity of Grid Electricity	Hourly Data 80% RES-E	gCO_2/MWh	[29]
Compressor Energy Consumption (Salt Cavern Storage)	1	kWh/kgH_2	[31]
Compressor Energy Consumption (Tanks)	1.9	kWh/kgH_2	[31]
Storage Pressure (Salt Caverns)	120	bar	[19]
Storage Pressure (Tanks)	300	bar	[20]

For the flexible grid-connected scenario, the electrolyser purchases electricity from the wholesale electricity market on an hourly basis, depending on the MBP, with the aim of buying cheaper and greener electricity first. The higher the MBP, the higher the capacity factor. Thus, the MBP is used to vary the capacity factor of the electrolyser.

For the off-grid scenario, the wind farm is assumed to be a fixed-bed offshore wind farm located off the east coast of Ireland in the Irish Sea. The size of the wind farm changes to vary the capacity factor of the electrolyser, providing more or less electricity with the same annual wind generation profile. The LCOE of the wind farm is assumed to be 65 EUR/MWh [30]. It is assumed that the cost of all the power produced by the wind farm is incurred, regardless of whether it is used for hydrogen production.

For the hybrid scenario, the hydrogen production is connected to a 100-MW wind farm in the same location as the off-grid scenario. Like the flexible grid-connected scenario, it is also able to purchase electricity from the grid on the wholesale market. By varying the MBP, the hybrid scenario varies the amount of grid electricity used to 'top-up' the power from the offshore wind farm, in turn varying the capacity factor of the electrolyser.

Though the total quantity of hydrogen production varies with capacity factor, it is assumed that the electrolyser supplies hydrogen to a constant demand. Two storage options are also considered for each scenario: low-cost storage in underground salt caverns, and high-cost storage in aboveground compressed hydrogen tanks. As mentioned above, the displacement of diesel buses with FCEBs and of natural gas usage in industrial heat and power generation are taken as reference cases.

4.3 Results

In this section, the results of the analysis are presented and discussed, showing that grid-connected electrolysis can produce lower cost hydrogen than off-grid electrolysis, whilst also delivering meaningful emissions reductions. Figure 3(A-C) depicts LCOH versus capacity factor for all three scenarios modelled, as well as the carbon intensity of hydrogen produced (CI) for the grid-connected and hybrid scenarios, and wind farm size for the off-grid scenario.

4.3.1 Carbon Intensity vs Capacity Factor

As shown in Figure 3(A), CI increases with the capacity factor for the flexible grid-connected hydrogen production scenario. This is because as the MBP increases, and in turn the capacity factor, the carbon intensity of the electricity used for hydrogen production also increases. Although on average, the grid electricity is 80% renewable, for any given hour this will vary considerably, depending on the output from wind and solar generation. If renewable generation is low, most of the electricity is supplied by gas-fired power generation. It is worth mentioning that since the model purchases the cheapest electricity first, by only using electricity that has zero cost (MBP = 0 €/MWh) and a low carbon intensity, the electrolyser is able to run with >20% capacity factor and a CI of <1 gCO_2/gH_2.

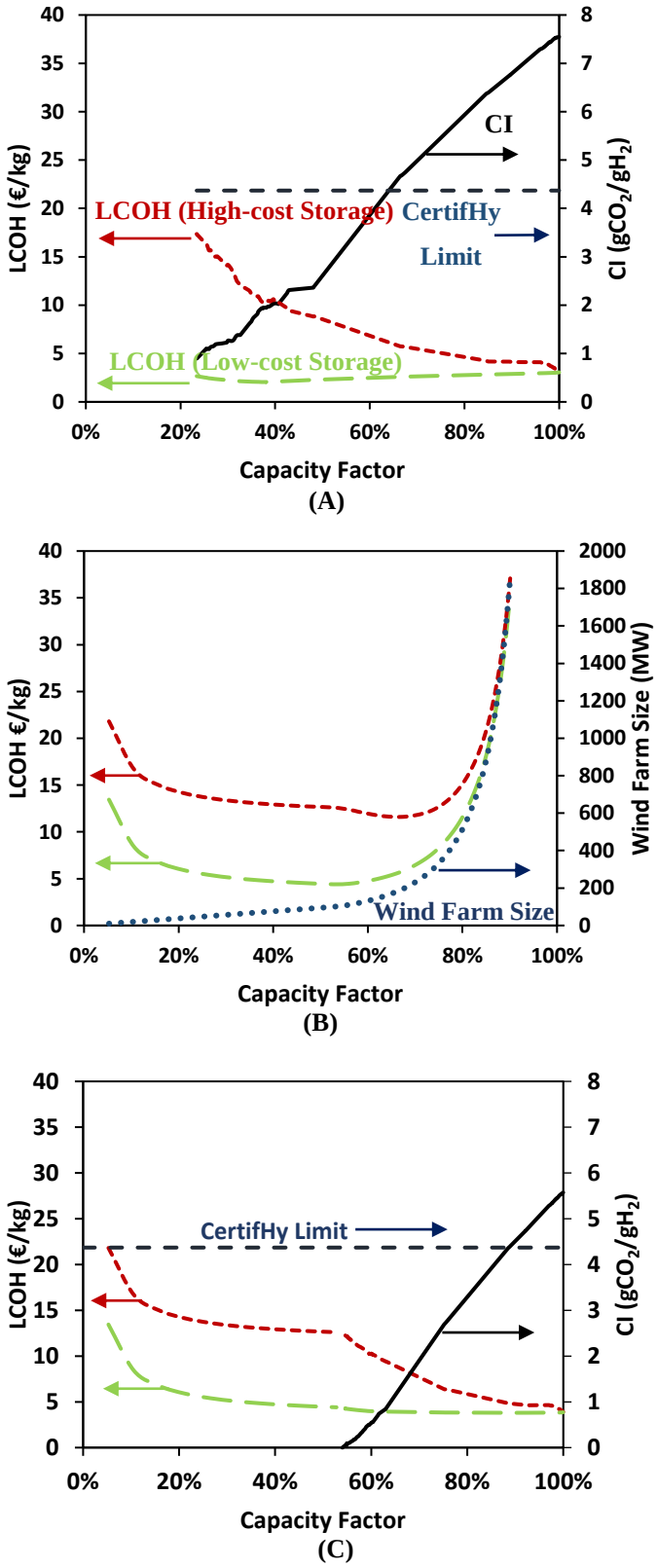


Figure 3: (A) CI and LCOH versus capacity factor for flexible grid-connected hydrogen production, (B) wind farm size and LCOH versus capacity factor for off-grid hydrogen production, and (C) CI and LCOH versus capacity factor for hybrid hydrogen production scenario, for both low and high-cost storage.

On the other hand, in Figure 3(B), the off-grid system is carbon emissions free, as it only consumes renewable power from the off-shore wind farm and no direct emissions are produced. By looking at Figure 3(C), it is worth noting that the hybrid system starts purchasing electricity when the capacity factor reaches that of the wind farm. Up until this point the CI value is 0 gCO_2/gH_2 and the LCOH trends follow those of the off-grid scenario. With the increase in capacity factor beyond 54%, the CI increases rapidly, due to the temporal correlation between the high emissions grid electricity and the low wind farm generation. In any case, at a 100% capacity factor, the CI in the hybrid scenario is almost 2 gCO_2/gH_2 lower than the grid scenario, making it a less polluting option.

4.3.2 Levelised Cost of Hydrogen

There is a substantial difference in LCOH between low-cost storage and high-cost storage across all three scenarios. This difference is due to the high specific CAPEX of storage tanks versus underground geological storage and highlights the effect of storage method on the LCOH of hydrogen supply to meet a set demand.

For low-cost storage, the main driver of LCOH is the cost of electricity. Hence, for the minimum LCOH of €2.05/kgH_2 in the flexible grid-connected scenario, the capacity factor is 38%, ensuring that only low-cost, and low-emissions electricity is used for hydrogen production. The CI at this capacity factor is 1.91 gCO_2/gH_2, below the CertifHy threshold of 4.37 gCO_2/gH_2. However, for a CF of 23% the CI drops down to 0.88 gCO_2/gH_2 with a higher LCOH of €2.66/kgH_2. In the case of high-cost storage for this scenario, the greater the capacity factor, the lower the storage cost, and this is due to the decreasing requirements of storage capacity to meet the constant demand during the year. The lowest LCOH here of €3.10/kgH_2, at a capacity factor of 100%, corresponds to a CI of 7.55 gCO_2/gH_2.

For the off-grid scenario, a minimum LCOH value for low-cost storage of €4.10/kgH_2 occurs for a wind farm size of 100 MW. However, for high-cost storage the minimum LCOH of €11.60/kgH_2 occurs when the wind farm is 1.8 times the capacity of the electrolyser and it reaches a capacity factor of 66%. This happens due to the trade-off between investing in a bigger wind farm or in more costly storage. When the CF is higher, with a fixed constant demand, the storage requirements are lower, and a bigger wind farm is required to increase the CF in the off grid-scenario. The minimum LCOH for an off-grid system is significantly higher

than that for a grid-connected scenario due to the cost of offshore wind compared to low-market prices at times of high renewable generation.

Whilst the off-grid scenario delivers a 100% emissions reduction and the grid-connected scenario results in a greater cost reduction, the hybrid scenario serves as a balance between the two. Capable of producing 100% renewable hydrogen, the hybrid scenario also has access to grid electricity to allow operation at higher capacity factors if necessary to increase supply and meet demand. Despite the hybrid scenario producing emissions at high CF, the values at the same CF are lower than in the grid scenario. The optimal LCOH for low-cost storage occurs at a capacity factor of 89%, whilst the optimal for high-cost storage is 100%, as in the flexible grid-connected scenario. The CIs at these capacity factors are 4.25 gCO_2/gH_2 and 5.55 gCO_2/gH_2, respectively. It is important to mention that between 60% and 100% CF in the low-cost storage scenario, there is little variation in the LCOH of the hydrogen produced. This is due to the balance between the cost of the electricity purchased that increases with the CF and the costs of storage that decreases with the CF increase.

For both the flexible grid-connected and hybrid hydrogen production scenarios, a trade-off between LCOH and CI exists, and finding the optimum operating point depends on CI limits and subsidies. In the case of the CertifHy limit, with a CI value of 4.37 gCO_2/gH_2, the LCOH, is 21% lower in the hybrid scenario than in the grid scenario when high-cost storage is considered (see Table 6). Nonetheless, this trade-off is only relevant if high storage cost is considered, which confirms the importance of the storage cost in supply chain configuration decisions.

4.3.3 Comparison to Diesel Bus Use Case

The cost per km of the hydrogen produced in each of the scenarios if used in a FCEB is compared to diesel in Figure 4(A) for both storage types. In Figure 4(B), the emissions reduction per km when compared to diesel is shown for the three hydrogen production scenarios modelled. Storage type has a minimal effect on emissions so is not compared.

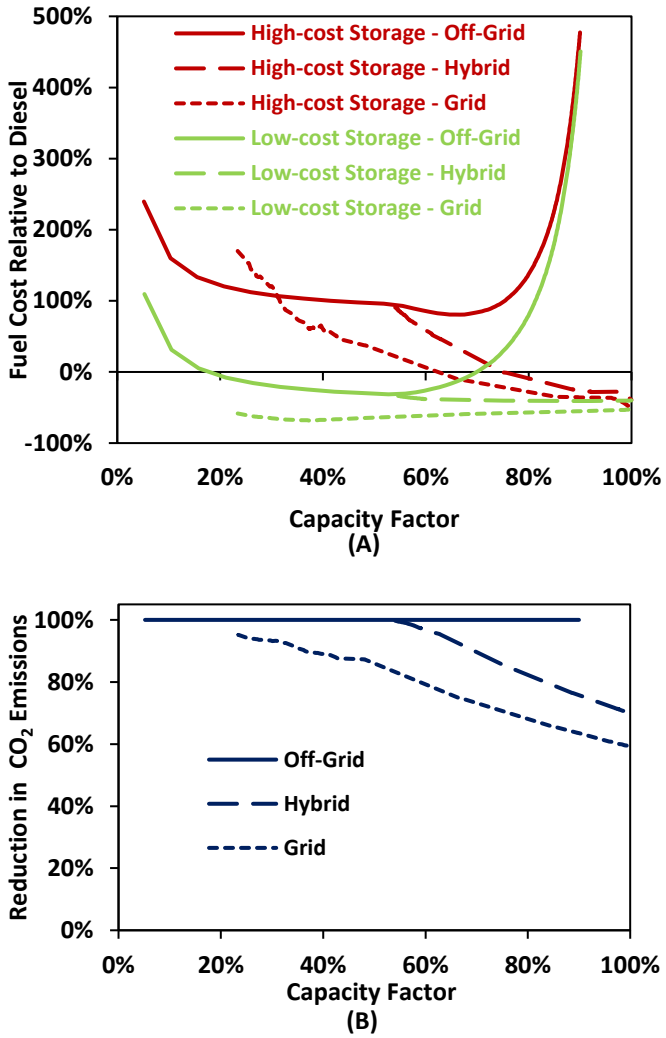


Figure 4: A) Percentage cost difference compared to diesel for low and high-cost hydrogen storage. Positive values indicate higher cost than diesel. B) CO_2 emissions reduction relative to diesel for grid, off-grid, and hybrid hydrogen production.

Table 6: Results for grid and hybrid scenarios at CertifHy threshold (4.37 gCO_2/gH_2).

Scenario	Capacity Factor	LCOH (€/kg)	Cost difference to diesel
Grid low-cost storage	65%	2.55	-60%
Grid high-cost storage	64%	6.15	-4%
Hybrid low-cost storage	90%	3.80	-41%
Hybrid high-cost storage	89%	4.90	-24%

4.3.3 a Low-cost Hydrogen Storage

Figure 4(A) shows the cost comparison of hydrogen to diesel expressed in percentage difference. For low-cost storage, the off-grid scenario shows a higher cost of hydrogen compared to diesel up to an electrolyser capacity factor of just under 20%. Hydrogen remains cheaper than diesel up to a capacity factor of 70%, with the maximum cost reduction of 31% observed at a capacity factor of 54%.

For the grid scenario, cost reductions greater than 50% are observed in all cases. This is particularly due to the availability of low-cost electricity from the grid due to 80% renewable penetration. The maximum cost reduction is observed at 38% electrolyser capacity factor, coinciding with the minimum LCOH. While in the hybrid scenario, cost reduction is observed only for capacity factors above 20%.

4.3.3 b High-cost Hydrogen Storage

For high-cost storage (Figure 4(A)), the off-grid scenario always shows higher hydrogen costs than diesel for the complete range of electrolyser capacity factors. This is due to the higher cost of storage and electricity from offshore wind.

For the grid scenario, higher cost of electrolyser and storage results in hydrogen being more expensive than diesel at lower capacity factors as seen in Figure 4(A). Increasing the electrolyser capacity factor above 62% results in higher amount of hydrogen production meeting the demand, resulting in a smaller storage tank, reduced storage costs, eventually producing hydrogen at a cost similar to diesel. As much as 52% cost reduction compared to diesel is observed for higher electrolyser capacity factors.

The hybrid scenario has a similar cost reduction behaviour to the grid scenario but with the electrolyser required to operate at a higher capacity factor compared to the grid scenario. At 75% capacity factor, cost parity with diesel fuel is achieved while a maximum cost reduction of 39% against diesel is reached at 100% capacity factor.

In terms of emission reduction, Figure 4(B) shows that the off-grid scenario reduces emissions by 100% for all capacity factors, but at a higher cost than diesel. For the grid scenario, emissions reduction ranges from 60-95%, with an emissions reduction of greater than 78% possible at a lower cost than diesel. The hybrid scenario delivers an emission reduction of 70-100%, with the potential for an 85% emissions reduction at cost parity with diesel. The extra

energy required for compression to 300 bar for high-cost storage has a minimal effect on emissions.

Though the hydrogen produced is not always 100% renewable, both grid and hybrid scenarios can result in significant emission reduction compared to diesel, even at higher electrolyser capacity factors. Considering the CertifHy limit (Table 6), an emission reduction of 77% compared to diesel can be achieved in low and high-cost storage for both grid and hybrid scenarios. In all these cases, the fuel cost per km is lower for FCEBs than for diesel, and up to 60% cheaper for low-cost hydrogen storage.

It is important to note that this emissions reduction is based on the average carbon intensity of the hydrogen produced, and that for the grid-connected scenarios, the carbon intensity of the hydrogen produced at any given hour varies as grid electricity emissions vary over time. In this analysis, an 80% renewable power system is considered. As a result, a large share of hydrogen production from grid electricity is from zero carbon sources, while the remainder is from natural gas turbines. This is the main reason for the observed high average emission reduction of 77%. Whether subsidy is based on emissions on an hourly or annual basis, hourly monitoring of carbon intensity is useful in determining the actual emissions footprint of hydrogen at any given time and ensuring full transparency.

Another important consideration is the volatility of diesel prices at the pump due to geopolitics and other factors. It is very difficult to predict future prices for oil products given the uncertain state of geopolitics and the energy transition. The level of future carbon tax is also subject to uncertainty, which also influences the price of diesel. It is therefore important to understand the results of the modelling in this context.

4.3.4 Comparison to Natural Gas Use Case

The cost per kWh of hydrogen produced in each of the scenarios is compared to natural gas in Figure 5(A) for both storage types. In Figure 5(B), the emissions reduction per kWh when compared to natural gas is shown for the three hydrogen production scenarios modelled. As in the diesel bus case, storage type has a minimal effect on emissions so is not compared.

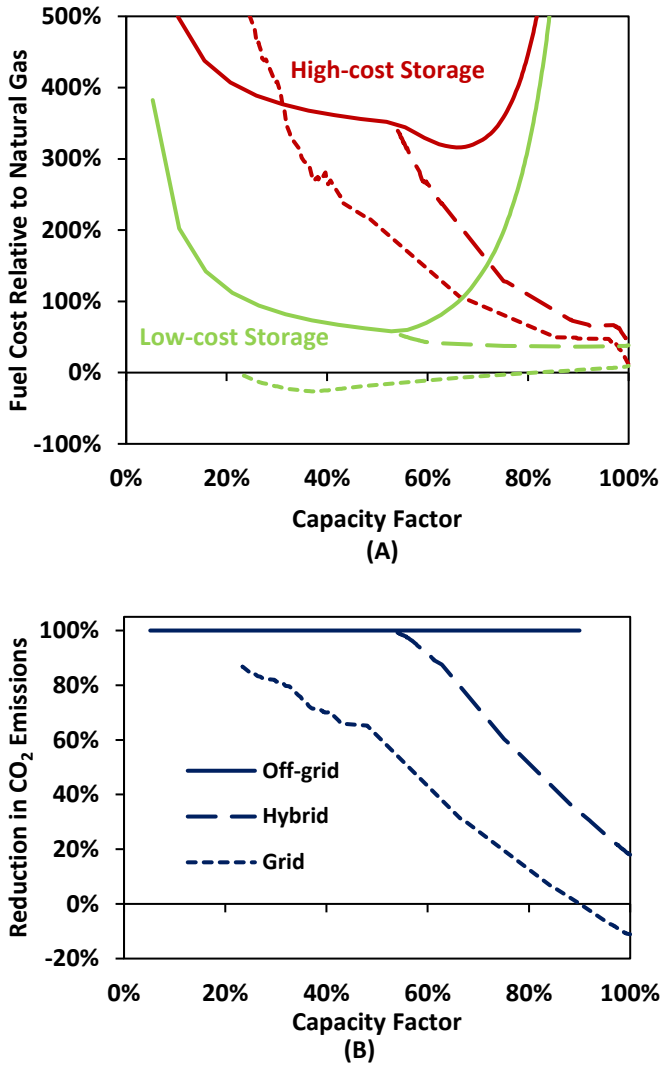


Figure 5: A) Percentage cost difference compared to natural gas for low and high-cost hydrogen storage. Positive values indicate higher cost than natural gas. B) CO_2 emissions reduction relative to natural gas for grid, off-grid, and hybrid hydrogen production.

It is clear from Figure 5(A) that hydrogen is much less competitive with natural gas, compared to the diesel bus use case. Although the shape of the graph is similar to that in Figure 5(A), the hydrogen produced is more expensive than natural gas in the majority of cases. For the high-cost storage off-grid scenario, hydrogen is 3 times as expensive as natural gas. Only for the low-cost storage flexible grid scenario is parity with natural gas achieved, for capacity factors below 80%, with a maximum cost reduction of 26%. It is also worth mentioning that the comparison is between a levelised cost (LCOH) and the market price of natural gas, two variables that do not include the same elements and that are not necessarily equivalent.

In Figure 5(B), it is shown that hydrogen produced in the off-grid scenario reduces emissions compared to natural gas by 100% for all possible capacity factors. This is the same as for the diesel case as the hydrogen produced is 100% renewable. However, unlike the diesel bus use

case, the hydrogen produced in the flexible grid scenario does not always deliver emissions reductions when compared to natural gas. In fact, for capacity factors greater than of 90%, there is an increase in emissions. For the hybrid scenario the emissions reduction ranges from 18-100%, depending on capacity factor. These lower emissions reduction percentages are in part due to the lower emissions factor of natural gas compared to diesel and part due to the lower efficiency of diesel buses when compared to their FCEB counterparts.

For the off-grid scenario, whilst 100% emissions reductions are delivered in all cases, the lowest possible cost is 58% more expensive than natural gas, and 3-5 times higher when high storage costs are considered. For the flexible grid scenario, considering the CertifHy limit, an average annual emissions reduction of at least 77% compared to natural gas is only achieved for capacity factors less than 34% and carbon intensities less than 1.56 gCO_2/gH_2 in the flexible grid scenario. However, the fuel cost is 25% lower relative to natural gas for low-cost storage in this case, and just over 2.5 times natural gas costs for high-cost hydrogen storage. For the hybrid scenario the capacity factor is 70% for the same carbon intensity and emissions reduction, with a fuel cost 40% or 170% higher than natural gas, depending on hydrogen storage costs. It is worth noting that the maximum carbon intensity of 1.56 gCO_2/gH_2 to ensure a 77% emissions reduction is much lower than the 4.37 CertifHy limit. This highlights how the emissions reduction potential of any hydrogen molecule produced is heavily dependent on its end use. It is therefore challenging to design rules for hydrogen production based on carbon intensity alone. It is also important to note that the emissions intensity and environmental footprint of natural gas can vary significantly depending on its source. Gas produced by horizontal hydraulic drilling, or 'fracking' has a significantly higher environmental footprint than conventional gas. The lifecycle carbon intensity of liquefied natural gas (LNG), is much higher than gas delivered only by pipeline, due to boil-off and leakage losses, resulting in an emissions intensity higher than coal in some cases [32]. This analysis however, only considers combustion emissions from natural gas.

4.3.5 Additionality vs Flexible grid

Despite many studies, including the present work, indicating the benefits of flexible grid-connected electrolysers, such as lower costs and greater energy system integration, European legislation is tending to push hydrogen production off-grid. The proposed additionality rules require electrolysers to be powered from renewables that are a) additional, b) in the same

bidding zone, and c) followed on an hourly basis from 2030. Electrolysers that are connected to the grid could operate flexibly in response to market prices, emissions criteria, and demand response signals, in full transparency of the transmission system operator (TSO). In Table 7 additionality and flexible grid-connected approaches for electrolysers are compared under different criteria.

Table 7: Additionality and flexible grid approaches pros and cons.

Criteria	Additionality	Flexible Grid
Emissions	Zero	"Low Carbon"
Use of grid	Lower	Higher
Strictness	High	Low
H_2 production cost	Higher	Lower
Flexible operation	Low	High
Grid services	No	Yes
System Integration	No	Yes

Additionality ensures that hydrogen production is 100% renewable whilst not diverting renewable electricity away from direct electrification. However, as this study has shown, this can result in higher hydrogen costs. By only being allowed to use renewable power coming from the additional renewable capacity built, the capacity factor is relatively low, relying on more storage to deliver the product to the customers. This leads to higher hydrogen costs of production, making it less attractive to consumers who will need to pay a high premium for it. Another aspect of additionality not captured by this study is that by obligating hydrogen projects to build new renewable capacity, the total CAPEX of the project increases and with this, the risk involved for the investors. This, in addition to higher overall costs, could discourage investment in hydrogen during the energy transition towards net zero. As mentioned previously, new electricity demand created by direct electrification technologies such as heat pumps and BEVs is not subject to additionality criteria. If hydrogen production is additional, and essentially off-grid, it is unable to contribute to electricity system flexibility. Exclusively additional hydrogen would be unavailable to help alleviate the issue of curtailment of existing renewables generation.

On the other hand, grid-connected electrolysers may not produce 100% renewable hydrogen, but could produce hydrogen at a lower cost if permitted to purchase electricity from the

wholesale market. However, strict controls over electricity consumption from the grid and transparent carbon accounting methods would be required to ensure sustainability.

Setting a carbon intensity limit for hydrogen on an average annual basis would allow flexibility to help grow a nascent industry, whilst also applying strict operational rules where necessary. For example, electrolysers could be disallowed from operation at peak electricity demand periods in winter, or when grid electricity emissions intensity passes a defined threshold. Electrolysers could be mandated to participate in grid services markets, which could provide an additional revenue source, reducing hydrogen costs further.

To ensure the penetration of new renewable capacity, the average annual carbon intensity limit for hydrogen production could shrink with time to ensure sustainability. This allows the demand for new renewable capacity to increase, due to the demand for renewable power created by the hydrogen production sector. Alternatively, electrolyser capacity could be procured via auctions, as is currently done with renewable generation, allowing for the simultaneous procurement of sufficient renewables capacity to meet this new demand. If given the flexibility to respond to market prices, emissions, and grid signals, grid-connected hydrogen could deliver low-cost hydrogen, whilst also facilitating the decarbonisation of the electricity system, by helping demand to match supply, reducing curtailment, and smoothing electricity prices. The main difference with additionality is that renewable generators and hydrogen producers are de-coupled and can develop independently according to the market signals.

Finally, it is worth noting that as part of REFuelEU Aviation, synthetic aviation fuels derived from hydrogen, are considered ‘low-carbon’ if they deliver a lifecycle emissions reduction of 70% [33]. This distinction between ‘low-carbon’ and ‘renewable’ is important, ensuring a degree of transparency whilst also allowing flexibility in how emissions reductions are achieved.

4.3.6 Limitations and Future Work

In this study, there are some limitations that will be addressed in future research, some of which are related to the electrolyser: ramping-up and down, and stand-by costs of the system. A sensitivity analysis of the electrolyser efficiency based on its load due to the big impact that electrolyser's efficiency has on economic indicators would also be useful [34]. Besides, one element that not considered as part of the economic analysis is grid services. Grid-connected electrolysers could provide different remunerated services to the grid which could increase the

revenues of the electrolyser and hence decrease hydrogen costs. Accounting for the uncertainty associated with wind forecast, hourly electricity prices and carbon footprint could also help in making the results more robust.

Another area of uncertainty mentioned previously is both the cost and emissions footprint of fossil fuels. The Russian invasion of Ukraine has had a significant effect on global fossil fuel markets, particularly gas, with a knock-on effect on electricity prices. This has highlighted the underlying volatility of fossil fuel prices, making future estimates for comparison to hydrogen challenging. Based on this, a sensitivity analysis and uncertainty quantification of fossil fuel prices and their impact on cost comparisons to hydrogen would be of interest. The emissions intensity of diesel and natural gas could also be included, particularly for natural gas, where, as mentioned in Methodology, total lifecycle emissions can be higher than coal in some cases.

The lack of life cycle assessment (LCA) means the CI only considers direct emissions of the grid electricity consumed by the electrolyser. LCA considered in the future would add other greenhouse gas emissions to the CI attributed to hydrogen production, which may affect the results of this study. Finally, this study does not consider the costs, or the emissions associated with changing infrastructure for diesel buses, an issue that future work will address.

4.4 Conclusions

This work investigates whether strict green hydrogen production policies are necessary or desirable to ensure the decarbonisation of existing and potential future hydrogen consumption. Using a TEA tool for hydrogen supply chains based on the work of Moran et al.[14,15], three hydrogen production scenarios for 2030 are analysed: Grid-connected, off-grid, and hybrid (use of both dedicated renewables and mixed-source grid electricity) electrolysis. One year of hourly wind data, and simulated 2030 electricity prices and carbon intensity for an 80% renewable electricity system in Ireland [29] and cost assumptions for wind power and alkaline electrolysis in 2030 are used to calculate a range of outputs. LCOH and CI for both low-cost (salt cavern) and high-cost (compressed hydrogen tanks) storage across all three scenarios for varying electrolyser capacity factors are compared and evaluated against CertifHy regulation. Finally, the cost and emissions of the hydrogen is compared to two fossil fuel reference cases: 1) Diesel buses 2) Natural gas.

The results show that lower LCOH values are achievable with significant emissions savings for a grid connected electrolyser with low-cost storage compared to the off-grid scenario. Grid-connected electrolyser scenario with low-cost storage values as low as \$2.05/kgH_2 are reached, with a carbon intensity of 1.91 gCO_2/gH_2 which is 56% lower than the current CertifHy suggested limit for low-carbon hydrogen. Besides, compared to the LCOH for off-grid scenario, it represents a 50% reduction in costs.

On the other hand, when high-cost storage is considered, not only does the LCOH increase substantially in all scenarios, but a trade-off is observed between the LCOH and the CI in grid-connected and hybrid scenarios. This trend shows that the LCOH decreases with the CF, but the CI increases drastically, something that does not hold in low-cost storage scenarios. This highlights the importance of emission limits for hydrogen production like the CertifHy threshold. Such policies can act as strong tools for limiting carbon emissions related to flexible grid operation.

All scenarios studied in this paper deliver emissions savings when compared to diesel buses, and in all grid-connected scenarios, cost reductions are also achieved at high capacity factors. However, when displacing natural gas usage, emissions savings can be significantly less for the grid-connected scenarios, and in some cases, emissions increase. This highlights how the emissions reduction delivered by hydrogen is heavily dependent on the end-use, representing a challenge for policymakers in designing sustainability criteria for hydrogen production.

The current EU policy on hydrogen production based on the colours taxonomy favours off-grid hydrogen production leading to decoupling from the electricity system. The results from this study indicate that this can lead to high-cost hydrogen in some cases. While grid-connected hydrogen production is beneficial in terms of LCOH, the potential effects on the electricity system of growing quantities of large, but flexible demand remain unclear. The hybrid scenario provides an interesting case as a compromise between off-grid and fully grid-connected electrolysis, delivering cost-effective hydrogen with a meaningful emissions reduction.

Further studies extending this analysis would be to consider the performance of different hydrogen production scenarios; (1) in other H_2 end use sectors like high-temperature heating, power generation and heavy-duty trucks, (2) effect of large electrolysis plant on the electricity system and (3) complete LCA of hydrogen production including embodied emissions and emissions from distribution.

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Chapter 5: The All-Island Hydrogen Study

Exploring the Scale and Cost of a Hydrogen Industry on the Island of Ireland for Different Decarbonisation Pathways

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Executive Summary

Although there is little existing industrial use of hydrogen on the island of Ireland (Ireland and Northern Ireland) today, the island'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. Whilst there is a growing appetite from industry and government to take advantage of this opportunity, progress to date has been slow, with much uncertainty around the future scale and nature of a renewable hydrogen industry in Ireland. The aim of this work therefore is to optimally size and cost all-island hydrogen production and storage capacity for a range of future hydrogen demand scenarios using a techno-economic analysis tool. Results indicate that the scale of infrastructure required to enable hydrogen's role in meeting climate and decarbonisation targets is vast, and the timelines for delivery short. In a scenario where government targets for decarbonisation are met, 19 GW of electrolysis, powered by over 25 GW of wind and solar is required by 2050. This is in addition to any variable renewables capacity needed to directly decarbonise the much-larger electricity sector. The levelised cost of hydrogen decreases from €4.30/kg in 2030 to €2.60/kg in 2050, due to the decreasing costs of solar, wind, and electrolysers, and the build out of low-cost large-scale storage infrastructure. The work highlights the critical nature and large-scale of hydrogen storage, with 12 TWh of storage capacity needed to balance hydrogen supply and demand. These findings can help to guide the ambitious policy and significant industry investment necessary for rapid scale up of the hydrogen industry and infrastructure to 2050.

5.1 Introduction

Located on the Atlantic edge of Europe, the island of Ireland is home to some of the highest average wind speeds in the world, making it a prime location for the development of both onshore and offshore wind. In fact, Ireland's offshore wind potential is far in excess of predicted future electricity demand. As the development of offshore wind scales up rapidly in line with ambitious government targets, wind generation has the potential to outgrow the domestic energy demand of an isolated, import reliant energy system with little heavy industry or existing hydrogen usage. This excess energy could be exported to Great Britain and Europe via electrical interconnectors, but the available power is likely to exceed interconnector capacity. In addition to interconnection, the island's excess wind could be used to produce hydrogen and other electrofuels for both domestic decarbonisation and export.

Having said this, fossil fuel imports currently account for 88% of final energy use in Northern Ireland, and 86% in the Ireland, exemplifying the level of transformation required of the energy system on the island [1,2]. The Irish and Northern Irish governments have ambitious renewable energy and decarbonisation targets, with both aiming for 80% penetration of renewables in the electricity sector by 2030 [3,4]. The Irish government, as part of the Climate Action Plan and Hydrogen Strategy, has set a target for 2 GW of offshore wind for hydrogen production to be in development by 2030 [5]. As part of the European Union, Ireland is included in targets for EU-wide renewable hydrogen penetration in transport and industry. By 2030, 42% of hydrogen use in industry must be produced from renewable sources, and 1.2% of aviation fuel must be derived from renewable hydrogen [6,7].

There is currently only one operational renewable hydrogen facility on the island, located at Long Mountain wind farm in County Antrim [1]. Operated by Energia, a 1-MW_e electrolyser powered by wind, supplies hydrogen to Belfast's fleet of hydrogen buses. Multiple small-scale (1-5 MWe) projects are in planning and development, including the Galway Hydrogen Hub and Bord na Mona's Mount Lucas Green Hydrogen project [8,9]. However, it is likely to be a number of years before any of these projects are realised. Whilst these projects may be important for initial learnings, they fall far below the scales required for development of a widespread hydrogen industry. Ireland's lack of an existing hydrogen market means that there is much uncertainty around the scale and timelines of future hydrogen demand, making it challenging for investors and developers. This is sometimes referred to as the 'chicken and egg' situation, as there is unlikely to be renewable hydrogen supply without steady demand, or hydrogen demand without secure supply. As a result, early projects are likely to involve a

consortium of players from across the hydrogen supply chain to ensure that hydrogen production, storage, distribution, and end-use are developed in conjunction. However, for a large-scale industry to develop, an economically liquid hydrogen market is desirable to reduce costs, increase flexibility and ensure security of supply. This would require widespread and integrated hydrogen production, storage, and distribution across the island.

The size of future hydrogen demand and the scale of production and storage required remain unknown, with timelines for hydrogen demand across many of its potential end-uses uncertain. Therefore, this work aims to size and cost future all-island hydrogen production and storage based on estimated hydrogen demand across three different decarbonisation pathways: Missing Targets, Meeting Targets, Exceeding Targets, which are described below. The specific objectives of the work are as follows:

1. Estimate future hydrogen demand for a range of end-uses across three different decarbonisation pathways: Missing Targets, Meeting Targets, Exceeding Targets.
2. Optimally size and cost an all-island hydrogen system of production and storage to meet the predicted demand in each scenario using a techno-economic analysis tool.
3. Based on the results, identify key considerations for policymakers and priority areas for future research.

5.2 Methods

5.2.1 Scenario Descriptions

As mentioned above, three different potential decarbonisation pathways to 2050 are considered as part of this study: 1) Missing Targets, 2) Meeting Targets, and 3) Exceeding Targets. In the first pathway, it is assumed that climate and decarbonisation targets are missed by a considerable margin, due to a lack of acceleration of the required policy and investment. In the second pathway, climate and energy targets for 2030 out to 2050 are realised and the Irish Energy System is negative carbon dioxide emissions by 2050. In the final pathway, decarbonisation exceeds climate and energy targets, with large volumes of energy export from the island by 2050. Given the short time frame to 2030 this pathway is unlikely to be achieved in that time, and the same case can also be made for the Meeting pathway. However, it is useful to consider the reality of what needs to be done to meet targets in relation to the reality of

current action. The more ambitious pathways also help to realise the challenges and opportunities in the longer time frame out to 2040 and 2050. Under each pathway, hydrogen demand on the island of Ireland is estimated for the years 2030, 2040, and 2050, meaning a total of nine scenarios are modelled using the techno-economic analysis (TEA) tool.

5.2.2 Demand Estimation

Firstly, the likely end-uses for hydrogen over the coming decades are identified based on decarbonisation targets and considering the potential of alternative clean technologies, such as battery electric vehicles (BEVs) and heat pumps. In transport, hydrogen and electrofuels are likely to play a role in decarbonising heavier modes of transport, such as high mileage trucks, buses, and coaches, as well as shipping and aviation. In industry, renewable hydrogen can replace existing fossil hydrogen usage in refining, chemicals, and fertiliser production. It can also provide high temperature heat for industrial processes unsuitable for electrification. Hydrogen and electrofuels can also play a crucial role in long-term energy storage to balance out seasonal and annual imbalances, but also for strategic purposes to enhance energy security. When renewables output is low, electrofuels can be used for power generation to meet electricity demand.

5.2.2 a Trucking

For trucking, a percentage penetration of hydrogen fuel cell trucks is assumed for each scenario (see Table 1). This assumption is based on the government policy such as the Climate Action Plan, and EU emissions standards for trucks [5,10]. The total number of trucks is based on the historical growth profile of trucks in both Ireland and Northern Ireland [11,12]. A daily travel distance of 600 km is assumed based on a survey of local trucking companies carried out. This aligns with results from a similar survey [13] as well as the findings of Gray et al. that trucks with daily ranges greater than 500 km are unsuitable for electrification [14,15]. The specific fuel consumption of hydrogen trucks is assumed to be 0.1 kg_{H_2}/km in 2030, 0.08 kg_{H_2}/km in 2040, and 0.07 kg_{H_2}/km in 2050 [16].

Table 1: Assumed number of hydrogen trucks as a percentage of total heavy-duty vehicles in Ireland and Northern Ireland.

		% Hydrogen Vehicles		
	Total No. of Trucks	*Missing*	*Meeting*	*Exceeding*
2030	29,500	1%	2%	2%
2040	41,000	5%	10%	10%
2050	53,000	15%	20%	25%

5.2.2 b Buses and Coaches

For buses and coaches, the total number of buses in Ireland and Northern Ireland is based on data from Bus Éireann, the Central Statistics Office (CSO), and the Northern Ireland Statistics and Research Agency (NISRA). Three categories are considered: Urban, Regional, and Intercity. The assumed daily distance covered per vehicle for each category is shown in Table 2, and are based on data provided by Bus Éireann. The specific fuel consumption is assumed to be 0.07 kg_{H_2}/km as it is assumed hydrogen buses reach technological maturity earlier than trucks [17].

Table 2: Assumed daily distance per vehicle per day.

Category	*Distance/Bus/Day*
Urban	270 km
Regional	615 km
Intercity	580 km

In 2030, it is assumed that in the Missing Scenario, there are no new hydrogen fuel cell electric buses (FCEBs) other than those currently in operation in Dublin and Belfast. For the Meeting Scenario, it is assumed that 40 more FCEBs are in operation in Ireland, and that 30% of the Belfast Metro fleet are FCEBs in line with the fleets' zero emission target for 2030 [18]. The remainder of the fleet is assumed to be battery electric vehicles (BEVs). For the Exceeding Targets Scenario, it is assumed that there are 10% more FCEBs than in the Meeting Scenario.

In 2040, for the Meeting Targets Scenario, all urban fleets in Ireland are zero emissions and have been since 2035 in line with national targets [19]. It is assumed that 20% of theses buses are FCEBs. For Northern Ireland, all public transport is zero emissions, and 20% of buses and coaches are FCEBs. For the Missing Scenario, the number of buses is found by linear

interpolation between the 2030 Exceeding and 2040 Meeting scenarios, whilst the Exceeding is found by interpolating between 2040 Meeting and 2050 Meeting scenarios.

In 2050, all bus and coach fleets are zero emission. It is assumed that 20% of urban buses are fuelled by hydrogen, 50% of regional, and 80% of intercity. For the Missing Scenario, the number of buses is found by linear interpolation between the 2040 Exceeding and 2050 Meeting scenarios. Finally, in the 2050 Exceeding Scenario, it is assumed that there is a higher penetration of hydrogen vehicles in the zero emission fleet (40% of urban, 75% of regional, and 100% of intercity vehicles).

5.2.2 c Aviation

For aviation in 2030, it is assumed there is no hydrogen derived synthetic aviation fuel demand in the Missing Targets Scenario. In the Meeting Targets Scenario, it is assumed that the 1.2% of aviation fuel demand is met by synthetic aviation fuel, in line with the minimum target mandated as part of REFuelEU Aviation [7] (see Table 3). For the Exceeding Scenario, it is assumed the 2040 target of 10% is met ahead of schedule.

In 2040, for the Missing Target Scenario, it is assumed the 2030 target for synthetic aviation fuel is hit belatedly. For Meeting, the target of 10% is met, whilst for Exceeding the 2050 target of 35% is met ahead of schedule.

In 2050, the Missing Scenario, sees the 2040 target met 10 years later, and 35% of total aviation fuel is derived from hydrogen in the Meeting Scenario, again in line with EU mandates. For the 2050 Exceeding Scenario, 100% of the total aviation fuel consumption of Ireland and Northern Ireland is synthetic hydrogen-derived fuels [20].

Table 3: Assumed synthetic aviation fuel demand as a percentage of total aviation fuel demand in Ireland and Northern Ireland [7].

	Missing	*Meeting*	*Exceeding*
2030	0%	1.2%	10%
2040	1.2%	10%	35%
2050	10%	35%	100%

5.2.2 d Shipping

For shipping, the percentage of total shipping fuel demand in Ireland and Northern Ireland [21] to be supplied by electrofuels is shown in Table 4. It is assumed that the dominant electrofuel in this sector is ammonia. For the Meeting Targets pathway, 25%, 50% and 75% of shipping fuel demand is met by electrofuels in 2030, 2040, and 2050 respectively. Similar to aviation fuels, it is assumed that these targets are met belatedly in the Missing Targets pathway or ahead of schedule in the Exceeding Targets.

Table 4: Assumed synthetic shipping fuel demand as a percentage of total shipping fuel demand in Ireland and Northern Ireland [21].

	Missing	*Meeting*	*Exceeding*
2030	0%	25%	50%
2040	25%	50%	75%
2050	50%	75%	100%

5.2.2 e Industry

For industry, demand estimates for hydrogen in each scenario are based on figures from the National Heat Study carried out by the Sustainable Energy Authority of Ireland and the Future Energy System Decarbonisation Scenarios Report for Northern Ireland [22,23]. Existing hydrogen demand for oil refining is also considered. Missing, Meeting, and Exceeding Scenarios for each year are based on low, medium, and high hydrogen demand estimates from the three different decarbonisation pathways from the aforementioned studies. This demand is predominantly for high temperature industrial heating. Across the scenarios, the role of hydrogen in industry ranges from usage in a small number of niche applications, to widespread adoption for medium to high temperature heating. For the Meeting Scenario in 2030, it is also assumed that 42% of existing hydrogen use in industry is renewable in line with EU mandates [6]. In Exceeding 2030, it is assumed that this figure rises to 100%.

5.2.2 f Power Generation

For 2030, it is assumed that there is no hydrogen used for power generation in the Missing Targets Scenario. For the Meeting Targets Scenario, it is assumed that 2 GW of planned new gas turbine generation capacity will operate at a 20% capacity factor with a 20% blend of hydrogen with natural gas by volume. It is assumed the majority of this new capacity is provided by open cycle gas turbines operating with an efficiency of 45%. For the Exceeding

Targets Scenario in 2030, it is assumed that any of the 6.8 GW of existing gas turbine generation capacity that will still be operational in 2030 burns an allowable blend of hydrogen based on each turbine's nitrous oxide control system and specifications [24,25].

For 2040 Meeting, it is assumed that the electricity system is zero emissions based on EirGrid's *Tomorrow's Energy Scenarios* report [26] and that 8% of electricity generation is from hydrogen fuelled turbines based on electricity system simulations carried out by Deane and Mehigan [27]. This primarily serves as a backup for when wind and solar generation are both low. For Missing Targets, it is assumed that only half of this amount of electricity is provided by hydrogen, and 100% decarbonisation of electricity is not achieved. For Exceeding Targets in 2040, electricity demand is 25% greater than the Meeting Targets due to greater electrification of heat and transport.

In 2050, for the Meeting Targets Scenario, it is assumed that electricity demand has grown by 25% due to population and increased electrification, with hydrogen still providing 8% of electricity production. For the Missing Targets Scenario, it is again assumed that hydrogen provides half the amount of electricity as in the Meeting Scenario. For the Exceeding Scenario, it is assumed that electricity demand is 25% larger again, due to a larger electrification and demand from new industry.

5.2.2 g Fertiliser

Hydrogen produced from renewable electricity can be used to produce ammonia via the Haber-Bosch process. This can then be used to produce urea fertiliser. The percentage of fertiliser demand in Ireland and Northern Ireland met by urea derived from renewable hydrogen for each scenario is given in Table 5. Total fertiliser demand data from 2021 is sourced from the CSO and the Department of Agriculture, Environment and Rural Affairs [28,29].

Table 5: Assumed amount of fertiliser produced from renewable ammonia as a percentage of total fertiliser demand in Ireland and Northern Ireland.

	Missing	*Meeting*	*Exceeding*
2030	0%	12.5%	25%
2040	12.5%	25%	50%
2050	25%	50%	100%

5.2.2 h Export

For hydrogen and electrofuel export, quantities are estimated based on Ireland meeting assumed percentages of import targets for Germany, Belgium, and the Netherlands, three countries with significant existing hydrogen usage. It is anticipated that all three countries will need to import large amounts of clean hydrogen and electrofuels to meet their domestic industrial and decarbonisation needs. The total size of the import market is calculated as the sum of the import targets included in each of the countries hydrogen strategies [30–32]. The assumed percentage of import targets for Germany, Belgium, and the Netherlands supplied by hydrogen produced on the island of Ireland in each scenario is detailed in Table 6.

Table 6: Assumed percentage of hydrogen and electrofuel import market (Germany, Belgium, the Netherlands) met by exports from Ireland and Northern Ireland.

	Missing	*Meeting*	*Exceeding*
2030	0%	2%	5%
2040	2%	5%	20%
2050	5%	20%	40%

5.2.3 Description of Techno-economic Analysis (TEA) Tool

The TEA tool used for this study was developed based on the previous models of Moran et al.[33,34]. The model takes a year of hourly hydrogen demand data, and calculates the cost-optimal electrolysis and renewables capacity required to meet hydrogen demand, based on hourly onshore wind, offshore wind, and solar data. The tool calculates the required storage capacity based on a user-defined dominant hydrogen storage method. The tool assumes all renewables capacity is additional to that required for electricity system decarbonisation. The island of Ireland is modelled as a single node. This is a simplistic approach but is useful in gaining an understanding of scale and cost of a hydrogen industry without building a complex supply chain model that would require more detailed assumptions about the locations of hydrogen supply and demand.

The tool calculates the levelised cost of hydrogen production ($LCOH_P$) and storage ($LCOH_S$). The sum of these is the overall levelised cost of hydrogen (LCOH). The LCOH represents the minimum breakeven selling price of hydrogen but does not include taxes and profit margins. It is not intended to be reflective of actual project cost but serves as a useful metric for comparison

[35]. The capital cost of the electrolyser, associated equipment, compression, engineering, and interconnection are included in the $LCOH_P$ as per Moran et al. [33]. The techno-economic assumptions for the main hydrogen production equipment are detailed in Table 7 for the different years modelled, where P_E is the capacity of the electrolyser in kW and C_{ME} is the total capital cost of the electrolyser and compressor.

Table 7: Techno-economic assumptions for hydrogen production.

Year	**2030**	**2040**	**2050**	**unit**	**ref**
Equipment					
Electrolyser	400	316	232	€/kW	[36,37]
Compressor		$4948 \times P_E^{0.66}$		€/kW	[38,39]
Energy mgmt unit		$0.1 \times C_{ME}$		€	[38,39]
Interconnection		$0.2 \times C_{ME}$		€	[38,39]
Engineering		$0.15 \times C_{ME}$		€	[38,39]
Other		$1.5652 \times P_E^{-0.154} \times C_{ME}$		€	[38,39]
LCOE					
Onshore Wind	41	33	25	€/MWh	[40]
Offshore Wind	66	56	47	€/MWh	[40]
Solar	56	46	36	€/MWh	[41]

For each scenario, a dominant hydrogen storage method is selected based on the pathway and year. Three potential methods are considered: 1) Compressed Hydrogen Tanks, 2) Liquid Hydrogen Tanks, 3) Underground Hydrogen Storage. The assumed storage method for each scenario is shown in Table 8, whilst the techno-economic assumptions for each technology are depicted in Table 9. For liquid storage, it is assumed that the liquefaction plant is fully flexible and capable of following variable hydrogen production. However, there is uncertainty around the feasibility of this as currently, commercial liquefiers rarely operate below 70% of their nominal capacity.

Table 8: Dominant storage method assumed for each scenario.

	Missing	*Meeting*	*Exceeding*
2030	Compressed H_2 Tanks	Liquid H_2	Liquid H_2
2040	Liquid H_2	Salt Caverns	Salt Caverns
2050	Salt Caverns	Salt Caverns	Salt Caverns

Table 9: Specific capital cost for the different hydrogen storage technologies considered (euro per kg of usable hydrogen storage).

Storage Method	**Specific Capital Cost**	**Unit**	**ref**
Compressed H_2 Tanks	500	€/kgH_2	[42]
Liquid H_2	30	€/kgH_2	[43,44]
Salt Caverns	10	€/kgH_2	[45]

The cost of hydrogen distribution, or end-user equipment such as dispensing is not included. It is important to note that these are critical aspects of a future hydrogen system, particularly large-scale distribution. Associated costs can be considerable, but this is beyond the scope of the current work, the focus of which is the future scale and cost of hydrogen production and storage on the island of Ireland.

Wind and solar data are taken from the open source database renewables.ninja [46]. Representative - not optimal - locations for onshore wind, offshore wind, and solar generation were chosen for data input to the TEA tool. All renewable generation capacity for hydrogen production is assumed to be additional to any capacity built for the direct decarbonisation of electricity. This is in line with European Union rules for hydrogen production which state that renewable electricity used for hydrogen production must be a) additional, b) in the same bidding zone/region as the electrolyser, and c) temporally correlated on an hourly basis from 2030. Grid electricity is only permitted for use for hydrogen production in very specific circumstances, which are if the wholesale price of electricity is less than €20/MWh, if 90% of grid electricity was generated by zero carbon sources in the previous calendar year, if the emissions intensity of electricity is lower than 18 gCO_{2eq}/MJ and is purchased through a PPA, or if electricity is consumed during and imbalance settlement period [47]. Whilst Ireland has ambitious legally-binding targets for decarbonisation that require a negative emissions power system by 2050, the use of grid electricity is not considered for this analysis. An energy systems modelling study would be required to model the integration of hydrogen production and the electricity system in more detail, an area that has been identified for future work.

5.3 Results and Discussion

The results of the all-island hydrogen modelling are outlined and discussed below. Firstly, the hydrogen demand estimates for each scenario are presented and discussed, followed by the scale and cost of storage and production required to meet the demand for each. The results of the sensitivity analysis carried out for the 2030 and 2050 Meeting Targets Scenario are then detailed. The overall results are then discussed, and some key future considerations are identified.

5.3.1 Hydrogen Demand

In 2030, total hydrogen demand on the island of Ireland, including exports, varies from 0.7 TWh in the Missing Targets Scenario to 14.9 TWh, in the Exceeding Targets Scenario, as shown in Figure 1. In the Missing Scenario, the majority of demand is in industry with small numbers of hydrogen trucks and buses on the roads. In the Meeting Scenario, shipping fuel is the largest domestic demand for hydrogen, accounting for 22% of the total demand of 6 TWh. For the 2030 Exceeding Targets Scenario, aviation is the largest demand sector with 2.8 TWh of hydrogen required for synthetic aviation fuel production, followed by shipping at 2.65 TWh, power generation is the third largest domestic demand at 1.75 TWh. In this scenario, hydrogen exports from the island total 4.8 TWh.

In 2040, hydrogen demand increases considerably to between 16.9 TWh and 63 TWh. Power generation is now the dominant domestic end-use for hydrogen, making up over 50% of total demand in both the Missing and Meeting Scenarios for 2040, and 36% in the Exceeding Targets Scenario. The remainder of the demand is made up of hydrogen used for trucking, industry, aviation and shipping fuel production, and fertiliser, with a comparatively small amount used in buses and coaches.

By 2050, hydrogen demand grows to between 35.6 and 116 TWh. Power generation for when wind and solar are low is still the largest domestic end-use sector for all three pathways, accounting for 36% of total demand of 66 TWh in the Meeting Targets Scenario. Demand for hydrogen for the production of aviation and shipping fuels, as well as fertiliser, all grow significantly from 2040. On average, hydrogen demand across these sectors, as well as in industry and trucking, doubles from 2040 to 2050 in the Meeting Targets Pathway. Exports account for almost 30% of the island's demand for hydrogen in 2050 in this pathway.

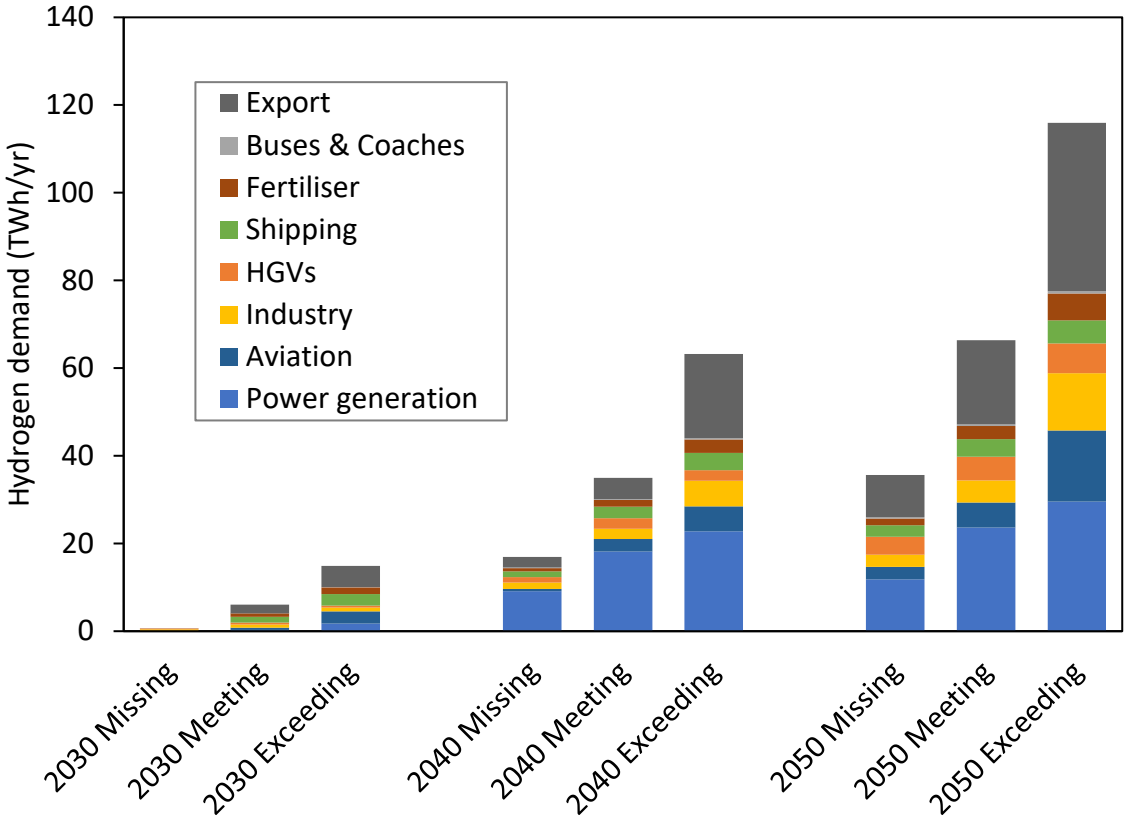


Figure 1: Estimated hydrogen demand on the island of Ireland in the 9 scenarios.

5.3.2 Production and Storage

The scale of hydrogen production for each of the scenarios modelled, as well as the LCOH, is shown in Figure 2. The optimal capacities of electrolysis, wind, and solar, for minimising LCOH are depicted for all scenarios from 2030 to 2050. The optimal hydrogen storage capacity for each is shown in Figure 3.

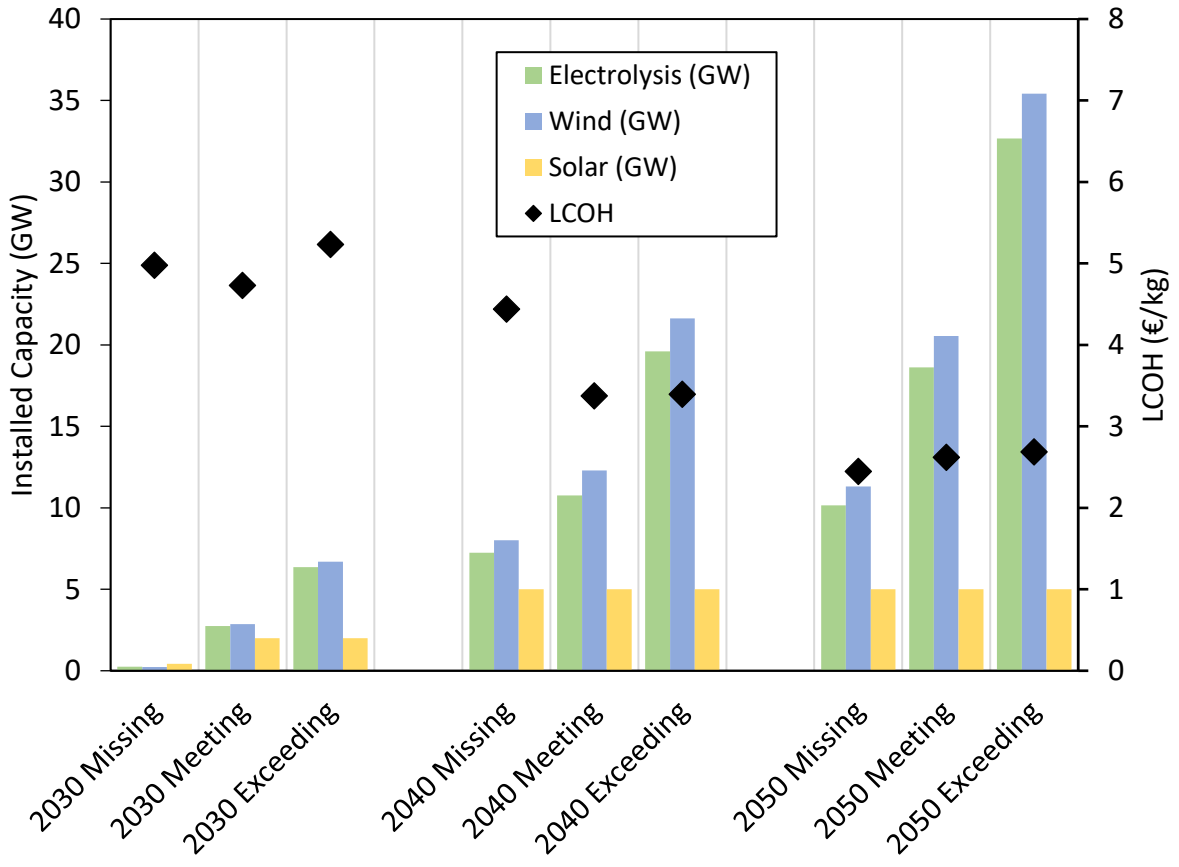


Figure 2: Installed capacity of electrolysis (green), wind (blue), and solar (yellow) for hydrogen production in each scenario (left axis). Levelised cost of hydrogen (LCOH) production and storage (black dots) for each scenario (right axis).

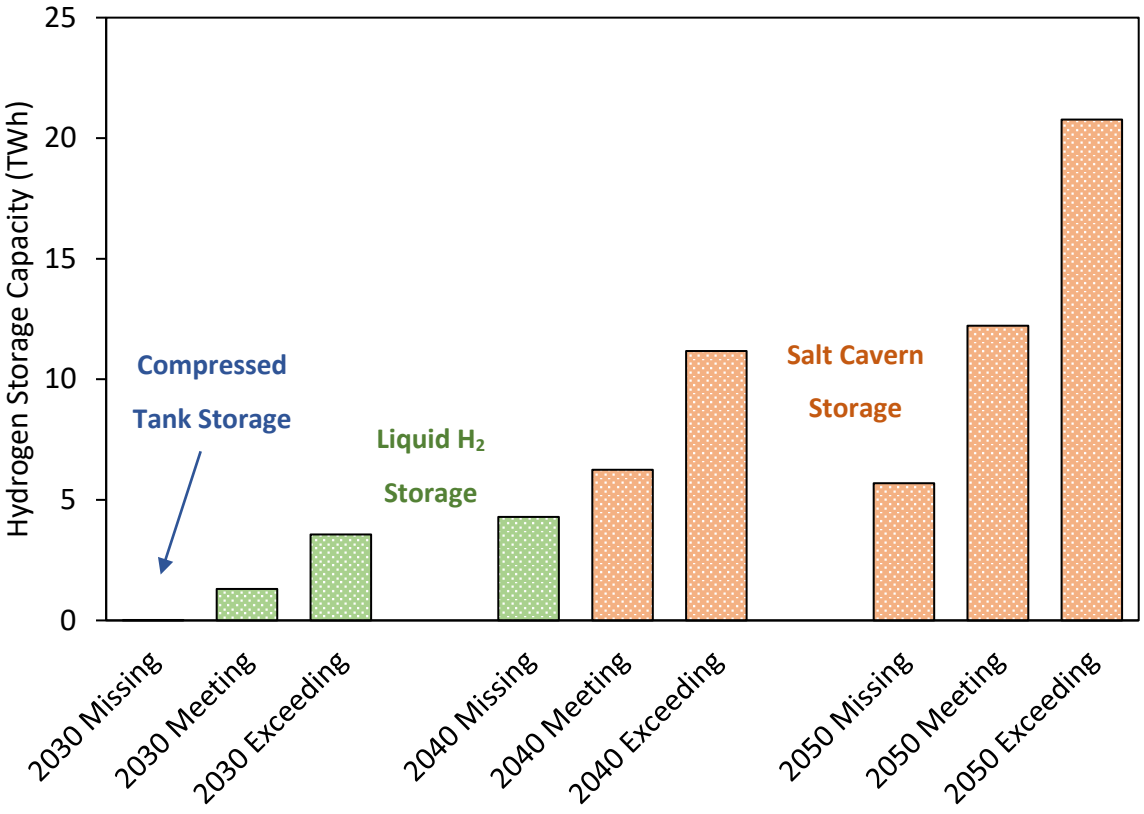


Figure 3: Required hydrogen storage capacities for each of the 9 scenarios modelled.

The 2030 scenarios have comparatively larger shares of solar capacity. As storage is relatively more expensive (compressed tanks in Missing Targets) or inefficient (liquid tanks in Meeting and Exceeding) when compared to salt caverns, the optimal system consists of more solar, which complements wind output, providing a more consistent hydrogen production profile, thus minimising the requirement for storage to 0.02 TWh, or 3% of annual hydrogen demand. For the 2030 Missing Targets Scenario, solar accounts for two-thirds of the renewable energy capacity for hydrogen production. However, it only provides 36% of the electricity used for electrolysis due to its low capacity factor. For the Exceeding Scenario, wind dominates, as it is assumed that the build out of solar for hydrogen production is constrained to a maximum of 2 GW. For the 2030 scenarios there is a vast difference in scale between the Missing and Meeting Scenarios, with 15 times electrolysis capacity required. This indicates the huge level of change required to realise climate and energy targets, and that perhaps they may already be out of reach. The difference in scale between these two scenarios is not the reason for the difference in cost however. This is primarily due to the change in the dominant storage technology. Although boil-off from liquid hydrogen storage causes 10% of the hydrogen produced to be lost, the capital cost of liquid storage tanks is less than compressed tanks on a per kilogram

basis. For the Exceeding Scenario, the LCOH increases. This is due to the model limits on the build out of onshore wind and solar. The model assumes that no more than 2 GW of onshore wind and 2 GW of solar for dedicated hydrogen production can be built by 2030. As a result, more expensive offshore wind is built instead, resulting in an increase in the cost of electricity used for electrolysis, and hence the LCOH. The Irish government has a target for 2 GW of offshore wind for hydrogen production to be in development by 2030, but the model chooses to use low-cost onshore wind and solar for electrolysis, with offshore wind only making up 20% of dedicated renewables capacity in the Meeting Targets Scenario.

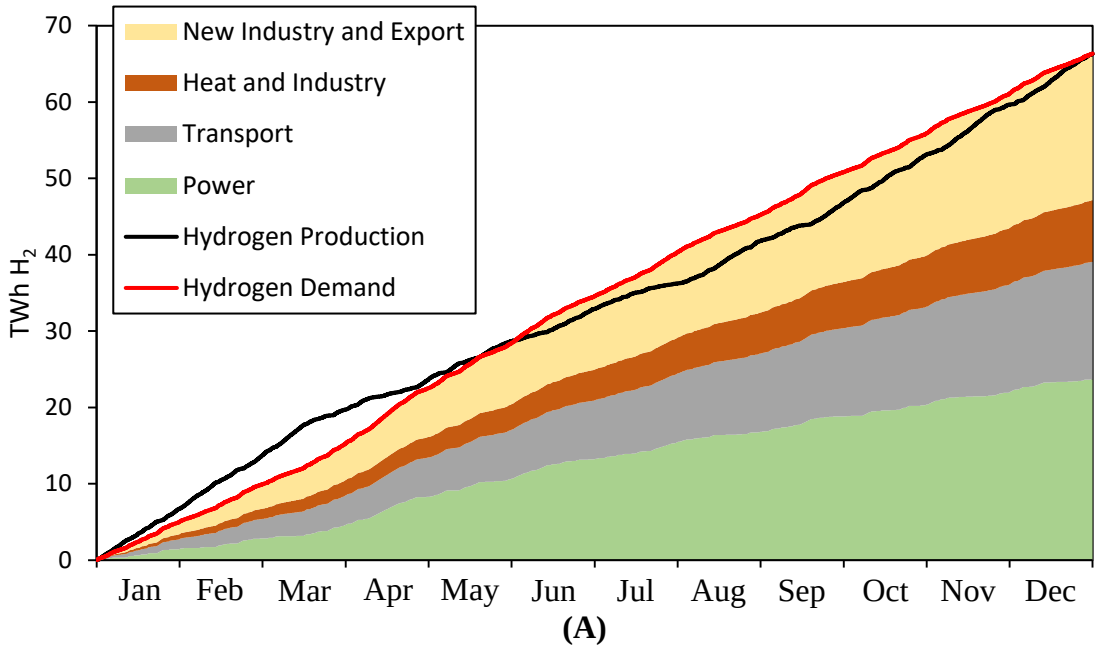
In 2040, a rapid scale up of hydrogen production from 2030 is required in all scenarios, with the LCOH falling due to the lower cost of wind, solar, and electrolysis technologies. The development of low-cost large-scale salt cavern storage in the Meeting and Exceeding Pathways is also a key contributor to this cost reduction. In the Meeting Pathway, electrolysis capacity increases by 4 times to 11 GW, supplied by 12 GW of wind and 5 GW of solar. This 5 GW figure for solar is the assumed maximum amount of solar power built for dedicated hydrogen production on the island, as most of the available solar capacity will be used to decarbonise other sectors of the economy through direct electrification. Hydrogen production is now dominated by offshore wind as capacity limitations of onshore renewables are reached, accounting for 42% of renewables capacity and 62% of electricity for hydrogen production in the Meeting Scenario. The decrease in LCOH from the 2040 Missing Targets Scenario to the Meeting is again due to the change in the dominant storage technology. In the Missing Scenario, it is assumed salt cavern storage is yet to be developed, with liquid hydrogen tanks used instead. In 2040 Meeting and Exceeding, large-scale, low-cost salt cavern hydrogen storage is assumed to have been developed. In the Meeting Pathway, over 6 TWh of salt cavern hydrogen storage has been developed by 2040, equivalent to 18% of annual hydrogen demand.

Further scale up of hydrogen production is required in all pathways by 2050 though not as steep as the previous decade. The required electrolysis capacity for 2050 is less than double that of 2040 for all pathways. Offshore wind is now even more dominant as the island begins to truly utilise the vast energy potential of its coast, with over 15 GW of capacity for hydrogen production in the Meeting Targets Scenario. Cost reductions are due to the assumed decrease in the costs of wind, solar, and electrolysis from 2040 to 2050. The cost of storage is unchanged. The LCOH of the Meeting Scenario is higher than in Missing, while the LCOH in the Exceeding Scenario is higher again. You may expect the opposite to be the case due to economies of scale. However all three scenarios are at sufficient scale that no more cost

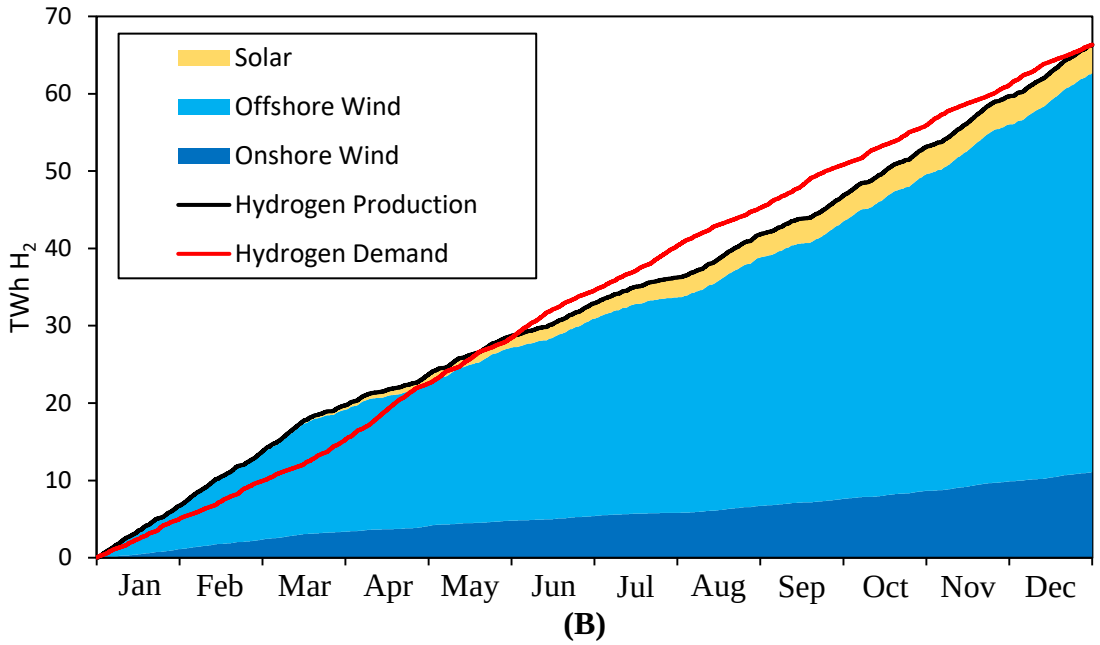
reductions with scale are assumed. Therefore the increase in cost is due to the larger share of offshore wind, which remains more expensive than onshore wind and solar. The scale of the hydrogen storage required in 2050, even in the Missing Targets Scenario, is vast. This storage is required to store hydrogen produced in the windier months for use in the calmer months as shown in Figure 4(B). There is also somewhat of an inverse correlation between hydrogen production and demand. As evidenced in Figure 4(A), when hydrogen production from wind is low, demand for hydrogen in the power sector is high due to low wind speeds, with hydrogen power generation providing backup electricity generation. The inverse case is also true. When wind speeds and hence electricity generation from wind are high, the demand for hydrogen-fired electricity is low. The 12 TWh of hydrogen storage required to meet climate targets according to this study is the equivalent to the energy storage capacity 6,000 Turlough Hill power stations, the island's largest pumped hydroelectric energy storage facility.

In relation to electrolysis capacity, the model always opts to oversize renewables, to increase the capacity factor of electrolysis. Despite this, very little renewable electricity generated goes unused. The worst performing scenario in this regard is 2030 Missing Targets, where 7% of electricity is curtailed. However, all other scenarios have curtailment of less than 2%.

A key point to note is that all renewables capacity for hydrogen production is assumed to be fully additional to renewables used for electrification. Whilst this aligns with EU and USA rules for hydrogen production, many studies highlight the potential benefits of closer integration of hydrogen production with the electricity system [48–52]. Electrolysers can act as flexible electrical loads, reducing curtailment and lowering electricity costs. This would also likely reduce the capacity of renewables required for both hydrogen production and electricity decarbonisation. Current strict rules on additionality and temporal matching for hydrogen production would not allow for this, and may inadvertently increase energy costs. Thus, more detailed energy systems modelling to interrogate the potential interactions between hydrogen production and the electricity system is a key area for future work.



(A)



(B)

Figure 4: Cumulative hydrogen demand (A) and production (B) for 2050 Meeting Targets Scenario.

5.3.3 Key Considerations

These results indicate that the scale of infrastructure required for hydrogen production is arguably akin to the electrification of rural Ireland in the 1940s and 1950s, if Ireland is to realise its decarbonisation targets. This is in addition to the renewable generation capacity needed to directly decarbonise electricity. This also calls into question the realism of such targets, certainly in the short-term, with a significant gap between the Missing and Meeting Pathways.

There is also significant uncertainty and much learning needed around the relevant hydrogen technologies from production and storage to end-use. The storage quantities in particular are vast, and the planning for such large infrastructure would need to begin this decade due to lead times which can be in excess of 10 years for such projects [53]. A caveat here would be that all of that storage capacity would not necessarily have to be on the island. If the island were connected to a pan-European hydrogen network, as proposed by the European Hydrogen Backbone [54], the island would have access to storage sites in Britain and the Europe. Hydrogen could be exported in the windier months and imported when domestic production is lower than demand. As mentioned previously, strict rules around hydrogen production that would limit interaction with the electricity grid, may increase costs. More research is required to inform policy in this regard.

5.4 Conclusions

With such uncertainty surrounding the nascent hydrogen industry on the island of Ireland, this study estimates hydrogen demand across a number of potential energy pathways, optimally sizing an island-wide system of hydrogen production and storage. The results and findings of the work have key implications on future research and policy. Based on literature, national, UK, and EU targets, demand for hydrogen is estimated for a range of likely hydrogen end-uses, from industry and power generation, to the production of fertiliser and aviation fuel. Using a techno-economic analysis tool based on the work of Moran et al. [33,34], hydrogen production and storage for the island is optimally sized to meet demand and minimise LCOH. Results indicate that the scale of renewables required for hydrogen production is very large, with 25.5 GW of dedicated wind and solar capacity for hydrogen production in 2050 to meet climate targets. The quantity of hydrogen storage needed to balance variable supply with demand in this scenario is similarly vast at 12 TWh. Some key trends identified across the scenarios modelled include the large share of solar used for hydrogen production in 2030, to complement wind production, reducing the need for expensive hydrogen storage. As low-cost storage is developed by 2040 and onshore renewables limitations are reached, hydrogen production from offshore wind begins to dominate, with LCOH dropping due to the lower cost of storage, wind, solar, and electrolysers. From €4.30/kg in the 2030 Meeting Targets Pathway, the LCOH drops to €3.40/kg by 2040 and €2.60/kg in 2050. The steepest scale up takes place in the 2030s, with

electrolysis capacity quadrupling from 2030 to 2040 in the Meeting Targets Pathway, before approximately doubling again by 2050. This outlines the critical need for strong supporting policy and regulatory guidance to provide certainty to a burgeoning industry that requires a capital investment of 1 billion euro by 2030 to meet targets, not including the cost of the wind and solar capacity required. In addition to this research and planning for the rapid scale up post-2030 is also crucial. It could also be said that this analysis serves as a reality check to those envisaging a quick and simple development of the industry, or the accomplishment of climate targets more broadly. Unprecedented action is required. The limitations of the work include its consideration of the islands hydrogen system as a single node, which does not capture the challenges and costs of electricity and hydrogen transmission. Instead, the work serves as a broad indicating of the scale of hydrogen demand under a variety of scenarios, and cost of producing and storing hydrogen to meet said demand, which are likely the main drivers of overall cost. The work also does not consider the cost of smaller scale distribution of hydrogen, blending, or dispensing of hydrogen for transport applications. In relation to hydrogen production, this study assumes that all renewables capacity is additional to that required for the decarbonisation of electricity, and dedicated solely to hydrogen production. As mentioned above, this aligns with EU, and UK rules for renewable hydrogen production, but does not allow for integration of hydrogen and the electricity system, which can be co-beneficial according to some studies. Further research is required to inform policy and is a priority area for future work. In relation to liquid hydrogen storage, the work considers liquefaction to be a fully flexible process, following the variable output of hydrogen from the electrolyser, more work is required to investigate the realism of this assumption. Nonetheless, this work serves as a useful indication of the future scale and costs associated with an industry that is likely to play a crucial role in limiting climate change. It also identifies a number of key trends and considerations for industry and policymakers, such as the interactions between wind, solar, and storage, and the significant importance of developing large-scale low-cost hydrogen storage. All of this storage capacity may or may not be located on the island, and connection to the European Hydrogen Backbone could improve the flexibility and resilience of a hydrogen network on the island. Nonetheless, access to low-cost storage is critical to the development of a large-scale, low-emissions, low-cost hydrogen system.

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Chapter 6: Discussion

In this chapter, the key findings of the previous chapters are discussed and compared. It is shown how each chapter relates to the others, highlighting some key themes. Based on this, the key themes of the work are as follows:

- The importance of considering the full supply chain in the analysis or design of hydrogen systems.
- The significant effect of hydrogen storage on overall cost, emissions, and production flexibility.
- The implications of grid-connected versus off-grid hydrogen production.
- The role of hydrogen in decarbonisation and the relevant scale of infrastructure required.

These themes and how they relate to the findings from this thesis are discussed under the above bullet points.

6.1 The importance of considering the full supply chain in the analysis or design of hydrogen systems

As discussed in detail in Chapter 2, much of the work on TEA of hydrogen systems and supply chains focused on one aspect of the supply chain in particular, most commonly production. Such studies failed to account for the significant technical and cost considerations relating to the storage and distribution of hydrogen. In the journal paper in Chapter 2: *"A flexible techno-economic analysis tool for regional hydrogen hubs – A case study for Ireland"*[1], this gap in the research is addressed, as the tool developed models hydrogen production storage and distribution on an hourly basis, finding an optimal lowest-cost system based on renewables input data, market prices, and hydrogen demand. The work examines a number of scenarios on the island of Ireland for the year 2030. The importance of temporal modelling of hydrogen storage and distribution is outlined by results for scenarios limited to 2 days of storage in compressed tanks. For these scenarios, the electrolyser is required to run at high capacity factors of 85-92%, topping up available wind power with grid electricity. This consistent level of hydrogen production is required to ensure a reliable supply to the end-user. The use of grid electricity for electrolysis increases the carbon intensity of the hydrogen produced of course. However, the carbon intensity is below the low-carbon CertifHy limit in all cases, based on an average emissions intensity for grid electricity. Results for scenarios with access to 10 days of salt cavern storage operate at much lower capacity factors. The larger storage size means that

the cost optimal configuration to meet demand is a larger electrolyser running at a lower capacity factor (42%). In this case, the grid-connected electrolyser can utilise periods of low market prices, shutting off when prices reach a certain threshold, instead supplying end-user demand with hydrogen from storage. The difference in capacity factor and operating schedule between the scenarios with 2 days and 10 days of storage not only highlights the need to include storage and distribution in TEA studies, but also that a gap exists for a study with a particular focus on storage and its effect on hydrogen supply chains. The nuances of how capacity factor, cost, and the use of grid electricity are all influenced by storage and distribution to the demand would not have been captured by a study focused only on hydrogen production.

This point is again highlighted in Chapter 3: *"The hydrogen storage challenge: Does storage method and size affect the cost and operational flexibility of hydrogen supply chains?"* [2], where it is found that storage in excess of 50 days is required to balance fully renewable hydrogen production with a constant hydrogen demand, significantly increasing costs in some cases. Chapter 4: *"Flexible Grid Hydrogen Production: Beyond The Colours Taxonomy"*, highlights the requirement to consider the full supply chain again, but from the perspective of emissions savings. One of the key findings of that work is how emissions savings from hydrogen are hugely dependent on the end-use. Hydrogen that delivers an emissions reduction of 77% relative to diesel use in buses, only reduces emissions 36% relative to natural gas, both of which are likely to be displaced by hydrogen for some end-uses. Finally, in Chapter 5: *"The All-Island Hydrogen Study"* the sheer capacity of storage required to balance hydrogen supply and demand in 2050 again indicates that the storage and distribution aspects of the supply chain are far from trivial.

6.2 The effect of storage on hydrogen supply cost, emissions, and flexibility

As discussed in Chapter 3 there are many different options for hydrogen storage, all ranging in size, cost, and efficiency. Compressed hydrogen tanks are one of the more expensive options, but can be deployed anywhere, depending on space limitations. This makes them suitable for small hydrogen production projects or for storage on-site at refuelling stations. Underground hydrogen storage in geological formations such as salt caverns are more suitable for large-scale storage, with a much lower cost per kilogram of hydrogen stored. Liquid hydrogen storage serves as an intermediate option between the two, both in terms of scale and cost. Challenges

around liquid storage include liquefaction energy consumption and flexibility, as well as boil-off losses, as discussed in Chapter 5.

In the first journal paper described in Chapter 2, the lowest-cost scenarios are those with access to large-scale, low-cost storage, resulting in an LCOH of €2.75/kg in 2030. The available storage size and cost clearly impacts the optimal configuration and therefore the overall cost. Largely unexplored in the literature, this became the focus of the second journal paper, described in Chapter 3. In this paper, the TEA tool for analysing hydrogen hubs is modified to include a generic storage submodel, for which the input parameters storage size and cost are varied to represent a range of potential storage technologies. The results proved significant. For renewable hydrogen production from onshore wind in Ireland, LCOH varied from €3.90/kg to €12.40/kg in 2030 depending on storage cost, for a required storage size of 56 days to ensure supply to a constant demand. If storage size is limited to 1 day, 14% of the electricity for electrolysis must be imported from the grid, with a similar quantity of renewables curtailed. This is because for smaller storage sizes, storage is full more often (during times of high production), and if storage is full and hydrogen demand has been met, there is nowhere to store or utilise further hydrogen production. Therefore, the electrolyser must shut down, even if there is renewable power available. However, this loss must be made up for at another time, when storage is low, and the dedicated wind output is low. To ensure hydrogen is supplied to the demand, the electrolyser must buy grid electricity for electrolysis to produce the deficit. For high-cost storage, lowering the storage size from 56 days to 1 day reduced the LCOH to €4.55/kg.

However, it is important to note the effect on emissions, as the carbon intensity of the grid electricity must be accounted for. In this paper, an average carbon intensity for grid electricity in 2030 is assumed. Based on this assumption, wind-based and solar-based hydrogen production with grid top-up required for 1 day of storage has an average annual carbon intensity of less than 1 gCO_2/gH_2. However, the carbon intensity of grid electricity varies significantly on an hourly basis, depending on the instantaneous penetration of renewables. This variance is likely to be exaggerated as the level of variable renewable power on electricity grids increases. As such, hourly carbon intensity data for grid electricity is included in the modelling as part of the third journal paper (Chapter 4). Again, this work highlights the huge difference in costs for different storage methods, in this case salt caverns and compressed hydrogen tanks. For the grid-connected high-cost storage scenarios analysed, LCOH decreases as capacity factor increases. This is due to the fact that the required storage size decreases, in keeping with the

findings from Chapter 3. Considering hourly carbon intensity of grid electricity, a clear trade-off arises. As the capacity factor of the electrolyser increases, and LCOH decreases, the carbon intensity of the hydrogen produced also increases (Figure 3(A) – Chapter 3). This is because to increase the capacity factor of electrolysis more electricity is purchased in the wholesale market that is of an increasingly higher carbon intensity. As a result, at very high capacity factors, the carbon intensity of hydrogen production can reach over 7 gCO_2/gH_2 based on a simulated 80% renewable electricity system in Ireland in 2030. In some cases, displacing natural gas usage with hydrogen of this carbon intensity would increase emissions.

These findings highlight how to ensure hydrogen production is clean, flexible, and affordable, large-scale, low-cost hydrogen storage is essential. However, such storage is likely to be developed underground, which is dependent on the availability of suitable geological formations such as salt deposits and depleted oil and gas fields. As such, not every hydrogen project will have access to such sites, and even if they were to, many first mover projects will not have the sufficient scale to warrant the development of such large-scale storage. This outlines the importance of developing storage in tandem with production and demand, and where required, connecting all three via a network. Timelines for underground storage, as mentioned previously, are a challenge, with lead times in excess of 10 years in some cases. A lack of regulation and standards for underground hydrogen storage is also a key barrier to be overcome. For smaller scale projects in the meantime, innovative solutions, and lenient policy or perhaps heavy subsidy, will be required to ensure affordability. Complementing renewables with grid electricity is one option, but comes with its own consequences for emissions. Taking advantage of the complementary nature of wind and solar to increase capacity factor is another solution, as is oversizing renewables capacity compared to the electrolyser capacity.

6.3 The impact of using grid electricity for hydrogen production

In Chapter 2, the lowest-cost scenario analysed, located near Belfast, produces hydrogen by purchasing electricity for hydrogen production in the wholesale market and storing it underground in salt caverns before delivering it to end-users. By operating at a capacity factor of 42% the electrolyser purchases low-cost, high-renewable grid electricity. Similarly in Chapter 4, in the grid-connected scenario, an LCOH of €2.05/kg is calculated for a capacity factor of 38% and a carbon intensity of 1.91 gCO_2/gH_2, well below the CertifHy low carbon limit of 4.37 gCO_2/gH_2. However, under current policy, neither of these scenarios would be

considered to produce renewable hydrogen, and as a result would not be eligible for meeting the relevant EU mandates for hydrogen use in transport and industry. According to the Renewable Energy Directive II [3], renewable electricity for hydrogen production must be a) additional, b) temporally matched, and c) geographically correlated as detailed in Chapter 4. This does not allow for grid electricity to be used for hydrogen production, to ensure that hydrogen is 100% renewable and does not inadvertently increase the dispatch of fossil fuel generators on the electricity grid. However, as shown in Chapter 3 and 4, off-grid hydrogen production costs are higher than grid-connected hydrogen production, and can be prohibitively high (>€15/kg) for scenarios restricted to high-cost storage options. This is due to the large storage quantities required to balance hydrogen supply and demand, with no possibility to utilise small quantities of grid power to ensure a reliable supply if renewables output and storage are insufficient to meet demand.

Hydrogen production that is limited to off-grid or additional renewables is separate from the electricity system and markets, and is therefore unavailable to provide flexibility or grid services to alleviate the growing issues of grid constraints, curtailment, and oversupply. This is despite the wealth of studies pointing to the benefits of close integration of hydrogen production and the electricity system to enable demand flexibility and reduce the cost of both hydrogen and electricity [4–8]. It is acknowledged that demand-side flexibility is crucial to the decarbonisation of the electricity sector, particularly in isolated systems such as the I-SEM (Integrated Single Electricity Market) in Ireland. According to EirGrid's *Tomorrow's Future Energy Scenarios* report, 20-50% demand-side flexibility is required in a zero carbon system [9]. Electrolysers could provide much of this flexibility by ramping up and down with the level of variable renewable electricity on the system. This is however, as discussed above, contingent on the development of large-scale hydrogen storage. It is questionable whether this vision of the flexible electrolysis demand, reacting to prices, emissions, and grid signals, is best achieved under the current rules for hydrogen production. Current policy is likely to push hydrogen production off-grid, whilst the issue of integrating large variable renewables capacity with the electricity system persists. As evidenced by the above findings, given the development of large-scale hydrogen storage, grid-connected hydrogen production can operate at low capacity factors, utilising renewable power and helping to alleviate, rather than exacerbate, system issues.

Strict rules on hydrogen production also threaten to stunt the growth of the hydrogen industry, by making small scale first mover projects prohibitively expensive. These projects may have

limited hydrogen storage options, and as such building storage capacity in excess of the 50 days required to balance supply and demand may be insurmountably expensive, if even technically feasible. Concerns that hydrogen projects may run at high capacity factors, increasing pressure on the electricity system and emissions concurrently are legitimate, as the unmitigated growth of electricity demand from data centres in Ireland has shown. However, the likely total capacity of hydrogen production in Ireland prior to 2030 or even 2035, is in the 10s of megawatts. Compare this to a daily peak electricity demand that ranges from 5000 to 7000 MW. On the other hand, data centres consumed 18% of Irish electricity in 2022 [10], with this number expected to grow. In light of this, it may be beneficial, if not crucial, that flexibility is given to projects in the short-term, to ensure viability of early projects, reducing the need for subsidy, with a likely negligible impact on the electricity grid. As discussed in Chapter 4, there are many policy options for ensuring the sustainability of electricity demand for hydrogen production in the short-term, such as enforcing shutdowns at peak times daily, or at a threshold carbon intensity or market price. Other electricity demands are in fact rewarded through the capacity market for providing similar services. Hydrogen production remains the only electricity demand which must build its own power capacity and use only what is available from said capacity. As hydrogen production capacity grows, rules can be tightened, or production capacity could be procured via auctions to align with the build out of sufficient renewables capacity for the system. Of course, as this production capacity grows, it will begin to have a significant effect on the system, the extent of which is not known. This is a crucial area for future work to aid in the planning and design of electricity systems and markets.

The electricity demand from hydrogen production is not the only interaction between hydrogen and the electricity system, as hydrogen is likely to be used for power generation in gas-turbines and fuel cells. Power generation is in fact estimated to be one of the largest end-users of hydrogen in Ireland, providing power when wind and solar generation is low. This is reflected in the results from Chapter 5, showing that hydrogen-fired power generation supplies 8% of our domestic electricity annually by 2050 (not including electricity for hydrogen production), and accounts for 36% of hydrogen demand, in a scenario where climate targets are met. As hydrogen is likely to be used for power generation when wind and solar are low, hydrogen demand in this sector will be inversely correlated to hydrogen production from wind and solar. This further increases the need for hydrogen storage to balance this supply and demand.

6.4 The role of hydrogen in the decarbonisation of the island of Ireland

With much uncertainty around the future capabilities of hydrogen and other clean technologies, in addition to the changing climate, where hydrogen should and should not be used is the source of often intense debate. While some see it as a panacea for climate change, others decry the current wave of interest in hydrogen as nothing more than the desperate attempt by the fossil fuel lobby to continue to sell fossil fuels under the guise of a clean fuel. In reality, it is far more nuanced, with a wide array of potential hydrogen production routes (as shown in Table 1 in Chapter 4), some cleaner than others, with numerous potential end-uses, but only some where hydrogen is truly suitable.

In the journal paper covered in Chapter 2 [1], a variety of different potential end-uses for hydrogen are considered. These include hydrogen use as a transport fuel for trucks, buses, and trains, hydrogen use in place of heavy fuel oil for industrial heating, and injection of hydrogen into the natural gas grid as a blend at both transmission and distribution level. Emissions savings vary significantly between scenarios. For scenarios with gas grid blending, overall emissions savings are large due to the large demand for natural gas on the network, whereas hydrogen demand in transport is much smaller in most cases. However, emissions savings per tonne of hydrogen produced were much higher for scenarios where hydrogen is used in transport, or to displace heavy fuel oil, as diesel and fuel oil are much more emissions intensive than natural gas. This is exemplified by Scenario 4 where hydrogen is supplied to transport fleets in Belfast. Compared to Scenario 5, where hydrogen is injected into the gas grid, more emissions savings are achieved despite only producing approximately 40% of the hydrogen. This highlights how the climate impact of hydrogen is heavily dependent on the end-use. This is again highlighted in Chapter 4, where emissions savings from hydrogen used for hydrogen buses in place of diesel buses are much higher than when displacing natural gas usage. In addition to this, cheaper more efficient solutions exist for some natural gas consumers. For residential and commercial space and water heating for instance, heat pumps can provide sufficient heat at low-cost. As such, many studies see no major role for hydrogen in heating for buildings [11]. One study by the group Physicians for Social Responsibility went as far as to say the use of hydrogen in buildings is unsafe [12]. Similarly, electric vehicles are tipped as the dominant solution for passenger vehicles. However, this is not to say that hydrogen will have not market share in passenger vehicles and low temperature heating. We do not live in a cost-optimal world. Some end-users may opt for solutions due to specific circumstances such as geographical location, government policy, or personal preference.

The use of hydrogen and electrofuels is likely to be best suited to applications where electrification is not possible or prohibitively challenging. As part of Chapter 5, these end-uses were identified as heavy-duty transport, including high mileage trucks, buses, and coaches, as well as shipping and aviation fuel, industrial processes and high temperature heat, and dispatchable power generation. Of these, transport demands dominated short-term market share on the island, but long-term power generation is predicted to be the largest domestic hydrogen demand by 2050 in the scenario where climate and decarbonisation targets are met, consisting of 36% of hydrogen demand. Overall, hydrogen usage is much smaller than the use of electricity directly, but demand is significant at 6 TWh in 2030 and 66 TWh in 2050 if targets are to be met. For reference, electricity and gas demand in Ireland in 2021 were 34 TWh and 50 TWh, respectively [13]. This indicates the potential scale of the industry. To realise this, huge investment in new hydrogen infrastructure would be required to produce, store, and supply this hydrogen demand across the island. To meet climate targets, 5 GW of renewables dedicated to hydrogen production is required in 2030, according to the modelling carried out in Chapter 5. This number rises to 25.5 GW by 2050. However, these numbers are based on the assumption that all renewables capacity for hydrogen production is additional to that used for electricity consumption. As discussed above, this may not be a cost-effective approach and the required capacities for hydrogen production could likely be reduced through closer integration with the electricity system. The work also sets out the island as a potential hydrogen exporter. This would likely be via the European Hydrogen Backbone pipeline network. Connection to such a network would also allow the island to utilise hydrogen storage elsewhere in Europe, reducing the need to build such projects here. It may be beneficial for the island to focus on one storage project as this would provide extra energy independence and security, whilst also planning to utilise European storage. This would be particularly useful given the storage figures calculated in Chapter 5 do not consider the need for inter-annual storage due to year to year weather fluctuations, or the potential to build extra storage for strategic or energy security purposes. Nevertheless, a physical connection to Europe would diversify both supply and storage, as well as providing a route to what is predicted to be one of the largest markets for hydrogen in continental Europe.

6.5 A note on parameter uncertainty and sensitivity

As discussed in Chapter 2, the cost of electricity and capital cost of main equipment for hydrogen production, primarily the electrolyser, have a significant impact on the overall

LCOH. There is also a large amount of uncertainty about the future values of such parameters. The LCOE of wind and solar, capital cost of electrolysers, and the cost of capital for hydrogen projects are likely to change over time due to factors such as inflation, interest rates, geography, government policies, and geopolitics. As a result, analyses such as uncertainty quantification and sensitivity analyses are very important in characterising the effect of this uncertainty on the affordability of hydrogen. It would be useful therefore, for any studies using a tool such as the TEA tool described in Chapter 2, to vary assumptions made regarding the cost of electricity, including the LCOE of renewables, market prices, and the cost of electricity that would otherwise be dispatched down, the capital cost of electrolysers, and discount rate. A tool that incorporates comprehensive uncertainty quantification and sensitivity analysis would be incredibly useful in this regard.

6.6 Bibliography

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Chapter 7: Conclusions

The level of understanding of hydrogen as an energy carrier and its potential role in a zero carbon energy system has risen significantly in recent years, due to an increased focus on renewable energy technology research and innovation. Whilst there is much more work to be done, many of the opportunities and challenges pertaining to hydrogen are now better understood across academia, industry, and policy. The pace of change has been rapid, with numerous breakthroughs in research, deployment, and economic policy. The work detailed in this thesis has generated new knowledge of hydrogen systems and supply chains, as evidenced by the three published journal papers described herein, whilst also helping to inform both project developers in industry and policymakers in government. What began as a study with a focus on identifying potential future hydrogen hubs in Ireland, and how both wind and grid electricity could be used to produce hydrogen for a variety of end-uses, spawned a comprehensive TEA tool that helped to identify storage as a previously neglected but critical piece of any hydrogen study or project. From this, it was shown that low-cost, large-scale storage is critical to development of clean, secure, and affordable hydrogen. However, suitable geological formations for low-cost underground hydrogen storage, are not widely available. This in turn raised the question of whether off-grid hydrogen production, as encouraged by policy, was better placed than grid-connected systems to deliver cost-effective emissions savings. The work showed that grid-connected hydrogen production can reduce costs, whilst delivering emissions savings, acting as a large flexible demand that can respond to market price signals. Finally, the scale and cost of hydrogen infrastructure required was examined, with the importance of the findings of the work highlighted by the sheer scale and pace of delivery required to enable hydrogen's role in realising climate targets. This showed that hydrogen has a crucial role to play alongside electrification, renewable electricity, and energy efficiency, and that planning for large-scale hydrogen production, storage, and transmission infrastructure must begin in earnest.

Key areas for future research include further investigation of the relationship between hydrogen production and the electricity system, as well as comprehensive total cost of ownership and total cost of abatement analysis of hydrogen applications. The effect of large electrolysis capacity on the electricity system is an area of critical importance to evaluate the consequences of large-scale hydrogen production on market prices and emissions, as this was not captured in the present work. This can help to uncover how best to integrate both systems and design market policy thereafter. A focus on how this compares with current EU and UK policy on

hydrogen production would be of interest. Total cost of ownership and total cost of abatement analyses can help to identify which end-uses are most affordable for hydrogen today, help to prioritise usage, and create timelines for deployment.