TOWARDS A LOW-CARBON HYDROGEN ECO-SYSTEM IN IRELAND

MaREI Centre for Energy, Climate and Marine

July 2025

Towards a low-carbon hydrogen eco-system in Ireland

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Citation:

Gray, N., Abualhussein, A., Murphy, P., Murphy J.D. (2025) "Towards a low-carbon hydrogen eco-system in Ireland" O'Gallachoir, B. (Reviewer) MaREI Centre for Energy, Climate and Marine, July 2025. Available at: https://www.marei.ie/wp-content/uploads/2025/10/ESB-Hydrogen-Report.pdf

Acknowledgements:

Karen O Callaghan for desktop publishing

Sustainable Energy Authority of Ireland and Department of Transport for funding of the research project "Developing pathways for a sustainable shipping and maritime fuel value chain in Ireland" (ShipFuel-IE) under Grant No. 22/RDD/800.

Cover Graphic:

Hydrogen Fuel Cell photo from ESB

Executive Summary

The decarbonisation of the power sector is key to meeting ambitious climate mitigation efforts. This is widely expected to be delivered through a significant increase in variable renewable generation (wind and solar) as well as short-duration energy storage (batteries). To ensure a resilient energy transition, sources of dispatchable low-carbon electricity will also be needed to deliver power at times when renewable output is low. Beyond the electricity sector, there are other areas of the energy system that are much more challenging to decarbonise. These include shipping, aviation, and chemical production and will likely be decarbonised via low-carbon molecules rather than low-carbon electrons.

Hydrogen is a versatile energy carrier that can be used to effectively address both these challenges. As a gas, hydrogen can be stored and used directly in a range of end-use applications, or it can act as a platform for the production of synthetic fuels such as methane, methanol, or ammonia. With one of the best wind resources in the world, Ireland has great potential to produce hydrogen via the process of electrolysis. However, there remain several barriers that must be addressed to help enable the development of a hydrogen ecosystem in Ireland. Therefore, the aim of this report is to provide an overview of the policy support mechanisms and regulatory frameworks that could be applied to spur the development of an indigenous hydrogen sector in Ireland.

The first risk that must be mitigated is the risk that hydrogen production costs are too high to encourage uptake amongst end-users. This is known as price risk and can be mitigated through the payment of a premium to support hydrogen producers. This can either be in the form of a fixed or variable premium model. The fixed premium model is seen as offering greater levels of certainty for producers, especially for early or small-scale projects, but is inflexible to changing market conditions. The variable premium model, similar to the Contract for Difference mechanism to support renewable electricity generation, allows the amount of subsidy paid to change with evolving market conditions, providing better value for government money while also ensuring producers can cover production costs with certainty. However, the effectiveness of the variable premium model hinges on selecting an appropriate reference price, which could be challenging for an emerging product such as hydrogen where there is currently no wholesale market to benchmark against. The other major challenge is that producers are unable to sell sufficient quantities of hydrogen to confidently cover production costs. This is known as volume risk and can be mitigated via a range of options. A sliding scale payment mechanism could be used to provide greater levels of price support if offtake levels fall below anticipated volumes. Further options, such as stimulating hydrogen demand, investing in infrastructure such as large-scale storage, and exploring the opportunities for exports can also be used to help mitigate against volume risk.

By co-locating hydrogen production, storage, and high-priority demand, a cluster-based approach to hydrogen development can help fast-track the development of hydrogen projects within Ireland. With 20% of Ireland's electrical generation capacity, an extensive gas transmission network, the islands only oil refinery, and large-scale geological storage in the depleted Kinsale Head gas field, the Cork area is well positioned to spearhead Ireland's development of a hydrogen-based ecosystem. The policy support mechanisms discussed in the report have the potential to be tested and refined in a Cork hydrogen cluster, before being rolled out and applied to hydrogen projects across the country, facilitating the development a national hydrogen ecosystem.

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1.0 Introduction

The decarbonisation of electricity production through the increased use of variable renewable energy (such as wind and solar power) and energy storage is widely expected to be the foundations on which the energy transition is built [1]. To complement this and ensure a resilient transition, sources of dispatchable low-carbon electricity will also be needed to supply clean power at times when renewable output is low, especially considering seasonal variation in weather patterns [2]. Beyond electricity generation, there are other sectors of the energy system that are likely to be much more difficult to fully decarbonise [3,4]. These so called "hard-to-abate" sectors include long-distance transport (particularly shipping and aviation), heavy industry, and chemical production. It is likely these hard to abate sectors will be decarbonised via renewable molecules (in the form of liquid or gaseous fuels) rather than low-carbon electrons (in the form of electricity).

Hydrogen is a versatile energy vector that has the potential to play a critical role in achieving global decarbonisation goals [5]. Hydrogen is widely used today as a feedstock within the chemical sector but has the potential to be used in a wide range of other applications. Current applications for hydrogen include the production of chemicals such as methanol (CH_3OH) and ammonia (NH_3) as well as the refining of crude oil [6]. In future low-carbon energy scenarios, hydrogen has the ability to be used in a range of novel applications, including [7]:

- As a transportation fuel in fuel cell vehicles
- As a source of high-temperature industrial heat
- As a source of dispatchable low-carbon electricity generation
- As long-duration, intraseasonal energy storage
- As a feedstock to produce low-carbon fuels and chemicals

In 2022, approximately 95 million tonnes of hydrogen were produced globally [8]. Production of hydrogen was dominated by the use of unabated fossil fuels, with low-carbon hydrogen production accounting for less than 1% of the global total. As such, current hydrogen production is a climate problem rather than a climate solution. In addition, hydrogen is an indirect greenhouse gas due to its atmospheric chemical reactions altering the quantities of the greenhouse gases methane, ozone, and stratospheric water vapor, as well as aerosols [9]. As we move towards a net-zero energy system, there are two main pathways for the production of low-carbon hydrogen, namely "blue" hydrogen produced by reforming natural gas in conjunction with Carbon Capture and Storage (CCS) or "green" hydrogen produced from renewable electricity via electrolysis [10]. Both of these technologies are novel and are not yet deployed at scale.

Within an Irish context, the Climate Action and Low Carbon Development (Amendment) Act 2021 has set a legally binding trajectory towards achieving net-zero emissions by no later than 2050, and a 51% reduction in emissions by 2030 [11]. Hydrogen produced from indigenous renewable resources presents a significant opportunity for Ireland to enable a secure and resilient transition to a low-carbon economy, as well as potentially attracting new industries to the island, driving economic growth and job creation.

The desire to develop a green hydrogen ecosystem is driven by several primary strategic reasons: decarbonisation of society, reduction of carbon penalties, enhancing energy security, maximising renewable assets, and creating new industrial and export opportunities:

1. Decarbonising the Economy and Manging Risk of Climate Penalties

Ireland is on a pathway to a net-zero emissions economy by no later than 2050, necessitating a transformational change in our energy system. Within the Irish context, there are certain limitations to the available low-carbon technologies that can be used to meet these ambitious targets. Generation of nuclear power is prohibited by law, the conditions for geothermal energy are not present, and interconnection to other grids, while important, is not sufficient on its own to enable deep decarbonisation. Renewable hydrogen, produced from indigenous wind resources, can play a crucial role in this transition. Hydrogen has the potential to displace fossil fuels in sectors that are hard to decarbonise, where direct electrification is not feasible or cost-effective. In addition, it is estimated by the Irish Fiscal Advisory Council and the Climate Change Advisory Council that the cost of missing EU emissions targets could be between €8 billion and €25 billion [12]. Decarbonising these sectors through green hydrogen reduces the opportunity cost of these fines. This makes the development of an indigenous hydrogen sector a pivotal component of Ireland's decarbonisation strategy.

2. Enhancing Energy Security

Hydrogen can bolster Ireland's energy security by reducing reliance on imported fossil fuels. Ireland imported 81% of its energy supply in 2023, leaving the nation vulnerable to shocks in global supply chains. Despite this, Ireland's wind resource has the potential to be one of the best in Europe [13]. Producing hydrogen from indigenous renewable resources could lessen reliance on imported fossil fuels, therefore enhancing the resilience of the energy system by increasing the utilisation of indigenous renewable energy. Where suitable geology exists, such as depleted oil and gas reservoirs or salt caverns, hydrogen can be stored in large quantities and used as a source of dispatchable energy that can enhance the resilience of energy systems with high penetrations of variable renewable generation [14]. This is particularly important during sustained calm and dark periods, where renewable generation is low, that can last for several days at a time. Where conditions for large scale geological storage of hydrogen do not exist, it can be used as a feedstock to produce synthetic fuels (such as methane, ammonia, or methanol) which are easier to store in above ground tanks. Although the conversion of hydrogen to synthetic fuels results in greater parasitic energy losses, their production could be justified on a case-by-case basis due to the significantly lower storage costs for areas without the conditions for large scale hydrogen storage in geologic formations.

3. Maximising Renewable Assets

At times when electricity generation from variable renewables is high, it is sometimes necessary for the electricity Transmissions System Operator (TSO) to dispatch down generation to maintain the safe operation of the electrical grid. The reason for dispatch down of renewables can either be due to the inability of the local distribution grid to accommodate the amount of energy being generated or due to system wide reasons, where renewable generation is significantly higher than system demand. These are termed dispatch down due to constraint or curtailment respectively. In Ireland, the level of wind energy lost to dispatch down has risen from ~3% in 2013 to ~11% in 2023 as the total installed capacity of wind generation increased from 2.5 GW to 6 GW [15]. Hydrogen production via electrolysis can act as a source of flexible demand, capturing renewable electricity that would otherwise be lost, therefore increasing the efficiency of renewable generators. While this can have important system wide benefits, it is important to note that research indicates that relying solely on electricity that would otherwise be dispatched down can result in high hydrogen production costs [16].

4. Creating Industrial and Export Opportunities
Beyond supporting decarbonisation and energy security, developing an indigenous hydrogen industry can present industrial and export market opportunities. With a large potential resource of renewable electricity, Ireland could produce more renewable hydrogen than is currently needed domestically, meaning there is significant potential to attract new industries to the island, creating high-skilled jobs and fuelling economic growth. Analysis commissioned by the Department for the Environment, Climate and Communications (DECC) indicates that Ireland's hydrogen resource from excess wind energy could be as large as 93 TWh, although the economic resource will likely be smaller and dependent on policy support mechanisms [17]. Once domestic demand has been satisfied, surplus hydrogen could be exported to meet the decarbonisation needs of other European countries. An export market would bring scale to hydrogen production, further utilising Ireland's large wind energy resource, potentially justifying the development of a national hydrogen network to transmit hydrogen from production site to export locations.

However, it is also highly likely that indigenous Irish hydrogen will initially be a relatively expensive energy vector, while also being significantly less efficient than direct electrification. Therefore, it is likely that policy measures will be needed to support and enable the development of a hydrogen ecosystem in Ireland. It is important that these policy measures are appropriate and encourage hydrogen to be directed towards end-use applications where direct electrification may be challenging.

The aim of this report is to provide an overview of potential policy supports and business models that could be used to develop a hydrogen market within the Irish context.

2.0 The role of hydrogen in decarbonising the Irish economy

The development of an indigenous hydrogen industry presents a significant opportunity for Ireland to meet ambitious decarbonisation targets. However, the development of such an industry also presents significant challenges, especially in the early stages of development. The following section will discuss pathways for the production of low-carbon hydrogen, hydrogen policy, end-use applications, and potential challenges, all within the Irish context.

2.1 Low-carbon and renewable hydrogen production pathways

Within the EU, hydrogen is defined as low-carbon as long as it meets an emissions reduction of 70% compared to the fossil fuel it displaces [18,19]. Low-carbon hydrogen can be produced via two main pathways: blue hydrogen and green hydrogen [20].

Blue hydrogen refers to hydrogen produced from steam reforming of natural gas in conjunction with CCS technology to capture a large portion of CO2 emissions from the process. Blue hydrogen has lower production costs than green hydrogen in the short-to-medium term and is therefore of interest to nations with large reserves of natural gas [21]. However, research shows that unless carbon capture rates are very high and methane leakage along the entire supply chain is very low, then the CO_2 footprint of blue hydrogen can be equal to or greater than the fossil fuels it seeks to displace [22]. This implies that unless methane leakage is minimised, and carbon capture rates are very high, blue hydrogen could potentially struggle to meet EU emissions reductions targets.

Green hydrogen is produced using renewable electricity to split water into oxygen and hydrogen via the process of electrolysis [20]. It is well established that the carbon footprint of green hydrogen is driven by the carbon footprint of electricity used to produce it and the carbon footprint of hydrogen will always be greater than that of the electricity from which it is produced, due to the inefficiency of the electrolysis process. As such, if electricity with the EU grid average carbon intensity is used the resulting hydrogen has a larger carbon footprint than conventional hydrogen [23]. However, if renewable electricity is used in the process, the resulting hydrogen carbon footprint is close to zero. Green hydrogen is more expensive than blue hydrogen in the short-to-medium term but is a promising option for regions with little reserves of natural gas (and associated depleted gas fields to store the captured CO_2) but a large resource potential for renewable electricity generation [24]. A further challenge of hydrogen is that it can act as an indirect greenhouse gas through chemical reactions with other atmospheric components, meaning hydrogen leakage across the value chain must be minimised [9].

Within the Irish context, the decommissioning of the Kinsale Head gas field leaves the Corrib Field as Ireland's only domestic source of natural gas production. Given this, along with the potentially very large resource for offshore wind generation, it is highly likely that any hydrogen produced domestically within Ireland will be green hydrogen.

2.2 Hydrogen policy and regulation

The growth of a hydrogen ecosystem in Ireland will largely be shaped by regulation, both at national and European Union (EU) level. Therefore, it is important to have an overview of EU policies (Table 1), as well as potential gaps that might exist in the Irish context.

Table 1 – Summary of EU policies relevant to the development of a hydrogen industry in Ireland

Policy	Objectives
EU Hydrogen Strategy [25]	The EU Hydrogen Strategy provides a roadmap for the development of a hydrogen industry in Europe, outlining a framework for hydrogen regulation, pathways to increase supply and demand, and setting out how hydrogen projects can be financed.
EU Energy System Integration Strategy [26]	The EU Energy System Integration Strategy sets out the need for energy system integration (across electricity, gas and end-users) to deliver an effective and resilient transition.
EU Hydrogen and Gas Market Decarbonisation Package [27,28]	The EU Hydrogen and Gas Market Decarbonisation Package creates a regulatory framework to facilitate the introduction of low-carbon and renewable gases on the EU market, including specific legislation regarding dedicated hydrogen infrastructure.
RePowerEU [29]	RePowerEU outlines the EU's roadmap to reduce dependence on Russian energy resources through improving energy efficiency, diversifying supply chains, and speeding the transition to renewables, including the target of 10 million tonnes of domestically produced hydrogen by 2030.
Fit for 55 [30]	The Fit for 55 package of legislation sets out the actions required to deliver a 55% reduction in greenhouse gas emissions by 2030. Specific targets for hydrogen use in shipping, aviation, and heavy industry are provided.

One of the major aims of EU regulation is to ensure green hydrogen production results in actual greenhouse gas reductions compared to the fossil fuels it will displace [31]. To do this, there are strict guidelines to ensure the sustainability of green hydrogen production (Figure 1). An electrolyser can either be connected directly to a renewable electricity generator or to the electrical grid, with regulations varying depending on which path is chosen. If the electrolysis facility is to be connected directly to a renewable generator, then there must be no connection between the grid and the generator, the generator must have come into operation less than 36 months before the hydrogen production facility, and the generator must not receive any subsidisation. If the hydrogen production facility is to be supplied with grid electricity, there are additional regulations that must be met. In general, the electricity for a grid connected hydrogen facility must be supplied using a Power Purchase Agreement, with a renewable energy generator that came into operation less than 36 months before the hydrogen facility. Furthermore, temporal correlation is required to match the electricity supplied from the generator and the electricity consumed by the production facility. These regulations are in place to ensure that green hydrogen production has the positive environmental impact that is needed to combat climate change. Research shows that if additionality and temporal regulations are not enforced, the additional electrical demand from the hydrogen production facility will likely be met by the marginal source of electricity, often coal or gas, therefore negating any climate benefit of the project [32].

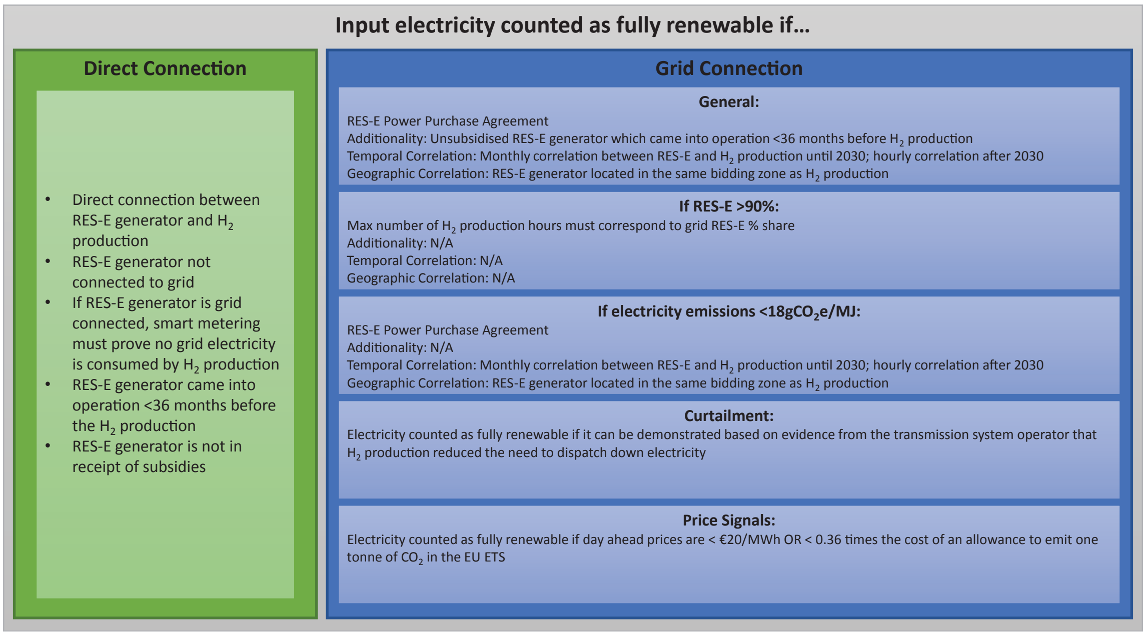

Figure 1 - Summary of EU regulations for the production of green hydrogen-adapted from RED II and associated Delegated Act [31]

Within the Irish context, there are several regulatory gaps that must be addressed to facilitate the development of an indigenous hydrogen industry. While Ireland has published a national hydrogen strategy it does not have any quantitative targets for electrolysis capacity by 2030, although it does indicate a 2 GW target of offshore wind in 2030 for the production of renewable hydrogen. No member state has yet transposed the hydrogen and gas decarbonisation package into national legislation (the deadline is August 2026), but some such as Denmark and Germany have run consultations on the needs for hydrogen network planning and tariffs.

Without clear guidelines for the certification of renewable hydrogen, as well as a regulatory framework for hydrogen transmission networks, storage, and health and safety regulations for hydrogen projects, Ireland may be at a disadvantage as regulatory uncertainty acts as a barrier for hydrogen producers and off-takers. By drawing on successful models used in other EU countries, such as the Energy Industry Act (EnWG) in Germany, which provides a regulatory framework for the development of hydrogen transmission and storage infrastructure, [33], Ireland can overcome these barriers through targeted legal reforms.

2.3 End-use applications for hydrogen

As previously highlighted, hydrogen and hydrogen derivatives are versatile energy carriers that have the potential to be used in a wide range of applications. However, for many end-uses energy efficiency measures and direct electrification offer a more efficient and lower cost pathway to decarbonisation. Therefore, when considering a hydrogen ecosystem, it is important to direct hydrogen and hydrogen derivatives towards applications that are hard to decarbonise and have fewer alternative options. In line with this, the National Hydrogen Strategy provides a hierarchy of end-uses where hydrogen should be prioritised with it the Irish context [34].

Existing Hydrogen Applications

Within an Irish context the Whitegate Oil Refinery, which is based in the lower harbour in Cork, is the only large producer and user of hydrogen on the island. Hydrocracking, desulphurisation, and hydrogenation are all steps of the refining process that require hydrogen and could act as an immediate source of demand for green hydrogen in Ireland. Beyond this, there are no other large-scale sources of hydrogen demand in Ireland. New industries and novel end-uses will need to be found to develop a mature indigenous hydrogen industry.

Long Duration Energy Storage and Flexible Power Generation

As the power sector in Ireland transitions to greater penetrations of variable renewables, there is a need to develop methods for generating decarbonised electricity at times when wind and solar output is low. Options for this that are available in other locations, such as nuclear or geothermal, are not possible in Ireland for regulatory and geographic reasons respectively. Therefore, renewable hydrogen (or derivatives) combined with large-scale storage are seen as one of the few feasible pathways for delivering a decarbonised and resilient power sector in Ireland, along with bioenergy coupled with carbon capture and storage [35]. Although this is expected to be a relatively expensive way to generate electricity, the resilience it adds to the system is valuable.

Uninterruptible Power Supply and Energy Parks

The rise of the data centre industry and other large energy users in Ireland has led to an increased focus on the need for dispatchable low-carbon electricity, where the supply to the end user remains uninterrupted no matter the weather conditions. It is currently possible to enter into a firm contract and pay a premium for non-interruptible electricity supply. However, this can put a strain on the electrical grid. The co-location of a large energy user, such as a data centre, with hydrogen powered dispatchable back-up generation is a potential route to market for hydrogen produced in Ireland that would help enhance Ireland's attractiveness for investors without putting additional stress on the electrical grid.

Maritime and Aviation

As an island nation, Ireland is highly dependent on both the aviation and shipping sectors for the transportation of goods and people. Both these sectors face significant challenges for electrification and are seen as hard-to-abate. Due to the low volumetric energy density of hydrogen, it is likely that hydrogen would be used indirectly, in the form of e-fuels, to decarbonise these sectors, which would also require a sustainable source of CO_2 for fuel synthesis. The development of an e-fuels industry to supply the shipping and aviation sectors, using domestically produced green hydrogen as a feedstock, would address the strategic objective of decarbonising our transport sector while maintaining global connectivity with the rest of the world.

Biogas Upgrading

The Climate Action Plan also aims to establish 5.7 TWh of biomethane production in Ireland by 2030 [36]. This amount of biomethane will also result in a large resource of biogenic CO_2 compared with what is currently available. Currently, biomethane facilities often vent their biogenic $CO_{\neg 2}$ into the atmosphere. Alternatively, hydrogen can be used to convert the CO2 in biogas to methane using the Sabatier Process ($4H_2 + CO_2 = CH_4 + 2H_2O$). This can be a catalytic process or can be carried out biologically in an ex-situ bio-methanation process where microbes consume hydrogen and carbon dioxide and produce methane as a product. This doubles as a biogas upgrading process as it converts the CO_2 in biogas to CH_4 and in so doing can increase the yield of biomethane by 67% [41].

Non-Energy End-Uses

Hydrogen can also be used as a feedstock to produce chemicals and other non-energy products. Ammonia represents a significant portion of current global hydrogen demand, primarily for fertiliser production. The discovery of the Kinsale Head Gas Field led to the development of Irish Fertiliser Industries (IFI) in the 1970's, using natural gas to produce ammonia in their Marino Point site. Though it closed in the 2000's as production from the Kinsale Head field decreased, the site could be repurposed to kickstart ammonia production from green hydrogen in Ireland.

Industrial and Domestic Heating

Within the domestic heating sector, the use of heat pumps and district heating networks are expected to be more efficient and cost-effective pathways towards decarbonisation than hydrogen, and therefore the role of hydrogen in this sector is expected to be small. The focus of hydrogen for heat will be in the industrial sector, where high temperature heat (>200°C) is often required. This will be a particular focus for breweries and distilleries in Ireland.

Road Transport

For passenger vehicles, hydrogen is not expected to play a role as battery electric vehicles (BEVs) are more energy efficient and offer a lower total cost of ownership than fuel cell vehicles. Although there is emerging evidence that the barriers to electrification of long-haul heavy goods vehicles and intercity coaches may be lower than initially anticipated [37,38], there may still be potential niche applications for hydrogen within this sector of land-based transportation. For daily travel of up to 450 kilometres, it is likely that battery electric vehicles in conjunction with a network of fast charging stations will be the lowest cost option for most haulage firms. Hauliers who require greater flexibility in their operational planning may value the larger range of hydrogen powered vehicles and as such may opt for a hydrogen fuel cell over battery electric.

Blending in Existing Gas Infrastructure

Existing natural gas infrastructure can accept blends of hydrogen of up to about 20% without modification, with ongoing research exploring the potential for higher levels. Blending may be able to offer a "demand sink" during the early stages of hydrogen development in Ireland, providing producers an offtake option for when production exceeds demand. However, in the long-term the National Hydrogen Strategy outlines that dedicated hydrogen transmission infrastructure is preferred, and blending is not a high-priority end-use.

Exports

Current practice with the sectors that use hydrogen today is to either produce hydrogen onsite or transport over short distances using a specifically designed network of pipes. As the energy transition progresses, there is increasing interest in the idea of exporting hydrogen internationally if production exceeds domestic demand. If the distance between the hydrogen production site and the demand for hydrogen is relatively short (i.e. between Ireland and Great Britain), then transmitting hydrogen through pipes may be a cost-effective pathway for export [39]. However, hydrogen pipelines for long-distance export are not likely to be feasible and other means of transmission will be required. The inherent chemical properties of hydrogen, in particular its volumetric energy density (approximately 3 kWh/m^3 at Standard Temperature and Pressure), mean that transporting it over long distances is a significant technical challenge. To combat these issues, hydrogen can be liquified, in a similar manner to Liquified Natural Gas (LNG) today. Liquefication of hydrogen occurs at -253°C and is a very energy intensive process, consuming between 8 and 12 kWh of electricity per kilogram of hydrogen [40]; when we consider that hydrogen has an energy density of 33kWh/kg this can result in a parasitic demand of between 24% and 36%. Not only is the liquification process highly energy intensive, it is also very capital expensive, with estimates of CAPEX for liquefication facilities ranging from 500 to 5,000 €/kWH$_2$ [40].

Furthermore, liquid hydrogen has a lower volumetric energy density than LNG. A Q-Max sized LNG tanker has the capacity to hold 266,000 m^3 of LNG, which equates to 1,690 GWh of energy (Box 1). If a hypothetical liquefied hydrogen tanker was to have the same volumetric capacity, it would only hold 628 GWh of energy. Despite having the same volumetric capacity, the liquefied hydrogen tanker would only transmit 37% of the energy of an LNG tanker. The implication of this is that it would require 2.7 times as many liquid hydrogen tankers to transmit the same amount of energy as a single LNG tanker, increasing costs significantly. There is currently only one liquid hydrogen tanker in operation globally, with a capacity of 1,250 m^3 [41], meaning the difference in energy transmitted is even more stark.

Hydrogen derivatives such as methane, methanol, or ammonia are much easier to transport and already internationally traded commodities that have well developed international trading infrastructure. Therefore, within an Irish context, if export of hydrogen to the international market is an option to be considered, the most likely options are via pipeline to Great Britian or via tanker in the form of a hydrogen derivative due to the difficulties in exporting liquid hydrogen by tanker.

Box 1 - Energy transported by hydrogen tanker compared to LNG

LNG Tanker
Tanker Capacity = 266,000 m^3 [42]
LNG Density = 410 kg/m^3
LNG Energy Density = 15.5 kWh/kg
Energy Transported = 266,000 m^3 × 410 kg/m^3 × 15.5 kWh/kg = 1690 GWh

Hydrogen Tanker
Tanker capacity = 266,000 m^3
LH2 Density = 70.85 kg/m^3
H2 Energy Density = 33.33 kWh/kg
Energy Transported = 266,000 m^3 × 70.85 kg/m^3 × 33.33 kWh/kg = 628 GWh

Therefore, a single large LNG tanker can transport 2.7 times as much energy as a potential LH$_2$ tanker.

2.4 Hydrogen research in Ireland

To date, the majority of research in Ireland has focussed on the production and end-use applications of green hydrogen and hydrogen derivatives. In a study into the economic sustainability of green hydrogen production in Ireland carried out by McDonagh et al. results indicate that high electrolysis capacity factors are required for economic hydrogen production, and therefore utilising only curtailed wind energy is currently not a viable business model for hydrogen production [16]. Hybrid wind/hydrogen systems have been shown to be a promising avenue for the development of wind energy in locations where grid constraints may hinder deployment [43]. A techno-economic model developed by Moran et al. indicates cost-effective large-scale storage is required to minimise hydrogen costs [44]. This study highlights the importance of geological storage, as it is one of the only ways to cost effectively store large volumes of hydrogen. A geo-spatial model developed by Vu et al. assessed the levelised costs associated with producing hydrogen from offshore wind in Irish waters, finding that East and Southeast marine areas produce the lowest cost hydrogen. The learning curve of the technologies in the future may reduce these costs however, as seen previously with wind and solar [45]. Dinh et al. investigated the cost of transmission for hydrogen and hydrogen derivatives (ammonia), finding that pipelines are economically attractive for transporting hydrogen distances of up to approximately 500 km [39]. Furthermore, they also establish for long-distance transmission, tankers are required and transporting ammonia is more cost effective than transporting liquified hydrogen. Research conducted by Gas Networks Ireland is currently ongoing to establish the feasibility of transporting hydrogen through the existing gas transmission network as well as developing a dedicated hydrogen transportation network [46].

On the demand side, Martins and Carton outlined the potential roles green hydrogen could play in Ireland's decarbonisation strategy, highlighting heavy-duty transport and long-duration energy storage as promising uses of hydrogen [47]. Gunawan et al. studied the cost implications of utilising hydrogen in city bus networks in Ireland, finding that higher carbon taxes than are currently applied are needed to make fuel cell buses competitive with diesel [48]. An energy balance conducted by Gray et al. found that using hydrogen to upgrade CO_2 from biomethane facilities can increase the gross energy produced from the system by between 32% and 63% depending on the fuel production pathway [49]. Further work by the same authors investigated the cost of using hydrogen and hydrogen derivatives within the long-distance, and heavy-duty transport sectors, particularly in heavy goods vehicles, shipping, and aviation. Within the HGV sector, it was found that battery electric vehicles result in the lowest total cost of ownership for hauliers but are limited in range to journeys less than 450 km. For vehicles that require a greater flexibility in range, hydrogen fuel cell trucks offer up to 900 km and result in a lower total cost of ownership than e-methane or e-diesel [37]. For shipping, e-methanol results in the lowest total cost of ownership for vessel operators, as it is a liquid under conditions of standard temperature and pressure meaning complex storage systems are not required onboard [50]. When considering the aviation sector, it was found that capturing CO_2 from the atmosphere using direct air capture technology and sequestering it in geological storage is a lower cost pathway than using the CO_2 to synthesise an e-jet fuel using green hydrogen [51]. However, the ReFuelEU aviation initiative targets 2% sustainable aviation fuel (SAF) supply at EU airports by 2025, rising to 70% by 2050 indicates that demand for e-fuels in the aviation sector will likely come in the form of fuel mandates [52].

From this brief summary of hydrogen research in Ireland, it is clear that there has been great emphasis on the production of hydrogen and the applications where it could be used. It is also clear that a bespoke detailed assessment is required to assess what is the optimal pathway for use of fuels produced from electricity. There has been much less focus on the steps needed to encourage the development of a market for hydrogen. This report aims to address this knowledge gap by outlining the business models and policy supports that could be applied to stimulate the growth of an emerging hydrogen market in Ireland.

2.5 The challenge of developing a hydrogen ecosystem in Ireland

Many European countries have already defined their hydrogen strategies and are in the process of implementing business models to drive growth in the hydrogen sector. Support schemes for low-carbon hydrogen have already been announced for nations such as the UK, Germany, and the Netherlands [53]. Ireland's National Hydrogen Strategy was only published in 2023, and therefore is still in the very early stages of implementation [34]. There are certain advantages to this, particularly being able to observe other nations attempts to set-up a hydrogen industry and apply best practice from their experience to the Irish case. However, there are also some challenges to be addressed, particularly around the low readiness commercial level of the hydrogen supply chain within Ireland.

For the successful development of any product, there must be an ample supply at a competitive cost as well as a source of demand to provide a route to market for the product. The first barrier to the development of a hydrogen market in Ireland can be summarised using the "chicken and egg" analogy. Ireland currently lacks a sufficient number of existing industries that could immediately utilise green hydrogen, acting as a baseload level of demand and assuring hydrogen producers that their product has a route to market. Without a level of assurance of route to market, hydrogen producers may be reluctant to set up within Ireland. Related to this, Ireland's position as an island on the western edge of Europe also poses a challenge to the development of a hydrogen industry. This is especially the case if new sources of domestic demand do materialise, as the transport of pure hydrogen over long distances is challenging and hydrogen producers may struggle to find alternative off-takers. There may also be a timing component, as not all elements of the supply chain may emerge simultaneously, with sufficient storage and transport infrastructure, alongside end-user and production infrastructure all required for a successful hydrogen ecosystem.

Despite these challenges, there are compelling reasons to support the development of an indigenous hydrogen ecosystem. Ireland is limited in decarbonisation pathways available in other areas (nuclear or geothermal for example) and is reliant on imported fossil fuels for a significant portion of its energy needs. Neglecting factors such as energy security and system resilience can have catastrophic consequences, as highlighted during the winter storms and associated power outages seen in Texas in 2021 [54]. The development of an indigenous hydrogen industry could have wide reaching benefits for Ireland, including meeting ambitious decarbonisation targets, enhancing energy system resilience, and attracting industrial investment. These system wide benefits are of benefit to Ireland as a whole but are not captured when only considering the financials of hydrogen production and are important to consider when deciding to support an indigenous hydrogen industry.

To overcome these challenges, a two-pronged approach to hydrogen development may be required where both hydrogen supply and demand is supported. This approach would give hydrogen producers assurance that their product will have a viable route to market while also assuring a steady supply to hydrogen users at a price they can bear, therefore supporting the development of the entire hydrogen value chain in Ireland. This would lead to a liquid market and greater availability of hydrogen; therefore, reducing the supply risk and increasing confidence of both users and suppliers.

The individual elements of a two-pronged approach can be analysed further by considering a range of support options to stimulate both hydrogen supply and demand. At time of writing (July 2025) the government of the United Kingdom has consulted on a Gas Shipper Obligation; where natural gas shippers will be required to pay a levy to fund the first and second Hydrogen Allocation Round projects in the UK [55]. Key considerations of the consultation process include whether the levy should be used to fund production, storage, transport or all three types of projects.
A combination could be considered, taking hydrogen storage as an example. There could be a market value for a storage operator in injecting hydrogen during periods when the hydrogen price is low and extracting it when it is during winter, when electrical demand is high. But there could be also an insurance value for the state in mandating a percentage of the hydrogen is held until the hydrogen equivalent of a Gas Emergency is declared [56]. Thus, it may be prudent to fund the insurance value portion from general taxation and the market value portion to be unfunded and traded commercially.

On the demand side there are also methods to support domestic demand growth. For example, there may be scope to provide grants to Large Energy Users (LEU's) through an extension of the SEAI Industrial Renewable heating grant to hydrogen ready boilers or for vehicle end users to extend the Gas Networks Ireland CNG vehicle grant scheme to hydrogen fuelled vehicles.

3.0 Policy options to support hydrogen ecosystems

The success of a hydrogen industry in Ireland depends on whether hydrogen can meet customer needs competitively, while also supporting other strategic goals such as the decarbonisation of society, enhancing system resilience, and attracting new industries. As highlighted in Section 2.5, there are several challenges that face the development of an indigenous hydrogen industry. The following section will provide an overview of the policy options that could be put in place to help overcome these challenges and support the growth of the hydrogen sector in Ireland.

3.1 Hydrogen business model principles

When designing policy options to support the development of a hydrogen industry, there are four main parties whose needs must be considered: government, producers, end-users, and the general public (Table 2).

Table 2 – Objectives and Priorities of parties involved in hydrogen ecosystems

Party	Objectives and Priorities
Government	• Meet ambitious decarbonisation targets, • Ensure resilient and efficient energy systems • Foster economic growth • Obtain value for money
Producers and End-Users	• Mitigate risks associated with hydrogen production • Mitigate risks associated with fuel-switching • Ensure there is sufficient supply through creation of a fit for purpose hydrogen transport and storage infrastructure
General Public	• Obtain value for money • Ensure fairness and a just transition away from fossil fuels • Have concerns surrounding safety of hydrogen adequately addressed

To help meet the governmental objective of ensuring ambitious decarbonisation targets are met, it is likely that hydrogen production will have to meet strict emissions standards to receive financial support. In the proposed UK Hydrogen Production Business Model (HPBM), producers must ensure that hydrogen has a carbon intensity of at most 20 gCO_2/MJ to be eligible for support [57]. The business model is designed to provide revenue support to hydrogen producers, to help overcome the operating cost gap between low carbon hydrogen and high carbon fossil fuels. It was found in the example of the low carbon electricity market that funding to cover the cost gap reduces uncertainty for investors and developers, reduces long term costs, and creates a strong project pipeline. In adopting a similar approach to the design of the HPBM, we aim to repeat the success seen in UK low carbon electricity generation. Within the Irish context, a suitable framework may be needed to ensure that hydrogen production meets the EU sustainability guidelines, outlined in Section 2.2. Furthermore, to help direct hydrogen to sectors where it is most needed (such as long duration energy storage or aviation) and away from sectors where it is not a priority (such as domestic heating or passenger vehicles), a list of qualifying end-users could be defined that are eligible for support. For both the government and general public, ensuring value for money, as well as fairness is an important consideration to account for when designing policies to support the development of a hydrogen ecosystem, with particular emphasis on how hydrogen support policies are to be funded.

For hydrogen producers and end-users there are two major, interlinked risks that need to be mitigated to encourage the development of a hydrogen industry:

- Price risk – This is the risk that the price achieved from selling hydrogen on the market does not cover the hydrogen production costs as it is uncompetitive relative to the cost of high-carbon fossil fuels that are currently used, especially if carbon capture and storage becomes a viable method of offsetting carbon emissions.

- Volume risk – This is the risk that hydrogen producers are unable to sell with certainty sufficient quantities of hydrogen to adequately cover their production costs. This could also be related to insufficient infrastructure to transport hydrogen to end-users that are not geographically co-located with hydrogen producers.

A two-pronged approach to hydrogen development, where production is supported and demand is stimulated, could effectively address both price and volume risk for producers and end-users. Key design principles to consider include reducing investor uncertainty, minimising complexity through clear guidelines, and ensuring transparency between producers and end-users.

3.2 Mitigating price risk

To effectively mitigate price risk, a sustainable production-focussed funding model should offer revenue support to hydrogen producers to compensate for production costs not covered by their achieved sales price, while also offering value for money for the funding agency. There are a number of considerations to take into account when designing appropriate price support options, which will be discussed in the following sub-sections.

3.2.1 Fixed vs variable premium model

There are two primary models for providing revenue support for hydrogen producers:

- Fixed premium – In a fixed premium model, hydrogen producers receive a fixed level of subsidy per unit of hydrogen produced, an example of this is through the EU Hydrogen Bank fund [58].

- Variable premium – In a variable premium model, the premium paid to the producer is calculated as the difference between a "strike price" and a "reference price", an example of this is through the UK Hydrogen Production Business Model [59].

There are both advantages and drawbacks for each model. The fixed premium model is seen to have low levels of complexity and is therefore easier and quicker to implement, especially for early or small-scale projects. However, as the hydrogen producer receives a fixed subsidy per unit of hydrogen produced, the fixed premium model is seen to be less able to adapt to changing market conditions and could lead to over subsidisation if production costs fall over the course of the support contract. Due to its simplicity, the fixed premium model may be an appropriate option for supporting the early stages of a hydrogen industry in Ireland.

The variable premium model addresses concerns surrounding the inflexibility of the fixed premium model. The variable premium model allows the amount of subsidy paid to change with evolving market conditions, providing better value for government money while also ensuring producers can cover production costs with certainty. Ireland's previous Renewable Energy Feed In Tariff (REFIT) scheme and current Renewable Electricity Support Scheme (RESS) for supporting renewable electricity generation is a proven method for supporting decarbonisation through a variable premium model using a Contract for Difference (CfD) mechanism. In such schemes, the renewable generator receives the wholesale electricity price for electricity they produce. They then receive a top-up if the wholesale price is below their strike price. If the wholesale electricity price is greater than the strike price, then the renewable generator returns the difference to the funding body. The key to the effectiveness of the variable premium model is selecting an appropriate reference price to benchmark against. In electricity markets, the wholesale price of electricity is a well-established and mature benchmark for renewable CfD support schemes. For nascent products, such as hydrogen, a wholesale market price does not yet exist, therefore selecting a suitable reference price could be challenging. Given the greater levels of flexibility and adaptability, the variable premium model is seen to be the long-term preference for supporting hydrogen production, but careful consideration must be given to selecting an appropriate reference price.

3.2.2 Setting an appropriate reference price

The implementation of an effective variable premium model relies on the setting of an appropriate reference price. In the UK Hydrogen Production Business Model (HPBM), it is proposed that the reference price is calculated as follows [57]:

- Reference price – The Reference Price is set as the higher value of (i) the Achieved Sales Price (price received from end-user under offtake agreement) and (ii) Floor Price

- Floor Price – The Floor Price is set at the lower value of (a) the Counterfactual Fuel Price (proposed to be the price of natural gas) and (b) the Strike Price

For clarity, a graphical representation is provided in Figure 2. In Zone 1, the Counterfactual Fuel Price is lower than the Strike Price and therefore becomes the Floor Price. The Achieved Sales Price is lower than the Floor Price, and therefore the Floor Price becomes the Reference Price. In this scenario, the hydrogen producer receives a top up from the Floor Price (Counterfactual Fuel Price) to the Strike Price.

In Zone 2 of Figure 2, the Counterfactual Fuel Price is lower than the Strike Price and therefore becomes the Floor Price. However, unlike in Zone 1, the Achieved Sales Price is greater than the Floor Price, and therefore the Reference Price is set at the Achieved Sales Price. In this scenario, the hydrogen producer receives a top up from the Achieved Sales Price to the Strike Price. To encourage hydrogen producers to negotiate sales prices above the Counterfactual Fuel Price, a price discovery mechanism is proposed in the UK Hydrogen Production Business Model, where producers receive and additional payment of 10% of the difference between the (a) the lower of the Reference Price and the Strike Price and (b) the Floor Price.

In Zone 3 of Figure 2, the Counterfactual Fuel Price is lower than the Strike Price and therefore becomes the Floor Price. Like in Zone 2, the Achieved Sales Price is greater than the Floor Price and therefore becomes the Reference Price. The Reference Price is greater than the Strike Price, and thus the hydrogen producer pays back the difference to the funding agency.

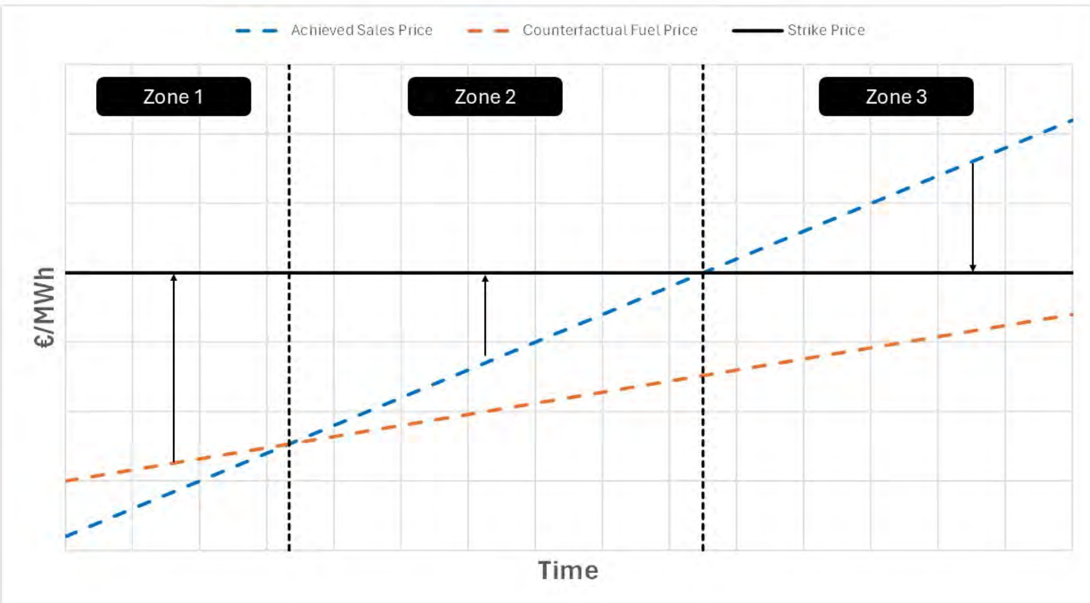

Figure 2 – Graphical representation of reference price for variable premium hydrogen price support

It is clear that setting a suitable reference price is not an easy task, and there a number of benefits and drawbacks to the methodology outlined in the UK Hydrogen Production Business Model. Using the Achieved Sales Price fairly reflects the value of hydrogen sold, while also allowing producers to price hydrogen differently across a range of end-users. The UK Hydrogen Production Business Model proposes using the natural gas price as the Counterfactual Fuel Price, which could be considered to be reasonable as it the most common and lowest cost counterfactual fuel below which subsidy support should not be given. The inclusion of a price discovery mechanism encourages producers to achieve sales prices above the natural gas price, which plays an important role in allowing a wholesale market benchmark price for hydrogen to emerge.

However, there are also concerns surrounding the proposed methodology for setting the reference price. Unlike Contracts for Difference to support renewable electricity generation, the proposed reference price for hydrogen projects is significantly more complex, which introduces several issues. Setting the floor price at the natural gas price means there is a risk that higher sales prices may be difficult to achieve if the price discovery mechanism does not work as intended, which would imply a true market price for hydrogen may struggle to be realised. Furthermore, given the recent volatility in natural gas prices, linking the reference price to the natural gas price could lead to instability in the revenue support model.

Alternative proposals for setting a reference price include simplifying the methodology by only using Achieved Sales Price as the reference price or utilising multiple counterfactual fuels to act as the Floor Price, based on what fuels are currently dominant for the end-use in question. As the market for hydrogen evolves and a benchmark price emerges, it is widely expected to be used as the reference price as soon as possible for future projects.

3.2.3 Indexation of strike price

Over the lifetime of a hydrogen project, changes in inputs costs that are outside the control of the producer can occur. By indexing the strike price, producers are protected from having returns reduced if production costs rise to levels higher than expected. Indexing can also ensure value for government money from over subsidisation if production costs fall to lower-than-expected levels. There are two strategies that can be employed to facilitate the indexation of the strike price:

- Indexing against main energy input – It is proposed that changes in cost for the main energy input could result in greater risk and higher financing costs for producers, if indexing is not considered. This is more relevant for blue hydrogen producers, who are reliant on natural gas as their main energy input, with an associated volatility in input costs. In an Irish context, green hydrogen procured from dedicated renewables is seen to be the preferred production pathway, with relatively fixed electricity input costs as a result.

- Indexing against inflation – For green hydrogen projects in an Irish context, it may be more appropriate to index against a more general inflationary benchmark, to account for rises in production costs outside of the main energy input. Options for this include the Retail Price Index (RPI), Consumer Price Index (CPI) as was the case for REFIT, Harmonised Index of Consumer Prices (HICP), as is the case for RESS supported projects or Producer Price Index (PPI).

3.2.4 Alternative revenue streams

Outside of a potential fixed or variable premium price support business model, additional streams of revenue can help to improve the business case for hydrogen production. As a source of flexible demand, hydrogen producers have the potential to provide services to the electrical grid, alleviating constraint and curtailment, if appropriate measures are put in place. There are three potential models to encourage hydrogen producers to act as a source of flexible demand [60]:

- Utilisation payments – Under this option, hydrogen producers would receive a utilisation fee (€/MWh) for consuming electricity during periods of curtailment or constraint.

- Availability and utilisation payment – In addition to receiving a utilisation payment, in this scenario the hydrogen producer would also receive an availability payment (€/MW), to be available as a source of flexible demand. The utilisation payment received (€/MWh) would be scaled appropriately to reflect the additional availability payment.

- Fixed payment – The hydrogen producer would receive a fixed yearly value for the level of demand response they make available to the grid operator.

These additional revenue streams are of particular relevance to hydrogen producers connected to the electrical grid rather than having a behind-the-meter connection to a renewable generator, but further work is needed to better understand the full costs and benefits of such a payment system.

3.3 Mitigating volume risk

Aside from price risk, another major barrier to the development of a hydrogen industry is volume risk. As an emerging product, there is still uncertainty surrounding the market size for hydrogen. This introduces the risk for hydrogen producers that they may not be able to sell sufficient quantities of hydrogen to cover their production costs with confidence. There are several options to mitigate volume risk, each with their own advantages and drawbacks, which will be discussed in the following sub-sections.

3.3.1 Sliding payment scale

It is possible to mitigate volume risk directly in the price support mechanism. The UK Hydrogen Production Business Model proposes a sliding scale payment mechanism where greater levels of price support are to be provided if offtake levels fall below levels anticipated at the outset of the project. There are a number of advantages to this sliding scale payment mechanism. The most significant is that it provides greater certainty for investors by helping to create a more stable revenue profile over the lifetime of the project. The design of the mechanism discourages overcapacity, as there is no incentive to create additional capacity without a route to market. Finally, the sliding scale mechanism is not overly interventionist and avoids many of the distortions that could occur if the government were to act as a "buyer of last resort", for example.

However, there are several concerns surrounding a sliding scale payment mechanism. Firstly, if offtake levels fall to zero, no support is provided. This could be a particular issue for early hydrogen projects who are reliant on a single off-taker that could fall away, with no alternative off-takers nearby leaving the producer with no viable route to market. Additionally, a sliding scale mechanism could be complex and burdensome to administer. Each hydrogen producer has their own specific volume risk, meaning a standardised approach may not be suitable. However, introducing a project-specific sliding scale would be burdensome for the funding body to administer. Further to this, calculating an appropriate strike price increase for lower-than-expected offtake volumes could be a complex task for producers and government to manage.

3.3.2 Demand stimulation

Beyond direct financial support, stimulating demand for hydrogen can be seen as an alternative form of volume support for hydrogen producers. By stimulating demand, the risk that hydrogen producers are unable to sell sufficient quantities to cover their costs is lessened. There are both monetary and non-monetary methods for stimulating hydrogen demand:

- Monetary mechanisms to stimulate hydrogen demand include
    - Revenue support to encourage fuel switching – Many end-users face significant cost barriers if they wish to switch to using hydrogen or hydrogen derivatives. Providing financial support to enable the purchase of equipment with a high capital cost (such as hydrogen turbines for power generation or fuel cell heavy goods vehicles for road haulage) could encourage greater levels of hydrogen adoption.
    - Increased carbon price – Increasing the price of carbon makes it more difficult for industries to continue using high-emitting fossil fuels, helping to close the price gap to hydrogen or hydrogen derivatives.
    - Carbon Border Adjustment Mechanisms (CBAM) – Similarly, Carbon Border Adjustment Mechanisms are tariffs placed on imports based on their carbon footprint, making low carbon alternatives such as hydrogen more attractive, especially in displacing fossil fuels.
- Non-monetary mechanisms to stimulate hydrogen demand include
    - Fuel mandates – Mandating the use of hydrogen in certain sectors (such as the RefuelEU Aviation and ReFuelEU Maritime policies) drive uptake of alternative fuels by mandating a market in certain sectors.
    - Pollution regulation – Regulating pollutants other than carbon dioxide (such as the International Maritime Organisation's ban on high sulphur fuels [61]) can have the synergistic effect of improving air quality while also driving the uptake of low-carbon alternatives.
    - Cluster-based development – Promoting a cluster-based approach to developing a hydrogen ecosystem can help mitigate volume risk by co-locating production with anchor loads.
    - Mandated storage targets – When large scale geological storage is available, shippers and suppliers could be mandated to put a percentage of their traded volumes into storage as a security of supply measure. This would also have the effect of inducing a source of demand.

3.3.3 Transmission and storage infrastructure

Investing in hydrogen transmission and storage infrastructure is another pathway to mitigating volume risk for producers. For early projects, injecting hydrogen into existing gas transmission infrastructure and blending with natural gas could play a role in providing producers with a backstop market, if other sources of demand fall away or fail to materialise. However, the emissions reduction potential of blending hydrogen in existing gas infrastructure is low [62]. Furthermore, any value that could be gained by de-coupling hydrogen production and consumption is lost when it is injected into existing gas pipelines. For these reasons, hydrogen blending is not seen as a long-term solution but as an interim step to help mitigate volume risk for early hydrogen projects.

The development of dedicated, large-scale storage would be preferable to hydrogen blending. Like blending, large-scale hydrogen storage also mitigates volume risk by providing producers a backstop market, but with additional benefits. De-coupling hydrogen production and consumption with large-scale storage allows for processes which require a continuous feed of hydrogen (such as chemical production) to be supplied from hydrogen produced using intermittent resources (such as wind power). Furthermore, large-scale storage can also act as a source of strategic energy storage, helping to enhance energy system resilience. Uncoupling hydrogen production and utilisation through large-scale storage has the potential to add significant value to the wider energy system.

Finally, the development of a dedicated network for hydrogen transmission would lessen the need for co-locating hydrogen production with hydrogen demand. By connecting hydrogen producers and hydrogen end-users in different locations, volume risk is further mitigated from the producers point-of-view as they have access to wide range alternative off-takers rather than being reliant on a single end-user.

3.3.4 Exports

As highlighted in Section 2.3, there are significant challenges surrounding the long-distance transmission of hydrogen. Nonetheless, the potential for export, especially for hydrogen derivatives, could be an option to mitigate volume risk for producers by greatly expanding the pool of potential end-users, and thus potential demand. While exports may play a role in mitigating volume risk for producers, the overarching objective of any policy measure implemented is to support the development of domestic hydrogen production and consumption in Ireland. Producers benefitting from price support policies should be free to explore the potential for exports, but careful consideration should be given to whether volumes of hydrogen (and hydrogen derivatives) that are exported should be eligible for support payments and therefore export the subsidies provided by the Irish taxpayer.

3.3.5 Buyer of last resort

As a final option for mitigating volume risk, the government could step in and act as the buyer of last resort. The hydrogen could then be deployed in areas such as public sector fleets, such as buses or trains, or stored as a strategic energy reserve. This option would be the least preferable, as it has the potential to create downstream market distortions and could lead to suboptimal outcomes if hydrogen is deployed in sectors where direct electrification is more efficient, such as public transport fleets. When large-scale hydrogen storage becomes available the government could also purchase an amount of hydrogen to put into storage as a strategic store of energy for security of supply.

3.4 Additional considerations

3.4.1 Funding revenue supports

An important consideration when designing policy supports for hydrogen ecosystems is where the funding should come from. There are five main options for raising funds to support the development of a hydrogen ecosystem in Ireland:

1. A levy on energy bills – Levies on energy bills through a Public Service Obligation (PSO) have been successfully used in the past to raise funding for renewable electricity generation and are well understood. Funding hydrogen supports through a levy on energy bills could create a link between hydrogen funding and those who may benefit from it. If the levy was specifically targeted towards natural gas bills and used for hydrogen production for example, it would raise the price of natural gas while funding the investment needed to make green hydrogen more competitive, thus incentivising decarbonisation choices. However, careful consideration needs to be given to ensure this does not increase fuel poverty and exemptions may be needed to protect vulnerable consumers. If it is targeted towards one type of fuel only, then it also runs the risk of a disproportionate share of the transition being funded by a declining pool of end users who cannot afford to transition to more carbon friendly choices (e.g. natural gas only could affect domestic customers reliant on gas for domestic heating and cooking).

2. Funding via charges -The proposed UK Gas Shipper Obligation (GSO) is an example of funding through charges. In this proposed model a levy will be placed on natural gas flows on a volumetric basis by gas shippers and potentially suppliers. These use of system charges will then be ring fenced to pay for the first two rounds of hydrogen production projects. However, in a similar manner to raising funding through a levy on energy bills, as the pool of natural gas end users decline these charges may have to be reassessed or they may not bring in sufficient revenue to fund further projects. Shippers and suppliers are network users who are used to paying tariffs for network access so it is believed that it will be more efficient to apply the levy to them, and they can then pass through the costs to the end users.

3. Inter temporal allocation – At time of writing the European Union Agency for the Cooperation of Energy Regulators have proposed a method to fund hydrogen transport infrastructure through a method that allows operators to recover their costs over an extraordinary time period, in a similar manner to current electricity or gas network investments [63]. The Temporal Allocation Mechanism works by shifting the recovery of a portion of the network annuities from the early years of operation to later periods. Deficits incurred during the initial ramp up phase can be placed into a separate regulatory account, which will be balanced over time as both hydrogen demand and therefore revenue increase. This is because during the early stage of network construction development costs will still be high, but the "pool" of network users will be small, therefore the tariff charges per user will be very high if set at real rates. There is a fear that these high fees will discourage new end users to join the network and consistently dampen demand to connect to the network. They note this does put

significant risk on the hydrogen network operators to cover the future costs when they are recovered in the future and suggest the operators can mitigate this with debt (that they suggest can be paid back with future tariff over recoveries) or that it may require further support schemes from the state such as state guarantees

There is one inter temporal allocation scheme in place in Europe set up by the German authorities known as the WANDA determination [64]. Funding for hydrogen infrastructure will by obtained setting a ramp-up tariff that will be applied uniformly at all entry and exit points starting in 2025. The aim of the ramp-up tariff is to enable the initial costs of the core network to be paid off by 2055 while keeping costs as steady and predictable as possible throughout the entire time period. Initially, the entry tariff will be set relatively low so the barriers to entry for new participants are not overly burdensome. As the number of network users increases, so does the network access tariff. The initial shortfall in revenue is offset by generating greater levels of revenue towards the end of the payback period, making it possible to recover the full cost of network development by 2055.

4. General taxation – Funding support for hydrogen projects from general taxation would spread the associated costs across a larger population. Given the uncertainty surrounding potential hydrogen end-users, this could be more equitable than a levy on specific energy bills. As decarbonisation is a societal good, funding decarbonisation and potentially making Irish industry more competitive and reducing potential fines for missing EU climate targets could be beneficial. General taxation could also be used in in the initial stages to set up an aspect of the green hydrogen industry and then transition to one of the other funding methods (such as a levy on energy bills or charges) at an appropriate maturity level.

5. Combination of funding mechanisms – A combination of levies and general taxation could be employed to better spread costs and diversify the revenue streams needed to support a hydrogen ecosystem. The government may consider that some hydrogen infrastructure projects are a public good, e.g. storing hydrogen for security of supply or that the government has a role in de-risking for High Impact Low Probability (HILP) events and cross chain risks, such as a storage or transport operator failing and may rebalance the exchequer taxation versus levy funding regime appropriately.

Given that the development of a hydrogen ecosystem has the potential to achieve a range of wide-reaching impacts (such as enhancing energy security) that benefit the general population even if they are not direct users of hydrogen, the fairest option may be to raise funds through general taxation in the initial stage but with the intent to move, when a critical mass has been reached ,to a tariff funded model (with less or no state support) . This could enable direct support to set up a hydrogen network and infrastructure, at least in its initial stages, as proposed by the Dutch government and outlined below. This would also have the advantage of lowering entry costs for the initial participants into the hydrogen market and build a critical mass of users to increase supply and move the network towards a tariff funded model, as currently seen with EirGrid or Gas Networks Ireland.

Two EU member states have developed funding mechanisms for hydrogen network development, namely Germany and the Netherlands. Of the two mechanisms the Dutch model appears to be the one that most closely matches Irelands case and ambitions [65]. The Dutch model follows a cluster-based approach to hydrogen network development, where hydrogen production sites are connected to industrial users and large-scale storage infrastructure. To fund network development, the Dutch state have reserved €750 million, with any remaining costs expected to be financed by network tariffs.

The similarities with any Irish network development are a network connecting production sites, industrial clusters and storage sites (therefore meeting national demand and securing domestic supply first, similarly to how a potential Cork energy cluster would operate) with the eventual potential of exporting to other European countries.

3.4.2 Contract types

While there is a relatively small hydrogen market in Europe and Ireland today, it is envisaged that over time a European market of the size and scale of the current natural gas market will emerge that could duplicate the existing structures of the gas market. The development of a European wide gas trading environment in the 1990s was built on the backbone of national gas networks, which were themselves built on previous town gas networks.

However, there are two major barriers to developing the necessary scale: significant supply and demand from large market participants, and the resultant infrastructure to transport and store hydrogen for them do not exist. Therefore, the primary aim of European regulation in general and Irish regulation specifically should be to facilitate the growth of this market by encouraging the uptake of hydrogen supply and demand with a secondary aim of building physical infrastructure to enable the transport and storage of hydrogen and subsequent trading.

There are several potential contract types that could be used in developing an energy market for hydrogen; that are already well understood, proven and used in the renewable electricity market. It has been found that long-term contracts, particularly in the renewable energy sector, have played a significant role in driving down the costs of generation technologies [66]. This has been largely due to their impact on financing costs. These contracts align well with the high capital costs associated with renewable electricity projects. Wind and solar power generation are heavily capital-intensive with upfront costs related to the construction, installation, and commissioning of the infrastructure (e.g. wind turbines, solar panels). Once these assets are in place, the ongoing operational and maintenance costs are relatively low, and the primary inputs (sunlight and wind) are free.

It is important to note that while renewable electricity will provide a good benchmark, there are nuances in renewable hydrogen generation where they differ that would have to be considered specifically:

- Infrastructure
    - o Hydrogen storage will be a requirement for the market to function. Hydrogen will be produced from renewable electricity where generation is variable. This will be the largest difference between existing natural gas and future hydrogen infrastructure and markets in the short to medium term, where stored natural gas stocks are essentially unlimited in fields, but hydrogen stocks must be produced and then stored in sufficient quantities to ensure no discontinuity of supply.

- Transport
  - o Gases such as hydrogen usually have an average speed of 25 km/hr in pipelines, and unlike electricity wires, gas pipeline, valves, skids, etc. must be set up to flow in either one direction or both directions and the network flow planned as it is a physical product. This could impose constraints on flow direction and rate if existing natural gas pipelines and infrastructure are being repurposed.

- Production
  - o Green hydrogen production is less capital-intensive but more operationally expensive, particularly as it relies heavily on electricity and water as feedstocks. This means that the ongoing operational costs are a significant portion of the total cost structure and hedging strategies may be needed.

- Utilisation
  - o Specific infrastructure will need to be built by end users to use the product unlike any form of electricity.

There are a number of differences between renewable hydrogen and renewable electricity that would have to be accounted for in the contract design [65]. These include (due to the need to comply with regulatory criteria for Renewable Fuels of Non-Biological Operations qualification) electrolysers needing to optimise their utilisation factors which may result in renewable electricity supply agreements structured over a broader portfolio of renewable electricity production assets, probably over a wider geographical area, and designed to optimise hydrogen production.

1. Bilateral agreements – This contract type is used today as most hydrogen currently produced in Europe is either produced and consumed onsite or acquired from producers via supply chain pathways. However, the existing market will not be comparable in size or scale to the potential market that could be generated by expanding into new industries and a whole new infrastructure would have to be set up to facilitate the expansion into new markets. In the future, a more liquid market with a variety of new buyers and suppliers entering, new forms of contracts would have to be introduced, albeit with some participants remaining in bilateral agreements, potentially for applications such as data centres

2. Hydrogen Purchase Agreements (HPA's) – This would work in a similar manner to current Power Purchase Agreement for renewable electricity and represent a long-term contract between a supplier and buyer of hydrogen. A HPA includes all the terms of the agreement, such as the amount of hydrogen to be supplied, the negotiated price, who bears what risks, the required accounting, and the penalties if the contract is not honoured. As it is a bilateral agreement, a HPA can be adapted to the wishes of the parties involved, so the supply contract can take many forms. Through HPA's, hydrogen project developers have access to finance to deploy, while the off-taking party gains access to stable hydrogen supply at a predictable price. The buyer and the shipper or producer come together to negotiate a price at which the producer will sell hydrogen to the end user, and the volume of hydrogen to purchase from the producer at that price point. This reduces price volatility and increases price stability for both the producer and consumer.

3. Contracts For Difference – Contracts for Difference are mechanisms to foster investments in assets with significant upfront costs by providing price visibility over the long term and has been used to support the deployment of renewable electricity projects. Within CfD contracts, two parties enter into an agreement to exchange payments based on a 'strike price'. Whenever there is a fluctuation between the reference index price and the strike price agreed in the contract payments are exchanged between the contracting parties, without the actual good ever-changing hands. In the case of a support mechanism, the buyer does not necessarily get access to the associated energy volume but only pays or receives symmetrically to or from the seller the difference between the strike and reference prices.

Research by the Oxford Institute for Energy Studies indicates that there has been some CfD activity in the renewable hydrogen market, but that there is some nuance; unlike the renewable electricity CfD, which relies on standardised, competitive auctions to drive cost reductions in a mature market, the Hydrogen CfD incorporates project-specific strike prices, volume caps, and a sliding scale support mechanism [66].

There are also several disadvantages associated with CfDs. They can distort dispatch incentives, as plants no longer face incentives to increase production in high-price hours, referencing the CfD on the day-ahead market can draw liquidity away from other markets and the method to allocate the costs and benefits of CfD's can distort end-consumer price signals.

Today natural gas is traded on 8 trading hubs within Europe and two of these hubs, the UK National Balancing Point (NBP) and the Dutch Title Transfer Facility (TTF) set the reference prices for the continent due to their scale. The major challenge for CfDs is that there is no reference price for hydrogen to benchmark against. The other hubs that trade continue trading at smaller volumes because they occupy a niche in the European market, for example the Austrian hub holds an important geographical niche in trading between western and eastern Europe. Similarly, there could be a potential niche for an Irish hydrogen trading hub to use its Atlantic wind resource to set a reference price in a future hydrogen market.

4. Feed In Tariffs – A Feed in Tariff (FIT) is a policy mechanism designed to promote the deployment of renewable energy technologies, such as wind or solar power, by providing financial incentives to producers of renewable energy. Under a Green Hydrogen FIT program, hydrogen producers would be guaranteed a fixed price for the hydrogen they produce and feed into the gas or hydrogen grid. This fixed price is typically higher than the market price for hydrogen, making it financially attractive for renewable energy producers to invest in and operate electrolyser projects.
In a FIT, electrolysers would generate hydrogen from their renewable energy sources. This hydrogen would then then fed into the grid and sold to the utility company. The utility company is required by law to purchase this hydrogen at a fixed price set by the government under the FIT program. This fixed price is typically guaranteed for a set period of time, usually 15-20 years, providing hydrogen producers with a stable and predictable income stream.

There are several benefits of a Feed-in Tariff. It provides a stable and predictable income stream for hydrogen producers, making it easier for them to secure financing for their projects. This stability also encourages investment in renewable energy projects, leading to increased deployment.

They do have several challenges however including setting the right price for hydrogen production. If the price is set too high, it can lead to increased costs for consumers. On the other hand, if the price is set too low, it may not provide enough incentive to invest in hydrogen projects.
As the market develops, contractual arrangements similar to those of long-term natural gas contracts (i.e. including take-or-pay or carry-over clauses, and nomination flexibilities) might emerge, to meet inflexible hydrogen demand needs.

5. Financial derivatives for ammonia – For completeness a different type of financial derivative is used for a hydrogen product, ammonia, today which could potentially set the scene for other hydrogen products. It should be noted that the derivatives market as a subset of the green hydrogen market may use hybrid contracts, although hydrogen derivatives are a less developed market utilising aspects of offshore wind. Ammonia is a sizeable (190 Mtpa) globally traded commodity [67]. The market is smaller than LNG (380 Mtpa in 2021) and only 10 per cent is globally traded versus almost all LNG. It is principally used as a feedstock for fertilisers and other industrial purposes, and it might appear logical to price green ammonia simply at a premium to traded 'grey' (made using natural gas or coal as feedstock) ammonia. However, ammonia pricing is quite volatile, and if the green ammonia industry does grow, it may be serving a different market i.e., fuel rather than fertiliser, and will overtake the current grey ammonia market in terms of precedents. Green ammonia is more complex than either LNG or offshore wind (or indeed conventional ammonia) in that it has more components: power generation, electrolysis, storage of power and/or hydrogen, ammonia production and shipping, as well as facilities to receive and, potentially, crack ammonia back into hydrogen.

Having reviewed the contract types above it is likely the best approach may be one that changes over time as the market maturity evolves. It is also worth noting that these contract types can act in a complimentary manner, with more than one being used by a single project. A hydrogen market may start with bilateral agreements between the early producers and end user adopters. Risk could then be reduced by using Hydrogen Power Agreements as that would be a market signal to investors that long term projects are viable. As the market grows, more short-term bilateral deals could be offered and that would evolve to a Day Ahead Market (DAM). When a DAM is in place that would become a good reference price to reference CfDs to.

3.4.3 Contract length

Setting an appropriate contract length is an important aspect to consider when designing hydrogen support policies. For green hydrogen projects, it may be more suitable to base the length of contract on electrolyser run hours, as the asset lifetime is more closely related to this than years. Longer contracts can help lower the costs associated with financing hydrogen projects, providing greater revenue certainty to lenders and investors, and could lead to lower strike prices. This is particularly important for First-Of-A-Kind (FOAK) projects, where risk levels are higher. For initial projects, it may be appropriate to set longer contracts with extension clauses to help mitigate uncertainty, while for subsequent projects the contract length could be shortened.

3.4.4 Hydrogen as a feedstock

There is debate surrounding if hydrogen to be used as a feedstock should be eligible for price support. There is an argument that allowing existing hydrogen users (such as chemical producers or petroleum refineries) to purchase green hydrogen at the natural gas price (suggested floor price for price support, see Section 3.2.2) could lead to over subsidisation and market distortions.
On the other hand, there are compelling reasons to include hydrogen as a feedstock within the end-uses eligible for support. Existing users of hydrogen have the potential to act as anchor loads, mitigating volume risk for producers. Selling hydrogen as a feedstock is a potential high-value market, which could help producers establish a true market value for hydrogen. Finally, excluding hydrogen as a feedstock from the list of qualifying end-uses could lessen the potential to attract new industries, such as ammonia production for fertilisers or e-fuels for shipping and aviation.
Within the Irish context, with only one major hydrogen consumer present on the island (Whitegate Refinery), the risk associated with over subsidisation is small. Therefore, including hydrogen as a feedstock as an eligible end-use, and maintaining the potential to attract new industries to the island, is preferable.

3.4.5 Funding allocation method

There are two main options for allocating funding for hydrogen projects:

- Bilateral negotiations – The funding contract is negotiated between the producer and the funding agency (government).

- Auction – Projects submit bids and allocation of support is determined by the lowest strike price.

- Unilateral decisions – The funding agency unilaterally sets the amount of funding available for projects, as was the case for the Renewable Energy Feed-In Tariff in Ireland.

In the near-term, bilateral negotiations are seen as the most appropriate model for allocating funds to projects. Hydrogen is still an emerging technology and is not mature enough for a competitive allocation process, which is especially true of green hydrogen projects. However, the bilateral allocation process must be transparent with clearly defined selection criteria. As the hydrogen sector matures, moving towards a more competitive allocation process is seen to be favourable, as it is seen to offer better value for money.

3.4.6 Scaling up production volumes

Hydrogen producers may wish to have the ability to scale up production volumes above the quantity defined in their contract to respond to increased levels of demand. There are several arguments around different options for scaling production:

- No scaling allowed – Volumes of hydrogen produced above the defined capacity would not be eligible for support. It is argued that including options for scaling production unfairly benefits incumbents and that new production capacity should go through a separate allocation process.

• Grandfathering – Hydrogen producers apply to the funding agency on an ad-hoc basis to increase their production capacity and receive the same terms as their original contract. Grandfathering could reduce the funding agencies administrative burden, however an upper limit on volume scaling should be considered otherwise monopolies could form.

• Accordion – Hydrogen producers can increase production capacity at will up to a pre-agreed maximum level. This is seen to be the most suitable option, as it offers best balance between value for money and avoiding local monopolies, while also being capable of scaling production quickly if needed.

4.0 A Cork hydrogen cluster

In line with the National Hydrogen Strategy, a cluster-based approach is proposed to help fast-track the development of hydrogen projects within Ireland. A cluster-based approach can reduce the need for large, upfront investment in transmission and distribution infrastructure by co-locating hydrogen production, storage, and high-priority demand. In other regions across the EU, industrial clusters often have already established hydrogen users such as refineries or chemical production but in an Irish context it is likely that new sources of demand will be needed to form regional hydrogen clusters.

The Cork Harbour area contains a significant amount of strategic energy related infrastructure, hosting 20% of Ireland's electrical generation capacity, an extensive gas transmission network, and the islands only oil refinery [68]. As such, it stands out as a prime candidate for spearheading Ireland's development of a hydrogen-based ecosystem. Furthermore, its proximity to significant offshore wind resources in the Celtic Sea means that the Cork area is well positioned to maintain its status as a strategic hub as the energy transition progresses.

The development of a green hydrogen cluster in the Cork Harbour area presents a significant opportunity to deliver a wide range of economic and environmental benefits for the local area and for Ireland as a whole. The deployment of green hydrogen production powered using offshore wind farms in the Celtic Sea assists in the delivery of the Climate Action Plan goal of delivering 2 GW of non-grid limited offshore electricity supply by 2030.

The nearby location of the depleted Kinsale Head gas fields presents the unique opportunity for large-scale geological seasonal hydrogen storage, which research indicates is highly important for the delivery of low-cost hydrogen [44]. The storage of large volumes of hydrogen helps to reduce dependence on imported fossil fuels and therefore enhances Ireland's energy security. Furthermore, the presence of large-scale storage has the potential to act as a "demand sink" for hydrogen producers, helping to mitigate volume risk if other sources of demand do not materialise. However, the suitability and cost of geological hydrogen storage can vary significantly from project to project, and work is ongoing to determine the feasibility of utilising the Kinsale Head gas field for large-scale hydrogen storage.

The green hydrogen can then be used in a range of end-use applications to meet ambitious climate targets and spur economic development in the Cork area. The Whitegate Refinery is already a user of hydrogen and could immediately utilise hydrogen produced in Cork Harbour, acting as a baseload level of demand and helping to mitigate volume risk for producers. Decarbonised dispatchable electricity is an important step in the development of a net-zero energy system, particularly for grids with high penetration of variable renewables. Green hydrogen stored in the Kinsale Head gas field has the ability to supply existing power stations in the lower harbour, such as Aghada (963 MW capacity) and Whitegate (445 MW capacity), providing back-up for when renewable output is low. Initially it is foreseen that hydrogen will be blended with natural gas in existing turbines, before transitioning to dedicated hydrogen infrastructure in the long-term.

The development of a green hydrogen cluster in the Cork Harbour area has the potential to attract new industries, particularly large energy users to the area. Data centres wishing to take advantage of the large offshore wind energy potential could also take advantage of stored hydrogen to ensure their energy needs are met consistently. The nearby location of the Port of Cork and Cork Airport presents the opportunity to develop an indigenous e-fuel industry, producing fuels such as methanol, ammonia, or e-jet fuel to decarbonise the shipping and aviation sectors. Irish Distillers, situated in close proximity to the lower harbour, is a source of approximately 50,000 t of biogenic CO_2, which is an essential ingredient in e-fuel production. The production of e-fuels for shipping and aviation could help contribute to meeting ReFuelEU Aviation and ReFuelEU Maritime targets. Furthermore, the production of ammonia (which does not require CO_2) could help develop an indigenous low-carbon fertiliser industry that could contribute to meeting climate goals within the agriculture sector. The development of fertiliser production in the 1970's and 1980's following the discovery of natural gas in the Kinsale Head gas field is a potential model to follow for green fertiliser production in the Cork area.

To help the development of a Cork hydrogen cluster, the support options discussed in Section 3 could be applied. The fortuitous co-location of hydrogen supply, large-scale geological storage, and high-priority demand mean that a Cork cluster is well suited to testing and refining such support systems. Once the business model and support options have been optimised, they can be rolled out and applied to hydrogen projects across the country, facilitating a national hydrogen ecosystem.

5.0 Developing a pathway for hydrogen ecosystems in Ireland

The following section aims to give a high-level overview of the steps and stages involved in developing a functional hydrogen ecosystem in Ireland, breaking the stages down into three main phases.

5.1 Phases of system development

5.1.1 Demonstration and development (2025 – 2030)

Between now and 2030, the primary goal is to demonstrate the viability of hydrogen technology and infrastructure. According to Gas Networks Ireland it will be the mid to late 2030s before, subject to scaling of hydrogen production, 100% UK hydrogen could become available through the Moffat Entry Point [69]. Initially one interconnector (IC1) would convert to hydrogen, providing resilience and security of supply to the emerging hydrogen gas system. This development will facilitate and underpin future ring main conversion and the integration of the hydrogen clusters to the national network. This phase focuses on establishing the fundamental infrastructure for hydrogen production, storage, distribution, and end-use applications. Key activities in this phase include:

• National certification scheme – The development of a national certification scheme, in line with the principles of additionality and temporal correlation proposed by the EU, is required to create a framework to ensure the sustainability of hydrogen production in Ireland.

• Domestic supply – Stimulate domestic supply through innovation funding for demonstration projects. Learnings from these early projects can be used to develop support mechanisms to mitigate risks (price and volume) for larger scale projects towards the end of the decade.

• Storage – For small-scale projects, storage pf hydrogen as a compressed gas is well understood and can be deployed quickly at decentralised locations. The development of large-scale storage is key for delivering a resilient low-carbon energy system. Work during this phase should aim to assess the feasibility of large-scale geological storage solutions where possible and identify locations that may require storage in the form of hydrogen derivatives where geological storage is not an option.

• Fuel switching of existing industries – Encouraging existing industries to switch fuels to hydrogen or hydrogen derivatives is a low-barrier pathway to scaling up hydrogen demand. In the Irish context, this would include the Whitegate Refinery, power stations who can utilise hydrogen blends (with potential to transition to full hydrogen operation in the long-term), and large energy users such as data centres who could use hydrogen to supply back up power to help alleviate strains on the electrical grid.

5.1.2 Expansion (2030 – 2040)

As the fundamentals of the hydrogen industry become established, the focus must shift from demonstration to expansion. Key activities in this phase include:

• Deploy policy supports for hydrogen ecosystems – After taking onboard learnings from demonstration projects, a roll out of policy support options should be implemented to help mitigate price and volume risks for large-scale hydrogen projects.

• Scale up production – With one of the best offshore renewable energy resources in the world, the potential for large-scale green hydrogen production is large. Leveraging Ireland's offshore wind potential to produce hydrogen can help in delivering the Climate Action Plan target of 2 GW of non-grid limited electricity supply.

• Development of hydrogen clusters – The scale-up in hydrogen production from offshore wind also presents an opportunity for the development of local hydrogen clusters, where supply is co-located with storage and high-priority demand. The development of a cluster-based approach can help mitigate volume risk for producers, by helping to ensure there is guaranteed offtake for their hydrogen.

• Attract new industries – As hydrogen production scales up, there is significant potential to explore new opportunities by attracting new industries to Ireland. Examples include e-fuels for shipping and aviation, ammonia for fertiliser production, or new large energy users who wish to take advantage of hydrogen as a source of clean, dispatchable electricity. This has the potential to attract high-skilled jobs and foster economic growth for the nation.

5.1.3 Full operation (2040 – 2050)

As the hydrogen industry reaches maturity, it is foreseen that the focus changes once again to ensure long-term stability for the sector. Key activities in this phase include:

- National transmission network to connect clusters – The development of a national hydrogen network presents the opportunity to connect producers and end-users who are not geographically co-located. Where possible, repurposing existing pipeline infrastructure would be preferable. The development of a dedicated hydrogen transmission network enhances the long-term viability of the sector by further mitigating volume risk for producers.

- Explore export potential – Once domestic demand has been satisfied, the market for exports could be explored. Due to the challenges of transporting hydrogen, exports are most likely to carried out via a pipeline to Great Britian or via shipping as hydrogen derivatives to other locations. Countries like Germany and the Netherlands have announced plans to scale up their hydrogen demand, potentially providing a lucrative market for Irish-produced green hydrogen. Based on the targets set to 2030 by the EU member states, Germany has the highest consumption goal for hydrogen (3-4 million tonnes per year), with France in second place with 0.77 million tonnes per year [65]. Austria would need to import 0.04 million tonnes per year by 2030 and 1.1 million tonnes per year by 2050. Belgium anticipates importing around 0.6 million tonnes per year by 2030 and 6.1-10.6 million tonnes per year by 2050 (that includes both renewable hydrogen and hydrogen derivatives), of which about half will be available for transit to neighbouring countries. Germany expects to import 1.4-2.7 million tonnes per year by 2030, corresponding to a significant share of the expected hydrogen demand (between 50% and 70%). Italy plans to import at least 30% of the renewable hydrogen it needs in 2030, corresponding to about 0.08 million tonnes per year. These numbers are indicative of a large potential export market for Irish hydrogen and hydrogen derivatives.

- Reduce incentive structures as industry matures – As the industry matures, the incentive structures and policy support that have been put in place can be reduced.

5.2 Short-term opportunities

The development of a functional hydrogen market within Ireland has the potential to address a wide range of goals, including meeting ambitious decarbonisation targets, enhancing energy security, and encouraging economic growth. There are a number of ways the introduction of a hydrogen ecosystem in Ireland could have immediate, tangible benefits:

- Maximising existing renewable assets – As a source of flexible demand, electrolysis can be used to minimise dispatch down and thus maximise the output potential from existing renewable assets. There are several models to implement this, including co-locating hydrogen production at wind farms where constraint is problematic. This option is likely to result in low electrolyser run hours, and therefore resulting in high-cost hydrogen, so price support may be needed to capture the benefits of minimising dispatch down. The system service model, where a grid connected electrolyser operates at ~50% full load and has ability to ramp up or down to help system balancing and minimise curtailment, could also be used. Although hydrogen produced via this model may struggle to meet EU additionality and temporal correlation guidelines, the system wide benefits may mean it is a promising pathway to explore.

• Existing hydrogen users – Encouraging existing hydrogen users to switch to green hydrogen is easiest pathway to stimulating hydrogen demand. In the Irish context, the Whitegate Refinery is the only large-scale user of hydrogen and is therefore well place to act as an initial off taker for early hydrogen projects.

• Flexible power generation – Existing power stations have the potential to utilise green hydrogen as a source of flexible dispatchable electricity generation. Initially, hydrogen could be used as a blend with natural gas without the need for significant modifications to the generating turbine. There is further potential to increase to full hydrogen operation as the industry matures.

• Large energy users – Ireland is already a major base of operations for global IT and software companies, hosting a large fleet of data centres. These data centres consume a significant amount of electricity and growth in the sector is often seen as hindering decarbonisation targets. Leveraging hydrogen (or hydrogen derivatives) as a source of back-up generation within data centres could be a way forward to expand the industry, while also helping reduce pressure on the electrical grid at times when demand is high and renewable generation is low.

6.0 Conclusions and recommendations

Ireland has significant potential to be a major player in the green hydrogen industry. To realise this potential and ensure Ireland's leadership in this emerging industry, immediate and coordinated actions are essential.

• Investment and policy support – Financial incentives and policy support mechanisms are needed to stimulate private sector investments in large-scale hydrogen production. For early projects this could come in the form of a fixed premium. In the medium-to-long term, a variable premium mechanism is seen to offer better value for money, but careful consideration must be given to selecting an appropriate reference price; a method for the organic development for a reference price through contracts must be considered. Furthermore, incentives for end-users to switch from high emitting fossil fuels to green hydrogen is needed to ensure a viable route to market for hydrogen in Ireland. Finally, the funding method must be chosen with great care to make sure that the burden of decarbonisation does not unfairly penalise end users through careful consideration of targeted exemptions, the possibility of the funding method changing at different points in time, and recognition that different points in the chain may require different funding focus. All of these actions should be underpinned by a detailed cost analysis to ensure policy support mechanisms represent value for money.

- Infrastructure development – A significant investment in hydrogen infrastructure, such as large-scale storage is essential to enable widespread hydrogen adoption across sectors. Investment in infrastructure can further mitigate volume risk for hydrogen producers by creating a large demand sin for hydrogen as well as connecting producers and end-users who are not geographically co-located. The development of large-scale storage can also help enhance system resilience and energy security and help facilitate dispatchable power generation. Consideration should be given to applying general taxation for funding for the public good of the insurance value of storage but funding the market value proportion through charges or tariffs.

- Policy and regulatory alignment – It is important to establish a robust policy framework that supports hydrogen development and aligns with national and EU climate objectives. This includes addressing existing regulatory gaps and providing clear guidelines for sustainable hydrogen production, transport, and storage.

- Public awareness and engagement - Raising awareness about the benefits of green hydrogen and engaging with stakeholders, including local communities, industry players, and policymakers, is vital for garnering support and ensuring a successful transition.

Ireland's commitment to developing a green hydrogen economy presents an opportunity to lead the global effort toward a sustainable future. By taking decisive action, Ireland can achieve its climate goals, enhance its energy security, and position itself as a pioneer in the green hydrogen landscape. This transition is not just an environmental imperative but a strategic opportunity to drive economic growth, job creation, and technological innovation for the benefit of current and future generations.

Keywords

Keywords	Meaning
Abatement	The act of reducing greenhouse gas emissions from the energy system.
Achieved sales price	The value a hydrogen producer receives from selling hydrogen on the market.
Additionality	Where the electrical load created by hydrogen production is met by an equal increase in low-carbon electricity generation to ensure that hydrogen production does not induce increased use of fossil fuels to generate electricity.
Ammonia	An inorganic chemical compound composed of hydrogen and nitrogen, often used in the production of fertilisers.
Biogas	A renewable fuel, composed of approximately 60% methane and 40% carbon dioxide, produced by the breakdown of organic matter by microorganisms in the absences of oxygen.
Biogenic CO_2	Carbon dioxide released as a result of the combustion or breakdown of organic material, having been previously removed from the atmosphere via the process of photosynthesis.
Biomethane	Biogas that has been upgraded to approximately 97% methane by removing the carbon dioxide content.
Blue hydrogen	Hydrogen produced by reforming fossil fuels (typically natural gas) where the carbon dioxide emissions from the process are captured and sequestered in geological storage.
Capacity	The potential to generate electricity when needed. In a capacity market a generator is paid for the availability of generation to come online as needed.
Carbon capture and storage	The removal of carbon dioxide emissions from industrial process or fossil fuel combustion before it is released to the atmosphere, followed by transportation to long-term geological storage.
Constraint	A reduction in electrical generation applied to a generator caused by localised network issues, such as insufficient grid capacity.
Counterfactual fuel price	The price of the main fuel currently used in a given end-use sector.
Cross chain risk	A risk that crosses across several elements of the energy supply chain.
Curtailment	A reduction in electrical generation applied to a generator caused by system wide issues, such as when renewable generation is significantly higher than system demand.
Day ahead market	The market for immediate delivery of natural gas as opposed to a future market.
Decarbonisation	The transition to an energy system that does not emit carbon dioxide from the combustion of fossil fuels.
Decommissioning	The process of dismantling an inoperative piece of infrastructure.
Desulphurisation	The process of removing sulphur or sulphur derivatives from fuels.
Dispatch down	Transmission system operator, instructs a renewable electricity generator to produce less electricity than it can or even to shut down entirely.
Dispatchable	Electrical generators that can be adjusted on-demand by grid operators to meet electrical demand.

Keywords	Meaning
District heating	A system for distributing residential and commercial heat from a centralised location through insulated pipes.
Ecosystem	A complex network of interconnected systems. In relation to hydrogen, it can refer to the production, transportation, storage, and end use of the fuel.
E-fuel	A fuel where the main energy input for production is electricity.
EirGrid	The state-owned electrical power transmission system operator in Ireland.
Electrolysis	A hydrogen production process where electricity is used to split water into oxygen and hydrogen.
End user	The final consumer of a product or service.
Energy carrier	Intermediate products that bridge the gap in the energy system between primary energy production and end-use applications.
Energy security	The uninterrupted availability of energy sources at affordable prices.
Energy vector	See energy carrier.
Feedstock	The raw material used to supply an industrial process.
Financial derivative	Contract that derives its value from the performance of an underlying entity
Floor price	The price below which subsidy support should not be provided.
Fuel cell	An electrochemical process that converts chemical energy stored in a fuel, often hydrogen, into electricity.
Fuel switching	The process of changing energy source for a particular industry or process.
Gas emergency	Any event or circumstance or combination of events or circumstances which have occurred or may occur and which in the opinion of the Transporter adversely affects, or may adversely affect, the safety or operational integrity of the Transportation System or any localised part thereof or which results or may result in the safety of life, property or the environment being at risk, and, where the context requires, a reference to an Emergency includes the event or circumstance which gives rise to such Emergency.
Gas Networks Ireland	The gas network transmission system operator in Ireland.
Geothermal	Heat energy stored in reservoirs beneath the surface of the Earth.
Green hydrogen	Hydrogen produced via the process of electrolysis.
Grid connected	An electrolysis facility where electricity is supplied from the main electrical grid.
Heat pump	A device that uses electricity to transfer heat.
Hydrocracking	The process of using hydrogen to catalytically crack long chain hydrocarbons into high-quality liquid fuels.
Hydrogen derivative	An energy carrier produced using hydrogen as the main feedstock.
Hydrogenation	The chemical process where hydrogen is used to saturate a chemical compound.
Interconnector	A gas pipeline or electrical wire connecting two separate national transmission systems (e.g. UK and Ireland).
Intraseasonal energy storage	Energy storage technologies that can be used to release power for weeks or longer.
Levelised cost	A metric used to determine the production cost of an energy carrier
Liquified natural gas	Natural gas that has been cooled to liquid form to ease of transportation and storage.
Long duration energy storage	See internal energy storage.

Keywords	Meaning
Methane	A colourless, odourless gas comprised of carbon and hydrogen (CH_4) that is the main component of natural gas and also a potent greenhouse gas.
Methane leakage	The inadvertent release of methane from natural gas supply chains.
Methanol	A clear, colourless chemical compound with the chemical formula CH_3OH.
Moffat entry point	The point of interconnection between the gas grids of Ireland and the United Kingdom.
Natural gas	A fossil fuel comprised mainly of methane gas.
Net zero	An energy system where greenhouse gases emitted to the atmosphere are balanced by removals, creating a system where net emissions of greenhouse gases are zero.
Network operator	As per TSO.
Off taker	See end user.
Opportunity cost	Value given up by choosing one option over another.
Reference price	The price received by a hydrogen producer under a variable premium support model.
Shipper	Any person that holds a Shipping Licence and has entered into a Framework Agreement with the Transporter to transport Natural Gas through the Transmission System whether for its own use or for use by a Third Party as an End User.
Social good	An action or asset that benefits society as a whole.
Storage	Infrastructure where hydrogen can be stored, allowing for the decoupling of supply and demand.
Strike price	The pre-agreed production cost of hydrogen in a variable premium support model.
Supplier	The holder of a Licence with respect to the supply of Natural Gas, issued by the Commission for Regulation of Utilities
Synthetic fuel	See e-fuel.
System balancing	System operations required within a period to match the inputted energy with the offtaken energy
Tariff	The applicable charges in respect of the transmission or distribution of Natural Gas utilising the Transmission System.
Temporal correlation	The matching of electricity used for hydrogen production with electricity produced by a generator of renewable electricity.
Transmission network	Natural gas transmission pipelines that are designed to operate at a pressure above sixteen (16) bar and connected into a system.
Transmission system operator	The operator of the gas transmission network i.e. Gas Networks Ireland.
Unabated	The use of fossil fuels where greenhouse gas emissions are released directly to the atmosphere.

Nomenclature

Abbreviations

Abbreviations	Meaning
€/kW	Euro per kilowatt
ACER	European Union Agency for the Cooperation of Energy Regulators
BEV	Battery Electric Vehicle
CAPEX	Capital Expenditure
CBAM	Carbon Border Adjustment Mechanism
CCS	Carbon Capture and Storage
CfD	Contact for Difference
CH_3OH	Methanol
CH_4	Methane
CO2	Carbon dioxide
CPI	Consumner Price Index
CRU	Commission for Regulation of Utilities
DAM	Day Ahead Market
DECC	Department of the Environment, Climate and Communications
DESNZ	Department of Energy Security and Net Zero
EnWG	Energy Industry Act
EU	European Union
FIT	Feed In Tariff
FOAK	First-Of-A-Kind
gCO_2/MJ	Grams of Carbon Dioxide per Mega Joule
GSO	Gas Shipper Obligation
GW	Gigawatt
GWh	Gigawatt hour
H2	Hydrogen
H2O	Water
HAR	Hydrogen Allocation Round
HILP	High Impact Low Probability
HPA	Hydrogen Payment Agreement
HPBM	Hydrogen Production Business Model
IC1	Interconnector 1
IFI	Irish Fertiliser Industries
km	Kilometre
km/hr	Kilometre per hour
kt	Kilotonnne
kWh	Kilowatt hour
kWh/kg	Kilowatt hour per kilogramme
kWh/m^3	Kilowatt hour per metre cubed

LEU	Large Energy User
LNG	Liquified Natural Gas
m^3	Metre cubed
mt	Megatonne
Mtpa	Megatonne per annum
MW	Megawatt
NBP	National Balancing Point
NGEP	Natural Gas Emergency Plan
NH_3	Ammonia
PPA	Power Purchase Agreement
PPI	Producer Price Index
PSO	Public Services Obligation
Q-Max	Largest category of LNG tanker, with a capacity of 266,000 m^3
RFNBO	Renewable Fuel of Non-Biological Origin
RPI	Retail Price Index
TAM	Temporal Allocation Mechanism
TSO	Transmission System Operator
TTF	Title Transfer Facility
TWh	TeraWatt hour

Symbols

Symbol	**Meaning**
~	Approximately

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