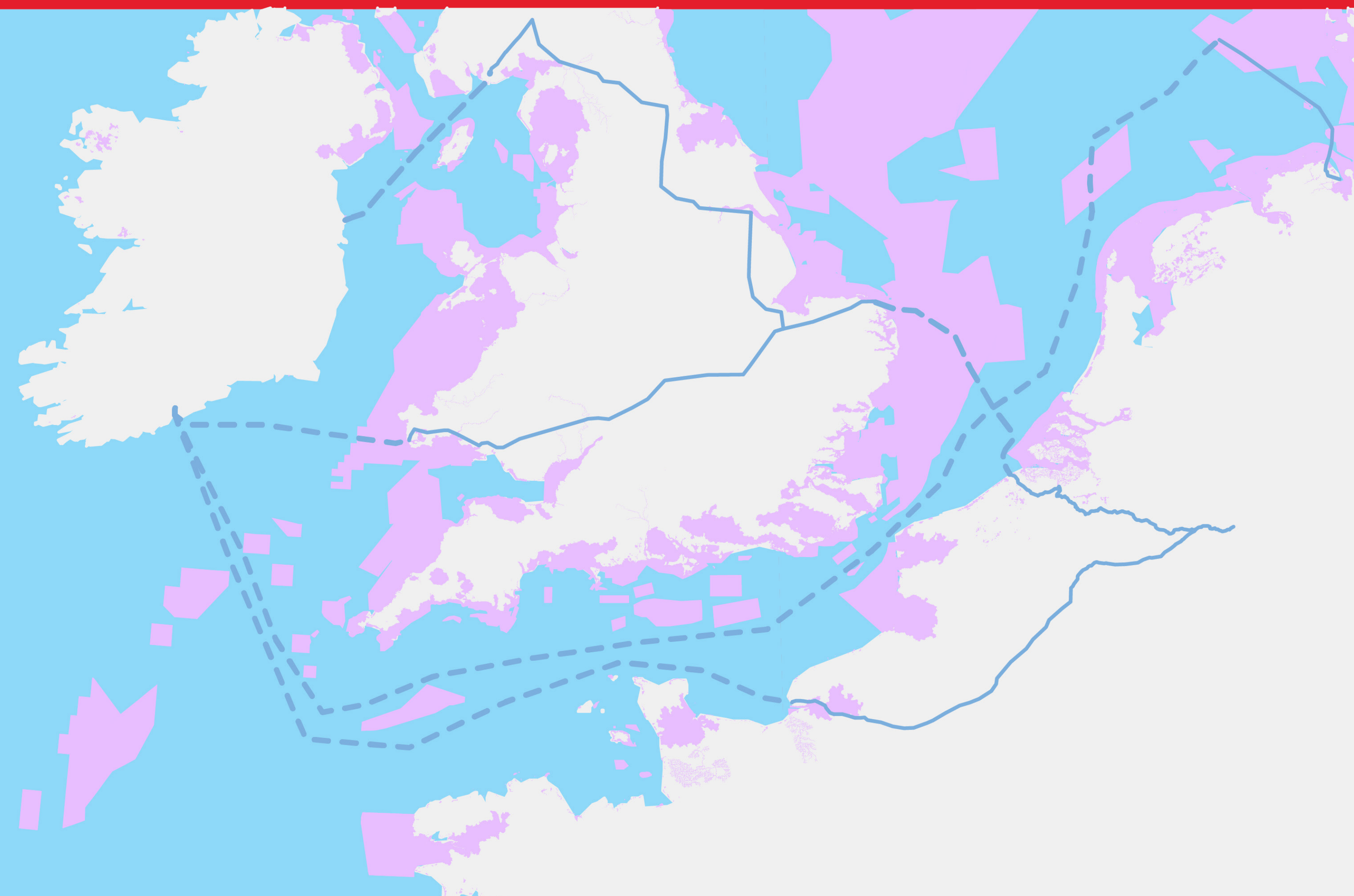
ARUP

Department of Climate, Energy and the Environment

Exporting Hydrogen from Ireland

Study to Explore the Potential for Exporting Hydrogen from Ireland to Continental Europe.

12 November 2025 | Reference 308588-00



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Executive Summary

The Department for Climate, Energy and the Environment (DCEE) commissioned Arup to undertake this study to explore the potential for exporting hydrogen from Ireland to continental Europe. This is a response to Action 8 of the National Hydrogen Strategy and includes an evaluation of the ambition and potential for renewable hydrogen production in Ireland. It evaluated the demand for hydrogen, domestically and in Europe, and performed high-level technical and commercial reviews of export transport routes, such as repurposing existing pipelines, new pipelines, and non-pipeline transport (i.e. shipping).

The expected domestic use of hydrogen in the power generation, industrial, commercial and transport sectors was studied. An evaluation of the Irish renewable hydrogen production potential using offshore wind energy (OWE) considering plans, ambitions and current progress was conducted. It was found that Ireland's hydrogen production potential significantly exceeds projected domestic demand, positioning the country as a future net exporter of renewable hydrogen and its derivatives. This underscores the strategic importance of aligning offshore wind development with hydrogen infrastructure to unlock Ireland's potential role in the European clean energy transition.

This was followed by an examination of the demand for hydrogen and its derivatives in continental Europe. It was found that Germany, Belgium, and the Netherlands are the key demand centres for both hydrogen and its e-ammonia and e-methanol derivatives. Great Britain (GB) and France were both considered as transit countries to connect Ireland, via Project Union / GB Hydrogen Backbone and the Europe Hydrogen Backbone, to the demand centres. Three export scenarios were considered: low (22 ktpa), base (215ktpa), and high (430 ktpa) for hydrogen and the equivalent quantities of e-ammonia and e-methanol that can be produced from those volumes of hydrogen. Several transport routes were technically reviewed, including both new and repurposed pipelines as well as shipping of four vectors (compressed gaseous hydrogen, liquid hydrogen, ammonia, and methanol). After a review of Irish port locations, Cork was chosen as the export point for both shipping and new pipelines for the purposes of this study. Other export locations should be considered in the future.

A levelised cost of transport (LCOT) model for each transport route was developed to estimate the cost of transporting hydrogen from Ireland to its end markets. For the pipeline options, repurposing existing natural gas interconnectors to GB and from GB to Belgium, and then using the planned UK Project Union and European Hydrogen Backbone pipelines, was found to be the most cost-effective option. A new hydrogen interconnector to the UK was also competitive. Routes with new pipelines via France and direct to Germany (the largest export market) were less competitive.

For the shipping options, using e-ammonia and then converting back to hydrogen at the destination port was the most cost effective. E-methanol was found to be more expensive than e-ammonia due to the higher CAPEX of its manufacturing process. A new technology for shipping compressed gaseous hydrogen may be even more cost effective than ammonia, but there remains uncertainty as larger capacity ships are not yet commercially available. Shipping liquid hydrogen was the most expensive shipping option. An evaluation of shipping ammonia and methanol directly (without converting back to hydrogen) was also undertaken with encouraging results. Germany and the Netherlands are developing plans for the import of ammonia and methanol for use as a raw material in industry.

Finally, a comparison of pipeline and shipping options was presented. Comparing all options, pipelines are more cost effective at the base (215 ktpa) and high (430ktpa) scenarios and shipping is more cost effective at the low (22 ktpa) scenario. The repurposed pipeline option was the cheapest, with the option for a new pipeline to France option still being cheaper than all the shipping options at the base scenario volume of hydrogen. However, it is noted that for the low scenario shipping would be much cheaper than pipelines. Therefore, we conclude that shipping should first be used for exporting hydrogen (or a derivative) from Ireland to continental Europe, at initially low volumes as the market develops and hydrogen production ramps up. When export volumes increase significantly (towards 100 ktpa), consideration should be given to the development of pipeline routes.

Ireland's hydrogen production potential is much larger than the expected domestic demand. One option to help derisk the development of the hydrogen economy in Ireland would be to include the export of hydrogen as a potential offtaker. This would support the development of large-scale hydrogen production in Ireland, which can also supply emerging domestic offtakers. This would also allow time for the development of the large-scale hydrogen storage necessary for the power sector to use hydrogen to provide grid flexibility services to the electricity grid, that will increasingly be dependent on supply from intermittent renewables (i.e. wind and solar).

The following next steps are recommended for the development of hydrogen exports from Ireland:

- Accelerate the delivery of offshore wind energy to provide the necessary electricity to produce renewable hydrogen using electrolysis.
- Enable (via regulation and commercial levers) hydrogen export and develop understanding of the market.
- Undertake stakeholder engagement with governments and gas transmission operators.
- Develop export system concepts to explore options in more detail.

Acronyms, Abbreviations & Definitions

The following acronyms, abbreviations and definitions are used throughout this report:

AWE	Alkaline water electrolysis
CAPEX	Capital expenditure
CO2	Carbon dioxide
DEVEX	Development expenditure
EHB	European Hydrogen Backbone
eSAF	Synthetic aviation fuel produced from renewable hydrogen and bioderived CO2
GB	Great Britain
Green Hydrogen	Hydrogen produced via electrolysis using renewable electricity, i.e., renewable hydrogen
Grey Hydrogen	Hydrogen produced from steam methane reformation of natural gas
H2	Hydrogen
IC1	Interconnector 1
IC2	Interconnector 2
Ktpa	Kilotons per annum
LCOT	Levelised cost of transport
LHV	Lower heating value
LOHC	Liquid organic hydrogen carrier
MEGC	Multiple-element gas containers
MW	Megawatts
MWth	Megawatts thermal
TWh	Terrawatt hours
MSm3	Standard cubic metre
MeOH	Methanol
NH3	Ammonia
OPEX	Operational expenditure
LH2	Liquefied hydrogen
CH2	Compressed gaseous hydrogen
LPG	Liquefied petroleum gas
rDME	Renewable dimethyl ether
REPEX	Replacement expenditure

BE	Belgium
DE	Germany
NL	The Netherlands
UK	United Kingdom

1. Introduction

The Department for Climate, Energy and the Environment (DCEE) commissioned Arup to conduct a study of export routes for hydrogen and its derivatives, including technical and commercial reviews of export routes such as existing pipelines, new pipelines, and non-pipeline transport options for Irish developers to export hydrogen to Great Britain and continental European markets.

1.1 Purpose of the Study

Currently, Ireland has limited industrial demand for hydrogen, while other EU countries have significant energy needs in hard-to-decarbonise sectors. This existing EU demand presents an opportunity to support the growth of Ireland's hydrogen industry. This study assesses the potential for connecting future Irish hydrogen infrastructure with continental Europe. Although GB is an unlikely final destination for Irish hydrogen exports, it is also considered here as a likely transit route for exports to continental Europe.

Key Study Objectives:

- Support Ireland's National Hydrogen Strategy
- Identify viable export routes to key European hydrogen markets
- Understand competitiveness of Irish renewable hydrogen
- Build evidence base to inform policy on hydrogen export to Europe

Key Study Outputs:

- **Work Package 1:** Define Ireland's hydrogen export opportunity
- **Work Package 2:** Pre-feasibility study of export routes (pipeline & non-pipeline)
- **Work Package 3:** Develop Ireland-specific levelised cost of transport (LCOT) model

1.2 Background

Hydrogen is the first element in the periodic table and the most abundant in the universe. On Earth it is primarily found bounded in compounds like water and hydrocarbons (such as methane, natural gas, coal and petroleum). While there are some natural hydrogen deposits, generally hydrogen needs to be manufactured. Globally most hydrogen is made either using steam methane reforming (called grey hydrogen) or gasification of coal (called black hydrogen) methods, which both unfortunately emit very large quantities carbon dioxide. This carbon dioxide can be captured and stored to make low-carbon blue hydrogen, but Ireland lacks sufficient deposits of both coal and natural gas, so we have not considered blue hydrogen in this study.

As both grey and black hydrogen manufacture generates so many emissions, hydrogen production is changing to low carbon blue or green hydrogen. Hydrogen can be produced by splitting water into its constituent elements, hydrogen and oxygen, using water electrolysis. If the electricity for the electrolysis is produced using renewable electricity (such as wind or solar power), it produces renewable or green hydrogen.

The National Hydrogen Strategy, published in July 2023, outlines Ireland's ambition to develop an indigenous hydrogen industry in Ireland between now and 2050. The National Hydrogen Strategy contains 21 actions to support the development of a hydrogen industry in Ireland, across all aspects of the value chain. The strategy sets out the need to better assess the competitiveness of Irish produced renewable hydrogen compared to international price benchmarks and the benefits that a future hydrogen export market could deliver to the Irish economy.

This export feasibility study will assist in the understanding of future industrial and economic opportunities, as well as potential routes-to-market as the hydrogen industry in Ireland scales up in the coming years and decades to 2050. The study will build the evidence base on hydrogen export to continental Europe to inform policy and decision making.

Ireland has an established onshore wind and solar sector contributing power to the grid but is planning a major expansion of offshore wind resources (up to 37GW by 2050) and this report will focus on how these offshore resources can be used to make hydrogen for export to Europe. This could be a major economic opportunity for Ireland as well as a chance to contribute to the decarbonisation of European industry and power generation.

Hydrogen is an energy carrier and can be used as a clean fuel for transport and power generation. It is a key industrial feedstock for the manufacture of fertilisers, chemicals and refinery processes (e.g., desulphurisation). Renewable hydrogen can be used to manufacture low-carbon synthetic fuels, such as e-ammonia or e-SAF, and to decarbonise high-temperature industrial processes such as steel, glass and ceramics manufacture.

There is a high demand from the industrial centres of Europe for renewable hydrogen to decarbonise these industries and we will be discussing how Ireland can export hydrogen and its derivatives to meet this need. Action 8 of the National Hydrogen Strategy sets out a requirement to conduct an assessment of the feasible potential for the export of hydrogen and its derivatives, which is presented in this report.

1.3 Approach

Work Package 1 (WP1) begins by evaluating the expected domestic demand for hydrogen in Ireland. We look at the availability of renewable electricity from potential offshore wind farm projects for renewable hydrogen production. We then consider the volumes of hydrogen and two of its derivatives (ammonia and methanol) that could be exported to Europe. An overview of current European hydrogen developments is undertaken followed by an assessment of the demand and export opportunity on a country-by-country basis. This leads us to draw up a shortlist of export destinations and transit countries, (countries that Irish hydrogen could pass through to reach its destination).

Work Package 2 (WP2) then provides a detailed technical overview for the hydrogen transport options of shipping and pipelines for the selected vectors (hydrogen, ammonia and methanol). An analysis of the processes required for hydrogen export is conducted considering efficiencies, losses and energy use. Pipelines that are new, repurposed and a mix of both are evaluated, and pipelines sizes and routes identified. Marine infrastructure needs are considered for the shipping options. Ship sizes, routes and destination ports are selected for the LCOT analysis.

Work Package 3 (WP3) estimates the cost of transporting hydrogen from Ireland to the three selected import countries using six methods (new and repurposed pipelines and four shipping vectors). A detailed LCOT model was developed and the cost per tonne of hydrogen exported calculated so that all the options can be compared. The results for each of the six methods are presented along with a comparative analysis. Finally, conclusions are drawn and recommendations for next steps presented.

1.4 Methodology

This report evaluates the technical feasibility of transporting hydrogen from Ireland to Great Britain and mainland Europe through three primary channels: existing pipelines, new pipeline infrastructure, and non-pipeline (shipping) methods. The shipping of hydrogen and hydrogen derivatives are in various stages of development. There is already commercial shipping of ammonia and methanol. International trials are ongoing for bulk shipping of liquid hydrogen while ships capable of carrying compressed hydrogen remain in the development and design phase. These issues are discussed in more detail in the report.

The following considerations were made for each transport channel:

Existing Pipelines

- **Pipeline Condition & Compatibility:** Assess the current state of existing pipeline infrastructure and its suitability for repurposing to carry hydrogen.

- **Infrastructure & Ownership Models:** Review the existing infrastructure and analyse ownership structures to understand potential regulatory and operational implications.

New Pipelines

- **Route Planning & Terminal Requirements:** Identify optimal start and end points for new pipelines, including necessary terminal infrastructure.
- **Technical Specifications:** Evaluate potential routing options, pipeline sizing, estimated construction timelines, and associated build costs.
- **Environmental Considerations:** Assess environmental risks and regulatory challenges related to new pipeline development.

Non-Pipeline (Shipping) Options

- **Maritime Infrastructure:** Review the capacity and readiness of maritime infrastructure to support hydrogen transport.
- **Port Operations & Ownership:** Analyse port operations at both export and import locations.
- **Conditioning Requirements:** Assess the technical requirements for conditioning hydrogen derivatives (e.g., ammonia, methanol) at both ends of the shipping route.
- **Cost Estimation:** Estimate the costs associated with conditioning and shipping hydrogen or its derivatives.

This report draws on several influential studies, see chapter 12, to align with Ireland's ongoing hydrogen initiatives, including the National Hydrogen Strategy, ongoing Project Hyreland by Fraunhofer ISE (ending October 2025), the 2024 Green Hydrogen in Ireland report by Friedrich-Ebert-Stiftung, the IEA's 2024 Hydrogen Production and Energy Infrastructure Database, and GNI's Pathway to a Net Zero Carbon Network.

2. WP1: The Expected Hydrogen Demand in Ireland

2.1 Introduction

While domestic hydrogen demand is not the primary focus of this report, understanding it is essential for evaluating Ireland's capacity to export hydrogen. The National Hydrogen Strategy[1] outlines a vision for integrating renewable hydrogen into Ireland's energy system, with key applications in sectors where electrification is challenging, namely heavy-duty transport, industrial processes, and flexible power generation. These sectors are expected to account for the majority of Ireland's future hydrogen demand.

Longer-term applications, such as aviation and maritime transport, are likely to rely on hydrogen-derived fuels and will emerge as demand drivers beyond 2040. This section explores anticipated hydrogen demand across these sectors and its implications for Ireland's hydrogen economy.

This section contributes to the overall analysis by:

- Establishing a clear picture of Ireland's **indigenous hydrogen demand** across priority sectors, based on national projections.
- Providing a foundation for comparing domestic demand with the **hydrogen production scenarios**, enabling an assessment of Ireland's **potential export capacity** once internal needs are met.

2.2 What can you use hydrogen for?

Hydrogen plays a pivotal role in the contemporary energy landscape and industrial processes. Its versatility as both an energy carrier and a chemical feedstock renders it indispensable across various sectors. It's important to highlight these dual uses, with a particular focus on hydrogen derived from wind energy and corresponding terminology and units of measurement to discuss each role.

As an energy carrier, potential uses of renewable hydrogen, produced using renewable energy sources through the electrolysis of water, include energy storage for grid balancing and long-term (interseasonal) storage. It can be used in hydrogen fuel cells to produce electrical energy for cars, buses, trains, and back-up power. Direct combustion applications in high temperature industrial process (replacing natural gas, and coal for furnaces and heat generation) and turbines for power generation will be critical for decarbonising these sectors.

As a chemical industry feedstock, renewable hydrogen is a versatile element that can be used in green steel, ammonia and methanol production leading to large reductions in carbon emissions. Hydrogen derivatives such as ammonia are used to manufacture fertilizers, while methanol can be further processed to produce more complex chemical products. Grey hydrogen (with its associated carbon emissions) is currently used widely in refinery processes (such as desulphurisation and hydrogenation for biofuels), and this can be replaced by green hydrogen to reduce the carbon footprint of fuels.

As a feedstock in synthetic fuels, renewable hydrogen is the key ingredient in the manufacture of synthetic fuels (or e-fuels), when it is combined with (usually bio-derived) carbon dioxide to produce synthetic versions of existing fossil fuels. These are particularly useful in providing a carbon-neutral solution for hard to abate transport sectors, such as aviation and maritime. Note that both ammonia and methanol produced using renewable hydrogen, described above as chemical feedstocks, are effective synthetic fuels for use in the marine sector. Further examples include Synthetic Aviation Fuel (eSAF or e-kerosene) to decarbonise air travel and even e-petrol for the automotive sector. The manufacture of e-fuels is an incipient industry globally and may present an exciting opportunity for Ireland to develop a new industry to create an added value product from locally produced renewable hydrogen and waste carbon dioxide from local biomethane production plants[2].

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[1] National Hydrogen Strategy, Department of the Environment, Climate and Communications, July 2023

[2] National Biomethane Strategy, Department of the Environment, Climate and Communications, May 2024

2.3 Current and Anticipated Hydrogen Demand

Currently, hydrogen demand in Ireland is relatively low, but it is projected to grow substantially in the coming decades. The National Hydrogen Strategy[3] estimates that domestic hydrogen demand, as highlighted in Table 1, could range from 4.6 TWh to 39 TWh by 2050, with further increases possible when non-domestic needs, such as international maritime and aviation, are factored in. This could push total demand to between 19.8 TWh and 74.6 TWh. Furthermore, the Strategy indicates that by 2050 approximately half of Ireland's gas-fired power stations could be replaced with hydrogen-fired capacity, reflecting a significant shift toward renewable hydrogen in the power sector. Table 1 below summarises the indicative outlook for renewable hydrogen across end-user sectors in Ireland for 2050.

In addition, Ireland anticipates that it may be favourable to repurpose some of its existing natural gas pipeline infrastructure[4] to create a national hydrogen network, which would facilitate new high-priority end-users and enable export opportunities. The network transition plan being developed under Action 12 of the National Hydrogen Strategy will assess how the gas network could be adapted to support hydrogen, providing a reliable energy backbone for Ireland as industry partners begin to produce renewable hydrogen at scale. Pending the completion of this plan, Gas Networks Ireland's Pathway to a Net Zero Carbon Network envisions what this might look like.

Table 1: Outlook for Renewable Hydrogen across end-use sectors in Ireland for 2050

End-use sector	Estimated Hydrogen Demand (TWh)	
	Low	High
Power Generation	3.6	13.3
Commercial and residential heating	0	1.5
Industry and processing	0	14.9
Road and Rail transport	1	9.3
Total Domestic Energy Needs	4.6	39

Source: Ireland National Hydrogen Strategy, 2023

To support this growing demand, the National Hydrogen Strategy envisions the emergence of regional hydrogen clusters as key hubs for early infrastructure development. These clusters will serve as focal points for hydrogen production, storage facilities, and high priority offtakers. The main potential regional hydrogen clusters identified in the National Hydrogen Strategy and Climate Action Plan are in Cork, Shannon, Dublin, and the North and West (areas along the north and west coasts, with focus on regions like Donegal, Galway, and Mayo). Regional clusters will be instrumental in supporting Ireland's transition to a renewable hydrogen economy, with each cluster focusing on leveraging regional strengths such as offshore wind, industrial activity, and transport infrastructure.

Figure 1 below is an illustration of these industrial clusters and the Top 3 electricity grid renewable surplus areas by 2030.

[3] National Hydrogen Strategy, Department of the Environment, Climate and Communications, July 2023

[4] Pathway to a Net Zero Carbon Network, Gas Networks Ireland, September 2024

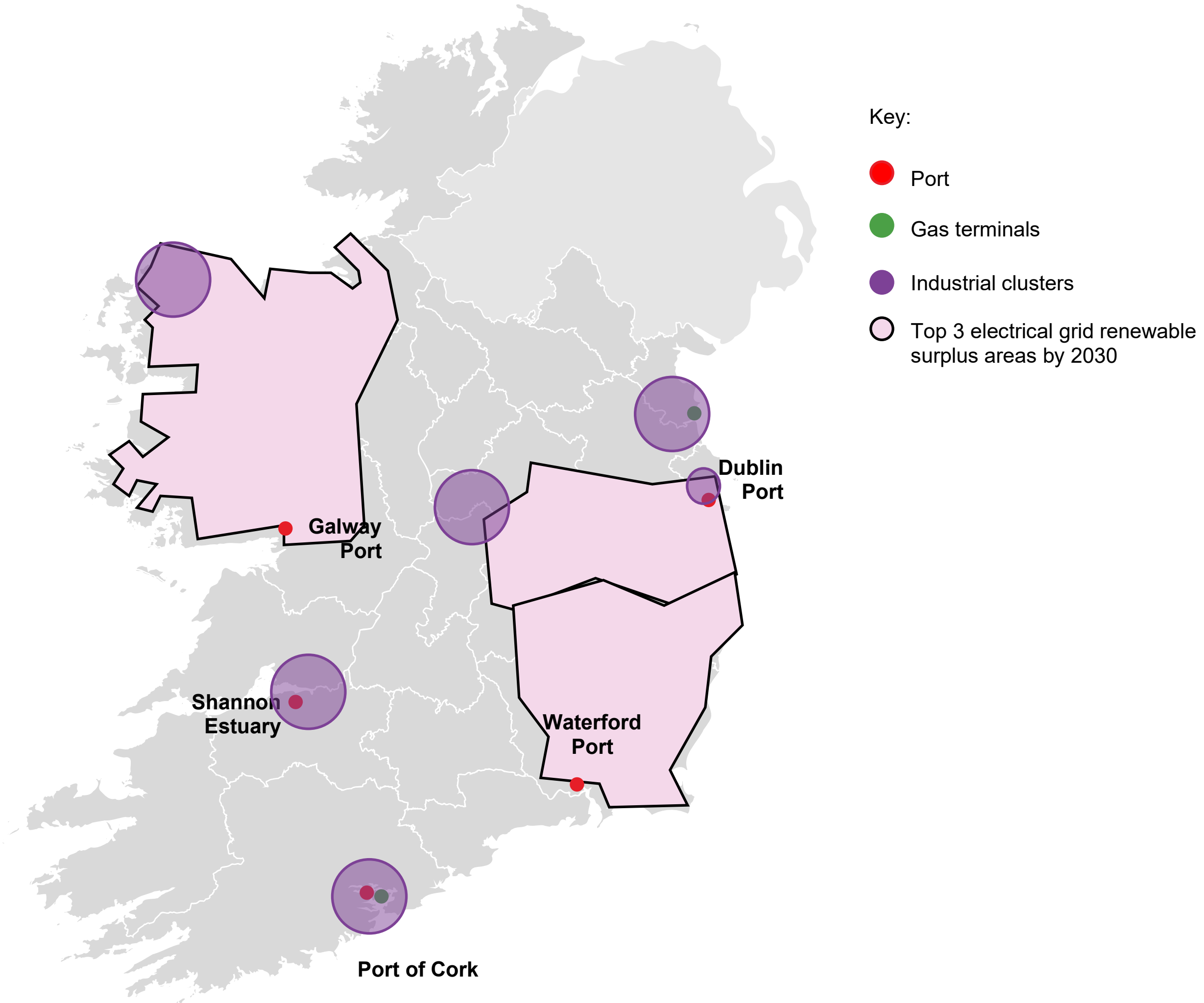


Figure 1: Potential Hydrogen Demand Clusters

Source: Arup analysis

Having established the likely regional hydrogen clusters in Ireland, it is important we explore the specific sectors of demand that will drive hydrogen usage. These sectors, namely, power generation, industrial processing, commercial and residential heating, road and rail transport, and new industries for hydrogen, are integral to understanding how hydrogen can be integrated into Ireland's economy to meet decarbonisation goals. Each sector presents unique opportunities and challenges for hydrogen adoption, and their demand profiles will shape the future development of Ireland's hydrogen infrastructure.

Anticipated Hydrogen Use Across Key Demand Sectors

Power Generation

Hydrogen is expected to play a key role in Ireland's electricity sector's ambition to reach net zero. The estimated demand for hydrogen in power generation is relatively high in comparison to the other end-use sectors, coming second to industry processing in the high scenario. The increasing share of variable renewable energy sources, like wind and solar, is likely to require renewable hydrogen to support dispatchable power generation. Hydrogen could help decarbonise conventional generation at times when renewable energy is less plentiful, such as during low wind periods, thus enhancing energy security and addressing system stability challenges.

In this context, open cycle gas turbines (OCGTs) are anticipated to be key offtakers of hydrogen. OCGTs currently operate on natural gas but can transition to hydrogen or hydrogen blends. Many turbines are already capable of handling a 3-5% hydrogen blend, and some can manage up to 30% (Electric Power Research Institute, 2019). By 2030, it is expected that turbines capable of operating on 100% hydrogen will be commercially available, with manufacturers like Mitsubishi targeting market-ready hydrogen turbines in the next year. This transition will enable OCGTs to provide the flexible, dispatchable power needed to complement intermittent renewable generation.

However, hydrogen-powered OCGTs will require large-scale hydrogen storage to meet system balancing needs, for long-duration storage during periods of low wind or solar activity, specifically when providing flexibility solutions to the grid. When hydrogen is being used for baseload power generation, this storage is not required. Hydrogen will need to be stored after production to ensure that OCGTs can be relied upon for grid stability and energy security when renewable generation is insufficient. Without such storage solutions, hydrogen's role in filling power gaps will remain limited. Therefore, while hydrogen will play an important role in decarbonising power generation, the development of hydrogen storage capacity is essential for ensuring that OCGTs can be effectively relied upon for grid stability and energy security. Currently, hydrogen storage infrastructure development in Ireland remains limited.

The 2023 Climate Action Plan sets a target of meeting 80% of electricity demand from renewable sources by 2030. Beyond this, a pathway to eliminate greenhouse gas emissions from the electricity system in Ireland has yet to be defined. The Department of Environment, Climate and Communications has asked the Sustainable Energy Authority of Ireland (SEAI) to lead on developing an evidence-based pathway, or choice of robust alternative pathways, for decarbonising the Irish electricity system after 2030. SEAI will develop the pathway based on rigorous research and engaging with a wide cohort of stakeholders to build consensus. A programme of work to generate this evidence base commenced in 2023 and the Decarbonised Electricity System Study (DESS) will be completed by the end of 2026. This aligns with Action 5 of the National Hydrogen Strategy.

Powering Prosperity - Ireland's Offshore Wind Industrial Strategy acknowledges the production of renewable hydrogen and its derivatives as a potential end-use for offshore wind energy and highlights the opportunity to add value to the energy in Ireland prior to export. As part of Powering Prosperity, DETE has commissioned an initial piece of analysis on the concept of green energy parks which could potentially accommodate Hydrogen and e-Fuel production as part of the co-location of renewable energy supply and large industrial demand in strategically developed sites post-2030.

Industry and Processing

Industrial heat and industrial manufacturing processes could make up a significant portion of Ireland's anticipated hydrogen demand. While electric heating technologies and heat pumps are effective for lower-temperature industrial processes, hydrogen is one of the few viable energy carriers capable of decarbonising high-temperature industrial processes. These high-temperature applications are critical for industries such as cement, steel, and chemicals, where direct electrification is often not feasible.

Irving Oil is currently Ireland's only large-scale hydrogen user, employing hydrogen in its refinery processes. As the market for hydrotreated vegetable oil (HVO) grows, Irving Oil's hydrogen demand is expected to increase significantly to meet the expanding needs of this sector. This illustrates the potential for renewable hydrogen to play a key role in decarbonising Ireland's refining industry and supporting the transition to sustainable fuels. While hydrogen use in agriculture is a possibility, the sector can currently substitute natural gas with biogas or electric heating, limiting the scale of hydrogen demand in this area. Therefore, the overall demand from the agricultural sector remains uncertain.

The pharmaceutical industry, which accounts for 10% of Ireland's large energy user demand, and the cement industry, making up 20%, are both well-positioned to benefit from renewable hydrogen as a substitute for fossil fuels. The Department of Enterprise, Tourism and Employment is actively working on a decarbonisation roadmap for industrial heat, informed by the SEAI National Heat Study, which will provide clearer insights into the future role of hydrogen in these sectors.

Commercial and Residential Heating

Hydrogen is not expected to play a significant role in commercial and residential heating in the near to medium term. The market timeframe for hydrogen in heating applications is expected to emerge around 2035-2040, as technological advancements, cost reductions, and infrastructure development progress. As shown in Table 1, the anticipated hydrogen demand for this sector is relatively small, even in the high-demand scenario. This limited role for hydrogen can be attributed to the fact that electrification and district heating systems are likely to dominate this sector as the primary means of providing low-carbon heating. Both technologies are more efficient, and cost effective compared to hydrogen for this application. In urban areas district heating networks can deliver at scale (SEAI, 2020, decarbonising heat in Ireland: strategic overview and policy). Other technologies such as heat pumps, biomass boilers and biomethane are also developing and are more likely to become dominant in low-carbon heating options (Climate action plan, 2019).

Hydrogen is likely to remain a niche solution in commercial and residential heating and used in areas where electrification is not feasible due to infrastructure limitations, geographical challenges, or the nature of the building stock. For example, in rural or isolated areas where district heating networks are not practical, hydrogen could provide an alternative for off-grid solutions. However, even in these cases, the role of hydrogen is expected to be limited compared to other clean technologies.

Road and Rail Transport

The National Hydrogen Strategy places particular emphasis on the role of hydrogen in heavy duty transport applications that require long duty cycles and travel longer distances, and where battery electrification is less feasible i.e., rail and long-distance road haulage. Heavy goods vehicles account for 15% of transport energy demand in Ireland today, but this is projected to rise to 30% by 2050. The likely market entry timeframes for hydrogen in road and rail transport is estimated to be around 2025-2030, making it one of the first end use sectors to develop. Binding EU targets for 2030 (EU Clean Transport Targets as part of the Fit-for-55 package) are also pushing the development of hydrogen in transport forward. However, the overall demand for hydrogen in road and rail may be constrained by the rapid development of alternative technologies, such as battery powered vehicles, bio-CNG and biofuels. Additionally in Ireland's Road Haulage strategy 2022-2031, the electrification of heavy good vehicles where technically feasible, remains a priority. Thus, the role of hydrogen will be to complement where electrification is not feasible.

New Industries for Hydrogen

As Ireland seeks to develop its hydrogen economy, there are emerging opportunities in synthetic fuels and chemical feedstocks that could contribute to both domestic needs and exports. Key sectors include synthetic aviation fuel (eSAF) and e-ammonia, which are gaining attention as sustainable alternatives to fossil fuels. Although Ireland currently does not produce ammonia domestically, renewable hydrogen could play a pivotal role in its production, transforming Ireland into a potential exporter of both ammonia and e-methanol. This shift would not only help reduce Ireland's dependency on fossil-fuel-based fertiliser imports but could also offer opportunities in the global synthetic fuel market (International Energy Agency, 2021).

Ammonia production is a major global use of hydrogen, primarily as a feedstock for fertiliser production. At present, Ireland's fertiliser demand is met entirely through imports, creating both a supply vulnerability and an opportunity for decarbonisation. Renewable hydrogen could potentially reduce reliance on imported fossil fuel-based fertilisers, supporting Ireland's transition to lower-emission and organic alternatives (SEAI, 2020). While the potential for domestic fertiliser production from renewable hydrogen remains uncertain, the broader focus of Ireland's hydrogen strategy is to support decarbonisation in the energy sector and improve energy security. The development of new industries, such as synthetic fuels and fertiliser production, may emerge as the hydrogen economy evolves. As these sectors mature, market feasibility studies will be crucial to assess whether these opportunities present strategic export potential for Ireland's hydrogen production.

DETE are also leading on an analysis of future hydrogen demand and end-uses in Ireland, with the objective of understanding the sectors where demand from hydrogen is expected to come from post-2030, and when that demand is expected to materialise. This initial piece of work is expected to conclude by the end of this year.

As shown above, the power and industrial sectors are expected to be the priority in adopting the use of renewable hydrogen. However, there are significant challenges in achieving this. For example, the effective use of hydrogen for power generation and industry will require large scale hydrogen storage to be in place which can take many years to develop. Furthermore, existing industry will need time to evaluate switching from fossil fuels to hydrogen, including the testing and procurement of new equipment. It will also take many years to develop and build new industries in hydrogen technology, for example an ammonia or synthetic aviation fuel plant, in Ireland. These applications, when they come onstream, will require large amounts of hydrogen to be available and this will be a key risk for such projects. As we will see in later chapters, Ireland's potential hydrogen production capacity is much greater than the estimated future domestic hydrogen demand. This will create significant opportunities for hydrogen exports to meet European decarbonised energy needs. Finally, it is worth noting that renewable hydrogen and e-fuel production plants and hydrogen export facilities would be ideal anchor tenants for both hydrogen clusters and green energy parks (e.g. by sharing waste heat from production processes). They can, therefore, effectively support the development of Ireland's renewable domestic hydrogen consumption.

2.4 Ireland Export Potential - Key Conclusions

Ireland's Indigenous Hydrogen Demand

Ireland's domestic hydrogen demand is expected to grow steadily, particularly in sectors where electrification faces practical limits, such as heavy-duty transport, industrial processes, and flexible power generation. These areas will form the backbone of indigenous hydrogen use, especially for applications like high-temperature industrial heat and long-haul transport, where hydrogen offers unique advantages.

However, the role of hydrogen in residential and commercial heating is likely to remain very limited. More cost-effective and scalable solutions, like electric heat pumps and district heating, are expected to dominate. Similarly, sectors like agriculture may elect to adopt biogas or electrification, depending on how technologies evolve and what proves most commercially attractive.

In transport, hydrogen could play a role, particularly for heavy goods vehicles (HGVs) and rail, but its uptake will be shaped by competition from battery-electric alternatives. Overall, the energy and industrial sectors are expected to be the largest domestic consumers, using hydrogen to enhance energy security and support decarbonisation.

Strategic Opportunity

Estimates suggest domestic demand could range from 4.6 TWh to 39 TWh by 2050, while total demand including aviation and maritime could reach up to 74.6 TWh. Even at the higher domestic demand estimates, Ireland with its abundant renewable resources, particularly offshore wind, is well-positioned to produce significantly more hydrogen than it consumes.

This opens a strategic opportunity for Ireland to become a net exporter of renewable hydrogen, supplying clean energy to European markets that are actively seeking to decarbonise their industrial, transport, and power sectors. Ireland's geographic proximity to key EU markets, combined with its potential to repurpose parts of the national gas network for hydrogen and develop regional hydrogen clusters (in Cork, Shannon, Dublin, and the North and West coasts), strengthens its potential as a reliable supplier of dispatchable renewable energy.

In essence, while Ireland's domestic hydrogen use will play an important role in its own decarbonisation journey, further strategic value lies in its ability to produce and export hydrogen at scale, helping to meet broader European climate goals and positioning Ireland as a central player in the emerging European hydrogen economy.

3. WP1: Ireland's Hydrogen Production Potential

3.1 Introduction and Strategic Context

Ireland is in the early stages of developing its hydrogen economy, with limited domestic production and demand. However, hydrogen offers a zero-carbon solution for hard-to-abate sectors such as heavy industry and high-temperature manufacturing. While Ireland's own industrial demand remains modest, significant needs across the EU present a strategic opportunity for Ireland to scale its hydrogen industry in alignment with European decarbonisation goals.

Ireland's potential lies in its abundant offshore wind resources and a clear national policy direction. The Climate Action Plan 2023 (CAP23)[5] set a target of 5 GW of grid-connected offshore wind by 2030. A further 2 GW should be in development for non-grid connected purposes (which could include renewable hydrogen production) by 2030. These targets could support the development of integrated green energy parks, combining hydrogen production, renewable fuels, and flexible power generation. Ireland's offshore wind pipeline is advancing, and hydrogen projects are progressing through feasibility and planning stages, supported by infrastructure initiatives such as gas network repurposing.

Projected domestic hydrogen demand could reach 5-39 TWh by 2050, and up to 75 TWh when including aviation and maritime sectors. In contrast, Ireland could produce 2-4 TWh of renewable hydrogen annually in the early 2030s, suggesting early-stage production may exceed internal needs and create an export opportunity. This positions Ireland to contribute meaningfully to European decarbonisation while enhancing its own energy security and economic resilience.

To assess Ireland's hydrogen export potential, this section:

- Reviews offshore wind policy, key targets, and the current project pipeline.
- Evaluates hydrogen production from dedicated renewable hydrogen initiatives.
- Establishes scenario parameters (low/base/high) for hydrogen production as a key input to this study.

3.2 Hydrogen Production Potential from Offshore Wind Development

Ireland's hydrogen production potential is closely tied to the scale and pace of offshore wind development. While onshore renewables will contribute, offshore wind offers greater consistency and capacity, making it the cornerstone of Ireland's renewable hydrogen strategy. This section assesses Ireland's offshore wind development and its implications for renewable hydrogen output.

3.2.1 Offshore Wind Projects – Phase 1 & 2

Ireland has set ambitious targets: 5 GW of grid-connected offshore wind and 2 GW for non-grid use to be in development by 2030. The 5 GW target is structured into two development phases, Phase 1 and Phase 2, as summarised in Table 2 below.

Table 2: Offshore Wind Development Projects - Phase 1 & 2

Phase	Project Name	Project Capacity (MW)	Detail
Phase 1 (ORESS 1 auction winners)	North Irish Sea Array	500	Total capacity 2.6 GW with maritime consents granted in December 2022. Projects are being developed under a project-led approach.
	Dublin Array	824	
	Codling Wind Park	1300	

[5] Climate Action Plan 2023, Department of the Environment, Climate and Communications, Dezember 2022

Phase	Project Name	Project Capacity (MW)	Detail
Phase 1 (unsuccessful at auction, but still going ahead)	Oriel Wind Farm	375	Total combined capacity of 1.17 GW. Projects unsuccessful at auction but moving forward with development through corporate purchase power agreements. As of June 2025, both windfarms have submitted planning applications.
	Arklow Bank	800	
Phase 2	Tonn Nua project	900	Total capacity 0.9 GW. CFD (contract for difference) auction taking place 22 Sept to 9 Dec 2025.
Phase 2	Lí Ban project	Up to 1,500	Total capacity of 1.1 to 1.5 GW. Anticipated auction in 2026.
Future Framework	South Coast DMAP sites C and D and National DMAP	TBD	Total capacity will be what remains to meet the Future Framework target of 20 GW for 2040.
Total Installed Wind Capacity (Phase 1)		3,799	

Foundational steps, including the completion of the ORESS 1 auction and designation of maritime areas, have been undertaken. According to the Powering Prosperity Implementation Progress Report (April 2025), 95% of the 40 actions due by the end of 2025 are either completed or underway, reflecting strong commitment. All Phase 1 projects have submitted planning applications, including those proceeding via corporate power purchase agreements. Planning permissions are expected by the end of 2026 and 2027. While these projects are primarily designed to supply the electricity grid, they demonstrate Ireland's capacity to deliver large-scale offshore wind. Phase 2 projects, which will complete the 5 GW target, remain undefined, and given current timelines, are unlikely to be operational by 2030.

3.2.2 Broader Offshore Wind Pipeline

Ireland's offshore wind pipeline extends beyond the structured Phase 1 and Phase 2 projects, encompassing a wider range of potential developments. While previous assessments included a mix of feasibility studies, conceptual proposals, and developer-led projects, many of these are now considered outdated or speculative.

Recent analysis from the Offshore Wind Technical Resource Assessment (2025) estimates that an additional 3.5 GW to 18 GW of fixed-bottom offshore wind could be developed around Ireland's coast, on top of the 5 GW targeted by 2030. This provides a more robust and technically grounded view of Ireland's offshore wind potential.

To deliver on the Programme for Government commitment to fast-track offshore wind development, the Government has recently approved a significant plan to accelerate offshore renewable energy deployment. This includes the development of a National Designated Maritime Area Plan (DMAP) for offshore wind, which will identify sites across Ireland's maritime area capable of delivering at least 15 GW by 2040, supporting the national target of 20 GW.

The State aims to adopt the national DMAP by the end of 2027, with designated sites expected to be brought forward for routes to market from 2028. This structured approach will provide greater certainty for developers and investors and help align offshore wind development with national energy and climate goals.

Given Ireland's long-term ambition is to reach 37 GW of offshore wind capacity by 2050, equivalent to six times the current peak electricity demand, this study adopts a longer-term outlook for hydrogen production. This scale of development will enable very large-scale hydrogen generation, supporting both domestic decarbonisation and export opportunities.

Current Planning Framework for Offshore Wind Development

DMAPs are the foundation for Ireland's offshore wind strategy - enabling project certainty, attracting investment, and supporting long-term hydrogen production potential.

Designated Maritime Area Planning (DMAP)

Ireland's ambitious offshore wind goals are largely dependent on the development of designated maritime areas, which have been identified as suitable locations for large-scale offshore wind projects. These areas, defined by the government, are crucial to achieving the targets for offshore wind. The DMAPs, are selected based on factors such as wind resource potential, seabed quality, environmental impact assessments, the levelised cost of energy and proximity to grid infrastructure.

As of July 2025, only one DMAP has been published, which is the South Coast DMAP (SC-DMAP). The release of the SC-DMAP opens a structured framework for developers to pursue offshore wind projects with clearer guidance and regulatory certainty is a significant milestone in the development of Irelands offshore wind capabilities. The national DMAP covering the rest of Ireland, which will identify other areas for offshore wind development, particularly in other parts of the coast such as the east and north coast, is expected by the end of 2027. Once finalised, the full suite of DMAPs is likely to unlock substantial investment opportunities by offering developers a more predictable and transparent pathway to deployment.

In May 2024, four designated areas within the SC-DMAP were defined (see Figure 2):

- Tonn Nua (Area A) - designated for the first offshore wind development under SC-DMAP
- Lí Ban (Area B)
- Manannán (Area C)
- Danu (Area D)

These areas were selected using consistent criteria and represent the first concrete steps toward plan lead large-scale offshore wind deployment. Tonn Nua (Area A) will be awarded through the ORESS 2.1 auction, expected to open in November 2025, with results anticipated in December 2025 and deployment targeted by 2030 or as soon as feasible thereafter.

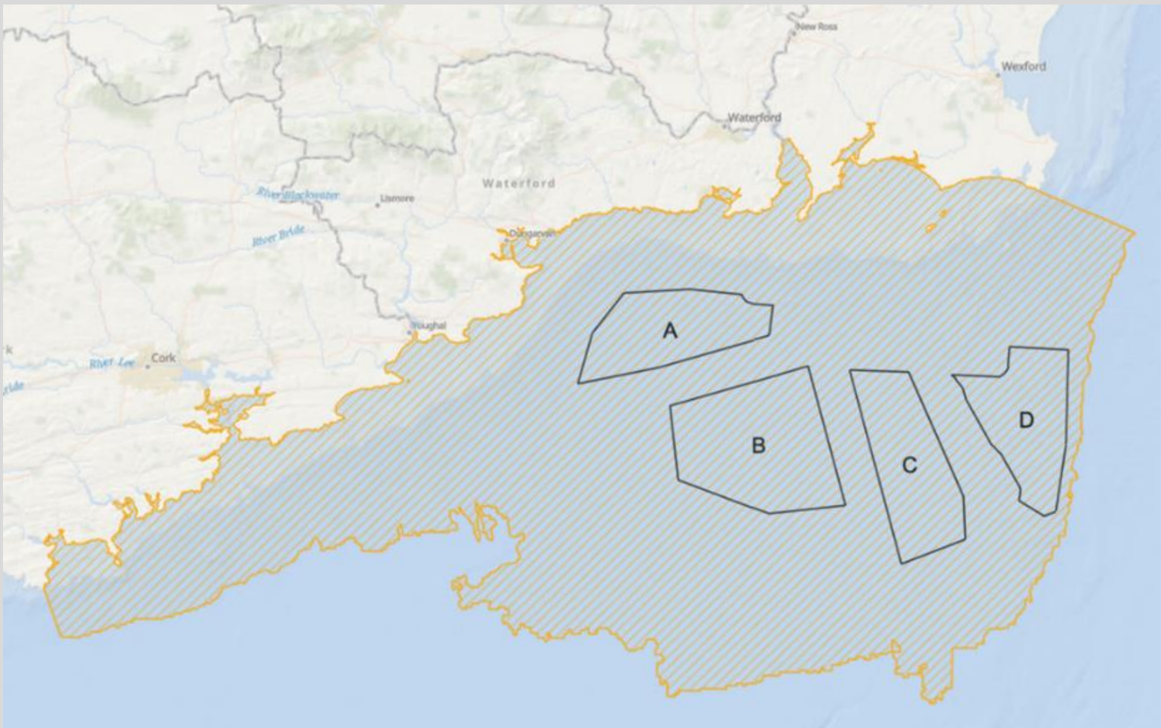


Figure 2: Designated Maritime Areas within the South Coast DMAP

3.3 Hydrogen Market Overview and Project Landscape

3.3.1 Ireland Hydrogen Market Overview

Developers in Ireland are actively exploring hydrogen projects, with many in the early stages of development. While these projects are still in the planning and conceptual phases, they hold the potential to significantly contribute to Ireland's hydrogen output, particularly as they align with the country's broader renewable energy and offshore wind goals. If successfully delivered, these projects could provide meaningful levels of hydrogen production to be utilised domestically and exported to meet growing energy needs across Europe. With continued collaboration between the public and private sectors, Ireland is well-positioned to accelerate its hydrogen ambitions and unlock its potential as a key player in the European hydrogen economy. While some elements of hydrogen policy are still evolving, there are clear pathways for scaling production in the coming years.

Like other emerging hydrogen markets across Europe, Ireland faces the challenge of scaling production, demand, and infrastructure in parallel. The government has recognised this need through several key policy instruments, including the *National Hydrogen Strategy*[6], *Climate Action Plan*[7], *Energy Security*[8] and Decarbonisation Policy[9], and more recently the *Future Framework for Offshore Renewable Energy* [10]and the *Powering Prosperity* [11]industrial strategy. Infrastructure development remains in its early stages, but progress is underway. Ireland is examining repurposing parts of its natural gas pipeline network for hydrogen, with Gas Networks Ireland (GNI) conducting feasibility studies to assess how existing infrastructure can be adapted for hydrogen transport and storage.

While financial support and regulatory frameworks for renewable hydrogen are still evolving, the strategic direction is clear. As outlined earlier, Ireland's offshore wind capacity, critical for scaling hydrogen production, is also in early development. With continued policy support and cross-sector collaboration, Ireland is well-positioned to overcome these challenges and unlock its hydrogen potential in line with broader European decarbonisation goals.

3.3.2 Ireland Hydrogen Project Pipeline

Renewable hydrogen production in Ireland is still in its infancy, with no large-scale commercial facilities currently operational. However, a diverse and expanding pipeline of projects reflects growing interest and investment in the sector. While timelines and delivery remain uncertain, these initiatives demonstrate technical feasibility and increasing stakeholder confidence.

Pilot and Demonstration Projects

- **Mount Lucas (Bord na Móna & BOC Gases):** Operational 0.5 MW electrolyser producing renewable hydrogen for industrial use; planning approved for a 2 MW facility targeting over 200,000 kg/year.
- **ESB Aghada:** Green Hydrogen Lighthouse Project exploring hydrogen integration in power generation; includes a 1 MW demonstration-scale electrolyser.

Feasibility and Planning Stage

- **Firlough Project (Mercury Renewables):** €200 million wind-hydrogen development in Mayo-Sligo; proposed 80 MW electrolyser targeting 4.5 million kg/year.

[6] National Hydrogen Strategy, Department of the Environment, Climate and Communications, July 2023

[7] Climate Action Plan 2024, Department of the Environment, Climate and Communications, December 2023

[8] Energy Security in Ireland to 2030, Department of the Environment, Climate and Communications, November 2023

[9] Long-term Strategy on Greenhouse Gas Emissions Reductions, Department of the Environment, Climate and Communications, April 2023

[10] https://www.gov.ie/en/department-of-climate-energy-and-the-environment/press-releases/government-pu…

[11] https://enterprise.gov.ie/en/publications/publication-files/powering-prosperity.pdf

- **Indaver Duleek:** Planning approved for hydrogen production from waste; 10 MW electrolyser using curtailed electricity.
- **Constant Energy (Killala & Bellacorrick):** Includes a 106 MW energy centre with hydrogen integration potential.
- **Celtic Hydrogen Cluster:** Regional collaboration aiming to build hydrogen infrastructure; potential for 20–50 MW electrolyser under consideration.
- **SH2AMROCK (Galway):** EU-supported hydrogen valley initiative focused on transport and sector integration; targets 5,000 tonnes/year.

Strategic Sites and Concepts

- **ESB Moneypoint – Green Atlantic & ESB Poolbeg:** Strategic sites under review for hydrogen development.
- **Galetech and others:** Exploring hydrogen concepts tied to renewable energy generation.

While many of these projects remain in early development or feasibility phases, they collectively represent a strong and diverse pipeline. The absence of mature hydrogen infrastructure (particularly for storage, transport, and end-use) remains a key barrier. However, the groundwork being laid today is critical. With sustained policy support and investment, Ireland is well-positioned to become a significant contributor to the European green hydrogen economy.

3.4 Export Scenarios Based on Offshore Wind Production

To assess Ireland's potential contribution to the European hydrogen market, this study models three export scenarios based on offshore wind capacity dedicated to renewable hydrogen production. For the purposes of this study, we have elected not to consider onshore wind or solar capacity, although these will play a role in the early phases of hydrogen production in Ireland. Hydrogen exports will, however, require much larger amounts of renewable electricity that only offshore wind can supply and therefore we focus on this resource to supply the electrolysis. The scenarios reflect varying levels of ambition and delivery, grounded in Ireland's current offshore wind development pipeline and informed by national policy targets.

Although Phase 1 and Phase 2 offshore wind projects are not initially configured for direct hydrogen production, they reflect the scale and ambition of Ireland's renewable energy sector. In line with the National Hydrogen Strategy[12], this study adopts a working assumption of 2 GW of offshore wind capacity dedicated to non-grid limited uses, including renewable hydrogen production, to be in development by 2030. This provides a consistent baseline for scenario development, recognising that actual delivery will extend into the 2030s. Future integration of offshore wind with hydrogen infrastructure will be essential to unlocking Ireland's full potential in renewable hydrogen production.

Based on this assumption, the study defines three scenarios:

- **Low Scenario (375 MW)**: Assumes 10% of the base case capacity. This conservative scenario accounts for potential delays in offshore wind deployment, regulatory bottlenecks, or slower infrastructure readiness. It provides a lower bound for hydrogen production and export potential. Furthermore, this scenario would provide sufficient hydrogen production to feasibly commence the export of hydrogen from Ireland.
- **Base Scenario (3,750 MW)**: Reflects a plausible offshore wind capacity, based on current progress, that could be assigned to hydrogen production during the 2030s. It represents a realistic medium-term outlook, assuming continued progress in project delivery, infrastructure development, and policy support. This scenario is higher than the in development 2030 off-grid connected offshore wind capacity target, but represents a scenario that can, by the late-2030s, build on the initial 2GW. As discussed later, the

[12] National Hydrogen Strategy, Department of the Environment, Climate and Communications, July 2023

base scenario would support sufficient production volumes of hydrogen to justify the development of an export pipeline.

- **High Scenario (7,500 MW)**: Assumes double the base case capacity. This reflects an accelerated build-out of offshore wind, supported by strong policy alignment, investment, and infrastructure delivery. While ambitious, it is technically feasible given Ireland's long-term offshore wind potential and strategic positioning within the EU energy landscape.

We have assumed that all the wind energy capacity, 3,750MW for the base scenario, will be dedicated to hydrogen production. Any energy demand associated with hydrogen transport is met in addition to the planned wind energy capacity. Consequently, the energy needed for compression, liquefaction, processing, and operations needed for export does not diminish the amount of hydrogen designated for export.

The scenarios are summarised in Table 3 below and form the basis for estimating Ireland's renewable hydrogen production capacity and export potential. They are used to model low, base, and high production volumes, which feed into broader assessments of infrastructure needs, market integration, and Ireland's contribution to European decarbonisation targets.

Table 3: Offshore Wind Capacity Assumptions for Hydrogen Export Scenarios

Scenario	Installed Wind Capacity (MW)	Comment
Low	375	Low Scenario assumes 10% of the base case.
Base	3,750	Base Scenario assumes plausible offshore wind capacity which could be assigned to renewable hydrogen production in the 2030s.
High	7,500	High Scenario assumes double the offshore wind capacity of the base case.

3.5 Hydrogen Production Potential from OSW - Key Conclusions

Overview

Ireland's offshore wind sector is a critical enabler of future hydrogen production, offering vast potential for renewable hydrogen development and recognised by the 37GW 2050 ambition for offshore wind. While the government's target of 5 GW of offshore wind by 2030 sets a strong foundation, achieving this goal at the current pace of planning, permitting, and infrastructure development is challenging.

Hydrogen production in Ireland remains in its early stages, but the country has the natural resources, policy ambition, and emerging project pipeline needed to become a key player in the European hydrogen economy. Ireland's strengths in offshore wind, combined with efforts to repurpose gas infrastructure for hydrogen transport and storage, position it well for long-term growth. The integration of hydrogen technologies with offshore wind projects will be essential to unlocking the full potential of renewable hydrogen.

However, progress will depend on continued strategic planning, investment, and the development of a cohesive regulatory framework. Clarity on timelines and infrastructure delivery will be vital to de-risking the market and attracting investment. The opportunity for Ireland is clear: with the right focus and commitment, the country can establish itself as a leading exporter of renewable hydrogen.

Scenario Outcomes – Offshore Wind Capacity for Hydrogen Export

To assess Ireland's hydrogen export potential, this study developed three scenarios based on offshore wind capacity dedicated to renewable hydrogen production:

- **Low Scenario – 375 MW**
  Represents a conservative outlook, assuming 10% of the base case capacity. Reflects potential delays or underperformance in offshore wind deployment.
- **Base Scenario – 3,750 MW** Represents a plausible offshore wind capacity which could be assigned to renewable hydrogen production during the 2030s, reflecting progress with the ongoing DMAP process.
- **High Scenario – 7,500 MW**
  Assumes accelerated offshore wind development, supported by strong policy alignment and infrastructure delivery. Reflects Ireland's longer-term potential.

These scenarios form the basis for estimating Ireland's renewable hydrogen production and export capacity, and will inform subsequent modelling of infrastructure needs, market integration, and Ireland's contribution to European decarbonisation targets.

4. WP1: Volumes of Irish Hydrogen Exports

4.1 Introduction

Ireland's offshore wind resources offer substantial potential for renewable hydrogen production. To accurately assess this potential, it is essential to account for conversion losses across the energy chain—from wind generation to hydrogen output and derivative production. This chapter outlines the methodology used to estimate hydrogen output under three different offshore wind scenarios and presents the resulting volumes of hydrogen, ammonia, and methanol. These estimates inform downstream analysis on infrastructure, market integration, and export strategy.

Key Objectives of this section include:

- Estimate hydrogen output from offshore wind using consistent conversion assumptions.
- Quantify energy losses across generation, transmission, and electrolysis stages.
- Present scenario-based outputs in MWth, TWh/year, and ktpa (LHV).
- Calculate derivative volumes for ammonia and methanol using stoichiometric conversion.
- Provide input data for infrastructure and export planning in WP2 and WP3.

4.2 Hydrogen Output Estimates – Accounting for Losses

Offshore wind presents a significant opportunity for renewable hydrogen production in Ireland. However, it is essential to account for conversion losses throughout the energy chain. These conversion losses are displayed schematically in Figure 3. Not all installed wind capacity translates directly into usable hydrogen. Based on current technical assumptions, only 25% of installed offshore wind capacity is typically converted into pure hydrogen, after accounting for generation efficiency, grid losses, and electrolyser performance.

The conversion process involves several stages of energy loss:

- 40% of installed wind capacity is realised as average generated energy due to downtime and utilisation factors.
- 39% of the installed wind capacity is input into the electrolyser, after accounting for grid and power electronics losses.
- Further losses occur during electrolysis and hydrogen purification, resulting in only 25% of the original installed wind capacity being converted into usable hydrogen.

This study applies these conversion factors consistently across all export scenarios to estimate hydrogen output potential. The results are summarised below and used as inputs for downstream analysis in WP2 and WP3.

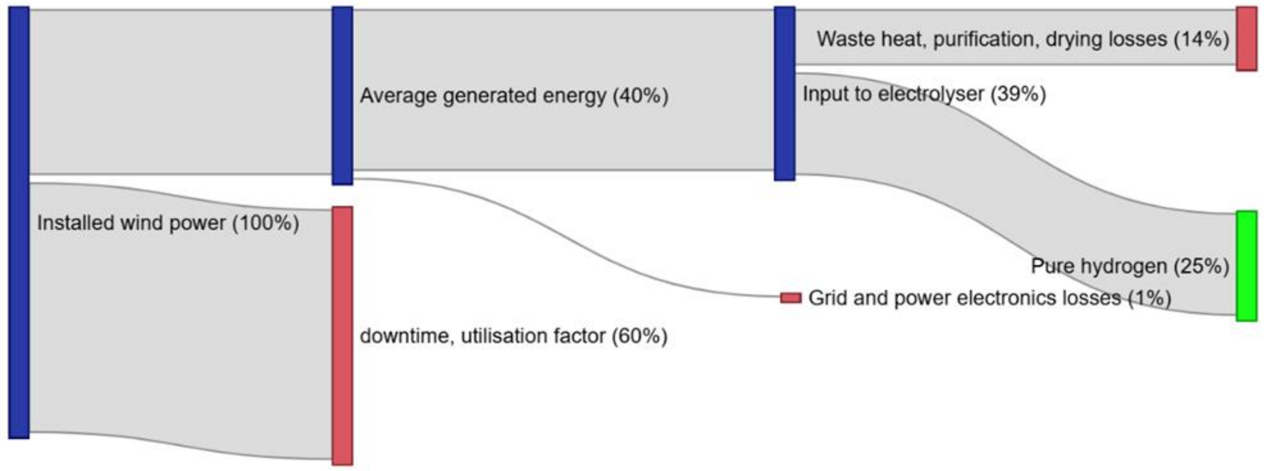


Figure 3: Energy flow and conversion in percentages for hydrogen as an energy carrier

4.3 Hydrogen Output by Scenario

As shown in Table 4, each scenario translates a different level of installed offshore wind capacity into usable hydrogen, accounting for conversion losses across generation, transmission, and electrolysis. These outputs are expressed in terms of thermal capacity (MWth), energy (TWh/year), and mass (ktpa, LHV), providing a clear picture of Ireland's potential hydrogen export volumes.

- **Low Scenario**: This scenario assumes 375 MW of installed capacity. After conversion losses, it yields approximately 91 MWth of hydrogen, equivalent to 0.7 TWh/year or 21.5 kilotonnes per annum (ktpa). This volume is suitable for small-scale industrial use or pilot exports, likely transported via ship.
- **Base Scenario**: Reflecting a realistic medium-term outlook, this scenario assumes 3,750 MW of offshore wind capacity. It results in 909 MWth of hydrogen, or 7.2 TWh/year, equating to 215 ktpa. This scale could support domestic decarbonisation and enable meaningful exports via either pipeline or shipping infrastructure, or a combination of both.
- **High Scenario**: Representing Ireland's long-term potential, this scenario assumes 7,500 MW of installed offshore wind capacity, with multiple hydrogen hubs reaching commercial scale. It delivers 1,818 MWth of hydrogen, or 14.3 TWh/year, equivalent to 430 ktpa. This volume positions Ireland as a major renewable hydrogen exporter, capable of supporting EU-wide decarbonisation across industry, transport, and energy sectors. Such large volumes would need to use pipelines to be cost-effective.

These outputs form the basis for downstream analysis in WP2 and WP3, including infrastructure planning, market integration, and transport logistics. They also highlight the importance of aligning offshore wind development with hydrogen infrastructure to fully realise Ireland's export potential. The conversion process from offshore wind to hydrogen involves multiple stages of energy loss, as illustrated in Figure 4 below. This diagram outlines the key assumptions used in this study, including capacity factors, electrolyser efficiency, and availability. It also provides a worked example for the Base Scenario, showing how 3,750 MW of installed wind capacity translates into 215 ktpa of hydrogen output.

Table 4 tabulates the wind capacity, electrolyser power and hydrogen outputs for the three scenarios. It also shows that the base scenario could use either shipping or pipelines for export which will later allow us to compare all export vectors in the LCOT analysis.

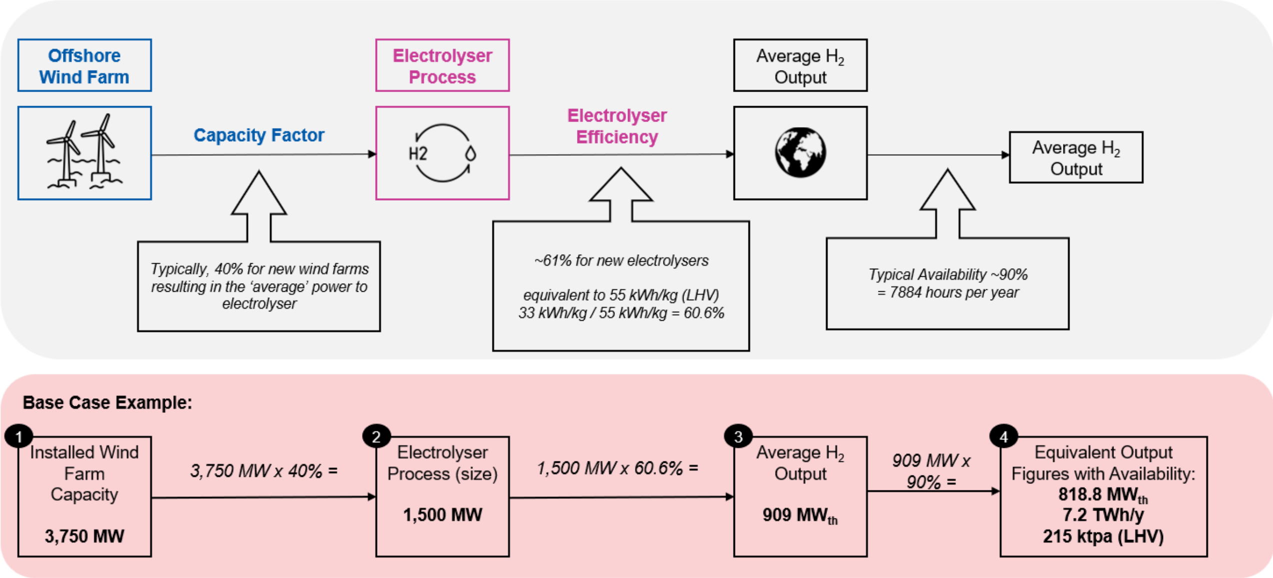
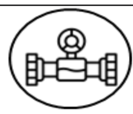
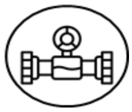


Figure 4: Offshore Wind to Hydrogen Conversion Pathway

Table 4: Proposed Hydrogen Export Scenarios

Scenario	Installed Wind Capacity (MW)	Avg. Power to Electrolyser (MW)	Average Hydrogen Output			Comment	Transportation Approach
			MWth	TWh/y	ktpa (LHV)		
Low	375	150	91	0.7	21.5	The assumption is based on a conservative outlook.	
Base	3750	1500	909	7.2	215.0	Provides a medium-term outlook for hydrogen production capacity in Ireland	 
High	7500	3000	1818	14.3	430.0	Provides a long-term outlook for hydrogen production capacity	

4.4 Selecting Hydrogen Derivatives for Export

In section 2.2, we discussed hydrogen derivatives including ammonia and methanol explaining that both are key feedstocks for the fertiliser and chemical industries. Both can be used as fuels in the maritime sector. Nearly all current global methanol and ammonia production uses grey hydrogen, with its associated carbon emissions, and can be decarbonised by using renewable hydrogen instead. There is a mature global market in trade of both ammonia and methanol which are shipped worldwide by sea. About 20 million tons of ammonia are shipped each year and there are commercial vessels of various sizes available for purchase or leasing. In the next chapter we will discuss export destinations, and a number of these countries are interested in importing both e-ammonia and e-methanol (made using renewable hydrogen) for use by their industry. While hydrogen can be shipped in either gaseous or liquid form, the technology for doing this is not as mature as for methanol and ammonia. For these reasons, we will be evaluating exports of methanol and ammonia from Ireland.

Green ammonia (or e-ammonia)

Chemical reaction for ammonia synthesis	$N_2 + 3\,H_2 \rightarrow 2\,NH_3$
Equivalent amount per ton of hydrogen	$4.7 + 1.0 \rightarrow 5.7$

Here we present the chemical reaction to make ammonia. We take 1 tonne of hydrogen with 4.7 tonnes of nitrogen to create 5.7 tonnes of ammonia.

Green methanol (or e-methanol)

Chemical reaction for methanol synthesis	$CO_2 + 3\,H_2 \rightarrow CH_3OH + H_2O$
Equivalent amount per ton of hydrogen	$7.3 + 1.0 \rightarrow 5.3 + 3$

Here we present the chemical reaction to make methanol. We take 1 tonne of hydrogen with 7.3 tonnes of carbon dioxide to produce 5.3 tonnes of methanol.

More technical details on ammonia and methanol will be presented in the WP2 chapters. We considered alternative hydrogen carriers such as liquid organic hydrogen carriers (LOHC), e.g. toluene-methylcyclohexane, but judged shipping LOHCs as relatively immature at scale and not appropriate for a new hydrogen exporter like Ireland. Export of synthetic aviation fuel (eSAF) was also explored, but this is also an immature sector, and Ireland is many years away from being a producer. Renewable Dimethyl Ether (rDME), an emerging lower-emission alternative to conventional fuels like diesel and LPG, could be an option but given the immaturity of this market at scale, we elected not to consider it. We decided to focus on ammonia and methanol export from Ireland for this study, as hydrogen derivatives that are technically mature with a developed shipping sector and thus best suited for exporting from Ireland. In the future, depending on export market demand, eSAF and rDME could be considered as export vectors.

Table 5 outlines the projected output of hydrogen and its key derivatives, ammonia and methanol, based on specified levels of installed offshore wind capacity. The scenarios (low, base, and high) demonstrate how Ireland's renewable energy resources can be converted into hydrogen using electrolysis, and subsequently into industrial derivatives through standard stoichiometric processes (1 tonne of H_2 yields ~5.7 tonnes of NH_3 or ~5.3 tonnes of MeOH). These figures incorporate conversion efficiencies and associated energy losses to provide realistic output estimates. The outcomes show that even under the base scenario, Ireland could produce approximately 215 ktpa of hydrogen, which translates into over 1.2 million tonnes of ammonia or 1.1 million tonnes of methanol annually.

Table 5: Proposed Hydrogen Derivative Export Scenarios

Scenario	Installed Wind Capacity (MW)	Avg. Power to Electrolyser (MW)	H_2 Output ktpa (LHV)	NH_3 Output ktpa (LHV)	MeOH Output ktpa (LHV)
Low	375	150	22	122	117
Base	3750	1500	215	1189	1140
High	7500	3000	430	2377	2279

4.5 Hydrogen Production Potential - Key Conclusions

Ireland's offshore wind capacity presents a major opportunity for renewable hydrogen production. However, technical conversion losses across the energy chain—spanning generation, transmission, and electrolysis—mean that only approximately **25% of installed capacity** is converted into usable hydrogen, based on current assumptions.

Under the **base scenario**, which assumes 3,750 MW of offshore wind capacity, Ireland could produce around **215 kilotonnes of hydrogen annually**, equivalent to **7.2 TWh**. This volume is sufficient to support both domestic decarbonisation and export activity. A low scenario of 375MW, at 10% of the base scenario, and a high scenario of 7,500MW, at twice the base scenario, will also be evaluated.

Hydrogen can also be converted into **ammonia and methanol**, enabling flexible and tradable energy carriers. In the base case, Ireland could produce over **1.2 million tonnes of ammonia** or **1.1 million tonnes of methanol** per year, highlighting the scale of potential industrial output.

Ireland's hydrogen production potential exceeds projected domestic demand, positioning the country as a future **net exporter of renewable hydrogen and its derivatives**. **This underscores the strategic importance of aligning offshore wind development with hydrogen infrastructure to unlock Ireland's role in the European clean energy transition**.

5. WP1: Ireland Hydrogen Export Opportunity

5.1 Introduction

This section focuses on identifying the European markets with the greatest potential for hydrogen exports from Ireland. It examines hydrogen's development both at the aggregate European level and at the individual country level, assessing the progress made in hydrogen policy, infrastructure development, and key hydrogen projects across different regions. The European Union has made considerable strides in advancing its hydrogen economy, creating robust strategies and frameworks to foster the development and adoption of renewable and low-carbon hydrogen.

5.2 Overarching European Hydrogen Development

The European Union has made substantial progress in advancing its hydrogen economy, establishing comprehensive strategies and frameworks designed to support the development and uptake of renewable and low-carbon hydrogen.

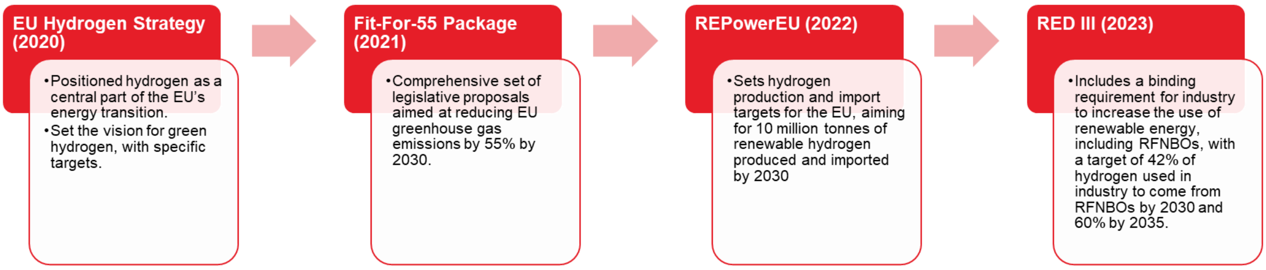


Figure 5 below illustrates European policy key to the development of the hydrogen economy.

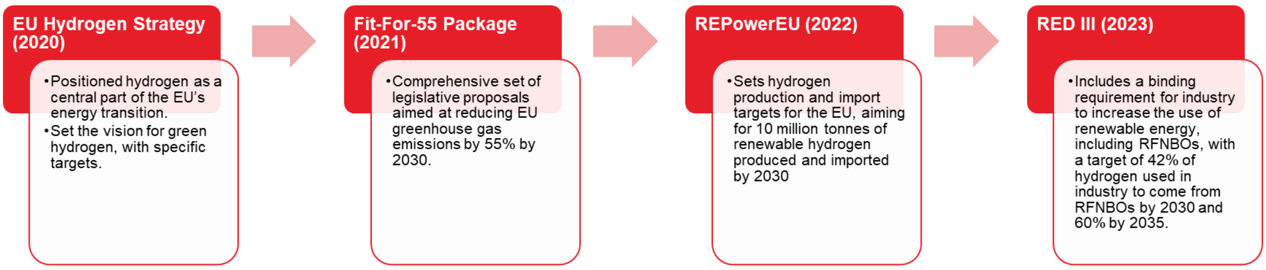


Figure 5: EU hydrogen policy development

Central to this effort is the EU Hydrogen Strategy (2020)[13] which set the foundation for Europe's Hydrogen ambitions. This was followed by the Fit-for-55-package (2021)[14] and the REPowerEU plan (2022)[15] which respectively turned strategy into actionable legislative proposals and set medium to long term targets for hydrogen production imports. RED III (2023)[16] set a 1% minimum target for renewable fuels of non-biological origin (RFNBOs) in transport by 2030 which includes renewable hydrogen as a key contributor. The establishment of direct policy tools in the form of clearly defined strategy with set targets, has helped accelerate the adoption of hydrogen as a renewable energy source.

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[13] A Hydrogen Strategy for a Climate-Neutral Europe, European Commission, July 2020

[14] Fit for 55 Package, European Commission, July 2021

[15] REPowerEU Plan - Communication from the Commission, European Commission, March 2022

[16] Directive (EU) 2023/2413 – Renewable Energy Directive III (RED III), Council of the European Union, October 2023

The European Commission aims for 10 million tonnes of renewable hydrogen production, and 10 million tonnes of renewable hydrogen imports by 2030, and for renewable hydrogen to cover approximately 10% of the EU's energy needs by 2050. However, the European Court of Auditors have recently criticised these targets as unrealistic, citing concerns about unclear methodologies and the lack of binding national goals. Additionally, EU Commission data revealed that no EU country has fully implemented the RED III targets by the May 2025 deadline, which was intended to unlock large-scale demand for renewable hydrogen. This indicates that progress may not be as swift as anticipated, and while the EU has laid out an ambitious roadmap for hydrogen, achieving these goals will require overcoming regulatory, market, and implementation challenges to ensure that hydrogen plays a central role in Europe's energy future.

Despite these challenges, recent developments have strengthened the regulatory and infrastructural foundation for hydrogen:

- In May 2024, the EU Hydrogen and Decarbonised Gas Market Package[17] introduced a regulatory framework for hydrogen infrastructure, including the creation of the European Network of Network Operators for Hydrogen (ENNOH). This framework supports the planning and conversion of existing natural gas infrastructure for hydrogen use.
- On July 8, 2025, the European Commission introduced a comprehensive greenhouse gas emission methodology for low-carbon hydrogen and fuels[18]. This provides a clear regulatory basis for investment and is expected to accelerate the scale-up of clean hydrogen production.
- The EU Clean Industrial Deal[19], announced in February 2025, will mobilize over €100 billion to support clean manufacturing. It includes a €1 billion budget under the Hydrogen Bank, aimed at de-risking and accelerating hydrogen uptake. The mechanism will connect offtakers and suppliers, facilitating financing and demand aggregation for hydrogen and hydrogen-derived fuels in hard-to-decarbonize sectors.

Looking ahead, the European Commission plans to launch a hydrogen pilot market mechanism by September 2025. This initiative will connect international producers with European buyers, enhance market transparency, and support price discovery. It is expected to play a key role in developing the infrastructure and trade structures needed to meet the EU's hydrogen import goals.

In summary, while challenges remain, the EU's strategic approach and recent policy and infrastructure developments are positioning hydrogen as a cornerstone of Europe's energy future. Continued progress will be essential to achieving the EU's hydrogen targets by 2030 and beyond.

5.3 Assessment of the Export Opportunity

This section explores a more detailed assessment of the export opportunities available to Ireland by providing an understanding of the development of the hydrogen market at the individual country level. For this assessment, Arup have conducted a review of European countries where hydrogen can be transported to via pipelines or ships, considering each country's hydrogen strategy, their progress in achieving stated targets and, where relevant, current and planned developments of hydrogen production projects and hydrogen infrastructure projects. As well as the level and availability of government funding initiatives aimed at supporting the growth of the hydrogen market in these countries.

The results of this analysis are presented through a Red, Amber, Green (RAG) assessment for each country, based on their policy framework and progress to achieving their stated targets. Table 6 below outlines the criteria used for the RAG rating, providing a clear basis for our evaluation.

[17] Hydrogen and Decarbonised Gas Market Package, European Commission, May 2024

[18] Delegated Act on the Methodology to Determine Greenhouse Gas Emission Savings of Low-Carbon Hydrogen and Fuels, European Commission, July 2025

[19] The Clean Industrial Deal: A Joint Roadmap for Competitiveness and Decarbonisation, European Commission, February 2025

Table 6: Country hydrogen policy and progress RAG assessment key

Policy RAG key		Progress RAG key	
Does not have a detailed domestic hydrogen policy or set targets for their hydrogen ambitions.		Has yet to release any funding or make significant development in their hydrogen strategy.	
Has a domestic hydrogen policy and clear and comprehensive targets but has no clear ambitions for hydrogen imports or exports.		Has started to issue funding and deliver on their projects but are yet to make significant progress towards their 2030 targets.	
Has a domestic hydrogen policy with clear and comprehensive strategy and targets and has clear ambitions and targets specifically for importing hydrogen.		Has made significant progress in the progression of their hydrogen strategy with multiple projects under way and are on track to achieve their 2030 targets.	

Table 7 provides an overview of the results of Arup's assessment.

Table 7: RAG assessment of European countries policy support for hydrogen production and imports and progress to meeting stated policy objectives.

Country	Policy	Progress	Rationale
Belgium			• Belgium published their National Hydrogen Strategy in 2021 with updates in 2022. They have no specific commitments on electrolyser capacity but have stated their ambitions for 20 TWh and 200TWh of hydrogen demand by 2030 and 2050 respectively. Their hydrogen strategy focuses on their hard-to abate sectors, specifically steel and transportation sectors. • Belgium's hydrogen ambitions are heavily geared towards the import of hydrogen, and positioning themselves as a hydrogen import location is the first pillar of their strategy. • Belgium is actively developing hydrogen infrastructure, including import terminals and distribution networks, to facilitate the planned import volumes. They are developing an open-access hydrogen pipeline connecting key industrial clusters. In 2025 Fluxys started construction on the first phase of the hydrogen pipeline network with the intention of the network to be operational by 2026.
Croatia			• The National Hydrogen Strategy was published in 2022; they have set within their strategy, clear capacity targets of 70 MW of installed electrolyser capacity by 2030 scaling to 2.8 GW by 2050. • Croatia have initiated 32 pilot projects focused on producing hydrogen from renewable sources. The Wave Energy project for example is a pilot plant under construction that plans to generate electricity from sea waves to produce hydrogen. • The Croatian Ministry of Economy and Sustainable Development is introducing a subsidy programme for investments in fuel supply infrastructure. The scheme aims to increase the use of renewable energy in transport with a significant part of the funding (EUR 23 million) earmarked for hydrogen refuelling stations. The program will be rolled out over the next three years, with approximately 65% of the funding released in the first year.
Denmark			• The National Hydrogen Strategy was introduced in 2020 and updated in 2022, stating ambitions to become a leader in renewable hydrogen production and export. • They aim to achieve an electrolyser capacity of 4-6 GW by 2030 and anticipates a production capacity of appx. 400 GWh per year by 2030 for domestic use and export. • Denmark has no stated ambitions for the import of hydrogen, and no official targets for the export of hydrogen although they do intend to be a leading exporter.
Finland			• The Clean Hydrogen Economy Strategy for Finland was published in 2023, with ambitions to position Finland as a significant player in Europe's hydrogen sector, leveraging its abundant renewable energy resources.

Country	Policy	Progress	Rationale
			• Finland aims to produce at least 10% of the EU's emissions free hydrogen by 2030. Finland have not explicitly stated any ambitions or volumes for the import of hydrogen but have plans to export 1 million tonnes of hydrogen per year by 2030, scaling up to 2.3 million tonnes by 2050. • Finland is actively working to establish a hydrogen backbone to connect industrial hubs through hydrogen transport pipelines, and they are strengthening cross-border hydrogen collaboration including developing a hydrogen pipeline to Germany via the Baltic Sea. Finland has some government funding mechanisms to support the development of the hydrogen economy i.e., through Business Finland there are investment grants for renewable hydrogen solutions, but there are no dedicated funding mechanisms for hydrogen from the Finnish government.
France			• France published an update to its national strategy in 2025. The electrolyser capacity targets were revised down from 6.5 GW by 2030 to 4.5GW and from 10 GW in 2035 to 8 GW. The strategies focus remains on decarbonising strategic industries such as chemical, steel and aviation. France has no official targets for the import of hydrogen. • The policy is backed by public funding worth €9 billion. The first 10 projects have been launched in France and approved by the European Commission involving public and private investment of €2.1 billion and €3.2 billion respectively. • Several projects have been initiated, such as the ZEV project in Auvergne-Rhône-Alpes and the H2 Corridor in Occitanie, however the downward revisions reflects that progress to targets is slower than previously anticipated.
Germany			• German National Hydrogen Strategy was updated in 2023. They have set a target for electrolyser capacity of 10 GW by 2030, aiming for 25 TWh of renewable hydrogen per year. • Their strategy is heavily reliant on imports with 50% to 70% of domestic hydrogen demand to be met by imports. Germany's 2024 hydrogen import strategy anticipates Germany needing between 95 and 120 TWh of hydrogen production per year by 2030 with 50-79% of this need being met by hydrogen imports. • Germany has allocated billions of euros to fund various renewable hydrogen projects, with public funding ranging between €9 billion to €17 billion. They have made significant progress thus far and are on track to achieve many of their hydrogen ambitions. They are developing 1,800 km of new and refurbished pipelines to be completed in 2027/8 as part of their hydrogen backbone network.
Greece			• Their National Energy and Climate Change Strategy (2021) sets a target of 1.7 GW and 30.6GW of electrolyser capacity by 2030 and 2050 respectively • Aside from these targets, they have no comprehensive framework for the deployment and use of hydrogen, including the potential for hydrogen imports, and no clear funding mechanisms. • Greece has made some progress to their targets, and have a few key hydrogen projects and initiatives underway, for example, the Hellenic Hydrogen project. • Greece also aims to position itself as a regional hub for importing renewable hydrogen from North Africa and the Middle and exporting it to European countries.
Italy			• The National Hydrogen Strategy was launched in 2020 with an ambition of 5 GW by 2030. Hydrogen is anticipated to account for 2% of Italy's final energy demand increasing to 20% by 2050. They have not explicitly stated any hydrogen import or exports targets • The Ministry of Economic Development is targeting an investment in the sector of €10 billion, from European public funds and private investments. Funding will be divided between hydron production, distribution and consumption facilities, research and development and infrastructure to integrate production with end uses. • Italy has some projects in development to help achieve their 2030 goals. For example, the SoutH2 Corridor which aims to supply low-cost renewable hydrogen produced in Algeria and Tunisia to European demand clusters. However, relative to other European nations their progress in policy is slow.

Country	Policy	Progress	Rationale
Netherlands			• The National Hydrogen Strategy published in 2020 set a target electrolyser capacity of 500 MW by 2025, 4 GW by 2030 and 8 GW by 2032. Their key areas of focus are storage, trade and infrastructure. Appx. 90% of their hydrogen demand is expected to be imported, amounting to 18 million tonnes per year. • They have made significant progress on policy and are on track to achieve their 2030 targets. Construction has commenced on a 1,200km hydrogen pipeline network with the first 30km section to be operational by 2025. • The Netherlands have allocated €7 billion for the development of renewable hydrogen, €300 million of which is specifically allocated to facilitating the import of renewable hydrogen. Government has increased its financial support for green hydrogen initiatives. In October 2024 they launched a €1 billion subsidy auction covering investment and operational costs for large-scale renewable hydrogen projects for 5 to 10 years. In April 2025, government announced a €2.1 billion subsidy to bolster renewable hydrogen production.
Norway			• Norway's National Hydrogen Strategy was introduced in June 2020. The strategy emphasises both green hydrogen and blue hydrogen from CCS and has a broad mandate surrounding the deployment and use of hydrogen domestically. Norway has no clear capacity targets for production or electrolyser capacity. According to their strategy, they aim to be a significant supplier of low-carbon hydrogen to Europe, however this is considered a long-term goal, and they have not published any targets for import or export volumes. • There is no clear funding mechanism specifically for the support of renewable hydrogen.
Portugal			• Portugal's National Hydrogen Study was published in 2020 with an ambition of 2.5 GW of installed capacity in electrolysers. More recently, in July 2023, the Portuguese Government presented a proposal to the European Commission to revise the National Energy and Climate Plan 2030, calling for an increase in the installed capacity of electrolysers in 2030 to 5.5 GW. • Approx €7 billion in funding has been allocated to the deployment of hydrogen and they have numerous projects already in place. Portugal's hydrogen projects include H2Med, alongside Spain, the Sines Refinery project, the Portuguese hydrogen backbone and project H2Evora which is Portugal's first commissioned solar-to-hydrogen project, using 15 solar hydrogen generators to produce an estimated 15 tonnes of renewable hydrogen per year.
Spain			• Spain introduced their hydrogen strategy in 2020 with a target of 4 GW by 2030. They updated their hydrogen strategy in 2024 and trebled their hydrogen target from 4 to 12 GW illustrating how significantly their domestic hydrogen ambitions have increased. Spain's strategy heavily focuses on their ambitions to export hydrogen, although they have not explicitly set a target for how much hydrogen they plan to export. • Similarly, Spain's investments in hydrogen infrastructure have been largely focused on export infrastructure. • Spain is making significant progress to achieving their goals, with Projects, such as the H2med project which will interconnect hydrogen networks from the Iberian Peninsula to Northwest Europe from 2030. However, there is room for improvement in terms of available funding mechanisms and business models to support uptake.
Sweden			• The Swedish energy agency introduced the Swedish hydrogen strategy in 2020, with plans of electrolyser capacity of 5 GW by 2030, and 15 GW by 2045. The energy agency has proposed a target of 22-42 TWh of renewable hydrogen production by 2030 and 44-48 TWh by 2045. • There are currently a number of major industrial projects in Sweden, where the production and use of hydrogen is, or is planned, to be central to one or more new value chains. However, there are no government funding programmes or initiatives that are directly related to the uptake of hydrogen and development of hydrogen infrastructure to progress their stated targets.
Turkey			• Turkey published their national hydrogen strategy and roadmap in 2023. The strategy has detailed targets of 2GW electrolyser capacity by 2030 and 5GW by

Country	Policy	Progress	Rationale
			2035, and 70 GW by 2053, although they have no specific policy or targets for hydrogen import. • Turkey is pursuing several hydrogen production projects to meet their production targets. However, the capacities of the projects in active development are relatively low in comparison to their targets they have set, meaning progress is present but slow. In addition, there is evidence of some funding mechanisms to support the development of hydrogen technologies, but no significant government funding mechanisms.
United Kingdom			• The UK has robust hydrogen plans and aims for hydrogen to account for 20-35% of its energy needs by 2050, with 10 GW of low carbon hydrogen by 2030 with 6 GW from renewable hydrogen. Their strategy is supported by the Hydrogen Production Business Models. Business models for the transport and storage of hydrogen are in development and due to open in 2026. • The UK government have not set any official targets for the import of hydrogen, as it is assumed that domestic production will be enough to facilitate domestic demand at this stage. • The UK has made significant progress in the progression of their hydrogen strategy. They are actively developing their hydrogen infrastructure across production, transportation and storage. HAR1 projects expected to be operational between 2025 and 2026. The UK government intends to support up to two large-scale hydrogen storage projects and associated regional pipelines by 2030, as part of its broader strategy to develop hydrogen infrastructure.

Based on the evaluation of the individual countries, Northwest Europe presents the greatest potential demand for Irish hydrogen. Germany, UK, Belgium, France and the Netherlands are the most relevant countries for further exploration; these countries have clear hydrogen strategies, funding initiatives, and relatively high domestic demand for renewable hydrogen in comparison the other countries, making them ideal markets for Irish exports. Geographically, these countries are strategically located to facilitate direct transportation routes for Irish hydrogen, making them more viable logistically in comparison to other European regions. The proximity of these markets to Ireland thus strengthens their potential as recipients for hydrogen exports.

The hydrogen developments in Mediterranean countries show that they will be serving as conduits for the transportation of hydrogen as opposed to being primary markets for Irish hydrogen, and that they are likely to use hydrogen produced in North Africa. For example, hydrogen infrastructure development in Spain shows a focus on the country serving as a conduit for hydrogen exports through projects like the H2Med initiative, which is a transnational project aiming to connect hydrogen networks from the Iberian Peninsula to Northwest Europe by 2030. Similarly, Italy is developing hydrogen infrastructure to transport hydrogen and its derivatives from North Africa (Algeria and Tunisia) to demand clusters in Germany through the SouthH2 corridor project.

Exporting hydrogen to Scandinavian countries would be challenging due to the absence of direct pipeline connections. Building a dedicated pipeline would be expensive, and shipping hydrogen across this distance would be less economically viable due to costs, logistical constraints and uncertain demand.

Additionally, countries like Norway, Denmark, Portugal, Spain and Poland are positioning themselves as potential hydrogen exporters in Europe, with their strategies involving leveraging renewable energy sources. The Netherland and France, particularly included for their access into the European core network, can also be seen as hydrogen exporters; however, these have been included in our shortlisted countries. Despite the Netherlands ambitions to be a hydrogen exporter, its critical role in hydrogen infrastructure and its position as a hydrogen hub for northwest Europe, make it a highly relevant market for Irish hydrogen exports. Similarly, France aims to scale up domestic renewable hydrogen production and thus could be seen as a potential exporter, but its future position in cross border hydrogen trade, and its proximity to Ireland make it a valued export opportunity. Furthermore, France is the nearest location for an export pipeline from Ireland to connect directly to the European Hydrogen Backbone (EHB), providing access to the largest import demand market in Europe, namely Germany. These factors will be further explored in section 5.4 where we provide a more detailed analysis of our shortlisted countries.

Table 8: Summary of RAG assessment of European countries

Import Country	Policy Support	Progress in Policy Objectives
Belgium		
Croatia		
Denmark		
Finland		
France		
Germany		
Greece		
Italy		
Netherlands		
Norway		
Portugal		
Spain		
Sweden		
Turkey		
United Kingdom		

Table 8 summarises the RAG ratings for the assessed European countries. We have shortlisted Germany, the Netherlands and Belgium as export destinations. Beyond being potential consumers of Irish exported hydrogen (or derivatives), both Belgium and Netherlands offer capability to act as intermediaries for further transport to Germany. GB and France, although not expected to import Irish hydrogen, are also shortlisted as their hydrogen infrastructure development plans would support the transit of Irish hydrogen to the three selected export destinations.

5.4 Shortlisted countries

5.4.1 Germany

Production

Germany's National Hydrogen Strategy[20] was updated in 2023, doubling its original target of 5 GW of domestic electrolyser capacity to 10 GW by 2030. This reflects a strong commitment to scaling up domestic renewable hydrogen production. While the long-term aim is to maximise domestic output, the strategy acknowledges that large-scale imports will be essential to meet future demand.

Demand

Germany's hydrogen demand is projected to grow significantly—from 95–130 TWh in 2030 to 360–500 TWh by 2045, alongside an additional 200 TWh of synthetic hydrocarbons and derivatives.

[20] Update to the National Hydrogen Strategy, Federal Ministry for Economic Affairs and Climate Action (BMWK), July 2023

The 2030 demand includes both pure hydrogen and derivatives like ammonia and methanol, with emerging demand estimated between 40–75 TWh, plus an existing industrial demand of 55 TWh (approx. 1,500 ktpa).

Sector-specific projections for 2045 include:

- Chemical industry: up to 240 TWh, primarily for ammonia and methanol production.
- Refineries: potential shift to 3.6 TWh of renewable hydrogen.
- Steel industry: up to 93 TWh as hydrogen replaces coal-based processes.
- Transport: up to 89 TWh.
- Heating: up to 58 TWh.

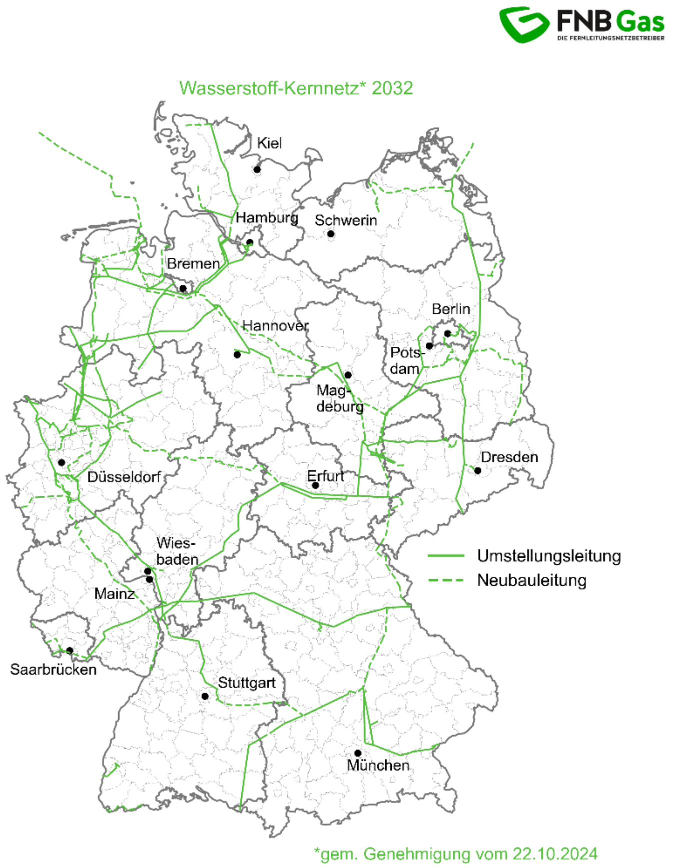

Figure 6: Hydrogen Backbone by 2050 (FNB GAS)

Network Development

Germany has taken tangible steps to support hydrogen infrastructure development, with a major milestone reached in October 2024 when the Federal Network Agency approved plans for a 9,040 km national hydrogen core network. This network, largely repurposed from existing gas infrastructure, is scheduled for completion by 2032 at an estimated cost of €18.9 billion. The network will prioritise connectivity with ports, industrial clusters, and cross-border interconnectors, creating favourable conditions for importing hydrogen and its derivatives.

While Germany aims to maximise domestic renewable hydrogen production in the long term, the strategy acknowledges the necessity of large-scale low-carbon imports to meet demand.

The German Hydrogen Import Strategy[21], published in July 2024, anticipates that by 2030, 50–70% of hydrogen demand will need to be met through imports, with this share expected to rise further beyond 2030.

The strategy outlines a structured approach to sourcing hydrogen and its derivatives from abroad, focusing on four key import corridors:

North Sea Corridor

- Targets imports from Denmark, Norway, the UK, the Netherlands, and Belgium.
- Gasunie (Netherlands) and Energinet (Denmark) join forces for international hydrogen network between the Germany, Denmark and Netherlands[22]
- In January 2023, Equinor (Norway) and RWE (Germany) signed an MoU to develop large-scale hydrogen value chains[23]. However, the project was put on hold in September 2024 due to slower-than-expected demand growth.
- A feasibility study for a direct pipeline between Germany and the UK was published in 2025, conducted by Arup[24].
- Plans include four German-Dutch interconnectors and one German-Belgian interconnector to be developed by 2032.
- Germany also anticipates ship-based imports via Belgium and the Netherlands.

Baltic Sea Corridor

- Includes the offshore “Baltic Hydrogen Collector”[25] and the onshore “Nordic Baltic Hydrogen Corridor”[26].
- Designed to connect Germany with Poland, the Baltic States, and Finland.

Southwest Corridor (Iberian Peninsula)

- Based on the EU Project of Common Interest (PCI) called “H2Med”[27].
- Connects Germany through France with Spain.

South Corridor (North Africa)

- Primarily consists of repurposed pipelines linking Germany with North Africa via Italy and Austria.
- This corridor is part of the “SoutH2” EU infrastructure project, which achieved PCI status in April 2024[28].

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[21] Import Strategy for Hydrogen and Hydrogen Derivatives, Federal Ministry for Economic Affairs and Climate Action (BMWK), July 2024

[22] Press release: Gasunie and Energinet join forces for international hydrogen network. November 2024

[23] Equinor and German energy major RWE to cooperate on energy security and decarbonization, Equinor, January 2023

[24] UK-Germany joint study on the trade of hydrogen, Arup, Dena and Adelphi, April 2025

[25] Baltic Hydrogen Collector (BHC), Gasgrid Finland Oy and Nordion Energi AB

[26] NBHC Pre-feasibility study results summary, Ontras et al., December 2024

[27] H2medproject.com

[28] Southh2corridor.net

Funding

The German Government has announced public funding allocations along the full hydrogen value chain. €7 billion is to be allocated into building a domestic renewable hydrogen production, with around €2 billion for international partnerships supporting the national import strategy[29]. The investment costs of the hydrogen core network are estimated at about €19 billion and financed with help of an amortisation finance model by the German funding bank KFW[30]. Additionally, Germany continues to invest in demand stimulation through frameworks for decarbonising basic materials industries and allocate funding for operational costs, which may create stable long-term offtake opportunities through a funding scheme called Carbon Contracts for Difference (CCFDs). The first allocation round of CCFDs was launched in March 2024 with a budget of up to €4 billion[31]. Fifteen projects were selected to receive a total of up to €2.8 billion[32].

The implementation of hydrogen applications is mainly envisaged in the industrial sector (such as steel and chemicals), transport and energy.

Other than Federal Government funding German projects can compete with European projects and win European funding, as for example, two renewable hydrogen production projects recently won support from the European Hydrogen Bank, one being near the Baltic Sea[33].

In July 2024, as part of the "Hy2-Infra Welle", the Federal Government together with State Governments of Germany announced €4.6 billion funding for 23 IPCEI (Important Projects of Common European Interest) projects in transport, storage and production of renewable hydrogen with additional €3.3 billion invested by the companies. Most projects are located in the north-west of Germany in proximity to the North Sea and neighbouring countries such as the Netherlands and Belgium. The funded projects cover the entire hydrogen value chain and have a particular focus on the interaction of projects to make the development of hydrogen clusters possible[34]. Furthermore Fertiglobe, the first winner of the German BMWK funded H2Global pilot auction, will import renewable ammonia from Egypt to European ports from 2027.

Relevance for Ireland: Germany's scale of demand, strong political commitment to imports, and emphasis on maritime supply routes make it the most strategically aligned partner for Irish hydrogen exports. Germany's National Hydrogen Strategy highlights potential import routes that Ireland can utilise. The demand for imported hydrogen and its derivatives is projected to be substantial by 2030, with further significant growth anticipated. The import strategy highlights the critical need for securing dependable and diversified supply routes through both pipeline and maritime infrastructure. Germany's strategy emphasizes a robust pipeline network with extensive connections to potential maritime import locations such as the Netherlands and Belgium and onshore connections to possible hydrogen production hubs in Spain and North Africa. This is an important consideration for potential exporters like Ireland.

5.4.2 GB Mainland

Production

The United Kingdom continues to make significant strides towards establishing a hydrogen economy. According to the UK Hydrogen Strategy[35] released in 2021, the nation is committed to achieving 5GW of low-carbon hydrogen production by 2030. The Department for Energy Security and Net Zero (DESNZ) has since expanded this goal, outlining in its Hydrogen Production Delivery Roadmap[36] from 2023 an increased target of up to 10GW of low carbon hydrogen production by 2030.

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[29] Update to the National Hydrogen Strategy, Federal Ministry for Economic Affairs and Climate Action (BMWK), July 2023

[30] Bundesnetzargentur.de

[31] Funding programme for carbon contracts for difference, Federal Ministry for Economic Affairs and Climate Action (BMWK), March 2024

[32] Habeck übergibt erste Klimaschutzverträge: 15 Transformationsprojekte können starten, Federal Ministry for Economic Affairs and Climate Action (BMWK), October 2024

[33] Wasserstoffbank fördert 15 Projekte, European Commission, May 2025

[34] Hy2Infra, Federal Ministry for Economic Affairs and Climate Action (BMWK), July 2024

[35] UK Hydrogen Strategy, Department for Energy Security and Net Zero, August 2021

[36] Hydrogen Production Delivery Roadmap, Department for Energy Security and Net Zero, December 2023

Other than green hydrogen produced using renewable resources, the UK emphasises the usage of so called "low carbon hydrogen" including hydrogen produced from natural gas by using carbon capture and storage (CCS) to achieve its goal. By 2030 6GW of low-carbon hydrogen production capacity is expected to be electrolytic, with 4GW of CCS-enabled hydrogen production.

The latest Hydrogen Strategy Update to the Market[37], published in December 2024, reaffirmed national ambitions for 10GW while indicating upcoming policy developments, including the launch of funding windows for Hydrogen Transport and Storage Business Models in 2025. These will underpin the rollout of regional infrastructure and aim to support up to two storage projects by 2030. Additionally, Scotland's 2024 Hydrogen Action Plan[38] outlined its intent to become a major renewable hydrogen producer and exporter by 2045, targeting 3.3 million tonnes of annual production.

Demand

The United Kingdom expects a significant increase in future demand for hydrogen. The demand is categorised by industry, power, heat in buildings, and transport. Government analysis projected that by 2035, the British industry could use 25-55 TWh of hydrogen, the power sector 5-30 TWh, heat in buildings 0-60 TWh, and transport 20-30 TWh. This amounts to an estimated requirement of up to 175 TWh. By 2050, it is expected to rise to 250-460 TWh of low-carbon hydrogen, representing 20-35 percent of the UK's final energy consumption.

Network Development

National Gas's Project Union has set out a plan to repurpose existing gas transmission pipelines and build 1,500-2,000km of new pipelines to create the GB national hydrogen backbone, and this is shown in Figure 7. National Grid state that they anticipate the first phases to be operational by the early 2030s to facilitate the transportation of 100% hydrogen. It aims to develop hydrogen transmission pipelines that would connect the main industrial cluster sites across GB.

As of July 2025, Project Union has not yet received funding approval. However, Cadent's HyNet hydrogen pipeline project near Burton Point received funding for FEED studies in 2021[39], and East Coast Hydrogen, connecting Teesside and Humber, received funding for FEED studies in June 2025[40].

Consequently, Irish hydrogen could be imported to continental Europe via pipeline, using interconnectors as starting points. The GB-Ireland gas interconnectors could be repurposed for this purpose. The hydrogen would be transmitted through Britain and then transported either by pipeline to the Netherlands or Belgium to reach the hydrogen offtakers in continental Europe. The hydrogen network of Great Britain would function as a conduit for Irish hydrogen, (or even also supply Great Britain if desired). In December 2023, GB's National Gas entered into a Memorandum of Understanding (MoU) with the Belgian gas network operator Fluxys to enhance their collaboration on decarbonisation infrastructure[41]. This initiative aims to leverage North Sea energy resources, such as offshore wind and hydrogen production, while also supporting carbon capture, usage, and storage (CCUS) technologies. The agreement includes considerations for developing a potential hydrogen connection along the existing Bacton to Zeebrugge pipeline route.

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[37] Hydrogen Strategy Update to the Market, Department for Energy Security and Net Zero, December 2024

[38] Hydrogen action plan, Energy and Climate Change Directorate, December 2022

[39] UK's hydrogen and CCS project HyNet North West has received £72m funding, Offshore Energy, April 2021

[40] UK Hydrogen Pipeline Network Gets Green Light for Next Phase, Pipeline and Gas Journal, June 2025

[41] Fluxys Belgium and National Gas join forces on large-scale decarbonisation and explore new cross-border links, Fluxys, December 2023

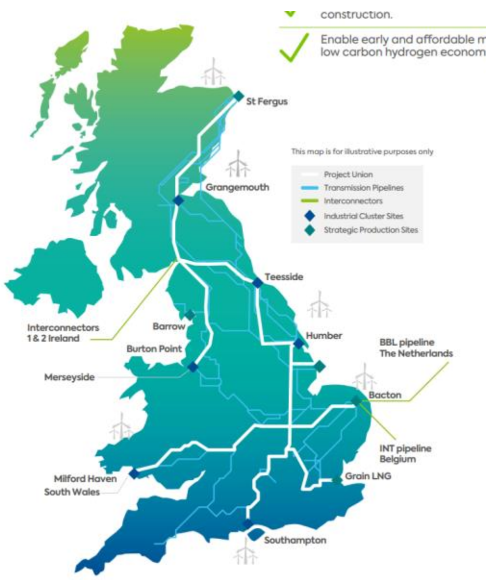

Figure 7: National Gas project "Project Union" to repurpose existing/build new transmission pipelines to create a hydrogen backbone by 2050 (FutureGrid Phase 1 Closure Report July 2024)

The gas interconnectors IC1 & IC2, between GB and Ireland, are the only pipeline connections for importing natural gas to Ireland. These interconnectors are of critical importance for Ireland's energy security and are unlikely to be repurposed soon. In 2024, the UK Government established the National Energy System Operator (NESO), a publicly owned body responsible for whole-system energy planning[42]. NESO will take charge of hydrogen transport and storage infrastructure planning as part of the Strategic Spatial Energy Plan (SSEP) from 2026, potentially paving the way for coordinated infrastructure planning across borders.

Funding

The UK Government provides production funding via Hydrogen Allocation Rounds (HAR) for non-CCUS enabled projects. Eleven projects of the first allocation round (HAR1) were confirmed in 2024, comprised £90 million in capital grants through the Net Zero Hydrogen Fund (NZHF) which provides support for the development and construction of new low carbon hydrogen production plants. The projects are expected to deliver a total of 125 MW electrolytic production capacity by the end of 2026.

In the latest funding round (HAR2), 27 projects were shortlisted in April 2024 for due diligence assessment. HAR2 aims to unlock 875MW of electrolytic hydrogen production capacity before 2029, which confirms a healthy pipeline of non-CCUS enabled projects in the UK.

The UK Hydrogen Strategy focuses on domestic low-carbon hydrogen production targets to avoid an over-reliance on hydrogen imports. The role of hydrogen imports is briefly mentioned as a possible addition to the hydrogen economy in the long-term. However, latest developments show, that British energy suppliers do see imports as a possible long-term solution. In June 2025, Centrica signed a £20 billion agreement with Norwegian state-owned energy company Equinor to import five billion cubic meters of natural gas to GB through 2035. The agreement includes a mechanism allowing Centrica to eventually replace some or all of the gas volumes with low-carbon hydrogen[43]. Centrica is already developing hydrogen-ready gas plants, including a 100MW project in Lincolnshire[44].

[42] Designation of the National Energy System Operator (NESO), Department for Energy Security and Net Zero and Ofgem, September 2024

[43] Britain's Centrica agrees $27 billion deal to import gas from Norway, Reuters, June 2025

[44] Centrica starts construction of UK hydrogen-ready power plant, H2 View, May 2024

Relevance for Ireland: GB Mainland is a strategically viable partner, particularly in the context of evolving regulatory convergence, geographic proximity, and existing energy trade ties. There is potential for bilateral cooperation on infrastructure development. Given the geographic proximity and existing energy interconnections between Ireland and Great Britain, this offers scope for coordinated hydrogen export/import corridors or integrated storage and balancing arrangements. The GB Mainland is positioning itself to be a hydrogen exporter to continental Europe. In the long-term plans published by the government, hydrogen import is either not mentioned or briefly referred to as a potential future opportunity once an import market has developed. The UK does not currently have an import strategy. However, some energy companies like Centrica include hydrogen as an optional development in their long-term supply contracts. It is possible that the UK could act as a conduit for Ireland to access the continental European hydrogen market, given the existing interconnectors between GB Mainland and continental Europe.

5.4.3 France

Production

France published an updated National Hydrogen Strategy in April 2025[45]. The revised plan lowers the 2030 electrolyser capacity target from 6.5 GW to 4.5 GW, while introducing an 8 GW target for 2035, and reiterates France's intention to meet demand solely through domestic production until at least that time. France values domestic hydrogen production as a strategic asset for national energy security, and it is affirmed as a key enabler for decarbonising and maintaining strategic industries, refining, fertilizers, basic chemicals, steel and heavy-duty transport. France has now designated four strategic industrial hubs for hydrogen production which are key nodes for chemicals and energy-intensive industries, down from seven in the previous strategy, as shown in Figure 8.

These industrial hubs include Dunkirk, which will be a major consumption hub for steelmaking and logistics with strong European connectivity, Fos-sur-Mer, which is home to petrochemical and refining clusters, Le Havre, and the "Vallée de la Chimie" in Lyon.

Demand

France's revised strategy highlights transport as a key growth sector for hydrogen, with projected demand reaching 150 to 180 kilotonnes per year (ktpa) by 2030. This reflects strong momentum in aviation, maritime, and heavy-duty road transport, where hydrogen offers a viable decarbonization pathway. While industry also shows significant demand potential - estimated at 55 to 190 ktpa - its uptake is more variable and dependent on sector-specific transitions. Refineries, supported by regulatory incentives like TIRUERT, are expected to require 115 to 150 ktpa. To meet these targets through water electrolysis, France anticipates an electricity requirement of 20 to 30 terawatt-hours (TWh) and plans to deploy 4.5 GW of electrolyser capacity by 2030.

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[45] Stratégie nationale de l'hydrogène décarboné 2025, Ministère de l'économie, April 2025

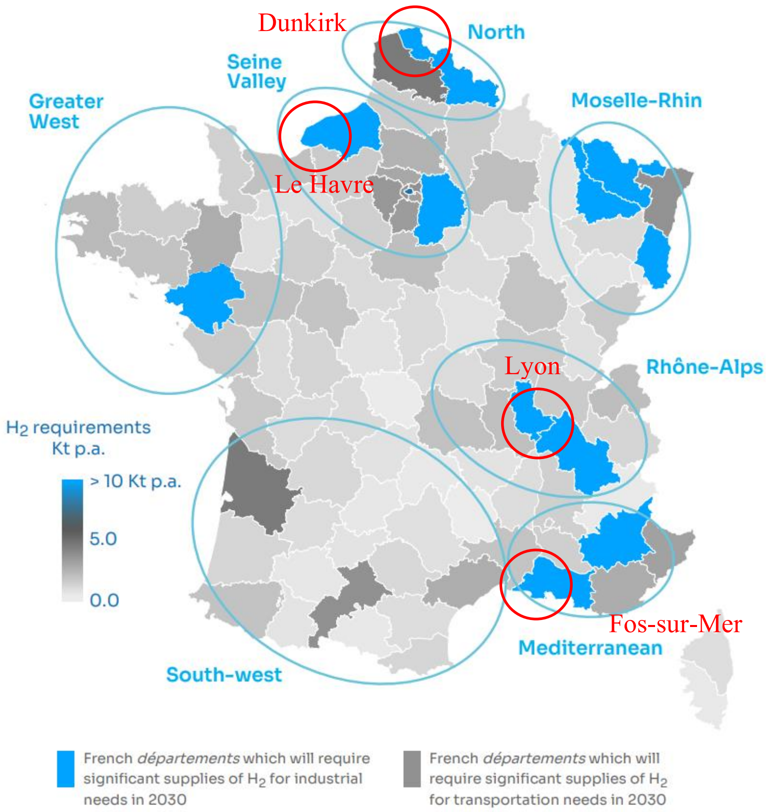

Figure 8: The 7 hydrogen clusters designated in the French Roadmap to Hydrogen in 2021[46]. Red marked are the focused clusters of the revised strategy in 2025.

Network Development

France positions hydrogen export as strategic priority. Its specific geographical location, between countries with large renewable energy resources which are capable of very large-scale (and cheap) renewable hydrogen production (Spain, Portugal, North African countries) and northern European countries with a very large appetite for low-carbon or renewable hydrogen (Germany, the Netherlands) could make it into a transit country for hydrogen produced in the south of Europe going to consumers in the north of Europe.

The French hydrogen transportation infrastructure is planned to become part of the greater European Hydrogen Backbone (EHB).

Figure 9 highlights some of the infrastructure projects currently planned to connect French offtakers and production with the neighbouring countries. A connection from Ireland to Le Havre (not shown in this figure but can be seen later as part of the European Hydrogen Backbone in Figure 21 may be an option to connect Irish exports to the German market via the EHB.

[46] A road-map for an ambitious Hydrogen strategy, France Hydrogène, September 2021

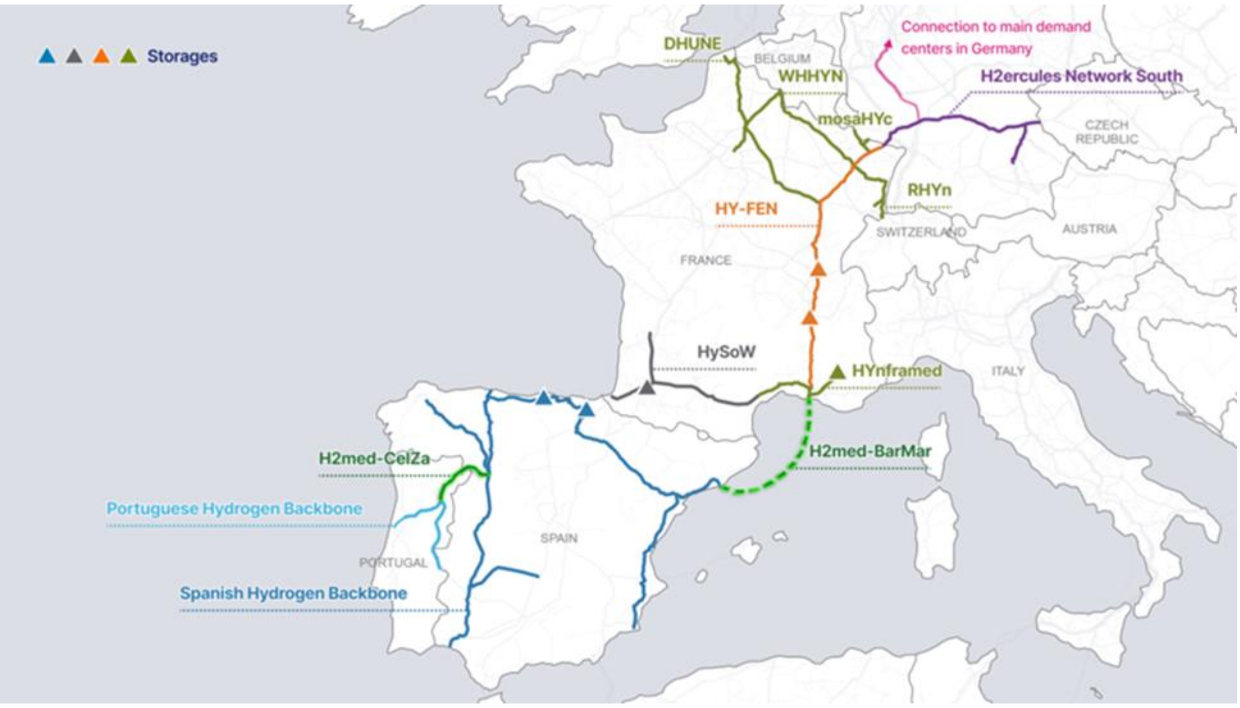

Figure 9 Planned hydrogen transportation infrastructure projects in and around France (H2med - Hydrogen corridor)

The H2med and Hy-Fen corridor is designed to secure Europe's energy supply by transporting around 10% of the total hydrogen consumption forecast for Europe by 2030. Of the 20 million tons of hydrogen expected to be consumed annually in Europe in 2030, this corridor aims to transport 2 million tons by 2030. Feasibility studies launched in June 2024 for HyFen connecting France and Germany. H2med projects are on the list of EPCI since 2024 and received European funding for over €35 million in January 2025. It's planned that this pipeline network will connect Spain via Marseilles and Lyon to Obergailbach in Germany by 2030. These projects aim to connect production areas of affordable clean hydrogen in the South region (mainly from solar resources) to the main areas of consumption in Northwest Europe. An advancement in France's hydrogen transportation infrastructure would also ensure French consumers would have access to low-cost hydrogen[47].

The development of large-scale hydrogen transport and storage infrastructure is recognised in France's hydrogen strategy as essential - particularly to ensure electrolysers contribute to greater flexibility in the electricity system. The target of 500 km of hydrogen pipelines by 2030 marks a first step. France has revamped its regulatory framework through the Green Industry Act[48] and the Renewable Energy Acceleration Law[49]. These measures are planned to cut environmental permitting timelines in half and streamline land-use approvals for electrolyser sites and hydrogen infrastructure as well as prioritise fast-track access to grid connections for hydrogen-related projects.

Despite this emphasis on self-sufficiency, the strategy recognises slow progress in market development and the need to support the entire hydrogen value chain, from manufacturing electrolysers to deploying grid-based electrolysis and developing infrastructure hubs.

Funding

The French hydrogen strategy features three priorities: decarbonise the industry, develop hydrogen mobility, support research, innovation and capacity building. It initially earmarked €7.2bn until 2030, including €2bn from the recovery plan launched in 2020.

[47] H2med - Hydrogen corridor

[48] Green Industry Act, Frensh Government, October 2023

[49] Renewable Energy Acceleration Law, Frensh Government, March 2023

Of this €9bn envelope about €6.8bn are allocated to industrial decarbonisation, €1.35bn to transport and €800m to research and development. One year later, the hydrogen plan received an additional €1.9bn from the France 2030 plan, including €1.7 bn dedicated to financing Important Projects of Common European Interest (IPCEI)[50].

As part of the €9bn fund, the government will spend €4bn on subsidies (in the form of contracts-for-difference style auction) to support the deployment of 1 GW of electrolyser hydrogen production over the next 3 years. The first tender was for 150 MW (with the possibility of extending this to 180 MW), with a second 250 MW tender in 2025 and a final 600 MW tender in 2026. The first tranche was launched in December 2024[51].

Upstream, a dedicated Priority Research Program and Equipment (PEPR) allowed for the allocation of €83m to 19 projects covering the entire value chain; production (low and high-temperature electrolysis, photo-electrocatalysis), storage (in solid, gas, and liquid forms), and end-use (proton exchange membrane fuel cells or PEMFC, solid oxide fuel cells or SOFC, etc.). The "Technological Bricks and Large Demonstrators" call, with €350 million from the Future Investment Plan (PIA4), supports projects developing electrolysers, fuel cells, and their entire upstream value chain. To date, 35 projects have been supported.

Examples of hydrogen projects announced in France include the ZEV project in Auvergne-Rhône-Alpes and the H2 Corridor in Occitanie, both of which reflect France's progress in deploying hydrogen technologies. The Air Liquide Normand'Hy hydrogen electrolysis project, set to be operational in 2026, is currently the largest hydrogen project in France, aiming to build an electrolyser capacity of at least 200 MW. In total, 55 hydrogen projects have been announced, with this number expected to grow in the coming years, particularly within the seven geographical clusters identified in the national strategy.

Relevance for Ireland: France is unlikely to serve as an early large-scale export market for Irish hydrogen due to its domestic production emphasis, but its strategic location as part of the European Hydrogen Backbone (EHB) mean France could be an effective conduit to deliver Irish renewable hydrogen to key demand centres like Germany. Ireland and France are currently collaborating on the electrical Celtic Interconnector and in the long term a hydrogen pipeline interconnector could also be considered. Le Havre in France is geographically the closest point for Ireland to connect to a key node of the EHB and thus to continental Europe.

5.4.4 Belgium

Production

Belgium's hydrogen strategy[52], outlined in the 2022 Vision and Strategy Hydrogen update, emphasises the country's ambition to become a key gateway for hydrogen in Europe. One of its four strategic pillars is supporting research and pilot projects in hydrogen technologies. To this end, Belgium is investing in federal R&D initiatives such as the Energy Transition Fund and the Clean Hydrogen for Clean Industry program. The strategy acknowledges Belgium's limited electrolysis capacity due to its constrained local renewable energy potential. Nevertheless, the country aims to have at least 150 MW of electrolysis capacity operational by 2026, although no specific electrolyser targets have been set for 2030 or 2050.

Several major projects are underway to boost hydrogen production. The Hyoffwind project aims to build a power-to-gas facility capable of converting 25 MW of renewable electricity into green hydrogen, with potential scale-up to 100 MW, and has been submitted for IPCEI funding[53].

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[50] The French Hydrogen Strategy: Focusing on Domestic Hydrogen Production to Decarbonise Industry and Mobility, Climate and Energy at the Institute for Sustainable Development and International Relations (IDDRI), 2024

[51] 4 milliards pour la production d'hydrogène décarboné, France Hydrogène, September 2023

[52] Belgian federal Hydrogen Strategy Update, federal government of Belgium, October 2022

[53] Hyoffwind project, Hypop-project.eu, July 2024

Additionally, the CHYMIA[54] initiative is exploring the development of a 100 MW renewable hydrogen production plant in the Port of Antwerp. These efforts reflect Belgium's commitment to expanding its hydrogen production capabilities despite geographical and resource limitations.

Demand

The Belgian hydrogen strategy[55] identifies four major hydrogen demand sectors, with current demand estimated at approximately 15TWh[56]. The largest share is used in industry, particularly for ammonia production in Antwerp and Tertre. Other key sectors expected to drive initial demand include steel manufacturing, heavy transport, and eventually the power sector, which will rely on hydrogen for flexibility and to manage periods of low renewable energy availability. In the longer term, the building sector may also adopt hydrogen and its derivatives.

Total hydrogen demand in Belgium could potentially increase to 125–200 TWh by 2050, although the strategy lacks detailed projections on how each sector will contribute to this growth. The Belgian government anticipates that most domestic hydrogen needs will be met through imports, as importing hydrogen has been found to be more cost-effective than local production.

Belgium's strategy also outlines preferences for hydrogen forms based on sectoral needs and availability. It is expected that 30% to 60% of local demand will be for pure hydrogen molecules, while 40% to 70% will be for hydrogen derivatives such as ammonia, e-methane, e-methanol, and e-kerosene. For example, the steel industry will primarily require hydrogen in its gaseous form, whereas the shipping industry will depend on derivatives like ammonia, methane, and methanol.

Network Development

Belgium is taking proactive steps to develop a robust hydrogen transport network in line with its ambition to become a European import and transit hub. The country has identified three major hydrogen import routes in its strategy:

- The North Sea pipeline,
- The southern route via pipelines from Southern Europe and North Africa,
- The shipping route, which involves importing hydrogen derivatives by sea.

Belgium already possesses a well-established hydrogen transport infrastructure and is expanding it through strategic investments. The government has committed €95 million to develop 100–160 km of hydrogen pipelines by 2026. A key project is the "H2 Highway", connecting Zeebrugge and Brussels, with the first phase between Gent and Brussels commissioned in early 2024 and full commissioning expected by 2026. The strategy highlights the importance of Zeebrugge, which hosts an existing LNG terminal, and Antwerp, Europe's second-largest port, as critical maritime import hubs.

To strengthen cross-border connectivity, a Memorandum of Understanding was signed in 2023 between Fluxys and National Gas (GB) to explore a hydrogen interconnector along the existing gas pipeline between Bacton (GB) and Zeebrugge. In April 2024, Fluxys was appointed as the national Hydrogen Network Operator, and in July 2024, the energy regulator CREG released a methodology for valuing repurposed gas assets, facilitating rapid infrastructure deployment.

Further developments include a planned hydrogen interconnector with Germany, scheduled for completion by 2028, and a direct connection to the AquaDuctus offshore pipeline in the North Sea. Belgium is also participating in the Green Octopus project (2019–2030)[57], which aims to integrate hydrogen transport and

[54] Cluster Hydrogen for Mobility and Industry in Antwerp (CHYMIA), Plug Power, June 2022

[55] Belgian federal Hydrogen Strategy Update, federal government of Belgium, October 2022

[56] The role of clean gas in a climate neutral Belgium, climate change, hydrogen, carbon neutral, Deloitte and the Federal Public Service (FPS) Economy, May 2023

[57] HyFLOW/Green Octopus Grensoverschrijdende ecosystemen vanuit Vlaams-Nederlands perspectief, WaterstofNet, April 2021

market development across Belgium, Germany, and the Netherlands. Figure 10 shows a schematic of Belgian Hydrogen projects and network plans.

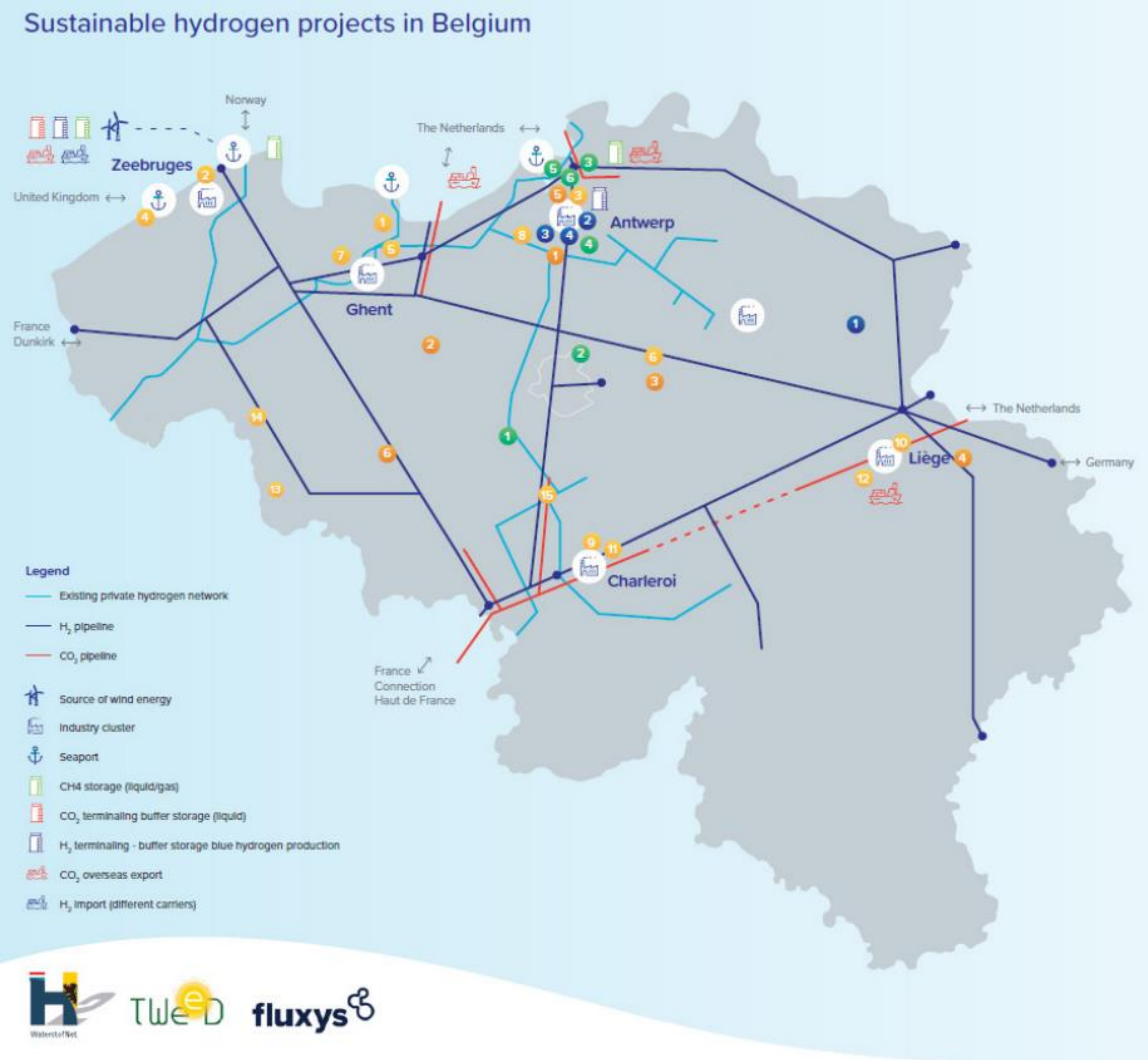

Figure 10: Map showing the geographical distribution of hydrogen projects in Belgium and the current and future infrastructure of hydrogen pipes (Vision and Strategy Hydrogen Update 2022).

Funding

To support the development of its hydrogen strategy, the Belgian Federal Government has committed up to €395 million to complement private investments in hydrogen infrastructure and innovation. This funding is aimed at accelerating the deployment of key projects and ensuring Belgium remains competitive as a hydrogen hub in Europe.

Among the initiatives seeking financial support is the Hyoffwind hydrogen project, which has been submitted for IPCEI (Important Projects of Common European Interest) funding. This project focuses on developing a power-to-gas facility capable of converting renewable electricity into green hydrogen, with potential for significant scale-up.

Additionally, the Port of Antwerp-Bruges has received Hydrogen Valley status, reinforcing its role as a central node in Belgium’s hydrogen ecosystem. The port has announced a commitment to import large volumes of sustainable hydrogen carriers and to expand infrastructure for converting these carriers into pure hydrogen, usable as both a raw material and a fuel.

Relevance for Ireland: Belgium's aspirations to become Europe's gateway for hydrogen and it's derivatives, coupled with its openness to low-carbon imports and well-developed port infrastructure (notably Antwerp and Zeebrugge), make it a strong candidate for re-export or transshipment of Irish hydrogen into continental Europe, which could form part of a broader northwest European export strategy. Belgium actively places itself as import hub but will also have some additional domestic hydrogen demand that could be fulfilled by imports.

5.4.5 Netherlands

Production

The Netherlands is positioning itself as a key producer of clean hydrogen, leveraging its offshore wind potential and existing oil and gas infrastructure. The Dutch government outlined its hydrogen ambitions in the Dutch Climate Agreement (2019)[58] and the National Hydrogen Strategy (2020)[59], with a focus on developing hydrogen infrastructure, unlocking supply channels, cross-sector cooperation, and facilitating renewable hydrogen projects. The strategy sets a target of 4 GW of electrolyser capacity by 2030, increasing to 8 GW by 2032. The Dutch Hydrogen Roadmap (2022)[60] further refines these targets, aiming for 6–8 GW of domestic hydrogen production by 2030.

The national strategy excludes blue hydrogen and blending, instead emphasizing the full hydrogen value chain, including storage, trade, and infrastructure. The phased rollout includes:

- **2019–2021**: Initial deployment of renewable hydrogen projects.
- **2022–2025:** Development of demand and regional infrastructure, scaling up to 500 MW of electrolyser capacity.
- **2026–2030:** Massive scaling up of electrolyser capacity, with a target of 4 GW by 2030 as outlined in the National Hydrogen Strategy, and a more ambitious goal of 6–8 GW by 2030 according to the Dutch Hydrogen Roadmap. This phase also includes expansion of hydrogen storage and infrastructure.
- **Post-2030:** Focus on renewable offshore hydrogen, large-scale imports, and hydrogen use in steel, chemicals, refineries, electricity generation, and transport.

Key production projects include:

- **NorthH2 (RWE, Shell, Equinor):** Supplying 2–4 GW of renewable hydrogen by 2030 and 10 GW by 2040, with a pipeline from Eemshaven to industrial hubs in Northwest Europe.
- **Eemshydrogen (RWE):** 50 MW electrolysis capacity with potential for upscaling; funding granted in 2024.
- **Rotterdam:** Multiple facilities including Uniper (100 MW) and Shell (200 MW), though Shell's project is currently on hold and BP's H2-Fifty has been abandoned.

Demand

The Netherlands is the second-largest hydrogen consumer in the EU, after Germany, with an estimated 50 TWh of annual hydrogen use, primarily in refining and chemical production. Major demand clusters include:

- Steel production near Amsterdam
- Refineries in Rotterdam, a key petrochemical hub
- Industrial zones in Den Helder, Eemshaven, and Zuid Holland

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[58] National Climate Agreement, Dutch government, June 2019

[59] Dutch National Hydrogen Strategy, the Ministry of Economic Affairs and Climate Policy, March 2020

[60] Hydrogen Roadmap for the Netherlands, the Ministry of Economic Affairs and Climate Policy, March 2022

Hydrogen demand locations have been identified in Den Helder–Amsterdam, Eemshaven–Groningen, and Rotterdam–Zuid Holland. The Dutch government has set a 4% green hydrogen mandate for industry by 2030, reinforcing its commitment to decarbonizing industrial sectors.

Internationally, the Netherlands aims to become the low-carbon hydrogen hub of Northwest Europe, connecting exporters and domestic production with industrial demand centres. Alongside Belgium, the Netherlands is forecast to collectively provide 62% of the EU's hydrogen import target[61].

Network Development

As a major energy gateway with advanced port logistics and gas infrastructure, the Netherlands is actively developing its hydrogen transport network. The government supports a national hydrogen backbone, connecting industrial clusters with import and export corridors.

Key infrastructure projects include:

- Gasunie's €1.5 billion hydrogen network, linking the Netherlands with Germany and Belgium. Construction has begun, with the first segment operational by 2025[62].
- H2Sines.RDAM: Imports from Portugal (Sines) via liquid hydrogen, expected to be operational by 2028, with EU financial backing[63].
- Delta Rhine Corridor pipeline: Intended to transport hydrogen from Rotterdam to Germany but delayed from 2028 to the early 2030s due to infrastructure challenges[64].

In Den Helder, projects include:

- H2Gateway: Blue hydrogen production facility (min. 0.2 Mt/a) via H2Backbone (construction starts in 2027)[65].
- Zephyros: Maritime hydrogen hub with solar park, electrolyser, refuelling station, and hydrogen-electric vessels (2028)[66].
- LH2 Bunker Station: Liquid hydrogen storage (200 m³) for maritime use (2028)[67].

In Rotterdam, 11 production facilities are in development. The Port of Rotterdam has allocated 24 hectares on the Tweede Maasvlakte for hydrogen plants, branding it a "conversion park" to host large-scale facilities by 2030. However, infrastructure limitations and project setbacks (e.g., Shell and BP) have slowed progress. Figure 11 shows a schematic of planned hydrogen infrastructure in the Netherlands.

[61] Netherlands & Belgium could lead H2 imports in NW Europe, Hydrogen Europe, November 2023

[62] Dutch national hydrogen network launches in Rotterdam, Gasunie, June 2023

[63] Sines and Rotterdam together in the H2Sines.RDAM Project, Port of Rotterdam & Consortium (Shell, ENGIE, Vopak, Anthony Veder), December 2022

[64] Gasunie Delays Hydrogen Pipeline Network to 2033 Amid Permitting Hurdles, World-Energy, December 2024

[65] Hydrogen factory H2Gateway, Port of Amsterdam / H2Gateway Consortium, October 2020

[66] Zephyros: Maritime hydrogen hub, H2Hub Noord-Holland / Statkraft, July 2025

[67] LH2 Bunker Station: Liquid hydrogen storage, New Energy Coalition / Royal HaskoningDHV, October 2023

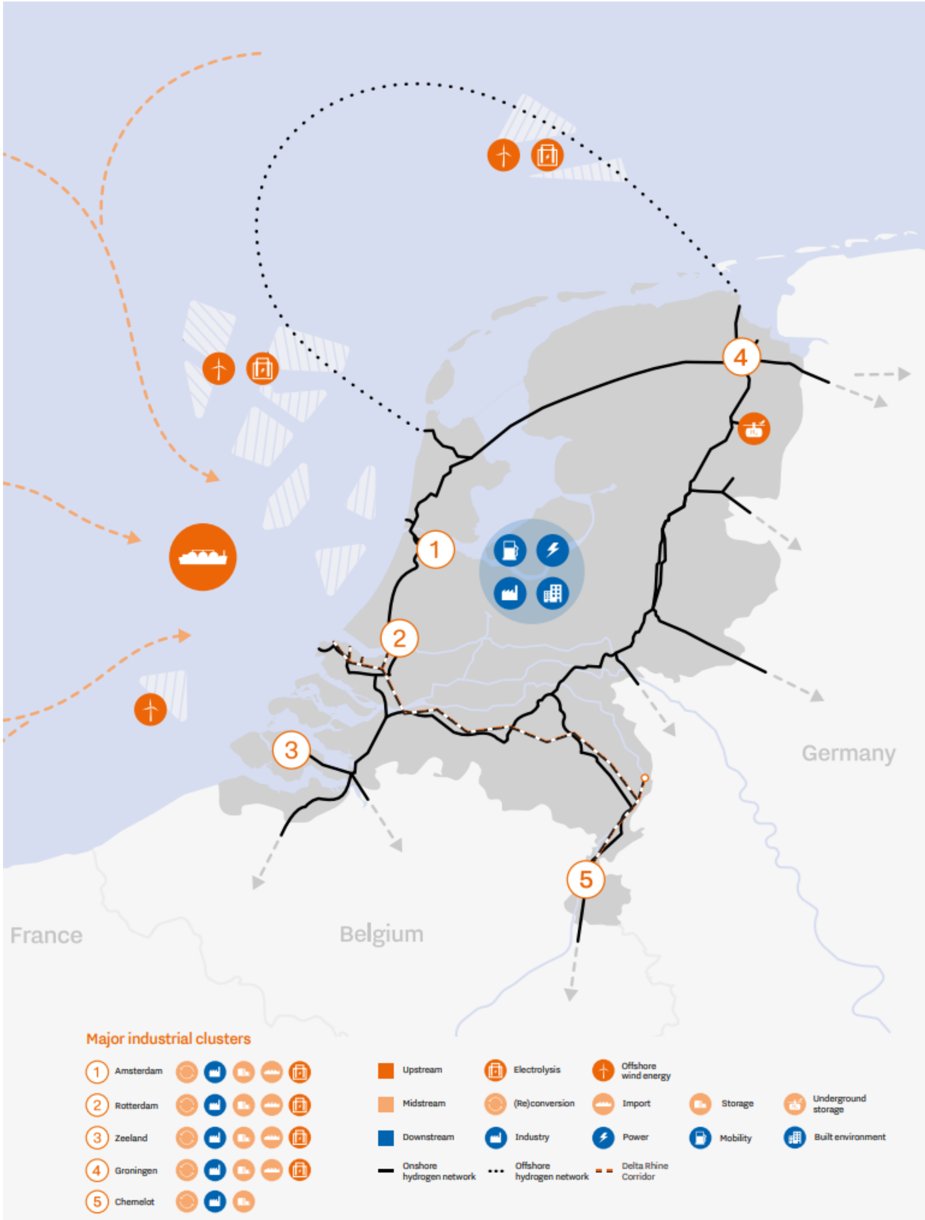


Figure 11: Possible future Dutch hydrogen grid connecting the industrial clusters with import and export corridors through the Netherlands

Funding

The Dutch government has committed substantial funding to support hydrogen development. In 2023, it announced €7.5 billion from a broader €28.1 billion climate fund, with most of the hydrogen funding directed toward domestic production capacity.

Key funding programs include:

- H2Global: Secures 10-year contracts for international hydrogen purchases and resale in the domestic market, covering both investment and operational costs[68].
- OWE Subsidy Scheme (2023): Allocates €998 million for large-scale green hydrogen production via electrolysis[69].

[68] Germany will work with H2Global to import green hydrogen products on a large scale from 2027, Federal Ministry for Economic Affairs and Climate Action (BMWK), July 2024

[69] Subsidy scheme for large-scale hydrogen production using an electrolyser (OWE), Netherlands Enterprise Agency (RVO), August 2024

- Green Growth Package (April 2025): Provides €2.1 billion for electrolyser projects over 0.5 MW, with operational support for 5–10 years, capped at €9/kg of hydrogen[70].
  - €662 million allocated to support hydrogen demand.
- SDE++ subsidy: Supports operational costs for renewable energy projects, including hydrogen[71].

In April 2024, the Dutch government awarded €250 million in subsidies to seven renewable hydrogen projects, totalling 101 MW of electrolytic capacity. Notable recipients include RWE's 50 MW Eemshydrogen and VoltH2's 50 MW plant in Delfzijl.

Relevance for Ireland: The Netherlands' ambition to serve as a key hydrogen import and transshipment hub for Northwest Europe, supported by its extensive port infrastructure in Rotterdam and Den Helder, and its integration into EU hydrogen corridors, makes it a strong candidate for re-export of Irish hydrogen into inland markets, particularly Germany. Its openness to low-carbon imports and strategic positioning within the European hydrogen backbone enhance its relevance to Ireland's broader export strategy.

While domestic Dutch demand is significant, particularly in refining and chemicals, the Netherlands' additional value to Ireland lies in its role as a logistics and distribution partner, facilitating access to continental demand centres through shared infrastructure and maritime connectivity.

5.5 Ireland Hydrogen Export Opportunity – Key Conclusions

Ireland is well-positioned to become a strategic exporter of renewable hydrogen within Europe, particularly as EU member states and neighbouring markets accelerate their hydrogen adoption and infrastructure development. Based on the country-level assessment, several key conclusions emerge:

- **Germany** stands out as the most strategically aligned export partner for Ireland, given its substantial projected demand, strong political commitment to hydrogen imports, and emphasis on maritime supply routes. Germany's National Hydrogen Strategy explicitly identifies import pathways that Ireland could leverage, and its integration with the European Hydrogen Backbone (EHB) enhances connectivity to broader continental markets. Germany is also a destination market for the renewable hydrogen derivatives ammonia and methanol, and H2Global is already funding a first ammonia import project.
- **Great Britain (GB Mainland)** offers a viable near-term opportunity, especially due to geographic proximity, existing energy interconnections, and potential for bilateral infrastructure cooperation. While the UK currently lacks a formal hydrogen import strategy, its evolving regulatory landscape and role as a potential transit hub to continental Europe could support Ireland's export ambitions.
- **Belgium** presents a strong opportunity for re-export and transhipment, thanks to its ambition to become Europe's hydrogen gateway, openness to low-carbon imports, and advanced port infrastructure. Its dual role as both a demand centre and logistics hub make it a valuable partner in a broader northwest European export strategy. It already is looking into a hydrogen interconnector to GB.
- **The Netherlands** as well as a potential consumer of Irish hydrogen, with its logistical capabilities, including storage, blending, and inland distribution, can be an important enabler of Ireland's access to continental demand centres. Shared infrastructure and industrial applications could further enhance export viability. Furthermore, Rotterdam is developing ammonia infrastructure to support the import of shipped e-ammonia.
- **France** is unlikely to be a primary offtake market in the short term, due to its focus on domestic hydrogen production. However, its location within the EHB and existing collaboration with Ireland on the Celtic Interconnector suggest long-term potential for pipeline-based hydrogen exports. Le Havre offers a geographically strategic connection point.

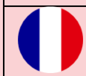
In summary, Ireland's hydrogen export strategy should prioritise partnerships with Germany, the Netherlands and Belgium for direct offtake and transhipment, while leveraging GB Mainland and France as strategic conduits and infrastructure collaborators. A coordinated approach across these markets will be essential to unlocking Ireland's full export potential and aligning with Europe's evolving hydrogen landscape.

[70] Netherlands commits €2.1 billion to green hydrogen, sets 4% industry mandate, Dutch Ministry for Climate and Green Growth, April 2025

[71] Sustainable energy production and climate transition subsidy scheme (SDE++), Netherlands Enterprise Agency (RVO), September 2024

Key export destinations which align with ambition in term of policy support and progression are **Belgium, Germany & Netherlands.**

Key transit countries have been identified as **United Kingdom** (Project Union) & **France** (European Hydrogen Backbone).

Key Export Destinations		**Comments**
	**Belgium**	• Aspires to be Europe's hydrogen gateway. • Strong port infrastructure (Zeebrugge, Antwerp) ideal for re-export. • Open to low-carbon imports; significant domestic demand. • Positions itself as a key import hub in NW Europe.
	**Germany**	• Largest demand scale in Europe; strong political commitment to imports. • Maritime routes prioritised in National Hydrogen Strategy. • Projected high import needs by 2030 and beyond. • Extensive pipeline links to Belgium, Netherlands, and southern Europe.
	**Netherlands**	• Positions itself as a key import hub in NW Europe. • Excellent port infrastructure (Rotterdam) ideal for re-export. • Close integration with German infrastructure development. • Appetite for green ammonia and methanol imports.
Key Transit Countries		**Comments**
	**United Kingdom**	• Mainland is a strategic partner due to proximity, regulatory alignment, and energy ties • Scope for joint infrastructure development and coordinated hydrogen corridors • UK could act as a conduit for Irish hydrogen exports to Europe via existing interconnectors
	**France**	• Strategic conduit via EHB to reach demand centres like Germany • Celtic Interconnector shows collaboration potential for future hydrogen links. • Le Havre is closest EHB access point for Ireland to continental Europe.

6. WP2: Technical Overview of Hydrogen Transport Vectors

6.1 Introduction

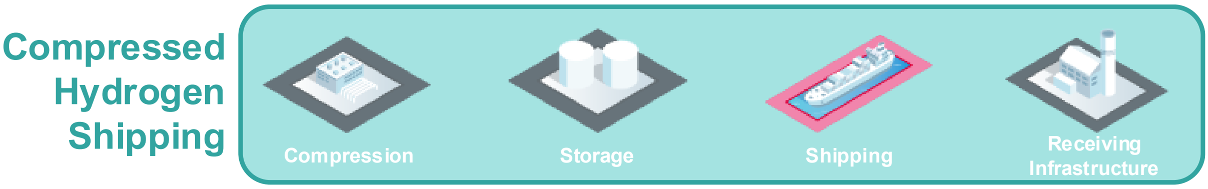
As the global transition to renewable energy accelerates, the efficient and safe transport of hydrogen becomes an essential focus for emerging energy economies. Multiple export pathways have been developed to move hydrogen from production sites to end-users across continents, each presenting unique opportunities and technical challenges. This study assesses potential export routes for hydrogen and its derivatives, focusing on both pipeline and maritime shipping options for transporting hydrogen from Ireland to continental European markets.

Pipeline alternatives for transporting gaseous hydrogen at normal transmission pressures (70-100 bar) include:

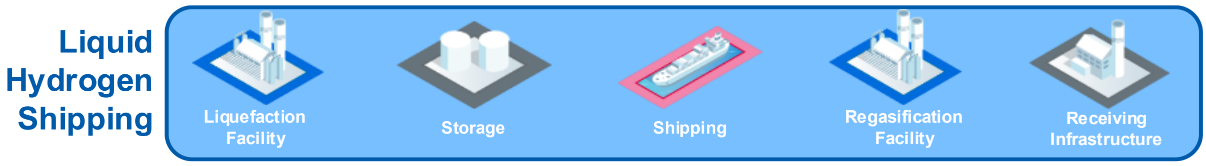
- **Repurposing Existing Natural Gas Pipelines**: Utilising existing natural gas pipelines for hydrogen transport may reduce costs and expedite implementation. However, technical challenges such as material compatibility, risk of hydrogen embrittlement, and differing pressure requirements necessitate detailed evaluation to ensure safe and reliable conversion. Other factors such as commercial availability, existing contractual commitments and security of supply considerations also need to be taken into account.

- **Construction of New Hydrogen Pipelines**: Developing new, dedicated pipelines tailored for hydrogen allows for optimal design, incorporating suitable materials and pressure ratings. This approach, while capital intensive, would facilitate large-scale, continuous exports and align with emerging European hydrogen infrastructure initiatives.

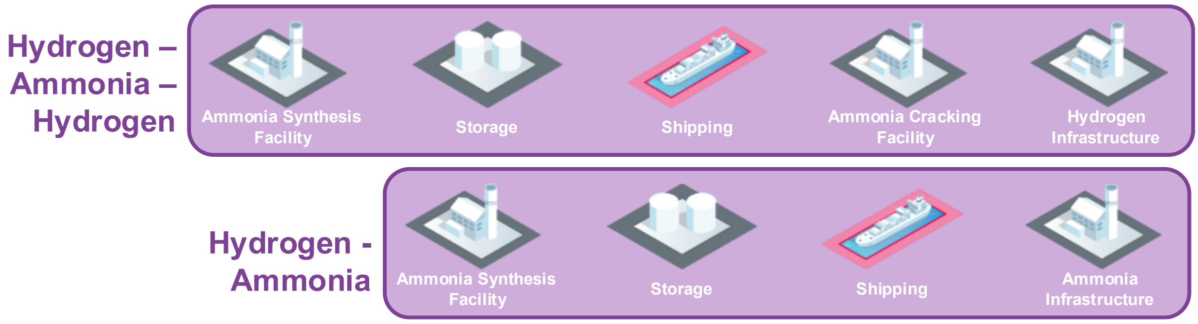
Maritime shipping alternatives include:



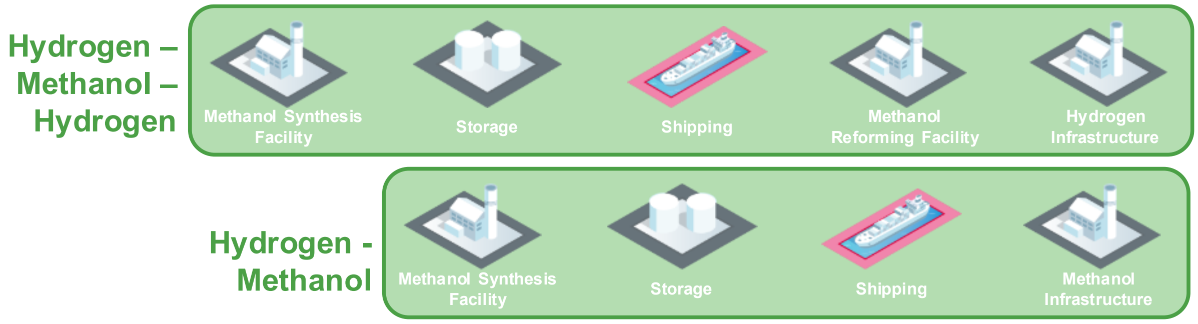
- **Compressed Hydrogen**: Suitable for short distances and modest volumes, compressed hydrogen in excess of 250-300bar can be transported using high-pressure tanks. Its low energy density, however, limits large-scale applicability.



- **Liquefied Hydrogen**: Hydrogen can be liquefied at -253°C, greatly increasing its energy density for bulk transport via specialised cryogenic ships. Liquefaction is energy-intensive and requires comprehensive thermal insulation.



- **Ammonia**: Hydrogen can be converted to ammonia, which is easier to store and ship, using established methods and can be converted back to hydrogen or used directly at the destination.



- **E-Methanol**: Produced by combining renewable hydrogen with captured carbon dioxide, e-methanol leverages existing infrastructure for transport and is in demand as a marine fuel and chemical feedstock and can be converted back to hydrogen or used directly at the destination.

A thorough evaluation of these vectors is essential to identify the most technically and economically viable export routes, supporting Ireland's ambition to play a significant role in European hydrogen markets and facilitating the broader energy transition.

The following sections provide a comprehensive technical overview of the main hydrogen transport vectors selected for this study – gaseous hydrogen via pipeline and compressed hydrogen, liquefied hydrogen, ammonia and methanol via ship. This section sets out the foundation for informed decision-making in developing robust, scalable and sustainable hydrogen infrastructure and discusses system configurations, engineering considerations, safety requirements, and logistical implications.

As discussed above we have assumed that all the wind energy capacity identified for each case will be dedicated to hydrogen production. Any energy demand associated with the conditioning of the hydrogen, or generation of the selected derivatives for transport, is in addition to the planned wind energy capacity. This does not diminish the amount of hydrogen designated for export.

If the low, base, and high wind energy production levels serve exclusively as the source of energy for export, the energy required for each transportation vector would be deducted from the total wind energy output, which would result in a reduced volume of hydrogen available for export. This would result in varying amounts of hydrogen at the destination point which would have complicated the comparison of LCOT for each vector.

6.2 Transport Vectors

The following sections provide details in the form of block flow diagrams for each of the selected transport vectors. It should be noted that the figures presented reflect the high scenario hydrogen input discussed in Section 4.

6.2.1 Gaseous Hydrogen

This section presents the configuration and technical considerations of a gaseous hydrogen pipeline export system, focusing on the infrastructure and processes involved from the outlet of a hydrogen production facility to the point of entry into the export country.

The system boundary begins immediately downstream of the connection from hydrogen generation, either directly from an adjacent production facility or via an onshore domestic transmission system. For both repurposing of existing pipelines and new build pipelines, key systems will be required to facilitate the export of hydrogen. These include:

- Ireland onshore terminal infrastructure which connects the domestic system to the offshore pipeline inlet. This will likely include isolation valving, metering, quality monitoring to confirm the product specification and associated telemetry and control systems to operate the pipeline system.
- Compression facilities in Ireland to boost the pressure from the production facility or the domestic transmission system to the inlet pressure of the offshore pipeline. This is likely to be combined into the Ireland onshore terminal.
- European or GB Terminal infrastructure which connects the offshore pipeline to the GB or European onshore transmission system. This will likely include isolation valving, metering, pressure reduction to control the inlet pressure to the GB or European pipeline system, quality monitoring to re-confirm the product specification for entry into the GB or European system and associated telemetry and control systems.

System Configuration

The process steps for hydrogen transport using pipeline infrastructure begin with the production of hydrogen from renewable energy sources, such as wind energy. The produced hydrogen is then compressed to transmission pressures (around 100 bar) and transported via pipelines to its destination. The energy losses in compression are assumed to be compensated by supplementary grid power. The total mass losses are negligible.

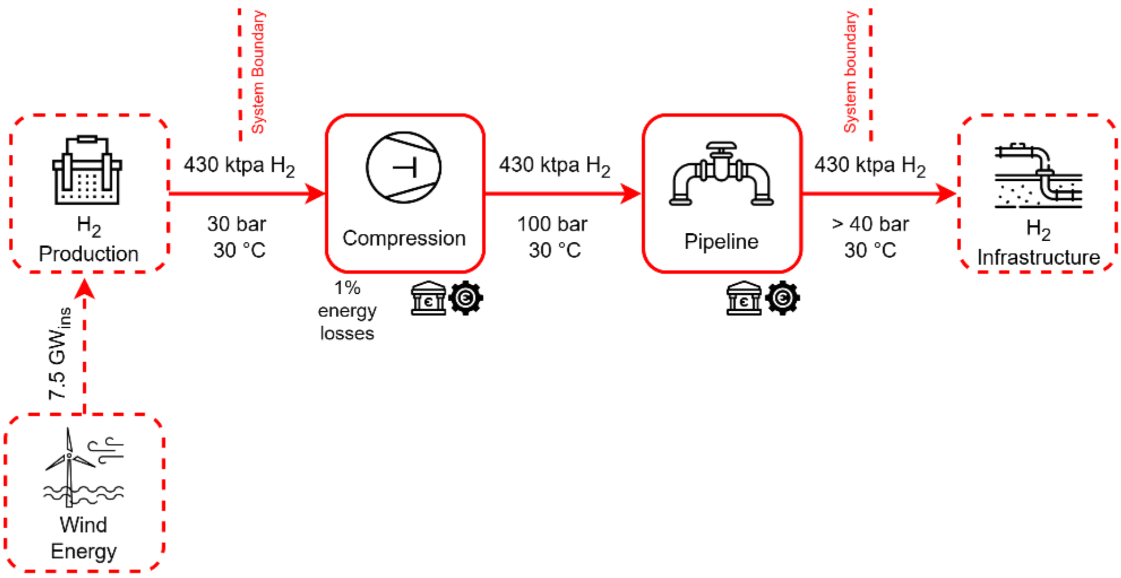


Figure 12: Block Flow Diagram of pipeline hydrogen transport system

Technical, efficiency and safety considerations

Hydrogen export starts with production at 430 ktpa under 30 bar and 30°C, followed by compression up to typical transmission pressures of 70-100 bar. Transportation of gases at these pressures is standard practice in transmission systems and is an efficient vector for steady throughput of large volumes over short to significant distances, however due allowance should be made for hydrogen specific considerations such as the increased compressor duty required and leakage issues because of the small hydrogen molecular size.

New build pipelines must be designed and sized to take into account normal values for pressure losses due to friction within the pipeline system over the transportation length to minimise the requirement for intermediate compression facilities. Velocities must be maintained within pipeline system operating norms to ensure efficient operation and avoid potential issues with erosion (typically gas velocity should be kept below 40m/s) and low flows (typically below 5m/s) impacting on normal and maintenance (pigging) operations.

There are multiple projects in Europe investigating and implementing hydrogen transport in pipelines with a focus on repurposing existing natural gas infrastructure in a transition period. Careful consideration should be made to the compatibility of utilising existing infrastructure for hydrogen service.

6.2.2 Compressed Hydrogen

This section presents the configuration and technical considerations of a compressed hydrogen export system via shipping, focusing on the infrastructure and processes involved from the outlet of a hydrogen production facility to the point of entry into the export country.

The system boundary begins immediately downstream of the connection from hydrogen generation, either directly from an adjacent production facility or via an onshore domestic transmission system and encompasses compression, intermediate storage, and subsequent export via ship utilising specialised high pressure (250 bar) compressed hydrogen gas vessels. Intermediate storage is required to account for the volumes needing to be stored from a continuous production process and the intermittent nature of batch transport of product via ship.

Industrial shipping of compressed hydrogen is currently under development. Development of compressed hydrogen carriers is ongoing with expected operation in 2026. The shipment of compressed hydrogen utilising standard containerised storage vessels has not been considered. The number of units to be transported for the target volumes is considered excessive and the safety and logistical challenges of moving high volumes of these units is not considered practical when compared to other vectors.

System Configuration

The process steps for compressed hydrogen transport using shipping begin with the production of hydrogen from renewable energy sources, such as wind energy. The produced hydrogen is then compressed and stored in a storage system. From there, it is transported via ships containing pressurised hydrogen tanks to its destination. The energy losses in compression are assumed to be compensated by supplementary grid power. The total mass losses are typically negligible.

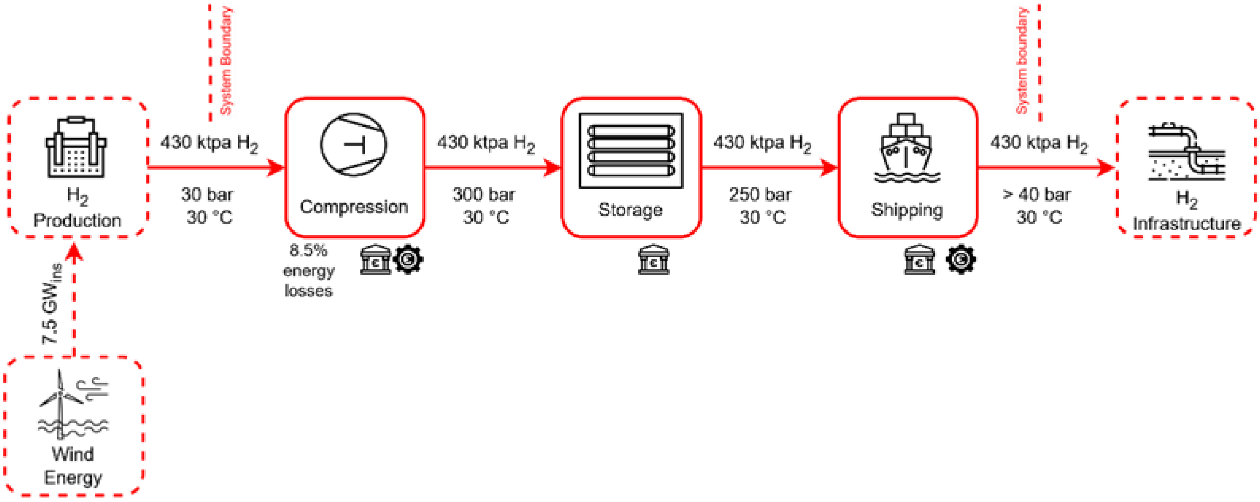


Figure 13: Block Flow Diagram of compressed hydrogen transport system

Technical, efficiency and safety considerations

Hydrogen export starts with production at 430 ktpa under 30 bar and 30°C, followed by compression up to 300 bar for storage. Current developments in compressed hydrogen shipping are targeting 250 bar systems. Compression is energy intensive, so techniques like isothermal compression and energy recovery are used, with wind energy as a sustainable, though intermittent, source. Advanced sealing, real-time monitoring, and minimising losses further improve efficiency.

Safety is crucial due to hydrogen's flammability and diffusivity. Systems must include pressure relief devices, leak detection, and explosion-proof equipment, with regular inspections and emergency shutdowns in piping systems. Personnel must follow international standards for safe operation.

For shipping, hydrogen is transported in high-pressure vessels, requiring specialised equipment and handling. Shipping offers flexibility for long distances, despite higher energy use and logistical complexity.

6.2.3 Liquified Hydrogen

This section presents the configuration and technical considerations of a liquefied hydrogen (LH2) export system, with a system boundary extending from the outlet of the hydrogen production facility through the stages of liquefaction, cryogenic storage, and final loading onto specialised transport vessels for maritime shipping.

Liquefaction offers a solution for long-distance, high-volume transport, particularly where pipeline infrastructure is uneconomic, impractical or unavailable. A high-level review of the engineering design, operational requirements, and safety protocols associated with handling hydrogen at cryogenic temperatures (approximately −255°C), as well as the logistical and economic implications of large-scale LH2 export are discussed.

System configuration

Unlike compressed hydrogen shipping or pipelines, liquefied hydrogen transport requires extensive cryogenic infrastructure - including liquefaction units, insulated storage, and specialised vessels - to maintain hydrogen at extremely low temperatures. This process incurs significant energy consumption due to liquefaction, intensive cooling and boil-off during storage and transit.

Retaining hydrogen in its liquefied state and to maintain a stable thermal and pressure system, boil-off losses are unavoidable. These can account for up to 0.5% per day. Figure 14 assumes 7 days of storage and 2 days of shipping. The total mass losses can amount to up to 5% and total energy consumption can reach a value equivalent to 35% of the transported hydrogen based on LHV over this time period.

The energy losses in compression are assumed to be compensated by supplementary grid power. The total mass losses result in delivery of 409 ktpa out of the 430 ktpa starting hydrogen production.

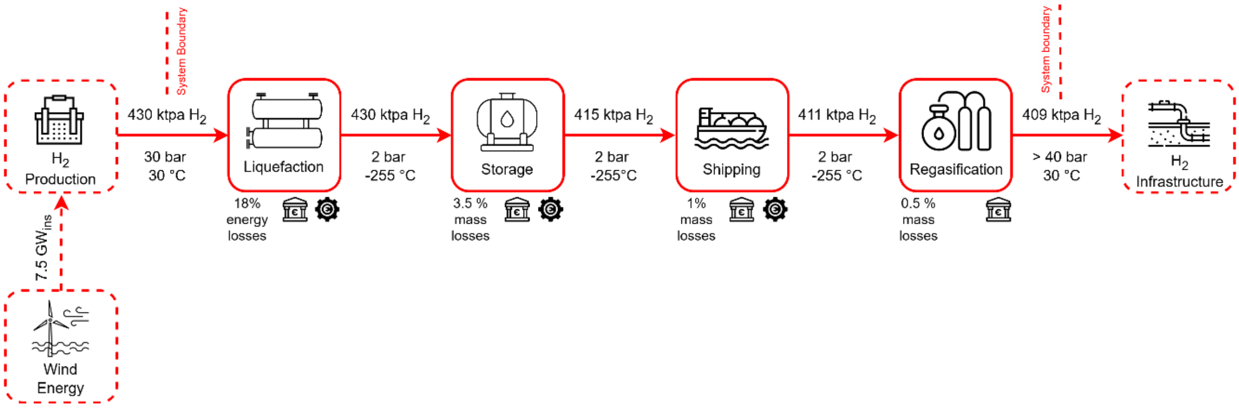


Figure 14: Block Flow Diagram of liquified hydrogen transport system

Technical, efficiency and safety considerations

While pipelines and compressed gas shipping demand robust pressure management, they avoid the substantial thermal management and insulation requirements unique to LH2, making liquefied hydrogen shipping more complex and less energy efficient, but possibly necessary for long-distance, high-volume export where pipelines are impractical or uneconomic. Liquid hydrogen density is 11 times higher than pipeline transmission pressure gas (assuming 80 bar) or 3.8 times higher than compressed gas at 250 bar.

Handling hydrogen at both high pressures and cryogenic temperatures introduces significant safety risks. Liquefaction and storage at -255°C require specialist materials resistant to brittleness and thermal shock. Shipping and regasification must include redundant safety systems such as pressure relief valves, leak detection, and emergency shutdown protocols. Ensuring containment integrity and operational safety across all phases is critical to prevent hazardous incidents.

- Liquefied hydrogen (LH2) export relies on complex cryogenic infrastructure, with significant energy and mass losses—5% mass during storage and shipping with substantial additional external electrical energy requirements to achieve and maintain the liquid state.
- Handling and transporting LH2 requires specialised vessels, materials resistant to extreme cold, and robust safety systems to prevent hazardous incidents.
- LH2 offers a dense, long-distance hydrogen transport option where pipelines are impractical, despite being less energy efficient than compressed gas methods.

6.2.4 Ammonia

This section examines the configuration and technical considerations of a renewable ammonia export system, with a system boundary beginning at the interface where green hydrogen - produced via electrolysis using renewable electricity - is combined with a nitrogen source to synthesize ammonia (NH3).

The process leverages the Haber-Bosch synthesis route, adapted for integration with renewable energy inputs, and includes downstream stages such as liquefied ammonia storage, loading onto maritime transport vessels, and delivery to international markets.

At the reception end, two primary utilisation pathways are considered: direct use of ammonia as a chemical feedstock or an energy carrier, and catalytic cracking to regenerate hydrogen for entry into the local hydrogen pipeline network.

This section explores the high-level engineering design, energy integration, and logistical challenges of the full ammonia value chain, with a focus on system efficiency, safety, and the role of ammonia as a scalable vector for global hydrogen transport.

System configuration

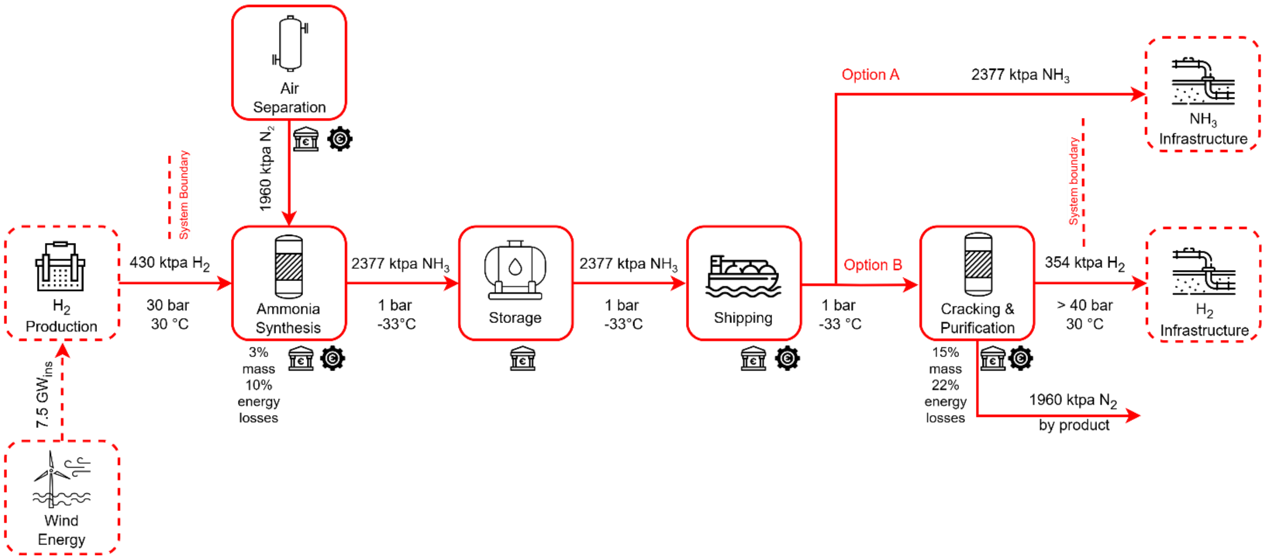


Figure 15: Block Flow Diagram of hydrogen transport through Ammonia system

Technical safety considerations

For the High Scenario, hydrogen is combined with 1,960 ktpa nitrogen sourced from an air separation unit to synthesize 2,377 ktpa of ammonia at 1 bar and -33°C, with around 3% process loss. This ammonia can be stored for shipping and then shipped for direct use in ammonia infrastructure (Option A) or cracking and purification to regenerate hydrogen (Option B).

From a technical and efficiency standpoint, the integration of units is critical. The hydrogen production unit requires operation at high efficiency to ensure optimal use of wind energy, while the air separation unit must reliably supply nitrogen at the required pressure. The high-pressure ammonia synthesis process must maintain precise temperature and pressure conditions to maximize conversion efficiency and minimize losses. Downstream, Option B introduces a significant efficiency challenge due to a 22% energy loss during cracking and purification back to hydrogen, which must be weighed against the benefits of hydrogen regeneration.

Ammonia, being toxic, necessitates stringent safety protocols during storage and transport. Ammonia-specific considerations for port infrastructure are critical due to its unique chemical and physical properties. Ammonia must be stored and handled at low temperatures (typically -33°C at atmospheric pressure) or under pressure to remain in liquid form, necessitating specialized cryogenic or pressurized storage tanks. These tanks must be constructed from materials resistant to ammonia-induced stress corrosion cracking. Port facilities must also include dedicated loading and unloading arms, vapour recovery systems, and spill containment measures to manage the risks associated with ammonia's toxicity and volatility.

Due to the toxic nature of ammonia, safety zones, gas detection systems, and emergency response protocols are essential to protect personnel and nearby communities. For receiving ports supporting hydrogen regeneration via ammonia cracking (Option B), infrastructure must also accommodate high-pressure systems and purification units, further increasing complexity and safety requirements.

Ammonia synthesis from grey hydrogen and the corresponding infrastructure are widely available and would require no major changes to be utilised to produce, store and transport green ammonia derived from renewable hydrogen. As a key chemical feedstock for fertilizers and several industrial chemicals, direct use of green ammonia offers significant reductions in global CO_2 emissions.

6.2.5 Methanol

This section outlines the configuration and technical considerations of a renewable methanol export system, with a system boundary beginning at the point where renewable hydrogen combined with carbon dioxide (CO_2), assumed to be supplied from CO_2 rich emission sources such as new biogas production facilities which are planned in Ireland[72]. Biogas is typically comprised of 60% methane and 40% CO_2 and presents itself as an option for carbon dioxide sourcing.

Through catalytic synthesis, these inputs are converted into methanol (CH_3OH), a liquid chemical that serves as a valuable industrial product, a potential marine fuel and as a potential hydrogen carrier.

The system includes methanol synthesis, storage, and loading onto maritime shipping vessels for international distribution. At the reception end, two primary utilisation pathways are considered: direct use of methanol as a fuel or chemical feedstock, and reforming to regenerate hydrogen for energy or industrial applications.

This section explores the high-level technical design, and logistical considerations of the full methanol value chain, with a focus on system efficiency and the use of methanol as a hydrogen carrier in enabling global hydrogen transport.

System configuration

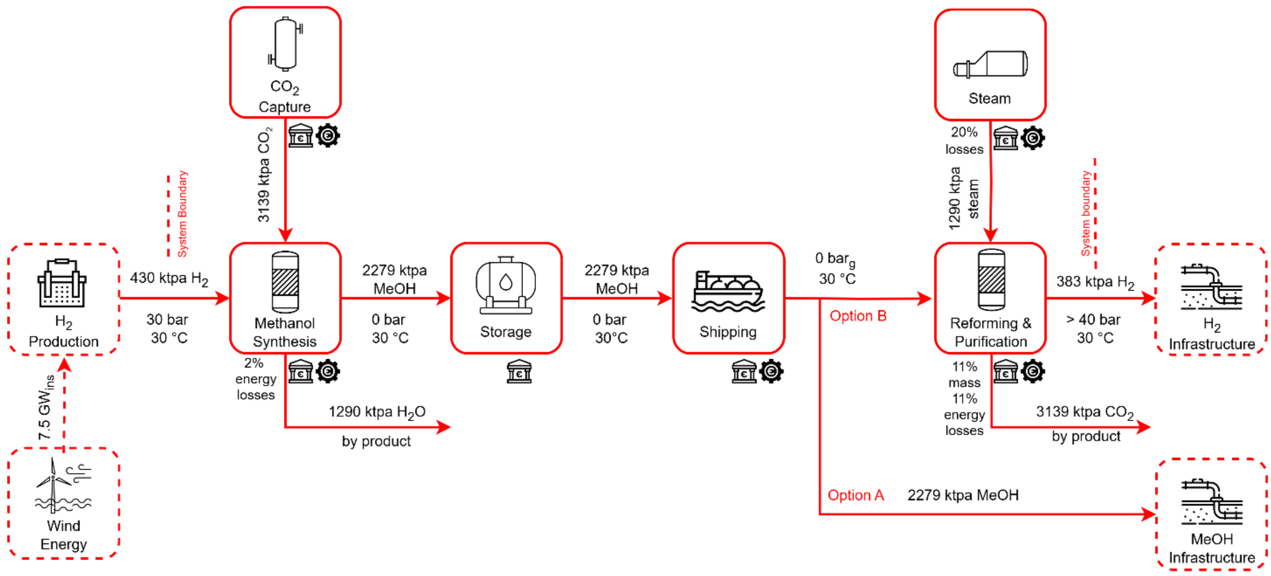


Figure 16: Block Flow Diagram of hydrogen transport through Methanol system

Technical, efficiency and safety considerations

For the High Scenario, the methanol production process combines 3,139 ktpa CO_2 and hydrogen (430 ktpa at 30 bar, 30°C). These feedstocks are combined in a methanol synthesis unit to produce 2,279 ktpa of methanol and 1,290 ktpa of water, with a 2% energy loss. The process requires precise control of reaction conditions - particularly temperature, pressure, and feedstock purity - to ensure high conversion efficiency and product quality. Integration with renewable energy sources adds complexity, requiring buffering or storage systems to manage intermittent power supply.

From an efficiency standpoint, the process demonstrates a high conversion rate of feedstocks to methanol, though losses in the reforming and purification step (Option B) are notable - 20% steam excess and 11% energy as well as an estimated 11% process loss. This step reformulates methanol using 1,290 ktpa of steam to produce 383 ktpa of hydrogen at 40 bar, generating 3,139 ktpa of CO_2.

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[72] Ireland's National Biomethane Strategy, May 2024

Efficiency improvements could focus on heat integration, steam recovery, and minimizing hydrogen losses. It's important to highlight that methanol reforming is not commercially available at large scale production capacities yet. Figures for efficiencies and yields are indicative of potential losses in reforming, purging, purification and drying.

Safety is crucial throughout the process. Hydrogen production and handling at high pressures require robust containment and leak detection systems. Methanol, being toxic and flammable, necessitates stringent safety protocols during storage and transport. The reforming step introduces high-temperature steam and CO_2 emissions, demanding proper thermal insulation, pressure relief systems, and emission controls. To maximise the green credentials of the process, the CO_2 should be captured in the reforming process. Return of the CO_2 for reuse could be considered although this is unlikely to be a cost-effective solution and sequestration to a permanent store offers the most likely option. Emergency response systems, real-time monitoring, and operator training are critical to mitigate risks across the entire value chain.

Methanol-specific considerations include its volatility, toxicity, and environmental impact. It must be stored in corrosion-resistant tanks with vapour recovery systems to prevent emissions. Handling protocols must address spill containment, fire hazards, and personnel exposure. For port infrastructure, specialized methanol facilities are required, featuring double-walled storage tanks, explosion-proof loading arms, fire suppression systems, and dedicated pipelines. Compliance with international maritime regulations and local environmental standards is essential to ensure safe and sustainable methanol logistics.

6.3 Technical Parameters for Export

The full list of technical design parameters and logistical considerations for the export of hydrogen used in this report are given in Appendix Technical Basis of DesignA.1

7. WP2: Pipeline Export Assessment

7.1 Introduction

To facilitate hydrogen export via pipeline, several technical considerations must be made. This section provides an overview of potential options as well as technical considerations associated with the use of different solution archetypes covering existing offshore and onshore pipeline systems and new offshore pipelines.

The methodology used to assess the various options is described together with how the locations for the start point within Ireland and the landing points in Great Britain and continental Europe were selected for the purposes of this study. Reference is made to Great Britain (GB) rather than the United Kingdom, as pipeline routes through England, Scotland and Wales only are considered as transit routes to Europe and no options through Northern Ireland from the Republic of Ireland are considered.

It should be noted that there are multiple potential exit and entry points for the offshore pipeline sections. A limited number have been taken forward for further discussion and these are described below.

Considering the assessment of the export opportunity, a number of scenarios for the transport of gaseous hydrogen via pipelines were developed. The scenarios are split into 4 main categories based on combinations of the described archetypes, namely (1) new direct pipelines, (2) repurposed interconnectors and onshore networks in GB and Europe, (3) hybrid new and repurposed offshore pipelines and onshore networks in GB and Europe and (4) new offshore pipelines and onshore networks in Europe.

Other considerations to be taken into account when designing new hydrogen pipeline connections are also discussed. The technical factors considered will impact on the overall cost of the export route and were considered during the development of the cost model.

7.1.1 Methodology

The approach for assessing pipeline export options for hydrogen begins by clearly defining the system boundaries, both geographically and technically. This involves pinpointing the primary export location, such as a coastal terminal in Cork, Ireland, as well as mapping out potential export destinations throughout GB and mainland Europe. Understanding the spatial limits and relevant pipeline networks at the outset is critical.

With the boundaries established, the next phase involves developing plausible export scenarios tailored to the projected hydrogen demand and logistical requirements. These scenarios are grouped into distinct categories, combining the use of repurposed interconnector pipelines, the construction of entirely new direct offshore pipelines, the use of proposed onshore pipeline systems within GB and mainland Europe and hybrid configurations that combine various configurations of both new and repurposed segments, with and without the requirement to utilise onshore systems.

A review of current infrastructure was performed, particularly existing major connections that could be leveraged for hydrogen transport. This analysis looks at existing links to key export markets through GB and mainland Europe, while also incorporating ongoing or planned regional initiatives such as Project Union (PU) in GB or the European Hydrogen Backbone (EHB) in mainland Europe.

Identifying, mapping, and evaluating alternative pipeline routes from the export origin to targeted destinations are then performed. This results in selecting representative landfall locations and identifying strategic border crossing points for the entry of hydrogen pipelines into the selected export destination country. For the purposes of this study, onshore pipelines are considered up to the border crossing point only. Subsequent onward transportation within each destination country's borders is outside of the boundary limits of this study.

7.2 Pipeline Landfall Locations

Landfall locations have been identified at either end of the various offshore pipeline sections to facilitate transport of gaseous hydrogen from Ireland to the selected European destination countries of Germany, the Netherlands and Belgium via the transit countries of GB and France.

7.2.1 Selection of Cork as representative export point from Ireland

As discussed in Section 2.3, the National Hydrogen Strategy identifies potentially favourable locations for the establishment of regional hydrogen clusters as key hubs for early infrastructure development. These clusters will serve as focal points for hydrogen production, storage facilities, and high priority offtakers. It is therefore sensible to assume these cluster locations would also be primary exit points for hydrogen transported by hydrogen from Ireland. Cork is one of the locations identified as a potential regional hydrogen cluster in the National Hydrogen Strategy and Climate Action Plan.

Cork offers a geographical advantage as it is the closest established major industrial location to continental Europe and its southeast coast of Ireland location would therefore offer the shortest pipeline length to connect to points on the coast of mainland Europe.

The area has further technical advantages as part of the wider Celtic Hydrogen Cluster as well as the potential for local large scale hydrogen storage in the depleted Kinsale gas field. For the purpose of this study, Cork is selected as the base pipeline export location within Ireland. The area around Dublin Port could be an option but the potential constraints on land availability and the additional distance to mainland Europe suggest there would be no advantage to utilising Dublin as the export point.

West coast pipeline export points such as the Shannon Estuary or within the North and West clusters along the coast in regions like Donegal, Galway, and Mayo have not been considered. The pipeline lengths to mainland Europe or GB are significantly longer and more challenging to build to achieve connection to GB (via a pipeline around the north coast of County Mayo, County Donegal and Northern Ireland to Brighouse Bay in Scotland) or to tie in with the northern end of AquaDuctus Phase 2 via a pipeline over the north of Scotland.

7.2.2 Selection of Le Havre as representative landfall in France

One of the shortest pipeline routes from Ireland to mainland Europe would connect to the coast of Northern France thereby minimising the cost of offshore pipeline construction. The connection point should also provide ease of connection to the EHB to allow transit of hydrogen across Europe to the target offtaker countries.

The French government recently published a revision of its National Hydrogen Strategy (Stratégie nationale hydrogène II) in April 2025. The strategy continues to prioritise industrial value-chain integration, equipment manufacturing, skills development, and energy sector sovereignty.

A cornerstone of this revised approach is the designation of the deep industrial port of Le Havre as a principal hydrogen hub under the EU's IPCEI framework. The Lhyfe Green Horizon project will develop a 100 MW+ electrolyser plant capable of producing 34 tonnes per day of renewable hydrogen. This facility will feature commercial pipeline connections to nearby industrial consumers, such as the Yara ammonia plant, with full operational status expected by 2029.

Concurrently, initiatives including an e-methanol facility and a hydrogen import terminal are advancing to bolster the maritime and chemical industries. These efforts further position Le Havre as a critical renewable hydrogen gateway for Western Europe.

Planned infrastructure expansions including the Le Havre - Chartres region, as well as the Franco-Belgian H_2 corridor, will integrate Le Havre within the broader European hydrogen network.

7.2.3 Selection of Milford Haven as representative landfall in GB

Milford Haven is designated as a key strategic hydrogen hub within the UK's Project Union programme, the national hydrogen backbone initiative led by National Gas. The port, located in Southwest Wales, is already a critical energy terminal for LNG imports and gas transmission, and its existing infrastructure, coupled with proximity to major industrial sites, positions it well for future hydrogen production, import, and distribution.

The region is central to the South Wales Industrial Cluster (SWIC) and several hydrogen-focused initiatives, including the development of renewable hydrogen production in the Celtic Sea and electrolysis projects powered by offshore wind on the Pembrokeshire Coast.

These aim to develop large-scale electrolytic hydrogen capacity in proximity to Milford Haven's transmission infrastructure, with plans to connect it to the UK hydrogen backbone via repurposed or new pipelines heading east toward Avonmouth, the Midlands and onward to the Northwest and Northeast.

7.2.4 Selection of offshore tie-in to AquaDuctus as access point into Germany

AquaDuctus[73] offers an offshore solution for hydrogen transport, delivering up to 20 GW from offshore wind. It reduces the need for multiple subsea cables and qualifies for EU funding as a Project of Common Interest.

The pipeline aligns with the planned UK–Germany Hydrogen Corridor and fits into Europe's hydrogen network, supporting open access and links to North Sea infrastructure for regional hydrogen trade. AquaDuctus Phase 1 (SEN-1 to coast) comprises offshore and onshore pipelines, with initial targeting for completion by 2030, in line with the European hydrogen core network roll-out.

The German government has strategically designated AquaDuctus as the primary offshore hydrogen import corridor to minimize environmental disruption along the highly sensitive North Sea coastline where permitting multiple landfalls would trigger significant ecological and regulatory barriers.

As outlined in Germany's updated National Hydrogen Strategy[74], AquaDuctus is intended to consolidate international hydrogen connections - including future links from the UK and Norway - into a single, scalable offshore pipeline system. This avoids redundant infrastructure, reduces seabed impact, and simplifies integration with onshore hydrogen infrastructure at a centralized landing point.

The project is technically mature, with feasibility studies complete and a commissioning target of 2030. This naturally positions AquaDuctus Phase 1 as the continuation or eastern leg of any Ireland-Germany pipeline corridor. The assumption for this study is that an offshore tie in would be made at the end of AquaDuctus Phase 1 to utilise this primary offshore hydrogen import corridor (Figure 17).

[73] https://aquaductus-offshore.de

[74] Import Strategy for hydrogen and hydrogen derivatives, Federal Ministry for Economic Affairs and Climate Action (BMWK), July 2024

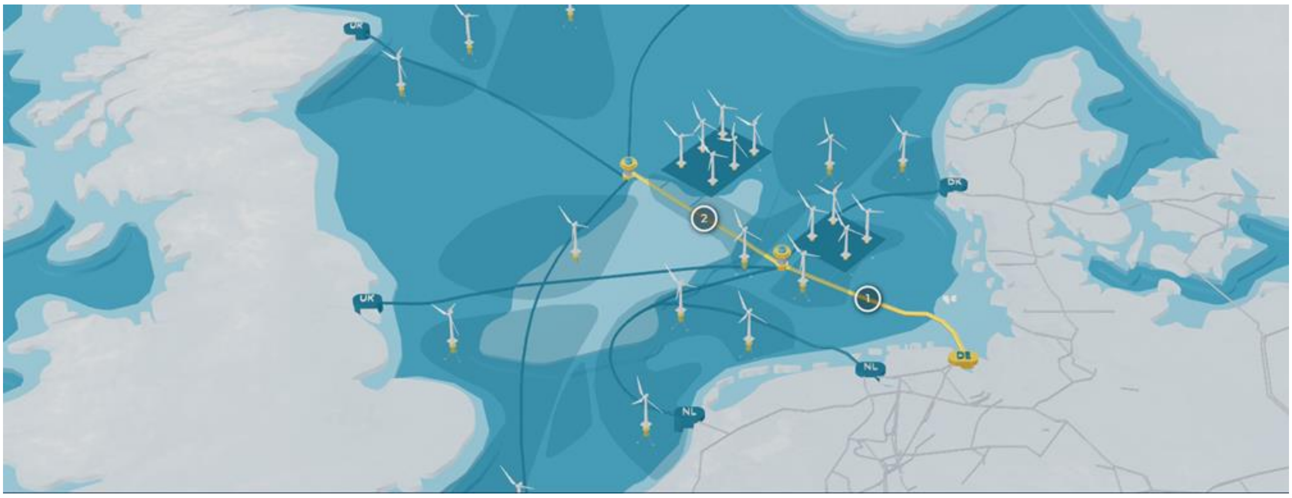


Figure 17: Graphical representation of the planned AquaDuctus network showing the termination point in Phase 1, marked by the pin at the end of the section denoted "1".

7.3 Solution Archetypes

The pipeline interconnection between Ireland and the selected entry points into continental Europe is facilitated by a combination of the use of existing offshore interconnector pipeline connections between Ireland and GB and between GB and Europe, proposed onshore hydrogen transmission networks in GB and Europe and the construction of new build offshore pipelines between Ireland and selected landfall locations in Europe.

7.3.1 Repurposed Interconnectors

Ireland to GB

The existing natural gas pipeline infrastructure connecting the UK and Ireland consists of several key interconnectors (Figure 18)

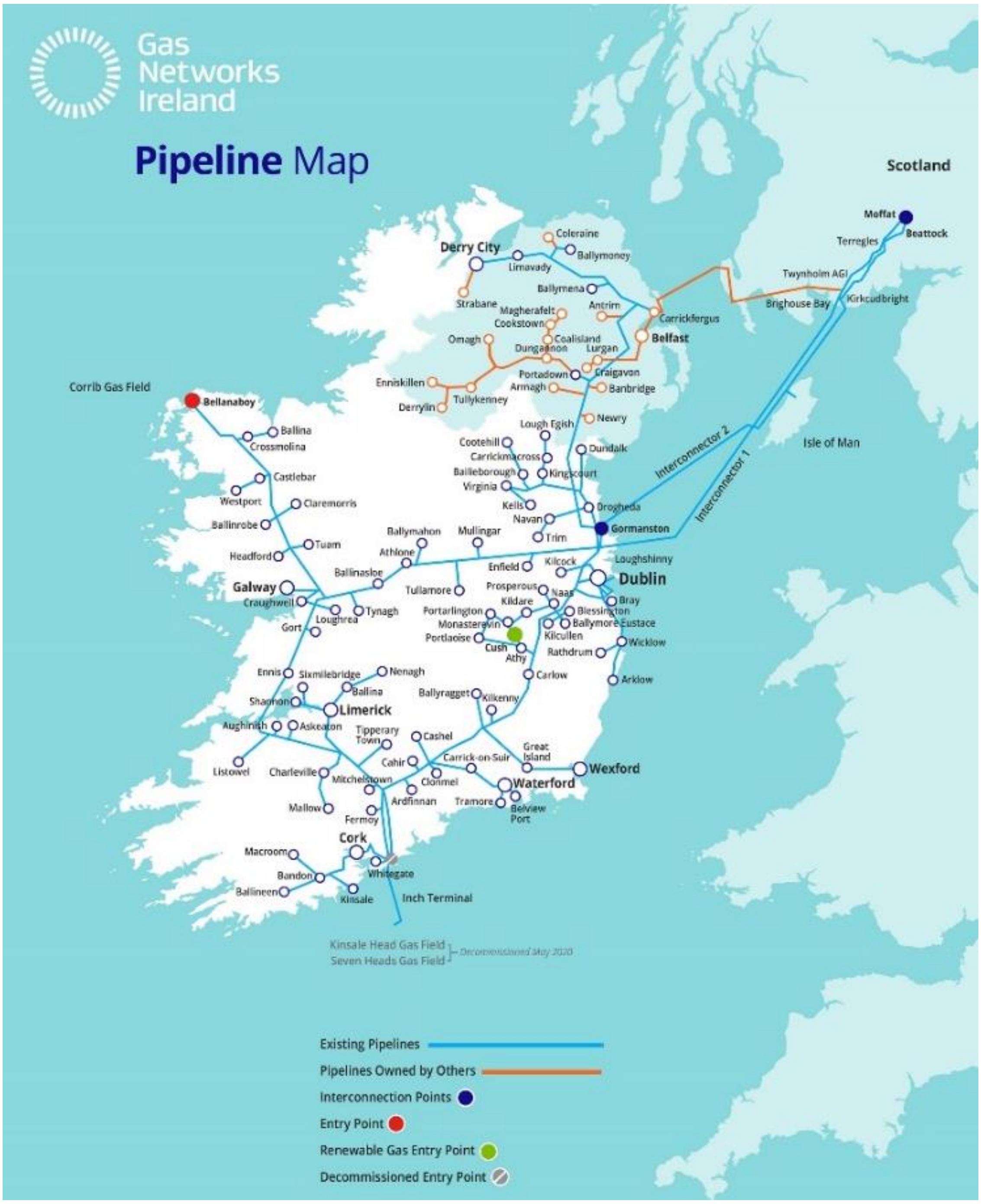


Figure 18: Gas Networks Ireland pipeline map showing existing interconnectors

Table 9: Existing Ireland to UK Interconnector Pipeline Information

Pipeline Name	Route	Year Constructed	Diameter	Design Pressure [bar]	NG Capacity [kSm³/h]
IC1 (Interconnector 1)	Loughshinny (IE) - Brighouse Bay (GB)	1991	24"	145	742
IC2 (Interconnector 2)	Gormanston (IE) - Brighouse Bay (GB)	2003	30"	145	1,497

Pipeline Name	Route	Year Constructed	Diameter	Design Pressure [bar]	NG Capacity [kSm³/h]
IoM Spur	IC2 Tee - Glen Mooar (Isle of Man)	2003	10"	70-100	29
SNIP (Scotland-Northern Ireland Pipeline)	Ballylumford (NI) - Twynholm (GB)	1996	24"	75	1,300

IC1 provides a supply of natural gas to Ireland from Scotland which, together with IC2, constitutes approximately 75% of Irish supply. It has been operational since 1991 and is 187km in length and has a 6.71bcm/yr capacity. Though presently unidirectional, it has the potential for reverse flow capabilities.

IC2 supplements IC1, providing additional natural gas from Scotland. It is 195km long with an 11.7km spur to the Isle of Man. It was completed in 2003.

SNIP connects Scotland (Twynholm) to Northern Ireland (Ballylumford) and was originally commissioned in 1996. It is a submarine pipeline approximately 135 km long. It does not offer a direct connection between the Republic of Ireland and GB.

All interconnectors could, subject to detailed assessment to determine suitability and compatibility for repurposing to 100% hydrogen service, be considered as an export route for hydrogen from Ireland.

As IC2 contains the spur which connects the Isle of Man (IoM) to the GB gas system, it would be challenging to convert this pipeline to hydrogen service without either constructing a new connection between the IoM and GB or providing an alternative source of natural gas supply, e.g. development of an LNG import and regasification facility on the IoM. The IC2 pipeline is therefore not considered as a potential option for exporting hydrogen from Ireland.

The SNIP pipeline provides the primary source of natural gas supply to Northern Ireland and its conversion to hydrogen service would pose security of supply challenges to gas supplies in Northern Ireland. Supply would have to be maintained solely via the South-North pipeline from the Republic of Ireland. The SNIP pipeline is therefore not considered as a potential option for exporting hydrogen from Ireland.

IC1 could be a suitable candidate for repurposing, but the SNIP currently connects to IC1. Therefore, SNIP would need to be connected to IC2 instead, if IC1 was selected for repurposing to hydrogen. The possibility is being considered that, at some stage in the future, the IC1 pipeline could evolve to supply a homogenous and increasing blend of hydrogen / natural gas and / or a 100% hydrogen supply. The repurposing of IC1 would only be possible once the security of supply of ongoing natural gas demands was confirmed as being able to be met via IC2 and SNIP. This is likely to not be possible for several years but, for the purposes of this study, IC1 has been assumed as a potential repurposed option for export from Ireland to GB.

GB to mainland Europe

There are currently two existing direct natural gas interconnectors connecting the UK and mainland Europe: The Interconnector (Bacton to Zeebrugge, Belgium), the BBL connection (Bacton to Balgzand, Netherlands) (Figure 19)

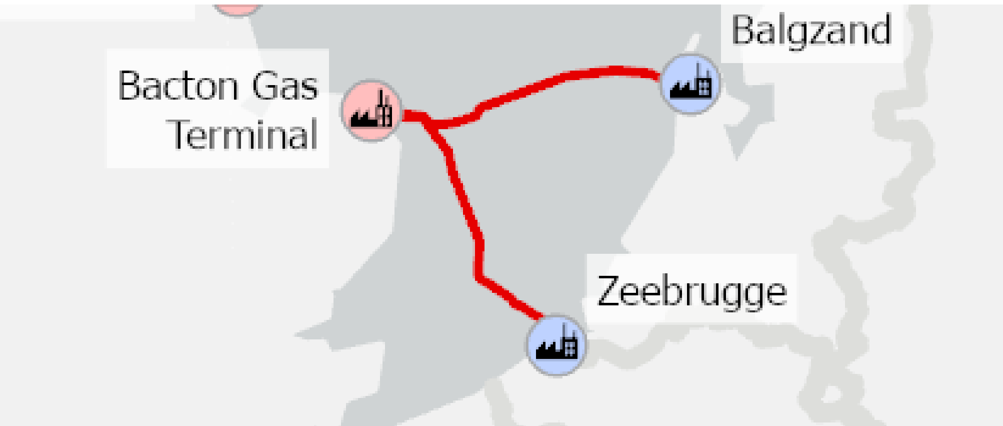


Figure 19: Existing UK to Mainland Europe Interconnectors

Table 10: Existing UK to Mainland Europe Interconnector Pipeline Information

Interconnector	Origin	Terminal	Description
Bacton to Zeebrugge (The Interconnector)	Bacton, UK	Zeebrugge, Belgium	Bi-directional gas pipeline between the UK and Belgium which connects the transmission system operated by National Gas at Bacton to the transmission system operated by Fluxys Belgium at Zeebrugge. Commenced operations in October 1998. The gas flows between terminals at Bacton in the UK (Interconnector Bacton Terminal – IBT), and Zeebrugge in Belgium (Interconnector Zeebrugge Terminal – IZT) via a 40” diameter, 235km subsea pipeline (Figure 19) operating at a MAOP of 147 bar.
Balgzand to Bacton Line (BBL)	Bacton, UK	Balgzand, Netherlands	The 36” diameter offshore pipeline, operating at a MAOP of 137.4 bar, comprises 230 km of the pipeline’s overall 235 km length. Installation of the pipeline across the North Sea took place in 2006. The onshore section is a 4 km length of pipeline that begins at the Anna Paulowna compressor station in the Netherlands and ends at the dune crossing location in Julianadorp. The BBL Company pipeline is connected to the Dutch national grid, which is owned by Gasunie Transport Services, at Grasweg near Anna Paulowna and is linked to the Anna Paulowna compressor station, formally called compressor station Noord-Holland (Figure 19).

As part of UK’s Project Union, a connection is planned to facilitate cross-border hydrogen flows between the United Kingdom and Belgium via the Bacton and Zeebrugge corridor. This initiative seeks to link the UK hydrogen backbone to mainland Europe and the developing European Hydrogen Backbone (EHB) through interconnectors jointly managed by National Gas and Fluxys Belgium.

The Zeebrugge terminal serves as a critical hub in Belgium’s hydrogen import and transmission infrastructure. Designated as a key node within the EHB, the terminal is equipped to receive hydrogen from maritime imports and distribute it inland through dedicated pipelines. Fluxys is currently upgrading the Zeebrugge–Brussels corridor to establish it as a primary entry point into Belgium’s hydrogen network, integrating hydrogen-ready pipelines toward industrial regions and cross-border connections.

From Zeebrugge, the network branches towards the Netherlands via the Zeebrugge–Antwerp–Rotterdam corridor and eastward to Germany through routes aligned with the Delta Rhine Corridor and other segments of the EHB. These corridors are designed to provide redundancy and bidirectional flow, supporting both Belgian domestic demand and transit to major industrial clusters such as the Ruhr area in North Rhine-Westphalia. The network further aligns with Dutch projects like Hynetwork Services' hydrogen backbone and Germany’s “Kernnetz” (core hydrogen grid), ensuring integrated northwest European hydrogen flows. Consequently, Zeebrugge functions as both a national hydrogen hub and a strategic gateway for hydrogen movement between the UK, Benelux, and Germany, consistent with EU hydrogen market integration objectives.

The Bacton to Zeebrugge interconnector has therefore been selected as the connection option between GB and mainland Europe for the purposes of this study.

Factors affecting repurposing NG pipelines for hydrogen export

A. Material compatibility

Hydrogen embrittlement risk depends on pipe steel grade, welds, and age. IC1, IC2, SNIP and The Interconnector are built from carbon steel (likely API 5L X65/X70), which are prone to embrittlement unless modified. This can be mitigated by weld inspections and lower design factors between operating and design pressures.

B. Operating pressure and flow conditions

Hydrogen requires 2.8 times the volumetric flow to deliver the same energy as natural gas. The IC1/IC2 pipelines, with a design pressure approximately 85/140 bar onshore/subsea, have moderate suitability for hydrogen but may need derating. The SNIP pipeline, with a maximum pressure of around 75 bar, also has moderate suitability but requires derating and potential compression retrofits. Additionally, compression systems may need to be redesigned to ensure that compressors are oil-free and compatible with 100% hydrogen service. Older pipelines like IC1 (1991), SNIP (1996) and The Interconnector (1998) may require more extensive retrofitting or replacement of components.

Table 11: Theoretical Hydrogen Capacity of Existing Interconnectors

Pipeline Name	Diameter	Design Pressure [bar]	H_2 Capacity[75] [MSm3/h]	H_2 Capacity [ktpa]
IC1 (Interconnector 1)	24"	140	1.3	950
IC2 (Interconnector 2)	30"	140	2.4	1,700
Bacton to Zeebrugge	40"	147	4.1	4,950

From a capacity perspective both IC1 and IC2 could potentially transport up to 950 and 1,700 ktpa of hydrogen which is higher than the maximum study basis of 430 ktpa corresponding to the upper bound of installed wind capacity of 7,500 MW. The Interconnector between the UK and Belgium (Bacton-Zeebrugge) could potentially transport 4,950 ktpa of hydrogen over the distance of 247 km to mainland Europe.

C. Economic Considerations

The IC1 pipeline was originally designed to operate in a unidirectional manner from the UK to Ireland. However, a proposal to upgrade it to a bi-directional pipeline was put forward to the EU[76] as a Project of Common Interest PCI 5.1.1 in 2016 but was later withdrawn. This flexibility is crucial for facilitating hydrogen trade between the two regions.

Additionally, both Ireland and the UK are part of the North Seas Energy Cooperation (NSEC), which aims to support the integration of hydrogen infrastructure across the region.

D. Strategic Considerations

Ireland is currently exploring the potential for renewable hydrogen production, while the UK has ongoing projects for both blue and green hydrogen. These pipelines could play a significant role in supporting cross-border hydrogen balancing and trade.

[75] Estimation based on technical assumptions listed under Appendix A.1 Technical Basis of Design. Hydrogen and natural gas capacity are not directly comparable due to different pressure basis and densities. The estimation is based solely on hydraulic capacity. Other compression, commercial, supply and demand considerations will lead to different numbers.

[76] Physical reverse flow at Moffat interconnection point (IE/UK) - https://ec.europa.eu/assets/cinea/project_fiches/cef/cef_energy/5.1.1-0005-UKIE-S-M-16.pdf

Continuation of natural gas supply and security of supply are major factors in the decision regarding pipeline conversion. IC2, IoM Spur, and SNIP are not recommended for near-term hydrogen repurposing considerations due to their critical role in ensuring the security of natural gas supply to Northern Ireland and the Isle of Man. IC1 can be considered, but we are assuming that the current SNIP connection at Twynholm would be transferred to IC2.

Ongoing assessment of the security of supply of natural gas from Europe to the UK via the existing interconnectors is part of the review being undertaken by National Gas and Fluxys to determine the potential to repurpose one of the existing lines to hydrogen service.

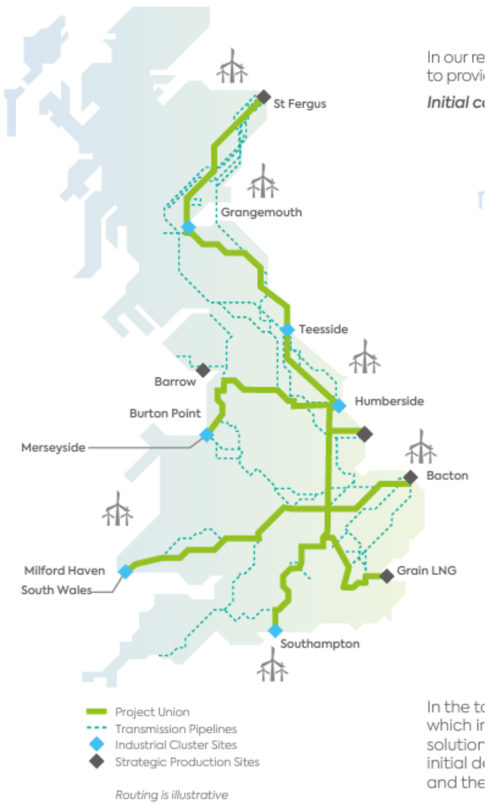
Recommendations for existing infrastructure

Given the current infrastructure and strategic priorities, repurposing IC1 is showing a potentially viable option for initiating hydrogen exports from Ireland to Great Britain. Repurposing of the Bacton to Zeebrugge interconnector would allow onward transmission from GB to mainland Europe. These repurposed options have been assumed as the basis for this study.

7.3.2 Onshore Networks

In addition to the interconnectors, hydrogen export from Ireland through a pipeline would need to rely on existing infrastructure in GB and the EU to reach the final destinations of Belgium, the Netherlands and Germany. Other projects are investigating and implementing the development of onshore networks through a combination of new build and repurposed natural gas pipelines for hydrogen transport across their respective countries. Notable projects include the GB Project Union[77] and the European Hydrogen Backbone[78].

Project Union in Great Britain



[77] https://www.nationalgas.com/future-energy/hydrogen/project-union

[78] https://ehb.eu/page/publications

Figure 20: Schematic of the proposed Project Union System. Source: (National Gas, 2023).

In the broader European hydrogen infrastructure context, Project Union is strategically aligned with potential future hydrogen interconnections to Ireland and mainland Europe. On the western side, Milford Haven offers a potential strategic connection location into the repurposed network for a new-build link under the Celtic Hydrogen Cluster and GNI initiatives, enabling hydrogen exports from Ireland to the GB backbone.

On the eastern side, Project Union is being examined as a potential connection point to the European Hydrogen Backbone (EHB) via an offshore hydrogen interconnector between Bacton (UK) and Zeebrugge (Belgium). This link would provide a bidirectional route for hydrogen trade, enhancing energy security and facilitating market integration between the UK and EU hydrogen economies. Such cross-border infrastructure is critical for leveraging offshore wind, import terminals, and balancing regional supply-demand mismatches across northwest Europe.

European Hydrogen Backbone

The European Hydrogen Backbone (EHB) is a transnational initiative coordinated by major European gas transmission system operators (TSOs) to develop a pan-European hydrogen transport infrastructure. The EHB vision foresees a network of over 50,000 km by 2040, primarily based on the repurposing of existing natural gas pipelines, connecting key hydrogen production and demand centres across the continent. One of the critical corridors under consideration includes a subsea pipeline from Bacton, UK, to Zeebrugge, Belgium, establishing a vital link between the emerging UK hydrogen backbone - such as Project Union - and the continental hydrogen grid. This interconnector would enable bilateral hydrogen trade, improve energy system resilience, and support security of supply by leveraging UK offshore wind and import potential, while connecting to the broader European demand centres.

On the western edge of mainland Europe, the Le Havre industrial cluster in France is also positioned to become a strategic node in the EHB through planned hydrogen pipeline links to Belgium, the Netherlands, and western Germany. The Le Havre port region, with its access to imported hydrogen derivatives, local electrolysis capacity, and petrochemical industries, is expected to act as both a demand and transit hub. This was confirmed by the recent update to the French Hydrogen Strategy. The connection from Le Havre into the Benelux and German markets would form part of the North Sea Hydrogen Valley corridor, a key segment of the EHB that supports transnational flows of hydrogen between supply-abundant coastal regions and high-demand inland industrial clusters.

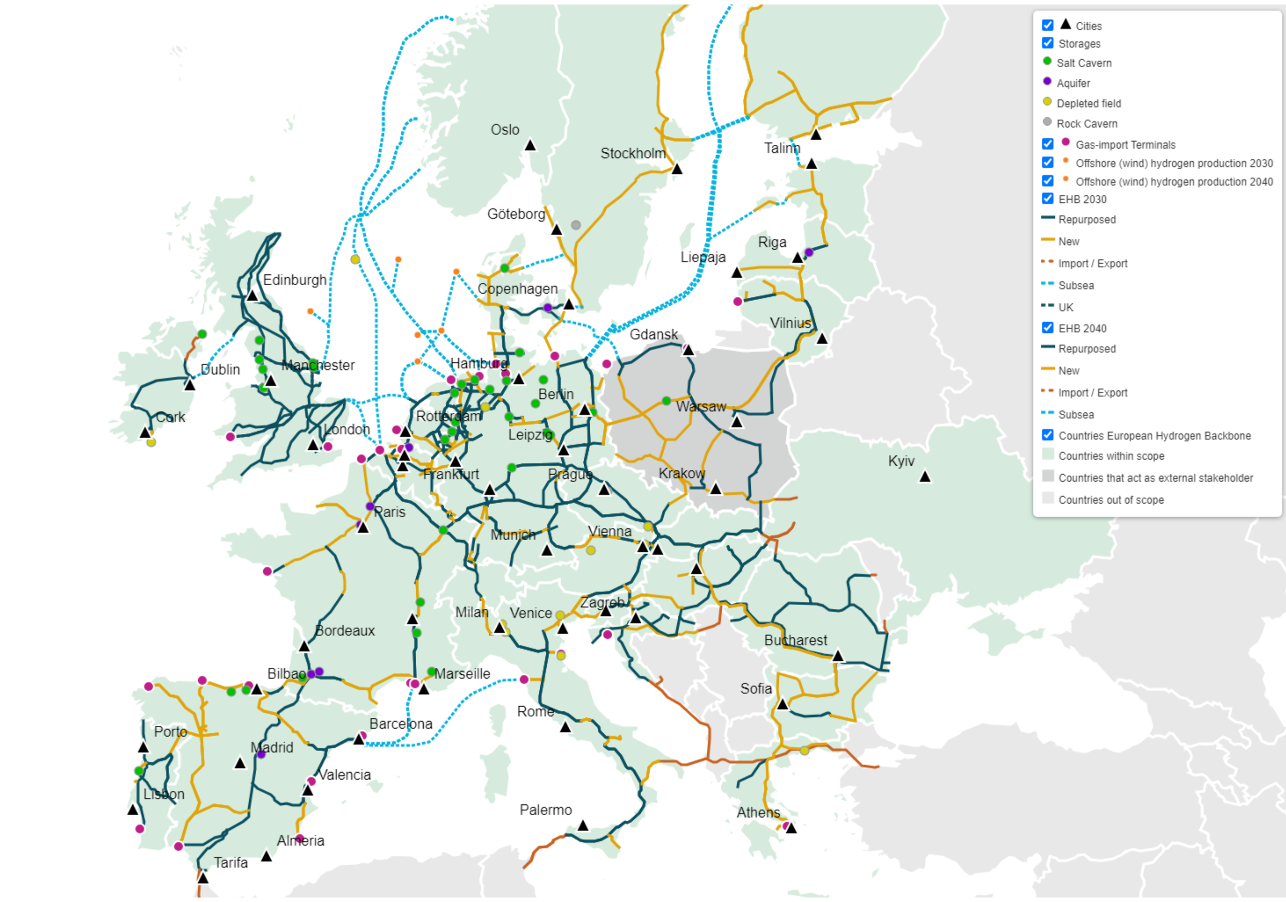


Figure 21: Map of the EHB system showing the provisional routes of the core network at full build out in 2040. Source: (European Hydrogen Backbone, 2024).

7.3.3 New Build Offshore Pipelines

As well as investigating repurposing pipeline options, the construction of a new high pressure, fully welded steel pipeline between Cork and import locations in GB and mainland Europe for connection into Project Union and the broader European Hydrogen Backbone to future-proof Ireland's hydrogen export strategy should be considered.

The size of the pipeline depends on the maximum volumetric flow rate of hydrogen, operating conditions, flow velocity limits and maximum pressure drop in the pipeline due to friction. Given the assumed design parameters from the technical basis of study, the theoretical minimum required diameter was calculated. The closest commercially available size was then selected and cross checked against pressure drop and increased as required such that continuous supply was possible without the need for additional offshore compression stations. The pipeline wall thickness was determined from design pressure, material of construction, design factors and commercial availability. These are shown in Table 12.

Table 12: Proposed New Build Pipeline Sizes

New pipeline segment	Relevant scenarios (Section 7.4)	Start location	End location	Distance [km]	Pipeline size [DN]	Thickness [mm]	Delivery pressure [bar]
1	S4	Cork, IR	AquaDuctus I, DE	1,500	700 (28”)	23.6	55
2	S5, S6, S7	Cork, IR	Milford Haven, UK	234	450 (18”)	15.5	46
3	S8, S9, S10	Cork, IR	Le Havre, FR	820	600 (24”)	20.4	51

Material selection

For subsea hydrogen pipelines, selecting a material involves balancing hydrogen compatibility, corrosion resistance in seawater, mechanical strength, and cost-effectiveness. Low-strength carbon steels such as X42/X52/X60 show higher resistance to embrittlement and are more commonly recommended for hydrogen service. API 5L X52 is widely used in the oil & gas industry for subsea natural gas pipelines, and emerging hydrogen standards and technical papers indicate it is among the most suitable carbon steel grades for hydrogen transport, especially in dry hydrogen service[79]

7.4 Pipeline Scenarios

7.4.1 Routing Scenarios

Several routing scenarios were developed for pipeline connections between Ireland and the selected pipeline landfall destinations in Germany, the Netherlands and Belgium, utilising a combination of repurposed and new build pipelines either directly to the end point or via the proposed onshore hydrogen systems in GB and mainland Europe. These are shown in Figure 22 and summarised in Table 13.

The selected scenarios investigate a range of possible solutions to allow the LCOT to be compared. Detailed analysis would be required to further investigate the viability of each option.

The route lengths presented in Table 13 have been assessed based on constraints such as the location of wind farm development areas, military zones and environmentally sensitive areas and protected areas. These are indicated on Figure 22.

The pipeline options are grouped into 4 categories:

- New Build Offshore Only Solutions
- Repurposed Offshore and GB & Mainland Europe Onshore Solutions
- Hybrid Offshore and GB & Mainland Europe Onshore Solutions
- New Build Offshore and Mainland Europe only Onshore Solutions

Further discussion of each option is given below.

[79] Recommendations from the following codes, standards and industry practice recommendations ASME B31.12, EIGA Doc 121/14, DNV-RP-F101 / DNV-ST-F101, ISO 13623, EHB Technical Paper (2021–2023), IGEM/TD/1

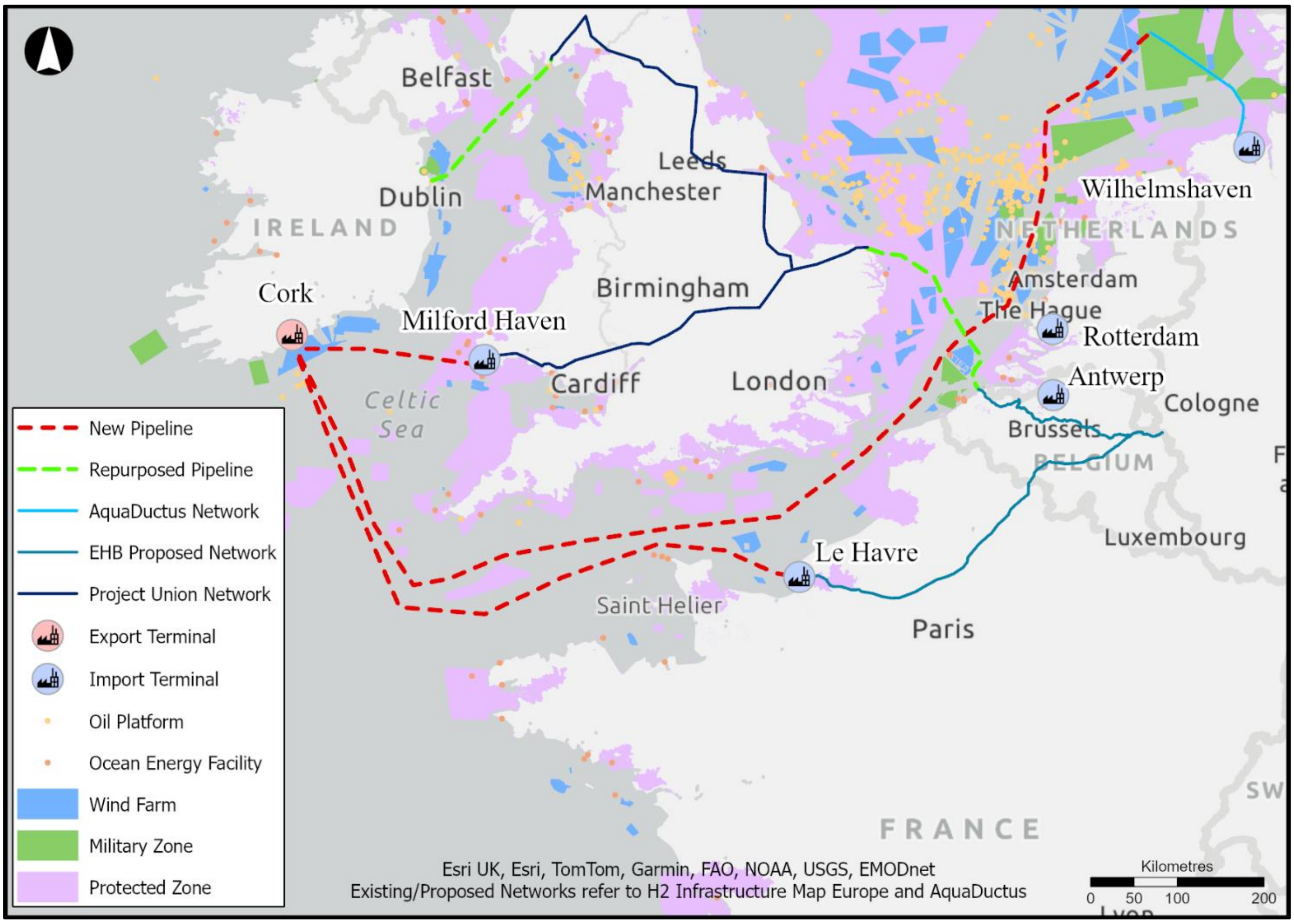


Figure 22: Overview of proposed routing for gaseous hydrogen transport via new pipelines and future onshore pipelines as part of Project Union and European Hydrogen Backbone.

Table 13: Pipeline export destinations and corresponding routes including new and repurposed pipelines

Scenario	Offshore Pipeline Primary Vector	Destination	Start	End	Distance [km]
S1	Repurposed offshore pipeline	Belgium	Loughshinny, IR	Zeebrugge, BE	1,037
S2	Repurposed offshore pipeline	Netherlands	Loughshinny, IR	Bergen op Zoom, NL	1,147
S3	Repurposed offshore pipeline	Germany	Loughshinny, IR	Aachen, DE	1,345
S4	New pipeline	Germany	Cork, IR	Aquaductus Phase 1, DE	1,500
S5	New and repurposed pipelines	Belgium	Cork, IR	Zeebrugge, BE	957
S6	New and repurposed pipelines	Netherlands	Cork, IR	Bergen op Zoom, NL	1,067
S7	New and repurposed pipelines	Germany	Cork, IR	Aachen, DE	1,265
S8	New and repurposed pipelines	Belgium	Cork, IR	Mons, BE	1,220

Scenario	Offshore Pipeline Primary Vector	Destination	Start	End	Distance [km]
S9	New and repurposed pipelines	Netherlands	Cork, IR	Maastricht, NL	1,295
S10	New and repurposed pipelines	Germany	Cork, IR	Aachen, DE	1,330

7.4.2 New Build Offshore Only Solutions

Scenario 4: A completely new pipeline would be constructed to supply hydrogen to Germany. This pipeline, covering a total distance of 1,500 km, would run directly from Cork, Ireland, to tie into Aquaductus Phase 1 offshore for onward supply to Germany (Figure 23).

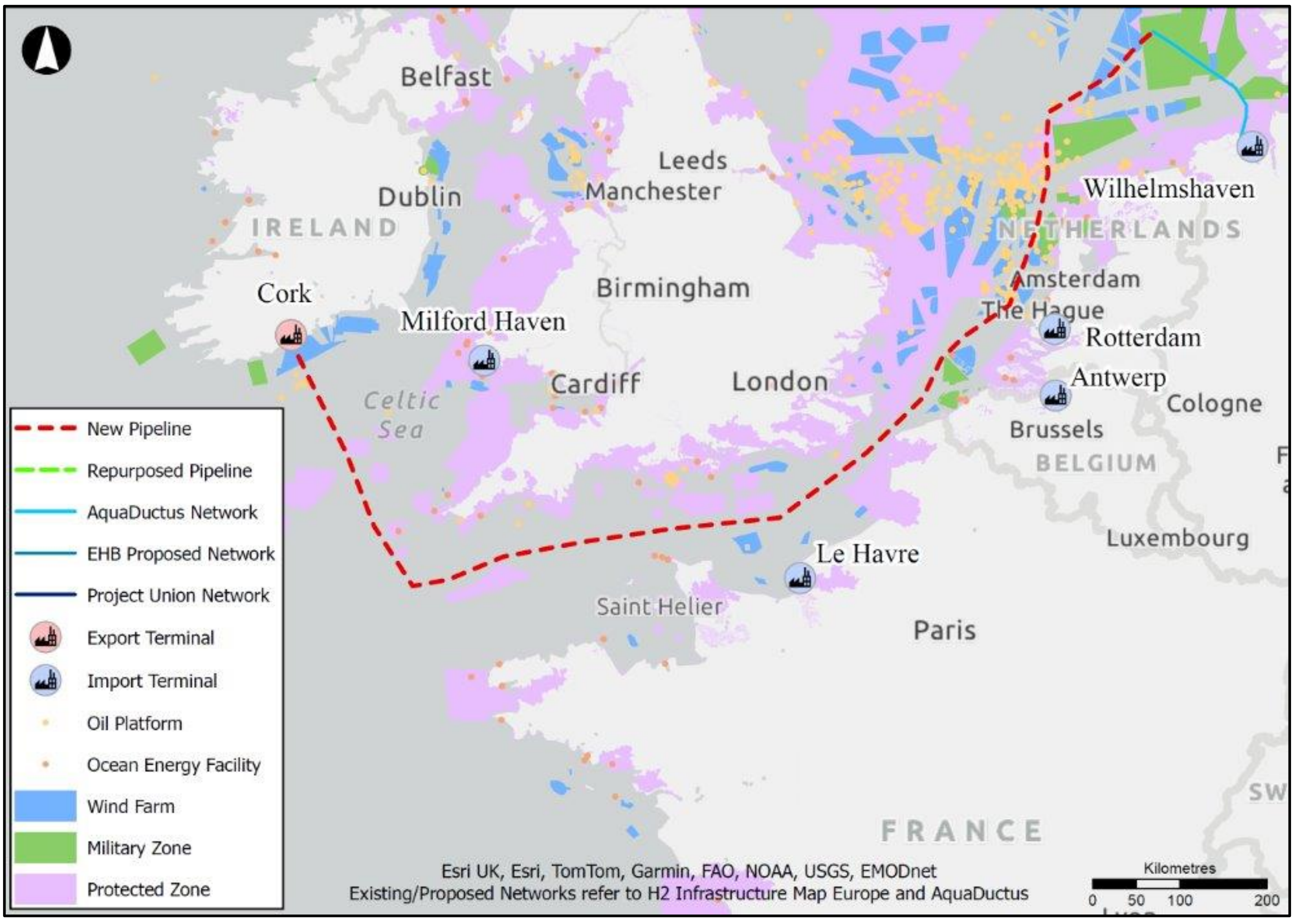


Figure 23: Scenario 4 Route Alignment

This scenario requires the construction of a new build pipeline into and along the English Channel to supply Germany directly.

The total length of the Scenario 4 pipeline has been split into two distinct zones. The first section, 740km from Cork to a point north of Le Harve, is likely to be a more conventional offshore pipelay. The second section, 760km from the point north of Le Harve to the tie in with the end of AquaDuctus Phase 1, will have to be constructed along one of the busiest shipping lanes in the world, with marine traffic both along and across the proposed pipeline alignment. There are also numerous crossings of other pipelines and cable interconnectors between the UK and mainland Europe which will add to the complexity, schedule and cost of construction.

7.4.3 Repurposed Offshore and GB & Mainland Europe Onshore Solutions

Scenario 1: Proposes repurposing existing pipelines to transport hydrogen to Belgium. The route would start at Loughshinny, Ireland, continue offshore to Brighouse Bay, UK (via IC1, 195 km), then proceed onshore from Brighouse Bay via Beattock to Bacton (via Project Union, 616 km). From there, the pipeline would travel offshore to Zeebrugge, Belgium (via Bacton to Zeebrugge Interconnector, 226 km). A total route length of 1,037 km.

Scenario 2: Proposes repurposing existing pipelines to transport hydrogen to the Netherlands. The route would start at Loughshinny, Ireland, continue offshore to Brighouse Bay, UK (via IC1, 195 km), then proceed onshore from Brighouse Bay via Beattock to Bacton (via Project Union, 616 km). From there, the pipeline would travel offshore to Zeebrugge, Belgium (via Bacton to Zeebrugge Interconnector, 226 km) and finally proceed onshore from Zeebrugge to Bergen op Zoom, Netherlands (via EHB, 110 km). A total route length of 1,147 km.

Scenario 3: Proposes repurposing existing pipelines to transport hydrogen to Germany. The route would start at Loughshinny, Ireland, continue offshore to Brighouse Bay, UK (via IC1, 195 km), then proceed onshore from Brighouse Bay via Beattock to Bacton (via Project Union, 616 km). From there, the pipeline would travel offshore to Zeebrugge, Belgium (via Bacton to Zeebrugge Interconnector, 226 km) and finally proceed onshore to Aachen, Germany (via EHB, 308 km). A route length of 1,345 km.

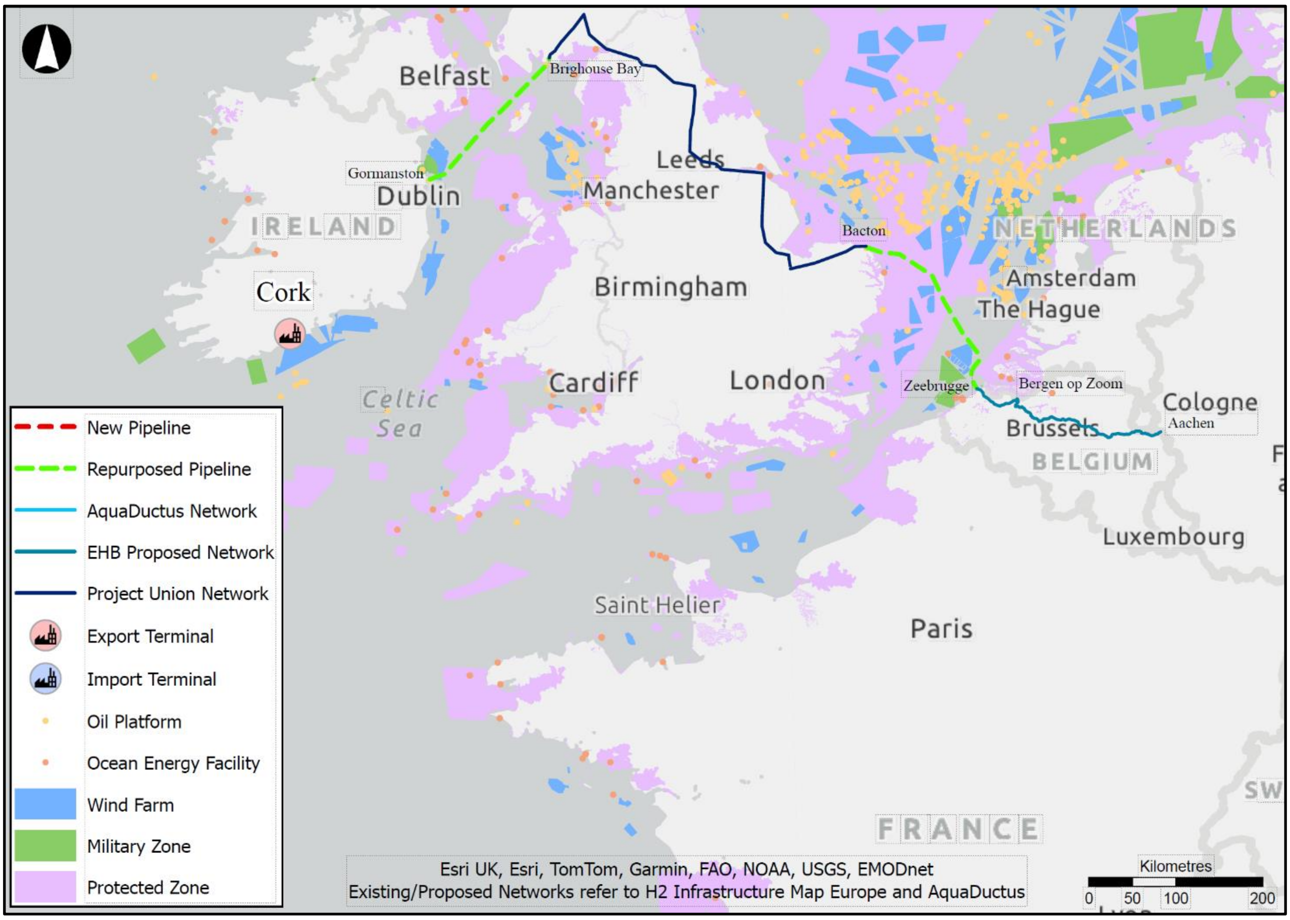


Figure 24: Scenarios 1, 2 and 3 Route Alignments

These scenarios assume the repurposing of offshore and onshore pipelines for the majority of the route. Repurposing of IC1 from Ireland to GB and the Bacton to Zeebrugge Interconnector from GB to Belgium negates the need to construct new offshore pipelines on the assumption that they are found to be suitable and compatible for hydrogen service. Note that the Bacton to Balgzand interconnector from GB to the Netherlands would be an equally valid solution and would give a similar result.

The proposed onshore systems within GB (Project Union) and mainland Europe (EHB) are targeting the repurposing of existing infrastructure where at all possible although some new sections, for example, HyLine Cymru from Milford Haven across South Wales and the connection from the IC1 landfall at Brighouse Bay to the National Transmission System at Moffat or Twynholm, will need to be constructed to complete the network.

7.4.4 Hybrid Offshore and GB & Mainland Europe Onshore Solutions

Scenario 5: Combines new and repurposed offshore pipelines to deliver hydrogen to Belgium. The route would start at Cork, Ireland, continue offshore to Milford Haven, UK via a new build pipeline (234 km), then proceed onshore from Milford Haven to Bacton (via Project Union, 497 km). From there, the pipeline would travel offshore to Zeebrugge, Belgium (via Bacton to Zeebrugge Interconnector, 226 km). A total route length of 957 km (Figure 25).

Scenario 6: Combines new and repurposed offshore pipelines to deliver hydrogen to the Netherlands. The route would start at Cork, Ireland, continue offshore to Milford Haven, UK via a new build pipeline (234 km), then proceed onshore from Milford Haven to Bacton (via Project Union, 497 km). From there, the pipeline would travel offshore to Zeebrugge, Belgium (via Bacton to Zeebrugge Interconnector, 226 km) and finally proceed onshore to Bergen op Zoom, Netherlands (via EHB, 110 km). A total route length of 1,067 km.

Scenario 7: Combines new and repurposed offshore pipelines to deliver hydrogen to Germany. The route would start at Cork, Ireland, continue offshore to Milford Haven, UK via a new build pipeline (234 km), then proceed onshore from Milford Haven to Bacton (via Project Union, 497 km). From there, the pipeline would travel offshore to Zeebrugge, Belgium (via Bacton to Zeebrugge Interconnector, 226 km) and finally proceed onshore to Aachen, Germany (via EHB, 308 km). A total route length of 1,265 km.

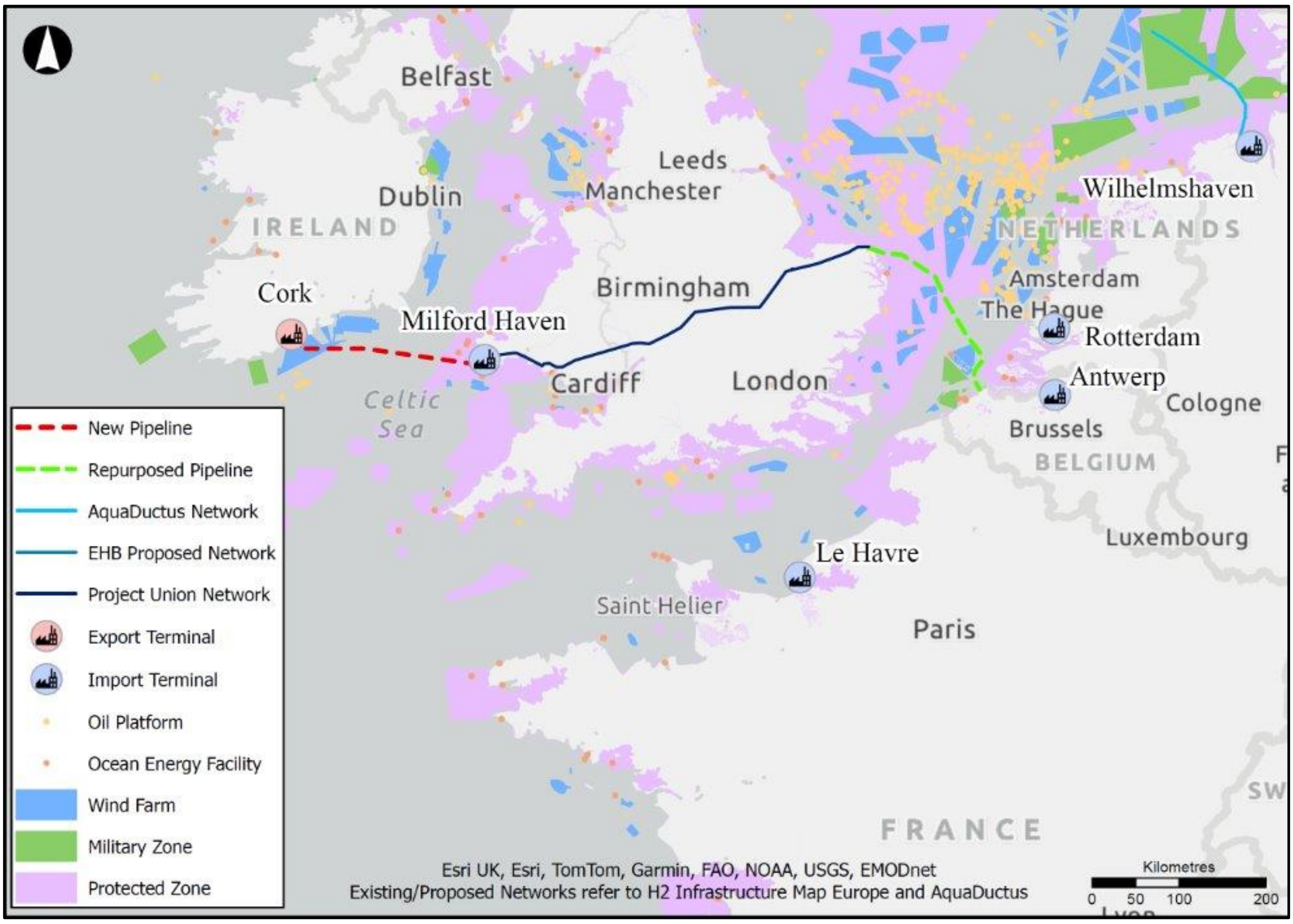


Figure 25: Example Hybrid Route Alignment (Scenario 5)

These scenarios assume a new build pipeline from Cork to the nearest point on the west coast of GB which links into the proposed Project Union system combined with repurposing of the Bacton to Zeebrugge Interconnector from GB to Belgium. This reduces the reliance on one of the GB-Ireland interconnectors being available, suitable and compatible for hydrogen service. Of course, it is possible that a new interconnector pipeline may be required for transporting hydrogen between Bacton and Zeebrugge but we did not consider this option for this report.

7.4.5 New Build Offshore and Mainland Europe only Onshore Solutions

Scenario 8: Combines new build only offshore and repurposed onshore pipelines to deliver hydrogen to Belgium. The route would start at Cork, Ireland, continue offshore to Le Havre, France via a new build pipeline (820 km), then proceed onshore from Le Havre to Mons, Belgium (via EHB, 400 km). A total route length of 1,220 km.

Scenario 9: Combines new build only offshore and repurposed onshore pipelines to deliver hydrogen to the Netherlands. The route would start at Cork, Ireland, continue offshore to Le Havre, France via a new build pipeline (820 km), then proceed onshore from Le Havre to Maastricht, Netherlands (via EHB, 475 km). A total route length of 1,295 km (Figure 26).

Scenario 10: Combines new build only offshore and repurposed onshore pipelines to deliver hydrogen to Germany. The route would start at Cork, Ireland, continue offshore to Le Havre, France via a new build pipeline (820 km), then proceed onshore from Le Havre to Aachen, Germany (via EHB, 510 km). A total route length of 1,330 km.

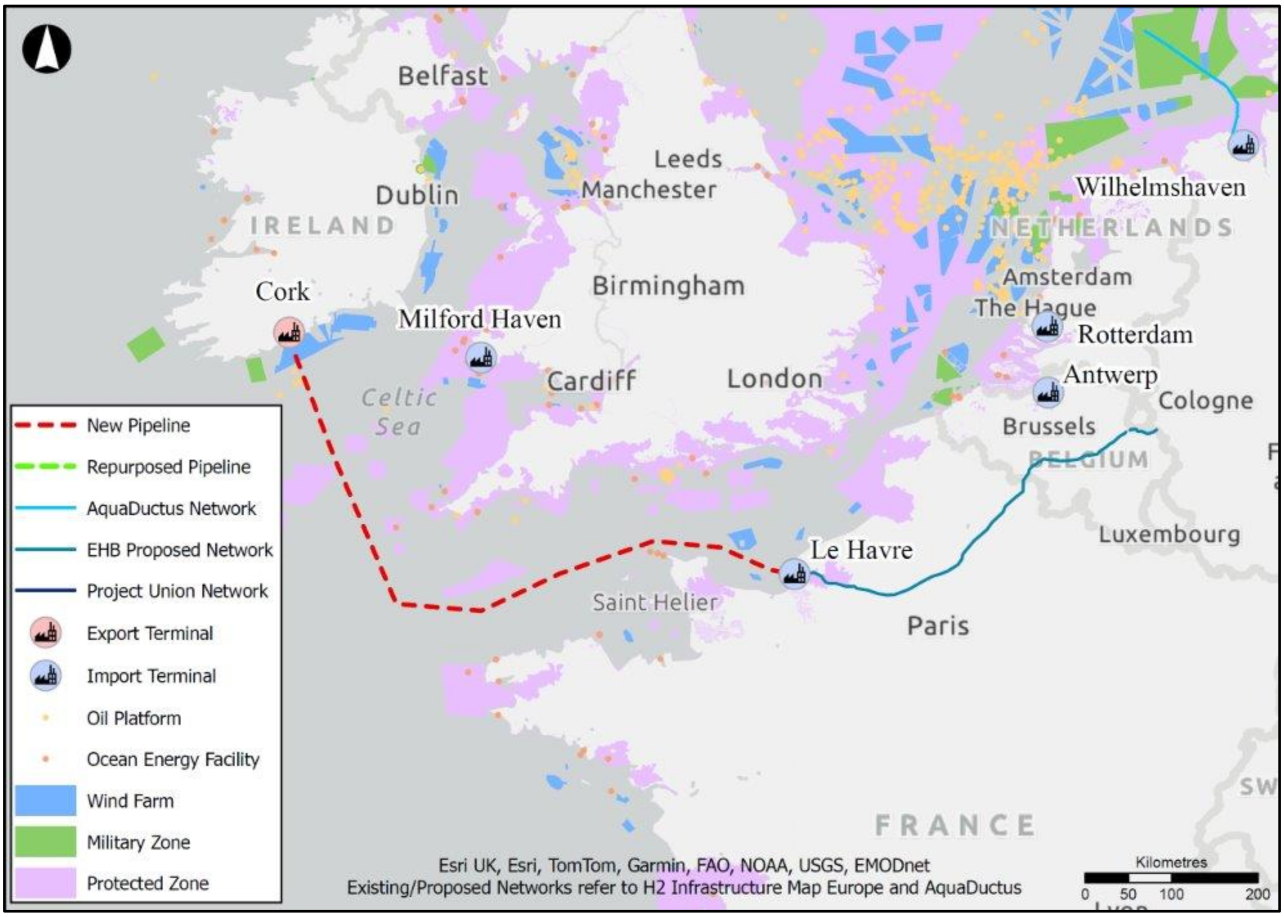


Figure 26: Example New Build Only Offshore Pipeline Route Alignment (Scenario 9)

These scenarios assume a new build pipeline from Cork to the nearest point on the northern coast of mainland Europe which links into the proposed European Hydrogen Backbone. There is no reliance on repurposing of either of the existing interconnectors and these scenarios also remove the need to transit via GB at all which may reduce the risk of post Brexit trade issues and regulatory compliance challenges between UK and EU legislative requirements.

7.5 Other Considerations

7.5.1 Codes & Standards

International hydrogen transport, by pipeline, gas, liquid, or chemical carriers like ammonia and methanol, must comply with strict engineering and maritime standards. These govern design, materials, safety, and operations to ensure integrity and regulatory compliance, with bodies such as ISO, ASME, DNV, IMO, and CEN/EN providing the relevant guidelines depending on the transport method. The following list is indicative of selected codes and standards. Depending on the application and time of project execution, a dedicated review of new and updated applicable standards is essential.

- I.S. 328 - Gas Transmission – Pipelines and Pipeline Installations
- EIGA IGC DOC 121 - Hydrogen Pipeline Systems
- ISO 15916 - Safety of hydrogen systems
- ASME B31.12 - Hydrogen Piping and Pipelines: This standard is specific to hydrogen applications, addressing the design, material selection, construction, and testing of hydrogen pipelines for both industrial and transportation purposes.
- ISO 13623 - Petroleum and Natural Gas Industries — Pipeline Transportation Systems: A comprehensive standard for pipeline integrity and safety, applicable to hydrogen pipelines, is included in Amendment 1
- IGEM/TD/1– Steel pipelines for high pressure gas transmission with hydrogen specific supplements
- ISO 19884 - Gaseous Hydrogen: Cylinders and Tubes for Stationary and Transportable High-Pressure Storage. Under development for hydrogen
- ISO 11326 Ships and marine technology - Test procedures for liquid hydrogen storage tank of hydrogen ships
- ISO 13985 - Liquid Hydrogen: Land Vehicle Fuelling System Interface: Although mainly for land use, this standard is pertinent to marine LH_2 bunkering and ship-to-ship transfer operations.

7.5.2 Planning, Consenting & Regulation

The development of offshore and onshore hydrogen pipeline systems will require numerous consents, permits and licences to build and operate the various components in accordance with the relevant legislation in the countries impacted. In Ireland these will include but are not limited to:

Planning Consent will be required for the onshore compression facilities and for any works partly on land up to the lowest local tide limit in Ireland. This is likely to be consented by An Bord Pleanála if the work is considered as a strategic infrastructure development (SID). This applies to developments that are of strategic economic or social importance to Ireland, the region or local areas.

Highway Improvements that may be required in Ireland will be covered under sections 47 to 49 of the Planning and Development Act 2000.

Consent and Licenses from Maritime Area Regulatory Authority (MARA). As specified by the Maritime Area Planning Act 2021, MARA will be responsible for Maritime Area Consent (MAC) applications which give the developer the legal right to occupy a certain portion of maritime land. They will also grant Maritime Usage Licenses (MUL), which are required for construction and maintenance of structures on the seabed as well as for surveying. MARA's remit extends from the high-water mark to the outer limits of the Irish Exclusive Economic Zone (EEZ) which extends 200 nautical miles from the coast.

Licenses required under the Foreshore Act 1933 are required for works between the average high tide mark and the Irish 12 nautical mile limit. Section 10 will likely be the most relevant. Most of these licenses will be overseen by MARA following the Maritime Area Planning Act 2021.

Environmental Permits and Water Extraction Licenses from the Environmental Protection Agency (EPA). Relevant licenses in Ireland are likely to include an Industrial Emissions License and Water Abstraction License, with the specific license depending on the volume of daily extraction.

Potential for Hydrogen Specific Consents in the Future. There is no existing regulatory or safety framework in place in Ireland for transporting hydrogen via pipelines, with the Gas Act, 1976, only covering natural gas. However, the National Hydrogen Strategy states that a statutory body will be appointed to facilitate future developments.

Appropriate Assessment (AA) will be required if the pipeline in Ireland could impact a Natura 2000 area, such as special areas of conservation (SAC) and special protective areas (SPA) which are protected under EU law.

EU Marine Strategy Directive requires that the development doesn't compromise the good environmental status (GES) of the Irish marine environment. This is measured across 11 qualitative descriptors such as sea floor integrity and introduction of energy such as underwater noise.

Environmental Impact Assessment required under the Espoo Convention which covers the area beyond 200 nautical miles.

Ireland's National Hydrogen Strategy was published in July 2023 with a focus on renewable hydrogen. However, the regulatory framework surrounding hydrogen is still emerging. Currently, pipeline regulation falls under the Commission for Regulation of Utilities (CRU) and there is no specific regulation for hydrogen pipelines yet; these are currently governed by the Gas Acts and EU directives.

Pipeline safety in Ireland is managed under the Gas Act, 1976, as amended, and the Gas Safety Framework Regulations. Although there are no hydrogen-specific amendments yet, they are expected to be introduced after the EU Hydrogen and Decarbonised Gas Market Package has been transposed into Irish Law. This will lead to the include the appointment of a Hydrogen Network Operator after a hydrogen economic regulator has been selected. Licensing and permitting for pipelines over 15 km require planning consent under the Planning and Development (Strategic Infrastructure) Act, 2006, and hydrogen projects may also trigger Environmental Impact Assessments.

Hydrogen regulation is in a more developed state in both GB and the three export destinations, Germany, Netherlands and Belgium and Ireland will be able to benefit from this experience.

7.5.3 Construction Timelines

High level estimates for the duration of pipeline projects are shown in the Figure 27 below, with a key shown for illustrative purposes. The assumptions used in this study and the LCOT model demonstrate that it could take approximately 10 years from FEED commencing until the first start-up and hydrogen being exported. Large-scale construction projects of this nature require comprehensive feasibility and pre-FEED studies to ensure smooth project delivery. These initial phases are crucial for identifying and managing risks, developing robust mitigation strategies, and preventing significant scope changes during later project execution. Proactive planning at this stage lays the foundation for efficient and timely construction, ultimately supporting the successful and safe export of hydrogen to international markets.

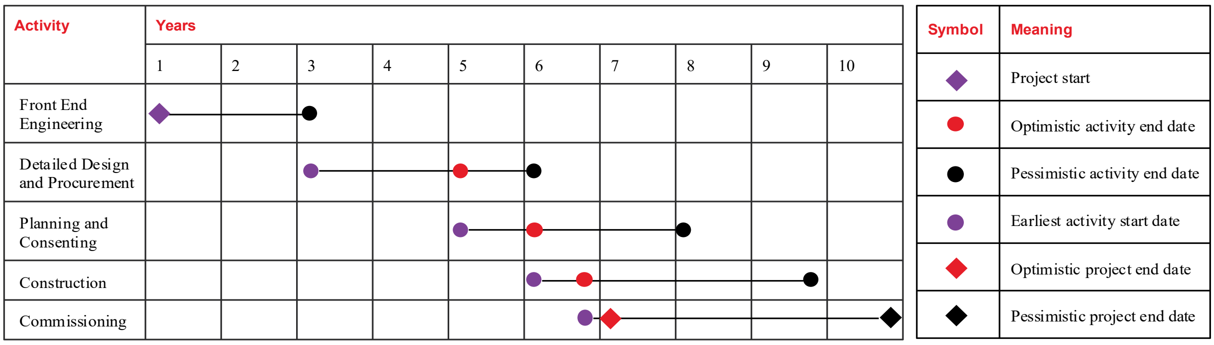


Figure 27: Indicative construction timeline for pipeline projects

8. WP2: Shipping Export Assessment

8.1 Introduction

To facilitate the export of conditioned hydrogen (compressed or liquefied) or the selected derivatives by ship, several technical considerations must be made. This section provides an overview of the potential options as well as technical considerations associated with port infrastructure requirements to enable exports from the Republic of Ireland. It should be noted that potential port locations in Northern Ireland have not been considered as part of this study.

Consideration has been given to the suitability of the location of several ports in the context of their potential for providing facilities to export hydrogen in compressed or liquid form or as ammonia or methanol. Factors such as the maximum ship size potential, the ability to expand, impact of onshore facilities required to facilitate export (compression and liquefaction facilities, derivative production, intermediate storage facilities, etc.), proximity to OWE developments and hydrogen production centres will be taken into account.

The approach looks at the functional requirements for port infrastructure to identify suitable representative port locations in Ireland and the selected destination countries as the export and entry points for shipped hydrogen vectors to mainland Europe.

An assessment of current vessel configurations for each vector and how this will need to develop as export volumes increase over time is discussed.

8.2 Functional Requirements

8.2.1 Vessels

The shipping market for hydrogen and its derivatives is in various stages of development. The fleet and market for the shipping of methanol and ammonia is relatively mature whereas the market for shipping of hydrogen in either liquefied or compressed state is still in the early stages of development.

In the case of methanol, it is largely compatible with the global chemical tanker fleet and therefore there is a high degree of certainty around the shipping technology and possible market rates. Similarly, ammonia is currently being shipped globally in large volumes. In the case of ammonia there are currently plans to expand the fleet with a slightly larger class of ships, designated “very large ammonia carrier - VLAC”, to accommodate the expected surge in global trading volumes and international trading.

When it comes to shipping hydrogen in either compressed or liquified states, there remains a lot of uncertainty. Arup have undertaken a literature review to estimate what the characteristics of the fleet will be in the future. Based on analysis of the current fleet of LNG, LPG, crude oil, and chemical tankers, it has been assumed that existing tankers could be retrofitted to be utilised as hydrogen-derivative carriers in the future, hence the potential volumetric capacity of derivative carriers has largely been based on the existing fleet.

The liquefied hydrogen carrier development is in its infancy, but it is anticipated that their development may track that of the current LNG carrier fleet. For example, Kawasaki received approval in principle for a 160,000m^3 liquified hydrogen carrier in 2022. At present, there is only one active Liquified Hydrogen Carrier namely the “Suiso Frontier” with a capacity of just 1,250m^3.

Similarly, compressed hydrogen carriers are still in early-stage development but there has been approval in principles (AIP) issued by classification societies for designs with capacities of 26,000m^3 and 120,000m^3. However, little is known about the physical dimensions and characteristics of these proposed ships.

The latest data available for ship dimensions together with an assessment of the potential future capacity of different vector carriers has been summarised in Table 14. These tanker sizes have been used as the basis of assumptions for our hydrogen shipping vectors, namely methanol, ammonia, compressed hydrogen and liquefied hydrogen.

Table 14: Vessel Characteristics

Carrier type	Current Capacity ('000m^3)	Future Capacity ('000m^3)	Length Overall (LOA) (m)	Draught (m)
Methanol	45 to 160	60 - 160	147-241	8.7 - 12.2m
Ammonia	22.5 to 35	22.5 - 80	160 - 225	9 - 13
Liquefied Hydrogen	1.25	1.25 - 160	116 - 346	4.5 - 12.5
Compressed Hydrogen	-	26 - 120	-	-

8.2.2 Terminal Infrastructure

To facilitate the export and import of hydrogen vectors from a port the infrastructure must be able to accommodate the size of vessel and the specific loading and unloading arrangements associated with the handling of hazardous and toxic products.

Marine Terminal Infrastructure

The marine terminal infrastructure will consist of storage tanks, marine berth(s) and associated loading infrastructure and utilities. The level of infrastructure required will be dictated by the product being handled, the number of expected vessel movements and the storage duration required.

In relation to the number of berths it should be noted that industry typically limits a single berth to between 60% and 70% occupancy to avoid charges due to delays and associated demurrage costs. Where occupancy exceeds this an extra berth is typically required increasing the marine infrastructure needs.

Storage Volumes at Export Terminal

As ship transport is an intermittent activity transporting discrete parcels of product while production of the product is likely to be a continuous process, intermediate storage at the export port will be required to manage the product when ships are not in port. The storage volume required at the export terminal is a significant consideration for several reasons. As well as the CAPEX of providing the storage tanks and conditioning equipment to maintain the product at the required pressure and temperature, it has a significant impact on the land requirements. Storage facilities also influence safety considerations when it comes to technical safety assessment and quantified risk analysis (QRA).

Calculating the required storage is a function of the export shipping operations and the production rates. A simplified method has been adopted for this study which looks at the expected average duration between shipping and then adds a buffer period to minimise interruption to production in the event of shipping delays due to mechanical issues or weather.

8.3 Port Locations

8.3.1 Ireland Export Points

Port locations with bulk liquid handling capabilities for hydrocarbons were considered for use as potential export locations based on existing facilities and expertise to support other cargo services. In addition, the proximity of ports to potential future green energy hubs (e.g. hydrogen clusters) as well as offshore wind developments was also considered. Based on the above criteria, the 3 primary cargo handling ports in Ireland, namely Dublin Port, Port of Cork and Shannon Foynes Port merit further consideration.

It should be noted that this is a very high-level review and final feasibility of port use will need to be based on project specific assessment as well as appropriate marine and technical safety studies to ensure the compatibility of the proposed export activity with existing port operations and the local environs.

Port of Cork

The Port of Cork is already a conventional energy hub with ongoing shipping operations for liquid bulk cargoes at Tivoli, Whitegate and Ringaskiddy. There are also the long-established refining operations at Whitegate. The depleted Kinsale gas field previously linked to the mainland at Inch has the potential for large scale hydrogen storage. The port is capable of handling vessels with a draft of up to 10m without tidal restrictions and, as the world's second largest natural harbour after Sydney, Australia, it has significant water frontage available in the lower harbour.

The Port Masterplan has a stated ambition for the lower harbour area to become a hub for green energy activities. This ambition is being realised with the ongoing quay wall extension works at Ringaskiddy which is intended to facilitate, and support OWE facility assembly activities at the south coast DMAP sites for offshore wind Phase 2 developments. There is also an emerging hydrogen cluster in the lower harbour with industry already actively investigating the feasibility of developing hydrogen production facilities.

Finally, the location of Cork on the South Coast has the advantage of being the closest port to the intended destination markets in Northern Europe with well-established trading operations with ports such as Antwerp and Rotterdam.

Dublin Port

Dublin Port is Ireland's largest port in terms of throughput. Its central location on the east coast and proximity to large population centres makes it an attractive location for logistics focussed activities. There are currently several berths handling refined products in the port as well as import activities for the National Oil Reserve Agency (NORA). In 2024 the port handled 4.6 MMTPA of liquid cargo.

However, land availability constraints at the port and a business focus on Lo-Lo and Ro-Ro traffic will limit its ability to act as a hub for green energy developments in the medium and longer term. In addition, these land constraints and its urban location may present challenges in terms of technical safety considerations for the large-scale production, storage and handling of hydrogen or its derivatives.

Shannon Foynes Port

The Shannon Estuary under the stewardship of Shannon Foynes Port Company is another established conventional energy hub with bulk liquid activities undertaken at Tarbert, Foynes and Shannon Airport.

There are also a number of energy related developments planned along the estuary with a proposed LNG import terminal at Ballylongford as well as proposals by ESB to convert lands at Moneypoint into a renewable energy hub, including potential for ammonia production. The aforementioned HYreland report, see chapter 12, will consider this in more detail. However, a new jetty would be required at Moneypoint to facilitate exports of hydrogen derivatives.

The location of the Shannon Estuary on the west coast makes it a very attractive location for green energy related activities when offshore floating wind comes online, however the opportunities for establishment of a hub are much more limited for the initial stages of offshore wind roll out which will be focussed on fixed bottom infrastructure off the east and south coasts. The west coast location also makes it the least attractive in terms of transit time to northern European markets.

Summary

On basis of above review, Port of Cork currently demonstrates the highest potential for development of export facilities for hydrogen to continental Europe and has been selected for this study.

This is due to it being the closest location to the target market ports in Northern Europe and the availability of land in the lower harbour to develop the required port infrastructure. It is also likely to be developed as a hub for offshore energy developments from the planned Celtic Hydrogen Cluster off the south coast. As the first large scale hydrogen (and/or hydrogen derivative) production plants are constructed in Ireland, a more detailed study should be undertaken in selecting the best port for export.

8.3.2 European Import Points

As previously noted, the potential export markets for hydrogen products by ship was restricted to Belgium, the Netherlands and Germany for the purposes of this study. A high-level assessment was undertaken in order to determine possible import locations in each of these countries. The main criteria considered were as follows:

- The port needed to be a node on the European Hydrogen Backbone (EHB)
- The port had to be of large scale and experienced in handling energy cargoes with plans for hydrogen infrastructure going forward
- It had to be near established shipping lanes between Ireland and Northern Europe.

It should be noted that this is not an exhaustive analysis and there are additional ports that would merit consideration on a project specific basis.

Germany – Port of Wilhelmshaven

- Located approximately 70km from the Dutch border, the Port of Wilhelmshaven is strategically placed for accepting the import of hydrogen from Ireland into the German market. It is also closer to Cork than other major German ports such as Hamburg and Bremen.

  There are plans in progress for the development of hydrogen and ammonia import facilities at the port with Uniper's "Green Wilhelmshaven" project currently at front end engineering design (FEED) stage. This project will consist of both an electrolyser and an import facility for ammonia, as well as connections to the gas pipeline grid and underground storage located nearby. Such a development would make Wilhelmshaven an attractive location for importing hydrogen to Germany.

Netherlands – Port of Rotterdam

- The Port of Rotterdam is Europe's largest Port. The port authority is currently working with various partners across the port with a view to making Rotterdam an international hub for hydrogen import, application and onward distribution to other northern European countries. Such an initiative makes it a strong candidate destination for Irish produced hydrogen or derivative products in the future.

Belgium – Port of Antwerp Brugge

- The port of Antwerp is Europe's second largest port and, similar to Rotterdam, has ambitions on becoming a significant hub for hydrogen imports. They have set up the "Hydrogen Import Coalition" comprising leading players such as DEME, Engie, Exmar, Fluxys and WaterstofNet. Together they have set out a roadmap for the import of hydrogen to Belgium. There is already well-established connectivity between Ireland and Antwerp making it a proven trade route.

The three ports named above have been selected as the import locations for shipped product from Ireland. It should be noted that other port locations in the target countries could be considered in the future should there be project specific considerations.

8.4 Shipping Scenarios

Several routing scenarios were developed for shipping connections between Ireland and the selected port destinations in Germany, the Netherlands and Belgium, utilising recognised shipping routes between Ireland and mainland Europe. These are shown in Figure 28 and Table 15. It should be noted that the distances calculated are approximate but are deemed appropriate for the purposes of this comparative exercise. They do not consider specific routes that may be required for weather or traffic management purposes.

The selected scenarios investigate a range of possible solutions to allow the levelized cost of transport to be compared for the different routes for hydrogen and the derivative vectors. These are summarised in Table 15 and represent a range of possible solutions. Further detailed analysis would be required to further investigate the viability of each option.

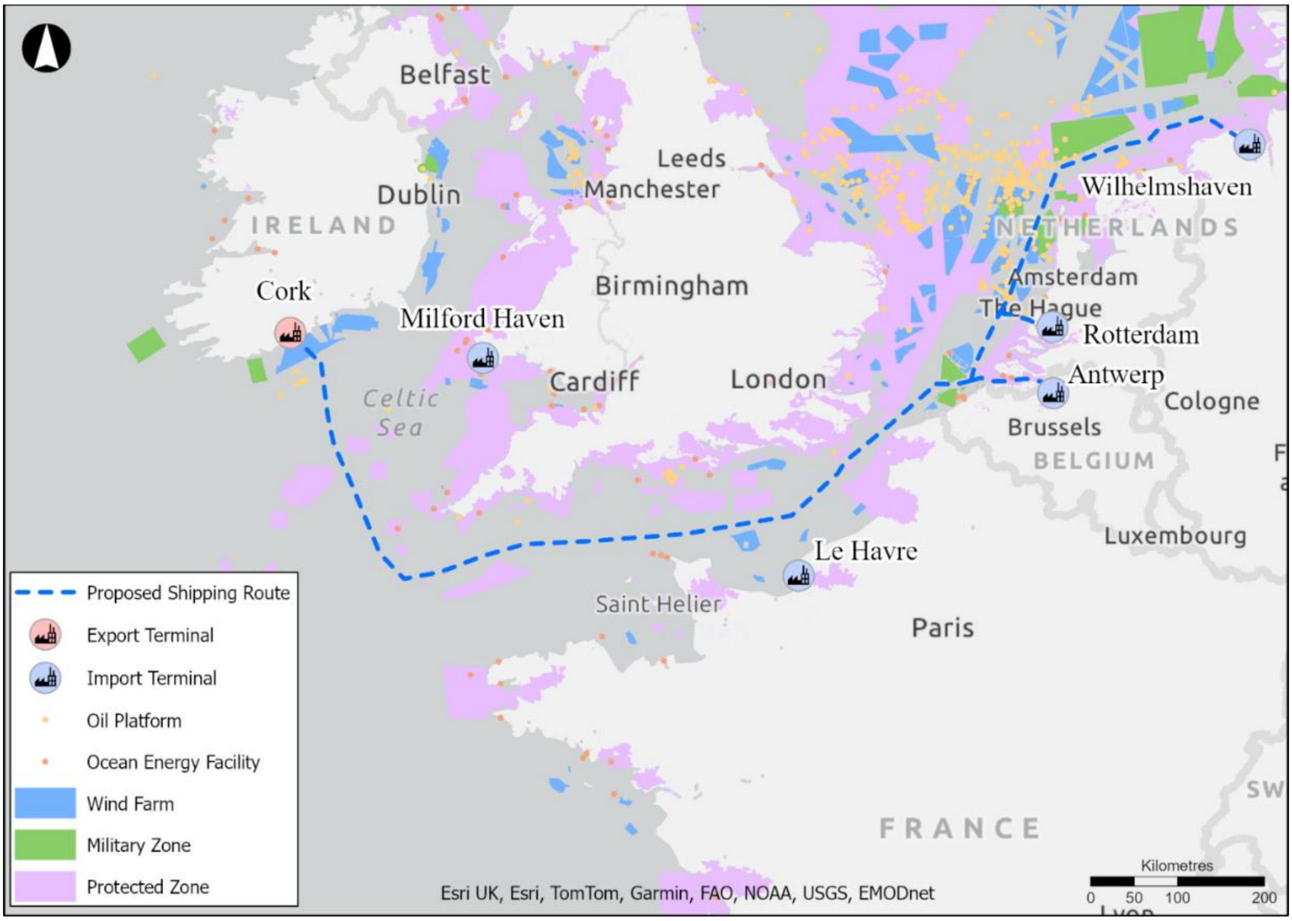


Figure 28: Proposed Shipping Routes

Table 15: Summary of export destinations and corresponding routes

No.	Vector	Destination	Start	End	Distance [km]
S11	Shipping - CH2	Belgium	Cork, IR	Antwerp, BE	1140
S12	Shipping - CH2	Netherlands	Cork, IR	Rotterdam, NL	1190
S13	Shipping - CH2	Germany	Cork, IR	Wilhelmshaven, DE	1550
S14	Shipping - LH2	Belgium	Cork, IR	Antwerp, BE	1140
S15	Shipping - LH2	Netherlands	Cork, IR	Rotterdam, NL	1190
S16	Shipping - LH2	Germany	Cork, IR	Wilhelmshaven, DE	1550
S17	Shipping - NH3	Belgium	Cork, IR	Antwerp, BE	1140
S18	Shipping - NH3	Netherlands	Cork, IR	Rotterdam, NL	1190
S19	Shipping - NH3	Germany	Cork, IR	Wilhelmshaven, DE	1550
S20	Shipping - MeOH	Belgium	Cork, IR	Antwerp, BE	1140
S21	Shipping - MeOH	Netherlands	Cork, IR	Rotterdam, NL	1190
S22	Shipping - MeOH	Germany	Cork, IR	Wilhelmshaven, DE	1550

8.5 Other Considerations

In a similar manner to the pipeline option (see section 7.5.2), consideration will need to be given to planning and consenting. Note that both ammonia and methanol are toxic substances so this process may take some time. Similarly careful consideration will be needed for options that include the storage of large volumes of either gaseous or liquefied hydrogen at the port to manage the significant safety risks.

8.5.1 Indicative Port Infrastructure Construction Costs and Timelines

To enable the export of hydrogen derivatives, new port infrastructure may be required in the form of a new jetty berth. The cost of developing this new infrastructure is not included in the levelised cost of transport model. Indicatively, the total cost for a new jetty and berth (including owner's cost, technical studies, prelims, and the construction of the approach jetty, loading platform, dolphins, and walkways) could be in the range of €50 - 200 million depending on size, site location, and geological conditions.

High level indicative durations for the development of a new port infrastructure project are suggested as follows:

- Planning Permissions, permitting: 1-4 years
- Front End Engineering Design: 1 year
- Environmental / Social / Health Impact Assessments: 1-2 years
- Procurement: 1 year
- Construction: 2-3 years
- Commissioning: 0.5-1 year

Some of these activities can occur concurrently, notably design work (front end and detailed engineering) and planning and consenting processes (environmental / social / health impact assessments) and – to some degree – procurement and construction, which are all time intensive processes. This means that the overall transition could be credible in a 5-year timeframe, unless the port already moves the product.

9. WP2: Technical Comparison of Hydrogen Export Vectors

Each of the different forms of transport vector reviewed as part of this study has advantages and disadvantages depending on the volume of hydrogen required to be transported and the relative distances to be transported. The maturity of the technology being deployed is also a factor as is the scalability of the method used to transport the selected vector.

A high level comparison of key parameters associated with the selected hydrogen export pathways: Gaseous via pipeline and Compressed hydrogen (CH2), Liquefied hydrogen (LH2), Ammonia (NH3) and Methanol (MeOH) products via shipping options is shown in Table 16. Option B, stated for ammonia and methanol, represents conversion back to pure hydrogen from the transported derivative.

Table 16: Transport Vector Comparison Summary

Parameter	Pipeline Transport	Shipping (CH2)	Shipping (LH2)	Shipping (NH3)	Shipping (MeOH)
Carrier form	Gaseous H_2 (20-100 bar)	Compressed H_2 (250 bar)	Liquid H_2 (-255° C, 1-10 bar)	NH_3 (Liquid, -33 ° C, 1 bar)	CH_3OH (Liquid, ambient cond.)
Maturity	High (natural gas infra exists)	Low-medium (pilot)	Medium (large scale under development)	High (existing infrastructure and demo projects)	Medium (less mature for H_2 recovery)
Energy losses[80]	1-3%	6-10%	20-30%	20-30% (option B)	10-15% (option B)
Hydrogen losses[81]	Negligible	Negligible	5-10%	15-18% (option B)	5-15% (option B)
Infrastructure availability	High (gas networks)	Low	Low-Medium	Medium-High (ammonia ports exist)	Medium (existing methanol terminals)
Production Inputs and Outputs	Green hydrogen	Green hydrogen	Green hydrogen	Green hydrogen + nitrogen (from air sep.)	Green hydrogen + water, captured and released CO_2
End-Use Options	Hydrogen only	Hydrogen only	Hydrogen only	1. Used as ammonia 2. Cracked to hydrogen	1. Used as methanol 2. Reformed to hydrogen
Toxicity / Safety	flammable, leak risk	flammable, leak risk	flammable, leak risk	flammable, leak risk, toxicity	flammable, leak risk, less toxic than ammonia

[80] Based on technical overview with energy losses per vector assuming supplementary energy supply from grid connection for energy intensive steps such as compression, liquefaction and synthesis. Input wind energy is completely converted to hydrogen.

[81] Ammonia cracking and methanol reforming have low technology readiness level. Losses are roughly assumed for comparative purposes.

9.1 Pure Hydrogen Options

Transportation of large volumes of gasses by pipeline is well understood and proven at scale. No conversion of hydrogen into another form is required and this will result in efficient transport over the distances and flowrates assumed in this study for the Base and High Scenarios.

However, at the Low Scenario throughput, pipeline options become sub-optimal. Use of existing pipelines may result in operational challenges due the resultant low flow rates and associated pressure drops in oversized pipelines for the flows. Construction of CAPEX intensive new build pipelines should realistically be considered as a one-time activity and future proofing for anticipated higher throughputs will offer the same operational challenges in the early years of low flow operation. In addition, material selection for pipelines is a key issue, particularly if repurposing of existing infrastructure is proposed and the impacts of compression requirements need to be further understood for this range of options.

Transportation as compressed or liquefied hydrogen at the Low Scenario volumes is likely to be possible but the technology maturity of vessels to ship at even these low volumes is still very low. Compressed hydrogen at 250+ bar has not been proven at any scale in dedicated tankers, and the largest operating liquid hydrogen tanker is still only 1,250m^3 capacity with scale up for shipping providers unproven. Compressed hydrogen attracts some energy losses but the key issue with liquefied hydrogen is the significant energy consumption in the liquefaction step and the largest energy losses in the transportation life cycle due to the very low operating temperature. However, the benefits are most visible in the import / downstream facilities as pressure let down and regasification is comparatively straightforward and has the lowest energy requirement.

In all cases (gaseous, compressed and liquefied) there are no chemical processes involved, and the product remains as pure hydrogen throughout the transport cycle.

9.2 Derivatives

Ammonia has the advantage of already being produced worldwide at scale and traded as a commodity in its original form. It has a high energy density and hydrogen content, and its handling is understood and proven, although it is a toxic substance and requires very careful handling. Significant energy consumption is required in the production of ammonia and in the cracking process required if the hydrogen is to be released at the point of delivery. Ammonia cracking is rarely provided at significant scale and may not be an efficient way to transport hydrogen, particularly at scale.

Methanol has the advantage of being able to be transported at ambient temperature and pressure making handling more straight forward using conventional chemical tankers. It is less toxic than ammonia but still requires careful handling. Whilst energy consumption in the production and cracking back to hydrogen is lower than for ammonia there are still significant penalties in converting back to hydrogen, with the added issue of having to deal with the CO2 released as part of the reformation process.

9.3 RAG assessment of shipping logistical considerations and feasibility

An assessment has been undertaken which combines a quantitative sizing analysis with a qualitative Red-Amber-Green (RAG) comparison based on estimated vessel size, ship movements and required storage.

Shipping of hydrogen and its derivatives including compressed hydrogen (CH2), liquefied hydrogen (LH2), ammonia (NH3), and methanol (MeOH) across the three demand scenarios: Low (22 ktpa), Base (215 ktpa), and High (430 ktpa) are included. The analysis considers both small and large ship configurations, calculating the number of shipments per year for the demand scenario and the corresponding buffer storage needed at the export terminals.

The rankings are determined by comparing estimated storage volumes against commercially available tank sizes and practical engineering limits. The RAG system then classifies each case as green if similar commercially available installations exist, amber for conditional feasibility with special considerations or announced as under development, or red for being impractical due to excessive size or frequency. The results are presented in Figure 29.

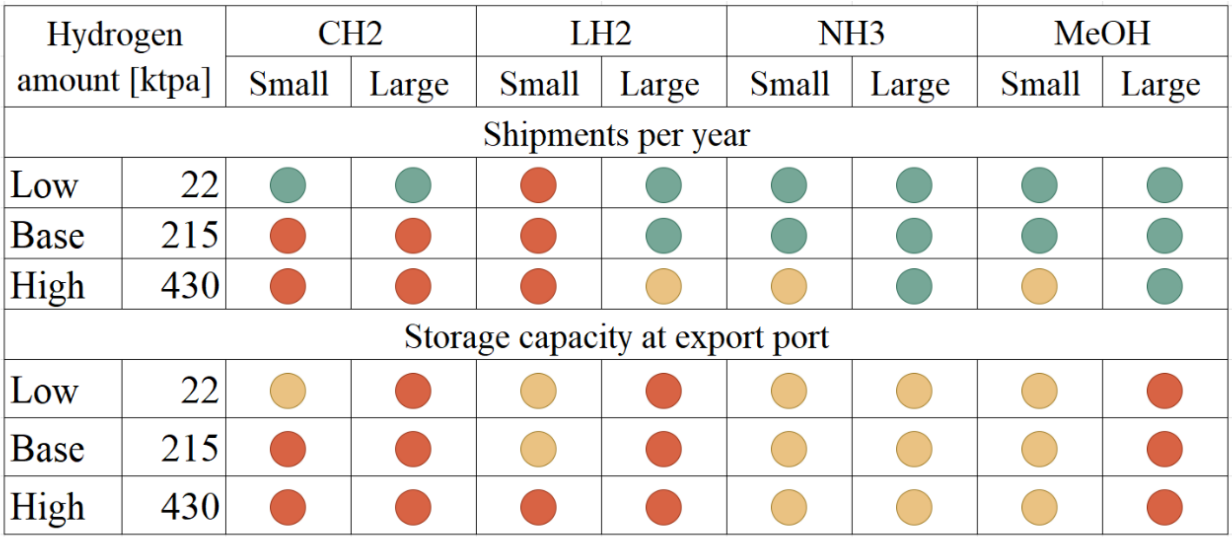


Figure 29: RAG Assessment of Shipping Logistical Factors

For compressed hydrogen, low volumes in small or large ships are considered practical but at the higher volumes movement by ship is considered to be impractical due to the current maturity of the vessels required to move larger volumes. The assumed small LH2 vessel size, based on the only existing vessel, is considered too small to practically move even the lowest volumes but development of larger vessels, similar in size to existing LNG carriers, would make shipping more feasible at all volumes considered in this study.

Generally, the movement of compressed or liquified hydrogen by ship is considered less practical whereas movement of ammonia and methanol is considered feasible at all volumes. The assessment depends on currently available or announced technologies. New technological advancements, especially in compressed and liquified hydrogen, would certainly change these findings.

Greater challenges when considering the required level of intermediate storage to facilitate the various shipping options. As the vessels sizes get larger the number of trips to transport the volume of product decreases and so to maintain continuity of production of hydrogen or its derivatives, much higher storage volumes will be needed at the port of origin. This will increase the real estate requirement with accompanying higher CAPEX and OPEX costs to operate the storage facility, particularly for LH2 where there are significant challenges managing boil off gas.

9.4 Comparison

The comparative analysis of hydrogen export pathways highlights both the technical challenges, and the logistical trade-offs associated with each method. Pipelines, while highly mature and benefiting from existing natural gas infrastructure, are best suited for bulk transport of high volumes over relatively short distances (below 1,000 km) and exhibit the lowest energy losses, typically between 1-3%. In contrast, shipping liquid hydrogen (LH2) and compressed hydrogen (CH2) allows for much longer transport ranges but at the expense of significantly higher energy and mass losses, where losses can reach up to 30% or higher, especially at longer distances due to boil-off. Methanol and ammonia emerge as promising alternatives for intercontinental distances as both can leverage established shipping terminals and offer options for reconversion to hydrogen or direct use in chemical industries. A more favourable scenario for ammonia and methanol is direct delivery as a chemical feedstock without cracking or reforming.

From a shipping infrastructure and operational standpoint, methanol and ammonia routes provide greater flexibility and resilience. Methanol, in particular, can be handled at ambient conditions, reducing the complexity and cost of storage and transport compared to cryogenic LH2 or highly compressed hydrogen. Both ammonia and methanol are produced with renewable hydrogen inputs, but ammonia also requires nitrogen sourced from air separation, and methanol production involves not only hydrogen and water but also captured and re-released CO_2. This interplay of feedstocks and by-products has direct implications for lifecycle emissions and environmental compliance, necessitating careful integration with carbon capture and renewable energy systems.

Safety considerations are critical across all pathways, but the nature of risks varies. While hydrogen in all its forms is highly flammable and prone to leaks, ammonia transport introduces additional toxicity concerns, demanding rigorous protocols for personnel and environmental protection. Methanol's toxicity is less severe than ammonia but still requires specialized handling and storage solutions. Ultimately, the choice of hydrogen carrier and export route must balance efficiency, infrastructure readiness, distance, safety, and environmental impact to enable a sustainable hydrogen supply chain.

Ammonia and methanol are the most practical options for large-scale hydrogen exports, with feasible storage and shipping under Low, Base and High scenarios. Ammonia matches current infrastructure, and methanol benefits from established petrochemical systems. However, there are high energy and efficiency penalties in the conversion from the transported derivative. Compressed and liquefied hydrogen require excessive storage and shipments even at low demand, making them impractical beyond small to medium scale with the ships that are currently available. Overall, liquid carriers like ammonia and methanol are preferred for shipping exports, as direct hydrogen transport by ship is limited by existing technology and safety standards.

10. WP3: Levelised Cost of Transport

10.1 Introduction

Following the technical work outlined in WP1 and WP2, Arup conducted an exercise to estimate the LCOT of transporting hydrogen from Ireland to end markets. Three end markets were modelled: Germany, Netherlands and Belgium as these were deemed the most likely markets for hydrogen exported from Ireland. Several different methods of transporting the hydrogen to these end markets was then explored including pipeline transport and ammonia, methanol, liquid hydrogen and compressed hydrogen shipping. An overview of the pathways explored are shown in Figure 30 below.

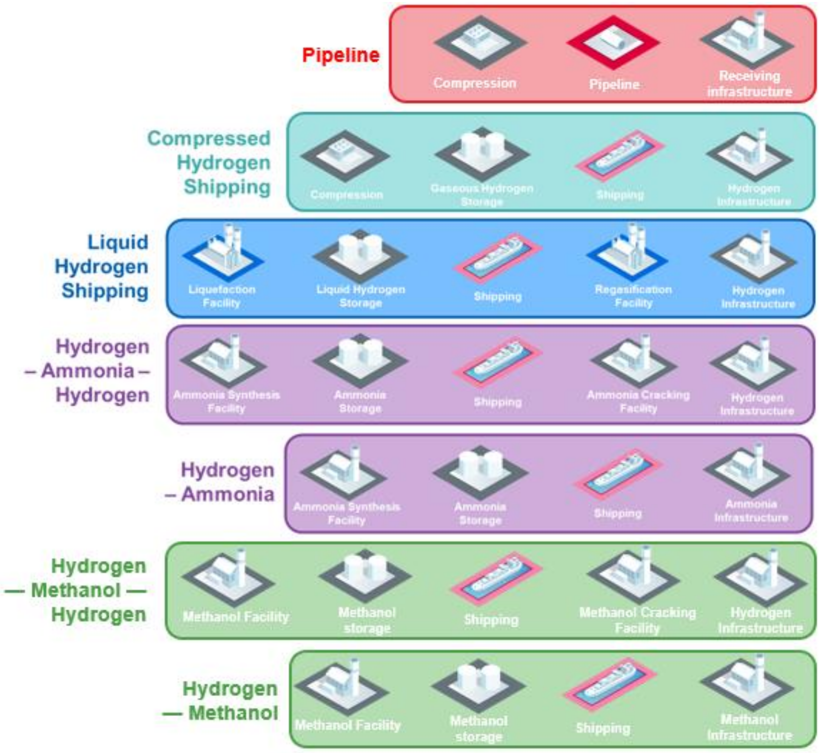


Figure 30: Transport pathways assessed (Source: Arup)

This section provides an overview of the following:

- Description of how the levelised cost modelling was conducted
- Scope of the levelised cost model
- Description of the key input assumptions per transport pathway
- Results of the modelling for each transport pathway

Note, in appendix A.2, we have included a sensitivity analysis per transport pathway demonstrating how different input assumptions effect the total cost of transport.

10.2 Levelised Cost Modelling

Levelised cost of transport considers the total costs – DEVEX, CAPEX, OPEX and REPEX – of transport, including where relevant, the costs associated with transforming hydrogen to its derivative form including ammonia, methanol and liquid hydrogen before shipping it, over the assumed 25-year life of a project.

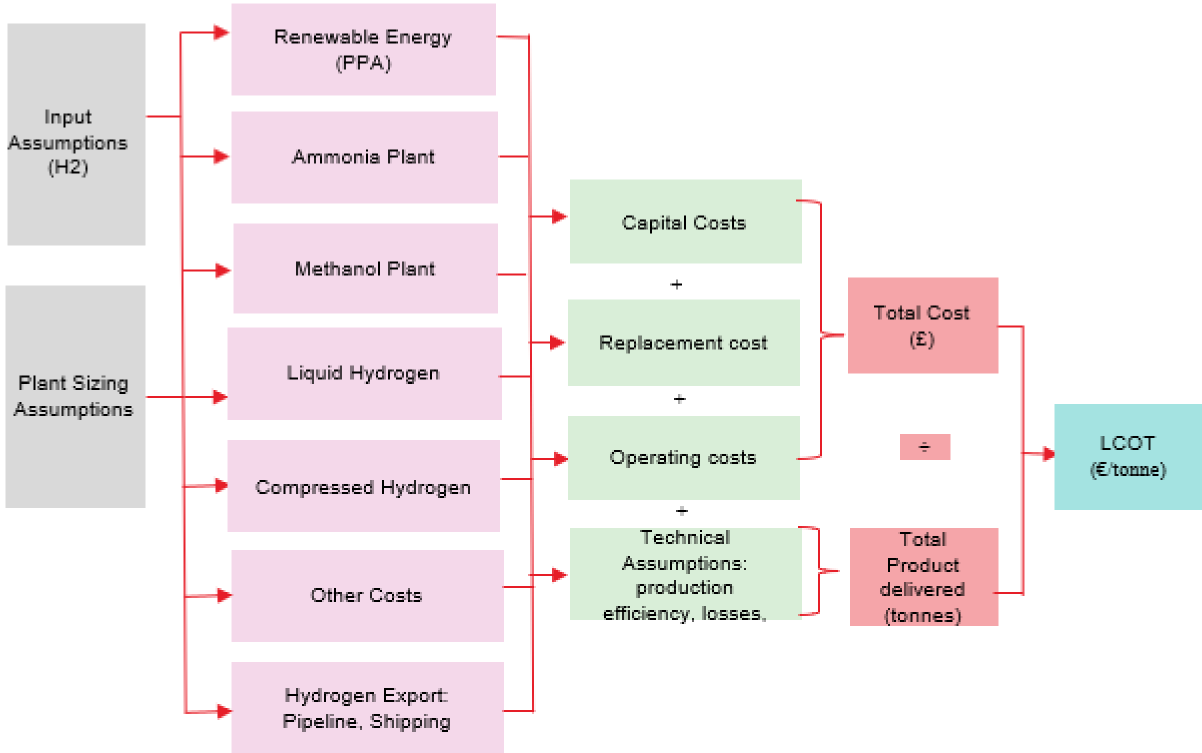


Figure 31: Levelised cost modelling assessment overview (Source: Arup)

The model calculates the levelised cost of transport by dividing the total project costs by the total volume of hydrogen or where relevant hydrogen derivative that has been delivered to the import country. The model assumes the total costs over 3 years of development time, 4 years of construction time and then 25 years of operation. Both the costs and volume of hydrogen or, where relevant hydrogen derivative, transported are discounted at a rate of 8%.

The sum of costs over the lifetime are based on constant input assumptions (for example, we do not assume costs vary per year). These inputs are based on Arup's own internal database and data from market providers such as, but not limited to, European Hydrogen Backbone (EHB), International Renewable Energy Agency IRENA, Hydrogen Europe and European Network of Transmission System Operators for Gas (ENTSOG).

The supply chain for each transport option is split into its relevant building blocks. For each building block per pathway the inputs are used to determine an annual cost split between the following categories:

- Development and wider project costs (DEVEX);
- Capital costs of infrastructure (CAPEX);
- Replacement costs of infrastructure (REPEX);
- Annual fixed and variable operating costs of infrastructure (OPEX).
- All results are shown in euro per tonne (EUR/Tonne) of hydrogen delivered to the end market. Where relevant results are shown in euro per tonne of hydrogen derivative. Note that this can easily be converted to Euro/kg by dividing the results by 1000.

See Figure 31 for a high-level overview of the levelised cost modelling assessment process.

10.3 Boundary of modelling

We have defined the segments of the hydrogen and where relevant hydrogen derivative value chain that are the focus of the levelised cost assessment. Figure 32 shows what assets have been costed for all relevant transport pathways.

It is important to note that the cost of producing hydrogen is not included in the model. In most cases the cost of hydrogen production is likely to be significantly higher than transportation costs. For modelling purposes, the costs include transporting hydrogen up to the border of the end market (Germany, Belgium or the Netherlands) for the pipeline pathways. For the derivative pathways it includes the cost of converting hydrogen to its derivative form, transporting hydrogen via ship to the import port and converting it back to gaseous hydrogen.

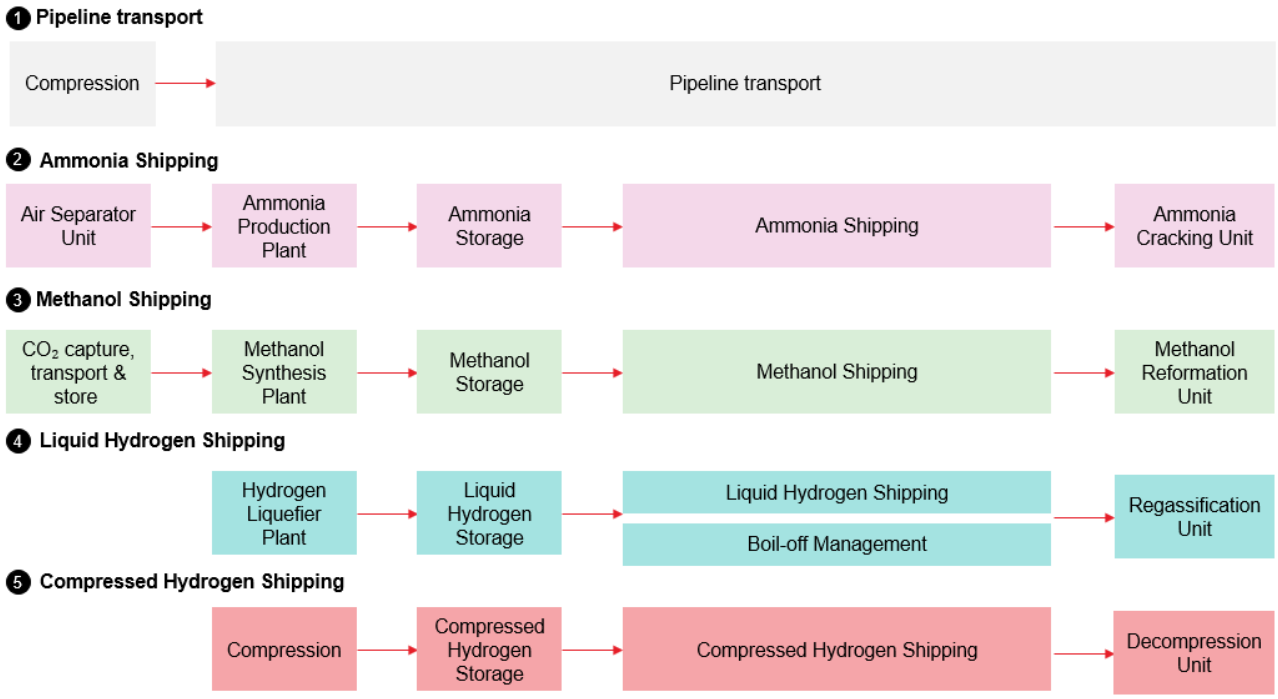


Figure 32: Boundary of levelised cost model

As shown, there is some variation in what needs to be costed depending on the shipping option explored. Similarly, we have considered a range of pipeline models including transport via new pipeline, repurposed pipeline or hydrogen backbone.

While there is variation in what needs to be costed per transport option, there are also consistent assumptions. These include:

- 215 kilotonnes per annum (ktpa) of hydrogen delivered in the base case.
- 25-year project life (3 years development time and 4 years construction time)

10.4 Transport Cost Modelling Assumptions

Pipeline

The LCOT model calculates the costs of compressing hydrogen to the pipeline operating pressure using an inlet compressor station. It then includes the costs of the hydrogen pipeline. Depending on the pathway chosen pipeline costs are either the costs of constructing new pipelines, the costs of modifying pipelines or the cost of using sections of the European Hydrogen Backbone (known as Project Union in the UK). In Figure 33 we set out the pipeline models considered per pipeline pathway.

Figure 33: Pipeline Pathways Modelled

The key considerations for the pipeline pathways include:

- Capital cost of the inlet compressor station. The cost of the station varies depending on the inlet pressure, outlet pressure and amount of hydrogen being compressed.
- Capital cost of the new pipeline. The unit cost varies as we have assumed different sized pipelines per pathway.
- Capital cost of modifying the compressor & AGI & pipeline integrity assessment costs.
- Operating cost of using the hydrogen backbone. We have relied on data provided by the European Hydrogen Backbone to inform our view of the hydrogen backbone network charges. Per the report[82], charges could range between €0.11-0.21 per kilogram per 1,000 kilometers.

Ammonia Shipping

As described in chapter 6, the proposed ammonia production plant will be based on the Haber-Bosch process which is the most common method for producing ammonia on an industrial scale. The process converts nitrogen produced via an air separator unit (ASU) to ammonia by a reaction with hydrogen using a metal catalyst under high temperatures and high pressures. Following the production of ammonia, storage tanks are required to store ammonia prior to distribution at the export port in Ireland. Ammonia is then loaded on specialised vessels to be shipped to Germany. Lastly, ammonia is converted back to hydrogen using an ammonia cracker. We note, efficient processes for the recovery of hydrogen from ammonia require further development to be applied in commercial applications.

The key considerations for the ammonia shipping pathway include:

- Capital cost of the ammonia production plant, air separator unit, storage tank & cracking unit.
- Operating costs such as the electricity consumption of the ammonia plant & cracking unit.
- Shipping costs such as vessel charter fees, fuel costs and port fees. The charter fee is an average of recent years of very large ammonia carrier (VLAC) spot earnings data for LPG/ ammonia carriers as provided by Clarksons. The fuels costs are an average of recent years of very low sulfur fuel oil (VLSFO) bunker costs from Ship and Bunker. The assumed port fees include costs associated to berthing and cargo handling per data from Brunsbuettel ports.
- Assumed speed of the vessels which varies between 15 knot and 15.5 knots depending on whether the vessel is travelling with or without cargo.

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[82] Extending the European Hydrogen Backbone, https://ehb.eu/files/downloads/European-Hydrogen-Backbone-April-2021-V3.pdf, 2021

- Hydrogen recovery loss of 15% from the cracking unit.

Methanol Shipping

As described in chapter 6, synthesis gas is produced using the renewable hydrogen and a supply of, ideally bio-derived, CO_2. The gas is then fed into a reactor with a catalyst under high temperatures and high pressures to produce methanol and water vapor. Methanol storage tankers are then used to store the fuel prior to distribution at the export port. The methanol is then loaded onto specialised vessels to be shipped to Germany. Lastly, the methanol is then converted back to gaseous hydrogen using a supply of steam and a methanol reformation unit.

The key LCOT considerations for the methanol shipping pathway include:

- Capital cost of the methanol synthesis plant, storage tank & reformation unit.
- Operating costs such as the electricity consumption of the upstream CO_2 capture unit, the methanol synthesis plant & reformation unit and steam costs for the reformation unit.
- Shipping costs such as vessel charter fees, fuel costs and port fees. The charter fee is an average of recent years of Medium Range spot earnings data for chemical tankers as provided by Clarksons. We have followed the same methodology and inputs for methanol shipping fuel and port costs as we have for ammonia.
- Hydrogen recovery loss of 11% from the methanol reformation unit.

Liquid Hydrogen Shipping

As described in chapter 6, gaseous hydrogen is liquefied in a liquefier plant by cooling it to temperatures below 250 degrees Celsius. Once it is liquefied it is stored in a cryogenic storage tank prior to distribution at the export port. The liquid hydrogen is then loaded onto specialised vessels to be shipped. Some amount of hydrogen stored on the ship will be lost through evaporation, or “boil off” of liquefied hydrogen. To manage this, we assume the vessel has boil-off management equipment on board. Lastly, once in Germany liquid hydrogen is then converted back to gaseous hydrogen using a hydrogen regasification plant.

The key considerations for the liquid hydrogen shipping pathway include:

- Capital cost of the liquefier plant, storage tank & regasification unit.
- Operating costs such as the electricity consumption of the liquefier plant and “boil-off” management system on the vessel.
- Shipping costs such as vessel charter fees, fuel costs and port fees. The charter fee is an average of recent years of LNG carrier spot earnings data provided by Clarksons. We have added an additional 50% to the fee to reflect the nascency of liquid hydrogen vessel technology. We have followed the same methodology and inputs for liquid hydrogen shipping fuel and port costs as we have for ammonia.

We note there is currently no global supply chain for shipping liquid hydrogen. As the technology is still being developed there is significant uncertainty in the key input assumptions used.

Compressed Hydrogen Shipping

Currently, there is no global supply chain for shipping compressed hydrogen. However, smaller scale vessels are currently being developed, and the first vessels could be operational as early as 2026 with larger scale vessels available by 2030.

The cost to ship compressed hydrogen will be dictated by the compression process, the capital costs of the vessel, OPEX, barge storage, port CAPEX and cost of movement. In the absence of enough data to do a full levelised cost calculation we have relied on levelised cost data from Provaris an Australian-based compressed hydrogen vessels company.

Provaris estimates an indicative cost range of between €4.9 – €5.9 /kg depending on the distance and vessel type used[83]. We've calculated our LCOT using an assumed vessel size, the distance to Germany and an average which incorporates this range. However, we note given the technology is still being developed there is significant uncertainty on costs.

10.5 Results for Pipeline Transport

New pipeline

Figure 34 shows the estimated levelised cost of transport for constructing a new pipeline directly from Cork to Germany. For this pathway we modelled a typical base case of new pipeline, but we also applied a sensitivity to reflect the difficulties and high costs of building a new hydrogen pipeline through the English Channel – one of the most the most crowded seabed and shipping routes in the world. This gives a range of €2,085 / tonne to €11, 237/ tonne. This range is on the high end relative to the other pipeline pathways indicating that this is a less commercially efficient option. However, it is the most direct pipeline route to transport hydrogen from Ireland to Germany, so it forms a useful basis for comparing against other routes and transport options.

We have also sized the pipelines to be able to export 430 ktpa of hydrogen to accommodate future potential growth in Ireland. However, for the purpose of our modelling, we have assumed a base amount of 215 ktpa of hydrogen is exported. Given this the overall cost of transport is higher as we are not using the total capacity of the pipeline.

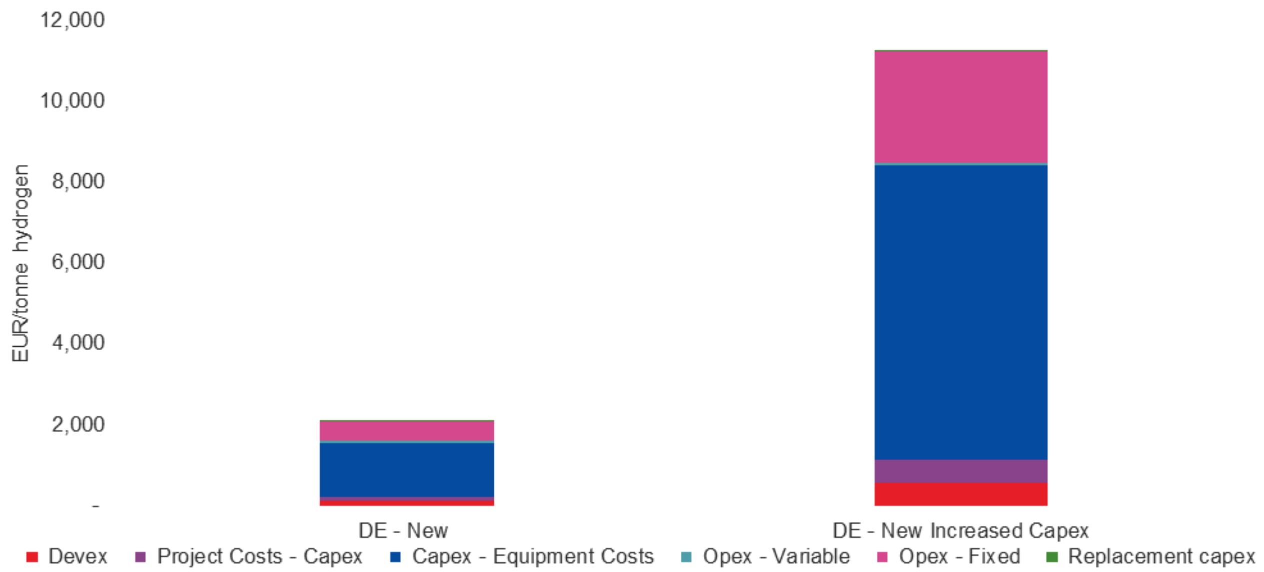

Figure 34 Estimated levelised cost of transport new to DE pipeline pathway (Source: Arup).

Mixture of new pipeline and use of European Hydrogen Backbone

Figure 35 shows the levelised costs of transporting hydrogen through the pathways that have a mixture of new pipeline, repurposed pipeline and use the EHB (Project Union in the UK). The costs in these scenarios are dominated by the capital costs of building new pipelines (and to a lesser degree repurposing existing pipeline infrastructure). The fixed OPEX – which is the cost of maintaining these offshore pipelines are also a significant proportion of costs. Variable OPEX costs in these scenarios are largely the cost of using the European Hydrogen Backbone (i.e. future network charges) and the electricity costs associated in powering the inlet compressor station.

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[83] Provaris, Independent research reinforce benefits of Provaris energy efficient regional delivery of green hydrogen, https://www.provaris.energy/news/independent-research-reinforce-benefits-of-provaris-energy-efficient-regional-delivery-of-green-hydrogen , 2023

The cost of Pathway B (Figure 33) - transporting hydrogen through GB via a new build pipeline from Cork to Milford Haven - varies between €627 / tonne to €679/ tonne depending on the import location, with Belgium being lowest cost given its relative proximity to Ireland.

On the other hand, the cost of Pathway C - transporting hydrogen via a new build pipeline from Cork to France (Le Havre) - is significantly higher varying between €1,658 / tonne to €1,675/ tonne depending on the import location, with similarly Belgium being lowest cost. This is primarily due to the much longer distance of the new pipeline from Cork to Le Havre as opposed to Cork to Milford Haven resulting in a much higher capital cost (CAPEX). The slightly smaller OPEX, as a result of incurring lower network charges, do not compensate for this increased CAPEX.

Lastly for Pathway D, the estimated cost of transporting hydrogen via the repurposed IC1 pipeline to GB pathway costs €469 / tonne. This is a much lower cost option relative to the other pathways as the CAPEX associated with repurposing a pipeline are significantly lower than the CAPEX of building new pipeline. However, we note should new or more involved works be required this would increase the overall cost of transport of this pathway significantly.

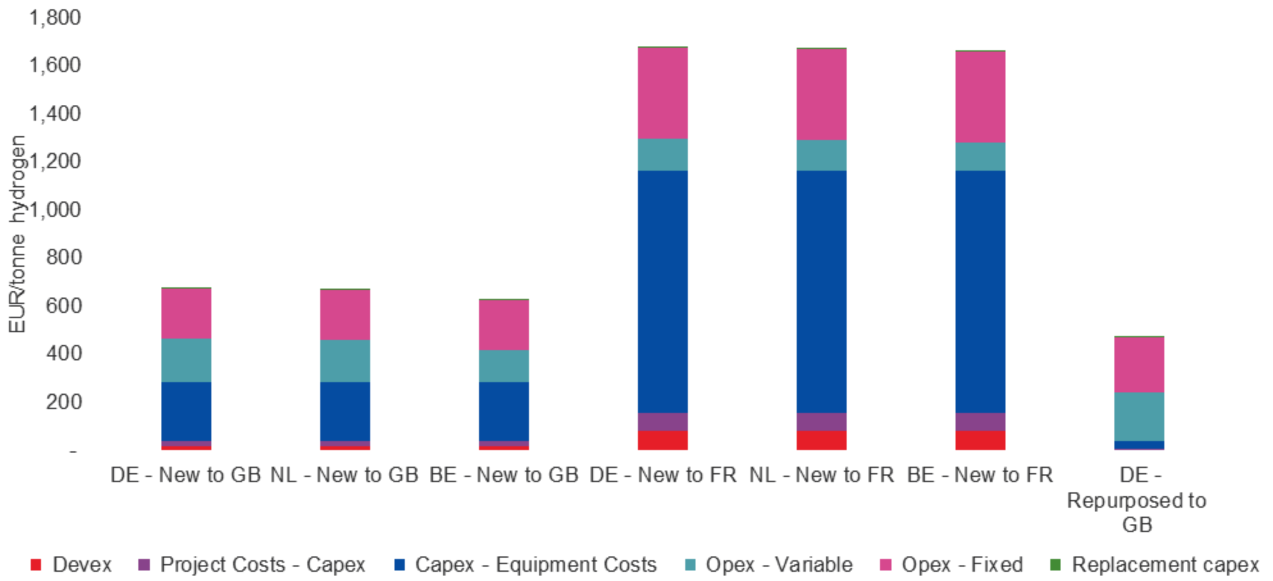

Figure 35: Estimated levelised cost of transport new to GB, new to FR and repurposed pipeline pathways (Source: Arup).

For all pipeline pathways, which in part or in full assume new build is required to transport hydrogen to the import location, the key driver of cost is the CAPEX associated with the new pipeline infrastructure. The key drivers of variable OPEX across all pipeline pathways include the electricity requirement of the inlet compressor station as well as the network charges associated with using either or both the European Hydrogen Backbone network or Project Union.

The routes that have more new pipeline infrastructure have higher costs. This is primarily because the capital costs of either repurposing existing offshore pipelines and/or the operational costs of using onshore transmission pipelines (the European Hydrogen Backbone/Project Union) are lower over the assumed 25-year period of operation.

Arup note that there should be some caution over the assumed cost of the European Hydrogen Backbone. The cost in EUR/km/tonne have been taken from what has been published in the Extending the European Hydrogen Backbone report[84]. It is unknown at this stage what the actual network charges for using the onshore hydrogen transmission network would be, they could potentially be significantly higher (See the sensitivity analysis in appendix A.2 for further detail).

[84] Extending the European Hydrogen Backbone, https://ehb.eu/files/downloads/European-Hydrogen-Backbone-April-2021-V3.pdf, 2021

This analysis does show that unless the network charges are significantly higher than expected, it is likely to be beneficial to try and use as much of the planned EHB onshore transmission network as possible, thereby minimising capital costs of new offshore pipeline infrastructure.

Sensitivity around repurposing

The repurposed pipeline is the lowest cost pipeline transport option. This is because, for the purposes of our baseline modelling, we have assumed that following a pipeline integrity assessment, no new build pipeline or modifications are required. We have however assumed a slightly higher fixed operational cost for this pathway relative to the others to reflect the complexity involved in operating a repurposed pipeline.

However, this may not be the case in practice and building new pipeline infrastructure, if necessary, would be costly. As shown below rebuilding a new pipeline between Bacton and Zeebrugge would increase the total overall cost of transport to €589 / tonne while rebuilding a new pipeline between Loughshinny and Brighouse Bay and Bacton to Zeebrugge would increase the cost €848 / tonne.

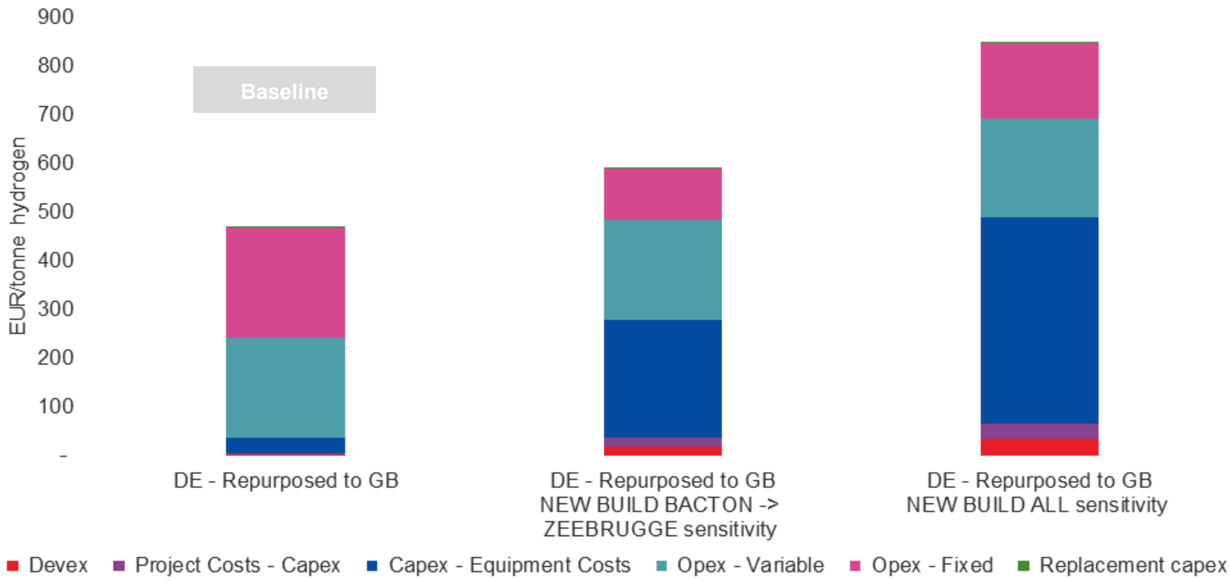

Figure 36: Estimated levelised cost of transport repurposed pipeline sensitivity (Source: Arup).

10.6 Results for Shipping Hydrogen Carriers

Baseline results

Figure 37 show the estimated levelised cost of transport to Germany via a range of shipping methods. As shown the estimated cost of transporting hydrogen is €2,321 / tonne, €2,853 / tonne, €4,136/ tonne, and €3,348/ tonne for ammonia, methanol, liquid hydrogen and compressed hydrogen shipping respectively. Note that the cost / tonne is calculated based on the quantity of hydrogen or derivative delivered to the destination, which may be less than the quantity of hydrogen sent from Ireland (as discussed in Chapter 6).

The cost of transporting liquid hydrogen is significantly more expensive relative to the other pathways due to the energy intensity of the liquefication process as well as the energy required to store and limit significant boil-off in-transit. While the cost of transporting methanol is somewhat more expensive than the cost of transporting ammonia, the key cost drivers for both pathways include the CAPEX of the ammonia and methanol production plants and the electricity requirement across the supply chains. We note that there are more significant losses in the process of converting ammonia back to gaseous hydrogen than methanol, however, the additional capital and operational costs associated with methanol transport outweigh this.

While costs for compressed hydrogen shipping are uncertain, current estimates show it to be in line with the other shipping options.

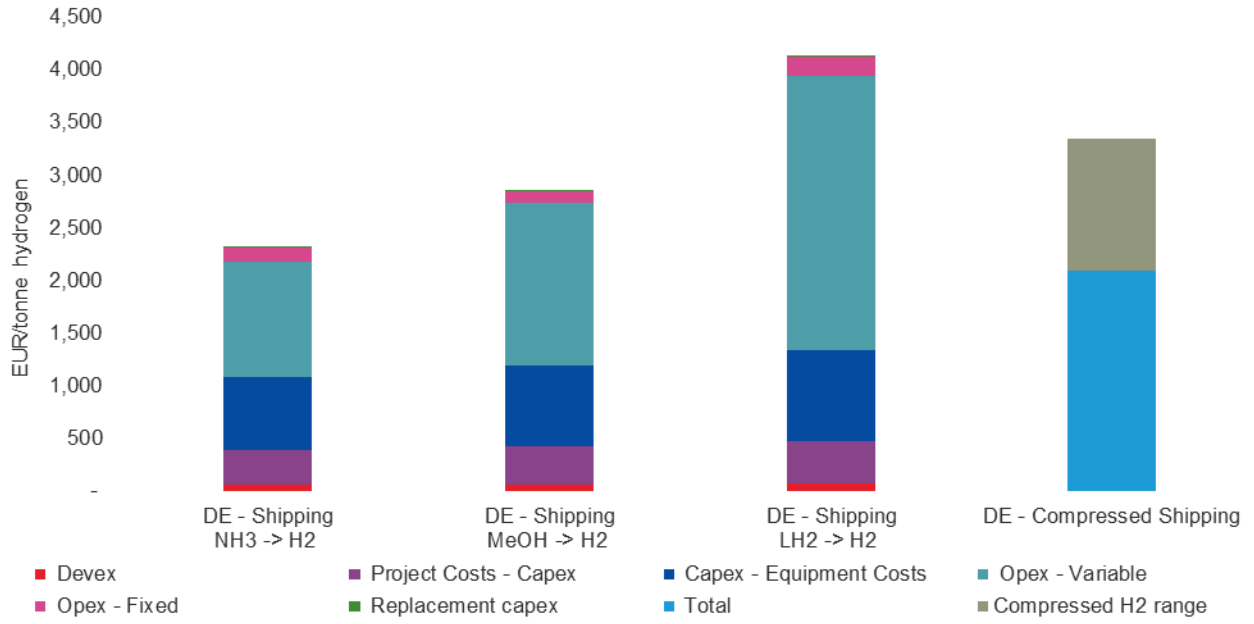

Figure 37 Estimated levelised cost of transport shipping (Source: Arup)

Direct use of derivative - alternative to hydrogen conversion

Figure 38 shows the results of transporting ammonia and methanol without reconverting the derivatives back to hydrogen in Germany. Per below, the cost of converting hydrogen to ammonia and methanol and shipping it to Germany is €259 / tonne of ammonia and €273 / tonne of methanol.

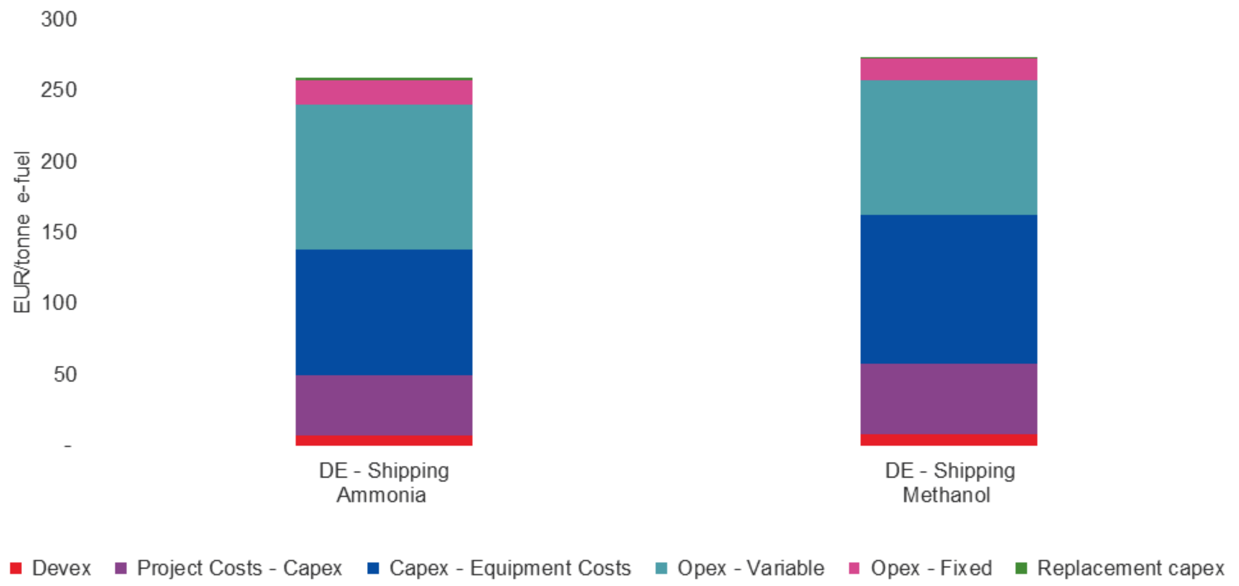

Figure 38: Estimated levelised cost of transport of hydrogen derivatives (Source: Arup)

Figure 39 shows the contribution of the CAPEX, OPEX including electricity costs, and REPEX of the ammonia cracking unit to the overall cost of shipping ammonia and reconverting it back to hydrogen in Germany. As shown, it adds an additional cost of c. 30% to this transport pathway. Excluding the cracking unit and selling on the hydrogen derivative is a less costly option. This is because it excludes the additional CAPEX and electricity costs associated with reconversion and it would also reduce hydrogen recovery losses. Arup has not investigated the low carbon ammonia or methanol market for this report, but it is understood that there is likely to be a market demand both in Germany and wider Europe.

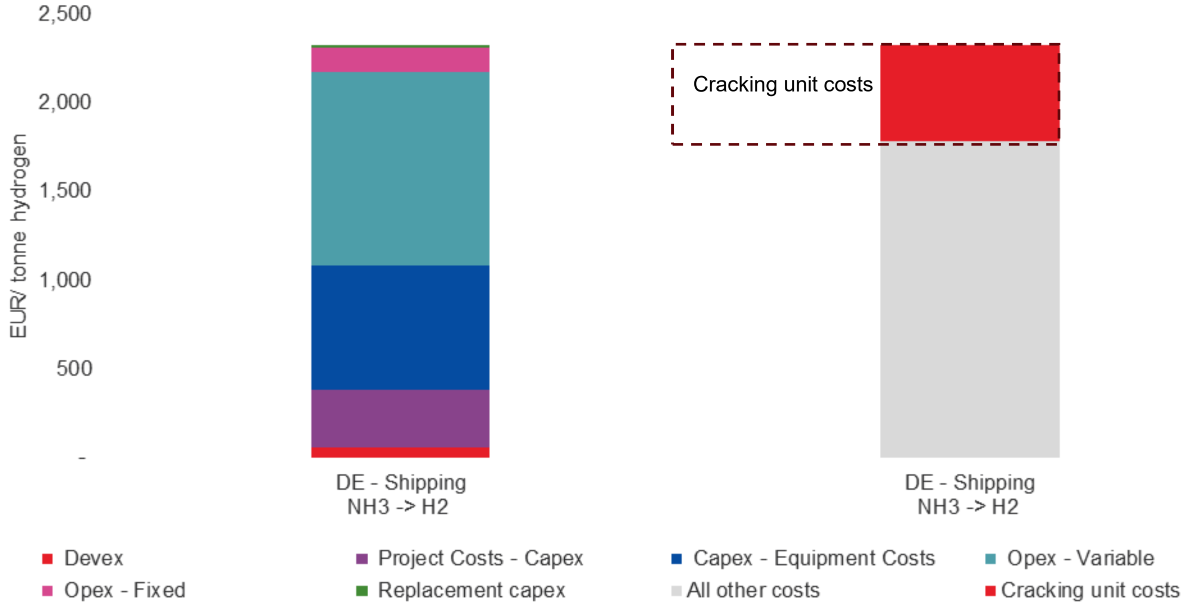

Figure 39: Estimated levelised cost of transport ammonia shipping cracking unit highlight (Source: Arup)

10.7 Pipeline vs. Alternative Comparison

Figure 40 compares the base scenario estimated levelised cost of transport results for all shipping pathways against the least cost and the technically sensible highest cost pipeline option. As shown, the cost of transporting via pipeline ranges between €469 / tonne and €1,675 / tonne. Even at the highest cost option the cost of transporting via pipeline is still c. €650 / tonne less than the lowest cost shipping option of transporting hydrogen via ammonia shipping.

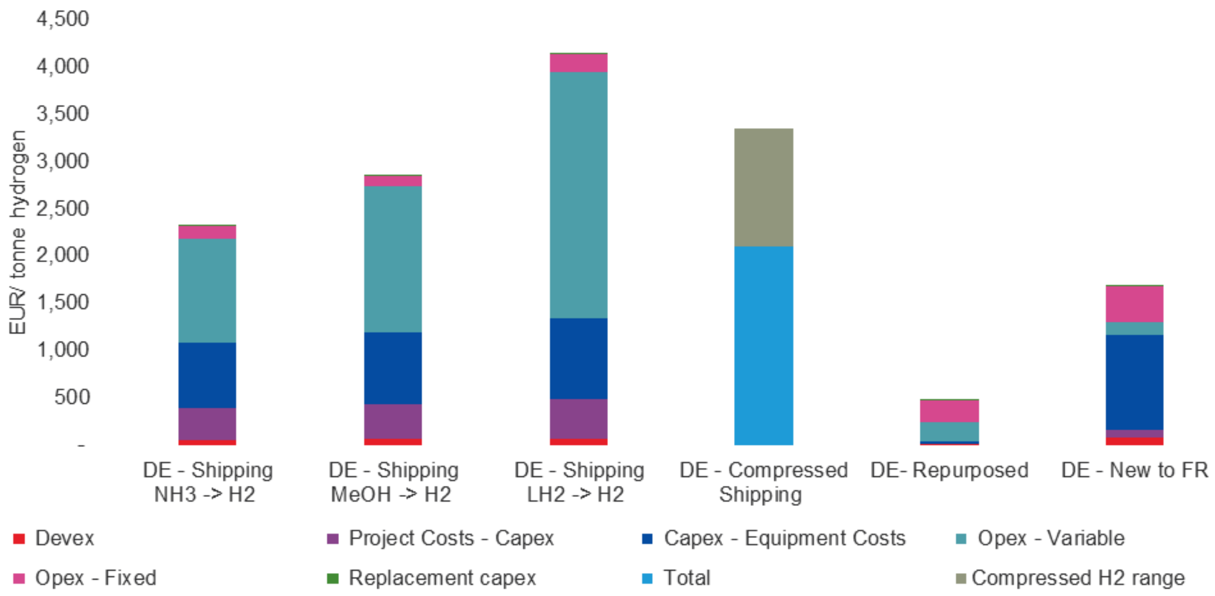

Figure 40: Estimated levelised cost of transport pipeline & shipping comparison at Base Scenario (Source: Arup)

The price range for the pipeline and shipping options are further illustrated in Figure 41 highlighting that transporting hydrogen via pipeline is more cost efficient. The red bar on the left shows that the range for a pipeline varies from €469 / tonne to €1,675 / tonne, while the purple bar shows the shipping options range from €2,320 / tonne to over €4,000 / tonne. This bar chart presents the comparison for the base scenario of 215 ktpa. Arup knows from experience that a pipeline price at the low scenario of 22 ktpa would be prohibitively expensive (far higher than the €4,000 / tonne shipping maximum), while the shipping costs would not change significantly. Therefore, there is a crossover point between 22 ktpa and 215 ktpa where a pipeline becomes more competitive than shipping.

We have not performed an analysis to identify this crossover point in this report, as do so accurately would require more mature cost data as well as the inclusion of secondary costs such as the development of port facilities. It would also be influenced by the choice of shipping vector, as a market for a particular derivative (e.g., ammonia) may have developed. We would recommend that when hydrogen exports from Ireland approach the 100 ktpa level, that consideration is given to the construction of a pipeline.

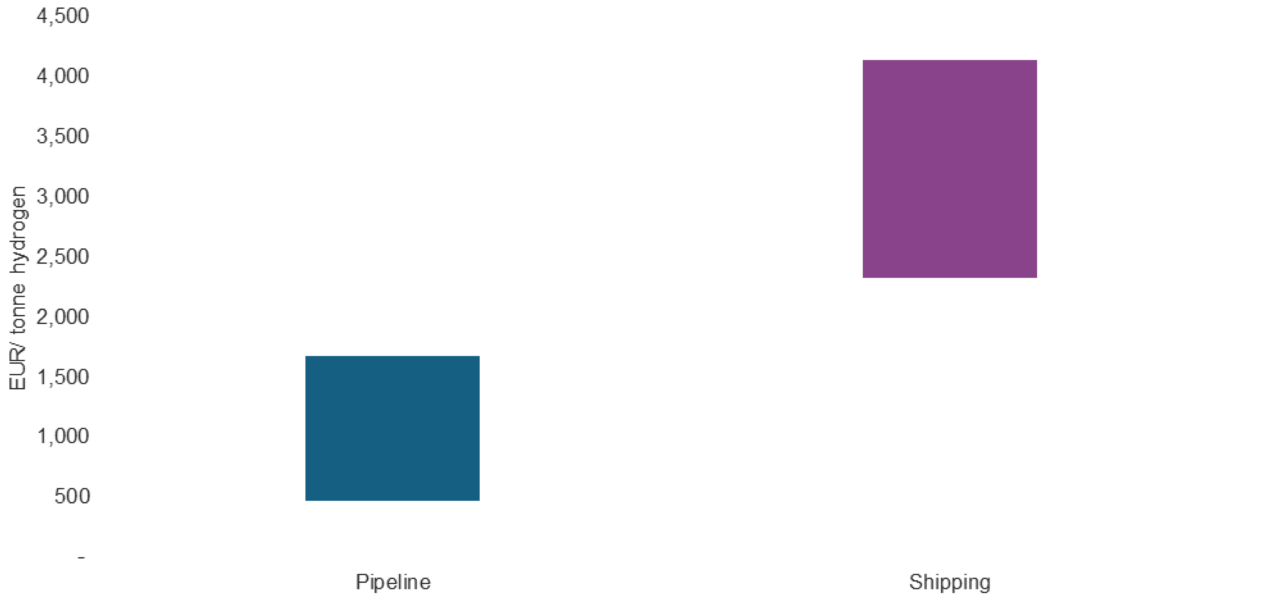

Figure 41: Maximum and minimum pipeline and shipping cost comparison (Source: Arup)

The pipeline transport option is CAPEX intensive given the upfront costs associated with new build pipeline infrastructure, with lower ongoing costs for use of the European Hydrogen Backbone and Project Union as well as the fixed OPEX of the pipeline itself. In comparison, the shipping options are more OPEX intensive driven by the electricity requirement associated with transforming hydrogen into its derivative form and transforming it back to hydrogen in Germany.

11. Discussion & Conclusions

11.1 General insights

This report commences with a review of the demand for hydrogen in Ireland, which suggested that significant volumes can be made available for export purposes. The ambition and potential for renewable hydrogen production in Ireland was reviewed and found to be very substantial. However, these investigations showed that Ireland is not yet producing any significant amounts of renewable hydrogen and is yet to scale up its deployment of offshore wind (OWE), which is essential to power electrolysis. It is likely that initial OWE deployment will be focussed on providing power to decarbonise the electricity grid and this may further delay the development of large-scale renewable hydrogen production in Ireland.

The planned development of hydrogen hubs and green energy parks in Ireland could be augmented by facilities for the production and storage of hydrogen, and additionally ammonia or methanol manufacture. If these were also located near a port facility, for example the Celtic Hydrogen Cluster in Cork Harbour, the hydrogen produced could supply both domestic and export demand.

This study has shown that there is a demand for e-ammonia and e-methanol in Europe, however, it would be a considerable challenge for Ireland to simultaneously develop new OWE, new renewable hydrogen production facilities as well as capital intensive ammonia or methanol manufacturing plants. Corresponding ammonia or methanol export facilities including storage would also need to be delivered.

Therefore, it is recommended that Ireland should first consider exporting low volumes of gaseous hydrogen by ship. This could begin with the transport of hydrogen by tube trailer for domestic use which, as volumes increase, could also be transported overseas by ship in multiple-element gas containers (MEGC). As available volumes of hydrogen further increase consideration for the use of specialised hydrogen transport ships could be given. As it will be a few years before reaching this point, it is possible that by this time improved technical solutions for gaseous or liquid hydrogen shipping could be available.

However, if it is possible to deliver, for example, an ammonia production facility in the shorter term, this may be the preferred route to initiate an export activity. This would require identifying committed offtakers for the direct use of ammonia, which as we have reported are likely to be present in Germany, the Netherlands and Belgium. Alternative markets should also be considered. Firm off-take agreements would need to be in place to de-risk such investment, as well as sufficient OWE capacity to generate the necessary hydrogen to manufacture e-ammonia. This would also apply to methanol exports.

Ireland is at an early stage in the development of its hydrogen economy and the approach suggested above would support the development of skills and capabilities in hydrogen, before attempting to achieve large scale hydrogen exports. Furthermore, it would complement the development of the domestic use of hydrogen and potentially help to de-risk early infrastructure investments.

At a later stage, as hydrogen export volumes increase, the use of pipelines will need to be explored as this is the most cost-effective transport solution for hydrogen at scale. Furthered detailed policy and technical studies will be required to decide the right timing and sizing of any new pipelines. Ideally one would maximise the dimensions of the pipeline to allow for the maximum export volume capacity in the long-term, but such a large diameter pipe may not be able to operate at the lower volumes available when the pipeline is commissioned. A detailed engineering study will need to be undertaken at the time to maximise the value of the investment, considering export volume projections at the time. Increasing the volume of gas transported through a given pipeline reduces the EUR/tonne price so ensuring export project demand levels are accurate will be critical. Developers will need to ensure the offtake and production agreements are in place to de-risk all elements of the transport system.

As shown in Figure 35, repurposing gas pipelines for use with hydrogen is expected to be the cheaper than building new pipelines. We have discussed repurposing IC1, but this may lead to security of supply challenges for Ireland. However, it would be sensible to evaluate repurposing pipelines before committing to a new build solution as these may be more cost-effective. This will required existing infrastructure to be assessed in terms of material compatibility for hydrogen service and its condition evaluated to ensure integrity over the predicted asset life extension.

11.2 Pipelines

The key findings on pipeline transport for hydrogen export are as follows:

- A direct new pipeline from Cork to AquaDuctus I, Germany is challenging due to the requirement to construct through the highly congested English Channel and its length.
- Limiting new infrastructure, by repurposing existing pipelines and incurring network charges, can significantly reduce overall costs compared to a full new-build pipeline.
- For the existing Ireland to GB interconnectors, IC1 could be suited for repurposing as long as the SNIP connection can be transferred to IC2. Similarly, IC2 could be used if the spur to the Isle of Man can be managed. IC1, as it is the smaller of the two interconnectors, may be best suited for repurposing first.
- A new GB pipeline option (e.g. Cork - Milford Haven connecting to Project Union) could be considered as an alternative to avoid the security of supply risk of repurposing IC1.
- A direct connection to the European mainland (e.g. Cork - Le Havre that then connects to the EHB) should be considered as an alternative to going via GB, if needed to avoid any post-Brexit challenges.

11.3 Shipping

The key findings on shipping transport for hydrogen export are as follows:

- The assessment presented in this report may change significantly with technological advances and progress, especially with the maturity of shipping compressed and liquefied hydrogen.
- Large scale gaseous hydrogen shipping is not mature, and this risk will need to be considered. Using cylinder trailers or MEGCs in the short term may be an option for small volumes.
- Shipping liquid hydrogen involves significant energy and hydrogen volume losses. Additionally, the low market maturity and limited infrastructure for LH_2 shipping further constrains its viability.
- Base and High amounts of export hydrogen are feasible using ammonia and methanol as shipping vectors. Currently compressed or liquified hydrogen are considered impractical.
- Shipping, either as derivatives or conditioned hydrogen, is a high-cost option compared to pipelines for high volumes - particularly when existing network infrastructure can be leveraged.
- Cracking derivatives like ammonia and methanol is inefficient (e.g., 30% of the overall costs for ammonia) and there is strong end-product demand for derivatives in Europe.

11.4 Recommendations for Next Steps

11.4.1 Deliver Hydrogen Production.

The priority should be the deployment of OWE at scale to provide the renewable electricity needed for green hydrogen production. This will enable the domestic hydrogen market to start to develop in hydrogen clusters and green energy parks. Expertise will develop in Ireland which can be used to expand hydrogen production and develop an export capability.

Consideration should be given to the early allocation of OWE resources dedicated to hydrogen so that production starts as soon as possible.

11.4.2 Enable and Understand the Export Market

A study considering the regulatory, supply, demand, and commercial levers that will influence the potential quantity of hydrogen that could be exported from Ireland should be undertaken to build the evidence base on the potential for hydrogen export. This will require engagement with counterparts in Germany, the Netherlands, Belgium, France and GB to progress the development of corridors and deliver the required market enablers.

Establishing what the network charges and arrangements would be for using the planned new hydrogen networks, Project Union and the EHB, will also be needed.

The potential of the markets in Europe for e-ammonia and e-methanol should be studied and evaluated.

11.4.3 Stakeholder Engagement

DCEE should engage with DESNZ (the UK energy department) to discuss export transit using Project Union pipelines and the possibility of repurposing interconnectors (e.g. IC1). GNI and National Gas need to establish the compatibility of IC1 and GB transmission lines for hydrogen repurposing and to consider new build alternatives (e.g., the Cork-Milford Haven option discussed in this report).

Engagement with DESNZ will also be needed to ensure security of supply for Ireland, the Isle of Man and Northern Ireland as the transition to hydrogen develops.

Engagement with the HYreland team would be invaluable as they are evaluating export vectors including options discussed in this report and Germany will be the key export destination for Irish hydrogen.

11.4.4 Develop the Export System Concept

It is recommended to undertake technical design development of the export system, for both pipelines and shipping.

A more detailed assessment of port infrastructure for derivative production and export is needed to understand how much investment is required to prepare ports for hydrogen or hydrogen derivative export.

It should be appreciated that the cost modelling used in this report was generally based on Class V (-50% to +100%) estimates, historical international project data and some projected pricing for newer technologies (e.g., compressed hydrogen shipping, large scale ammonia cracking) and should not be used for investment purposes. Engineering concept and feasibility studies will be required to develop more accurate cost estimates for the Irish market.

12. Key Reference Documents

The following documents are referred to throughout this report:

[1]	Ireland's National Hydrogen Strategy	2023
[2]	Project HYreland - Fraunhofer ISE	ongoing - oct. 2025
[3]	Green Hydrogen in Ireland - Friedrich-Ebert-Stiftung	2024
[4]	Hydrogen Production and Energy Infrastructure Database - IEA	2024
[5]	GNI Pathway to a Net Zero Carbon Network	2024

Appendix A

A.1 Technical Basis of Design

The following technical design parameters and logistical considerations for the export of hydrogen from Irish ports have been assumed.

A.1.1 Hydrogen production and specifications

Electrolyser uptime percentage	90 7884	% h per year
Electrolyser power consumption	55	kWh/kg H_2 (typical for AWE)
Maximum amount of pure hydrogen export	3000 600,000 60	MWe Nm^3/h t/h
Minimum amount of pure hydrogen export	150 30,000 3	MW Nm^3/h t/h
Hydrogen boiling point	- 252.8	°C
Hydrogen purity	99.5	vol %

A.1.2 Pipeline

Pipeline operating pressure (Injection)	80	bar
Pipeline operating temperature	5-15	°C
Maximum pipeline gas velocity	40	m/s
Minimum pipeline gas velocity	5	m/s
Minimum pipeline diameter	6	in
Max allowable pressure drop	50	% of inlet pressure
Minimum delivery pressure	40	bar
Material of construction	X42/X52	low carbon steel with coating

A.1.3 Compressed Hydrogen

Onshore storage pressure level	100-300	bar
Pipeline compression energy consumption (100 bar)	0.5	kWh/kg H_2
Storage compression energy consumption (300 bar)	5	kWh/kg H_2
Energy losses	8.5	% from 30 to 250 bar
On-ship storage pressure level	250	bar
Small ship size	430	t (~23,700 m^3 advanced dev.)
Large ship size	2000	t (~110,300 m^3 early dev.)

A.1.4 Liquified Hydrogen

Shipping unit	ISO Cryogenic tank-trailers	
Density of liquid hydrogen	71	kg/m^3 atmospheric
Weight per unit	20,000	kg
Boil-off	0.5	%/day
Liquefaction energy consumption	10-13	kWh/kg H_2

Small ship size	88	t (~1,250 m^3 advanced dev.)
Large ship size	5668	t (~80,000 m^3 early dev.)

A.1.5 Ammonia

Hydrogen weight fraction in Ammonia (NH_3)	17.8	wt %
Ammonia boiling point	-33	°C
Synthesis energy losses	10	%
Synthesis mass losses	3	% (Haber-Bosch process)
Cracking energy losses	22	% (Haber-Bosch process)
Cracking mass losses	15	%
Small ship size	24,000	t (~27,000 m^3)
Large ship size	60,000	t (~67,500 m^3)

A.1.6 Methanol

Hydrogen weight fraction in Methanol (MeOH)	12.5	wt %
Methanol boiling point	65	°C
Synthesis energy losses	2	% assumption, low TRL
Reforming energy losses	11	% assumption, low TRL
Reforming mass losses	11	% assumption, low TRL
Small ship size	25,000	t (~31,700 m^3)
Large ship size	100,000	t (~126,700 m^3)

A.1.7 Shipping

Shipping speed	30	km/h
Minimum buffer duration for sizing port storage	3	Days

A.2 Levelised Cost Modelling Sensitivity Analysis

A.2.1 Pipeline Sensitivity Analysis

Figures 42, 43, 44, and 45 show the results of the pipeline sensitivity analysis. The sensitivities that have been considered include:

- **New build pipeline unit cost (-):** For the new build to DE, new build to GB and new build to FR pipeline pathways, we assume developers are able to construct the pipelines at 10% less the assumed pipeline unit cost.
- **Onshore network charge (+):** For new build to GB and new build to FR pipeline pathways we assume developers incur a higher network charge of 0.21 EUR/ kg/ 1,000 km for using the Project Union or European Hydrogen Backbone.
- **Hydrogen amount exported (+):** For new build to FR and repurposed pipeline pathways, we assume Ireland has greater export potential and exports 430 ktpa of hydrogen.
- **Repurposed pipeline works (+):** For the repurposed pipeline pathway, we assume in one instance that following an integrity pipeline assessment the pipeline from Bacton, UK to Zeebrugge, BE needs to be replaced in its entirety. In another instance we assume both the Gormanston, IR – Brighouse Hay, UK and the Bacton, UK – Zeebrugge, BE need to be replaced in their entirety.

As shown in Figure 42, reducing the new build pipeline unit CAPEX for the new build to DE pathway by 10% reduces the overall cost of transport from €2,085 / tonne to €1,887 / tonne.

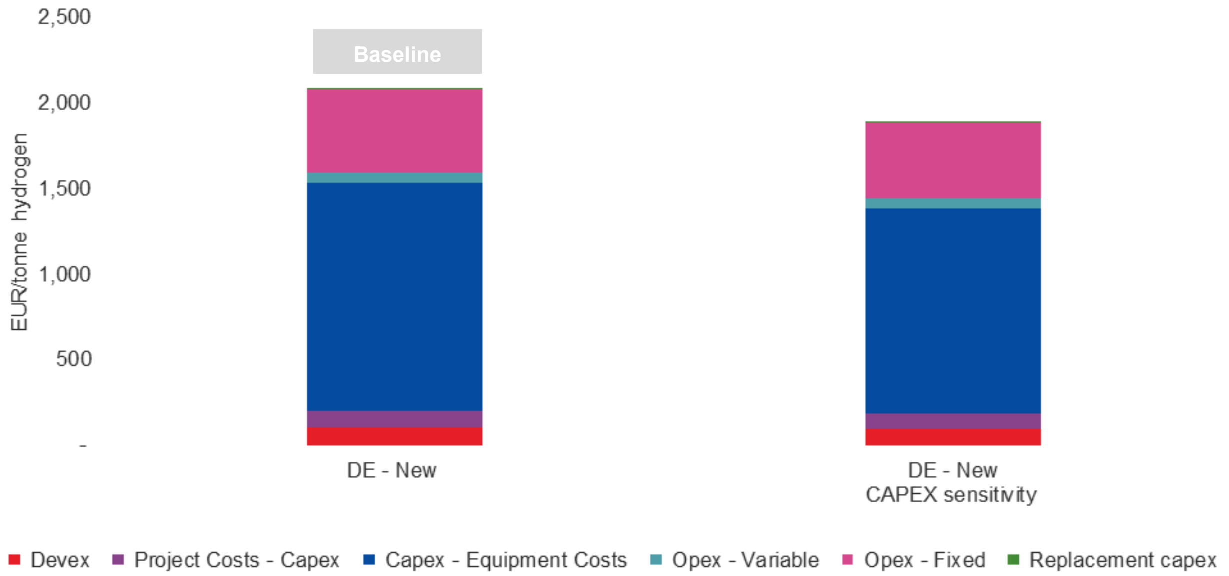

Figure 42: Estimated levelised cost of transport new to DE sensitivity (Source: Arup)

Figure 43 shows the results of the new build to GB pipeline pathway sensitivity analysis. Decreasing the new build pipeline unit capex reduces the overall cost of transport from €676 / tonne to €642 / tonne while increasing the onshore network charge increase the overall cost of transport to €716 / tonne as well as the contribution of variable OPEX to total costs.

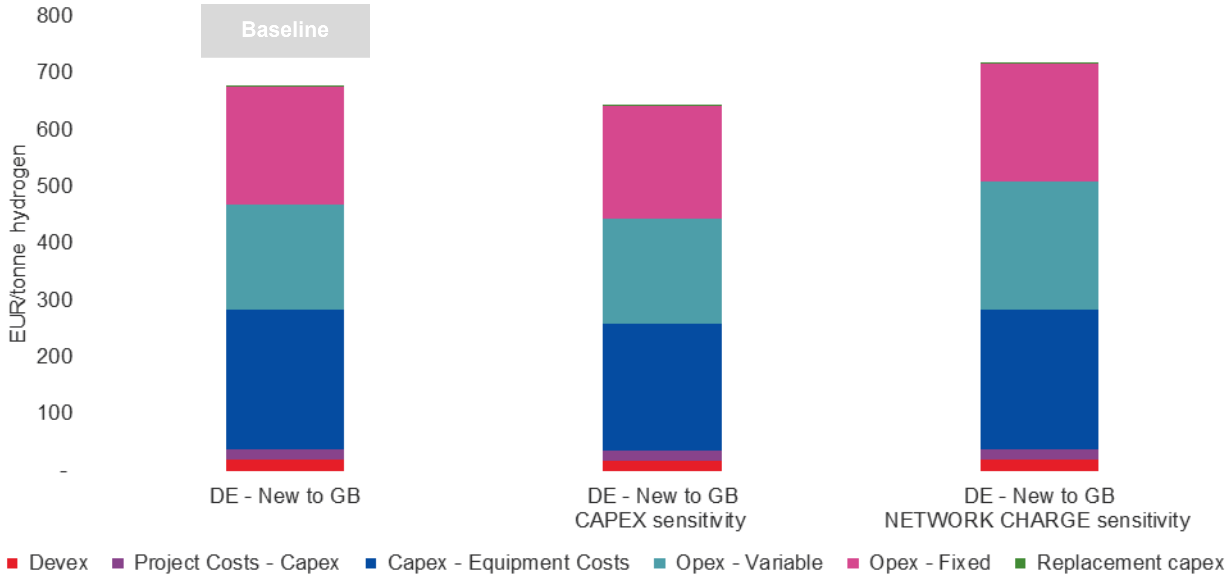

Figure 43: Estimated levelised cost of transport new to GB sensitivity (Source: Arup)

Figure 44 shows the results of the new build to FR pipeline pathway sensitivity analysis. Decreasing the new build pipeline unit CAPEX reduces the overall cost of transport from €1,675 / tonne to €1,525 / tonne while increasing the onshore network charge increase the overall cost of transport to €1,701 / tonne. Increasing the amount of hydrogen exported reduces overall transport costs to €916 / tonne. Note, as the pipeline has already been sized to accommodate the maximum hydrogen capacity, we assume no additional pipeline cost is required. However, we do assume a larger scale inlet compressor station is required. This has resulted in the proportion of CAPEX declining more significantly relative to the other case while the variable OPEX is broadly in line.

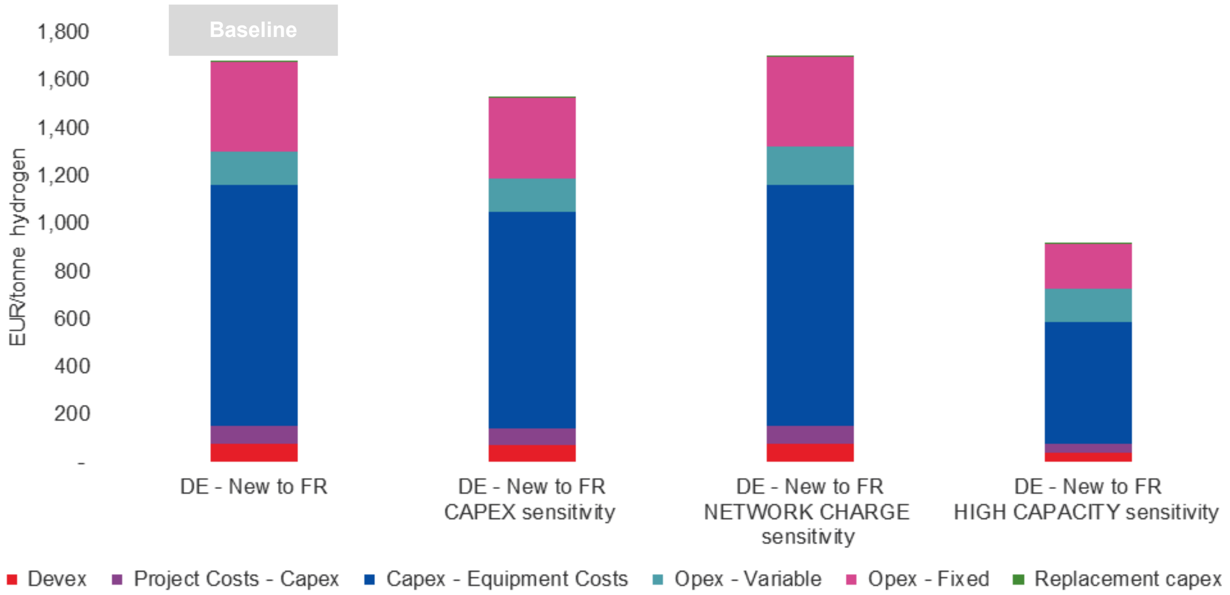

Figure 44: Estimated levelised cost of transport new to FR sensitivity (Source: Arup)

Figure 44 shows the results of the repurposed pipeline pathway sensitivity analysis. Assuming the Bacton, UK – Zeebrugge, BE pipeline needs to be replaced in its entirety increases the overall cost of transport from €469 / tonne to €589 / tonne and significantly increases the contribution of CAPEX to total costs.

Similarly, assuming both the Gormanston, IR – Brighouse Hay, UK and the Bacton, UK – Zeebrugge, BE need to be replaced in their entirety increases the total cost of transport to €848 / tonne. Lastly, increasing the amount of hydrogen exported reduces overall transport costs to €347 / tonne.

Note, we only assume the inlet compressor station increases in capacity to reflect the increased amount of hydrogen being transported and we assume that the costs associated in operating the repurposed pipeline, the compressor modifications, AGI upgrades or pipeline integrity assessments do not scale up.

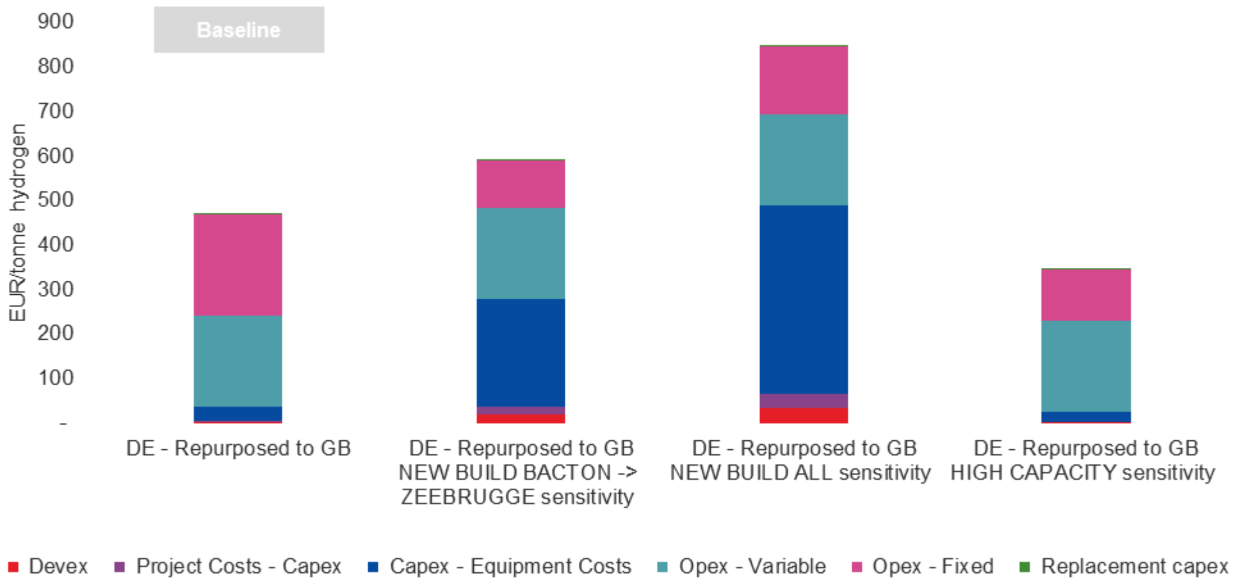

Figure 45: Estimated levelised cost of transport repurposed pipeline sensitivity (Source: Arup)

A.2.2 Shipping Sensitivity Analysis

Figures 46, 47, and 48 show the results of the shipping sensitivity analysis conducted for the ammonia, methanol and liquid hydrogen pathways. The sensitivities that have been considered include:

- **Production plant unit cost (-):** A 10% reduction in the assumed capital cost of the ammonia production plant, methanol synthesis plant and the liquefier plant.
- **Electricity requirement (-):** A 10% reduction in the electricity requirement for the ammonia cracking unit, methanol reformation unit and the liquefier plant.
- **Combination (-):** We assume the sensitivities described above occur for all 3 shipping pathways.

Figure 46 shows the results of the sensitivity analysis for the ammonia shipping pathway. Decreasing the CAPEX of the ammonia plant reduces the overall cost of transport from €2,321 / tonne to €2,238 / tonne while decreasing the electricity requirement of the ammonia cracking unit used for hydrogen recovery decreased the overall cost of transport to €2,279 / tonne. The combination of these results in an overall transport cost of €2,197 / tonne. Ultimately securing a lower cost production plant and more efficient cracking unit could result in savings of c. €120 / tonne.

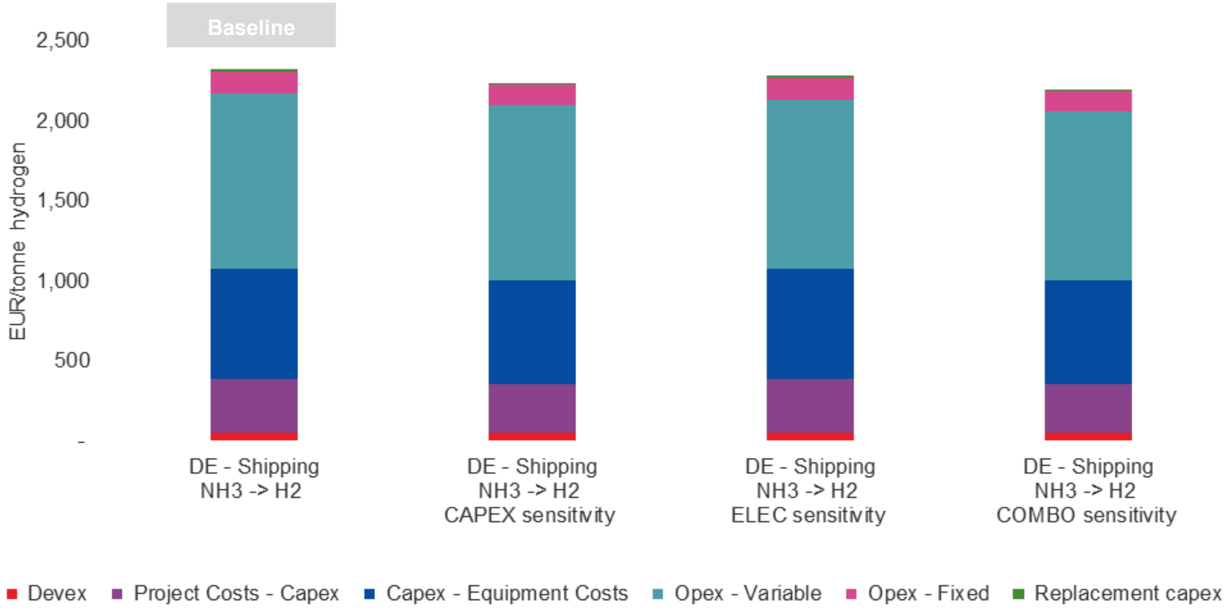

Figure 46: Estimated levelised cost of transport ammonia shipping sensitivity (Source: Arup)

Figure 47 shows the results of the sensitivity analysis for the methanol shipping pathway. Decreasing the CAPEX of the methanol synthesis reduces the overall cost of transport from €2,853 / tonne to €2,780 / tonne while decreasing the electricity requirement of the methanol reformation used for hydrogen recovery decreased the overall cost of transport to €2,757 / tonne. The combination of these results in a total reduction of c. €170 / tonne.

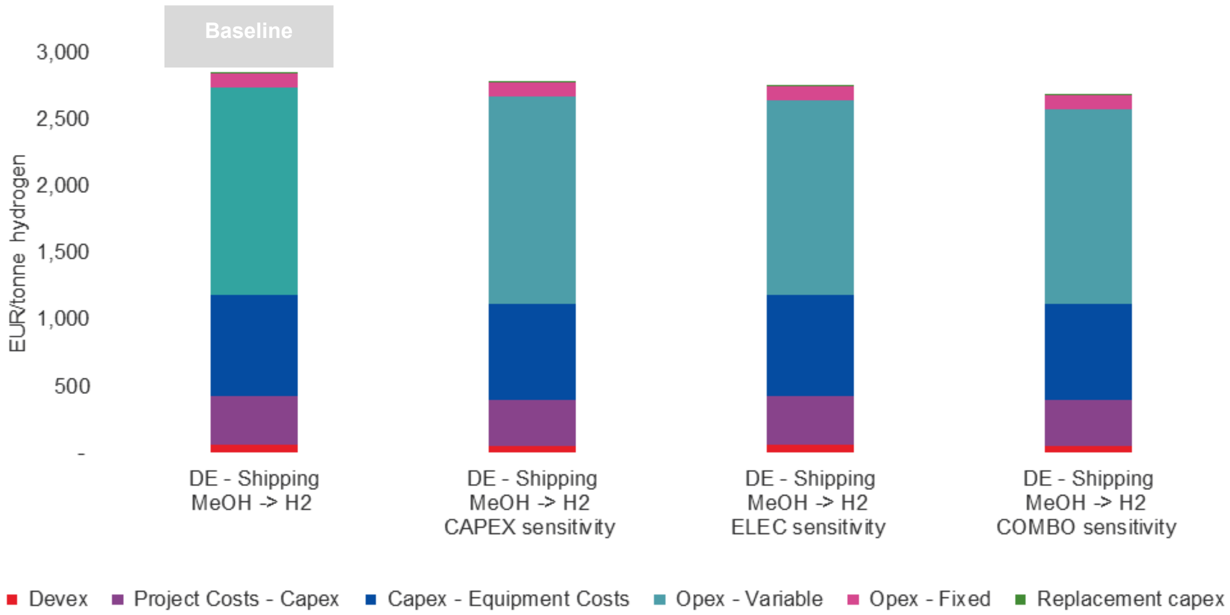

Figure 47: Estimated levelised cost of transport methanol shipping sensitivity (Source: Arup)

Figure 48 shows the results of the sensitivity analysis for the liquid hydrogen pathway. Decreasing the CAPEX of the liquefier reduces the overall cost of transport from €4,136 / tonne to €4,038 / tonne while decreasing the electricity requirement of the liquefier reduces the cost of transport to €3,976 / tonne. The combination of these results in a new overall cost of transport of €3,878 / tonne.

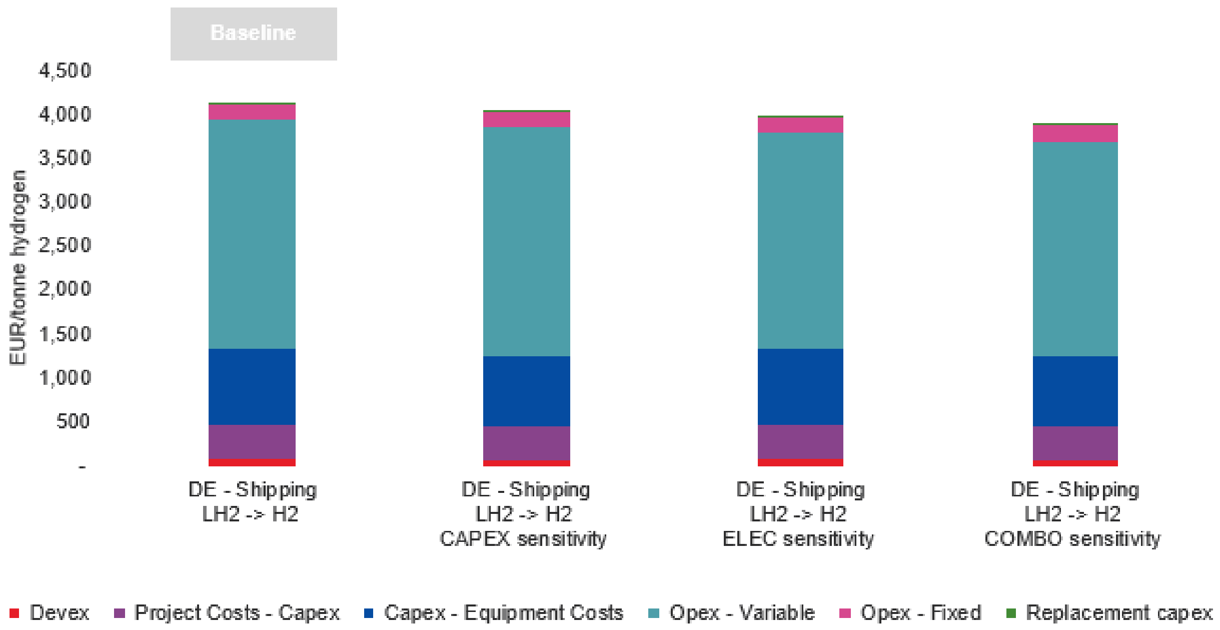

Figure 48: Estimated levelised cost of transport liquid hydrogen shipping sensitivity (Source: Arup)

Figure 49 presents a comparison of the LCOT for the shipping of compressed hydrogen to Germany (Wilhelmshaven), the Netherlands (Rotterdam) and Belgium (Antwerp). As discussed in section 10.4, there is some uncertainty in the costs as the technology for large scale compressed hydrogen ships is still under development, so results are shown for an optimistic scenario (the low estimate) and a conservative scenario (the high estimate). For the optimistic scenario the values are €2,093, €1,735 and €1,662 for Germany, the Netherlands and Belgium respectively. The more conservative values are €3,348, €2,776 and €2,659 respectively. This shows the expected trend that the shortest distance is cheaper (Belgium), and that even if Germany is the final destination for the exported hydrogen, consideration should be given to exporting by ship to Antwerp and then onward to Germany via pipeline. The final choice of export port will, of course, depend on the location of the offtaker.

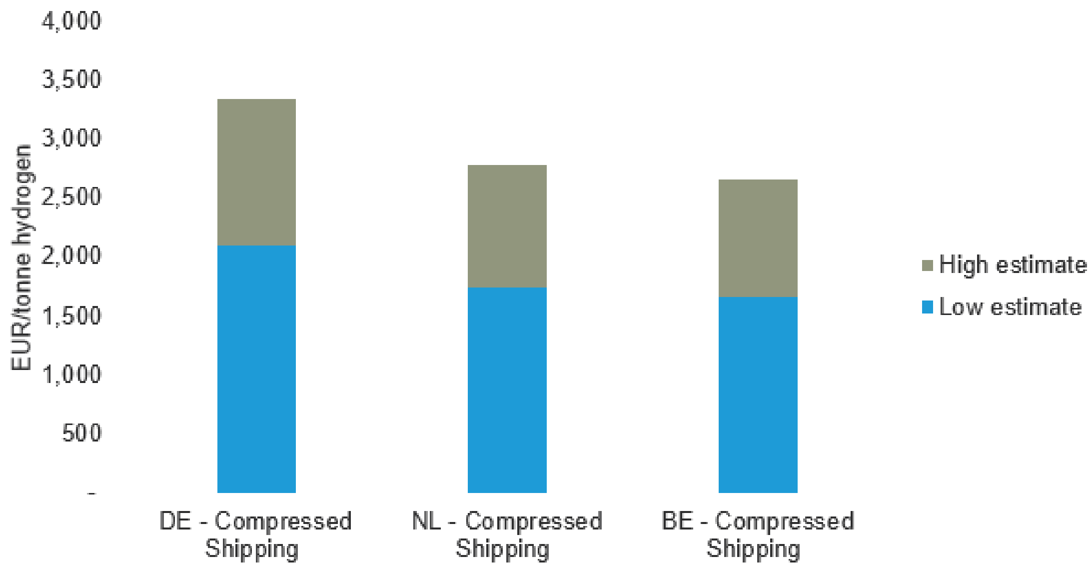

Figure 49 Estimated levelised cost of transport compressed hydrogen destination sensitivity (Source:Arup)

ARUP