Economics of Hydrogen and Associated Synthetic Fuels for Northern Ireland

OLLSCOIL NA GAILLIMHE
UNIVERSITY OF GALWAY

This report is prepared by the University of Galway, with partners HyEnergy Consultancy and Dublin City University (DCU). It has been funded by Northern Ireland's Department for the Economy to contribute to the evidence base for the development of a new energy strategy.

The University of Galway and DCU are two of Ireland's leading energy research institutions, and are both members of MaREI, the Science Foundation Ireland Centre for Energy, Climate and Marine Research. University of Galway has expertise in the techno-economics and sustainability of hydrogen technologies and supply chains, and is a partner in GenComm, SEAFUEL and HUGE EU Interreg projects. DCU has expertise in hydrogen for mobility, power-to-X, fuel cell & electrolyser technology, energy storage and modelling, and is a partner in the EU funded projects HySkills and Hydrogen Mobility Ireland.

HyEnergy is an experienced consultancy with over 50 years of expertise in the global hydrogen and renewable energy sectors. It supports sector organisations and national governments in transitioning to sustainable energy solutions. HyEnergy, alongside the University of Galway, have been active in designing and developing the Galway Hydrogen Hub (GH2) project, and SH$_2$AMROCK hydrogen valley application.

The University of Galway, DCU, and HyEnergy are founding organisations of Hydrogen Ireland.

1 Executive Summary

This report reviews and analyses the role that green hydrogen and associated synthetic fuels can play in the decarbonisation of Northern Ireland's energy system. Hydrogen and hydrogen-based synthetic fuel pathways are reviewed. Those most relevant to Northern Ireland are identified in light of current and future energy landscapes and pathways. These include hydrogen, ammonia, methanol, sustainable aviation fuels (SAFs), and synthetic methane. Sectoral roles for hydrogen are identified in high-temperature and industrial heat, heavy-duty transport (buses and trucks), as well as rail, maritime, and air transport. Key enabling policies in Northern Ireland and the UK, as well as their drivers, are discussed. The importance of equality of accessibility to future energy value chains is highlighted.

Seventeen scenarios for the roll-out of hydrogen and synfuels in Northern Ireland in the near- (2025) and medium-terms (2035) are analysed. The key findings are: (1) by 2025, green hydrogen could be a cost-effective decarbonisation option for certain heavy-duty transport operators and industrial energy users who do not currently use natural gas, (2) co-production of hydrogen and electricity can result in cost-effective hydrogen production when hydrogen production is prioritised, (3) by 2035, green hydrogen could be highly cost-effective for a wider range of off-takers in heavy-duty transport and industrial heating, (4) increases in renewable electricity penetration will make grid-produced hydrogen cleaner than fossil fuels in 2035, but not clean enough for current UK standards, (5) geological storage of hydrogen has a major cost reducing impact, and (6) successful deployment of synthetic fuels, most likely for export but also for decarbonisation of domestic shipping and aviation, hinges on the development of offshore wind for economies of scale and the availability of non-fossil CO_2.

This report recommends that (1) green hydrogen should be supported as a route to decarbonise heavy-duty transport and industrial heat, (2) cost-effective full decarbonisation of these will require policy support for hydrogen production, (3) the impact of co-production of hydrogen and electricity on the operation of the electricity system should be investigated, (4) grid-connected hydrogen production and scale-up of renewable electricity should be synergistically rolled-out, (5) the rapid development of offshore wind energy is crucial for Northern Ireland to produce hydrogen at scale, (6) the potential of geological storage of hydrogen in Northern Ireland should be investigated and demonstrated as rapidly as possible, (7) the supply chain of sustainable CO_2 for synfuel production must be assessed and supported, (8) the costs of modifying Northern Ireland's energy infrastructure to handle hydrogen must be assessed in future work, and (9) export of hydrogen in various forms should be a central part of Northern Ireland's hydrogen strategy.

2 Introduction and methodology

The society we live in today is experiencing a generational change in its mindset several key geopolitical issues, none more so than the environment. Climate scientists have slowly been convincing politicians and policy makers of the need to act before we harm the planet beyond repair resulting in hundreds of nations now committed to legally binding climate agreements, signalling the now international desire to change. However, the pace with which this change is occurring is still being met with external pressure from independent bodies and climate activists alike, as current strategies and activities will not obtain the 1.5 ^{0}C target set by The Paris Agreement by 2050.

Substantial progress has already been achieved, primarily by reducing the carbon-intensity of global electricity grids with large amounts of renewables – particularly onshore solar and wind. These grids, however, are already beginning to struggle and strain due to the large-scale intermittency of GW-scale deployments of renewable electricity. This problem will only be exacerbated further in the next phase of renewables deployment from offshore wind, which will far outsize today's installed capacity. Additionally, as electricity only accounts for 23.2%[1] of the final energy consumption in the EU, there is a clear need for alternative energy solutions that can help alleviate the intermittency exhibited by Renewable Energy Sources (RESs) and help to address the >50% of energy demand of oil, petroleum, and natural gas. That solution can be energy vectors such as hydrogen, and hydrogen-derived and other synthetic fuels.

National governments are starting to recognise the importance that these solutions will play in future energy systems. Recent world events, whether that be the COVID-19 pandemic or the Russian invasion of Ukraine, have thrust this issue front and centre on the global political agenda. Hydrogen and synthetic fuels can stimulate green growth, reduce emissions by increasing renewable penetration into hard-to-abate sectors, and increase energy security.

To date 27 countries have released hydrogen strategies looking to take advantage of the beneficial properties of hydrogen as an energy storage mechanism and fuel, including the UK. The UK's plans have focused greatly on scaling hydrogen infrastructure around the country's industrial hubs – historic clusters of industrial activity and expertise such as Humberside - and less so around renewable energy hotspots – locations featuring exemplary renewable energy resources such as the East and South East of England, and Scotland. However, with new revisions changing the UK's ambitions from 5GW of low-carbon hydrogen production to 10GW featuring 5GW of green hydrogen production[2], these hotspots, will be key to achieving national targets. Ireland launched a public consultation on a national hydrogen strategy, which is targeting a late-2022 release.

Northern Ireland, due to its considerable renewable resources, is a prime location for hydrogen and synthetic fuels production technologies. These technologies represent an opportunity to provide sustainable growth, in line with both the UK and The Executive net-zero targets, whilst also transforming the local energy landscape – reducing use of emitting fossil fuels whilst decreasing import dependency. With centralised UK government continuing to focus their efforts on decarbonising industrial clusters, the deployment of hydrogen within Northern Ireland has not been prioritised. Instead, domestic sector growth has been spearheaded by local and EU funds, from sources such as the Departments of the Economy and the Interreg North West Europe programme. To realise its full potential, Northern Ireland continue to develop local knowhow and experience with

[1] Eurostat. Energy statistics – an overview. Accessed at: https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Energy_statistics_-_an_overview#Final_energy_consumption (2022).
[2]Department for Business, Energy & Industrial Strategy. British energy security strategy (2022).

regards to these technologies to enable the deployment of large-scale systems in the short-to-medium-term.

This study, analyses which fuels, application technologies, and deployment scenarios will be best suited within the Northern Ireland geography to continue development of a low-carbon fuels sector and help achieve short-term goals, and long-term ambitions. The methodology for the techno-economic analysis included uses a discounted cash-flow analysis to determine a Levelised Cost of Hydrogen (LCOH), including production and storage steps, presented in units of £/kg and £/MWh. Units of £/kg enables comparison with the published literature on hydrogen costs. Units of £/MWh enables comparison between hydrogen, synfuels and incumbent fossil fuels on a consistent energy basis. The equations used to calculate LCOH are provided in section 8.2 – Analysis Methods. Note that the majority of the literature only considers hydrogen production cost, omitting storage costs, which can be significant. Hydrogen production and storage equipment is sized and costed for each scenario using the University of Galway Hydrogen Techno Economic Assessment Tool, which has been described in various publications[3] [4] [5] [6].

Econo-environmental performance of the scenarios is evaluated using a CO_2 abatement cost calculation. This calculation, which can also be seen in section 8.2 – Analysis Methods, divides the cost increase in providing a MWh of energy (in £/MWh) by switching from a fossil fuel to hydrogen/synfuel by the reduction in CO_2 intensity (in tCO_2/MWh) resulting from the switch.

Results from the techno-economic and econo-environmental analysis carried out as part of this study can be found in section 8 – Northern Ireland Hydrogen and Synfuel Fuels Roll-Out Scenarios.

[3] Gunawan, Dinglitico, Blount, Burchill, Carton, and Monaghan. At what cost can renewable hydrogen offset fossil fuel use in Ireland's gas network? (2020).
[4] Gunawan, Williamson, Raine, and Monaghan. Decarbonising city bus networks in Ireland with renewable hydrogen. (2021)
[5] Gunawan and Monaghan. Techno-econo-environmental comparisons of zero- and low-emission heavy-duty trucks (2022).
[6] Gunawan, Cavana, Leone, Monaghan. Solar hydrogen for high capacity dispatchable, long-distance energy transmission – A case study for injection in the Greenstream natural gas pipeline. (2022).

3 Hydrogen and Hydrogen-Based Synfuel Pathways

3.1 Hydrogen

3.1.1 Gaseous Hydrogen

Hydrogen is seen as many to be the *key energy carrier* to unlocking the next stage of renewables in international economies – enabling further clean energy penetration to reduce emissions in areas which electrification is not a viable option. However, today, the global hydrogen landscape is still dominated by well-established, and often fossil intensive, pathways.

Most hydrogen produced today is grey hydrogen. This hydrogen is produced from natural gas via steam methane reformation (SMR) or coal gasification where the by-product CO2 is emitted directly into the atmosphere. It is a mature, low-cost, and large-scale production method, typically co-located to petroleum refineries/chemical plants and directly connected by pipeline systems to enable delivery of large volumes that these processes require. This method has historically produced the lowest cost hydrogen – at just £1-1.50 /kg_{H2}.

Actions are being taken to mitigate the emissions produced from grey hydrogen production pathways by introducing Carbon Capture Utilisation and Storage (CCUS) technologies – transitioning today's SMR based systems to a 'blue' hydrogen production pathway. This technology, although having received considerable financial and policy backing, particularly from countries bordering the North Sea with access to multiple undersea CO2 storage sites, is still being piloted. Blue hydrogen is seen by most as a transitional measure until electrolytically hydrogen is suitably mature and economically viable. This pathway has been championed as a low-cost form of hydrogen carbon abatement that utilises mature technology to enable production emission savings of 80-95% (depending on capture rate and leakage). However, with the recent developments in Ukraine, the EU is seeking to reduce reliance on Russian natural gas, which could reduce emphasis on this intermediate pathway. In fact, in November 2021, due to spikes in natural gas prices before the Russian invasion, it was reported grey hydrogen production had been more expensive than green hydrogen production for roughly 2 months – at £4.16/kg compared to £3.39/kg[7] (with renewable PPAs of £45/MWh).

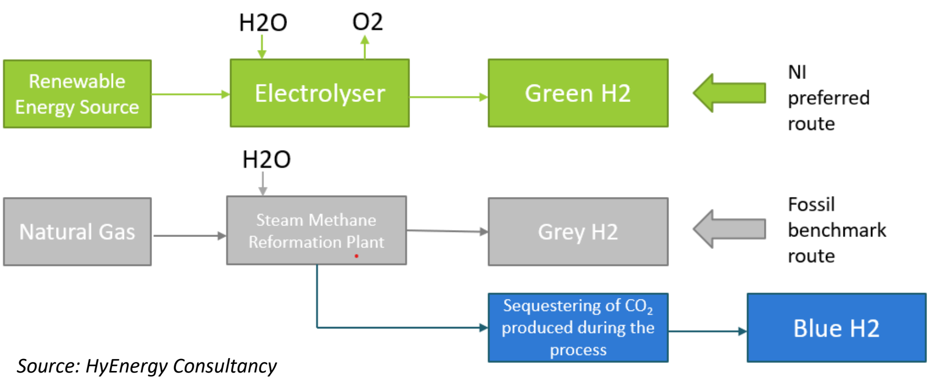


Figure 1: Major hydrogen production pathways

[7] RECHARGE News. 'Green hydrogen now cheaper to produce than grey H2 across Europe due to high fossil gas prices. Accessed at: https://www.rechargenews.com/energy-transition/green-hydrogen-now-cheaper-to-produce-than-grey-h2-across-europe-due-to-high-fossil-gas-prices/2-1-1098104 (2021).

Whilst blue hydrogen is facing a critical development juncture, green hydrogen – hydrogen produced from renewable sources - is going from strength-to-strength, particularly surrounding the technology of electrolysis. Innovation in this area has been a key focus of the European hydrogen sector for some time, simultaneously driving increases in efficiency and size to achieve large-scale emission saving across the continent. This has cemented the positions of the two premier electrolysis technologies – alkaline and proton electrolyte membrane (PEM) - each with their own unique advantages and disadvantages. Alkaline electrolysis is the most mature technology type, having been used for well over 100 years and has, until recently, been the go-to option due to its reliability and scale. PEM, due to increased efficiency and operability range has gained significant momentum. Come 2022, the majority of installed projects will feature PEM electrolysers – a change that has materialised in just three years where alkaline dominated the market in 2019.

The EU's planned electrolysis pipeline is really starting to gather pace, with proposals almost exceeding its 6GW 2024 target[8], despite having an installed capacity of just 0.3GW today. This ramp-up of capacity is based around two principal scenarios in Europe:

- Areas in which renewable resources are readily available, leading to the production of lowest cost green hydrogen possible;
- Areas of high hydrogen demand.

These production methods make hydrogen in its gaseous form which is readily used by industry as feedstock and chemical building block in refineries and ammonia production. Nevertheless, gaseous hydrogen is not perfect for every application. For some processes, liquid hydrogen (LHY) is much better suited.

3.1.2 Liquid Hydrogen

In order to produce LHY from gaseous hydrogen, an extra step is required – liquefaction. During liquefaction, hydrogen is cooled to below -250 ^{0}C, at which point it changes phase (condenses), and then is typically stored in large cryogenic storage containers. Whilst this process is relatively new to the European market, the US has been utilising liquefaction for over two decades to maximise the volume of hydrogen that can be distributed along lengthy transportation corridors. It is worth noting that this process is extremely costly and energy intensive – requiring roughly 30% of the total energy delivered to operate current plant sizes[9] - but as LHY tankers carry around 2.5-5x as much hydrogen as conventional gaseous tube trailers, it makes the economics surrounding long-distance hydrogen delivery much more viable. Aside from cost-effective long-distance distribution of hydrogen, green LHY is also seen as a promising zero-emission fuel for heavy-duty vehicle applications as its energy-to-weight density is far superior to that of battery alternatives, making it particularly intriguing to the aviation and aerospace sector and other heavy-duty transport.

[8] European Commission. A hydrogen strategy for a climate-neutral Europe (2020).

[9] Office of Energy Efficiency & Renewable Energy. Liquid Hydrogen Delivery. Accessed at: https://www.energy.gov/eere/fuelcells/liquid-hydrogen-delivery#:~:text=Liquid%20Tankers,-Currently%2C%20for%20longer&text=Over%20long%20distances%2C%20trucking%20liquid,for%20boil%2Doff%20during%20delivery. (2022).

3.2 Hydrogen-to-X

The synthetic fuels, and Renewable Fuels of Non-Biological Origin (RFNBOs) discussed within this report, whether they be clean versions of conventional fuels, or completely new fuelling options, all feature green hydrogen as a feedstock. These fuels are at the forefront of global political discussion due to a number of key factors in the recent geopolitical climate, including:

1. Consistent downward trend in the price of renewable electricity which will have a direct effect of the production costs of hydrogen[10], this trend is particularly apparent in PV and wind generation technology.
2. Persistent increase in variable renewable electricity generation[11], with an accompanying rise of excess/curtailed electricity and grid constraint[12].
3. Fall in associated costs with hydrogen production technologies, particularly electrolysers. This decrease is driven by the scale-up of manufacturing practices, research and development combined with technological learning[10].
4. Increased pressure on policy to shift its focus from reduced emissions to net-zero emissions by 2050 or even sooner[13], particularly for hard-to-abate sectors.

As well as green hydrogen, some of these fuels also require a CO_2 feedstock. The emission intensity of these fuels is highly dependent on the source of this CO_2 which can be split into two categories: renewable (atmospheric, biogenic) and non-renewable fossil sources (power plants, steel works, cement flue gas etc.). For renewable CO_2 capture methods, direct emissions are net zero. Concentrated sources of CO_2 are a less expensive capture method as these methods are less energy intensive and more available. The production of fuel reliant on CO_2 feedstocks, will change substantially in the coming decades in order to achieve net-zero targets. If these fuels are synthesized utilising sustainable feedstocks, such as green hydrogen and clean CO_2, they can be defined as renewable with the lowest possible emissions intensity.

The two leading pathways to source sustainable CO_2 are from Direct Air Capture (DAC), which can reach large scales but is very expensive and innovative, or biomass gasification, which is cost-effective but only produces small quantities of CO_2 in comparison to what is required. To realise domestic production of Methanol, Sustainable Aviation Fuels, and Synthetic Methane, these technologies will need to be deployed in addition to green hydrogen production. This will incur further infrastructure costs, and supply chain complexity but could still reach cost-competitiveness with low enough cost of electricity. For the production of all fuels included within the next section, their overall delivered cost is highly dependent upon the Levelised Cost Of Energy (LCOE) used to produce them – between 50 - 90% of total fuel cost[14]. Therefore, the deployment of excess large-scale, cost-effective renewables will be pivotal to all of Northern Ireland's future hydrogen and synthetic fuel strategies and should be heavily prioritised.

[10] IRENA. Green Hydrogen Cost Reduction. (2020).
[11] Department for Business, Energy & Industrial Strategy. UK Energy in Brief 2021. (2021).
[12] Staffell, Green R, Green T, Jansen, Gross. July to September 2022 Electricity Insights Quarterly. (2022).
[13] United Nations Climate Change. Climate Plans Remain Insufficient: More ambitious Actions Needed Now. Accessed at: https://unfccc.int/news/climate-plans-remain-insufficient-more-ambitious-action-needed-now (2022).
[14] IEA Bioenergy. Status and perspectives of non-biogenic renewable gases (2022).

3.3 Ammonia, Methanol, and Liquid Organic Hydrogen Carriers

Hydrogen is a very energetically dense molecule on a mass basis, much more than that of conventional fossil fuels, but due to its low volumetric density it is difficult to store without high cost, high-pressure equipment. Therefore, in some situations, it may be preferable to convert hydrogen into another molecule that is easier or more cost-effective to handle rather than dealing with hydrogen itself. These molecules can then either be a fuel themselves, or act as a hydrogen carrier – storing hydrogen and releasing it when it is required.

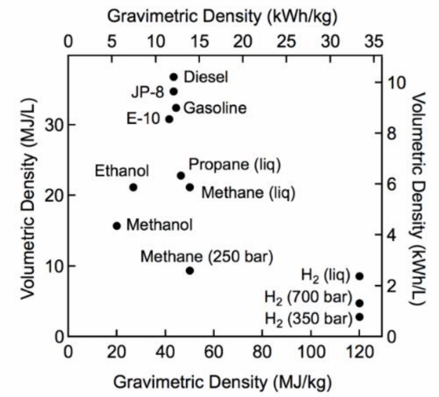


Figure 2: *Gravimetric density vs Volumetric density of various fuels – Office of Energy Efficiency & Renewable Energy*

Ammonia is a key example of one of these molecules. Ammonia, or NH_3 to use its chemical formula, has beneficial characteristics that make it an ideal hydrogen carrier. It is internationally recognised as a key industrial feedstock, particularly in fertiliser production, and as such is readily traded and handled in large quantities with established regulation and safety frameworks. Thus, with its high hydrogen storage density (17.7wt%H_2 gravimetrically[15]), transporting hydrogen as ammonia can enable cheaper, safer, and easier large-scale movement of hydrogen.

Conventionally, ammonia is producing using the Haber-Bosch process – a staple chemical reaction since its discovery in the 20th century. This process reacts nitrogen and hydrogen together, in the presence of catalyst, to produce ammonia. This is a highly energy intensive and carbon emitting process currently requiring 8MWh of energy per tonne produced, but 90% of these emissions currently come from the production of grey hydrogen to use as a feedstock[16]. Hence, if the hydrogen feedstock can be switched to a less emitting variation, such as green, coupled with renewable-powered separation of nitrogen from air, then you can produce emission-free ammonia.

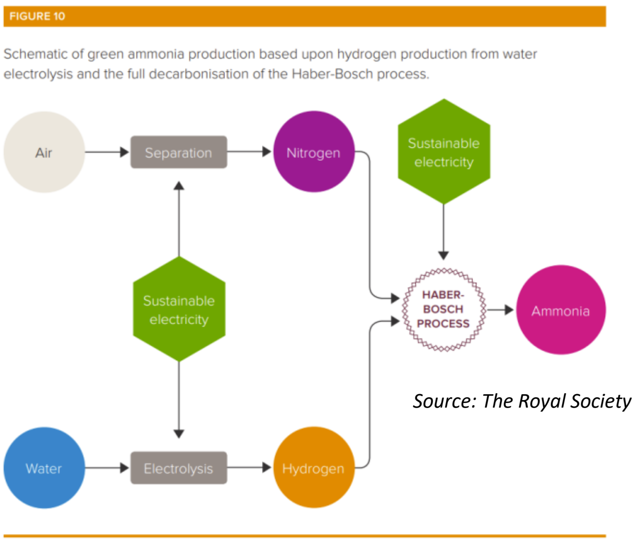


Figure 3: *Green ammonia production pathway*

[15] Andresson and Grönkvist. Large-scale storage of hydrogen (2019).
[16] The Royal Society. Ammonia: zero-carbon fertiliser, fuel and energy store (2020).

Ammonia conversion is becoming increasingly important in the global-energy landscape. GW-scale projects are positioning hydrogen-to-ammonia pathways as the premier route of hydrogen chemical storage with a view to international distribution via ships, since ammonia shares thermos-physical similarities with Liquefied Natural Gas (LNG). These projects are extremely popular in renewable energy hotspots across Africa, Australia, and the Middle East as they necessitate the cost-efficient transportation of thousands of tonnes of hydrogen in order to this approach viable. NEOM, which is based in Saudi Arabia, is a planned zero-emission megacity where Air Products (AP), along with partners ACWA Power, are investigating one such pathway. An exclusive $5bn deal will see AP produce 1.2 million tons of green ammonia per year from green hydrogen. AP will then take this ammonia and distribute it around the world, where it will be dissociated back to hydrogen for sale into lucrative transportation markets.

Whilst this hydrogen-to-ammonia pathway is well established, the dissociative step to acquire hydrogen back from ammonia is much newer to the market. Ammonia dissociation requires either expensive and rare Platinum Grade Metal (PGM) catalysts and temperatures >650 ^{0}C, or nickel catalysts with temperatures >900 ^{0}C[17]. Thus, progress must be made in this area to make ammonia as a carrier truly competitive.

Ammonia, as well as methanol (see next section), has a chance to play a role as a fuel itself predominantly for the shipping market. International energy projects are already planning to produce green methanol and ammonia in large quantities to ship around the globe, which presents vessel operators with an opportunity. The port infrastructure necessary for transportation of these molecules around the world can also be utilised to convert fleets to zero-emission analogues.

Ammonia-fuelled ocean-going vessels are in the early stages of their development life cycle, with the first 'ammonia ready' vessel[18] – a Suezmax - having been delivered to Avin International in early 2022, although currently it is still being conventionally fuelled by fossil sources. MAN, a German based multi-national company, is currently developing an ammonia dual-fuel medium-speed engine[19] that will become commercially available by 2024 with retrofits packages on the market by 2025. Whilst Wärtsilä have received €10m of EU funding to develop their two- and four-stroke engines[20] which can run on blends of up to 70% ammonia, with a pure ammonia prototype expected by 2023. These developments will be key to establishing the industry surrounding ammonia for maritime – latest projections forecasted within DNV's Maritime Forecast to 2050 show ammonia could account for ~25% of final shipping energy demand by 2050 in order to achieve net-zero.

Methanol**,** like ammonia, is another potential chemical storage medium for hydrogen. It does not quite exhibit the same hydrogen density as ammonia (12.5wt%H_2[7]), but it is traded in just as large quantities for use in formaldehyde and plastic production amongst other uses. Around 100 million metric tons are produced annually, meaning much of the necessary infrastructure and supply chains relating to the distribution and storage of methanol are already in place. Methanol production is currently responsible for 11% of hydrogen demand from industrial applications.

[17] Lucentini, Garcia, Venrell, and Llorca. Review of the Decomposition of Ammonia to Generate Hydrogen (2021).
[18] Offshore Energy. World's first ammonia-ready vessel delivered. Accessed at: https://www.offshore-energy.biz/worlds-first-ammonia-ready-vessel-delivered/ (2022).
[19] MAN Energy Solutions. Unlocking ammonia's potential for shipping. Accessed at: https://www.man-es.com/discover/two-stroke-ammonia-engine (2022).
[20] Wärtsilä. Wärtsilä coordinates EU funded project to accelerate ammonia engine development. Accessed at: https://www.wartsila.com/media/news/05-04-2022-wartsila-coordinates-eu-funded-project-to-accelerate-ammonia-engine-development-3079950 (2022).

Methanol is produced by subjecting syngas – a synthetic gas mixture typically containing hydrogen, carbon monoxide, carbon dioxide – to a catalytic process in which CO_2 is hydrogenated. Today, 65% of methanol is produced via reformation of natural gas, with almost all of the remaining 35% coming from the most carbon-intensive production route possible, coal gasification. Just 0.2% is produced via green pathways[21]. This production portfolio means that for every tonne of methanol produced, 2.3 tonnes of carbon dioxide is released into the atmosphere. However, the production of green methanol, utilises proven, technologies to conventional methanol production pathways with the addition of sustainably sourced hydrogen and carbon dioxide feedstocks through electrolysis for hydrogen and Direct Air Capture (DAC), or Anaerobic Digestion (AD), for CO_2. Global methanol production will require 200 Mt/year of sustainable CO_2 by 2030 to decarbonise existing production and expected growth within the sector.

Figure 19. Proposed classification of methanol from various feedstocks

Source: IRENA and Methanol Institute

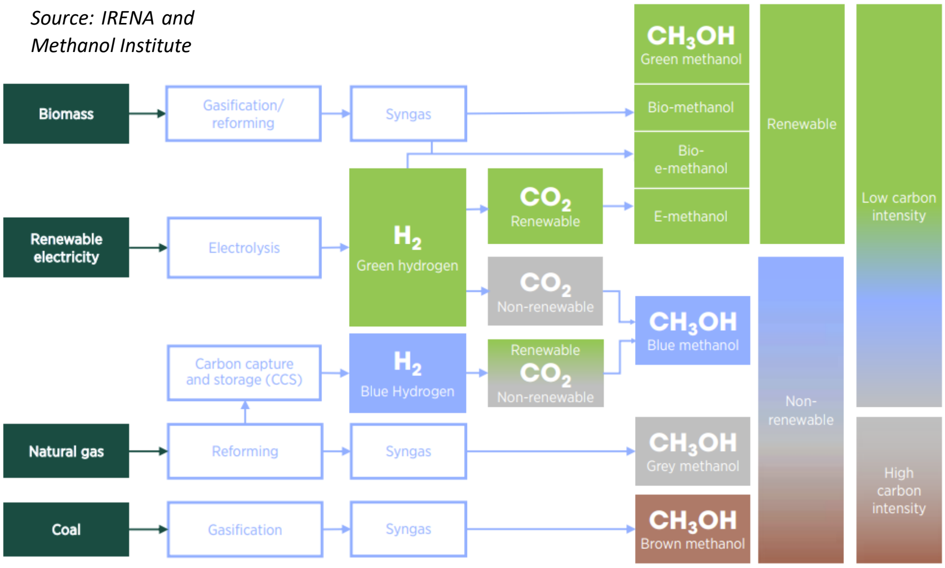


Figure 4*: Different methanol production pathways*

Methanol vessels have already started to make waves within the shipping industry, with Swedish ferry company Stena Line converting a 240-metre vessel to run on a dual fuel system in 2015 and has since run on blue methanol[22] from recycled residual steel gasses. These successes have led to companies like Maersk – one of the largest names in shipping – ordering more than 10 ocean-going ships with methanol power-trains worth around £130m each[23]. Maersk will need significant amounts of fuel to fill these 16,000 container capacity vessels and thus the company is seeking to accelerate the market with production agreements.

Methanol and other saturated hydrocarbons can also be used as **Liquid Organic Hydrogen Carriers (LOHCs)**, where they behave as a storage medium for the transportation of hydrogen. Examples of LOHC carrier molecules include naphthalene (7.2 wt%H_2), toluene (6.5 wt%H_2), or dibenzyltoluenes (6.2 wt%H_2)[24] to name just a few. Through an LOHC approach, value-chains can make best use of

[21] IRENA, Methanol Institute. Innovation Outlook Renewable Methanol (2021).
[22] Vessel Performance Optimisation. Recycled methanol powers Stena ferry from Sweden to Germany. Accessed at: https://vpoglobal.com/2021/06/24/recycled-methanol-powers-stena-ferry-from-sweden-to-germany/ (2021)
[23] BBC News. The Shipping giant banking on a greener fuel. Accessed at: https://www.bbc.co.uk/news/business-60433204 (2022).
[24] Grigorii Soloveichick. Bridging Renewable Electricity with Transportation Fuels presentation (2015).

existing infrastructure and processes. Within established sectors this is being considered to move high volumes of hydrogen over long distances (>1500km) in point-to-point delivery mechanisms, or in extreme weather conditions where conventional hydrogen apparatus would not function effectively, as demonstrated by the HySTOC project in Finland. LOHCs require reconversion to separate the hydrogen from its carrier molecule, which is recycled. This process, and its associated cost and energy requirements, are highly dependent on the carrier molecule, hydrogen end-use and necessary purity. Conversion and reconversion for a fuel-cell grade application, for instance, currently requires 35-40% of the total energy of the hydrogen transported (lower heating value). These penalties may be brought down closer to 25% if the heat released during dehydrogenation is captured and used effectively. For this reason, LOHCs are seeing limited use in niche scenarios currently until improvements make the technology more cost-effective and efficient for large-scale value chains, with conventional methods such as tube trailer and pipeline deliveries of hydrogen, currently preferred by the sector.

3.4 Sustainable Aviation Fuels (SAFs)

Aviation is currently responsible for 2.5% of global carbon dioxide emissions, and 3.5% of the total warming effect (effective radiative forcing) exhibited within 2020 due to additional emissions (NO_x and contrails) impact on the atmosphere. Sustainable Aviation Fuels (SAFs) are one of the leading alternative fuels to replace conventionally used kerosene and mitigate aviation's environmental impact. These fuels are obtained from low-carbon feedstocks and can be frequently combined with conventional jet fuel to realise considerable lifecycle emissions savings. The UK's recent Sustainable Aviation Fuel Mandate consultation[25] response defines the current expected criteria for eligible SAF's as such:

- Meet the fuelling standards set out within the DEF STAN 91-091 specification – the standard for aviation turbine fuel
- Be produced from waste-derived biofuels, power-to-liquid using either renewable or nuclear energy sources, or recycled carbon fuels
- Achieve at least a 50% GHG saving compared to a fossil fuel comparator of 89 gCO_2e/MJ Meet land criteria when derived from agricultural wastes and meet forestry criteria when derived from forestry wastes
- Use low carbon hydrogen where hydrogen is used as an input which contributes to fuel's energy content.

Due to the standardisation of the global aviation sector, the demand for SAFs seen worldwide, which grants flexibility and economically optimised in planning and decision making. With increasing crude oil prices, SAFs offer greater energy and financial security to regions who can develop production domestically, whilst also providing an opportunity to transition carbon-intensive jobs to a more sustainable pathway. Although currently SAF production only satisfies <1% of the total jet fuel demand, substantial recent growth has occurred in the area. By December 2019 at least 215,000 flights had been completed utilising SAFs, 40 airlines now have some experience with SAFs and 6 billion litres of purchase agreements for the future have realised. Additionally, it was projected in 2019 (200,000 tonnes globally[26]) that there would be an increase of approximately 3-4-fold the current SAF availability in the next year due to increases in production[27]. The European Commission has proposed

[25] Department For Transport. Sustainable aviation fuels mandate summary of consultation responses and government responses. (2022)
[26] World Economic Forum. All Aircraft Could Fly on Sustainable Fuel by 2030, Says World Economic Forum Report. Accessed at: https://www.weforum.org/press/2020/11/all-aircraft-could-fly-on-sustainable-fuel-by-2030-says-world-economic-forum-report/ (2020)
[27] International Air Transport Association. FACT SHEET 7: Liquid hydrogen as a potential low-carbon fuel for aviation. (2019)

a SAF blending mandate for fuel supplied to EU airports, with a minimum share increasing from 2% in 2025 to 63% in 2050, requiring at least 2.3 million tonnes of SAF by 2030[28].

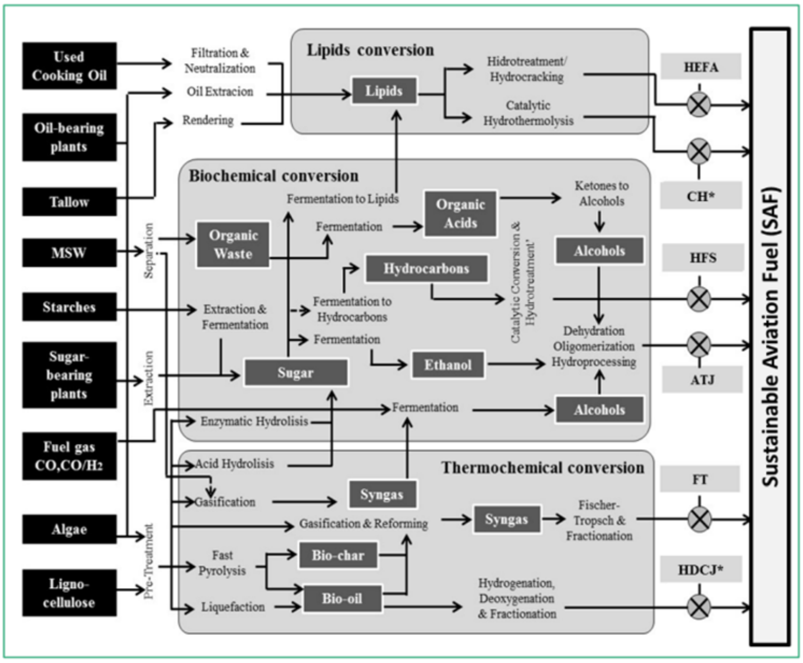


Figure 5*: Drop-in SAF production pathway overview*

As shown by the above figure, the SAF definition covers a number of fuels with different production pathways. These fuels largely split into three distinct areas: e-fuels, hydrogen, and biofuels. E-fuels and biofuels are manufactured with the aim to be almost chemically identical to conventional jet fuel. If this is achieved, they can be classified as a 'drop-in fuel' – a fuel that can be used interchangeably with conventional jet fuel with no required modifications to existing infrastructure. One of the most explored drop-in fuel production pathways is that of e-kerosene. This e-fuel is produced by combining sustainable CO_2 (As detailed in the Hydrogen-to-X section of this report) and low-carbon hydrogen whilst using renewable electricity. Readily available drop-in fuels, such as e-kerosene, are attractive to consumers as the initial investment to implement transition to this fuel is low.

Hydrogen, on the other hand, is not a drop-in fuel. Hydrogen is a new low-carbon fuel for the aviation industry that offers 2.5 times more energy per kilogram than kerosene when in its liquid form (LHY). This attribute dictates that higher efficiencies can potentially be reached due to the lower take-off weight of the aircraft which is being investigated by the aviation sector both in fuel cell and hydrogen jet powered aircraft. LHY only results in water vapour as a by-product of combustion of the fuel and features no particulate matter. When a fuel cell is used, nitric oxides are reduced by 90% compared to the combustion process. However, LHY has a much lower volumetric density than kerosene, and, currently, requires four times as much storage space for the same amount of energy, and therefore requires costly alterations to refuelling infrastructure and aircraft designs to implement – the primary barrier preventing widespread deployment. The use of LHY as an aviation fuel also emits 2.6 times

[28] European Union Aviation Safety Agency. Sustainable Aviation Fuels. Accessed at: https://www.easa.europa.eu/eco/eaer/topics/sustainable-aviation-fuels (2022)

more water vapour than kerosene, which can amplify the effect of other GHGs, although this is offset by its zero-carbon nature[19].

	Liquid Hydrogen	**Kerosene**
Specific Energy	120 MJ/kg	43.7 MJ/kg
Energy Density	8.7 MJ/L	35.2 MJ/L
Emissions	Water Vapour	CO2, water vapour, nitrous gases (NOx), Carbon monoxide, Carbon, particles, and numerous organic compounds
Thermal Stability*	550°C	220°C

Table 1*: Approximate values taken from currently available literature*

**Value to represent thermal stability is auto-ignition temperature*

Biofuels are also an alternative worth exploring. Today there are currently five biofuel conversion processes which are produce drop-in fuel certified under ATSM D7566:

1. Synthesized Paraffinic Kerosene produced from the Fischer-Tropsch process (FT-SPK). The possible feedstocks for FT-SPK are coal, natural gas, and biomass. However, in a completely decarbonised future, biomass is the only feedstock option. FT-SPK can currently be blended to a 50% volume ratio.
2. Synthesized Paraffinic Kerosene from Hydroprocessed Esters and Fatty Acids Process (HEFA-SPK). The possible feedstocks for HEFA-SPK are vegetable oils and fats, animal fats and recycled oils. HEFA-SPK can currently be blended to a 50% volume ratio.
3. Synthetic Iso paraffins from Hydroprocessed Fermented Sugars (HFS-SIP). The possible feedstocks for HFS-SIP are biomass to harness the sugar. HFS-SIP can currently be blended to a 10% volume ratio.
4. Synthesized Paraffinic Kerosene from Alcohol-to-Jet process (ATJ-SPK). Biomass is utilised for starch and sugar formulation. Additionally, cellulosic biomass is employed for isobutanol fabrication. ATJ-SPK can be blended with conventional jet fuel up to 30% by volume.
5. Synthesized Paraffinic Kerosene from the Fischer-Tropsch process with increased aromatic content (FT-SPK/A). The aromatic content is sourced from alkylation of light aromatics that are not derived from petroleum.

There are numerous sources for the required feedstocks including agriculture, forestry, organic residues, used cooking oils, residual animal fats, and waste materials. As the need for rapid decarbonisation increases, these options are increasingly being considered by airlines alongside conventional methods of e-kerosene production. For instance, between 2014 and 2016 Air France carried out 78 flights with a 10% SAF in collaboration with a Total affiliate[29]. In terms of bio feedstocks from crops, two species have been identified as potential alternative sources of vegetable oil - Jatropha and Cameline. Camelina which originated in northern Europe, is of particular interest for indigenous production in Northern Ireland, as according to Teagasc, this crop can be cultivated in the climate. Camelina is currently being used for experimentation across Canada and the US. The first

[29] TotalEnergies. Air France-KLM, Total, Group ADP and Airbus join forces to Decarbonise Air Transportation and Carry Out The first Long-Haul Flight Powered by Sustainable Aviation Fuel Produced in France. Accessed at: https://totalenergies.com/media/news/press-releases/First-Long-Haul-Air-France-Floght-Powered-By-Sustainable-Aviation-Fuel-Produced-by-Total-in-France (2021).

commercial flight was conducted by LAN Columbia using a 50% blend of camelina derived fuel in 2013[30].

However, when considering biofuel SAF production pathways, it is important to take into account the land-space required for crop-production. As can be seen in the UK's expected SAF classification criteria, they are hesitant to commit land space, whether that be agricultural or forestry, to fuel production. This position is mirrored in Europe through a reduction in incentives for biofuel production pathways in The Commissions' second Renewable Energy Directive (RED II).

Alternatively, biofuel SAF production can be realised through waste-to-SAF routes by exploiting resources such as used cooking oils and animal fats rather than crops. NESTE, the leading producers of SAFs and renewable diesel globally, now offer 'MY Sustainable Aviation Fuel'. This drop-in fuel is made from 100% wastes and residues and can reduce lifecycle GHG emissions by 80% compared to conventional jet fuel[31]. Similar drop-in solutions could be of extreme interest to both the NI and RoI agricultural sectors who are the first and second most emitting sectors in their countries respectively. Therefore, as demand for SAFs across the island of Ireland is expected to be large, with Ryanair already committed to reaching 12.5% SAF usage by 2030[32], this approach could represent an interesting cross-border collaboration opportunity to exploit over the coming decade.

3.5 Synthetic Methane

Synthetic methane refers to methane with non-biological origins, which is typically produced from a chemical process known as methanation. Methanation has two feedstocks carbon dioxide and hydrogen and therefore, depending on the origin of these feedstocks, can be produced in a sustainable way. The methanation reaction, which requires a catalyst, is as follows:

$$CO_2 + 4H_2 \rightleftharpoons CH_4 + 2H_2O$$

The most widely used catalyst is nickel due to its cost effectiveness and satisfactory yield of methane. However, nickel is problematic as it produces toxic by-products such as nickel carbonyl which must be managed appropriately.

As mentioned, CO_2 can be sourced from DAC, AD or the upgrading of biogas plants to acquire pure CO_2 by-product. The cost to integrate biomethane facilities to capture and upgrade biogas by-product CO_2 for subsequent applications is approximately 20% of the original investment cost of the biomethane plant. Renewable methane could become financially competitive by 2030 provided electricity reduces to 30€/MWh in conjunction with reductions in capital expenditure (CAPEX) and operational expenditure (OPEX) due to technological maturity.

[30] International Civil Aviation Organization. Sustainable Aviation Fuels Guide (2017).
[31] Gabriel Koetsiern NESTE. Wind meets Gas… and SAF presentation. Accessed at: https://www.groningenairport.nl/wind-meets-gas-2022 (2022).
[32] Reuters. Ryanair commits to 12.5% sustainable fuel by 2030. Accessed at: https://www.reuters.com/business/sustainable-business/ryanair-commits-125-sustainable-fuel-by-2030-2021-04-29/ (2021).

4 Energy Strategy and Economics

4.1 Existing Northern Ireland (NI) Energy Landscape

Energy Mix

Today NI is heavily reliant on imported fossil fuels to supply its energy needs. With no indigenous fossil resources, production or refining, fossil imports account for the vast majority of NI's heat and transport energy requirements. In addition, despite the high rate of growth in renewable electricity generation, imported fossil fuels, in particular coal and natural gas, comprised over 40% of NI's electricity feedstock in 2019[33].

Fuel	2019 Fuel Consumption (ktoe)	% of Total
Coal	2,045	3.9
Manufactured Fuels	354	0.68
Petroleum Products	28,833	54.94
Natural Gas	7,074	13.48
Electricity	7,472	14.24
Bioenergy and wastes	6,698	12.76
Total Final Consumption	52,476	100

Table 2*: Total Consumption of Energy by Fuel in Northern Ireland in 2019*

Direct use of fossil fuels mainly used in heating and transportation made up 86% of NI's total final consumption of energy. The remainder, which is met by electricity, is generated according to the sources show in Table 3.

Fuel	2019 Electricity Generated by Fuel (GWh)	% of Total
Coal	164	2.63
Natural Gas	2,360	37.86
Renewables	3,367	54.04
Oil and Other	341	5.47
Total Electricity Generated	6,232	100

Table 3*: Electricity Generation by Fuel Type in 2019 in Northern Ireland*

Outside the electricity generation sector, coal, manufactured fuels, and natural gas are predominately used for heating purposes. Consumption of petroleum products is approximately evenly split between heating and transport[25]. Bioenergy and wastes are mostly used for heating purposes.

[33] Department for Business, Energy & Industrial Strategy. Total final energy consumption at regional and local authority level: 2005 to 2019. Accessed at: https://www.gov.uk/government/statistics/total-final-energy-consumption-at-regional-and-local-authority-level-2005-to-2019 (2021)

5 Electricity

Renewable electricity generation in NI, mostly from wind, has grown significantly in the last decade. In 2013, 19.5% of electricity generation in NI was from renewable sources, compared to 42.3% in 2018 and then 54.04% in 2019. The rest of the electricity generation mix is mostly produced by natural gas-fuelled thermal generation at 37.86%. This is followed by Oil and other fuels at 5.47% and coal at 2.63%. Across Northern Ireland there are 5 fossil fuel-based power plants with a total installed generational capacity of 1.88GW

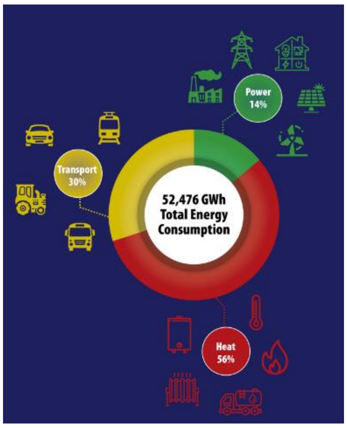


Figure 6*: Final Energy demand by sector – taken from NISRA's Energy in Northern Ireland 2022*

Northern Ireland is a constituent of the Single Electricity Market – a market operated by a Single Electricity Market Operator (SEMO). The SEMO is a joint venture between the system operators in Northern Ireland (SONI) and the Republic of Ireland (EirGrid Plc) – making the grids within NI and RoI strongly linked, not only in terms of operation but also infrastructure. NI and RoI's electricity infrastructure is connected via an interconnection between Cavan and Tryone[34] which has 3-tie lines with a combined 400MW transmission capacity. In 2019, 302 GWh of electricity was imported into NI from ROI, and 1,126.72 GWh was exported from NI to ROI[35]. NI's grid is also connected to Scotland via the Moyle interconnector – a set of submarine cables running between Antrim and Ayshire with a capacity of 500 MW[36] In 2019, 1,475.44 GWh of electricity was imported into NI from Scotland, and 494.79 GWh was exported from NI to Scotland[25]. Further interconnectors are planned across the island of Ireland to robustness of the electricity system for greater renewable deployment – these will be covered individually in the next section.

Overall, total electrical consumption in NI was 7,574 GWh, 3,131 GWh of which was generated from renewables (2021). The breakdown of renewable electricity generation in 2021, is shown in Figure 7[37].

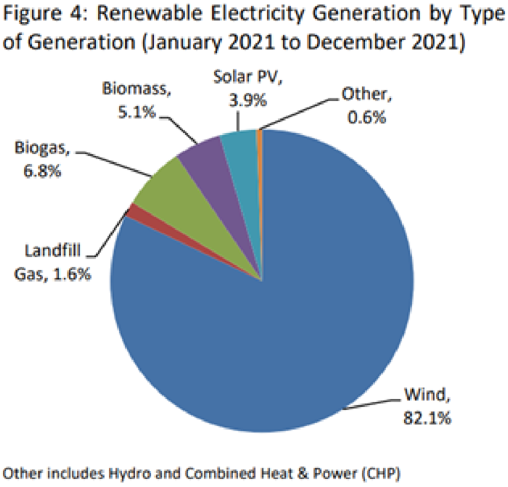


Figure 7*: Renewables Generation Breakdown*[25]

[34]SONI. North South Interconnector. Accessed at: https://www.soni.ltd.uk/the-grid/projects/tyrone-cavan/the-project/#:~:text=The%20Tyrone%20to%20Cavan%20Interconnector%20(also%20known%20as%20the%20North,and%20the%20Republic%20of%20Ireland (2022).

[35] Northern Ireland Statistics and Research Agency. Energy in Northern Ireland 2020 (2020).

[36] Mutualenergy. History and development of the Moyle Interconnector. Accessed at: https://www.mutual-energy.com/portfolio-items/history-and-development-of-the-moyle-interconnector/ (2022)

[37] Northern Ireland Statistics and Research Agency. Electricity Consumption and Renewable Generation in Northern Ireland: Year Ending December 2021 (2022).

5.1 Future NI Energy Landscape

Despite being part of the UK - the first major economy to announce legally binding obligations to reduce GHG emissions by 100% by 2050 - Northern Ireland has been slow to make similar domestic commitments. However, the need for a fair and fast transition has been recognised within by both the domestic private and public sector. This includes the Northern Ireland Executive (The Executive), who released 'The Path to Net Zero Energy' in December 2021[38] – a roadmap that aims to deliver 56% reduction in energy-related emissions by 2030 enroute to achieving net-zero carbon emissions and affordable energy by 2050. To accompany this piece of work, The Executive has published the inaugural version of a yearly action plan which includes goals, targets, and activities in energy efficiency, mobility, sustainable economic growth, public and community involvement, and strategic design.

Across both these documents, The Executive has laid out key intermediary targets to monitor NI's decarbonisation progress which largely mirror the ambitions seen in the UK, and within RoI. These include:

- Increases in energy in energy efficiency – 25% energy savings from buildings and industry to mitigate current fossil fuel usage.
    - This includes sub-targets to ensure all new buildings within Northern Ireland are net-zero ready by 2026/2027, or earlier if possible, whilst also ensuring current households and businesses using high carbon-intensity heating fuels are able to switch to low-/zero-carbon analogues.
- Increase penetration of renewable electricity – 70% of electricity consumption from a diverse mix of sources
    - Including solar, and both onshore and offshore wind.
- Double the size of low-carbon/renewable energy economy in Ireland to a turnover of >£2bn
    - Turn Northern Ireland into a leading low-carbon innovation hub – both deploying technologies/infrastructure and developing the necessary markets to integrate low-carbon energy in a cost-effective manner.

This impetus has led to the development of NI's first ever climate change policy. Initially targeting 82% reduction in emissions by 2050, the legislation has increased ambitions to a 100% reduction following further deliberation and has now passed into law[39]. Therefore, with NI now required to achieve net zero, transforming its energy portfolio will be pivotal to its success. Energy emissions account for almost 60% of NI's total emissions – >70% of total fuel consumption and >45% of total electricity generation in NI is still accounted for by petroleum products, natural gas, and coal.

In order to realise these targets, massive investment and scale-up of renewable technologies is required. This will not only help to satisfy the electrical grid's requirements, but also, via electrification and conversion, realise emissions savings in hard-to-abate areas, particularly heat, power, and transport.

Northern Ireland has already successfully scaled-up renewable energy production once, achieving its 2020 targets of 40% renewable electricity generation by some margin. However, to achieve 2030 targets, it must utilise a multi-pronged approach – achieving greater magnitudes of deployment, whilst simultaneously maximising captured potential by minimising curtailment and dispatch down. In Northern Ireland, the dispatch down of wind resources alone in 2020 reached 461 GWh, equivalent to 14.8% of the available wind energy for the time period, or 6.09% of the NI's final electrical demand

[38] Northern Ireland Executive. The Path to Net Zero Energy (2021).
[39] Northern Ireland Assembly. Climate Change Act 2022 (2022).

in 2021[40]. EirGrid and SONI, the transmission grid operators in RoI and NI respectively, are tackling this issue by installing a number of interconnectors across the island of Ireland to increase the grid's capacity and reduce bottlenecks, whilst also providing wider spread access to low-carbon electricity. This includes the North-South (900MW) interconnector between RoI and NI, as well as the Celtic (700MW) interconnector between RoI and France, which will also benefit NI due to the all-island electrical grid system. The North-South interconnector has been designated as a key project to enable the transition of the electricity system to 70% renewable by 2030. The project has received two rounds of planning approval, firstly in December 2016 and then again in September 2020, and will be operational by 2026. The Celtic Interconnector is also expected to be operational by 2026, having received final consent from An Bord Plenála in May 2022[41].

New interconnectors will not solve all the current energetic challenges exhibited within NI. Recent geopolitical events, such as the Russian invasion of Ukraine, and subsequent energy price and supply security shocks have highlighted the need to increase Northern Ireland's energy security, whilst still prioritising sustainability and cost-effectiveness. Latest estimates by UK government, from 2018, show an 18% fuel poverty level for households within NI. However, according to Consumer Council research, this figure has skyrocketed to 34% in early 2022, whilst the Utility regulator also estimated that potentially 50%[42] of households were in fuel poverty in March. This sudden increase has been driven by an overreliance on costly, imported fossil fuels and will only be mitigated by realising greater amounts of indigenous low-carbon fuel production.

The Executive, within the Net Zero roadmap document, have recognised the potential of hydrogen, and other biofuels, to symbiotically couple with increasing renewable deployments to decarbonise hard-to-abate sectors, whilst also improving domestic energy poverty and security. The groundwork laid by demonstration projects, such as GenComm and Translink, is already being converted into larger-scale developments within RoI, both in terms of hydrogen hub concepts, such as the Galway Hydrogen Hub (GH2), and hydrogen valleys, in SH$_2$AMROCK. To realise similar large-scale deployments over the coming years, NI will make available considerable amounts of innovation funding dedicated to fostering the development of a hydrogen economy – including running trials in key sectors such as heating and mobility, establishing a domestic centre of excellence, and creating catapult scheme to maximise the impact of research and innovation activities.

40 EIRGRID, SONI. Annual Renewable Energy Constraint and Curtailment Report 2020 (2021).

41 EIRGRID GROUP. Celtic Interconnector. Accessed at: https://www.eirgridgroup.com/the-grid/projects/celtic-interconnector/whats-happening-now/ (2022).

42 Belfast Telegraph. Warning: Almost three quarters of NI households in fuel poverty by next year. Accessed at: https://www.belfasttelegraph.co.uk/business/northern-ireland/warning-almost-three-quarters-of-ni-households-in-fuel-poverty-by-next-year-41885934.html#:~:text=%E2%80%9CThis%20figure%20increased%20to%2034,NI%20were%20in%20fuel%20poverty. (2022).

NI is not only well suited to green hydrogen production thanks to its considerable renewable potential, but also to large-scale storage too. For very-large hydrogen storage, there are five possible storage locations: Salt Caverns, Aquifers, Depleted gas/oil fields, hard rock caverns, and abandoned mines. These locations are ideal to store gaseous hydrogen at a pressure of between 130 to 260 bar[43]. The Island-Magee gas storage facility at Larne, which is currently under development, features seven joined salt caverns capable of storing 1.2 TWh of hydrogen (total capacity of 500 MNM^3_{H2}). Each of these caverns has the potential to provide hydrogen for 3 days of the country's power station needs, heat homes for almost 2 weeks, or power NI's bus fleet for 6 months. With all necessary test drills and technical checks having already been carried, the facility is expected at least one cavern from natural gas to hydrogen by 2025, with further conversions expected as public confidence and the hydrogen market grows. This facility will be of incredible importance to both NI and RoI to deliver greater long-term energy security for the island's energy systems.

Figure 8: *Hydrogen proposition for Northern Ireland taken from The Path to Net Zero*

Before 2020	**2021**	**2025**	**2030**	**2050**
Test drilling complete	P2X project, 20MW GT fed by hydrogen, Cavern Licensing, brine disposal	1 H_2 cavern, or 2 H_2 cavern, 6-7 NG cavern, Monitoring hydrogen market to build more caverns	3-4 H_2 Cavern, & 4-3 NG cavern	7+n Caverns fully hydrogen, no NG

Figure 9: *Timeline to net-zero energy operations at Island-Magee*

By 2030, the NI energy system will have changed considerably, however it will still need for oil and its derivatives whilst continuing its journey towards a completely net-zero solution. By 2050, this need will have almost depleted completely, which has been mapped by The Executive in two separate 2050 scenarios – Power Play and Flexible Fit:

- **Power Play** – focus on direct electrification via renewable energy scale-up in all areas
- **Flexible Fit** – Prioritising electrification with a greater use of fuels such as hydrogen and bio-fuels solutions depending on location and geography.

43 Zivar D, Kumar S, F4oroozesh J. Underground hydrogen storage: A comprehensive review. Int J Hydrogen Energy 2021;46:23436–62

Each scenario will see a significant decrease in final energy demand as widespread energy efficiency measures are deployed, as well as an increase in electrical demand due to electrification. Oil usage in heating and transport will decrease from 60% of the final energy demand in 2018 to 3%, or lower by 2050. Expected breakdown of these scenarios can be seen below from Figure 10. Both scenarios see key roles for hydrogen in transportation and industrial decarbonisation.

Figure 14: Final Energy Demand by Scenario to 2050

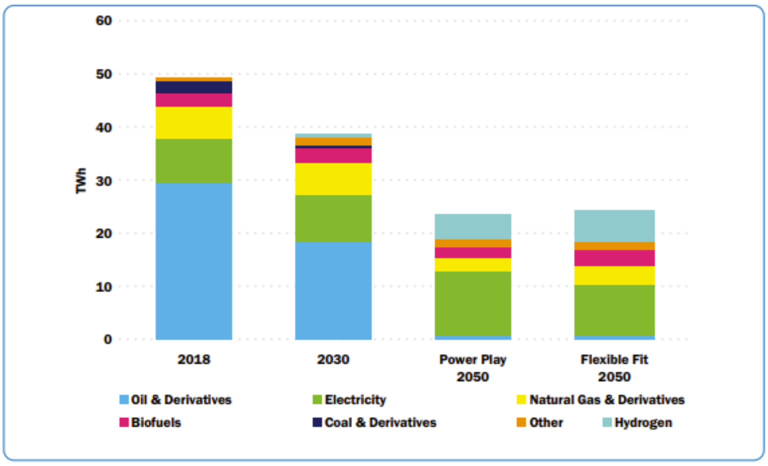


Table 11: Characteristics of Illustrative Future Energy Scenarios in 2050

POWER PLAY	FLEXIBLE FIT
• With high levels of electrification and energy efficiency, overall energy demand falls by 52%. • Electricity is the largest energy source across heat, power and transport: 50% of total demand. • Hydrogen (19%) plays a key role in transport and industry and biogas is an important energy source. • Oil and gas continue to play a very small role due to the 'hard to electrify' areas • Coal is no longer in use.	• A diverse mix of technologies, greater decentralisation and energy efficiency means energy demand falls by 50%. • Electricity is the largest energy source: 38% of total demand. • Biofuels account for 29% of total energy demand, due to biomethane use in the gas network and biofuels replacing some heating oil. • Hydrogen contributes 24% across transport, heat and industry, whilst coal is no longer in use. • Oil accounts for 3% of final energy demand for transport.

Figure 10*: 2050 final energy demand scenarios taken from The Path to Net Zero*

5.2 International and Interregional Energy Supply Trends

The issues of energy supply and security are at the very forefront of the global political discussion. Current world events have provided the required emphasis to drive the UK and EU to act and reduce its reliance on Russian gas, paving the way for completely new international and domestic energy trade routes. In the short term, to mitigate this reliance, one possible scenario could be increasing domestic fossil-fuel production. The UK government announced a licensing round to commence new North Sea fossil fuel projects for Autumn 2022 - confirming the immediate desire to increase the share of domestic energy sources in the energy mix. Whereas to satisfy the impending need for alternative energy in the EU, they will import more energy from different external markets, such as LNG from Qatar and the US.

However, with an expedited need to decarbonise, the long-term plan of both the UK's energy security strategy and the EU's REPowerEU, is to increase the prevalence of low-carbon and renewable assets to reduce emissions whilst also developing a flourishing sustainable economy. These developments will principally split regions and countries into two discreet categories:

- **Energy Exporters** – Energy exporting locations are areas with considerable renewable potential that far exceeds their demand. Typically, those with high solar load factors or large offshore wind potentials.
- **Energy Demand Centres** – Locations which have considerably higher energetic demand than can domestically be produced via low-carbon sources. Therefore, low-carbon energy will be required from surrounding areas to satisfy their needs.

Whilst all countries will endeavour to increase their low-carbon energy production portfolios, some areas are intrinsically more suited to production than others due to their geographic locations and makeup. For instance, in Europe, the North Sea and Spain are ideal renewable locations and thus will exhibit the lowest LCOE due to higher capacity factors. Whereas, on a global scale, renewable projects are springing up constantly in Africa, Australia, and the Middle East due to their wealth of renewables. The vast majority of this increased deployment is expected to come from mature renewable technologies such as solar. Solar is the fastest growing renewable energy sector, and can already provide the cheapest source of electricity in history, at just $30-60 MWh in Europe/US, and even cheaper in China[44]. Global solar capacity was estimated to be just shy of 600 GW in 2019, but could rise to 1.5-3 TW by 2030[45]. Considerable progress will also be made in wind, particularly offshore wind which is increased deployment globally and could reach 330 GW of capacity by 2030 from just 34 GW in 2021[46].

However, increasing capacity is just one of the challenges facing the energy transition – the efficient transportation of this energy to end use is another key issue that requires addressing. For a variety of renewable deployment locations, conventional electrical connection via high-capacity grid links is not capable for a variety of reasons (location, poor national grid, costly, etc.). Instead, to overcome this issue, global-scale projects are converting this energy into a physical commodity that can be readily traded and stored in similar ways to oil and gas today. Energy supply agreements have been announced at an unprecedented level, between companies and nations alike, following the COVID-19 pandemic as governments look towards sustainable areas of growth for their economies. These deals feature the production and movement of green ammonia, hydrogen, and other sustainable fuels, from energy exporter to energy demand centre locations such as: Portugal to the Netherlands, Saudi Arabia to Europe, and Australia to the UK to name just a few.

These trade routes are considering two premier distribution methods– shipping and pipelines – both of which are extremely mature technologies[47]. It is likely that in the long-term pipelines will be more suitable for the transportation of fuels such as hydrogen within Europe itself through the installation and refurbishment of gas-network infrastructure. The EU's Hydrogen Backbone Plan will establish a continent-wide distribution network of sustainable fuels, backed by a considerable number of the continent's network operators. Whilst in the UK, plans set out recently through the National Grid's Project Union[48] show similar ambitions to create a 100% hydrogen gas grid across the country,

[44] CarbonBrief. Solar is now 'cheapest electricity in history', confirms IEA. Accessed at: https://www.carbonbrief.org/solar-is-now-cheapest-electricity-in-history-confirms-iea/ (2020).
[45] GlobalData. Solar Photovoltaic (PV) Market, Update 2019 (2019).
[46] RENews. Global offshore wind capacity to 'reach 330GW by 2030'. Accessed at: https://renews.biz/77932/global-offshore-wind-capacity-to-reach-330gw-by-2030/ (2022).
[47] IRENA, Geopolitics of the Energy Transformation: The Hydrogen Factor (2022). Accessed at: https://www.irena.org/publications/2022/Jan/Geopolitics-of-the-Energy-Transformation-Hydrogen
[48] S&P Global Commodity Insights. UK national grid targets hydrogen network, build from 2026. Accessed at: https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/051222-interview-uks-national-grid-targets-

connecting the nation's industrial hubs, starting with Teesside and Humberside. It is not yet clear whether this network will be extended for Northern Ireland. To install a dedicated pipeline network across the UK and EU, as envisaged by these two projects, will require a considerable amount of CAPEX support. For instance, the EHB initiative is expected to require between €62.7-91bn in investment costs for its pipelines and a further €17.2-52.4bn for associated compression technologies. This cost will be minimised by utilising repurposed natural gas infrastructure wherever possible. Current natural gas infrastructure, when not made of polyethylene as in Northern Ireland, is suitable for blending hydrogen but must be tested thoroughly to prevent hydrogen embrittlement occurring[49] when carrying high hydrogen blends (>20%) or dedicated hydrogen supplies.

Shipping, on the other hand, is being explored to move the green versions of readily traded materials such as ammonia and methanol. The maturity of this technique means that thousands of tonnes of these substances can moved across borders without any further policy, regulatory, or technological implications - the carbon-intensive ammonia/methanol only needs to be switched for its green analogue. This can then be used directly in applications upon reaching its import terminal, converted to hydrogen, or combusted in turbines, to serve local needs. The transportation cost of shipping hydrogen in the form of ammonia and methanol is comparable to pipeline transportation. The added cost of reconversion to obtain hydrogen upon import (dissociation, liquefaction, gasification etc.) as well as the import terminal itself, however, means that only the largest-scale value chains, such as the NEOM megaproject, or those with substantial subsidy support will be able to import hydrogen at a cost-competitive level by 2025 or 2035 via these mechanisms. LHY shipping is also being trialled between Australia and Japan, but due to its scale (Just 75Mt compared to a potential >10,000Mt) will only be economically viable for applications where no extra conversion steps are required such as computer processor manufacturing.

5.3 The Cost of International Energy Supply Pathways

Ports based within Northern Ireland will act as energy hubs – as key onshoring locations for domestic renewable energy production, and import terminals for energy produced from other countries in the form of hydrogen and synthetic fuels. The Northern Ireland Green Seas project is already exploring how NI's energy and maritime sectors will symbiotically couple to unlock their full potential – including offshore renewables generation, large-scale energy storage, and conversion of fossil fuel vehicle fleets. Due to its indigenous wind energy resource, Northern Ireland could have the potential to produce enough hydrogen to meet its own needs and export excess to GB and beyond. There exists however a risk that if domestic production does not scale in line with demand, import channels, many of which entail large-scale, long-term infrastructural investments, will open and thus impede growth of domestic production.

In the absence of rapid growth in domestic hydrogen production, NI can gain access to low-cost, high-volume products on the international market, which will help to enable further deployment of zero-emission technologies. The UK has already secured several trade deals which ensure foreign low-carbon fuels will aid local large-scale decarbonisation, such as the agreement signed with Fortescue Future Industries (FFI) in October 2021. The MoU will see FFI supply JCB and Ryze Hydrogen, who also own NI-based fuel-cell electric bus manufacturer Wrightbus, with 10% of the company's global hydrogen production which is predicted to reach 15 Mt per annum by 2030, growing to 50 Mt in the decade following worth potentially billions[50]. International co-operation, such as that seen between

hydrogen-network-build-from-2026#:~:text=National%20Grid%20envisages%20Project%20Union,the%20existing%20natural%20gas%20infrastructure (2026).

[49] SIEMENS Energy. Hydrogen infrastructure – the pillar of energy transition. (2021).

[50] BBC News. JCB signs green hydrogen deal worth billions. Accessed at: https://www.bbc.co.uk/news/uk-59107805 (2021).

FFI, JCB, and Ryze, will be crucial for NI to provide bankable, cost-effective business models in the short-term whilst the country is building its national competencies in the area of hydrogen and synthetic fuels. Once these competencies are fully developed, NI can then utilise this experience to deploy export value-chains of their own if production volumes exceeds domestic demand.

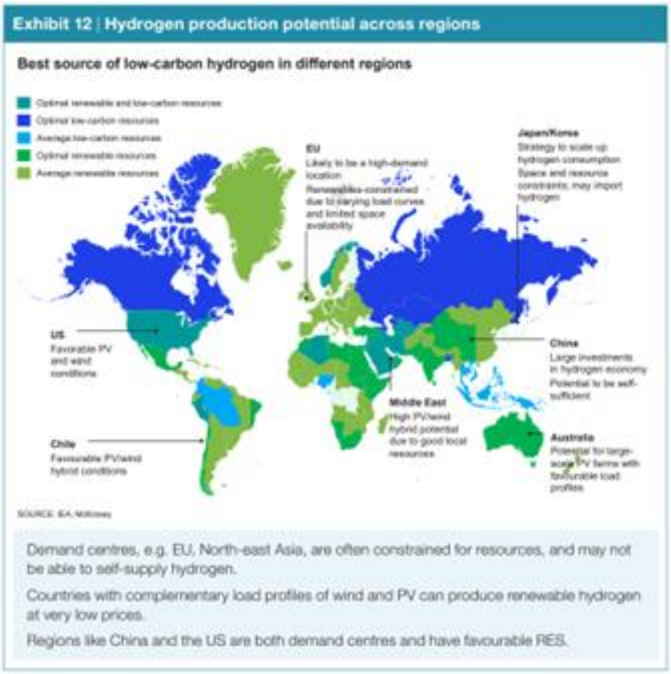


Figure 11*: Best global hydrogen production locations - taken from Hydrogen Council*

The most likely production pathways of internationally distributed hydrogen will be by renewable energy coupled with electrolysis. Any momentum surrounding the development of blue hydrogen international value chains has been dampened by the ongoing energy crisis and Russian invasion of Ukraine. This this pathway is only being strongly considered in locations with advantageous geographic properties, such as large-scale CO_2 sequestration opportunities as seen around the North Sea. Therefore, for this analysis the import of blue hydrogen will not be considered.

CAPEX costs of electrolysis deployments are admittedly large, however when offset over the lifetime of deployments its impact on every kilogram of hydrogen produced is low. This amortised cost is also expected to be reduced further from economies-of-scale as so-called ‘giga-factories’ come online. Instead, the majority of the cost to produce hydrogen via electrolysis comes from the cost of electricity to run the system. Thus, to generate the lowest cost hydrogen, the best, and lowest cost, renewable resources must be utilised. Such areas, like Saudi Arabia and Australia, are already deploying large-scale dedicated renewables coupled to electrolysers and could achieve costs of >$1.50 by the end of the decade.

Hydrogen, unlike conventionally traded fuels such as diesel and kerosene, requires conversion into a transfer molecule, with far superior storage qualities, to make large-scale international distribution financially viable. The hydrogen sector is investigating liquid hydrogen, ammonia, and LOHCs, for this purpose. Ammonia is the sector’s current front runner as can be seen in the NEOM project where Air Products, with Saudi Arabian governmental backing, will deploy a 4GW, $5bn green hydrogen plant capable of producing 650 tonnes per day. The majority of this hydrogen will be converted to ammonia and distributed around the world via ship. Shipping ammonia is a readily used process within the chemicals industry already, particularly for fertiliser production, and is therefore seen as a cheaper, safer, and easier option to quickly implement cross-border distribution of green hydrogen too. This transportation is likely to be initialised in 2025, with large-scale deployment realised between 2030-2035.

Alternatively, for short to medium distances (<1500km) hydrogen could be piped. For NI this could be achieved: via converted natural gas interconnectors directly into Northern Ireland (Ireland to Scotland interconnector) or indirectly (e.g. RoI); or via completely new dedicated hydrogen pipelines connecting to the UK or EU. This infrastructure must also include the option to reverse the flow direction to enable NI's a long-term energy exporter position, unlike currently installed pipelines, which would also require support from RoI and GB. It is unlikely either of these options will be deployed by 2025, as the sector will not be sufficiently mature to permit investment in such expensive infrastructure. By 2035, however, the hydrogen economy could be sufficiently scaled-up to warrant deployment in line with the European Hydrogen Backbone initiative. Furthermore, Northern Ireland's gas grid is uniquely positioned to support conversion to hydrogen as it is largely made up of polyethylene piping which has suitable embrittlement and durability characteristics for both blended and dedicated hydrogen transmission. This approach has the added benefit of distribution in gaseous form, therefore negating need to convert into a carrier molecule which comes with financial and efficiency losses but does need an incredible amount of invasive and time-consuming ground works to realise.

In the long-term, both shipped and pipeline distribution of hydrogen will be necessitated. The 'Global Hydrogen Flows: Hydrogen trade as a key enabler for efficient decarbonisation' report produced by Hydrogen Council and McKinsey & Company in October 2022 states that >1,000 ships and >100 million tons per annum of piped-hydrogen capacity will be required to meet growing global demand by 2050.

	2025* **	**2035*** **
Green Hydrogen Production cost (£/kgH2)[51]	2.15 – 3.23	1.29 – 1.94
Hydrogen to Ammonia conversion cost (£/kg$_{H2}$)[52]	0.70	0.65*
Ammonia to Hydrogen conversion cost (£/kg$_{H2}$)[42]	0.88	0.84*
Hydrogen to Liquid Hydrogen conversion cost (£/kg$_{H2}$) [42]	0.98 – 1.91	0.95 – 1.46*
Shipping ammonia (£/kg$_{H2}$ per 1000km) [42 53]	0.023	0.017*
Shipping Liquid Hydrogen (£/kg$_{H2}$ per 1000km) [42]	0.082	0.053
Dedicated pipeline (£/kg$_{H2}$ per 1000km) – LCOT	0.16 – 0.70[42]	**0.08-0.52[54]

*To generate 2035 data for these areas, the author has applied learning factor rates based on current sector estimates and their market expertise. **Costs dependent on size and location (onshore or offshore) of deployment. ***Exchange rate used £1 = €1.15

[51] Pwc. The green hydrogen economy. Accessed at: https://www.pwc.com/gx/en/industries/energy-utilities-resources/future-energy/green-hydrogen-cost.html (2022).
[52] Guidehouse, Tractebel Impact. Hydrogen Generation in Europe (2020).
[53] Al-Breiki, Bicer. Comparative cost assessment of sustainable energy carriers produced from natural gas accounting for boil-off gas and social cost of carbon. (2020).
[54] EHB. European Hydrogen Backbone. (2022).

6 Applications

Whilst biofuels will be an important aspect of Northern Ireland's decarbonisation journey, the scope of this report focuses on technologies, scenarios, and recommendations relating to hydrogen and synthetic fuels and thus will be the focus of the following sections.

6.1 Industrial and High Temperature Heat

Industrial heat has four different classifications - low-grade (<100°C), medium-low-grade (100-150°C), medium-grade (150-500°C), and high-grade (500°C). Decarbonising this sector is a considerable challenge due to the need to provide versatile fuelling solutions that satisfy requirements across the four heating grades. Currently, >70% of heat demand within NI is met by fossil fuels, whilst around 25% come from more sustainable bioenergy and waste feedstocks[55].

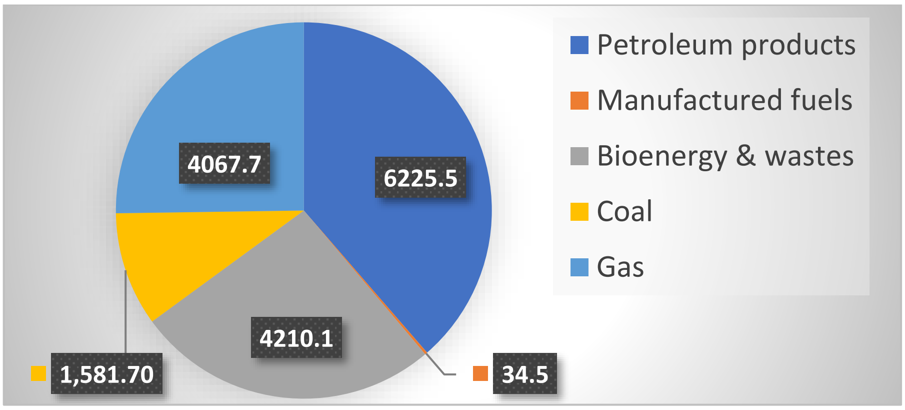


Figure 12: *NI Heat energy consumption (GWh) in 2019*

Within NI there are two premier industrial and high-temperature heat applications – cement and glass production:

- **Cement** – Produced via a clinker and grinding process where raw materials are mixed, homogenised, and preheated before being transferred to a kiln where they are transformed into cement clinker by eating to temperatures up to 1450 °C. This clinker is then cooled and ground to create the final product.
- **Glass** – Manufactured by mixing raw materials – typically sand, soda ash, and limestone – and melting in a furnace at 1500 °C, after which the product is then placed in moulds to settle and be finished.

Mannok Cement, formerly Quinn Cement, operates a cement production unit in Derrylin, as well as one just across the border in Ballyconnell. Its Ballyconnell kiln consumes around 100 tons of hard coal, and 30,000 – 36,000 tons of alternative fuel (SRF – Solid Recovered Fuel) per annum, resulting in a total heat requirement of 8,000 GJ per year, or 2,222 MWh per day. Cookstown cement, who also operate within NI, operate a kiln requiring 400GWh of fuel per year which is currently met by coal (62%), Recycled Liquid Fuel (RLF) (26%), and Solid Recycled Fuel (SRF) (12%). Given both company's operational familiarity with RLF and SRF it would be possible to decarbonise operations completely utilising these solutions, possibly in combination with CCUS-based solutions. Hydrogen could also be used to decarbonise these processes by mitigating fossil fuel use and, whilst it is more difficult to convert solid-fuelled kilns straight to low-carbon sources, this is being heavily explored within

[55] Northern Ireland Statistics and Research Agency. Energy in Northern Ireland 2022 (2022).

industrial processes across Europe and could be an opportunity to transfer learnings from elsewhere to the island of Ireland.

Encirc Ltd. is the only glass manufacturer based in NI. They function 2 glass-melting furnaces of roughly equal size and consume approx. 40MW of natural gas and for the melting process, and 4-6 MW for electrical power. The company also operate a Combined Heat and Power (CHP) generator facility for their operations which is fuelled by biogas to provide 4.5MW of electricity to their site. Encirc could replace their natural gas processes with hydrogen-based alternatives. As stated within the UK's industrial decarbonisation strategy, Encirc are readily investigating low-carbon fuel switching projects as a way to reduce their process emissions. In 2021, Encirc, in partnership with Glass Futures, successfully trialled switching one of its furnaces from natural gas to sustainable biofuels (derived from organic waste). They are also already exploring the possibility to produce green hydrogen as an option to enable decarbonisation across all operations – including both production and transportation of its glass products.

For low-grade and medium-low grade heat, industrial hydrogen boilers could be a feasible solution to replace analogous natural gas systems. These systems represent a low-cost, and low-disruption option due to their similarity to existing infrastructure. Whereas hydrogen-fired furnaces and kilns could utilise similar frameworks to fossil-fuel systems to decarbonise higher-temperature operations, but currently are at a less commercial level. Pilkington UK Limited carried out a world-first trial to decarbonise their carbon footprint by hydrogen and proved that operations could run safely at full production capacity and temperatures[56] (1,600 ^{0}C), without impacting product quality. Similarly, CEMEX carried out initial trials with hydrogen injection technologies to enhance the combustion of their Alicante cement kiln in July 2019. Following this trial, the technology was installed across all of CEMEX's cement plants across Europe[57]. These approaches should be of incredible interest to NI and its industrial sector as a way of partly or entirely replacing their fossil fuel heat requirements.

6.2 Mobility

Transport is responsible for 30% of the final energy consumption of Northern Ireland. Currently, the majority of this demand is met from non-renewable sources – across the UK just 5.9% of all consumed fuel was considered renewable in 2020. Therefore, decarbonisation of this sector will be key to realising economy-wide emission reduction targets.

Conventional vehicles, those powered by fossil-fuels burned through internal combustion engines or turbines, will be able to mitigate their emissions through displacement with low-carbon synthetic fuel equivalents (drop-in fuels). E-diesel and e-kerosene are already compatible with existing infrastructure and vehicles and will help to reduce emissions without the need for conversion kits or replacement. This, therefore, represents a suitable option for these vehicles, but will still produce NO_x and particulate emissions which are highly impactful GHGs. The UK requires that all new passenger vehicles and vans by 2035, and trucks by 2040 will be zero-emission through the tailpipe[58] and so this approach is likely to be a short-to-medium-term solution.

[56] Pilkington. Architectural glass production powered by hydrogen in world first. Accessed at: https://www.pilkington.com/en-gb/uk/news-insights/latest/architectural-glass-production-powered-by-hydrogen-in-world-first# (2021).

[57] FuelCellWorks. CEMEX Successfully Deploys Hydrogen-based Ground-Breaking technology. Accessed at: https://fuelcellsworks.com/news/cemex-successfully-deploys-hydrogen-based-ground-breaking-technology/ (2021)

[58] Department for Transport. UK confirms pledge for zero-emission HGVs by 2040 and unveils new chargepoint design. Accessed at: https://www.gov.uk/government/news/uk-confirms-pledge-for-zero-emission-hgvs-by-2040-and-unveils-new-chargepoint-design (2021).

The following section of this report instead focuses on alternative hydrogen and synthetic fuel decarbonisation technologies across five-major areas – Buses, Trucks, Maritime, Rail, and Aviation – which are capable of delivering zero-emission mobility.

6.2.1 Buses

Having first hit the roads in the mid-2000s, hydrogen buses are now one of the most mature hydrogen mobility applications available. These vehicles have received extensive testing through fledgling projects over the past decade and are now produced by over 10 suppliers worldwide, including the Northern Ireland-based Wrightbus – producers of the world's first hydrogen double decker bus.

Today, demand for these vehicles has never been greater with public authority managed fleets often assigned as key targets for zero-emission replacement. Battery-Electric buses still dominate the new vehicle market, but that landscape is changing. Bus fleet operators are recognising the need for a hybrid approach – deploying both battery and hydrogen vehicles simultaneously - for a number of reasons:

- Hydrogen vehicles have advantageous refuelling profiles similar to that of fossil fuel vehicles today. A hydrogen bus can refuel in just 15 minutes allowing greater operational flexibility.
- Hydrogen refuelling infrastructure is often less invasive and costly to implement. Large-scale fleet replacement with BEVs can necessitate expensive grid connection and cabling upgrades to provide suitable electrical supply to vehicles. Instead, hydrogen vehicles can be refuelled in conventional forecourt environments as has been demonstrated by bus operators across NI and UK.
- Hydrogen vehicles offer a greater power-weight ratio than BEVs. BEVs perform best on flat routes with frequent stopping to enable regenerative breaking. To cope with hilly terrains and offer extra amenities such as air conditioning and other power intensive processes, hydrogen vehicles can offer better performance.
- Hydrogen vehicles also typically offer a greater range than battery electric vehicles.

In Europe hydrogen buses have already reached mainstream success with projects such as JIVE/JIVE2 and H2BUS EUROPE ordering hundreds of buses for rollout over the next decade. Whereas, on the island of Ireland, buses are just starting to make an impression. Following an initial single-deck hydrogen fuel cell bus trial in November 2020, the National Transport Authority along with Bus Éireann, purchased three double decker Wrightbus models to run between Dublin and Ratoath in July 2021. In Northern Ireland, public transport operator, Translink, has been heavily involved in realising zero-emission bus transport, including hydrogen, and announced in March 2022 that their new fleet would feature 23 hydrogen powered buses[59].

6.2.2 Trucks

Progress has slowed amongst the light-duty hydrogen-fuelled vehicles in recent years. BEV's are continuing to dominate the zero-emission market due to their increased range, improvement and accessibility of charging infrastructure, and government incentives. Instead, the hydrogen sector's focus has shifted of to heavier duty applications such as trucks, where the power-to-weight density of batteries, and their refuelling profiles continue to be a barrier to widespread deployment.

Both the private and public sector have realised that for road-based Heavy-Duty Vehicles (HDVs) hydrogen is the leading decarbonisation fuel option. Currently, these vehicles are only available in small numbers due to small-scale production. However, there are several truck manufactures starting

[59] Translink. New Electric Powered Buses. Accessed at: https://www.translink.co.uk/corporate/media/pressreleases/newelectricpoweredbuses (2022).

to enlarge their production lines ranging from established automobile names like Hyundai and Toyota, to respected hydrogen sector companies such as Cummins, to new players like Hyzon and Nikola. These production lines are predicted to supply Europe with thousands of trucks through to 2030, with the EU's public private partnership and EU transport commissioner, Adina Vălean, estimating 17% of new trucks in 2030 will be run on hydrogen, equating roughly 60,000 hydrogen lorries[60].

Recent research from July 2022 has shown that there is a high interest to decarbonise Irish (RoI) HDVs using hydrogen. HDVs can act as a key driver for establishment of hydrogen mobility, and the country's hydrogen economy due to the large demand required – hydrogen demand from RoI's haulage industry is estimated to be between 1,141 – 4,626 tonnes per year. Furthermore, by initialising production and demand simultaneously, not only are project risks kept to a minimum, but the delivered cost of hydrogen is also minimised, which could be as low as €1.63.

6.2.3 Maritime

World events, such as Brexit, COVID-19, and even the blockage of the Suez Canal, have all shown the importance of international trade to national economies. However, this comes at a significant cost – international shipping is responsible for 3% of global GHG[61] emissions including significant NO_x and SO_x emissions, two of the worst indirect GHGs.

Previously, the industry has seen LNG as a potential replacement fuel, which emits no SO_x or particulate matter, and significantly less NO_x when burned due to the pre-liquefaction process the fuel undertakes. However, these vessels only reduce CO_2 emissions by <25% compared to conventional 'heavy' maritime fuels. Plus, with potentially significant LNG leakages (which is mostly made up of methane, a GHG with 86x the potency of CO_2 over a 20-year period), these ships still have a significant GHG footprint. Therefore, experts at the World bank are now questioning the fuel's long term decarbonisation potential, saying that, due to its carbon intensity, it should not form a large proportion of the bunker fuel mix in 2050 and policy should instead focus on incentivising the development and deployment of zero-carbon bunker fuels[62].

Maritime covers a broad range of vessels right the way from small fishing boats through to international cargo ships, each with their own unique set of requirements. These vehicles have drastically different power, bunkering, and payload requirements meaning there is no one-size fits all approach which can be taken to decarbonising all water-borne vehicles. Instead, the sector needs a number of different zero-carbon solutions – including hydrogen, methanol, and ammonia – in order to adequately meet their decarbonisation needs.

Ammonia and Methanol-based vessels are starting to be realised, and a number of companies, such as the aforementioned Maersk and Avin International, are ordering models for large-scale freight distribution. Hydrogen maritime technologies have also received substantial funding from EU bodies over the past 5 years and have reached maturity quickly, however, where ammonia and methanol is well suited for large vessels, hydrogen is best for small-to-medium size vessels, such as Norled's MG Hydrogen – the first delivered liquid hydrogen-powered ferry. In this vessel, liquid hydrogen will power two 200kW fuel cells and two 440 kW generators, in order to carry 300 passengers and 80 cars. Whilst elsewhere in Europe, other projects are starting to deploy hydrogen-powered inland water barges, and tugboats.

[60] Euractiv. 17% of new trucks in 2030 will run on hydrogen, EU believes. Accessed at: https://www.euractiv.com/section/energy/news/17-of-new-trucks-in-2030-will-run-on-hydrogen-eu-believes/ (2021).
[61] UK Parliament POST. International shipping and emissions. (2022).
[62] European Parliament. Sustainable maritime fuels 'Fir for 55' package: The FuelEU Maritime proposal (2022).

6.2.4 Rail

The decarbonisation of trains has been dominated by line electrification. This has allowed train operators to do away with heavy diesel engines almost entirely, giving trains more space and reducing their weight to allow for a larger number of passengers whilst also using less carbon-intensive grid electricity. Electrification has been seen as a major success in the UK with 38% of the rail network now converted, but this is a costly and labour-intensive process which cannot be deployed for all lines. According to the Railway Industry Association, the rate of electrification is half as fast as it needs to be to achieve decarbonisation by 2050, and thus other solutions must be explored in tandem to increase the pace of rail decarbonisation[63].

The first hydrogen train, the Coradia iLint manufactured by Alstom, was first presented in 2016. This model has gone from strength-to-strength, accelerating its way through tests and trials to achieve entry into commercial service by 2018 in Germany. To date, 41 of these trainsets have now been ordered in Germany, 14 in Italy, and successful trials have also been carried out in Netherlands and Austria – but there's just one problem, the hydrogen storage. In Europe, the bridge tolerances train manufacturers have to contend with are much higher and so, like hydrogen bus manufacturers, the hydrogen storage is placed in a cab on the top of the train. In the UK, this would be physically impossible without significantly investing in changing, rail, road, and other infrastructure, due to low hanging bridges and therefore different designs are required.

HydroFLEX is a hydrogen project investigating just this – the different hydrogen train design required for the UK rail network compared to mainland Europe. Operating out of the University of Birmingham's Centre for Railway Research and Education, the project converted a class 319 train car into a hydrogen-ready vehicle with a new powertrain consisting of fuel cells, batteries and an electric motor, and 20 kg of hydrogen in four high-pressure storage tanks. The train was successfully trialled on the UK's mainline railway network in September 2020 and its technology will be available by 2023 to retrofit current in-service trains to hydrogen, although this will come at the cost of passenger space[64].

Figure 13: *The HydroFLEX hydrogen-powered train in operation*

[63] Railway Industry Association. The UK is electrifying its railway at less than half the rate needed to decarbonise by 2050. Accessed at: https://www.riagb.org.uk/RIA/Newsroom/Press_Releases/ORR_Electrification.aspx (2021).
[64] Porterbrook. HydroFLEX. Accessed at: https://www.porterbrook.co.uk/innovation/hydroflex-cop (2022).

6.2.5 Aviation

Aviation is at a decarbonisation crossroads – as one of the most decarbonising wings of mobility, the sector is starting to recognise the pace and breadth with which change is required in order to address not just carbon emissions, but NOx and contrails too. Some of the industry's main sector bodies, such as the International Air Transport Association and International Airlines Group amongst others, have committed to achieving net-zero CO_2 by 2050. However, with just one in every 50 of the industry's climate targets being achieved since 2000, according to a report by the climate charity Possible, more must be done if these targets are to be achieved.

There are two possible routes for decarbonisation of aviation vehicles, Sustainable Aviation Fuels (SAFs) which a lower carbon variation of existing fuels, or carbon free alternatives, of which liquid hydrogen is seen as the most applicable option. These solutions will not compete but instead work together symbiotically to address the emissions of different areas of the aviation industry:

- **SAFs –** are a great solution or reducing the emissions of existing aircraft without the need for expensive and laborious retrofitting processes. Instead, modern-day engines can easily handle sustainable fuels and eliminate, depending on their carbon intensity, up to 80% of an airline's flying emissions. SAFs will also, past 2050, continue to play a key role in enabling long-distance no-stop flights. Zero-carbon fuels will struggle, without substantial advances in storage technologies, to provide the necessary power output required to fuel aircraft >5,000-mile journeys. Therefore, SAFs will continue to be a part of the Aviation fuel portfolio.
- **LHY** –SAFs will take priority within the long-haul market, but all flights from the regional to short- to medium-haul market will be capable of being switched to zero-carbon alternatives by 2050. Whilst fuels like ammonia and methanol may be applicable to maritime, LHY is being increasingly preferred by the aviation industry as the zero-carbon fuel of choice due to its emission and power profile.

SAFs are being are expected to continue to play a key role long-term (through to 2050) within the aviation industry by enabling long-distance no-stop flights. Zero-carbon fuels, such as LHY, will struggle, without substantial advances in storage technologies, to provide the necessary power output required for >5,000-mile journeys. The Ibec group, which includes representatives of the aircraft leasing sector in Ireland, called for the government to include innovative measures within RoI to drive the development and use of SAFs including tax credits, subsidies, elimination of taxes for passengers on SAF blended flights, and an R&D budget for the area[65]. Whereas the UK government has, as part of its Jet Zero Strategy, announced SAF mandates with a minimum of 10% of jet fuel - ~1.5 billion litres – required to be made by 2030, with 5 large-scale production plants to be online by 2025.

There are a number of early projects currently testing the viability of hydrogen in the aerospace and aviation sector. The ZeroAvia led HyFlyer project achieved the world's first fuel cell powered flight involving a commercially-sized aircraft in 2020. However, with major manufacturers, such as AIRBUS, detailing their plans to offer hydrogen aircraft by 2035, the deployment of supporting infrastructure must be accelerated to service these vehicles in this timeframe. Currently, there are yet to be any hydrogen aviation projects realised across the island of Ireland. However, the recently designed SH2AMROCK hydrogen valley project based in Galway, plans to carry out a set of hydrogen-powered test flights on the west coast. This will transfer knowhow and operational expertise from experienced

[65] The Ibec group. Budget 2023 an opportunity to make Ireland a leader in sustainable aviation fuel. Accessed at: https://www.ibec.ie/connect-and-learn/media/2022/09/23/budget-2023-an-opportunity-to-make-ireland-a-leader-in-sustainable-aviation-fuel (2022).

companies in this field (European Marine Energy Centre) to the island of Ireland. Northern Ireland is yet to undertake any similar activities.

6.3 The most suitable technologies for NI

Buses - Hydrogen buses have been shown to be well suited to operation within NI, with initial trial carried out by operator Translink already resulting in the order of a fleet of 20 fuel cell buses. Across the rest of the UK, fleet operators are increasingly considering hydrogen buses as part of their vehicle matrix in order to achieve mandated zero-emission targets. In Brighton, Metrobus will deploy 20 hydrogen buses by 2022, whilst Birmingham has recently increased ambitions to introduce >140 hydrogen buses, enabled by grants from Department for Transport and the Zero Emission Bus Regional Areas (ZEBRA) scheme. Therefore, hydrogen buses, due to the experience and knowhow of both vehicle operators, and policy makes in these technologies, will continue to see further deployment.

RoI through the GH2 and $SH_2AMROCK$ projects have recently announced ambitions to trial long-range intercity hydrogen coaches within the Galway City region. If the knowledge obtained through these activities is made available on an all-island basis, as already planned within the projects' centres of excellence in Galway and Belfast, then any of the 1,310-strong bus (1,144) and coach (154) fleet within NI feasibly be replaced by hydrogen analogues. It is expected that replacement will start with the NI's oldest fleets, Ulsterbuses which have an average age of 10.5 years[66]. These buses also carry the most customers of any bus fleet type within Northern Ireland (12.2 million passenger journeys 2020-2021) and thus could play a key role in increasing public confidence and acceptance of hydrogen technologies as deployment increases.

HDVs - Both NI and RoI, due to the EU's Alternative Fuels Infrastructure Regulation (AFIR), will be required to rollout hydrogen refuelling stations along the TEN-T CORE network by 2030 - which links Belfast to Dublin and along to Cork and Limerick. This necessitated deployment of this refuelling infrastructure represents the perfect opportunity to realise hydrogen mobility across the island of Ireland. Whilst BEVs will continue to dominate passenger vehicle sales, hydrogen is much better suited to heavy-mobility (refuelling times, power-weight density ratio, range). Thus, The Executive, within its Path to Net Zero Strategy, has stated that, due to the difficulty of electrification in this area, NI will take an all-island approach to developing alternative fuels such as hydrogen and biomethane for this purpose.

Currently there are no deployments of dedicated hydrogen heavy duty refuelling infrastructure or vehicles within Northern Ireland. However, the experience and groundwork carried out by Translink's ever-increasing fuel-cell electric bus portfolio will be pivotal to the successful introduction of further hydrogen mobility technologies in the region. Similarly, RoI is yet to operate any hydrogen heavy-duty vehicles on its roads, however, through the knowhow gained in fuel-cell bus trials, hydrogen-powered trucks will be introduced in coming years as part of the GH2 project. This project, which is part of the $SH_2AMROCK$ hydrogen valley concept, will enable the growth of hydrogen mobility, particularly heavy-duty, across the island of Ireland, and has received a wealth of public and private sector support from both sides of the border. Therefore, it is expected that hydrogen-powered truck deployments will follow in NI before the end of 2030 as the primary way of decarbonising this mode of transport. Alternatively, NI could choose to address these emissions through the production of synthetic fuels which, depending on their production method, could significantly reduce GHG emissions. Following the precedent set by Great Britain, Northern Ireland deployed the new E10 petrol standard in November 2022. The standard, which blends 10% renewable ethanol into the petrol mix, could be further decarbonised by coupling to sustainable carbon feedstocks as well. However, current supply

[66] Department for Infrastructure. Northern Ireland Transport Statistics 2020-2021 (2021).

of these feedstocks from anaerobic digestion technologies in NI are small-scale and decentralised, most commonly based on rural farms due to government grants schemes. Therefore, to completely replace NI's HDV current fossil fuel feedstocks with renewable alternatives NI would need to heavily invest in costly deployments of DAC, or similar technologies to provide sustainable carbon in suitable scales. Thereby, in the short-term, prominence of both synfuels and hydrogen refuelling for HDVs is expected to increase in NI. However, due to the maturity of green hydrogen technologies, in comparison to sustainable carbon production, hydrogen is expected to increase its market share considerably in the medium-term.

In Northern Ireland, roughly 1,200 new HDVs are registered every year, not including any agricultural vehicles. This would represent an introduction of just over 200 Hydrogen-HDVs, following the EU's 17% prediction. However, this acquiring these vehicles is just one part of the problem – you also have to refuel them. Industrial gas and oil companies, who traditionally operate petrol refuelling stations, are beginning to scale up the necessary refuelling infrastructure for large quantities of these vehicles.

Ports and Maritime - As a coastal region, Northern Ireland has a storied history in maritime activities and still have five commercial ports today: Belfast, Larne, Londonderry, Warrenpoint, and Coleraine. To investigate the decarbonisation of these ports – both portside activities and domestic maritime fleets - the Northern Ireland Green Seas project has been established[67]. The project will be pivotal to understanding the steps NI must undertake to achieve the UK government's target of net-zero maritime by 2050. Whilst this project does feature activities investigating how best to integrate offshore renewable energy and hydrogen production and storage, it will not deploy hydrogen, or hydrogen-derived fuels to power vessels as part of its activities, instead opting for an entirely electric approach. Whereas the 12-month Ballylumford Power-to-X project, based at Islandmagee, is delivering a Front-End Engineering Design (FEED) study to demonstrate how a full-cycle hydrogen economy (production, storage, distribution and applications) can be developed within port-side locations[68]. The project is particularly focused on making best-use of large-scale production coupled with storage for the purposes of grid balancing and has even received a grant of £986,000 from BEIS' Longer Duration Energy Storage Demonstration programme to investigate this area. Results from this study are expected in 2023.

Across Europe, projects such as Blue Danube, are seeking to exploit the cross-coupling opportunities presented by offshore wind farms, electrolysis, and maritime applications to directly contribute the decarbonisation of local vehicle fleets, such as tugboats or passenger ferries via hydrogen. These vehicles and powertrains are still relatively early in their development lifecycles, exhibiting TRLs in the range of 6-8, but are highly relevant to the NI context – offering opportunities to directly replace old vessels or mitigate large portions of emissions from existing vessels via conversion.

It is expected that NI's small- to medium-scale domestic fleets will be well suited to hydrogen, due to relatively low travelling distances, return-to-base operational cycles that make regular bunkering possible, and the availability of hydrogen at port locations. For larger vessels however, hydrogen will not be able to be stored in sufficient quantities to make large payloads and long journeys plausible. Instead, alternative derivatives such as ammonia or methanol will be preferred due to their superior storage properties. These larger vessels however are extremely innovative and will not achieve widespread commerciality before 2030. For instance, Maersk who are one of the earliest movers in this area have 19 such vessels on-order with the earliest dual-fuel deliveries expected between 2025-

[67] UK Research and Innovation. Clean maritime: decarbonising marine transport in Northenr Ireland. Accessed at: https://www.ukri.org/news-and-events/responding-to-climate-change/developing-new-behaviours-and-solutions/clean-maritime-decarbonising-marine-transport-in-northern-ireland/ (2022).

[68] Ballylumford Power2X. Accessed at: https://ballylumfordp2x.co.uk/ (2022).

2030[69]. Therefore, by 2025, NI will need to be capable of offering hydrogen refuelling for shifting landscape of domestic maritime fleets, and by 2035 this offering will need to expand to include alternative refuelling options for international shipping vessels – principally methanol, ammonia, and other e-fuels. This will require an incredible amount of infrastructure to be deployed, not only in the area of hydrogen production, but the capture of CO_2 via sustainable methods (e.g. AD or DAC) to enable zero-emission fuel conversion – similar to that which is required for the production of SAFs.

Trains - Current rail operations within NI are still very much reliant of fossil fuels. In 2020, Translink, who operate both NI's rail and bus services, rolling stock order comprised of 21 Class 4000 units[70], which operate completely on diesel. However, Translink is aware of the need to decarbonise their vehicle portfolio and, through the company's Climate Positive Strategy, has set out ambitions to reduce their current emissions by at least 50% by 2030, on the way to achieving net-zero emissions by 2040.

To achieve decarbonisation within their rail activities, Translink are strongly considering conventional methods such as electrification. Electrification has been readily deployed across the UK's other regions, with >35% of the total network now having been converted, and Translink have been readily investigating deployments within Wales to understand how these solutions can be readily transferred within a Northern Irish context. This newly learned experience coupled with RoI's intent to start deploying electrified lines in the north (between Malahide and Drogheda), will make electrification well-suited to NI.

Alternative rail technologies, such as hydrogen trains, are yet to be trialled within Northern Ireland. However, due to the size of the domestic rail market – just 220 miles of track across 5 major transport routes (4 national, and 1 into Dublin)[71] – it will be difficult to provide a commercial case for hydrogen train Original Equipment Manufacturers (OEMs), such as Alstom and Siemens, to deliver their initial fleets. Due to the fledgling nature of emission saving rail technologies, OEMs prefer to supply their products to areas with high recurring demand to secure bankable business models. Northern Ireland, with a lack of zero-emission rail, and other mobility technology, experience currently does not exhibit the required skillset or infrastructure to be considered ideal deployment locations. Instead, in the medium-term UK, or Ireland-based secondary manufacturers of these technologies may enter the market who can suitably alter these technologies to the domestic rail system. Therefore, it is unlikely that in the short-term a large number of hydrogen, or hydrogen-derived trains will enter service within NI. Instead, the deployment of electrification in conjuncture with synthetic fuels, such as synthetic diesel, will lead the decarbonisation efforts of NI's rail sector. This expected trend could be reversed, however, in the medium- to long-term depending on the movement of adjacent markets and drive to achieve 100% decarbonisation.

[69] MAERSK. Maersk continues green transformation with six additional large container vessels. Accessed at: https://www.maersk.com/news/articles/2022/10/05/maersk-continues-green-transformation (2022).
[70] Global Railway Review. Translink receives first three of 21 new train carriages. Accessed at: https://www.globalrailwayreview.com/news/119526/translink-first-three-new-train-carriages/ (2021).
[71] Data.gov.uk. Northern Ireland Railways NIR data set. Accessed at: https://www.data.gov.uk/dataset/dd7eeba0-9591-410c-9559-88291f1c41da/northern-ireland-railways-nir-inspire-view-service (2014).

7 Sustainable Fuels Policy

7.1 UK and NI policy

The Electricity Act of 1990 and the simultaneously released Non-Fossil Fuel Obligation (NFFO), were the first pieces of legislation to encourage the installation of renewable power within the UK. Following its release, the first commercial wind farm in the UK (10 wind turbines with a combined capacity of 4 MWe) was built under this program at the Delabole location[72] in 1991. Over the period of 1991 – 1998 four updates of the NFFO were imposed (1991, 1994, 1997, 1998) to secure greater capacities of renewables deployment, primarily led by waste-to-energy and wind technologies at this time. Over the past two decades, renewables legislation and support mechanisms have been released frequently to incentivise the sector's journey to maturity. These include: Renewable obligation; RO (2002-2017), Feed in Tariff; FIT (2010-2019), Contract for differences; CfD (2014-Present), Renewable Heat Incentives; RHI (2008 – 2022), Renewable Transport fuel obligation; RTFO (2008 – present). A breakdown of the implementation timeline of these support mechanisms can be seen in Figure 14.

- During the period of **NFFOs**, 3271.11 MW of renewable capacity was developed across 794 total contracted projects. Waste-to-Energy (2240 MW) was the most commonly deployed technology, followed by wind (971.8 MW)[73].
- The **RO** encouraged the generation of electricity in the UK from qualified renewable sources. This measure required licensed electricity companies to increase their proportion renewable electricity from 3% in 2002 to 40.9% in 2018. 35.2 GW of total capacity was accredited over the timeframe[74].
- The UK's solar boom can be strongly attributed to the **FIT** scheme (2010-15). Share of renewable electricity increased from **6.8% in 2010 to 19.2% in 2014** during this short period. However, tariffs on solar were reduced in 2016 which slowed the pace of solar deployments until 2018-2019 when it was announced that the scheme would close to new applicants from 2019. This the FIT Scheme added 6.43 GW of capacity by the 11th year (2021) of the FIT scheme[75] .
- The latest support mechanism, **CfD**, has given tremendous boost to wind industry (onshore & offshore). Nearly 13 GW of offshore wind capacity has added since CfD has implemented[76], leading to a total RE electricity share of 43.1% in year 2020.
- **RHI** has helped in adoption of Air and Ground source heat pumps. RHI was implemented in the non-residential sector in 2011, and residential in 2014 and to date (2022) has resulted in 22,265 and 114,245 installations respectively.

[72] J. K. Panagiotis Triantafyllou. Wind Power Industry and Markets (2022).
[73] DBERR. Digest of United Kingdom (2007).
[74] IRENA. United Kingdom Market Review (2012).
[75] OFGEM. Feed-in Tariff Annual Report 2020-2021 (2021).
[76] A Durankovic. UK to Hold Yearly Contracts for Difference Auctions from 2023 onwards. Offshore BIZZ (2022).

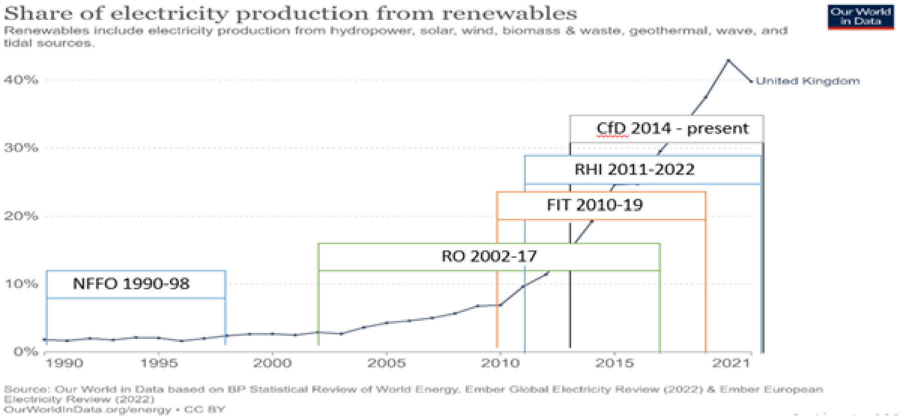


Figure 14*: A graphical timeline of the UK's renewable initiative programs – altered graphic taken from Our World in Data's United Kingdom: Energy Country Profile*

The **RTFO** and **RHI** followed more targeted approaches than the NFFO, RO, FIT, and CfD schemes. These support mechanisms encouraged the penetration of renewables into designated hard-to-abate sectors, rather than incentivising increases in renewable generational capacity. At its inception in 2008, the RTFO's focus was the introduction of biodiesel and bioethanol into the transport fuel portfolios to increase decarbonisation and strengthen sustainability. This has been incentivised by **Renewable Transport Fuel Certificate** (**RTFC**) which rewarded suppliers of these fuels with a premium. These mechanisms have increased the proportion of renewable fuels in road transport from 2.7% to

5.9% in a 12-year period and are frequently expanded to include fuels from alternate sustainable pathways such as green hydrogen and other Renewable Fuels of Non-Biological Origin (RFNBOs).

	Million litre	**Indigenous %**	**% of total road transport fuel**	**Biodiesel %**	**Bioethanol %**
2009	1284	--	2.7	82	18
2010	1568	--	3.33	71	29
2011	1514	22	3.27	59	41
2013	1340	21	3	37	59
2014	1744	19	3.46	49	48
2015	1671	30	3.29	50	48
2016	1565	25	3	47	50
2017	1541	27	3	47	49
2018	1624	16	3.1	49	46
2019	2680	11	5.1	62	28
2020	2537	12	5.9	64	22

Table 4*: Statistics taken from UK renewable fuels statistics*

With a total emissions share of 27% (2019), the transport sector is an area of critical focus for the UK's push towards a net-zero future. Recognising this, the UK government has also introduced mandates to phase out the petrol and diesel vehicles over the coming two decades. This includes a ban on the sale of new petrol/diesel cars by 2030, with all required to be zero-emission through the tailpipe by 2035, whilst all new HGVs sold by 2040 will also need to be zero-emission. Local authorities have also been encouraged to replace their vehicle fleets through support schemes – this includes the Zero Emission Bus Regional Areas (ZEBRA) scheme which made available £120 million of funding in 2021 to aid the delivery of 4,000 new zero-emission buses, including hydrogen and battery-electric technologies. Now, due to this mix of schemes, incentives, and measures, the UK has 175,000 zero-emission vehicles on its roads, but if the country is to realise its 12.4% renewable transport fuel target by 2032 more must be done, particularly in the areas of aviation and maritime. Competitions have been launched to tackle the emissions made by these sectors (38.4 and 13.6 Mt_{CO2e} respectively – domestic and international in 2019) including the Clean Maritime Demonstration Competition (£20m) and the Green Fuels, Green Skies' Competition (£15m), but long-term policy and regulation is still unclear for these areas.

7.2 Notable International Policy

International renewables policy continues to iterate with the shifting global energy landscape. Hydrogen legislation often follows similar frameworks to previously implemented, successful policy measures whilst innovating to provide suitable geographic applicability for the local governing region. This includes:

- **Netherland SDE++:** Sustainable Energy Transition subsidy scheme (Stimulering Duurzame Energietransitie, SDE++) in Netherlands has also included subsidy for hydrogen production by electrolysis. Subsidies are granted for periods of 12 or 15 years (depends upon technology). In 2021, green h2 was applicable for €300/tonne CO2 limit. (https://english.rvo.nl/subsidies-programmes/sde/features)
- **Germany and UK** are considering **contract for difference (CfD)** policy mechanism for hydrogen markets, the same mechanism which proved to be successful in developing UK's offshore wind market.
- **Guarantee of Origin (GO's)** is one of the essential mechanisms being considered globally to define the carbon intensity of hydrogen. 'CertifHy' is the 1st EU-wide Guarantee of Origin scheme for Green and Low Carbon Hydrogen and is readily used in European member states with no national GO system.
- **USA** Electrolyser tax credit system - For the hydrogen produced in the United States, tax credits of up to $3 per kilogram for a period of ten years are available, as well as an investment tax credit of up to 30% of the cost of the electrolyser and other equipment.
- **India** - Manufacturers of green hydrogen and green ammonia will be exempt from interstate transmission taxes for a period of 25 years if their projects are completed by June 30, 2025, reducing taxes (corporate, business, sales) & fees on electricity.
- **Europe –** the European Commission envisages 40 GW of electrolysis capacity by 2030 as part of the European Hydrogen Strategy[77]
    - The three strategic phases lay out a step-by-step approach where initial deployment, towards 2024, is located close to demand centres, e.g. industry or refuelling stations, thus limiting the infrastructure needs.

	Installed electrolyser GW	Renewable H_2 production (million ton)	Sectoral targets
Phase 1 (2020-2024)	6	1	Reduce fossil based industrial H_2
Phase 2 (2025-2030)	40	10 (1% of EU demand)	New applications
Phase 3 (2030-2050)	Large scale	10 % EU demand	Scale up to all sectors

Table 5*: The EU's three phased hydrogen approach*

[77] European Commission. A hydrogen strategy for a climate-neutral Europe. (2020).

- **RePowerEU –** The European Commission introduced the REPowerEU plan in March 2022 to make Europe independent of Russian fossil fuels by 2030. This includes goals of producing 10 million tonnes (Mt) of renewable hydrogen within member states and importing 10 Mt of renewable hydrogen by 2030, representing 65-80 GW of electrolysis capacity in the European Union.

	France	Germany	Spain	Portugal	UK	Netherlands	Italy
Electrolysis capacity	**2023:** 870 MW **2030:** 6.5 GW	**2030:** 5 GW **2035 – 2040:** 10 GW	**2024:** 300-600MW **2030:** 4 GW	**2030:** 2 GW **2050:** 5 GW	**2025:** 1 GW **2030:** 10 GW	**2030:** 3-4 GW	**2030:** Possibility of 5 GW
Industrial	**2023:** 10% carbon-free H_2 **2028:** 20-40%	--	**2030:** 25% renewable H_2	**2030:** 5% of total energy consumption **2050:** 20% consumption	Existing hydrogen supply decarbonized through CCUS/electrolysis	CCS development	--
Transport vehicles	**2023** 200 HDV **2028:** 800-2000 HDV **2023:** 5,000 LUV **2028** 20,000-50,000 LUV	Not clear targets	500 cars 150-200 buses 5,000-7,000 LDV/HDV	**2030:** 5% of road transport fuel consumption	--	**2020:** 15,000 vehicles **2030:** 300,000	**2030:** 2% trucks
	2023: 100 HRS **2028:** 400-1,000 HRS	**2025:** 400 HRS **2030:** 1,000 HRS	**2020** 20 HRS **2030** 100-150 HRS	**2030:** 50-100 HRS	No targets 13 HRS in 2019	**2025:** 50 HRS	--

Table 6*: A Summary of hydrogen strategy commitments from major European economies*

7.3 Hydrogen Policy for NI and its Cost

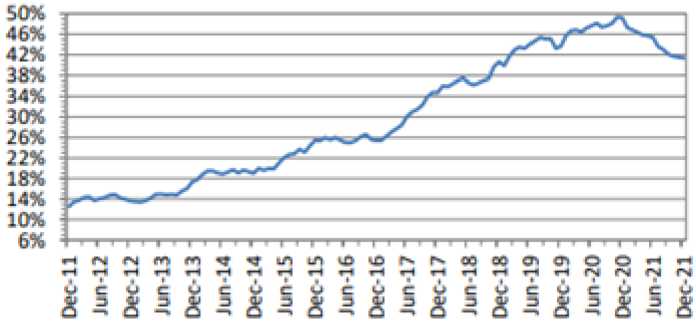


Figure 15*: Northern Ireland electricity demand by renewables – taken from Electricity Consumption and Renewable Generation in Northern Ireland: Year Ending December 2021.*

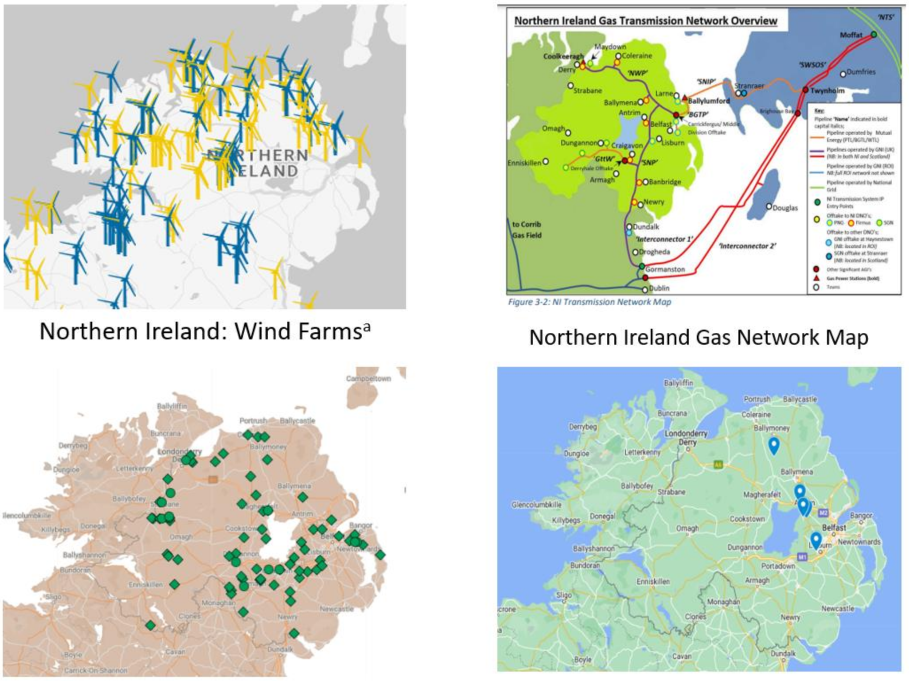
When the **Northern Ireland Renewables Obligation incentive program** (NIRO) was first launched in 2005, renewable energy only accounted for 3% of total electrical demand. In December 2020, according to statistics released by the Department for the Economy (DfE), renewable electricity accounted for 49.8 % of total electricity usage - much ahead of NI's Strategic Energy Framework target of 40% for the timeframe. In 2021, Over 7,574 GWh total electricity was consumed in Northern Ireland and of which 3,131 GWh was from RE sources[78]. To stimulate similar levels of growth NI must make best-use of the UK's various hydrogen support schemes in order to enable scale-up and innovation. These include the £240m Net Zero Hydrogen Fund, £60m low Carbon Hydrogen Supply Competition, and £68m Longer Duration Energy Storage competition. NI must also encourage growth domestically through projects such as:

1. **Belfast power to X Project**: A new clean energy system project which increases the penetration of renewables (curtailed and dedicated generation) into a diverse array of applications, servicing the public and private sector, as well as communities in the Belfast City region. Opportunity to simultaneously develop domestic competencies with different energy vectors and grow NI's low-carbon economy by aiding decarbonisation across power, transport, and heating.
2. **NI Water**: NI water is already in the process of installing a 1 MW electrolysis unit for oxygen production to process wastewater. This business model can be suitably scaled to decarbonise larger proportions of wastewater whilst enabling green transport technologies through the facility's hydrogen production.
3. **Energia Group H2 Project**: Energia, through the GenComm project, have installed a 500kW electrolyser at Long Mountain Wind Farm capable of producing up to 70,000 kg_{H2}/year from curtailed energy production. This green hydrogen has fuelled 3 hydrogen double-deck buses for Translink through a five-year hydrogen supply agreement and has led Translink to order 20 more hydrogen buses to add to their operational fleet. The expertise gained in the regulatory, technical, and operational areas of this project can be utilised to realise green hydrogen mobility technologies in key areas such as heavy-duty vehicles.

[78] Department for Economy. Electricity Consumption and Renewable Generation in Northern Ireland: Year Ending December 2021 (2022).

7.4 Future Cost of Fuels and Inequality Impact

Hydrogen and synthetic fuels, as indigenous sustainable fuel sources, have a great opportunity to help address the energy inequality exhibited across NI. These fuels can mitigate fossil fuel usage across transport, heat, and power, to ensure the most vulnerable members of society are not impacted significantly by the energy transition. Currently, these members of society, typically those in isolated areas who are not connected to extensive electrical or any gas infrastructure, are at risk of being significantly impacted by rising energy prices and impending carbon tax increases. Hydrogen and synthetic fuels can reverse this trend, instead enabling these areas and communities to take an active involvement in their energy transition. Figure 16 showcases the energy distribution of NI and just how decentralised sustainable energy production is within NI.



Northern Ireland: Wind Farms[a]

Northern Ireland Gas Network Map

Biogas plants in Northern Ireland[b]

Northern Ireland: Solar farms

a= GNI, mutualenergy. Northern Ireland Gas Capacity Statement 2021/21 – 2029/30. (2020).
b= The Official Information Portal on Anaerobic Digestion. Biogas Map. (2021).

Figure 16: Locations of key energy infrastructure in Northern Ireland

A household is considered in fuel poverty if it spends more than 10% of its income on fuel to maintain a sufficient degree of warmth. In the UK, in 2020, an estimated 13.2% of households (3.16 million) were in fuel poverty. Latest government estimates for Northern Ireland, from 2018, suggest 18% of households were in fuel poverty, however, due to the recent energy crisis this figure is expected to have ballooned. Research by the Consumer Council estimated that 34% of households were placed into energy poverty, whilst the utility regulator stated the number could be closer to 50%.

2021	Gas usage <2000 kWh	5.8 p/kwh
	Gas usage >2000 kWh	3.9 p/kwh
	Electricity unit cost	~17 p/kwh
July 2022	Gas usage <2000 kWh	14.04 p/kwh
	Gas usage>2000 kWh	9.62 p/kwh
	Electricity unit cost	27 p/kwh

Figure 17*: The prices of commodities (SSE Airtricity)*

The prices of gas and electricity have drastically increased elevating this poverty risk as detailed within the above tables, with most energy providers increasing consumer costs by 20-50% since the Ukraine-Russia war. This raised price of energy leads to significant social inequality and severely affects health of low-income households. Therefore, it is important to utilise national energy and fuel production sources to reduce dependence on other countries.

Critically, hydrogen and synthetic fuels also represent an opportunity to deliver sustainable growth and green job creation to the NI population. According to DfC[79] (2021), 17% of NI were deemed to be in relative poverty before housing costs, whilst 13% were in absolute poverty. Investments in renewables, hydrogen, and synthetic fuels, can help to unlock the necessary training programmes, upskilling, and transitioning of the workforce towards a sustainable net-zero future. A white paper published by Hydrogen Mobility Ireland, suggested that the green hydrogen sector could be work 1,800 jobs by 2030[80] to the RoI economy. With considerable geographic and policy advantages within NI, such as regulatory experience deploying green hydrogen technologies domestically, gaseous cavern storage opportunities, and large renewable potential, it would not be conservative to say NI's hydrogen sector could create >1,000 jobs across the same period.

[79] Department for Communities. Poverty in Northern Ireland. Accessed at: https://www.communities-ni.gov.uk/articles/poverty-policy (2022).
[80] Irish Times. Green hydrogen industry could create up to 1,800 jobs. Accessed at: https://www.irishtimes.com/business/2022/08/09/green-hydrogen-industry-could-create-up-to-1800-jobs/ (2022).

8 Northern Ireland Hydrogen and Synfuel Fuels Roll-Out Scenarios

A series of scenarios to explore the costs and benefits of hydrogen and synfuel roll-out for Northern Ireland were developed as part of this study. This section of the report describes the scenarios, the analysis methods, and results. A discussion of the overarching trends is presented. Due to Northern Ireland's renewable electricity potential, the scenarios exclusively consider hydrogen produced by electrolysis.

8.1 Scenario descriptions

The key parameters likely to affect economic performance of hydrogen roll-out scenarios were determined to be those listed below. Descriptions of these parameters and their possible options are given in Table 7. E-diesel and e-kerosene are considered as one synfuel due to their similar production routes and chemical compositions.

1. Year of commencement of roll-out
2. Electricity source for electrolysis
3. Strategy for electrolyser operation
4. Hydrogen storage type, which includes synfuels
5. Hydrogen off-taker type, which sets the requirement for storage size.

Parameters	Possible Options	Notes
Year of commencement of roll-out	• 2025 • 2035	The earliest possible hydrogen deployment will be around 2025. 2035 represents progress between the UK's and EU's 2030 targets and net zero by 2050.
Electricity source for electrolysis	• Onshore wind • Offshore wind • Electricity grid	Northern Ireland has a large, successful, and growing onshore wind sector. Offshore wind is the next obvious resource to exploit. The grid will become greener over time.
Electrolyser size	• 5 MW • 50 MW • 500 MW	5 MW electrolysers are smallest commercially viable scale. 50 MW units are in advanced planning stages across Europe, and plans for 500 MW units and larger are being planned for the 2030s.
Strategy for electrolyser operation	• Excess electricity • Full-time • Electricity first, then hydrogen • Hydrogen first, then electricity • Only hydrogen	Excess electricity encompasses curtailment and constraint and is also known as dispatch down. Full-time operation maximises hydrogen production but requires constant input. The next two strategies envision co-production sites for electricity and hydrogen. The two strategies prioritise these two different products. Only hydrogen means that no electricity is exported.

Parameters	Possible Options	Notes
Hydrogen storage type	• Gas cylinders • Salt caverns • Hydrogen-to-X (synfuels), including ammonia, e-methanol, e-diesel/e-kerosene, e-methane	Gas cylinders are common for small-scale hydrogen roll-out. Salt caverns, similar to those in Islandmagee, are under investigation for large projects. Hydrogen-to-X opens routes to export and/or ensure domestic decarbonisation via clean fuels, for example ammonia and e-methanol displacing oil as shipping fuel, e-diesel/e-kerosene displacing diesel, kerosene, jet fuel and shipping fuel, and e-methane displacing natural gas.
Hydrogen off-taker type	• Flexible off-taker • Inflexible off-taker	For hydrogen produced from variable renewable electricity, storage is needed to buffer between production rate and off-taker demand. Two extremes are considered: (1) a flexible off-taker that will accept hydrogen whenever it is available that entails a nominal 2 days' worth of storage, and (2) an inflexible off-taker that will only accept hydrogen at a constant rate that entails as much storage as necessary to convert variable production into steady supply.

Table 7*: Descriptions of scenario parameters and their possible values*

These parameter options are combined to create the scenarios shown in Table 8. The justification for studying each scenario is given in the furthest right-hand column of the table. A balance between ambition and pragmatism has been sought in their development. They can be grouped as follows:

1. 2025 scenarios. These are small-scale deployments that mostly use onshore wind and 5 MW electrolysers, and store hydrogen in gas cylinders.
2. 2035 medium-scale scenarios. These deployments mostly use onshore wind and 50 MW electrolysers, operated under a wide range of strategies, and store hydrogen in gas cylinders.
3. 2035 large-scale scenarios. These deployments use offshore wind, prioritise hydrogen production from 500 MW electrolysers, and store hydrogen in salt caverns or synfuels. Offshore wind is used exclusively in these scenarios since 500 MW electrolysers would require onshore wind farms that are likely impractically large for Northern Ireland, given its dispersed, low-density population.

No.	Scenario	Year	Electricity source	Electro-lyser size	Electrolyser strategy	Storage	Notes
1	Onshore excess, 5:5, cyl	2025	5 MW onshore wind	5 MW	Excess electricity	Cylinders	Curtailment is frequently proposed for hydrogen. This is a worst-case scenario.
2	Onshore excess, 5:100, cyl	2025	100 MW onshore wind	5 MW	Excess electricity	Cylinders	Best-case curtailment scenario.
3	Grid, 5, cyl	2025	Grid	5 MW	Full-time	Cylinders	Grid maximises electrolyser operation.
4	Onshore H2 only, 5:5, cyl	2025	5 MW onshore wind	5 MW	Only hydrogen	Cylinders	Small-scale dedicated hydrogen.
5	Onshore excess, 50:100 cyl	2035	100 MW onshore wind	50 MW	Excess electricity	Cylinders	Medium-scale curtailment scenario.
6	Onshore elec first, 50:100 cyl	2035	100 MW onshore wind	50 MW	Electricity first 50 MW, H2 second 50 MW	Cylinders	Medium-scale electricity (first) and hydrogen export.
7	Onshore H2 first, 50:100 cyl	2035	100 MW onshore wind	50 MW	H2 first 50 MW, electricity second 50 MW	Cylinders	Medium-scale electricity and hydrogen (first) export.
8	Onshore H2 only, 50:50, cyl	2035	50 MW onshore wind	50 MW	Only hydrogen	Cylinders	Medium-scale dedicated hydrogen.
9	Onshore H2 only, 50:100, cyl	2035	100 MW onshore wind	50 MW	Only hydrogen (oversized wind)	Cylinders	Medium-scale dedicated hydrogen with higher operational hours.
10	Grid, 50, cyl	2035	Grid	50 MW	Full-time	Cylinders	Grid maximises electrolyser operation.
11	Offshore H2 first, 50:100 cyl	2035	100 MW offshore wind	50 MW	H2 first 50 MW, electricity second 50 MW	Cylinders	Medium-scale offshore electricity and hydrogen (first) export.
12	Offshore H2 first, 500:1000 cyl	2035	1 GW offshore wind	500 MW	H2 first 500 MW, electricity second 500 MW	Cylinders	Large-scale electricity and hydrogen (first) export, impractical storage.
13	Offshore H2 first, 500:1000, geo	2035	1 GW offshore wind	500 MW	H2 first 500 MW, electricity second 500 MW	Salt cavern	Examination of geological storage.
14	Offshore H2 first, 500:1000, methane	2035	1 GW offshore wind	500 MW	H2 first 500 MW, electricity second 500 MW	e-methane	Examination of hydrogen-to-methane for NG displacement & export.
15	Offshore H2 first, 500:1000, ammonia	2035	1 GW offshore wind	500 MW	H2 first 500 MW, electricity second 500 MW	Ammonia	Examination of hydrogen-to-ammonia for shipping fuel displacement & export.
16	Offshore H2 first, 500:1000, methanol	2035	1 GW offshore wind	500 MW	H2 first 500 MW, electricity second 500 MW	e-methanol	Examination of hydrogen-to-methanol for shipping fuel displacement & export.
17	Offshore H2 first, 500:1000, diesel/kerosene	2035	1 GW offshore wind	500 MW	H2 first 500 MW, electricity second 500 MW	e-diesel/ e-kerosene	Examination of hydrogen-to-diesel/kerosene for heating, road, shipping, jet fuel displacement.

Table 8*: Description of hydrogen and Synfuel Roll-out Scenarios*

8.2 Analysis Methods

8.2.1 Description

Techno economic performance of the scenarios are evaluated using a discounted cash-flow analysis to determine a Levelised Cost of Hydrogen (LCOH), which includes production and storage steps. Econo-environmental performance of the scenarios is evaluated using a CO_2 abatement cost (CAC) calculation. The boundary of the analysis is shown in Figure 18. The cost of hydrogen production and storage, as well as the conversion of hydrogen to synfuels, is calculated using LCOH. The prices of onshore, offshore or grid electricity (in £/MWh) are included as inputs. Due to high uncertainties in the costs of replacing or modifying energy end use technologies, such as trucks, buses, trains, ships, aircraft, and industrial processes, to use hydrogen instead of the incumbent fossil fuels, this analysis omits them. Addressing this issue should be prioritised in any future work. The techno economic and econo-environmental performance of hydrogen and synfuels are compared to those of incumbent fossil fuels n the sectors of interest.

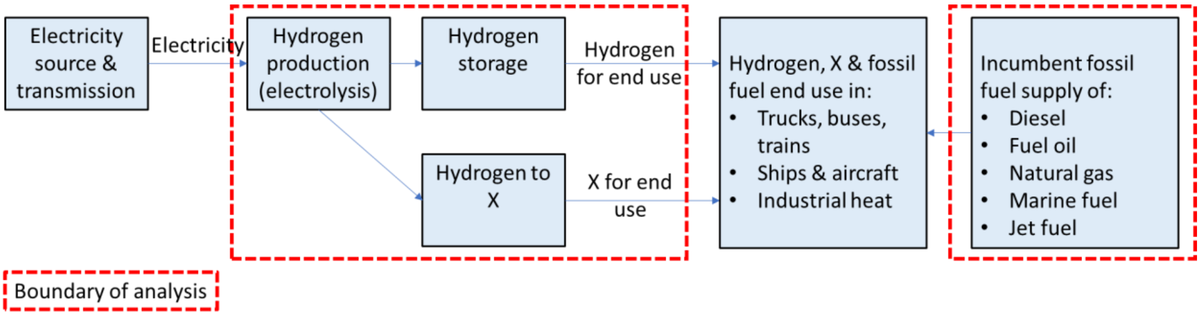


Figure 18: Layout and boundaries of the scenario analysis

LCOH is presented is units of £/kg and £/MWh. Units of £/kg enables comparison with the published literature on hydrogen costs. Note that the majority of the literature only considers hydrogen production cost, omitting storage costs, which can be significant. Use of units of £/MWh enables comparison between hydrogen, synfuels and incumbent fossil fuels on a consistent energy basis. The equations used to calculate LCOH are given below.

$$LCOH_{H_2}\left[£/kg\right]=\frac{\sum_{t=0}^{T}Capex_t\left(1+r\right)^{-t}+\sum_{t=0}^{T}Opex_{\mathrm{var},t}\left(1+r\right)^{-t}+\sum_{t=0}^{T}Opex_{fix,t}\left(1+r\right)^{-t}}{\sum_{t=0}^{T}M_{H_2,t}\left(1+r\right)^{-t}}$$

$$LCOH_{H_2X}\left[£/MWh\right]=\frac{\sum_{t=0}^{T}Capex_t\left(1+r\right)^{-t}+\sum_{t=0}^{T}Opex_{\mathrm{var},t}\left(1+r\right)^{-t}+\sum_{t=0}^{T}Opex_{fix,t}\left(1+r\right)^{-t}}{\sum_{t=0}^{T}MWh_t\left(1+r\right)^{-t}}$$

LCOH is found by dividing the total present value of the discounted expenditures of a hydrogen production and storage project by the total present value of the discounted production. The units of production (mass of hydrogen $M_{H2,t}$ in kg/yr or energy of hydrogen/synfuel MWh_t in MWh/yr) determine the units of LCOH obtained ($LCOH_{H2}$ for hydrogen only or $LCOH_{H2X}$ for any fuel). In the equations above, $Capex_t$, $Opex_{var,t}$ and $Opex_{fix,t}$ are annual capital expenditures, and variable and fixed annual operating expenditures in each year t of the project economic lifetime T. All scenarios are assumed to have a one-year construction time, followed by 20 years of economic operation. The discount rate r for all scenarios is 6%/year.

Hydrogen production and storage equipment is sized and costed for each scenario using the University of Galway Hydrogen Techno Economic Assessment Tool, which has been described in various publications[81] [82] [83] [84].

CAC provides a simple and flexible way to compare the cost of decarbonisation due to fuel switching. This calculation, which is shown below, divides the cost increase in providing a MWh of energy (in £/MWh) by switching from a fossil fuel (*FF*) to hydrogen/synfuel (*H_2X*) by the reduction in CO_2 intensity *I* (in tCO_2/MWh) resulting from the switch.

$$CAC\left[£/tCO_2\right] = \frac{LCOH_{H_2X} - P_{FF}}{I_{FF} - I_{H_2X}}$$

The CO_2 intensity values used in the analysis include the following assumptions:

1. For hydrogen/synfuel (I_{H2X}), only operational CO_2 emissions associated with electricity generation are considered. No embedded CO_2 emissions for the energy infrastructure are considered as this is highly case dependent.
2. For fossil fuels (I_{FF}), only end-use combustion emissions are considered for the same reason. These emissions are the dominant ones in all scenarios.
3. All CO_2 needed for synfuel production is assumed to be sustainable/biogenic and available at a price of £85/tCO_2.

[81] Gunawan, Dinglitico, Blount, Burchill, Carton, and Monaghan. At what cost can renewable hydrogen offset fossil fuel use in Ireland's gas network? (2020).
[82] Gunawan, Williamson, Raine, and Monaghan. Decarbonising city bus networks in Ireland with renewable hydrogen. (2021)
[83] Gunawan and Monaghan. Techno-econo-environmental comparisons of zero- and low-emission heavy-duty trucks (2022).
[84] Gunawan, Cavana, Leone, Monaghan. Solar hydrogen for high capacity dispatchable, long-distance energy transmission – A case study for injection in the Greenstream natural gas pipeline. (2022).

The key input parameters used in the analysis are shown in Table 9.

Variable	Units	2025 value	2035 value	Reference
Onshore wind electricity price	£/MWh	40	30	Central estimate from IRENA Future of Wind report 2019[85]
Offshore wind electricity price	£/MWh	Not used	38	Lower estimate from IRENA Future of Wind report 2019[84]
Grid electricity price	£/MWh	55	55	Authors' assumption
Curtailed electricity price	£/MWh	0	0	Authors' assumption
Grid CO_2 intensity	gCO_2/kWh	225	105	Source[86] and authors' calculation
Electrolyser specific Capex	£/kW	427	342	Hydrogen Europe report[87]
Electrolyser specific Opex	£/kW/yr	17	11	Hydrogen Europe report[86]
Diesel price	£/L	2	2	Authors' assumption
Natural gas price	£/MWh	45	45	Authors' assumption

Table 9*: Key input parameters used in the scenario analysis*

8.2.2 Model Limitations

The approach outlined above straightforward and offers a way to make initial comparisons of the costs of hydrogen, synfuels and incumbent fossil fuels. Its simplicity leads to the following limitations, which should be addressed with further study.

1. It compares hydrogen/synfuel LCOH, which does not include taxes, profits, etc., with a price for an incumbent fuel to the end user, which does include these parameters, therefore not strictly comparing like with like. Since there is currently not an established commercial unsubsidised market for green hydrogen, this methodology is as valid as any other imperfect comparison for the current work.
2. It does not compare the costs required to strengthen the electricity transmission infrastructure needed to deliver renewable electricity for hydrogen production, or modify the natural gas or other fuel transmission and distribution systems to deliver hydrogen to end users. Such costs are highly case dependent and, in most situations, not yet established to a meaningful degree of certainty.
3. It does not include the costs of modifying or replacing the existing fossil fuel-burning equipment and vehicles. Such costs are highly case dependent and, in most situations, not yet established to a meaningful degree of certainty.

[85] IRENA. Future of Wind. (2019).
[86] Northern Ireland Statistics and Research Agency. Northern Ireland Carbon Intensity Indicators 2021. (2021).
[87] Fuel Cells and Hydrogen Joint Undertaking. Multi-Annual Work Plan 2014-2020. (2018).

8.3 Results of 2025 Scenario Analysis

Results of the 2025 scenario analysis are shown in Figure 19 to Figure 22. Figure 19 shows that the cost of hydrogen produced using excess electricity (scenarios 1 and 2) depends strongly on the ratio of electrolyser size to wind farm. A lower ratio produces cheaper hydrogen but captures less excess electricity that would be otherwise wasted. Scenarios 1, 2 and 4 require expensive storage if their variable production is to meet inflexible off-takers' demands. Figure 20 shows that scenarios 2, 3 and 4 could supply energy cheaper than diesel, but not natural gas, for flexible demands. Figure 21 shows that scenario 3, a grid-connected electrolyser, produces hydrogen with a significantly higher CO_2 intensity than natural gas, diesel, or the UK's low-carbon hydrogen standard. Scenarios 1, 2 and 4 have a CO_2 intensity of zero, as they use renewable electricity. Figure 22 combines the findings shown in Figure 20 and Figure 21 to present CO_2 abatement cost (CAC) for the 2025 scenarios. Key trends include:

1. The nature of off-taker demand, flexible (dark blue bars) or inflexible (light blue bars), which sets storage size, strongly influences CAC.
2. The fossil fuel being displaced, natural gas (grey outlines) or diesel/kerosene (black outlines), strongly influences the CAC.
3. Since scenario 3 has a higher CO_2 intensity than either of the incumbent fossil fuels (see Figure 21), its CAC would misleadingly be shown as negative. It is therefore excluded from the CAC plot.
4. Scenarios 2 and 4 could deliver cost-effective decarbonisation (CAC less than zero) to flexible off-takers who currently use diesel or kerosene.

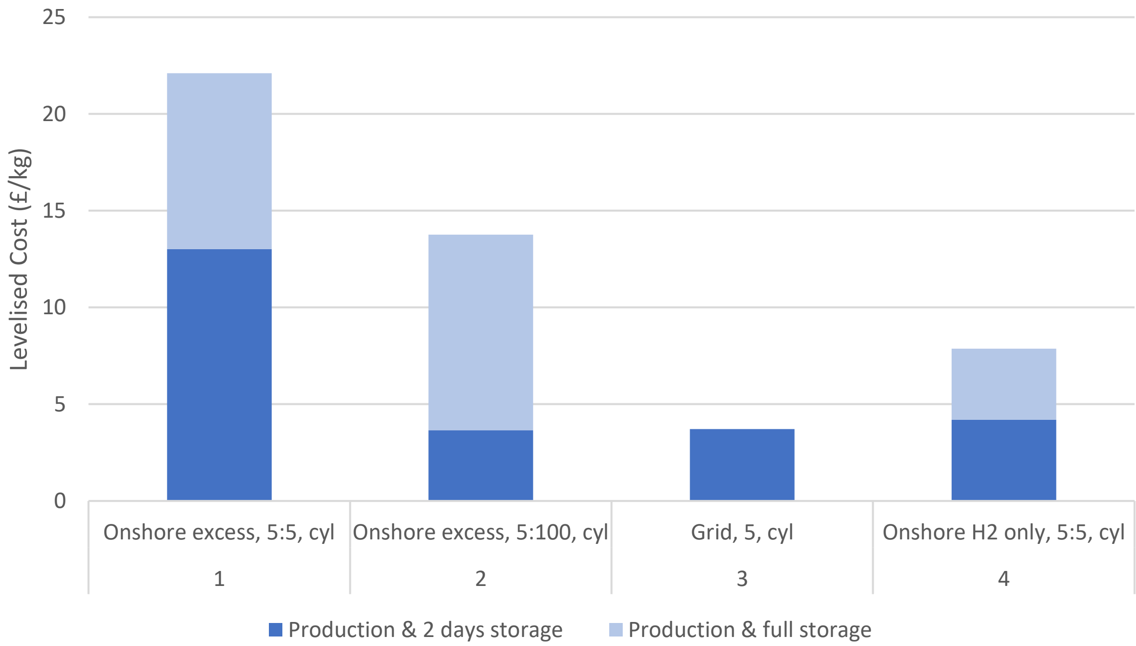


Figure 19: *Cost of Hydrogen for 2025 Scenarios in £/kg*

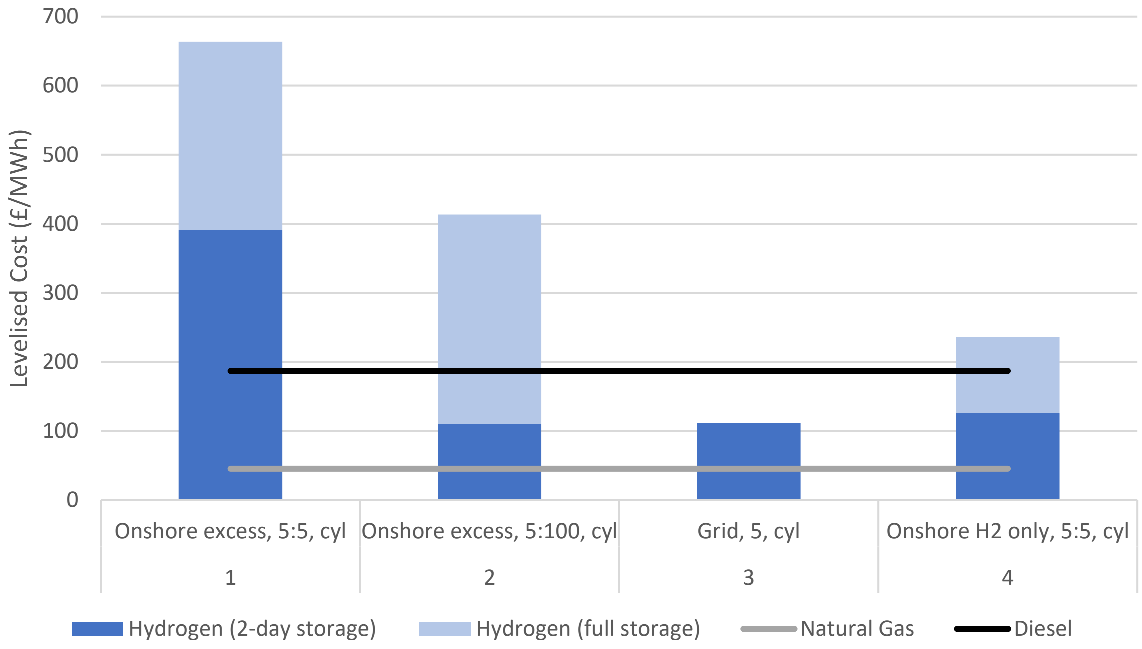


Figure 20: *Cost of Hydrogen for 2025 Scenarios in £/MWh*

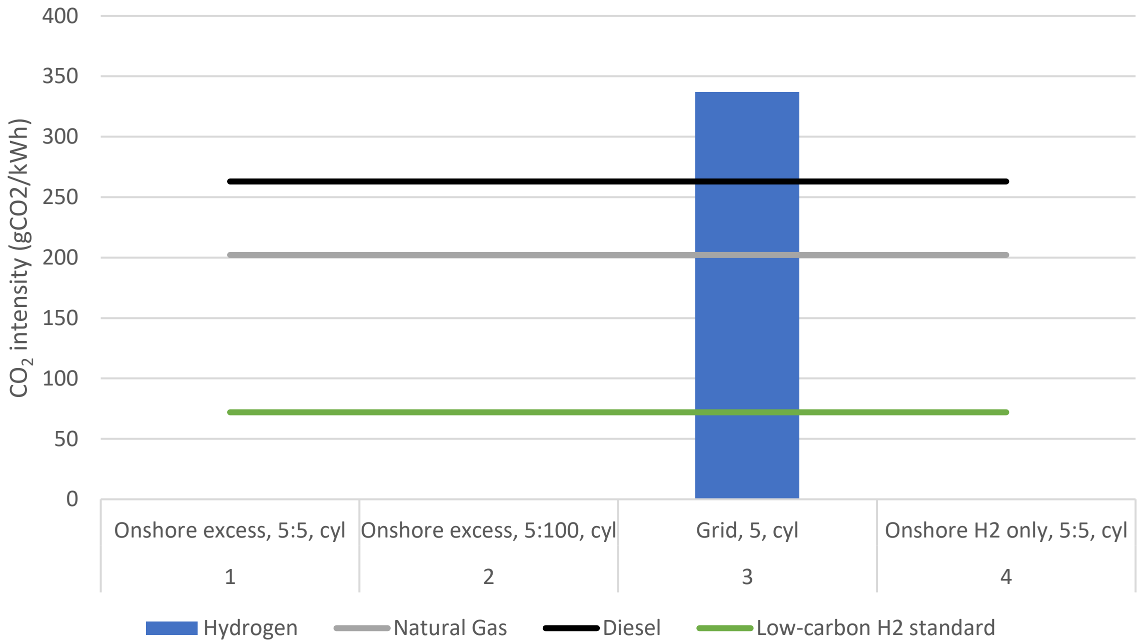


Figure 21: *CO_2 Intensity for 2025 Scenarios*

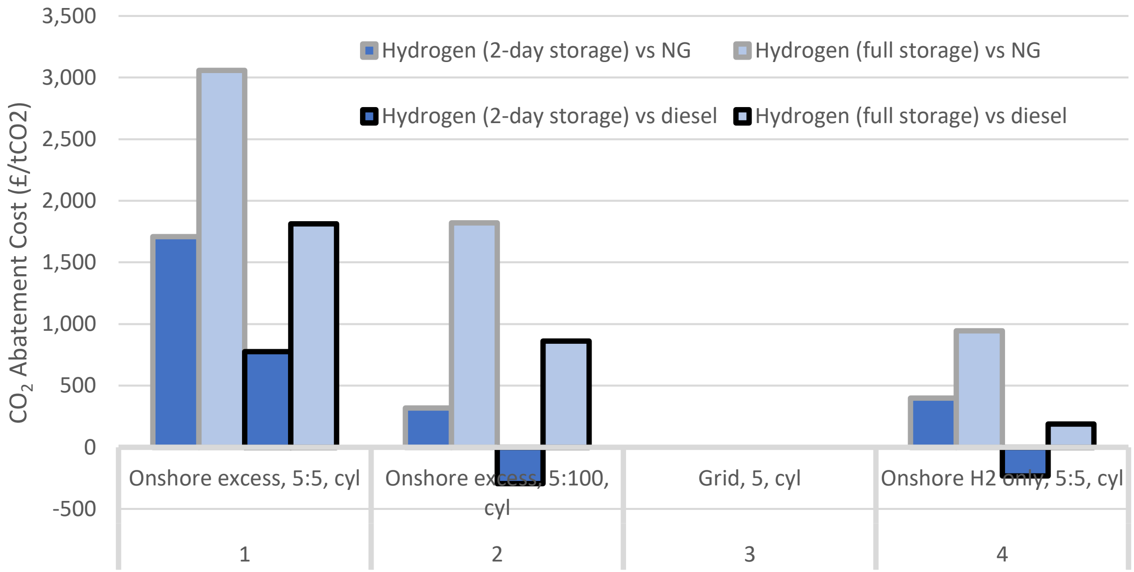


Figure 22: *CO_2 Abatement Cost for 2025 Scenarios*

8.4 Results of 2035 Medium-Scale Scenario Analysis

Results of the 2035 medium-scale (50 MW electrolyser) scenario analysis are shown in Figure 23 to Figure 26 shows that prioritising hydrogen production reduces production cost due to higher electrolyser capacity factors. Prioritising hydrogen also reduces storage cost for inflexible off-takers due to more constant production. Figure 24 shows that no scenarios are cost-competitive with natural gas, regardless of off-taker flexibility. Scenarios 7 to 11 are competitive with diesel, even for inflexible hydrogen demand. Scenarios 5 and 6 are only competitive with diesel for flexible demand. Figure 25 shows that scenario 10, a grid-connected electrolyser, produces hydrogen with a lower CO_2 intensity than natural gas or diesel, but higher than that for the UK's low-carbon hydrogen standard. The improvement in CO_2 intensity for grid-connected scenarios from Figure 21 to Figure 25 is due to Northern Ireland's expected progress in decarbonising electricity generation. Figure 26 combines the findings shown in Figure 24 and Figure 25 to present CO_2 abatement cost (CAC) for the 2035 medium-scale scenarios. Key trends include:

1. The nature of off-taker demand, flexible (dark blue bars) or inflexible (light blue bars), which sets storage size, strongly influences CAC.
2. The fossil fuel being displaced, natural gas (grey outlines) or diesel/kerosene (black outlines), strongly influences the CAC.
3. Scenarios 7 to 11 could deliver cost-effective decarbonisation (CAC less than zero) to all off-takers who currently use diesel or kerosene.
4. Scenarios 7, 8, 9 and 11 could also deliver relatively cost-effective decarbonisation (CAC near zero) to flexible off-takers who currently use natural gas.
5. Scenario 10 (grid-connected electrolyser) has high CAC when displacing natural gas because (a) its hydrogen is more expensive than gas (see Figure 24) and (b) it does not offer significant CO_2 intensity reductions (see Figure 25).

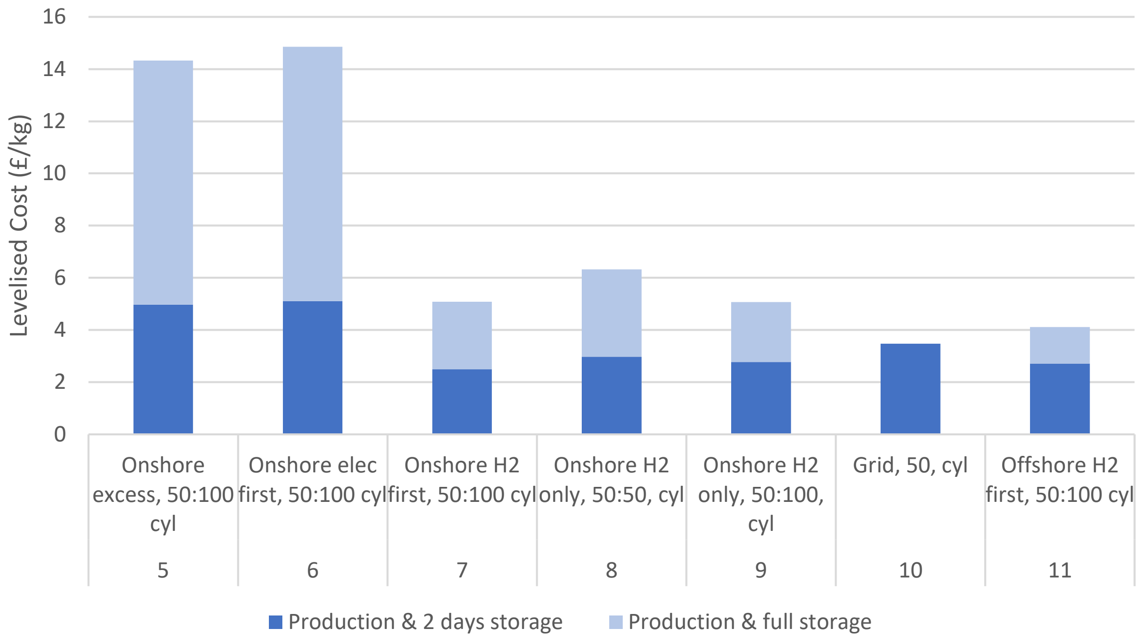


Figure 23: *Cost of Hydrogen for 2035 50-MW Electrolyser Scenarios in £/kg*

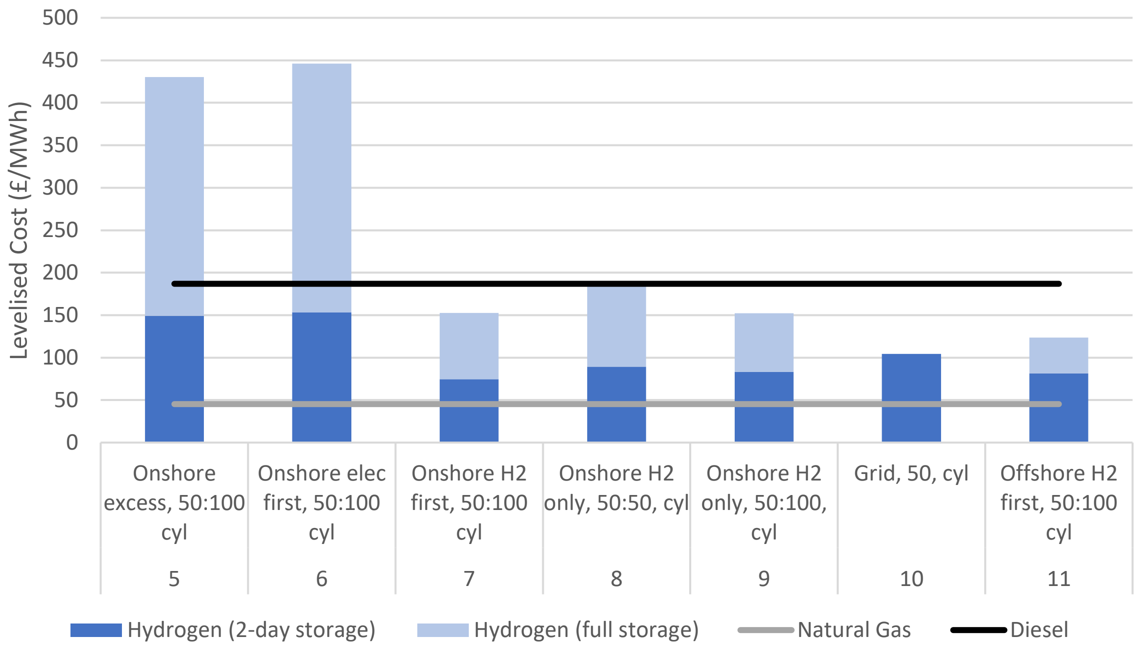


Figure 24: *Cost of Hydrogen for 2035 50-MW Electrolyser Scenarios in £/MWh*

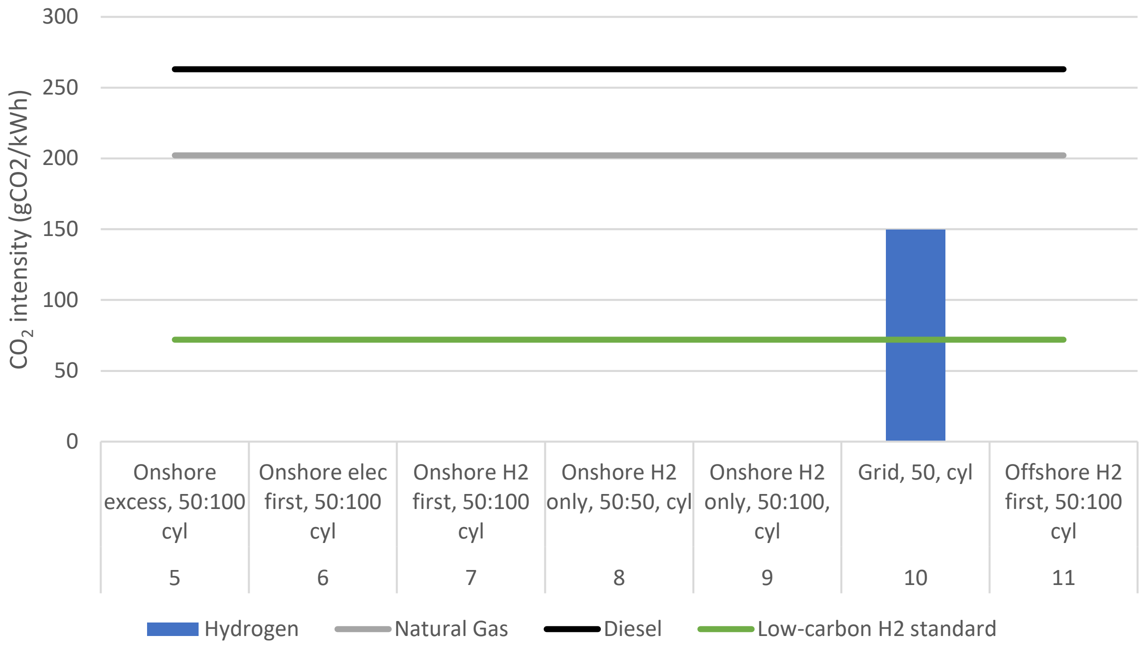


Figure 25: *CO_2 Intensity for 2035 50-MW Electrolyser Scenarios*

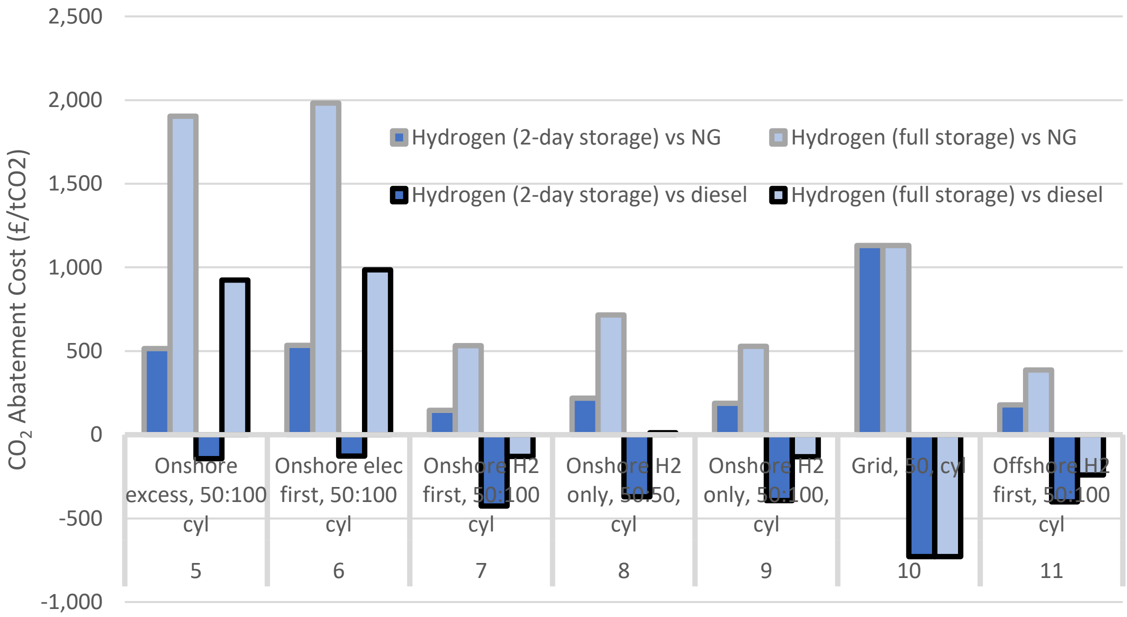


Figure 26: *Carbon Abatement Cost for 2035 50-MW Electrolyser Scenarios*

8.5 Results of 2035 Large-Scale Scenario Analysis

Results of the 2035 large-scale (500 MW electrolyser powered by offshore wind) scenario analysis are shown in Figure 27 and Figure 28. The 2035 large-scale scenarios assume all off-takers are inflexible, which requires large-scale storage or conversion to synfuel. LCOH figures in £/kg are not shown as these units are not useful when assessing synfuels with different heating values to hydrogen. Figure 27 shows LCOH (in £/MWh) for hydrogen stored in cylinders and salt cavern and for synfuels including methane, ammonia, methanol, and diesel/kerosene. All scenarios are shown to be highly competitive for the displacement of diesel/kerosene. None are competitive with natural gas, although scenario 13, which involves the storage of hydrogen in salt caverns, comes closest. Since these scenarios assume (a) all hydrogen is produced from renewable electricity and (b) all CO_2 necessary for synfuel production is sustainable, i.e., obtained from biogenic sources, their CO_2 intensities are 0 gCO_2/kWh. Salt cavern storage, which is typically done at pressures below 100 bar, also results in lower compression costs compared to cylinder storage, which is at 350 bar at least. This can be seen in the difference between the dark blue portions of the scenario 12 and 13 bars.

Figure 28 presents CO_2 abatement cost (CAC) for the 2035 large-scale scenarios for inflexible off-takers only. Additionally, replacement combinations are deemed impractical and excluded from Figure 28. These combinations include (a) e-methane replacing existing diesel/kerosene use, (b) e-methanol replacing existing natural gas use, and (c) e-diesel/e-kerosene replacing existing natural gas use. Key trends include:

1. Scenario 13 (hydrogen stored geologically) can be cost-effective for decarbonising diesel and possibly natural gas use.
2. Ammonia, e-methanol, and e-diesel/e-kerosene can be cost-effective for decarbonising diesel, kerosene, and fuel oil use, if sufficient quantities of sustainable CO_2 are available.
3. The CO_2 abatement cost of e-methane replacing natural gas is relatively high.

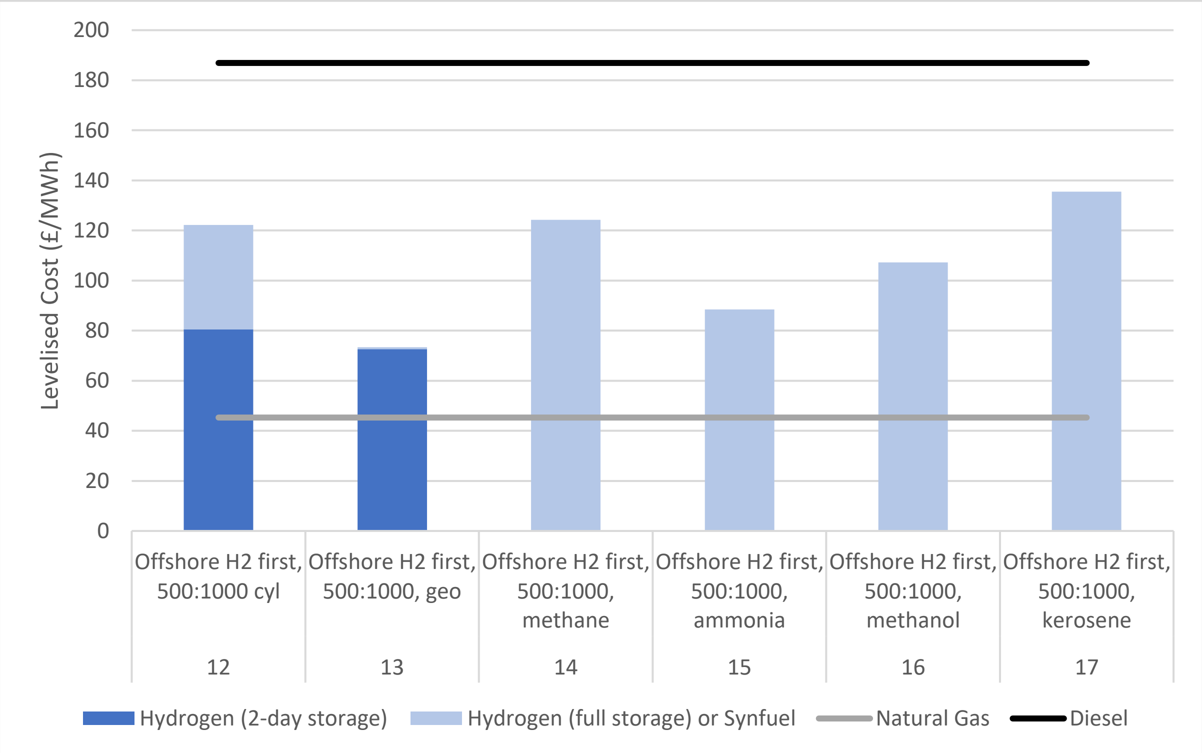


Figure 27: *Cost of Hydrogen or Synfuel for 2035 500-MW Electrolyser Scenarios in £/MWh*

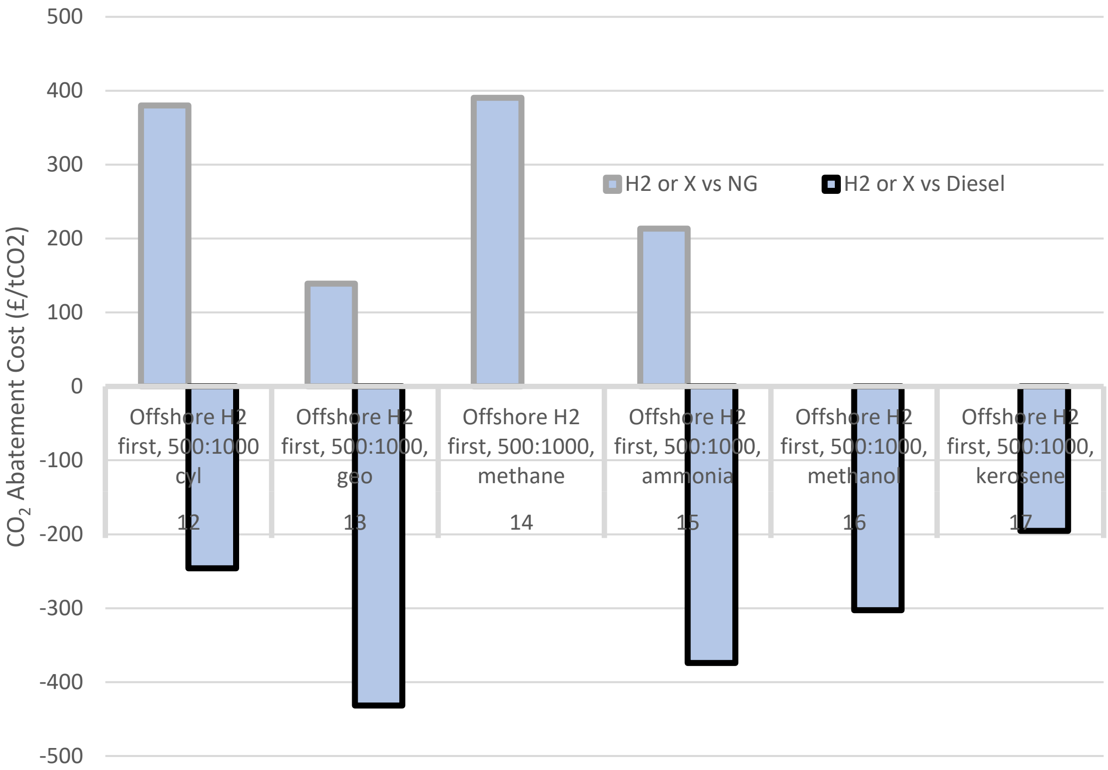


Figure 28: *Carbon Abatement Cost for 2035 500-MW Electrolyser Scenarios*

8.6 Supports Required for Cost Competitiveness

Many scenarios result in hydrogen/synfuels with levelised costs higher than prices expected to be seen for incumbent fossil fuels. Support mechanisms to bring parity between hydrogen/synfuels and the incumbents may therefore need to be considered. For each scenario, the values of three separate types of support are determined.

1. The capital expense (Capex) support needed to bring the levelised cost of hydrogen/synfuel to the assumed price of incumbent fuel, expressed in £/kW of electrolyser capacity.
2. The operational expense (Opex) support needed to bring the levelised cost of hydrogen/synfuel to the assumed price of incumbent fuel, expressed in £/MWh of electricity consumed.
3. The hydrogen price support needed to bring the levelised cost of hydrogen/synfuel to the assumed price of incumbent fuel, expressed in £/kg of hydrogen produced.

For each scenario, each support mechanism is calculated four times in order to find its value for the two fossil fuels being displaced (natural gas and diesel) and the flexibility of the end-user (flexible and inflexible), except for the 500-MW scenarios, which are all to meet inflexible demands. The calculated amounts shown here are standalone, not summative. We again acknowledge that the calculated values of the different supports do not account for all changes required to the energy system or end-user technology. Furthermore, the analysis compares a levelised cost to a market price, but in the current situation of there being no significant commercial market for hydrogen as a fuel, it is as valid a starting point as any other.

Table 10 displays the calculated Capex supports in £/kW of electrolyser capacity needed for parity between the levelised cost of hydrogen/synfuel for each scenario with natural gas and diesel for flexible and inflexible users. Parity with diesel is achieved without Capex support for several scenarios, especially those involving flexible users. This is because of diesel's much higher price per unit energy than natural gas. Capex support is needed for all scenarios for parity with natural gas, regardless of user flexibility. For most scenarios, especially those for inflexible users, Capex support exceeds the specific price (£/kW) of the electrolyser due to the need for large amounts of hydrogen storage cylinders. The impact of using much cheaper geological storage of hydrogen on Capex support is seen by comparing the results for scenarios 12 (cylinder storage) and 13 (use of geological storage).

			Capex support for parity (£/kW) with			
		Year	Natural gas		Diesel	
No.	**Scenario**	**Storage**	**2 days**	**Full**	**2 days**	**Full**
1	Onshore excess, 5:5, cyl	2025	718	1,231	479	991
2	Onshore excess, 5:100, cyl	2025	513	2,863	-	1,966
3	Grid, 5, cyl	2025	2,393	2,393	-	-
4	Onshore H2 only, 5:5, cyl	2025	1,068	2,564	-	1,026
5	Onshore excess, 50:100 cyl	2035	427	1,581	-	1,111
6	Onshore elec first, 50:100 cyl	2035	85	1,650	-	1,111
7	Onshore H2 first, 50:100 cyl	2035	769	2,735	-	-
8	Onshore H2 only, 50:50, cyl	2035	675	2,244	-	598
9	Onshore H2 only, 50:100, cyl	2035	940	2,906	-	-
10	Grid, 50, cyl	2035	2,393	2,393	-	-
11	Offshore H2 first, 50:100 cyl	2035	1,154	2,436	-	-
12	Offshore H2 first, 500:1000 cyl	2035	n/a	2,521	n/a	-
13	Offshore H2 first, 500:1000, geo	2035	n/a	940	n/a	-
14	Offshore H2 first, 500:1000, methane	2035	n/a	1,538	n/a	-
15	Offshore H2 first, 500:1000, ammonia	2035	n/a	1,154	n/a	-
16	Offshore H2 first, 500:1000, methanol	2035	n/a	1,368	n/a	-
17	Offshore H2 first, 500:1000, diesel/kerosene	2035	n/a	1,624	n/a	-

Table 10*: Capex support (£/kW) needed to bring the levelised cost of hydrogen/synfuel to the assumed price of incumbent fuel*

Table 11 displays the calculated Opex supports in £/MWh of electricity consumed for parity between the levelised cost of hydrogen/synfuel for each scenario with natural gas and diesel for flexible and inflexible users. As with Capex, parity with diesel is achieved without Opex support for several scenarios, especially those involving flexible users. Opex support is needed for all scenarios for parity with natural gas, regardless of user flexibility. For many scenarios, especially those for inflexible users, Opex support exceeds the assumed price of electricity (£/MWh) due to the need for the support to cover the costs of large amounts of hydrogen storage cylinders. The impact of using much cheaper geological storage of hydrogen on Opex support is seen by comparing the results for scenarios 12 (cylinder storage) and 13 (use of geological storage).

No.	Scenario	Year	Opex support for parity (£/MWh) with			
			Natural gas		Diesel	
		Storage	2 days	Full	2 days	Full
1	Onshore excess, 5:5, cyl	2025	231	397	154	321
2	Onshore excess, 5:100, cyl	2025	8	46	-	32
3	Grid, 5, cyl	2025	43	43	-	-
4	Onshore H2 only, 5:5, cyl	2025	54	128	-	51
5	Onshore excess, 50:100 cyl	2035	64	235	-	167
6	Onshore elec first, 50:100 cyl	2035	85	303	-	229
7	Onshore H2 first, 50:100 cyl	2035	21	73	-	-
8	Onshore H2 only, 50:50, cyl	2035	32	103	-	27
9	Onshore H2 only, 50:100, cyl	2035	22	67	-	-
10	Grid, 50, cyl	2035	38	38	-	-
11	Offshore H2 first, 50:100 cyl	2035	24	51	-	-
12	Offshore H2 first, 500:1000 cyl	2035	n/a	51	n/a	-
13	Offshore H2 first, 500:1000, geo	2035	n/a	19	n/a	-
14	Offshore H2 first, 500:1000, methane	2035	n/a	31	n/a	-
15	Offshore H2 first, 500:1000, ammonia	2035	n/a	24	n/a	-
16	Offshore H2 first, 500:1000, methanol	2035	n/a	28	n/a	-
17	Offshore H2 first, 500:1000, diesel/kerosene	2035	n/a	32	n/a	-

Table 11*: Opex support (£/MWh) needed to bring the levelised cost of hydrogen/synfuel to the assumed price of incumbent fuel*

Table 12 displays the calculated price supports in £/kg of hydrogen produced for parity between the levelised cost of hydrogen/synfuel for each scenario with natural gas and diesel for flexible and inflexible users. Similar trends, for the same reasons, to those observed for Capex and Opex are seen here. For comparison, the UK Renewable Transport Fuel Obligation (RTFO) scheme offers support of up to £7.33/kg while the US Inflation Reduction Act offers of up to $3/kg (approximately £2.40/kg) for zero-carbon hydrogen. The calculated price supports are colour-coded in Table 12, based on the UK and US supports available:

- **Green**: calculated price support falls below the £2.40/kg available in the US, or no support is required for price parity.
- **Yellow**: calculated price support falls between the £2.40/kg available in the US and the £7.33/kg available in the UK.
- **Red**: calculated price support falls above the £7.33/kg available in the UK.
- **Grey**: calculated GHG intensity does not meet UK low-carbon criteria.

It should be noted, that as seen in Figure 21 and Figure 25, the two grid-powered scenarios, scenario 3 in 2025 and scenario 10 in 2035, produce hydrogen with a GHG intensity in excess of that required for the low-carbon standard. Data relating to these scenarios is therefore greyed-out in the table.

No.	Scenario	Year Storage	Price support for parity (£/kg) with			
			Natural gas		Diesel	
			2 days	Full	2 days	Full
1	Onshore excess, 5:5, cyl	2025	11.51	20.59	7.70	16.78
2	Onshore excess, 5:100, cyl	2025	2.14	12.26	-	8.45
3	Grid, 5, cyl	2025	2.20	2.20	-	-
4	Onshore H2 only, 5:5, cyl	2025	2.69	6.36	-	2.55
5	Onshore excess, 50:100 cyl	2035	3.47	12.82	-	9.00
6	Onshore elec first, 50:100 cyl	2035	4.29	15.23	0.47	11.42
7	Onshore H2 first, 50:100 cyl	2035	1.04	3.66	-	-
8	Onshore H2 only, 50:50, cyl	2035	1.59	5.18	-	1.37
9	Onshore H2 only, 50:100, cyl	2035	1.27	3.56	-	-
10	Grid, 50, cyl	2035	1.97	1.97	-	-
11	Offshore H2 first, 50:100 cyl	2035	1.20	2.60	-	-
12	Offshore H2 first, 500:1000 cyl	2035	n/a	2.56	n/a	-
13	Offshore H2 first, 500:1000, geo	2035	n/a	0.94	n/a	-
14	Offshore H2 first, 500:1000, methane	2035	n/a	2.63	n/a	-
15	Offshore H2 first, 500:1000, ammonia	2035	n/a	1.44	n/a	-
16	Offshore H2 first, 500:1000, methanol	2035	n/a	2.06	n/a	-
17	Offshore H2 first, 500:1000, diesel/kerosene	2035	n/a	3.00	n/a	-

Table 12*: Hydrogen price support (£/kg) needed to bring the levelised cost of hydrogen/synfuel to the assumed price of incumbent fuel*

Three different types of support for hydrogen/synfuel applied in isolation have been explored in his section. It would be valuable to conduct studies of combinations of two or more of these support types and how they align with current and future proposed policies to support hydrogen. This is recommended as a future piece of work.

8.7 Water Consumption

Electrolysis consumes around 9 kg of water per kg of hydrogen produced. Additional quantities of water are required for equipment cooling and other uses, but this water is not consumed. After treatment, it can be returned to the local environment. The water consumed by electrolysis is ultimately returned to the ambient environment upon use as either liquid or vapour. Given the fact that hydrogen can be transported significant distances from its production location to end use sites, this return of water to the environment warrants consideration. All of the scenarios studied assumed the supply of mains water to a demineralisation unit, which is part of the electrolyser pack, and therefore included in the system costs.

For the scenarios considered, annual water consumption ranges from less than 500,000 litres for scenario 1, to over 600 million litres for scenarios 12-17. To get a sense of scale for these numbers, consider Northern Ireland's per capita daily domestic water consumption of 145 litres[88], which translates to per capita annual domestic consumption of around 53,000 litres. The electrolysers in the scenarios therefore have water consumption from the equivalent of less than 10 people for scenario 1, to around 12,000 people (slightly smaller than the population of Enniskillen) for scenarios 12-17. The amounts of hydrogen produced in these scenarios is enough to fuel from 6 (scenario 1) to 8,000

[88] https://www.niwater.com/why-save-water-at-home-audit/

(scenarios 12-17) double-decker fuel cell buses operating 365 days a year. Compared to the energy delivered by the produced hydrogen, the consumed quantity of water is relatively small.

Desalination of seawater could be used to supply water to electrolysis while avoiding the use of mains water. Recent work by the University of Galway showed that state-of-the-art desalination technologies can produce freshwater comparable to mains water for less than £1 per cubic metre[89]. The volumetric charge for mains water in Northern Ireland is £1.17 per cubic metre[90], which shows that desalination is a viable option for water supply. Regardless of source, the impact of water price on LCOH is very small. For the scenarios, the annual cost of water is around 2% of the annual cost of electricity.

[89] Gunawan, Cavana, Leone, Monaghan. Solar hydrogen for high capacity dispatchable, long-distance energy transmission – A case study for injection in the Greenstream natural gas pipeline. (2022).
[90] https://www.niwater.com/measured-charges/

9 Recommendations Based on Scenario Analysis

Based on the findings of the scenario analysis, the following recommendations are made:

1. Green hydrogen should be supported as a route to decarbonise heavy-duty transport and industrial heat, especially when that heat is currently delivered by heavily polluting methods such as coal or oil.
2. In the short term, cost-effective full decarbonisation of these key, hard-to-abate energy applications will require policy support for hydrogen production if locked-in dependence on hydrogen imports is to be avoided.
3. The impact of co-production of hydrogen and electricity on the operation of the electricity system should be investigated.
4. The synergistic roll-out of grid-connected hydrogen production and renewable electricity should be encouraged and enabled with policy and financially supported with funding since more renewables enables greener hydrogen, and hydrogen enables more renewables by providing energy storage and stability.
5. The rapid development of offshore wind energy is crucial for Northern Ireland to produce hydrogen at scale.
6. The potential of geological storage for hydrogen in Northern Ireland should be investigated and demonstrated as rapidly as possible.
7. The supply chain of sustainable CO_2 for synfuel production must be assessed and, if of sufficient size, supported.
8. To fully compare the domestic decarbonisation costs of hydrogen and synfuels, the costs of modifying, upgrading and/or replacing Northern Ireland's electricity and gas transmission infrastructure to accommodate hydrogen must be assessed in future work.
9. The costs of modifying and/or replacing end use technologies in the heavy-duty transport and industrial heat sectors must be addressed in future work.
10. In parallel to local supply and use, the exporting of hydrogen in various forms should be advanced to become a central part of Northern Ireland's hydrogen strategy. This will drive economies of scale of production and, equally importantly, storage.
11. The impact of combinations of Capex, Opex and hydrogen price supports on cost competitiveness should be assessed. A comparison of these supports should also be made to existing and proposed policies in Northern Ireland.

10 Conclusions

Green hydrogen and synthetic fuels can play transformative roles not only in Northern Ireland's decarbonisation transition, but also as a driver of indigenous innovation and employment. The capacity for Northern Ireland to produce hydrogen is limited only by its ability to grow its renewable electricity and in particular, offshore wind, generating capacity. Northern Ireland has a unique natural advantage in the form of salt cavern storage potential, which can significantly reduce hydrogen costs. Cost-effective use cases of hydrogen can be found first in heavy-duty transport and industrial heating for which electrification may not be suitable due to vehicle range, charge time, or high temperature requirements. Later applications of hydrogen and synfuels can be found in decarbonising shipping and aviation. Northern Ireland has the potential to become an exporter of hydrogen to GB and the EU. Promotion of exports could stimulate production and storage deployment, which would reduce costs and project risk, and increase security of supply. An important consideration in the roll-out of hydrogen and synfuels in Northern Ireland is the equality of access to the value chain for potential suppliers and users. This is particularly important given the non-uniformly dispersed nature of renewable energy generating potential.

As part of this study, seventeen scenarios for the roll-out of hydrogen and synfuels in Northern Ireland in the near- (2025) and medium-terms (2035) were created and analysed. The key findings were: (1) by 2025, green hydrogen could be a cost-effective decarbonisation option for certain heavy-duty transport operators and industrial energy users who do not currently use natural gas, (2) co-production of hydrogen and electricity can result in cost-effective hydrogen production when hydrogen production is prioritised, (3) by 2035, green hydrogen could be highly cost-effective for a wider range of off-takers in heavy-duty transport and industrial heating, (4) increases in renewable electricity penetration will make grid-produced hydrogen cleaner than fossil fuels in 2035, but not clean enough for current UK standards, (5) geological storage of hydrogen has a major cost reducing impact, and (6) successful deployment of synthetic fuels, most likely for export but also for decarbonisation of domestic shipping and aviation, hinges on the development of offshore wind for economies of scale and the availability of non-fossil CO_2.

This report recommends that (1) green hydrogen should be supported as a route to decarbonise heavy-duty transport and industrial heat, (2) cost-effective full decarbonisation of these will require policy support for hydrogen production, (3) the impact of co-production of hydrogen and electricity on the operation of the electricity system should be investigated, (4) grid-connected hydrogen production and scale-up of renewable electricity should be synergistically rolled-out, (5) the rapid development of offshore wind energy is crucial for Northern Ireland to produce hydrogen at scale, (6) the potential of geological storage of hydrogen in Northern Ireland should be investigated and demonstrated as rapidly as possible, (7) the supply chain of sustainable CO_2 for synfuel production must be assessed and supported, (8) the costs of modifying Northern Ireland's energy infrastructure and (9) energy end uses to handle hydrogen must be assessed in future work, (10) export of hydrogen in various forms should be a central part of Northern Ireland's hydrogen strategy, and (11) the impact of combinations of different hydrogen support schemes should be assessed and compared to current and future policies.

11 Abbreviations

Abbreviation	Meaning
AD	Anaerobic Digestion
AFIR	Alternative Fuels Infrastructure Regulation
AP	Air Products
ATJ-SPK	Alcohol-To-Jet Synthesised Paraffinic Kerosene
BEVs	Battery Electric Vehicles
CAC	Carbon Abatement Cost
CAPEX	Capital Expenditure
CCUS	Carbon Capture Utilisation and Storage
CfD	Contracts for Difference
CH_4	Methane
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
DAC	Direct Air Capture
DfC	Department for Communities
DfE	Department for the Economy
EU	European Union
FEED	Front-End Engineering Design
FFI	Fortescue Future Industries
FIT	Feed-in Tariff
FT- SPK	Fischer-Tropsch Synthesized Paraffinic Kerosene
FT-SPK/A	Discher-Tropsch Syntesised Paraffinic Kerosene / increased Aromatic content
GB	Great Britain
GHG	Greenhouse Gas
GOs	Guarantee of Origins
GW	Gigawatt
GWh	Gigawatt hour
H_2	Hydrogen
HDVs	Heavy-Duty Vehicles
HEFA-SPK	Hydroprocessed Esters and Fatty Acids Synthesised Paraffinic Kerosene
HFS-SIP	Hydroprocessed Fermented Sugars Synthetic Iso Paraffins
kW	Kilowatt
kWh	Kilowatt hour
LCOE	Levelised Cost of Energy
LCOH	Levelised Cost of Hydrogen
LHY	Liquid Hydrogen
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carriers
MW	Megawatt
MWh	Megawatt hour
NFFO	Non-Fossil Fuel Obligation
NH_3	Ammonia
NI	Northern Ireland
NIRO	Northern Ireland Renewables Obligation
NO_x	Nitrous Oxides

OEMs	Original Equipment Manufacturers
OPEX	Operational Expenditure
PEM	Proton Electrolyte Membrane
PGM	Platinum Grade Metal
PV	Photovoltaic
R&D	Research and Development
RED	Renewable Energy Directive
RES	Renewable Energy Sources
RFNBO	Renewable Fuels of Non-Biological Origin
RHI	Renewable Heat Incentive
RLF	Renewable Liquid Fuel
RO	Renewable Obligation
RoI	Republic of Ireland
RTFO	Renewable Transport Fuel Obligation
SAF	Sustainable Aviation Fuel
SEMO	Single Electricity Market Operator
SMR	Steam Methane Reformation
SO_x	Sulphur Oxides
SRF	Solid Recycled Fuel
TEN-T	Trans-European Transport Network
TW	Terawatt
TWh	Terawatt hour
UK	United Kingdom
US	United States
wt%H_2	Weight percentage hydrogen
^0C	Celsius