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Cost reduction pathways of green hydrogen production in Scotland – total costs and international comparisons

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1 Executive summary

Green hydrogen, produced by electrolysis using renewable or low-carbon electricity, is expected to play a key role in the Scottish Government's net zero emission targets.

The purpose of this study is to determine if Scotland can produce green hydrogen at scale and export it at a competitive cost to the EU market. We explore the costs of producing hydrogen in Scotland, Chile, Norway, Morocco and France and the northeast region of the USA and exporting to northwest Europe, focusing on:

- **Production of hydrogen at scale:** A large-scale electrolytic hydrogen production plant (1GW) powered by a low-carbon energy source.
- **Transport via pipeline:** The hydrogen produced is distributed to Rotterdam, where it enters the EU, via either a dedicated pipeline, which transports it from a single facility, or shared pipeline, transporting it from the facility and additional producers.
- **Transport via shipping ammonia:** The hydrogen produced is converted to ammonia, shipped to Rotterdam and converted back into hydrogen in the Netherlands.
- **Transport via shipping compressed hydrogen:** The hydrogen produced is compressed to a high pressure and shipped to Rotterdam.

1.1 Findings

Figure 1 shows the costs of production and transport per country. From the countries analysed, hydrogen production is cheapest in France given its access to low-cost nuclear electricity. The most expensive is Scotland due to the higher cost of power from offshore wind compared with the other low-carbon power technologies used. Other countries are expected to become more competitive as low-carbon electricity costs reduce and technology improves.

The most cost-effective transport option varies depending on distance, volume, and technology. For longer distances, converting hydrogen to ammonia and shipping via ammonia vessels is most effective. In contrast, for shorter distances, pipeline or compressed hydrogen transport options are more cost-efficient. Pipelines are most cost-efficient when repurposed and the capacity is fully utilised. Where existing infrastructure is not available and the pipeline is not fully utilised, compressed hydrogen shipping offers a cost-saving alternative for shorter distances.

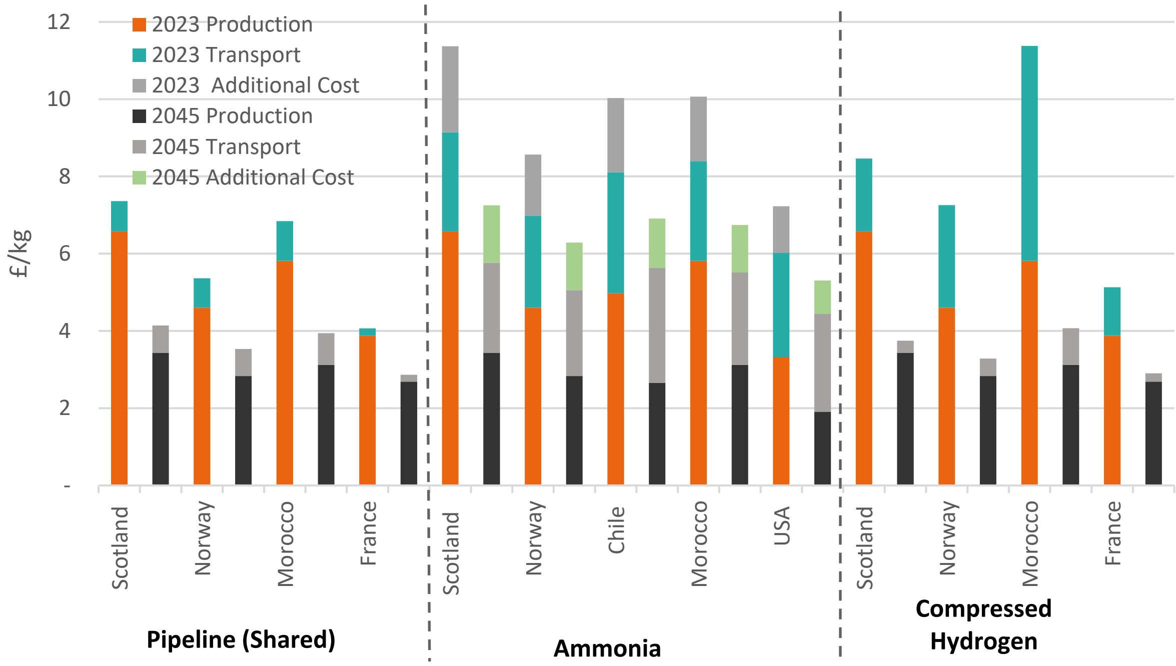

Figure 1 – Levelised cost of hydrogen production and transport (£/kg)

It is more costly to produce hydrogen in Scotland as compared to all other case study countries. This is because the cost of offshore wind generated power in Scotland is higher than the other low carbon power technologies used. In other case study countries, such as France which can produce hydrogen at a significantly lower cost, there could be low carbon power constraints without additional investment in nuclear technology. In contrast, the Scottish Government has set ambition to invest in and scale up its onshore and offshore wind power to enable the growth of its green hydrogen sector.

Exporting hydrogen via ammonia is a feasible option for countries further afield such as the USA and Chile because as distance from the EU increases the costs associated with ammonia shipping movement do not increase significantly. As a result, this allows countries further away from the EU to participate in the hydrogen market. Given the additional costs associated to recovering hydrogen from ammonia, this export method becomes particularly cost effective where ammonia is the end product.

Transporting compressed hydrogen via vessels could be an export method for shorter distances and smaller scale production. However, as the technology is not yet operational, the cost effectiveness and feasibility of this method will need to be further evidenced.

Scotland's proximity to Rotterdam gives it a competitive advantage because it enables export of hydrogen via pipeline, which is the export option with the lowest cost. In comparison, countries that are further away cannot export via pipeline or compressed shipping due to technical and cost feasibility issues.

To outcompete countries that are closer to Rotterdam, production costs in Scotland must decrease. However, even if the cost of production remains higher in Scotland than in other European countries, Scotland will likely still be a market player as France and Norway alone cannot meet EU hydrogen import targets.

Considering the evolving state of the hydrogen industry, cost estimates for production and transportation carry uncertainty, which affects assessments of market competitiveness.

1.2 Recommendations

Government support could close the cost gap and enable Scotland to become a major competitor in the EU market. We recommend:

- Continue to support the scale up of offshore wind and hydrogen production to access economies of scale and enable the generation of surplus low-carbon power for export. Scale up should target a reduction in low-carbon electricity costs as well as capital expenditure for electrolysers (needed for producing green hydrogen).
- Provide subsidies to the sector of between £60m and £500m per year, depending on the export method chosen, to enable Scottish hydrogen producers to outcompete producers who benefit from USA and EU subsidies.
- Valuate the opportunity to repurpose pipeline infrastructure and develop a co-ordinated export strategy with multiple hydrogen producers to maximise use of shared pipelines.

2 Contents

3 Glossary

Term	Meaning
Green hydrogen	Green hydrogen is hydrogen produced via electrolysis of water using renewable electricity and is zero carbon.
Low carbon power	Low carbon power is electricity produced with substantially lower greenhouse gas emissions than conventional fossil fuel power generation.
Levelised cost of hydrogen (LCOH)	The levelised cost of hydrogen is a standardised methodology used by economists to compare the costs of producing hydrogen by different methods. It considers the total costs (both fixed and variable) of production per kilogram over the life of the plant. It is a common metric that is used as a proxy for the price of hydrogen in today's terms (where future costs are discounted), which is required to "break-even" financially. Therefore, it is an important calculation to assess early-stage project feasibility and compare options.
Levelised cost of electricity (LCOE)	The levelised cost of electricity is an economic measure used to compare the lifetime cost of generating electricity across the various generation technologies. It is the discounted lifetime cost of building and operating a generation asset, expressed as a cost per unit of electricity generated. It considers all relevant costs facing the generator.
Levelised cost of transport (LCOT)	The levelised cost of transport is the discounted lifetime cost of building and operating a hydrogen transportation method (i.e. a pipeline), expressed as a cost per unit of hydrogen produced. It considers the total costs (both fixed and variable) of transporting hydrogen per kilogram over the lifetime of the asset.
Electrolyser utilisation	The amount of time, represented as a %, an electrolyser is producing hydrogen. Thus, annual electrolyser utilisation would be measured over a year.
Sleeved Power Purchase Agreement (PPA)	Sleeved PPAs are a private agreement between an energy developer and an off-taker, for the purchase of electricity generated by the energy project.
Baseload capacity	Generating equipment which are designed to operate for long periods of time or near full load.
Shared pipeline	Pipelines which transport hydrogen from multiple hydrogen producers.
Repurposed pipeline	Pipelines which previously transported natural gas or other fuels, which have been adapted to transport hydrogen.
Load factor	Defined as the average consumption, output or throughput over a period of time of a particular technology or piece of infrastructure, divided by its consumption, output, or throughput if it had operated at full (rated) capacity over that time period.

Table 1 – Glossary of terms

4 Introduction

The purpose of this study is to estimate the cost of producing and exporting green hydrogen at scale to the EU market in Scotland compared to other major exporting countries. We have selected the identified exporting countries and the Port of Rotterdam as the key import location into the EU market to, in part, simplify the analysis. We note, as part of a liquid hydrogen market, there will be many exporting countries and import terminals in the EU. These insights will be used to inform recommendations on how the Scottish Government can best support its hydrogen export economy.

5 Green hydrogen in Scotland

5.1 Importance of green hydrogen to a net zero Scotland

In March 2020, Scotland committed to achieving net zero greenhouse gas emissions by 2045 and a 75% reduction by 2030 relative to 1990 levels (Scottish Government, 2019). Hydrogen will play a crucial role in achieving the Scottish Government's ambition to achieve its Net Zero target by serving as a sustainable energy source for a range of applications. Additionally, hydrogen has the potential to work alongside renewable electricity in reducing carbon emissions in the transportation, power, and industry.

In its 2022 Hydrogen Action Plan, the Scottish Government confirmed its initial ambition to produce 5 gigawatts (GW) of low carbon hydrogen by 2030 and 25GW by 2045 (Scottish Government, 2020a). This would be enough to meet a sixth of Scotland's energy needs. The most ambitious scenario of the Scottish Hydrogen Assessment estimates that by 2045 Scotland could become a leading exporter of hydrogen (Scottish Government, 2020b).

5.2 Scaling up hydrogen production in Scotland

To meet Scotland's production targets, wind energy capacity will need to be built, hydrogen production and associated infrastructure scaled-up, and early market creation supported.

The Scottish Government's Hydrogen Action plan aims to achieve a 5GW hydrogen target by 2030, with the majority of this capacity coming from renewable sources. The Scottish Government has stated plans to continue to support the development of onshore and offshore wind projects in Scotland to realise this ambition (Scottish Government, 2022a) as generally the renewable power required is 1-2 times the installed electrolyser capacity.

As of 2022, Scotland had c. 9GW of installed onshore wind capacity and c. 2.2GW of installed offshore wind capacity (Scottish Government, 2022a). The Scottish Government intends to enable the significant ramp up of both onshore and offshore wind energy. For example, in its 2022 Onshore Wind Policy Statement the Scottish Government set an ambition to deploy 20GW of onshore wind by 2030 (Scottish Government, 2022b) and in its Offshore Wind Policy Statement, it set a target to achieve 8–11GW of offshore wind in Scottish waters by 2030 (Scottish Government, 2020c). More recently, the Crown Estate

Scotland announced the outcome of the 2022 ScotWind leasing round, with 17 successful applicants being offered option agreements totalling c. 25GW of capacity (Crown Estate Scotland, 2022). Realising this renewable capacity in Scotland will enable the uptake of green hydrogen production.

Increasing the size of green hydrogen production plants will also support the Scottish Government to meet its targets at pace and cost effectively. Larger scale hydrogen production plants can lead to increased economies of scale, particularly related to reduced balance of plant, power electronics, and hydrogen purification costs (IRENA, 2020a). So, Scottish Government's hydrogen production targets are more likely to be achieved through the development of large-scale projects; however, this needs to be supported by a corresponding scale-up in demand.

Government has a role in enabling early market creation by supporting research, innovation, and commercialisation of hydrogen technologies across a wide range of end uses. It can also develop policy to encourage early use cases. Establishing the early market for hydrogen in Scotland will enable production at scale, which could reduce costs, thereby further unlocking new markets. As the next section explains, export of hydrogen and its derivatives could be an avenue for accessing large scale demand.

5.3 Hydrogen production for export

In the Hydrogen Action Plan, Scottish Government established its intention to become a leading producer and exporter of hydrogen and hydrogen derivatives for use in the UK and in Europe with the aim of hydrogen to be delivered to mainland Europe in the mid-2020s (Scottish Government, 2022a). In the longer term, the Scottish Hydrogen Assessment estimates that approximately 3.3Mt (126 TWh) of renewable hydrogen could be produced in Scotland, with 2.5Mt (94 TWh) exported to the UK and European markets annually (Scottish Government, 2020b). Meeting Scotland's hydrogen production targets and establishing it as a key hydrogen exporter will not only contribute to reducing emissions but has the potential to safeguard industry and employment.

6 Green Hydrogen in Europe

6.1 Importance of green hydrogen to a net zero Europe

Developing a hydrogen sector in the European Union (EU) will enable it to achieve sustainability targets while allowing greater energy independence. The EU aims to achieve net zero greenhouse gas (GHG) emissions by 2050 and a minimum GHG emission reduction of 55% by 2030 (EU Commission, 2022a). As noted, hydrogen's suitability as a sustainable energy source across a range of sectors means the EU expects hydrogen to play an important role in achieving these targets. Further, geopolitical events have triggered momentum around the development of the EU hydrogen sector and in May 2022, via its RePowerEU plan, the European Commission declared an ambition for renewable hydrogen uptake to enable it to move away from imported Russian fossil fuels (EU Commission, 2022b). Currently, the EU is on track to produce 1 Mt of renewable hydrogen by 2024 and has set the ambition to produce 10 Mt of renewable hydrogen and import 10 Mt by 2030 (EU Commission, 2022b).

6.2 Role of imports in meeting hydrogen demand

Centres of hydrogen demand in Europe may not be in the same location as regions with favourable characteristics to produce hydrogen. Given this, there is a need to develop hydrogen transport infrastructure within the continent as well as globally to enable hydrogen to be moved from where it is produced to where it is consumed. The European Hydrogen Backbone initiative seeks to develop pan-European hydrogen pipeline infrastructure to connect demand centres such as industrial clusters and ports to areas of hydrogen production (EU Hydrogen Backbone Initative, 2022). In the near term, it seeks to transport half of the 10 Mt hydrogen production target via five large-scale pipeline corridors including corridors in the North Sea, Nordic & Baltic, southwest Europe, southeastern Europe, and North Africa (EU Hydrogen Backbone Initative, 2022). To meet the European Commission's import targets cost effectively, the EU may also seek to import hydrogen produced further afield. Despite the additional transport costs, some imports may remain cost competitive particularly in countries with an abundance of cheap low carbon electricity.

6.3 Key export countries

The global hydrogen market is nascent. While the announcement of new projects for the production of low-emission hydrogen continues to grow, only 5% of these have undertaken firm investment decisions (IEA, 2023a). However, the market is expected to grow as importing countries seek to meet climate objectives and diversify their energy supply. Many governments have already set targets for hydrogen exports or imports to be reached in the coming decades.

The global trade of hydrogen will require new transport infrastructure, coordinated standards and regulations, and demand creation across multiple sectors in import countries. Hydrogen is expected to be transported globally via a range of technologies including pipelines and shipping vessels. The location of the export countries and status of existing transport infrastructure will dictate the most cost-effective option. Importing countries globally will seek to establish common standards and regulations to allow governments to discern between hydrogen of varying emissions intensities. Importing countries will also need to drive early hydrogen adoption across different sectors including difficult to abate sectors such as industry and heavy transport.

We have chosen to compare Scotland's competitiveness in the EU market against Chile, Norway, Morocco, France, and the USA. This is because these countries cover a range of geographies, production methods, have appropriate infrastructure and are in good proximity to major EU hydrogen import terminals. While Chile is further afield, its access to an abundance of natural resources, particularly wind, will enable it to produce green hydrogen at scale. The US's IRA subsidy is expected to accelerate the deployment of green hydrogen in the country enabling the US to become a major producer and exporter of hydrogen.

The export distances to the Port of Rotterdam from each of the case study countries are illustrated in Figure 2.

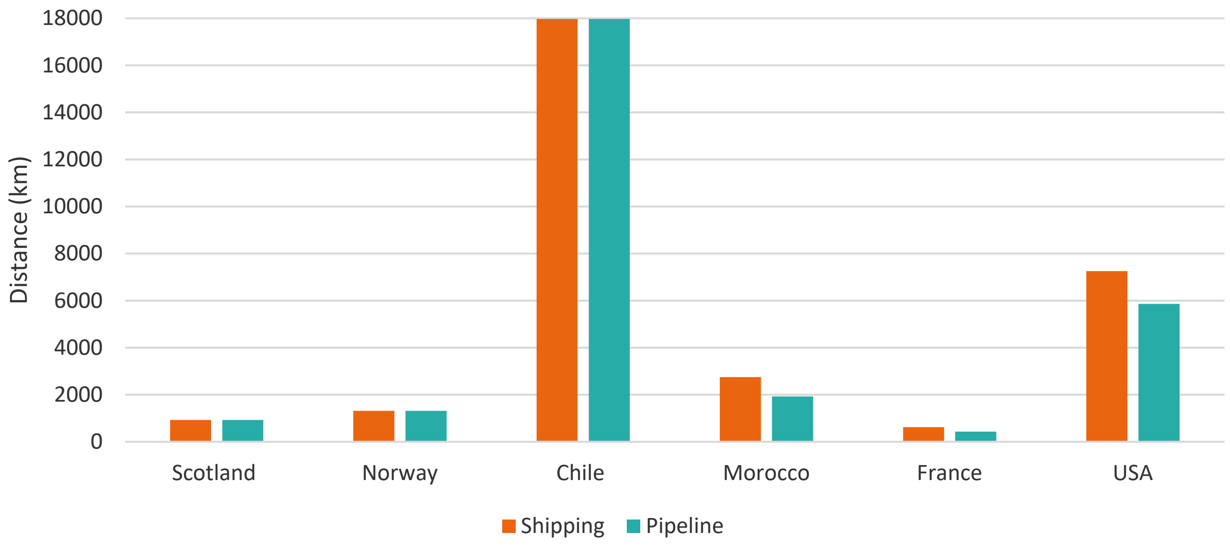

Figure 2 – Export distances to the Port of Rotterdam for each case study country via shipping and pipeline

7 Green hydrogen production and export supply chain

This section reviews cost components that will be key input assumptions for the levelized cost model.

7.1 Production and export supply chain overview

The hydrogen supply chain can be divided into two main stages. Low-carbon electricity generation to produce the feedstock power for the production of hydrogen by electrolysis. Hydrogen can then be exported by pipeline or by ship. For export by ship, the hydrogen may be converted into more easily transportable forms. Methods currently being considered by the industry include ammonia, metal hydrides, liquified hydrogen, liquid organic hydrogen carriers such as toluene and high-pressure gaseous hydrogen.

We have considered three pathways for hydrogen export, as illustrated in Figure 3:

- **Transport pathway 1 – Pipeline:** Gaseous hydrogen can be transported via a pipeline cost effectively particularly at large scale. We have considered a range of pipeline export models including via new or repurposed infrastructure and via a dedicated pipeline sized to a GW scale electrolyser and a shared pipeline sized to accommodate the transport of hydrogen from multiple producers.

- **Transport pathway 2 – Shipping ammonia:** Hydrogen can also be converted to ammonia and transported via dedicated vessels. Ammonia's higher energy density relative to hydrogen makes it particularly cost effective to transport via ship.
- **Transport pathway 3 – Shipping compressed hydrogen:** High pressure gaseous hydrogen can be transported via dedicated vessels. Similarly, compressing hydrogen increases its energy density making it more economical to ship. Shipping pure hydrogen rather than a hydrogen derivative reduces additional costs associated with reconversion.

We have selected pathways to provide a wide and representative range of vectors for hydrogen export. We have not considered the transport of hydrogen in liquid form or as liquid organic hydrogen carriers (LOHC). This is because liquid hydrogen as a transport option is increasingly become less cost-effective relative to alternative options. While LOHC offers a reasonable route to export, it has notable similarities to the ammonia and compressed hydrogen pathways.

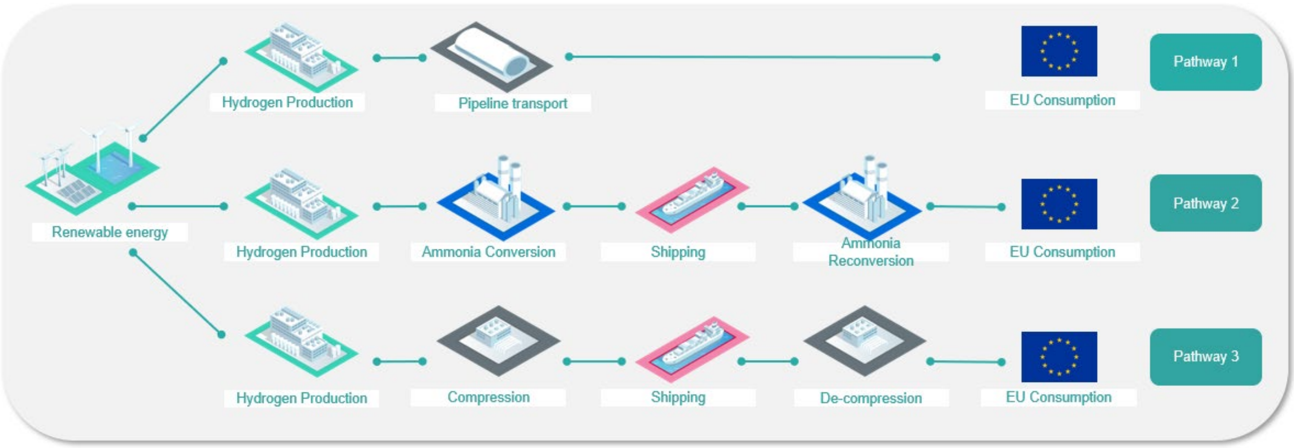

Figure 3 – Schematic of transport pathways considered in this report

7.2 Large scale hydrogen production

7.2.1 Low-carbon electricity

Low-carbon electricity is the key feedstock for hydrogen production. The cost of the electricity and the capacity factor of the low-carbon generator are typically the largest contributors to the cost of hydrogen production. We have considered:

- The cost of electricity represented as the levelized cost of energy (LCOE).
- Capacity factor which is defined as the electricity produced in a period divided by the electricity it could have produced if it had operated 100% output for the period.
- Hourly energy production profile per generator for a given year in each case study country in order to size the generation capacity.

We set out the cost of electricity, capacity factor, and assumed generator size per case study country. We have reviewed a wide range of data to inform these inputs and the data presented below represents an informed average. A summary of the current and future assumed costs of electricity per country is shown in Figure 4.

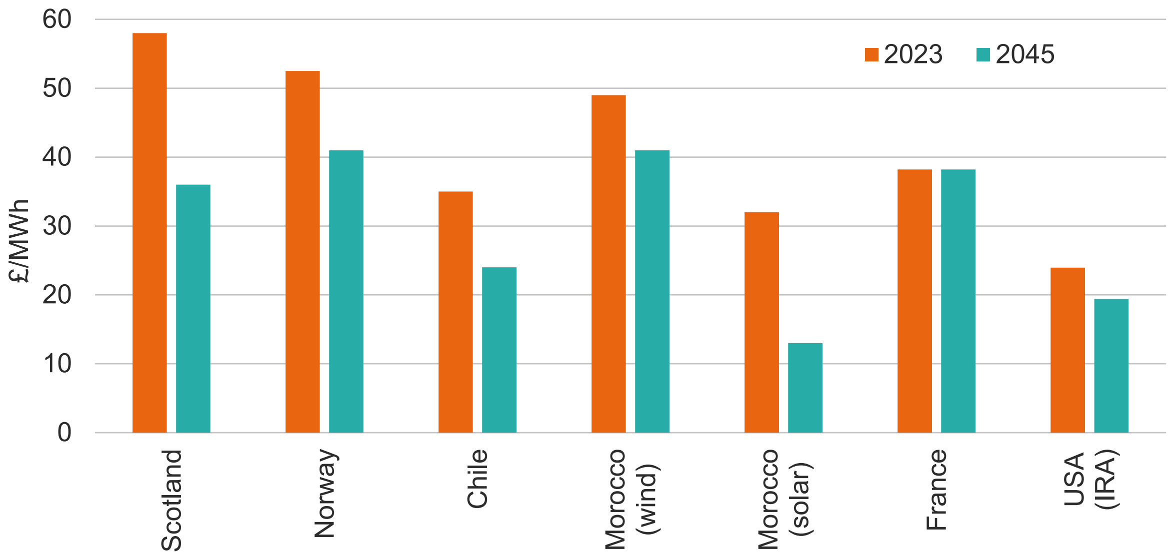

Figure 4 – Electricity price assumptions by country

Offshore wind in Scotland

Scotland has abundant access to offshore wind resources, much of it remote from end users. This is expected to be the dominant power source for large scale hydrogen production in Scotland. We assume the LCOE for Scotland to be £58/MWh currently and £36/MWh in 2045. Similarly, the current capacity factor of offshore wind in Scotland is 55% today and is projected to increase to 61% in future (BloombergNEF, 2023). The size of the low-carbon generator required today will be 1.4GW and reduce in future to 1.3GW to power the electrolyser enabling an electrolyser utilisation of 65% and 67% respectively. The future projections are driven by assumed reductions in capital expenditure (CAPEX) costs due to improved supply chains, reduction in operations and maintenance (O&M) costs due to increased competition of service providers and technological improvements and innovation driven by global learnings (IRENA, 2020b).

Nuclear energy in France

Producers in France may use nuclear energy to generate low-carbon hydrogen. France has one of the largest nuclear power programs in the world, with nuclear power plants accounting for 68% of the country's annual electricity generation (U.S. Energy Information Administration, 2023). This technology can provide a baseload capacity, ensuring a consistent and reliable source of power that allows for efficient and potentially high utilisation of hydrogen producing equipment (electrolysers).

The LCOE for nuclear in France is £37/MWh which we do not project to reduce in future (IEA, 2020). Nuclear power plants in France have a capacity factor of 85% due to the aging nature of the reactor stock resulting in more outages (IEA, 2020). Given the high-capacity factor, the generating capacity will be the same size as the GW scale electrolyser, resulting in a plant utilisation of 85%.

Hydropower in Norway

Norway has an almost entirely renewables-based electricity system, with low-carbon resources accounting for 98% of generation in 2020, of which hydro power was the dominant source at 92% (IEA, 2022a). This means low-carbon hydrogen in Norway can be produced via grid electricity resulting in high electrolyser utilisation.

Grid electricity prices vary in Norway depending on the bidding zone a customer is in. Zones are regularly redefined by Statnett, the System Operator, and currently Norway is divided into five bidding zones (NO1-NO5) (NVE-RME, 2023). Prices are set daily by NordPool to reflect the current level of congestion in the bidding zone. Prices are lower in zones where there is a surplus of power and higher in zones where there is a power deficit. Bidding zone NO4, which is in the north of Norway, has the lowest electricity prices in the country, due to more abundant wind and hydropower output, with a recent price of between €42/MWh and €50/MWh (Nordpool, 2023). Prices in bidding zones surrounding Oslo, the southern coastal hub Kristiansand and Bergen on the west coast have higher electricity prices of between €80/MWh and €86/MWh (Nordpool, 2023). In 2022 grid electricity prices in all zones increased significantly, driven by low reservoir filling levels in southern Norway and power export cables from the UK to Germany. We have assumed an LCOE of £52/MWh which represents an average of the recent wholesale electricity prices in Norway, and project this may decline in future as the external factors which have caused a recent spike are resolved.

Using electricity from the grid allows producers to run at a constant, maximum capacity factor, equalling their availability once annual maintenance has been considered. Given this, we assume the capacity factor to be 98% resulting in a high electrolyser utilisation rate.

Hydrogen producers in Norway will also incur the cost to connect to the electricity grid. This upfront cost will vary depending on the size and location of the connection. We assume a connection cost of £25,000/MW (Arup benchmark, n.d.).

Onshore wind in Chile

The geographical characteristics of Chile, particularly in the southern Magallanes region, enable access to significant amounts of onshore wind power. Producers will use this technology as their key electricity source.

We assume the LCOE for wind in Chile is £35/MWh which will reduce in future to £24/MWh (BloombergNEF, 2019a). We project reductions in cost driven by reductions in turbine prices and balance of plant costs, greater wind farm operational experience and improved preventative maintenance programmes (IRENA, 2020b). Based on electricity production data in the Magallanes region, the capacity factor of onshore wind in the area is particularly high at 59% resulting in an electrolyser utilisation rate of c.67%. Given the existing high-capacity factor of onshore wind technology in Chile, we project this will not increase significantly in the future.

Solar power and onshore wind in Morocco

Combining multiple low-carbon energy resources, such as solar and onshore wind power, can help reduce intermittent electricity production from a single low-carbon technology. Morocco has good natural resources to enable access to significant amounts of both solar and onshore wind.

We assume the current LCOE of solar in Morocco to be £32/MWh which will decline to £13/MWh in future. The current capacity factor of the technology is 28.8% which will increase to 30.6% (IEA, 2021). For onshore wind in Morocco, we assume the current LCOE is £49/MWh which will reduce to £41/MWh in future. Lastly, the capacity factor of onshore wind technology today is 37% and will improve to 45.9% in future (IEA, 2021). We project price reductions and improved capacity factors for both technologies due to global learnings. Significant declines in the LCOE of solar is driven by declines in module prices and plant costs and scaled up manufacturing capability (IEA, 2022b). The complimentary nature of the combination of solar and wind production enables an electrolyser utilisation rate of 65% with solar generating capacity sized at 1.2GW and wind sized at 1.3GW.

Onshore wind in the USA

In the US, the North East region has been selected as the basis for analysis. Although there are a number of projects and regional hubs exploring the potential to export low carbon hydrogen throughout the US, the North East Hub presents significant opportunities for exports to the EU. In November 2022, New York State Energy Research and Development Authority (NYSERDA) submitted a concept paper on behalf of seven states to be considered and compete for funding to develop a hydrogen hub in the area (NYSERDA, 2023). Given the Northeast's relative proximity to the EU and this hydrogen hub initiative, we assume production takes place in this region. The USA has good wind resources enabling it to have access to significant amounts of onshore wind power. However, given the land constraints in the region, we assume hydrogen producers procure onshore wind capacity via sleeved purchase power agreements (PPAs). PPAs are contractual agreements between energy suppliers and consumers which enable consumers to procure electricity from a renewable asset without being directly connected to it. Sleeved PPAs are contractual arrangements for large consumers of electricity, such as hydrogen developers. The most prevalent PPA structure is a 'pay-as-produced' structure, whereby the offtake purchases all or a % of the renewable energy production and there is no volume or delivery obligation (U.S. Department of Energy, n.d.). We assume hydrogen producers procuring onshore wind PPAs will be eligible for the full IRA hydrogen production subsidy.

Wind purchase power agreement prices in the east coast are c. £24/MWh (U.S. Department of Energy, 2022) and while this price has been increasing slightly over the last few years due to supply chain pressures, it is projected to decline in future to £19.40/MWh due to increasing economies of scale, more competitive supply chains and further technological improvements (IRENA, 2019). The current capacity factor of onshore wind is 35% (U.S. Department of Energy, 2022) and will increase to 43.4% driven by improved wind turbine technologies, deployment of higher hub heights and longer blades with larger swept areas

(IRENA, 2019). This enables an assumed electrolyser utilisation of 66.3% with a sleeved PPA agreement with a generator size of 1.3MW.

7.2.2 Electrolysis plant

Low-carbon hydrogen production requires electrolysis to convert low-carbon electricity and water into hydrogen and oxygen. There are currently several electrolyser technologies available. For this study, we have assumed the use of a 1GW alkaline electrolysis (AE) plant given it is currently and comparatively a more mature technology and lower cost. It is also currently the only technology that has been applied in commercial applications at sizes of more than 10MW. In Appendix 10.2 we considered the impact of using a proton exchange membrane (PEM) electrolyser on the levelized cost of production as a sensitivity.

The key considerations for this stage of the supply chain include the capital cost of the electrolysis plant, the indirect capital costs, and key operating parameters including electrolyser utilisation and efficiency of the system.

Capital costs

There is a wide range of capital costs for alkaline electrolysers quoted in literature, driven in part by the wide range of suppliers, locations of manufacture and the scope for the estimation of costs can be unspecified or inconsistent. For the purposes of this study, the overall capital cost used (see Section 8.1) is inclusive of the stack itself (the key component that separates hydrogen from oxygen) and indirect capital costs associated to power electronics, hydrogen purification and balance of plant. The range of alkaline electrolyser capital costs can be between c. £430/kW and £1,110/kW. We assume a CAPEX of £800/kW in 2023 (Oxford Institute for Energy Studies, 2022). This cost reflects the economies of scale of a 1GW plant, assuming manufacture in Europe.

Costs are expected to decline in future with maturing supply chains, increased economies of scale and technology improvements including increased stack lifetime, increased module and stack size, minimization of the use of scarce materials, and increased scale of production of electrolysers. The projected future costs of alkaline electrolysers could be between £150/kW and £600/kW (IEA, 2022c). We assume a conservative cost of £400/kW in 2045.

As noted, increased module and stack sizes can reduce the capital costs as large-scale hydrogen production benefits from economies of scale. The stack cannot be increased significantly due to challenges related to the manufacturing and possible mechanical instability issues of large-scale components (IRENA, 2020a). This means that the costs associated with the stack itself grows linearly as hydrogen production capacity increases. There are, however, opportunities for economies of scale particularly associated to reductions in shared costs such as balance of plant and development costs. Reductions in these shared costs, especially to the balance of plant could in turn have a large effect on cost savings as these costs contribute significantly to the overall CAPEX.

The largest economies of scale are around a 1GW module size after which the marginal cost decrease for increasing the capacity is much lower compared to smaller module sizes

(IRENA, 2020a). This is because, it is anticipated that hydrogen production will be developed in multiple phases creating parallel production trains in a similar way to LNG and therefore accessing limited economies of scale. Figure 5 shows the LCOH reductions from scaling up from a 1MW facility to a 5GW facility in Scotland. To note, currently, the largest electrolyser installed is a 150MW facility in the Chinese region of Ningxia (Recharge, 2022), so reductions in LCOH due to economies of scale for system beyond this size are based on projections.

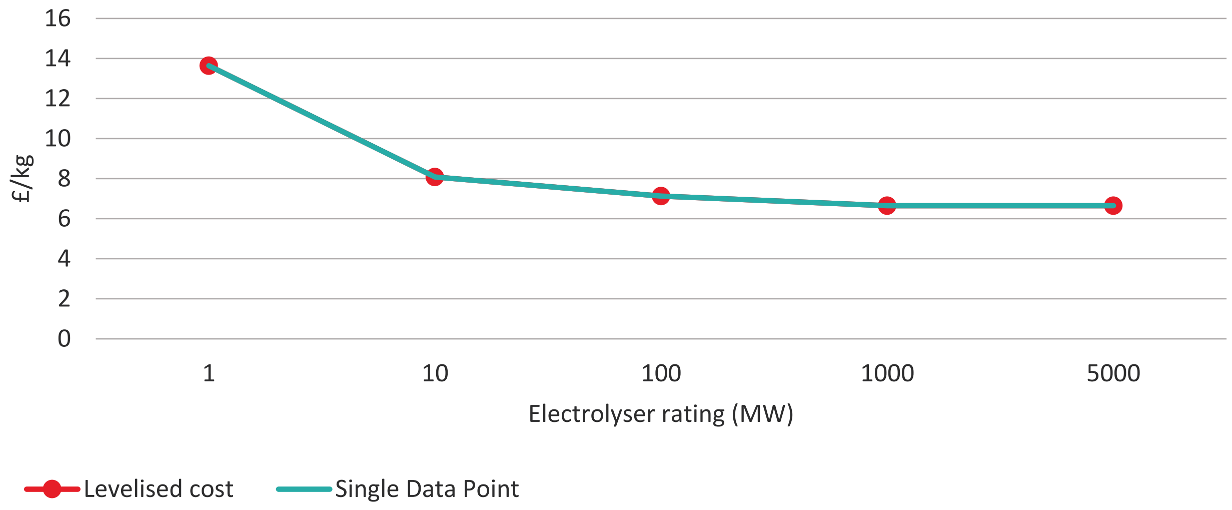

Figure 5 – Effect of economies of scale in electrolyser rating on LCOH

Operating parameters

In addition to capital costs, the operational parameters of the alkaline system can affect the levelized cost of production. The key operational parameters to consider include the efficiency of the asset, the stack life and electrolyser utilisation. These are presumed to improve in future due to technology improvements (Oxford Institute for Energy Studies, 2022).

7.3 Hydrogen transport via pipelines

Hydrogen can be transported in gaseous form via pipeline. Examples of hydrogen transport by pipeline are currently limited, however there are planned projects in multiple countries, including Scotland. We have assumed hydrogen will be transported via offshore subsea pipelines for Scotland, Norway and partly for Morocco. Similarly, most likely onshore pipelines will be used to transport hydrogen from France. Both onshore and offshore pipelines will be used for Morocco as subsea pipelines are required to transport hydrogen from Morocco to Spain. Pipelines from Chile and the USA have been excluded from the analysis due to the distances involved.

A compressor station is required to pressurise the gas, allowing the hydrogen to be transported long distances. Given how capital-intensive building or repurposing a pipeline is, it is typically only a cost-effective option for large scale hydrogen transport. The following sections provide more detail on the costs underpinning the cost of hydrogen transport by pipelines.

7.3.1 Pipeline inlet compression

To ensure hydrogen can be delivered to Rotterdam at an appropriate pressure, it must first be compressed at a large pipeline inlet compressor station.

The major driver of cost for the compressor station are the capital costs. The unit cost per megawatt for a large-scale station can range from £1.9m/MWe to £5.8m/Mwe (EU Hydrogen Backbone Initative, 2022). We assume the price of pipeline inlet compressor station will not change in future as the technology is already commercially mature resulting in limited opportunity for significant cost reductions.

The size of the pipeline inlet compressor station, and therefore the total CAPEX, will vary per case study country as the amount of hydrogen produced and distance it needs to travel will dictate the required size.

7.3.2 Pipelines

The components required for a hydrogen pipeline are essentially the same as for natural gas pipelines which are operated today. The cost estimates of hydrogen pipelines, as set out in European Hydrogen Backbone reports, are determined by gas transmission system operators experience in investing in and operating existing natural gas networks and initial hydrogen infrastructure pilot projects. The range of pipeline cost assumptions are based on assumed pipeline diameter, whether the pipeline is new or repurposed, whether the pipeline is offshore or onshore, and the pipeline utilisation. New, small diameter onshore pipelines (i.e. 20 inch) are cheapest at £1.2m/km to £1.6m/km whereas large diameter offshore pipelines can be c.£5m/km, depending on size (EU Hydrogen Backbone Initative, 2022). Finally, the cost of transporting hydrogen via a shared pipeline can be reduced on a levelised basis as pipeline utilisation is maximised. Shared pipelines are those with larger diameters that maximise utilisation by transporting hydrogen from multiple hydrogen producers. The full list of these cost assumptions can be found in Appendix 10.1.

7.4 Hydrogen transport by ship as ammonia

Figure 6 – Schematic of ammonia transport pathway

The low energy density of hydrogen can make it challenging to transport economically by ship. To overcome this, gaseous hydrogen may be converted to a more energy dense medium such as ammonia.

Today, ammonia is produced and transported globally in large quantities, especially for use as fertiliser. This means there is already a developed global supply chain for ammonia including production plants, storage tanks and transport vessels (although current production methods are carbon-intensive).

7.4.1 Ammonia production

We assume that ammonia will be produced using the Haber-Bosch process, which is the most common method for ammonia production at scale. The process requires: (1) hydrogen with buffer storage to enable a steady supply, (2) an air separator unit (ASU) to produce nitrogen and (3) ammonia synthesis plant where nitrogen reacts with hydrogen to form ammonia in the presence of a catalyst.

The key cost drivers of this process include the CAPEX of the buffer storage, ASU and ammonia synthesis plant.

Pressurised buffer storage CAPEX can vary depending on the storage pressure because lower pressures require larger storage tankers. CAPEX costs can range from £800-£1,300/kg of hydrogen (CSIRO, n.d.). For the purposes of this project, we assume more pressured buffer storage is required in case study countries where electrolysers are powered with intermittent renewables. We project less buffer storage in France and Norway where electrolyser utilisation rates are comparatively higher.

We assume the CAPEX cost of the ASU is c. £50,000/tons per day (tpd) and the cost of the ammonia synthesis plant is c. £285,000/tpd (Arup benchmark, n.d.). We assume the cost of the ASU remains constant in future due to the mature nature of the technology. However, we assume the ammonia synthesis plant CAPEX decreases in the future to £190,000/tpd (Arup benchmark, n.d.)as the existing global network of ammonia production grows to accommodate the future global hydrogen market.

7.4.2 Ammonia transport

Ammonia will be transported from a port at every case study country via a dedicated ammonia vessel. According to IEA, there are currently over 120 ports worldwide which can handle ammonia on a large scale (IEA, 2022c). Nonetheless it is projected that expanding the capacity of port infrastructure will be required to further enable the transport of large amounts of ammonia. Given this, we assume that the ports in all case study countries will require upgrades which involve CAPEX costs associated with new jetties, quay wall development and loading facilities.

Ammonia can be transported via different ship types, depending on how it is stored and today ammonia is typically transported in gas carriers designed for liquefied petroleum (LP). According to IEA, there are currently 200 gas tankers in operation across the world capable of transporting ammonia. They range in size with a carrying capacity of between 30,000 m^3 and 80,000 m^3, with the most recent orders having capacities of up to 87,000 m^3 (IEA, 2023b).

The cost to ship ammonia will be dictated by the CAPEX of the vessel, OPEX, storage and cost of movement. According to BNEF, the total levelized cost of a 10,000 km trip of an ammonia vessel size with a carrying capacity of 23,000 tonnes is £1.37/kg H_2 (BloombergNEF, 2019b) .

Transporting ammonia in liquid form can result in reduction in volume as the temperature difference between the ammonia storage tanker and the ambient air temperature results in boil-off gas. The total daily energetic boil-off gas for ammonia is c.0.1%, which is less than other liquified energy carriers such as LNG, given ammonia has a comparatively higher boiling point (Al-Breiki & Bicer, 2020). This may have a limited effect on case study countries transporting ammonia short distances to Rotterdam, such as France, however the effect is more significant in countries further away, such as for Chile.

7.4.3 Ammonia cracking

Ammonia will be converted back to hydrogen at Rotterdam. We note, in some instances ammonia could be the end use product for, for example, fertiliser production. To decompose ammonia to hydrogen and nitrogen, an ammonia cracker is used. Crackers reverse the ammonia synthesis reaction via an endothermic process resulting in a cracked gas of hydrogen and nitrogen after which purified hydrogen can be obtained. Efficient processes for the recovery of hydrogen from ammonia require further development to be applied in commercial applications.

The key cost drivers of ammonia crackers include the CAPEX of the system and the energy required to recover the hydrogen, represented as a reconversion loss. According to a report by UK Government, the CAPEX of a cracker is £2.37 million/ tpd H_2 and we assume a recovery of 75% (UK Government, 2020). This study assumes that future technology improvements will increase efficiency and drive down energy consumption for ammonia cracking by 2045 (UK Government, 2020) .

7.5 Hydrogen transport by ship as compressed gas

Compressing hydrogen before loading it onto tanker ships analogous to those transporting compressed natural gas has potential to be a cost-effective mode of transport for lower volumes over shorter distances. The case for export via compressed hydrogen vessels from Chile and the USA have been excluded from the analysis due to infeasibility.

Currently, there is no global supply chain for shipping compressed hydrogen. However, smaller scale vessels are currently being developed and the first vessels could be operational as early as 2026 with larger scale vessels operational by 2030 (Provaris, 2022) . Although compressed hydrogen shipping is still nascent, it has been included as a pathway option due to its economic potential over shorter export distances, e.g. Scotland to Europe.

Compressed hydrogen will be transported via specialised vessels. Provaris, an Australian-based technology provider is planning to have vessels with carrying capacity of 26000 m^3 by 2026 and 120,000 m^3 by 2030 (Provaris, 2022). The smaller scale vessel will have a shipping range of up to 2,000 nautical miles and the larger vessel will have a range of up to 3,000 nautical miles making this pathway infeasible for countries further afield such as Chile and the USA.

The cost to ship compressed hydrogen will be dictated by the compression process, CAPEX of the vessel, OPEX, barge storage, port CAPEX and cost of movement. Provaris estimates an indicative levelised cost of transport (LCOT) of £3.75/kg for a single smaller vessel and £0.80/kg for the larger vessel (Provaris, 2022). Given the technology is still being developed there is significant uncertainty on costs.

8 Hydrogen production and transport costs

To determine if Scotland can produce green hydrogen at scale and export it cost competitively to the EU market, we have estimated the levelised cost of hydrogen production (LCOH) and transport to Rotterdam per case study country. We present this analysis for the hydrogen production pathway and three hydrogen transportation pathways:

- Production pathway
- Pathway 1 – Pipeline
- Pathway 2 – Shipping (Ammonia)
- Pathway 3 – Shipping (Compressed hydrogen)

For pathway 1, the LCOT has been evaluated based on the use of both dedicated and shared pipelines and new or repurposed pipelines. We have not presented the LCOT in 2045 for this pathway, as we assume no opportunity for cost reductions in future. For pathways 2 and 3, the LCOT has been evaluated for the years 2023 and 2045 to identify opportunities for cost reductions in future. We have compared the outputs of each pathway for each case study country to determine the most effective model for Scotland to produce and export hydrogen competitively in the EU market.

The key input assumptions for the levelized cost model are based on the cost review in section 7 of this report. All input assumptions and model methodology can be found the Appendix 10.1.

8.1 Large scale hydrogen production

8.1.1 Scotland analysis

Figure 7 shows the calculated LCOH in 2023 and 2045 for Scotland. The cost breakdown for the various production elements is also shown.

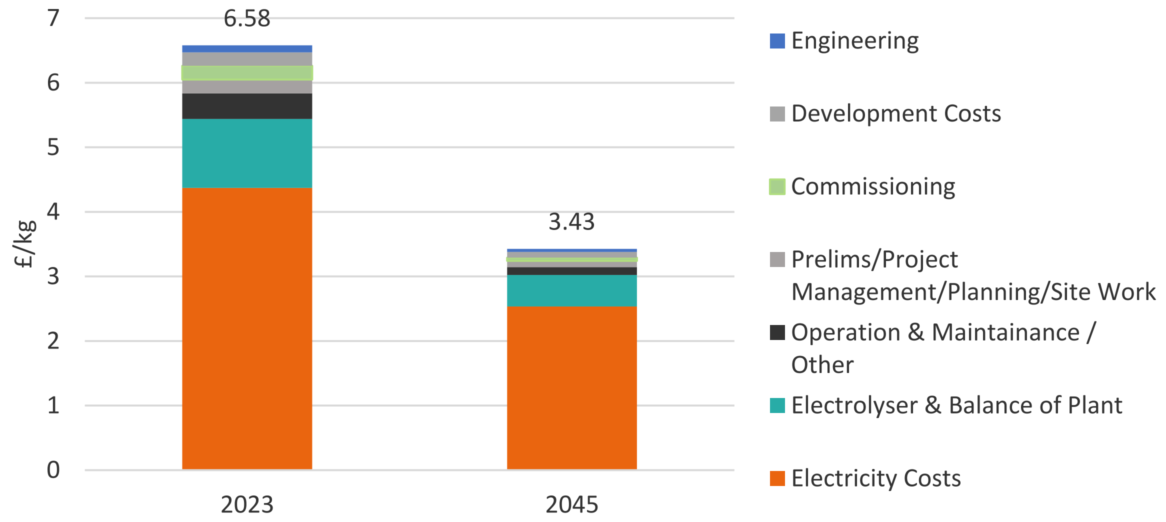

Figure 7 – Calculated LCOH for production of hydrogen in Scotland

The current cost to produce hydrogen in Scotland is estimated to be £6.58/kg H_2. The main drivers of this are the electricity input costs and the electrolyser capital costs, which account for 66% and 17% of the overall LCOH, respectively.

Figure 8 shows that the future cost to produce hydrogen in Scotland is expected to decline by 2045 to £3.43/kg H_2. This is driven by reduced electricity costs due to supply chain competition and scale up and reduced O&M, improved capacity factor of offshore wind generators driven by technological improvements and innovation and reduced electrolyser CAPEX due to maturing supply chains and technology improvements.

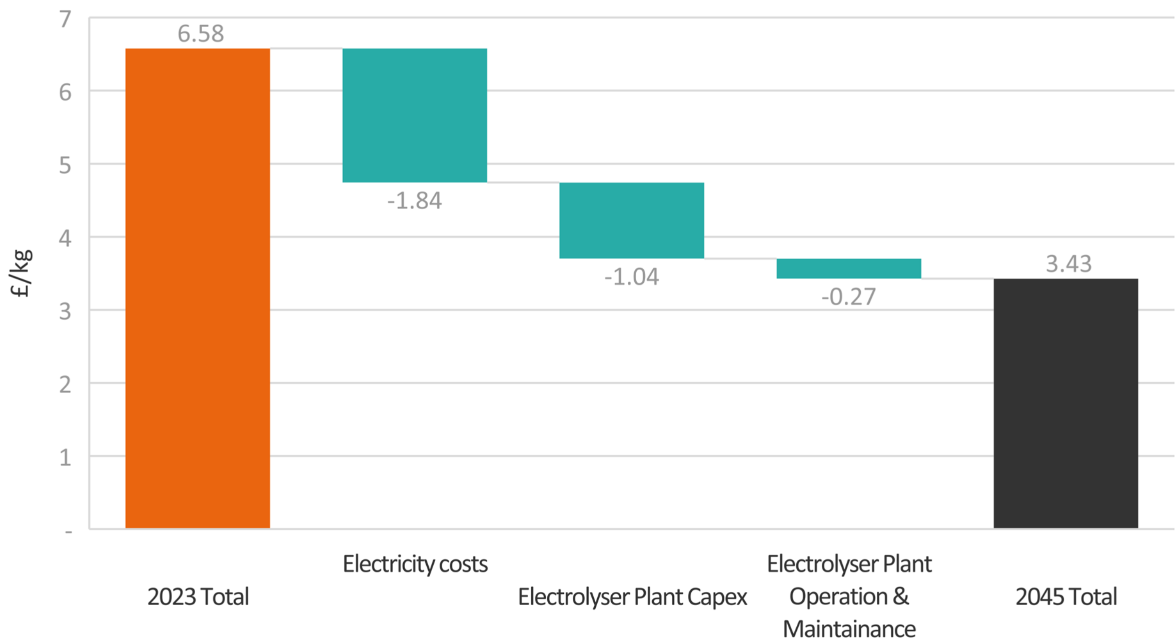

Figure 8 – Future production cost drivers for H_2 2023 to 2045

8.1.2 Cost competitiveness

To understand Scotland's potential as a large-scale exporter of hydrogen, the cost to produce in Scotland has been compared against the other case study countries in Figure 9.

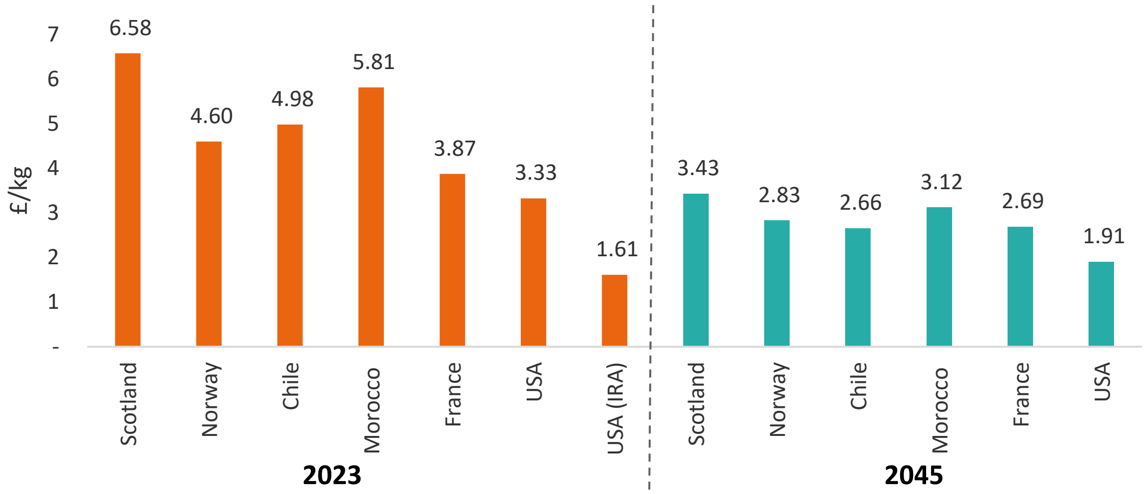

Figure 9 – Calculated LCOH cost comparison

Today and in future, it will be cheaper to produce hydrogen in all case study countries compared to Scotland. This is due to the relatively high cost of offshore wind generated power compared to other technologies. In Norway and France, hydrogen producers benefit from low-cost electricity and high electrolyser utilisation, thanks to the high-capacity factor of grid electricity and nuclear power plants. There may be electricity constraints in France, as nuclear power is used to supply consumers rather than hydrogen producers. This means there could be limited 'spare' nuclear capacity available to supply producers. Building new nuclear plants are expensive and time consuming to construct. In Morocco, the complimentary coupling of onshore wind and solar generation also improves the electrolyser utilisation, but the additional cost of the second electricity sources increases its LCOH. Onshore wind costs in Chile and the USA are significantly lower than current offshore wind costs in Scotland. Electricity prices in the USA are particularly low as the Renewable Energy Production Tax Credit (PTC), a federal incentive that provides financial support for the development of renewable energy facilities, which has enabled and accelerated the onshore wind market. The hydrogen fuel tax credits via the IRA subsidy further reduces the cost of production in the USA.

Looking forward, Norway and France are expected to have limited overall cost reduction potential. Comparatively, we see a more significant cost reduction in Scotland, Chile, Morocco and the USA in future. LCOE and capacity factors for onshore/offshore wind and solar are projected to improve driven by reductions in CAPEX due to improved supply chains, reduction in O&M costs and innovation.

Overall, hydrogen production in Scotland is relatively more expensive compared to the other case study countries in the near and long term. The USA is estimated to be the most cost-effective large scale hydrogen producer with and without the IRA subsidy driven by the very low cost of onshore wind electricity. France and Norway are estimated to be relatively cost-effective large-scale hydrogen producers driven by cost-savings from the non-intermittent nature of their electricity source. However, by 2045, we expect Scotland's hydrogen production cost competitiveness to significantly improve compared to the other case study countries due to efficiency advances and the cost reduction of offshore wind electricity.

8.2 Pathway 1: Pipelines

8.2.1 Pipeline transport pathway overview

Figure 10 – Schematic of pipeline transport pathway

The pipeline transport pathway considers an export model where, following production, the hydrogen is compressed and then transported to Rotterdam via a pipeline.

8.2.2 Scotland analysis

The calculated LCOT for transport via a pipeline from Scotland to Rotterdam is shown in Figure 11.

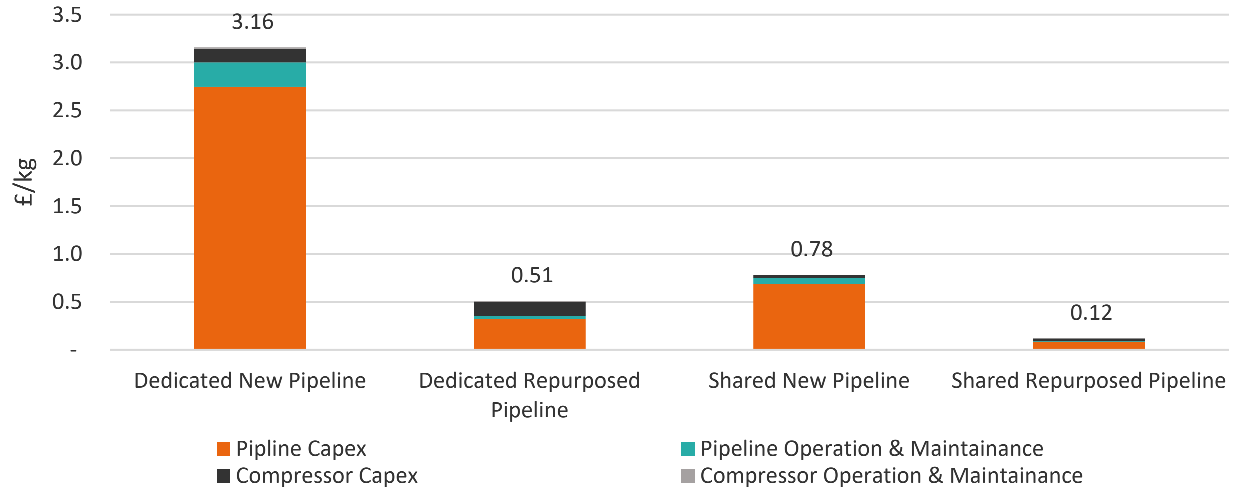

Figure 11 – Calculated LCOT for pipeline (pathway 1)

The cost to transport hydrogen from Scotland to Rotterdam is estimated to be £0.12– £3.16/kg H_2 depending on the pipeline model used. Transporting hydrogen via a new offshore pipeline is more expensive than via a repurposed pipeline because the work associated with repurposing is less extensive than building new infrastructure. Furthermore, transporting hydrogen via a shared large-scale pipeline is less expensive than via a dedicated smaller pipeline, as producers benefit from economies of scale. Figure 12 further illustrates that as the amount of hydrogen transported increases, LCOT declines significantly.

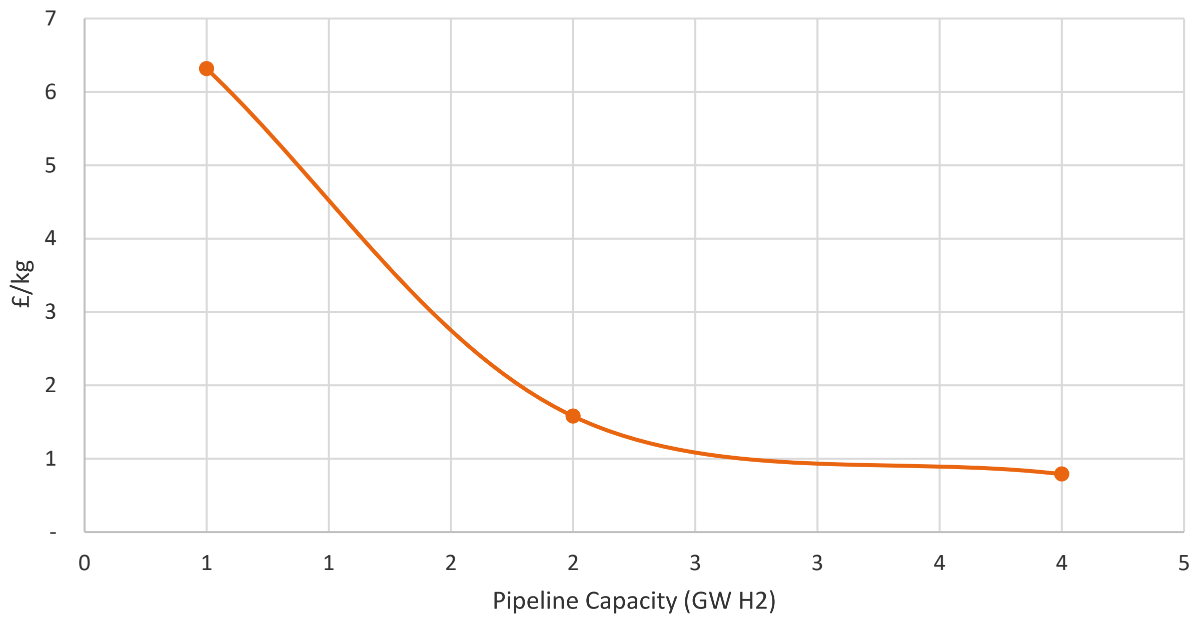

Figure 12 – Pipeline economies of scale

8.2.3 Cost competitiveness

To understand Scotland's potential as a large-scale exporter of hydrogen, the cost to produce and transport via dedicated and shared pipelines from Scotland to Rotterdam has been compared against other case study countries in Figure 13 and 14.

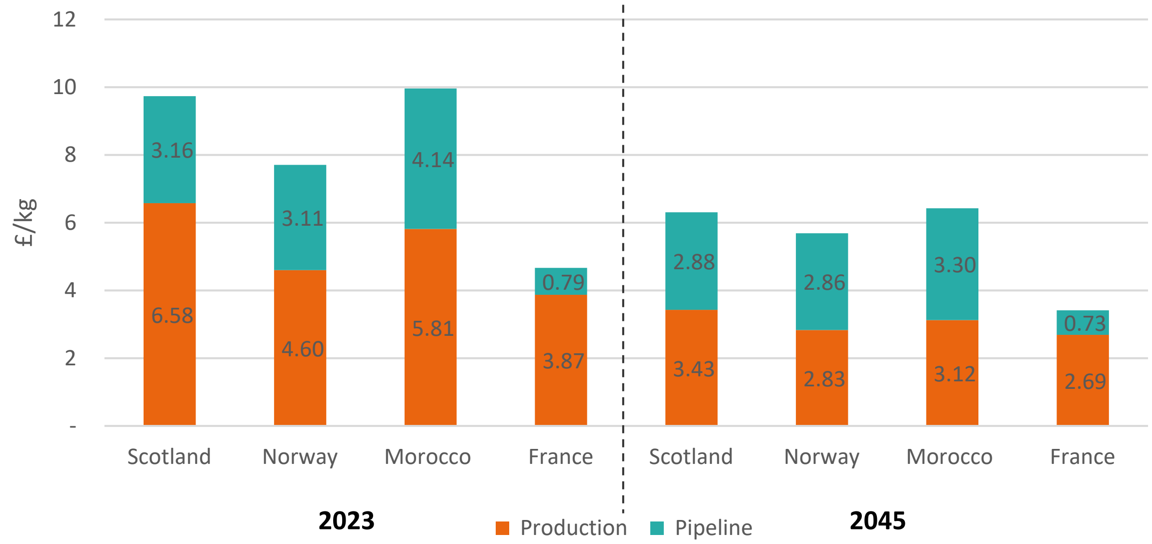

Figure 13 – Pathway 1 calculated LCOH and LCOT cost comparison for a dedicated pipeline

Variation in levelised transport costs across the case study countries are driven by distance and cost of pipeline material. Transporting hydrogen from France is cheapest given its proximity to Rotterdam and ability to use onshore pipelines which are less expensive than offshore pipelines. The cost to transport from Morocco is more expensive than the other case study countries given its further distance from Rotterdam and requirement for some offshore pipelines to transport to Spain. Norway is able to transport hydrogen more cost effectively than Scotland, despite the further distance from Rotterdam and same assumption that offshore pipelines are used. This is driven by the ability to transport a larger volume of hydrogen (based on a 1GW electrolyser) from Norway as producers benefit from higher electrolyser utilisation.

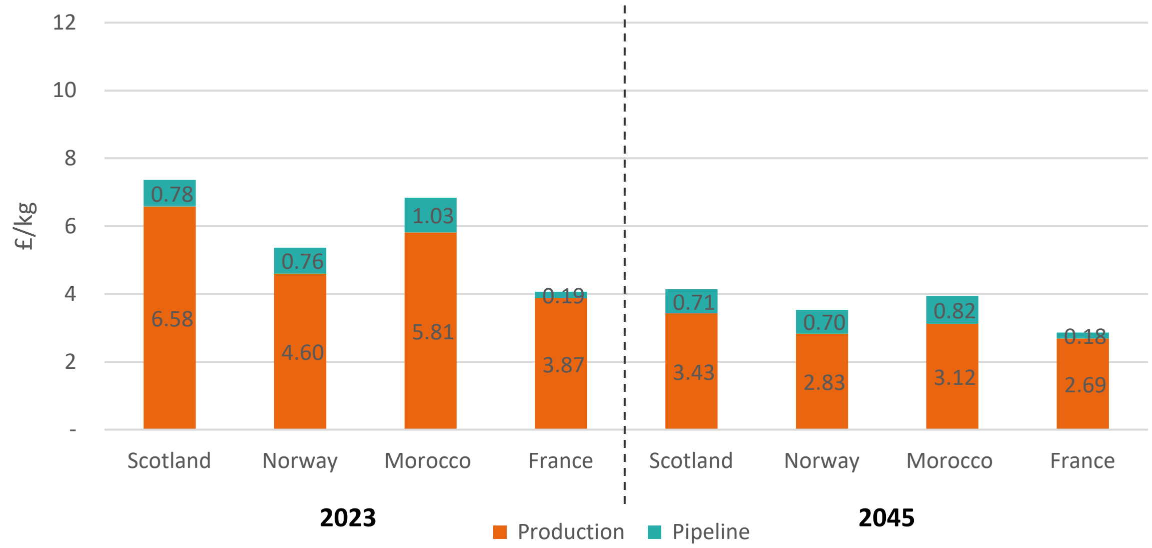

Figure 14 – Pathway 1 calculated LCOH and LCOT cost comparison for a shared pipeline

Our analysis shows that Scotland can transport hydrogen via pipeline cost competitively compared to the other case study countries. We have excluded Chile and the USA from this comparison as the distance to Rotterdam makes this transport option unfeasible. It is most economical for producers to transport hydrogen via large scale shared pipelines rather than smaller scale dedicated pipelines due to economies of scale. This indicates that a consolidated export strategy for Scotland to Europe could ensure that Scotland is able to remain cost competitive with competing countries. While France can export at a lower cost due to the use of onshore pipeline, routing and right of way could be challenging if dedicated pipeline corridors are not currently available.

8.3 Pathway 2: Ammonia Shipping

8.3.1 Ammonia shipping overview

Figure 15 – Schematic of ammonia shipping transport pathway

The ammonia shipping pathway reflects the supply chain for hydrogen exports in the form of ammonia. Pathway 2 considers the implications of converting hydrogen into ammonia, transporting it via ammonia carrier vessels and recovering hydrogen at Rotterdam.

8.3.2 Scotland analysis

Figure 16 shows the LCOT ranges for ammonia shipping in 2023 and 2045.

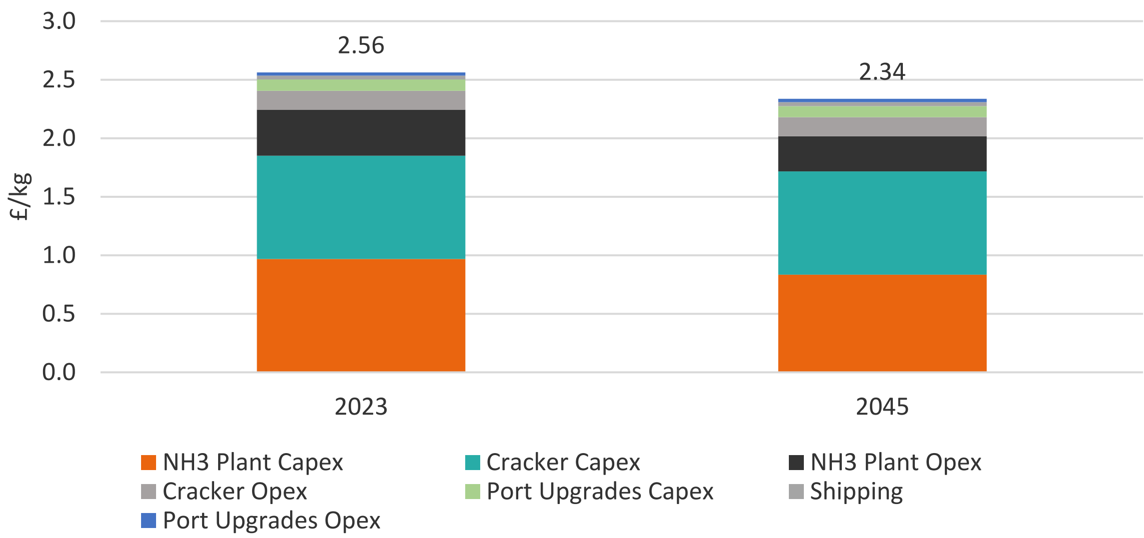

Figure 16 – Calculated LCOH for ammonia shipping (pathway 2)

The costs to transport hydrogen via ammonia shipping from Scotland to Rotterdam is estimated to be £2.56/kg. The main drivers of the LCOT are the CAPEX-related costs of ammonia production, namely, the CAPEX costs of the ammonia plant, and the ammonia cracker which account for 38% and 34%, respectively of total LCOT in 2023.

The future cost to transport hydrogen via ammonia shipping from Scotland to Rotterdam is expected to decrease to £2.34/kg by 2045. This is due to assumed reduction in ammonia production capital costs and reduced reconversion losses from the ammonia cracker. This is driven by maturing supply chains and technological innovation as ammonia is increasingly used as a hydrogen derivative for transport.

As noted, a key cost driver to the LCOT for this pathway is the ammonia cracker CAPEX and OPEX. Excluding the ammonia cracker from the supply chain reduces the LCOT by c.41% (Figure 17). This suggests ammonia shipping becomes a more attractive transportation option where ammonia is being used as the end product, as opposed to re-converting to hydrogen.

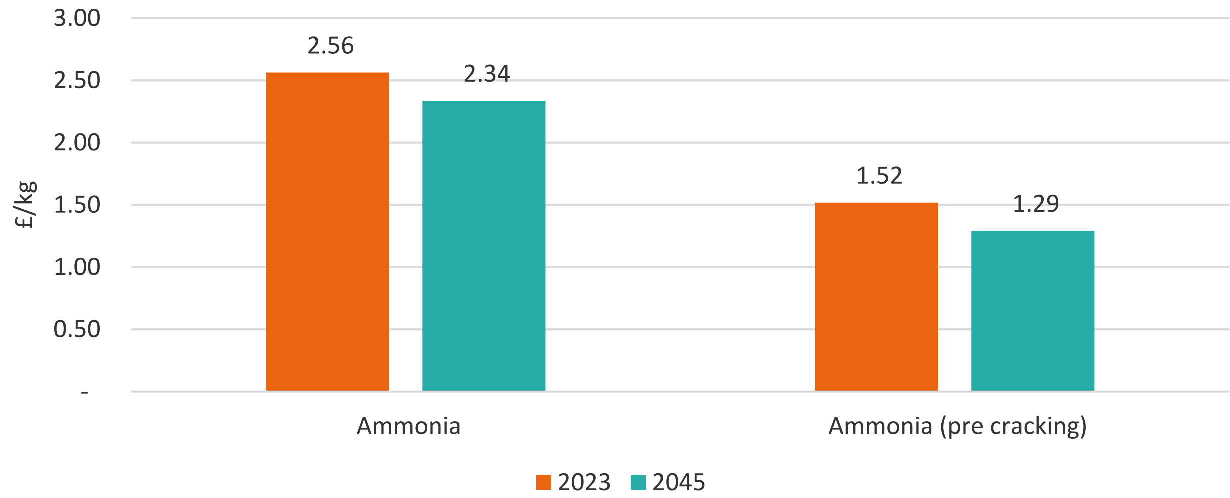

Figure 17 – Pathway 2 pre-cracking cost comparison

8.3.3 Cost competitiveness

Figure 18 shows the LCOT of the ammonia shipping pathway for the case study countries, in 2023 and 2045.

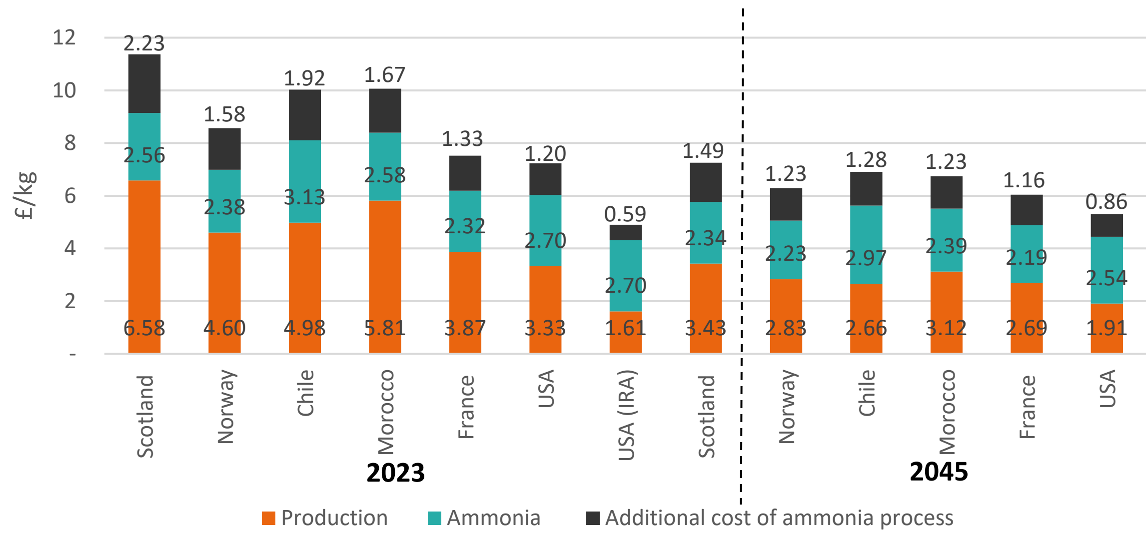

Figure 18 – Pathway 2 LCOH production and transport cost comparison

The levelised cost to ship ammonia to Rotterdam today and in future are relatively aligned across the case study countries, with the cost to transport being slightly higher for Chile, Morocco and the USA. This is due to the longer distance the ammonia has to travel resulting in a higher cost of movement and increased effects of boil-off gas. As shown in Figure 18, hydrogen production costs contribute significantly to the total cost of export, both today and in future. This is why hydrogen producers in the USA, particularly those which benefit from the IRA subsidy, can export to the EU market via this pathway most competitively. Given this, Scotland should seek to reduce production costs to be able to transport via ammonia vessels competitively to the EU market.

Overall, the analysis shows that Scotland can transport hydrogen via ammonia shipping competitively compared to the other case study countries. Given how costly recovering hydrogen from ammonia is, this export model is most cost effective where ammonia is the end product.

8.4 Pathway 3: Shipping as compressed hydrogen

8.4.1 Shipping compressed hydrogen overview

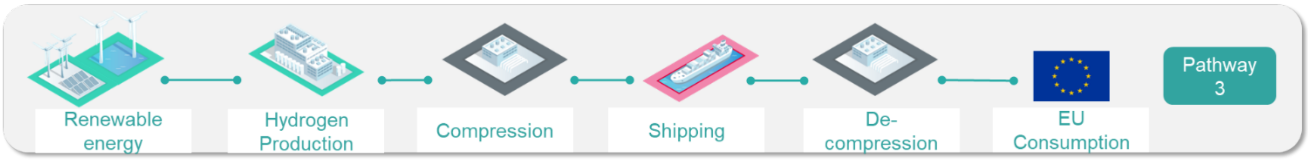

Figure 19 – Schematic of compressed hydrogen shipping transport pathway

The compressed hydrogen shipping pathway reflects the supply chain for hydrogen exports in its compressed form. Pathway 3 considers the implications of compressing the produced hydrogen and transporting it via compressed hydrogen carrier vessels.

8.4.2 Scotland analysis

Figure 20 shows LCOH estimates for shipping compressed hydrogen from Scotland to Rotterdam.

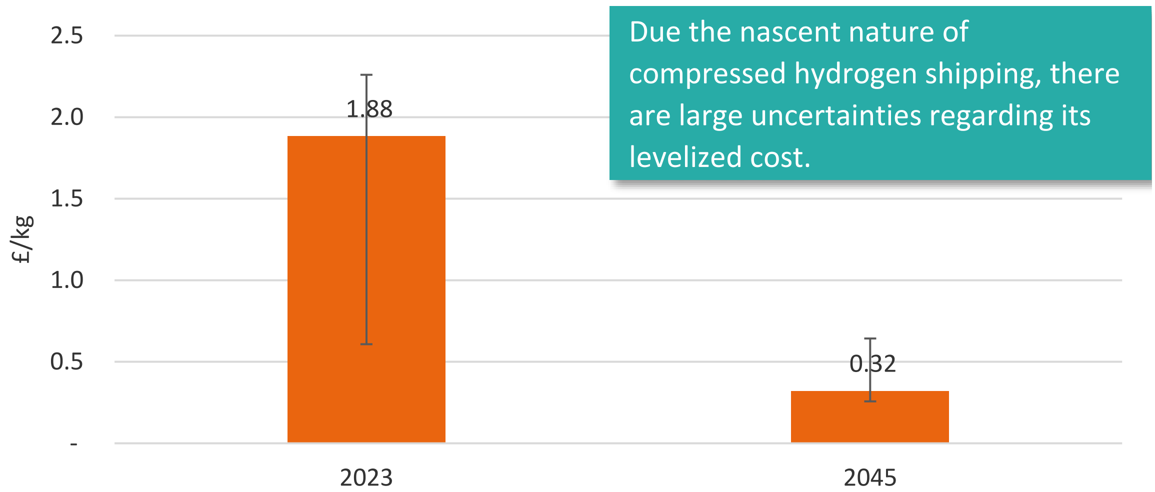

Figure 20 – Calculated LCOH for compressed hydrogen shipping (pathway 3)

The costs to transport hydrogen via compressed shipping from Scotland to Rotterdam is estimated to be £1.88/kg and is expected to decrease to £0.32/kg by 2045. As compressed hydrogen shipping is in early-stage development, vessel sizes are relatively small at 26000m^3. As a result, transportation costs are higher due to a larger number of trips required to transport GW scale hydrogen production. In future, as vessel sizes increase, transportation costs are projected to decline hence the reduction in LCOT by 2045.

Due to the constraint on shipping size, the feasibility of transporting via compressed hydrogen at the 1GW scale may need to be reviewed further. We also note, given the infancy of the technology, the costs are very uncertain.

8.4.3 Cost competitiveness

To understand Scotland's potential as a large-scale exporter of hydrogen via compressed hydrogen vessels, the cost to transport from Scotland to Rotterdam has been compared against the other case study countries in Figure 21.

The analysis shows that countries in proximity to Rotterdam have an export advantage due to reduced transportation costs. Scotland, Norway, and France have significantly lower unit costs than Morocco, given the shorter shipping distances.

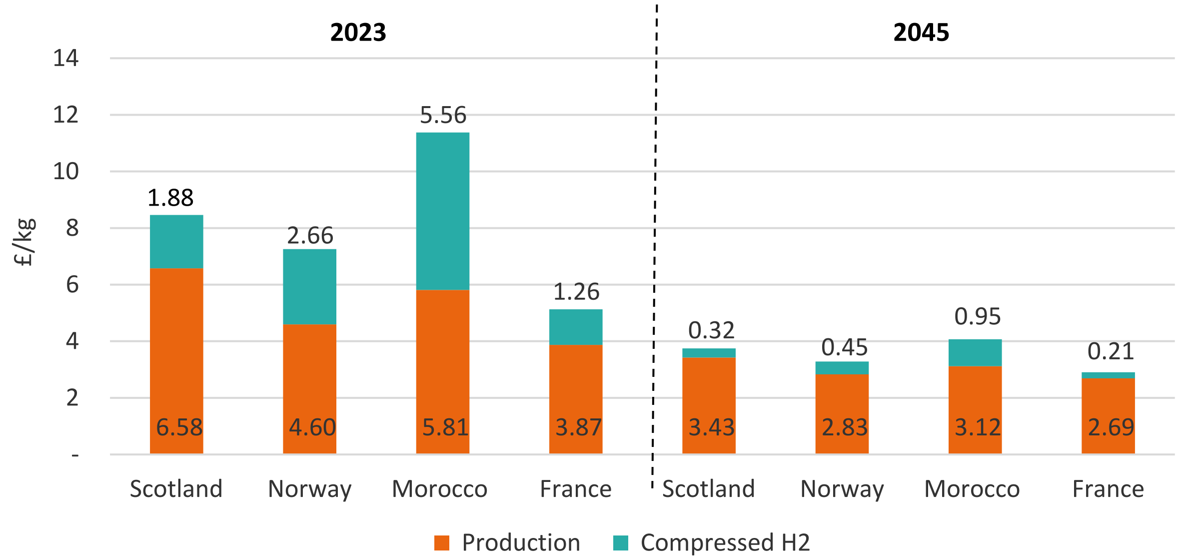

Figure 21 – Pathway 3 LCOH production and transport cost comparison

Countries with significant transport distances (Chile and Morocco) have disadvantages given that the small shipment loads of the compressed hydrogen vessels, which means that a high number of ships are required, subsequently increasing the costs. The high number of ships could also pose logistical problems that would need to be considered. Currently, it is cheaper for France to transport hydrogen via either dedicated or shared pipelines, however in future, it could be more cost efficient for France to export hydrogen via compressed vessels compared to pipeline transport.

Overall, the analysis shows that Scotland can transport hydrogen via compressed hydrogen shipping competitively compared to the other case study countries. Given the early stage of the technology, the feasibility of transporting GW-scale hydrogen production via compressed vessel must be explored further. Additionally, as the technology is not yet operational, projected costs are still uncertain.

8.5 Pathway comparison

Figure 22 presents the outputs of the Scotland base case levelized cost for each of the pathways that have been reviewed.

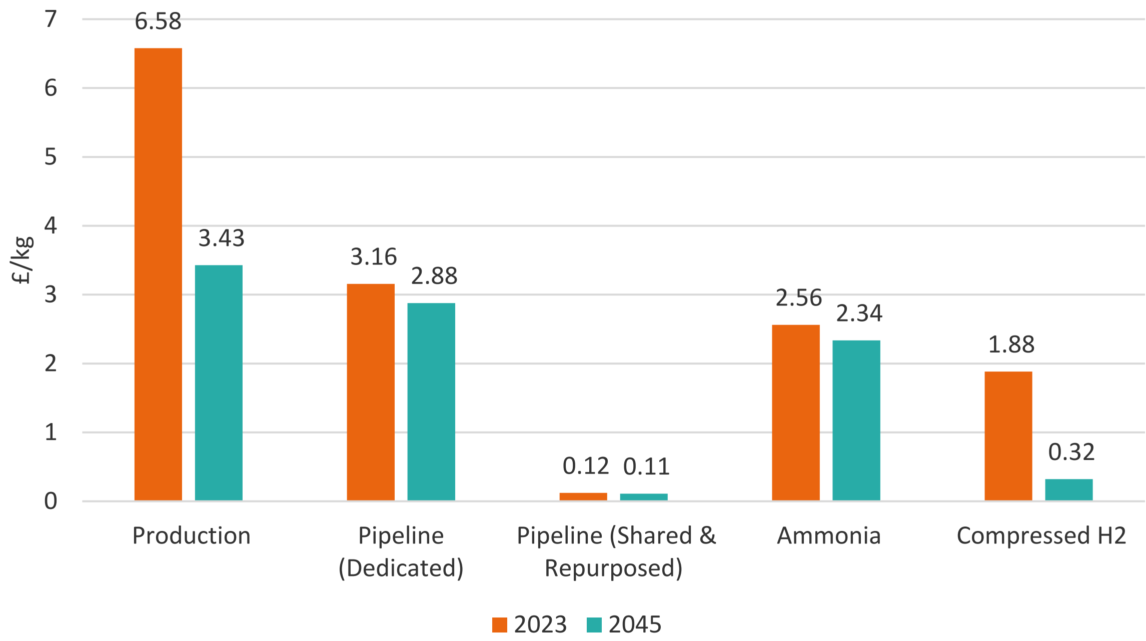

Figure 22 – Calculated LCOH and LCOT Scotland pathway comparison

The levelized cost analysis has shown that future cost reductions are expected across the pathways. It also illustrates that Scotland's largest blocker to cost effective hydrogen exports is the current cost of production. Support from the Scottish and UK Governments in the form of subsidies and grants could help improve this.

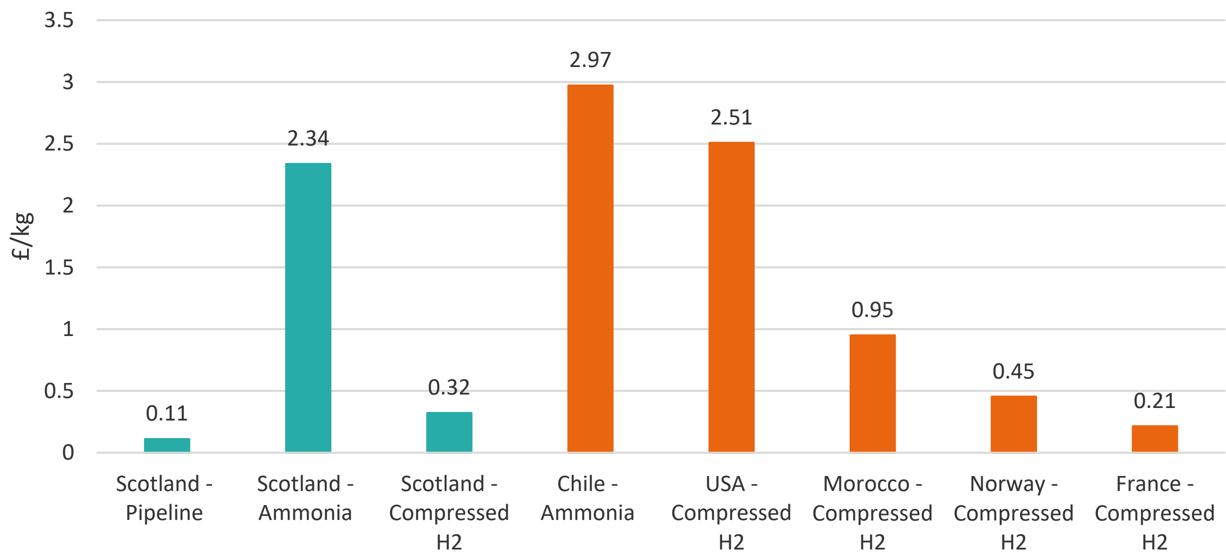

Figure 23 – Most cost-effective transport pathway in 2023

Exporting large scale hydrogen production via shared pipelines is a cost-effective option due to economies of scale. For longer distance, converting hydrogen to ammonia and shipping via dedicated vessels is economical. Given how costly recovering hydrogen from ammonia is, this export model is most cost effective where ammonia is the end product. Shipping compressed hydrogen could be most competitive, particularly for smaller scale production and via shorter distances, however the technology still needs to be developed and proved Figure 23).

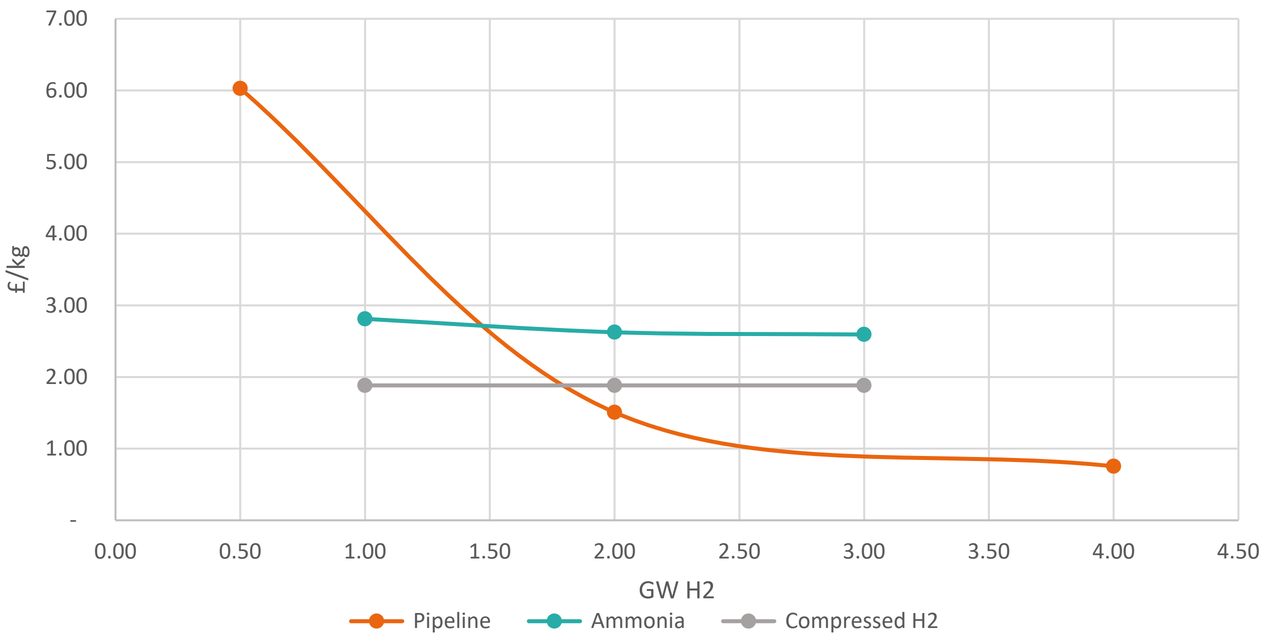

Figure 24 – Calculated LCOH pathway comparison by production scale

The cost of exporting via a pipeline is the only pathway that becomes more cost effective as production scales up (see Figure 24). Significant gains are expected up to 2GW after which cost reductions diminish. Both shipping pathways have a positive relationship between cost and scale. Large scale efficiencies tend to be limited for shipping as increased production requires a higher number of ships or frequent trips which affects costs.

The cost to ship ammonia is not influenced significantly by distance to the European market which makes this a cost-effective option for exporting countries further afield, such as Chile (see Figure 25). In contrast, there is a direct relationship between the cost to ship compressed hydrogen and distance making this export model most economical for shorter distances.

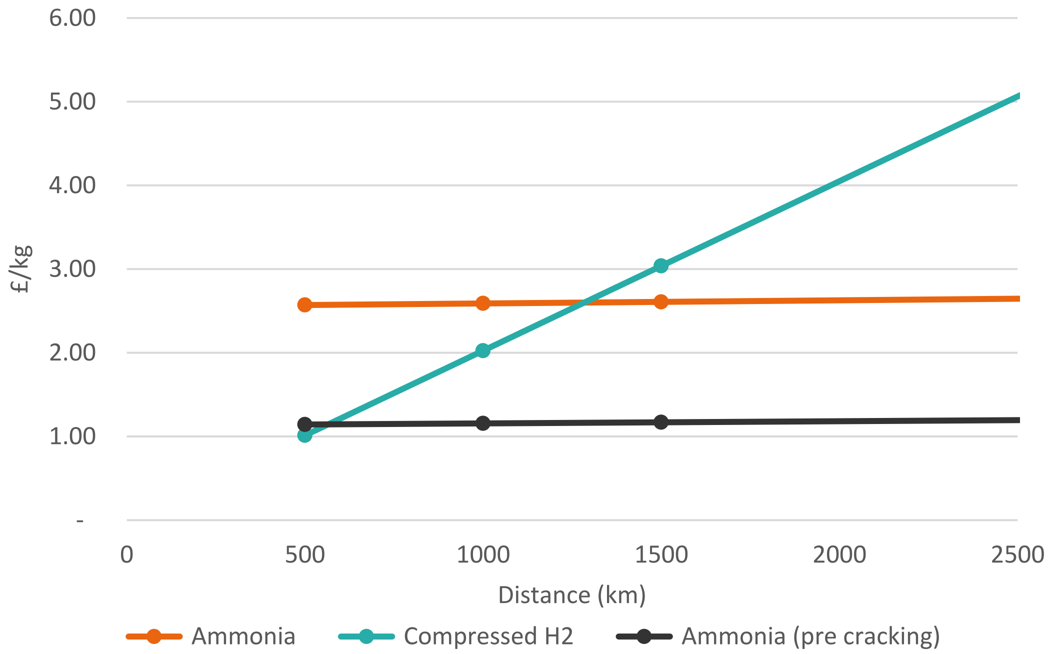

Figure 25 – Calculated LCOH ammonia and compressed hydrogen comparison by distance

9 Conclusions and recommendations

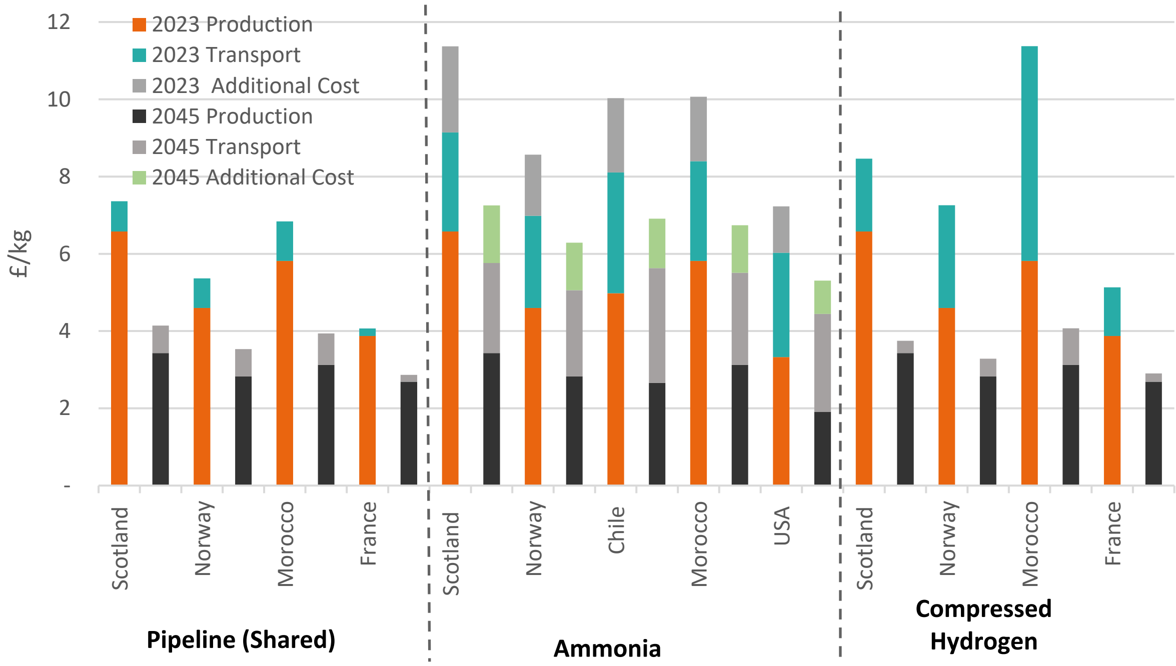

Figure 26 – Levelised cost of hydrogen production and transport (£/kg)

It is more costly to produce hydrogen in Scotland than in all other case study countries. This is because the cost of offshore wind generated power in Scotland is higher than the other low-carbon power technologies used. In other case study countries, such as France, which can produce hydrogen at a significantly lower cost, there could be low-carbon power constraints without additional investment in nuclear technology. In contrast, the Scottish Government has set ambition to invest in and scale up its onshore and offshore wind power to enable the growth of its green hydrogen sector.

Transporting hydrogen via pipeline is the most cost-effective option for shorter distances, large scale production and where the pipeline used is repurposed. Scotland should, therefore, evaluate the opportunity to repurpose existing pipeline infrastructure to improve its competitiveness in the EU hydrogen market. It should also develop a co-ordinated export strategy, bringing together multiple hydrogen producers to maximise utilisation of shared pipelines.

Exporting hydrogen via ammonia is a feasible option for countries further afield such as the USA and Chile. Additional costs associated with ammonia production and cracking back to hydrogen are significant. However, as distance from the EU increases, the costs associated with ammonia shipping movement do not increase significantly. As a result, this allows countries further away from the EU to participate in the hydrogen market. Given the additional costs associated to recovering hydrogen from ammonia, this export method becomes particularly cost effective where ammonia is the end product.

Transporting compressed hydrogen via vessels could be a promising export method for shorter distances and smaller scale production, driven by viable shipping range and size of

the vessels. However, as the technology is not yet operational, the cost effectiveness and feasibility of this transport method will need to be further evidenced.

Scotland's proximity to Rotterdam gives it a competitive advantage compared to countries further afield. This is because its proximity to the EU market enables it to export hydrogen via multiple transport pathways. In comparison, countries that are further away cannot export via pipeline or compressed shipping due to technical and cost feasibility issues. Secondly, Scotland's proximity to the EU also allows it to export hydrogen via pipeline, which, today is the lowest cost export option.

To outcompete countries such as France and Norway, Scotland must reduce its production costs. However, even if the cost of production remains higher for Scotland relative to other European countries, Scotland will likely still be a market player, as France and Norway alone cannot meet EU hydrogen import targets.

Considering the evolving state of the hydrogen industry, it's important to note that cost estimates for different aspects of production and transportation carry uncertainty. This variation introduces some level of uncertainty when assessing the competitiveness of hydrogen production and transportation in the EU market.

Government support could close the cost gap and enable Scotland to become a major competitor in the EU market. To do this, it should continue to support the scale up of offshore wind and hydrogen production to access economies of scale and enable the generation of surplus low carbon power for export. Scale up should target a reduction in low carbon electricity costs as well as electrolyser CAPEX. Secondly, it could provide subsidies to the sector. To enable Scotland to be competitive in the EU market today, a subsidy range of £60m to £500m per year (depending on the export method chosen) could be required. There is a particular need for UK government and Scottish government support for Scottish hydrogen producers to be able to out compete producers who benefit from USA IRA subsidy support and EU based support.

10 Appendices

10.1 Levelised cost model methodology and assumptions

The levelised cost model considers the cost of hydrogen production and transport in years 2023 and 2045. It considers the total costs (capital, operating, replacement CAPEX) of production and transport over the project life and divides it by the total volume of hydrogen produced and transported. Both the costs and volume of hydrogen produced and transported is discounted at a rate of 10% using the following formula:

$LCOH$ (£ kg) = $Sum\ of\ costs\ over\ lifetime$ (£) × $discount\ rate$ (%) / $Sum\ of\ hydrogen\ produced$ and transported $over\ lifetime$ (kg) × $disount\ rate$ (%)

The sum of costs over the lifetime are based on the constant input assumptions outlined in Table 2. These input assumptions remain constant across all pathways. In addition to the constant input assumptions, there are input assumptions that vary between pathways and countries, such as the size of a pipeline inlet compressor, the supply chain requirements, etc. These supplement the constant input assumptions in order to determine the volume of costs for each part of the supply chain. The total discounted costs of production are then summed over the project life and divided by the total discounted volume of hydrogen produced.

The input assumptions are based on the literature review for each part of the supply chain (Section 7 of the report). We have used the trends that have been developed to identify the likely cost range for 2045. Table 2 highlights which sources have been used for which part of the supply chain per pathway.

The building blocks of the model are broken down into electricity generation, electrolyser (hydrogen production), compression, ammonia production (if applicable), transport, reconversion/ recompression (if applicable). For each part of the supply chain the inputs are used to determine an annual cost split between these categories:

1. Capital costs of infrastructure
2. Replacement costs of infrastructure
3. Annual variable costs

Annual fixed costs	Unit	Current	Future	Sources	Confidence rating
Scotland – Offshore wind					
Offshore wind plant size	GW	1.40	1.30	Arup energy balancing tool based on Global Atlas Data	3
Capacity factor	%	55%	61%	(BloombergNEF, 2023)	3
LCOE	£/MWh	58	36	(BloombergNEF, 2023)	3
Morocco – Solar PV and onshore wind					
Solar PV plant size	GW	1.20	1.20	Arup energy balancing tool based on Global Atlas Data	3
Capacity factor (solar)	%	28.8%	30.6%	(IEA, 2021)	3
LCOE (solar)	£/MWh	32	13	(IEA, 2021)	3
Onshore wind plant size	GW	1.30	1.30	Arup energy balancing tool based on Global Atlas Data	3
Capacity factor (wind)	%	37%	45.9%	(IEA, 2021)	3
LCOE (wind)	£/MWh	49	41	(IEA, 2021)	3
Norway - Hydropower					
Capacity factor	%	98%	98%	(Department for Business, Energy & Industrial Strategy, 2021)	3
LCOE (wholesale)	£/MWh	52.50	41	(Nordpool, 2023)	3
France – Nuclear					
Nuclear power plant size	GW	1	1	Arup energy balancing tool based on Global Atlas Data	3
Capacity factor	%	85%	85%	(IEA, 2021)	3
LCOE	£/MWh	38.2	38.2	(IEA, 2021)	3
Chile – Onshore wind					
Onshore wind plant size	GW	1.40	1.40	Arup energy balancing tool based on Global Atlas Data	3
Capacity factor	%	59%	59%	(IEA, 2021)	3
LCOE	£/MWh	35	24	(IEA, 2021)	3
USA – Onshore wind					
Onshore wind plant size	GW	1.3	1.3	Arup energy balancing tool based on Global Atlas Data	3

Annual fixed costs	Unit	Current	Future	Sources	Confidence rating
Capacity factor	%	35%	43.4%	(U.S. Department of Energy, 2022), (IRENA, 2019)	3
Onshore wind PPA	£/MWh	24	19.40	(U.S. Department of Energy, 2022), (IRENA, 2019)	3
Alkaline Electrolyser					
Efficiency	kWh/kg	56.55	52	(Department for Business, Energy & Industrial Strategy, 2021), (IRENA, 2021)	2
Output pressure	bar	1	1	(Oxford Institute for Energy Studies, 2022)	2
Stack life	hours	80,000	100,000	(Oxford Institute for Energy Studies, 2022)	2
Water consumption	kg H20/ kg H_2	12	9	WaterSMART solutions	2
Capex unit cost	£/kW	800	400	(Oxford Institute for Energy Studies, 2022), (IEA, 2022c), Arup confidential quotes	2
Fixed OPEX cost	% of CAPEX	4.5%	2.5%	Arup benchmark	2
Stack replacement CAPEX	% of CAPEX	20%	15%	Arup benchmark	2
PEM Electrolyser					
Efficiency	kWh/kg	56.27	56.27	(IRENA, 2021) and Arup benchmark	2
Output pressure	bar	30	30	(IRENA, 2021)	2
Stack life	hours	80,000	110,000	(IRENA, 2021)	2
Water consumption	kg H20/ kg H_2	25	19	Arup benchmark	2
CAPEX unit cost	£/kW	1,159	562	Arup benchmark	2
Fixed OPEX cost	£/kW	4.5%	2.5%	Arup benchmark	2
Stack replacement CAPEX	% of CAPEX	33%	20%	Arup benchmark	2

Transea compressor					
Capex unit cost	£/MWe	3	3	(EU Hydrogen Backbone Initative, 2022)	3
Fixed OPEX	% of CAPEX	1.25%	1.25%	(EU Hydrogen Backbone Initative, 2022)	3
Scotland – compressor rating (dedicated pipeline)	MWe	36	36	Arup internal software.	3
Morocco – compressor rating (dedicated pipeline)	MWe	40	40	Arup internal software.	3
Norway – compressor rating (dedicated pipeline)	MWe	60	60	Arup internal software.	3
France – compressor rating (dedicated pipeline)	MWe	45	45	Arup internal software.	3
Scotland – compressor rating (shared pipeline)	MWe	30	30	Arup internal software.	3
Morocco – compressor rating (shared pipeline)	MWe	31	31	Arup internal software.	3
Norway – compressor rating (shared pipeline)	MWe	44	44	Arup internal software.	3
France – compressor rating (shared pipeline)	MWe	39	39	Arup internal software.	3

New Onshore Pipeline					
Capex unit cost	£m/km	1.3	1.3	(EU Hydrogen Backbone Initative, 2022)	3
Fixed OPEX	% of CAPEX	1.25%	1.25%	Arup benchmark	3
New Offshore Pipeline					
Capex unit cost	£m/km	2.21	2.21	(EU Hydrogen Backbone Initative, 2022)	3
Fixed OPEX	% of CAPEX	1.25%	1.25%	Arup benchmark	3
Repurposed Onshore and Offshore Pipeline					
Capex unit cost	£m/km	0.26	0.26	(EU Hydrogen Backbone Initative, 2022)	3
Fixed OPEX	% of CAPEX	0.5%	0.5%	Arup benchmark	3
Ammonia production plant					
Energy consumption	kWh/ kg H_2	1.1	1.0	(IRENA, 2022)	3
Capex unit cost	£/tpd NH3	238,500	190,000	Arup confidential quotes	3
Replacement CAPEX	% of CAPEX	15%	15%	Arup confidential quotes	3
Fixed OPEX	% of CAPEX	4%	4%	Arup confidential quotes	3
Air Separator Unit					
Capex unit cost	£/tpd N2	51,000	51,000	Arup confidential quotes	3
Fixed OPEX	% of CAPEX	2.5%	2.5%	Arup confidential quotes	3
Buffer storage					
Scotland – storage requirement	tonnes	139.3	152.84	Arup LCOH model calculation.	3
Morocco – storage requirement	tonnes	137.93	173.08	Arup LCOH model calculation.	3
Norway – storage requirement	tonnes	40.32	43.85	Arup LCOH model calculation.	3
France – storage requirement	tonnes	36.07	39.23	Arup LCOH model calculation.	3
Chile – storage requirement	tonnes	142.09	154.52	Arup LCOH model calculation.	3
Capex unit cost	£/kg	708	495	(CSIRO, n.d.), Arup confidential quotes	3
Replacement CAPEX	% of CAPEX	25%	25%	(CSIRO, n.d.), Arup confidential quotes	3
Fixed OPEX	% of CAPEX	0.5%	0.5%	(CSIRO, n.d.), Arup confidential quotes	3

Port upgrades					
Scotland – CAPEX	£m	54	54	Arup benchmark	1
Scotland – fixed OPEX	% of CAPEX	4%	4%	Arup benchmark	1
Morocco – CAPEX	£m	43.3	43.3	Arup benchmark	1
Morocco – fixed OPEX	% of CAPEX	4%	4%	Arup benchmark	1
Norway – CAPEX	£m	59.4	59.4	Arup benchmark	1
Norway – fixed OPEX	% of CAPEX	4%	4%	Arup benchmark	1
France – CAPEX	£m	54	54	Arup benchmark	1
France – fixed OPEX	% of CAPEX	4%	4%	Arup benchmark	1
Chile – CAPEX	£m	43.3	43.3	Arup benchmark	1
Chile – fixed OPEX	% of CAPEX	4%	4%	Arup benchmark	1
Ammonia shipping					
Vessel size	t NH3	53000	53000	(BloombergNEF, 2019b)	3
Cost of transport	£/kg H_2/ 10,000 km	0.26	0.26	(BloombergNEF, 2019b)	3
Boil of gas rate	%	0.1%	0.1%	(Al-Breiki & Bicer, 2020)	3
Ammonia cracking					
Scotland – cracker size	tpd H_2	208.63	23.60	Arup LCOH model calculation.	2
Morocco – cracker size	tpd H_2	205.82	241.05	Arup LCOH model calculation.	2
Norway – cracker size	tpd H_2	301.64	306.16	Arup LCOH model calculation.	2
France – cracker size	tpd H_2	270.24	274.29	Arup LCOH model calculation.	2
Chile – cracker size	tpd H_2	205.88	208.97	Arup LCOH model calculation.	2
Cracker CAPEX	£m/ tpd H_2	2.37	2.37	Arup benchmark	2
Fixed OPEX	% of CAPEX	2.5%	2.5%	Arup benchmark	2
Reconversion losses	%	75%	70%		2
Compressed hydrogen					
Vessel size	m^3	26000	26000	(Provaris, 2022)	1

Cost of transport	£/kg H_2/1000 NM	3.75	0.64	(Provaris, 2022)	1
Shipping distance to Rotterdam					
Scotland	km	930	930	Marine Vessel Traffic	3
Morocco	km	2747	2747	Marine Vessel Traffic	3
Norway	km	1312	1312	Marine Vessel Traffic	3
France	km	38.2	38.2	Marine Vessel Traffic	3
Chile	km	17970	17970	Marine Vessel Traffic	3
Pipeline distance to Rotterdam					
Scotland	km	930	930	Marine Vessel Traffic	2
Morocco	km	1930	1930	Marine Vessel Traffic	2
Norway	km	1312	1312	Marine Vessel Traffic	2
France	km	435	435	Marine Vessel Traffic	2

Table 2 – Model input assumptions and sources

10.2 Sensitivities

10.2.1 Hydrogen Production Sensitivities

Table 3 provides a summary of the impacts on the production LCOH when key input parameters are changed. These results provide insights into the drivers the LCOH estimates.

	Notes	2023	2045
Base case	Offshore wind with Alkaline electrolyser	6.58	3.43
Improved efficiency	5 kWh/kg efficiency improvement	6.00	3.10
Lower CAPEX	Low end of CAPEX cost range	5.28	2.91
Lower O&M	Low end of O&M cost range	6.38	3.36
Lower electricity costs	Low end of offshore wind cost range	5.49	2.79
Increased utilisation	High end of utilisation rate range	5.72	2.98
PEM electrolyser	Offshore wind with PEM electrolyser	7.73	5.90

Table 3 – Hydrogen production key sensitives

The results in Table 3 indicate the following:

- Increased efficiency in the production model yields a lower LCOH compared the base case, as it will reduce the electricity costs associated to power the electrolyser. Similarly, when lower CAPEX and OPEX cost assumptions are included, the LCOH declines. In particular, a decrease in CAPEX yields a significant drop in LCOH as it is major contributor to total costs.
- Over both years, the inclusion of lower electricity costs is expected to result in lower LCOH values. As electricity input costs are a major driver of production costs, minimising these costs will incur significant cost savings.
- In the near-term, the use of alkaline electrolysers is expected to offer cost-saving benefits due to their lower cost. However, by 2045, PEM electrolysers are expected to provide a lower LCOH due to cost reductions and longer stack life.

10.2.2 Ammonia Shipping Sensitivities

Table 4 illustrates the impact on LCOT for the Scotland base case when the shipping cost parameter is varied.

	Notes	2023	2045
Base case	£0.26/kg H_2	2.56	2.34
Medium case	£0.56/kg H_2	2.60	2.38
High case	£0.82/kg H_2	2.63	2.41

Table 4 – Pathway 2 transport distance sensitives

The analysis indicates that as transportation costs increase, the LCOT for ammonia shipping also increases. In practice, shipping costs may decline as ammonia transport is increasingly used to enable a global hydrogen market.

10.2.3 Compressed Hydrogen Shipping Sensitivities

Table 5 illustrates the impact on LCOH for the Scotland base case when the ship capacity is varied.

	Notes	2023	2045
Base case	Compressed hydrogen ship capacity of 10 ktpa	1.88	0.32
30 ktpa	Compressed hydrogen ship capacity of 30 ktpa	0.76	0.13
65 ktpa	Compressed hydrogen ship capacity of 65 ktpa	0.61	0.11
100 ktpa	Compressed hydrogen ship capacity of 100 ktpa	0.57	0.10

Table 5 – Pathway 3 production scale sensitivity

The analysis indicates that as overall ship capacity of compressed hydrogen vessels increase, the LCOH of this transport option decreases. As the compressed hydrogen industry continues to develop and transport vessels up-scale, further cost reductions could be realised.

10.3 Inflation Reduction Act (IRA) subsidy background

The Inflation Reduction Act (IRA) was passed by U.S. Congress in 2022 and provides a variety of incentives for clean energy projects in the USA. An estimated $369 billion will be spent under the Act to help address energy security and transition over the coming decade (International Council on Clean Transportation, 2023).

As part of the IRA, the 45V Hydrogen Production Tax Credit was introduced. It provides an income tax credit for every kilogram of qualified clean hydrogen produced. To qualify for the credit, hydrogen producers must meet the following criteria (Saber Equity, 2023):

1. The production process must have a lifecycle greenhouse gas emissions rate of less than 4kg CO_2e/kg H2.
2. The hydrogen must be produced in the US or a possession of the US.
3. They hydrogen must be produced "in the ordinary course of a trade or business of the taxpayer".
4. The hydrogen must be produced for sale or use.
5. An independent party must verify the "production and sale or use of such hydrogen".

The tax credit is tiered based on the GHG emission intensity of the hydrogen produced. Hydrogen producers can earn up to $3 per kg of hydrogen produced for projects with a lifecycle greenhouse gas (GHG) emission intensity of less than 0.45kg CO_2e/kg H_2 (Center for Strategic & International Studies, 2023). In contrast, hydrogen projects which are more carbon intensive, such as steam reformation combined with CO_2 capture and sequestration, will qualify for a lower credit amount. Further guidance from the US Treasury Department in required for calculation of emissions intensity levels of electrolysis-based hydrogen (Center for Strategic & International Studies, 2023).

The tax credit will expire in 2032 so projects which become operational in 2023 can benefit from the full 10 years of the credit, while plants which become operational later will receive progressively less (International Council on Clean Transportation, 2023). Additionally, the 45V Hydrogen Tax Credit is also "direct pay" for the first five years of operation. This allows clean hydrogen producers to claim a tax refund equal in value to their tax credits for five years.

The US Government also introduced the 45V Renewable Electricity Production Tax Credit. This offers renewable electricity producers a tax credit up to 2.6 cents per KWh of energy produced (The International Council on Clean Transportation, 2023). The renewable energy credit works in a similar set up to the hydrogen production credit. Projected figures suggest the IRA tax credit for renewable electricity and clean hydrogen can reduce the cost of green hydrogen production by almost 50% (The International Council on Clean Transportation, 2023).

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