WHEN TRUST MATTERS

Specification of a European Offshore Hydrogen Backbone

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Producing hydrogen offshore should be considered as a priority for Europe...

Given the large future demand for hydrogen, imports and domestic production of hydrogen will need to coexist, and there are strategic benefits for considering domestic production:

Hydrogen demand will increase substantially in Europe in the coming decades to meet decarbonisation goals. By 2050, hydrogen demand could exceed 2,000 TWh, with a corresponding need for large quantities of green hydrogen production from within the EU to help maintain Europe’s energy security.

It is likely that hydrogen produced in the North Sea will be competitive with imports:

In the view of independent experts such as DNV, Agora Energiewende and Aurora Energy Research, European hydrogen production transported via pipelines is likely to be competitive with imported hydrogen transported via ships, as it will not need the associated costly processing steps.

Transport infrastructure will constitute a relatively small part of the total infrastructure cost for the energy transition on the North Sea:

Considering the cost, overall spatial footprint and onshore spatial footprint issues, offshore hydrogen production is an attractive option in many cases. Given the lower costs and larger capacities of pipelines, and the opportunity for pipelines to aggregate offshore hydrogen production from several windfarms, we assess that the discriminating distance for favourable offshore hydrogen production is around 100km distance from shore. The levelised cost of hydrogen at 150km distance from shore could be €4.59/kg in 2030, falling to €3.24 /kg in 2050. The cost of pipelines and compressors is likely to be only 10% or less of the total.

Executive Summary (2/2)

…as it provides an economical path to both decarbonisation and energy security for the European Union.

There is sufficient offshore wind generation planned for the North Sea to support round 300 TWh of offshore hydrogen:

In the North Sea, there is at least 66 GW_{el} of offshore wind potential advertised in development zones and another 13 GW_{el} in an early planning phase which will be coming to life before 2050 and matches the criteria of being a distance of at least 100 km from shore. An offshore hydrogen backbone could support the production of around 300 TWh of offshore hydrogen in the North Sea, enabling a significant portion of Europe’s hydrogen production. In the Baltic Sea, an offshore backbone could be a more logical and cost-effective alternative to two parallel onshore North-South pipelines to transport green hydrogen from Sweden and Finland to major demand centers in Europe.

Coordination is needed to realise an offshore hydrogen backbone in practice:

As the spatial distribution of the potential offshore hydrogen production sites shows, the sea areas of different countries are involved in the determination of the total potential. This suggests that transnational coordination will be necessary to develop the full identified hydrogen generation potential. It will be equally important to balance the potential use for electricity generation against the potential generation of hydrogen across countries. As we have shown, the potential of offshore hydrogen production can only be fully exploited through network effects.

Clear joint offshore hydrogen production targets should be set by the littoral states, as per offshore wind targets:

As the demand for hydrogen is set to rise sharply in the coming years, we believe it is necessary for the littoral states to further coordinate their efforts to develop areas in the North Sea, including those at greater distances, and to define clear expansion targets for hydrogen as well. Infrastructure development driven purely by individual initiatives at country level and research will not do justice to the potential and importance of offshore hydrogen production.

1. Introduction

The aim of this report is to provide insights on whether and how to set up offshore hydrogen production and to develop an offshore hydrogen pipeline backbone that integrates this production in an efficient way into the European energy system.

Background and scope of the study

This report sets out the economic and technical potential for an offshore hydrogen backbone in the North Sea and Baltic Sea, consisting of offshore wind production, offshore electrolysis, and offshore hydrogen pipelines. This infrastructure has the potential to make an important contribution to Europe's energy security and decarbonisation, complementing offshore wind for the electricity sector and hydrogen production onshore. The study has been carried out by DNV on behalf of GASCADE and Fluxys, a consortium of pipeline operators that intends to actively support Europe's energy transition and move towards greater energy security.

The current energy crisis is a vivid reminder that singular dependencies on energy supply entail major economic risks. At the same time, the climate crisis is becoming increasingly noticeable due to more frequent extreme weather events. In this respect, a rethinking of our European energy system, which has been a guarantor for security and prosperity in Europe for decades, is urgently required.

Hydrogen as an energy vector is today seen next to electrification as the most promising possibility in order to fully decarbonise. Whilst electricity is mainly seen as the way forward for various sectors such as private transport and low/medium temperature heating, hydrogen is seen mainly as the energy vector that enables also the decarbonisation of very energy intensive (so called hard-to-abate) sectors like steel manufacturing, heavy transport or air transport. Decarbonizing these sectors will lead to a significant increase of demand for hydrogen over the coming years and finding ways to economically source and distribute the needed hydrogen is currently at the center of many feasibility studies.

One of the central questions on hydrogen sourcing is the **economic feasibility**, and here the levelised cost of hydrogen (LCOH) plays an important role to help evaluate different sourcing options. The LCOH is a variable that indicates how much it costs to produce 1 kg of Green Hydrogen, considering the estimated costs of the investment required and the cost of operating the assets involved in its production.

The **strategic dependencies** also play an essential role. The recent energy crisis in Europe – propelled by the war initiated by Russia against Ukraine – has clearly shown that Europe is well advised to source energy from stable partners and that it should also do much more to assure its own energy generation. To that end, making Europe again dependent on importing hydrogen from other regions of the world might not be the best option. Therefore, Europe should seek for ways to produce hydrogen in bigger quantities on its own.

Whilst producing hydrogen domestically in Europe should be a key part of Europe's energy policy, as described above, these production facilities should not cannibalise the much-needed electricity production which, for efficiency reasons, is taking on the biggest part of the decarbonisation challenge. As we will lay out in this study, production of hydrogen offshore from wind energy is one of the most effective and efficient ways to set up a domestic supply for Europe, especially for those offshore sites further away from shore.

Logic of the report

This report uses the following logic in its analysis:

- First, hydrogen is widely recognised as a valuable part of Europe's energy transition, with both EU and German hydrogen strategies envisioning widespread hydrogen use to decarbonise industry and other sectors, alongside extensive electrification. Hydrogen use will therefore increase over the coming years as we will show.
- Second, there are clear energy security benefits from producing hydrogen in Europe, using European renewables. Undoubtedly, there will be imports of hydrogen and derivative fuels from other parts of the world, but as the current energy crisis is showing dramatically, Europe needs to reduce its reliance on energy imports from unreliable countries. In addition, European hydrogen production transported through pipelines will have a lower greenhouse gas footprint than hydrogen imported from further afield, as it does not require the shipping and liquefaction or derivative processing steps. Europe should therefore seek to produce hydrogen in larger quantities on its own.
- Third, the potential energy generation from offshore wind in the North Sea and Baltic Sea is immense, and possibly greater than the electricity system alone can handle. In certain circumstances, producing hydrogen from offshore electrolysis can be a cost-effective and practical way of utilising Northern Europe's vast offshore wind resources – and given the scale of offshore wind, it has the potential to make a major contribution to meeting Europe's need for green hydrogen.

The aim of the study is therefore to investigate the practical possibility to set up remote offshore hydrogen production and develop an offshore hydrogen pipeline backbone that integrates this production in an efficient way into the European energy system, so that the economic and technical potential of offshore hydrogen production in the North and Baltic Sea can be achieved.

1. Introduction

Any form of hydrogen production will compete with direct electrification, and in DNV's view there is a need to strike the right balance between these two energy vectors.

DNV's viewpoint

Where decarbonisation through direct electrification of a sector is feasible, this is the first priority due to the inefficiencies of converting electricity to hydrogen. Where electrification is not an option — or a very poor one — then hydrogen is the best alternative, as is the case in many so-called hard-to-abate sectors, like aviation, shipping, and high-heat industrial processes. Hydrogen will also be used in making sustainable end products (e.g. ammonia/fertilisers), green materials (e.g. steel and aluminium), and low-carbon chemicals (e.g. methanol and plastics), many of which could be utilised as fuels for long distance or heavy-duty travel.

Both hydrogen and electricity are an important part of the energy transition, and they are also linked. Some 80% of energy professionals that DNV has surveyed believe that hydrogen and electrification will work in synergy, helping both to scale up[1]. Neither solution can provide the full energy demand given limitations to the amount of renewable power available, as well as the diminishing cost-benefit of grid expansion in the case of extensive electrification. In certain European countries, where a dense natural gas distribution infrastructure is already in place, hydrogen can be delivered to end users by existing gas distribution networks at lower costs than a wholesale switch to electricity.

DNV's main Energy Transition Outlook forecast is that hydrogen (and derivatives) will constitute 11% of Europe's total energy mix in 2050, at 37 million tonnes (approximately 1,200 TWh) of hydrogen per year. In DNV's pathway to net zero (PNZ) scenario, hydrogen use in 2050 is 122 million tonnes (approximately 4,000 TWh) – over three times higher.

Boundary conditions considered in this report

- There is a large potential for renewable energy generation in the North Sea and Baltic Sea
- There is need for EU domestic production of hydrogen, as outlined by the European Commission
- There are limits to the extent Europe can cost-effectively electrify, due to grid expansion constraints
- There is competition for land-use onshore as well as offshore

Statements

Taking DNV's viewpoint into consideration, together with the boundary conditions, some conclusions are drawn:

- Large scale offshore hydrogen production in the North Sea, which is located further than 100 km offshore, and collectively connected to European demand centres via an offshore hydrogen backbone system, is well suited for domestic European hydrogen production. On the basis of levelised cost of hydrogen and onshore space claim, it outperforms any of the analysed value chains that feature onshore hydrogen production.
- However, the sea area required for renewable energy generation to produce this hydrogen might also be needed for electricity production to support direct electrification. **This report explicitly does not compare this competitive use of space** in these cases, and does not provide a general statement on what to prioritise.
- Therefore, the total hydrogen production potential presented in this study should be interpreted as an upper technical potential, based on current projections of sea areas that are dedicated for energy production by national governments. The actual realisation of offshore hydrogen production will critically depend on decisions of national governments, striking a balance between direct electrification and hydrogen by announcing additional sea areas that are dedicated to energy production, setting offshore hydrogen production targets and enabling legislation, as well as hybrid- or hydrogen based tender structures for the sea areas.

1: DNV (2021) *Rising to the Challenge of a Hydrogen Economy.*

DNV

1. Introduction

There are significant challenges to build a net zero Europe, and hydrogen as an energy carrier, derived from offshore wind, has several advantages.

Key challenges for a net zero Europe

The challenges for a carbon free future for Europe include:

- Claiming sufficient surface space for renewable energy production and conversion;
- Transporting the energy from these areas to end-users;
- Bridging the moment of production with the moment of use; and
- Coping with cost.

Of course, the European energy transition will be a complex process, but based on these considerations it can be concluded that the use of hydrogen as an energy carrier, derived from offshore windfarms, has a definite set of advantages:

1. The surface space claim for offshore wind can be filled in by a part of the North Sea and Baltic Sea. This has the advantage that no land-based surface is needed and due to the availability of wind it has a rather high specific energy production density.
2. Especially for large amounts of energy, hydrogen transport in pipelines may be an order of magnitude cheaper than electricity transport in cables. Also, a meshed grid for hydrogen transport is a realistic option.
3. Geological storage of hydrogen is lower cost than direct electricity storage. A further benefit is that the materials need for the geological hydrogen storage does not scale with capacity like with batteries (2x battery storage = 2x materials needed, whereas 2x hydrogen storage can be achieved with moderately larger reservoirs or different pressure regimes).
4. Hydrogen can be used in hard to abate sectors such as high temperature industries, feedstocks, aviation, navigation and heavy road transport. The costs are foreseen to drop quickly.

In the following chapters the hydrogen demand and production potential, the potential for hydrogen from offshore wind in both the North Sea and the Baltic Sea, and a concept of an offshore hydrogen backbone are discussed in more detail.

Source: DNV

1. Introduction

This report lays out in five chapters how offshore hydrogen production from offshore wind might supply a large share of the European hydrogen demand and what a technical offshore hydrogen infrastructure could look like.

Reading instruction

The study is set up to deliver a rough draft for a corresponding infrastructure – consisting of wind turbines, offshore electrolysers and pipeline systems. It provides an overview of the potential of such an infrastructure and gives a first set-up and assessment of an offshore hydrogen network. As stated, this infrastructure shall not be investigated as an alternative to offshore wind power generation but rather as a complementary pillar of a secure energy supply in Europe.

This report provides our recommendations and findings and should be understood as input to decision-making when offshore wind and offshore hydrogen production is discussed. This report is based on the following information sources:

- Inputs from Gascade and Fluxys on existing alternatives
- DNV and other reports and EU and country strategies of hydrogen plans and roadmaps
- Publicly available information and databases on offshore wind development and hydrogen production initiatives

After the introduction in Chapter 1, the following chapters are presented:

- **Chapter 2** describes the demand for hydrogen in Europe up to 2050 and the opportunities for local production. Although electrification is key to net zero, Europe will also need large quantities of renewable hydrogen to meet decarbonisation goals, and a large proportion of this hydrogen is planned to be produced in Europe.
- **Chapter 3** investigates five onshore and offshore hydrogen value chains on cost and spatial impact criteria, finding that offshore hydrogen production is an attractive option, particularly for offshore wind at distances of more than 100km from shore.
- **Chapter 4** describes at a high level the existing offshore wind generation in the North and the Baltic Sea and analyses the hypothetically available capacity for hydrogen production in both sea areas that matches the 100km criterion set out in chapter 3. This defines the basis for a potential offshore hydrogen backbone.
- **Chapter 5** introduces the considerations of the construction of an offshore hydrogen backbone infrastructure and shows a first set up for the North Sea and the Baltic Sea. It also considers reflections on the reuse of existing oil and gas pipelines.
- **Appendices**: Abbreviations, levelised cost calculation methodology, offshore wind areas dataset description, assumptions and input data to the various analyses.

Source: DNV

2. Hydrogen demand and European production potential

2.1 Introduction

This chapter considers hydrogen demand and the potential to produce green hydrogen in Europe. Hydrogen demand will grow considerably to help achieve decarbonisation, and there is a strategic need to source much of it from Europe.

In this chapter, we consider the potential growth of hydrogen demand in Europe to help achieve decarbonisation, including of hard-to-abate sectors. We examine a number of scenarios and hydrogen strategies – all point to considerable growth in hydrogen demand. We also consider the main issues for hydrogen production at scale within Europe, and the strategic need for production within the EU.

Demand

The current use of hydrogen is characterised by customers in the refinery and chemical industries. The main areas of use are the production of fuels and petroleum processing and the production of ammonia. The total demand for hydrogen in Europe today is estimated at 285 TWh in 2020.

RePowerEU set a target of 660 TWh of green hydrogen use in the EU in 2030 – a significant increase from today's grey hydrogen demand – with half of this coming from European production. Various scenarios for hydrogen deployment in Europe have been put forward, with differing growth rates. But all envisage demand of at least **1,000 TWh in 2050**, and most scenarios envisage demand of **more than 2,000 TWh**. The Onshore European Hydrogen Backbone expects a total demand of 2,400 TWh in 2050 and expects the majority of demand to come from industry, transportation and power.

Strategic importance of production in the EU

There are a number of important considerations for hydrogen production within Europe, including the available surface area; the transport distances from production to end-use; the time-matching of production and consumption, and hence the need for storage at scale; and the economics of production.

Nevertheless, it is clear from the current energy crisis that strategically a region should have a balanced resourcing of energy and that relying on a limited amount of energy suppliers can have strong adverse effects on the economy if these relationships fail.

And, from an economic perspective, although green hydrogen production will likely be cheaper in parts of the world with exceptional renewable resources, there are significant costs associated with the shipping of hydrogen over long distances, meaning that European production could remain competitive.

Source: DNV

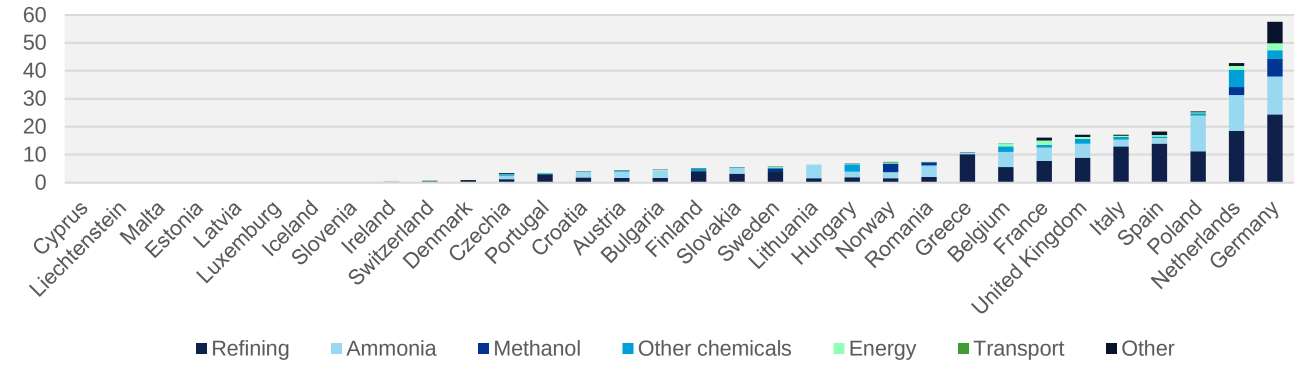
2. Hydrogen demand and European production potential

2.2 Demand – current hydrogen demand

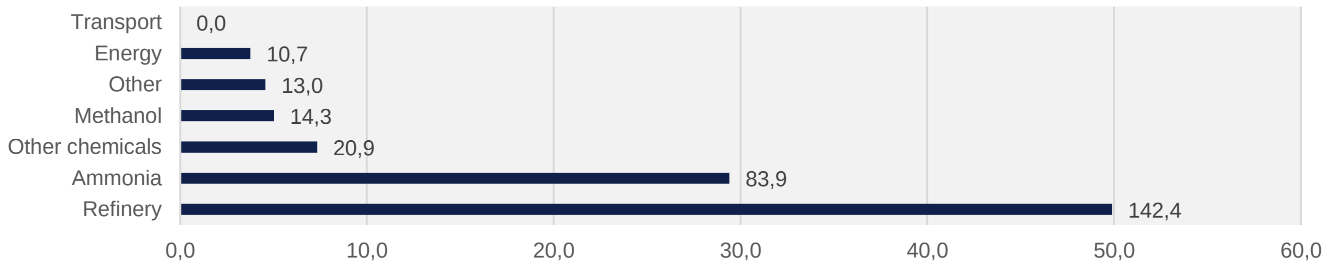
Hydrogen already is a very important energy vector that is used by various industries. The total demand in the EU is currently about 285 TWh per year. The chemical and fertiliser industries in particular use significant amounts of hydrogen.

- At present, Germany has the highest hydrogen demand at 58 TWh a year, around 20% of the total European hydrogen demand, followed by the Netherlands (43 TWh) and Poland (26 TWh).
- The use patterns in the respective countries differ to a large extent which can be explained by the different industry structures that the respective countries have.
- It is quite obvious that especially those countries that have larger chemical and refiniery industries are the ones that have today the largest hydrogen demand. Having stated this, the current use of hydrogen is characterised by customers in the refinery and chemical industries.
- The main areas of use are the production of fuels and petroleum processing and the production of ammonia (which is a core ingredient of most of today's fertilisers), followed by the chemical industry. Other industries like the semiconductor industry, plastics production, metal processing and the pharmaceutical industry contribute only marginally to hydrogen use.
- The total demand for hydrogen in Europe today is estimated at 285 TWh in 2020. Given that most of the current hydrogen demand comes from the refining and ammonia industries, this demand is almost exclusively met from hydrogen based on natural gas or as a by-product of chemical processes. This means that this demand is currently almost entirely catered by hydrogen that is not carbon neutral - so called grey hydrogen. Use cases such as energy production or transport today play a very minor role.

Total demand for hydrogen in 2020, by country, TWh



Percentage of total demand in 2020 and absolute value, TWh



Source: Fuel Cells and Hydrogen Observatory, FCHO, 2022

2. Hydrogen demand and European production potential

2.2 Demand – future demand areas

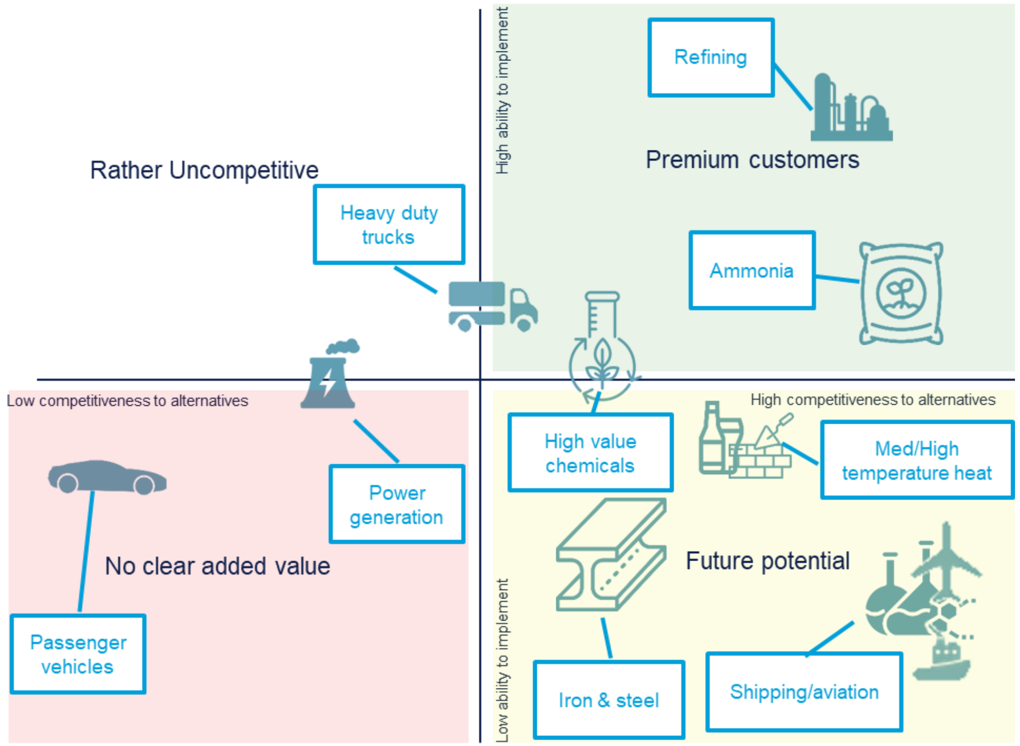
Green hydrogen can become an important energy asset to decarbonise hard to abate sectors like industry and heavy transportation. The shift to green hydrogen is likely to start in those sectors that already today rely on hydrogen.

- With decarbonisation becoming an urgent issue for society, there are two factors to consider looking at the hydrogen demand in Europe for the coming decades and they go in parallel. The first is that the current demand for hydrogen needs to be decarbonised as it has a major CO2 footprint. Secondly and even more important, hydrogen – as green hydrogen – produced by renewable energy is likely to become an **important energy vector** to decarbonise hard to abate sectors. In view of the gradual increase in the price of CO2 certificates and the EU's goal of greenhouse gas-neutral production by 2050, companies with very high CO2 emissions, such as steel mills and aviation companies, are under pressure to significantly reduce their emissions. This is where the use of hydrogen will come into play and lead to a significantly increasing demand over the coming decades.

- As it is laid out on the coming pages the demand scenarios currently show a significant demand spread as potential uses for hydrogen are still under investigation and the economics for applying hydrogen in new use cases are not fully clear. Nevertheless, almost all studies agree that we will see a massive uptake of hydrogen demand across Europe due to the need to decarbonise industry, transport and the energy sector. The graph on the right hand side shows generally which segments will demand hydrogen. Most of the predictions today vary with the extent these sectors really pick hydrogen in the future as an alternative energy vector.

- The most promising launching market segments for **green** hydrogen are **refining** and **ammonia**. The key enablers are: no real alternatives; existing hydrogen users (limited equipment adaptation necessary) with high concentrated volumes of demand; embedded in existing hydrogen eco-systems; and willingness to pay a premium in refining due to blending targets in transportation.

- In addition to the premium customers there are some segments where hydrogen could play an important decarbonisation role. In these segments there are alternatives (all-electric or biomass) but hydrogen has a good competitive position. These industries are steel, high temperature heat and shipping and aviation. The sectors on the left hand side of the graphic are on the other hand likely not the ones driving the future demand in Europe.



Sources: Internal DNV analysis and Liebreich 2021

2. Hydrogen demand and European production potential

2.2 Demand – EU hydrogen strategy and RePowerEU

In the EU's strategy, hydrogen use is being accelerated through additional funding of production projects, partly due to the Ukrainian war. The funding schemes are backed by market incentive mechanisms – significant potential emerges.

EU's Hydrogen Strategy

The European Commission's hydrogen strategy, presented in July 2020, outlines upscaling the demand and supply of renewable hydrogen. This strategy has the key objective to install at least 40 GW_{H2} of renewable hydrogen electrolyser capacity within the EU, producing about 165 TWh[1] (5 Mt) of renewable hydrogen based upon an estimated demand of up to 330 TWh (10 Mt) per year of renewable hydrogen in the EU by 2030. That would mean that by 2030 half of the European demand would be covered by domestic production and that also 40 GW_{H2} of hydrogen production is available for Europe from abroad. Investment projections also assume 500 GW_{H2} of renewable electrolysers by 2050 leading to 2,250 TWh of hydrogen per annum.

RePowerEU

As a consequence of the Russian invasion of Ukraine, the European Commission presented REPowerEU in 2022 with even higher ambitions for EU hydrogen production. RePowerEU creates a demand pull for hydrogen and targets expected use of 660 TWh (20 Mt H2) in 2030 – with 330 TWh domestically sourced and 330 TWh of hydrogen imported.

In addition, the European Commission wants to align the sub-targets for renewable fuels of non-biological origin under the Renewable Energy Directive for industry and transport with the REPowerEU ambition. This implies a target for 75% for industry and 5% for transport (in the revision of REDII from 2021 the target was 50% for industry and for transportation 0.7%).

Implementation is achieved by funding schemes which are based on PRIMES calculations. The PRIMES model is an EU energy system model which simulates energy consumption and the energy supply system.

[1] Note that the EU's hydrogen strategy uses a convention of 40 GW_{H2} of hydrogen (LHV) at the output of the electrolyser. The 165 TWh is achieved with 4125 full load hours and the 2,250 TWh from 500 GW_{H2} with 4500 hours. This can only be achieved from a sustainable source like offshore wind. The remainder of this report uses the standard convention of electrical input capacity for the electrolyser (GW_{el}), see additional clarification in Appendix.

Additional developments

The current European energy crisis has created an even greater push for accelerating hydrogen production in Europe. The European Clean Hydrogen Alliance announced 750 projects to produce H2 with more than 50 GW_{el} electrolyser (electricity input) capacity (approximately 130 TWh, based on 4,000 full load hours) by 2030. Hydrogen production is expected to accelerate further in Northern Europe with the expansion of offshore wind in the North Sea (Esbjerg declaration) and Baltic Sea (19.6 GW_{el} offshore wind). The AquaVentus project of 10 GW_{el} offshore wind is expected to produce 1 million tons of hydrogen.

Hydrogen production is also expected to be supported with the implementation of currently already launched and further to be expected governmental strategies and funding schemes. The table below highlights the hydrogen strategies of countries that are bordering either the North or Baltic Sea.

Country	Document	Publishing Year	Production capacity targets (normally 2030)
Denmark	Government strategy on Power-to-X	2021	4 – 6 GW
Sweden	National Strategy on Hydrogen	2021	5 GW
Poland	Government Strategy on Hydrogen	2021	2 GW Low Carbon H2
UK	British Energy Security Strategy	2022	10 GW Of which at least 5 GW electrolysis
Germany	National Hydrogen Strategy	2020	5 GW electrolysis
Netherlands	National Climate Agreement Government Hydrogen Strategy	2019 2020	3 – 4 GW electrolysis
Norway	Government Strategy on Hydrogen + Roadmap	2020 2021	No official target known – only supporting policies

2. Hydrogen demand and European production potential

2.2 Demand – forecasted demand to 2050

Studies expect significant growth in (green) hydrogen demand and agree that heavy transportation and industry will be the drivers. However, studies differ to a large extent on the amount demanded in segments such as buildings and power.

As stated above European hydrogen demand studies show a significant spread due to uncertainty in terms of possible future applications. The main differences in the studies stem from assumptions on the extent to which hydrogen plays a role in the heating, industrial and transport sectors in the future.

Common for all studies is that green hydrogen is expected to be applied in hard to abate sectors. The studies emphasise that early investments in hydrogen production and infrastructure are needed to create the necessary scale and the expected volumes demanded in 2050.

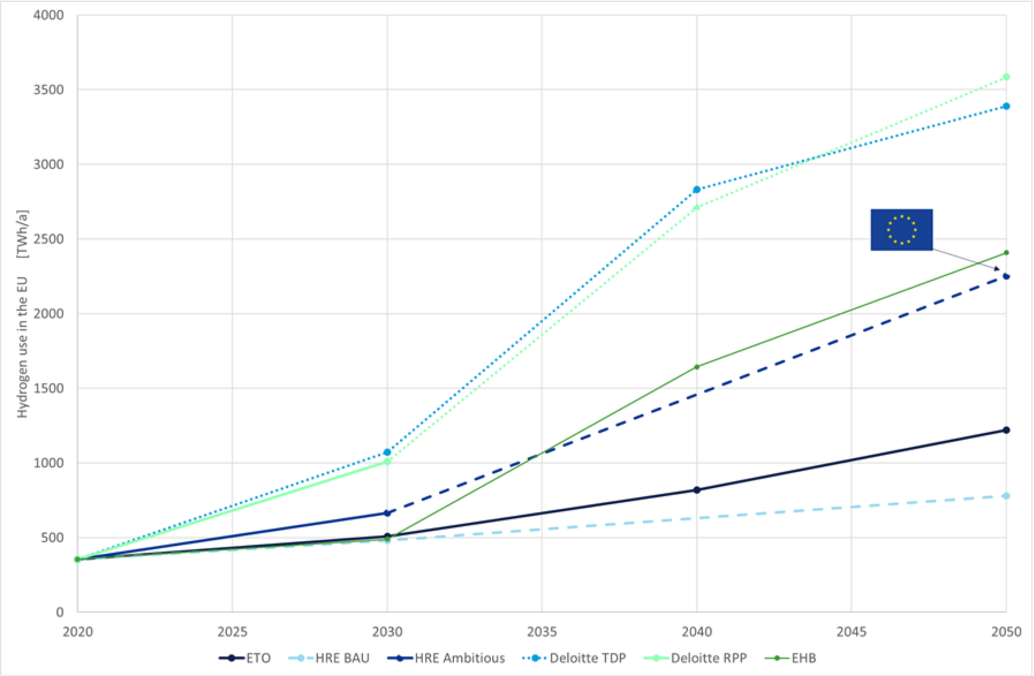
The report carried out by Deloitte and Hydrogen4EU predict a hydrogen demand of more than 3,300 TWh in 2050. The study has two pathways, Technology Diversification Pathway (TDP) and Renewable Push Pathway (RPF), each with similar levels of hydrogen demand. On average, more than half of the hydrogen demand comes from the transportation sector (1,650 TWh) with a fair share from aviation (660 TWh). The majority of the rest of the demand is expected to come from industry (1,485 TWh) and a smaller amount from buildings and power generation (165 TWh).

The European Hydrogen Strategy predicts a hydrogen demand of 2,250 TWh in 2050. The majority of the demand is expected to come from industry (885 TWh) and transportation (675 TWh). Although overall demand is lower than in the Deloitte scenarios, heating for buildings (579 TWh) and Power (112 TWh) have a larger share of the total hydrogen demand.

DNV's Hydrogen Forecast 2050 has a more conservative outlook for hydrogen demand of 1,205 TWh in 2050. The forecast by DNV predicts that the majority of the demand will come from transportation (452 TWh), manufacturing (320 TWh) and buildings (267 TWh). In DNV's Pathway to Net Zero scenario, however, overall hydrogen demand is more than three times higher, at around 4,000 TWh – which illustrates the importance of hydrogen to achieving net zero in practice.

The European Hydrogen Backbone expects a total demand of 2,400 TWh in 2050 and expects the majority of demand to come from industry, transportation and power. The report does quantify the demand from each segments as the report focuses on the different demand from each and the potential corridors of supply.

Scenarios for hydrogen demand towards 2050



Source: DNV based on publicly available reports

2. Hydrogen demand and European production potential

2.3 Strategic importance of hydrogen production in the EU (1/2)

There is a strong rationale for maximising production of hydrogen in Europe to complement imported sources of hydrogen and derivatives – both on cost and energy security grounds.

Theoretical advantage of hydrogen imports

As has been shown in this chapter, hydrogen is important for core European industries such as the chemical industry today, and hydrogen demand will grow in the coming years to achieve full decarbonisation by 2050. The future sourcing of energy to maintain Europe's wealth is a key task.

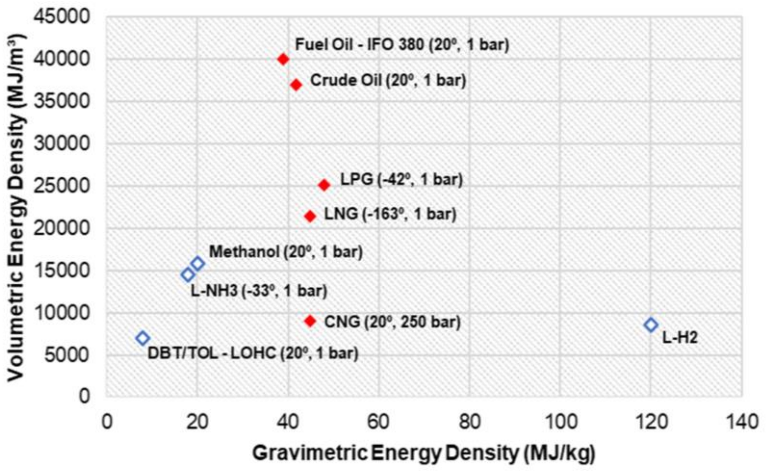
Various studies show that the Levelised Cost of Hydrogen (LCOH) for the production of hydrogen in Europe is likely higher than in sites that are closer to the equator and where wind and solar in combination can achieve a constantly high utilisation of an electrolyser infrastructure.

Practical constraints on imports

Still, there are two aspects that need to be considered when discussing a future potential sourcing of hydrogen from other regions.

The first aspect is that the **long distance transport of hydrogen greatly increases the LCOH** of the hydrogen by the transport and processing costs that need to be considered on top. Transporting hydrogen can either be done in liquid form (LH2), as ammonia or by using carrier oils (LOHC). Each of these transport options has some downsides. The transport of liquid hydrogen demands significant cooling and space for insulation on potential ships which makes such transport less economic. Using ammonia has also the downside that you need to convert hydrogen into ammonia – and at for many uses later back to hydrogen – which also means that this transport chain looses some of the LCOH advantages of other regions. The same applies for LOHC carriers, with the additional flaw that you need to buy the carrier oil which comes at high capex initially.

The following graph shows the energy densities of the different hydrogen carriers and also shows how much higher the volumetric energy densities of today's incumbent fuels are.



Source: DNV

The second aspect is that the current energy crisis has shown that **strategically a region should have a balanced resourcing of energy** and that relying on a limited amount of energy suppliers can have strong adverse effects on the economy if these relationships fail.

When hydrogen infrastructure is discussed it is for the above reasons very important that we take possible scale effects, land use and efficiencies into account. Ideally Europe can jointly agree on an infrastructure that incorporates from the beginning the potential for large economies of scale.

To sum up: both aspects indicate that, for covering the future European demand of hydrogen laid out in this chapter, a significant European hydrogen production capacity should be of importance.

2. Hydrogen demand and European production potential

2.3 Strategic importance of hydrogen production in the EU (2/2)

DNV research and other studies conclude that hydrogen imports via pipeline or for end-use in derivative form (e.g. ammonia) are most advantageous. For end-use as gaseous hydrogen, European production is competitive with hydrogen imported by ship.

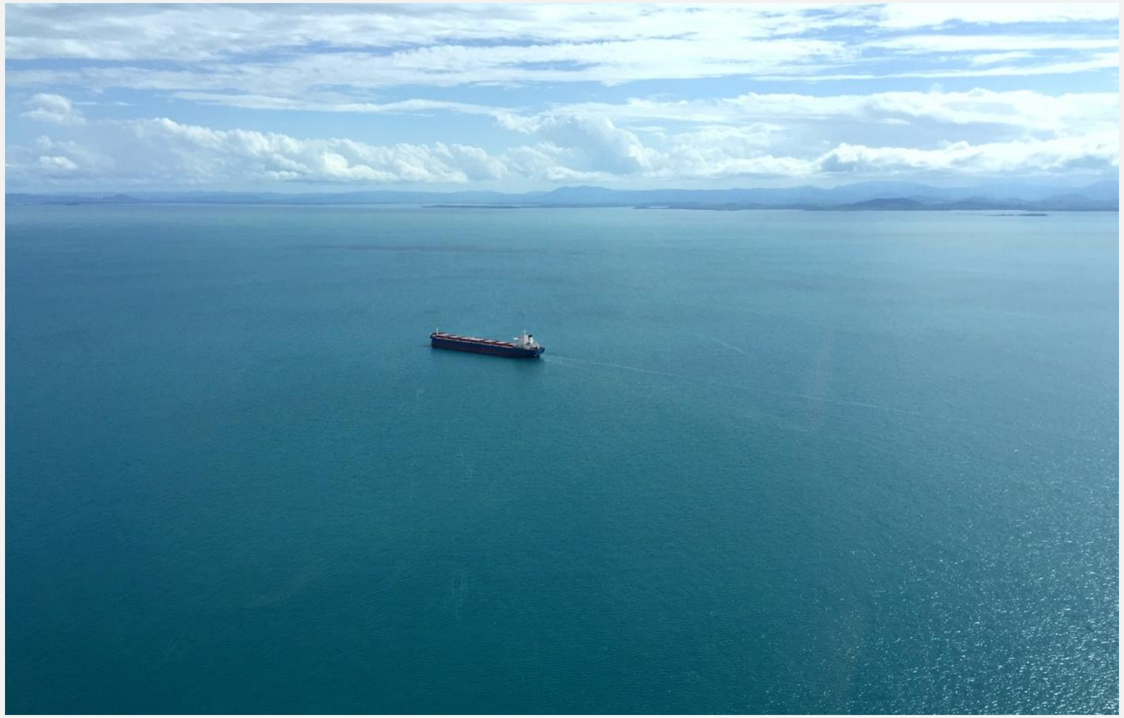
European hydrogen production compared with imports

As DNV and others have found, shipping hydrogen can be relatively expensive, especially when the hydrogen carrier needs to be converted back into gaseous hydrogen for end-use. In many cases, the additional transportation and processing steps can make imported hydrogen uneconomic compared with European production:

- **DNV** forecasts that the majority of hydrogen in 2050 will be produced and consumed in the same region, with limited inter-regional trade via pipeline. Shipping of hydrogen will account for a very small proportion of the total.
- By contrast, DNV forecasts that around half the world's ammonia for energy use, e.g. as a maritime fuel, will be shipped between regions in 2050. This is because shipping of ammonia, for end-use as ammonia, does not require the costly step of cracking back into hydrogen. In this case, ammonia production from regions with low renewable costs is likely to competitive with European ammonia production.
- In similar fashion, **Agora Energiewende** has concluded that the cost of hydrogen shipped to Europe, for end-use as gaseous hydrogen, would be uncompetitive with European hydrogen production, given the high transportation and processing costs of shipping hydrogen. Agora also found that hydrogen transported to Europe via pipeline e.g. from Morocco, could be competitive with European production.
- Agora concluded that the main opportunities for shipping of hydrogen would come from the shipping of "energy-intensive hydrogen-based products such as ammonia, methanol, and other high-value chemicals".
- A further report by **Aurora Energy Research** found that hydrogen imported to Northern Europe from Spain and Morocco would be cost-effective against local production, but that hydrogen transported by ship from the Middle East (e.g. United Arab Emirates) may not be competitive with domestic production.

Overall, this means that there is a good economic rationale for gaseous hydrogen production in Northern Europe, in addition to the energy security rationale. Regarding the economics, we will see in the next chapter at what cost levels hydrogen can potentially be produced in Northern Europe over the coming decades.

But the key point is that European hydrogen production is a necessary complement to imported hydrogen, and therefore it is logical to investigate the most cost-effective options for production, also considering the spatial aspects.



Source: DNV

3. Hydrogen demand and European production potential

2.4 Key takeaways

Hydrogen demand is set to increase substantially in Europe to help meet decarbonisation goals, possibly to above 2,000 TWh by 2050. European hydrogen production is strategically rational and in many cases competitive with imports.

This chapter considered the potential growth of hydrogen demand in Europe to meet decarbonisation goals, and the key considerations for European production.

Hydrogen demand

Hydrogen demand in Europe is currently around 285 TWh (2020), although almost all of this demand is met by grey hydrogen:

- Refineries account for 142 TWh, around 50% of total demand, and ammonia production a further 84 TWh, around 30% of the total.
- Hydrogen demand is greatest in Germany (58 TWh), followed by the Netherlands (43 TWh) and Poland (26 TWh).

In the coming years, hydrogen demand in Europe is set to increase substantially:

- The EU's RePowerEU strategy envisages demand for green hydrogen of 660 TWh in 2030, more than double today's grey hydrogen demand.
- The EU Commission is also aiming for a target of 75% renewable fuels of non-biological origin (RFNBOs) in industry and 5% in transport by 2030.
- Numerous studies reviewed in this chapter point to a substantial increase in hydrogen demand through to 2050, generally above 2,000 TWh. The European Hydrogen Backbone expects a total demand of 2,400 TWh in 2050 and expects the majority of demand to come from industry, transportation and power.

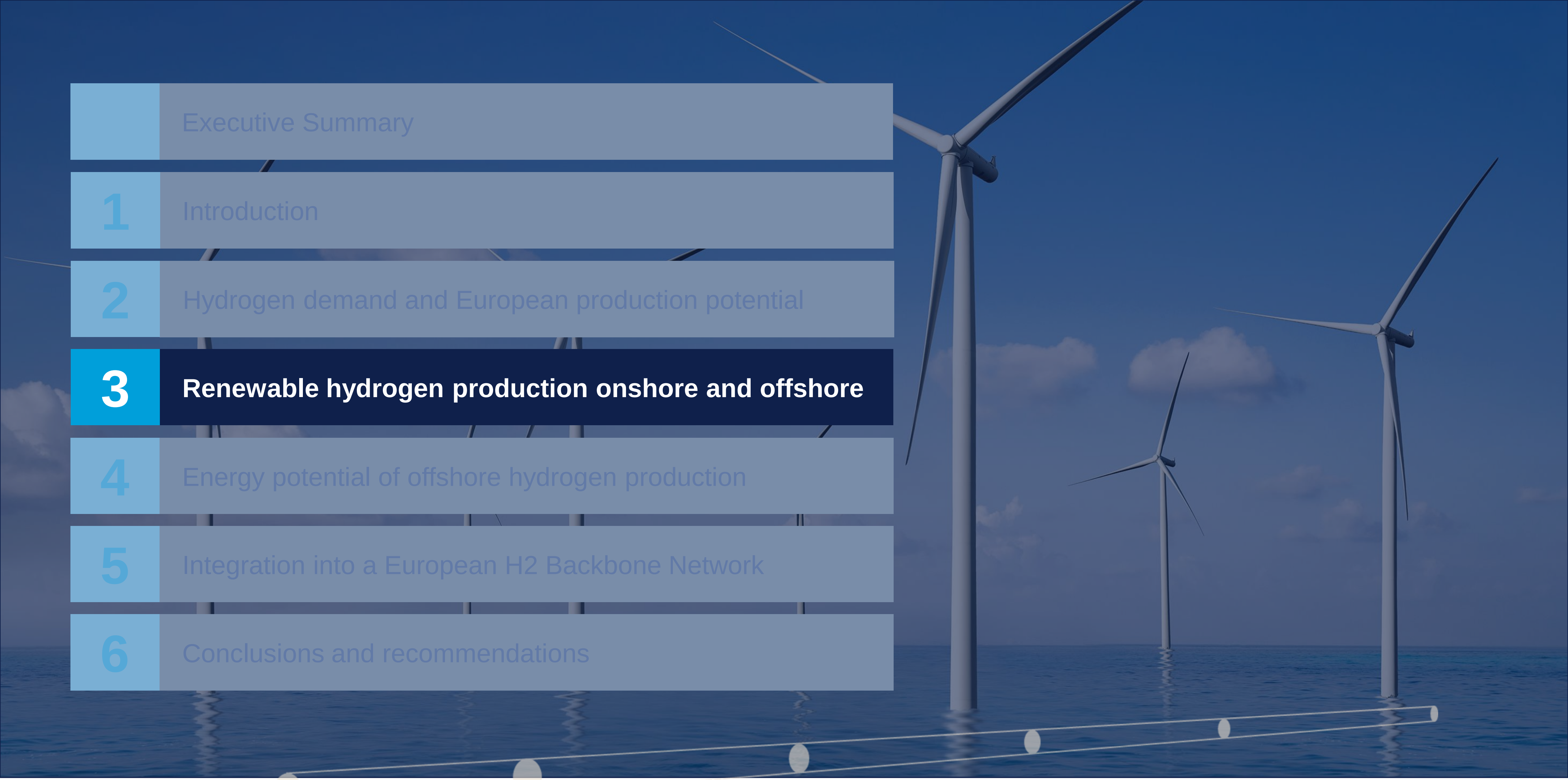
Hydrogen production in Europe

There is a strategic rationale for large-scale hydrogen production in Europe:

- Although hydrogen produced in other parts of the world may be cheaper, given very favourable solar and wind conditions, the cost of shipping and processing of hydrogen and derivatives can be very high. This can make imports of hydrogen less competitive with European production connected to pipelines, which does not need to incur the shipping and processing costs.
- A recent Agora Energiewende report concluded that imports of hydrogen may be uncompetitive with European production given the high transportation and processing costs of shipping hydrogen, and DNV envisages limited interregional transport of hydrogen via ship, with shipping focused on ammonia and other hydrogen derivatives, without being converted back into hydrogen. In similar manner, Aurora Energy Research has concluded that hydrogen imported to Northern Europe by pipeline from Spain and Morocco would be competitive, but that hydrogen imported by ship from the Middle East may not be.
- The current energy crisis has shown that strategically a region should have a balanced resourcing of energy and that relying on a limited amount of energy suppliers can have strong adverse effects on the economy if these relationships fail.

Overall takeaway

1. Hydrogen demand will increase substantially in Europe in the coming decades to meet decarbonisation goals.
2. Under RePower EU alone, green hydrogen production within the EU should reach 330 TWh by 2030.
3. By 2050, hydrogen demand could exceed 2,000 TWh, with a corresponding need for large quantities of green hydrogen production from within the EU to help maintain Europe's energy security.



3. Renewable hydrogen production onshore and offshore

3.1 Introduction

This chapter compares five onshore and offshore hydrogen value chains on cost and spatial footprint characteristics. Hydrogen produced offshore is especially analysed in terms of the distance from shore.

In this chapter, we **compare the economics** and as well **the spatial requirements of five different onshore and offshore value chains** for hydrogen production, to understand which options are the most attractive on cost and spatial footprint criteria. We show that, based on the demand we have elaborated in chapter two of this report, producing hydrogen offshore can be a very attractive option. In particular, the further the distance that lies between the offshore wind turbines and the shore, the more advantageous offshore hydrogen production might be. In many cases, the potential cost of producing the hydrogen in offshore locations may be lower than onshore.

The importance of full-load hours

Electrolysis installations usually consist of the electrolysis itself, a water supply, purification plants for treating the water and tanks for intermediate storage of the hydrogen produced. Other systems are also required for supply and control. The construction of an electrolysis plant is correspondingly capital-expensive, so it is important to operate such plants as close as possible to their nominal capacity for as many hours a year as possible in order to reduce the specific cost per generated energy unit. Since the plants are dependent on the electricity produced from renewable sources. The renewable sources with a higher number of full load hours can achieve lower costs for the hydrogen produced.

Under the climate conditions of Northern Europe, including the given latitudes regarding solar irradiation, the highest full load hours can usually be achieved with **offshore wind**. Onshore wind and solar have significantly lower full load hours on average.

Spatial density

Another important factor is the spatial density at full load, which describes the energy that can be generated per covered area. Here solar is the most efficient technology, as solar panels can be installed at high density levels, whereas onshore and offshore wind energy needs more space as wind cover aspects need to be considered – however, offshore wind is considerably more dense than onshore wind. And offshore hydrogen production has the advantage of a much lower spatial footprint onshore, close to where people live.

Source: DNV

3. Renewable hydrogen production onshore and offshore

3.2 Five hydrogen value chains

DNV has analysed five onshore and offshore hydrogen value chains in Northern Europe, covering renewable energy source, transport of energy, and production of hydrogen, both onshore and offshore.

Five hydrogen value chains

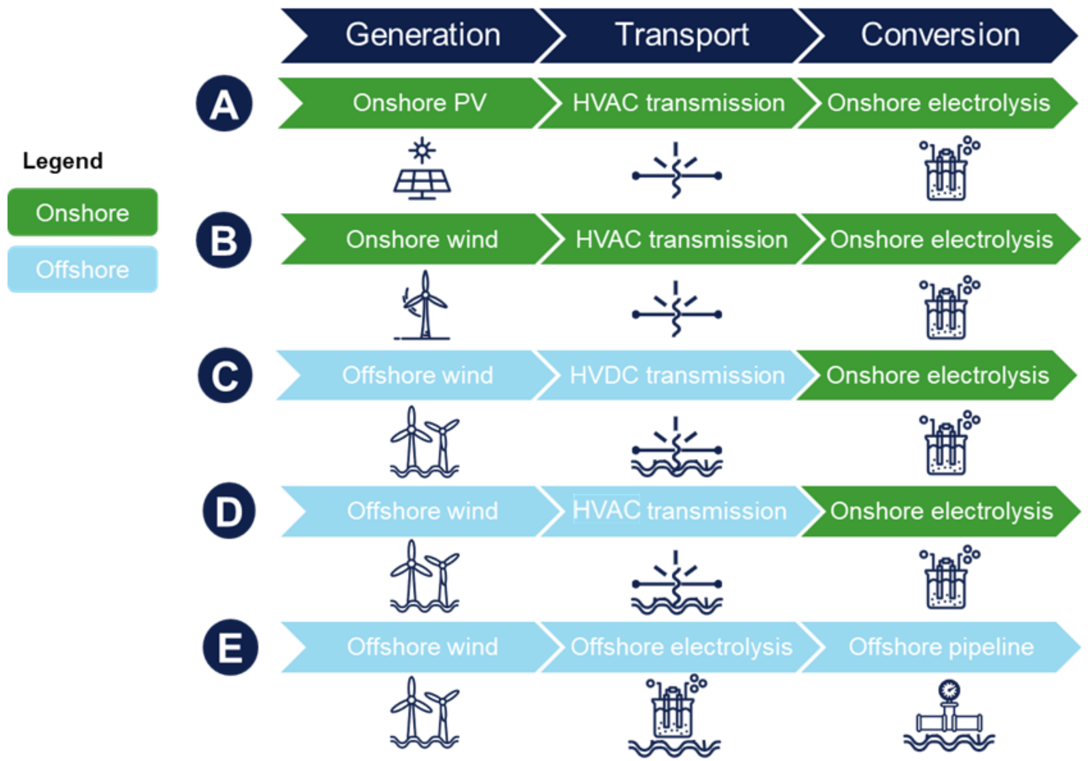
As provided in the introduction in this chapter, five different hydrogen value chains in Northern Europe are analysed for 2030, 2040 and 2050, comparing:

- **Renewable generation assets:**
  - Onshore solar PV
  - Onshore wind
  - Offshore wind
- **Energy transmission vectors:**
  - High voltage alternating current cables
  - High voltage direct current cables
  - Hydrogen pipeline
- **Hydrogen production locations:**
  - Onshore co-located with onshore generation assets
  - Onshore connected to offshore wind
  - Offshore

These value chains are labelled A – E, as shown in the diagram. Note that, in case E, the hydrogen production takes place on an offshore platform co-located with the offshore windfarm, array cables collect the power from the wind turbines and route these to the platform, where electrolysers produce hydrogen from desalinated water and compressors put it into an offshore hydrogen pipeline. In this case it is assumed that no additional electrical infrastructure to land is created. The key determinators are:

- **Levelised cost of hydrogen** (LCOH), calculated for all cases for the years 2030, 2040 and 2050.
- The impact of **distance to shore** on LCOH, to illustrate the breakeven distance where pipelines are more cost effective when compared to cable transmission.
- **Space claim** to produce 1 million tonnes (Mt) of hydrogen, estimated for all cases.

General methodology, assumptions, and inputs to the levelised cost and space claim calculations can be found in the Appendix.



Source: DNV

3. Renewable hydrogen production onshore and offshore

3.3 Comparison of levelised cost of hydrogen – cost breakdown for onshore renewables to hydrogen

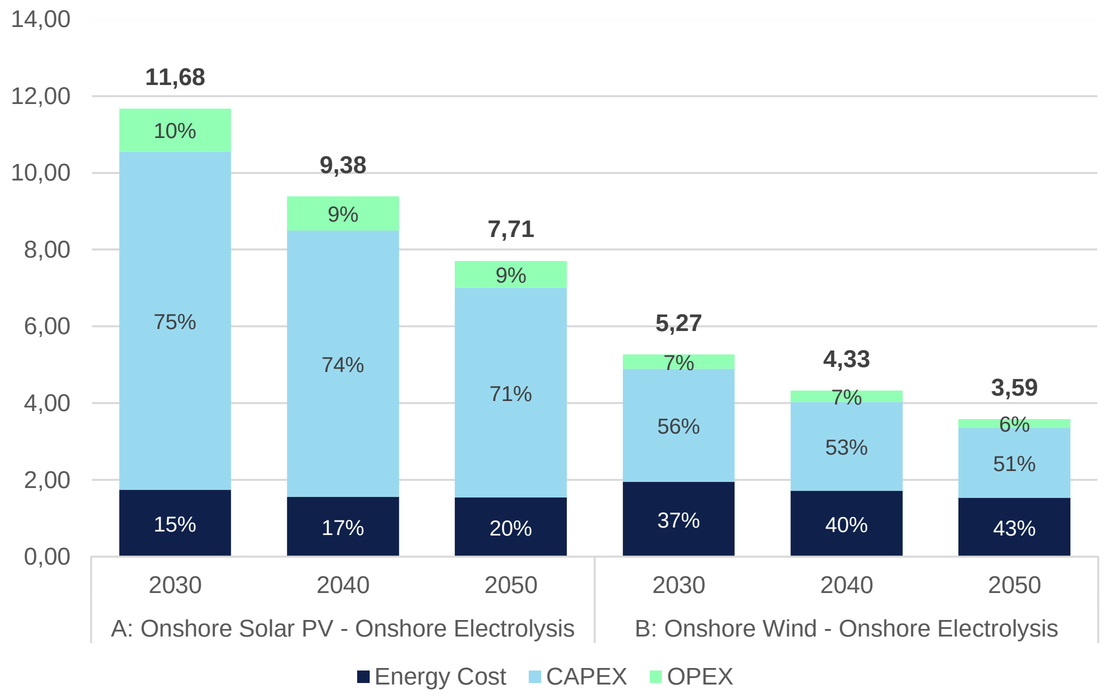
The biggest variable in the LCOH is the CAPEX of electrolysers, which is highest for solar PV, given the low solar load factors in Northern Europe. Onshore wind shows with a higher capacity factor significantly lower LCOH.

Onshore: Energy costs, CAPEX and OPEX

- The low capacity factor of solar PV results in significantly higher electrolyser CAPEX share and thereby the highest LCOH amongst the different value chains considered. This is the case even though the LCOE of electricity produced from solar PV is the cheapest amongst the options considered. Note that a Northern European solar profile is used in this analysis – the comparison is more favourable to solar with a Southern European solar profile (which is outside the scope of this report).
- Hydrogen production from onshore wind has a lower CAPEX share when compared to production coupled to solar PV due to a higher capacity factor.
- As shown on the following pages, even though more transmission infrastructure costs are required for offshore hydrogen production, the CAPEX share for hydrogen production from onshore wind is higher than for offshore production. This is due to the lower capacity factor for onshore wind when compared to offshore wind.
- Over time, the hydrogen production capex is forecast to decrease substantially, mainly due to improvements and cost reductions in electrolyser technology.

LCOH Breakdown – Onshore Renewables to Hydrogen

Units: €/kg H_2



Source: DNV

3. Renewable hydrogen production onshore and offshore

3.3 Comparison of levelised cost of hydrogen – cost breakdown for offshore renewables to hydrogen

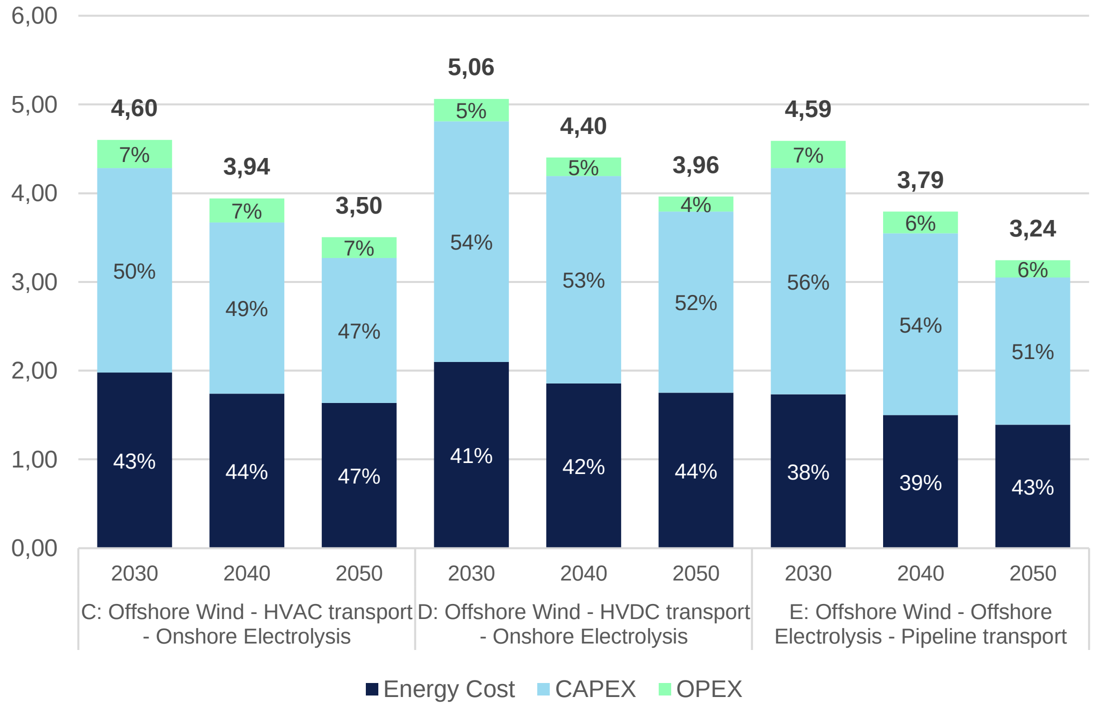
CAPEX is also the biggest component of LCOH for offshore hydrogen value chains. At higher distances from shore, the lower cost of energy transmission through pipelines compared with cables is the main reason why offshore hydrogen production has the lowest cost.

Offshore: Energy costs, CAPEX and OPEX

- CAPEX is the key cost component for all analysed offshore wind to hydrogen value chains, although given higher number of full load hours for offshore wind, the capex share of the Levelised Cost of Hydrogen (LCOH) tends to be lower than for the onshore renewable value chains.
- The differences in LCOH across scenarios C, D and E denote primarily the difference in energy transmission costs through HVAC cables, HVDC cables and hydrogen pipelines respectively.
- Energy transmission LCOH is dependent on the transmission distance. When comparing the LCOH with a 100km transmission distance against a 150km transmission distance, HVAC transmission cost have the highest rate of increase, followed by HVDC transmission costs and then by pipeline transmission.
- For pipelines the capacity increases significantly with the diameter while the investment cost are proportional. On the contrary large scale electricity transport is limited by the cable capacity. AC-transport cables have a maximum capacity of around 350 MW_{el} and DC-cables of 2 GW_{el}. Contrary to pipelines the specific cable investments measured in €/kW/100 km will not decrease with larger capacities.

LCOH Breakdown – Offshore Wind to Hydrogen (150 km Distance to Shore)

Units: €/kg H_2



Source: DNV

3. Renewable hydrogen production onshore and offshore

3.3 Comparison of levelised cost of hydrogen – impact of distance from shore

The transition zone between the most cost-effective option being offshore wind to onshore hydrogen and offshore wind to offshore hydrogen is 100km.

Impact of energy transmissions costs on overall LCOH

A comparison of the impact of **energy transmission costs** on overall LCOH between three options:

1) cable bound **HVDC** and 2) cable bound **HVAC** versus 3) pipeline bound **hydrogen** transmission, shows that:

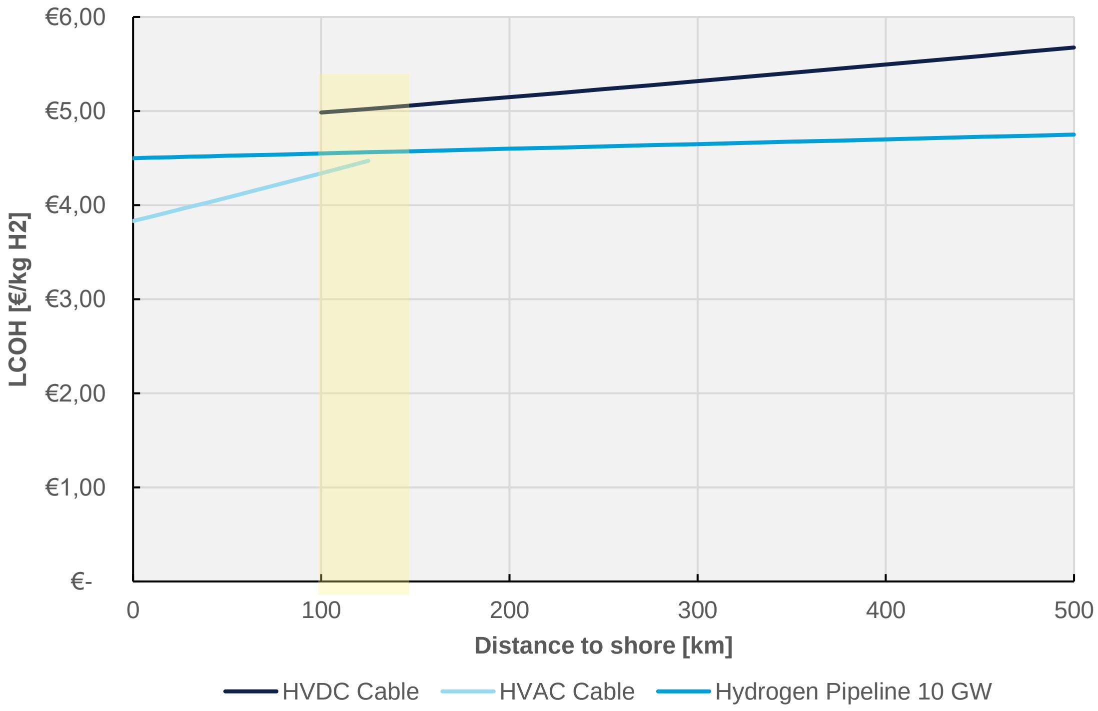
- Up to ~125 km distance from shore, HVAC transmission is more cost-effective when compared to HVDC transmission, and results in a lower levelised cost of hydrogen. In this region however, it is very likely that direct use of the electricity of the wind farms will be the preferred option, rather than producing hydrogen from it either onshore or offshore.
- After the maximum distance limit for cost-effective HVAC transmission is reached (100 – 150 km depending on conditions, as indicated by the yellow shaded region) **hydrogen pipelines offer a cheaper and more scalable mode of energy transport than HVDC transmission.**
- As a backbone pipeline grid can, however, combine the transport of hydrogen from several offshore windfarms, and with that the specific hydrogen transport cost will be even lower. Given this, the discriminating distance for favourable offshore hydrogen production **is therefore around 100km from shore.**

As a result of these points, the total LCOH from offshore hydrogen production greater than 100 km distance to shore will be lower than that of HVDC connected to onshore hydrogen production facilities.

This is likely to create an incentive for offshore wind developers, hydrogen project developers and governments to pursue **offshore hydrogen production**. Note also that it is preferable from a cost perspective to have larger capacity hydrogen pipelines, because the cost does not scale linearly with the capacity, rendering larger pipelines cheaper per capacity.

The above calculations are based on a single dedicated pipeline to shore. A backbone grid can and will combine the transport of hydrogen from several windfarms, given the high capacity of hydrogen pipelines, and with that the specific transport cost will be even lower. We therefore assess that the discriminating distance for favourable windfarms for offshore hydrogen production is around 100km distance from shore.

LCOH from offshore wind by transmission vector in 2030



Source: DNV

3. Renewable hydrogen production onshore and offshore

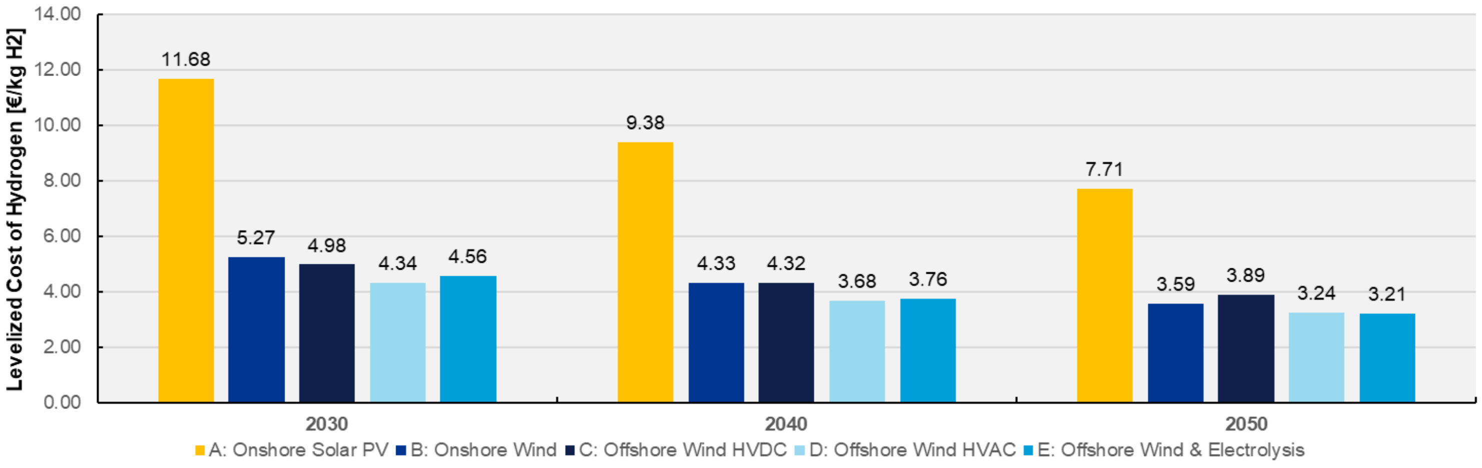
3.3 Comparison of levelised cost of hydrogen – overall results for up to 100km distance from shore

When comparing the onshore hydrogen value chains with offshore value chains at up to 100km distance from shore, the cheapest option overall in 2030 and 2040 is offshore wind using a HVAC cable to power onshore electrolysis. By 2050, however, offshore electrolysis is the cheapest option overall.

LCOH up to 100km distance from shore

- When comparing the different scenarios of production and transmission of hydrogen at up to 100km distance to shore, **offshore wind with HVAC transmission to an onshore hydrogen production facility** is found to be the most cost-effective solution in 2030 and 2040.
- **Offshore electrolysis utilizing energy from offshore wind and subsequent transmission of hydrogen through pipelines to shore** has the second lowest LCOH in 2030 and 2040 but becomes cheaper by 2050.
- The LCOH of all the production technologies are found to decrease from 2030 through to 2050 due to decreasing energy and technology cost.
- Offshore wind based hydrogen production scenarios have in general a lower LCOH when compared to onshore renewables based hydrogen production scenarios primarily due to a higher capacity factor. Onshore electrolysis utilizing solar PV or onshore wind have the highest and second highest LCOH respectively amongst the production technologies compared primarily due to low capacity factors.
- The case of combined onshore wind and solar PV was excluded from the analysis, given the full load hours of the combined option are not additive (e.g. solar PV and wind energy production might be concurrent), and the ratio of solar PV and wind capacity might vary, therefore it is not possible to get a single estimate of full load hours for the electrolyser.

High-level cost calculations for various Northern European hydrogen value chains



Source: DNV

3. Renewable hydrogen production onshore and offshore

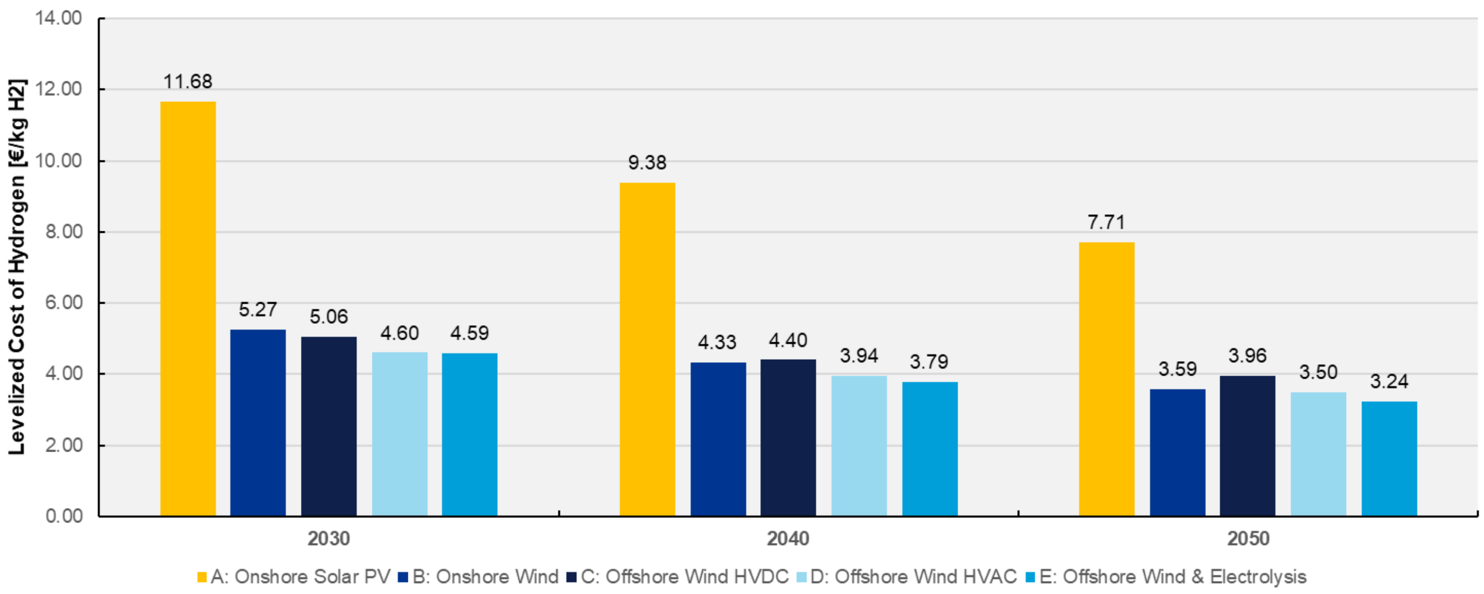
3.3 Comparison of levelised cost of hydrogen – overall results for 150km distance from shore

When comparing the onshore hydrogen value chains with offshore value chains at 150km distance from shore, the cheapest option overall is offshore electrolysis through the full time period to 2050.

LCOH at 150km distance from shore

- When increasing the distance to shore of the offshore wind farms to 150 km, offshore electrolysis utilizing energy from offshore wind and subsequent transmission of hydrogen through pipelines to shore is found to be the most cost-effective solution for all analysed years.
- This trend will continue with increasing distance to shore, as was demonstrated earlier.
- Note also that a backbone grid can combine the transport of hydrogen from several windfarms, given the high capacity of hydrogen pipelines, and hence the specific transport cost would be even lower.
- Even though the absolute differences in levelised cost might seem small, at the envisioned European scale of 10 Mt H_2/yr a €0.01 kg/H_2 increase will result in a €100,000,000,- difference in revenue.

High-level cost calculations for various Northern European hydrogen value chains



Source: DNV

3. Renewable hydrogen production onshore and offshore

3.4 Spatial claim of hydrogen value chains – overall space claim

Solar PV has the lowest overall space claim of the five hydrogen production options, but deployment will be limited by the high levelised cost. Offshore hydrogen production has the second smallest space footprint, mainly due to the lower space requirements of pipelines compared to cables.

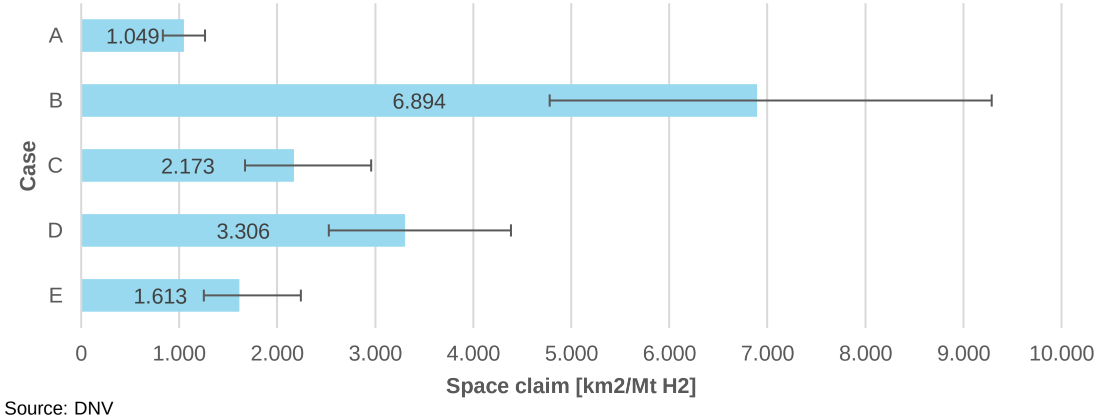
Space requirements

Next to the cost the spatial requirements for the hydrogen generation is important as space is limited in most European countries. On the right, a comparison is made between the overall space claims (onshore and offshore combined) of the five value chains, each producing 1 million tonnes of hydrogen per year. Included in the calculation is the space needed for the renewable electricity generation, the electricity cable or hydrogen pipeline, and the electrolyser. The results provide the following insights:

- Solar PV has a relatively small footprint compared to wind energy based value chains, even though the installed capacity to produce 1 Mt/yr is much larger. Unfortunately, it was shown before that the small amount of full load hours in Northern Europe is a limiting factor for cost effective deployment of this hydrogen production option.
- Between the wind based options, onshore wind has the largest space requirement. This is mainly driven by the relatively small turbines sizes, wake effects and wind sheer effects from nearby onshore structures, yielding less energy per square kilometre, thus driving up the total space required to produce 1 Mt/yr.
- Between the offshore wind based options, the share of space required for power generation is fairly similar:
  - 1,608 km2 for case C, 1,652 km2 for case D and 1,507 km2 for case E.
  - This is driven by the difference in transport efficiency.
- The share of space required for transport differs between cases due to the smaller capacity of HVAC cables, the larger capacity of HVDC cables and the largest capacity per area for hydrogen pipelines.
  - 563 km2 for case C, 1,652 km2 for case D and 106 km2 for case E.
  - In these calculations, the substations and offshore hydrogen production platforms have a negligible impact.

Case	Value Chain Efficiency [% LHV]	Installed capacity [GW_{el}]
A: Onshore solar – onshore electrolysis	64.14%	52.0
B: Onshore wind – onshore electrolysis	64.14%	17.3
C: Offshore wind HVDC – onshore electrolysis	59.20%	11.3
D: Offshore wind HVAC – onshore electrolysis	57.64%	11.6
E: Offshore wind – offshore electrolysis	63.18%	10.5

Space claim for various 1 Mt/yr hydrogen value chains



Source: DNV

3. Renewable hydrogen production onshore and offshore

3.4 Spatial claim of hydrogen value chains – onshore space claim

The offshore electrolysis value chain may also be the most attractive in regions with constrained space onshore – such as parts of Germany and the Netherlands.

Space requirements

As mentioned, in Northern Europe, space onshore is often at a premium. Electrical cable landings have already proven difficult for countries such as the Netherlands and Germany, and these factors might provide an incentive to move hydrogen production offshore.

- As can be seen in the table to the right, for cases C – D the share of space required onshore is a very small proportion of the total space claim.
- The space claim of cases A – B required for onshore power generation is 1,039 km2 for solar PV and 6,891 km2 for onshore wind.
- The space claim of cases A – D required for hydrogen production is 9.55 km2, 3.18 km2, 2.08 km2, and 2.14 km2, and respectively. This is primarily driven by the full load hours of the value chain, and to a lesser extent by the efficiency of the value chain.

Nonetheless, a hydrogen production facility that is placed onshore needs somewhere in the range of 37,500 – 330,000 m2/GW_{el}, depending on compactness of the design and the battery limit, e.g. the inclusion/exclusion of high voltage to medium voltage transformers and hydrogen storage. In this report, we have used the midpoint of the above range to calculate the onshore electrolysis spatial footprint.

The results show, that the **space claim for offshore projects with offshore electrolysis** is in terms of land use the **most favourable**. On the coming page an additional argument in favour of offshore wind electrolysis is made. It deals with the reduced land claim for connections of offshore hydrogen wind farms.

Heat recovery

A possible advantage of onshore application of electrolysers that is often found in literature is the possibility of recovering waste heat produced by electrolysers. Although it is true that waste heat recovery is possible to a larger extent when space is not limited, many of the project developers looking into offshore hydrogen production (where space is limited) are considering utilizing waste heat for enhancing the sea water desalination through membrane distillation.

Value Chain	Space claim total [km2]	Space claim onshore* [km2]	Space claim onshore [%]
A: Onshore solar – Onshore Electrolysis	1,049	1,049	100%
B: Onshore wind – Onshore Electrolysis	6,894	6,894	100%
C: Offshore wind HVDC – Onshore Electrolysis	2,173	2.08	0.1%
D: Offshore wind HVAC – Onshore Electrolysis	3,306	2.14	0.1%
E: Offshore wind – Offshore Electrolysis	1,613	0.0	0.0%

* Onshore space claim is the sum of renewable generation (case A – B) and the hydrogen production facility (applicable for all cases except E).

Artist impression of 1 GW_{el} onshore hydrogen production plant layout.
Source: ISPT

3. Renewable hydrogen production onshore and offshore

3.4 Spatial claim of hydrogen value chains – difficulty of extensive electrical cable landings

The offshore wind targets set in Esbjerg will provide a challenge when landing all energy onshore through electrical cables. Instead, hydrogen pipelines might alleviate this due to their higher individual capacity and lower space requirements.

Difficulty of extensive electrical cable landings

Electrical **cable landings** have already proven difficult for countries such as the Netherlands and Germany. As can be seen on the image below, nature protected areas closely hug the coastlines of the North Sea countries, rendering it difficult to find suitable routes for landing either cables or pipelines.

Pipelines would be advantageous in this sense, given their **relatively larger individual transport capacity**, when compared to cables, thus lowering the total space required for landing the energy onshore.

- Large scale hydrogen transport can be facilitated by pipelines. The capacity increases significantly with increasing diameter, while the investment cost remain proportional.
- Large scale electricity transport is limited by the cable capacity. AC-transport cables have a maximum capacity of around 350 MW_{el} and DC-cables of around 2 GW_{el}. Cable investments will not decrease with larger capacities. The landing of multiple cables in parallel is complicated by the distance requirements between them, which are a technical limit imposed by electromagnetic induction.

Nature protected areas around the coastlines of the North Sea countries

Electricity transmission

BritNed Interconnector

Length	260 km
Investment	600 MEUR
Capacity	1 GW_{el}
Specific investment	230 €/kW/100 km

Gas transport

Bacton-Balgzand Pipeline

Length	230 km
Investment	600 MEUR
Capacity	20 GW_{CH4} capacity
Specific investment	11 €/kW/100 km

Plans for offshore hydrogen infrastructure

If the North Sea countries are pursuing the targets set in the Esbjerg conference of 65 GW_{el} of offshore wind by 2030 and 150 GW_{el} by 2050, the considerations on this page might provide an incentive to move hydrogen production and subsequent pipeline transport, as outlined by recent developments:

- The Dutch ministry of economic affairs has announced the creation of a ‘Energy Infrastructure Plan North Sea 2050’, with the main objective of outlining a guiding framework for the government, TSOs and market parties of the further rollout of offshore wind, hydrogen production at sea, scenarios for reusing existing gas infrastructure for hydrogen transport, and interconnected electricity and hydrogen transportation infrastructure to both the Dutch mainland and to (offshore energy hubs of) our surrounding North Sea countries.

3. Renewable hydrogen production onshore and offshore

3.5 Key takeaways

Producing hydrogen offshore if the coast distance is higher then 100km is the most economic alternative of the compared value chains in this chapter.

This chapter compared five dedicated hydrogen value chains on cost and spatial footprint criteria:

A. Onshore PV to onshore hydrogen production

B. Onshore wind to onshore hydrogen production

C. Offshore wind with HVDC transmission to onshore hydrogen production

D. Offshore wind with HVAC transmission to onshore hydrogen production

E. Offshore wind to offshore electrolysis with transport of hydrogen via offshore pipeline

Levelised cost of hydrogen

A detailed model was set up to compare the LCOH of these five value chains, keeping most elements constant in order to investigate the effects of items such as the renewable source, the transport distance and the hydrogen production location.

Up to 100km distance from shore:

- Value chain *D: Offshore wind with HVAC transmission to onshore hydrogen production* has the lowest LCOH in 2030 (€4.34 per kg) and 2040 (€3.68 per kg).
- Value chain *E: Offshore wind to offshore electrolysis with transport of hydrogen via offshore pipeline* has the lowest LCOH in 2050 (€3.21 per kg).

At 150km distance from shore:

- Value chain *E: Offshore wind to offshore electrolysis with transport of hydrogen via offshore pipeline* has the lowest LCOH in 2030 (€4.59 per kg), 2040 (€3.79 per kg) and 2050 (€3.24 per kg).

In all cases, value chain *A: Onshore PV to onshore hydrogen production* is by far and away the most expensive, due to the much lower full load hours of solar in Northern Europe.

Spatial footprint

The spatial footprint calculation included the space needed for the renewable electricity generation, the electricity cable or hydrogen pipeline, and the electrolyser.

For overall space:

- Value chain *A: Onshore PV to onshore hydrogen production* has the lowest spatial footprint, given the much higher density of solar compared to wind generation. But given the very high LCOH, it is unlikely to be developed at scale in Northern Europe.
- The second lowest spatial footprint is accounted for by value chain *E: Offshore wind to offshore electrolysis with transport of hydrogen via offshore pipeline.* This is mainly due to the more compact nature of pipelines compared to cables and the higher efficiency of offshore electrolysis, given that less electricity will be lost in transit as long-distance electricity cables will not need to be used.

Onshore space is also a big issue in certain regions, including in parts of Germany and the Netherlands:

- Value chain *E: Offshore wind to offshore electrolysis with transport of hydrogen via offshore pipeline* clearly has virtually no onshore spatial footprint.
- Value chains *C: Offshore wind with HVDC transmission to onshore hydrogen production* and *D: Offshore wind with HVAC transmission to onshore hydrogen production* also have relatively low onshore spatial footprints, as the space required by electrolysers is a small fraction of the space required by the renewable generation assets.

Overall takeaway

- Considering the cost, overall spatial footprint and onshore spatial footprint issues, offshore hydrogen production is an attractive option in many cases.
- Given the lower costs and larger capacities of pipelines, and the opportunity for pipelines to aggregate offshore hydrogen production from several windfarms, we assess that the discriminating distance for favourable offshore hydrogen production is around 100km distance from shore.

4. Energy potential of offshore hydrogen production

4.1 Introduction

This chapter provides the spatial insights for both North and Baltic Sea in terms of the potential available capacity of offshore wind with distances further away than 100km from shore.

Based on the analysis in the previous chapter, this chapter will provide more insight into the offshore hydrogen production potential that is available in the North Sea and Baltic Sea – taking into consideration the distance aspect of more than 100 km where the tipping point between onshore and offshore and hydrogen production is calculated.

First, we provide some insight about the currently installed fleet of offshore wind farms in both sea areas and then investigate the current spatial and auction planning. As a next step we apply the above-mentioned threshold and determine the values for offshore wind hydrogen production potential in both sea areas.

This analysis will then develop in chapter 5 to sketch a possible integration of these hydrogen production sites into an offshore hydrogen backbone which then is joined with the planned onshore hydrogen backbone currently under development.

The strong growth we find in the projections in this chapter is based on various initiatives. On the EU level the following are relevant (listed here by historical order):

- **2012 – Blue Growth Strategy:** Marine-based energy (*Blue energy*) is considered a priority area. Noted that by 2030, 14% of electricity demand in the EU could be supplied by offshore wind energy.
- **2015 – Paris Agreement:** The Paris Agreement sets out a global framework to avoid dangerous climate change by limiting global warming. According to IRENA's projections (2019) to meet the goals, the global cumulative installed capacity for offshore wind power would increase to 228 GW_{el} by 2030 and nearing 1,000 GW_{el} by 2050.
- **2019 – European Strategic Energy Technology Plan (SET- Plan):** Mechanism to promote technological development, which includes the objective of consolidating the EU's leadership in offshore wind energy, identifying the development of floating wind power as one of the priority actions.
- **2019 – European Green Deal:** European long-term strategy to 2050 for climate-neutral economy. It highlights that increasing offshore wind production will be essential.
- **2020 – EU Strategy on Offshore Renewable Energy:** Sets the objective of increasing offshore wind energy production capacity in the EU to at least 60 GW_{el} (starting from 12 GW_{el}) by 2030, with a view to reaching 300 GW_{el} by 2050.
- **2022 – RePowerEU:** Proposed to increase the target in the Renewable Energy Directive to 45% by 2030, up from 40% in last year's proposal. This would bring the total renewable energy generation capacities to 1,236 GW_{el} by 2030. Offshore wind is seen as a key part of meeting the overall targets.
- Furthermore, various country strategies or additional pledges propel these plans. Most important of these is the in May 2022 agreed Esbjerg declaration where Germany, Denmark The Netherlands and Belgium agreed on the important the role of home-grown North Sea offshore wind in strengthening the EU's energy security. The pledge agreed in Esbjerg was that these four countries intend to expand the combined North Sea offshore wind capacity to 65 GW_{el} by 2030 and 150 GW_{el} by 2050.

For the analysis done in this chapter especially the plans of Germany, The Netherlands, Belgium, Denmark, UK, Norway, Sweden, Poland and Finland are of relevance and have been used.

4. Energy potential of offshore hydrogen production

4.2 Existing areas (combined view North Sea and Baltic Sea)

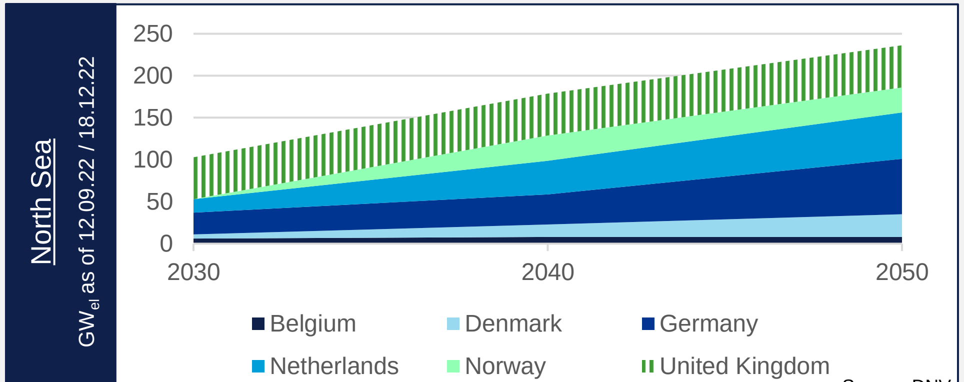
Most of the countries in the Baltic and the North Sea have significant targets in the upcoming years, although policy targets beyond 2030 still need to be confirmed and adjusted in most cases.

North Sea

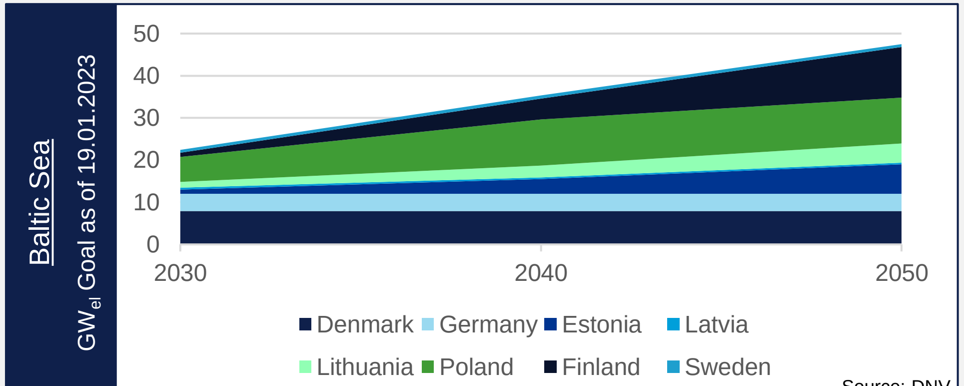
- The North Sea is one of the most active regions in Europe for offshore wind development, with several countries having significant offshore wind projects in operation or under development. The countries with the largest offshore wind deployments in the North Sea include the United Kingdom (currently at 14 GW_{el} overall capacity), Germany (currently at 7.6 GW_{el} overall), the Netherlands, and Belgium.
- The graph on the right shows an estimation for the North Sea only, based on overall policy targets and declarations made in the North Seas Energy Cooperation (NSEC) agreement of 12th September 2022. These are non-binding targets with a considerable possibility that these will still change in the upcoming years, especially beyond 2030.
- The UK targets are only based on a Memorandum of Understanding (MoU) with the NSEC-members as the UK is no longer an official member of the NSEC due to Brexit. The target of 50 GW_{el} displayed, however, is the overall national target and includes sites beyond the North Sea.

Baltic Sea

- All the countries located on the Baltic Sea are actively looking to develop their offshore wind power potential in the future. The graph on the right concerning the Baltic Sea targets is based on the non-binding agreement on goals based on the Baltic Energy Market Interconnection Plan (BEMIP) and the corresponding Marienborg declaration relevant for the Baltic Sea, with the targets issued on 19 January 2023.
- While most targets for 2030 are confirmed by the member states, some countries have not finalised their targets yet, especially for the goals in 2040 and 2050. This said, the front-runners in the Baltic Sea are clearly Denmark (currently at 2.3 GW_{el} overall), Germany and Poland, accounting for around 80% of the foreseen installed capacity in the Baltic Sea by 2030. Denmark and Germany are also expected to focus more on the development in the North Sea, hence the rather static outlook. Poland has no sites commissioned yet.
- Countries like Finland and Estonia are expected to pick up the pace by 2050, although no binding targets have been established. Estonian authorities have estimated the potential to be 7 GW_{el} while Finland expects 12 GW_{el} of potential.



Source: DNV



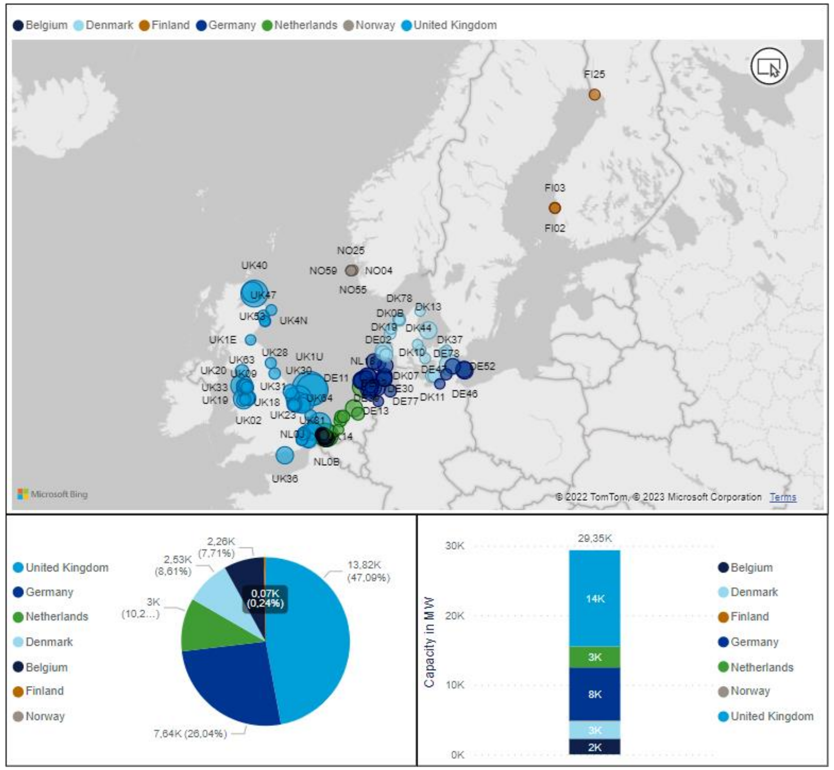
Source: DNV

4. Energy potential of offshore hydrogen production

4.2 Existing areas (combined view North Sea and Baltic Sea)

As of today offshore wind has mainly been realised in zones that are relatively close to shore – with diminishing space in these direct costal zones – that are also quite often national habitats. Consequently, there is an increasing tendency to move deeper into the sea space so that longer distances to shore need to be bridged.

- The majority of windfarms are currently operating in the North Sea, with UK, Germany, Netherland, Belgium and Denmark being the front-runners. In total the current installed capacity in the North Sea is about 29 GW_{el}, producing about 90 TWh of power.
- In the Baltic Sea, especially Denmark and Germany have commissioned the majority of the currently running projects. Here the current installed capacity is about 2.8 GW_{el}, producing about 9 TWh of power. As can be seen on the map, currently the eastern and northern parts of the Baltic Sea, beside countries such as Poland, have not been at the centre of offshore wind project development. This will change over the coming years, as we will see on page 38.
- What can also be seen on the maps is that most of the currently operating plants are nearshore. Over the last decade the areas have grown – with increasing space demands – further away from shore and the respective authorities have already assigned new areas even further out so that the European and local targets for renewable energy production can be met by potentially available space.
- All of these existing offshore windfarms are directly connected and integrated into the respective power transmission grids of the respective countries the sea area belongs to. Discussions on setting up a more meshed power grid for the offshore wind production have recently been started, and the first so called hybrid integrations – where offshore wind farms feed into the grids of more then one country – have recently been realised.
- Hydrogen production offshore is not practiced anywhere today. Just recently the first tender zones have been announced – for example in the German Bight the SEN 1 (95 km2) lease area – to test hydrogen offshore production at a larger scale.



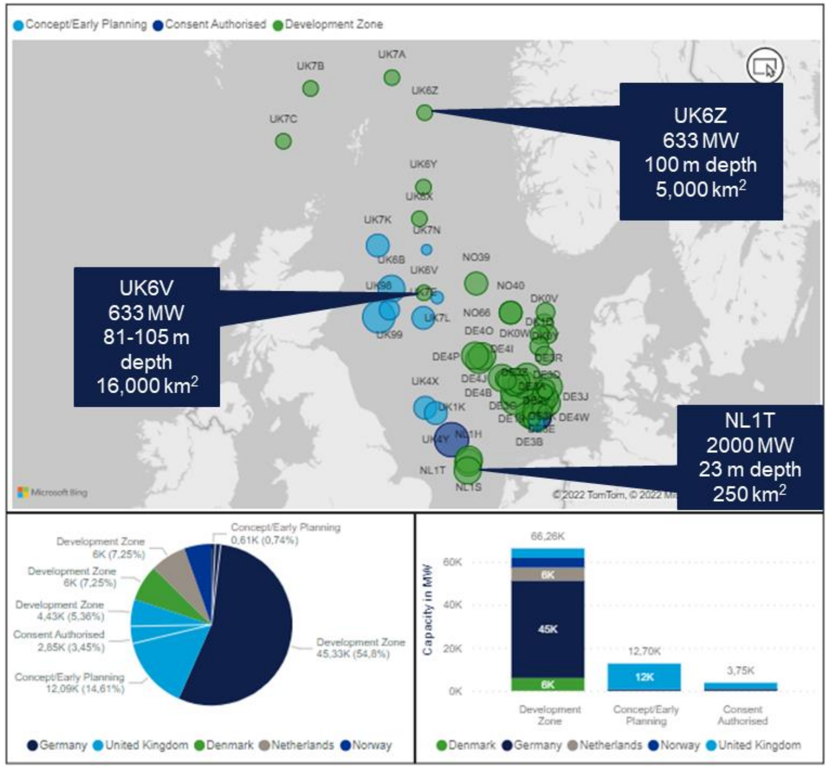
Source: DNV

4. Energy potential of offshore hydrogen production

4.3 Hydrogen generation supply potential – North Sea spatial distribution

The North Sea offers a substantial potential for offshore wind energy production. As a lot of the development potential towards 2050 is rather far away from shore, hydrogen production at these sites is economically attractive.

- The North Sea borders some of the most affluent and populous parts of Europe. It hosts large fishing and aquaculture activity; major shipping lanes; the region's biggest ports; Europe's most important sources of fossil fuels; and growing renewable energy production. Characterised by shallow waters and other conditions suitable for many of these industries, spatial competition will intensify over the coming decades.
- Current planning for offshore wind energy indicate that in addition to the already 29 GW_{el} in operation and around 9 GW_{el} under construction in the region – which are all aimed to be connected by means of electricity – there is at least 66 GW_{el} of potential advertised in development zones and another 13 GW_{el} in an early planning phase which will be coming to life before 2050 and **match the criteria of being a distance of at least 100km from shore,** as laid out in Chapter 3. In addition, there is another 4 GW_{el} which already have been consented by the United Kingdom authorities, and a further 6 GW_{el} developed near the Shetlands.
- The total capacity from these sites adds up to 89 GW_{el} of potential capacity that could/should be used for dedicated hydrogen production. This would provide a production capacity of around **297 TWh/a (LHV), which equals 8.9 Mton of hydrogen.**
- More sites may become available but have not been fully assessed. If these are included the capacity for offshore wind would be 135 GW_{el} resulting in 450 TWh/a or 13.5 Mton of hydrogen (LHV)
- Most of these projects will be German projects, followed by many projects from the Netherlands, Denmark and the UK. The biggest potential can be found in the central North Sea around the Dogger Bank but there also sites reaching up to the Shetland area.
- The three callouts are giving examples of the windfarms in terms of size, water depth and area use.
- For almost all of these wind farms no concrete plans regarding the grid connection exist today. Generally, they could be integrated in the electricity grid or, if an alternative production is preferable, they can also be used for offshore hydrogen production. The possible integration variants do not represent mutually exclusive opposites. On the contrary, mixed forms are also conceivable, so that the future desired energy mix in Europe is achieved in the best possible way, taking strategic considerations into account.



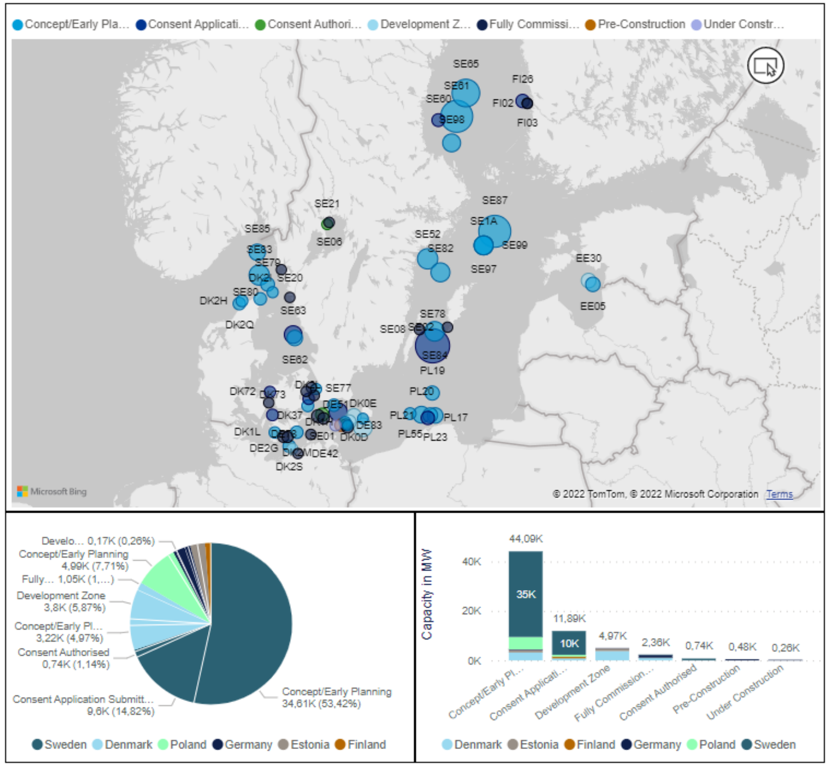
Source: DNV

4. Energy potential of offshore hydrogen production

4.4 Hydrogen generation supply potential – Baltic Sea spatial distribution

Due to the vast potential for the production of green hydrogen in the Baltic region, an offshore backbone is still an economic option despite the offshore areas being closer to shore, as otherwise parallel infrastructures would be needed in Sweden and Finland.

- The Baltic Sea is almost fully enclosed by EU Member States (except for two minor parts of the Russian EEZ). The total area is close to 400,000 km^2, of which 86% has water less than 100 m deep, making it attractive for offshore wind installations. Large parts of the northern Baltic Sea are covered by ice during the winter months, so that activities require extensive ice management.
- The distances to shore in the Baltic Sea, for the currently planned projects up to 2040, are far smaller than in the North Sea, so that the situation for offshore hydrogen production is different. From the perspective of shore distance onshore hydrogen production is economically beneficial.
- Nevertheless, other aspects might change this first evaluation. In Sweden and Finland there are vast opportunities to produce hydrogen both onshore and offshore and transport this hydrogen to the major demand centers in Europe. This may offer a significant European potential and provides Sweden and Finland good export opportunities:
  - Building separate pipeline corridors South from Sweden and Finland is rather inefficient, as there would be a largely parallel line routing.
  - A shared transportation infrastructure is therefore likely to be beneficial from a routing perspective, and this pipeline could be led through the Baltic Sea – where additional capacities in terms of offshore wind hydrogen production can be easily tied in. In addition, this solution may avoid obstructions from the onshore permitting regime for pipelines.
- Currently, Gasgrid Finland and Nordion Energi, gas transmission system operators (TSOs) in Finland and Sweden, have picked up this idea in a consortium with several investment companies. This report assumes therefore that an offshore pipeline might also be the best possible option in the Baltic Sea. It would primarily be driven by the rationale described above, rather than the 100km offshore wind threshold.



Source: DNV

4. Energy potential of offshore hydrogen production

4.5 Key takeaways

Offshore hydrogen production could reach 300 TWh per annum in the North and Baltic Sea. Offshore hydrogen backbones could therefore be a cost-effective way of transporting green hydrogen from the North Sea + Sweden and Finland to the major demand centres in Europe

This chapter provided insight into the offshore hydrogen production potential that is available in the North Sea and Baltic Sea.

North Sea

In the current plans for offshore wind development set out by the countries with a North Sea coastline, there is at least a potential for 89 GW_{el} of offshore wind capacity that would be greater than 100km distance from shore.

- This capacity could be used for dedicated hydrogen production, and would provide a production capacity of almost 300 TWh/a (LHV), which equals almost 9 MTon of hydrogen.
- This is equivalent to around 25% of Europe's 2050 hydrogen demand, as set out in DNV's Energy Transition Outlook main forecast, or around 13% of the overall European hydrogen demand envisaged by the European Hydrogen Backbone study.

This study finds that an offshore **hydrogen backbone** could be an **important enabler** for a significant share of Europe's hydrogen production.

Baltic Sea

The Baltic Sea generally has coastlines less than 100km away, and so the 100km distance for economic offshore hydrogen production is less relevant here.

However, there are other good reasons for an offshore hydrogen backbone in the Baltic Sea. In Sweden and Finland there are vast opportunities to produce hydrogen both onshore and offshore and transport this hydrogen to the major demand centres in Europe:

- Building separate pipeline corridors South from Sweden and Finland is rather inefficient, as there would be a largely parallel line routing.
- A shared transportation infrastructure is therefore likely to be beneficial from a routing perspective, and this pipeline could be led through the Baltic Sea – where additional capacities in terms of offshore wind hydrogen production can be easily tied in. In addition, this solution may avoid obstructions from the onshore permitting regime for pipelines.

Overall takeaway

- An offshore hydrogen backbone could support the production of around 300 TWh of offshore hydrogen in the North Sea, enabling a significant portion of Europe's hydrogen production.
- In the Baltic Sea, an offshore backbone could be a more logical and cost-effective alternative to two parallel onshore North-South pipelines to transport green hydrogen from Sweden and Finland to major demand centres in Europe.

Source: DNV

5. Integration into a European H2 Backbone Network

5.1 Introduction

This chapter outlines the essential aspects of the realisation of an offshore hydrogen network that would connect the far distant windfarms by means of a backbone with a European hydrogen network. It considers the techno-economic factors and provides an initial possible layout.

After outlining the economic aspects of offshore hydrogen production and explaining the possible hydrogen production capacities in the previous chapter, this chapter describes conditions for technical implementation and focuses on the aspect of pipeline integration. In particular, the networking of offshore hydrogen production and a centralised transport of hydrogen via an offshore hydrogen backbone can enable cost-effective large-scale offshore hydrogen production.

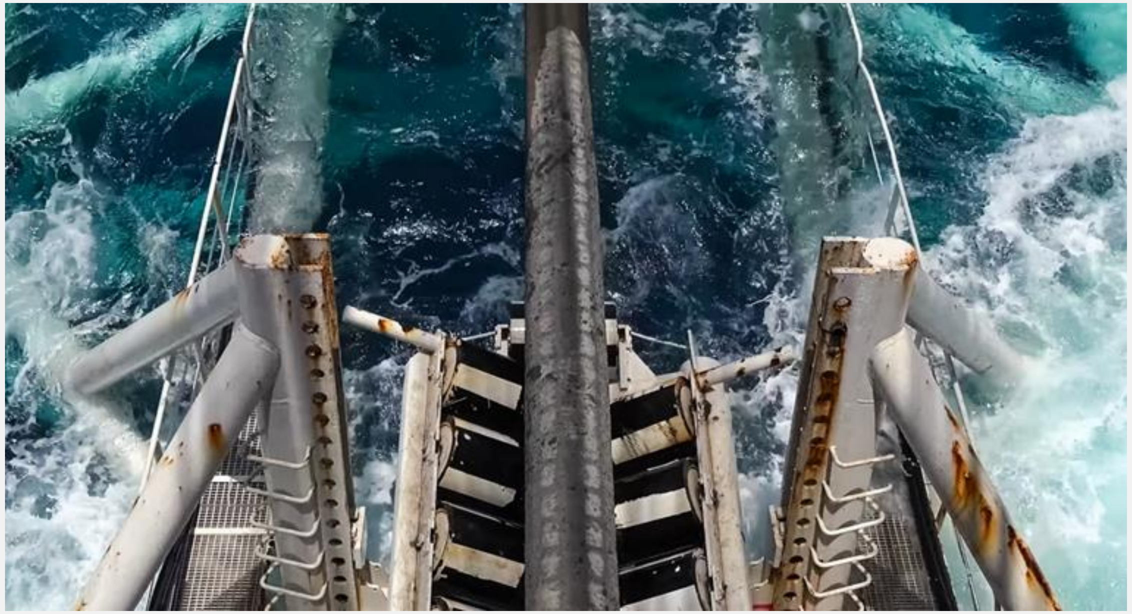
However, this is breaking new technological ground in various respects. On the one hand, hydrogen pipelines have so far only been built onshore and, on the other hand, not in the dimensions necessary for such a backbone. The latter concerns not least the required pressure level, the required diameter and the required materials to ensure safe transport, always.

This chapter outlines the essential aspects of the realisation of such an offshore hydrogen network. The starting point is a network sketch that would integrate the potential areas described in the previous chapter. For the sake of simplicity, this chapter assumes that the areas described are used entirely for hydrogen production. In reality however, mixed forms of hydrogen and electricity use will probably arise in the future. However, the aspect of this combined use is not analysed further in this study. Instead, the aim of this study is to describe in more detail the essential technical aspects of implementing a corresponding offshore hydrogen network and thus to contribute to its future implementation.

The chapter is structured as follows:

In the **first part** of this chapter **technical and economic considerations** for offshore hydrogen pipelines, especially in comparison to onshore hydrogen pipelines and natural gas pipelines (design criteria), will be laid out. Then we will describe key aspects for considering the repurposing of pipelines for hydrogen transport versus the construction of new ones.

The **second part** of this chapter is then devoted to describing and analysing the **layout of hypothetical backbones in both the North Sea and the Baltic Sea**. It will describe the potential routings (taking into consideration also some related initiatives ongoing), the design and the economics of the backbones. The chapter closes with some key takeaways.



Source: DNV

5. Integration into a European H2 Backbone Network

5.2.1 Design criteria of natural gas pipelines vs. hydrogen pipelines

Due to its different volumetric and gravimetric properties, transporting hydrogen is different from natural gas. Offshore hydrogen pipelines need to fulfil specific design criteria for adequate transport capacity and to be operated safely and durably.

Current status – Existing hydrogen pipelines

For transportation of hydrogen in offshore pipelines, both design of new pipelines and re-qualification of existing natural gas pipelines are possible options. Hydrogen has been used in large quantities for over 100 years as a chemical feedstock, in fertiliser production, and in refineries. During this period, several hundred kilometers of hydrogen pipelines have been operated in a safe and reliable way. There are approximately 4,500 km hydrogen pipelines in operation today. However, these are all onshore and designed according to onshore standards. There currently are no offshore hydrogen pipelines, nor are there any available standards for their design.

Physical properties of hydrogen versus natural gas

With regard to technical implementation, there are numerous issues that need to be addressed in order to set up a hydrogen backbone that can be operated safely. When comparing the transport of natural gas, which is common in offshore environments, with the transport of hydrogen – which currently has not yet been conducted in offshore environments – several aspects need to be considered. First, natural gas and hydrogen have different energy content when transported through a pipeline. Natural gas is mostly composed of methane (CH_4) and typically has an energy content of between 34 and 43 MJ/m³ (H_s). Hydrogen has a much lower volumetric energy content than natural gas, with an energy content of about 12.7 MJ/m³). This means that when transporting hydrogen through a pipeline, a much larger volume of gas is required to convey the same amount of energy as natural gas. However, hydrogen is also a much lighter gas than natural gas. For example, at normal temperature and pressure, one cubic meter of hydrogen has about one-ninth of the mass of one cubic meter of natural gas which results in a much higher flow at the same pressure differences. The combination of these two aspects (low calorific value and light gas) have the effect that the energy flow of hydrogen and natural gas are very much comparable.

Pipeline material and wall thickness

Additionally, hydrogen is much more diffusive than natural gas also through steel and it therefore promotes crack growth (embrittlement) as a result of cyclic loads. The effect is limited by avoiding cyclic loads, using less high-grade steels and using a thicker pipeline wall. This also generally limits the reusability of existing natural gas pipelines for the purpose of hydrogen transport. For re-qualification, intervention may be necessary to reduce fatigue on welds

There are still uncertainties related to how hydrogen gas or blends may affect the mechanical properties of pipe materials. This is currently under investigation in several research programs. In 2021, DNV launched a Joint Industry Project to develop a Guideline for Design, Construction and Operation of Offshore Hydrogen Pipelines[1]. The Guideline will also cover re-qualification of existing natural gas pipelines to hydrogen use. Parallel to this, there are several other initiatives in the industry looking at conversion of existing natural gas pipelines to hydrogen use.

The probability of hydrogen embrittlement occurring in hydrogen pipelines can be reduced by a combination of:

- Low partial pressure of hydrogen
- Low temperatures
- Pipeline material selection
- Conservative design (low hoop stress) and
- Suppression/damping of pressure fluctuations, e.g., through storage

On the next page, we look at these factors from the perspective of the hydrogen pipelines that have already been realised onshore and explain the differences between these projects and the offshore backbone approach outlined in this chapter.

In summary, natural gas transport pipelines have been in use for many decades, both onshore and offshore, and although there are similarities with hydrogen transport, key differences are that hydrogen pipelines have not yet been applied offshore, the required wall thickness is higher (or the pressure and with that the capacity is lower) and different materials would be selected. Further research is ongoing.

1: DNV H2Pipe JIP.

5. Integration into a European H2 Backbone Network

5.2.2 Design criteria of offshore pipelines vs. onshore pipelines

The design criteria will need to be based on loading scenarios that are typical for the offshore domain, and include material choice, pressure regime, diameter, utilisation strategy, stability considerations, connection to geological hydrogen storage and compatibility of secondary assets.

Pipeline loading and failure mechanisms

The loading (forces acting on the pipeline) and failure mechanisms differ significantly for onshore and offshore pipelines. For onshore pipelines, external and internal corrosion and third-party damage are particularly considered. For offshore pipelines, more dynamic loads (due to seabed movement) on the pipelines are investigated and fatigue and buckling are specifically considered.

Design criteria

1. **Material choices.** The first issue relates to the material choices of today's hydrogen pipelines and what would be needed for offshore installations. It is important to note that hydrogen can embrittle certain steels, so it is crucial to carefully select the steel based on its mechanical properties, corrosion resistance and on the hydrogen service conditions.

2. **Pressure regime.** The next aspect is the pressure regime that is applied. Any gas transport in a pipeline will result in a loss of pressure due to friction of the gas with the pipeline wall. This pressure drop increases with transport distance – therefore a pressure regime needs to be selected that can deliver the required output pressure at the end of the pipeline. Whilst onshore pipeline are mainly utilised at 100 bar for long distance transport and at considerably lower levels if the distance is lower, offshore pipelines would need to operate – due to the higher distance – rather at pressure levels around 200 bar.

3. **Diameter.** In general, it can be said that pipelines with large diameters (inches) are more cost-effective, as they can transport more energy. This is due to the fact that, when doubling the diameter, the transport capacity increases by more than quadratic.

4. **Utilisation.** Even though a pipeline is designed for a certain pressure, operators often choose to lower the default pressure during operations. The utilisation equals the operational pressure divided by the design pressure. In designing a pipeline (system), there is a trade-off between increasing the diameter of the pipeline (which increases pipeline material cost), increasing the design pressure (increasing the compressor capex and opex) and setting the utilisation / operational pressure.

5. **Vertical and static stability.** The design should make sure that the pipeline will be stable at the soil of the bottom of the sea so that no floating can occur nor that the pipeline can move on the soil due to impact of waves and streams. Recommended practices exist to ensure a stable design. Mitigation measures may include weight coating, trenching, burial, mattresses, structural anchors etc.

6. **Connection to geological hydrogen storage.** About 30% of the annual production volume from offshore wind needs to be stored for short (days) or longer (year) periods. This has consequences for routing, capacity to the salt caverns in northern Germany and for the pressure cycling of the pipelines and thus have implications for material and wall thickness.

7. **Secondary assets**. To operate the backbone and to allow for maintenance and inspection facilities such as valves and pig launching and receiving stations need to be part of the overall design. Also flow and other measurement equipment specific to hydrogen must be added.

Overall, as the offshore pipeline accessibility is very limited in comparison to onshore pipelines, circumstances are quite different and lengths and diameters larger, the design will need to be based on these differences and requirements related to the offshore environment.

5. Integration into a European H2 Backbone Network

5.2.3 New pipelines vs. repurposed natural gas pipelines – technical requirements

Repurposing existing natural gas pipelines is not straightforward. A detailed analysis on each individual pipeline segment and applicability for the requirements of capacity and lengths is needed to identify its usefulness.

New pipelines

The design parameters of newly constructed pipelines can be well matched to the required transport capacity and operational parameters such as temperature, pressure and pressure fluctuations. For example, by using steel grade API 5L PLS2 -X42 and X52, which are proven for use with hydrogen gas.
It is generally recommended that only API 5L PLS2 grades of steel with lower strength (X52 or lower) be specified, keeping hoop stresses low and allowing "standard" pipeline sizes, materials and welding procedures developed for natural gas pipelines to be used.

Repurposed pipelines

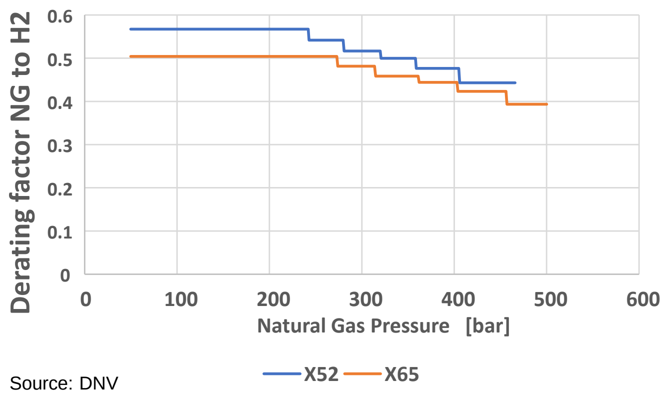
Repurposing means using an existing pipeline for purposes other than its original intended use, for instance transporting hydrogen instead of natural gas. The repurposing of a pipeline system must be coordinated with upstream and downstream assets.

Repurposing can be achieved with or without modifications of the pipeline system, depending on:

- Safety issues related to change of transported fluid
- Physical properties of the transported fluid
- The transported fluids impact on the pipeline systems material properties
- Operating conditions
- Lifetime

Repurposed pipelines shall comply with relevant safety and integrity requirements, similar to pipeline specifically designed and constructed for transportation of hydrogen. The Re-Stream project[1] concluded that most offshore pipelines – typically API 5L steel grade X65, with a Maximum Allowable Operating Pressure (MAOP) of 160 bar, and a diameter of >24 inches – can be reused for pure hydrogen,
based on the current state of knowledge and standards. Individual pipelines will need to go through re-certification and thorough examination of the integrity of the pipeline systems. If the combined load cases and effects of hydrogen gas on pipeline structural materials do not result in a significant increase in the probability of leaks or bursts, it is considered feasible to demonstrate safety levels equivalent to current operation with natural gas. However, the assessment was based on using the ASME B31.12 standard for hydrogen piping, which lacks offshore specific design limits. The ASME B31.12 has a penalty factor for these higher-grade steels (X65, X70 and above, see graph below) which are typical for current offshore pipelines, which will result in a low MAOP and therefore a relatively low transport capacity. Next to the pipeline material, also the materials used in welds, valves and flanges should be subject to investigation to make sure the materials (including those of welds) are compatible.

Concluding, there are many remaining uncertainties regarding repurposing of offshore natural gas pipelines for use with hydrogen.



Source: DNV

The derating factor in ASME B31.12 determines the Maximum Allowable Operating Pressure (MAOP) of the pipeline operating with hydrogen, and always results in a reduction of pressure when compared to operation with natural gas.

1: DNV, Carbon Limits, "ReStream - Study on the reuse of oil and gas infrastructure for hydrogen and CCS in Europe," 2021.

5. Integration into a European H2 Backbone Network

5.2.3 New pipelines vs. repurposed natural gas pipelines – cost (1/2)

Many offshore natural gas pipelines exist today, which might be repurposed for use with hydrogen at around 10% of the cost of building new pipelines. However, there are a number of other aspects that need to be taken into account.

There is still little experience worldwide with offshore pipelines for hydrogen transportation. To this end, cost estimates in various studies vary quite a bit. An overview from relevant literature can be found in the table to the right.

Metric for comparing pipeline cost

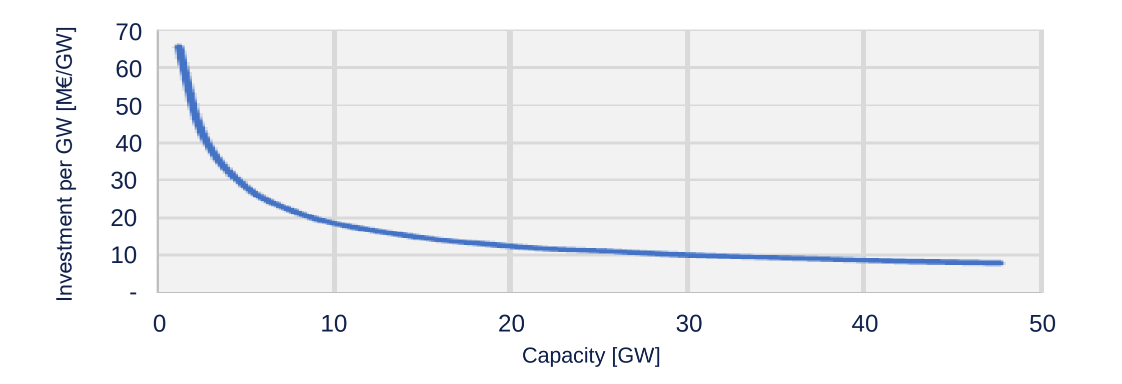
The cost of pipelines is best compared using the unit k€/inch/km, as this scales almost linearly with the material requirements for the pipelines and does not depend on the chosen pressure regime. In general, it can be said that pipelines with large diameters (inches) are more cost-effective, as they can transport more energy. This is caused by the fact that, when doubling the diameter, the transport capacity increases by more than double. This effect can be seen in the image to the right.

Natural gas pipeline repurposing cost

The European Hydrogen Backbone study[1] states that the capital cost per km of refurbished *onshore* hydrogen pipelines would amount to ~15-30% of the cost of newly built hydrogen pipelines. This same figure is estimated at ~10% in the case of *offshore* pipelines, mainly driven by their relatively higher capex cost. The estimate for offshore will, however, be highly uncertain, given there are no existing reference cases for converting offshore natural gas pipelines to hydrogen. The offshore cost will depend critically on amount of intervention, inspection and testing required to re-purpose for hydrogen use.

The cost aspect is even more complicated as existing pipelines will have a shorter remaining lifetime, may not come available for free (if a new market for H2 and CO2 pipelines emerges), may have to be maintained for a number of years between its abandonment and its re-utilisation, may only be used for a number of years due to a smaller diameter whereas hydrogen production will develop over time and may only be applicable for a part of the distance. On the following page we detail some of these aspects.

1: European Hydrogen Backbone, "A European hydrogen infrastructure vision covering 28 countries", April 2020



Specific investment cost for a hydrogen pipeline with increasing pipeline capacity (assumed inlet pressure: 100 barg, outlet pressure 30 barg, length 100 km).
Source: DNV

Type	Low	Typical	High	Units	Source
Newbuilt	30	-	72	k€/inch/km	TNO
Repurposed	0.3*	-	7.2*	k€/inch/km	TNO
Ratio	1%	-	10%	-	TNO
Newbuilt	92	101	124	k€/inch/km	European Hydrogen Backbone
Repurposed	8.3	10.8	13.2	k€/inch/km	European Hydrogen Backbone
Ratio	9%	11%	11%	-	European Hydrogen Backbone
Newbuilt	90	119	157	k€/inch/km	North Sea Wind Power Hub

5. Integration into a European H2 Backbone Network

5.2.3 New pipelines vs. repurposed natural gas pipelines – cost (2/2)

The overall practical cost for reusing pipelines within the hydrogen backbone needs to be analysed on a case-by-case basis. The overall repurposing cost may be similar to building new pipelines.

Cost comparison for repurposing existing pipelines

The cost for repurposing pipelines is estimated to be very low. However, the following aspects are to be considered as well for a more reliable comparison. For this an economic model has been set up.:

1. Remaining lifetime of the existing pipelines. To compensate for this it is assumed that after the useful lifetime (which could be ageing or lack of capacity) of the pipeline it will be replaced by a new one with sufficient capacity. The period over which the calculation is done is set at 40 year. The new pipelines will have a zero value and the replacing pipelines have a remaining value that will be rated with the same percentage as in aspect 2. No decommissioning cost are taken into account.
2. The price to be paid for these pipelines to hand over to hydrogen transporters (if a new market for H2 and CO2 pipelines emerges), Although the alternative for a natural gas pipeline owner may be to completely decommission the pipeline it is also possible that it will be revalued and comes with a cost for the hydrogen transporting company. The percentage in the model varies from 0% to 50% of the remaining value. This percentage is also used in aspect 1.
3. There may be a gap in time between the end of the original use and the re-utilisation for hydrogen. During this period the pipeline needs to be maintained. The opex for this is set at 0.5%. For normal operations this is 1%
4. Limited applicability due to a smaller diameter or a lower MAOP. The pipeline may have only a limited utilisation period as the required transport capacity may only be sufficient for a limited period as the hydrogen transport capacity builds up. At the moment the remaining capacity falls short a new pipeline is constructed.
5. The needed capacity for hydrogen transport of the pipeline will probably build up over a number of years.
6. The existing pipelines may not be at the optimal location so that a part of the connection will have to be newly build. See graph on the right. The part that needs to be added varies from 0% to 25%

Five example cases have been identified to compare repurposing pipelines with newly build ones. As can be seen in the table the modelled cost are varying from 57% (a relatively positive case) to 117% (an unfavourable case). In the above calculations, the down rating of the operational pressure (see page 44) is not yet included as this is very specific and depends on diameter, lengths, flows and allowable pressures.

1: European Hydrogen Backbone, "A European hydrogen infrastructure vision covering 28 countries", April 2020.
2: Power-to-Hydrogen IJmuiden Ver, TenneT.

	Compensation	Gap	Diameter existing pipeline	Build up of hydrogen	New build	Remaining. Life	Refurbish cost	Cost repurpose /cost new
Case	% of remaining value	year	Inch	year	%	Year	%	%
1	0%	0	36	20	0%	20	10%	77%
2	25%	5	28	10	25%	20	15%	124%
3	0%	5	36	10	20%	30	10%	109%
4	50%	3	32	15	15%	20	12%	114%
5	10%	10	28	15	0%	15	10%	103%

Case study for connecting IJmuiden Ver to the Maasvlakte[2]. The left picture is for a 400 MW_{el} offshore electrolyser, the middle for 1 to 2 GW_{el} (required pipeline diameter: 16", resp. 36"), the right picture is for > 2 GW_{el}. Yellow lines are reused natural gas pipelines, green lines are newly built hydrogen pipelines. Source: DNV

5. Integration into a European H2 Backbone Network

5.2.3 New pipelines vs. repurposed natural gas pipelines – other considerations

Even though it may technically be possible to repurpose a pipeline, other factors such as availability, realisation time, future-proofness, ecological impact, footprint of the landfall, and societal value are likely to play a role in the choice to repurpose.

Non-technical factors that might influence the choice of repurposing versus building new pipelines

Next to technical and safety criteria, there might be other considerations that influence the choice of repurposing pipelines for hydrogen transport versus building new pipelines as part of a hydrogen backbone.

1. **Availability.** A key issue for the reuse of natural gas infrastructure is the time frame in which it can be made available for repurposing. This is determined by several factors, such as the current business case for transporting natural gas, with future demand and natural gas price playing an important role. Furthermore, long-term transportation agreements between operators of the gas fields and transportation infrastructure, sometimes without specified end date.

2. **Realisation time.** In general, the lead time for building offshore infrastructure for hydrogen transport is not part of the critical time frame for projects, provided that the spatial procedures are started in good time and orders are issued for new construction or conversion. Construction of new offshore hydrogen pipelines indicatively takes 5 to 6.5 years, including permitting. Reuse of existing pipelines indicatively takes 2.5 to 3 years including re-certification.

3. **Future viability.** Future-proofing factors for an offshore hydrogen backbone are technical lifetime, capacity and connectivity. The technical lifetime of pipelines is an important issue, which applies to existing and new pipelines. It is currently not yet demonstrated if repurposed pipelines feature a reduction in service life, therefore it is unsure if the service life of a hybrid (repurposed + new pipelines) backbone can be guaranteed. Furthermore, the infrastructure will need to be deployed with sufficient transport capacity, such that it can meet the required (future) transport capacity. For newly constructed pipelines, this is part of the design process, whereas for repurposed pipelines this might provide a bottleneck, caused primarily by limitations in Maximum Allowable Operating Pressure (MAOP). Then, connectivity needs to be considered. Further development into an offshore hydrogen network will involve interconnecting multiple hydrogen production facilities to demand centres by connecting existing, reused, pipelines or newly constructed pipelines. Redundancy will also need to be built into such a network so that the security of hydrogen supply is not compromised in the event of a single pipeline failure. In addition, possible future storage of hydrogen in offshore gas fields would increase the flexibility and utilisation of the hydrogen network.

4. **Ecological impact.** The ecological impact of constructing, operating and decommissioning new offshore hydrogen pipelines versus reusing existing infrastructure can be divided into three phases: The construction phase (high impact), the operational phase (low impact) and the decommissioning phase (high impact). The ecological impact of constructing new infrastructure will be higher than that of reusing existing infrastructure, mainly driven by soil degradation and habitat loss due to pipe laying. Assuming the same rules (will) apply to new and reused infrastructure with respect to decommissioning, there is no significant difference in the ecological impact of removing reused infrastructure versus new infrastructure.

5. **Landfall and footprint.** When connecting the offshore pipeline to an onshore landing point. A spatial constraint may occur when selecting a suitable route to land the pipelines. Usable space on a route is determined by mainly three factors: Morphological uniformity (soil properties), areas of natural value and spatial constraints due to existing infrastructure and enclosed areas (e.g. military). Repurposing pipelines has a positive impact on landfall, as space on (especially) the North Sea coast is a limiting factor.

6. **Societal value.** In many cases, offshore infrastructure is partially owned by national governments through organisations such as pension funds. Therefore, the residual value that this infrastructure represents might not be easily be depreciated in an accelerated fashion, since it was financed by tax-payers. Governments are likely to promote repurposing where possible for this reason.

Overall, while there are cost benefits and several other advantages to repurposing existing offshore natural gas pipelines to hydrogen, there are also many challenges to repurposing offshore. We expect that newbuild pipelines will be needed in many cases for an offshore hydrogen backbone, and assume newbuild pipelines in our cost calculations later in this chapter.

5. Integration into a European H2 Backbone Network

5.3 Outlining a European offshore hydrogen backbone – Analysis

The preliminary set-up of a backbone is based on connection to major wind farm areas, including existing initiatives, integration with the European onshore hydrogen backbone initiative and connecting countries around the North Sea and the Baltic Sea.

After we have discussed the basic technical and economic aspects that need to be considered for offshore hydrogen pipelines in the last subchapters, in the following we take up the analyses of the fourth chapter with regard to suitable potential areas for hydrogen production in the North Sea and Baltic Sea individually. For this purpose, we first address the relevant framework conditions for the construction of such a backbone network. We then link the production areas described in chapter four via pipelines and connect them to suitable feed-in points of an assumed onshore hydrogen network. Finally, we explain the technical details of the network infrastructure, such as the required pressure levels, and conclude with the costs associated with the construction.

European offshore hydrogen backbone – analysis boundary conditions

For the analysis of what a European offshore hydrogen backbone might look like, some boundary conditions were set, based (partially) on the results of previous chapters. These are the following:

A. All major areas of present and future windfarm development in the North Sea and Baltic Sea further than 100 km offshore should be included,

B. Landing points of hydrogen should be selected based on industrial ports with existing natural gas infrastructure, and facilitate integration into the onshore European hydrogen backbone,

C. Expected connections between countries should be included,

D. The flows are expected to be bi-directional; This is to facilitate connections between countries and to and from storage. Although this may not be applicable to all pipelines the MAOP is expected to be similar throughout the hydrogen backbone.

E. Existing initiatives should be considered and where possible included.

To elaborate on boundary condition E: In the analysis we take various studies into account that have previously dealt with the idea of a backbone and, as such, provide relevant input into the analysis.

These studies are:

1. RWE, Equinor H_2 pipeline from Norway to Germany
2. RWE, GasUnie, GASCADE, Shell AquaDuctus pipeline
3. GasUnie offshore backbone in Dutch EEZ
4. The Finnish and Swedish gas transmission system operators (TSOs) Gasgrid Finland and Nordion Energi, and offshore wind developers OX2 and Copenhagen Infrastructure Partners (CIP) have initiated the development of a hydrogen backbone in the Baltic Sea.
5. North Sea Energy Programme, Energy Hubs & Transport Infrastructure in the Dutch EEZ (2022)
6. North Sea Wind Power Hub (GasUnie, TenneT, Energinet) Research papers:
   - Hubs and Spokes, viable beyond theory (2022)
   - Unlocking the North Sea as a green Powerplant (2022)
   - Integration of offshore wind (2022)
7. Benefits of an integrated power and hydrogen offshore grid in a net-zero North Sea energy system, Martínez-Gordón et. Al. (2022)
8. Comparing hydrogen networks and electricity grids for transporting offshore wind energy to shore in the North Sea region. A spatial network optimisation approach, Brosschot (2022).
9. Repurposing of NGT and NOGAT natural gas pipelines, Offshore hydrogen transportation through re-used natural gas pipeline on the North Sea - Noordgastransport

These initiatives include announced pipelines, tenders for dedicated offshore hydrogen production, scientific and industrial research on hybrid hubs, energy islands and the integration of wind energy into to the Northern European energy system. They will support the set up of an offshore hydrogen backbone and show the need for a coordinated action. Especially initiatives 1, 2 and 3 are adapted explicitly in the proposed hydrogen backbone in this study, while initiative 4 outlines a very similar backbone in the Baltic sea.

5. Integration into a European H2 Backbone Network

5.3.1 Spatial results North Sea – Potential routing of offshore backbone

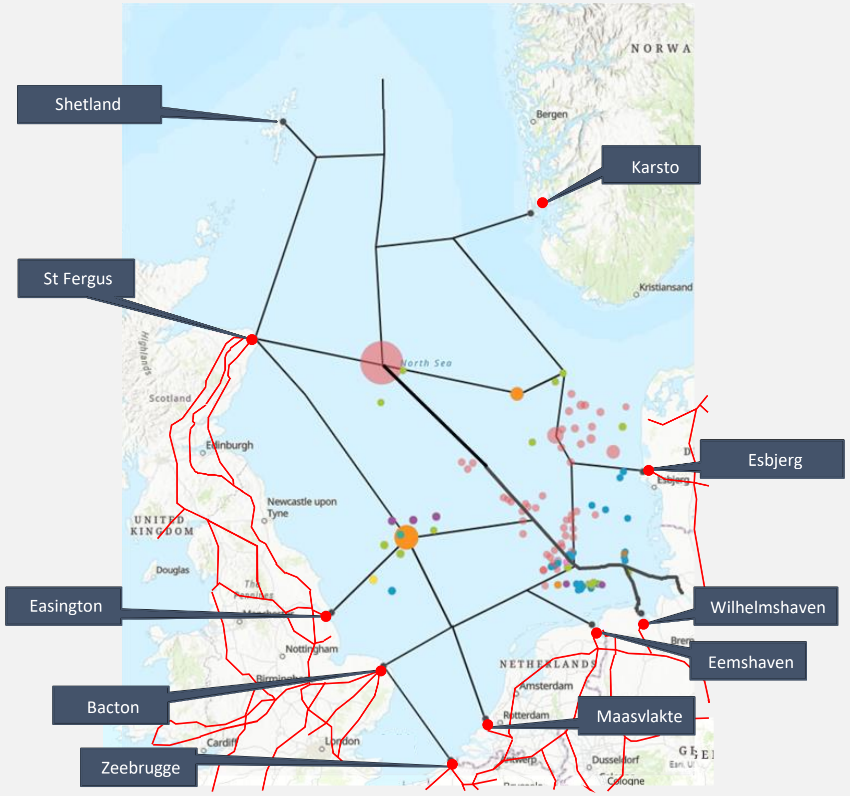
A preliminary design of a meshed backbone connects the main landing point of the onshore hydrogen network around the North Sea and the foreseen main areas of offshore hydrogen production. It also facilitates flows between countries and connection to hydrogen storage in salt caverns.

Windfarm locations and land integration

To integrate the offshore wind farms evaluated in chapter four into a hydrogen backbone, the question quickly arises as to the course, which is essentially shaped by the positions of the individual generation areas in relation to each other and the integration points into the onshore hydrogen grid. Due to the fact that onshore planning is already relatively advanced, numerous integration points can be identified along the North Sea coast. These are:

1. **Shetland**, as it may be a location for onshore hydrogen production connected by cables to near shore windfarms. This hydrogen can be transported to mainland Britain.
2. **Karsto** in Norway is not connected to the onshore backbone but is already a major gas and condensate terminal.
3. Two sites in UK **Easington** and **Bacton**, which are foreseen to be integrated into the UK backbone
4. **Zeebrugge** (BE), **Maasvlakte** and **Eemshaven** (both NL) in the Benelux – each of these with major planned hydrogen activities that combine use in Chemical plants with foreseen activities to transport hydrogen to other areas (e.g. the Ruhr area in Germany)
5. **Wilhelmshaven** in Germany – the foreseen main hub for hydrogen imports in Germany. Which, together with Eemshaven, also is important due to the geological formations in the Northern part of Germany with significant salt cavern storage potential.
6. **Esbjerg** in Denmark – the central energy port on the west side of the Danish coast

In such a setup, all North Sea countries could benefit from the development of an integrated pipeline system. By interconnecting with important import hubs and integrating storage reservoirs, such a network would enable a secure hydrogen supply for all countries tied to it.



Source: DNV

5. Integration into a European H2 Backbone Network

5.3.2 Spatial results Baltic Sea – Potential routing of offshore backbone

A preliminary design of an offshore hydrogen backbone for the Baltic Sea includes a direct connection to the South Scandinavian areas, and facilitates export of hydrogen and integration with storage in salt caverns. It avoids building an extensive onshore infrastructure.

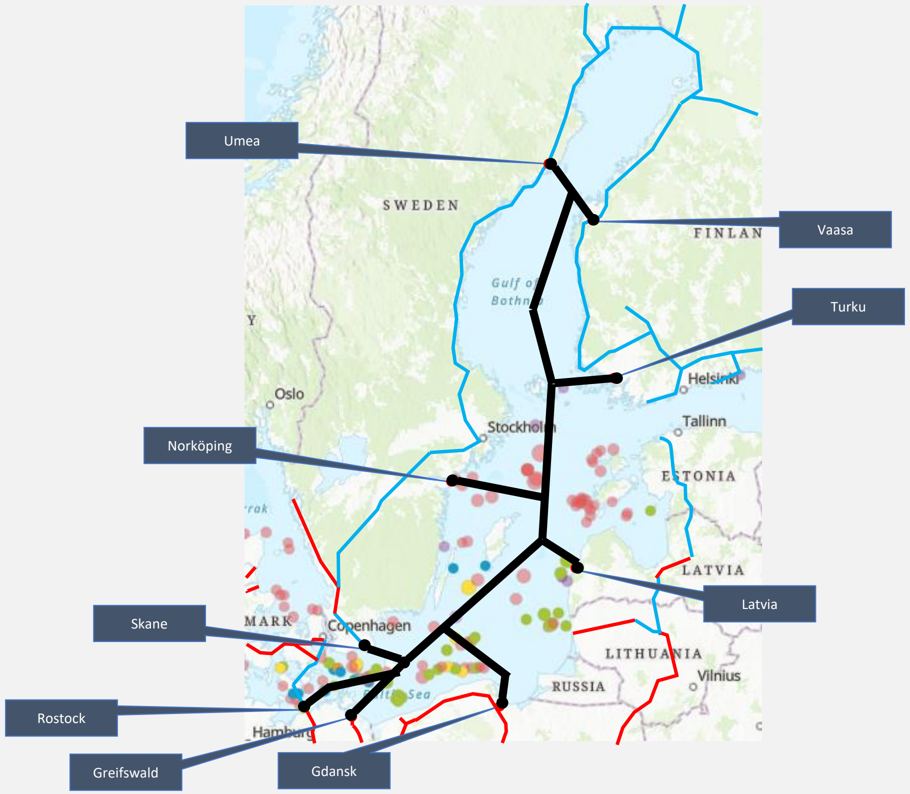
Windfarm locations and land integration

A first draft of the hydrogen backbone for the Baltic Sea is shown on the map on the right.
It indicates:

1. The possible onshore pipeline network, which needs to be newly constructed. This is shown on the right by the blue lines. The red pipelines are existing natural gas pipelines to be converted to hydrogen transport.
2. The indicated landing points. The landing points in the south are selected as these connect to the existing pipelines. The other landing points are examples of how this may be realised. This may be changed when the hydrogen production in and around the Baltic sea will develop over time.
3. The projected offshore backbone alternative (black lines). If the production potentials of the wind farms and the points of connection to the onshore grid are considered for route finding, the result is an internationally meshed grid that will essentially be characterised by a north-south load flow. Its total length is about 1900 km.

Considerations to choose an offshore alternative are that it is directly connected to the storage facilities in Northern Germany, and it facilitates the export of hydrogen to mainland Europe. The total investments of the offshore alternative may be lower as the pipeline length is less than the onshore alternative and compression needs are expected to be lower as well due to the shorter distance to storage facilities. However, a further detailed investigation, including the local use of hydrogen, the need for storage capacity and export quantities, will give a more accurate estimate.

This design is also aligned with the Swedish and Finnish initiative (see page 48).



Source: DNV

5. Integration into a European H2 Backbone Network

5.3.3 Technical details of proposed backbone – North Sea

Key characteristics of the hydrogen backbone show a general North–South flow pattern through an internationally meshed grid of 4,200 km of pipeline that operates at 200 bar.

If the production potentials of the wind farms and the points of connection to the onshore grid are taken into account for route finding, the result is an internationally meshed grid that will essentially be characterised by a north-south load flow.

Its main characteristics are as follows:

Pipelines

- Total length is 4,200 km. This has been determined based on the preliminary setup. It includes the AquaVentus initiative, the RWE and Equinor connection between Norway and Germany and the pipelines as initiated by Gasunie.
- Diameter for pressure drop calculations is assumed to be 48 inch.

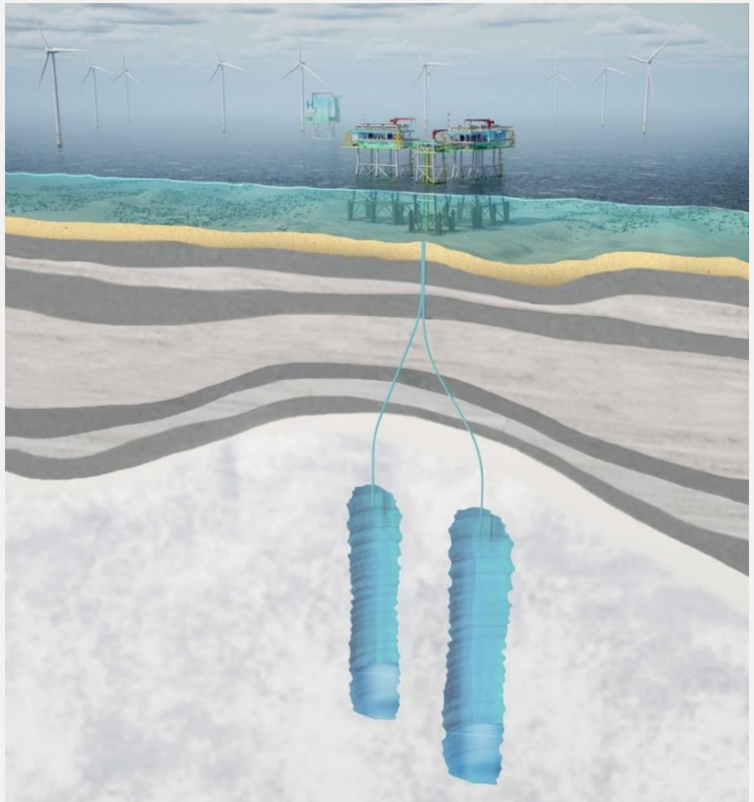
Compression

- Pressure regime should be at a level of 200 bar to facilitate transport flexibility based on a diameter of 48 inch. This has been assessed by simulation of the South-East part of the North Sea and calculating hydrogen transport from Norway to Germany (details on the simulation can be found in the Appendix).
  This requirement limits the use of existing pipelines due to pressure restrictions, connected to the derating factor in ASME B31.12 as discussed in chapter 5.2.3.

Storage

- Connection to sufficient storage capacity (around 30% of the annual production needs to be stored on shorter – intra daily or, longer – seasonal scales to obtain a near continuous supply profile) will be a requirement for any sustainable energy source. The hydrogen backbone should be able to facilitate this as it connect to Northern Germany and the Netherlands where sufficient salt formations exist.

More details and insights under which assumptions the above results have been obtained, are provided on the following pages.



Source: Tractebel Overdick

5. Integration into a European H2 Backbone Network

5.3.3 Technical details of proposed backbone – North Sea Pressure regime and diameters

A partial simulation of the hydrogen backbone network, including the AquaDuctus pipeline shows that the required pressure, even with 48-inch pipelines is over 100 bar to achieve a receiving pressure of 50 bar

Required pressure calculation

A detailed analysis for the pressure regime of the backbone is at this stage not possible - it would demand a more detailed planning of the pipeline system which is not the purpose of this study. Nevertheless, an approximation can be carried out by the following two approaches:

1. A partial hydraulic simulation of the gathering function of the network has been done. This includes the projected AquaDuctus pipeline, as this is one of the key connections, especially for connection to the hydrogen storage in salt caverns and it is a more concrete application. This approach is outlines on this page.
2. A pressure drop calculation for the connecting pipeline between Norway and Germany for long range hydrogen transport as initiated by RWE and Equinor, with an assumed capacity of 25 GW_{H2}. This approach is outlined on the next page.

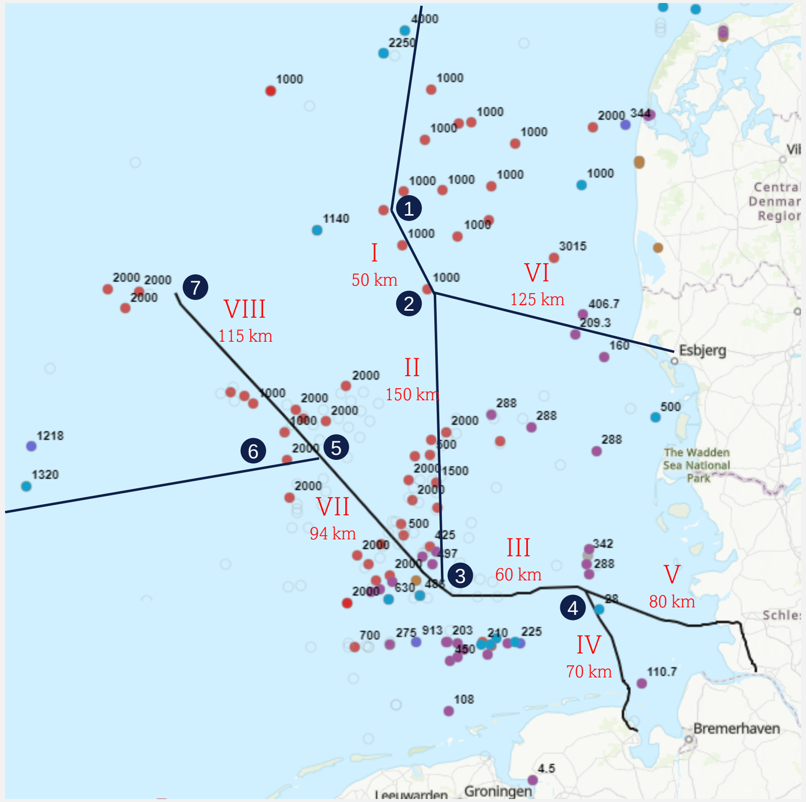
Partial simulation

In the graph on the right the part of the network that has been used for the partial simulation is shown. It contains 7 nodes (indicated by dark blue circles) and 8 pipeline sections (in Roman numerals).

The calculation is based on the gathering of hydrogen produced by the indicated windfarms, of which the momentary design capacity is shown in the graph. An overview of the hydrogen amount that is transported, as well as the characteristics of the pipelines have been summarised in tables in the Appendix. There, both the short windfarm name and the nominal size are given. For some windfarms the capacity has been assessed for this study. These values are indicated with an asterix (*). It is assumed that the flow at node 2 is evenly split between pipelines II and VI and at node 4 between pipelines IV and V. The diameter of the pipelines are selected at 48 inch.

Results

The resulting **operating pressure** to facilitate the transport of hydrogen produced by the projected windfarms is **107 bar** (at the inlet of pipeline VIII) with an assumed receiving pressure of 50 bar at the landing locations in Germany.



Source: DNV

5. Integration into a European H2 Backbone Network

5.3.3 Technical details of proposed backbone – North Sea Pressure regime and diameters connecting pipeline

A calculation for the required pressure to transport hydrogen from Norway to Germany shows that a pressure of 200 bara is required to transport 25 GW_{H2} (8.4 MNm3/h)

Hydrogen transport between Norway and Germany

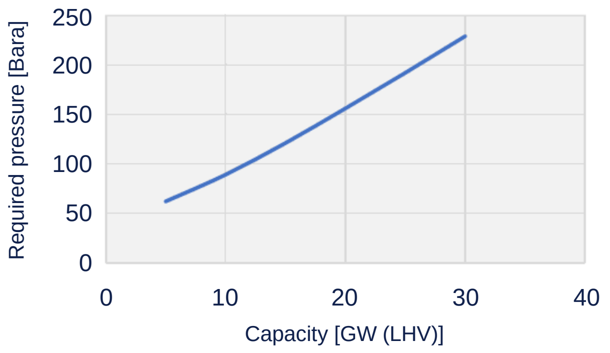
To determine the required inlet pressure for transporting hydrogen from Norway to Germany, the involved pipeline sections have been used to perform calculations. The pipeline is shown in the graph on the right. The assumed pipeline diameter is 48 inch.

In the graph below the required inlet pressure is calculated for varying capacities of the pipeline. For 25 GW_{H2} capacity the inlet pressure is calculated to be 192 bara. This 25 GW_{H2} is about half the capacity that is summarised in the table in the Appendix: the windfarms produce 46 GW_{H2} at full load.

Recommendation

To build for a future situation it is recommended to design the pipeline for 200 bar. This will allow for the export of hydrogen from the area, connection between countries with reasonable capacity, application of storage facilities, line pack capabilities and flexibility of use of the pipelines.

The DNV Joint Industry Project (JIP) H2Pipe[1] is currently investigating design, construction and operation of offshore hydrogen pipelines with a pressure up to 250 bar. Although these pipelines are not yet commercially available, DNV and the JIP partner companies do not foresee major technical bottlenecks for the realisation of such pipelines. The economic feasibility with regards to material selection of the pipelines and auxiliary equipment will need to be demonstrated in the upcoming decade.



Source: DNV

Source: DNV

1: DNV H2Pipe JIP.

5. Integration into a European H2 Backbone Network

5.3.3 Technical details of proposed backbone – Baltic Sea

Although the precise hydrogen production volume in the Baltic Sea is still to be determined the export capabilities for 30 GWH2 require a 150 bar pressure regime with 48 inch diameter and for 40 GW_{H2} this is 200 bar.

Estimation of capacity

The potential amounts of hydrogen production in the Baltic Sea are still only preliminary estimates. An estimate of diameter and operating pressure have been assessed as follows:

1. The total capacity of hydrogen production is 30 GW_{H2} to 40 GW_{H2}.
2. The production is evenly distributed along the export pipeline.
3. The pipeline has one similar diameter
4. Hydrogen is injected into the pipeline at the most northern point and every 100 km along the pipeline.
5. The estimated length of the export pipeline is 1000 km (and of the side branches around 900 km)
6. The output pressure is 50 bar.

The pressure drop of each segment is calculated. The results are in the table below.

			Starting point	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6	Point 7	Point 8	Point 9	End point
Length		km	0	100	200	300	400	500	600	700	800	900	1000
Case 1	Flow	GW_{H2}	3,6	7,3	10,9	14,5	18,2	21,8	25,5	29,1	32,7	36,4	40,0
	Pressure	bara	194,5	194,3	193,3	191,0	187,0	180,7	171,1	157,3	137,4	107,2	50,0
Case 2	Flow	GW_{H2}	2,7	5,5	8,2	10,9	13,6	16,4	19,1	21,8	24,5	27,3	30,0
	Pressure	bara	148,4	148,2	147,5	145,9	143,0	138,4	131,5	121,7	107,5	86,5	50,0

Conclusions

For a 30 GW_{H2} hydrogen production the pressure regime would be 150 bar and for 40 GW_{H2} 200 bar, while the pipeline diameter is 48 inch.

Source: DNV

5. Integration into a European H2 Backbone Network

5.3.4 Economic details of proposed backbone – North Sea

The cost of the pipelines for the outlined hydrogen backbone will add only 13 to 20 €ct/kg to the levelised cost of hydrogen.

Cost of the North Sea hydrogen backbone

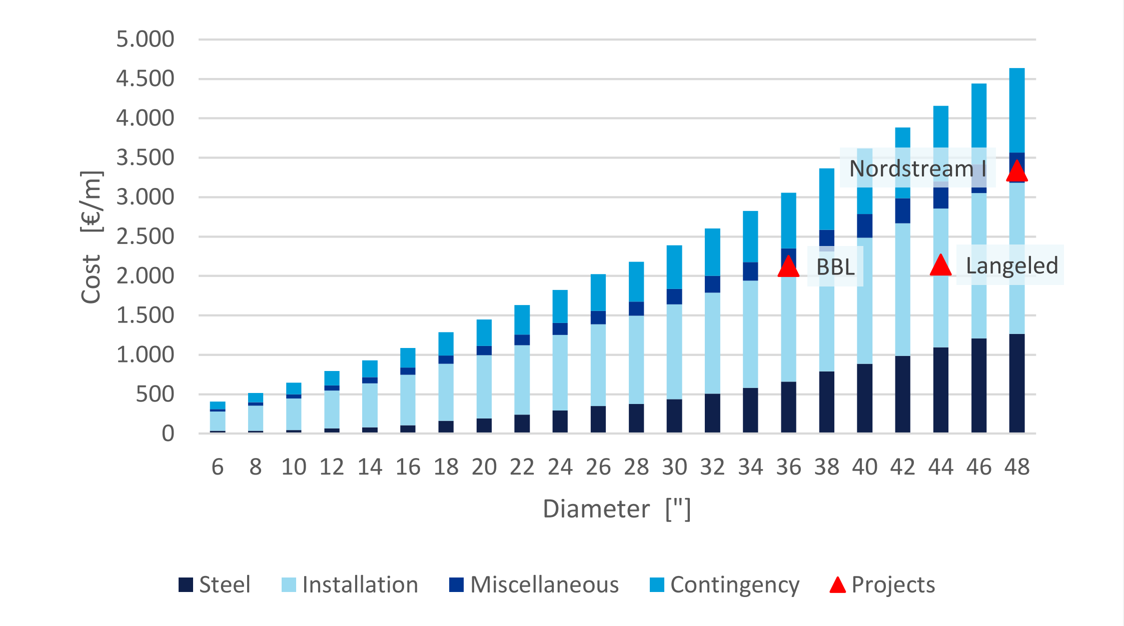
DNV uses a model to calculate the cost of the pipeline that incorporates cost of steel, construction work, miscellaneous and uncertainty. The high level results are shown in the graph on the right. Also the investment cost of three realised major natural gas pipelines in the North Sea and Baltic Sea are shown. As can be seen the cost for hydrogen pipelines are higher due to recent cost increases but also as a result of wall thickness and pipeline stability measures.

For the North Sea, the total length of the projected backbone is 4.200 km. Assuming a range of 36 to 48 inch the price will range from 3.000 to 4.500 €/m of pipeline.

With the assumptions presented in the table below the added LCOH are from 0.13 to 0.20 €/kg of hydrogen, which is 4.0 to 6.6 €/MWh. As the overall levelised cost of offshore hydrogen is in the range of 3 to 5 €/kg. this is an addition of only 2.6 to 6.7%.

Inputs		Levelised Cost	
Variable	Value	€/MWh	€/kg H_2
WACC	8%		
Lifetime	40 year		
Opex	1%		
Hydrogen production	297 TWh/a 8.9 MT/a		
Cost @ 3000 €/m		4.0	0.13
Cost @ 4500 €/m		6.0	0.20

Next to the pipeline cost itself the compression cost need to be considered – which will add to the LCOH. These are detailed on the following page.



Investment figures for hydrogen pipelines depending on the diameter.
Source: DNV reference database.

5. Integration into a European H2 Backbone Network

5.3.4 Economic details of proposed backbone – Cost of hydrogen compression

The cost of the compressors for the hydrogen backbone will add only 6 to 8 €ct/kg to the levelised cost of hydrogen.

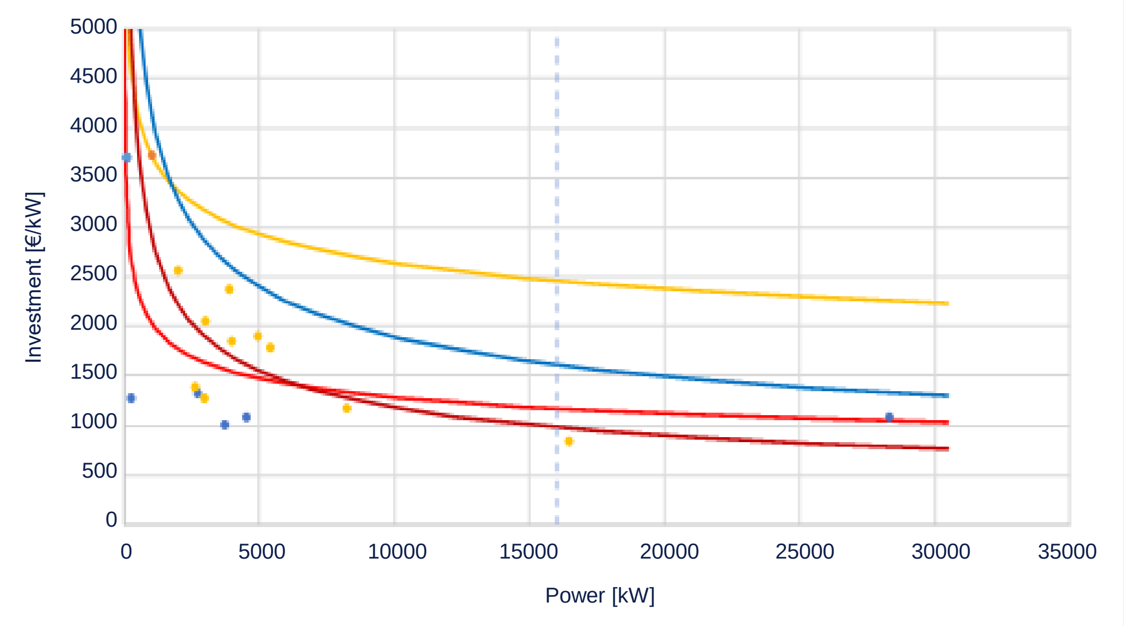
Cost of the compression North Sea hydrogen backbone

The cost of a compressor vary significantly with the size. The maximum capacity of nowadays compressors is around 16 MW_{el} (input power). This is indicated in the graph on the right. Assuming centralised compressors for a windfarm, the outlet pressure of the electrolysers to be 30 bar and the inlet power for the hydrogen backbone 200 bar, a set up of 4 compressors with each 50% of the total required capacity and 200% installation cost, the investment for a 1 GW_{el} windfarm are 46 M€ and for a 2 GW_{el} windfarm 66 M€.

With the assumptions presented in the table below the added LCOH are from 0.06 to 0.08 €/kg of hydrogen, which is 2.0 to. 2,7 €/MWh. As the overall levelised cost of offshore hydrogen is in the range of 3 to 5 €/kg. this is and addition of only 1.2 to 2.7%.

Inputs		Levelised Cost	
Variable	Value	€/MWh	€/kg H_2
WACC	8%		
Lifetime	20 year		
Opex	4%		
Cost 1 GW_{el}		1.7	0.078
Cost 2 GW_{el}		2.4	0.056

Overall, the pipeline and compression cost is expected to sum to around 10% or less of the total levelised cost of hydrogen. Additionally to the pipeline and compression cost, also storage needs to be considered as a third component adding to the LCOH. The economic aspects of storage will be considered on the next page in order to complete the economic picture..



Investment figures for hydrogen compressors. Dots are individual reference prices and lines represent fitted models.
Source: DNV reference database.

5. Integration into a European H2 Backbone Network

5.3.4 Economic details of proposed backbone – Cost of geological hydrogen storage

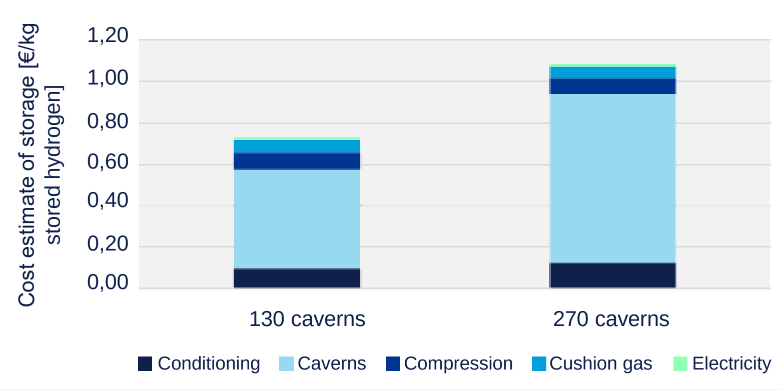
The cost of geological storage of the hydrogen will add 22 to 35 €ct/kg to the levelised cost of hydrogen

Cost of storage of North Sea hydrogen backbone

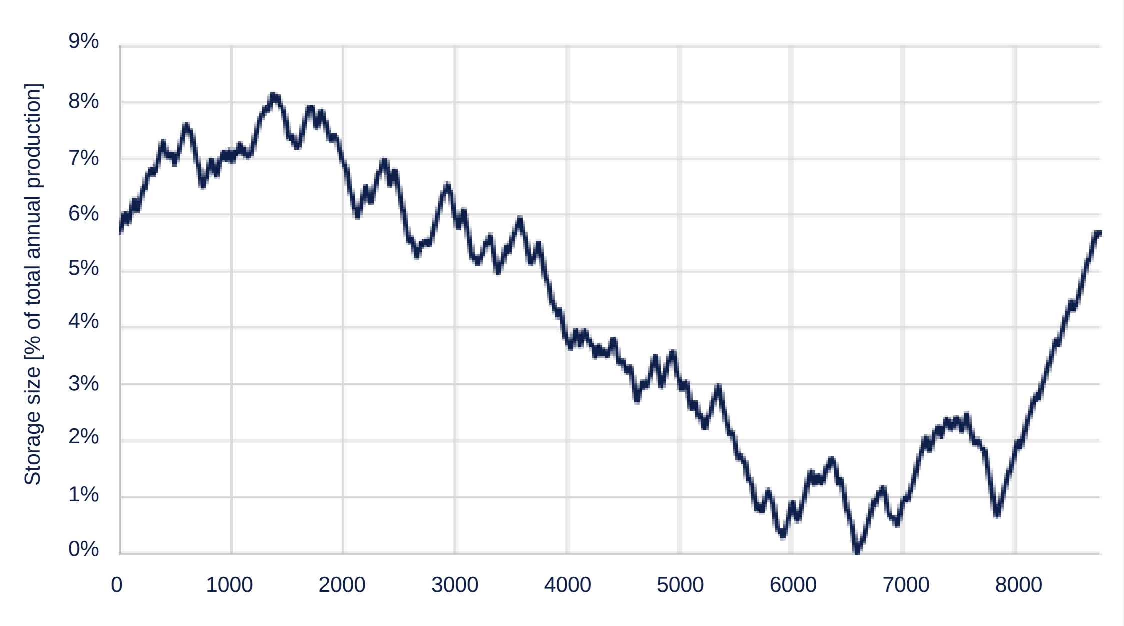
Although storage is not part of the hydrogen backbone it is a key enabler for the hydrogen economy and the backbone will facilitate transport from the production area to the storage and subsequently to the end user. An example of the amount of energy in storage from a windfarm to end-users with a near constant demand profile is shown in the graph on the right. As can be seen it follows an annual profile which is driven by the wind conditions. In this case the required storage size would be 8% of the total annual production. The average residence time in storage for this example is 1200 hours.

Hydrogen storage

The most efficient way to store hydrogen is in a salt cavern. If caverns hold a (water)volume of 1,000,000 m3 and have operational pressures from 70 to 200 bar about 130 caverns are required to facilitate the hydrogen coming from 100 GW_{el} of wind power. For smaller caverns (500,000 m3) with operational pressures of 60 to 180 bar this number is estimated at 270 units. The cost will vary from € 0.70 to € 1.10 per stored kg of hydrogen. See the graph below. From the production profile (and assuming a constant demand over time) it can be derived that 32% of the annual production is to be put in storage. The overall cost increase will be 22 to 35 €ct/kg. Investments would be 20 to 30 B€.



Estimates for cost of hydrogen storage in salt caverns, including the caverns, compressor cost, conditioning for retrieved gas, cushion gas and electricity for compression.
Source: DNV



Example of the percentage of hydrogen in storage from wind turbines.
Source: DNV.

5. Integration into a European H2 Backbone Network

5.3.4 Economic details of proposed backbone – Summary

With an investment of 15 – 22 B€ to build the North Sea hydrogen backbone and 20 to 30 B€ for storage, a total levelised cost of hydrogen of 4.69 – 4.97 €/kg can be achieved. The investment cost of the Baltic Sea backbone is estimated at 7.2 – 10 B€. Levelised costs cannot yet be calculated.

Cost of North Sea hydrogen backbone

A summary of the estimated cost of the outlined North Sea hydrogen backbone is given below, split between the three main cost components: pipelines, compression and storage.

Pipelines

- Total length is 4200 km
- Required investments are:
  - With 36-inch pipelines (3,000 €/m): 12 B€
  - With 48-inch pipelines (4,000 €/m): 16 B€
- Added LCOH: 0.10 to 0.20 €/kg of hydrogen (WACC 8%, OPEX 1% of CAPEX/yr)

Compression

- Investment for compression are estimated (with backup position) at 3 to 6 B€
- Added LCOH: 0.05 to 0.10 €/kg of hydrogen (WACC 8%, OPEX 5% of CAPEX/yr)

Storage

- Investment for 130 salt caverns of 1,000,000 m^3 storage: 20 B€
- Investment for 270 salt caverns of 500,000 m^3 storage: 30 B€
- Added LCOH: 0.22 to 0.35 €/kg of hydrogen (WACC 8%, OPEX 5% of CAPEX/yr)

Total investment and Levelised Cost of Hydrogen

The above figures show that a total investment of 35 – 52 B€ is required to build the proposed North Sea hydrogen backbone. Furthermore, combined with the results of chapter 2 – hydrogen from offshore windfarms in the North Sea can be delivered to central Europe at a Levelised Cost of Hydrogen of about **4.69 – 4.97 €/kg in 2030** (assuming a price of 4.32 €/kg which results from the calculations as described on pages 27 and 28, with subtraction of infrastructure cost (pipelines and compressors).

Cost of Baltic Sea hydrogen backbone

A summary of the estimated cost of the outlined Baltic Sea hydrogen backbone is given below, split between the three main cost components: pipelines, compression and storage. Please note that a levelised cost calculation was not performed for this backbone, as the amount of hydrogen that will need to be transported is highly uncertain. This, since not only offshore hydrogen production might feed into this backbone, but also hydrogen generated from onshore renewable power in the north of Scandinavia which is outside of the scope of this research.

Pipelines

- Total length is 1900 km
- Required investments are:
  - With 36-inch pipelines (3,000 €/m): 5.7 B€
  - With 48-inch pipelines (4,000 €/m): 7.5 B€

Compression

- Investment for compression are estimated (with backup position) at 1.5 to 2.5 B€

Storage

- Cost of storage are similar to the North Sea figures. The amount of storage caverns depends on the amount of hydrogen that will be produced but that is still very uncertain (see page 40).

Total investment and Levelised Cost of Hydrogen (Excluding storage)

The above figures show that a total investment of 7.2 – 10 B€ is required to build the pipelines and compression of the proposed Baltic Sea hydrogen backbone. Levelised Cost of Hydrogen cannot be estimated accurately since the total production & transport volume is highly uncertain.

5. Integration into a European H2 Backbone Network

5.4 Key takeaways

An offshore hydrogen backbone would, due to high economies of scale, enable the transport of hydrogen from offshore areas to end-users very efficiently. The technical realisation is new, but possible with today's technologies; and it would likely account for 10% or less of the total levelised cost of hydrogen produced offshore.

This chapter provided insight into technical and economic considerations for offshore hydrogen pipelines and investigated the layout of hypothetical backbones in both the North Sea and the Baltic Sea. It describes the options of reuse of existing pipelines that may become obsolete when oil and natural gas demands decrease.

Technical and economic considerations for offshore hydrogen pipelines

Natural gas transport pipelines have been in use for many decades, both onshore and offshore, and although there are similarities with hydrogen transport, hydrogen pipelines have not yet been applied offshore.

There are cost benefits and several other advantages to repurposing existing offshore natural gas pipelines to hydrogen, but there are also many challenges to repurposing offshore. We expect that newbuild pipelines will be needed in many cases for an offshore hydrogen backbone, and assume newbuild pipelines in our cost calculations in this chapter

Layout and cost of hypothetical backbones in both the North Sea and the Baltic Sea

The preliminary set-up of an offshore hydrogen backbone is based on connection to major wind farm areas more than 100km from shore, including existing initiatives, integration with the European onshore hydrogen backbone initiative and connecting countries around the North Sea and the Baltic Sea.

- **North Sea:** Key characteristics of the hydrogen backbone in the North Sea show a general North–South flow pattern through an internationally meshed grid of 4,200 km of pipeline that operates at 200 bar. The backbone connects Norway, Denmark, Germany, the Netherlands, Belgium and the UK, and integrates with the planned onshore hydrogen backbone..
- **Baltic Sea:** A preliminary design of an offshore hydrogen backbone for the Baltic Sea includes a direct connection to the South Scandinavian areas in Sweden and Finland and facilitates export of hydrogen and integration with storage in salt caverns. It also connects to Latvia, Poland, Denmark and Germany, and avoids building an extensive onshore infrastructure.

In the North Sea, the costs for pipelines and compressors for the offshore hydrogen backbone are estimated to account for 10% or less of the total levelised cost of hydrogen produced offshore, meaning that the offshore backbone can offer good value for money:

- The cost of the **pipelines** for the outlined hydrogen backbone will add only 13 to 20 €ct/kg (2.6-6.7%) to the levelised cost of hydrogen.
- The cost of the **compressors** for the hydrogen backbone will add only 6 to 8 €ct/kg (1.2-2.7%) to the levelised cost of hydrogen

Geological storage of the hydrogen is calculated to add 22 to 35 €ct/kg to the levelised cost of hydrogen – this storage will be needed in any case, including if all hydrogen was produced using onshore variable renewables, and represents a cost-effective energy storage solution at scale.

Overall takeaway

- With an investment of 35 – 52 B€ to build the North Sea hydrogen backbone, a total levelised cost of hydrogen of 4.69 – 4.97 €/kg can be achieved, rendering it a cost-effective approach to maximising energy production from the North Sea. The investment cost of the Baltic Sea backbone is estimated at 7.2 – 10 B€, whilst levelised costs cannot yet be calculated.
- The setup of an offshore hydrogen backbone in the North Sea and the Baltic Sea is doable, economically feasible and helps to facilitate the European energy transition.

6. Conclusions and recommendations

An offshore hydrogen backbone comes with significant advantages for Europe. Its realisation requires coordinated and timely action by the North Sea and Baltic Sea countries.

Summary

As outlined in chapter two, Europe will have a large demand for hydrogen, driven in particular by decarbonisation needs in heavy industry. The demand scenarios currently show a large variance, but are all far above the level of today's hydrogen production. As outlined, Europe should strategically diversify its sourcing of hydrogen and, in particular, also build up its own significant production capacity, which should be designed as efficiently as possible.

As explained in chapter three, this efficiency can only be achieved through plants with high full load hours. At the same time, the necessary land use should be taken into account from the beginning when building such an infrastructure. Both parameters speak strongly in favour of building an offshore infrastructure. As further shown in chapter three, areas further than 100 km from the coast should be considered for offshore hydrogen production, as such locations perform particularly well in terms of production costs. As outlined the offshore production capacity of these areas has the potential to produce 300 TWh of hydrogen per annum, accounting for 13 to 25% of the European demand in 2050.

In chapter four, possible production sites in the North Sea and the South Sea were identified. For the North Sea, a large area and production potential was shown based on the 100 km criterion. This should be realised via a meshed pipeline connection (a backbone). In the Baltic Sea region, the situation is different, as fewer areas meet the 100 km criterion - however, a combined pipeline could also make sense here if Sweden and Finland in particular decide to produce hydrogen on a larger scale, and join forces in collectively transporting the hydrogen to demand centers to the south.

Finally, in chapter 5 it was explained how such an offshore infrastructure can be built. This involves efficient networking of the individual production sites (in order to minimise the individual connection costs), but also sensible integration into a land-based hydrogen network. Chapter four presented initial boundary conditions for this, which was then used as the basis for calculations regarding the technical characteristics of the pipeline integration. It became clear that relatively high pressure levels must be achieved, even with large diameter pipelines, such that the option of repurposing existing natural gas pipelines may not be a feasible solution. As was also explained, technical implementation is possible – but requires new standards to be developed that are specific to offshore hydrogen pipelines.

In the North Sea, the costs for pipelines and compressors for the offshore hydrogen backbone are estimated to account for 10% or less of the total levelised cost of hydrogen produced offshore.

With an investment of 35 – 52 B€ to build the North Sea hydrogen backbone (including associated geological storage, which would also be needed for onshore hydrogen production) a total levelised cost of hydrogen of 4.69 – 4.97 €/kg can be achieved, rendering it a cost-effective approach to maximising energy production from the North Sea. The investment cost of the Baltic Sea backbone is estimated at 7.2 – 10 B€, whilst levelised costs cannot yet be calculated.

Conclusions

As the spatial distribution of the potential offshore hydrogen production sites shows, the sea areas of different countries are involved in the determination of the total potential. This suggests that transnational coordination will be necessary to develop the full identified hydrogen generation potential. It will be equally important to balance the potential use for electricity generation against the potential generation of hydrogen across countries. As we have shown, the potential of hydrogen production can only be fully exploited through network effects.

Given the steep increase in hydrogen demand in Europe, which all current studies assume, there is a certain urgency in coordinating such a seaside infrastructure. This can only realise its full potential if all parties involved participate in a coordinated and timely manner. Without such coordinated measures, there is a risk that a dispersed development of hydrogen production and subsequent transport in Europe will lead to a situation where hydrogen can only be produced in Europe at relatively high costs. In the long term, this could lead to stranded investments.

Technically, we assume that realisation is possible in the foreseeable future – although there are no reference projects for an offshore hydrogen pipeline to date. It will from our perspective be essential to foster the development of offshore hydrogen pipeline standards in order to be able to secure safe operational as well as proper financing.

6. Conclusions and recommendations

Looking at the obvious advantages of the backbone we consider that it only can be realised if the involved countries develop a joint concept and start implementation measures on short notice.

Recommendations

As the demand for hydrogen is set to rise sharply in the coming years, we believe it is necessary for the littoral states to further coordinate their efforts to develop areas in the North Sea, including those at greater distances, and to define clear expansion targets for hydrogen as well. Infrastructure development driven purely by individual initiatives at country level will not do justice to the potential and importance of offshore hydrogen production. We see therefore four points in particular as being essential in order to be able to realise this important infrastructure:

1. Coordinated cross-border planning of spatial use in the area of the North Sea.
2. Coordination of the relevant countries with regard to their hydrogen strategies in relation to the use of offshore hydrogen production.
3. Prompt implementation of measures already initiated in the German coastal region (AquaDuctus) in order to gather experience for scaling up offshore electrolysis and hydrogen pipelines.
4. Prompt joint development and establishment of new standards for hydrogen offshore pipelines.

Source: DNV

Appendix

Appendix

Abbreviations

AC – Alternating Current

API – American Petroleum Institute

ASME – American Society of Mechanical Engineers

BEIS – Department for Business, Energy and Industrial Strategy (UK)

BFE – Bundesamt für Energie (CH)

CAPEX – Capitial Expenditure

CCS – Carbon Capture and Storage

CIP – Copenhagen Infrastructure Partners

DC – Direct Current

EEZ – Exclusive Economic Zone

ETO – Energy Transition Outlook (DNV)

EU – European Union

FCHO – Fuel Cells and Hydrogen Observatory

GW – Giga Watt electrical

HHV – Higher Heating Value

HVAC – High Voltage Alternating Current

HVDC – High Voltage Direct Current

IEA – International Energy Agency

IRENA – International Renewable Energy Agency

ISPT – Institute for Sustainable Process Technology

JIP – Joint Industry Project (DNV)

LCOE – Levelised Cost of Energy / Electricity

LCOH – Levelised Cost of Hydrogen

LHV – Lower Heating Value

LOHC – Liquid Organic Hydrogen Carriers

MAOP – Maximum Allowable Operating Pressure

MJ – Mega Joule

MW – Mega Watt

MWh – Mega Watt hour

NEC – New Energy Coalition

NSEC – North Seas Energy Cooperation

OPEX – Operational Expenditure

PEM – Proton Exchange Membrane (Electrolyser)

PNZ – Pathway to Net Zero (scenario)

PRIMES – Price-induced market equilibrium system (model)

PV – PhotoVoltaics

REDII – Renewable Energy Directive II (European Commission)

RPF – Renewable Push Pathway (scenario)

RWE – Rheinisch-Westfälisches Elektrizitätswerk Aktiengesellschaft

SET – Strategic Energy Technology (European Commission)

TDP – Technology Diversification Pathway (scenario)

TWh – Tera Watt hour

WACC – Weighted Average Cost of Capital

Source: DNV

Appendix

Installed capacity & energy content of hydrogen (heating value) conventions

Capacity

When discussing installed capacity of energy assets, it is important to distinguish between electricity and hydrogen as the energy vectors. Therefore, we have chosen to include subscripts when discussing capacity figures, to ease the reader in understanding what is being considered.

GW_{el} – Giga Watt electrical

- Used to denote wind farm electrical output capacity and electrolyser electrical input capacity, as per conventions.

GW_{H2} – Giga Watt hydrogen

- Used to denote hydrogen pipeline transport capacity as per conventions.
- Can be used to denote electrolyser hydrogen output capacity, although this is not the convention this approach is taken in some publications. Clearly, the industry is not yet fully aligned on which approach to take.

Energy content

Furthermore, when discussing conversion efficiency and amounts of hydrogen in terms of energy content, it is important to distinguish between

Higher Heating Value (HHV) is also referred to as the gross calorific value. During combustion of hydrogen rich fuels water is released by combining hydrogen and oxygen. This subsequently evaporates which consumes some of the energy which is then not available anymore to “do work”. The Lower Heating Value (LHV), or net calorific value, corrects for this “loss” and is therefore lower. The higher and lower heating value of hydrogen are 142 and 120 MJ/kg respectively.

- ***In this report, by default the LHV is taken as a basis, as this is the default for many gas grid operators.***

Source: DNV

Appendix

Levelised cost calculation methodology – introduction

Levelised Cost of Energy

The levelised cost of energy (LCOE) is a common metric used in the energy industry to compare the cost of different sources of electricity generation. It represents the average cost of electricity over the lifetime of a power-generating asset, such as a wind turbine or solar panel. The LCOE takes into account the cost of building and operating the asset, as well as a discount rate to account for the time value of money. LCOE is often expressed in units of currency per unit of energy (e.g., €/MWh). By comparing the LCOE of different power sources, policymakers and investors can make informed decisions about which types of generation are the most cost-effective.

Levelised Cost of Hydrogen

The same methodology is extended to compare hydrogen value chains by including the cost of building and operating hydrogen production- and transportation assets, such as electrolysers or hydrogen pipelines. The levelised cost of hydrogen (LCOH) represents the average cost of hydrogen over the lifetime of the full value chain. It is often expressed in units of currency per unit mass of hydrogen (e.g., €/kg H2). This unit is preferred, since on an energetic basis (€/MWh) it is not explicit whether the lower heating value (LHV) or higher heating value (HHV) of hydrogen is taken as a basis.

- *In this report, by default the LHV is taken as a basis, as this is the default for many gas grid operators.*

Discount rates

A discount rate is a method used to account for the time value of money in financial analysis. It is the rate at which future cash flows are discounted to their present value. In other words, it is the rate at which future costs and benefits are "discounted" to reflect their relative value in the present.

The discount rate is an important factor in determining the economic feasibility of a project or investment. A higher discount rate will lead to a lower present value for future cash flows, making a project appear less valuable. Conversely, a lower discount rate will lead to a higher present value, making a project appear more valuable.

Source: DNV

Appendix

Levelised cost calculation – general assumptions (as used in chapter 3.3)

General assumptions

- All costs are reported as unit costs and are modelled to scale linearly with capacity (economies of scale effects are neglected)
- Energy price data is extracted from the DNV Energy Transition Outlook and is assumed to be valid for the Europe region. Based on this, power prices and levelised cost of renewable energy technologies are expected to reduce from 2030 through to 2050.
- Learning rates are made explicit by providing cost figures for the years 2030, 2040 and 2050 based on ETO data and DNV expert judgement.

Topology assumptions

- Onshore hydrogen production is assumed to be co-located with the energy source, there are therefore no energy transmission costs involved for transporting electricity from the energy source to the electrolyser.
- For offshore wind to hydrogen, the battery limit of the model has been assumed to be the onshore electrolyser or the pipeline landfall.
- For offshore hydrogen production, only the decentralised hydrogen production topology with an offshore hydrogen production platform is considered.
- Hydrogen pipeline transmission capacity is assumed to 1 or 10 GW_{H2} per pipeline.

Electrolysis assumptions

- Electrolyser capacity is defined per electrical input capacity (Gw_{el}).
- Grid based electrolysis is not considered to be part of this analysis
- Renewable generation capacity and electrolysis capacity are assumed to be equal.
- Electrolyser topology is chosen as PEM, due to ability to cope with intermittent sources.
- Electrolyser costs are reported as unit costs per building block of 100 MW_{el} electrolyser capacity, and modelled to scale linearly with this capacity. This, because DNV experts deem that after 100 MW_{el} the economies of scale effects for electrolysers have flattened out.
- Electrolyser costs include stacks, balance of plant (electrical systems such as medium voltage transformers and rectifiers, a safety & control system and cables, as well as gas systems such as pipes, pumps, heat exchangers, liquid/gas separators, dryers, and gas purification and treatment equipment), water treatment and subsequent hydrogen compression from 30 to 80 bar.
- Installing and operating electrolysers offshore is expected to be more costly than their onshore counterparts, this is reflected in the cost figures for the offshore cases.
- Electrolyser CAPEX is assumed to reduce and efficiency to increase over the years from 2030 through to 2050, based on DNV expert analysis.

Economic modelling

- Nominal discount rate (WACC) has been assumed to be 10%
- Project lifecycle has been assumed to be 20 years
- Calculated costs are only direct costs and don’t include indirect costs such as financing and contingency.

Appendix

Levelised cost calculation – input data (as used in chapter 3.3)

Renewable Energy Source

Cost of Energy (EUR/MWh)	Unit Cost 2030	Unit Cost 2040	Unit Cost 2050
Offshore wind	32.12	27.86	25.96
Onshore wind	37.64	33.12	29.54
Onshore solar PV	33.53	30.08	29.70

Operational Capacity	Full Load Hours	Capacity Factor
Offshore wind	5000	57%
Onshore wind	3000	34%
Onshore solar PV	1000	11%

Transmission

Technology Cost Data	CAPEX (EUR/MW)			OPEX (% of CAPEX)			Energy Efficiency (%)		
	2030	2040	2050	2030	2040	2050	2030	2040	2050
HVAC Cable (per MW*km)	3,000	3,000	3,000	2.5%	2.5%	2.5%	95.6%*	95.6%*	95.6%*
HVDC Cable (per MW*km)	800	800	800	3.0%	3.0%	3.0%	97.0%*	97.0%*	97.0%*
Onshore HVAC substation	35,000	35,000	35,000	1.0%	1.0%	1.0%	99.0%	99.0%	99.0%
Offshore HVAC substation	80,000	80,000	80,000	1.5%	1.5%	1.5%	99.0%	99.0%	99.0%
Onshore HVDC substation	200,000	200,000	200,000	1.5%	1.5%	1.5%	98.0%	98.0%	98.0%
Offshore HVDC substation	685,000	685,000	685,000	2.3%	2.3%	2.3%	98.0%	98.0%	98.0%
Hydrogen Compression	15,000	15,000	15,000	4.0%	4.0%	4.0%	98.5%	98.5%	98.5%
Hydrogen Pipeline 1 GW_{H2} (per MW*km)	615	615	615	1.0%	1.0%	1.0%	100%**	100%**	100%**
Hydrogen Pipeline 10 GW_{H2} (per MW*km)	500	500	500	1.0%	1.0%	1.0%	100%**	100%**	100%**
Offshore Platform	110,000	110,000	110,000	0.5%	0.5%	0.5%	N/A	N/A	N/A

Hydrogen Production

Technology Cost Data	CAPEX (EUR/kW)			OPEX (% of CAPEX)			Energy Efficiency (% LHV)		
	2030	2040	2050	2030	2040	2050	2030	2040	2050
PEM Onshore 100 MW_{el}	1,445	1,139	898	1.5%	1.5%	1.5%	64.1%	64.2%	64.3%
PEM Offshore 100 MW_{el}	1,926	1,519	1,198	1.5%	1.5%	1.5%	64.1%	64.2%	64.3%

* Efficiency of HVAC and HVDC transport depends on distance in the calculations, an illustrative distance of 150 km is assumed in this table.
** The pressure drop in the pipelines is a design variable and as such can be optimised. The cost optimal design typically results in a total energy loss of 1.5% including the energy cost of compression. As such, the efficiency of the compressors is set to 98.5%.

Appendix

Space claim calculation – input data (as used in chapter 3.4)

Renewable Energy Source

Space claim & Operational Capacity	Specific space claim (km^2/MW_{el})			Full Load Hours	Capacity Factor
	Low	Mid	High		
Onshore Wind	276	398	536	2000	34%
Onshore Solar PV	16	20	24	1000	11%
Offshore Wind	111	143	200	5000	57%

Hydrogen Production

Space claim	Specific space claim (km^2/GW_{el})			Note
	Low	Mid	High	
PEM Onshore	276	398	536	
PEM Offshore	N/A	N/A	N/A	Included in Offshore Platform

Transmission

Space claim	Specific space claim (km^2/GW)			Typical capacity (MW)	Note
	Low	Mid	High		
HVAC Cable (per GW*km)	1.0714	1.4286	1.7857	2 * 350	Safety distance of 500m assumed
HVDC Cable (per GW*km)	0.3750	0.5000	0.6250	2 * 1,000	Safety distance of 500m assumed
Onshore HVAC substation	0.0010	0.0014	0.0017	2 * 350	Safety distance of 500m assumed around ~90m (each way) 800 MW platform
Offshore HVAC substation	0.0010	0.0014	0.0017	2 * 350	Safety distance of 500m assumed around ~90m (each way) 800 MW platform
Onshore HVDC substation	0.0005	0.0006	0.0008	2 * 1,000	Safety distance of 500m assumed around ~120m (each way) 2000 MW platform
Offshore HVDC substation	0.0005	0.0006	0.0008	2 * 1,000	Safety distance of 500m assumed around ~120m (each way) 2000 MW platform
Hydrogen Compression	N/A	N/A	N/A	N/A	Included in Offshore Platform
Hydrogen Pipeline 1 GW (per GW_{H2}*km)	0.7500	1.0000	1.2500	1,000	Safety distance of 500m assumed
Hydrogen Pipeline 10 GW (per GW_{H2}*km)	0.0750	0.1000	0.1250	10,000	Safety distance of 500m assumed
Offshore Platform	0.0013	0.0017	0.0021	800	Safety distance of 500m assumed around ~160m (each way) 800 MW platform

Appendix

Technical details of proposed backbone – North Sea Pressure regime and diameters (as used in chapter 5.3.3)

Detailed inputs and outputs of the simulation of the South East part of the North Sea backbone show that a minimum pressure of 100 bar is needed to operate the backbone to achieve a receiving pressure of 50 bar.

The short windfarm name and the nominal size are given. For some windfarms the capacity has been assessed for this study. These values are indicated with an Asterix (*). It is assumed that the flow at node 2 is evenly split between pipelines II and VI and at node 4 between pipelines IV and V. The diameter of the pipelines are selected at 48 inch.

Node	Windfarm ID	Size	Node	Windfarm ID	Size	Node	Windfarm ID	Size	Node	Windfarm ID	Size
		MW_{el}			MW_{el}			MW_{el}			MW_{el}
1	DK0Y	1000*		DK1D	1000		DE2Z	425		DE4D	2000
	DK0P	1000		DK1E	1000		DE39	112		DE4L	1000
	DK0Z	1000*	3	DE3R	2000		DE11	497		DE4M	2000
	DK0U	1000		DE3Q	1000		DE3S	1500		DE4H	1000
	DK1P	1140		DE3F	500		DE3B	2000		DE4U	1000
	DK1R	4000		DE3K	500*		DE3A	2000		DE4J	1000
	DK1Q	2250		DE3O	1500		DE4W	2000	6	DE3Z	2000
	NO66	1000		DE3J	2000		DE23	400		DE4B	2000
	DK1B	1000		DE3D	2000		DE19	900		UK7V	1218
	DK0W	1000		DE58	2000	4	DE05	302		UK1F	1320
	DK0V	1000		DE3C	2000		DE33	342	7	DE4D	2000
	DK0X	1000		DE17	500		DE06	295		DE4O	2000
	DK1A	1000		DE12	288		DE07	288		DE4Q	2000
2	DK49	1000*		DE02	288	5	DE41	2000			
	DK1C	1000		DE2U	288*		DE4E	2000			

Overview of the nodes in the partial simulated network and the windfarms and their nominal capacity that may directly feed into these nodes.

ID	L	Diameter	Flow		Pin	Puit
	Km	Inch	Nm3/s	GW_{H2} (LHV)	Bara	Bara
I	50	48	966	10	103	102
II	150	48	594	6	102	99
III	60	48	3330	36	99	66
IV	70	48	1699	18	66	52
V	80	48	1699	18	66	50
VI	125	48	594	6	102	100
VII	94	48	1363	15	106	99
VIII	115	48	333	4	107	106

Characteristics of pipelines in the simulation.

Example: The total hydrogen flow arriving at node 1 comes from 17,390 MW_{el} of offshore wind farms that produce 200 Nm3/MW_{el}/h. This results in 966 Nm3/s (or 10 GW_{H2} (LHV). Flow calculations give a 1 bar pressure drop over pipeline I of 50 km with a required output of 102 bar, which is the inlet pressure for pipeline II.

DNV

Appendix

Offshore wind areas dataset – Description and limitations (as used in chapter 4)

- The database has a cut-off date from September 2022 and is generally based on the information provided by an external database provider. However, DNV has amended this database according to their expert knowledge of the respective countries relevant for this project assessment. The database uses public news and information and own analysis to determine the estimated commissioning date and the location of the respective offshore wind farm site.
- The database is focusing more on confirmed sites, with development zones and early-stage sites included in its assessment. Therefore, potential sites which might be commissioned beyond 2040 are represented only to a limited extent.
- Also, the type of offshore wind site (e.g. dedication to electricity production or other alternative models) are not covered for the entire dataset and therefore not a reliable measure. In some cases, the decision of the type of offshore wind site has also not been taken yet. To account for this, DNV produced their own assessment methods on the suitability of these sites into a hydrogen backbone (as described in the respective chapters).
- The dataset has some gaps when it comes to not officially confirmed sites, such as the Dutch EEZ that have not yet been officially “allocated” by the Dutch government, and as such are not present in the dataset, but that are marked already by the government as “search areas”, almost all of which will need to be utilised to meet the targets of the Esbjerg conference.
- To account for the uncertain development in both North and Baltic Sea we refer to the policy targets which have been set by the core countries in our analysis.

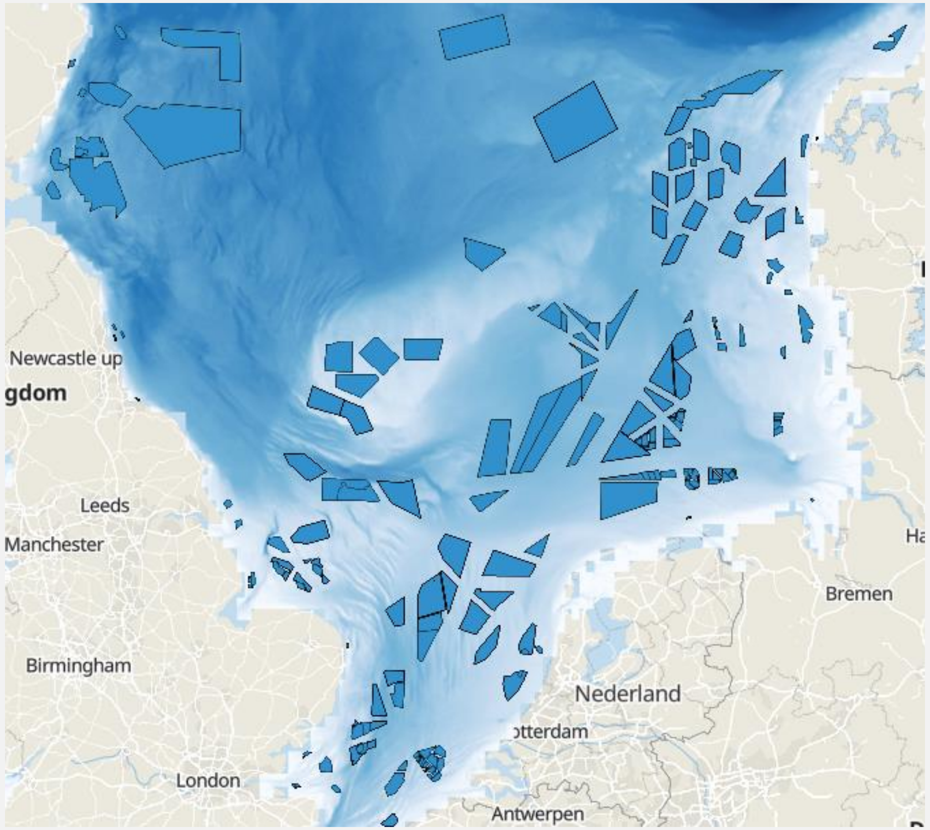


Image source: North Sea Energy Atlas

Appendix

Challenges in design and re-qualification of offshore pipelines for hydrogen transport

The stress-strain curve, fatigue crack growth rate and fracture toughness of pipeline steels pose challenges when designing new offshore hydrogen pipelines or re-qualifying existing natural gas pipelines.

Stress-strain curve

- Relationship between stress and strain.
- Tensile properties up to ultimate tensile strength apparently little affected by hydrogen.
- Ductility significantly reduced in hydrogen environment (especially for slow strain rates).
- Could affect pipeline resistance to accidental loads (third party damage). May require additional pipeline protection (additional cost).

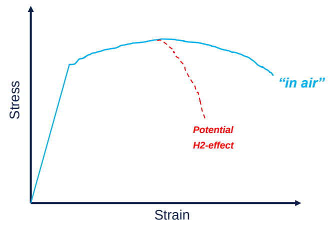
Fatigue crack growth rate

- A crack growth equation is used for calculating the size of a fatigue crack growing due to cyclic loads.
- Hydrogen environments can lead to significant acceleration of fatigue crack growth rates. Understanding conditions for accelerated fatigue crack growth is key for hydrogen pipelines.
- Increased crack growth rate will influence the acceptable initial flaw size in hydrogen pipelines which may have to be reduced compared to natural gas.
- For re-qualification, intervention may be necessary to reduce fatigue on welds (additional cost).

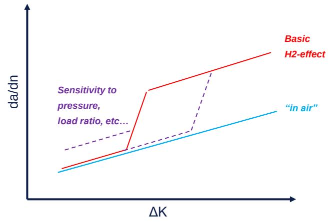
Fracture toughness

- Fracture toughness is a materials resistance to crack propagation.
- Hydrogen environments will reduce the fracture resistance.
- For re-qualification, intervention may be necessary to reduce free spans in uneven seabed and limit strain in pipeline (additional cost).
- This could limit the maximum acceptable flaw size, rendering a larger share of natural gas pipelines unsuitable for reuse.

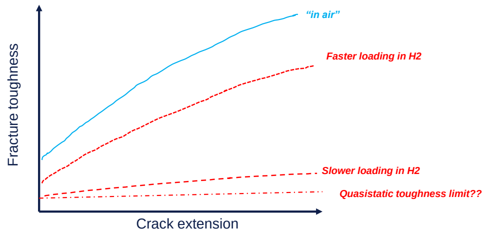
Stress-strain curve



Fatigue crack growth rate



Fracture toughness



Appendix

Cost of new-built offshore hydrogen pipelines, used in the economic analysis of the cost of the outlined backbone (as used in chapter 5.3.4)

Category	Sub-category	Cost	Reference
CAPEX	Material cost	Estimated from steel pipeline suppliers cost data according to diameter, steel grade and weight plus 30% for concrete coating	1
	Laying cost	Average of 0.04 MEUR/inch/km	2, 3
	Commissioning/RFO	1.5% of total cost (pigging and pipeline preparation work)	DNV expert assumption
	Management and Engineering	10% of total cost	DNV expert assumption
	Contingency	30% of total cost	DNV expert assumption
OPEX	Maintenance, intervention, survey	Pipeline yearly fixed OPEX assumed to be 1% of CAPEX	4

1: Material cost: https://www.tridentsteel.co.in/carbon-steel-price-list.html
2: DNV, Carbon Limits, "ReStream - Study on the reuse of oil and gas infrastructure for hydrogen and CCS in Europe,", June 2020.
3: Mikunda et al, Towards a CO2 infrastructure in North-Western Europe: Legalities, costs and organisational aspects, GHGT10, 2010.
4: European Hydrogen Backbone, "A European hydrogen infrastructure vision covering 28 countries", April 2020

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