Assessment of connection concepts for Germany's far out North Sea offshore wind areas for an efficient energy transition

Short study on behalf of AquaVentus Förderverein e.V.

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ASSESSMENT OF CONNECTION CONCEPTS FOR GERMANY'S FAR OUT NORTH SEA OFFSHORE WIND AREAS FOR AN EFFICIENT ENERGY TRANSITION

SHORT STUDY ON CONNECTION CONCEPTS FOR OFFSHORE WIND

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Sponsors

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CONTENTS

At a glance

1. **Connecting offshore wind farms simultaneously via electric cables and offshore electrolysers and a pipeline** offers many benefits in terms of energy system integration, total cost and implementation risks for far out offshore wind farms in Germany's Exclusive Economic Zone. In the following, we refer to such connections as **mixed connection concepts.**

2. **Mixed connections concepts increase the flexibility of energy supply:** electricity can be supplied when needed. When RES is abundant, hydrogen is produced. When offshore wind is limited, the power cable can also be used to supply the offshore electrolysis with onshore electricity. This sensibly **increases the utilisation of offshore electrolysers and the connecting infrastructure**.

3. Compared to an electricity- or hydrogen-only connection, **hydrogen-dominant mixed connection concepts have a significantly higher revenue potential** and can be implemented **below the costs of an electricity-only connection concept.** Both factors **lower the socially shared cost** of further developing offshore wind in the North Sea.

4. In a superordinate comparison of the connection approaches "pipeline vs. cables" (including respective platforms), there is **no clear preference from an environmental perspective** for one or the other system. Although a conclusive assessment is not yet possible and **no general obstacles to approval seem to be expected**, suitable avoidance or minimisation measures and compensations are required for both types of platforms and connection systems.

5. **Despite their advantages and in contrast to the neighbouring countries in the North Sea, there is a statutory exclusion of mixed connection concepts in Germany.** This study proposes amendments to the WindSeeG to unlock the full potential of mixed connection concepts.

MANAGEMENT SUMMARY

Introduction. Offshore wind farms (OWFs) and green hydrogen production are core pillars of the German energy transition, providing substantial benefits but also presenting challenges.

On the one hand, investment costs for electric connections of OWFs remote from the shore are substantial and distances further increase due to the necessity of onshore grid connection points reaching far into the mainland. Additionally, OWFs' revenues depend on power prices in times of wind with the risk of low prices if onshore renewable energy resources (RES) produce simultaneously. Both circumstances may lead to either the necessity of support mechanisms and corresponding (socially shared) costs or the risk that necessary investments to facilitate the energy transition will be postponed.

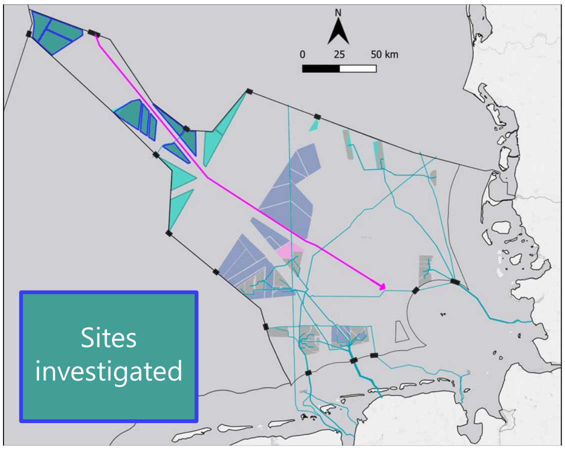
On the other hand, green hydrogen production via electrolysis is exposed to power price risks (onshore electrolysis) or a limited amount of full load hours (offshore electrolysis only directly supplied by an offshore wind farm). As the hydrogen economy is still in an early phase, hydrogen price risks are high. Once again, there is a risk that necessary investments in electrolysers are deferred.

Objective. The study assesses the following connection concepts for far-out OWFs from a socio-economic and environmental impacts perspective. The following concepts are investigated:

1. OWFs with a purely electric connection (all electric, "All E")
2. OWFs with offshore electrolysers and hydrogen pipeline connection (all hydrogen, "All H2")
3. OWFs in a combination of 1 and 2: "mixed connection concept" (MC).

The conceptual analysis is complemented by a consideration of the corresponding legal and regulatory conditions for offshore hydrogen and mixed connection concepts.

Scope. The analysis focusses on the far-out zones 4 and 5 in the German Exclusive Economic Zone (EEZ) in the North Sea, often referred to as "duckbill". Within these zones we focus on areas close to the planned AquaDuctus pipeline (magenta).



Investigation for zones 4 and 5 of the German EEZ, commonly described as duckbill

Methodology. To derive robust assessments of future revenue streams of the OWF-sites, three different energy scenarios are used. The first scenario, Climate Neutrality 2040 (CN), focuses on high energy efficiency gains and electrification in Germany and Europe as well as the highest level of renewable energy development and deployment. Selected countries like Germany attain decarbonization targets already in 2040. The second scenario, Molecule Based Energy Transition (MET), expects decarbonisation and climate neutrality by 2045, in line with German energy policy targets, through a strong(er) use of green gases such as hydrogen. Both, hydrogen imports and domestic production are on a higher level than in CN. The third scenario, Delayed Energy Transition (DET), assumes an overall slower pace of energy transformation due to acceptance issues in the society, high cost, slower efficiency gains and high level of bureaucracy. The DET scenario assumes that decarbonisation and climate neutrality is achieved by 2055 (10 years delay compared to the MET scenario).

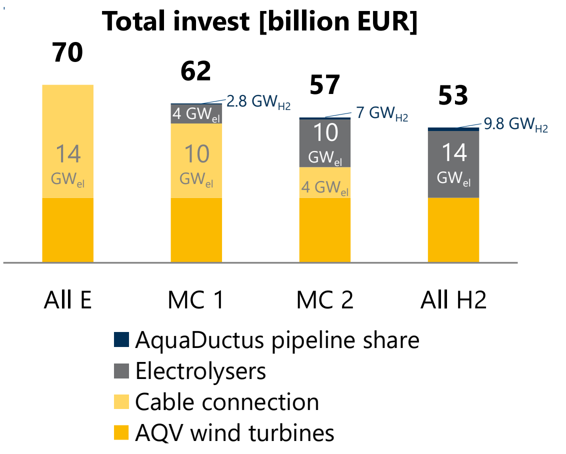
For each scenario a comprehensive electricity market simulation is conducted for the reference years 2035, 2040 and 2045. Average hourly (nominal) electricity prices are expected to rise in the CN scenario from 100 EUR/MWh in 2035 to 109 EUR/MWh in 2045. In the other two scenarios average prices fall from 122 to 111 EUR/MWh in MET and from 135 to 90 EUR/MWh in the DET scenario. All scenarios expect between 2000 h and 3000 h with electricity prices ≤ 0 EUR/MWh in 2045. Hydrogen prices decrease from around 200 EUR/MWh_{H2} in 2035 to slightly above 100 EUR/MWh_{H2} in 2045 in all three scenarios, mainly driven by cost-efficient import options.

To assess the three connection concepts, four configurations are assessed against each scenario. Each configuration connects 14 GW OWFs in zones 4 and 5 with total connection capacity of 14 GW:

- (All E) a purely electrical cable connection,
- (MC 1) an electricity-dominant mixed connection,
- (MC 2) a hydrogen-dominant mixed connection and
- (All H2) a purely hydrogen-based connection.

Techno-economic assessment. The different configurations are assessed regarding their investment and operating costs, supplied energy, and revenues.

For the assessment of the economic value of different variants in the duckbill, a comprehensive investment cost assessment was conducted. Since capital expenditures vary over time due to scaling and learning effects, different start years were investigated as well. The following figure summarizes the investment cost of the main analysis. Operating costs were assumed to be 2.6% p.a. of the investment costs for each system component, plus the costs of replacing the electrolysis stacks.

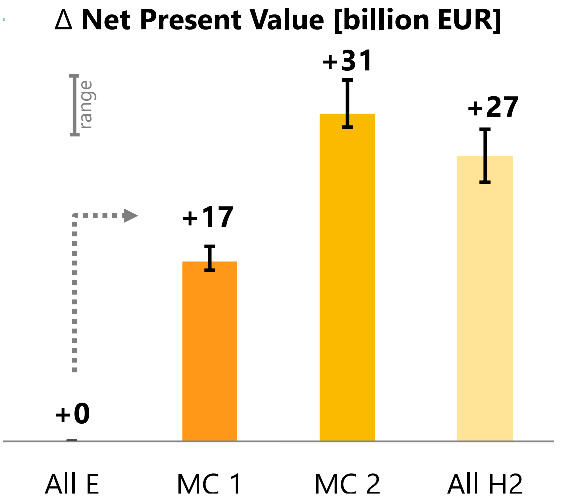


Investment cost of assessed connection concepts

Among the investigated configurations, at around EUR 70 billion, All E has the highest, at around EUR 53 billion All H2 has the lowest investment cost. Depending on the configuration, the costs for mixed connection concepts are somewhere in between.

For the assessment of revenues and supplied energy, an optimisation approach was applied. Based on the revenues and the investment costs, the net present value (NPV) of each configuration is calculated. The NPV covers the investment and operation costs of the required offshore wind and hydrogen systems as well as connection costs and revenues. Weighted average capital costs (WACC) of 9% are assumed throughout all configurations. Due to high investment cost, integrating offshore wind results in a negative NPV with all connection concepts. In the future, negative NPVs must be offset or compensated via levies or similar socially funded support schemes to enable investments. Therefore, a higher NPV is also a suitable indicator of greater socio-economic- benefit.

The higher revenue potential and lower costs of offshore electrolysis (All H2) increase the NPV by roundabout EUR +27 billion compared to All E. Among the investigated configurations, the hydrogen-dominated mixed connection concept MC 2 with 10 GW_{el} electrolysis and 4 GW cable offers the greatest benefit; the NPV increases by EUR +31 billion.



Difference in net present value for different connection concepts compared to All E

Within mixed connection concepts, bidirectional cable utilisation also allows for onshore electricity consumption, which increases the utilisation of electrolysers and the output of hydrogen. This applies in times of abundant onshore RES production while offshore wind is insufficient to fully supply the electrolysers capacity.

Mixed connection concepts are enabled by offshore electrolysis. They decrease the investment cost for the integration of offshore sites in EEZ zones 4 and 5 and increase the revenues compared to an electric-only or even hydrogen-only concept. This minimises risks that necessary investments in electrolysers or OWFs are deferred. The results are robust for all scenarios.

Contribution to energy sovereignty. A higher domestic production of hydrogen limits import risk exposure.

Environmental assessment. A preliminary environmental assessment of offshore electrolysis shows that all components relevant in this context (OWFs, cables, pipelines, offshore electrolysers) will have environmental impacts. Some of these impacts are relevant in a way that they must be considered further in relation to environmental law, but most of them can be countered with appropriate avoidance and mitigation measures. *In a superordinate comparison of the connection approaches via pipeline vs. cables (including their respective platforms), there is no clear preference for one or the other connection type from an environmental perspective*. Although a conclusive assessment is not yet possible and no general obstacles to approval seem to be expected, suitable avoidance or minimisation measures and compensations are required for converter and electrolyser platforms and respective connection systems. The next step will be to highlight suitable technical avoidance and mitigation measures for possible relevant environmental impacts of hydrogen pipelines and offshore electrolysers and to integrate them into further planning.

Legal assessment. Current German law rules out mixed connections for offshore hydrogen production in the EEZ as the Offshore Wind Energy Act (WindSeeG) restricts maritime areas eligible for hydrogen production exclusively to installations without connections to the electricity grid.

The categorical ban of power grid connections for offshore hydrogen production systematically prevents the economic and system benefits of mixed connections. Moreover, the right to a grid connection as a (general) prerequisite for the right of grid access is denied for all electrolysers. With the exclusion of mixed connections German regulation also deviates from the regulatory practice of Germany's neighbours in the North Sea (NSEC) region. The common goal of the NSEC countries to develop an integrated energy infrastructure in the North Sea requires a joint and common approach. A unilateral exclusion of mixed connection concepts by one country should be avoided.

Given the German government's 1 GW goal in 2030 for future offshore hydrogen production, the legislative framework for offshore electrolysis should be made fit for purpose.

Next to abolishing the current ban for mixed connections, the expansion targets for (offshore) electrolysis should be enshrined in law. Furthermore, the tendering conditions, particularly the strict realisation deadlines and associated penalty payments under the SoEnergieV (Sonstige-Energiegewinnungs-bereiche-Verordnung) ordinance, should be reviewed and alleviated to enhance practicability and provide the necessary planning and investment security for investors.

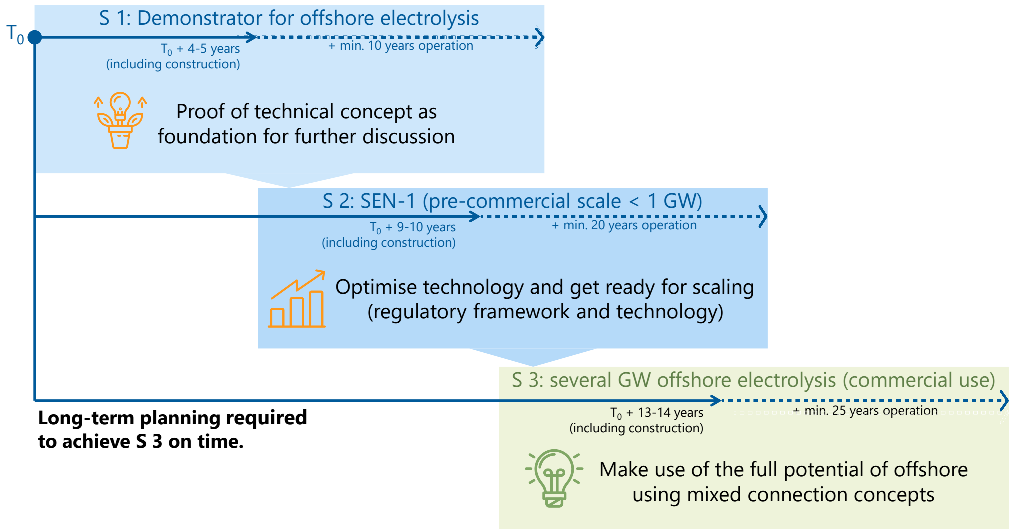
Summary. Mixed connection concepts with a focus on hydrogen production offer the greatest advantage in the integration of the investigated offshore wind farms in EEZ zones 4 and 5. They contribute valuable electricity when demand is high, sufficient quantities of hydrogen and can be realised cost-effectively with higher revenue potential. Mixed connection concepts reduce feed-in peaks into the electric grid in general and especially in times when onshore RES is abundant. This is likely to positively affect the need for congestion management in the electrical grid. However, the implementation of mixed connection concepts is not provided for in German law and requires appropriate adjustments.

Beyond this study. Further investigations are justified to substantiate the benefits of mixed connections for the electricity grid, specifically in terms of congestion management. Additionally, the potential combination of mixed connection concepts with hybrid interconnectors, the design of future auctions and the organisation of the future energy markets offshore require further research. This may impact the optimal configuration for zones 4 and 5, but the advantages of the mixed connection concepts evaluated in this study are likely to persist.

Recommendations for action. *To unlock the full offshore potential and avoid the risk of postponing necessary investments in OWFs and domestic hydrogen production, a three-stage approach is proposed as starting point for further discussions*.

- **Step 1 "Demonstration"**: Aim to prove the feasibility of the technology. Enable demonstration projects for offshore electrolysers to gather practical experience in planning, construction, operation and the environmental concept applied. Identify potential for improvement. This step should include rapid, small-scale demonstrator projects, accompanied by the ambition to develop a technical concept for large-scale offshore hydrogen systems. This ambition should be underpinned by the ambition to realise modular building blocks of such systems. This will most likely require a separate demonstration project.
- **Step 2 "Pre-commercial scale"**: Learn how to get faster (in construction) and aim to get cheaper by scaling up. Prepare supply chains for ramp-up. Scale-up and optimise concept for large-scale offshore hydrogen systems and optimise environmental concept. Adapt regulatory framework (see legal assessment). Develop a common view of all NSEC countries on an integrated system plan for the North Sea and the role of mixed connection concepts. Based on this, enable tendering of wind areas in zones 4 and 5 with the possibility of a mixed connection concept.
- **Step 3 "commercial use":** Benefit from the experience of earlier phases and harvest the full potential of the offshore wind using electricity, hydrogen from offshore electrolysers and mixed connection concepts.

There are limits to the extent to which these steps can be taken in parallel as each requires several years of planning, construction and testing. Therefore, step 1 should be implemented as soon as possible in order to reap the full socio-economic benefits of step 3 as soon as possible. As necessary, we recommend that financial support mechanisms are used to enable a rapid start of step 1. The costs are limited compared to potential benefits of step 3.



Three-step approach towards implementing offshore hydrogen.

1 Introduction

In 2023, more than 70% of Germany's primary energy demand was met by fossil fuel imports. To realize climate neutrality by 2045, Germany must meet its energy demands through renewable energy sources, domestic hydrogen production, and hydrogen imports. In the decarbonized German energy system, onshore hydrogen transport and storage infrastructure will be essential. This infrastructure is necessary to ensure a sustainable supply of green energy for key industrial sectors in Germany that depend on molecule-based energy carriers to achieve further decarbonization, such as steel production or the chemical industry. Further applications of hydrogen in heating and transport as well as in hydrogen power plants may foster the necessity of this infrastructure and may increase its transport capability in the future.

Offshore wind farms (OWFs) and onshore electrolysers are core pillars of the German energy transition, providing substantial benefits but also presenting challenges:

- Offshore wind farms are essential for the energy transition as they provide energy even during times when onshore renewable energy sources (RES) are not producing. The revenue potential depends on the electricity prices in times of wind. Due to their connection to the grid in Northern Germany, OWFs face challenges such as an increased risk of curtailment when onshore RES are already producing, which threatens to increase congestion management costs and prevents the utilisation of the full potential of clean offshore energy. There are also limited routes and high investment costs for electric connections. As more OWFs are being expanded, the distance to the coastline increases offshore – and onshore to prevent further grid congestion - resulting in overall higher connection costs. As the internal electricity grid in Germany is already dealing with congestion today and is projected to remain so, even with the anticipated investments until 2045, alternative solutions to transport energy to the shore and beyond are needed.
- Onshore electrolysers utilise renewable energy sources (RES) to supply green hydrogen and support decarbonisation efforts. Domestic hydrogen production enhances national and European sovereignty by reducing hydrogen import dependency. However, there is utilisation competition for onshore water and spatial competition for land use. The revenue potential of onshore electrolysers depends on the availability of low electricity prices. Their impact on congestion management depends on location and operation, with (local) incentive mechanisms contributing to improved performance in both aspects.

This raises the question how offshore wind farms and electrolysers can be integrated with greatest socio-economic benefit. Next to an electric connection, offshore electrolysis could contribute to hydrogen production, feed into a pipeline and improve the impact of offshore wind and electrolysers on the electric grid. However, in such a pure hydrogen connection scenario, electrical energy would be removed from the electrical system and become unavailable when renewable energy sources are scarce.

As an alternative to a connection exclusively via power cable or pipeline, a combination of an electrical and a pipeline connection concept could also be applied. In the context of this study, **we define such combination of transport infrastructures, including hydrogen pipelines and offshore cables as "mixed connection concepts"**[1] (cf. Figure 1). The different connection concepts have not been compared in greater detail so far.

[1] The terminology differentiates it from already existing concepts. "Hybrid" or "combined grid solutions" describe concepts which connect to wind farms and are utilized as interconnector simultaneously (cf. Kriegers Flak). It is also not to be confused with "meshed offshore-grids".

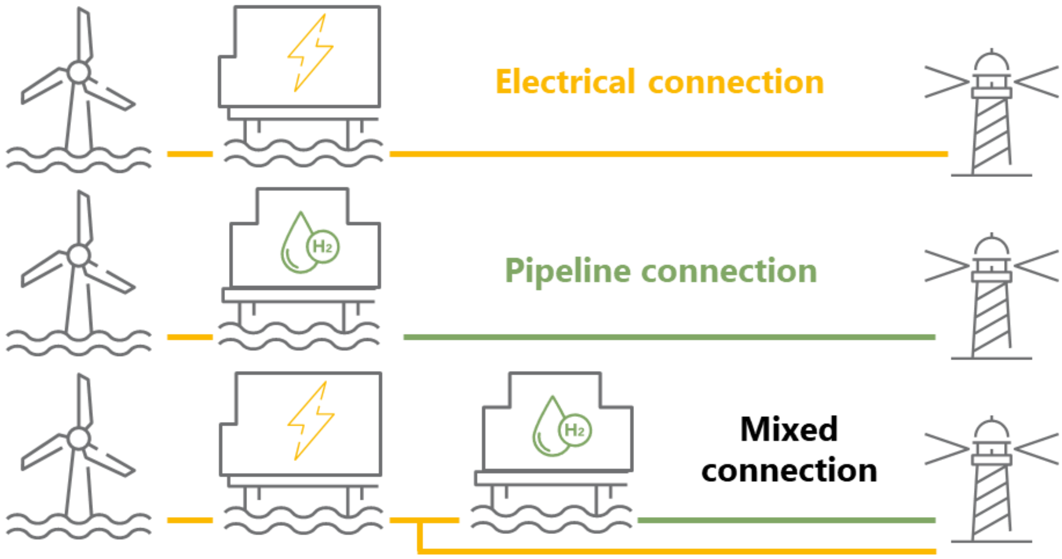


Figure 1: Simplified depiction of connection concepts to be discussed in this study

1.1 Objective and scope of the study

The objective of the study is to assess the socio-economic benefits of different connection concepts[2] **and evaluate them accordingly.** The analysis assesses the **connection concepts from a technical, economic, environmental and legal perspective.** The study aims to provide an overview of the various relevant factors and derive recommendations for further action.

Specifically, this study examines connection concepts via cables and electrolysis for OWFs in the German Exclusive Economic Zone (EEZ) in the North Sea. The connection concepts are compared for EEZ zones 4 and 5 (cf. Figure 2), often referred to as "duckbill".

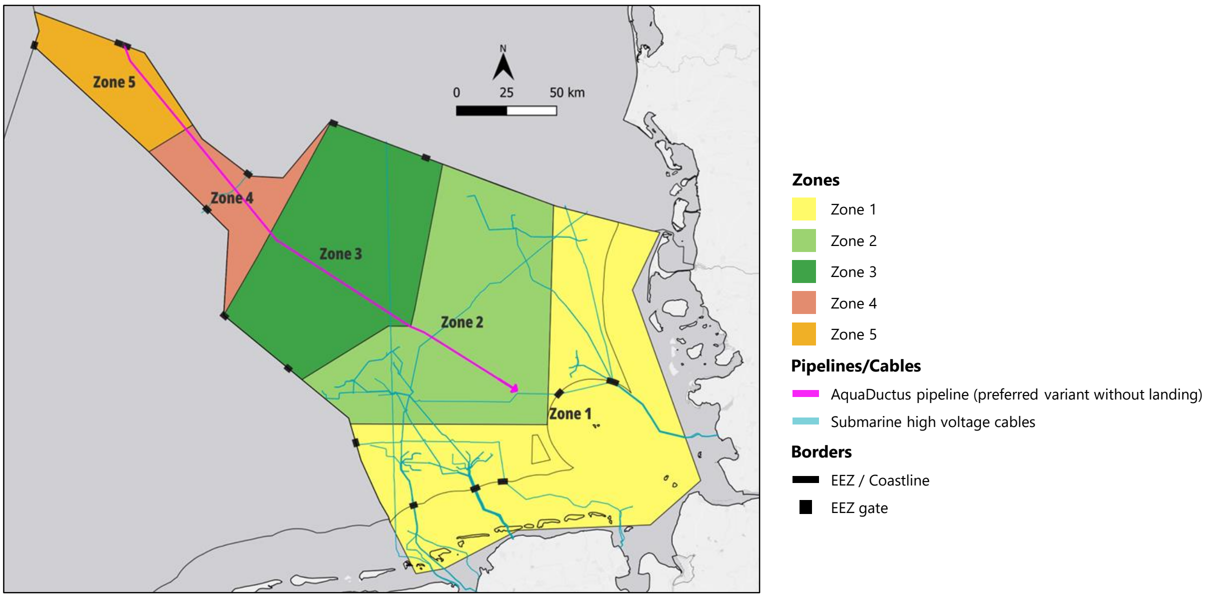


Figure 2: Connection concepts are being investigated for zones 4 and 5 of the German EEZ

In contrast to the SEN-1 test areas (cf. Figure 3), the specific use of the wind farm areas in zones 4 and 5 is currently under investigation, and implementation is expected in the mid-2030s the

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[2] incl. different design variants

earliest. Here, comparatively large distances must be covered to connect to the shore, which increases the connection costs.

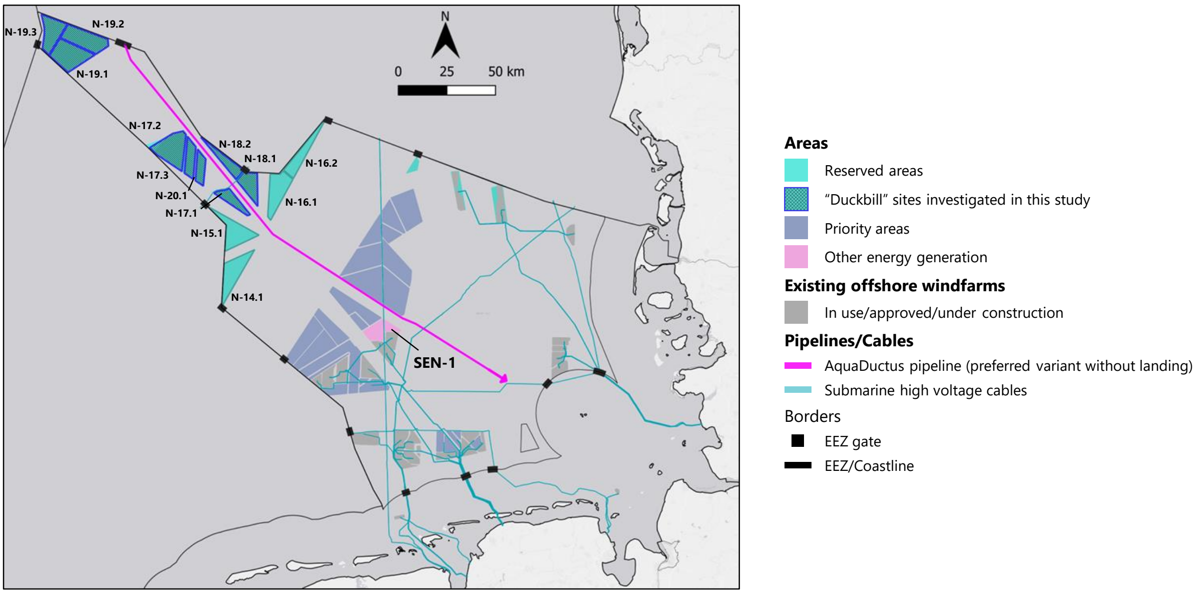

Figure 3: For the investigation of (mixed) connection concepts in zones 4 and 5, only wind farms in the EEZ's duckbill are investigated

In total, eight areas of the duckbill are estimated to have an expansion potential of roundabout 14 GW. The respective areas are highlighted as dark green shapes with blue framing in Figure 3. These areas of the duckbill have comparably short distances to the planned hydrogen pipeline (AquaDuctus) and are therefore most suitable to assess the relevance of OWF connection concepts with hydrogen components. The estimate is based on the latest preliminary draft of the area development plan, in which capacity estimates were given (BSH, 2021). In later publications of the area development plan, the area layout has been changed slightly, yet without updated capacity estimates. Based on the last capacity estimates, it is assumed that wind farms in zone 5 offer a potential capacity of around 6 GW. Accordingly, a capacity of 8 GW is assumed for the marked areas in zone 4. For the purposes of the study, a more detailed analysis is not necessary for the time being. Figure 3 shows the project status based on which the connection concepts have been analysed. The illustration differs from the latest draft of the area development plan published in June 2024 (BSH, 2024). On the one hand, the area development plan is in a constant state of development and on the other hand, the changes have no impact on the following conceptual assessment.

There are several reasons why these areas are chosen for a comparison in particular:

- The areas are far out the shore which makes the connection of OWFs especially costly.
- The investigated areas in the duckbill are allocated closely to the planned AquaDuctus hydrogen pipeline which is foreseen to transport hydrogen from Norway to Germany from 2030 onwards. Offshore electrolysis could utilize AquaDuctus at least partially. For the purposes of the study, the costs of the pipeline are allocated proportionally to the capacity of the respective connection concept. Further areas which have not been considered but are within "sight" of AquaDuctus would have to overcome greater distances and other marine obstacles.
- The specific use of these areas is still under investigation. Conversely, this study does not analyse any change of use of the areas in zones 1-3.

Clearly, the areas were also chosen to carry out concept comparisons. The restriction to "one set" of areas reduces the scope of the study considerably. Yet, possible findings can be transferred to other areas as well.

Based on the findings from the previous AquaVentus study "Comparison of system variants for hydrogen production from offshore wind power", **only grid-bound connections are examined in the following.** This refers to submarine cables and hydrogen pipelines. Other concepts, such as off-grid coastal production or hydrogen transport via ship are not investigated further because of their inferiority in cost efficiency and speed of implementation (AFRY, 2022). **The comparison further refers to platform-based systems for both electrolysis and power converters ("central concept"). In-turbine electrolysis ("decentral concept")** has its justification. Respective insights could be transferred to decentralized in-turbine concepts implicitly. Designing wind farms for decentralised concepts is therefore not off the table. A more detailed comparison is neglected to focus on the required transportation infrastructure.

The study is structured as follows: Chapter 1 describes the background and objective of the study and further describes hypotheses which further need to be investigated. Chapter 2 describes the methodology of the study, which also structures its subsequent Chapters.

Chapter 3 describes three energy scenarios that depict potential developments of the broader energy system of Germany and Europe. These scenarios aim to cover a relevant range of developments for the deployment of offshore wind farms and electrolysis. Important results are electricity and hydrogen prices, which are used in the subsequent evaluation. Similarly, Chapter 4 introduces the connection concepts in greater detail, also highlighting particular benefits and challenges. In order to be able to make an initial economic assessment, investment costs must also be estimated, which are derived in Chapter 5.

Chapter 6 then evaluates the connection concepts from a techno-economic perspective. Chapter 7 provides an initial assessment of the environmental impact of the different connection concepts and discusses how the effects of offshore electrolysis can be mitigated in real-life applications. Chapter 8 covers the current legal and suggests legal implementation strategies for mixed connection concepts in particular. The final Chapter 9 concludes with recommendations for action.

1.2 Hypotheses: mixed-connection concepts offer several advantages

Until 2045, Germany wants to increase its offshore wind capacity up to 70 GW, of which up to 60 GW are expected in the North Sea, which is an essential part of achieving the climate targets. Germany's hydrogen strategy further intends to increase the security of hydrogen supply and competitiveness. The connection concepts must be analysed from this perspective. The following hypotheses will be examined as part of this study:

- Mixed connection concepts can be implemented at comparable system cost to singular connection concepts yet allow to participate in two markets - power and hydrogen - at the same time. This increases revenue opportunities and therefore decreases development risks. Singular concepts can only serve one market.
- Offshore electrolysis utilizes energy on site and solves the energy transport issue with pipelines, which also reduces the need for redispatch measures significantly (Consentec, 2023). In mixed grid connections, electrolysis still reduces the impact on the electric grid, but provides valuable energy when it is in short supply on the electricity markets. This reduces electricity cost and – although not focus of this study – grid fees.
- In a mixed connection concept, cables cannot only be used to transport energy to the shore (unidirectional), but also to use onshore electricity for hydrogen production offshore (bidirectional). This bidirectional utilisation of offshore cables increases the capacity factors of cables and electrolysers and contributes to a more effective utilisation of scarce space in the German EEZ. Note: this requires an adequate legal framework for offshore consumers that further guarantees the production of green hydrogen.
- Mixed grid connection can reduce the costs not only for the projects mentioned, but for the integration of offshore in the North Sea as a whole. Together with the higher operational flexibility of the mixed connection concepts and their ability, to facilitate more potential revenue streams (power and hydrogen), mixed connection concepts make OWFs economically more

attractive. This minimizes the risk of a delayed energy transition and further reduces costs that need to be borne socially (charges or subsidies).

Offshore wind farms in a mixed connection concept could harvest the potential of both, electric integration and offshore electrolysis while increasing the benefits. The concept could increase the energy output, revenue potential and security of supply, but is also associated with different investment costs, environmental impacts and legal implementation requirements.

Out of scope: Within this study, neither hybrid connections (i.e. connecting the OWF to an electrical interconnector) nor a coupling to a potential interconnected “North Sea HVDC grid” are investigated. Additional assumptions regarding the maximum utilisation of the connections arising from operational restrictions of the electricity system are also not considered. Both concepts and such operational restrictions may impact the overall results. However, neither hybrid connections nor a “North Sea HVDC grid” can transport the entire energy produced by the 14 GW OWF capacity which is assumed to be installed in these investigated areas. Additional connections to the German shore– via hydrogen pipeline or electricity cable – will be required.

The objective of the study is to reveal insights which connection types are beneficial from a socio-economic perspective instead of identifying the exact configuration that should be realized in the future. Beneficial connection types should be enabled as soon as possible (as core pillar of the second phase of the energy transition). For the exact configuration E-Bridge recommends conducting further studies incorporating the above mentioned and further points which are not part of the study.

2 Methodology

The following study evaluates different offshore connection concepts. The structure of the report is adapted to the steps required for the evaluation. The aim is to determine the connection concept with the greatest socio-economic benefit. The evaluation is based on qualitative arguments and quantitative analyses. Quantitatively, the market development, possible investment and operating costs, operations and the energy provided are analysed and compared for each concept. From this, further statements can be made on security of supply and energy independence, system integration, subsidy costs, and the effects on energy costs. In line with this, possible implementation risks are analysed, evaluated and appropriate countermeasures proposed. Figure 4 provides an overview of the applied methodology.

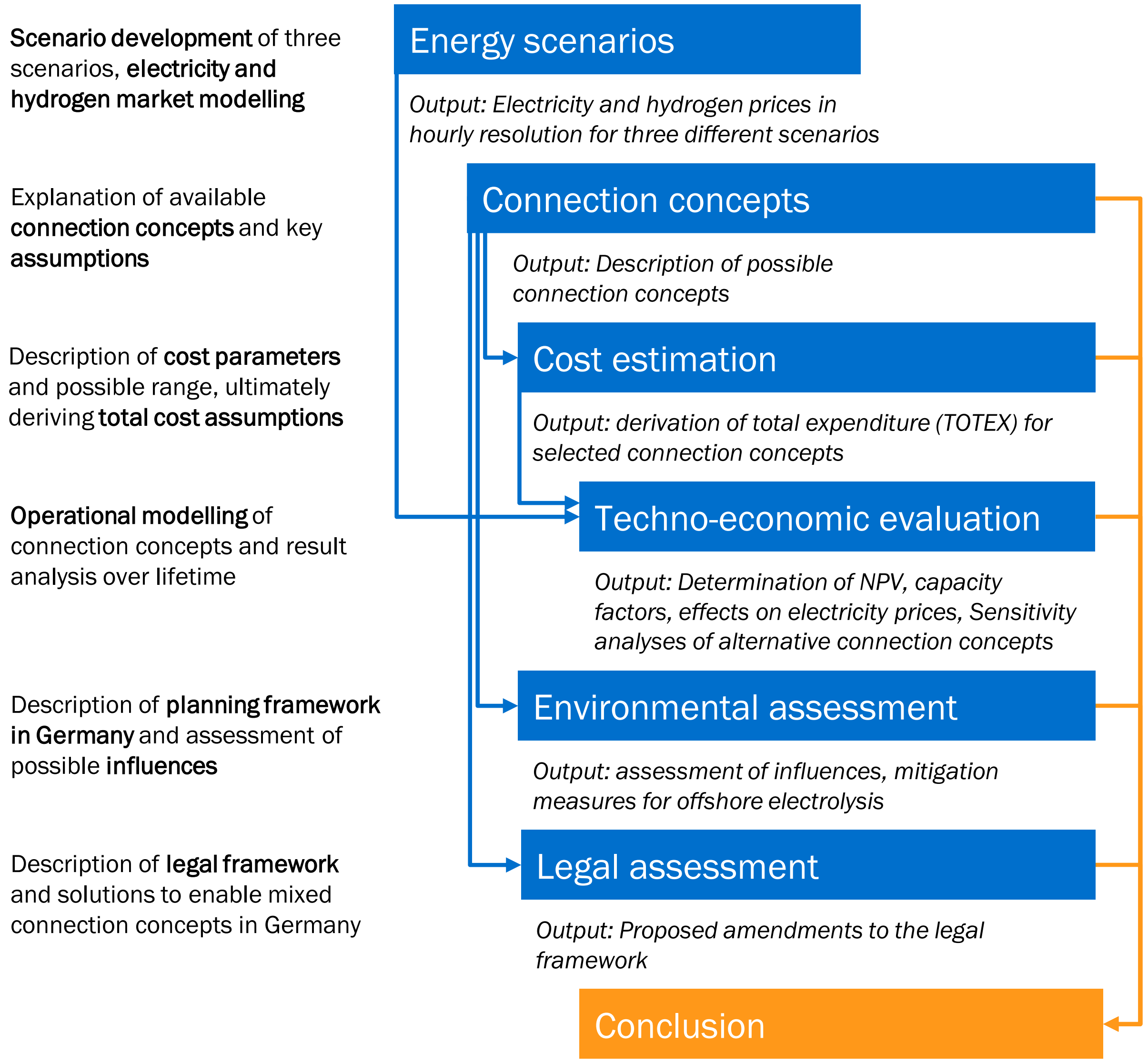

Figure 4: Methodology of the study

To describe the future in which the offshore connection concepts must be evaluated in, we use three scenarios which are described for 2035, 2040 and 2045 (Chapter 3). The scenarios vary regarding their development of electrification vs. the application of hydrogen and their transition speed. The scenarios are used to calculate electricity prices based on a European market model in hourly resolution. A subsequent model determines prices for hydrogen for Germany. Beyond 2045, the scenarios are extrapolated using 2045 to carry out an assessment over a service lifetime of up to 25 years.

Possible connection concepts and necessary assumptions are introduced in Chapter 4. Based on these assumptions, the costs for the connection concepts are then determined in Chapter 5. A range of costs is determined for individual cost components, such as the expansion of wind farms, the laying of cables, electrolysers and pipelines, as described in the literature. Furthermore, specific investment, operating and capital costs are determined for specific configurations, which are analysed in more detail in the following Chapter 3, in order to be able to carry out an evaluation.

The techno-economic analysis in Chapter 6 uses an operating model to determine the optimised use of the wind farms in their respective connection concept. For example, it examines how much energy is provided, what utilisation of the operating resources is achieved, what revenues can be generated and how this - minus CAPEX and OPEX - affects the overall economic assessment. By determining the most economical connection concept (extended by sensitivities), the concepts that require the least overall subsidisation are ultimately determined. The effects of the connection concepts on electricity prices are also analysed.

The environmental assessment in Chapter 7 describes the legal framework and planning parameters. The effects of different connection concepts are described qualitatively. At this stage, environmental planning is only feasible to a limited extent. For this reason, influencing parameters and mitigation measures are described, particularly for the new offshore electrolysis.

The legal framework of the connection concepts is the focus of Chapter 8. After summarising the status quo, the legal requirements are explained and, if necessary, proposals for changes are presented.

Cost and price projections are carried out in nominal terms, using 2024 base year prices. Exclusively in the calculation of net present values, inflation is inherently considered by the weighted average cost of capital, but only to compare investments that were made at the same time.

If energy values for hydrogen are given and not otherwise stated, they refer to the lower calorific value.

3 Energy scenarios

Guiding questions

- What developments are relevant for electricity and hydrogen markets in the future? How is this depicted in the study?
- What are the central assumptions for the scenario development?
- What electricity and hydrogen prices are assumed in this study?

To describe the future in which offshore connection concepts must be evaluated in, three scenarios have been developed by E-Bridge and applied in this study. These scenarios vary regarding their development regarding electrification vs. the application of hydrogen and their transition speed. The scenarios are first introduced descriptively in Chapter 3.1.

Each scenario describes one possible development for the energy system towards 2045 and beyond. Suitable and numerical values are added based on a detailed description of the scenario, mostly in reference to existing studies. Such assumptions include, the installed capacity of renewables, the demand for energy or future CO_2 prices for 2035, 2040 and 2045 as described in Chapter 3.2.

Resulting electricity and hydrogen prices are described in Chapter 3.3. For each scenario, the described input data is used in the first step to determine electricity market prices and the operation of electrolysers using an electricity market simulation. In a second step, hydrogen prices are derived using this data and under further assumption on hydrogen import prices.

3.1 Storyline

In recent years, the complexity of challenges coming along with the energy transition increased. While the first phase of the energy transition mainly focused on the decarbonization of the electrical energy system, the decarbonization of the overall energy system, especially the heat and transport sector, concern the largest part of the society. Affordability, acceptance and practical feasibility of target-implementation will become more relevant. This increases uncertainty and requires diversity in the solutions mix for risk diversification (saturation, technological risk, and security of supply) and synergy (sector coupling). A consistent storyline is necessary to model long-term energy scenarios. Keeping this in mind, E-Bridge developed three scenarios based on national and EU-wide targets (cf. Figure 5), which deem to be suitable to evaluate different offshore concepts against relevant developments and to derive a robust decision foundation for this study's recommendations[3]. These scenarios align with E-Bridge's view on the development of the energy transition and represent possible developments without a stated probability of occurrence.

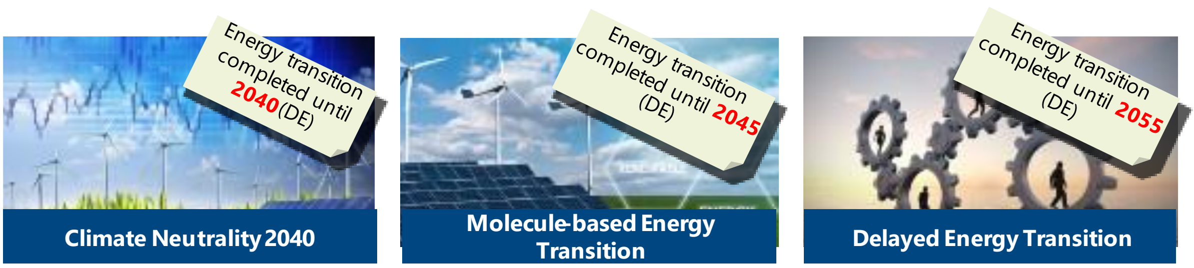

Figure 5: Overview of scenarios

[3] Since offshore concepts with electrolysers are evaluated for 2035 onwards, we believe that modelling different directions of the overall developments is necessary. Yet, we do not assign probabilities of occurrence to these scenarios. It is rather the target to show that the results are robust against different developments.

The scenario “Climate Neutrality 2040” (CN) focusses on high efficiency gains and electrification in Germany and Europe. Germany achieves climate neutrality in 2040 which is in line with Germany’s federal targets. This is achieved by a high level of acceptance in the population fostering a rapid expansion of RES and power grids. Coal phase-out plans are reached by 2030. Through costly investment programs, additional efficiency improvements (high housing renovation rate, shifts in transportation), ambitious transformations in the industries (electrification as far as possible and high efficiency gains) and a strong focus on electrification in buildings (heat pumps), and transportation (electric cars and trucks) is assumed in this scenario. We differentiate the European countries in their transition speed, i.e. some reach climate neutrality 2045 (cf. Ten-Year Network Development Plan (TYNDP)). Domestic H_2 electrolysis production is encouraged and growing through the availability of cost-efficient RES electricity.

The scenario “Molecule-based energy transition” (MET) achieves the decarbonization until 2045 in line with the German policy targets by a strong(er) use of green gases (in comparison to CN). In line with the forecast of this transition scenario, a decisive share of current CH_4 demand within the industry- and heating sector get substituted. Yet, the increased use of H_2, especially in industry beyond material utilisation but also in some regions in the heating sector (e.g., heating networks) and in some parts of the heavy-duty transport sector leads to an overall higher level of hydrogen utilisation. This development is also driven since limitations in acceptance of RES extension and a stronger push from society in the direction of (green-)gas applications for diversification, whole system efficiency, and cost reasons. The scenario has consequently a higher level of energy (hydrogen) import in the long run but therefore can manage to decrease the final onshore RES extension level (while maintaining it at a high level). A coal phase-out is reached latest by 2038.

The scenario “Delayed energy transition” (DET) assumes an overall slower transformation speed due to acceptance issues, costs, lack of materializing efficiency gains and bureaucracy. Acceptance issues with renewable energy expansion as well as skilled labour shortages, especially in building housing renovation and the required power grid expansion, are leading to delayed achievement of climate protection goals. Political objectives are being diluted and implemented only with delay. Prolonged retention of unabated fossil fuels – and especially of methane – in the energy system are assumed. With approximately ten years delay, the energy system ends in 2055 results in a comparable system design to the MET scenario.

3.2 Overview of the three energy scenarios

In this chapter the three modelled energy scenarios and their respective assumed input parameters for the electricity market simulation are introduced. The scenarios were modelled in a fundamental European electricity market model. The model requires data on supply and demand as well as commodity prices, renewable energy capacity and volumes (RES) and conventional power plant capacity, demand, fuel and emission prices, flexible capacities (electrolysers, EV, etc.). Also, cross border interconnection capacities (NTC) for import and export power flows have been modelled. Hourly time series input data were used for RE generation and electricity demand, which were based on the historical climate year 2018 (actual data ENTSO-E) and scaled according to the respective capacity and energy of the reference year and scenario. All input data were validated and verified in light of current fundamental developments or policy.

The European countries modelled in the market simulation are shown in Figure 6. Developments of countries with a particular impact on electricity (and hydrogen) prices in Germany are modelled with greater detail: North Sea countries, electric neighbours and countries with high demand. The development of the other European countries is modelled using an average scenario, mostly based on CN.

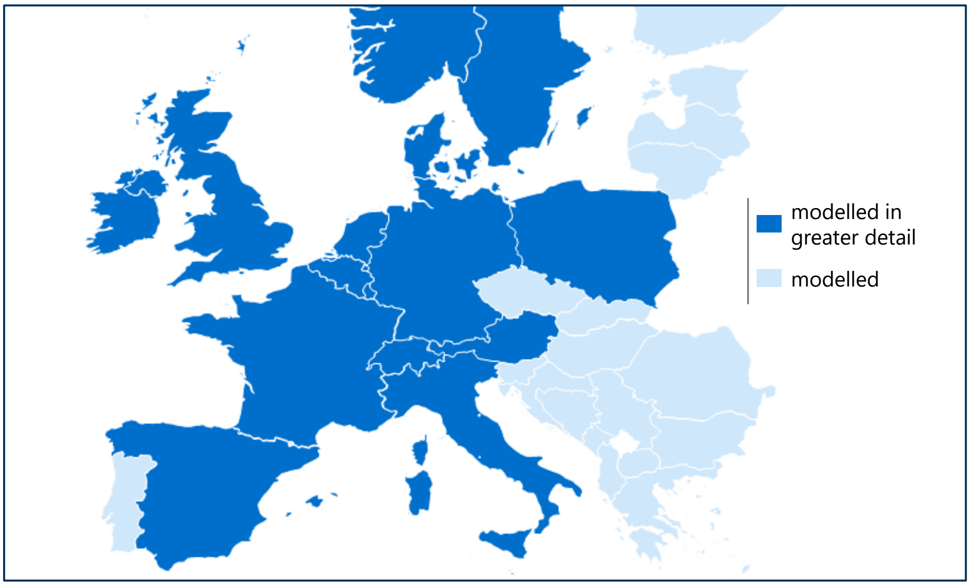

Figure 6: Countries considered for this study

For the scenario “Climate Neutrality 2040” (CN) input data from the Network Development Plan (NEP) 2037/45 (2023, scenario B) was used for modelling Germany, in particular from the scenario B (decarbonisation through intensive electrification). The NEP data was supplemented with input data for H_2 demand import potential from other relevant H_2 industry studies and projects like the TransHyDE European H_2 infrastructure study. The modelling of the other countries is predominantly based on the TYNDP scenario “Distributed Energy“. For RES, the updated TYNDP data published by ENTSO-E in 2024 was used, for conventional and flexible capacity as well as demand data, input from the TYNDP 2022 was used, as more recent data has not been published yet.

Scenario “molecule-based Energy Transition” (MET) is based on the scenario T-45 H_2 of the 'BMWK Langfristszenarien' (2022). For the modelling of the other countries, the TYNDP scenario 'Global Ambition' was used as the basis for the model. RES data published by ENTSO-E in 2024 were implemented, whereas capacities were based on the data from TYNDP 2022.

The data sources used for “Delayed Energy Transition” used for the DET scenario are the same as for the MET scenario but implemented with a delay of up to 10 years. For conventional capacity the same levels as in MET scenario were used, but with a slower coal phase out and slower gas-fired power plant increase in the years after. For demand, RES and flexibilities such as Battery Energy Storage Systems (BESS), Electric Vehicles (EVs) and electrolysers, a slower increase from today’s numbers was assumed.

In the following, the input data for Germany is explained in greater detail. The different amounts of installed RES capacity per scenario can be seen in Figure 7. From 2024 onwards, RES expansion is fastest in the CN scenario, where the maximum solar capacity in Germany is already reached in 2040, while the maximum capacities for onshore and offshore wind are reached in 2045. The expansion of RES is slower in the MET scenario, where the maximum capacity for all three technologies is reached in 2045. These maximum levels are lower than in the CN scenario since the overall electricity demand is lower due to an overall lower electrification rate than in CN and increased hydrogen imports. However, in MET H_2 demand is therefore higher (see below). In line with the storyline of the scenarios, the lower expansion of RES capacity only affects the onshore system where large ground-mounted PV-projects and onshore wind face acceptance limitations. The slowest expansion of RES takes place in the DET scenario leading to the fact that the maximum level is not reached until 2055. Capacities here correspond to those in the MET scenario in 2045.

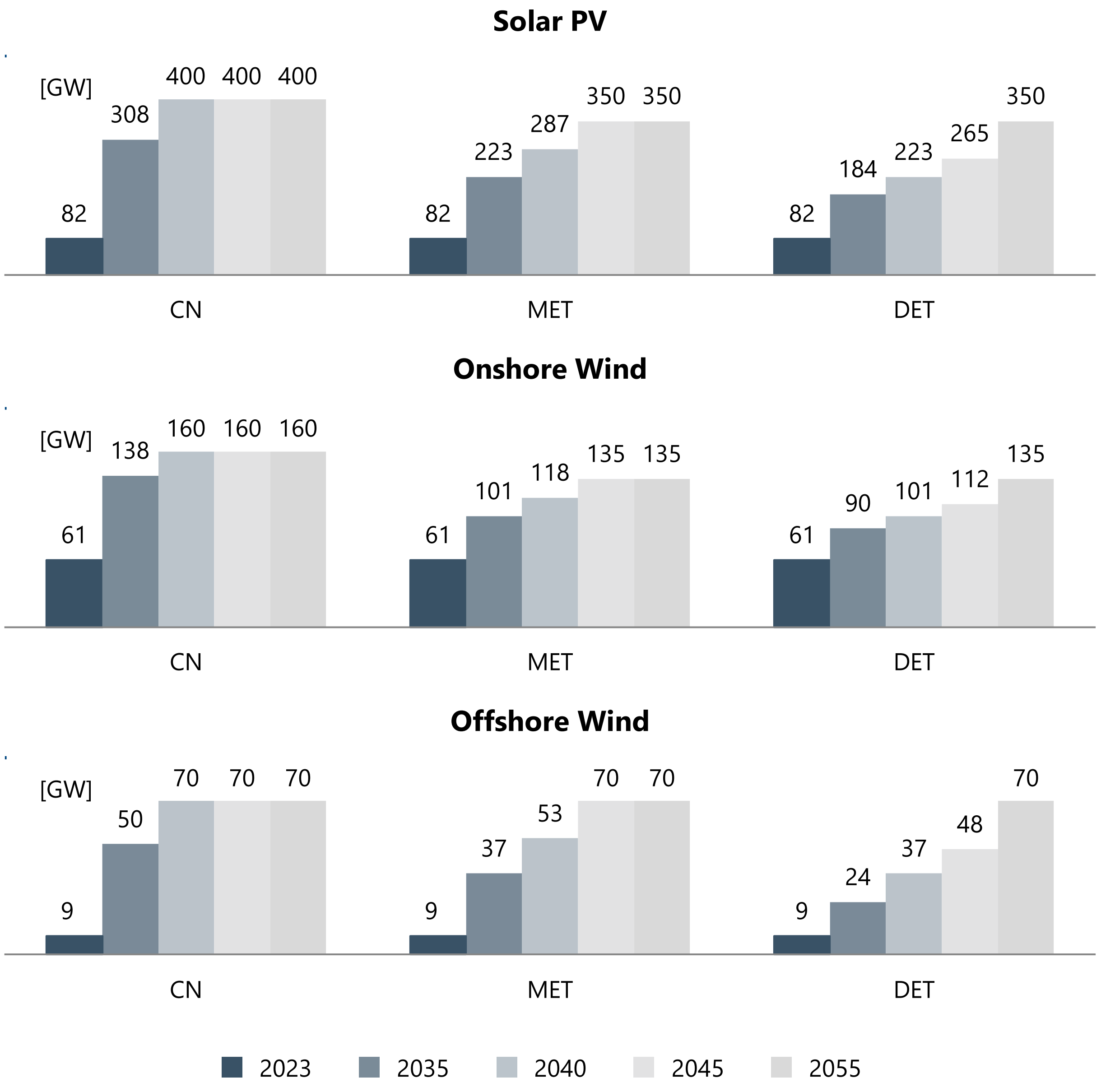

Figure 7: Installed RES capacity in Germany per scenario and year

For electrolysers, the slowest expansion is in the CN scenario, as shown in Figure 8. Yet, an ambitious start of electrolysers is assumed in all three scenarios[4]. The maximum level is reached in 2040 but is lower than the 50 GW_{el} in the other two scenarios. The MET scenario has the fastest expansion, with 50 GW_{el} being reached in 2045. In the DET scenario, 50 GW_{el} is reached in 2055. The expansion until 2045 is similar to the CN scenario, although the capacities in 2035 and 2040 are slightly higher.

In contrast, the CN scenario has the highest maximum capacity for large scale battery storages (BESS) which is rather logical since this scenario offers the largest amounts of high and low prices fostering business cases for flexibility. The maximum capacity of 43 GW is reached in 2045. This is 15 GW more than the maximum capacity in the other two scenarios. In the MET scenario, 28 GW is reached in 2045, while in the DET scenario it is not reached until 2055. Home storages were included in the modelling but with limited impact on electricity wholesale prices. EV flexibility is only

[4] Since H_2 import will be limited at least until the early 2030s a sufficient political support level for construction of electrolysers is necessary in all scenarios to enable the offtake of the H_2-economy anyhow.

modelled as demand side flexibility not as vehicle to grid (V2G) flexibility as we deem the realistic potential of V2G low and not significant enough.

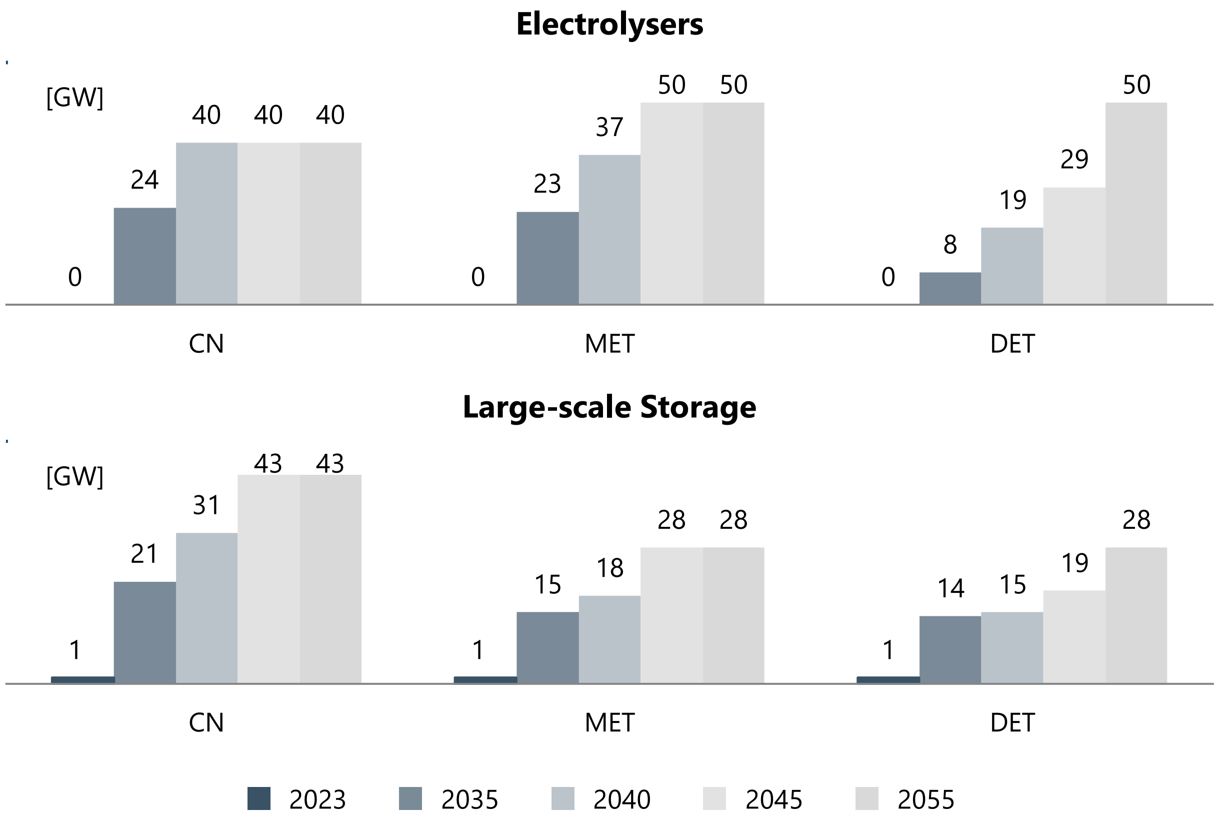

Figure 8: Installed electrolyser and large-scale storage capacity in Germany per scenario and year

Of the mentioned electrolyser capacity, 90% operates based on price signals in the CN and the MET scenario and 50% in the DET scenario in 2045. For 2035 this percentage was 60%, 30% and 0% and for 2040 90%, 80% and 10% for the CN, MET and DET scenario respectively. The resulting absolute flexible capacity for 2045 can be seen in Figure 9. This capacity produces hydrogen if the electricity price is below a certain threshold (65 EUR/MWh in 2045).

For electric vehicles (EV), it is assumed that a certain percentage (15% in 2035, 20% in 2040, 25% in 2045) can load flexibly between 7 PM and 7 AM. This corresponds to 13 GW in 2045 for the CN and MET scenario and 9 GW for the DET scenario. EV and electrolysers are only modelled as consumers and therefore do not feed electricity back into the grid.

The installed RES capacity is significantly higher than flexible capacity as Figure 9 shows, although in practice the full output of RES is rarely available.

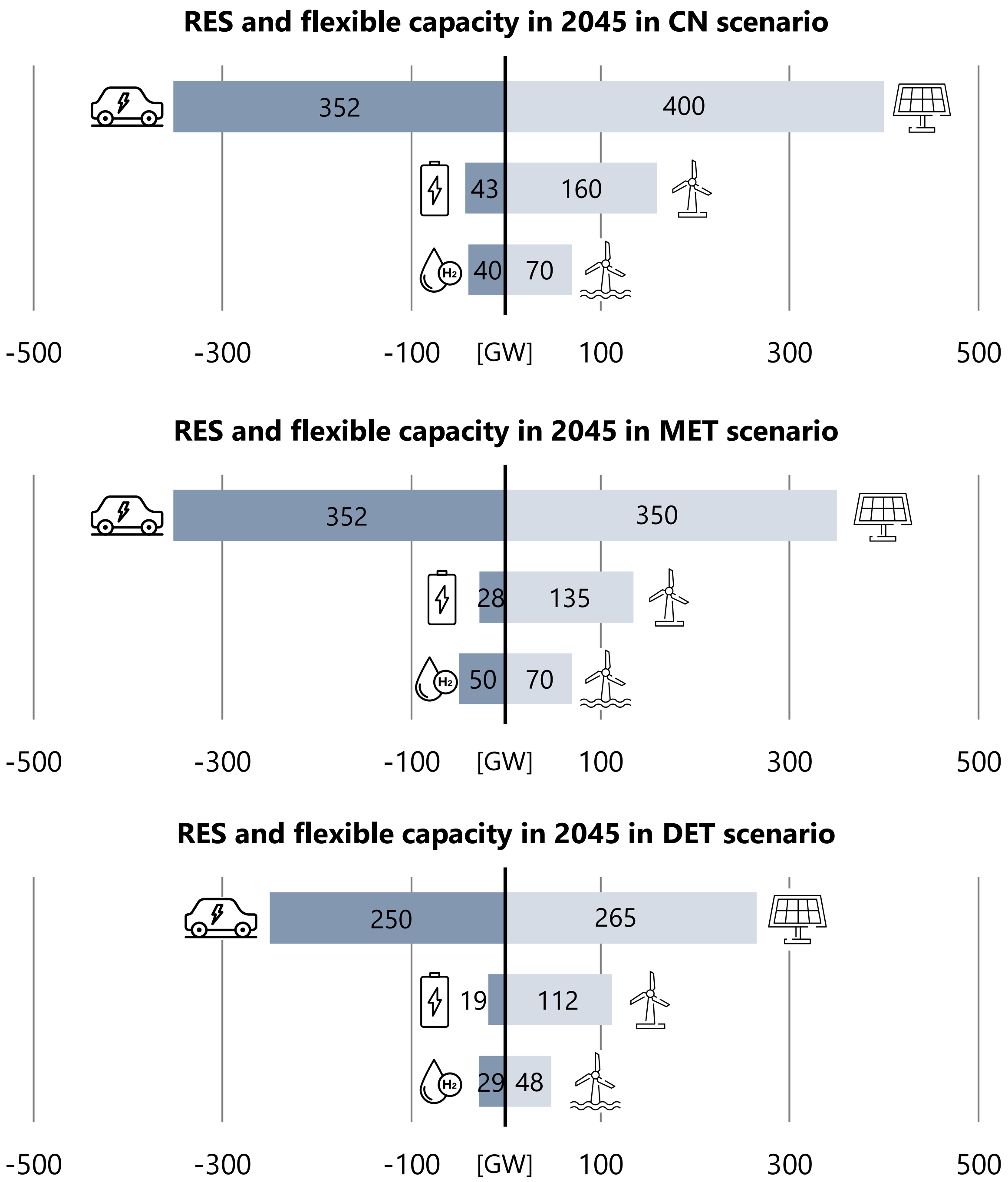

Figure 9: Comparison of installed RES capacity with capacity of flexible consumers and storages for each scenario in the year 2045

The installed capacity of gas or H_2-fired power plants is assumed to be similar in all three scenarios and the total is fairly constant over the years[5]. The transition from natural gas to H_2 is fastest in the CN scenario as Figure 10 shows. Half of the capacity is already converted to H_2 in 2035 and in 2040 all gas-fired power plants are converted to H_2. In the MET scenario, the full transition is

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[5] Regarding the focus of this study the overall capacity level is less important. Yet, for capacity adequacy issues and corresponding questions it is of utmost importance for the future. E-Bridge advocates for an ambitious progress in terms of the “Kraftwerksstrategie” and the capacity market to back up the energy system

completed between 2040 and 2045, while in the DET scenario around 30% of gas-fired power plants remain in 2045.

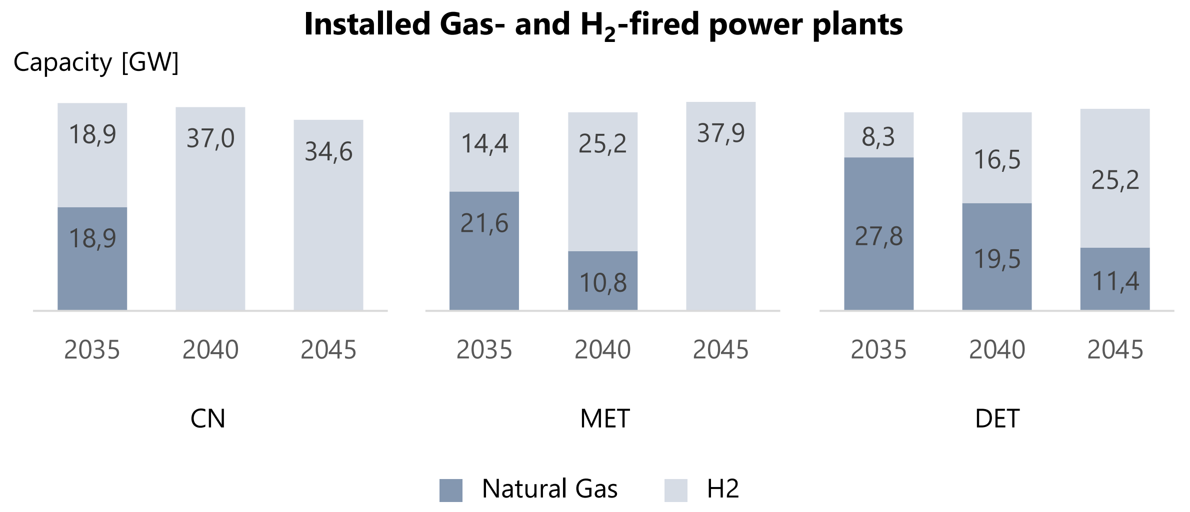


Figure 10: Installed Gas- and H_2-fired power plant capacity in Germany per scenario and year

As Figure 11 shows, the increase in electricity demand is highest in the CN scenario, where the maximum level is already reached in 2040. The total maximum electricity demand is also highest in this scenario. Due to the higher use of hydrogen, electricity demand increases more slowly in the MET scenario. The maximum level is reached in 2045. In both the CN and MET scenarios, electricity demand decreases after 2045 due to decreasing domestic hydrogen production. This is due to the fact that, following 2045, an increase in hydrogen imports is assumed as more and more other countries build up significant hydrogen production capacity. In the DET scenario, the maximum level of electricity demand is reached in 2055 and corresponds to the level of electricity demand in the MET scenario for the same year. In this scenario, demand increases continuously as hydrogen production also increases continuously.

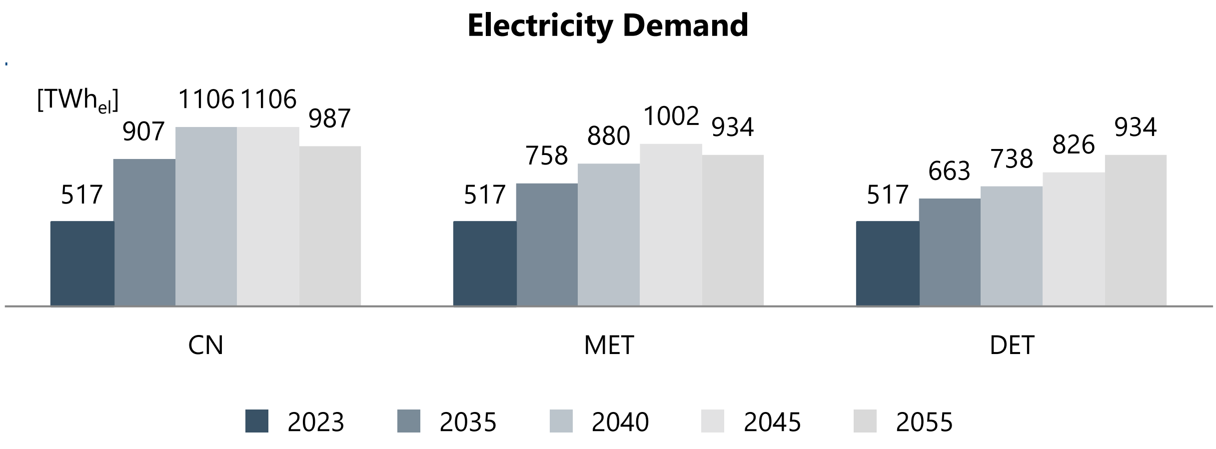


Figure 11: Assumption for electricity demand in Germany per scenario and year

While the CN scenario has the highest electricity demand, the MET scenario has the highest hydrogen demand as Figure 12 shows. The maximum level of 472 TWh_{th}[6] is reached in 2045 in the

[6] Within this study, all energy-related values for hydrogen (e.g., MWh, GWh, TWh, EUR/MWh) are related to the lower heating value of 33.324 kWh/kg_{H2}.

MET scenario and in 2055 in the DET scenario. The maximum hydrogen demand level in the CN scenario is 357 TWh_{th} which is reached in 2040 already.

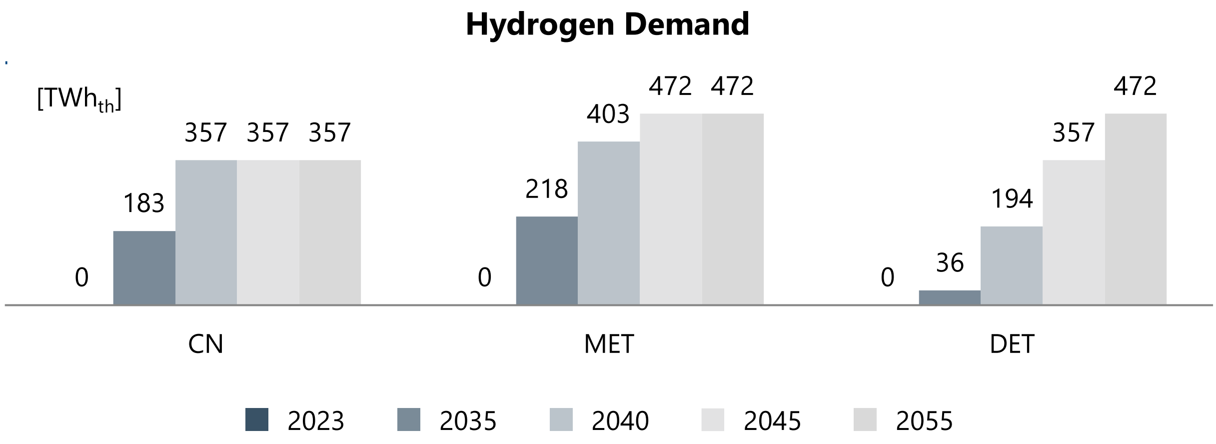


Figure 12: Assumption for hydrogen demand in Germany per scenario and year. Hydrogen demand in 2023 is covered by cracking methane and thus (still) part of the methane demand.

Commodity market prices for natural gas, hard coal, hydrogen and CO_2 are next to supply and demand development a key driver of electricity prices. The commodity price assumptions for 2035, 2040 and 2045 have been projected and aligned with the current future prices at relevant exchanges and the price assumptions of the International Energy Agency (IEA) in the World Energy Outlook (2023). The prices for the CN scenario have been aligned with the "Net Zero Emission" scenario (known as NZE); the MET scenario with the Announced Pledge scenario (known as APS) and the DET scenario with the Stated policy scenario (known as STEPS) of the IEA.

Figure 13 gives an overview of the assumed gas and emission prices. The CN scenario assumes the fastest decrease in commodity prices (gas and coal) and the fastest increase of CO_2 prices to 150 EUR/t in 2035 and 225 EUR/t in 2045. This is driven by a high degree of electrification, reducing gas and coal demand. Coal demand is further reduced by an early coal fired generation phase out. Higher CO_2 prices are driven by a more ambitious policy towards emission reduction and achieving climate neutrality.

The MET scenario assumes a slower electrification and still relatively stable gas and coal demand which keep gas prices (and also coal prices) higher than in the CN scenario. The slower degree of electrification also by industries and the heating sector keeps gas demand and prices stable.

In the DET scenario reflects the slowest decarbonization path. Demand for gas and coal remains stable and not significantly reduced until 2040 on the back of a less ambitious decarbonization policy and slower degree of electrification. This leads to a slower decrease of gas and coal prices. Emission prices are rising on a slower path due to lower decarbonisation targets.

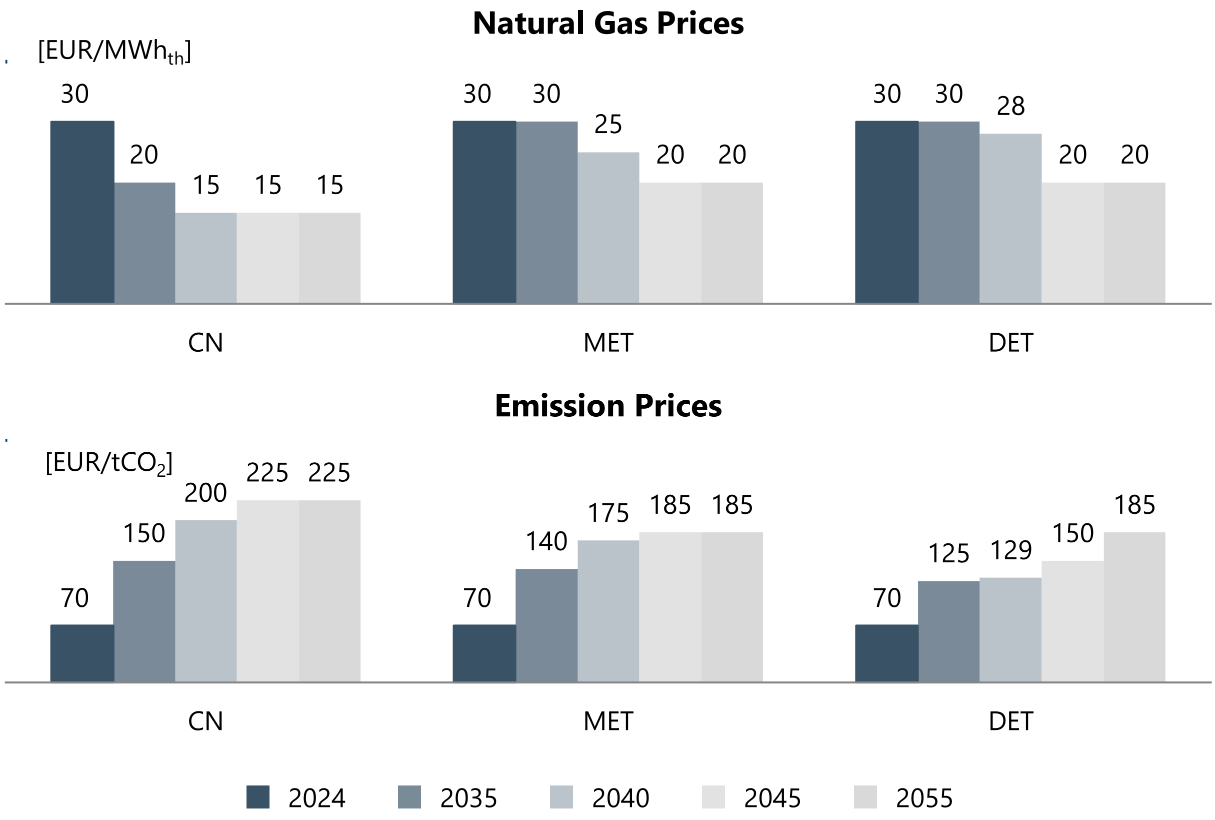


Figure 13: Assumption for natural gas and emission prices per scenario and year[7]

3.3 Development of electricity and hydrogen prices

This chapter presents the results of the electricity market simulation. For each of the three scenarios, the simulation was carried out for the three target years 2035, 2040 and 2045, making a total of nine simulations. Developments after 2045 are extrapolated in line with the year 2045. Only in the DET scenario is it assumed that the developments from 2055 onwards correspond to the MET 2045 scenario.

Figure 14 shows the average base electricity prices as well as the peak price (average of 3000 h with the highest price) and the off-peak price (average of 3000 h with the lowest price) for all three scenarios and target years. It has to be noted that the minimum price in the fundamental market model is 0 EUR/MWh. Negative electricity prices are cut off at 0 EUR/MWh by the model as there is not sufficient fundamental and historical data available on negative electricity prices. Negative prices are currently caused by inflexible generation, wrongly skewed incentives through subsidies (e. g. EEG market premium) and inflexible demand. These effects will decrease in the future, meaning that prices below at 0 EUR/MWh or below are becoming more unlikely.

[7] The prices are nominal prices in 2024 Euros, which applies to all prices stated in this report.

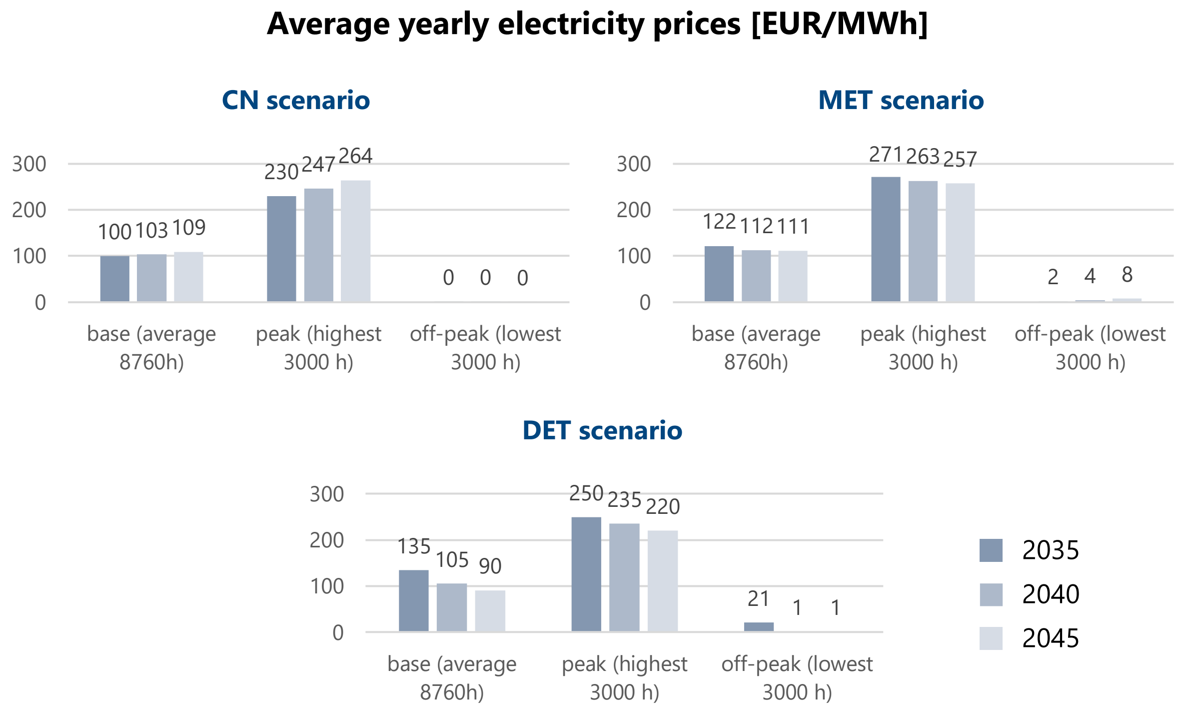


Figure 14: Average annual base, peak and off-peak electricity prices per scenario and year

The average baseload electricity prices are in all three scenarios to reach 100 – 120 EUR/MWh for the reference years. In the CN scenario especially, peak prices are expected to gradually increase to higher electricity demand from H_2 production and higher share of expensive H_2-based power generation towards 2045. Also strongly increasing CO_2 prices (225 EUR/t_{CO2}) are driving the power price increase.

In the MET scenario the prices are decreasing somewhat from 2035 towards 2045. This can be explained by stronger RES growth versus relatively lower demand increase compared to the CN scenario. Also, the switch from gas power generation to expensive H_2 power generation is slower in the MET scenario across all countries.

The DET scenario shows a pronounced price decrease towards 2045 from elevated levels in 2045. Main explanation is the relatively higher RES growth versus demand increase as well as the higher share of gas generation still available until 2045 with lower expected gas prices.

In Figure 15 the monthly averages of the electricity prices are shown for each scenario and the reference year 2045, which is decisive for the later evaluation, as it is extrapolated for the following years. However, the seasonal and monthly pattern of electricity prices is similar across all three scenarios and years. Highest monthly prices are expected in January and February due to high demand and low RES generation.

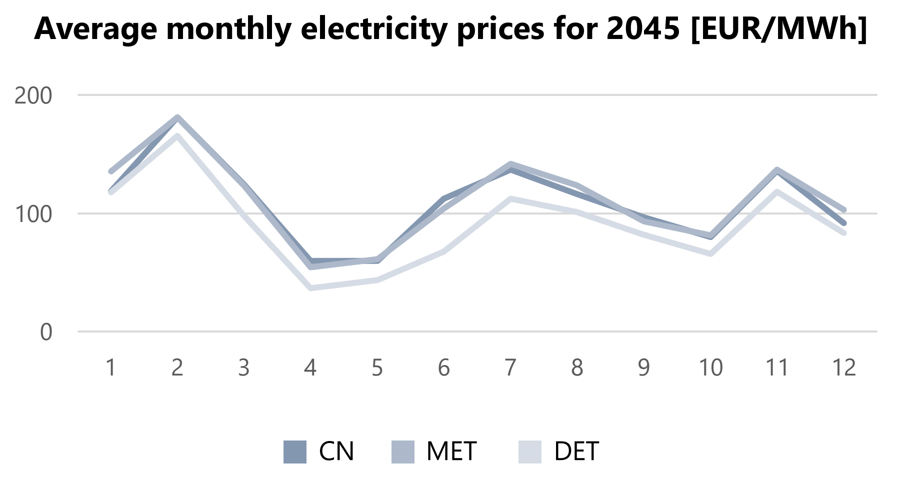


Figure 15: Average monthly electricity prices for each scenario in 2045

Figure 16 shows the average daily hour electricity prices for all three scenarios for the reference year 2045. The price pattern is again similar in all three scenarios and years. The lowest average prices are expected during the midday hours with high solar generation, while the evening hours (7-9 PM) are expected to be the most expensive due to high demand and low RES generation. From 2035 to 2045, the spread between day and night increases in particular - but the shape of the “duck curve” remains similar.

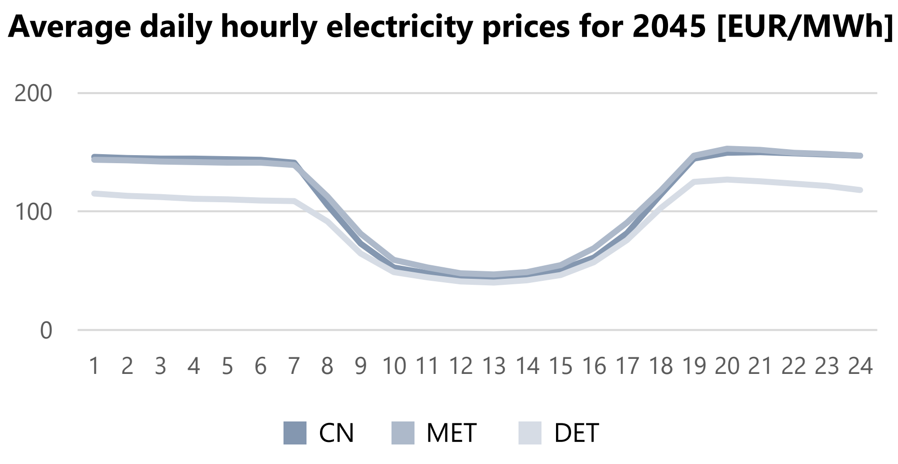


Figure 16: Average daily hourly electricity prices for each scenario in 2045

The hourly price duration curve also shows similar patterns in all three scenarios as can be seen in Figure 17. All scenarios have a significant amount of zero or below priced hours and around 1200 - 2200 hours with a price above 200 EUR/MWh. In the CN and MET scenario there are more hours with a price of 300 EUR/MWh or above due to the increase of H_2 based power generation in contrast to the more gas-based generation in the DET scenario.

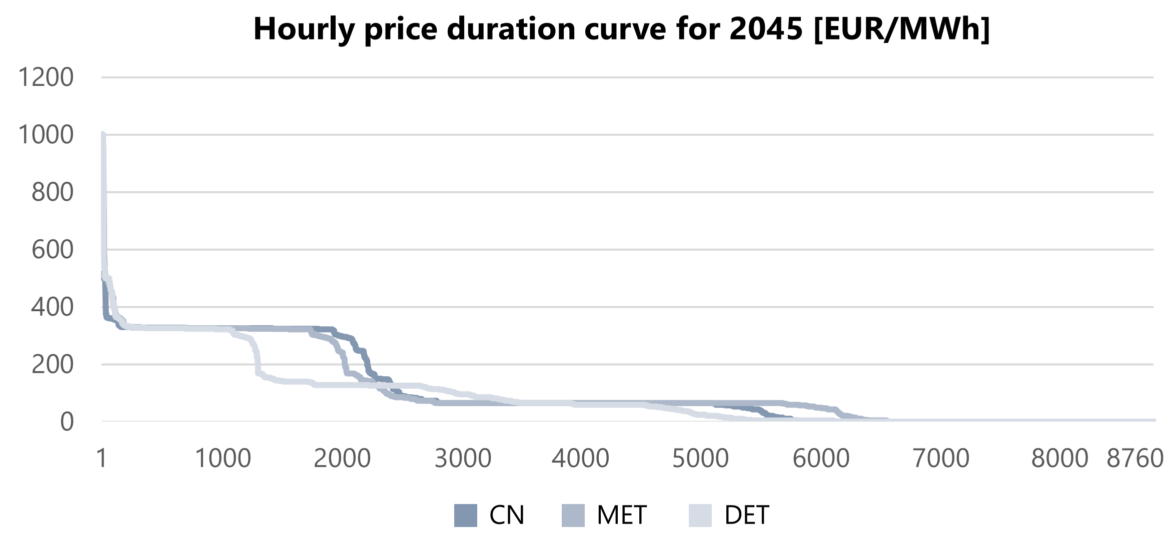


Figure 17: Hourly price duration curve for each scenario in 2045

Due to the strong increase of RES supply all scenarios will produce 2000 or more hours with a price of zero or below as Figure 18 shows. The CN scenario will produce the highest amount of zero priced hours due to the strongest rise of RES. The relatively higher amount of flexible load in the MET scenario causes less numbers of zero priced hours compared to the DET scenario.

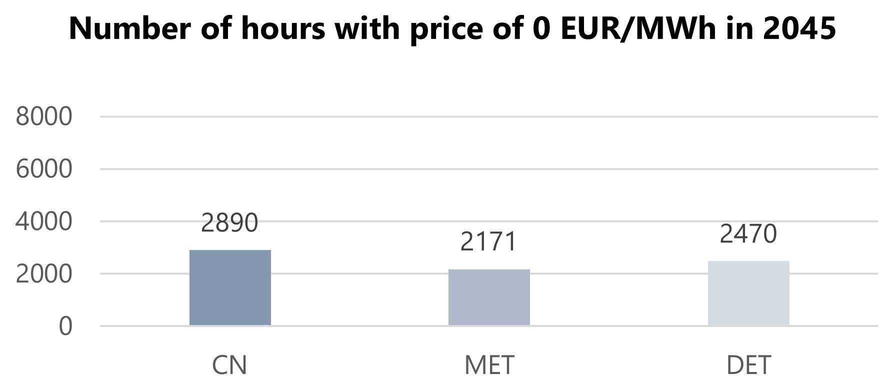


Figure 18: Number of hours with an electricity price of 0 EUR/MWh for each scenario in 2045

The electricity procurement criteria from EU 2023/1184 have been transposed 1:1 into national law and are therefore also included in the 37th BImSchV (Federal Emission Control Act). A distinction must be made between fully and partially renewable fuel. As a rule, fully renewable fuel must fulfil all electricity purchase criteria, including the conclusion of a green PPA. Partially renewable fuel does not have to fulfil these criteria. Except for biomass, all renewable sources are permitted for electricity generation. To ensure that green electricity generated specifically for hydrogen production is used, electricity generation and H_2 production must be linked either physically directly or through power purchase agreements (PPAs). In principle, the installation of the renewable energy plant from which the electricity is drawn must not be more than 36 months prior to the date of installation of the electrolyser. A transitional period applies until 1 January 2027, during which this regulation does not apply. In addition, there are three conditions to produce green hydrogen exclusively from the public grid, of which only one needs to apply:

1. In the previous year, over 90% of the electricity generated in the electrolyser's bidding zone came from renewable energies.

2. The electricity price on the day-ahead market for an hourly product is not higher than 20 EUR/MWh.

3. The electricity price on the day-ahead market for an hourly product is less than 0.36 times the price for one tonne (t) of CO_2-equivalent (European Union Allowances, EUA).

As Figure 19 shows, the number of hours with an electricity price below 20 EUR/MWh is slightly higher than the number of hours with a price of 0 EUR/MWh for the CN and MET scenario. For the DET scenario the difference is bigger, resulting in 3,651 hours in which electrolysers could produce green hydrogen compared to 3,175 hours in the CN scenario and 2,547 hours in the MET scenario. If electricity prices are below 0.36 times the CO_2 price (cf. Figure 20), the number of hours increases to 6,000 for both the CN and the MET scenario while there are only around 4,200 hours in the DET scenario. This is mainly explained by the higher CO_2 prices in the CN and MET scenario.

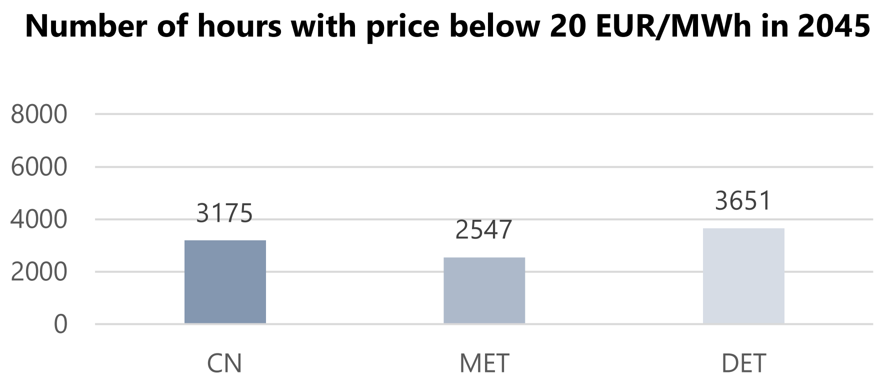


Figure 19: Number of hours with an electricity price below 20 EUR/MWh for each scenario in 2045

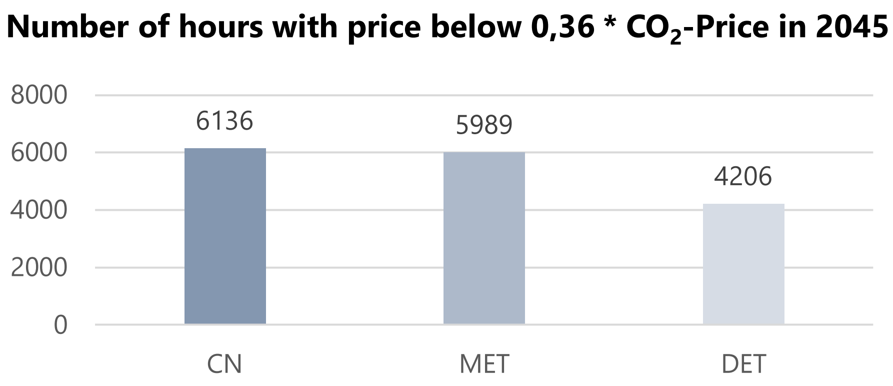


Figure 20: Number of hours with an electricity price below 0.36 * CO_2 price for each scenario in 2045

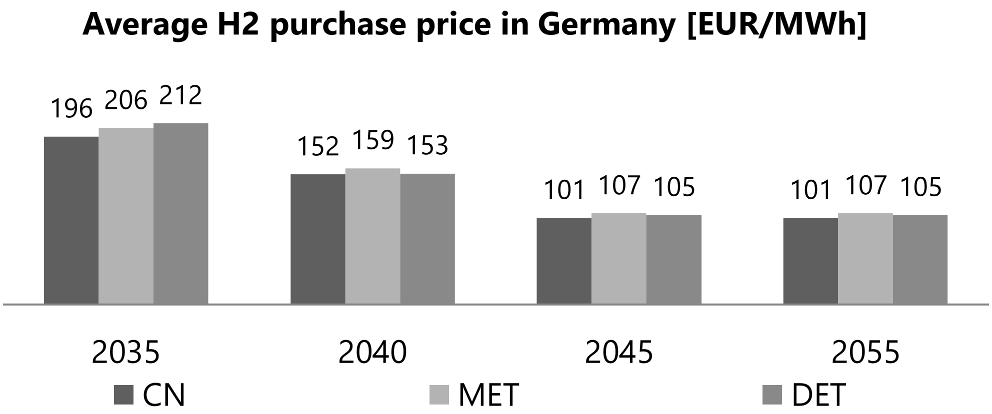


Figure 21: Average hydrogen prices per year and scenario (rel. to lower heating value of H_2)

As import prices decrease over time and the amount of available (and low cost) domestic electricity increases, the prices for hydrogen decrease over time. Furthermore, the characteristics of the temporal resolved hydrogen price curve changes as well between 2035 and 2045. In 2035 the relatively higher import prices lead to more hours when domestic hydrogen is produced. This can be seen in the fluctuating course of the graph in Figure 22. The graphical progression smooths out over time due to the higher hydrogen demand that needs to be covered by imports with constant prices. In comparison to gas price curves in recent years, the overall seasonal flatness of the curves can be explained by the strongly decreasing influence of the space heating sector. Hydrogen is mostly demanded in the industry and mobility sector that both show a rather constant demand.

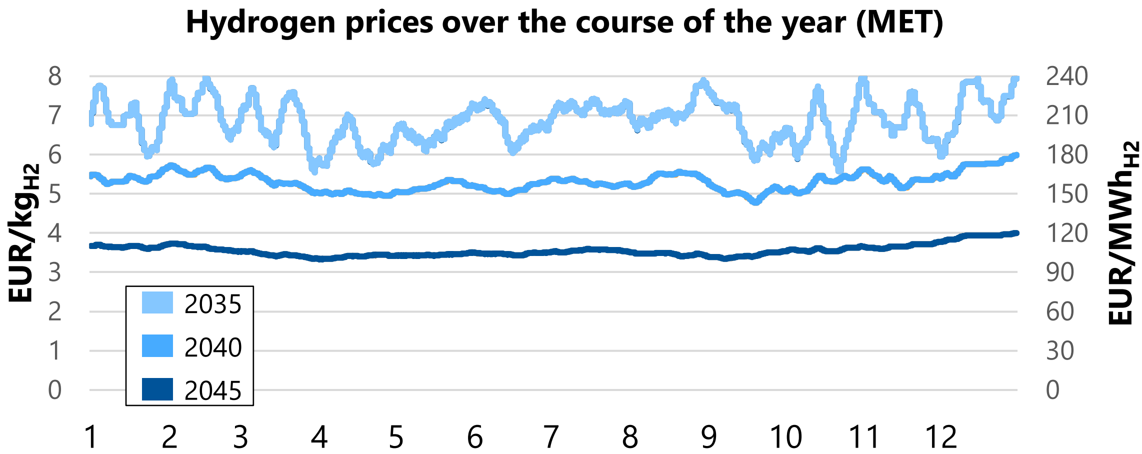


Figure 22: German hydrogen wholesale prices in scenario MET (from 2035 to 2045)

Conclusion

- What developments are relevant for electricity and hydrogen markets in the future? How is this depicted in the study?

  The development of the **electricity markets** is largely dependent on the **expansion of renewables and future electricity demand (incl. electrolysers)**. The applied **electricity market simulation** takes such developments into account in various scenarios. The **hydrogen markets** are driven by **demand, imports and local hydrogen production**, the costs of which depend on electricity prices. The **hydrogen prices are therefore derived in a second step.**

- What are the central assumptions for the scenario development?

  Scenarios are used to project **possible developments** of the energy system into the future. **Three scenarios** have been developed: **Climate Neutrality 2040 (CN), Molecule-based Energy Transition 2045 (MET) and Delayed Energy Transition 2055 (DET).** While the climate targets are achieved in scenario CN and MET until 2045, with different executions and timings, DET delays the transition by 10 years. CN represents a strong **electrification**, MET and DET consider a stronger application of molecules. Overall, this setup covers a broad range of developments.

- What electricity and hydrogen prices are assumed in this study?

  The electricity and hydrogen prices were derived from the modelling results. The average electricity price in 2045 ranges between **90 to 111 EUR/MWh**. Significant differences per scenario for the evaluation of electrolysers and mixed connection concepts result from the number of hours with low and high electricity prices (and the hydrogen prices). The most low-price hours are to be expected in the CN scenario, the fewest in the MET scenario. The number and amount of very expensive hours varies per scenario and year. Hydrogen prices develop to **roundabout 3.5 EUR/kg$_{H2}$**, just over 100 EUR/MWh$_{H2}$. In 2045, hydrogen is cheapest in CN (101 EUR/MWh$_{H2}$) and most expensive in MET (107 EUR/MWh$_{H2}$).

4 Connection concepts for offshore wind farms

Guiding questions:

- What components do the connection concepts consist of?
- Which connection systems are being considered and how much power should they be able to transmit?
- Which connection concepts will be investigated in detail?

The existing options for connecting offshore wind farms (OWF) to onshore grid infrastructure are associated with different engineering challenges and different costs. In the following, the technical concepts pursued are presented to subsequently derive the necessary costs in the following chapter. In accordance with the subject of the study and as shown in Figure 23, the following connection concepts are considered:

1. The electrical connection of OWFs by means of DC grid connection system
2. The combination of OWFs with offshore electrolysis and connection via hydrogen pipeline
3. The combination of both concepts: electrical connection, offshore hydrogen production and transport via pipeline

A mixed connection is therefore a combination of the two singular concepts, which (theoretically) can be combined in many variants.

It should be noted that wind turbines and electrolysers require auxiliary power supply even when no wind energy is available. Auxiliary supply can be achieved using battery storage or a connection to a neighbouring wind farm. An advantage of mixed connection concepts is that auxiliary supply is available for all system components. However, since this represents a minor technical challenge, this aspect will be neglected in later comparisons.

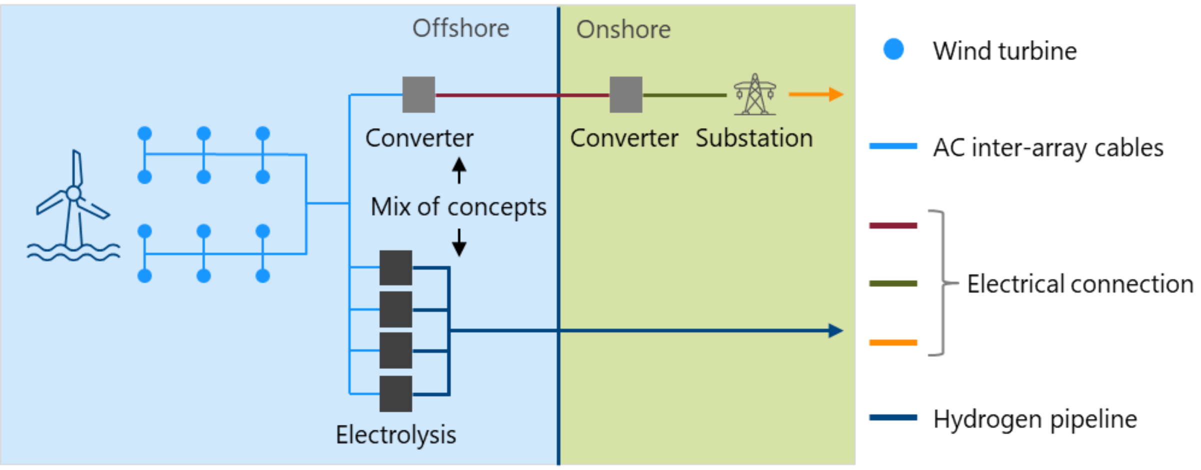


Figure 23: Schematic illustration of a mixed connection concept

4.1 Key components of the connection concepts

Wind farms – The starting point of energy transmission to shore is represented by OWFs. It is assumed that the OWF sites to be connected to the shore will be allocated in a total size of 2 GW maximum capacity per area, which may still consist of several OWFs. The maximum capacity is based on the same standard size for offshore transmission cables. It is further assumed that the individual wind turbine has a nominal capacity of 20 MW per unit and that a radial OWF topology is chosen. Possible increases in turbine capacity in the future could change the number of turbines, but not the total installed capacity of 2 GW per area.

Wind turbines are organised in strings of 100 MW and connected via an array cable system, which operates at 132 kV AC. The strings are connected directly to the offshore platforms, which either transform the electricity for long-distance transmission through a DC cable or utilise it directly to produce hydrogen for transport in a dedicated pipeline. Apart from the assumptions regarding turbine and string capacity – for which no specifications exist – this corresponds to the technical standards of the German site development plan (BSH, 2024).

Electrical connection of OWFs by means of DC grid connection system – In accordance with the assumed OWF maximum capacity and the technical standards of the site development plan, the capacity of the electrical connection system is assumed to be 2 GW and consists of the following key components. No multi-terminal capability and therefore no DC breaker is assumed for the converters.

- Offshore converter station comprising a 525 kV Voltage Source Converter (VSC): Collects the AC power generated by the OWF, transforms it to 525 kV and converts it to DC for transmission.
- Bipolar DC cable system with metallic return conductor/dedicated metallic return, a voltage of 525 kV and a capacity of 2 GW: High-voltage direct current (HVDC) transmission from the offshore converter station to the onshore converter station. A distinction must be made here between offshore and onshore cable sections, as these differ significantly in terms of installation method, space requirements and costs.
- Onshore converter station comprising a 525 kV Voltage Source Converter (VSC): Conversion of DC power back to AC and transformation to 380 kV for integration into the onshore grid.
- 380 kV cable and substation: Connection between converter station and substation, which in turn acts as the grid connection. Either an existing station can be extended or a new site including the connection to the main grid via 380 kV overhead line (or cable) is necessary.

Offshore electrolysis and connection via hydrogen pipeline – Hydrogen production takes place on centralised electrolysis platforms. These platforms are connected to the turbines in the same way as a converter station using the 132 kV AC direct connection concept. In standalone configuration an emergency power supply for periods without wind power generation via a hydrogen storage system and a fuel cell system must be considered to maintain grid voltage and frequency during periods without wind energy production. A unit size of 500 MW_{el} of input power is envisaged for the electrolyser platforms[8]. The platforms would be constructed close to the AquaDuctus pipeline. For a total capacity of 2 GW_{el}, four electrolysis platforms would utilise wind energy generation at nameplate capacity.

In the future, the AquaDuctus offshore pipeline is foreseen to transport low-carbon hydrogen from the North Sea directly to the mainland. With an overall capacity of 20 GW_{H2}, the pipeline is conceptualized as an open-access pipeline with over 400 km of total length. So far, the project is a cooperation between Norway and Germany but further stakeholders like Denmark, the Netherlands and the United Kingdom (UK) could gain access to the pipeline. In the context of the AquaVentus project, 330 of 400 km of offshore distance need to be considered in this analysis. With a pressure level of 100 bar and a diameter of 48 inch (1,220 mm) the pipeline is operated at a gas velocity of about 18 m/s. As the pipeline is supposed to connect not only the OWFs and hydrogen production platforms but also other European countries and their hydrogen production facilities with the German coastline, the cost of the pipeline assigned to the OWFs equal to the capacity share.

As a side note, it should be noted that the use of the AquaDuctus pipeline by offshore electrolysers could further reduce the risk of pipeline becoming a stranded asset. Therefore, it also has positive effects on the investment security of infrastructure that is already being planned.

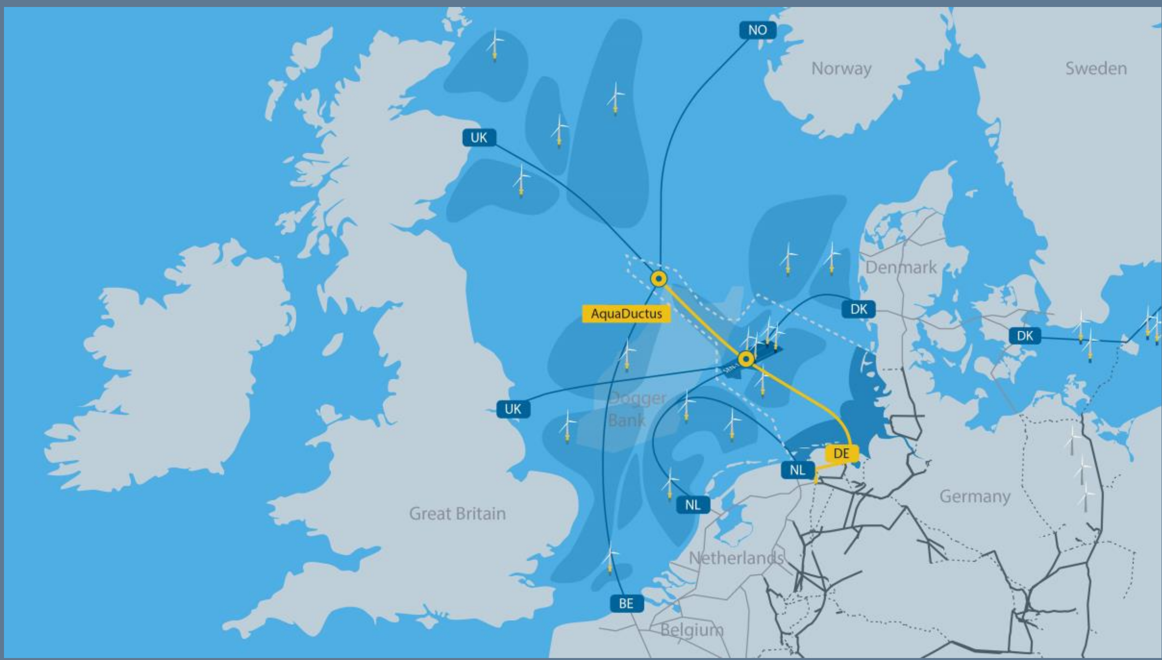
[8] The capacity of electrolysis system usually refers to the electrical input power. Hence, the suffix “el” is added to the units kW, MW or GW.

Hydrogen pipeline AquaDuctus

AquaDuctus is part of the AquaVentus initiative and will be a GW-scale offshore hydrogen pipeline located in the German North Sea. The pipeline provides open access to multiple network users on a non-discriminatory basis. The project will connect large amounts of green hydrogen obtained offshore in the North Sea with the European mainland and the emerging onshore hydrogen infrastructure.

The IPCEI project AquaDuctus is part of the German hydrogen core grid and will become the nucleus of an interconnected offshore infrastructure between Germany and the North Sea countries of the Netherlands, Belgium, Denmark, the United Kingdom and Norway.

In this way, the European production and demand centres for green hydrogen will be interconnected.



This study estimates overall costs for AquaDuctus in the low single-digit billion range. In so far as the connection concepts utilise pipeline capacities, the shares of the investment and operating costs of the pipeline capacity are allocated to the connection concept.

Mixed connection concept – The combination of the two concepts – via HVDC on the one hand, and hydrogen production and transport via pipelines on the other hand – represents a central subject of investigation in the study. The redundancy of systems offers the option of following the market prices and deciding based on hourly resolution if electricity is produced and directly sold via cable to the electricity system or if wind power is used to produce hydrogen in case of low electricity prices on the market. This reduces the electricity selling price risk for the overall investment. However, mixed connection concepts usually show higher investment cost than single purpose connections as wind energy can only be used for one purpose at the same time. Therefore, higher revenues may be necessary to compensate the higher capital expenditures.

Several options for connections are conceivable as cable and electrolysis capacity can be varied in technical standardised and pre-defined steps. Following technical standards of the site development plan, a mixed connection concept would include cable connection in capacity steps of 2 GW. For electrolysis, 0.5 to 2 GW_{el} will be installed per OWF, based on a 500 MW_{el} platform concept. Hence, each OWF is then equipped with hydrogen production capacities (min. 500 MW_{el} and max. 2 GW_{el}), a pipeline connection (min. 0.35 GW_{H2} and max. 1.4 GW_{H2})[9] and a (partial) access to a HVDC converter (standard 2 GW), leading to a shared transmission capacity between 500MW and 2 GW. Accordingly, all combinations of cable and electrolysis capacities of this step size over seven OWFs of up to 14 GW cable and 14 GW_{el} electrolysis capacity are conceivable. The study determines and investigates suitable and cost-effective combinations, not necessarily optimal. In real-life configurations, downtime and maintenance times must also be considered. The design of the electrolysers therefore depends on several factors. An overview of the assessed concepts and the techno-economic parameters is given in Chapter 5.

Further considerations for the connection concepts – Wind farms in zones 4 and 5 in the EEZ are always connected separately from each other due to the significant distance between the zones and areas. Depending on the connection concept, a varying number of electrolysers and cables are installed. In some cases, multiple wind parks may share a cable or one or more electrolysers, yet only within one zone. A detailed configuration is not part of this study.

4.2 Connection concepts analysed

The following provides an overview of the connection concepts analysed, broken down by installed electrolysis capacity and cabling. In total, 14 GW of offshore wind capacity is connected to the same equivalent in cable and/or electrolyser capacity. To prepare a starting position for comparison, an all-electric (All E) and an all-hydrogen site configuration (All H2) is assessed. The mixed connection variants MC 1 and MC 2 representatively analyse the impact of the two dimensions: (1) the electric connection and (2) the dimensioning of the electrolyser (which directly influences the maximum use of the AquaDuctus pipeline).

- **All E** – This variant comprises a full electrical connection of all OWFs in zone 4 and zone 5 to the coast, resulting in a total of 14 GW of electrical connection.
- **MC 1 "electricity dominant"** – For the 4 GW_{el} electrolysis variant MC 1, it is assumed that 2 GW_{el} of electrolysis will be installed for the OWFs constructed in zone 4 and 2 GW_{el} of electrolysis for the further OWFs in zone 5. Additionally, 6 GW of electrical connection will be installed to connect zone 4 and 4 GW electrical connection will be installed to connect zone 5.
- **MC 2 "hydrogen dominant"** – For the 10 GW_{el} electrolysis variant MC 2, it is assumed that 6 GW_{el} of electrolysis will be installed for the OWFs constructed in zone 4 and 4 GW_{el} of electrolysis for the further OWFs in zone 5. Additionally, 2 GW of electrical connection will be installed to connect zone 4 as well as 2 GW electrical connection will be installed to connect zone 5.
- **All H2** – In this variant, 2 GW_{el} of electrolysis will be installed per OWF, resulting in a total of 14 GW_{el} of electrolysis. No installation of electrical connection systems towards onshore is assumed.

The spatial distribution of the concepts is schematically shown in Figure 24.

[9] With respect to an assumed average electrolysis efficiency of 70% rel. to the lower heating value of hydrogen (33,324 kWh/kg)

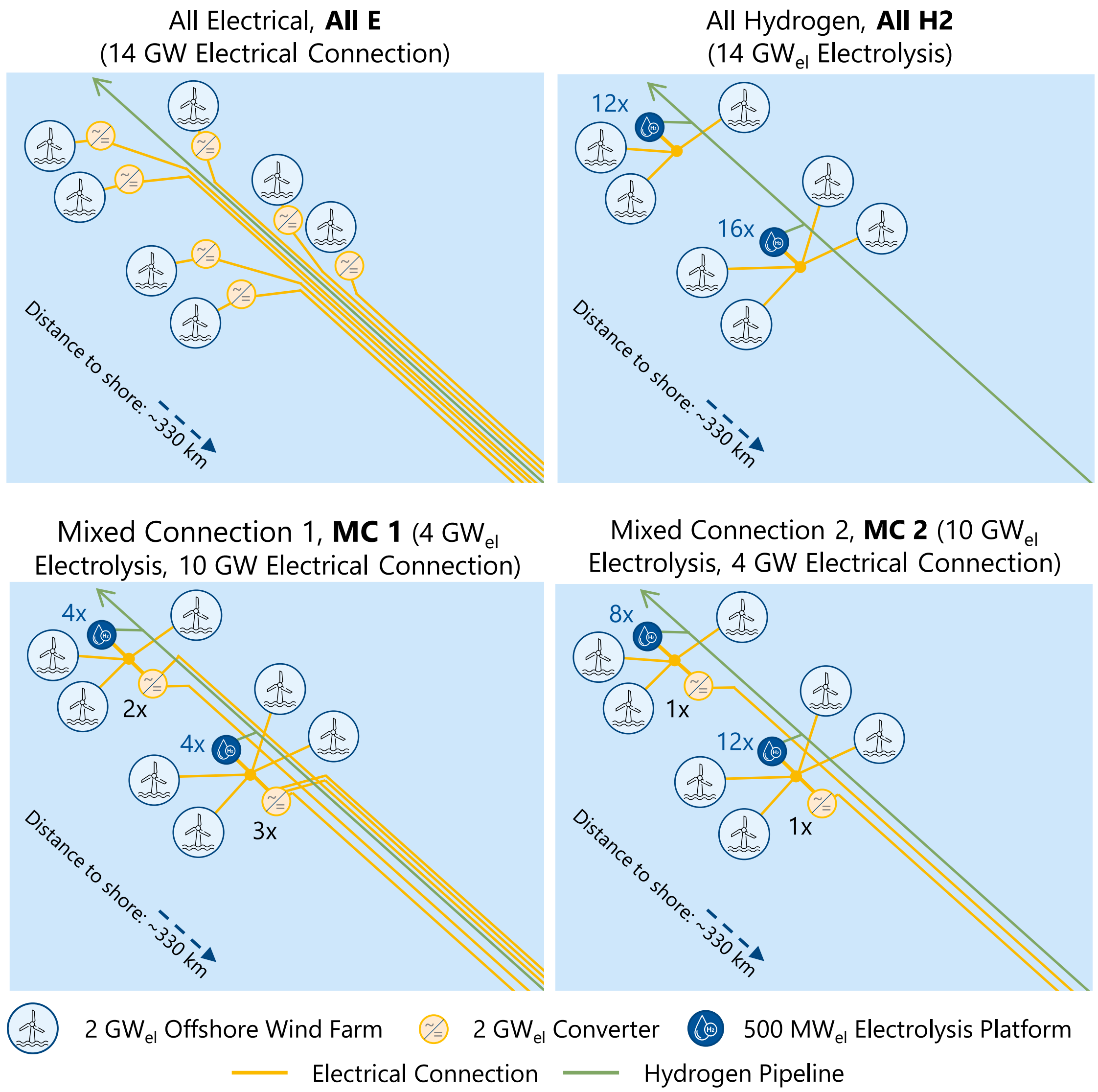


Figure 24: Connection concepts considered in this study

In addition to the total capacity used per technology (electrolysis and hydrogen pipeline vs. DC connection system) per variant, their expansion must also be considered in temporal dimension. As the OWFs considered in this study can be clearly divided into OWFs in EEZ zone 4 and EEZ zone 5, it is initially assumed that 8 GW offshore capacity in EEZ zone 4 will be installed first and 6 GW in EEZ zone 5 will be installed 5 years later. The connection systems for these OWFs are installed accordingly.

Regarding the timing: The years 2035 and 2040 are considered as start years, i.e.

- in expansion period 2035 – 2040, 8 GW in zone 4 are installed in 2035 and 6 GW in zone 5 in 2040,
- in expansion period 2040 – 2045, 8 GW in zone 4 are installed in 2040 and 6 GW in zone 5 in 2045.

The expansion in temporal dimension is listed in Figure 25.

Both electricity dominant cases, All E and MC 1, can show significant economic advantages in an electrical-driven energy system with high electricity demand and relatively small share of hydrogen as an energy carrier in the overall energy system. The electrolysis capacity of 4 GW_{el} in case MC 1 can be understood as a risk mitigation for hours with low electricity prices when direct power transport and supply on the exchange is not profitable.

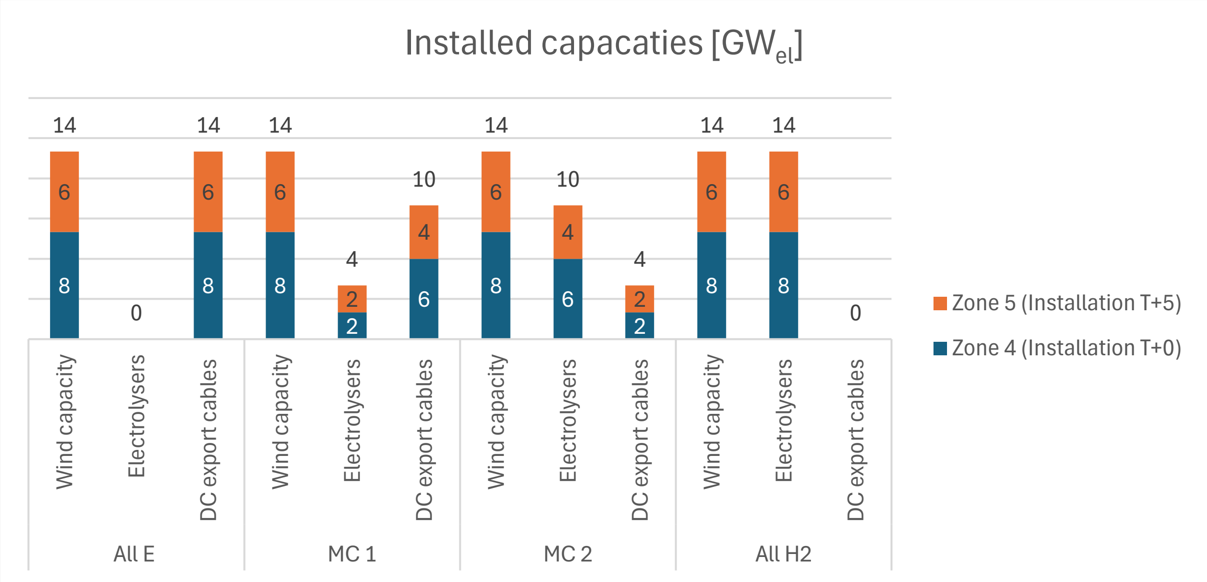


Figure 25: Overview of the analysed connection variants regarding the spatial distribution of the different capacities; T corresponds to the start time of the expansion period under consideration, e.g. T+0 = 2035 for the expansion period 2035 – 2040

The H_2-dominant cases MC 2 and All H2, however, can show advantages if periods with low electricity prices dominate the electricity markets as hydrogen can be fed into the system and be stored long-term and on large scale. Especially the mixed connection concept MC 2 combines several advantages.

Conclusion

- What components do the connection concepts consist of?

  The connection concepts analysed below consist of the wind turbines, the converter required to connect to a HVDC export cable and the converter onshore, offshore electrolysers which are connected to the wind farms as well as the (AquaDuctus) pipeline, which transports hydrogen to the shore.

- Which connection systems are being considered and how much power should they be able to transmit?

  In total, the study compares two different connections: via cable and via pipeline. Each cable has a transmission capacity of 2 GW. The pipeline has a transmission capacity of up to 20 GW_{H2}. When utilising the pipeline, only up to half of the pipeline capacity is required for the hydrogen produced by AquaVentus.

- Which connection concepts will be investigated in detail?

  In total, 4 different connection concepts are investigated in detail (cf Figure 26). An electric-only connection (All E) and a hydrogen-only concept (All H2) fully integrate the OWFs via cables or electrolysers. The mixed connection concepts vary the connection capacity via cable and electrolyser/pipeline. MC 1 focusses on electricity with 10 GW cable capacity and 4 GW_{el}

electrolyser capacity. Conversely, MC 2 has 4 GW cable capacity and an electrolyser capacity of 10 GW_{el}.

	All E	MC 1 "Electricity dominant"	MC 2 "H2 dominant"	All H2
AQV offshore wind capacity [GW_{el}]	14 GW (Expansion period 1: 8 GW zone 4 2035, 6 GW zone 5 2040, Expansion period 2: 8 GW zone 4 2040, 6 GW zone 5 2045)			
Electrolysers [GW_{el}]	/	4 GW (2 GW zone 4, 2 GW zone 5)	10 GW (6 GW zone 4, 4 GW zone 5)	14 GW (8 GW zone 4, 6 GW zone 5)
Share of use of AquaDuctus pipeline	/	(max.) 15 %	(max.) 35 %	(max.) 50 %
Additional cable connection for AQV offshore wind capacity [GW_{el}]	14 GW	10 GW (6 GW zone 4, 4 GW zone 5)	4 GW (2 GW zone 4, 2 GW zone 5)	/
Investigation purpose	*Evaluate all electric case*	*Impact of different mixed connection concepts*		*Evaluate all H2 case*

Figure 26: Overview of the analysed hydrogen production and connection variants including the temporal and spatial distribution of the installed capacities and the investigation purpose

5 Cost estimation: investment, operating and capital costs of different connection concepts

Guiding questions

- What are the main cost drivers of (mixed) connection concepts?
- What are the total investment costs for each connection concept?

For the cost estimation, it is essential to determine which capital costs will be used. The weighted average cost of capital (WACC) is used to consider the debt service for equity and debt capital together. The WACC is a valuable tool for company and risk assessment and serves as a reference value for the minimum return on investment projects. Within the scope of this study, a common and uniform WACC of 9% over all technologies is assumed. This is in line with the estimation of the consortium experts.

The costs were determined by means of literature research and dialogue with the consortium. A comprehensive list of cost parameters and their sources can be found in the appendix (cf. Table 8). Additional equipment such as GIS systems, transformers and circuit breakers, as well as installation and environmental protection measures, are already part of the cost assumptions unless explicitly stated.

5.1 Offshore wind farm

For the construction of the offshore wind farm (OWF), the years 2035 / 2040 / 2045 (cf. chapter 4.2) are considered in the further course of the study. The costs for the inter-array cable system are not differentiated by year. A common rate for operation and maintenance of 2.6% of total invest per year for all systems is assumed. The costs per MW or km are presented in Table 1. If significantly different cost figures were determined for the operating resources, the range is shown in brackets.

Table 1: Investment costs of a 2 GW OWF with 132 kV direct connection concept

Cost components	Costs per unit (range)	2 GW OWF costs (range)
20 MW wind turbines, 2 GW OWF, incl. foundation, installation	1.74 / 1.68 / 1.66 m EUR/MW in 2035 / 2040 / 2045 (1.32 – 1.74 m EUR/MW)	3.48 / 3.36 / 3.32 bn EUR in 2035 / 2040 / 2045 (2.64 – 3.48)
132 kV inter-array cable system	1.25 m EUR/km (0.252 – 2.00 m EUR/km)	0.30 bn EUR (0.06 – 0.48)
Sum	-	**3.78 / 3.66 / 3.62 bn EUR in 2035 / 2040 / 2045 (2.70 – 3.96)**

5.2 DC grid connection system & onshore grid connection

In addition to fixed components such as converters and alternate current (AC) station, the investment costs of a direct current (DC) grid connection system depend on the distance between the OWF and the coast and between the coast and the grid connection point. The connection concepts analysed in the following chapters use the actual lengths of the connection systems already planned, with the connection systems being selected that include the shortest possible route. As with the inter-array cable system, the costs of these components are not differentiated according to the year of installation for the period considered in this study (cf. Table 2). A common rate for operation and maintenance of 2.6% of total invest per year for all systems is assumed.

Table 2: Investment costs per unit of electrical connection components

Cost components	Costs per unit (range)
525 kV VSC offshore converter	0.70 m EUR / MW (0.55 – 0.79 m EUR / MW)
2 GW 525 kV bipolar & DMR offshore cable	6.00 m EUR / km (3.36 – 6.00 m EUR / km)
2 GW 525 kV bipolar & DMR onshore cable	7.60 m EUR / km (3.36 – 10.86 m EUR / km)
525 kV VSC onshore converter	0.30 m EUR / MW (0.25 – 0.43 m EUR / MW)
380 kV substation	50 m EUR (29 – 50 m EUR)

5.3 Electrolysis

The technical concept of the offshore hydrogen production follows several studies and reports on this specific topic. AFRY Management Consulting compared system variants of hydrogen provision based on offshore wind energy on behalf of the AquaVentus initiative (AFRY, 2022). Furthermore, the Danish Energy Agency in cooperation with DNV (DNV, 2023) and the Fraunhofer Institute for Solar Energy Systems (Projekt OffsH2ore, 2023) published studies about technical concepts of offshore hydrogen production based on wind energy and respective cost parameters.

As the specific technical layout of a hydrogen platform has been subject of various studies, this assessment does not discuss the technical details of the platform design. This paragraph serves as an overview of main aspects that need to be taken into consideration in the planning process. Following the common principle of these studies, this report considers offshore electrolysis platforms with a capacity of 500 MW_{el} each. Within the scope of this report, a Proton exchange membrane (PEM) electrolysis system is seen as the most suitable technology due to the compact design and the high-performance density. In comparison to other electrolysis technologies, the PEM shows significantly higher load gradients and lower partial load limits. In combination with the expected cost degression discussed in the following, PEM shows the most potential for offshore application. The efficiency of the electrolysis is expected to increase to 70% - 72% (rel. to the lower heating value of hydrogen of 33.324 kWh/kg). Taking into consideration the degradation of the stack, efficiency drops about 4 – 6 percentage points. Hence, in this study an average efficiency of 68% is assumed.

Besides the electrolysis system consisting of the stack and the peripherical structure for the balance of plant (BoP), each platform holds a water conditioning system (desalination and deionisation), a gas conditioning system (drying and oxygen removal) and compressors, as well as necessary pumps and piping to provide infrastructure for water and gas transportation. While the BoP system as well as the additional systems are considered to have a lifetime of 25 years, the stack of the electrolysis has a lifetime of about 50,000 full-load hours. Taking into consideration annual full-load hours between 4,000 and 5,000, the stack needs to be replaced after ten years.

With respect to the platform itself, the structure comprises a foundation (steel piles or concrete) below sea ground, a steel jacket to surmount the water depth of 30 – 50 m and the distance between water surface and the platform, and a topside structure to hold the hydrogen production systems. The OffsH2ore project assumes the platform design to consist of five levels of the topside structure, each comprising 100 MW_{el} of electrolysis capacity. The above-mentioned additional systems (water and gas conditioning, compression, piping and pumps) shall then be allocated to the five levels. However, interviews with experts from the AquaVentus consortium showed concerns regarding effectiveness and safety about the superimposed hydrogen production elements on an offshore platform. Hence, a different layout has been suggested with the following four-level-design:

1. Water conditioning / utility gas area / high-voltage system
2. Electrolysis rectifier & transformer
3. Electrolysis
4. Compression & export on weather deck

For safety purposes, hydrogen production and conditioning equipment should be positioned on the top decks to enable hydrogen to escape into the atmosphere in case of leakage and to protect the platform in case of explosion. As system and operation concepts need more development efforts in the next years more safety details as well as the specific technical conception and design are not further discussed in this report.

The costs of the hydrogen production platform comprising the electrolysis system, water treatment, gas conditioning, platform structure, construction, and engineering are derived based on studies and literature sources as well as on expert interviews due to a lack of existing project experience. In contrast to offshore hydrogen production, onshore projects have already been carried out. So, the offshore costs are derived based on onshore hydrogen system costs.

Currently, investment costs for electrolysers are around 1,800 EUR/kW_{el}. Due to the modular structure of electrolysers, specific costs do not scale significantly with size. However, additional installation costs of +70% for installation need to be considered in addition to the material cost (DNV, 2023). Due to the lack of experience with large-scale electrolysis plants, particularly in relation to offshore installations, this factor is subject to a high degree of uncertainty. In this study the conservative mentioned installation costs of +70% are assumed.

It is expected that for offshore applications, the electrolyser will be installed in an onshore fabrication yard and then transported offshore. With respect to the pure installation, the costs between onshore and offshore electrolysis are not expected to be significantly different. Additional costs for marinisation, transport and commissioning for offshore applications are already included in the mark-up of 70% for installation. This results in total specific invest costs for offshore electrolysis of 3,000 EUR/kW_{el} for 2024. This includes the power electronics (transformer and rectifier) and the electrolysis system with stacks and BoP components. Educt water treatment, compressed air and nitrogen supply as well as gas purification and compression are not included in the costs of the electrolysis system. The operating costs for maintenance and servicing costs for the replacement of the electrolysis stacks are also added according to the specified stack service lifetime.

Over the next decades a significant cost decrease is expected. Figure 27 shows the development for electrolysis systems until 2050. Costs are expected to decrease by 72% until 2050. This results in a cost level of 850 EUR/kW_{el} (500 EUR/kW_{el} (Projekt OffsH2ore, 2023) plus installation costs). This cost decrease appears to be realistic as the experience with renewable energy sources has shown similar cost drops over the last 15 years. The price of onshore wind electricity, for example, declined by 70% in 10 years from 2009 until 2019 (Lazard, 2024). The unit costs of solar energy even dropped by 85% from 2009 until 2019 (IRENA, 2021).

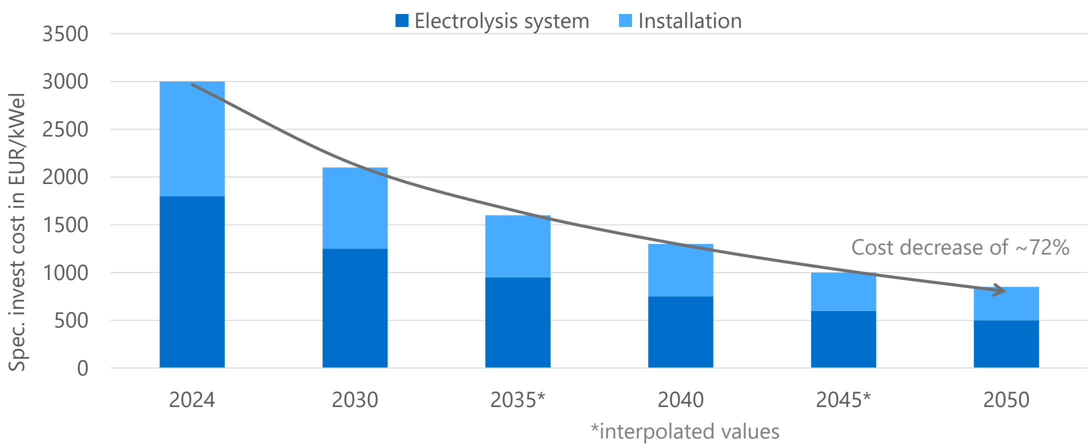


Figure 27: Cost development of offshore electrolysis systems based on various studies and expert interviews, cf. (Holst, et al.), (Agora Verkehrswende 2018), (Bristowe und Smallbone 2021), (Deutsche Energie-Agentur 2018), (He, et al.), (Wuppertal Institut 2020),), (Forschungszentrum Jülich 2020), (Prognos 2020) and (Zun and McLellan 2023)

Within the scope of this study the cost of the additional systems such as platform, gas and water conditioning are assumed to be constant over time due to their level of maturity. These costs also cover the marinisation of these additional systems. However, a cost decrease can be expected in case platform designs are optimised in terms of size or weight (mostly driven by smaller and lighter hydrogen production systems). In relation to the electrolysis capacity, the costs of the additional systems are shown in Figure 28. Per kW_{el} of electrolysis capacity, around EUR 580 of additional systems need to be installed, of which 77% are attributable to the platform (consisting of foundation, jacket and topside structure. As the required cooling with sea water is already included in the electrolysis cost, the remaining cost share of 23% are contributed by the water desalination and deionisation, the gas purification (drying and oxygen removal), compression, piping and pumps. These costs are derived regarding electrolysis capacity, system weight and overall platform size. A surplus for offshore installation of around 30% in comparison to onshore installation is already included.

As offshore electrolysis requires a higher engineering effort than onshore systems, an additional cost contribution of 20% in relation to the additional systems costs is assumed. For a platform with an electrolysis capacity of 500 MW_{el}, additional system costs of around EUR 290 million and engineering costs of around EUR 58 million are required. Assuming the start of investment in 2035 and thus electrolysis costs of 1,600 EUR/kW_{el}, the overall 500 MW_{el} platform costs amount to EUR 1.15 billion.

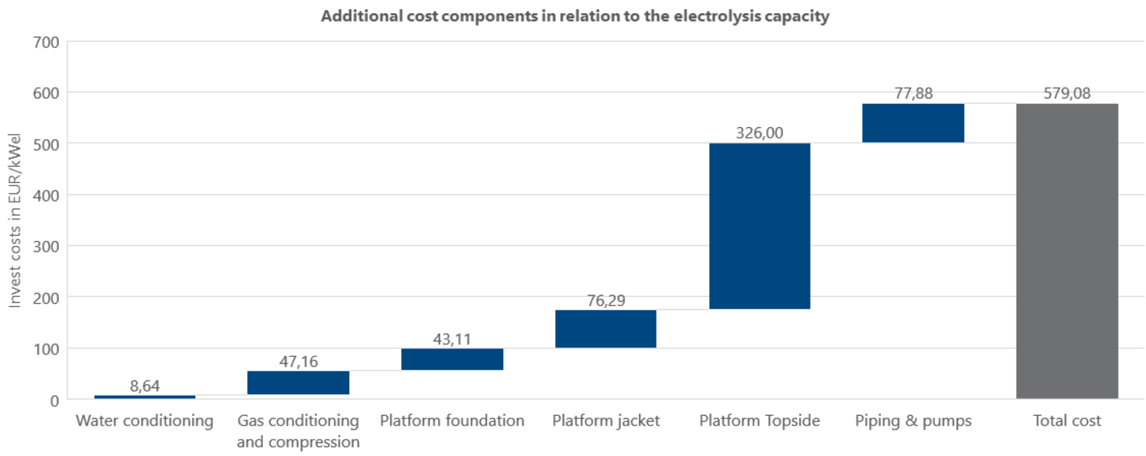


Figure 28: Additional cost components in relation to the electrolysis capacity

The comprehensive breakdown of the platform components is given in Table 3.

Table 3: Breakdown of the cost components of offshore hydrogen production (in relation to electrolysis capacity)

Cost components	Specific costs (range)	Costs for 500 MW (range)
Electrolysis system	1,600 EUR/kW_{el} in 2035 (1,000 – 2,200 EUR/kW_{el}) 1,300 EUR/kW_{el} in 2040 (850 – 1,700 EUR/kW_{el})	EUR 800 million in 2035 (EUR 500 – 1,100 million) EUR 650 million in 2040 (EUR 425 – 850 million)
Water conditioning (desalination and deionisation)	8.64 EUR/kW_{el}	EUR 4.32 million
Gas conditioning and compression	47.16 EUR/kW_{el}	EUR 23.58 million
Platform foundation	43.11 EUR/kW_{el}	EUR 21.55 million
Platform jacket	76.29 EUR/kW_{el}	EUR 38.15 million
Platform topside	326.00 EUR/kW_{el}	EUR 163.00 million
Piping and pumps	77.88 EUR/kW_{el}	EUR 38.94 million
Engineering	115.80 EUR/kW_{el}	EUR 57.90 million
Sum	-	EUR 1,147.4 million in 2035 EUR 997.4 million in 2040

Even though capital expenditures account for the biggest share of total expenditures, operational cost over the lifetime of 25 years need to be considered as well. For simplicity, a common rate for operation and maintenance of 2.6% of total invest per year for all systems is considered. As the stack of the electrolysis requires replacement after ten years, additional OPEX need to be added. By means of the future value method, the yearly OPEX surcharge can be calculated. In case of an initial investment in 2035, first stack replacement takes place in 2045. Therefore, the annual replacement OPEX share is calculated with respect to stack cost in 2045. The procedure is similar for an initial investment in 2040 and a replacement in 2050 (cf. Table 4).

Table 4: Overview of cost assumptions of electrolysis systems

Cost components	Unit	2024	2030	2035	2040	2045	2050
Invest costs							
Electrolysis system	EUR/kW$_{el}$	3,000	2,100	1,600	1,300	1,000	850
Add. Systems and platform	EUR/kW$_{el}$	579.1	579.1	579.1	579.1	579.1	579.1
Engineering	EUR/kW$_{el}$	115.8	115.8	115.8	115.8	115.8	115.8
Operation and maintenance							
O&M	% of invest per year	2.6	2.6	2.6	2.6	2.6	2.6
Stack replacement	EUR/kW$_{el}$/a	42.13	34.23	26.33	22.38	22.38	22.38

5.4 Pipeline

Regarding the costs of the AquaDuctus pipeline, a similar cost approach is taken. As offshore gas pipelines have been built and operated for some time, no cost decrease until 2050 is assumed. The specific invest costs for an onshore pipeline amount to EUR 4.4 million per km. To account for the greater effort for offshore application, a factor of 1.7 is considered (mark-up of +70% in alignment with the European Hydrogen Backbone and Gascade (EHB, 2023) (Gascade, 2024). Hence, specific invest costs of EUR 7.48 million per km are assumed. Depending on the configuration variant, either 4 GW$_{el}$, 10 GW$_{el}$ or 14 GW$_{el}$ of electrolysis capacity are planned to be installed. As these capacities are referring to the electrical input, an assumed electrolysis efficiency of ~70% leads to 2.8 GW$_{H2}$, 7 GW$_{H2}$ or 9.8 GW$_{H2}$ of hydrogen output, respectively. In relation to the overall capacity of the AquaDuctus pipeline, these hydrogen outputs account for 14%, 35% or 50%, respectively. As mentioned above the distance to surmount is about 330 km and the cost share of the AquaVentus project takes the derived 14%, 35% or 50% of pipeline capacity. The residual capacity of the pipeline can be allocated to hydrogen imports from Norway, Denmark, the UK or other stakeholders. The operating costs of the pipeline of 2.6% are in line with the operating costs of the other system components.

5.5 Planned and utilised electrical connection systems

Offshore grid connection systems have already been foreseen for the areas for OWF considered in this study in the German TSOs grid development plan (GDP) 2037/2045 (2023) and have already been confirmed as necessary by Germany's national regulatory authority. Yet, they have not yet been legally stipulated for implementation. While the plans are labelled as having no activities to date, some of these systems may become part of future multi-terminal DC systems, which increases their significance for overall system planning[10]. Figure 29 shows the intended offshore grid connection systems (left), and the approximate offshore and onshore length shares of these

[10] NOR-17.1 (Amprion, planned commissioning 2034, MT system in connection with NOR-18.1 by additional cable between both offshore converters); NOR-17.2 (TenneT, 2037, MT system in connection with NOR x.11, NOR-17.2, DC40 using the onshore converter location as a DC-hub); NOR-18.1 (TenneT, 2035, Multiterminal system in connection with NOR-17.1 by additional cable between both offshore converters); NOR-19.1 (Amprion, 2036); NOR-19.2 (Amprion, 2037); NOR-19.3 (Amprion, 2036); NOR-20.1 (TenneT, 2039, MT system in connection with NOR-13.1, NOR-20.1, DC34, DC35 using the onshore converter location as a DC-hub ('NordWestHub').

systems (right). Key criteria for determining the onshore grid connection points (GCP) and the reasons for the resulting selection shown are:

- Geographical proximity due to lower cost
- Free capacity criterion (according to the ENTSO-E): Failure of coupled busbars must not lead to generation losses of more than 3 GW; structural decoupling/expansion of grid connection points is not possible in some cases
- Systemic influence of the geographical location of the GCP: Northern GCPs and the subsequent energy transport to the south require additional AC systems with additional losses and reactive power requirements; DC converters can provide regionally necessary ancillary services and flexibility

Connection of offshore generation can make economic and systemic sense despite long onshore distances, particularly at load-near GCPs that connect large-scale power plants that will be decommissioned in the future. But benefits as provision of ancillary services and flexibility could also be achieved by utilising the gas grid and hydrogen-capable gas-fired power plants. Added to this would be typical advantages of hydrogen applications in terms of storage capacity and flexibility.

Overall, the connection systems with long-distance onshore connections would be predestined to be replaced by alternative grid connection concepts like the AquaDuctus pipeline connection. According to the plans shown, this would address four systems, with three of the affected OWF being in EEZ zone 5, and one being in EEZ zone 4 (NOR-17.1). For three systems, a nearshore electrical connection is possible.

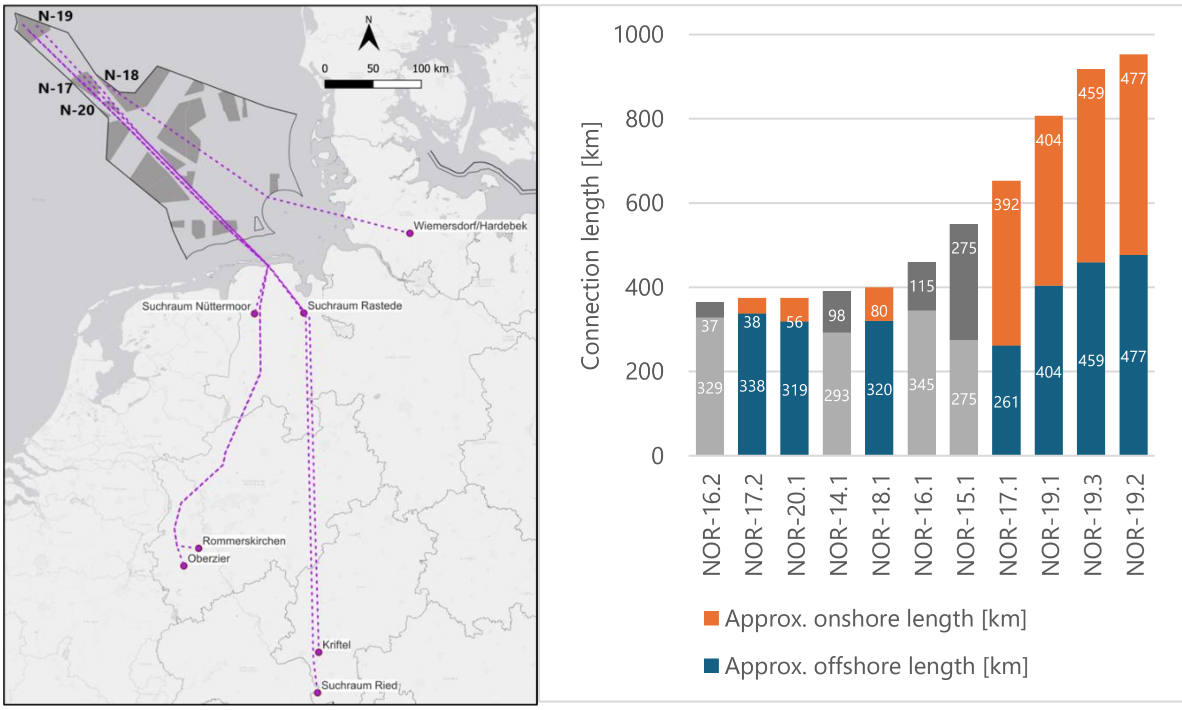


Figure 29: DC grid connection systems of considered OWFs as planned by Grid Development Plan 2037/2045 (2023) (left); approximate offshore and onshore length shares of these systems (right) as well as further planned connections for zone 4 (grey).

Table 5 shows the connection systems utilised for the investigated variants.

Table 5: Overview of the electrical offshore grid connection systems utilised and the resulting offshore and onshore DC cable lengths per variant

	All E	MC 1	MC 2	All H2
DC export cable capacity	14 GW (8 GW zone 4, 6 GW zone 5)	10 GW (6 GW zone 4, 4 GW zone 5)	4 GW (2 GW zone 4, 2 GW zone 5)	0 GW
DC connections zone 4	NOR-17.2, NOR-20.1, NOR-18.1, NOR-17.1	NOR-17.2, NOR-20.1, NOR-18.1	NOR-17.2	-
DC connections zone 5	NOR-19.1, NOR-19.3, NOR-19.2	NOR-19.1, NOR-19.3	NOR-19.1	-
Offshore export cable length	2,576 km	1,838 km	741 km	0 km
Onshore export cable length	1,904 km	1,036 km	441 km	0 km

5.6 Investment cost per hydrogen production and connection variant

Figure 30 shows the investment costs of the analysed variants for the investment start years 2035 and 2040 respectively the construction periods 2035 - 2040 and 2040 - 2045, assuming the cost values specified as best guesses in the subchapters above.

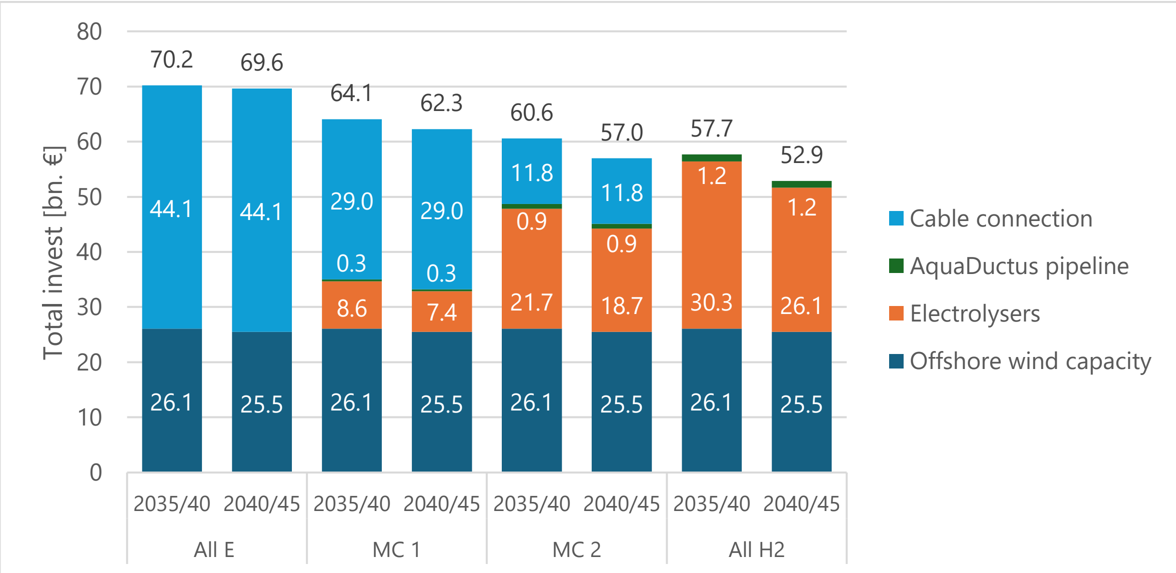


Figure 30: Expected investment costs broken down by cable connection (incl. converter & AC-subst.) for offshore wind capacity, cost-share of AquaDuctus pipeline, electrolysers and offshore wind farms

The entire range of possible investment costs, both regarding the assumption of specific cost parameters and the start of the investment can be found in Figure 31.

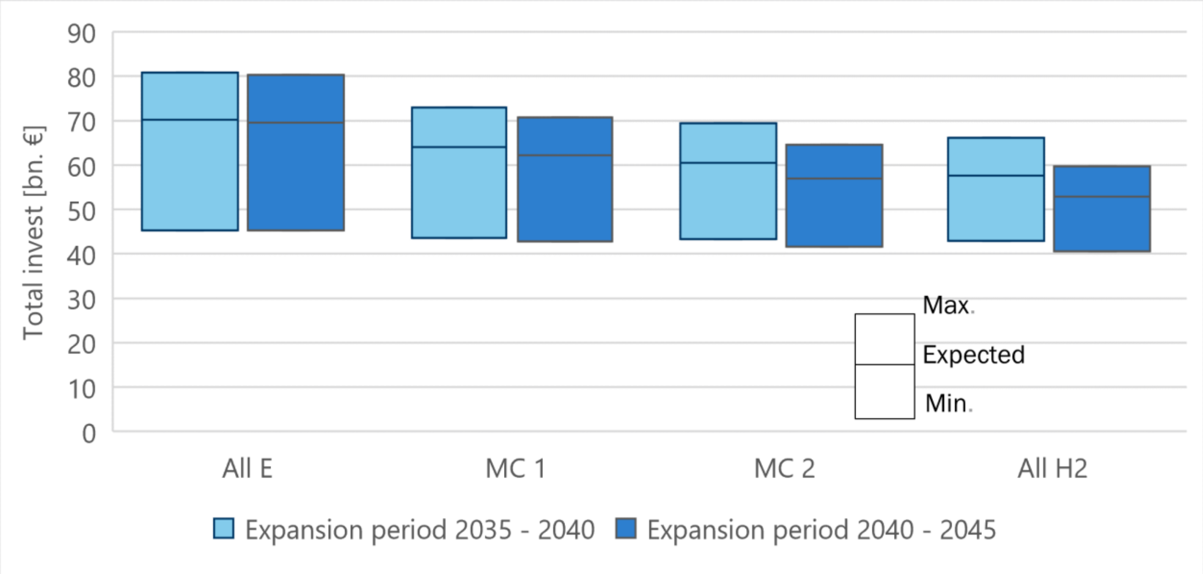


Figure 31: Overview of the cost range resulting from different assumptions of cost parameters and start years of the investment. Please note that the uncertainty for wind turbines is no greater than for offshore electrolysis. However, we were able to identify a wider range of values through many publications. The expected value is decisive for the evaluation.

Conclusion

- What are the main cost drivers of (mixed) connection concepts?

  At EUR 25 billion, the investment cost of wind farms equal in all concepts. A cable-only connection has been estimated to cost roundabout EUR 44 billion, assuming around EUR 4 billion per 2 GW of cable for the shortest and correspondingly higher costs for longer connections. The third most expensive components are the electrolyser platforms at EUR 20 to 30 billion. The pipeline connection itself is estimated at EUR 1 billion.

- What are the total investment costs for each connection concept?

  The investment costs not only vary from concept to concept, but also depend on the years of construction. At around EUR 70 billion, the electrical connection concept has the highest investment costs. In contrast, a connection using only hydrogen can be expected to cost around EUR 55 billion, depending on the year of installation. Depending on the design, the costs for a mixed connection concept range between these assumed investment costs. At around EUR 63 billion, MC 1 is slightly more expensive than the hydrogen-based MC 2 at around EUR 59 billion. Additionally, operating (2.6% p.a. plus stack replacement) and capital costs (WACC 9%) are considered.

6 Techno-economic evaluation of connection concepts

Guiding questions

- Which connection concept provides the greatest benefits?
- Should mixed connection concepts tend more towards electricity or hydrogen?
- Wouldn't it be more beneficial to produce hydrogen onshore?

The following assessment evaluates key technical performance parameters and the economic viability of the presented (mixed) connection concepts in zones 4 and 5 of the German EEZ.

For the evaluation, the **connection concepts are evaluated as a whole, i.e. the OWFs, electrolysers, converter platforms, cables and (proportionately) the pipeline are included**. In reality, these components would be commissioned and operated by different companies. Those companies would also apply different parameters for evaluation, such as capital costs or risk analysis. Infrastructure costs are not typically included in the evaluation of OWFs; however, they are a crucial driver of the analysis in this case. To determine the overall socio-economic benefit the components of the connection concepts are evaluated together in the following.

The operation of the wind farms and offshore electrolysis was optimized using an operating model. The model has knowledge of the available wind energy as well as electricity and market prices (as previously presented). Based on the available marketing opportunities, the revenue-maximizing operation is chosen. Wind farms that are only electrically connected (All E) only supply electricity. If only a pipeline connection is possible (All H2), only hydrogen can be supplied. Wind farms in mixed connection concepts can make more operating decisions, which allow them to supply electricity, hydrogen or withdraw electricity from the grid for electrolysis. Downtime has been accounted for with an availability of 95%. Complex failures (individual failures of OWFs, electrolysers, cables, or pipelines) are not considered.

The following **techno-economic analysis** examines various aspects. First, the **energy supplied** by each connection concept is evaluated (cf. chapter 6.1). Based on the electricity and hydrogen prices of the respective reference years and scenarios, the **revenues from the respective connection concepts** can also be derived as a second step (cf. chapter 6.2)[11]. The comparisons assume that the connection concepts are fully commissioned at the respective scenario and year, which makes it easier to compare the scenarios and spot the developments in energy supply and revenue potentials.

Another important aspect is the utilisation of components. In addition to the OWFs, cables, electrolysers and pipelines are deployed in the marine environment and impact it. A high level of utilisation of available resources avoids wasteful expansion and thus unnecessary impacts. Therefore, utilisation of equipment (cables & electrolysers) in the context of offshore consumption and a bidirectional use of the power cables is examined in chapter 6.3.

In a fourth step, the revenues from electricity and hydrogen are then compared to the investment and operation costs as well as the total cost of ownership (cf. chapter 6.4). The connection concepts are evaluated using the **Internal Rate of Return (IRR) and Net Present Value (NPV)**. Both evaluate the value of the projects, including the cost of connection. Connection concepts with a higher value can make a greater contribution to the connection costs and thus also minimise the social borne costs (grid or offshore charges). Therefore, NPV and IRR can also be interpreted as indicator for socio-economic benefits. A higher rate of return is equivalent to lower costs for promoting the expansion of offshore wind energy.

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[11] Due to necessary decision making, the energy supplied is already a result of the revenue potential itself. The two results are only presented sequentially.

Furthermore, offshore wind feed-in impacts electricity prices. Selling offshore electricity during periods of high demand reduces electricity prices for all consumers. Chapter 6.5 therefore examines an electricity market simulation sensitivity, how electric offshore wind feed-in, or in the case of offshore electrolysis the absence of it, affects the electricity market. Hydrogen production increases independence from energy imports. However, the impact on hydrogen prices is negligible.

Finally, two additional sensitivities are considered. The first sensitivity examines overplanting, which describes connecting OWFs with a reduced connection capacity. The sensitivity is aimed at understanding why a reduced connection can be advantageous in the first place.

The second sensitivity explores another connection concept where the electrolysers are located onshore. The OWFs are connected to the grid, known from All E. The electrolysis takes place directly at the grid connection point, at which the electrolysers can directly source electricity from the wind turbines. As before, the wind energy can still be sold to, and electrolysers can purchase electricity from electricity markets (without transmission constraints). The aim is to investigate whether the increased investment costs for offshore electrolysis are justified. Additionally, overplanting is examined, which involves designing the connection cables for lower capacity. This sensitivity analysis is distinct from coastal electrolysis, where the location choice leads to lower connection costs but permits grid connection under specific conditions only.

6.1 Generation of electricity and hydrogen

Depending on the development of electricity and hydrogen prices, different operating decisions are optimal. These differ between the scenarios, but also depending on the calculated year of expansion. Figure 32 shows the energy supplied in all calculated scenarios from 2035 to 2045. For a better comparison, it is first assumed that the entire wind farm including electrolyser, cable and pipeline is expanded in the corresponding scenario year.

Overall, a comparable utilisation can be identified for each connection concept across all scenarios. In connection concept All E only electricity, and in All H2 only hydrogen is being supplied. The amount of energy does not vary in these cases, as only one energy carrier can be chosen, and the scenarios are based on the same weather year. The difference between electrical and hydrogen energy corresponds to the efficiency losses of the electrolysers.

In contrast to the singular connection concepts, wind farms in mixed connection concepts can provide both electricity and hydrogen - even simultaneously. In addition to the use of offshore wind energy, the connection of a cable also makes it possible to utilize onshore energy to produce additional hydrogen and is shown accordingly as “Surplus H_2” in Figure 32[12].

In mixed connections, electrolysis reduces the impact on the electric grid by converting electricity to hydrogen but wind farms still provide electricity when it is in short. Depending on the scenario, the dimensioning of the mixed connection has different effects on the actual operating decisions. Overall, with a larger cable connection (MC 1), more electrical energy is transmitted but also less hydrogen is being produced. With a smaller cable and more electrolysers, the result is reversed.

[12] By 2045 at the latest, the hydrogen produced with onshore energy will be RFNBO-compliant in the CN and MET scenarios. The DET scenario will reach this compliance with a delay of 10 years in 2055. However, compliance with the RFNBO mechanism is determined by the CO_2 intensity of the entire electricity market. The hydrogen itself is produced at a much lower intensity. At the times when electrolysers are operated the share of renewables is above 90% and below a limit of 5 g CO_2/kWh for all scenarios from 2035 onwards. In the following assessment we assume the production of green hydrogen when onshore electricity is utilised.

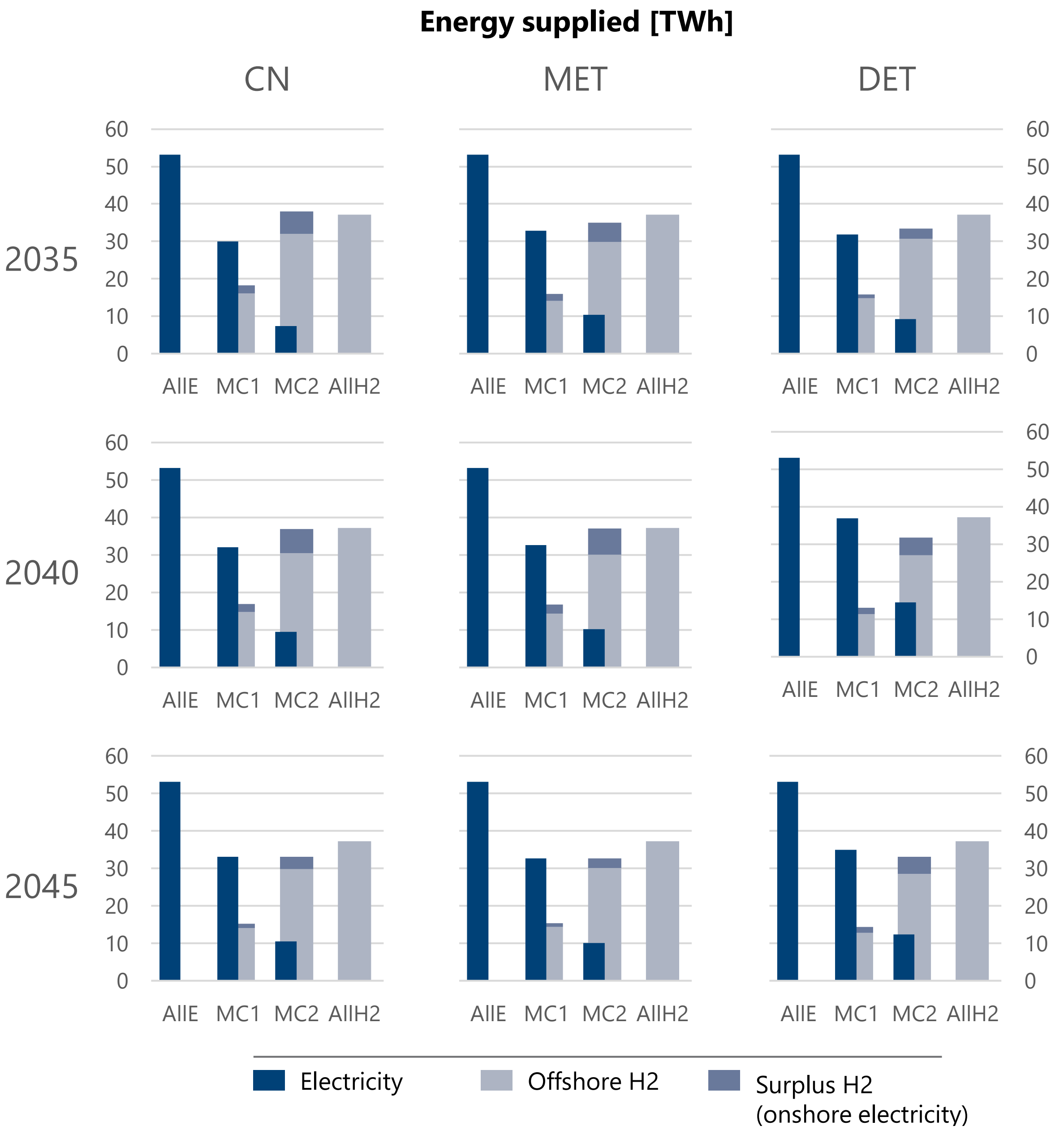

Figure 32: Comparison of annually energy supplied in different scenarios, assuming full expansion of the respective connection concept in the respective scenario year

Depending on the scenario, different operating decisions can be observed. In the DET scenario, electrical energy is more valuable in times of higher demand, leading to higher prices and the decision to feed-in electricity instead of producing hydrogen. Conversely, lower electricity prices in the CN and MET scenario lead to more surplus hydrogen being produced. However, the production of surplus hydrogen decreases across all scenarios until 2045. The main reason are stable electricity prices with falling hydrogen prices - it is less worthwhile to produce additional hydrogen. Even under poor conditions for the additional production of hydrogen, the output can be increased by 6%, and at its peak even by 20%. On average across all scenarios, hydrogen output is increased by 13%, and by 9% in the long-term (2045 and likely beyond). Nevertheless, it is of note that with a reduced capacity of 10 GW_{el} of electrolysers (MC 2, instead of 14 GW_{el} in All H2), comparable quantities of hydrogen can be produced. Although the scenarios predict a decline in this surplus hydrogen from 2045 onwards, this bidirectional cable utilisation makes better use of existing resources and electrolysers in particular.

6.2 Evaluation of revenue streams

As operating decisions are directly linked to electricity and hydrogen prices, they in turn determine annual revenue. Total annual revenues in a certain year do not vary significantly from scenario to scenario. Differences are mainly due to the supply of energy forms. Figure 33 shows the revenues for all connection concepts for the years 2035, 2040 and 2045 across all scenarios. As before, we assume full expansion of the OWFs, incl. electrolysers and connections for a better comparison of the scenarios.

A decline in revenue over the years is clearly recognisable across all scenarios. If only hydrogen volumes are sold (assuming the full expansion of 14 GW_{el} of electrolysers), revenues of almost EUR 8 billion can be expected in 2035. Until 2045, revenues will halve to around EUR 4 billion due to globally falling prices of hydrogen. Revenues from the sale of only electricity remain stable overall, but are lower in all circumstances, ranging from EUR 3 to 4 billion annually.

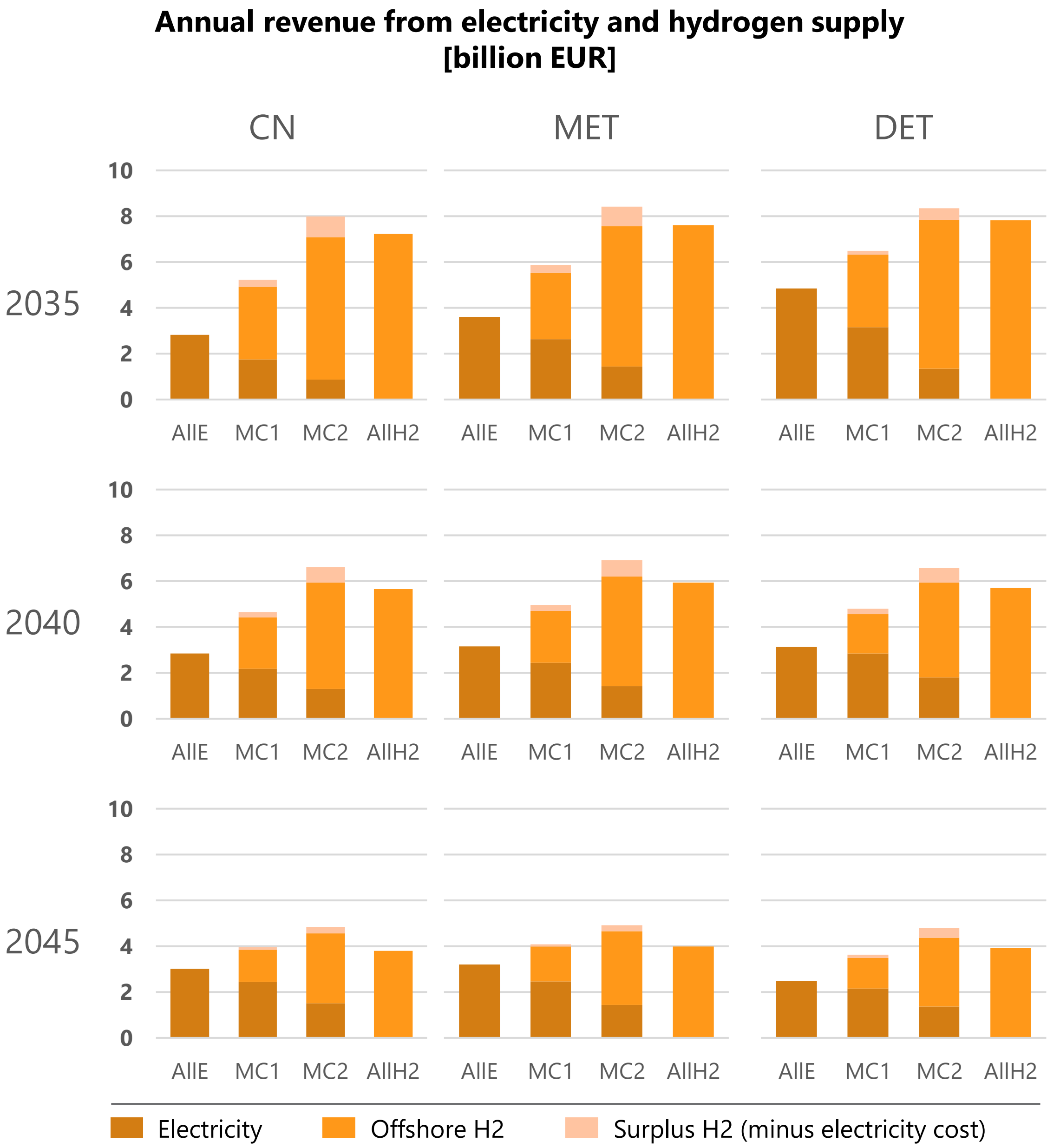

Figure 33: Example revenues from connection concepts in different years in scenario MET

The revenue potential of the mixed connection concepts differs. The electricity-dominant MC 1, with 10 GW of cable connection, has higher revenues compared to the electricity-only All E concept. The hydrogen-dominant MC 2 is not only able to generate higher revenues than All H2 but has the highest revenues across all years and scenarios. Overall, hydrogen production has greater revenue potential, which is why a hydrogen-dominant mixed connection concept has higher revenues despite falling hydrogen prices. At the same time, revenues from the sale of electricity are reduced by an average of no more than 50%, even though cable connection capacity has been reduced by more than 60%. From a revenue perspective, it is therefore advantageous to choose a hydrogen-dominant mixed connection concept.

6.3 Utilisation of equipment (cables & electrolysers)

The capacity factor describes the average annual utilisation of cables and electrolysers. In the case of unidirectional cable use, the utilisation depends on the available wind energy. Naturally, reducing the connection capacity increases the average utilisation but leads to operational curtailment in other cases. Over-sizing the connection reduces the utilisation. By using the cable bidirectionally, the utilisation and thus the benefit of both the cable and the electrolyser can be increased. The average utilisation of cables and electrolysers is shown in Figure 34.

If bidirectional cable use is allowed, electrolysers are allowed to consume onshore electricity and utilisation increases. Depending on the scenario, in the case of MC 2, an average utilisation of up to 60% can be achieved for cable and electrolyser. For mixed connection concepts with bidirectional cable use, an average increase in the capacity factor for cables of 11 percentage points – compared to the unidirectional case – is to be expected in 2045. The capacity factor of the electrolysers increases on average by about 6 percentage points. It may still be observed that the capacity factor is below the average utilisation of 43% in singular connection concepts - but in this case in favour of an intensive utilisation of the complementary cable/electrolyser.

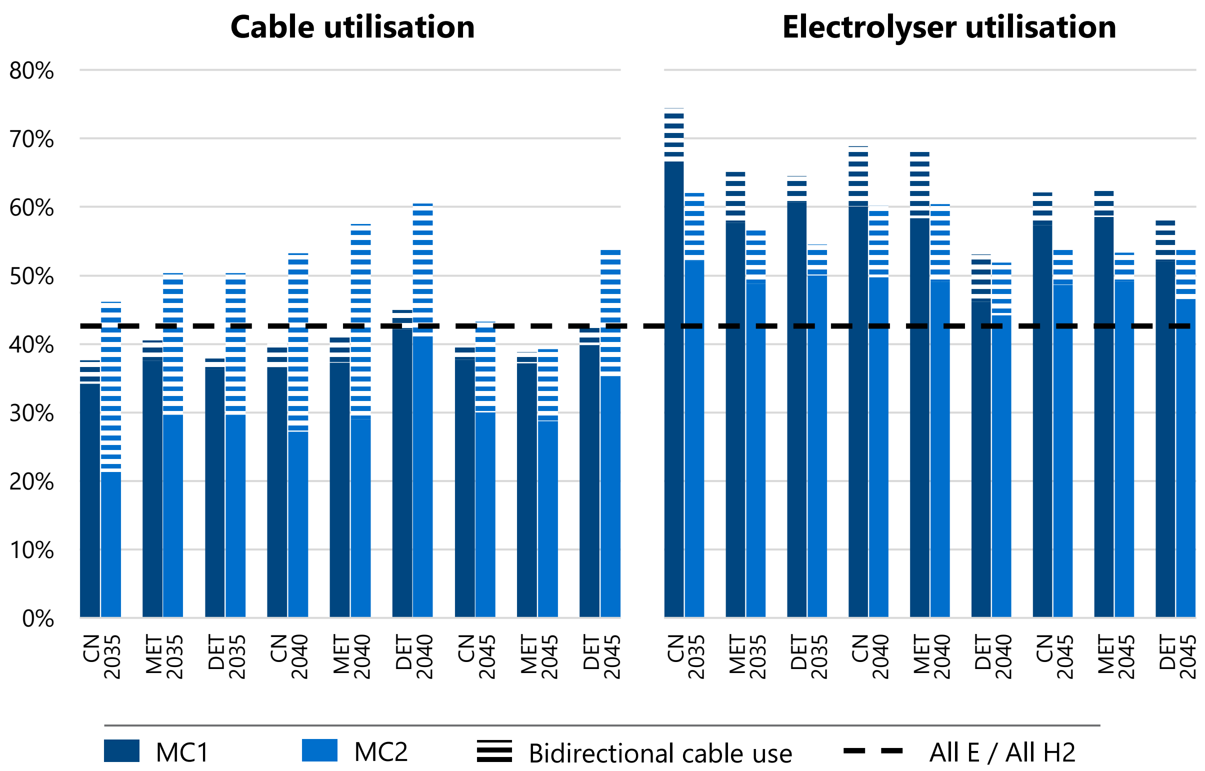

Figure 34: Capacity factors of cables and electrolysers compared to standard utilisation. Due to the increased flexibility of a mixed connection, capacity utilisation is split between cable and electrolyser. The scenarios investigated lead to a higher utilisation of electrolysers. Bidirectional cable use maximises capacity utilisation of cable and electrolysers overall.

Utilisation of cables and electrolysers could also be increased by under-dimensioning, if bidirectional use of the cable is not permitted. However, with mixed connection concepts, bidirectional use of the cable can noticeably increase the capacity factor and thus the utilisation of the equipment. Under almost all circumstances, existing resources are utilized more in bidirectional mixed connection concepts in comparison with their singular counterparts.

6.4 Case evaluation and economic suitability of configurations

Results for the economic assessment have been calculated for the years 2035, 2040 and 2045. The internal rate of return (IRR) is calculated as the discount rate that makes the net present value (NPV) of all cash flows from a project equal to zero. The net present value (NPV) is determined by summing the present values of all expected cash inflows and outflows, discounted at a specified rate. Cash outflows are the initial investment costs for the entire system and the replacement costs for the electrolysis stacks (if relevant). Cash inflows correspond to the annual revenues as shown above or revenues minus the electricity procurement case in case of hydrogen production with onshore energy.

In the following, connection concept All E is used as a baseline for comparison. In almost every sscenario and year, a purely electrical connection leads to negative IRRs around -4% and a NPV of around EUR -55 billion. This result is driven in particular by the high cable costs. The differences in the NPV of all connection concepts are summarised in Figure 35.

All alternative connection concepts have a better IRR and NPV than All E across all assumptions. Connection concept MC 2 almost consistently has the best IRR and NPV. Of the mixed connection concepts, IRR and NPV are higher for the hydrogen-dominant MC 2 than for the electricity-dominant MC 1, which confirms the results from the revenue potential. However, a positive net present value is not possible in any variant. At least under the assumptions made, certain investment signals are needed in connection concepts to incentivise the expansion of OWFs in the EEZ. Nevertheless, the configuration with the highest revenue potential also promises to be the configuration with the lowest need for subsidies and therefore levies or tax revenue.

Using the power cable to draw energy from the onshore grid (bidirectional use case) increases the IRR for mixed connection concepts by an average of 1 to 2 percentage points compared to unidirectional cable use (not shown in Figure 35). Bidirectional cable utilisation therefore not only leads to higher capacity utilisation, but also to an economically measurable improvement.

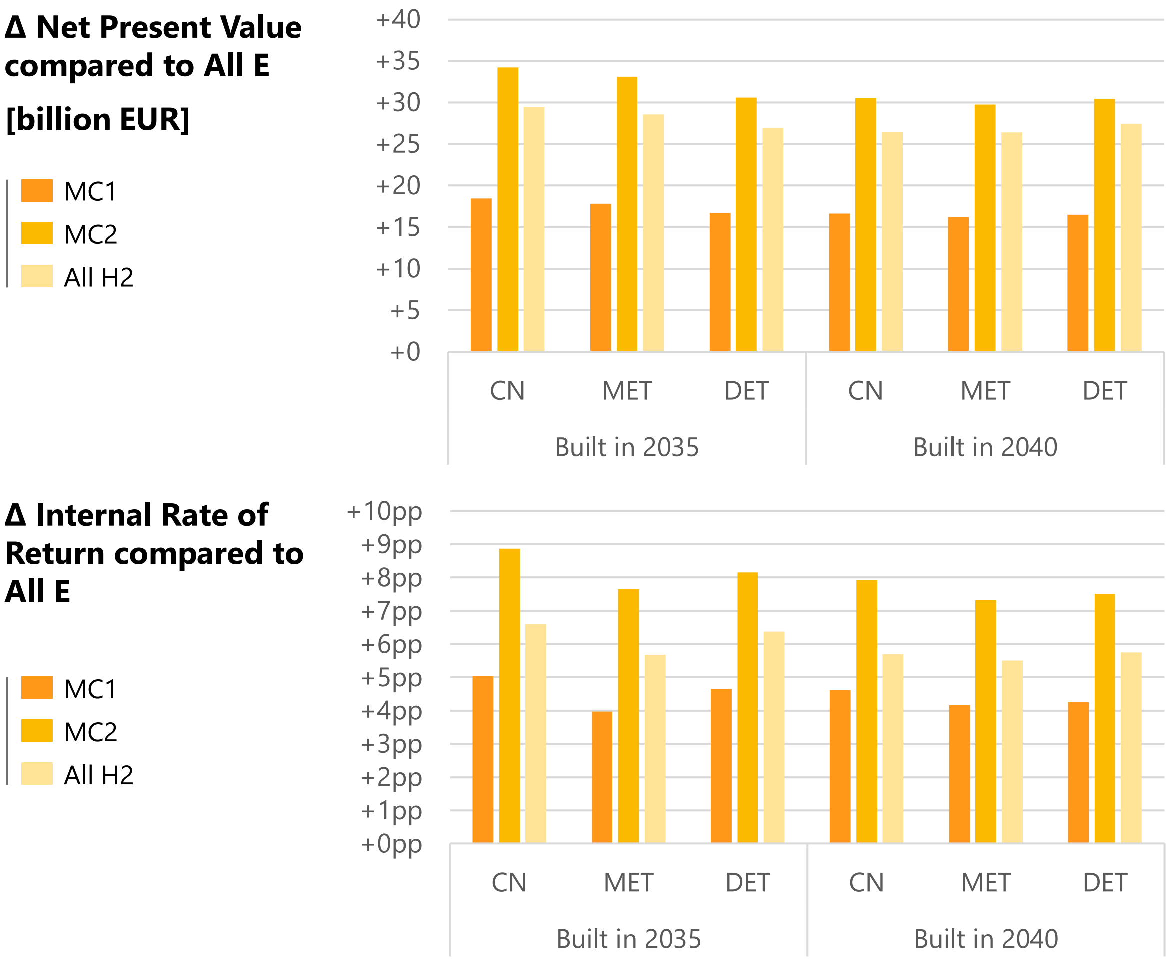

Figure 35: Difference in NPV and IRR of connection concepts in comparison to All E

It is also noticeable that commissioning in 2035 means a higher NPV than in 2040. This is mainly explained by higher hydrogen prices expected in 2035, before decreasing after 2040, but does not affect the result of the overall best performing connection concept. Mixed connection concepts allow to benefit from higher hydrogen prices, but as soon as hydrogen prices fall, power cables secure additional revenues on the electricity markets, which is the case in all scenarios.

6.5 Sensitivity: impact of connection concepts on electricity market prices

This sensitivity indicatively analyses the effect of the different connection concepts on electricity market prices, in comparison to the initial market prices that were calculated assuming an electric cable connection of 14 GW (cf. All E). Two different sensitivity calculations of the original All E case (chapter 3.2) were conducted for the reference year 2045:

- Only pipeline connection (All H2): 14 GW of offshore wind and 14 GW_{el} of electrolysers are not connected by cable. Only a H_2 connection by pipeline exists. Neither the offshore wind turbines nor the electrolysers can participate on the electricity market.
- Mixed connection concept (MC 2): 14 GW of offshore wind and 10 GW_{el} of electrolysers are connected by a 4 GW electricity cable and the pipeline. Offshore wind and electrolysers both participate on the electricity market yet constrained by 4 GW of cable capacity.

The total exclusion of offshore wind capacity from the electricity market (All H2) leads to an increase of 5 – 8 EUR/MWh on German electricity market depending on the scenario, as shown in Figure 36. The impact on the market prices is the highest in the DET scenario which can be explained by the overall lowest total offshore wind capacity in this scenario. This increases the system and price effect of the excluded 14 GW_{el}.

In MC 2, the cable is used to transfer electricity to the electrolyser during hours when wind generation is insufficient, and the electricity market price is below the hydrogen market price (leads to price increase). In turn, up to 4 GW capacity of offshore wind energy are supplied to electricity markets, if electricity prices are high (leads to price decrease). As can be seen in Figure 36 the impact on electricity market prices of such a reduced cable connection is rather small. The price increase lies between 1.5 and 5 EUR/MWh compared to the All E case. The impact is especially lower compared to the All H2 case. Using a mixed connection concept can therefore mitigate the risk of higher electricity prices when using offshore wind predominately to generate hydrogen.

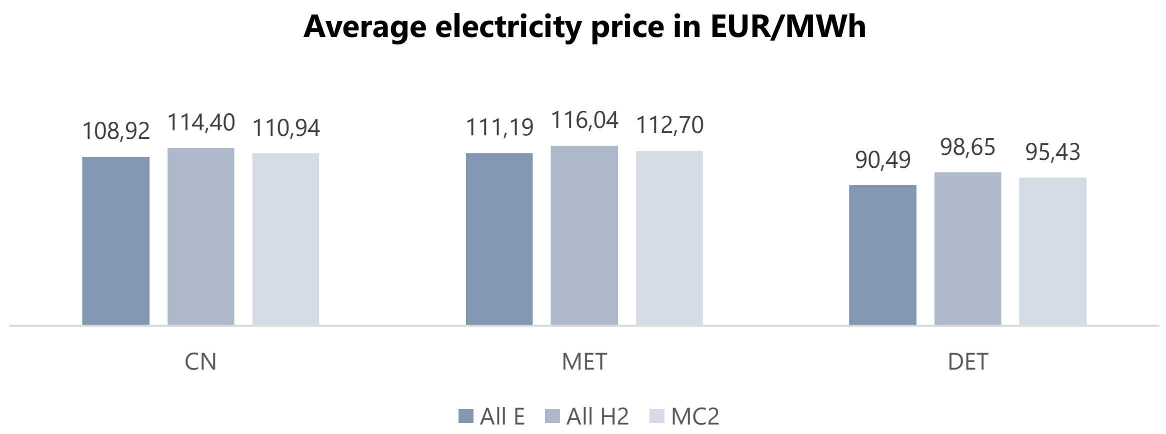

Figure 36: Average electricity price in the All H2 and MC sensitivity compared to All E in the year 2045

The change in electricity prices also influences hydrogen prices. However, these effects are marginal and do not consider, for example, the inherent added value of reduced import dependency, which cannot be reflected in the modelling approach. Importantly, the mixed connection concept MC 2 has a significantly lower impact on scarcity signals, i.e. the electricity price, compared to All H2. The price effects are worse in the DET scenario: in a delayed energy transition, scarcity situations noticeably benefit from available offshore electricity.

6.6 Sensitivity: overplanting of electric capacity

Besides connecting OWFs at full capacity, there is also the option to connect them electrically to the shore with a reduced cable capacity. Overplanting describes when more capacity is installed than can be transported. The following analysis examines how a reduction in connection capacity in a purely electrical configuration (All E) contributes to an improvement in the economic evaluation – with 14 GW of OWFs installed.

By reducing the number of cables, the average connection costs decrease (cf. Chapter 5). The following sensitivity presents the economic evaluation for a cable capacity of 10 GW and 4 GW (instead of 14). The electrical connection costs considered for 10 GW and 4 GW correspond to the electrical connection costs in MC 1 and MC 2, respectively. In the analysis, we also examined other theoretical capacity configurations, whereby a capacity of 6 GW represented the best overplanting result overall. To complete the picture, a 6 GW configuration was included in the comparison. The costs were calculated by linear interpolation of the other connection costs.

By reducing the connection capacity, there is a substantial increase in curtailment of energy due to a lack of transmission capacity (not due to grid congestion). Although this reduces revenue opportunities, it predominantly occurs during hours when there is already sufficient RES available. The results are presented in Figure 37.

As indicated, connection capacity of approximately 6 GW leads to the highest IRR. The highest NPV is achieved with a connection capacity of 4 GW, which can be explained by the significantly lower investment cost. This is consistent across all investigated scenarios. Yet, even with overplanting, a purely electrical connection performs worse than with the initially presented connection concept MC 2.

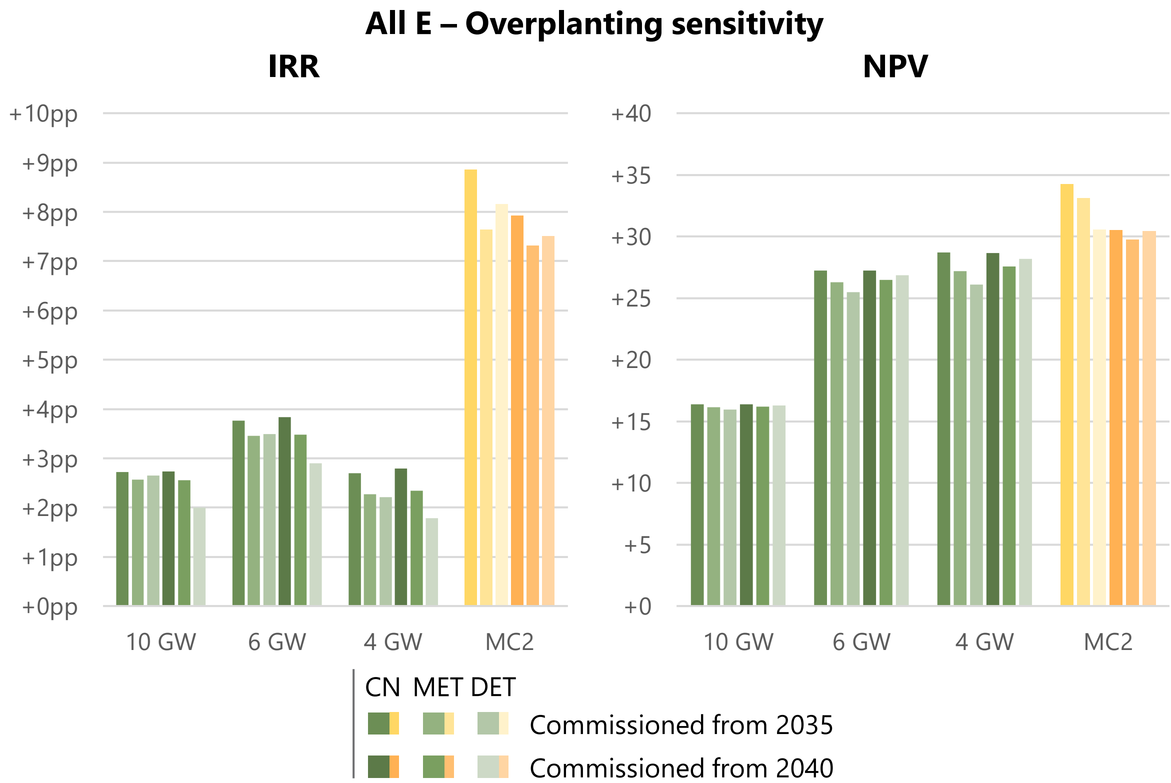

Figure 37: Difference of IRR and NPV in the overplanting sensitivity, again compared to All E with 14 GW of cable capacity. MC 2 is shown for better comparison.

In the sensitivity analysis, the optimal scenarios involve a 14 GW offshore wind farm (OWF) connected by a cable of 4 – 6 GW capacity. It implies that curtailing production to approximately one-third of the generation capacity results in the best economic performance. Consequently, it is more economical to curtail a substantial portion of electricity rather than invest in transmission infrastructure. At the same time, despite an improved IRR and NPV rating, 40% to 50% of the offshore energy must be curtailed which does not seem to be rational. Indirectly, the result indicates why a hydrogen-dominant mixed connection concept yields better overall results: a smaller electrical connection might be more advantageous overall.

Overplanting is also possible with hydrogen. Considerations on overplanting with hydrogen and the levelized costs of hydrogen (LCOH) can be found in Appendix C.

6.7 Sensitivity: producing hydrogen onshore instead

So far, only concepts in which electrolysis took place offshore have been investigated. Would it be cheaper to produce hydrogen onshore instead? In the following, onshore electrolysers are evaluated as part of the connection system. The 14 GW OWF are connected by a cable capacity of 14 and 10 GW. At their respective onshore grid connection points, electrolysers of the same size (14 GW_{el} and 10 GW_{el}) are connected. The sensitivity therefore investigates whether an electrical connection with subsequent electrolysis could be a more favourable concept.

The comparison of offshore vs. onshore electrolysers is based on different conditions: an onshore hydrogen concept with 14 GW_{el} capacity requires as many cables and electrolysers as All E and All H2 combined. A connection with 10 GW_{el} capacity combines the cable capacity from MC 1 and the electrolyser capacity from MC 2[13]. A comparison of economic parameters nevertheless allows some conclusions to be drawn.

The cost parameters assumed so far do not change. However, the toal investment costs for onshore electrolysis are lower than offshore: onshore electrolysers do not have to be marinised and require fewer auxiliary systems. In total, a cost reduction of roundabout 50% for the electrolysis part - compared to offshore electrolysis - is assumed. The electrical connection is made at the designated connection points in the electrical grid - an installation elsewhere would presumably not allow any electrical system integration. The costs of connecting to an (existing) pipeline onshore and the costs for the acquisition of land are neglected. The total investment costs amount to EUR 88 billion for 14 GWel (EUR +20 billion compared to All E) and EUR 68 billion for 10 GWel (EUR +/- 0 billion compared to All E).

In this sensitivity, wind turbines remain capable of selling their energy to electricity markets or to supply the electrolysers. The operation of the electrolysers with onshore energy is only limited by the capacity of the electrolyser (and not any available cable capacity). Two factors are compared against the mixed connection concept MC 2: the NPV and IRR on the one hand and the total energy supplied on the other. In the case of a transport capacity of less than 14 GW, a curtailment of energy supply must also be accounted for.

Figure 38 shows the NPV and the IRR for the connection concepts with onshore electrolysis and compares it to All E (as well as MC 2 and All H2). A connection with 10 GW_{el} of cable and onshore electrolysers offers a greater NPV and IRR than with 14 GW_{el}. This is because a reduction to 10 GW_{el} implicitly equals to overplanting.

Due to the increased profitability of hydrogen production, the onshore hydrogen concepts perform better than All E. While the IRR is higher than with the All H2 concept, All H2 consistently has the greater NPV. Despite the lower IRR, offshore electrolysis benefits from lower investment costs. Despite its lower IRR, the decisive factor is that All H2 has the higher NPV and, unlike the 10 GW_{el} onshore configuration, does not yet exploit the potential of overplanting.

Regardless, the hydrogen-dominant mixed connection concept MC 2 yields the best results in all cases, both in terms of NPV and IRR. Offshore electrolysis reduces grid expansion, which justifies its higher construction costs. At the same time, MC 2 maintains the flexibility of onshore configurations, which results in comparable revenue streams.

[13] An onshore hydrogen connection concept with less capacity, is not compared, as large amounts of energy have to be curtailed due to a lack of transport capacity. Although this could further improve the evaluation, it would make the comparison weak. Overplanting would then also have to be considered with other connection concepts.

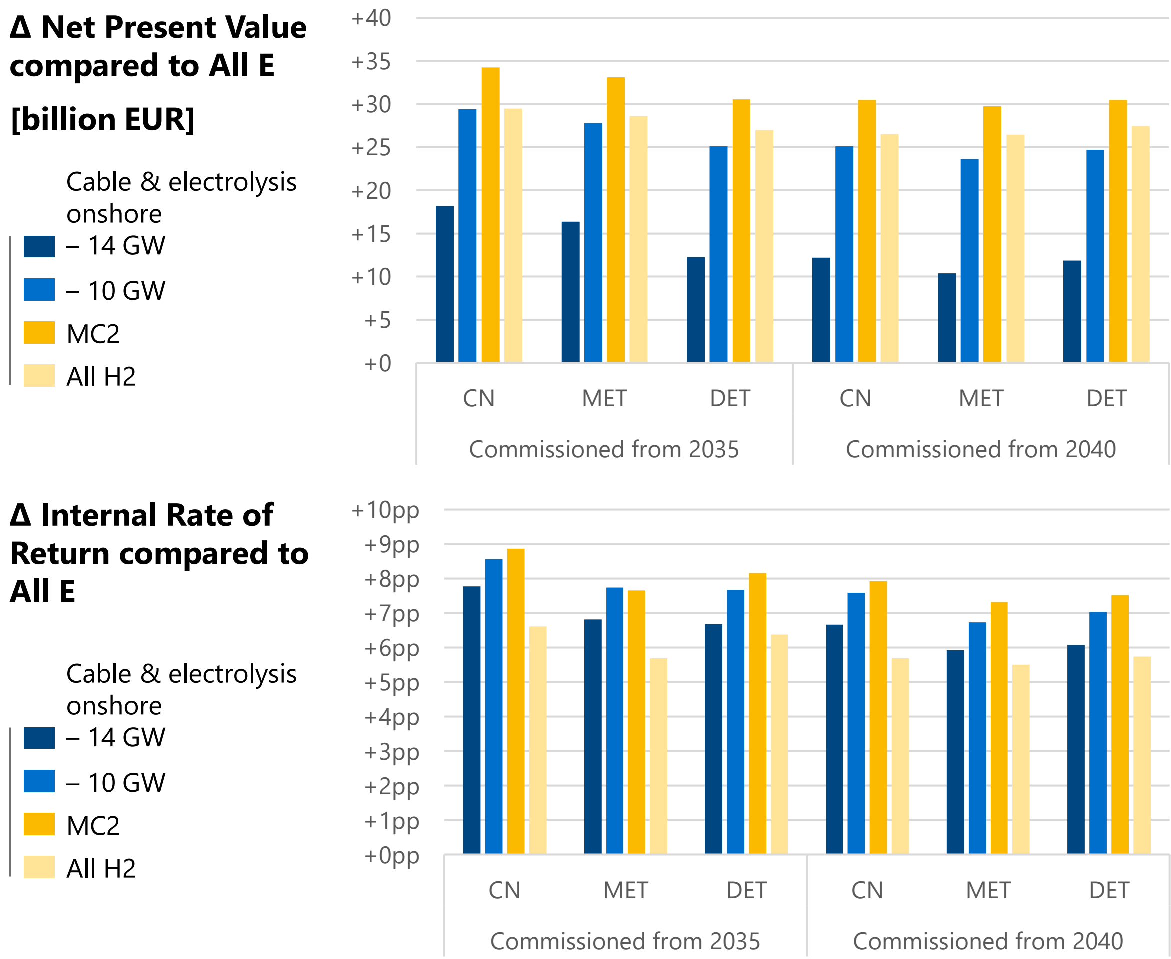

Figure 38: NPV and IRR of the onshore electrolysis case (compared to All E). Despite its lower IRR, All H2 has a better NPV in comparison. Due to all NPVs being negative in absolute values, lower investment costs (here for All H2) lead to an improved valuation.

To illustrate the consequences of onshore electrolysis in greater detail, Figure 39 shows the energy supplied in scenario MET 2045 as an example. As shown before, the analysis shows the supplied electricity, hydrogen and the hydrogen produced with onshore electricity. A fourth category evaluates the energy which is curtailed because of limited transport capacity.

In a direct comparison of 10 GW_{el} "onshore electrolysis" (On – 10 GW_{el}) and MC 2, almost the same amount of hydrogen is produced. The electrolysers are therefore similarly utilised. Furthermore, 10 GW_{el} onshore electrolysis provides 7 TWh of electricity, but also 5 TWh of electricity must be curtailed. In comparison, MC 2 provides roundabout 10 TWh of electricity without curtailment. The concepts lead to practically the same output (with only little variation across the scenarios).

Lastly, onshore electrolysers require connection points within the onshore electricity grid. Integrating electrolysers onshore, despite being possible at lower costs and similar benefits offshore, limits the available capacity for the full potential of onshore electrolysis. Concurrently, offshore capacities remain underutilised, as overplanting is a necessity for the onshore configuration to become economically viable. While onshore electrolysis is a crucial component of the energy transition, it is not a necessary component for the integration of offshore wind turbines. Offshore electrolysis, within mixed connection concepts, is equally effective and demands less connection capacity in the electrical system. To a certain extent, offshore electrolysis enables the realisation of mixed connection concepts in the first place, which could become essential for the cost-efficient and advantageous integration of distant OWFs in the North Sea.

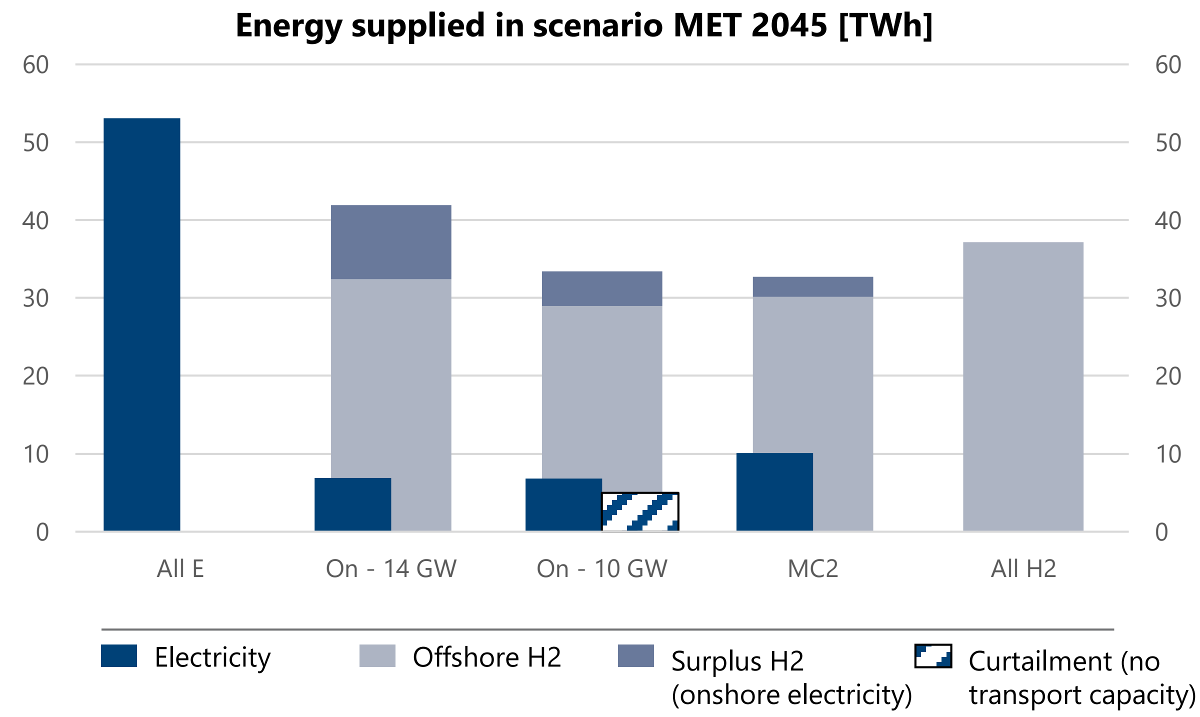

Figure 39: Energy supplied on onshore sensitivity in scenario MET 2045 (example).

Conclusion

- Which connection concept provides the greatest benefits?

  In our investigation, to connect 14 GW OFWs in EEZ zones 4 and 5, a mixed connection concept with 10 GW_{el} of electrolysis capacity and 4 GW of bidirectional cable capacity had the greatest benefits with robust results. Despite a 70% reduction in cable capacity (compared to an only electric connection) the revenue opportunities from electricity remain high, while the effect on the markets, due to reduced offshore wind capacity are marginal. The electric cable can also be used to increase the utilisation of cables and electrolysers, which also increases the value of the offshore wind projects. The increased profitability of these concepts ultimately also reduces the need for subsidies.

- Should mixed connection concepts tend more towards electricity or hydrogen?

  Our results show that mixed connection concepts (in EEZ zones 4 and 5) benefit from a smaller electrical connection in the overall assessment, so that hydrogen becomes the dominant energy carrier.

- Wouldn't it be more beneficial to produce hydrogen onshore instead of offshore?

  Moving offshore electrolysis onshore is more expensive and offers no added value compared to offshore electrolysis. Overall, the capital and resource expenditure increases, but at the same time utilised connection capacities onshore are no longer available to other required electrolysers. The additional cost of offshore electrolysis is justified by reduced connection cost and the overall benefit. Offshore electrolysis becomes an enabler of mixed connection concepts, which in turn enable the cost-effective and beneficial system integration of far out OWF.

7 Environmental perspective

Guiding questions

- What are the environmental legal bases and the planning frameworks in the German EEZ for hydrogen production areas?
- What effects are caused by offshore hydrogen productions and what are their environmental impacts?
- What aspects of offshore hydrogen projects need to be considered in particular from an environmental perspective?

7.1 Introduction & guiding perspective

From the point of view of the environment (assuming no human involvement), a habitat is at its best when it can develop naturally and without technical influences, being undisturbed. The regulatory mechanisms of the environment are self-sufficient, nature is fine by itself. This means that any intervention by humans, such as in this case the installation of technical facilities, must initially be regarded as negative for the environment, even if projects aim to promote renewable energies and are therefore seen as positive from a climate protection perspective.

The most important guiding principle, which is also embedded in law and will become even more important in the future, is therefore that of avoiding and minimising technical interventions and thus environmental impacts. The following analysis therefore focuses on the presentation of impact factors and mechanisms and on how avoidance and mitigation can be taken into account already at an early stage of technical planning.

7.2 Environmental law and environmental reports

In the German Exclusive Economic Zones (EEZ) environmental law considerations for offshore hydrogen production facility are currently based on the requirements of the Offshore Wind Energy Act (Windenergie-auf-See-Gesetz (WindSeeG)). According to § 3 WindSeeG, an offshore hydrogen production facility is classified as an "other form of energy generation". The licensing authority is the Federal Maritime and Hydrographic Agency (Bundesamt für Seeschifffahrt und Hydrographie (BSH)).

As part of the plan approval procedure (Planfeststellungsverfahren (PFV)) under the WindSeeG, environmental documents, such as the Natura 2000 impact study and the environmental impact assessment (cf. Figure 40), must also be submitted to the BSH as part of the planning approval procedure.

To investigate and determine whether a project may pose a threat to the marine environment, expert statement reports are prepared by environmental planners for the application to the BSH. The following topics are covered:

- Environmental impacts and their significance in general (environmental impact assessment (EIA))
- Impacts on the European Natura 2000 network of protected sites for birds, plants and animals (impact assessment concerning Habitats Directive sites and Special Protection Areas (SPAs) under the Birds Directive)
- Impacts on certain strictly protected species of animals and plants (Species Protection Assessment Report)
- Impacts on specially protected biotopes (Biotope Protection Assessment Report)
- Impacts on water bodies (Water Law Technical Report)

- Determination of compensation requirements and of compensatory and replacement measures for the environment (document on compensation and restoration needs)
- Concepts for monitoring bird collisions with offshore constructions and a concept for the implementation of monitoring of the construction related impacts of the project on the marine environment

All the above-mentioned reports are produced based on German and European regulations (Federal Nature Conservation Act (Bundesnaturschutzgesetz), Federal Water Act (Wasserhaushaltsgesetz), Environmental Impact Assessment Act (Umweltverträglichkeitsprüfungsgesetz)).

Data on the current state of the local environment forms the basis for the reports. The main focus of the investigations is on the protected assets benthos, fish, avifauna, bats, landscape and marine mammals. The impacts on these protected assets are assessed by the experts (for impact factors, see Chapter 7.3 below). This is partly based on technical expert reports that are commissioned externally by the project developer (noise prognosis, emission report, heat emission study for planned cables or pipelines, marine archaeological technical report etc.).

7.3 Spatial planning as planning framework

The primary steering instrument for offshore energy generation in the German EEZ is the Site Development Plan (FEP), which sets out the requirements for the spatial and temporal offshore expansion (§ 5 WindSeeG) in the North Sea and the Baltic and is drawn up by the Federal Maritime and Hydrographic Agency (BSH). In the current draft of the FEP dated June 7, 2024 (BSH 2024), an area classified as “other form of energy generation” is designated in the German North Sea EEZ. The area covers a size of 102 km² and is located 102 km north of the island of Borkum. The FEP does not make any spatial determinations regarding pipelines for the connection of the area SEN-1 (BSH 2023). However, the current draft of the FEP presents possible routes for a hydrogen pipeline for discussion to access the area SEN-1. Further areas for offshore hydrogen production facilities are currently not defined in the FEP (BSH 2024). However, the preliminary designation of SEN-1 creates an initial framework for the inclusion of such energy generation and transmission in terms of both environmental and spatial planning.

In case of a future access to zones 4 and 5 of the FEP (in the north-western region of the German EEZ), from today's perspective, particular attention must be paid to shipping, wind energy, connection lines and the marine environment. The nature conservation area Doggerbank covers large parts of the zones 4 and 5 of the German EEZ and its protection concerns must be dealt with in future proceedings. In terms of species and possibly also area protection, avoidance and mitigation measures are likely to become increasingly relevant on the technical side in the future.

7.4 Effects/impacts on the environment

The technical planning of the project provides the basis for deriving the project-related effects on the environment. An effect is caused by an impact factor. This impact factor affects an environmental condition or a protected asset. This leads to an impact, usually an impairment of the environment or the aspect under observation. This is assessed by the environmental expert in terms of its extent (strength, duration, range) and compared with the legal requirements (see above).

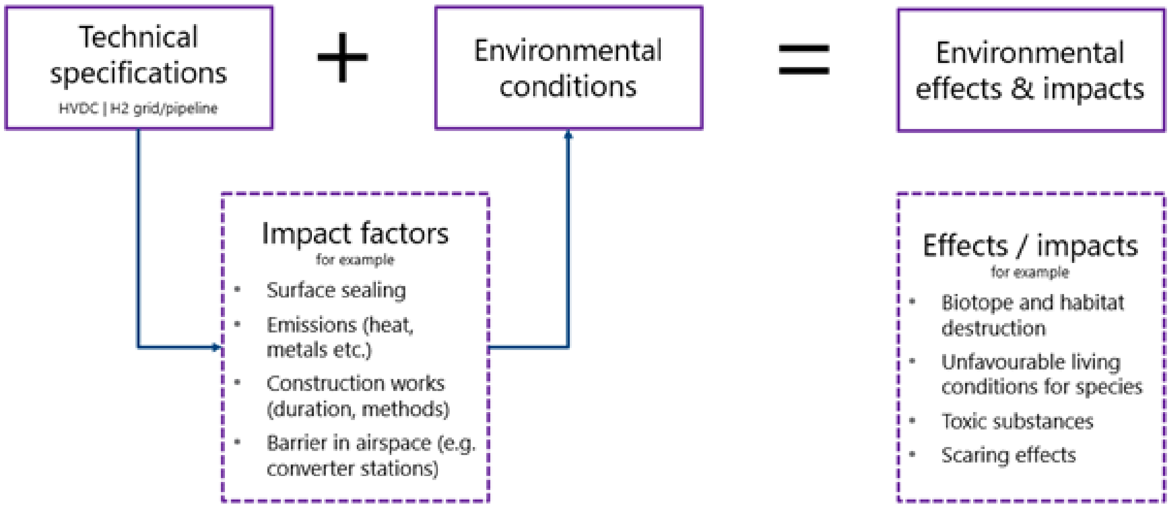

Figure 40: Workflow scheme of environmental assessment

Different configurations of offshore hydrogen production facilities and required pipelines have different kinds and combinations of environmental effects (cf. Figure 41).

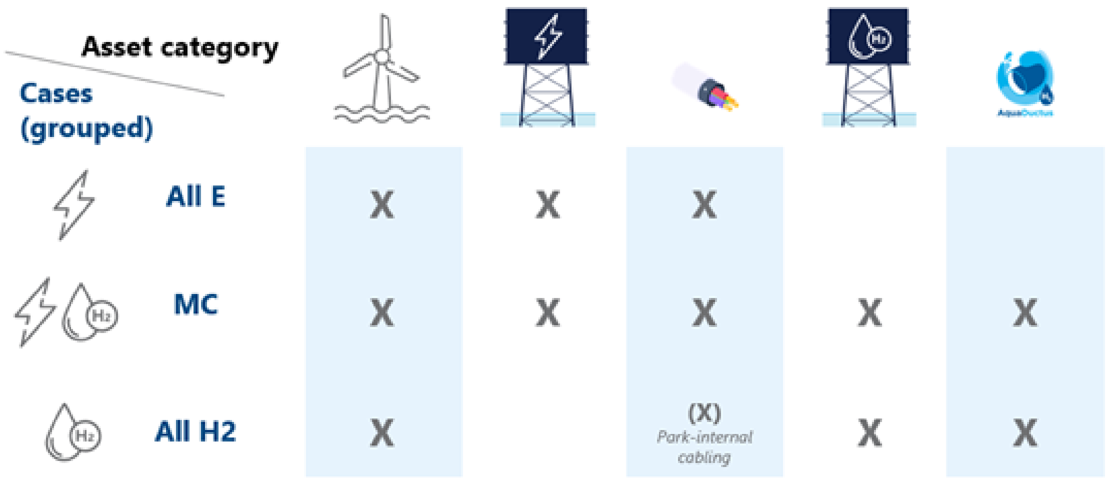

Figure 41: Overview of investigated cases (site configurations) and the effects they are related with

The consideration of environmental effects is typically divided into the three phases

- construction/dismantling (e.g. noise emissions during foundation piling),
- system (e.g. surface sealing on the floor, system as an obstacle in the air column) and
- operation (e.g. cooling water discharge into the environment).

The following Table 6 shows typical effects of the above-mentioned offshore projects as well as in which phase they affect which environmental protected asset. Not all effects occur for all components (OWT, cables, pipelines, converter platforms, hydrogen platforms). A detailed component specific overview is provided in Table 9 in the appendix to the report.

Table 6: Allocation of the period of the impact (●) and the protected assets (X) to project-related effects

Effects	Construction/dismantling	System	Operation	Human beings	Biotopes	Benthos	Fish	Marine mammals	Resting birds	Migratory birds	Bats	Biodiversity	Ground (sediment)	Area	Water	Climate	Air	Landscape/Scenery	Cultural heritage and other material assets
Sediment turbulence/ turbidity plumes	●				X	X	X					X	X		X				
Sediment shift	●				X	X						X	X						
Noise emissions	●		●		X	X	X	X				X							
Visual disturbance	●		●						X			X							
Light emissions	●	●							X	X	X	X						X	
Area use	●	●				X	X					X	X	X					X
Sediment compression	●				X	X						X	X						
Insertion of hard substrate		●				X	X					X		X					
Obstacle in the water body		●				X						X			X				
Obstacle and visibility in the airspace	●	●							X	X	X	X						X	
Chemical pollution		●	●			X	X					X	X		X				
Extraction and discharge of water		●				X	X					X			X				
Utilization restrictions		●		X		X	X					X	X						
Heat emissions			●			X	X					X	X						
Electromagnetic fields			●			X	X	X				X							

● Period of impact divided into construction/dismantling, system and operation
X Allocation of the protected assets affected by the impact

7.5 Special aspects of offshore hydrogen projects

Since environmental impacts of the construction and operation of wind turbines, cables and converter platforms are already being considered regularly in past and current OWF projects, in the following text and Table 7, the focus will be on the possible additional, special and/or not yet established environmental impacts of electrolysis platforms and hydrogen pipelines. The main purpose of this is to draw conclusions about the most advantageous technical configurations at the currently early planning stage and to clarify the points at which overlaps and the need of considerations between technology and environmental concerns exist.

Table 7: Parameter, possible impacts and avoidance and mitigation measures that are new or especially important at offshore electrolysis and pipeline projects from an environmental perspective

Parameter	Possible impacts	Avoidance and mitigation measures
Hydrogen platforms		
Discharge of salt enriched water [concentration and volume]	■ Influence on the pH value → Impacts on fish and benthos ■ Influence on the oxygen solubility → Impacts on fish and benthos ■ Influence on the food chain (benthos and fish) → Impacts on marine mammals and birds	■ Dilution with seawater to reduce the concentration. Dilution of brine with the cooling water arising is intended anyway. (But: possibly extraction of larger quantities amounts of seawater needed.) ■ Discharge through several nozzles for better mixing in the water body
Water extraction for cooling and desalination [volume and noise emission]	■ Removal of eggs and larval stages of benthos and fish fauna ■ Disturbance of resting birds and marine mammals by noise emission of seawater pumps	■ Keep the intake speed as low as possible ■ Keep the noise emission as low as possible ■ If possible, use a fine-mesh net/filter in front of the suction opening ■ Optimised position in water column for cooling water intake
Discharge of heated water into the marine environment [temperature and volume]	■ Pelagic habitat change → dependents on quantity, temperature difference and mixing processes a dispersal modelling may be required	■ Keep the temperature difference as low as technically possible and feasible by increasing the cooling water flow rate (results in higher cooling water consumption and discharge of biocides)
Discharge of biocides (biocides are currently regularly used to keep the cooling circuits free of fouling. The use of biocides is part of the permitting process and might not be generally accepted in future projects) [concentration and volume]	■ Accumulation of pollutants in marine organisms and sediment	■ Alternative cleaning methods, avoidance of biocides if possible
Release of pollutants by possible sacrificial anodes (corrosion protection) [amount of substance input]	■ Accumulation of pollutants in marine organisms and sediment	■ Use of alternative corrosion protection (external current corrosion protection (e. g. ICCPs))
Piling the foundations [depending on the pile diameter]	■ Interference of marine mammals (scare effect, avoidance movement, change in behaviour)	■ The noise protection concept (BMU, 2013) must be followed, where limits for impulse noise are defined. If the critical level is exceeded, noise protection

Parameter	Possible impacts	Avoidance and mitigation measures
		measures must be taken (e.g. bubble curtains) ■ Construction time schedules, coordination of simultaneous work in the surrounding
Obstacle in the airspace [depending on the size/height of the topside and lighting]	■ Disturbance of resting and migratory birds (barrier effect, attraction and scaring effects at close range, habitat loss, collision)	■ Lighting concept
Maintenance traffic	■ Disturbance of resting birds and marine mammals	■ Minimize shipping traffic ■ Slow moving ships ■ Adherence of shipping routes
Hydrogen emissions to air due to purging and venting events	■ Hydrogen has a global warming potential due to its chemical reactions with greenhouse gases	■ Use of technical solutions to minimise the emissions
Pipeline		
Area use by the pipeline on the seabed	■ Permanent use of benthic habitats, possible destruction or significant impairment of biotopes protected by law	■ Possible installation under the seabed. That is causing other impacts that can probably be regenerated after a few years.
Insertion of hard substrate by pipeline and, if necessary, safety elements (rock fills)	■ Habitat changes from soft-substrate to hard-substrate habitats	■ Install as few safety elements as possible (number, area)
Temperature changes in the surrounding sediment and lower water column due to pipeline operation	■ Habitat changes for benthic organisms, changes in sediment chemistry	■ Temperature differences to seawater at the pipeline surface should be as small as possible (e. g. by insulating the pipeline), sufficient laying depth when laying below the seabed surface
Underwater noise Emissions caused by the pipeline during operation (e.g. infrasound)	■ Scaring effects, barrier effects for fish and marine mammals	■ Adjusted transmission speed
Installation vessel (depending on size, height of superstructure, lighting and speed of installation) and maintenance traffic	■ Visual disturbance and scaring effect on resting birds (habitat loss), potential attraction of migratory birds (risk of collision) ■ Acoustic disturbance → scaring effects, barrier effects on fish and marine mammals	■ Lighting concept for installation vessel ■ Adapted construction time schedule (adapted to the life cycles of the animals, use as few ships as possible, as economical as possible)

The basis for deriving impacts and impact factors is generally a detailed project description. Such a description is not yet available for the project in question here. The provided information is therefore for general guidance only and does not claim to be fully comprehensive.

Conclusion

- What are the environmental legal bases and the planning frameworks in the German EEZ for hydrogen production areas?

  Environmental law considerations for offshore hydrogen production facilities are currently based on the requirements of the **Offshore Wind Energy Act**. As part of the **plan approval procedure, environmental investigations** are required, and environmental reports must be submitted to the Federal Maritime and Hydrographic Agency. These **environmental reports** are based on German and European regulations (Federal Nature Conservation Act, Federal Water Act, Environmental Impact Assessment Act).

  Based on the Offshore Wind Energy Act, the **Site Development Plan** is the primary steering instrument for offshore energy generation in the German EEZ. Currently, one area for "other forms of energy generation" is designated in the German EEZ of the North Sea. In the case of future access to the northwestern parts of the EEZ, from today's perspective, particular attention must be paid to **shipping, wind energy, connection lines and the marine environment**.

- What effects are caused by offshore hydrogen productions and what are their environmental impacts?

  The **technical planning** of the project and the **current state of the environment** provide the basis for deriving the **project-related environmental impacts**. The environmental impacts are diverse and affect a large number of protected assets. To minimise the environmental impacts, **suitable avoidance and mitigation measures** must be defined as part of the plan approval procedure.

- What aspects of offshore hydrogen projects need to be considered in particular from an environmental perspective?

  Compared to established offshore projects, **hydrogen platforms and pipelines have additional and, in some cases, more intense parameters that have an impact on the environment**. These parameters require **particular attention in future approval processes**. In the case of hydrogen platforms, the new parameters are mainly related to operational aspects of the electrolysers. In contrast to electricity connections, an offshore hydrogen production requires more platforms, which also results in higher environmental impacts. The construction and operation of a pipeline differs from offshore cables in terms of several parameters. Depending on the type of pipeline installation, the parameter area use, insertion of hard substrate, temperature changes in the surrounding sediment and lower water column, underwater noise Emissions and disturbances due to the installation vessel are important parameters with possible environmental impacts that must be considered in the plan approval procedure. **At the current stage, it cannot be conclusively determined whether the molecule- or electron-based system is more advantageous from an environmental perspective.**

8 Legal perspective

Guiding questions

- What are the legal requirements for the construction and operation of offshore hydrogen production plants in the German EEZ?
- Which conditions must be met to qualify hydrogen as ”green hydrogen”?
- Which legislative action is required to facilitate achieving the German government`s targets for offshore electrolysis? How does the exclusion of mixed connections under current German law compare with the regulatory framework of neighbouring countries in Europe?

8.1 Introduction & Guiding questions

The production of green hydrogen by offshore electrolysis is an integral part of the instrument mix of the updated Federal Government's National Hydrogen Strategy of July 2023. The 2030 target for domestic hydrogen capacity has been doubled to 10 GW, of which 1 GW or 10% are to be contributed by offshore electrolysis. Next to onshore electrolysis and the import of hydrogen and hydrogen derivatives offshore hydrogen production is thus to become a central and indispensable source of supply for the evolving hydrogen economy.[14]

However, this means that government expectations for the development of offshore hydrogen electrolysis go well beyond the original, essentially open-ended testing purpose of Germany’s current offshore hydrogen legislation.[15]

8.2 Offshore hydrogen production in the German EEZ under current law

Subsequently, the current legal conditions for the installation and operation of the devices necessary for offshore electrolysis are presented. Authoritative statutory basis is the Federal offshore wind power act (WindSeeG).[16] Pursuant to its sec. 2 para. 1 no. 3 the WindSeeG regulates the permitting, installation, commissioning and operation of wind energy installations on the sea. This includes other energy production facilities, offshore connection cables and transportation lines which export energy or energy carriers from wind energy installations or from other energy production facilities in so-called other energy production areas.

8.2.1 Offshore hydrogen production facilities are subject to the WindSeeG

The future production of offshore hydrogen is to be carried out by wind turbines (WT) and electrolysers (EL), including the necessary pipeline infrastructure, in the exclusive economic zone (EEZ).

Wind turbines (WTs) in the EEZ fall under the definition of offshore wind energy installations in accordance with sec. 3 no. 11 WindSeeG. EL are categorised as so-called other energy production

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[14] Cf. Fortschreibung der Nationalen Wasserstoffstrategie, NWS 2023, BMWK, July 2023, p.8; https://www.bmwk.de/Redaktion/DE/Wasserstoff/Downloads/Fortschreibung.html: the updated National Hydrogen Strategy stresses the urgent need to safeguard sufficient supply of hydrogen: *In order to ensure the rapid development and ramp-up of the hydrogen market and to meet the expected demand, especially in the transformation phase,*
and thus enable the technological switch to hydrogen, at least until sufficient green hydrogen is available other colours of hydrogen will also be used, in particular low-carbon hydrogen from waste or natural gas in combination with CCS; p.4.

[15] See sec. 4 para 3 WindSeeG. The explanatory memorandum to the Federal act introducing the relevant stipulations for building offshore hydrogen installations also stresses that, *other energy production areas offer space to test the practical feasibility of innovative concepts for energy generation without a grid connection*, BT-Drucks. 19/5523 of 6.11.2018, p. 124.

[16] Windenergie-auf-See-Gesetz (WindSeeG), Offshore Wind Energy Act of October 13, 2016 (Federal law journal/BGBl. I p. 2258, 2310), last amended by art. 10 of the Act of May 8, 2024 (BGBl. I No. 151).

installations in accordance with sec. 3 no. 8 WindSeeG. In addition to installations for the generation of electricity at sea from renewable energy sources other than wind, these also include installations to produce other energy sources, in particular gas, or other forms of energy, in particular thermal energy.[17]

8.2.2 Requirement for planning approval (Planfeststellung)

Pursuant to sec. 65 para. 1 no. 1 WindSeeG, the construction and operation of offshore wind turbines and other energy production facilities in the EEZ as well as the associated grid infrastructure[18] and the technical and constructional ancillary facilities necessary for the construction and operation of the turbines, are governed by part 4 of the WindSeeG (sec. 65-92). WTs and electrolysers (Els) for offshore hydrogen production require planning approval in accordance with sec. 66 WindSeeG. The Federal Maritime and Hydrographic Agency (Bundesamt für Seeschifffahrt und Hydrographie - BSH) is the competent authority pursuant to sec. 66 para. 2 WindSeeG and should issue the permit within 18 months (sec. 69 para. 4 s. 1 WindSeeG) and limit it to 25 years (sec. 69 para. 7 s. 1 WindSeeG).

8.2.3 License award in the area tender procedure is prerequisite for planning approval application

Pursuant to sec. 67 WindSeeG, however, the application for a planning approval procedure may only be submitted by a party which has before been awarded a license for the area to which its project plan relates. Corresponding proof of the award of a license for the area in question must be submitted as part of the project plan in accordance with sec. 68 para. 1 no. 1 WindSeeG.

Sec. 92 WindSeeG stipulates that the BSH must determine the authorised applicant for the other energy production areas of the EEZ defined in the maritime Area Development Plan (Flächenentwicklungsplan, FEP) by means of a tendering procedure. According to the definition in sec. 3 no. 8 WindSeeG, the other energy production areas are intended for the construction of WT at sea and other energy production facilities with both not being connected to the grid. Other energy production areas must also be located outside of areas within the meaning of sec. 3 no. 3 WindSeeG, i.e. outside of marine areas intended for the construction and operation of offshore WTs which are connected to the electricity grid. EL in areas for OWFs with grid connections are not provided for by the law.

The prerequisites for applying for planning approval for offshore electrolysis facilities are therefore the designation of other energy production areas (see 8.2.4. below) and the applicant's successful participation in the area tendering process (see 8.2.5. below).

8.2.4 Designation of other energy production areas in the FEP

Other energy production areas are determined by the BSH`s maritime area development plan (Flächenentwicklungsplan - FEP), which, in accordance with sec. 4 para. 1 s. 1 WindSeeG, defines technical planning specifications for offshore energy installations in the EEZ. Pursuant to para. 3, the FEP can make stipulations for offshore wind energy installations and other energy production facilities which are not connected to the grid with the aim of enabling the practical testing and implementation of innovative energy production concepts without grid connections. This should be done in a spatially organised and land-saving manner. Regarding possible spatial and technical specifications in the FEP, the BSH is bound by further statutory requirements, in particular sec. 5 WindSeeG.

The currently valid FEP 2023 provides for only one other energy production area in the North Sea, labelled SEN-1. The spatial extent of SEN-1 has been expanded to 101.61 km^2 compared to the

[17] Cf. the explanatory memorandum to the law, which explicitly refers to offshore hydrogen electrolysis as an example of `other` energy production, BT-Drucks. 19/5523 of 06.11.2018, p. 124.
[18] Grid infrastructure comprises offshore connection lines, installations for the transmission of electricity from offshore wind turbines and installations for the transmission of other energy sources from offshore wind turbines or other energy generation installations.

previous FEP However, in contrast, a second other energy production area, labelled SEO-1, which had been included in the previous FEP has been cancelled. In addition to sec. 3 no. 8 WindSeeG ruling out electricity grid connections, the FEP 2023 excludes the (legally possible) laying of a cable to connect SEN-1 to land, for example to an electrolysis plant, as this option is considered an "inefficient connection option from a spatial perspective".[19]

Currently, the FEP 2024 is being prepared. There is a discussion on creating other energy production areas in the north-western parts of the German EEZ. However, the latest draft of the upcoming FEP 2024 does not foresee any such extensions of other energy production areas in the North Sea[20].

8.2.5 Tender to determine authorised applicants for planning approval

The invitation to tender for authorised applicants pursuant to sec. 92 WindSeeG builds on the provisions of the ordinance on other energy production areas (SoEnergieV)[21]. The ordinance is based on sec. 96 no. 5 WindSeeG and provides for the regulation of the award procedure as well as for specifications for the securities to be provided and realisation deadlines for the offshore project.

To participate in the tender, the bidder must submit a comprehensive project description and an economic and financing plan in accordance with sec. 8 para. 2 and 3 SoEnergieV. The award decision is made in accordance with sec. 9 SoEnergieV on the basis of a points-based evaluation system using the following criteria: (1) expected annual energy volume of the final energy source (2) energy efficiency in the course of conversion and transport (3) technology maturity (4) scalability of the project (5) costs of energy provision and (6) foreseeable, significant impact on the marine environment. If there are no grounds for exclusion, the BSH must grant the desired application authorisation for plan approval to the bid with the highest evaluation score. This must be done within four months after the bidding date pursuant to sec. 12 para. 1 no. 5 SoEnergieV.

Subsequently, the party entitled to submit the application is bound by the realisation deadlines set out in sec. 14 SoEnergieV. It must submit the necessary application documents for plan approval to the BSH within 24 months of being notified of the granting of the application authorisation. Once the planning approval decision has been issued, proof of financing for the project must be provided within a further 24 months and proof of the start of construction must be submitted within another 12 months. The technical operational readiness of the facilities must be demonstrated within 52 months of the planning approval decision being issued.

If these deadlines are not met, penalties of at least 30% of the security provided[22] may be imposed in accordance with sec. 15 para. 1 and 2 SoEnergieV, unless the project developer can prove that he is not at fault. Irrespective of the payment of a penalty, the SoEnergieV also provides for the

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[19] Cf. FEP 2023, p. 88.

[20] Cf. Draft FEP2024, p. 54 and 110; https://www.bsh.de/DE/THEMEN/Offshore/Meeresfachplanung/Laufende_Fortschreibung_Flaechenentwicklungsplan/Anlagen/Downloads_Entwurf_FEP/Entwurf_FEP.html;jsessionid=A5FB7E583364CB26F4E17E22E6E8F86B.live11314.

[21] Sonstige-Energiegewinnungsbereiche-Verordnung (SoEnergieV), Other Energy Recovery Areas Ordinance of September 21, 2021 (BGBl. I p. 4328), last amended by art. 11 of the Act of July 20, 2022 (BGBl. I p. 1325).

[22] Pursuant to sec. 7 s. 3 SoEnergieV, the amount of the security is EUR 2 per square meter and is to be based on the size of the other energy production area as defined in the FEP or the corresponding sub-area to which the bid relates. Accordingly, an amount of up to EUR 203.22m would be at risk for the developing of the entire SEN-1 area given its size of 101.61 square kilometres.

revocation of the application authorisation if the timely proof of financing or the timely notification of the start of construction is not provided.[23]

8.3 Requirements for the qualification as green hydrogen

Hydrogen production must meet a certain green, i.e. renewable quality to be eligible for direct financial support.[24] The green quality, however, is not a prerequisite for project approval under the WindSeeG and it is also not part of the evaluation system in the area-related tenders for application authorisation.

The German government's National Hydrogen Strategy defines green hydrogen as follows:

„Green hydrogen is produced by water electrolysis, whereby only electricity from renewable energy sources is used for electrolysis. Regardless of the electrolysis technology selected, the production of hydrogen is CO_2-free, as the electricity used comes 100 per cent from renewable sources and is therefore CO_2-free."[25]

Requirements for green hydrogen are defined by the Delegated Regulation (EU) 2023/1184[26] supplementing the Renewable Energy Directive (EU) 2018/2001 which is binding for the German legislator as part of its obligation to implement the third Renewable Energy Directive.

The requirements to be met by green hydrogen will be regulated in a Federal Government ordinance in accordance with sec. 93 Renewable Energy Act (Erneuerbare-Energien-Gesetz - EEG)[27] which contains the general prerequisite that only electricity generated from renewable sources which has not received financial support may be used for producing green hydrogen.[28] In addition, the ordinance will regulate spatial and temporal requirements for the combined production of renewable electricity and hydrogen as well as specifications for the required commissioning date of the plant for electricity production and corresponding verification. Currently, the ordinance is still pending.[29]

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[23] For the future, the Federal Ministry for Economics and Climate (BMWK) was planning to carry out funding calls prior to the area-related tenders. This way project sponsors could apply for investment funding for WTs, EL and hydrogen transport pipelines in a bidding process based on the lowest funding requirement. Participation in the funding call would be optional and not a necessary condition for participation in the following area-related tenders. BMWK envisaged the first funding call for the SEN-1 area after state aid approval of the funding guideline by the EU Commission. It is unclear, whether the idea for a call for funding is currently still being pursued. Cf. Marktkonsultation Eckpunkte Förderrichtlinie zur Erzeugung von grünem Wasserstoff auf See: „Förderrichtlinie Offshore-Elektrolyse";
https://www.bmwk.de/Redaktion/DE/Downloads/E/marktkonsultation-eckpunktepapier-foerderrichtlinie-offshore-elektrolyse.pdf?__blob=publicationFile&v=1.

[24] Direct financial support of hydrogen production is limited to the production of green hydrogen, Fortschreibung der Nationalen Wasserstoffstrategie, NWS 2023, BMWK, July 2023, p.3; https://www.bmwk.de/Redaktion/DE/Wasserstoff/Downloads/Fortschreibung.html.

[25] Die Nationale Wasserstoffstrategie, BMWi, June 2020, glossary, p. 29. https://www.bmwk.de/Redaktion/DE/Publikationen/Energie/die-nationale-wasserstoffstrategie.html.

[26] Commission Delegated Regulation (EU) 2023/1184 of 10 February 2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a Union methodology setting out detailed rules for the production of renewable liquid and gaseous transport fuels of non-biological origin, OJ L 157, 20.6.2023, p. 11–19.

[27] Renewable Energy Act of 21 July 2014 (BGBl. I p. 1066), last amended by art. 1 of the Act of 8 May 2024 (BGBl. 2024 I No. 151).

[28] Cf. Report of the Parliamentary Committee on Econimics and Energy (Ausschuss für Wirtschaft und Energie), BT-Drucks. 19/25326, p. 30 which explicitly refers to minimum standards („Mindestvoraussetzung").

[29] In contrast, the Ordinance on the inclusion of electricity-based fuels and co-processed biogenic oils in the greenhouse gas quota of 17.04.2024 (37. BImSchV), which also refers to green hydrogen has already been passed, BGBl. 2024 I Nr. 131).

Pursuant to art. 5-7 of the Delegated Regulation, the main criteria for qualification as green hydrogen are the additionality of the renewable electricity generation being used, i.e. the creation of new generation capacities, as well as the temporal and geographical correlation of electricity and hydrogen production. According to the system of the Delegated Regulation, a distinction must be made between electricity supply through direct lines and grid-connected electricity supply for hydrogen production.

1. Electricity supply via direct line

If hydrogen electrolysis is carried out using electricity supplied via a direct line, this must be verified in accordance with art. 3 of the Delegated Regulation. If there is also a grid connection in place, an intelligent metering system must be used to prove that no electricity was drawn from the grid to produce hydrogen. To fulfil the additionality criterion the corresponding electricity generation plant must have been commissioned no earlier than 36 months before the EL.

2. Electricity supply via grid connection

If the electricity used for hydrogen production is procured via a grid connection, qualification as green hydrogen is possible in the following cases:

A. The EL is located in a bidding zone in which the average share of renewable electricity exceeded 90% in the previous calendar year. In addition, the production of renewable fuels must not exceed a maximum number of hours set in relation to the share of electricity from renewable energy sources in the bidding zone (art. 4 para. 1 Delegated Regulation - “90% model”);
B. The EL is located in a bidding zone in which the emission intensity of electricity is less than 18 g CO_2 equivalent/MJ. In addition, the hydrogen producer is obliged to conclude electricity supply contracts for renewable energies, through which electricity is generated at least in the amount specified as fully renewable. In addition, the conditions of temporal and spatial correlation must be met (Art. 4 para. 2 Delegated Regulation - "climate model");
C. The electricity taken from the grid is used for hydrogen production during a redispatch period. Proof is required that electricity generation plants using renewable energy sources have been re-dispatched downwards and that the electricity used for hydrogen production has reduced the need for re-dispatching accordingly (Art. 4 para. 3 Delegated Regulation - "redispatch model");
D. Fulfilment of the criteria of additionality as well as geographical and temporal correlation. This requires supply of the full amount of electricity used for hydrogen production via own generation or a PPA from renewable generation facilities which were commissioned no earlier than 36 months before the commissioning of the EL and which have not received state aid at any time. In addition, the power used for hydrogen production must have been generated in the same calendar month (from 2030 on in the same hour) and within the same bidding zone -(Art. 4 (4) Delegated Regulation - "grid electricity model").

In case of direct line supply the green quality can easily be met. The approach corresponds with the off-grid hydrogen production as foreseen by the WindSeeG. In case of a power grid connection the "90% model" and the "climate model" appear to be realistic in the future event of the establishment of offshore bidding zones and/or through the progressive increase of the share of renewables in electricity generation beyond 90%. The "redispatch model" is already a suitable option if corresponding surplus electricity is being used. The strictest requirements would apply to the use of grid electricity via a PPA.

8.4 Legislative adaptations to achieve government targets for offshore hydrogen production

If offshore hydrogen production is to provide a relevant share of Germany`s future electrolysis capacity the existing legal framework should be fit for purpose and, where necessary, further improved.

8.4.1 Introduce quantified statutory targets for offshore hydrogen capacities

With the updated National Hydrogen Strategy and its target of 1 GW offshore electrolysis capacity or 10% of Germany`s overall electrolysis capacity in 2030, government expectations go clearly beyond the previous legislative purpose of the WindSeeG for other energy production areas. In 2018 the legislative goal was simply to "create a space to test the practical feasibility of such innovative energy generation concepts"[30]. This original testing purpose has been replaced by a quantified expansion target.

It seems logical to enshrine the hydrogen expansion targets in the same way in law as the targets for renewable power generation in the EEG and WindSeeG.

Codification of both the general hydrogen capacity targets and the specific offshore target would underline the equal status of the targets for renewable electricity generation and electrolysis capacity in the German government's 2023 climate protection program,[31] Both goals must be met to achieve Germany`s GHG reduction targets. Such codification would not be purely symbolic but would have a practical impact, as can be seen in the designation of other energy production areas in the FEP2023 which prioritises meeting the statutory targets of sec. 4 para. 2 no. 1 WindSeeG for offshore wind connected to the electrical system over the development of offshore electrolysis:

„The designation of additional other energy production areas would further exacerbate the need to identify additional potential areas and the associated competition for utilisation. Due to the statutory targets for the expansion of offshore wind turbines that are connected to the grid, this use is prioritised over the identification of additional other energy production areas.[32]

If other energy production areas are respectively deprioritised the targeted development of offshore hydrogen production is endangered. In fact, the holistic management of the energy transition through quantified government targets is called into question if some of its quantified (sub-)targets can simply be ignored or set aside by public authorities due to a lack of statutory status.

8.4.2 Enable mixed connection concepts for offshore hydrogen production

Currently, there is a statutory exclusion of power grid connections for WTs and ELs for offshore hydrogen production which follows from the wording and system of the WindSeeG. The statutory definition of other energy production areas in sec. 3 no. 8 WindSeeG and the regulatory purpose laid out in sec. 1 SoEnergieV[33] are expressly limited to installations without a grid connection. The term `grid` is to be understood as the electricity grid for general supply within the meaning of sec. 2 no. 35 EEG[34]. The landfall connection via a power line is only considered if the discharged electricity would be fully consumed immediately without ever being fed into the grid. This could be

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[30] Sec. 4 para. 3 WindSeeG and Explanatory Memorandum on sec. 3 no. 8 WindSeeG, BT-Drucks. 19/5523, p. 124.

[31] The target of 10 GW of electrolysis capacity in 2030 is included in both the 2021 coalition agreement and the German government's 2023 climate protection programme. According to the updated National Hydrogen Strategy of 2023, 1 GW of electrolysis capacity is to be achieved offshore. Like the expansion targets for renewable energies, it is a necessary building block - as part of the measures in the industry sector - for achieving a 65% reduction in greenhouse gases as stipulated by sec. 3 para. 1 no. 1 of the Federal Climate Protection Act.

[32] FEP 2023, p. 88; https://www.bsh.de/DE/THEMEN/Offshore/Meeresfachplanung/Flaechenentwicklungsplan_2023/flaechenentwicklungsplan_2023_node.html.

[33] In contrast to offshore connection lines to the onshore grid according to sec. 3 no. 5 WindSeeG, the WindSeeG refers to connection infrastructure for other energy recovery areas in sec. 4 para. 3 s.2 WindSeeG as lines or cables that transport energy or energy sources or of systems for the transmission of hydrogen from other energy recovery areas.

[34] Cf. Kirch/Huth, Die Erzeugung von grünem Wasserstoff durch Windenergieanlagen auf See, EnWZ 2021, 344 (347).

in an onshore EL without a grid connection[35]. In contrast, there is no restriction on the discharge of the hydrogen produced.

There are numerous reasons to question the current exclusion of mixed grid connections:

8.4.2.1 Own power consumption of WTs and Els

The WTs' and ELs' own power consumption needs already speak against a categorical exclusion of power grid connections. If the power supply for rotor blade adjustment, wind direction tracking or obstruction lighting etc. cannot be provided directly from the WT operation due to calm wind conditions, the electricity required for operation must be provided either from the grid or from an electricity storage system. An external power supply for WT operation is at least highly advisable for technical reasons alone.[36]

8.4.2.2 System advantages: security of supply and efficient integration of renewables

The power grid connection of offshore electrolysis enables flexibility options which become increasingly important: Power grid integration allows to use surplus electricity generated both onshore and offshore for hydrogen production and can thus help to avoid unwanted curtailment of renewable generation.[37] The updated National Hydrogen Strategy stresses the important flexibility options 'system-serving electrolysis' can provide and thus help to limit the need to expand the electricity grid.[38]

In case of capacity shortages in the grid WTs otherwise used for hydrogen production can jump in and help maintain system adequacy and security of power supply. The shared use of landfall grid connections with WTs for grid electricity production can allow for higher and thus more efficient line utilisation.[39] Depending on the costs of the grid connection, the flexibility to use offshore WT for both offshore electrolysis and electricity feed-in can improve the economic efficiency of operation and respectively reduce the need for subsidisation. At these advantages, which are desirable from an energy industry perspective, are ruled out a priori by the current legislation.

8.4.2.3 Non-restrictive connection regulation in other European countries and objectives of NSEC (work in progress)

The categorical exclusion of electricity grid connections for offshore electrolysis in Germany is not in line with the technology-open developments in offshore electrolysis in neighbouring European countries. It also complicates reaching the common goal of the countries bordering the North Sea to enable a coordinated and integrated development of renewable energies as part of the North Sea Energy Cooperation (NSEC).

Other European countries and partners in NSEC like the Netherlands, the UK, Denmark and Belgium are not only refraining from such bans on electricity grid connections for offshore hydrogen installations, but instead there is a visible tendency to recognise and explore the potential advantages of combined hydrogen and electricity grid connections.

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[35] BT-Drucks. 19/5523, p. 123.

[36] Cf. Kirch/Huth, Die Erzeugung von grünem Wasserstoff durch Windenergieanlagen auf See, EnWZ 2021, 344 (347) who consider a landfall connection to the onshore grid to be indispensable. Alternatively, one could imagine supply connections from other offshore wind generators or substations which are not part of landfall grid connections within the meaning of sec. 3 no. 5 WindSeeG as the latter are part of the supply grid pursuant to sec. 17d para. 1 s. 3 EnWG.

[37] According to the Federal Government's response of October 30, 2023, to a minor inquiry from the Bundestag, offshore wind power is particularly affected by curtailments, with a share of the reduction in offshore wind power generation of 24% in Q1/2023; see BT-Drucks. 20/9016, p. 2.

[38] Cf. Fortschreibung der Nationalen Wasserstoffstrategie, NWS 2023, BMWK, July 2023, p. 6; https://www.bmwk.de/Redaktion/DE/Wasserstoff/Downloads/Fortschreibung.html.

[39] Sec. 5 para. 4 no. 1 WindSeeG explicitly refers to efficient line utilization as a criterion for prioritization of maritime areas.

In the Netherlands, two demonstration projects for offshore electrolysis are currently being prepared. In the "Demo 1" project, a 100 MW electrolyser is to be added to an existing OWP that is already connected to the grid. Hydrogen production is to supplement the existing electricity grid connection. In the "Demo 2" project, an OWP is to be constructed in the area called Ten Noorden van de Waddeneilanden and will be used for hydrogen electrolysis. Here, too, the government's intention is to enable an additional electricity grid connection.[40]

In the UK, there are also no plans to ban grid conn offshore electrolysis. Instead, the government's hydrogen strategy emphasises the advantages of mixed-grid approaches and refers to the use of surplus electricity, the storage function and optimised sector coupling.[41] Denmark and Belgium are equally open to mixed connections.

In 2024 the Danish Co-Presidency of NSEC stressed in its agenda the significance of offshore hydrogen production and the necessity of integration in the electrical system which implies the need for mixed cinnections:

Offshore green hydrogen is projected to become a fundamental part of the energy system beyond 2030. Its widespread adoption can play a significant role in mitigating climate change by reducing greenhouse gas emissions in sectors that are challenging to electrify directly. Furthermore, integrating green hydrogen with offshore wind development bears the potential to enhance the overall impact of renewable energy initiatives. It addresses challenges related to intermittency, provides a clean energy carrier for multiple sectors, supports grid stability, and creates economic opportunities in the global shift toward sustainable energy systems.[42]

8.4.2.4 Denial of the right to grid connection under EU law

Sec. 3 no. 8 WindSeeG effectively deny offshore hydrogen producers (WT/EL operators) the right to a power grid connection. This raises the question of compatibility with European energy law.

The current Electricity Market Directive (EU) 2019/944[43] and its predecessor directives do not contain an explicit provision regarding the general obligation to connect third parties to the power grid. According to the European Court of Justice (ECJ), the right to grid access pursuant to art. 6 of the directive is also different from the concept of grid connection. Grid access refers to the right to use the electricity system whereas the term connection corresponds with the physical link to the electricity system.[44]

It is, however, acknowledged that the provisions of the directives regarding the tasks of the national regulatory authorities[45] require that connection to the transmission and distribution networks must be granted. Under EU law, network operators are obliged to connect all types of customers to their networks.[46]

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[40] Cf. Kamerbrief „Structuurvisie Windenergie op Zee“, MinEZK, 28.6.2023, S. 2 f.; https://zoek.officielebekendmakingen.nl/kst-33561-58.html.
[41] Cf. UK Hydrogen Strategy, August 2021, p. 57-59; https://assets.publishing.service.gov.uk/media/64c7e8bad8b1a70011b05e38/UK-Hydrogen-Strategy_web.pdf.
[42] The North Seas as Europe's Green Energy Hub, Danish Co-Presidency of the North Seas Energy Cooperation (NSEC) 2024, p. 6; https://www.kefm.dk/Media/638439502250796923/NSEC.pdf.
[43] Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU, OJ L 158, 14.6.2019, p. 125–199.
[44] ECJ, Sabatauskas, judgement of 9.10.2008, C-239/09, 2008, I-7523, para. 40-42.
[45] See art. 59 no. 1q and no. 7a of Directive (EU) 2019/944, resp. Art. 37 Directive 2009/72/EC.

[46] Cf. Bösche, in: Säcker, Berliner Kommentar zum Energierecht, 4. Ed. 2019, EnWG sec. 17 para. 5.

Obviously, the physical grid connection is an indispensable prerequisite for third party grid access which Is the foundation for a functioning internal market for electricity.[47] If grid connection is denied grid access is impossible.

The Electricity Market Directive of 2019 also stresses the significance of effective grid access and even calls on the Member States to actively advance and facilitate it: Promoting easy access for different suppliers is of the utmost importance for Member States in order to allow consumers to take full advantage of the opportunities of a liberalised internal market for electricity.[48] All customer groups (industrial, commercial and households) should have access to the electricity markets to trade their flexibility and self-generated electricity.[49]

Grid access must be granted based on objective, non-discriminatory and transparent criteria.[50] If these strict standards are to be effectively maintained they may not easily be bypassed by restricting physical grid connections. While Member States have legislative discretion in detailing out connection rules the right to connect as such is not at their disposal.[51]

Under German law grid connection rights are also structured differently in detail depending on the group of connectees. Next to the general connection right pursuant to sec. 17 Energy Industry Act (Energiewirtschaftsgesetz - EnWG)[52] there are a number of specific stipulations, e.g. for connections serving the general supply of end consumers at low voltage and low-pressure level according to sec. 18 EnWG or for priority connections according to sec. 8 EEG and sec. 3 of the combined-heat-and-power-act (Kraft-Wärme-Kopplungs-Gesetz - KWKG)[53].

However, a general exclusion of the right to connect to the grid is only provided for L-gas connections according to sec. 17 para. 1 s.2 EnWG, with respect to the so-called market area conversion. The term L-gas refers to low caloric natural gas which will be phased-out of the market and will be replaced by high caloric H-gas until 2030 as L-gas production in the Netherlands and Germany is largely declining. It therefore makes sense to avoid any new L-gas grid connections in the transition. Nevertheless, even in the case of L-gas gas grid operators can be obliged to connect if the applying party can demonstrate that its connection to an H-gas grid would be impossible or unreasonable for economic or technical reasons.

The reason given for the current regulation is and avoid competition for maritime areas within the framework of the FEP.[43] The limited availability of routes and route spaces for offshore connection lines may also have contributed to the exclusion of grid connections for offshore electrolysis. An indication of this assumption could be seen in sec. 5 para. 4 no. 1 WindSeeG which refers to the efficient use of offshore connection lines as a criterion for determining areas in the FEP.

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47 ECJ, Sabatauskas, judgement of 9.10.2008, C-239/09, 2008, I-7523, para. 46.
48 Directive (EU) 2019/944, recital 12.
49 Directive (EU) 2019/944, recital 39.
50 ECJ, Sabatauskas, judgement of 9.10.2008, C-239/09, 2008, I-7523, para. 46; art. 6 para. 1 Directive (EU) 2019/944.
51 Accordingly, in the Sabatauskas judgement of 2008, the ECJ acknowledged the principal right of Member States to oblige customers to connect to certain voltage levels. However, the right to get connected to the electricity grid as a prerequisite for grid access was not relativised in any way; case C 239-09, para. 49.

52 Energy Industry Act of 7 July.2014 (BGBl. I p. 1970), last amended by art. 26 of the Act of 15. July 2024 (BGBl. 2024 I No. 236).
53 Combined-Heat-and-Power-Act of 21 December 2015 (BGBl. I p. 2498), last amended by art. 9 of the Act of 20. December 2022 (BGBl. I p. 2512).

Against this background, the question arises as to whether the complete exclusion of any electricity grid connection in the case of offshore electrolysis can be justified.

The reason given for the current regulation is to avoid competition for maritime areas within the framework of the FEP[54], i.e. to reserve sufficient maritime space for offshore WT producing for general electricity supply. The limited availability of routes and route spaces for offshore connection lines may also have played a role.

However, it seems at least questionable whether the blanket exclusion of grid connections for offshore electrolysis is appropriate in this respect.

The exclusion of landfall grid connections for offshore hydrogen facilities is not necessary to safeguard reaching the expansion targets for grid connected offshore wind power as stipulated by sec. 1 para. 2 WindSeeG. The requirement of additionality (and partly the mandatory use of non-subsidized renewable power) to qualify for green hydrogen production already protects the planned ramp-up of green power production for general electricity supply. Above all, the FEP system of allocating maritime areas to certain purposes offers sufficient control to control the shares of offshore wind power for general electricity supply on the one hand and for hydrogen production on the other.

8.4.2.5 Review of the requirements of the SoEnergieV

In view of the early development phase of offshore electrolysis, the political desire for rapid capacity expansion and the need for planning certainty for project sponsors, it also seems sensible to review the requirements of the SoEnergieV once again.

This applies in particular to the specified realisation deadlines and the threat of penalties. The system of realisation deadlines was formulated based on the regulations for offshore WTs serving general electricity supply. However, there are a couple of differences in offshore hydrogen production compared to offshore WT feeding into the onshore electricity system which should be sufficiently reflected. Offshore hydrogen production means

(1) considerably more complexity: This is due to the combination with electrolysers including water treatment and desalination as well as the need for hydrogen transport including compressor stations to bring the hydrogen to different pressure levels from production to interim storage and pipeline transport. On top of this all the different components need to be coordinated and centrally steered in line with the corresponding power availability.

(2) a lack of experience in both construction and operation. The development of offshore electrolysis is running 15-20 years behind “traditional” offshore WTs feeding only into the power grid and

(3) there is a larger dependency on external factors outside the sphere of influence of the project developers including permitting issues and market uncertainties like the development of demand for hydrogen.

(4) Unlike in EEG or offshore wind tenders without EL, the penalties for offshore electrolysis projects are not offset by a general subsidy system.

Given these specific circumstances the realisation plan should foresee extension options, the penalty payments should be reviewed, and securities should be returned as quickly as possible.[55]

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[54] Cf. Explanatory Memorandum, regarding sec 3 no.8 WindSeeG, BT-Drucks. 19/5523, p.124. see also Kirch/Huth, Die Erzeugung von grünem Wasserstoff durch Windenergieanlagen auf See, EnWZ 2021, 344 (347).
[55] For a more detailed analysis of the SoEnergieV see Kirch/Huth, Die Erzeugung von grünem Wasserstoff durch Windenergieanlagen auf See, in: EnWZ 2021,344 (350f.).

9 Recommendations for Action

Based on the comprehensive analysis of this study, the hypotheses stated in Chapter 1.2 can be verified. Mixed connection concepts can significantly contribute to a socio-economic beneficial development of Germany's EEZ zones 4 and 5. Mixed grid connections can reduce costs not only for the projects mentioned, but for the integration of OWFs in the North Sea as a whole. Together with the higher operational flexibility of mixed connection concepts and their ability to enable more potential revenue streams (electricity and hydrogen), mixed connection concepts make investments in far out OWFs more economically attractive. By improving the economics of OWFs, further domestic production of hydrogen can be secured in the long term, which reduces the risk of import dependency and paves the way for a successful energy transition.

The following applies for the investigated OWF areas:

- **Mixed connection concepts can be implemented at comparable system cost to singular connection concepts.** Our analyses show that implementation is cheaper than an electrical connection and, depending on the design, only marginally more expensive than a pure hydrogen connection.

- **Mixed connection concepts increase revenue potentials by means of flexibility.** The revenue potential of the hydrogen-dominated mixed connection concept is more than double that of an all-electric one. This significantly reduces the need for socially funded support schemes to enable offshore investments.

- **In mixed grid connections, electrolysis reduces the impact on the electric grid, but provides electricity when it is short.** In our example, the hydrogen-dominant connection system reduces electrical feed-in by around 80%. When electricity is short, it is supplied at maximal available capacity. Long-term, the output of hydrogen can be increased by an average of 9% by using surplus onshore electricity - mid-term even more. Positive effects on congestion management are likely but should be analysed in further studies.

- **The bidirectional utilisation of offshore cables in mixed connection concepts increases the capacity factors of cables and electrolysers and contributes to a more effective utilisation of scarce space in the German EEZ.** The utilisation of the offshore electrolysers and cables can potentially be increased by several 10% compared to singular connection concepts. The actual utilisation of cables and electrolysers is case-dependent, but higher overall.

Mixed connection concepts are the most favourable connection concept under certain pre-requisites but legally excluded. To harvest the full offshore potential and avoid the risk of postponing necessary investments in OWFs and domestic hydrogen production, a three-step approach is proposed as starting point for further discussions.

The three-step approach (see Figure 42) includes the following recommendations for action.

Step 1 "Demonstration": Aim to prove the feasibility. Enable demonstration projects for offshore electrolysers to gain initial practical experience in planning, construction, operation and the environmental concept applied. Identify potential for improvement. This step should include rapid, small-scale demonstrator projects for (initial) practical experience, accompanied by the ambition to develop a technical concept for large-scale offshore hydrogen systems. This is to be underpinned by the aim of realising larger systems in the future.

- **Step 2 “Pre-commercial scale”:**
    - Learn how to get faster (in construction) and aim to get cheaper by scaling up. Prepare supply chains for ramp-up. Optimise and scale-up concept for larger systems and refinement of the environmental concept.
    - Develop a common view of all NSEC countries on an integrated system plan for the North Sea and the role of mixed connection concepts. Based on this, enable tendering of wind areas in zones 4 and 5 with the possibility of a mixed connection concept.
    - Given the German government’s 1 GW goal in 2030 for future offshore hydrogen production, the legislative framework for offshore electrolysis should be made fit for purpose. Next to abolishing the current ban for mixed connections the expansion targets for (offshore) electrolysis should be enshrined in law. Furthermore, the tendering conditions, particularly the realisation deadlines and associated penalty payments under the SoEnergieV ordinance, should be reviewed and alleviated to enhance practicability and provide the necessary planning and investment security for investors.

- **Step 3 “commercial use”:** Benefit from the experience of earlier phases and harvest the full potential of the offshore wind with pure OWFs and OWFs with offshore electrolysers connected by mixed connection concepts.

There are limitations to how much these steps can be undertaken concurrently, as each phase necessitates several years of planning, construction, and testing. Therefore, step one should be initiated immediately to fully realise the socio-economic benefits of step three at the earliest opportunity. Financial support mechanisms may facilitate a swift commencement of step one. The costs involved are minimal compared to the potential benefits of step three.

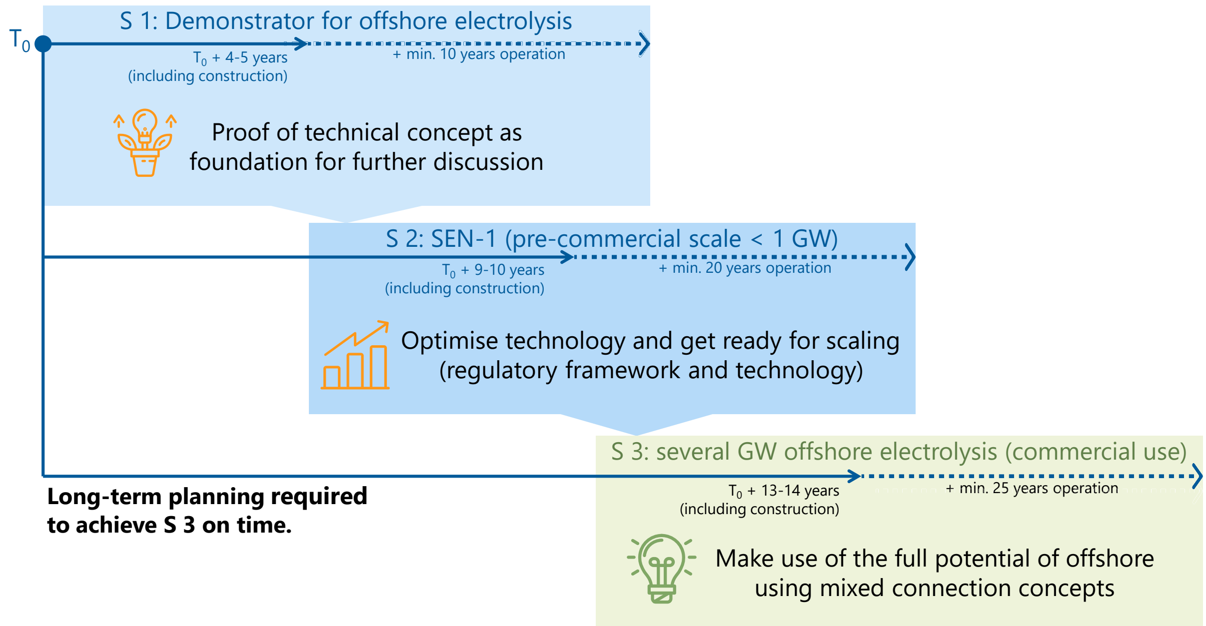

Figure 42: Three-step approach towards implementing offshore hydrogen.

APPENDIX

A. Cost assumptions

Table 8: Cost figures of electrical connection elements, offshore wind farms and hydrogen production

CATEGORY	COMPONENT	YEAR	INVEST	INCL. INSTALLATION	UNIT	SOURCE
ELECTRICAL CONNECTION	DC-Offshore Cable	-	-	3.36	m EUR / km (for 2 GW)	(ENTSO-E, 2024) Cost set 1
			-	6	m EUR / km	(ENTSO-E, 2024) Cost set 3
	DC- Onshore Cable	-	-	3.36	m EUR / km (for 2 GW)	(ENTSO-E, 2024) Cost set 1
			-	7.6	m EUR / km	(ENTSO-E, 2024) Cost set 3
			-	10.86	m EUR / km	Consortium Feedback
	AC inter array cable	-	-	0.252	m EUR / km	(North Sea Wind Power Hub Consortium, 2019)
			-	1.25	m EUR / km	(ACER, 2023)
			-	2.083	m EUR / km	Consortium Feedback
	Converter	-	-	0.25	m EUR / MW	(ENTSO-E, 2024) Cost set 1
			-	0.3	m EUR / MW	(ENTSO-E, 2024) Cost set 2
			-	0.43	m EUR / MW	Consortium Feedback
	DC-Offshore-Converter	-	-	0.55	m EUR / MW	(ENTSO-E, 2024) Cost set 1
			-	0.7	m EUR / MW	(ENTSO-E, 2024) Cost set 3
			-	0.786	m EUR / MW	Consortium Feedback
	Onshore AC Substation	-	-	28.57	m EUR / 2 GW	Consortium Feedback
			-	50	m EUR / 2 GW	Consortium Feedback
OFFSHORE WIND FARM	Wind Turbine	-	-	1.32	m EUR / MW	Consortium Feedback
		2035	-	1.74	m. W	Interpolated
		2040	-	1.68	m EUR / MW	(Danish Energy Agency, 2024)
		2045	-	1.66	m EUR / MW	Interpolated
HYDROGEN	Electrolysis	2024	1,800	3,000	EUR/kW_{el}	Expert estimation from real projects (E-Bridge)
		2030	700	1,200	EUR/kW_{el}	(Agora Verkehrswende, 2018)
			1,200	2,100	EUR/kW_{el}	(Prognos, 2020)
			1,500	2,500	EUR/kW_{el}	(Prognos, 2020)
		2035	600	1,000	EUR/kW_{el}	Interpolated
			950	1,600	EUR/kW_{el}	Interpolated
			1,300	2,200	EUR/kW_{el}	Interpolated
		2040	500	850	EUR/kW_{el}	(Zun & McLellan, 2023)
			750	1,300	EUR/kW_{el}	(Bristowe & Smallbone, 2021)
			1,000	1,700	EUR/kW_{el}	(He, et al., 2021)
		2045	400	650	EUR/kW_{el}	Interpolated
			600	1,000	EUR/kW_{el}	Interpolated
			800	1,400	EUR/kW_{el}	Interpolated
		2050	300	500	EUR/kW_{el}	(Deutsche Energie-Agentur, 2018)
			500	850	EUR/kW_{el}	(Forschungszentrum Jülich, 2020)
			700	1,200	EUR/kW_{el}	(Wuppertal Institut, 2020)

B. Environmental effects

Table 9: Summary of the construction/dismantling related, system related and operation related effects of OWT, cables, pipelines, converter platforms and hydrogen platforms

Effect	Effects of OWT	Effects of cables	Effects of pipelines	Effects of converter platforms	Effects of hydrogen platforms	Examples that cause effects
Sediment turbulence/turbidity plumes	construction/dismantling					During construction/demolition, sediment suspension and turbidity plumes can be caused by seafloor touching installation work.
Sediment shift	construction/dismantling					Sediment shifts can be caused by seafloor touching installation work, e. g. while the installation of cables and pipelines. Ground levelling with soil removal and relocation may also be required for the construction of converter platforms.
Noise emissions caused by general construction operations and vessel traffic	construction/dismantling					Noise emissions during construction operations are caused by the pile-driving work of the OWT and platform foundations (in case of pile foundations) and by the engine as well as the ship propulsion. The emissions occur in the air and in the water.

Effect	Effects of OWT	Effects of cables	Effects of pipelines	Effects of converter platforms	Effects of hydrogen platforms	Examples that cause effects
Visual disturbance caused by general construction operations and vessel traffic	construction/dismantling					Construction operations and the necessary vessel operations cause visual disturbance with scaring effects and loss of habitat for animals.
Light emissions caused by general construction operations and vessel traffic	construction/dismantling					The vessel and construction lighting causes light emissions during construction operations, which cause attraction, scaring and barrier effects for animals (especially for birds).
Use of seabed space	construction/dismantling & system					Uses of seabed space are caused by construction areas during construction/deconstruction and by the installations themselves. In the case of underground cables and pipelines, crossing structures can result in area uses. Pipelines that lay on top of the seabed are as well causing area uses.
Sediment compression	construction/dismantling					During the construction of offshore facilities such as OWT and cables, seafloor touching equipment compress the sediment due to their load.
Insertion of hard substrate	system					Usually, scour protections in the form of rockfills are installed around the foundations of OWT and platforms to protect the sediment against a washout around the foundations. Crossings of cables and pipelines are usually protected by rockfills or other hard substrates.

Effect	Effects of OWTGs	Effects of cables	Effects of pipelines	Effects of converter platforms	Effects of hydrogen platfomrs	Examples that cause effects
Obstacle in the water body	system	n/a	system (if installed on the seafloor)	system		Offshore facilities are obstacles in the water body for animals or the human activities.
Obstacle and visibility in the airspace	system	n/a	n/a	system		Installations located above the water surface are an obstacle in the airspace for animals or human use.
Light emissions	system	n/a	n/a	system		For identification and flight safety, installations in the airspace are equipped with light sources that cause light emissions. This primarily affects animals (birds, bats).
Chemical pollution	system	n/a	system	system & operation		The use of galvanic anodes as corrosion protection for offshore facilities results in the introduction of substances in the ocean. When operating converter and hydrogen platforms, antifouling additives are added to the cooling water to protect the cooling systems. The hydrogen platforms additionally discharge salt enriched water in the ocean.

Effect	Effects of OWT	Effects of cables	Effects of pipelines	Effects of converter platforms	Effects of hydrogen platforms	Examples that cause effects
Extraction and discharge of water	n/a	n/a	n/a	operation		Cooling water needs to be extracted and afterwords discharged to cool down the technical systems during operation. The heat input into the water locally changes the living conditions in the water and the properties of the water body itself.
Utilization restrictions	system					The construction of the facilities will result in utilisation restrictions in the direct surroundings of the installations. In coastal waters, the construction facilities also have a negative impact on the recreational function.
Obstacle and visibility in the airspace (through rotor movement)	operation	n/a	n/a	n/a	n/a	The operational rotor movement of the OWT represents a (moving) obstacle and affects visibility in the airspace. This has an impact on resting and migratory birds as well as bats.
Noise emissions under water operating noise	operation	n/a	n/a	n/a	n/a	During operation, OWT vibrate due to technical devices such as the gearboxes and generators. The vibrations are transmitted to the water and cause underwater noise emissions.

Effect	Effects of OWT	Effects of cables	Effects of pipelines	Effects of converter platforms	Effects of hydrogen platforms	Examples that cause effects
Visual disturbance, especially through maintenance, repair and vessel operations	operation					There is visual disturbance from the facilities due to maintenance, repair work and the associated vessel operations.
Noise emissions through vessel operations	operation					Maintenance and repair work result in regular vessel operations, which cause noise emissions.
Electromagnetic fields	n/a	operation	n/a	n/a	n/a	Cables emit electromagnetic fields during operation.
Heat emissions	n/a	operation				Cables and pipelines generate heat due to the electrical resistance or friction of the gas. The heat is emitted into the environment (sediment or water body). This changes the habitat conditions in the near surrounding and possibly the properties of the soil or water itself.

C. Considerations of Overplanting

Besides the option of electricity price risk mitigation, the combination of wind power and lower electrolysis can be more economically viable. Limiting the electrolysis capacity to 75% (MC 2) of the OWF capacity results in minor hydrogen production losses, making this an economically practical configuration from a hydrogen production viewpoint.

Due to the volatility of electricity generation, the full load hours of the electrolysis correspond to those of electricity generation and the electrolysis would mostly operate at partial load. At the same time, the investment costs would be comparatively high in view of the low-capacity utilisation. It is therefore not economically viable to design the electrolysis capacity for full utilisation of the electricity. If a certain range of the electricity generation capacity were to be curtailed, the electricity generation costs would increase, but the installation costs of the electrolysis would decrease accordingly. It can therefore be assumed that, depending on the volatility of the electricity generation time series, a cost-optimised expansion level of electrolysis can be found in relation to hydrogen production. For this purpose, the cost-optimised regulated output at which the full load hours of the electrolysis could be increased to an optimum level would have to be determined. Figure 43 shows the exemplary hourly resolved power time series of the cumulated wind capacity with 14 GW of installed capacity and a representative offshore wind generation profile. In the cost-optimal case 25% of the output is curtailed, which leads to an energy loss of around 7.2% (blue area).

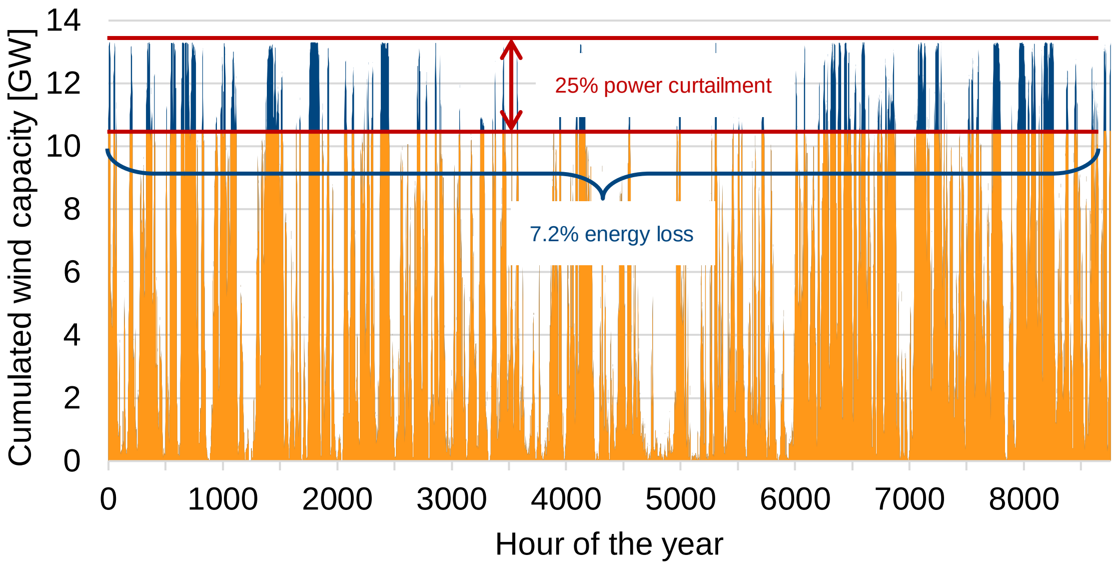

Figure 43: Output curve with hourly resolution of a cumulated wind farms (14 GW) with a curtailment of 25% (in relation to the installed capacity) and an energy loss of 7.2%

To determine the curtailment rate and the associated cost-optimised expansion capacity of electrolysis, the hydrogen production costs are calculated in discrete curtailment steps of 5 percentage points each. The resulting local minimum of the cost curve for hydrogen production defines the cost-optimised curtailment rate. Figure 44 illustrates this relationship in a comparison of Levelized Cost of Energy (LCOE), hydrogen generation costs and energy losses over various discrete curtailment rates. In this example, the cumulated wind capacity is 14 GW and a power curtailment of 25% results in an energy loss of around 7.2% and a minimum hydrogen production cost of 5.53 EUR/kg_{H2}. This means that the cost-optimal cumulated electrolysis capacity is found at 75% of the wind capacity (10.5 GW). As this short analysis is dependent on the assumed invest cost parameters of offshore wind energy and offshore electrolysis, the results are to be understood as examples. Nevertheless, the results show clearly that the cumulated electrolysis capacity should be less than the cumulated wind energy capacity regarding minimal levelized cost of hydrogen.

Combining the concepts results in additional efforts for the electrical collector system regarding the operating concept and cabling.

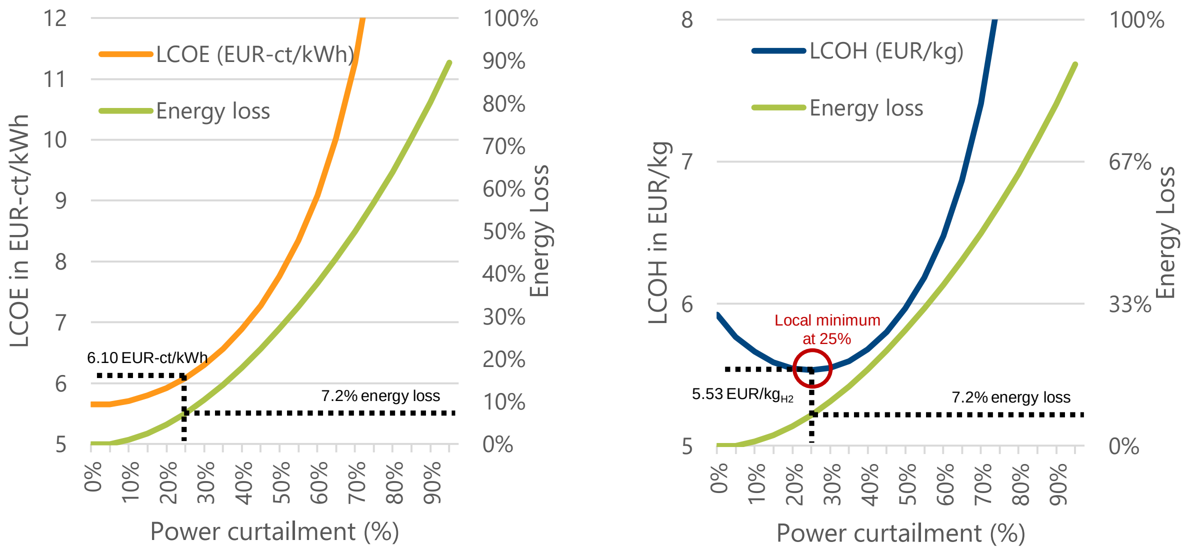

Figure 44: Exemplary determination of the cost-optimal curtailment rate in relation to the hydrogen production costs using an exemplary wind farm profile and an overall capacity of 14 GW

D. List of figures

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F. List of references

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G. Abbreviations

AC	Alternating Current
All E	Connection concept: purely electrical connection
All H2	Connection concept: purely hydrogen-based connection
APS	Announced Pledge scenario
BESS	Battery energy storage system
BImSchV	Federal Emission Control Act (Verordnung zur Durchführung des Bundes-Immissionsschutzgesetzes)
BMWK	Federal Ministry for Economics and Climate (Bundesministerium für Wirtschaft und Klimaschutz)
BoP	Balance of plant
BSH	Federal Maritime and Hydrographic Agency (Bundesamt für Seeschifffahrt und Hydrographie)
CN	Climate neutrality
CO_2	Carbon dioxide
DC	Direct Current
DET	Delayed Energy Transition
e.V.	Registered association (eingetragener Verein)
EEG	Renewable Energy Act (Erneuerbare-Energien-Gesetz)
EEZ	Exclusive Economic Zone
EL	Electrolyser
ELs	Electrolysers
EVs	Electric vehicles
EnWG	Energy Industry Act (Energiewirtschaftsgesetz)
EUA	European Union Allowances
FEP	Site Development Plan (Flächenentwicklungsplan)
GCP	Grid Connection Point
GDP	Grid Development Plan
GmbH	Limited liability company (Gesellschaft mit beschränkter Haftung)
GW	Gigawatt
GWh	Gigawatt hour
H_2	Hydrogen
HVDC	High-voltage direct current
IEA	International Energy Agency
IRR	Internal rate of Return
LCOE	Levelized cost of energy
LCOH	Levelized cost of hydrogen
MC 1	Connection concept: electricity-dominant mixed connection
MC 2	Connection concept: hydrogen-dominant mixed connection
MET	Molecule-based Energy Transition
MWh	Megawatt hour
NEP	Network development plan (Netzentwicklungsplan)
NPV	Net present value
NSEC	North Seas Energy Cooperation
NTC	Interconnection capacities
NZE	Net Zero Emission

OPEX	Operational expenditures
OWF	Offshore wind farm
OWFs	Offshore wind farms
PEM	Proton exchange membrane
PFV	Plan approval procedure (Planfeststellungsverfahren)
PPA	Power Purchase Agreement
PV	Photovoltaic
RES	Renewable energy source
RFNBO	Renewable fuels of non-biological origin
SoEnergieV	Other energy production areas ordinance (Sonstige-Energiegewinnungsbereiche-Verordnung)
STEPS	Stated policy scenario
t	ton
TWh	Terawatt hour
TYNDP	Ten-year network development plan
UK	United Kingdom
VSC	Voltage Source Converter
WACC	Weighted average cost of capital
WindSeeG	Wind Energy at Sea Act (Windenergie-auf-See-Gesetz)
WT	Wind turbine
WTs	Wind turbines

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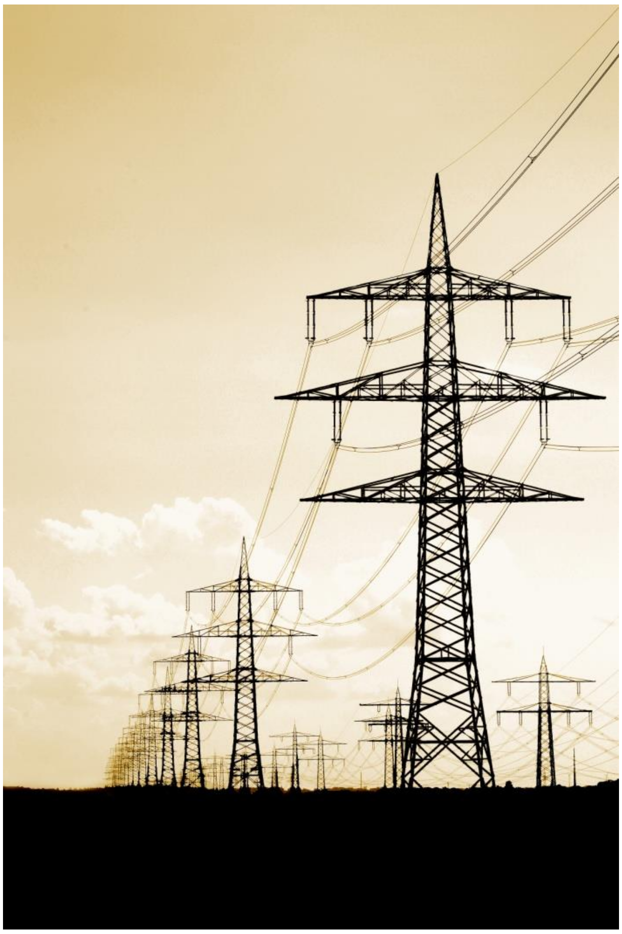

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