North Sea
Wind Power Hub
Programme

Pathway Study 2.0

Final Report

Powered by

ENERGINET gasunie TenneT

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Nomenclature

Abbreviation	Full Name
DE	Distributed Energy
EC	Electrolysis
FLH	Full Load Hours
GWe (or GW)	Expression of capacity in terms of electricity
GW_{H2}	Expression of capacity in terms of H2
IC	Interconnection
LZ	Landing Zone
NS	North Sea
NSWPH	North Sea Wind Power Hub
OWF	Offshore Wind Farm
PDC	Price Duration Curve
PtX	Power-to-X
PV	Photovoltaics
PW	Pathway
TYNDP	Ten Year Network Development Plant
VRE	Variable Renewable Energy
WT	Wind Turbine

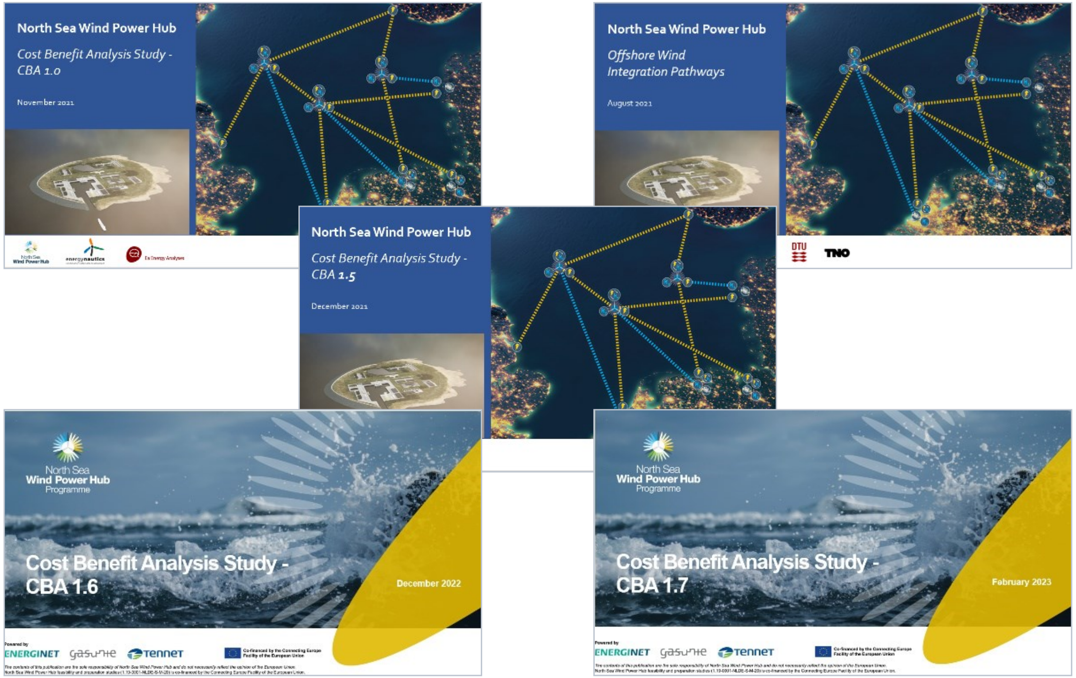
Introduction

Background

Offshore wind power is one of the large renewable energy sources (next to onshore wind and solar power) which are foreseen to ensure the green transition of the European Energy system and support the goal of net zero greenhouse gas emissions by 2050. The **North Sea Wind Power Hub** works with **Hubs-and-Spokes concepts** to facilitate the integration of large amounts of offshore wind. The Hubs-and-Spokes concept combines the deployment of offshore wind with energy exchange options, by constructing cross-border electricity grids, hydrogen pipelines and offshore hydrogen production.

The **NSWPH works with analyses of the Hubs-and-Spokes concept at different levels from the broadest system view in Pathway studies to the most detailed in Cost-Benefit-Analyses (CBA)** of impact of specific single Hubs-and-Spokes configurations. The first Pathway study was completed in July 2021, with a report highlighting key results and perspectives. In parallel, several CBA studies have been performed between the end of 2020 and 2023. The current study updates previous assumptions and methodologies to explore Offshore Wind integration Pathways in the European Energy system towards 2050, aiming at **identifying specific drivers impacting the Offshore Integration Pathways**.

The study has been carried out by Ea Energy Analyses and Energynautics, in collaboration with the NSWPH consortium.



Note: The NSWPH consortium includes TenneT, Gasunie and Energinet (https://northseawindpowerhub.eu/).
Ea Energy Analyses (https://www.ea-energianalyse.dk/en/).
Energynautics (https://energynautics.com/en/)

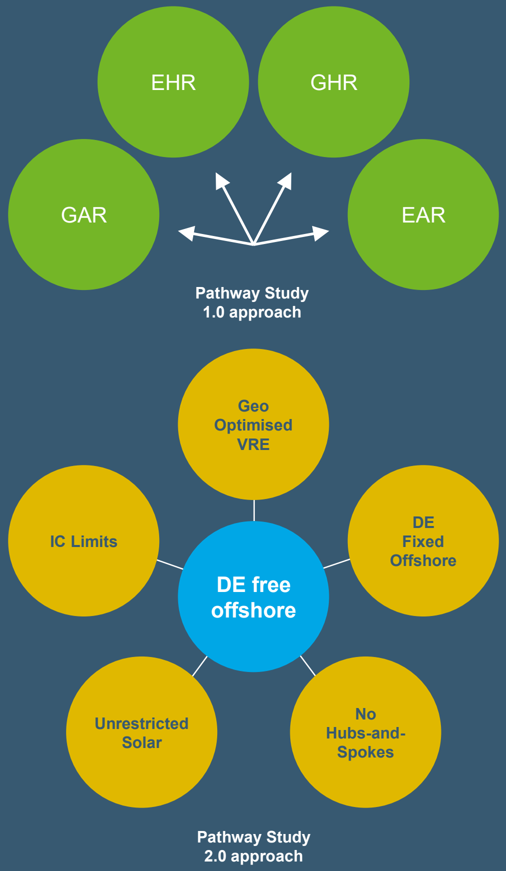
North Sea Wind Power Hub Programme
Ea Energy Analyses
energynautics solutions for sustainable development

Pathway Study 2.0 vs Pathway Study 1.0

The first key activity carried out by the NSWPH consortium was a study on **Offshore Wind Integration Pathways** (also named Pathway Study 1.0), where four pathways toward 2050 were explored. The study was completed in July 2021, with a report highlighting key results and perspectives. **Pathway Study 2.0 builds on the previous** Pathway 1.0 study to further improve data and methodologies and increase insights to integration of offshore wind in the European energy system:

- **Updated scenario data based on ENTSO-E's Ten Year Network Development Plan (TYNDP) 2022**, considering more recent developments in the pledges, plans and strategies of the various European countries, which leads to higher renewable energy targets for the key countries studied.
- **Incorporation of lessons learned and several updates to the modelling and input data approach** carried out in the period between the two studies;
- Increased focus on **better understanding specific drivers and barriers** for the integration of offshore wind by moving from a broader scenario focus to an approach in which a base case is established and several corresponding **sensitivity analyses** are conducted.

Unlike the Pathway Study 1.0, in which two roll-out pathways were analysed - NIRO vs. ICRO for all scenarios under consideration (National Incremental Roll-Out vs. International Coordinated Roll-Out) , in the Pathway Study 2.0 there is one baseline scenario based on TYNDP Distributed Energy (DE) scenario and several sensitivities.



Objectives

The research questions of the present study can be summarised below:

I. What are the **drivers and design principles for possible integration routes**, in the context of the roll-out pathway of the first and following hubs-and-spokes projects?
II. What are the key **challenges** on both a national and transnational level for the integration of offshore wind?
III. How **robust** is the hubs-and-spokes concept to various factors?
IV. How does the **first hub and spoke** project to be realised in the early 2030_s fit into the broader pathways toward 2050?

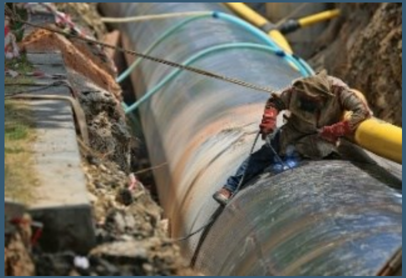
Exploration of such questions will provide thorough insights in key objectives of energy systems analyses, some of which are:

- **Deepen the understanding of the offshore wind integration** challenges on both a national (intra-zonal) level and transnational level **with updated scenario data and scenario set-ups according to developed national targets** and concrete first projects.
- **Determine the design principles** for possible integration routes, in the context of the roll-out pathway of the first and following hub-and-spoke projects, **thereby supporting decision making** for the first hub and spoke project to be realised in the early 2030s.
- Identify bottlenecks for a fast integration of offshore wind energy into the changing energy system.

Key Factors of Uncertainty

Power & H_2 demand

Power infrastructure



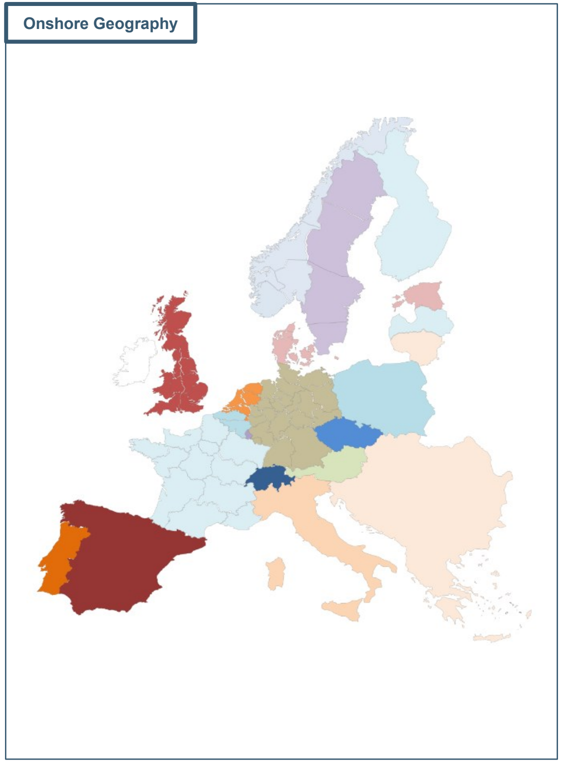
H_2 infrastructure

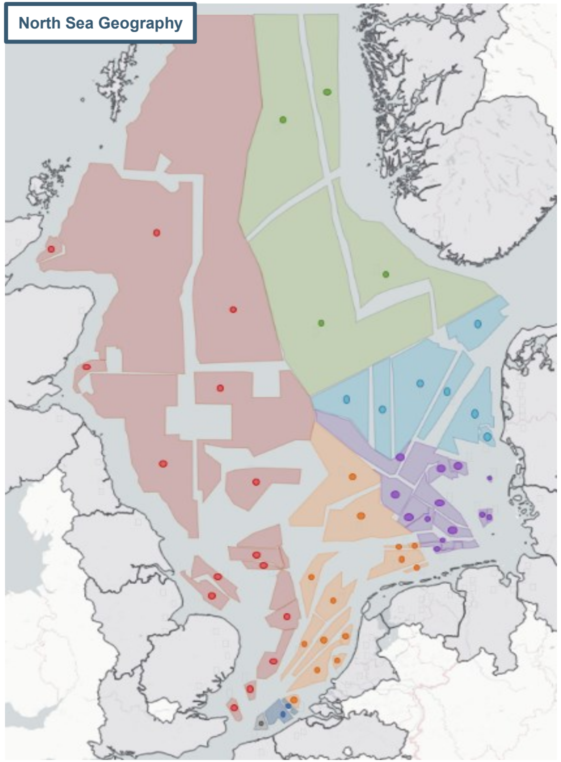
Other factors
(fuel prices, H_2 imports, PV buildout, weather)

Focus areas

This study contains focuses on system impacts of the integration of offshore wind. For this purpose, a number of assumptions and methodologies have been chosen to reflect potential integration options and challenges.

- High resolution data on potentials for offshore wind in the North Sea, including capacity potentials distributed at different sites, their potential generation profiles. DTU Wind (Technical University of Denmark) has provided valuable input to this modelling with data on 1244 sites including estimates for the impact of wakes.
- Potentials for establishing an offshore grid in the North Sea includes options for interconnecting offshore sites to both the home market and other offshore sites and markets. Both electrical and hydrogen connections are considered, and offshore electrolysis is considered at selected sites
- The onshore system around the North Sea is modelled with high geographical resolution to reflect the options to integrate offshore wind. The modelling reflects both the distribution of demand and generations capacities, as well as grid limitations in the electricity and hydrogen grid.
- The hydrogen system is modelled explicitly to reflect the hydrogen balance between generation and demand at any given time and thus adequately reflect the flexibility option, that hydrogen production can provide to improve integration of renewables.





System scenario and analyses approach

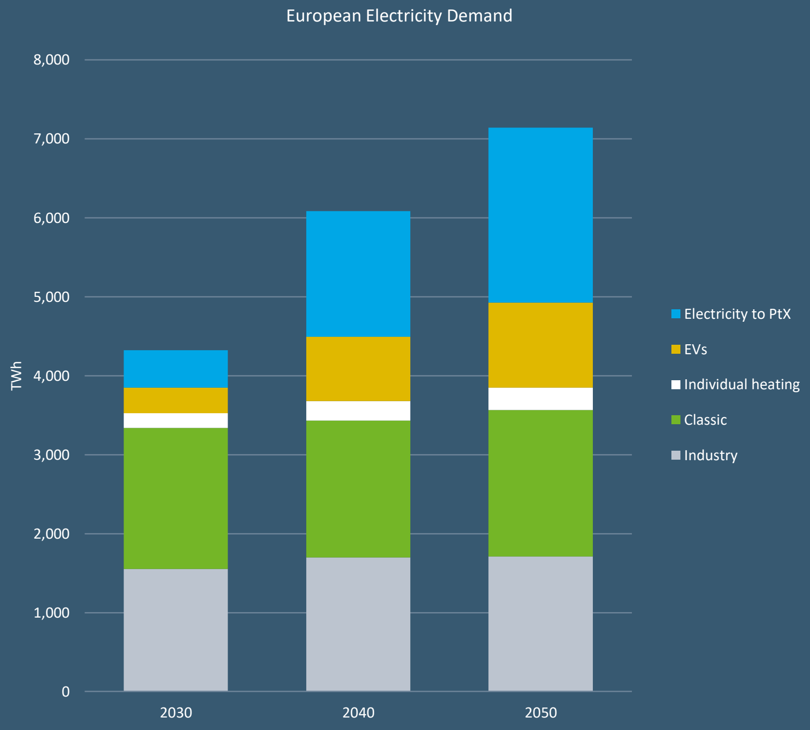
The main system scenario is based on ENTSO-E's Distributed Energy (DE) scenario defined as part of the TYNDP 2022. The scenario supports a transition of the European energy system towards net zero in 2050. For the current study, the DE-scenario is applied to define the development of end use of electricity and hydrogen, as well as the buildout of solar PV and onshore wind (varied in sensitivities). Compared to TYNDP, main differences include:

- The deployment of offshore wind and system integration by means of electricity and hydrogen grids, energy storage, peak supply capacities and hydrogen production are subject to optimisation. In the main scenario *DE Free Offshore* the amount and deployment of offshore wind is therefore not directly defined, but strongly led by the need to supply demand (hydrogen demand can also be met by imports).
- The pathway study shows higher amounts of imported hydrogen, reducing the need for local generation and thus reducing total European power generation compared to the DE-scenario. This is a result of the economic optimisation, showing especially lower buildout of offshore wind.
- The pathway study results in lower amounts of thermal based power generation, especially from based on gas.

A comprehensive overview on optimised and exogenously defined parameters is shown in Appendix II, while assumptions are defined in Appendix I. A more detailed comparison with the actual TYNDP DE scenario can be seen in the Appendices[i,ii].

Based on this setup, different integration pathways for offshore wind are analysed – supplemented with selected sensitivities, as laid out on the table below. For details, see the Description of Sensitivities.

Geo-optimised VRE	DE Free Offshore	DE Fixed Offshore	No Hubs-and-Spokes	Unrestricted Solar	IC Limits
Optimisation of distribution of solar PV and onshore wind across Europe (at same annual electricity generation)	Main scenario	Deployment of offshore wind according to ENTSO-E's DE scenario	Only radially connected offshore wind	Allowing for higher deployment of solar PV	Lower interconnection options to Iberian Peninsula and South-Eastern Europe (hydrogen and electricity grid)



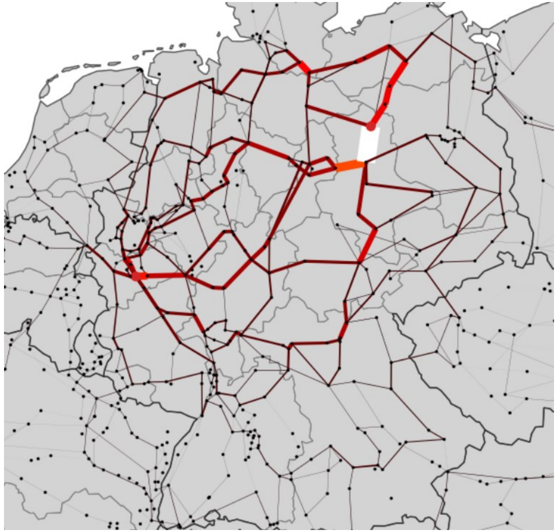
Note: Electricity use for hydrogen (PtX) is subject to model optimisation. Imported H2 quantities may reduce the illustrated needs for locally generated electricity towards PtX use.

Limitations

Some limitations have been chosen as part of the modelling process and number of scenarios. Important limitations include:

- One central scenario has been chosen for the demand development based on ENTSO-E's Distributed Energy scenario. The scenario defines both annual amounts, spatial distribution and variations in time. Other scenarios like for example ENTSO-E's Global Ambition scenario with a higher demand for hydrogen or pathways with a lower demand for hydrogen may influence the amount of offshore wind needed as well as the flexibility of demand (e.g. with electrolysers).
- The study only focuses on the production, use and import of hydrogen and does not move further down the production chain of PtX products, nor are different levels of hydrogen demand included. This could be the result of a scenario, where liquid e-fuels (e.g. ammonia) are imported instead of produced locally.
- The study incorporates assumptions on the starting system in 2030, namely with respect to starting grid for electricity and hydrogen. Variations on those starting grids have not been evaluated.
- Buildout options for generation capacities in the onshore system are predefined in the main scenario, but alternatives are explored in sensitivities focusing on onshore wind and solar power. A general change of focus on other generation technologies (CCS, nuclear) has not been explored.
- Grid limitations are reflected on high geographical resolution but are based on NTC-modelling. Load flow calculations analysing the actual physical flows and potential impacts on selected grid elements have not been included.
- Regions further away from the North Sea have been modelled in a coarser resolution, limiting the detail on transmission grid buildout needs, e.g., in Spain because of heavy deployment of solar PV.
- System operation and balances are ensured on an hourly level. Challenges with system operation on a sub-hourly level as well as reserve-requirements have not been explored.
- The study does not include explicit calculations for security of supply, which would require e.g. analyses of the impact of different weather years, as well as considerations on dimensioning faults owing to different grid buildout options.
- In general, modelling studies for 2050 are subject to large uncertainties, and only some of them could be explored in the current study.

The section on Perspectives inspires ideas of further analyses, which to some extent address the limitations mentioned here.



Note: Illustration of power flow calculation for the physical grid

Executive Summary

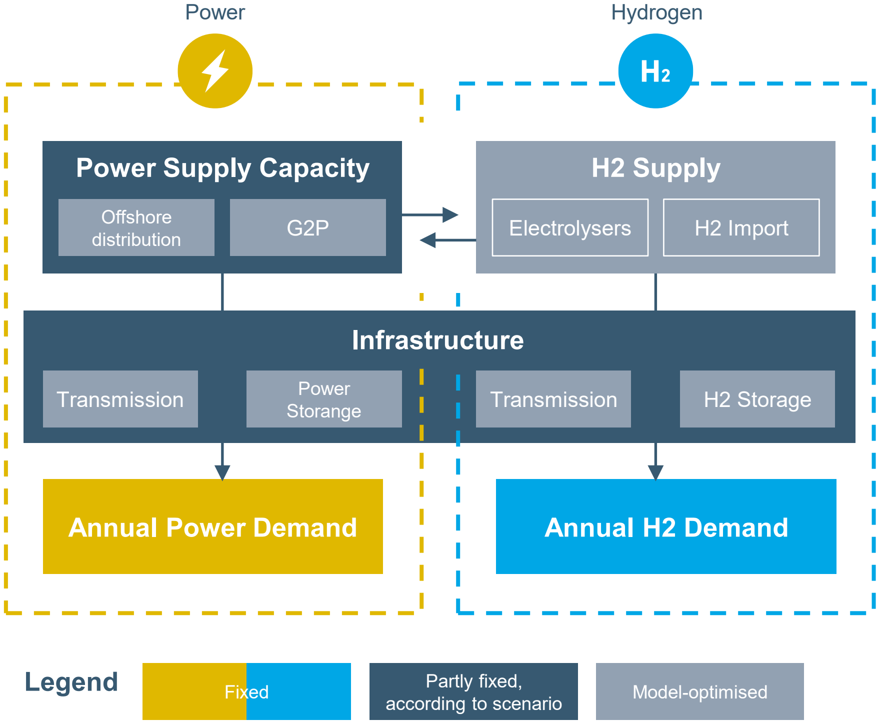
Background of the study

Dear reader,

The current study analyses **potential development pathways for the European power system with a focus on the integration of offshore wind** and the role of both electricity and hydrogen infrastructure. The ambition has been to apply a level of detail and modelling methodologies, which allow a holistic analyses without locking assumptions on central parameters. We have therefore attempted to co-optimise generation capacities, flexibility measures and grid infrastructure at high spatial granularity, and believe that this provides valuable insights when comparing different options.

Annual power and hydrogen demands are considered the driving force for the energy system and are exogenously defined **inspired by ENTSO-Es Ten Year Network Development Plan - Distributed Energy scenario (TYNDP DE)**, which ensures, that the overall energy scenario is build around the target of least a 55% reduction of emissions by 2030 (compared to 1990 levels), and a climate-neutral Europe by 2050. **Focus of the study is how this demand can be supplied** and how efficient energy system integration can be achieved. For this purpose, model optimisation is applied to **determine the installed power & hydrogen generation/storage/transmission infrastructures to supply the imposed demands** in a socioeconomically optimal manner (least possible system cost across the modelled geography).

A series of future design options are considered in the optimisation algorithm (Hubs-and-Spokes, Landing Zones (LZ), offshore/LZ/onshore electrolysis), **leading to a high degree of conceptualisation freedom**, taking into account the spatial and temporal dimensions of the energy system. **The interplay of the electricity and hydrogen systems along with the role and integration of large-scale offshore wind shape the results of the study.**



Note: Heat supply capacities are optimized for Nordic Countries. Explicit methane modelling is not within the scope of the Pathway Study.

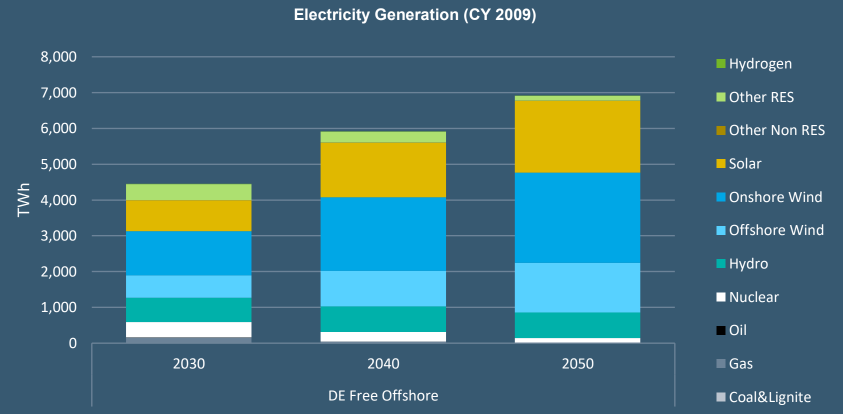
Offshore wind plays a vital role in Europe’s energy system

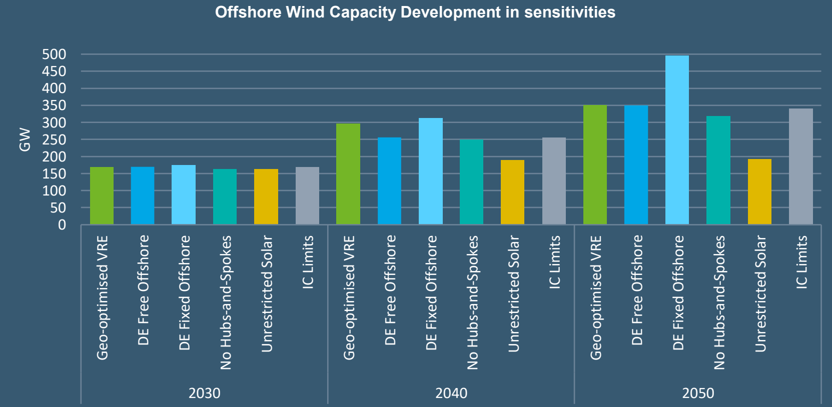
Compared to today's system, total electricity generation in Europe is set to double by 2050 in order to ensure a transition towards a net zero scenario for Europe. Offshore wind contributes with an important share of the increasing electricity generation and is expected to account for up to 20% of electricity generation in Europe in 2050.

With expected limits for the deployment of onshore wind and solar, offshore wind is key to ensuring energy independence for Europe and ensure sufficient pace for the energy transition. Challenges with realising ambitious onshore deployment of renewable energy could further increase the importance of offshore wind.

Cost competitive solar PV or onshore wind can significantly challenge the importance of offshore wind – if strong onshore buildout can be accepted and realised. However, even with good options for Solar PV and despite higher direct costs for offshore wind compared to solar PV, offshore wind capacities up to 193 GW would be cost competitive due to advantages in system integration (Unrestricted solar sensitivity). Without hubs-and-spokes, the long term economical amount of offshore wind would be reduced (no hubs and spokes sensitivity).

Higher offshore wind capacities as shown in the fixed offshore sensitivity inspired by the Distributed Energy scenario in the TYNDP 2022 can serve electricity demand for additional hydrogen generation. While economically less efficient compared to the Free offshore scenario, imported hydrogen amounts can be reduced.





Note: A more detailed overview of VRE generation capacities across sensitivities can be found in the Appendices.

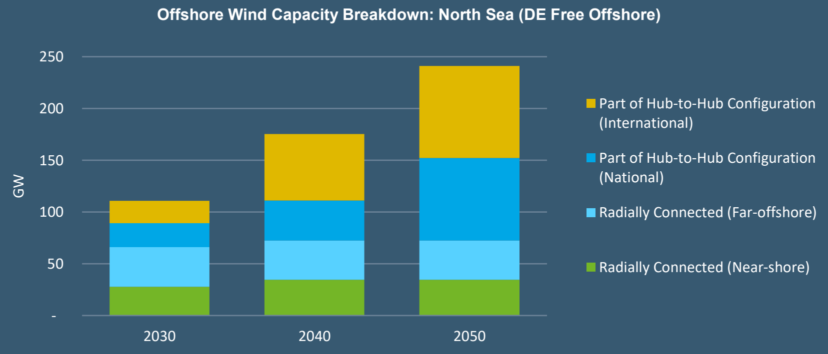
Large deployment of offshore wind at hubs in the North Sea

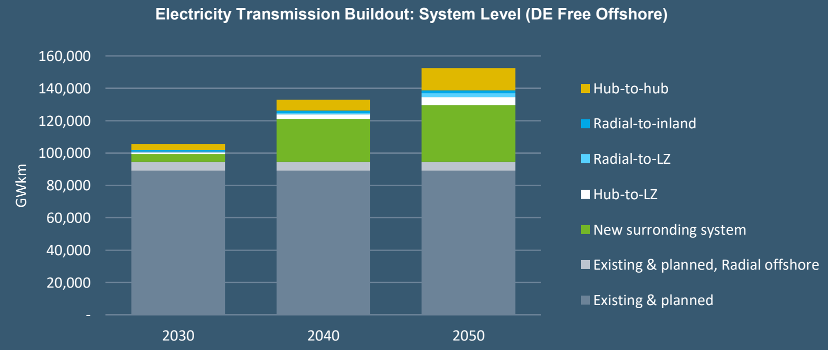
A large share (Around 240 GW) of European offshore wind is placed in the North Sea. The DE Free offshore scenario shows that **70% of this NS capacity (~50% on a system level) is part of hubs-and-spokes** to ensure efficient integration. All hub-to-hub capacity in the graphs is located in the North Sea.

Hub-to-hub and hub-to-shore buildout in the North Sea represents an important share of the total electricity grid buildout needs towards 2050, accounting for up to 33% of all new transmission capacity in 2050. **System wide grid capacities are increased by around 60%*** in the period after 2030 and towards 2050, which is closely related to the increased electricity consumption in the overall system.

Radially connected offshore wind capacity accounts for 52% of all offshore wind in the system, but only **34% of the offshore transmission in 2050. Reasons are both the shorter distances to shore, and the longer hub-to-hub connections,** which are part of the offshore grid.

Realisation of a larger amount of operational hubs-and-spokes in 2030 can be difficult to achieve in reality due to planning and construction constraints. At the same time, model simulations show, that the importance of hubs-and-spokes increases over time and their role is not pivotal in 2030. However, model simulations show, **that a system with the assumed rapid development of demand and supply, could benefit from higher interconnection capacity than the exogenously defined buildout can provide**. In the absence of options to build further direct interconnections, hubs-and-spokes can provide system benefits even with little or no offshore wind associated. In later years, offshore wind can be increased or added to the hubs-and-spokes.

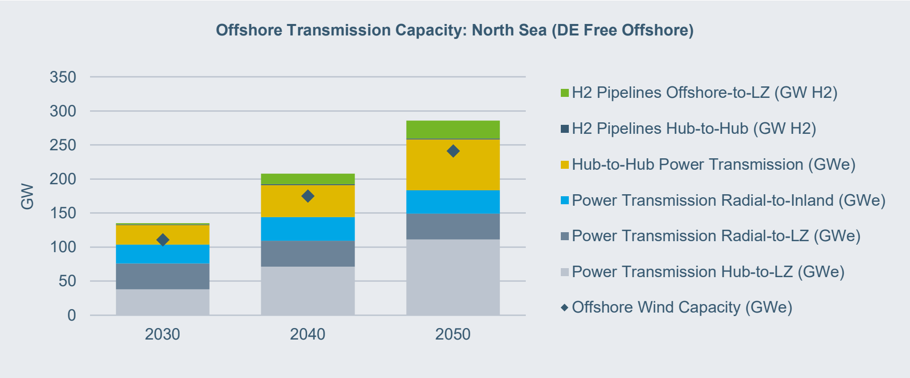


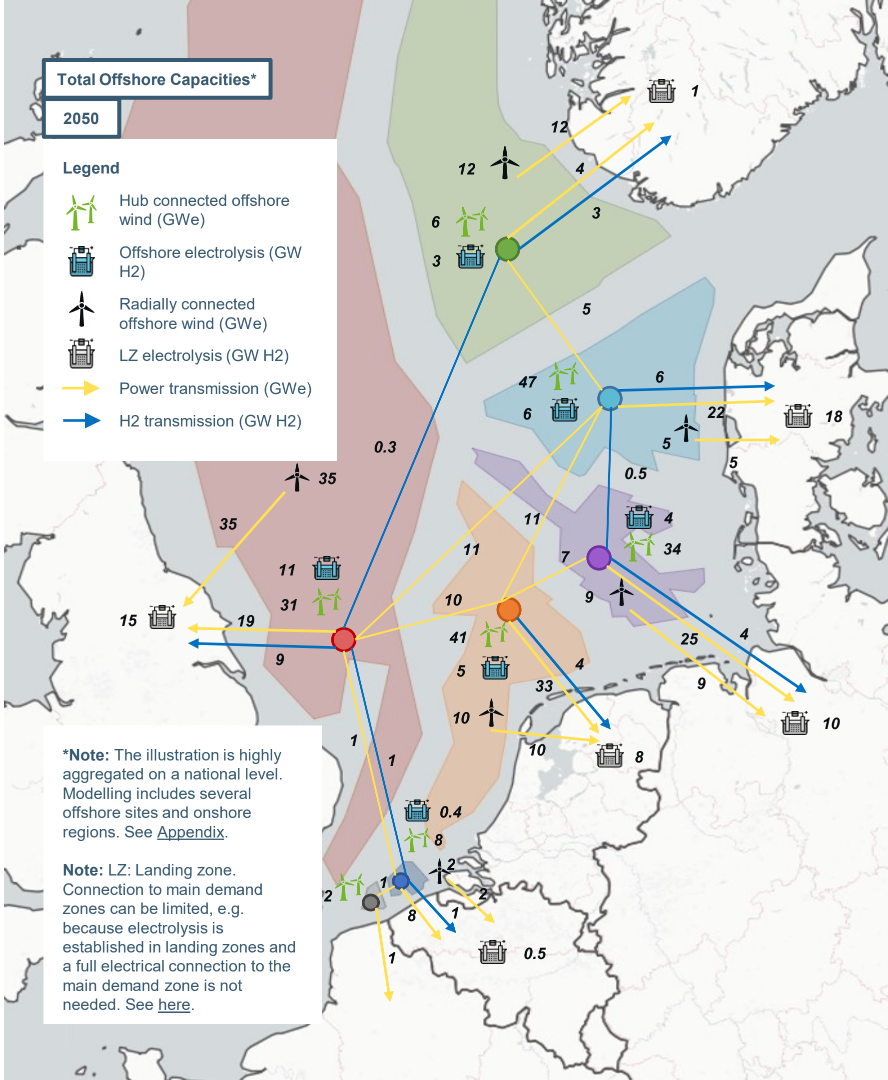


Notes: Radial Near-shore is transmitted directly inland, not to landing zones. Existing GWkm depend on actual total line length for which centroid-to-centroid distance have been used as estimate. For new lines, shorter distances have been assumed as a reinforcement might not need total length (see Appendix for more information). Up until 2030, onshore grid development is defined exogenously based on projects in ENTSO-Es Ten Year Network Development plan and only connections for the deployment of offshore wind (radially or in hubs-and-spokes) are part of the model optimisation.

An offshore grid in the North Sea facilitates efficient system integration

- Scenario calculations suggest a strong **electrical transmission corridor connecting the Nordic power system and Danish offshore wind in the North with the UK, Germany and the Netherlands in the South and West**. While varying in size, this corridor is found across analysed sensitivities. See here.
- Realising the **hubs-and-spokes concept can reduce total system costs by 1.0 bn EUR22/year** corresponding to around 1 EUR22/MWh offshore wind in the North Sea compared to a system without a North Sea grid.
- The 241 GW of NS offshore wind present in the base case (DE Free Offshore) require 184 GW shore landing capacity (111 GW Hub-to-LZ, 38 GW Radial-to-LZ, 35 GW Radial-to-Inland); **hubs-and-spokes reduce the need for electrical landing cables to shore by 24%** (184 vs 241 GW[i]). It is the combined effect of differences in spatial production flowing via the offshore hub-to-hub network and offshore electrolysis that reduces the need for landing capacity. Restrictions on the onshore transmission system can thus increase the importance of an offshore grid.
- Sensitivity calculations show, that a different distribution of renewable generation in the onshore system or limited connections to Southern European countries have limited impact on the formation of hubs-and-spokes. However, a fixed national approach to distribute offshore wind reduces the need of them, as the option to optimise usage of best sites is reduced. A general reduction in need for offshore wind would also reduce the need for hubs-and-spokes (see Robustness of the offshore grid).



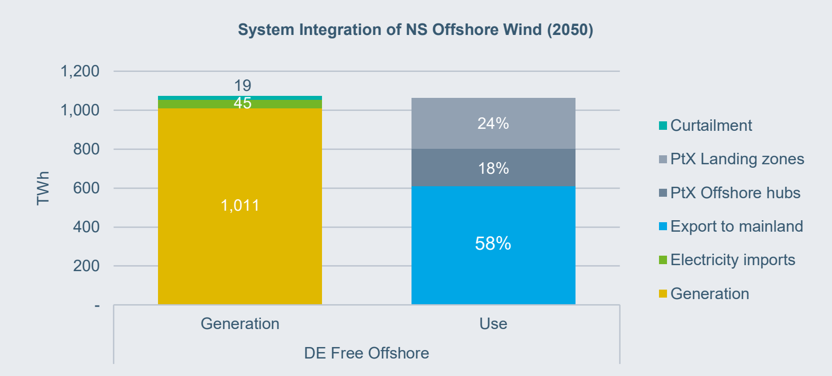


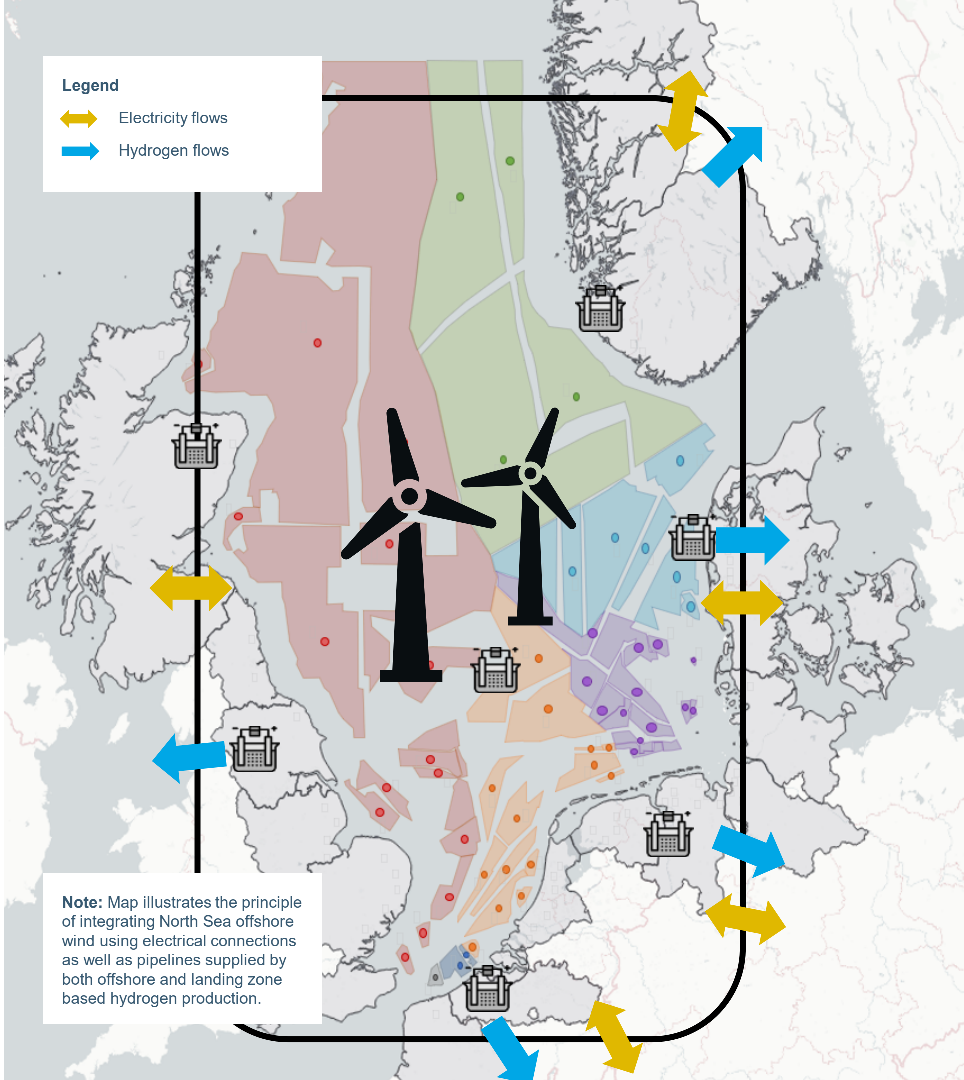
Integration of offshore wind

Offshore wind in the North Sea is integrated in the overall energy systems in three ways:

- Direct export of electricity all the way from the offshore sites to the onshore energy system to serve electricity demand.
- Production of hydrogen in landing zones. From here, hydrogen is transported in pipelines to serve hydrogen demand in the onshore energy system.
- Production of hydrogen at offshore sites. Offshore pipelines supply the onshore hydrogen demand.

In the DE Free offshore scenario, 58% of the offshore wind generation is used for direct export of electricity, while the remaining 42% is used for hydrogen production both in landing zones and offshore. The offshore grid allows to always export to the most valuable regions and additionally offers the option for transit between different onshore regions. On an annual basis the grid enables a transit of around 38 TWh. The role of North Sea hydrogen production across sensitivities is further shown here.





European hydrogen production supplies majority of demand

79% of Europe's hydrogen demand is supplied from domestic production in scenario calculations. Pipeline based H2 imports are most likely cost competitive to European hydrogen production and provide up to 15% of European demand.

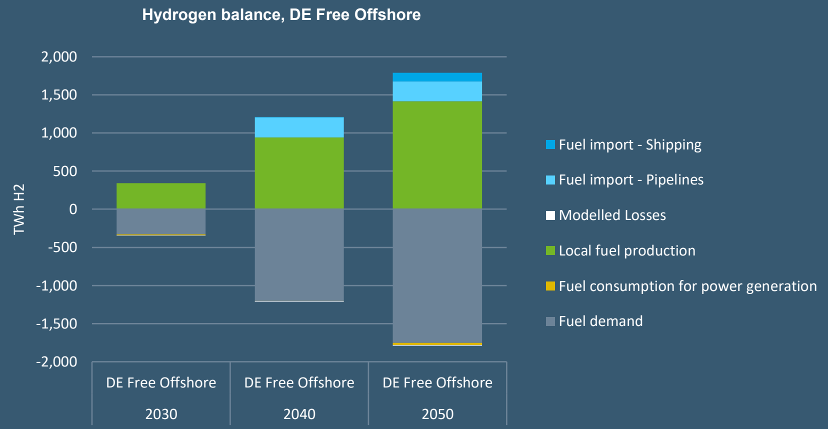
A large amount of European hydrogen production is cost competitive to the more expensive shipping based hydrogen imports, as long as system synergies can be harvested. The marginal hydrogen supply, which cannot achieve large system synergies, could be based on import of shipped hydrogen.

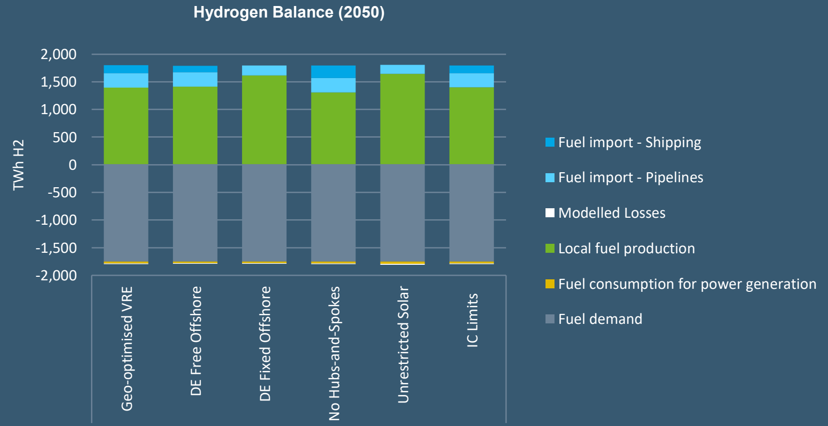
- The study only focuses on the production, use and import of hydrogen and does not move further down the production chain of PtX products, nor are different levels of hydrogen demand included. This could be the result of a scenario, where liquid e-fuels (e.g. ammonia) are imported instead of produced locally.

The role of hydrogen based power generation in the power system is limited to peak load supply, with G2P units rising up to max ~250 FLHs in certain countries, and an annual demand of around 29 TWh hydrogen in 2050.

The level of H2 imports does not surpass 27% of the modelled geography's needs in any of the sensitivities. This could change, if the restriction on pipeline imports were relaxed. Hydrogen imports are impacted by the different sensitivities:

- Scenarios with enforced deployment of VRES or ample potential for solar power (DE Fixed Offshore, Unrestricted Solar) increase the potential for available cheap electricity production, thus and in turn reduce the need for imports.
- Without hubs-and-spokes in the North Sea, integration options for offshore wind are less favourable reducing total offshore wind capacities and increasing the amount of imported hydrogen.
- Limits on the interconnection to Southern Europe as well as relocation of onshore VRE deployment have limited impact on the total imports, albeit increasing them slightly.





Electrolysers are an important asset for system balancing

Electrolysers are the most important flexibility source on the demand side with the potential for long term flexibility, while other demand categories provide shorter term flexibility. Electrolysers are deployed throughout the system to supply hydrogen needs. They operate flexibly to achieve optimal ratios between low electricity cost and the investments needed to enable flexibility (hydrogen storages and production capacity). In periods with low electricity generation compared to direct electricity demand, electrolysers stop operation, but use electricity when higher amounts of electricity is available. In this way, they reduce the need for other system balancing such as batteries, transmission capacities or backup generation.

Other balancing assets:
The system runs with 139GW H2 G2P units and 335GW batteries. Those assets serve a completely different role.

- Batteries provide flexibility in the power system, while hydrogen based power generation supplies peak demand
- Batteries run at 1,500 to 3,500 FLHs serving power shifting, while H2 gas units aim peak load supply at 30 to 250 FLHs.
- Batteries are located close to solar PV centres (southern Europe).

Investment estimates for batteries and hydrogen based power generation are vulnerable to price formation in few hours and closely linked to security of supply analyses. A full assessment requires close analysis of the value of lost load (price ceilings) and alternative scenarios for weather years and outages.

An illustration of supply/demand balance for Germany in 2050 is shown on the following slide.

Balancing assets 2050	Capacity (GWe)	Generation/Demand (TWh electricity)	Capacity factor (%)
Hydrogen G2P	139	16	1% (~115 FLHs)
Batteries	335	765	26% (~2,280 FLHs)
Electrolysis	566	1,854	38% (~3,275 FLHs)
Flexible load*	259	167	7% (~645 FLHs)

Note: Numbers rounded to the nearest integer. The capacity factor of batteries is calculated as the sum of electricity flows (in + out) divided by the power component of the storage.

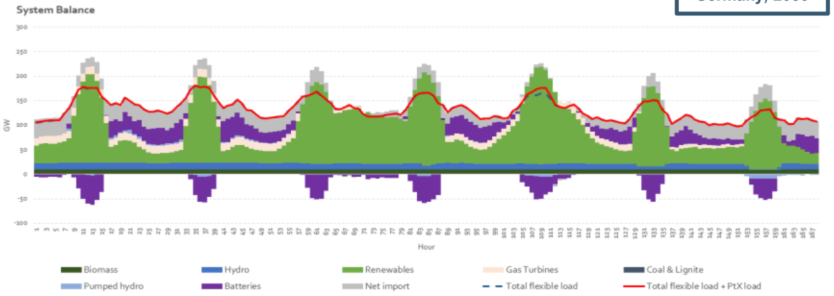
*Flexible load represents the total demand side flexibility from Classic Demand, EVs and Individual Heating categories. A smaller part of these demands can deviate of their “natural load” based on price signals. However, this demand can only be shifted for up to 2 hours in time for individual heating and 4 hours in time for electric vehicles.

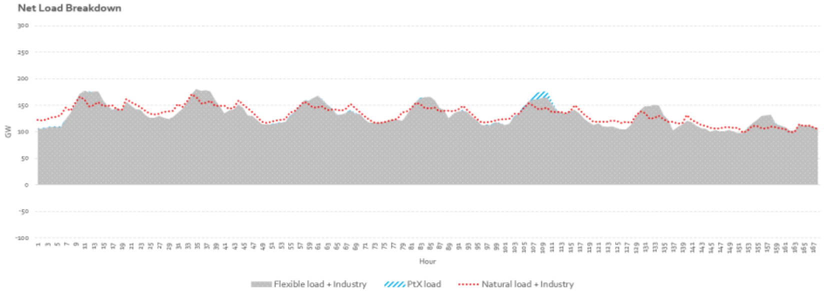
System balances are ensured even at very high shares of variable renewable generation

	H_2 G_2P			Batteries			Electrolysis		
2050	Capacity (MW)	Generation (GWh)	FLHs	Capacity (MW)	Total Flow (GWh)*	FLHs*	Capacity (GWH2)	Generation (TWh H2)	FLHs
Germany (DE)	32,579	6,121	188	63,877	134,755	2,110	50	149	2,992

Low VRE Week

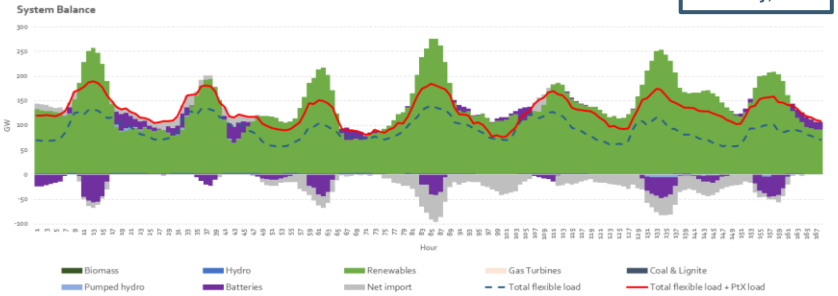
Germany, 2050

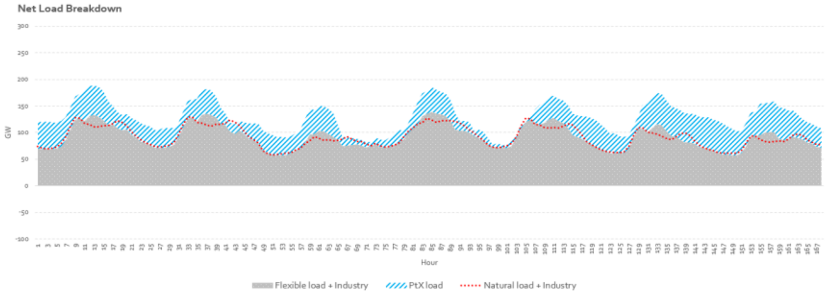




High VRE Week

Germany, 2050





Note: Import is (+). Flexible load includes Classic, Individual Heating and Electric Vehicle demands, after demand-side responses to electricity price signals. Such signals convert the natural load (original profile) to flexible load (resulting profile).

Possible future pathways don’t lead to highly fluctuating system costs. However, the conditions and implications of each scenario vary

Sensitivity calculations show the socio-economic implications of the different aspects.

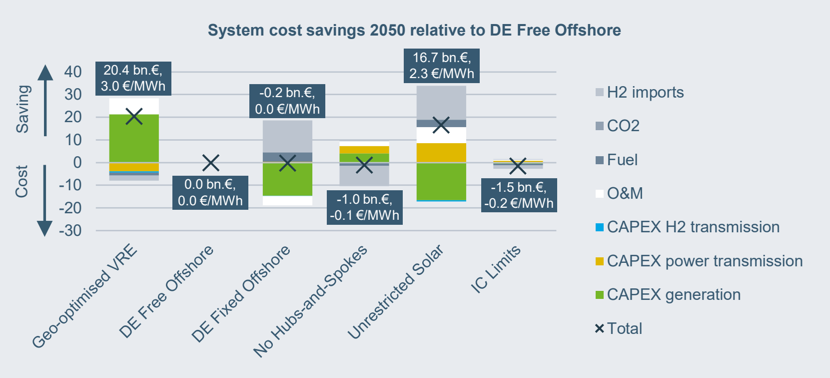
The Geo-optimised VRE sensitivity results in considerable supply side savings due to the optimal redistribution of capacities across the modelled geography, harvesting therefore higher FLHs which lead to lower capacity needs. Of course, with capacities moving to the outskirts of Europe, additional transmission costs are emerging. Considerations of unsatisfied political targets, VRES capacity density in some countries, as well as geolocational obstacles of energy transmission could challenge such a solution.

The DE Fixed Offshore sensitivity enforces higher amounts of offshore wind in the system, at high additional supply side costs. This fact naturally drives the available cheap electricity to higher levels increasing European hydrogen production and eliminating H2 imports via shipping while also challenging the cheaper pipeline options. Savings on cost for imported hydrogen are to offset the higher supply side cost to a large extent. While the European H2 self-sufficiency is getting strengthened at an almost unchanged system cost, it is worth considering the real-world dynamics, which could include long term price responses from electricity and hydrogen.

The No Hubs-and-Spokes sensitivity leads to a drop of the overall offshore wind capacity in the system with consequent transmission savings, something overturned by the increasing needs of H2 imports from North Africa emerging as the least cost solution of the residual H2 demand. In other words, Hubs-and-Spokes (as well as higher offshore wind buildout illustrated by the DE Fixed Offshore scenario), can increase energy independence at limited costs.

The Unrestricted Solar sensitivity replaces a large amount of offshore wind with more solar PV in southern Europe due to their considerably lower LCOE. Expectedly, this translated to higher local H2 generation volumes (thus higher generation costs vs the base case) and large savings on H2 imports, leading to a highly self-sufficient Europe. The public acceptance of solar PVs in southern European countries, the land use competition with other sectors (e.g. agriculture) and the vulnerability of such centralised power regions can be subject to further scrutiny.

The IC Limits sensitivity doesn’t lead to considerable scenario changes as the effects are mostly concentrated in southern European countries which act as H2 sinks (Italy, Balkans), and therefore getting addressed by further H2 imports than the base case.



Note: Positive values correspond to savings of the indexed (x-axis) scenario against the referenced scenario within the figure’s title. Values are annual. Savings per MWh reflect savings in terms of system wide power demand. For a more detailed cost breakdown across scenarios, refer to upcoming sections.

2050	Geo-optimised VRE	DE Free Offshore	DE Fixed Offshore	No Hubs-and-Spokes	Unrestricted Solar	IC Limits
Total System Cost (bn. €)	554	574	575	575	558	576
% Savings against DE Free Offshore	3.55%	-	-0.04%	-0.17%	2.90%	-0.25%

Policy recommendations

The current study confirms a potential to establish offshore electricity and hydrogen grids to enable efficient system integration of offshore wind. However, the realisation of potential benefits requires European coordination and valuation of contributions from European neighbours to national targets. While the focus of the current study is on technical and socio-economic impacts rather than the regulatory framework and its' implications a number of policy recommendations can be drawn:

- Maritime special planning is not only crucial for national plans for offshore wind, but also for the potential for European coordination. Therefore, efforts should be made to create a European view on the usage of areas in the North Sea.
- Development of policy framework for hybrid connections, both regarding investments, ownership and market operation (bidding zone configurations) is important to further develop options for hubs-and-spokes.
- (Large) pilot projects can ensure practical experiences, foster technology advancements and provide real-world cost numbers.
- The value of a North Sea grid and European offshore wind is also dependent on the assessment of the value of energy independence, security of supply and risk assessments. While model studies can provide quantitative insights into system aspects, the value of these topics is a political question, which should be addressed directly – both nationally and on a European level. A clear view can further contribute to determining the usefulness of a North Sea grid.

Perspectives 1/2

The current study shows important conclusions on the aspects of European offshore wind and a North Sea grid. The analysed results and the established modelling framework provide indicators and options, for topics which deserve further attention:

System composition
The assessment of security of supply deserves further analyses. The full value of flexibility and backup assets also depends on inter-annual variations and cannot be fully assessed from a single scenario and climate year. Hours with strained supply options and the importance of different weather patterns should be analysed further to assess the resilience of different systems and the value of an offshore grid in this regard.

- Detailed comparisons of backup generation capacities, batteries and long term electricity storage, as well as electrolysis and hydrogen storage
- Requirements for European energy independence (levels of allowed hydrogen imports)
- Optimal supply system considering different climate years

Country-by-country assessments could further lay out the national implications of European wide system aspects. How much can countries rely on European neighbours?

Offshore hubs
Concrete technical design of single hubs-and-spokes systems and the operation in envisaged market setup

Perspectives 2/2

Offshore grids

- The starting grids assumed for both hydrogen and electricity are strong but assumed in place only six years from now. At the same time, realisation of infrastructure projects across Europe have proven difficult. The importance of the starting grids as well as the options and costs for establishing new grids beyond 2030 should be investigated further, as they can be an important driver for the value of an offshore grid.
- Real world realisation of offshore infrastructure will be based on discretised buildout in steps. The impact of this (compared to the option to invest in smaller steps in the modelling applied here) should be further investigated.

Offshore wind

- Realisation of an offshore grid requires application of DC-technologies, which (depending on the length) are more expensive and less mature than AC-technologies. An offshore wind deployment with a higher degree of closer-to-shore AC-options would provide less flexibility, but potential cost reductions could challenge the role, timing and magnitude of a DC grid.
- Wake-effects can impact the potential generation from offshore wind at high offshore wind densities in single offshore areas. The technical University of Denmark provided insights into potential impacts of both wind-farm internal and mesoscale wake-effect, but simulations show uncertainties and the importance for e.g. relative competitiveness of different offshore sites. This topic should be further investigated, since one of the benefits of an offshore grid is increased utilisation of high-resource sites.
- Optimisation of the usage of different offshore wind sites across the North Sea is one of the drivers of a North Sea grid. However, costs at different sites do not only depend on depth and resource quality, but also on e.g. seabed conditions, and cable/pipeline routing options. A more detailed screening could further detail cost assumptions at different sites.

Offshore Wind in the European Energy System

Offshore wind in the European context

Offshore wind will be an important pillar in the European Energy system, if the path towards a net zero Energy system implying large amounts of direct and indirect electrification is to be pursued. The current study provides insights on how large amounts of offshore wind can be integrated and provides an important basis for designing deployment pathways. We show valuable principles of offshore grids and the operation of the hydrogen system and explore the potential impact, if those options are absent. The study focus is the overall energy system, while the concrete design of the single offshore hubs will be subject to further analyses. Important aspects include detailed cost estimates for site dependent factors such as seabed and grid routing options, the concrete connection points to the onshore grid and the prospects of reinforcing the onshore grid and creation of landing zones.

The value of an offshore grid for security of supply in the power system as well as the political value of energy independence have not been subject to detailed analyses, but the results show, that offshore wind can contribute to ensuring energy independence and an offshore grid can enhance system integration, which lays the foundation for increasing security of supply.

The current report provides further insights into the results, assumptions and reasoning behind the main findings presented in the executive summary.

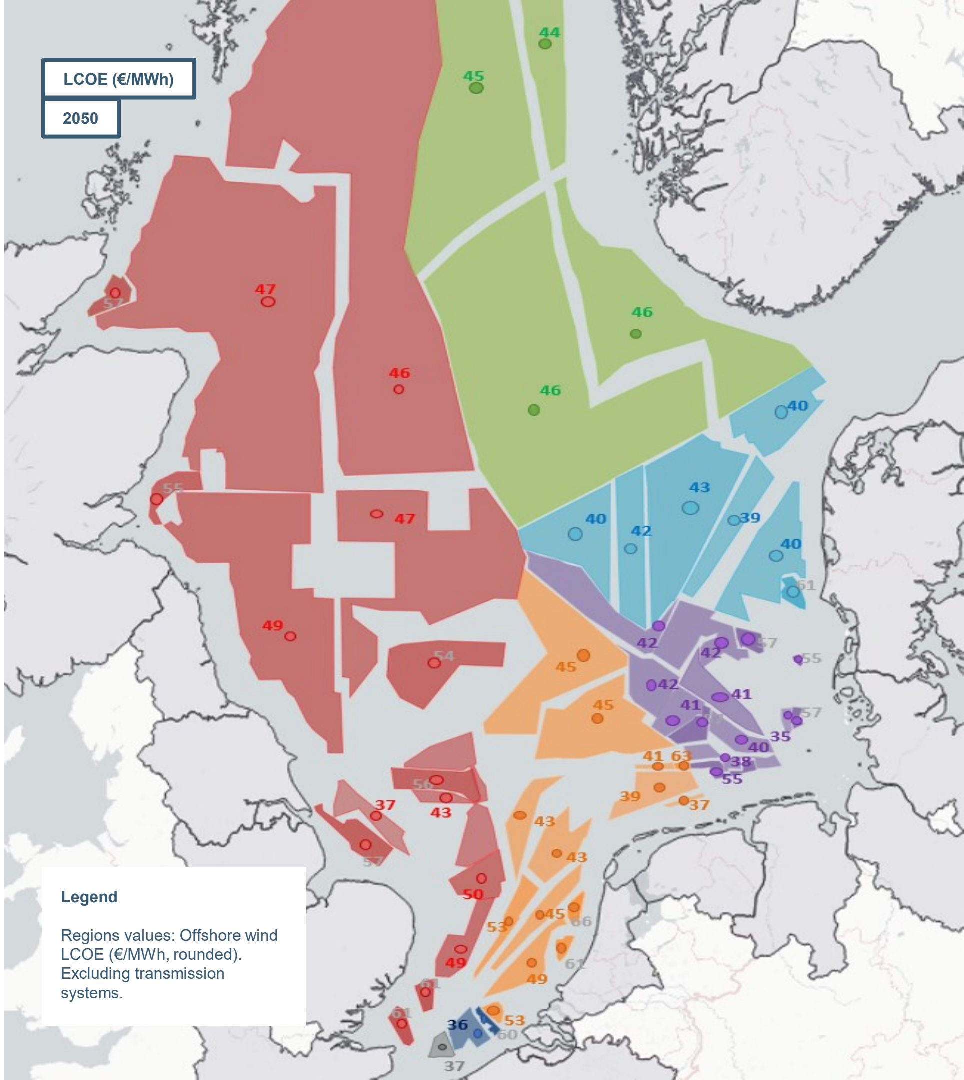
Distribution of offshore wind in the North Sea

Estimates for the cost of offshore wind at different offshore sites in the North Sea are based on assumptions for the cost of offshore wind, the depth at the individual sites and estimated capacity factors provided by the Technical University of Denmark. The resulting estimates for cost of offshore wind are illustrated by the levelised cost of electricity (LCOE) for 2050 on the map on the right. Transmission costs are not included in the figure.

Danish sites have comparably low LCOEs. Exploiting the offshore potential at those sites therefore holds the potential for system benefits. Cost for longer transmission lines, similarity of generation profiles and wake effects can limit the extent to which the cheapest sites are utilised.

The full detail behind the modelling is more nuanced. In each offshore region, there are multiple areas with different LCOEs and different potentials, reflecting different depths within regions, but also decreasing capacity factors as the exploitation of offshore wind within a region increases. This map shows the LCOE weighted with potential of the entire region, but the modelling takes into account the different sites. Transmission costs are not included in this map. Factors such as different seabed conditions are not included.

The LCOE is coloured grey for some areas, which have existing or planned capacity in them. Their LCOE reflects the LCOE of older turbines, and therefore is not fully comparable to other numbers. Further explanations about the wind modelling can be found in the Appendix.



Integration of offshore wind generation

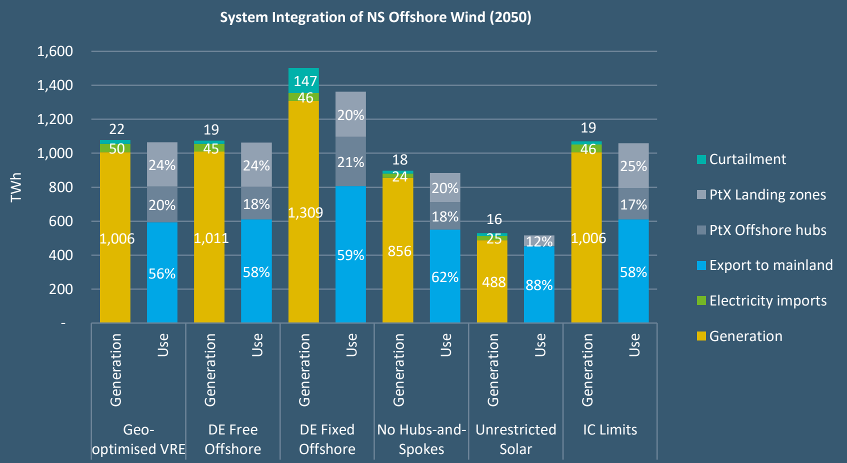
Offshore wind in the North Sea is integrated in the overall energy systems in three ways:

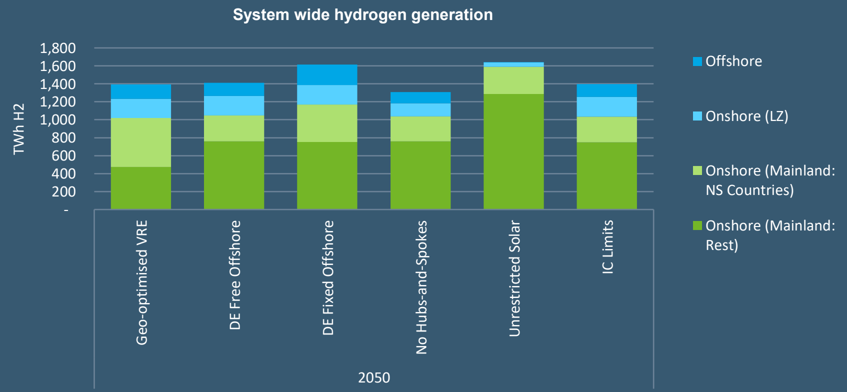
- Direct export of electricity all the way from the offshore sites to the onshore energy system to serve electricity demand.
- Production of hydrogen in landing zones. From here, hydrogen is transported in pipelines to serve hydrogen demand in the onshore energy system.
- Production of hydrogen at offshore sites. Offshore pipelines supply the onshore hydrogen demand.

The majority of the North Sea offshore wind generation is routed to the mainland across all evaluated scenarios (56 to 88%), with roughly half of the remaining generation utilised directly on the landing zones towards hydrogen generation, allowing a more efficient and cost-effective grid development and utilisation.

The offshore grid allows to always export to the most valuable regions and additionally offers the option for transit between different onshore regions. On an annual basis the grid enables a transit of around 38 TWh.

On a system wide basis, 25% of hydrogen production is directly linked to offshore wind in the North Sea: 15% in landing zones and 10% offshore (DE Free Offshore). Sensitivities show, that enforced deployment of offshore wind in the Fixed Offshore scenario increases North Sea hydrogen production, while large solar deployment or the lack of an offshore grid reduces the role of North Sea hydrogen.





Note: An overview of the NS offshore wind system integration across years can be found in the Appendix.

A minimum of ~200 GW of offshore wind capacity is deployed across analysed sensitivities

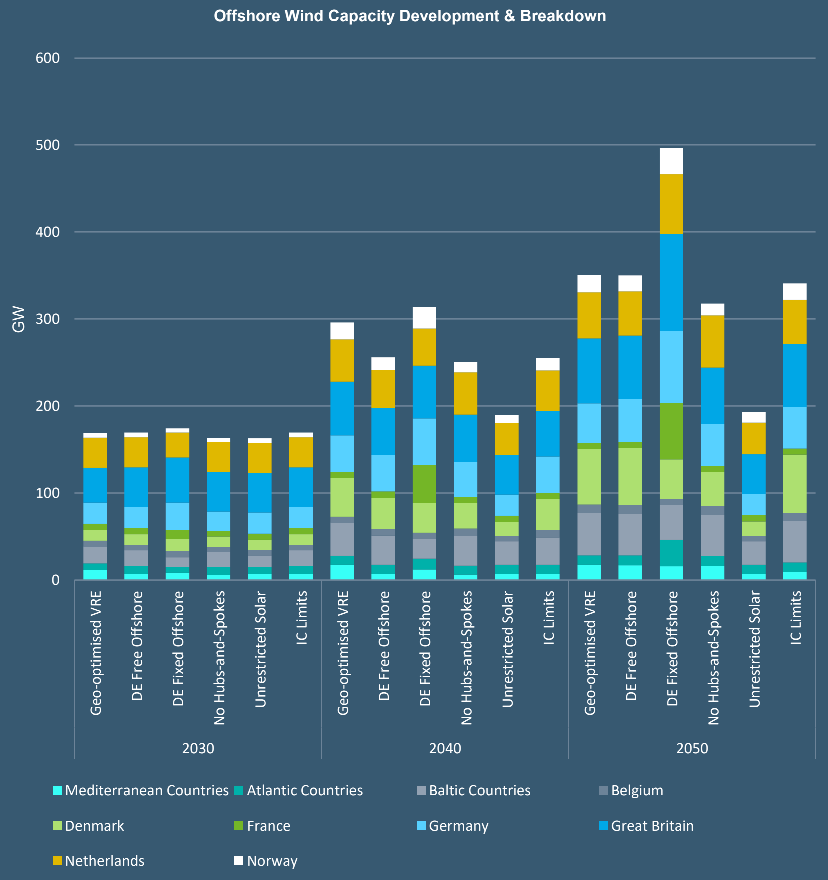
Under the utilised set of assumptions (fixed power and H2 annual demand levels), a minimum level of almost 200 GW offshore wind consistently deployed in Europe across analysed sensitivities. A firm level of no regret decisions is observable for countries like Denmark, the United Kingdom, the Netherlands and Germany. Denmark proves to be the country with the lowest average LCOE for offshore wind, thus dominating a part of the offshore wind development under free development scenarios.

Without hubs-and-spokes, the total installed wind capacity is reduced by approximately 10%, as the integration options are less favourable. The reduction also reduced European hydrogen production (see upcoming sections)

Even in scenarios with additional onshore VRE allowances (Unrestricted Solar) versus the base case (DE Free Offshore), a considerable level of offshore wind is still present at 193 GW, surpassing the enforced minimum level of around 130 GW of offshore wind, which is considered as the minimum buildout compliant with political ambitions by 2030 (80% of TYNDP DE numbers per country). However, total installed capacity is significantly reduced, with large impacts in Denmark.

Enforcing offshore wind capacities defined in ENTSO-Es Distributed Energy scenarios significantly increases total offshore wind capacity, which in turn increases European hydrogen production at cost of H2 imports (see hydrogen balance here)

Note:
Atlantic countries: Ireland, Portugal.
Baltic countries: Estonia, Finland, Latvia, Lithuania, Poland, Sweden.
Mediterranean countries: Italy, Spain, Balkans (Albania, Bosnia & Herzegovina, Bulgaria, Croatia, Greece, Kosovo, Montenegro, North Macedonia, Romania, Serbia and Slovenia).



Hub-to-hub capacity additions become dominant in 2050

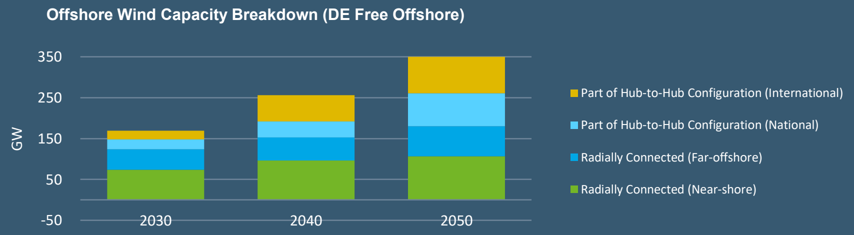
In offshore wind capacity terms, **radially connected offshore wind is dominant in the system in 2030 and 2040**.

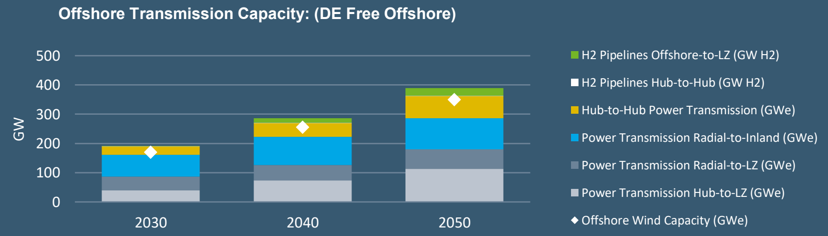
In 2050, **hub-connected offshore wind capacity accounts for almost 50% of total capacity** (~170 GW).

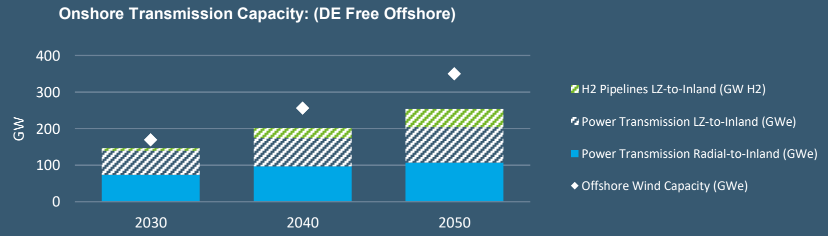
Zooming in on the North Sea[i], the transmission capacity shows that in 2050, 241 GW of offshore wind is integrated in the system using only 184 GW of electrical connection to shore. Compared to a full 1-to-1 electrical radial connection (241GW), hubs-and-spokes thereby **reduce the need for electrical landing cables to shore by 24% (184 GW vs 241 GW)**. Total transmission capacity (to shore and between hubs) follows the installed offshore wind capacity closely in all years (middle graph).

DE Free Offshore results in the installation of 38 GWe of offshore electrolysis, signaling that it is the combined effect of differences in spatial production flowing via the offshore hub-to-hub network and not just electrolysis that reduces the need for landing capacity across the modelled geography (184+38=222 < 241 GW). 184+38=222

Seen from main demand zones, a total of 350 GW offshore wind is integrated using only 204 GW electrical connections and 51 GW of pipelines (bottom graph).







Note: Radial Nearshore is transmitted directly inland, not to landing zones. Existing GWkm depend on actual total line length for which centroid-to-centroid distance have been used as estimate. For new lines, shorter distances have been assumed as a reinforcement might not need total length (see Appendix for more information).

Note: Near-shore corresponds to sites closer than 22 km from shore.

Hub-to-hub connection capacities

Decreased offshore wind levels challenge hub-to-hub connections, unlike the impacts from increased offshore wind capacities which mainly increase radial connections.

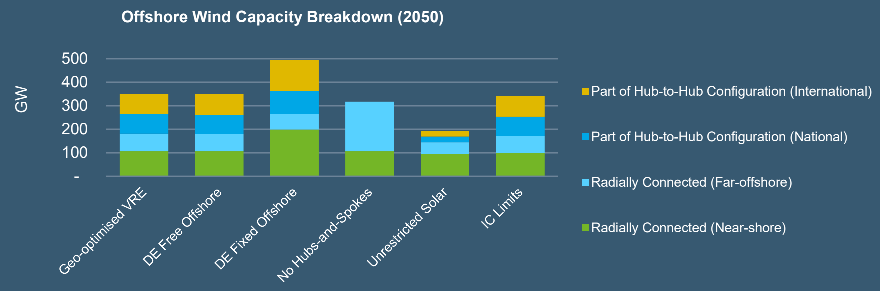
The overall level and composition of offshore power transmission remains unchanged across the majority of the undertaken sensitivities when offshore wind capacities are preserved around 350 GW.

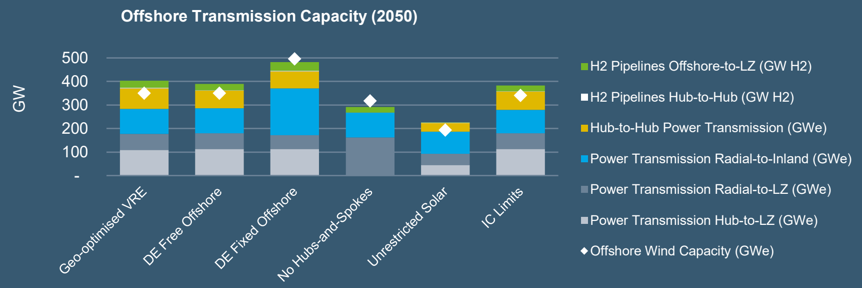
Increased offshore wind capacities do not lead to increased capacity of hub-to-hub interconnections, even though almost half of the additional offshore wind is part of hub-to-hub configurations. In fact, hubs-and-spokes in terms of GWkm decrease (see further below).

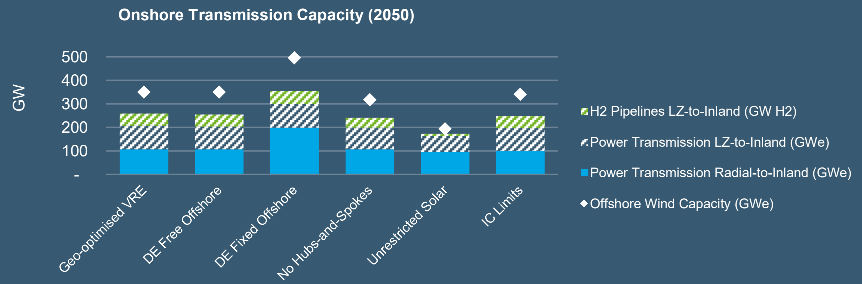
Increased transmission capacities are mainly routed directly to shore, also since additional offshore wind is mainly placed closer to shore. One of the reasons is lower value of offshore wind and higher curtailment levels in general (2.3% to 9.7%).

On the contrary, when offshore wind capacity levels drop to ~200GW (Unrestricted Solar), the imminent impacts mostly affect hub-to-hub related capacities for both installed wind and transmission capacities.

Even without a hubs-and-spokes overplanting and hydrogen production mean, that 318 GW of offshore wind is integrated in the system using only around 267 GW electrical transmission to shore (middle graph), while demand zones are connected with less than 200 GW electrical connections to the offshore wind (bottom graph)







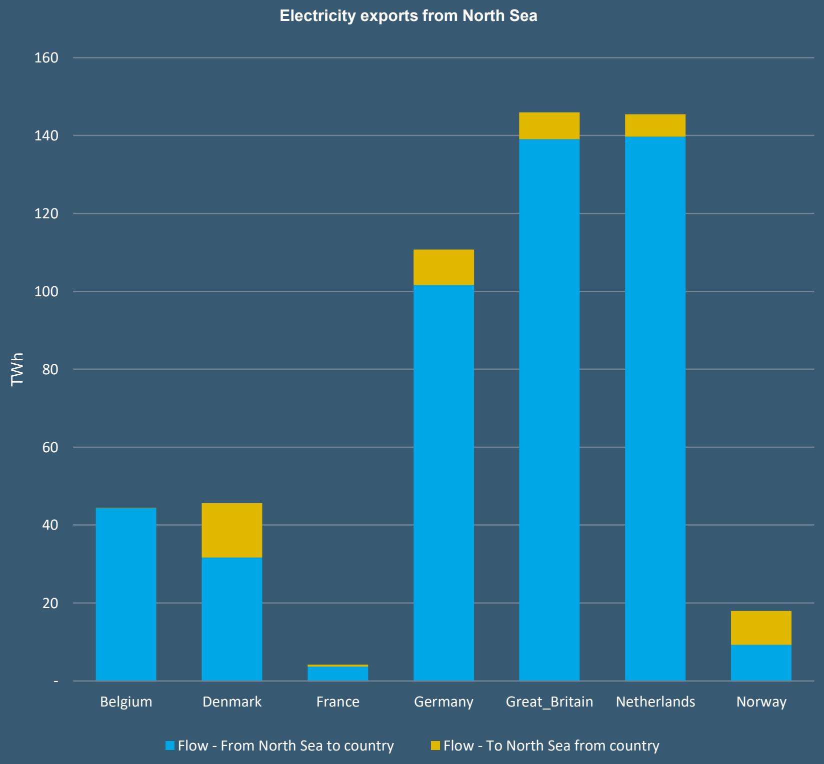
Note: Near-shore corresponds to sites closer than 22 km from shore.

North sea offshore wind supplies Europe’s demand centres

The major off-takers of electricity generation from offshore wind in the North Sea are the UK, Netherlands and Germany.

Denmark is one of the major producers of offshore wind, accounting for 25% (248 TWh) of total generation, but only importing roughly 13% of this generation (32 TWh) to the Danish shore as electricity. Exports from Danish offshore sites are supplemented with flows from the mainland through the North Sea grid.

Norway serves as a net zero off-taker of North Sea wind, as it receives around 9 TWh electricity from the North Sea, but feeds 9 TWh into the grid as well.



Note: The graph shows where the North Sea electricity generation is fed into. It also shows if countries feed electricity into the North Sea grid. Figure represents flows between Landing Zones and the corresponding home countries. A country-based summary of flows between offshore sites and landing zones, signalising the magnitude of power-to-X conversions on Landing Zones, can be found in the Appendix.

Offshore electricity grids

Hub-to-hub connections are an important part of total transmission system buildout

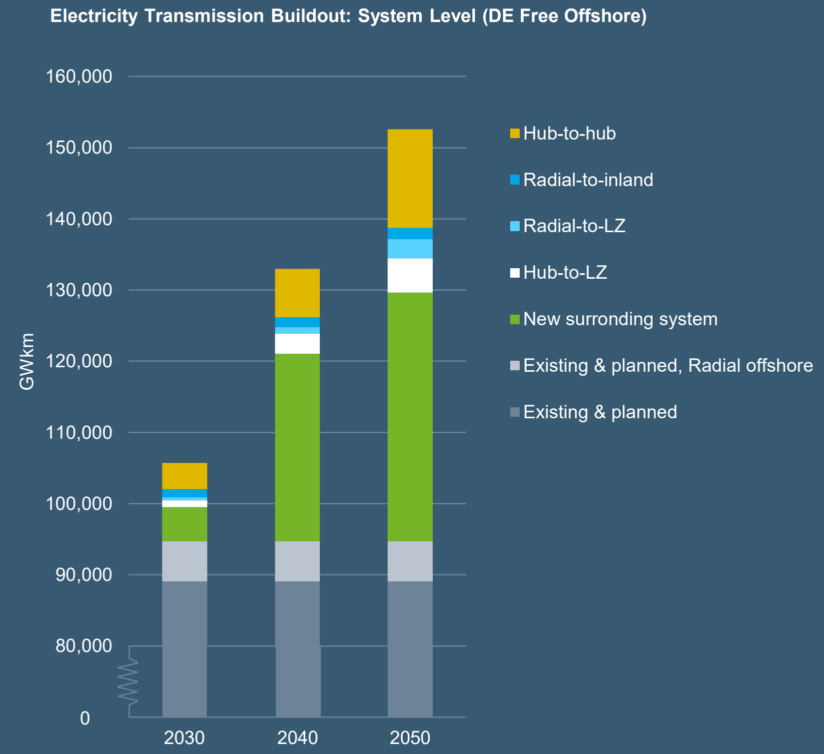
The development of the electricity transmission system towards 2030 is defined exogenously based on projects in ENTSO-Es Ten Year Network Development plan. The model optimised **transmission buildout in 2030 is therefore limited to connecting offshore wind - either radially or hub-to-hub.**

The overall grid is significantly reinforced between 2030 and 2050 and increases 60% in the period.* **In 2040 and 2050**, the grid of the surrounding system is **significantly increased**, as the model is allowed to optimise capacity between onshore zones. The increase is closely related to the increase in electricity consumption.

Hub-to-hub and hub-to-shore buildout is quite significant accounting for 33% of all new transmission capacity in 2050, indicating that hubs-and-spokes can provide a significant amount of the total grid needs.

Pure radial connections take up 34% of the offshore transmission in 2050, while radially connected offshore wind capacity accounts for almost 52% of all offshore wind in the system. The reason is the shorter distance of radially connected offshore wind to shore. In the short term towards 2030, the majority of offshore wind is radially connected (see previous slide). However, in terms of grid investments, the need GWkm established for hub-to-hub connections account for around 60% across the entire period.

Notes (*): Existing GWkm depend on actual total line length for which centroid-to-centroid distance have been used as estimate. For new lines, shorter distances have been assumed as a reinforcement might not need total length (see Appendix for more information). Planned transmission capacities correspond to offshore wind farms which are expected to come online before 2027 and are only connected radially to the onshore system.

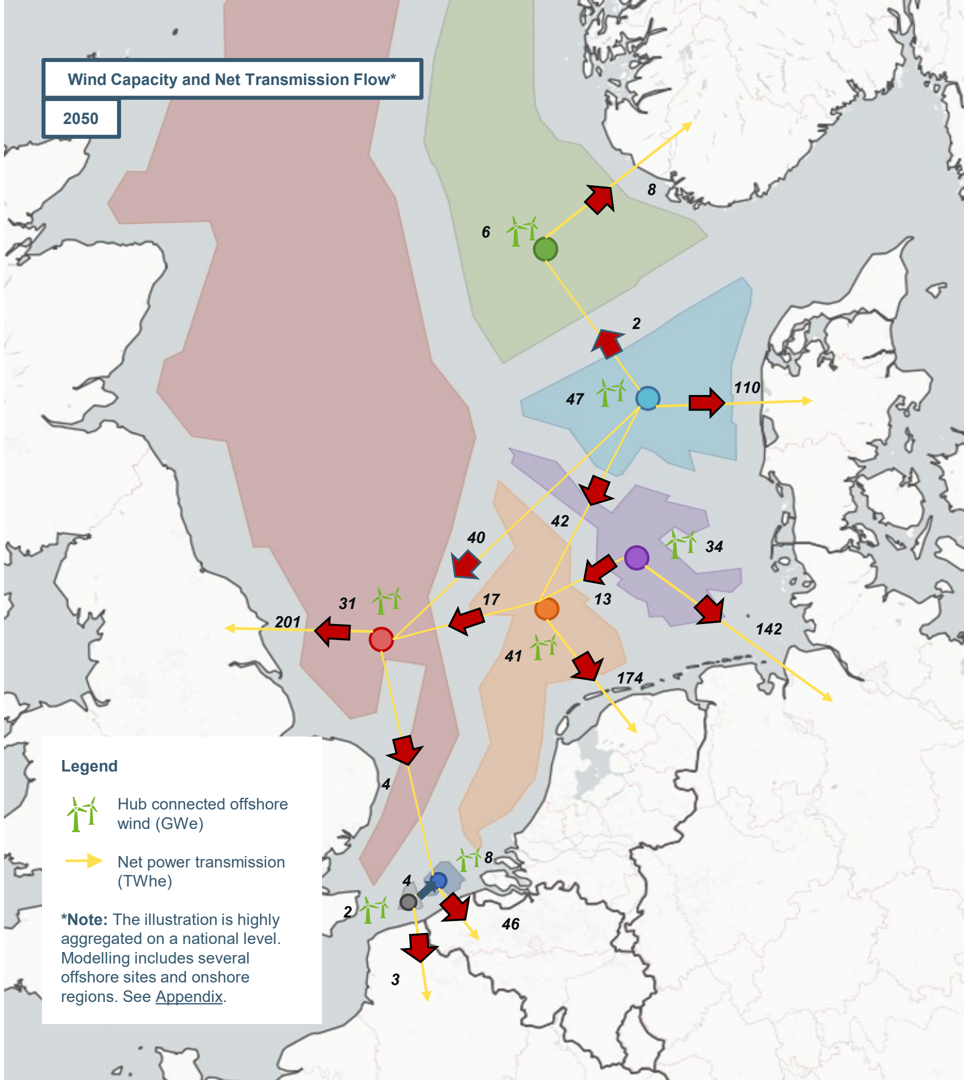


Note: In 2030, the new surrounding system's additional capacity is from landing zones to their parent region, and thus related to deployment of offshore wind.

The corridors’ large net electricity flows towards the UK and the Netherlands

The offshore grid in the North Sea enables electricity flows **from mostly the three Danish hubs to the UK and the Netherlands.** The Danish hubs have large wind farms connected to the North Sea Grid at 20 GW, 13.5 GW and 13.5 GW OWF capacities. In total, **~40 TWh flows from the Danish hubs to the UK and ~42 TWh flows from the Danish hubs to the Dutch hubs (net figures)**. This is equivalent to approximately 20 GW turbine capacity. The overall hubs-and-spokes have several smaller flows in all directions utilising differences in generation profiles across the North Sea. The German hubs export some electricity towards the Netherlands, but the major share is exported to the German shore.

On an annual basis, Germany is a large importer of hydrogen, while Germany’s electricity supply is close to balanced. A large part of the hydrogen imports are supplied from Denmark and other Nordic countries. The UK also imports both hydrogen and electricity, again with Denmark being an important source. A closer view on the individual countries electricity and hydrogen balances is found in the Appendix.



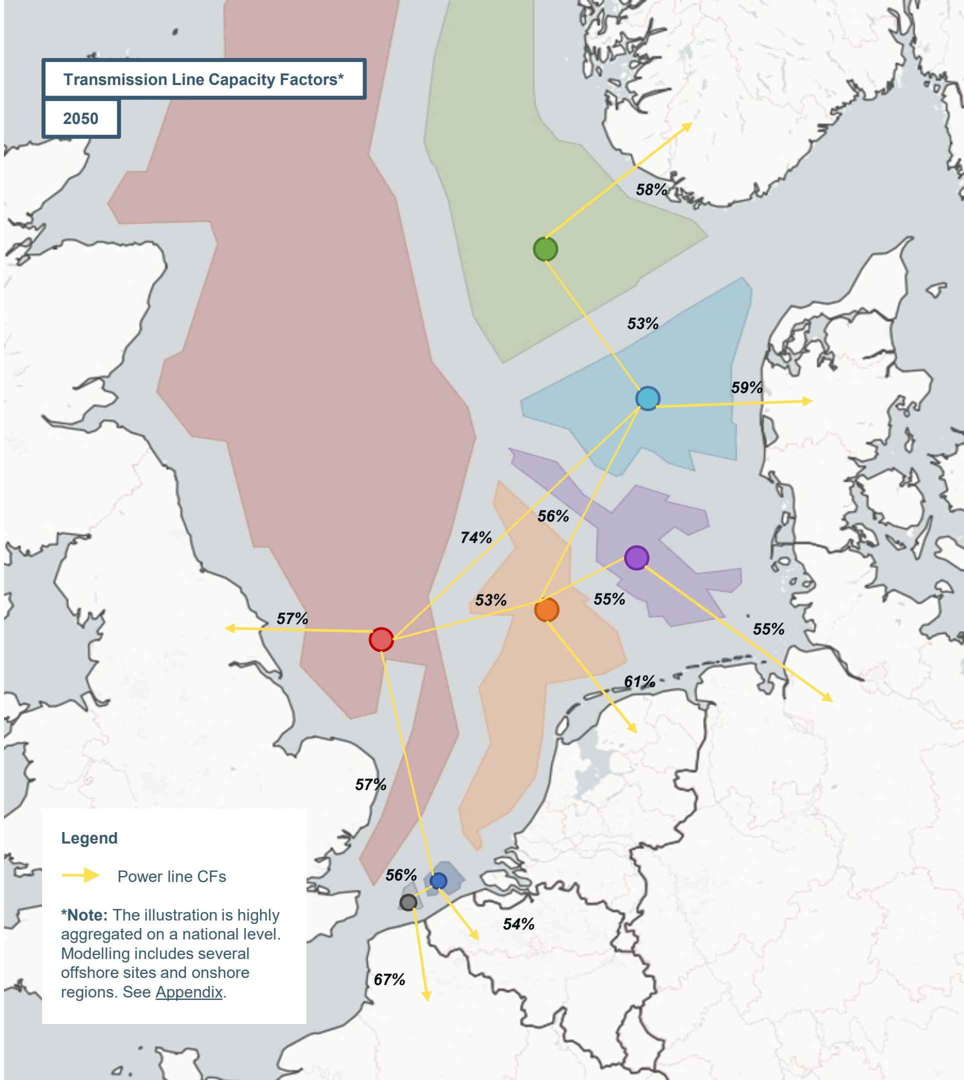
Note: Transmission flows to shore include flows from radially connected WT.

Higher transmission capacity factors reflect steadier flows, while lower ones signalise occasional but important for the system balancing needs

The utilisation of the electricity-corridors illustrates one of the advantages of hubs-and-spokes: Many grid elements are used at higher capacity factors, than the capacity factors of offshore wind farms. Higher capacity factors (CF) indicate a higher average utilisation of each corridor, while lower capacity factors show more flexible operation towards more occasional than flat balancing purposes.

Especially the corridor between Danish offshore sites and UK sites (North-South corridor) reflects a high capacity factor, translating to more constant power flows across the North Sea.

For existing or planned radially connected wind farms, the capacity factor of the transmission-to-shore line matches the capacity factor of offshore wind, as transmission and WT capacities are conventionally matching (some overplanting can be beneficial).



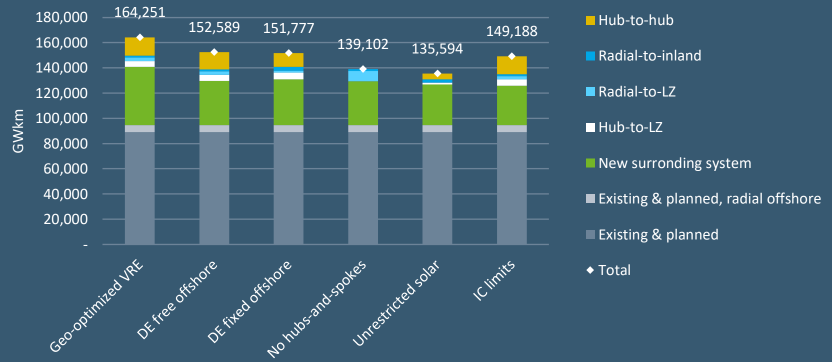
An offshore grid provides benefits across sensitivities

The impact of the sensitivities on the need for an offshore grid shows that main corridors are beneficial across scenarios with one exception: A significant reduction of need for offshore wind will also reduce the need or benefits from a North Sea offshore grid. **Most sensitivities show a two main corridors from the DK hubs, one to UK ranging from 2 to 8 GW, and one to the Netherlands ranging from 3 to 13 GW (as seen in detailed maps[1,2]).**

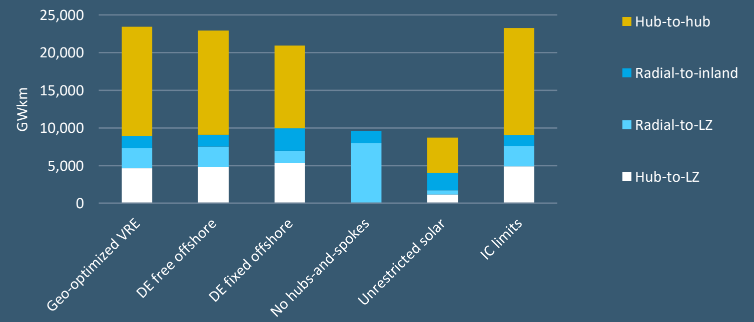
- A redistribution of onshore renewable energy in the Geo-optimised VRE scenario results in higher capacities of solar PV in southern countries and higher onshore wind in Norway and France, increasing system transmission needs in general, including the offshore grid.
- Limits on the interconnection towards southern countries in the IC Limits scenario have little impact on the offshore grid
- Higher solar deployment at the expense of offshore wind in the unrestricted solar scenarios reduces the offshore grid significantly
- Enforced deployment of offshore wind in the DE fixed offshore scenario reduces the location optimisation and decreases the size of the offshore grid. Main corridors however prevail.

See the following two slides for illustrations of the impact of sensitivities on the different offshore grid corridors.

Electricity transmissions buildout, system level



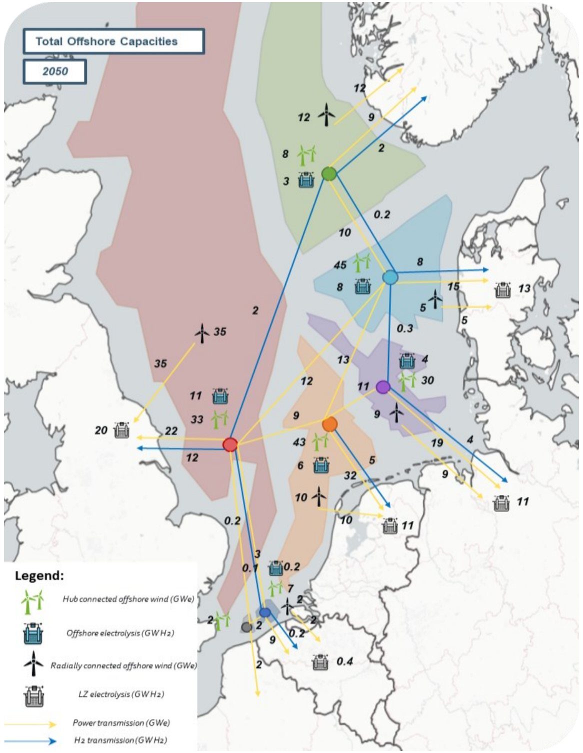
Electricity transmissions buildout, offshore wind



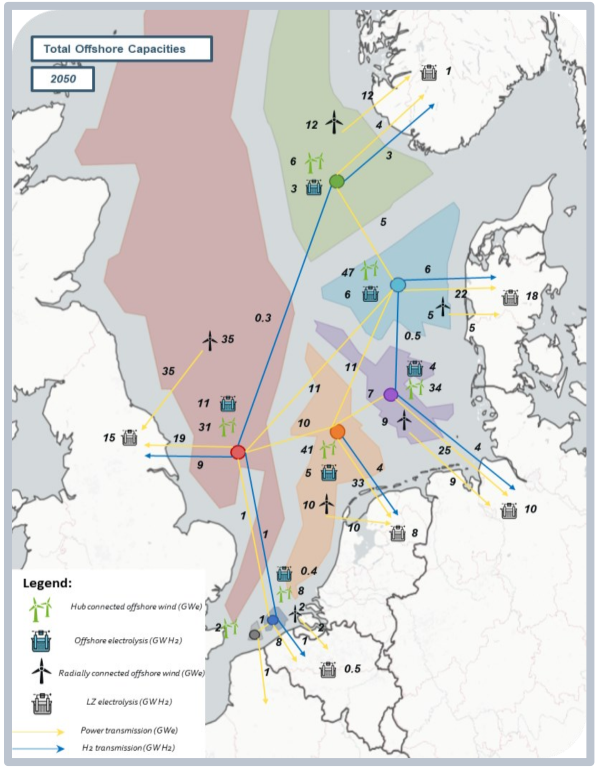
Note: Modelling detail on the grid is limited to the transmission between NUTS2-regions for the core countries and to bidding zones for countries further away from the North Sea (see Appendix). A maximum length of 100 km for connecting regions is applied for cost estimates. For large regions, internal transmission grid upgrades can therefore be underestimated. For buildout of onshore wind and solar PV, a generalised assumption on the grid reinforcement cost for the distribution grid are included, but distribution grid capacities are not explicitly modelled.

Overview of offshore transmission corridors, 2050 (1/2)

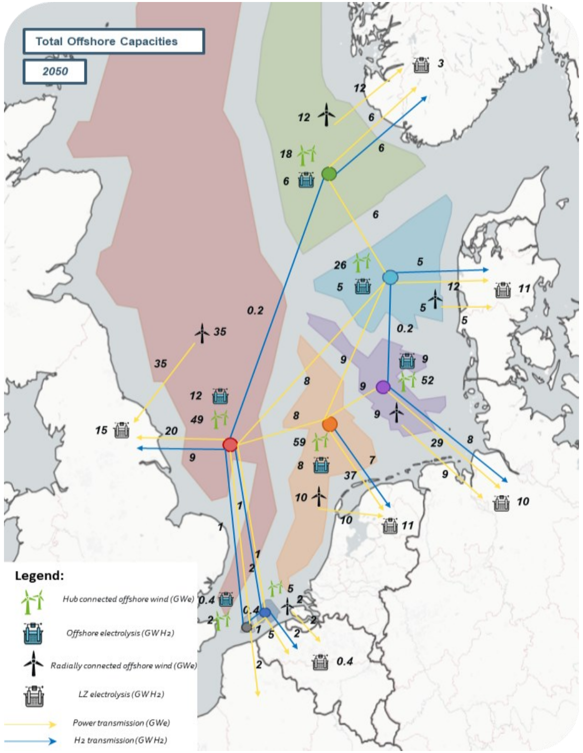
Geo-optimised VRE



DE Free Offshore



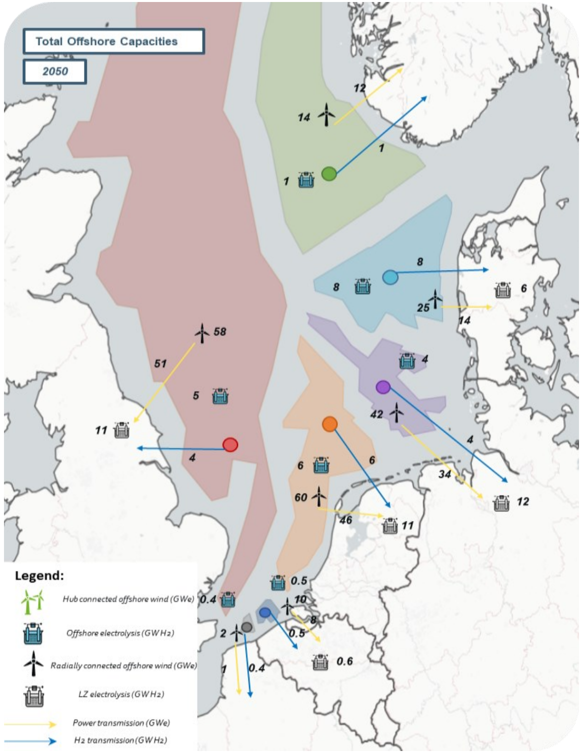
DE Fixed Offshore



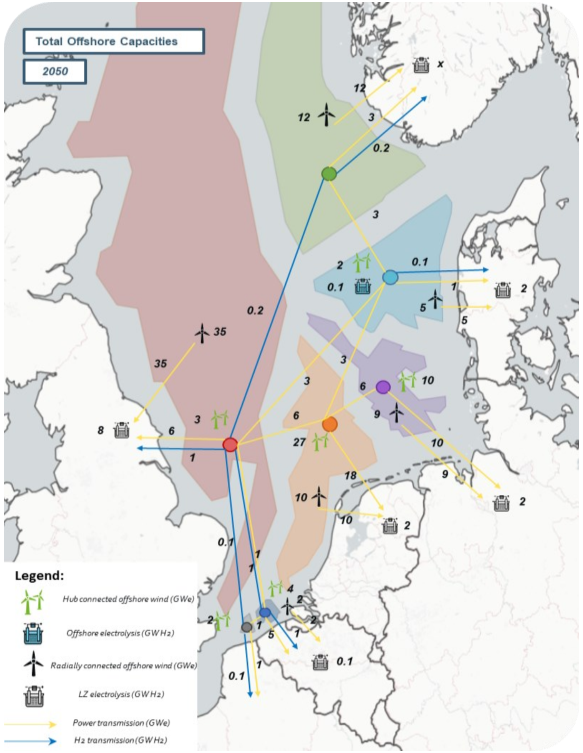
***Note:** The present figures are highly aggregated on a national level. For the fully detailed breakdown, refer to upcoming slides.

Overview of offshore transmission corridors, 2050 (2/2)

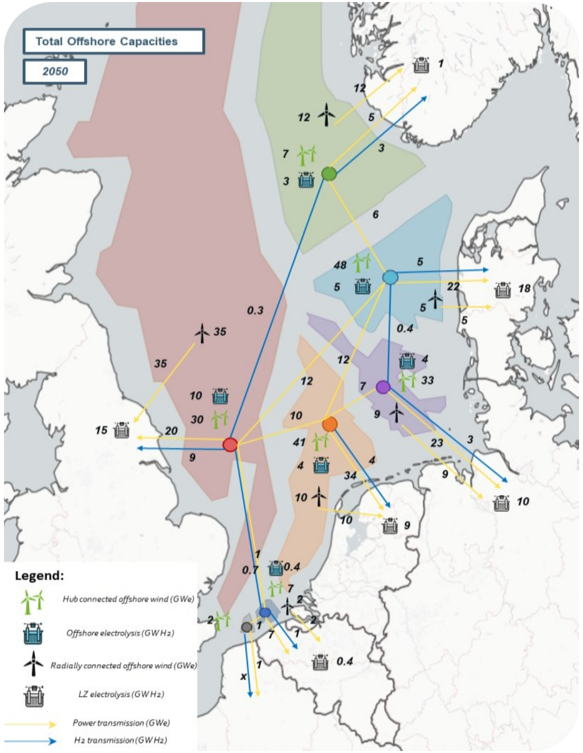
No Hubs-and-Spokes



Unrestricted Solar



IC Limits



***Note:** The present figures are highly aggregated on a national level. For the fully detailed breakdown, refer to upcoming slides.

Hydrogen production and offshore wind

Hydrogen production from offshore wind is based on a mix of both on- and offshore electrolysis

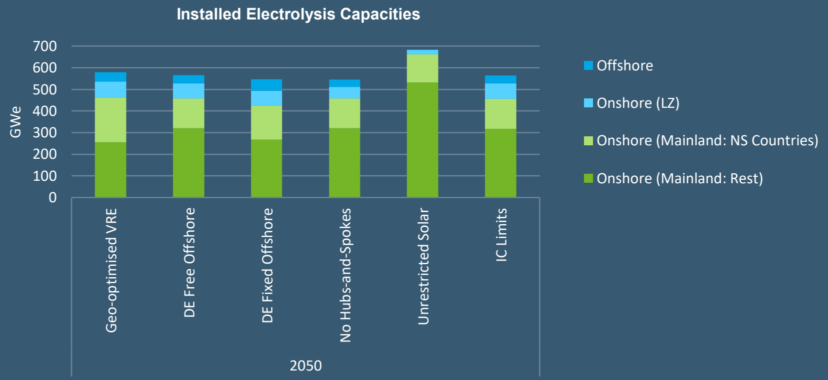
The majority of electrolysers installed in the system are onshore electrolysers in inland regions, as shown in the figure to the right. Much of this electrolyser capacity is **supplied by electricity from solar PV and onshore wind turbines.** A more detailed breakdown can be found in the Appendix.

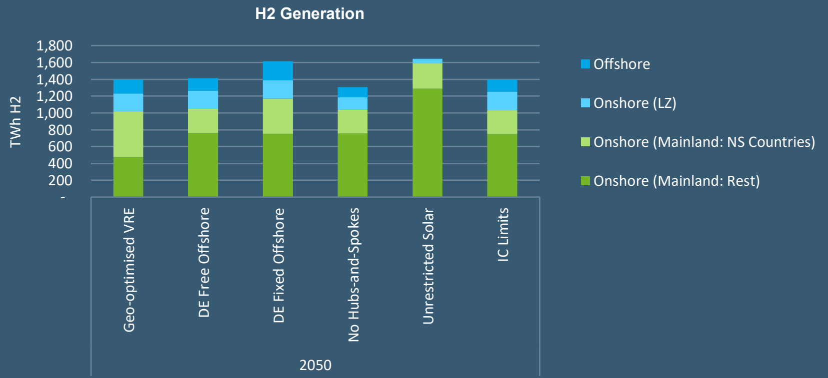
If the system was to produce hydrogen with offshore wind generation, the model has the option to place the electrolysers in either offshore or in a landing zone.

In 2030, there are no offshore electrolysers while 14 GWe is installed in landing zones. In 2040 however, there is 39 GWe installed in landing zones and 22 GWe offshore electrolysers, showcasing close cost competitiveness when accounting for system synergies. An illustrative cost comparison between onshore and offshore electrolysis is shown in upcoming sections.

Transitioning to 2050 electrolyser capacities are further increased both offshore and in landing zones, where electrolysers also have the advantage of being supplied by radially connected offshore wind farms, which are not part of the offshore grid.

The hydrogen production in landing zones and offshore can be heavily challenged by a higher solar PV buildout. No hubs-and-spokes buildout would also reduce the hydrogen production from offshore sites and in landing zones.





Note: A more detailed view of the capacity figure can be found in upcoming slides, where the development and placement of electrolysis capacities across years is presented.

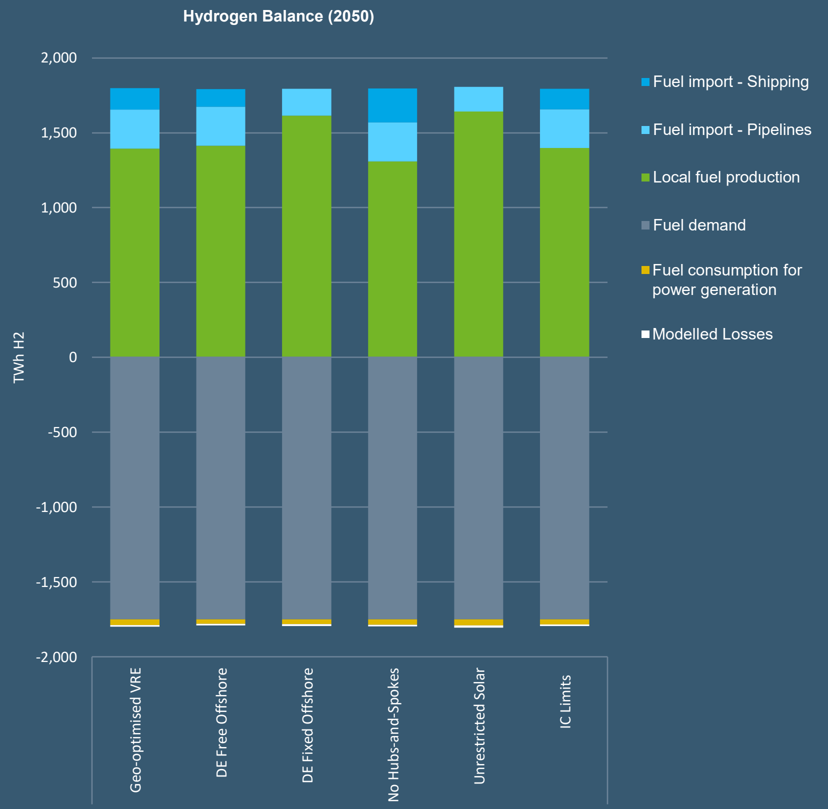
Local European H_2 production is cost-competitive to shipping imports from North Africa

Under none of the analysed sensitivities the level of H2 imports surpassed 27% of the modelled geography's needs. This could change, if the restriction on pipeline imports were relaxed (a maximum of 30 GW_{H2} pipeline-based import is applied). Hydrogen imports are impacted by the different sensitivities:

- In scenarios with enforced deployment of offshore wind or ample potential for solar power (DE Fixed Offshore, Unrestricted Solar) European hydrogen production becomes cost competitive even to the cheaper level of H2 import options (pipeline), thus decreasing imports.
- Without an offshore grid in the North Sea, integration options for offshore wind are less favourable reducing total offshore wind capacities and European hydrogen production and increasing the amount of imported hydrogen.
- Limits on the interconnection to Southern Europe as well as relocation of onshore VRE deployment have limited impact on the total imports, albeit increasing them slightly.

The role of hydrogen in the power system is expected to be limited, with H2-fueled back-up generators not surpassing ~250 FLHs of annual operation in the most extreme scenarios. Widespread use of hydrogen as dedicated long term storage (Power -> H2 -> Power) does not present a widely used option, limited to a role as a peak supply fuel.

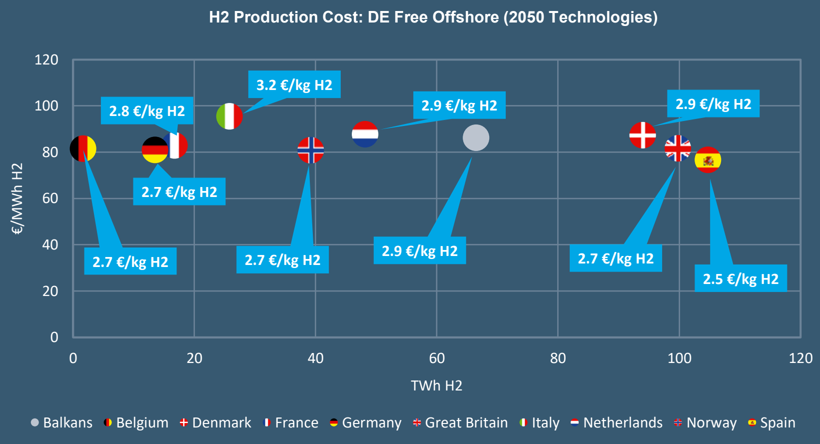
The operation of electrolysis units vary among regions. Solar PV heavy countries are characterised by 2,000-2,600 FLHs in 2050, while wind dominated regions rise this number to ~4,000 (on average).

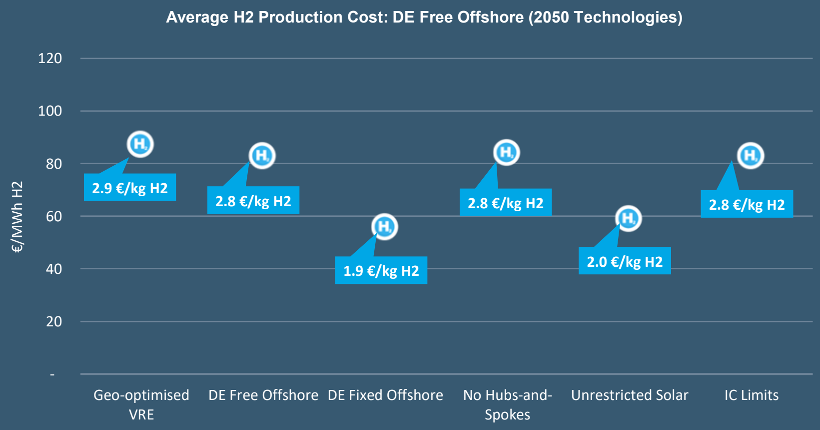


Hydrogen production cost

European average hydrogen production costs in 2050 are around 80 €/MWh in 2050. This includes CAPEX and OPEX for electrolysers and the impact of flexible operation at low electricity prices as well as marginal operation at higher electricity prices. A breakdown of production at different electricity price levels is found in the Appendix. Since the marginal willingness to pay for electricity electrolysers depends on the alternative supply option, the price for hydrogen imports by shipping of 77 €/MWh$_{H2}$ set a rough upper limit to production costs. The costs for storage and hydrogen transmission are not included in the direct production costs shown here but included in modelling. Transport costs within Europe can be an argument for choosing local production at higher cost over imports.

Since deployment of solar PV and onshore wind is fixed across scenarios, the marginal European hydrogen supply is based on offshore wind. The question is, whether this marginal supply is best placed offshore or in landing zones. As the two previous slides show, both options are part of the simulated scenarios. In all cases, both on- and offshore electrolysis benefit from system integration, but the degree differs. The topic is further elaborated on the following slide.





Note: Graphs show production costs for electrolysers established in 2050. Fleet average production costs are higher due to the lower efficiency and higher CAPEX of earlier vintages. LCOH of different technologies in different years can be found in the Appendix[i,ii].

Options for hydrogen production

Optimal placement of electrolysis is dependent on a number of factors and the role of the particular electrolyser in the system. The latter can change for the “first” and “last” electrolyser deployed.

Full flexibility: Electricity generation from offshore wind can supply either electricity demand or the electrolyser at all times.

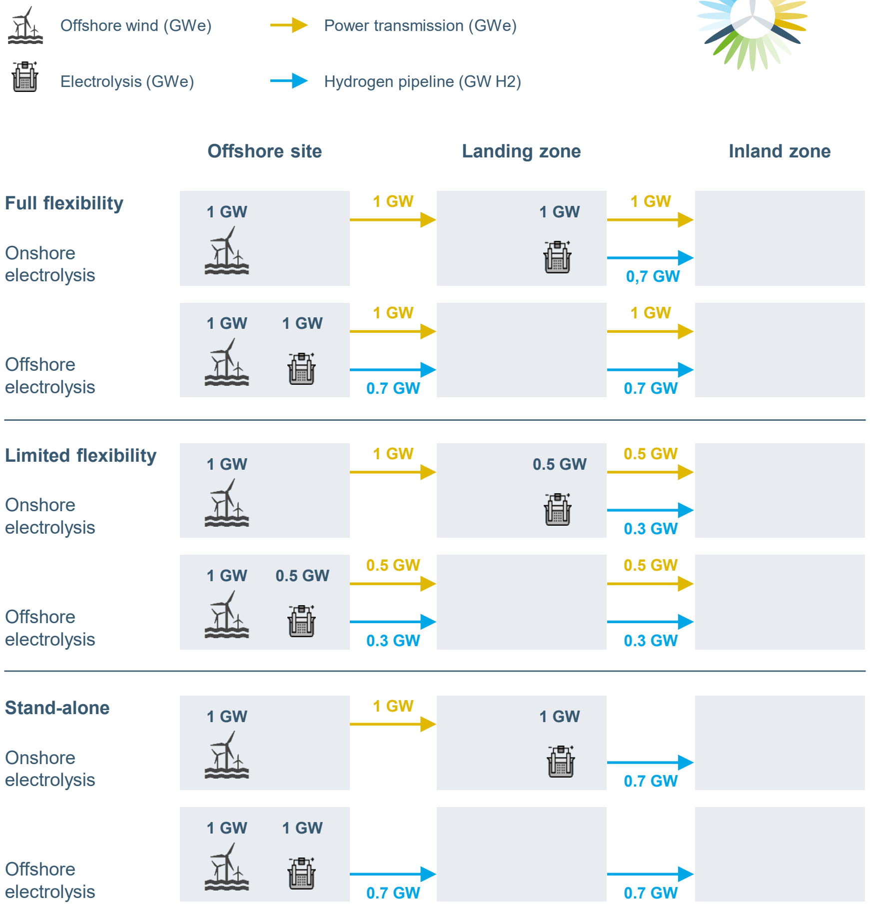
- As long as full flexibility is beneficial, there is value in supplying the inland zone with electricity, therefore placement in onshore landing zones is cost efficient. Placement offshore would not enable reduction in the electrical connection to shore, and therefore the additional costs for the more expensive offshore electrolysis cannot be offset.

Limited flexibility: Offshore wind capacity is higher than electrical connection to the inland zone. The system can still harvest synergies, since the full 1 GW of offshore wind capacity benefits from electricity exports, as long as generation is below 50%. When generation exceeds 50%, only the electrolyser can utilise it.

- In this case, placing the electrolyser onshore or offshore provides the same system synergy, and offshore electrolysis can be cost efficient, if the additional cost for the offshore electrolyser can be offset by savings in electrical connection to shore (cable and substations).

Stand-alone: Stand-alone hydrogen production provides no system synergies and while it is a principal option in the modelling framework, it is not used, and all hydrogen production is system integrated to some extent.

- The question whether onshore or offshore electrolysis is more cost efficient is the exact same as for the case of limited flexibility. Therefore, the stand-alone option can serve as an illustrative example, when comparing onshore and offshore electrolysis



Onshore vs offshore electrolysis

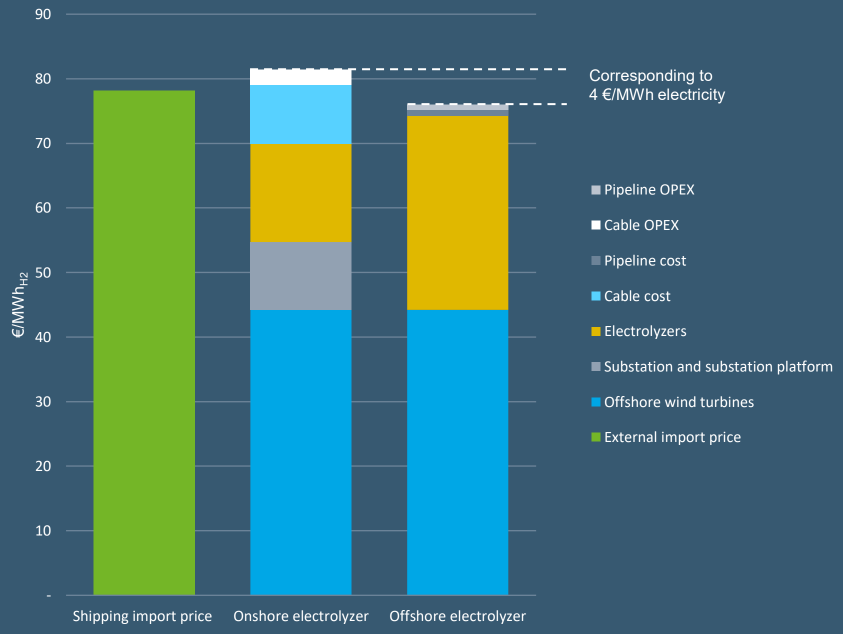
The production of hydrogen in Europe is in direct competition with shipping based hydrogen imports to Europe. The cost of shipping imports is based on a cost calculation of solar based hydrogen production in Northern Africa and transport by ship. As the graph on the right illustrates, hydrogen production based on offshore wind can be cost competitive to imported hydrogen, even without system synergies, but dependent on the LCOE of offshore wind at the respective site. As soon as significant system synergies can be achieved, European hydrogen production is cost efficient, which explains why imports based on shipping are limited. Additional considerations can be the cost of storage (included in modelling, but not shown here).

The question of offshore versus onshore electrolysis is also illustrated by the example on the right: If cable and substation cost cannot be saved by placing an electrolyser offshore, onshore electrolysis will be more cost efficient. This would be the case for the “first” buildout of hydrogen production where full flexibility is needed (see previous slide). Or put in another way: System benefits as low as around 4 €/MWh of electricity would mean, that onshore electrolysis is cost efficient.

However, the marginal buildout, which only provides *limited flexibility* with respect to the option for sending electricity to the inland zone, can prove to be cost efficient offshore. The reasons are slightly lower cost of offshore electrolysers and pipelines compared to onshore electrolysers, cables and substations. A requirement however is, that large production potentials can be pooled at central hubs to ensure sufficient use of the large hydrogen pipelines (small pipelines would be more costly and would therefore change the comparison).

Landing zones additionally provide the option to pool generation from a number of radially connected closer-to-shore offshore sites, which would be too small to individually justify offshore hydrogen production.

LCOH (2050) – Illustrative example for standalone hydrogen production
Offshore Area 160 km from shore in Danish waters



Note: For areas closer to shore, the difference between offshore and onshore electrolysis is lower, as pipelines are cheaper than cables pr km, and their absolute cost-advantage therefore increases for longer distances. Electrolyser costs offshore include platform costs. As this is an illustrative example of stand-alone application electrolyser capacity equals offshore wind capacity – both on- and offshore.

Landing zones support the integration of offshore wind in the onshore system

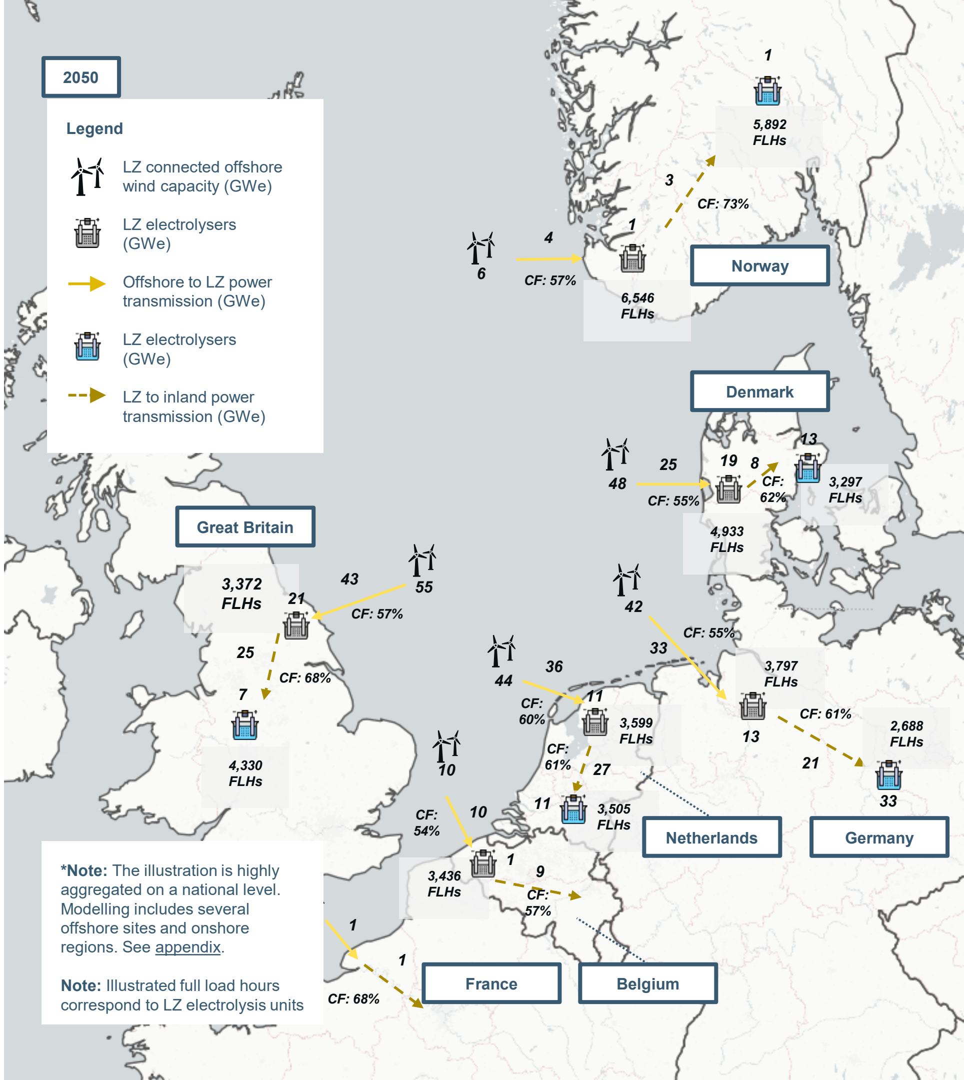
Landing Zones (LZs) stand in the middle of offshore regions and the onshore system. Electrolysers found on LZs aim to harvest the benefits of collecting electricity from multiple offshore sites, but also from power coming through the mainland. Electrolysers can operate as flexible units during hours with low power prices or when the available onshore VRE generation surpasses the local demand but interconnections to other demand regions are congested.

An evident role of LZ-electrolysers towards the integration of increased VRE power emerges, where increased power transmission investments are prevented or expensive and electrolysers can utilise power generation during periods with high VRE infeed. Electrolysers invested in LZs generally operate for longer hours (higher FLHs) when compared to the corresponding inland units, which need to be more flexible to capture low electricity prices. LZ electrolysers operate on average ~570 FLHs above the inland units, while transmission lines from LZ to mainland reflect on average 8 CF percentage points (~690 FLHs) higher versus lines from offshore to the LZ.

In the North Sea, from the 149 GW of offshore power transmission that reaches the LZs (DE Free Offshore, 2050), only 93 GW continues to the mainland. The rest is directed to the 66 GWe LZ electrolysers, which are connected via 51 GW_{H2} pipelines to inland zones.

NS LZ (2050)	NS Offshore Electrolysis GWe (FLHs)	NS LZ Electrolysis GWe (FLHs)	Inland Electrolysis GWe (FLHs)	Offshore-to-LZ Power Connection GWe (FLHs)	LZ-to-Mainland Power Connection GWe (FLHs)
BE	1 (3,827)	1 (3,436)	- (-)	10 (4,747)	9 (4,943)
DE	6 (4,362)	13 (3,797)	33 (2,688)	33 (4,789)	21 (5,322)
DK	8 (4,027)	19 (4,933)	13 (3,297)	25 (4,789)	8 (5,434)
FR	- (-)	- (-)	- (-)	1 (5,214)	1 (5,955)
GB	14 (5,860)	21 (3,372)	7 (4,330)	43 (4,929)	25 (5,907)
NL	6 (4,770)	11 (3,599)	11 (3,505)	36 (5,281)	27 (5,348)
NO	4 (5,836)	1 (6,546)	1 (5,892)	4 (4,988)	3 (6,408)

Note: FLH values represent weighted averages across the corresponding national regions. DK_E and DE_8 are located on the south west side of Denmark but not visualised in the present map. Offshore connections reflect all connections to the referred LZ. Onshore connection represents the connection of the LZ to its parent region (inland).



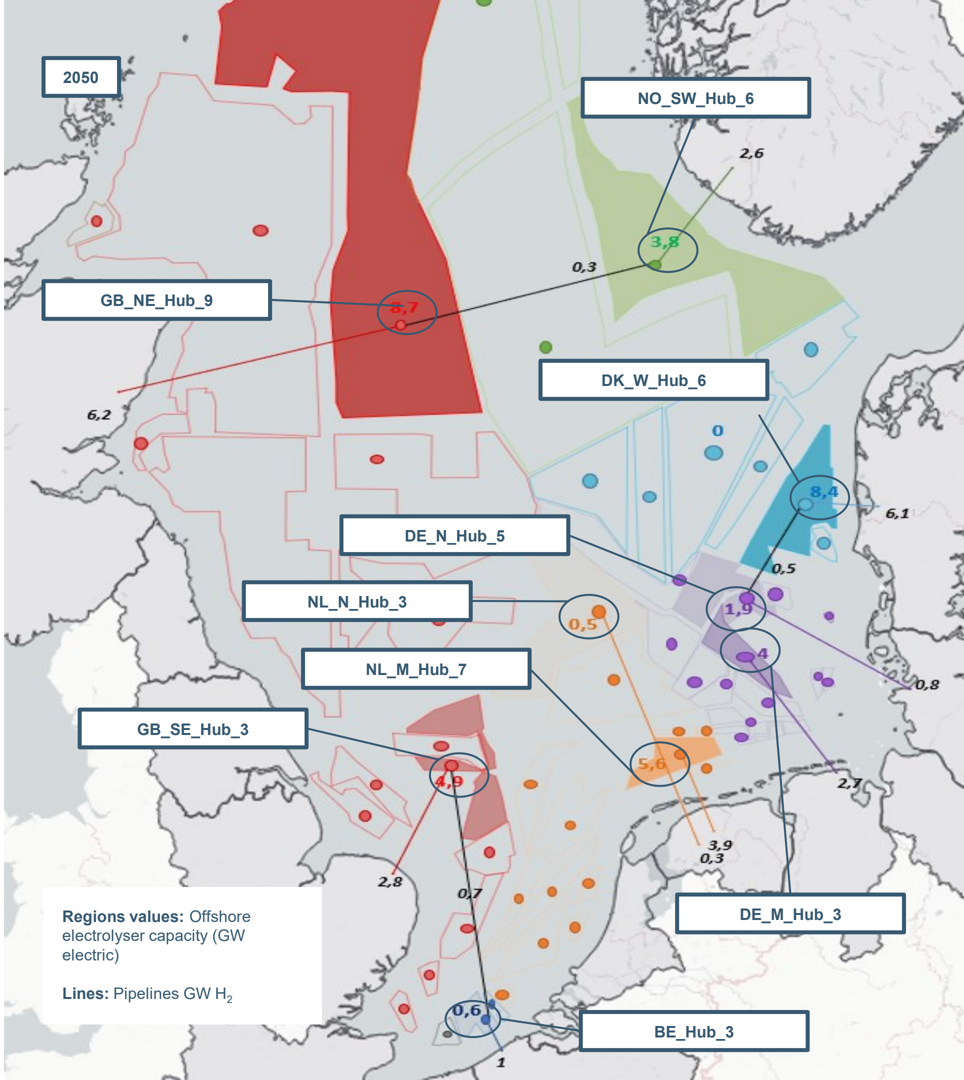
Offshore hydrogen production is mainly transported to shore radially

Offshore hydrogen production potential is mainly transported radially to parent regions, but a part of the transmission network is also connected to other hubs for transporting hydrogen to other countries. All sites with offshore electrolysis are also connected to the electrical grid. Each site has an optimised wind capacity/electrolyser capacity/substation capacity ratio. The option to save substation capacity is vital for the economic case of offshore electrolysis. However, the real-world configuration has yet to be proven, and the AC-grid has to have sufficient size to ensure supply to the electrolysers. Options for “hydrogen-array-grids” have not been explored.

The presence of an exogenous to the model starting hydrogen network, reflecting the EHB’s 2030 plans, could from an economic point of view limit the necessity of a more extensive offshore H2 network, the evaluation of which is however out of the scope of the present study.

Site / [GWe]	Wind Capacity	Electrolyser Capacity	Offshore sub-station capacity	Cable Capacity to LZ	Cable to other Hubs	Wind Generation	Electrolyser Consumption	Transmission Flow – Out
BE_Hub_3	7.8	0.6	6.2	7.5	2.2	31	2	29
DE_M_Hub_3	6.5	4.0	2.5	2.6	1.4	27	18	10
DE_N_Hub_5	4.0	1.9	2.0	1.6	1.9	17	8	9
DK_W_Hub_6	19.9	8.4	11.1	10.0	3.5	87	33	54
GB_NE_Hub_9	13.7	8.7	5.1	2.3	3.9	64	52	13
GB_SE_Hub_3	8.6	4.9	3.3	8.5	15.6	34	28	6
NL_M_Hub_7	8.5	5.6	2.7	2.8	2.4	32	26	6
NL_N_Hub_3	1.3	0.5	0.7	5.9	16.9	6	2	4
NO_SW_Hub_6	6.2	3.8	2.1	3.9	4.9	29	22	7

Note: Table shows DE Free Offshore scenario for 2050



Discussion and conclusions

Offshore wind, grids and hydrogen production in Europe

The current study shows how offshore wind can play an important role in Europe's energy system, if a pathway towards net zero including increased demands for hydrogen and electricity is pursued. In total 350 GW of offshore wind are deployed in the main scenario, but up to 500 GW are part of sensitivity calculations enabling increased hydrogen production, and therefore competitiveness to imports from cheaper "external" sources (North Africa). Even at high deployment of solar PV, offshore wind plays an important role with a European capacity of around 200 GW. However, potential impact on offshore capacities illustrates that offshore wind is the marginal source for electricity and subsequent hydrogen production in Europe.

Hubs-and-spokes in the North Sea, as well as flexible hydrogen production offshore and in landing zones help integrating offshore wind power. Hydrogen demands ensure a minimum value of "high" offshore deployments, as long as imported hydrogen can be replaced with additional local production. In general, the large amounts of electricity use for hydrogen across the entire system provides a very important source of flexibility. Hydrogen dedicated for power generation, on the other hand, is limited to supplying peak demand while power->hydrogen->power conversion patterns do not have a large role in storing energy.

Deployment of hubs-and-spokes in the North Sea can improve energy independence and facilitate larger offshore wind deployment compared to a pure radial buildout. Hubs-and-spokes concepts can show socio-economic benefits of around 1 €/MWh of offshore wind in the North Sea. However, while cost efficient, the absence of hubs-and-spokes has a limited impact on the wider European system in economic terms, as it only constitutes a smaller share of total system costs. Therefore, political assessments of the value of risk management (e.g. against delays in deployment of grids and generation capacity onshore), energy independence, security of supply and resilience across different climate years can play a decisive role for hubs-and-spokes. These topics deserve further attention.

Key drivers for hubs-and-spokes in the North Sea are system integration and the option to deploy wind at the most cost-effective sites across the entire North Sea. A corridor connecting Denmark and the Nordic system with the UK and Netherlands is consistently part of the optimal system setup across analysed sensitivities.

Comprehensive modelling framework

Pathway 2.0 employs a high level of detail aiming to rise the ambitions of international sector-coupling modelling-based analyses:

1. **Input data & spatial granularity**

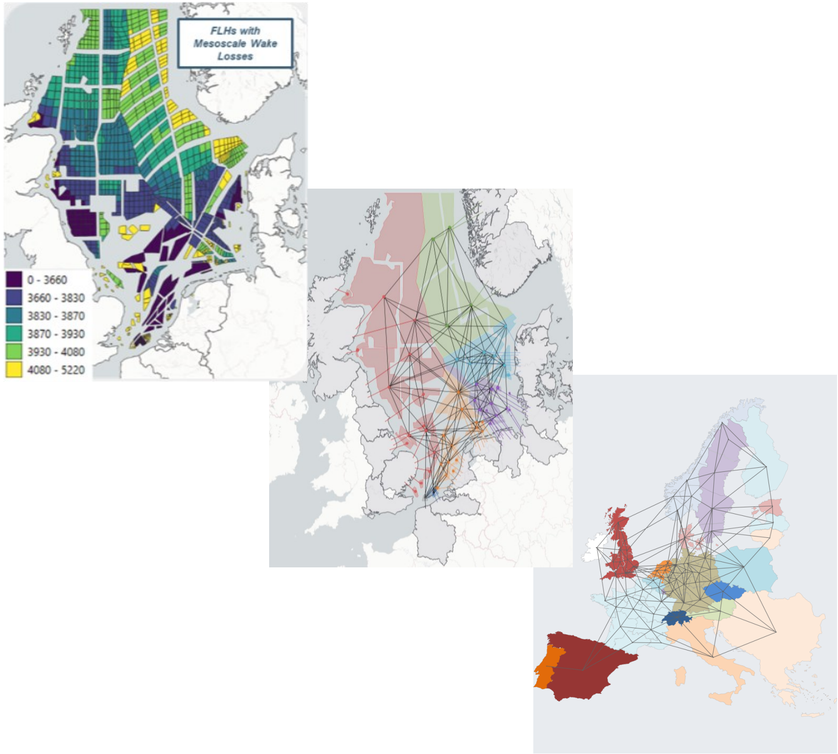
   - High spatial granularity (NUTS1-2 level) for key data on consumption, existing supply system and interconnection options has been applied. Data has been disaggregated[i,ii] from the country level TYNDP values (available online) as well as by supplemented estimates for the transmission system.

2. **Offshore wind and variable renewable generation**

   - New fine grained spatial wind data, including engineering and meso scale wake losses[iii] has been developed by DTU Wind, covering both resource qualities and potentials for offshore wind across the entire North Sea (available online).
   - Data for onshore renewable resources (onshore wind and solar) are aligned with the climate-conditions of the detailed offshore wind data.
   - Model simulations use aggregation of the detailed offshore wind data on clusters in order to reduce calculation times[iv].

3. **Model setup**

   - Simultaneous optimisation of onshore and offshore transmission infrastructure, generation capacity, batteries and hydrogen storage to supply demand. The applied spatial resolution around the North Sea allows for adequate consideration of the investments needed to integrate offshore resources.
   - Truly sector coupled model that minimises system costs to simultaneously meet both hydrogen and electrical end demands[v].
   - Employing novel concepts as landings zones along with hubs and spokes[vi].



Sector-coupling is a driver for hubs-and-spokes

I. What are the drivers and design principles for possible integration routes, in the context of the roll-out pathway of the first and following hubs-and-spokes projects?

The value of hydrogen production plays a vital role for system integration of the large amounts of offshore wind and close to 50% of the offshore wind energy ends up as molecules[i] across all sensitivities.

More sophisticated offshore wind design approaches than today's main approach of radially connected offshore wind should be deployed towards 2050. An efficient energy system also consists of:

1. **Landing zones with flexible consumption**
   - Allow efficient integration of electricity from offshore wind (and at times even onshore generation), which can be converted and stored as hydrogen, alleviating the pressure for excessive transmission infrastucture[ii].
2. **Offshore electrolysis**
   - Along with onshore and landing zone electrolysers, offshore electrolysis enables a higher utilisation of the offshore electricity grid[iii].
3. **Hubs-and-spokes**
   - Allow for simultaneous use of electrical infrastructure for interconnection and landing of offshore electricity.
   - The main benefits from offshore electricity networks are based on large-capacity corridors[iv].
   - Hubs-and-spokes facilitate a larger integration of offshore wind via wind sites further from shore[v], while enabling a higher degree of European hydrogen self-sufficiency[vi].
   - Drivers for North-South and East-West corridors are different[vii], and East-West corridors are more dependent on the total offshore wind buildout needs.

It is important to note that the 3 components can be used independently, but the full benefits for spokes are not realised without all three components leading to a "full system integration package"[viii]. It is the combined effect of all 3 that enables higher utilisation rates of spokes, that in turn supports development of far offshore areas[v].

Ambitions for a self-sufficient European energy system would enhance the need for offshore wind with only minor increases in total system costs[ix].

Energy system perspectives

- Roll out of solar PV[x], dependency of import levels of hydrogen[xi] and energy efficiency will impact the need of offshore wind (see next slide).

- The Pathway 2.0 is a sector coupled model that optimises both onshore and offshore systems simultaneously, leading to decreased system costs against a scenario with independent optimisation attempts. The magnitude of savings may be addressed in follow up studies.

- Throughout all sensitivities, a robustness of competitive pipeline-based hydrogen imports from North Africa is observed[xii]. Marginal H2 production from offshore wind cannot, in most cases, compete with pipeline imports from North Africa.

- Electrolysers are the largest balancing assets by 2050[xiii]. All hydrogen production is system integrated within the study results. Flexible consumption aids a direct system electrification through VRE sources and overplanting, as an alternative to time-shifting measures.

- Absence of hubs-and-spokes yields a higher need of biomass for electricity generation[xiv].

Optimal deployment of offshore wind is a multi-variable equation

II. What are the key challenges on both a national and transnational level for the integration of offshore wind?

The roll-out of offshore wind in the North Sea is a challenge which requires considerable attention for planning on both a national and transnational level:

- 300 GW offshore wind in the North Sea corresponds to 20.000 offshore wind turbines of 15 MW per unit.
- These will cover an area of approximately 30.000 km^2 (=the size of Belgium) in seven Exclusive Economic Zones (BE, DE, DK, FR, NL, NO and UK).
- The shear amount of offshore wind turbines, and therefore also converter platforms, electrolyser platforms, cables and pipelines, hub-to-hub and shore interconnections could potentially lead to bottlenecks.
- Meso-scale wake-effects can lead to benefits from larger geographical distribution of offshore wind compared to current roll-out plans at a national level.
- Countries take individual decisions and will develop through the energy transition towards climate neutrality at different paces. For example, Denmark in 2030 is at the stage of higher RES supply compared to national demand. Naturally, a question arises on how offshore wind should further develop in a way that decisions made at a national level also result in an efficient offshore wind roll-out on a transnational level. For this, planning on a national level while working towards a common understanding of the end picture of North Sea offshore wind development is needed.

The integration of offshore wind benefits from timely development of both electricity and hydrogen markets as well as the onshore and offshore energy systems, however:

- This comes to a contrast with today, where planning focuses primarily on build out of generation[ii,iii], which can be done due to the possibility of ”turning down” production levels of conventional plants. But when the need for ”flexibility up” start to occur locally, introduction of flexible consumption with for example electrolysis is key[iv].
- The pathways in this study illustrate that large amounts of offshore wind is integrated in landing zones. A slower development of these landing zones will significantly impact the system and the cost of integrating offshore wind[v].
- Onshore interconnection limits towards Southern Europe have limited impact on the build-out of the offshore system[vi].
- Placing onshore VRE more optimally can provide system savings, but additional needed onshore grid build out (12% and timing) may not be feasible[vii].

The need for power plants remains important, but the business case of the conventional as well as hydrogen fueled power plants might become a challenge due to the needs for high capacity (GW) at low utilisation (FLHs)[vii]. The ambition to decarbonise the electricity system by 2035 could create a pull for low carbon fuels, but no such target was included in the study.

Recommendations

- Increased focus on joint build out of generation and consumption, accompanied with incentives to guide energy system development: Investment incentives, subsidy schemes, CFDs. PPAs affects the system’s consistency, but can also be used to ”force” the system in the right direction
- The socio-economic optimum from Pathways sets a different magnitude and spatial distribution of offshore wind compared to the political national ambitions. As a result, a higher degree of European self sufficiency can be observed[viii].

Study Insights

- Large-scale far-offshore wind can be challenged by extensive solar PV roll-out. However, spokes between hubs still emerge as a cost beneficial design principle[ix]
- Only the Unrestricted Solar scenario has a significant impact on the Hubs-and-Spokes buildout in the North Sea and electricity system build out[x]. In this case, robust hub locations are limited to the Netherlands, Germany and the UK[xi].

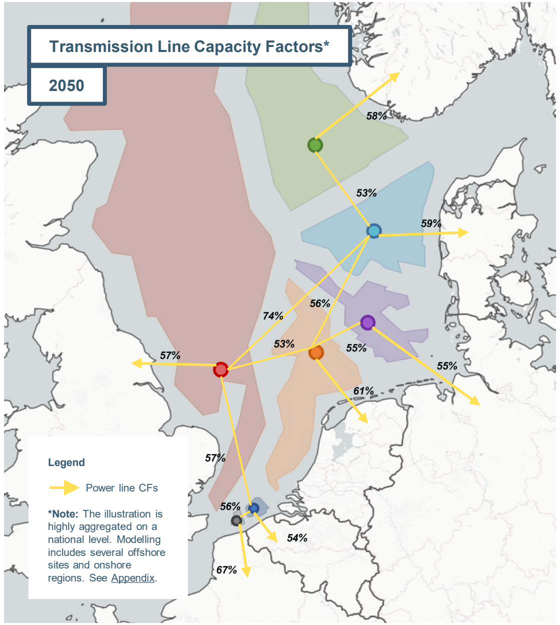
Hubs-and-spokes enable far-offshore wind

III. How robust is the hubs-and-spokes concept to various factors? (1/2)

The utilised model has a broad set of investment options[i,ii]. From all of these options, the model's optimal least-cost solution points to investments in hubs-and-spokes across all sensitivities that connect offshore hubs across the North Sea. If spokes are not allowed, the far-offshore locations are not chosen for investments while individual countries to a higher degree focus on serving own needs with wind, as the model does not find large investments in enhancing IC routes to replace the hybrid interconnections efficient[iii]. Thus results illustrate, that hubs-and-spokes allow for a larger degree of inter-country integration of the socioeconomic most valuable wind options. Hubs-and-spokes robustly deliver:

- Well connected consumption areas and offshore production sites.
- The possibility to utilise far offshore wind locations through a North-South transport corridor.
- Even in the Unrestricted Solar sensitivity, where much less wind is needed, hubs-and-spokes remain a significant part of the offshore wind system[iv].

It is the high utilisation rate of spokes that renders them as attractive investment candidates. High utilisation is achieved by taking advantage of the spatiotemporal variation of wind and by positive interactions between landing of electricity, interconnection of bidding zones and very importantly flexible electricity consumption (i.e. electrolysis) in landing zones and offshore. Thus, spokes achieve their value through sector coupling and not "just" by allowing hybrid utilisation as trading and landing cables.



2050 wind technologies reflect a CF of ~42-54%. Flexible consumption along with inter country trading enables the average CF of the combined infrastructure to be higher. This is the key reason why the model finds it advantageous to invest in hubs and spokes[v,vi].

Further Work Needed

- Electricity and hydrogen assets can be interconnected in many ways; turbine level, clusters, platforms etc. Studies outlining the most promising concepts will be of great value to guide development offshore. The present study takes an approach at platform-level but more effective integration may exist.
- Costs of DC breakers are maturing. Inclusion of these will increase costs which can soften some of the appetite to invest in interconnection using scopes.
- How do offshore interconnections off the North Sea affect the resiliency of the European power grid? Spatio-temporal differences of renewable generation and consumption are expected to be utilised more in an interconnected system. However, calculating such value was out of the scope of Pathway 2.0. Such value can be very pronounced across climate years.
- Each hub has its own offshore bidding zone (OBZ). In practice, transmission bottlenecks will arise within hubs as well. Additional methods to evaluate the significance of these limitations should be examined in combination with infrastructure models.

Which hubs-and-spokes are most robust?

III. How robust is the hubs-and-spokes concept to various factors? (2/2)

A North-South transport corridor for electricity is more robust than an East-West corridor[vii,viii]:

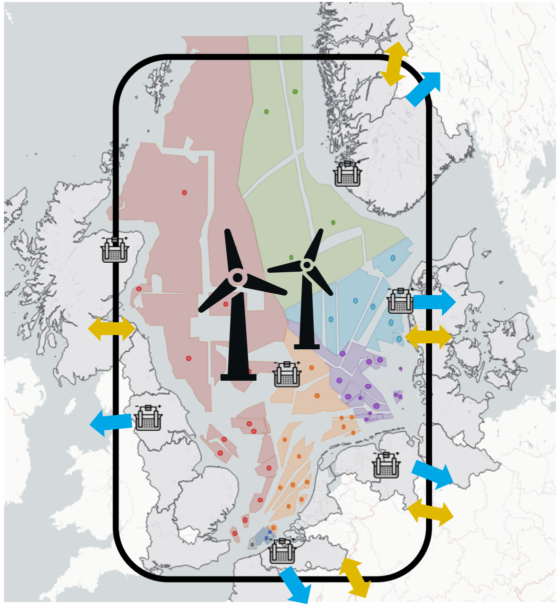
- The North-South corridor is present in all sensitivities allowing for hubs-and-spokes.
- In the *Unrestricted Solar sensitivity,* less wind is invested in. In this sensitivity the North-South corridor stays relatively intact while the East-West corridor weakens, with lower power imports for the UK, translating to lower local H2 generation and higher H2 imports from southern Europe via France.
- In the *Geo-optimised VRE sensitivity,* the good conditions for onshore wind in northern parts of Scandinavia is utilised. In this sensitivity the capacity of the North-South corridor is increased, while the East-West stays more or less unchanged[ix].

Southern hubs are the most robust:

- Hubs in the southern North Sea, closer to consumption centres, are more robust than northern hubs. This is seen in the *Unrestricted Solar sensitivity* where southern hubs are still present[x].
- As the North-South corridor is still present in *Unrestricted Solar*, it is noted that additional wind can be utilised (if planned for) along this route (as discussed in the previous page)

Sector-coupling of the North-Sea is very robust:

- Flexible consumption is an important driver for achieving high utilisation rate of electrical spokes connecting hubs (as discussed in the previous page).
- We see a balancing of pure electricity and hydrogen landing in the North Sea across all sensitivities[xi]. System integration thus adds value not captured by either pure electricity or hydrogen landing.
- Domestic hydrogen production, both near coast (landing zones) and offshore is robust.



Across all sensitivities 56-88% of all wind are exported as electricity while 12-44% of the offshore energy leaves the North Sea energy system as hydrogen from either landing zones or offshore electrolysis. It is thus important not to interpret North Sea resources as either electricity or hydrogen potentials, but as an opportunity allowing a large sector-coupled system that enables an electrically very interconnected system.

Importance of hubs-and-spokes grows over time

IV. How does the first hubs-and-spokes project to be realised in the early 2030s fit into the broader pathways toward 2050?

Already in 2030, the economic attractiveness of hubs-and-spokes is realised in some locations[i,ii].

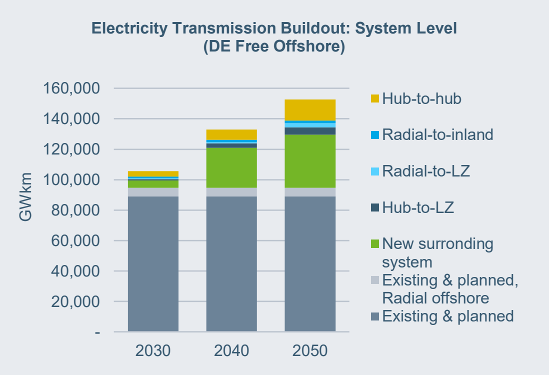
- Still, the majority of offshore wind capacities are connected radially.
- Electrolysers are mainly installed in landing zones or further onshore.
- Hubs mainly profit from an increase in electrical trading possibilities.
- The economic attractiveness of hubs is subject to possible technical limitations present in 2030 (i.e. availability and resulting cost of DC circuit breakers which are important to facilitate the effective routing identified by the Pathway model).

The role of hubs-and-spokes increases from around 2040 and beyond, especially for far offshore wind locations (i.e. due to the shorter cable lengths between the single platforms)[iii,iv].

A gradual development of hubs-and-spokes is also materialised in locations initially connected radially before 2040. Thus, modularity and scalability (i.e. at low additional investment cost) are interesting topics to consider in first projects. Incremental buildout of hubs-and-spokes will be a challenge for the current design of offshore tenders.

In general, hubs and spokes profit by facilitating in parallel the overplanting of installed wind capacities, offshore electrolysis and the resulting increased utilisation of electricity lines (as discussed in conclusion I and previous NSWPH studies[v]). The deployment of hubs-and-spokes in the scenario follows an incremental pathway. How tender design can support such a development deserves further attention.

Considering the undertaken sensitivities, the amount of renewable energy seems correlated with the investments in hubs-and-spokes. Integrating more renewable energy (i.e. in later years) requires higher levels of flexibility and interconnection amounts[vi].



Further Work Needed

- The hubs-and-spokes concept requires more detailed technical analysis. Current modelling focuses on high level connections based on supply & demand which deviate from connecting the network and related physical effects in real life situations.
- The methodology on how to look at CBA from a total system perspective towards CBAs for single projects requires more research and development[v]

Contributions to the energy trilemma

Accelerated
green transition

Security of supply
in a changing world

Affordability
also in the future

- Hubs & spokes can:
  - Facilitate larger OSW development compared to purely radial build out.
  - Help to reduce the need for biomass and dispatchable energy.
  - Provide timewise short cuts to onshore build out.
- Across sensitivities a north-south corridor across the North Sea is consistently part of the optimal system.
- System integration of hydrogen production through flexible consumption of electrolysers is important to effectively integrate fluctuating renewables.
- Electrolysers in an integrated system prevent zero-valued renewables and increase the utilisation of electrical infrastructure.

- Hub-and-spokes enable more cost-efficient utilisation of far shore wind.
- Ambitions for import of hydrogen and solar build out in Europe impact the need of OSW. In a low offshore wind case, ~200 GW OSW is required in the system, rising to 500GW in a high case.
- The costs of hubs-and-spokes are a minor part of total system costs. If self-sufficiency of H2 is not key, hubs-and-spokes can be left out with an added cost increase of 1 EUR/MWh for the system.
- The various analysed future routes for a renewable energy system result in similar infrastructure costs, providing room for policy choices towards a net-zero system.

- Large scale offshore wind (OSW) plays a central role in a net zero European energy system.
- The required level of European self sufficiency and the need for hydrogen affects the required OSW build out.
- Flexible consumption renders OSW, when exiting a landing zone, to resemble a power plant more than traditional wind
- Hydrogen for power plays a small role as storage. However, it serves an important role of supplying peak demand when wind and solar is limited, at limited occasions.
- Hubs-and-spokes can provide more robustness and resiliency to the system, as more energy highways are present to ensure back up in case of unforeseen events and unfavorable climate years.

Appendices

Appendix I – Data and Assumptions

List of Main Data Sources

Data type	Source
Fuel & CO_2 Prices	IEA (WEO22)
Power & Hydrogen Demands: Annual Amounts & Variation Profiles	ENA
Onshore VRE Potentials & Variation Profiles	DTU Wind
Offshore Wind Potentials & Variation Profiles	DTU Wind
Power Generation & Storage Costs	DEA (Technology Catalogue)
Power Transmission Costs	TenneT & Energinet
Power NTCs	Energynautics
H_2 Generation, Use & Storage Costs	Gasunie & Energinet
H_2 Transmission Costs	Gasunie & Energinet
H_2 NTCs	Energynautics
H_2 Import Prices from 3rd Countries	Ea
Modelling Approaches (Balmorel)	Ea

Notes:
NSWPH consortium includes TenneT, Gasunie and Energinet (**Source:** https://northseawindpowerhub.eu/).
DTU Wind: Technical University of Denmark (**Source:** https://wind.dtu.dk/).
ENA: Energynautics (**Source:** https://energynautics.com/en/).
Ea: Ea Energy Analyses (**Source:** https://www.ea-energianalyse.dk/en/).
DEA: Danish Energy Agency (**Source:** https://ens.dk/en/our-services/projections-and-models/technology-data/technology-data-generation-electricity-and).
IEA: International Energy Agency (**Source:** https://www.iea.org/reports/world-energy-outlook-2022)

Geospatial Resolution of the Analysis: Onshore

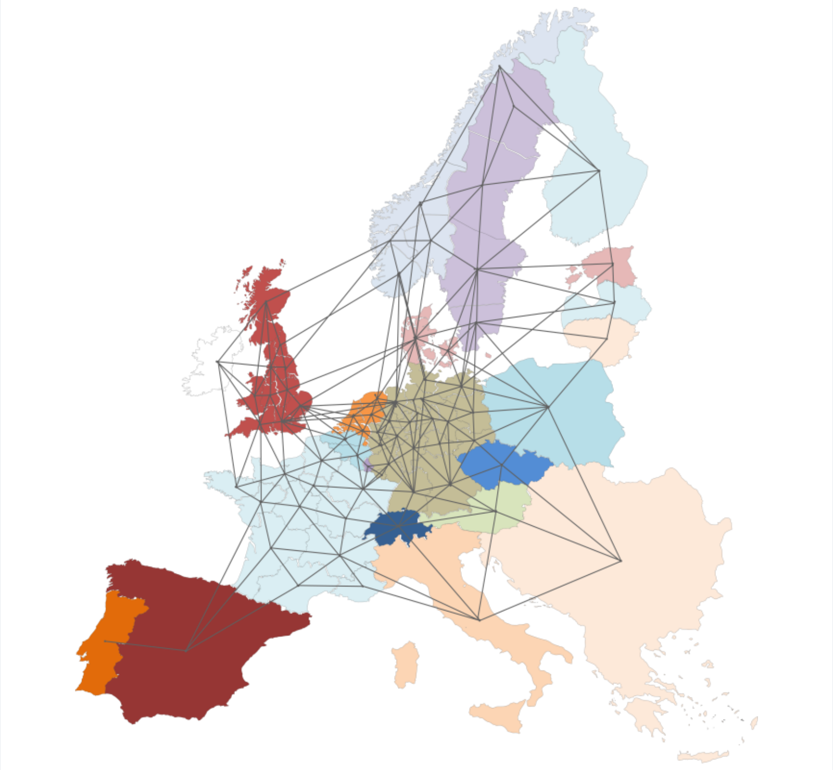
The onshore geospatial resolution showcased across the following analysis is based on a combination of Eurostat's NUTS1-2 territorial units for statistics[1], in an attempt to capture the most important regional differences and transmission needs in the most adequate way. More specific definitions of those boundaries are:

- NUTS 2-resolution: High level of detail for key North Sea Countries
- NUTS 1-resolution: Applied for the wider geographical scope

In detail, the modelled onshore geography is reflected in the following breakdown, and can be seen on the right:

- **21 Countries[#Nodes] + 1 Group of Countries**: Austria (AT[1]), Belgium (BE[2]), Czech Republic (CZ[1]), Denmark (DK[2]), Estonia (EE[1]), Finland (FI[1]), France (FR[12]), Germany (DE[20]), Great Britain (GB[11]), Ireland (IR[1]), Italy (IT[1]), Latvia (LV[1]), Lithuania (LT[1]), Luxembourg (LX[1]), Netherlands (NL[4]), Norway (NO[5]), Poland (PL[1]), Portugal (PT[1]), Spain (ES[1]), Sweden (SE[4]), Switzerland (CH[1]) and the Balkans (BK[1]) (Albania, Bosnia & Herzegovina, Bulgaria, Croatia, Greece, Kosovo, Montenegro, North Macedonia, Romania, Serbia and Slovenia).

- **74 Onshore Regions**
- A series of distinctive areas within each region.
- 444 onshore connection options for power and hydrogen transmission modelling



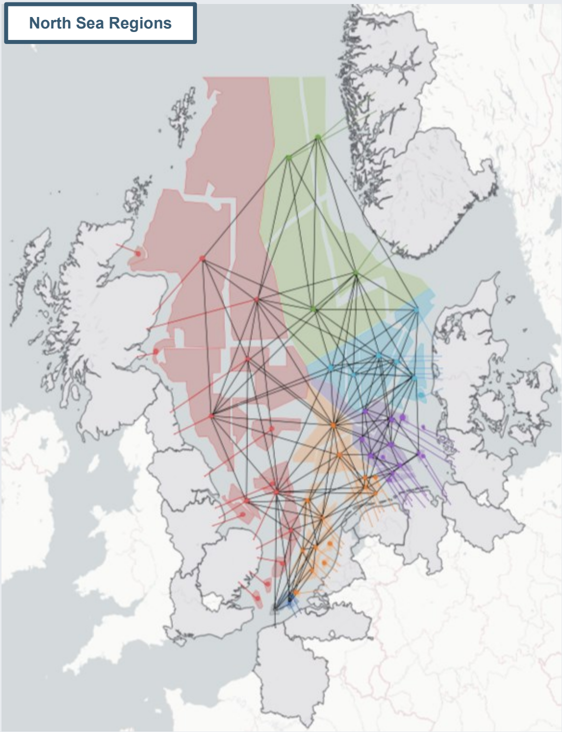
Geospatial Resolution of the Analysis: Offshore

For the North Sea countries, a **detailed representation of available offshore sites** is applied to enable thorough analyses of potential Hubs-and-Spokes configurations. For other countries, a more aggregated approach is applied.

In parallel, **the representation of 21 distinctive Landing Zones within the corresponding parent region of each offshore region is utilised** in order to capture the competitive nature and advantageous edge that each location brings forward for various types of investments, as will be discussed in the present report.

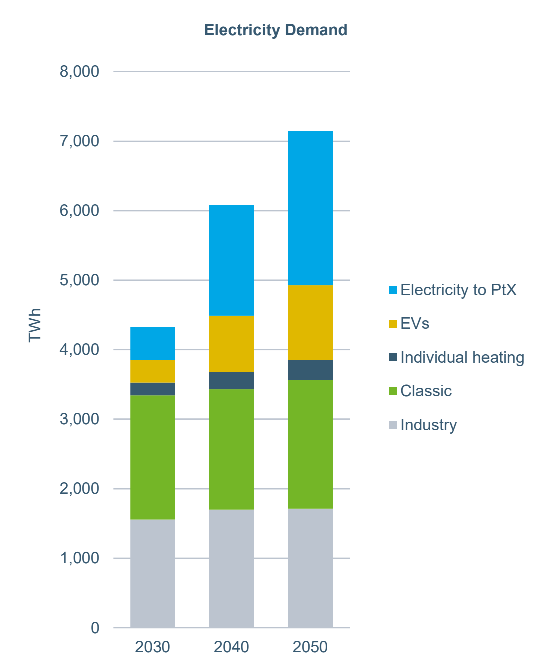
Note that the figures to the right only shows the available North Sea regions and LZ, but there are more offshore regions available across the modelled geography, as described in upcoming slides.

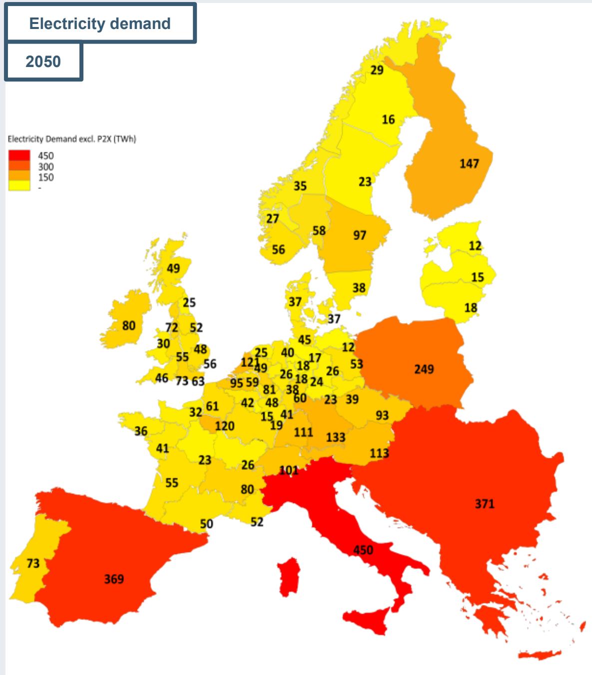
The total number of evaluated offshore transmission options rises to 348, based on 79 offshore regions.

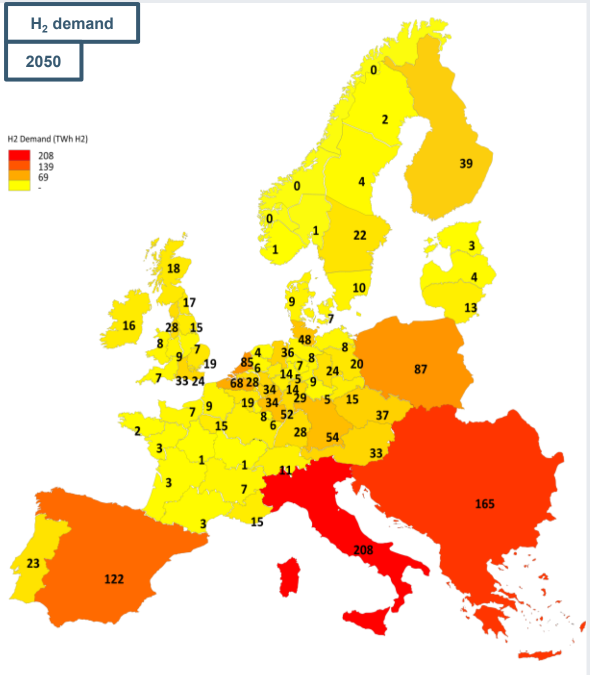


Demand Drivers

The model is demand driven and must supply the electricity and hydrogen demand. The demand is exogenously defined, following TYNDP's Distribute Energy (DE) scenario information. H_2 demand (TWh_{H2}) can be satisfied either by European production or by imports (Pipelines to Southern Europe or shipping). Additional H_2 demand may stem from the need to supply hydrogen based electricity production for system balancing. The additional H_2 demand is also part of the overall modelled H_2 supply through imports or European production.







Notes: The illustrated demand is exogenously defined. Electricity to PtX shows the potential electricity use, if all hydrogen demand is supplied from local production. Quantities may differ after the end of the optimisation results, due to inflows of H_2 from third countries (North African Countries), and electricity losses during unit operations. A more detailed breakdown can be seen in upcoming Appendices.

Hourly Demand Profiles

Total annual demands are distributed across the modelled horizon via the utilisation of hourly demand variation profiles. The profiles are deterministic across the modelled years and are based on the correlation of demand / generation patterns originating from the weather year of 2012. Ultimately, the model is aiming to achieve demand satisfaction in each modelled timestep (hour) in the least cost possible manner.

Demand-side flexibility is included[i]:

General flexibility of classic and industrial demand

- *General flexibility refers to **some demand response capability (time-shift)***
- ***This is modelled by providing exogenous storage capacity (2h) as a certain percentage of the peak demand.***
- *This number is growing overtime, is differentiated by country based on TYNDP (demand response) and on average 12% in 2050.*

Special flexibility is applied to EVs and individual heating

- *EVs: the exogenous demand profile coincides with the natural charging pattern. **A part of the vehicle fleet is assumed to be flexible** (willing to charge/refrain from charging) and willing to participate in demand-side management (smart charging). **A flexible charging profile is thus endogenously determined, depending on power prices.***
- *Individual heating: **a 2-hour virtual storage is implemented to allow time-shifting** of power consumption.*

Electricity Generation Sources and Potentials

A series of technologies are available for the model to utilise and generate electricity towards serving all exogenous and endogenous demands. Some of the main categories are:

- Coal, lignite, natural gas, hydro, nuclear, offshore wind, onshore wind, solar PV (onshore), biomass, hydrogen, other renewables and other non-renewables.

Existing and firmly planned installed capacities are defined in the model on a regional basis for each modelled year. For thermal power plants, different vintages are applied to reflect anticipated efficiencies and operating costs. Natural gas capacities were furthermore split to CCGT and OCGT technologies. For onshore wind and solar PV capacities, 50% of the scenario data for 2030 are assumed to be of older technology with corresponding lower capacity factors, while the remaining 50% are based on technology assumptions for 2025-2030

Nuclear power capacities are exogenously defined through to 2050 and not subject to model optimisation, as they are heavily dependent on national policies. Coal and lignite contribution in the electricity mix is disallowed from 2040 and on, while natural gas usage is disallowed in 2050. Existing natural gas units can get retrofitted into hydrogen based G2P units.

In parallel, the model has the opportunity to optimise system dispatch via various flexibility measures such as:

- Electric storage (batteries), pumped hydro, hydrogen storage (underground type) and of course the aforementioned flexible types of demand.

Energy inflows from non modelled countries are limited to the form of hydrogen from North Africa, which can then endogenously be converted to power via hydrogen-based gas to power units (H_2 G2P), which are either newly invested, or retrofitted natural gas based turbines.

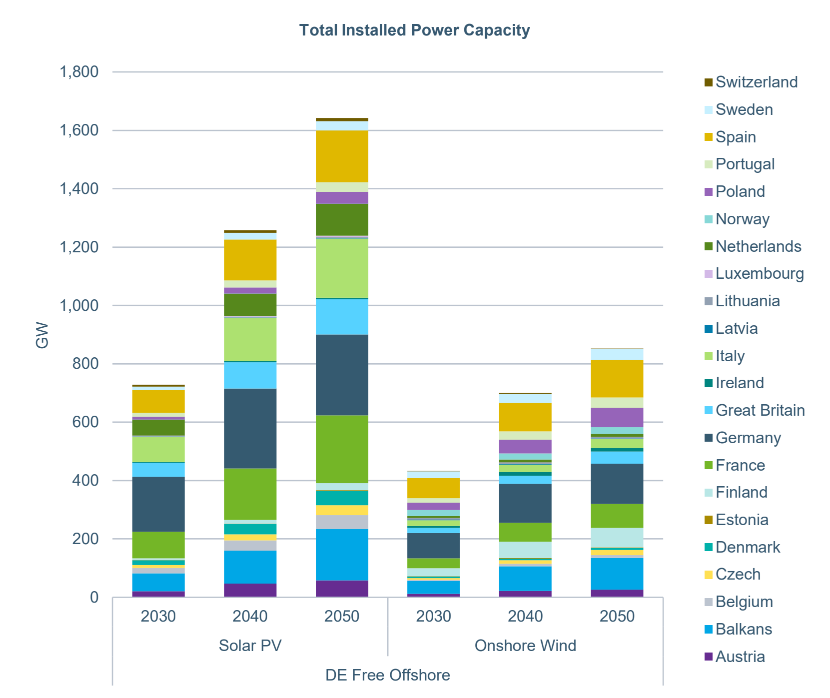
Fuel for power generation	2030	2040	2050
Coal	Yes	No	No
Lignite	Yes	No	No
Natural gas	Yes	Yes	No

DE Free Offshore Background – Onshore VRE Capacities

Within the analysed scenario, **power and hydrogen demands, but also capacities and siting of onshore VRE (onshore WT and solar PV) are based on the utilised scenario data for each modelled year, reflecting TYNDP's Distributed Energy (DE) figures (see following slide)**. Offshore wind capacities are subject to model optimisation, according to the available offshore wind potentials.

Due to full load hour (FLH) differences between the model's regional VRE profiles and TYNDP DE's publicly available generation data, **a scaling of the "target" regional capacities was undertaken, in order to preserve the level of onshore VRE contribution in the electricity mix relatively similar**. A descriptive table of the utilised scaling factors can be seen on the right.

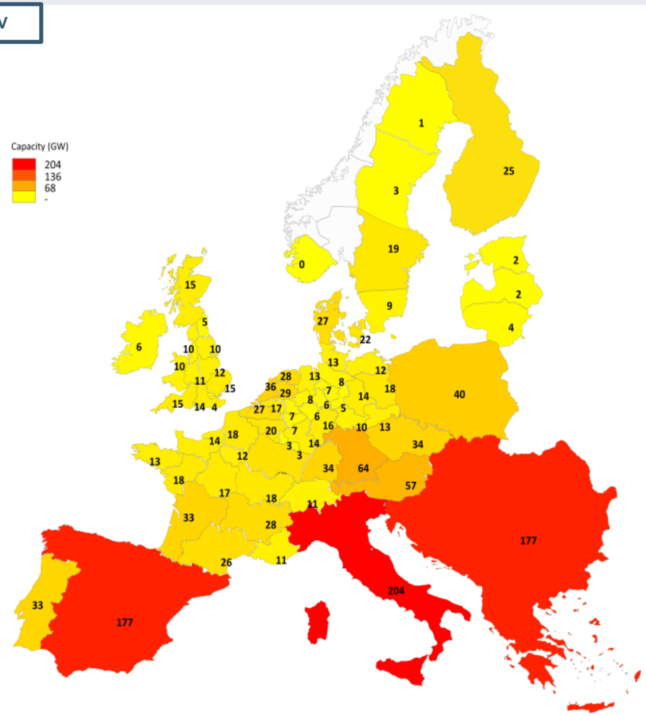
Mean (StDev)	TYNDP DE FLH	Modelled FLH	Average Scaling Factor
Solar PV			
2030	1,033 (286)	1,087 (191)	0.89 (0.22)
2040	1,022 (225)	1,096 (197)	0.88 (0.19)
2050	1,118 (635)	1,100 (200)	0.83 (0.23)
Onshore WT			
2030	2,454 (538)	2,829 (564)	0.95 (0.20)
2040	2,496 (478)	2,908 (635)	0.93 (0.16)
2050	2,345 (528)	2,934 (668)	0.89 (0.14)



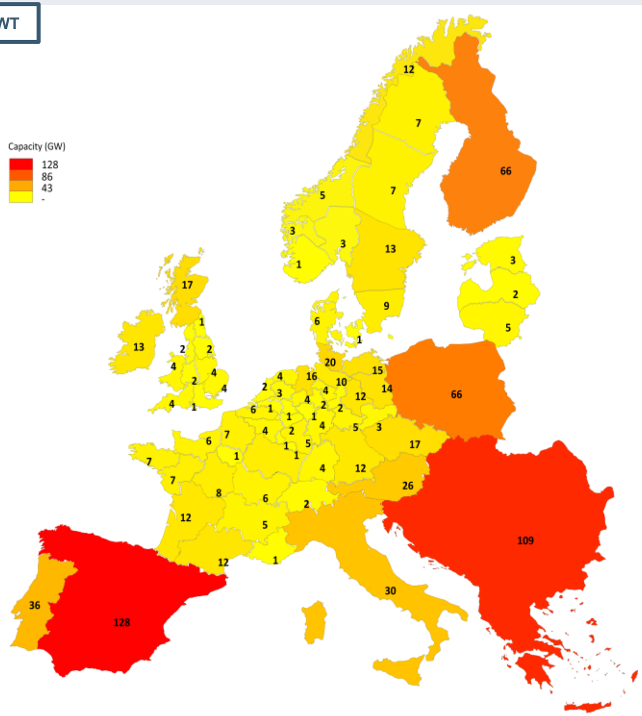
Onshore VRE Mapping (DE Free Offshore, 2050)

Larger capacities of solar PV can be observed in the southern modelled area (Spain, Italy, Balkans), while onshore wind presence is stronger in the periphery of the assessed geography. A more detailed, country specific, table breakdown is presented in the *Appendix*.

Solar PV



Onshore WT



Note: Capacities are rounded to the nearest integer. A more detailed breakdown can be seen in upcoming Appendices.

Renewable Resource Potentials – Technical Potentials

GW	Solar PV	Onshore WT	Offshore WT
Modelled Geography	**10,589**	**8,525**	**1,419**
Austria (AT)	156	51	-
Balkans (BK)	1832	1071	55
Belgium (BE)	100	10	3
Czech Republic (CZ)	277	102	-
Denmark (DK)	210	19	141
Estonia (EE)	75	74	14
Finland (FI)	142	239	82
France (FR)	1697	1291	74
Germany (DE)	1045	377	57
Great Britain (GB)	979	685	437
Ireland (IR)	309	442	65
Italy (IT)	776	560	19
Latvia (LV)	123	154	27
Lithuania (LT)	183	190	11
Luxembourg (LX)	6	1	-
Netherlands (NL)	174	102	128
Norway (NO)	65	731	182
Poland (PL)	981	485	23
Portugal (PT)	108	173	4
Spain (ES)	980	1294	2
Sweden (SE)	270	450	95
Switzerland (CH)	104	24	-

In the case of analysed scenarios (sensitivities) where the VRE capacities are subject to model optimisation and are not exogenously defined to match TYNDP's DE numbers and regional distributions, **a regional technical potential is utilised as a ceiling of investments**. Those upper bounds of investments may get tighter according to each scenario's structure, as described in the *Sensitivities* section.

Technical potentials have been provided by the NSWPH consortium on a NUTS 3 level, based on which a conversion to the present project's resolution (NUTS 1-2) followed. **Technical potentials reflect the total available power specific capacity that a region can possibly install, when considering topographic, environmental, and land-use constraints.**

Of course, the full technical potential is not expected to directly translate in feasible investments, however is a good metric of evaluating the observed capacity redistribution tendencies and also assists in setting rational boundaries to the model's operation.

Renewable Resource Potentials – Overview

Allowed **PV and onshore WT resource potentials directly impact the observed level of offshore wind capacity deployment** across the modelled geography, due to their relatively lower LCOE and necessary power infrastructure development needs.

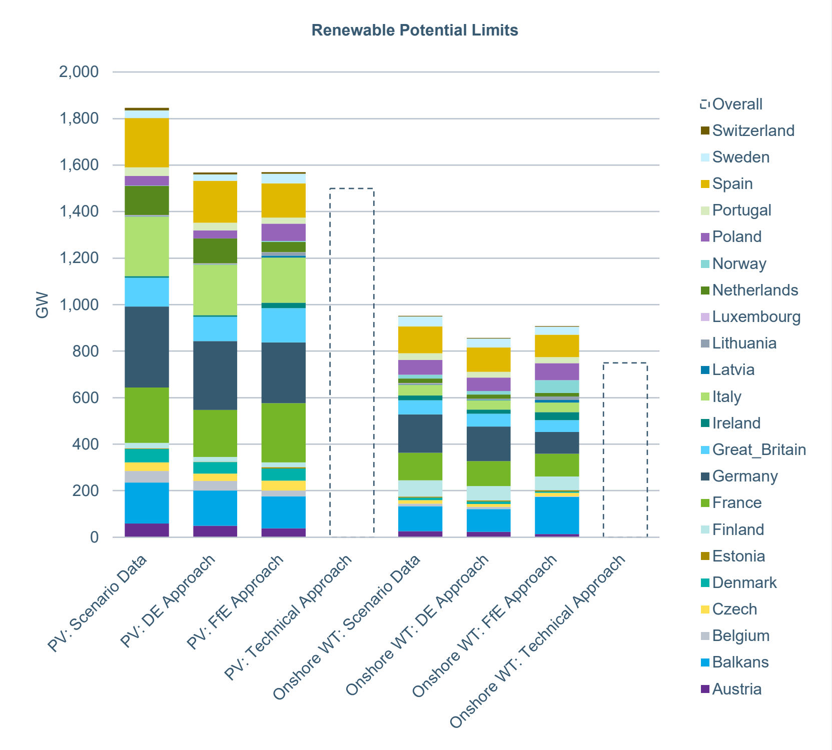
The modelled power and H2 annual demand levels as well as their geographical distribution are based on TYNDP's Distributed Energy (DE) scenario. Therefore, in scenarios with model optimised supply side VRE levels investments (e.g. *Geo-optimised VRE*), VRE potentials would have to take into consideration the geographical distribution of the supply side data included TYNDP DE, in order to preserve to an extent the patterns of the supply/demand side dynamics. Capacities and national distribution of solar PV and onshore wind in TYNDP DE can be seen on the to the right under the notation "Scenario Data".

However, since this study applies higher full load hours for solar PV and onshore wind turbines when compared to TYNDP, the scenario data capacities had to be adjusted in order to preserve uniform VRE generation estimated across the modelled geography.

On that note, **three approaches of potential definition have been assessed** during the present study's development, namely:

I. DE Approach
II. FfE Approach
III. Technical Approach

The next slide will go into detail regarding each approach.



Note: The maximum allowed potentials are aggregated to a country level for illustration purposes, but are imposed on a regional level during the study.

Renewable Resource Potentials – Specifics

DE Approach
Purely **TYNDP Distributed Energy[1] driven potentials**. The maximum potentials for both onshore WT and solar PV can be seen lower than the scenario data, due to higher assumed FLH in Balmorel according to the adopted generation profiles from DTU Wind, when comparing with estimated TYNDP FLHs. Lowering the achievable potentials to 85% of Scenario Data for Solar PV and 90% of Scenario Data for Onshore WT yields similar overall source-based generation levels with the TYNDP levels.

FfE Approach
Mixed approach of **correlating the DE supply side scenario data to the technical potential of each country as assessed by FfE[2]**. Due to the practical infeasibility of utilising the total technical potential in each country (competition with other types of land use, but also competition with other power sources), a tier-based methodology was followed (3 tiers), where the scenario data capacities are compared to the overall FfE technical potential levels. Based on the comparison, a fraction of the overall FfE technical potential is being assigned as the maximum potential in the model. The showcased tier-based fractions were tuned to return similar RE generation levels with the DE Approach and subsequently with the TYNDP data.

Tier	Fraction of overall FfE technical potential to be utilised (same for all regions of a country)
≥ 25%	25%
<25% & ≥ 10%	15%
<10%	7.5%

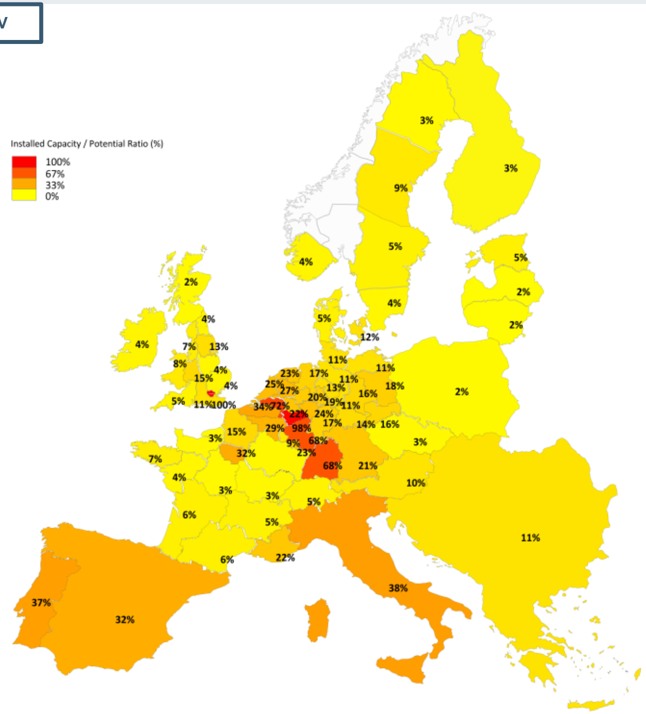
Technical Approach
The FfE Approach's redistribution of country-based potentials turned out to limit the regional deployment of RE sources in some countries (e.g. WT in Germany), while allowing further investments in others (PV in PL) – see figure on the previous slide - when comparing to the TYNDP DE scenario Data but also overall publicly available political ambitions to-date. For this reason, a freer approach has been designed to be aligned with the overall goal of a Pathway study, i.e. the observation of a competitive cross country power development scene. The present approach **adopted the methodology of setting the overall modelled geography onshore VRE potential to a level which would roughly approximate the anticipated electricity generation from onshore VRE in the TYNDP DE results. The overall modelled geography "cap" was set to 1500GW of solar PV and 750GW of onshore wind in 2050, aiming to result in 1,950TWh from solar PV and 2,350TWh from onshore wind (cap adjusted to 2030 and 2040 based on the TYNDP relative change). The model is allowed to utilise the full regional based technical potential and redistribute the total installed capacities on a cost competitive basis, while accounting for all possible synergies. As examined and visualised in the next slide, the Technical Approach returns an acceptable level of technical potential utilisation across the modelled geography and thus will be deployed ahead for the Geo-optimised VRE case.**

Note: Due to the proximity of 2030 to the present analysis' date, 80% of each fuel type capacity in TYNDP DE is set as a lower bound to the model (2030 only).

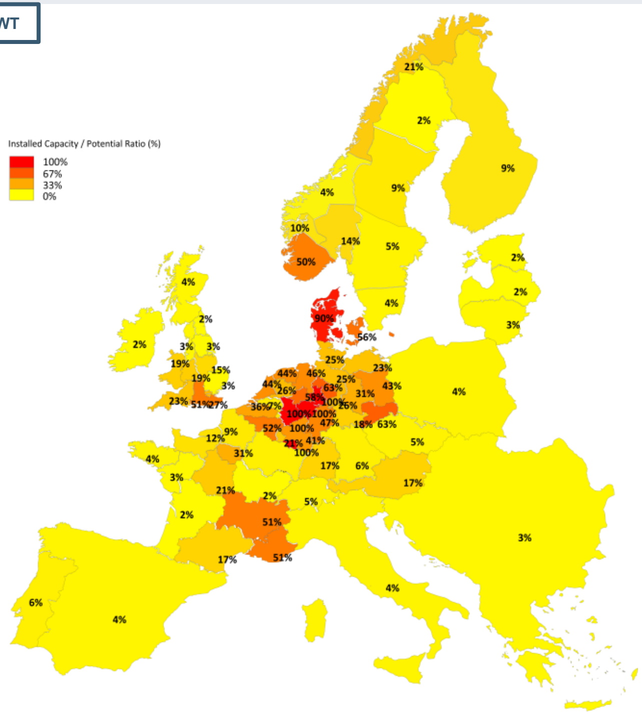
Technical Potential Utilisation (Geo-optimised VRE, 2050)

An evaluation of the total installed capacities against the assumed technical potentials was carried out to sense check and solidify the adopted VRE potential approach. It becomes evident, that even when considering the cumulative PV and WT technical potential utilisation within the same region (where access to resource utilisation is of competing nature), the ultimate surface area consumption is not rising to a concerning degree even in scenarios with onshore redistribution capabilities (Geo-optimised VRE, Unrestricted Solar).

Solar PV



Onshore WT

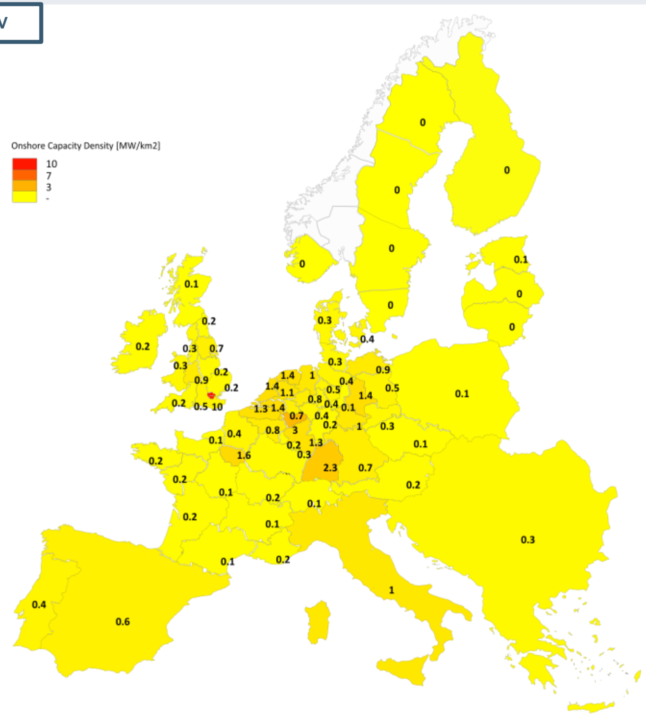


Notes: Maxed out regions have negligible potentials, thus not considerably affecting the overall modelling results. Following TYNDP's DE data, North and central Norwegian regions were excluded as options for solar PV development due to considerably low FLHs.

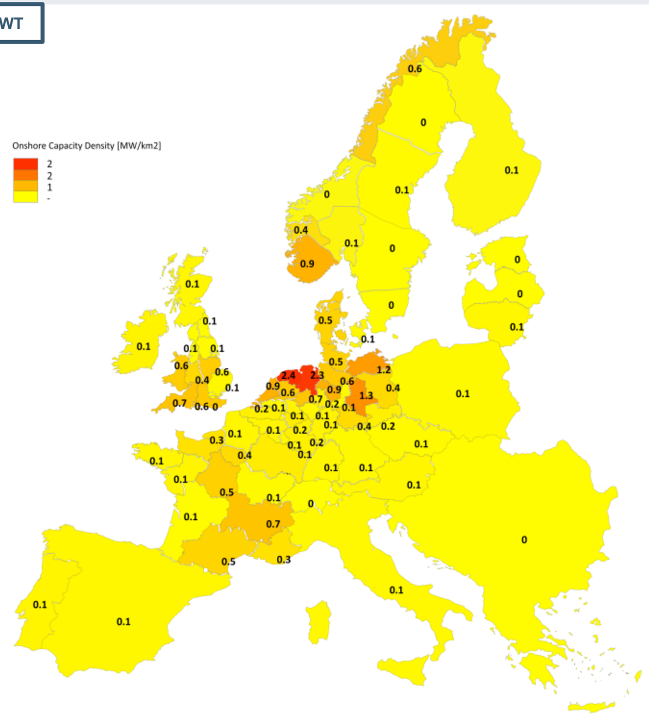
Onshore Capacity Density (Geo-optimised VRE, 2050)

Due to the NUTS 1-2 breakdown of European regions, results may not seem comparable when comparing “regions” matching a whole country (e.g. Spain) vs “regions” consisting a part of a whole country (e.g. Germany). For this reason, installed capacities are also showcased via the metric of capacity density according to the NUTS1-2 surface areas (km²).

Solar PV



Onshore WT



Renewable Variation Profiles (Climate Year 2012): Data provided by the Technical University of Denmark (DTU)

Solar PV

One generation profile per region.
Use 25 % best solar locations for each region.
Fixed south-facing installations.

Onshore WT

3 wind speed profiles per region:

- Wind class A (RGA): 50% best.
- Wind class B (RGB): 40%.
- Wind class C (RGC): 10% worst.

Wind speeds above 5.5 m/s.
Power curves applied based on Danish Technology catalogue.

Offshore WT

2 types of OWF sites:

- Aggregated Sites (≤22km from shore, Close-to-Shore):
- Individual Sites (>22km from shore, Far-Offshore):

2 types of modelling:

- North Sea offshore areas:
  - 2 wind power generation profiles (engineering wake losses, meso-scale wake losses). Profiles provided by DTU Wind.
  - Spacing: 8 GW/km^2.
  - Representative power curves: Siemens SWT-4.0-120 (4MW) for existing wind farms, MHI-Vestas (8MW) for planned wind farms and NREL (15MW) for future wind farms.

- Residual offshore areas:
  - Power curves applied based on Danish Technology catalogue.
  - Based on a standard farm: Size: 3 GW.
  - Spacing: 7 GW/km^2.
  - Standard turbine: 18 MW (Danish TC for 2040). Specific power: 340 W/m^2.

Notes: Data provided by the Technical University of Denmark. When using wind speeds, power curves implemented to closely match the resulting FLHs from DTU Wind generation profiles. Weather data reflect 2012 patterns (climate year).

North Sea Wind: Aggregation of Areas

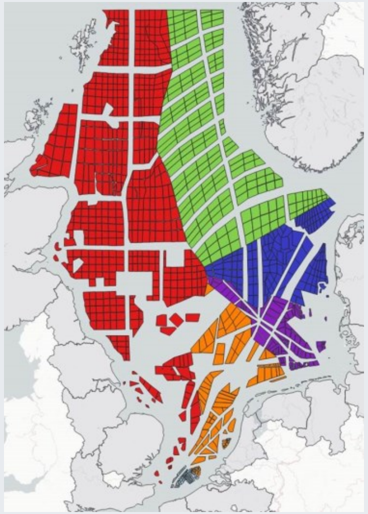
Due to **very high simulation times during the fully detailed runs** (2) + (1), a need to further aggregate areas and regions in the model emerged.

Many of the northern most regions were aggregated into larger groups with one point of connection to shore and to other hubs. Some of the NL, DE and BE hubs were also aggregated if very close to the same location.

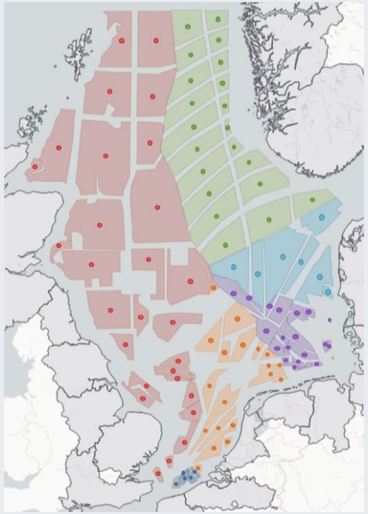
Each final representative "regional" polygon (3) includes a representative "areal" polygon (1) for each of the aggregated detailed regional polygons (2). The representative "areal" polygons reflect the polygons closest to the average FLHs of the corresponding "parent region" in (2).

- These areas provide the geographical and technical information (individual depth, distances to shore, variation profiles, etc) which are ultimately modelled in the simulations, affecting cost information but also experienced FLHs.
- The regional polygons are used to define transmission options

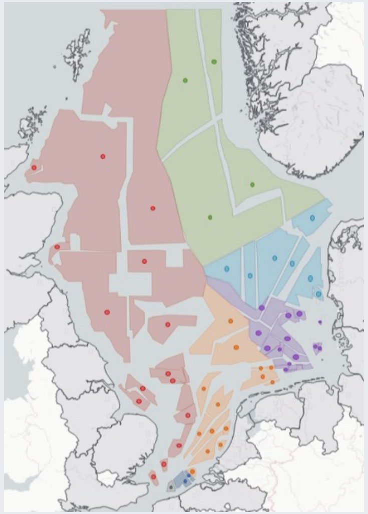
DTU Wind / NSWPH Data (1)



Detailed Areal Aggregation (2)



Representative Areal Aggregation (3)

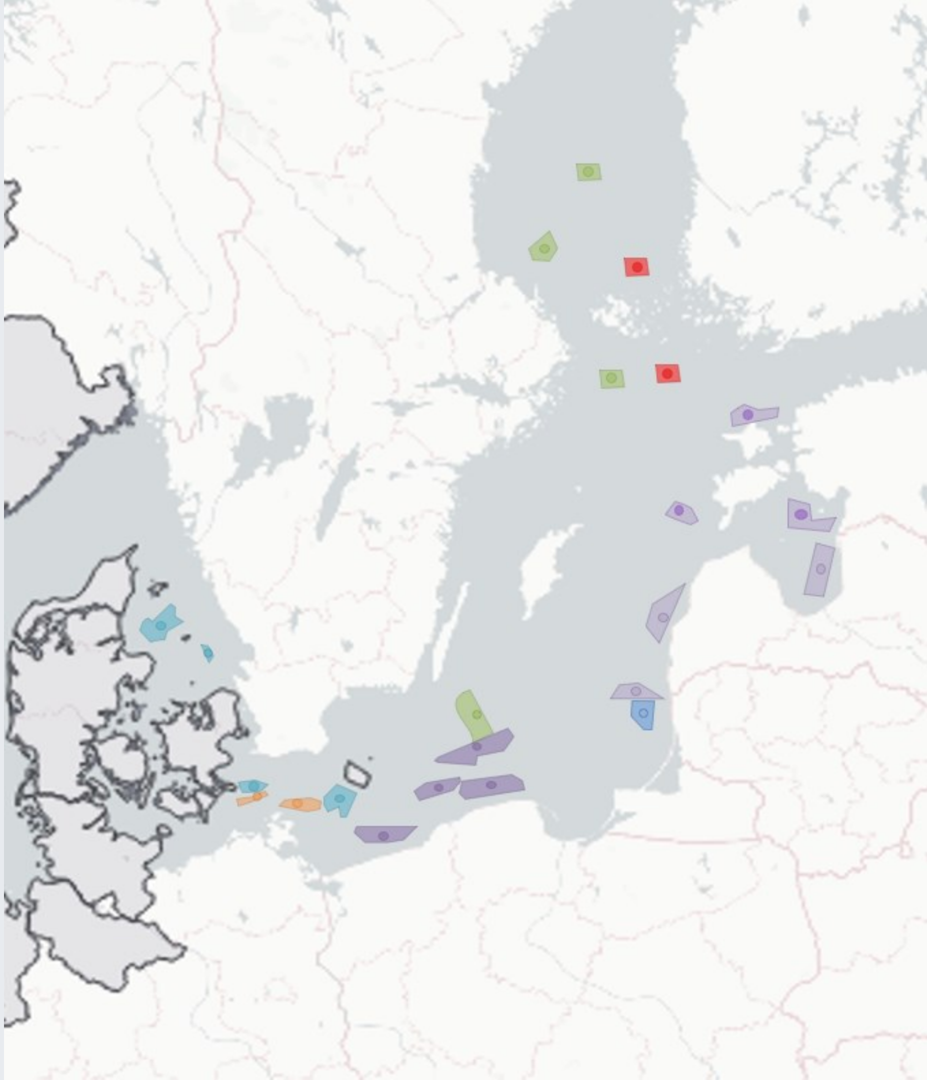


Non-NS Offshore Wind Regions

Of course, more far offshore wind regions are distinctively represented across the modelled geography, among 149 areas, bringing the overall potential to ~2,115 GW.

Most of the non-North Sea offshore wind regions are located in the Baltic Sea, an overview of which can be seen on the right.

A number of not illustrated offshore wind regions are also located in the Atlantic Ocean as well as around the coasts of the residual southern European countries.

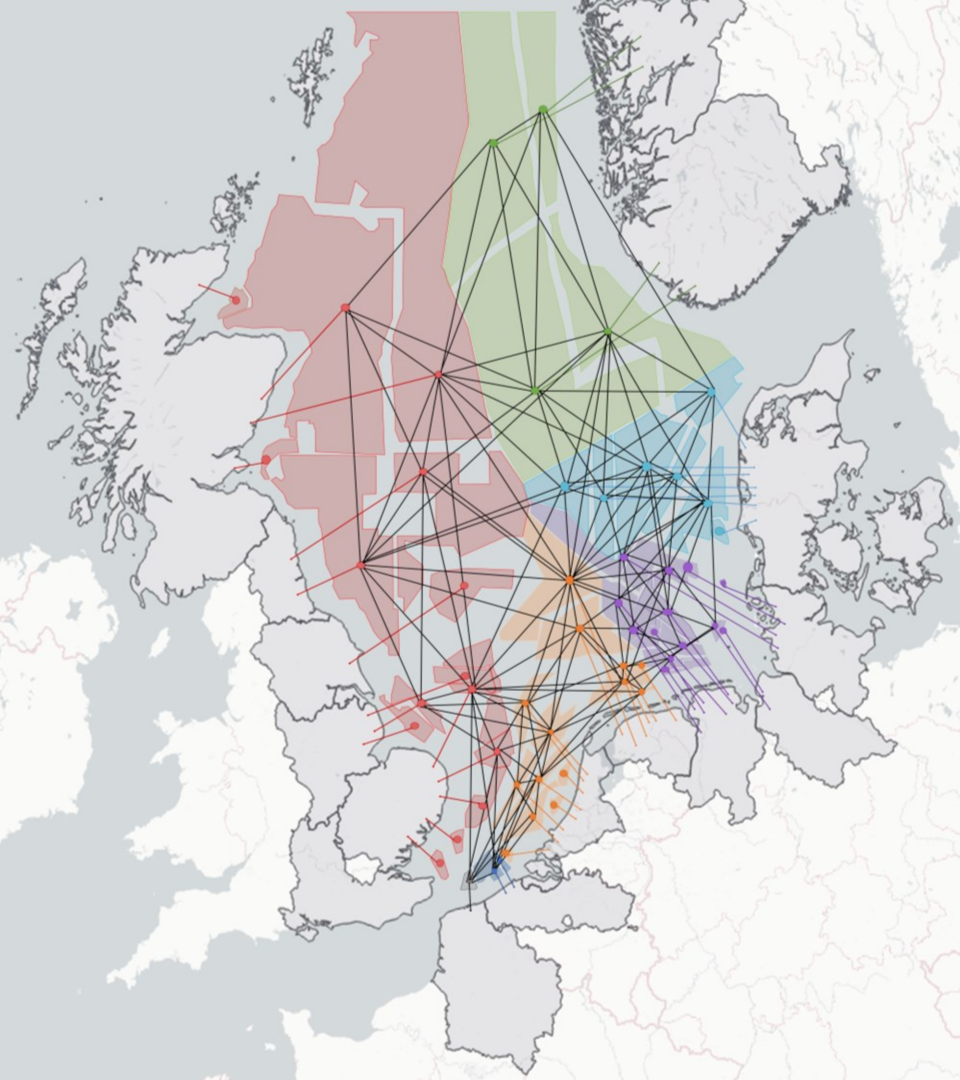


Hub-to-Hub Overview: North Sea

The model has the option to build offshore transmission capacity between each aggregated hub connection. The possible connections can be seen within the illustration on the right.

All existing and planned offshore wind capacities up to 2027, according to inputs from the NSWPH consortium, are only allowed to a radial connection to their “parent-region” and cannot participate in a future hubs-and-spokes set-up. In contrast, all other offshore wind installations can participate in Hubs-and-Spokes formations during the optimisation horizon.

Of course, offshore wind modelling does not only take place in the North Sea, but in all modelled countries. However, due to the scope of the present study, illustration will focus on the dynamics between the North Sea developments and the residual power system across Europe.

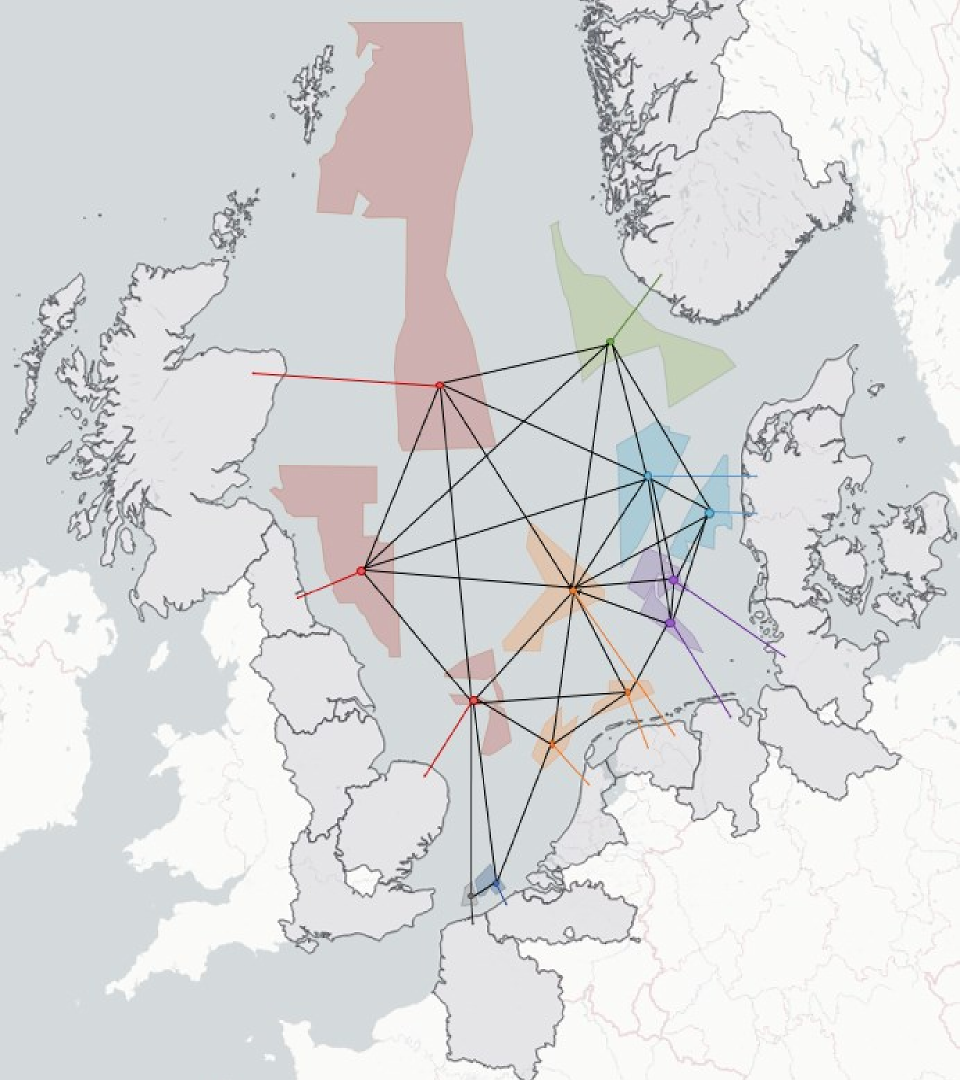


Offshore Electrolysis Options

The model has the option to build offshore electrolysers at different locations in the North Sea, coupled to an OWF. Offshore electrolysis cannot take place outside of the North Sea regions.

The options for offshore electrolysers and pipelines was limited to wind dominated offshore sites in order to alleviate the model's computational time. The selected offshore sites are a mixture of farther but also closer to shore locations, in order to capture all possible synergies that may emerge.

The generated hydrogen can circulate among the modelled geography via the showcased paths, or land to the LZ and enter the onshore network. H_2 storage can only take place on onshore regions.



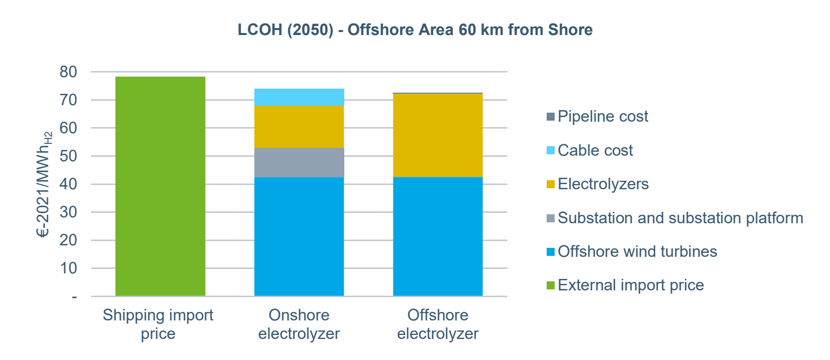
Onshore vs Offshore Electrolysis

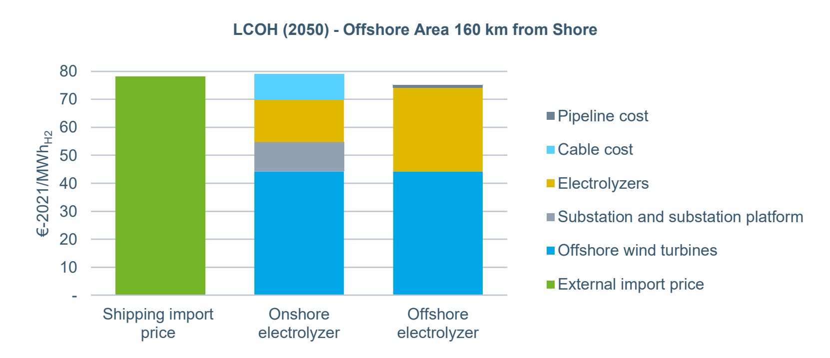
Before analyse energy system synergies the LCOH of different options for stand-alone hydrogen production can be analysed. In this case we compare a two standalone options. Firstly, 1:1 wind capacity and electrical transmission capacity with an onshore electrolyser. Secondly, 1:1 wind capacity and offshore electrolysis with no electrical connection.

The production of hydrogen locally in Europe is in direct competition with the external shipping import to Europe. The cost of shipping imports is calculated as being the cost of building solar PV and electrolysers in North Africa and shipping it to Europe.

- LCOH are shown for DK_W_Hub_6 offshore area, ~60 km from shore, and DK_W_Hub_3, ~160 km from shore, with offshore wind as standalone supplying either offshore electrolysers or onshore electrolysers. **The main difference between the two is the transmission costs for both power and H2 at 60 km and 160 km respectively.**

The cost of offshore electrolysers and pipeline appear to be slightly lower than onshore electrolysers and cable, with increasing advantage for larger distances. Synergy effects with the remaining electricity grid are not accounted for in the onshore electrolyser option. If the onshore electrolyser configuration can benefit from sending electricity to the onshore system in times of high electricity prices, the competitive situation would change. Therefore, the marginal hydrogen production with little synergy to the onshore energy system is likely best placed offshore, while onshore hydrogen production has an advantage as long as synergies with the onshore system can be realised.





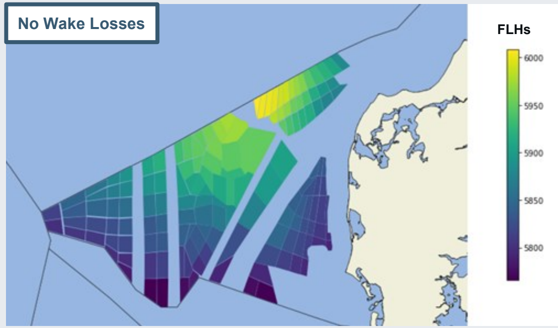
Wake Modelling: Offshore Wind

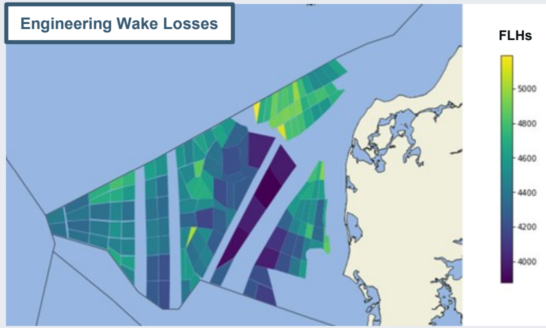
Each one of the modelled offshore wind areas in the North Sea is characterised by site specific FLHs and hourly variation profiles according to DTU Wind's calculations for 2030. Those FLHs are adjusted to 2040 and 2050 according to DEA's technology catalogue FLH expectations. **3 types of profiles were assessed**:

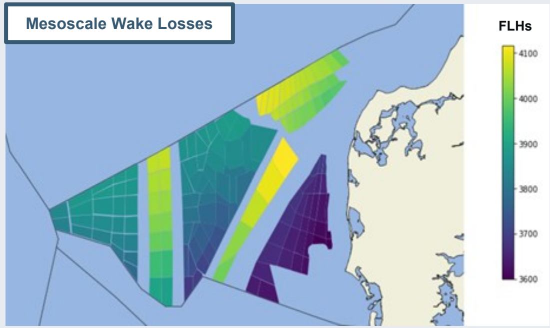
- **No wake losses**.
- **Engineering wake losses** (internal wake losses within the actual wind farm).
- **Mesoscale wake losses** (wake losses from both internal and also neighboring wind farms).

The latter 2 profiles are utilised in the undertaken modelling based on the offshore wind potential utilisation of each modelled area. **Engineering wake losses are applied to all capacities up to each area's 50% potential threshold, while profiles including mesoscale wake losses are applied on the marginal addition beyond the 50% point**.

An example of the Danish North Sea regions can be seen to the right. A broader depiction across the North Sea can be found in upcoming slides.







Note: Data provided by the Technical University of Denmark (DTU Wind).

Power Generation Costs: Onshore RE Technologies

Solar PV

- DEA's ground mounted utility scale panel costs.

Onshore Wind

- DEA's costs.
- For more detailed modelling, a further technology and therefore cost split takes place.

2030 (2050)

i. High Wind (HW) WTs - SP [W/m^2]: 275 (270), HH [m]: 100 (110)
ii. Medium Wind (MW) WTS - SP [W/m^2]: 238 (222), HH [m]: 115 (120)
iii. Low Wind (LW) WTs - SP [W/m^2]: 200 (175), HH [m]: 130 (130)

Data 2030 (2050)	CAPEX (mEUR21/MW)	Fixed O&M (kEUR21/MW)	Variable O&M (EUR21/MWh)
Solar PV	**0.38 (0.30)**	**7.7 (6.0)**	**- (-)**
Onshore Wind			
- High Wind (HW) WTs	1.15 (1.04)	13.5 (11.7)	1.5 (1.3)
- Medium Wind (MW) WTs	1.25 (1.14)	15.6 (13.7)	1.7 (1.5)
- Low Wind (LW) WTs	1.40 (1.29)	18.4 (16.5)	2.0 (1.8)

Note: Cost figures for Solar PV and Onshore WT include an additional connection cost of 0.07 m€/MW, to reflect grid reinforcement needs.

Power Generation Costs: Offshore Wind Benchmarking

Previous NSWPH Projects' Cost Approach

- 2030 NSWPH estimates scaled based on Danish Energy Agency's (DEA) technology data catalogue cost development and a 10% learning rate.
- Main concerns against previous DEA figures: Absence of depth specific foundation cost information.

New Evaluation Method

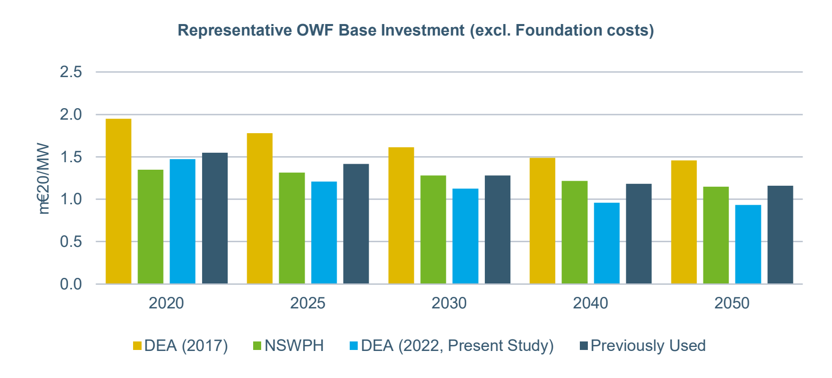
- The DEA undertook an elaborated offshore wind chapter update within the latest published technology catalogue (March 2022)[1].
- Backtracking the utilised methodology results in depth-specific foundation cost estimates, which run close to previously used NSWPH estimates. Therefore, **DEA (2022) figures will be used along with depth specific foundation costs, without any NSWPH estimate adjustments**.

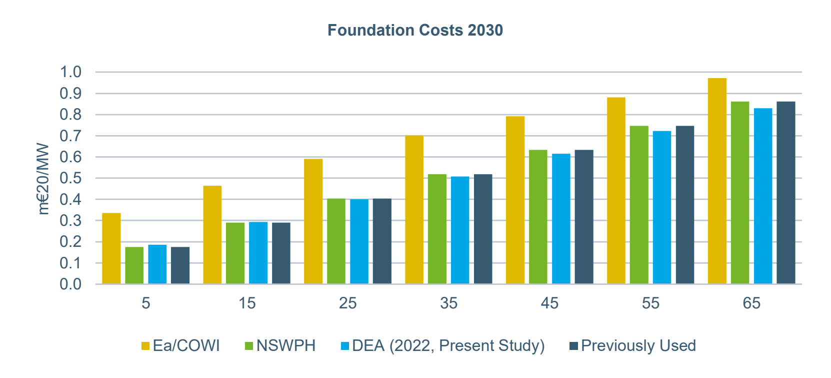
Platform/Substation Costs

- Platform/substation costs are also being deducted from base investment according to DEA's figures (**flat 0.25 m€$_{20}$/MW across years)** and will be separately modelled. In this way, in case of offshore H_2 production, savings on the electrical infrastructure can be achieved.

O&M Costs

- O&M cost application is also based on distance to shore. Default distance: 82.5km.





Notes: Detailed information over the utilised offshore wind modelling elements can be found in the section "Modelling Approaches & Assumptions". On top of the illustrated cost assumptions, the utilised OWF Base Investment (€/MW) also excludes all transmission costs aside of array cables.c

Power Generation Costs: Offshore Wind

Ultimately, the year-specific OWF Base Investment costs in PW 2.0 are based on DEA's 2022 estimates, with the following representative costs of the technology catalogue modified to site specific estimation:

- Foundation costs.
- Transmission costs (see next slide for applied costs). Array cabling is included in the OWF Base Investment.
- Platform & Substation costs (see next slide for applied costs).

Those costs are applied on top of the OWF Base Investment cost and are geospatially specific to each wind farm.

OWF O&M costs: 2030 (2050)

- Fixed O&M (kEUR21/MW): 47.8 (40.4)
- Variable O&M (EUR21/MWh): 4.77 (3.99)

Data 2030 (2050)	CAPEX (mEUR21/MW)
OWF Base Investment	0.99 (0.74)
Foundation Costs (Depth Specific)	
- 0 to 10m	0.19 (0.16)
- 10 to 20m	0.29 (0.27)
- 20 to 30m	0.40 (0.38)
- 30 to 40m	0.51 (0.48)
- 40 to 50m	0.62 (0.59)
- 50 to 60m	0.72 (0.70)
- 60 to 70m	0.83 (0.80)
- 70 to 80m	0.94 (0.91)

Notes: All power transmission, for both near and far offshore wind farms, is assumed to reflect DC costs. AC transmission is only used for array cabling within wind farms.

Power Grid Costs & Assumptions

Background

- **DC assumptions are utilised** across the undertaken analysis in an attempt to account for difficulties in onshore grid buildout. The cost level/development expectations of DC figures according to the NSWPH consortium can be seen on the right. Only underground/submarine options are taken into consideration to reflect the reluctance of the public towards overhead line development.

Technical factors

- **A representative cost per MW/km is calculated for "standard" length assumptions (250 km)** for each modelled year and is then applied for each potential region to region connection with a **length cap of 100km** for all onshore connections and 300km for all offshore.
- An **expansion cap of 6GW per 10 years is applied** on each onshore modelled connection, while the offshore development is let free to follow the optimal offshore wind development.

Cost factors

- **15% mark-up factor (reinforcement) is applied on all power line costs**, aiming to reflect a "reality factor" for cost of transmission, considering further reinforcement needs or additional distance to cover.
- **5% contingency** on total connection costs **for transmission losses is also utilised**.
- Fixed O&M costs are applied as 1.5% of the total region to region connection CAPEX.
- *PW 2.0 introduces an aadditional 9% topside adjustment cost per additional MW of Hub to Hub connection on the same DC substation (9% x (DC Platform Costs + DC Substation Cost). Hybrid connections (Hub to "Foreign" Shore) (if any), are subject to half of the aforementioned costs, while Radial connections (Hub to "National" Shore) are not subject to such adjustment.*

Data 2030 (2050)		CAPEX (kEUR21/MW/km)
DC Onshore	Underground	3.59 (3.38)
DC Offshore	Submarine	2.07 (1.96)
DC Platform	Offshore	0.26 (0.24)
DC Substation	Offshore/Onshore	0.26 (0.24)
Topside DC Adjustment (9%)	Offshore	0.05 (0.04)

Notes: An additional 0.07 m€/MWp is applied on the generation side for onshore WT and PVs, reflecting additional connection costs needs.

H_2 Network Costs & Assumptions

Background
The model can invest in hydrogen transmission infrastructure, newly invested or/and repurposed (where applicable) pipelines, **against a fixed cost per MW_{H2} and km**. This cost includes one compression station, pipeline cost and laying.

The detailed pool of region-to-region connections assessed by within the European Hydrogen Backbone[1] study (v.04/2022) was evaluated. For connections where the length of the existing methane grid (if any) did not require a detour larger than 130% of the centroid-to-centroid distance between 2 regions, **repurposing of pipelines was allowed**.

Technical factors
Costs are calculated in a similar fashion to the power transmission lines, but **by considering the actual distances between regional centroids**. **No expansion limit is set in place** for the H2 network expansion.

Fixed O&M costs 2030 (2050), including compression:
- Offshore: 11 (10) EUR21/MW_{H2}/km/y
- Onshore (new): 6 (6) EUR21/MW_{H2}/km/y
- Onshore (repurposed): 2 (2) EUR21/MW_{H2}/km/y

Data 2030 (2050)	Type	Metric	CAPEX (EUR21/MW_{H2}/km)
Offshore pipelines	New	NSWPH Calculations	443 (418): Infrastructure 220 (208): Compression
Onshore pipelines	New	EHB Weighted Average	442 (416): Infrastructure 59 (56): Compression
	Repurposed	EHB Weighted Average	96 (91): Infrastructure 48 (45): Compression

Fuel & CO_2 Prices

IEA's WEO 2022[1] is the ruler of the anticipated fuel prices within the modelled years.

A convergence from today's fuel prices and price forwards to IEA's price levels in 2030 takes place. The Sustainable Development scenario used in previous studies is no longer part of the WEO analysis. Therefore, the **Announced Pledges scenario is utilised as the price development ruler**, reflecting efforts leading to a temperature increase of 1.7 °C in 2100 (with a 50% probability).

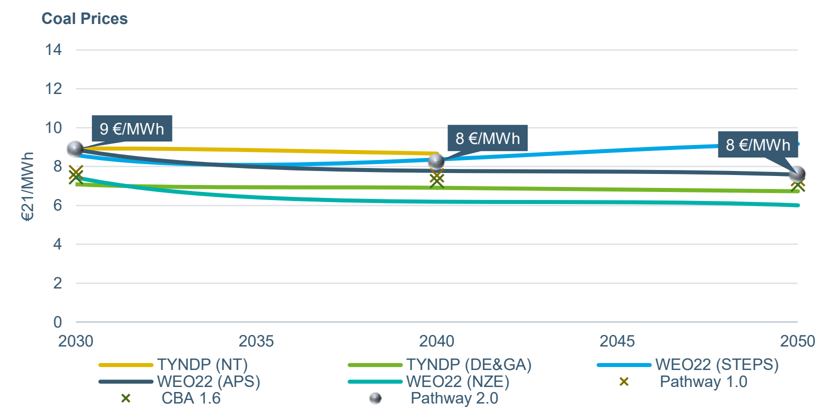
The shared opinion among the NSWPH consortium during the time of development of the present study is the expectation that the marginal price of gas supply in Europe will be based on Japanese based LNG imports, thus the respective price level is utilised.

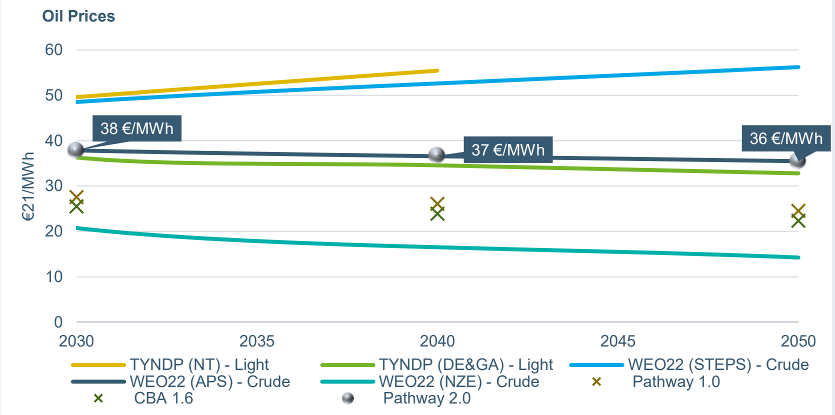
Even though a normalisation of prices takes place towards 2030, the fuel prices remain still above the pre-gas-crisis levels, with quite low fossil fuel prices in the long term. CO2-prices reflect long term abatement cost.

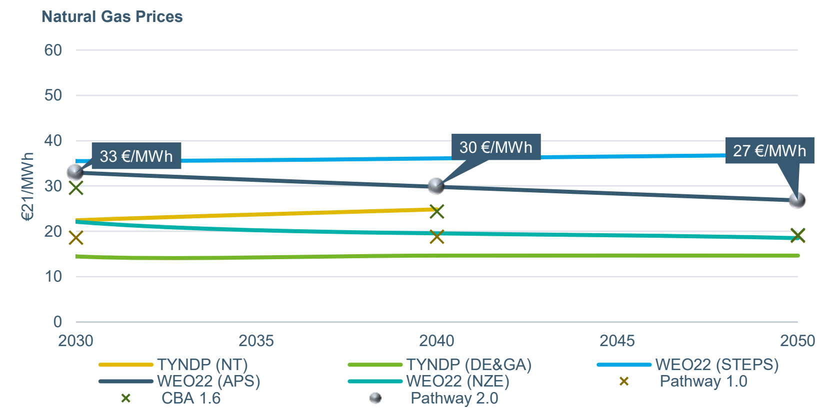
	2020	2030	2040	2050
Coal [€/MWh]	6	9	8	7
Oil [€/MWh]	23	38	37	36
Natural Gas [€/MWh]	11	33	30	27
CO2 Price [€/ton]	31	130	168	192

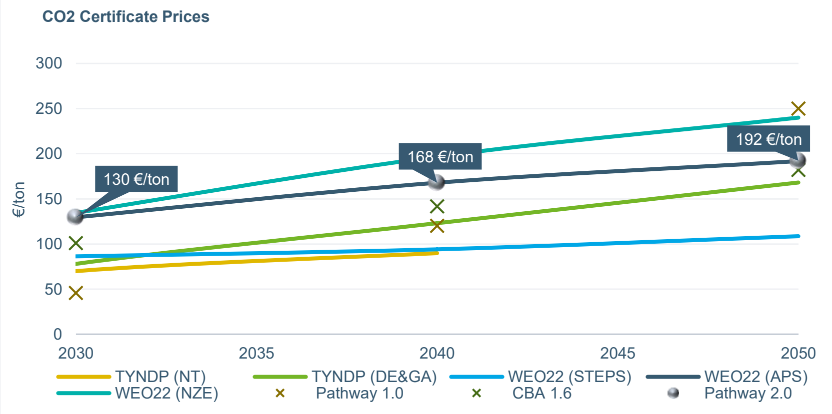
Notes: The following conversion rates have been utilised across the present study: 1 USD = 0.96 EUR, 1 barrel crude oil = 5.84 GJ, 1 Mbtu natural gas = 1.06 GJ, 1 ton steam coal = 25.12 GJ, 1 HHV natural gas = 1.11 LHV natural gas.

Fuel & CO_2 Prices – Benchmarking[1,2]









H_2 Import Prices

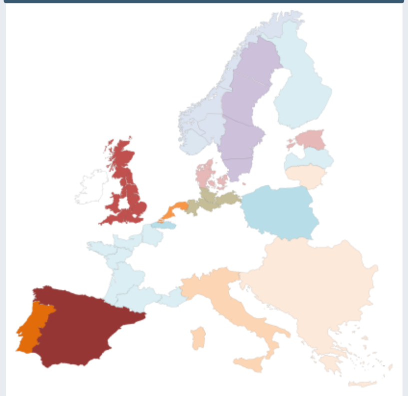
H_2 imports from competitive North African production are allowed across the modelled geography via 2 methods and corresponding price levels:

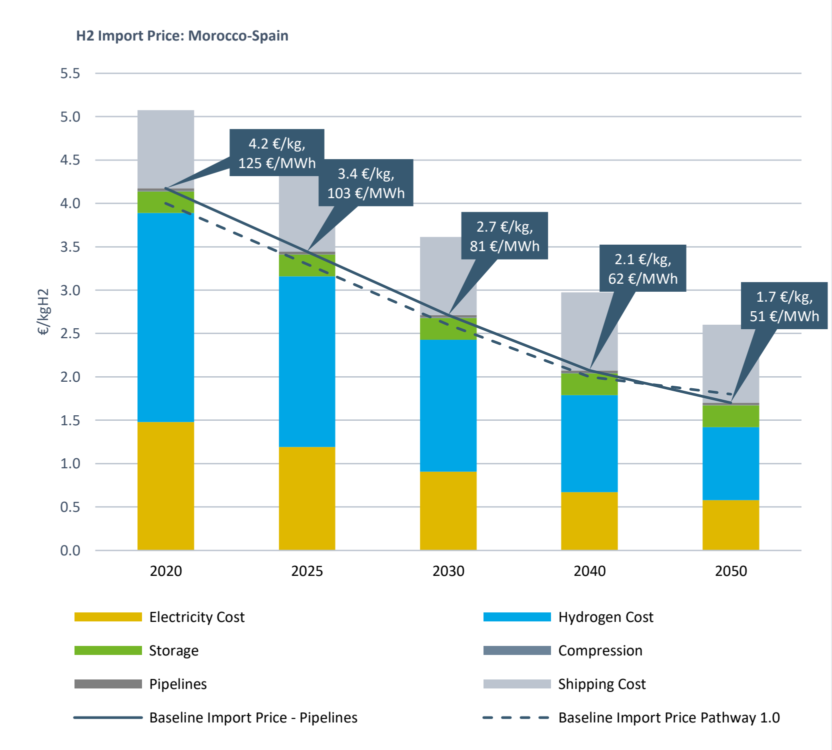
- **Pipeline imports** (capacities according to the European Hydrogen Backbone[1] (EHB) options)
  - 15 GW_{H2} entering Italy ≥ 2030
  - 15 GW_{H2} entering Spain ≥ 2040
- **Shipping imports**
  - Coastal regions ≥ 2030

Import prices are constructed in a **bottom-up way** (representative of a PV-coupled stand-alone facility's **LCOH) and location specific transport/shipping costs are applied on top**. The latter is estimated based on rough distance and project estimates, alongside EHB's[1] assumptions, illustrated below:

European Hydrogen Backbone (EHB) Pipeline Availability

H_2 Shipping Availability (All Modelled Coastal Regions)





Note: The bottom-up calculation of the lower price tier import price (via pipelines from North Africa), can be found in upcoming slides.

H_2 Generation, Use & Storage Costs

Hydrogen will consist an integral part of the under-consideration energy system. It **will consist a key flexibility measure for the system**, and thus directly compete with batteries, transmission expansion and the activation of other demand response measures.

Figures for the generation, use and storage of "**locally" produced hydrogen** can be found on the right, which **will directly compete with H2 imports from third countries**, outside of the modelled geography (North Africa).

2030 (2050) data		Efficiency	CAPEX ($mEUR_{21}/MW_e$)	Fixed O&M ($kEUR_{21}/MW_e$)	Variable O&M (EUR_{21}/MWh_e)
Electrolysis (PEM)	**Offshore**	70% (79%)	1.42 (1.06)	35.5 (29.5)	- (-)
	Onshore	70% (79%)	0.90 (0.53)	22.5 (13.3)	- (-)
Gas to Power (new)	**OCGT**	41% (43%)	0.56 (0.52)	18.6 (18.0)	4.2 (4.0)
	CCGT	58% (60%)	0.83 (0.80)	27.8 (26.0)	4.2 (4.0)

2030 (2050) data		Efficiency (round-trip)	CAPEX ($EUR_{21}/MWhH_2$)	Fixed O&M ($kEUR_{21}/MWhH_2$)	Variable O&M ($EUR_{21}/MWhH_2$)
H_2 Storage	**Underground**	98% (98%)	434.0 (434.0)	7 .0 (7.0)	- (-)

H_2 Import Prices – Benchmarking[1,2]

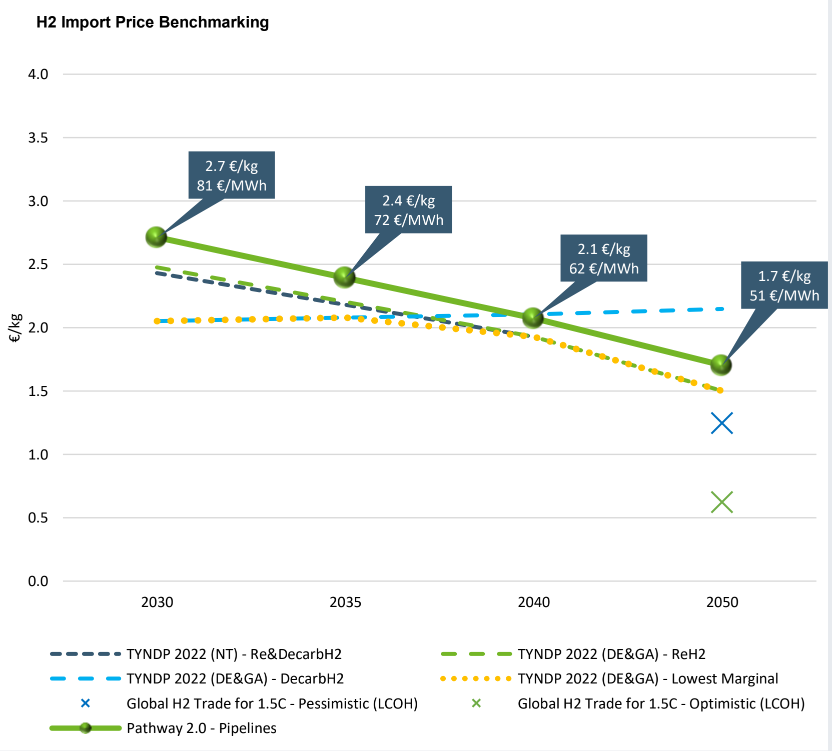
North African supply is assumed to be produced via **coupled PV & PEM stand-alone facilities in North Africa**, with the sole goal of feeding into the European system. No other type of trading takes place, and the via pipelines imports are assumed to serve a baseload purpose at full utilisation.

- PV capacities are being overplanted against fixed PEM capacities to achieve the lowest possible LCOH.
- Technological costing is matching the model inputs for both PV and PEM data.

Full flat utilisation of the H2 transmission lines is assumed. The approach ensures, that import is not modelled as a very cheap flexibility option and that hydrogen flexibility is handled within Europe. Storage costs have been accounted for on the sending side for such reasons.

EUR21	Morocco - Spain	2050
PV	CAPEX (m€/MWp)	0.22*
	LCOE (€/MWh)	13.7
PEM	CAPEX (m€/MWe)	0.53
	LCOH (€/kgH2)	1.42
Other Costs	Storage Cost (€/kgH2)	0.25
	Compression Cost (€/kgH2)	0.01
	Pipeline Cost (€/kgH2)	0.03
	Pipeline Import Price (€/kgH2)	**1.70 (51 €/MWh)**
	Shipping Cost (€/kgH2)	0.90
	Shipping Import Price (€/kgH2)	**2.57 (77 €/MWh)**

Notes: PV capex excludes inverter costs due to stand alone application assumptions. 1,899 FLHs for Solar PV. Assumed distance between Morocco & Spain: 286 km



Note: The graph serves as a benchmarking of the modelled pipeline import price, as presented before, against the expectations of other international studies.

Appendix II – Modelling Approaches

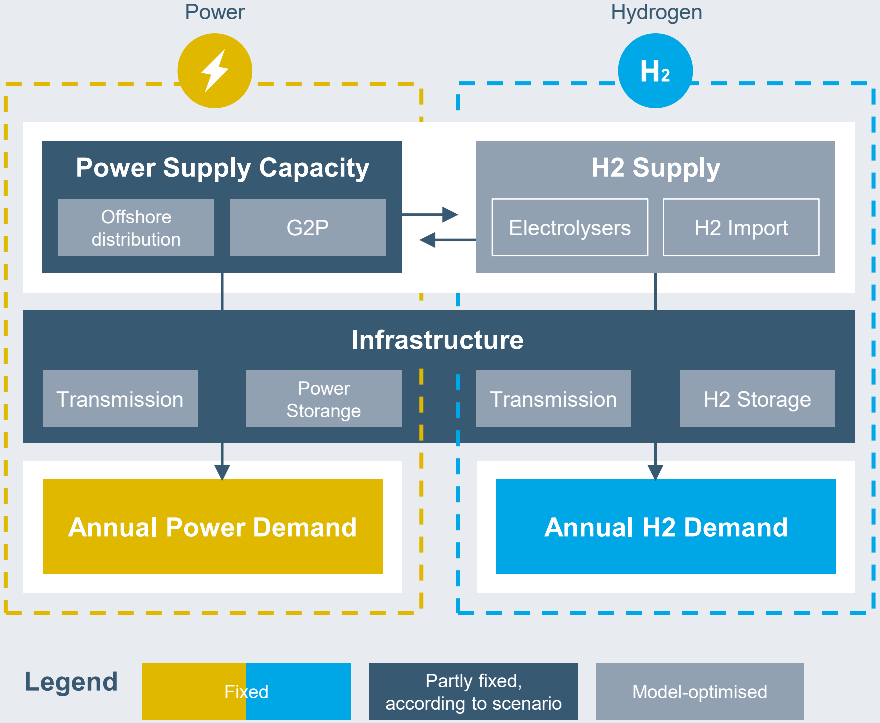
Adopted Modelling Rationale

The main scenario (DE Free Offshore) is inspired by ENTSO-Es Distributed Energy scenario and based on an **optimisation of offshore wind capacity, flexibility measures and transmission infrastructure towards 2050** with calculation years 2030, 2040 and 2050. In other words, annual power and H2 demand is exogenously defined and **the model will endogenously determine the installed offshore wind power & hydrogen capacities, as well as complimentary infrastructure needs** (power and H2 transmission, power and H2 storages) to supply the demand. Deployment of other main supply capacities (Onshore wind, solar power, hydro power) is defined exogenously, but endogenous scenarios are explored in sensitivities.

For the time horizon up to and including **2030, investment in transmission infrastructure is based on current plans** (European Hydrogen Backbone study for the hydrogen network (v.04/2022) and TYNDP 2022 for the electricity grid), without further optimisation (see next slide).

Assets subject to optimisation are: Offshore wind capacity, Power transmission, Power storage, Hydrogen based power generation (G2P), Electrolysers, Hydrogen transmission, Hydrogen storage.

A number of sensitivities explore impact of selected factors and modelling approaches.

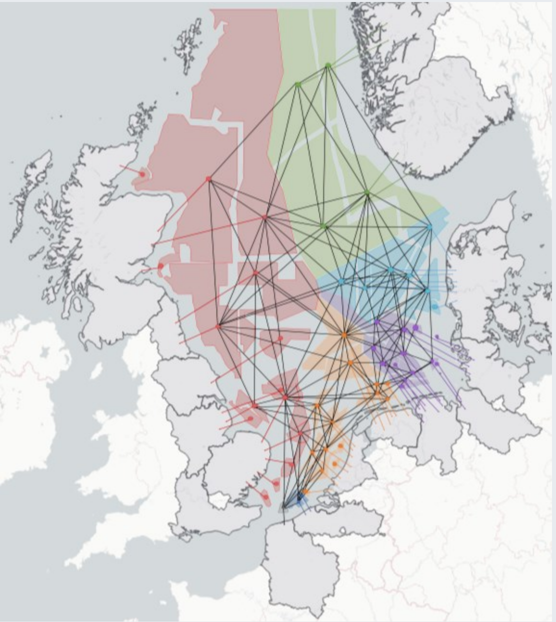


Offshore Wind Sites

Offshore wind sites are implemented in two ways:
- **Individual sites** (>22km to shore)
- **Aggregated sites** (<22km to shore)
  - Both types have an assigned wind speed profile provided by the Wind Energy department, Danish Technical University, DTU Wind.

Polygons shown consist of aggregated (by geolocational data) individual sites.
- Polygons modelled as Balmorel regions with offshore wind **potential equal to the aggregated individual site potentials**.

Individual Sites	Aggregated Sites
Investments in wind turbines and transmission lines optimised independently	**Transmission = turbine capacity**
Connected to landing zones	**"Within" parent regions**
Allows for: ▪ Hybrid or hubs-to-hub connections ▪ Modelling of energy islands (batteries, electrolysers)	**No options for:** ▪ Hybrid or hub-to-hub connections ▪ Energy islands ▪ Landing zone representation



Landing Zones (LZ)

Landings zones are defined as entry points for power transmission and hydrogen connections, either from direct transmissions to third countries, radial connections to offshore wind, or connections to hubs. By placing additional assets, e.g. electricity storage or hydrogen production in landing zones, the need for power transmission buildout towards the remaining onshore areas can be reduced and cost optimised. 21 **Landing Zones are defined around the modelled geography (see coloured regions on the right), with 18 located in the North Sea.**

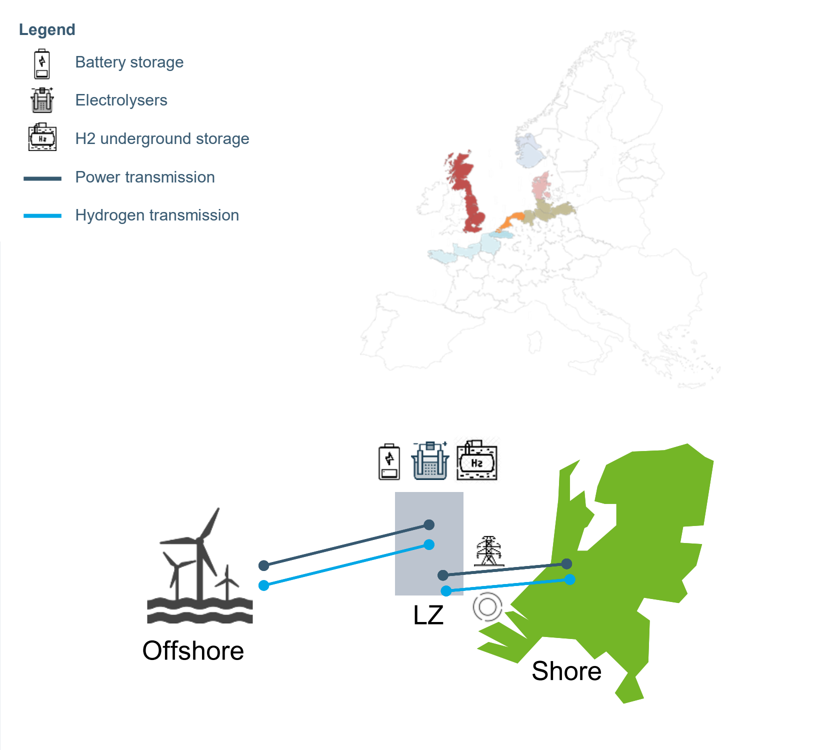
Cost distribution

Connection costs from offshore farms/areas to LZs:
- Power
- H_2

Connection costs from LZs to demand centres (onshore regions):
- Power
- H_2

Investment options on LZs:
- Battery storage
- Electrolysers
- H2 underground storage

Usage of landing zones depends on the optimisation process. **Some landing zones can be utilised for exploiting synergies between offshore entry points and installation of storages and electrolysers**. Not all landing zones are expected to reveal uniform synergies between the different assets, but may be simply used for connecting transmission lines, or may ultimately not have a separate function at all.



Platforms & Substations

Separation of offshore substation and platform costs from the individual offshore wind farm investment costs can lead to overall cost savings from overplanting of turbine capacities and optimising of electrolyser-substation-platform ratio. The cost breakdown implementation in the model is as follows:

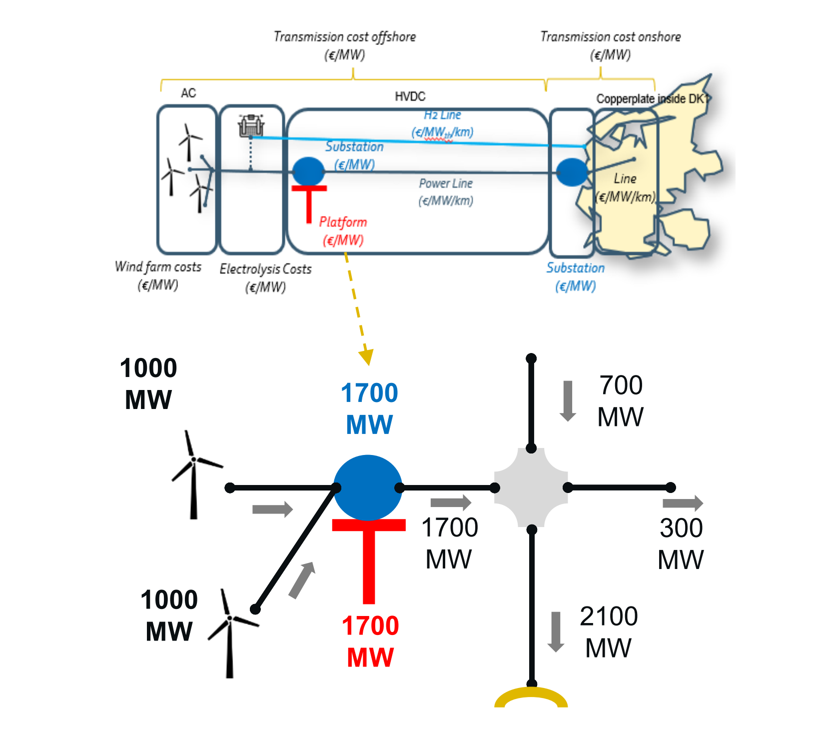
Cost distribution

Wind farm costs[1]
- OWF Base Investment
- Foundation Costs (Depth Specific)

Electrolysis costs[2]
- Base investment

Hub-to-LZ costs[2,3,4]
- Platform and offshore substation
- Offshore submarine cables (DC) and H2 pipelines
- Onshore substation

LZ-to-region connection costs[3,4]
- Onshore underground cables (DC) and H2 pipelines



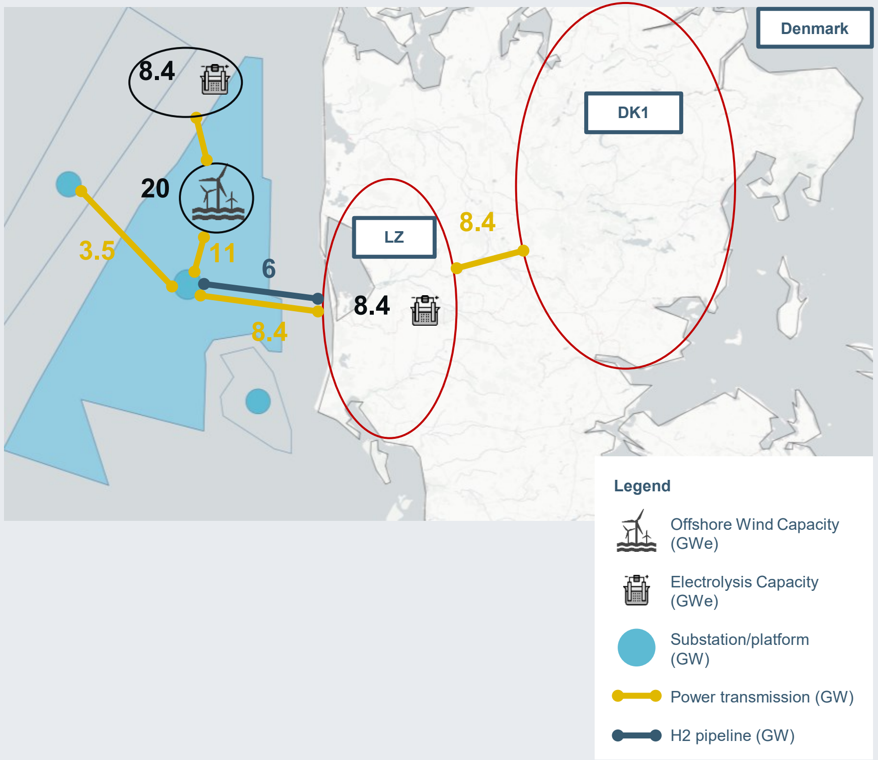
Notes: Connections between offshore regions do not require the presence of a DC substation. Only connections to shore do.

Example of Offshore vs Onshore Electrolysers 1/2

The principles of when onshore or offshore electrolysis is cost efficient, depends on the flexibility level aimed at, from full flexibility to limited flexibility and stand-alone hydrogen production[i]. This is an example to further explain the dynamics between offshore and onshore electrolysers. The example is of a DK hub with 20 GW wind capacity.

All parameters in the offshore hubs are optimised in the model runs, so wind capacity, electrical transmission capacity to landing zone, electrical transmission to the parent zone, substation capacity, offshore electrolysis, pipeline capacity and onshore electrolysis capacity in landing zones.

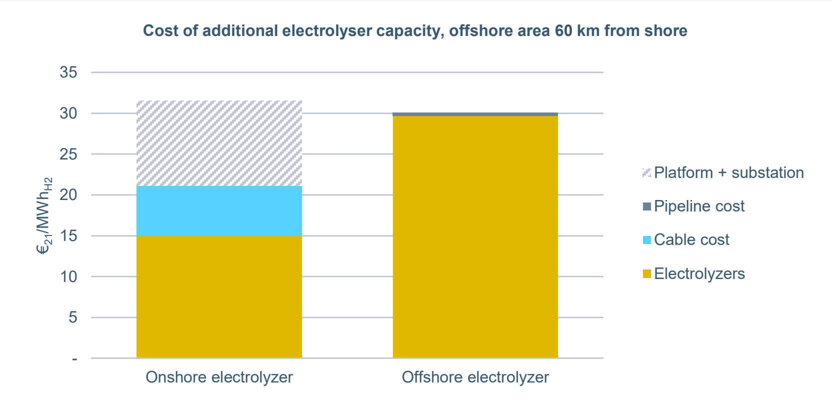
In a simple setup, the cost advantage of offshore electrolysis (see next slide) would mean that there should be no need to invest in cable to landing zone capacity higher than the transmission to the parent region (in this case DK1). This would mean, that 8,4 GW onshore electrolysis should be cost efficient, as they can achieve “full flexibility”, while additional electrolysers with “limited flexibility” should be placed offshore. This theoretical situation is illustrated on the right, while the actual model choice is explained on the next slide.

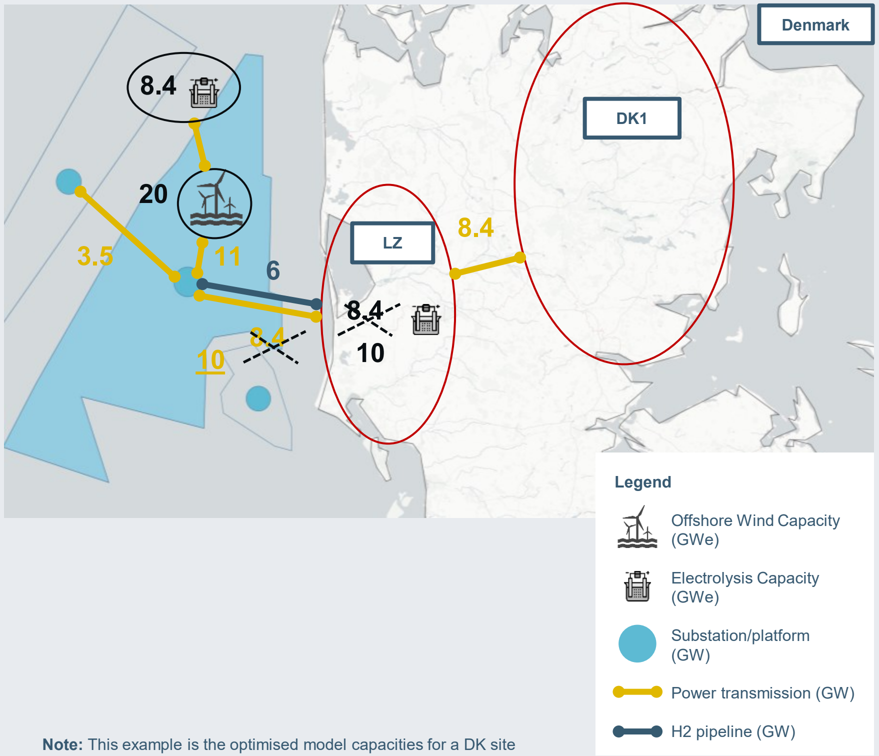


Example of Offshore vs Onshore Electrolysers 2/2

In the current example the model has optimised a total substation capacity of 11 GW, as the electricity is not only sent to the landing zone, but also to other hubs. Thus, if the additional electrical transmission to the landing zone is needed, only cable capacity to the landing zone has to be increased. This means, onshore electrolysis is cheaper than offshore electrolysis for the step from 8,4 GW onshore to 10 GW onshore (or a maximum of 11 GW, if that would have proven optimal).

The example illustrates, that potential economic advantages of offshore vs onshore electrolysis requires the option to save the entire cost of transporting electricity to the landing zone, that is, both the cable and the offshore platform and substation. This is further supported by the illustrative cost comparison below, which does not include the cost of providing the electricity (in this case offshore wind), which would be the same in both cases.





Note: This example is the optimised model capacities for a DK site

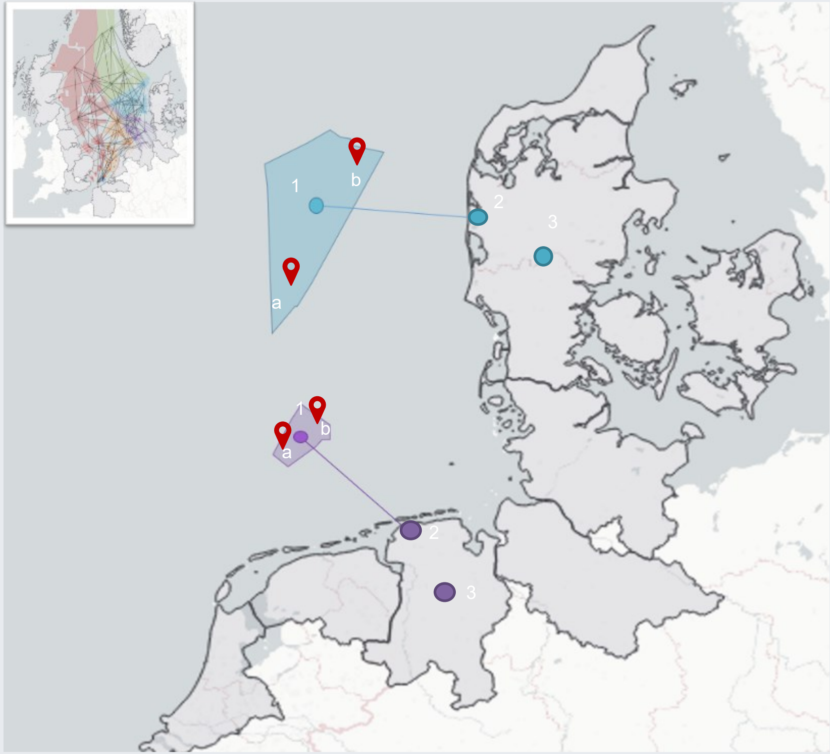
Offshore Power Transmission – Hubs

For the calculation of realistic power transmission costs of hub configurations, 3 distances are being taken into account.

- Demand region – Landing zone centre
- Landing zone centre – Hub centre
    - Point of connection isn't coastal.
- Hub centre – Individual windfarm centre

Such calculation may prove to be more costly vs the possible individual site modelling (see table), but increasing savings will arise on the assumption that the polygons offer the possibility of aggregations of a large number of individual sites.

[km]	Denmark		Germany	
	Hub	**Individual**	**Hub**	**Individual**
Demand region – Landing zone centre (3 to 2)	91	91	71	71
Landing zone centre – Individual windfarm centre (2 to a + 2 to b)		159 + 149		148 + 123
Landing zone centre – Hub centre (2 to 1)	154		137	
Hub center – Individual windfarm centre (1 to a + 1 to b)	102 + 62		15 + 23	
Total	**409 (+10)**	**399**	**246 (-96)**	**342**



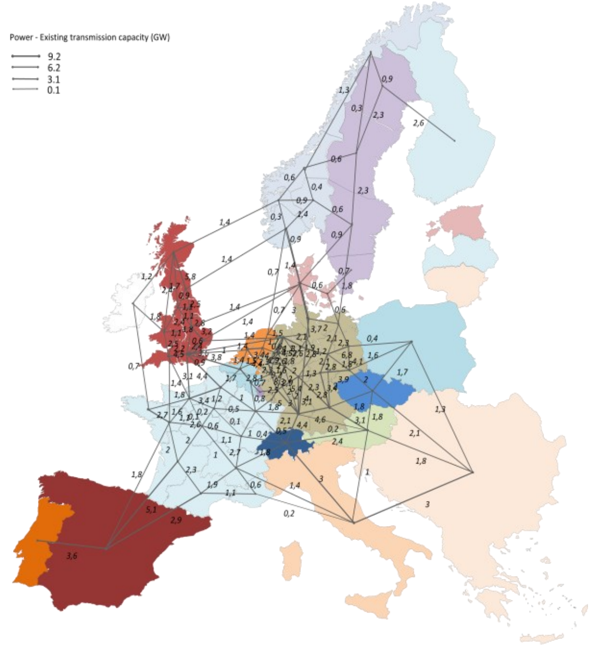
Starting Power and H_2 Networks

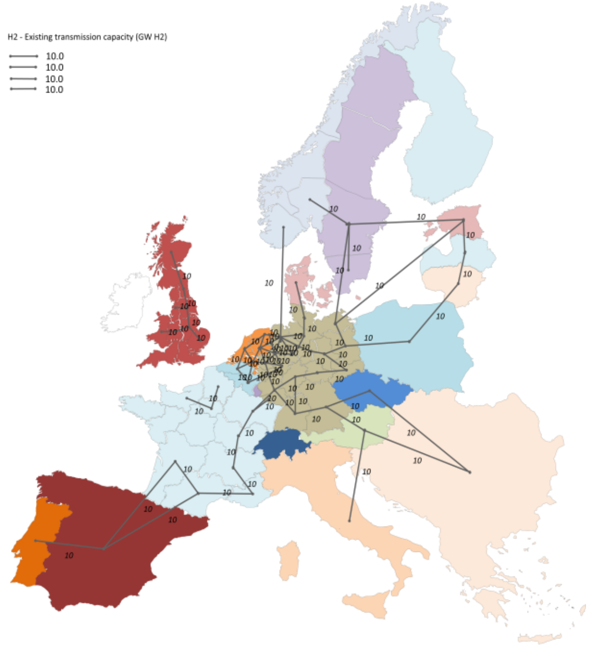
Power Grid

- NTCs estimated by Energynautics based on grid model calculations for the existing grid and firmly planned expansion, as described in the upcoming slides.

H2 Network

- Exogenously defined region to region capacities matching the European Hydrogen Backbone (EHB) network of 2030 (v.04/2022). 10GW$_{H2}$ of existing capacity per connection is expected to alleviate bottleneck issues.
- Capacities assumed to be in place across the whole modelling horizon.





Note: The map colouring only serves as a country boundary distinction and no further information is reflected in the present maps.

Calculation of the Power Net Transfer Capacities (NTC)

The calculation of NTCs is based on an open model dataset of the European power system in PyPSA, called PyPSA-Eur. The dataset is based on ENTSO-E data and contains voltage levels from 220 kV and above. For a first estimation of the NTC's, 45 % of the thermal line capacities have been used. Using the dispatch from the Balmorel optimisation, the NTC's have been calculated in more detail with linearised load flow calculations:

- In order to determine the NTC between two zones, the generation is increased in the exporting bidding zone and decreased in the importing bidding zone until at least one critical branch element is overloaded. By this, the Total Transfer Capacity (TTC) is received.
- The TTC contains no security-reserves. To include forecast uncertainties, the TTC is reduced by the Transmission Reliability Margin (TRM):

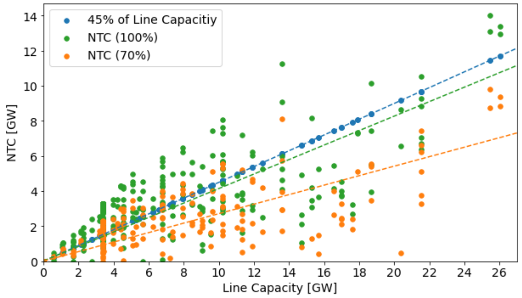
$$NTC = TTC - TRM$$
$$TRM = \sqrt{n} \cdot 100\ MW$$

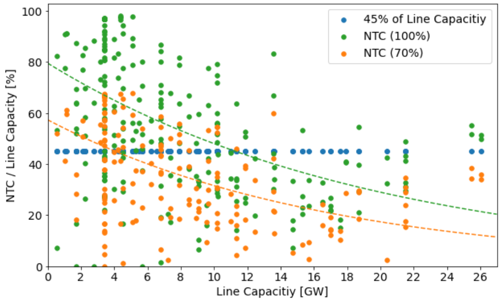
n: Number of interconnection lines

- The NTC is calculated for all borders so that it can always be used regardless of the exchanges on other borders.

Correlation between NTC's and Line Capacities

- The NTC is calculated for an overloading limit of 100 % and 70 % in order to take the (N-1)-criteria into account .
- The lower the thermal line capacity between two regions is, the higher is the NTC as percentage of the line capacity.
- This is mainly due to the fact that the network element, which is most sensitive to the load flow, has the biggest impact on the NTC, even when more lines are added.

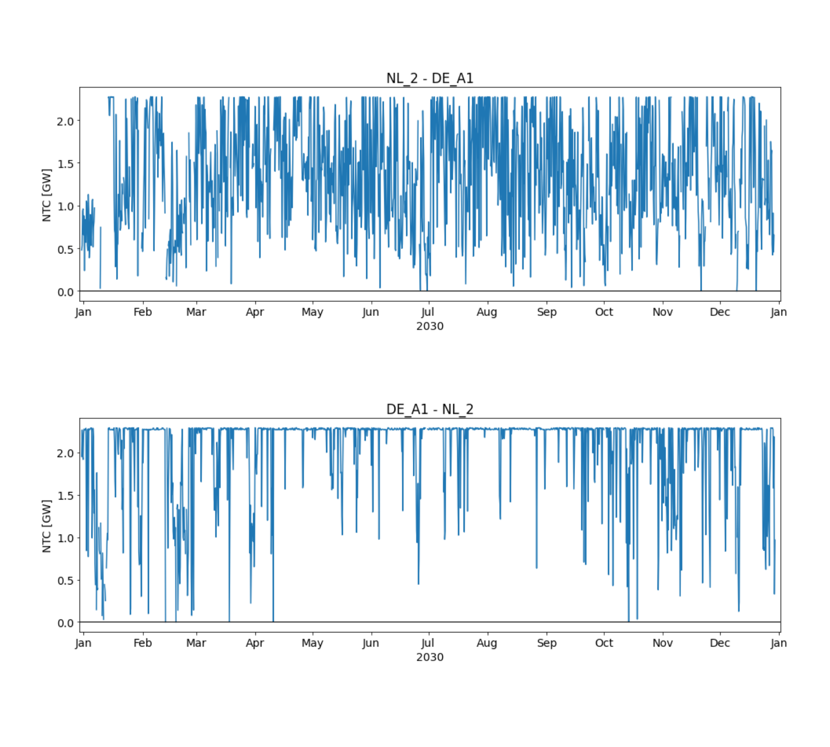




NTC Between NL_2 and DE_{A1} Over the Year

The NTC can differ significantly from timestep to timestep and also in the direction.

The reason for this is that the NTC value between two regions depends highly on the initial load flow conditions, which are set by the base generation and load patterns.



Power and H_2 Networks Development

Power Grid

- Region-to-region **expansions are allowed up to a level of 6GW per 10 years**, while taking into account the exogenously defined NTCs.
- Onshore investments in 2030 are disallowed in the model, given the proximity of the anticipated plans.

H2 Network

- Unlike the power transmission network, **no region-to-region expansion limits are imposed on the model**, after the evaluation of the sensible observed results.
- However, a more complicated investment approach is being followed, to take into account but not exactly match international plans such as the European Hydrogen Backbone (EHB).
  - The overall goal of such methodology is while taking into account the 2030 network expectations, provide a slight advantage (10% lower cost) on all selected by the EHB connections, while give a slight disadvantage to all connections including regions not part of the overall EHB pool of options (10% higher cost). Options assessed but not selected by the EHB will be represented by the presented costs of new pipelines, while, where applicable, repurposing of the existing methane grid will be possible, similarly at the previously listed costs.

H2 Network Connection Types & Costing: Regional Connections

Connection Type	2030	2040	2050
Backbone Selected	Existing (No Investments)	Existing (+ Lower Cost Investments)	Existing (+ Lower Cost Investments)
Existing Methane Grid	Repurposing	Repurposing	Repurposing
Out of Backbone Pool	New (Higher Cost Investments)	New (Higher Cost Investments)	New (Hihger Cost Investments)
Backbone Non-selected	Disallowed (No Investments)	New (Data Cost Investments)	New (Data Cost Investments)

Demand and Demand Profiles – Background

Electricity Demand

Electricity demand is split into the 5 following demand categories:

- ***Classic*** *demand, which includes all end-use sectors excluding industry, transport and individual heating*
- *Direct* ***industrial*** *demand for electricity*
- *Demand from* ***electric vehicles***
- ***Individual heating*** *demand*
- *District heating demand.*

Hydrogen Demand

End-use hydrogen demand is **mainly defined exogenously, however G_2P** is a result of model optimisation

Power-to-hydrogen demand is found endogenously through market competition with external H_2 imports at a defined price

Demand Profiles

Electricity demand profiles from the NSWPH python tool are used for all demand types
Flat profile is applied for shipped hydrogen import

Demand Buckets and Related Flexibility

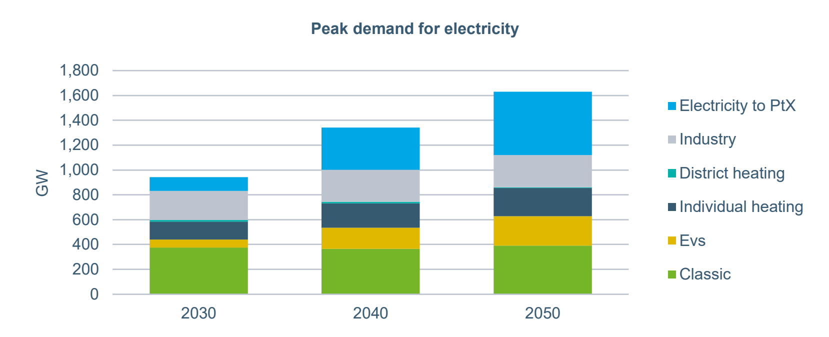
Demand projections cover 6 main categories outlined below. Flexibility options are modelled specifically for each category.

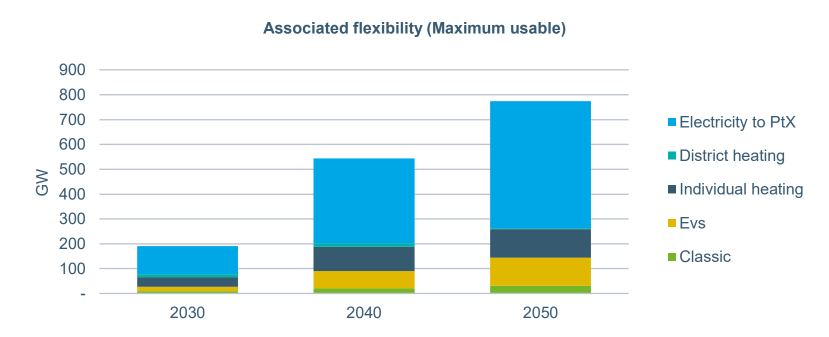
Demand bucket	Description	Flexibility	Associated cost
Classic	Classic electricity demand mainly for households, the industry and service sector. Contains demand types not explicitly covered under the other categories.	In 2050, 10% of average demand is assumed flexible and **can be moved in time with up to 2 hours**. In 2030, 3% of average demand is assumed flexible.	Two main cost levels. 50% of flexibility activated at a cost of 15 €/Mwh, 50% of flexibility activated at a cost of 30 €/MWh. This means that flexibility will be activated at this price difference.
Electric vehicles	Demand includes all **electricity for road transport.** Initial profile is based on charging patterns matching transport demand (Estimated for individual countries based on empirical data from Norway)	Towards 2050, 65% of total load for electric road transport will participate in flexible charging and be **able to move planned charging by up to 4 hours**. The EV flexibility considers driving patterns and ready-to-drive constraints	Flexibility activated at a cost of 15 €/MWh.
Individual heating	Includes electricity consumption for **space heating in buildings**. The demand is supplied by heat pumps and electric boilers.	Flexible heat generation by adjustments to initial demand profile. Average demand **can be moved 2 hours**.	Flexibility activated at a cost of 10 €/MWh.
District heating	**Heat demand for district heating** is included. Heat pumps, storage and electric boilers are among the options to supply the district heating demand. Other options are fuel based district heating generation from heat only boilers or CHP.	Flexibility consists of the option to fulfill the heat demand by electricity or other heat generation, depending on the power prices	Investment and operational cost for electric boilers or heat pumps included. Using alternative options for heat generation yields additional cost.
Power-to-X	**Demand for production of e-gasses, e-liquids and hydrogen** based on EU commission scenarios. Modelled as electricity consuming generation facilities (electrolysers).	Model optimised hydrogen storages can be installed to enable flexible use of electrolysers, while demand is modelled constant.	Investment and operational cost for electrolysers and cavern storages included.

Demand and Flexibility in Europe

Demand projections show increasing importance of electricity for hydrogen production (Electricity to PtX), both regarding annual energy amounts, but also regarding the associated flexibility. The largest demand types in the model are reflecting in the categories of classic demand and industry in 2030, actors with little contributions to the overall flexibility, unlike new demand types in the system (e.g. Electricity to PtX). Note that the peak Electricity to PtX demand and its associated flexibility are model optimised (magnitude of electrolysis investments (GW) and the corresponding flat or variable operational patterns).

Actual usable share of flexible capacities depend on the system state. As an example, maximum flexibility for additional power generation (by reducing demand) can only be provided in situations where the initial load is high. For EVs this corresponds to peak loading, while for individual heating and district heating this would correspond to winter peaks.





Note: Model area, covering large parts of Europe.

Note: The top figure illustrates the stacked individual peak hour of each category. Those hours do not necessarily take place simultaneously within the modelling horizon.

Flexibility on Classic Demand

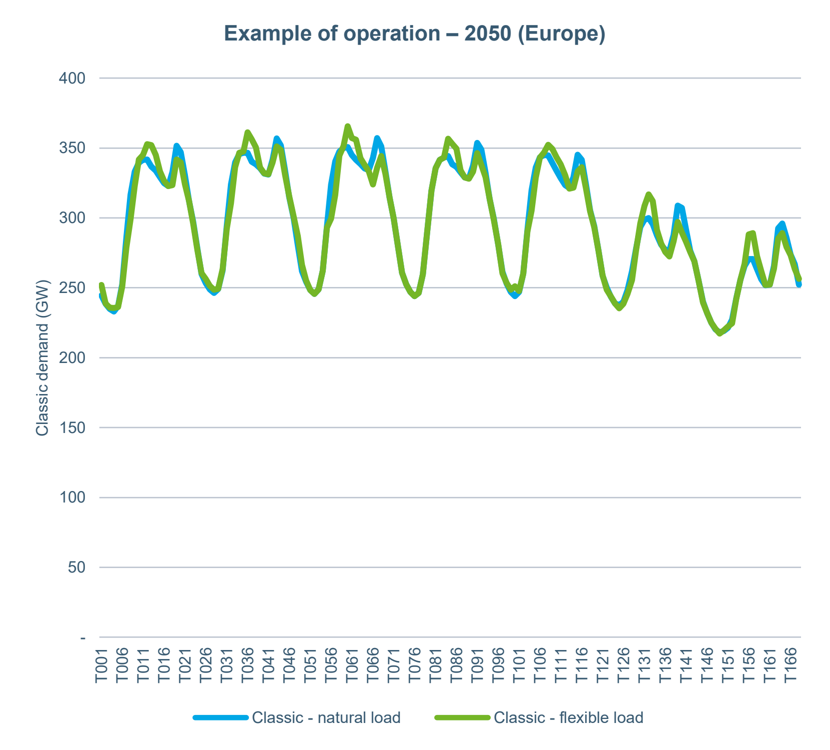
Assumptions on demand response for classic electricity demand (households + industry) are based on an estimate of long term flexibility equaling 10% of average demand in 2050. Flexibility is phased in from 2020, leading to 3,3% of average demand being flexible in 2030.

Demand response is implemented as a potential to shift of demand in time for up to 2 hours. For comparison, ENTSO-E reported average DSR (Demand side response) of roughly 9% of average demand in 2040 in the TYNDP 2018 Global Climate Action scenario.

50% of flexibility is activated at a cost of 15 €/MWh, while the remaining 50% of flexibility is activated at 30 €/MWh, meaning that the difference between achievable electricity prices has to be at least 15 €/MWh, before load shifting takes place.

Deployment of locally distributed battery solutions (for example residential batteries in combination with rooftop PV) are not considered in the modelling and could provide a portion of this flexibility potential.

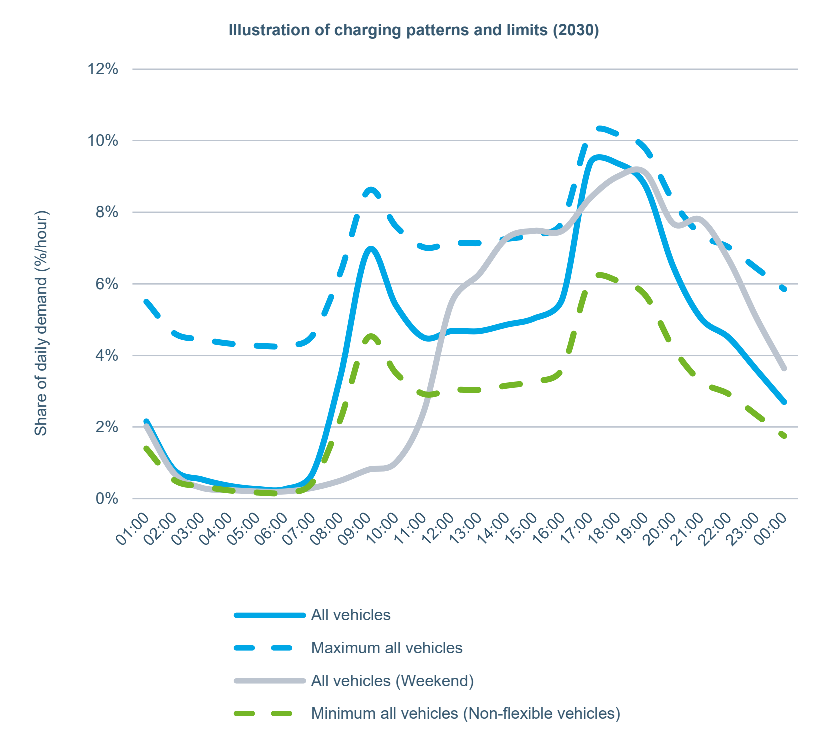
Utility scale batteries are not included in the estimates here as they are subject to explicit optimisation.



Flexibility on Electric Vehicles

Charging patterns
Charging patterns for electric vehicles are assumed to be flexible relative to an initial charging profile. The initial charging profile is based on estimates of immediate charging profiles according to driving patterns (Full blue line for weekdays and full grey line for weekends)[1]. These charging profiles would ensure EV's are fully charged as fast as possible after driving. Thus, charging profile follow peak commuting hours with a little time lag. Charging patterns are based on research on personal vehicles, but are used here to represent all electricity use for road transport.

Only a share of all vehicles are assumed to be flexible, which leads to certain minimum (red dashed line) and maximum (blue dashed line) loads for charging electric vehicles at all times. The resulting potential load patterns exclude option for vehicle-to-grid technologies, which could significantly increase flexibility options, albeit at a higher cost, to take into account technology needs and lifetime reductions on batteries due to additional cycling.



Note: [1]Source: Liu, Z., Nielsen, A. H., & Wu, Q. (2016). Optimal Operation of EVs and HPs in the Nordic Power System. Technical University of Denmark, Department of Electrical Engineering.

Limits on Flexibility of Electric Vehicles

Time shifting
Flexibility is implemented as a potential to shift the average charging load (of the flexible vehicles) of up to 4 hours in time. Energy demand has to be served over a 24 hour period, and all energy demand has to be served by 7 am in the morning, where all EVs are charged to the desired level

Restriction on flexibility
Flexibility of charging for electric vehicles is subject to a number of restrictions, which develop over time

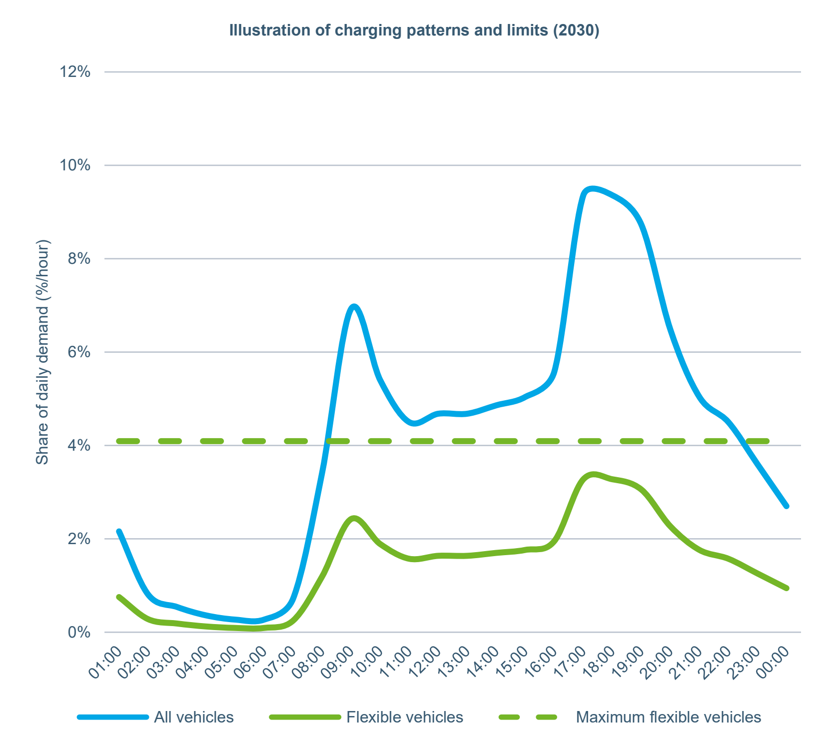
Only a fraction of vehicles participate in flexible charging, meaning the remaining vehicle will follow the initial charging pattern at all time. The maximum charging is limited to a multiple of the estimated peak demand of the initial profile

Maximum charging for flexible vehicles cannot exceed 125% of the peak of their initial charging profile.

Flexibility is activated at a cost of 15 €/MWh independent of time difference. This means, the difference between achievable electricity prices has to be at least 15 €/MWh, before load shifting takes place. For an average personal vehicle with annual driving ranges of 15.000 – 20.000 km and electricity demand of around 3 MWh/year, this corresponds to savings of 45 €/year via the shifting of its assumed charging patterns.

Restrictions on flexibility

	2020	2030	2050
Share of vehicles participating in flexible charging (%)	20%	35%	65%
Maximum charging (% of peak of flexible carss)	125%	125%	125%



Flexibility on Individual Heating

Electricity used for heating can be flexible by exploiting heat capacity in buildings and hot water tanks. The initial demand profile follows the heat demand, which is dependent on hot water usage and outside temperature. An increasing share of buildings are participating in providing flexibility to the system by allowing the average seasonal demand to be shifted by up to 2 hours.

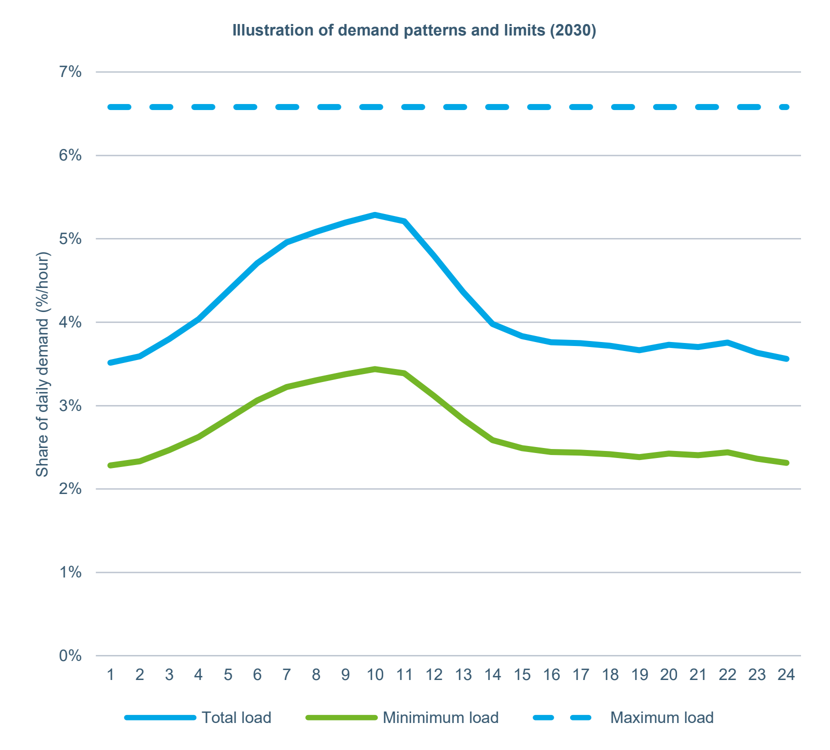
Load for buildings not participating in flexible heating will have to be served at all times. Maximum load for individual heating cannot exceed maximum annual peak demand, which is well below the total cumulative installed technical capacity of heat pumps.

Heat demand has to be supplied within 24 hours and thus cannot be shifted across days.

Flexibility is activated at a cost of 10 €/MWh, meaning the difference between achievable electricity prices has to be at least 10 €/MWh, before load shifting takes place.

Restrictions on flexibility

	2020	2030	2050
Share of buildings in flexible heating (%)	20%	35%	65%



Flexibility on Electric Vehicles

Flexibility in charging patterns is used in dispatch optimisation as illustrated, showing a move away from peak load in initial charging profile at the expense of higher peaks. Flexibility activated at a cost of 15 €/MWh.

Flexibility on electricity for hydrogen production

The hydrogen demand is modelled to be constant in all hours throughout the year. Electricity used for hydrogen production can be flexible by exploiting underground storage options, thereby making it totally flexible to produce hydrogen when electricity prices are low and using storage when prices are high.

The cost of this flexibility is more indirect as the model needs to install H2 underground storage capacity in order to have flexibility.

Example of EV operation – 2050 (Europe)

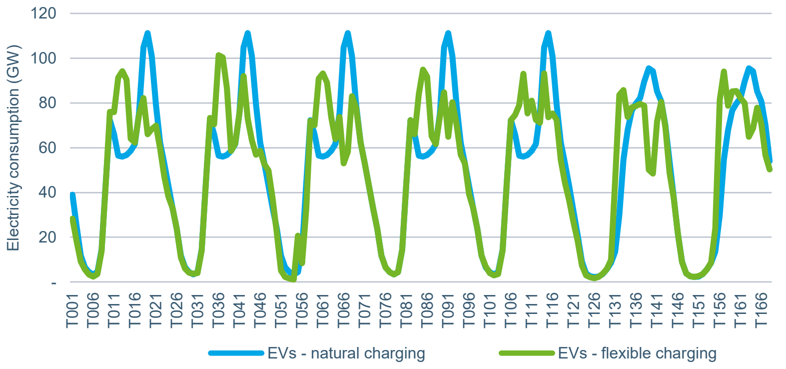
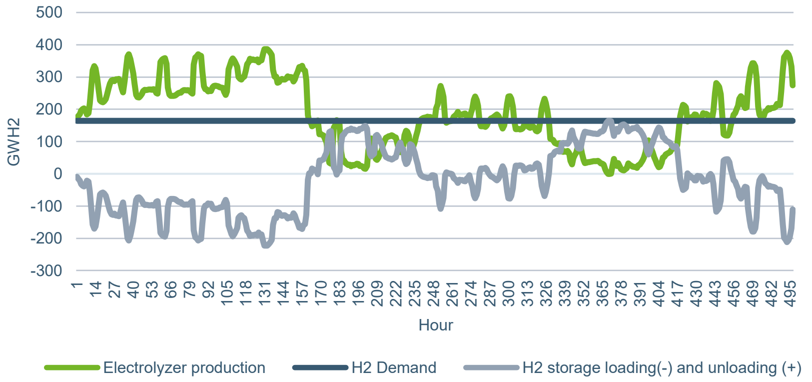


Illustration of the H2 supply and demand (2050), first 500 hours



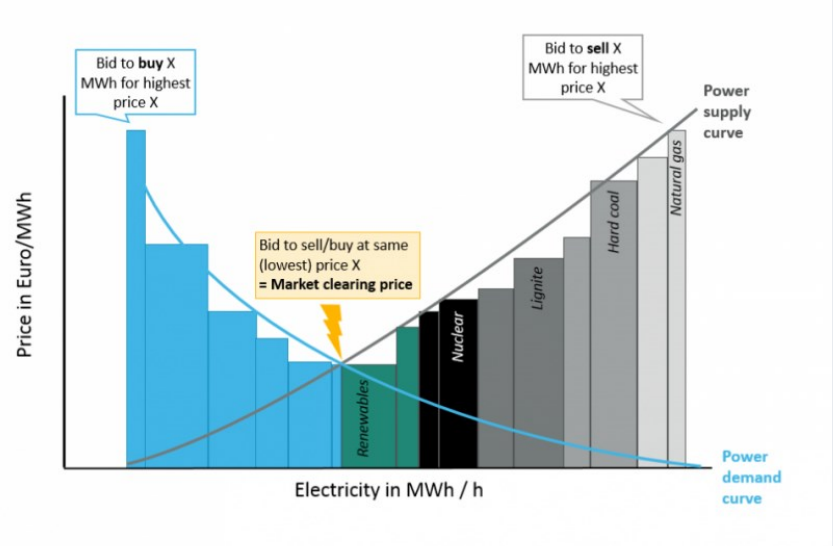
Note: Maximum charging capacities and volume based on simplified estimate of 7,5 GW charging capacity/vehicle and 2 MWh average electricity demand pr. vehicle and average battery sizes of 50 kWh/vehicle

Electricity Price Definition

The electricity prices, that are shown in the listed result slides, are clearing prices in each bidding zone. This is illustrated to the right.

The price is defined by the marginal costs of the last supplier to enter the market in a given hour.

This is not to confuse with consumption-weighted capture prices for different types of consumption, classical, industry, EVs, PtX and so on.



Appendix III – System Pathways to 2050

Main System Pathway

Base Case Scenario: DE Free Offshore

The main scenario data of the present work is built upon the energy system data developed by ENTSO-E for the Ten-Year Network Development Plan. The North Sea Wind Power Hub consortium, attempting to assess the feasibility of hub-and-spoke projects as a possible concept for energy infrastructure development in the North Sea, developed the Integrated Energy System Scenarios study, which aims to provide the NSWPH consortium with high-granularity datasets for the European and other countries of interest for time horizons up to 2050.

Energy system data (supply, demand, and generation capacities) is available on sectoral and national level, shaping ultimately the utilised Base Case Scenario, as well as driving the development of the undertaken sensitivities. The DE Free Offshore scenario builds upon ENSTO-E’s Distributed Energy Scenario, however, the applied modelling methodologies and data assumptions, optimisation approaches and higher geographical resolution lead to some differences on a system basis, which are described in the following.

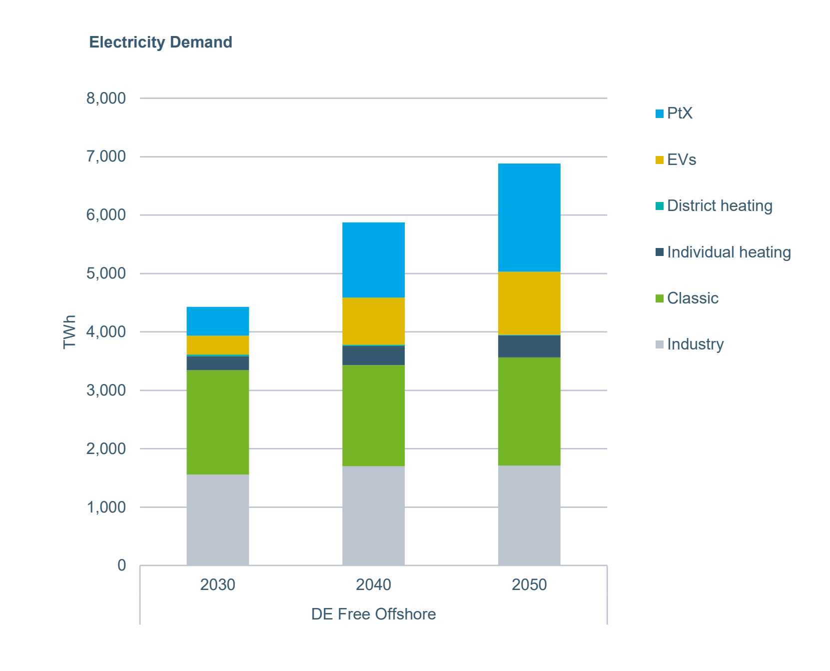
A key difference is, that only onshore wind and solar PV are defined to match ENTSO-E’s scenario generation, while the amount of offshore wind as well as flexibility measures supporting system operation are optimised.

Electricity Demand

Massive electrification across different sectors increase electricity demand by approximately 59% between 2022[1] and 2030 and 100% between 2022 and 2050.

- In 2050, more than 30% of all electricity demand is used for hydrogen production
- Classical electricity demand for households and industry accounts for 53% of total electricity demand

Further comparison of Pathway 2.0 results with TYNDP Distributed Energy can be found in an upcoming Appendix.



Note: PtX shows electricity use for hydrogen production in Europe.

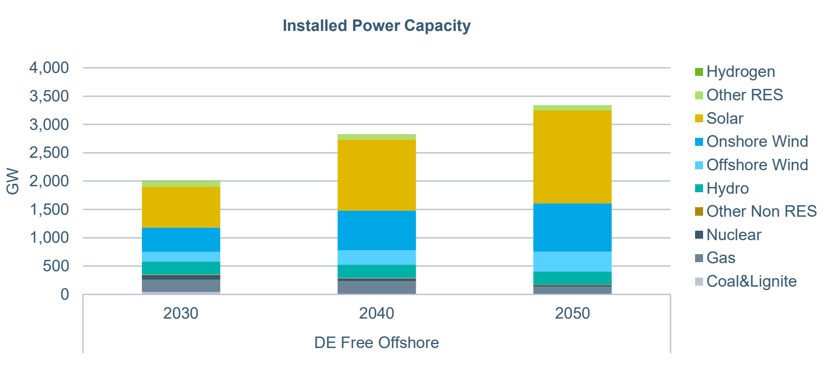
Notes: Electricity to PtX quantities in Pathway 2.0 are approximated on the basis of the respective year's PEM electrolysis LHV efficiencies (2030 – 70.0%, 2040 – 75.5%. 2050 – 79.0%).
The Hydrogen Balance figure sets side by side results for TYNDP EU27 countries against the whole model geography of the present study. UK, Norway, Switzerland, Albania, Serbia, Montenegro, North Makedonia, Bosnia Herzegovina and Kosovo are additionally included in the "Baseline" figures.
The TYNDP DE scenario H2 balance is based on the publicly available TYNDP data. The electricity for H2 production and the total fuel demand come from raw data, while the import is estimated based on the difference.
TYNDP DE import assumptions (Total Potential) are 259 TWh H2 from North Africa, and 217 TWh H2 from Norway, which are respected in the graphs.

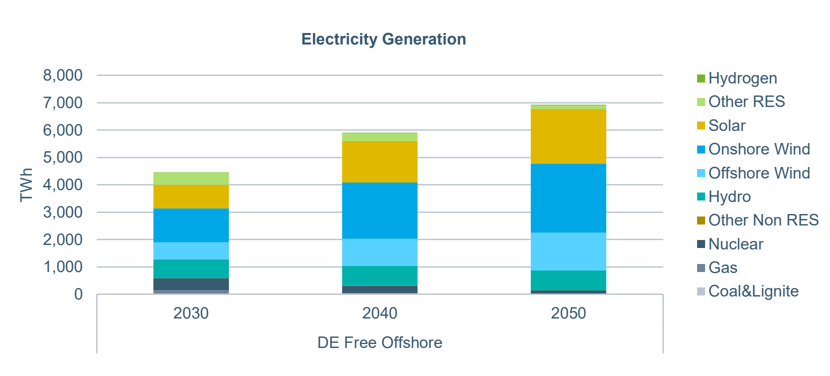
Power Capacity & Generation

100% decarbonised system in 2050. Thermal generation from Nuclear and Gas based capacities provide very limited electricity generation on an annual basis (~2%). System balancing ensured mainly via interconnections and storage operations.

- **Low natural gas utilisation is observed**, mostly for peak purposes, due to the fuel cost impacts of the latest gas market developments over Europe.
- **Nuclear capacities are exogenously defined** by the utilised scenario data (not model optimised).
- As already discussed, the utilised VRE profiles reflect higher full load hours for solar PV and onshore wind turbines against the calculated TYNDP ones, resulting in less necessary capacities for the approximation of same total VRE generation. The resulting **power contribution from onshore WT and solar PV in Pathway 2.0 is higher by ~261TWh (6% of onshore VRE, 3% of total)**. Further comparison of Pathway 2.0 results with TYNDP Distributed Energy can be found in an upcoming Appendix.
- **Gradual increase in renewable capacities is observed up to 2050**. More specifically, in 2050:
  - Solar PV: 1,642 GW, 2,004 TWh.
  - Onshore WT: 852 GW, 2,525 TWh.
  - Offshore W: 350 GW, 1,387 TWh.

A mapping of the showcased capacities can be found in the next slide, and a detailed breakdown within an upcoming *Appendix*.





Note: Hydrogen based electricity generation (bottom graph) reflects generated amounts from both newly installed (H2 G2P) and retrofitted natural gas units. The top graph, however, differentiate the capacities where Hydrogen values reflect only new units with the rest incorporated into the Gas category. Use of natural gas in the power mix is disallowed in 2050, while for coal and lignite already from 2040 and on.

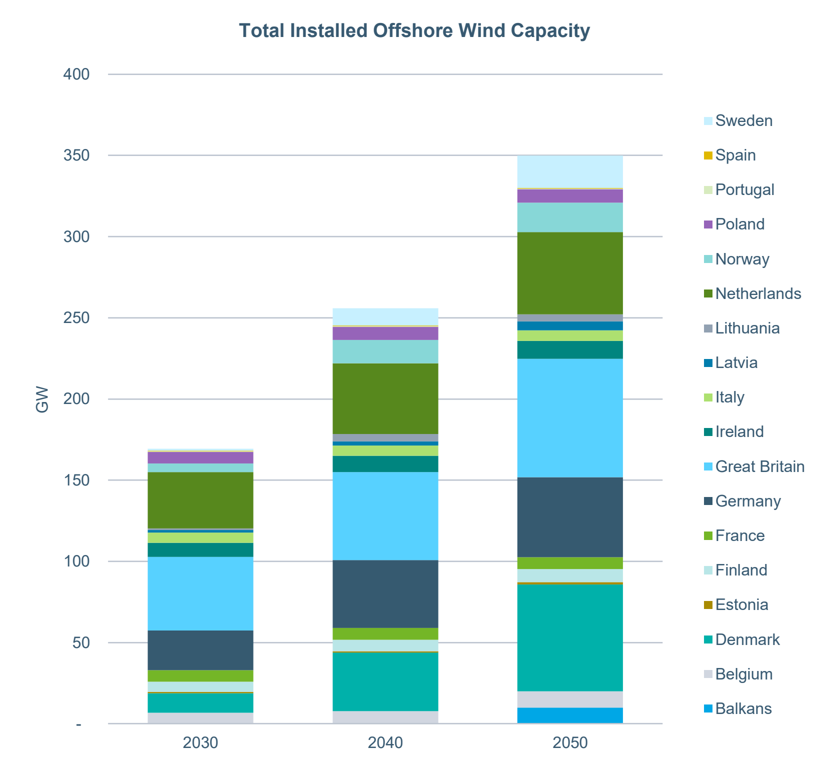
Offshore Wind

Offshore wind reaches 350 GW in Europe by 2050, with 68% of total installed capacities distributed across 4 countries:

- Great Britain
- Denmark
- Netherlands
- Germany

A summary of the capacities located in the North Sea related countries, can be seen below vs the latest known political targets at the time of the study.

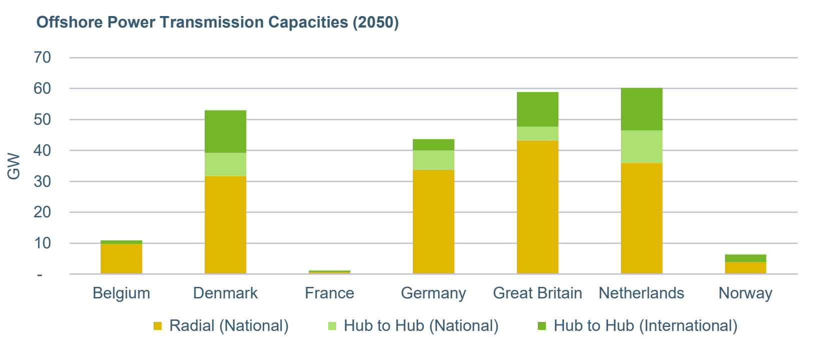
GW, 2050	TYNDP DE	Model Results	Delta
Belgium	7	10	+3
Denmark	45	66	+21
France	65	7	-58
Germany	83	49	-34
Great Britain	112	73	-39
Netherlands	68	51	-17
Norway	30	18	-12



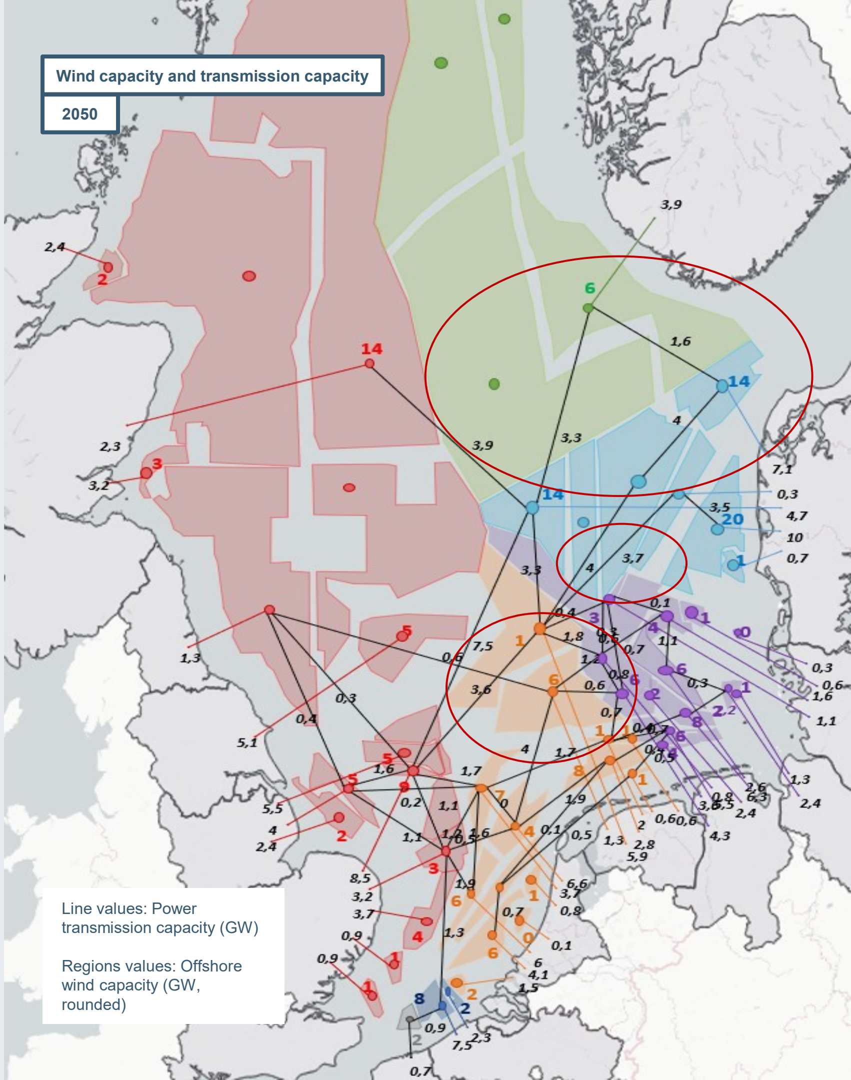
A north-south electricity corridor is valuable to the system

The results show that **it makes socio-economic sense to connect hubs-and-spokes across the North Sea region**. Several benefits stem from such formations. Well-connected offshore hubs can optimise flows to different countries depending on the need and price of electricity, consequently higher capacity factors are experienced on key transmission assets. In parallel, hubs can be used as interconnectors between countries when wind generation is low.

The figure to the right shows that central hubs in the far-offshore Danish and Dutch zones become highly connected to neighbouring countries. **A robust corridor is formed going from Norway to two Danish hubs which continues down through the Dutch hubs to the southern UK hubs**. German hubs are connected to the corridor via Dutch hubs.

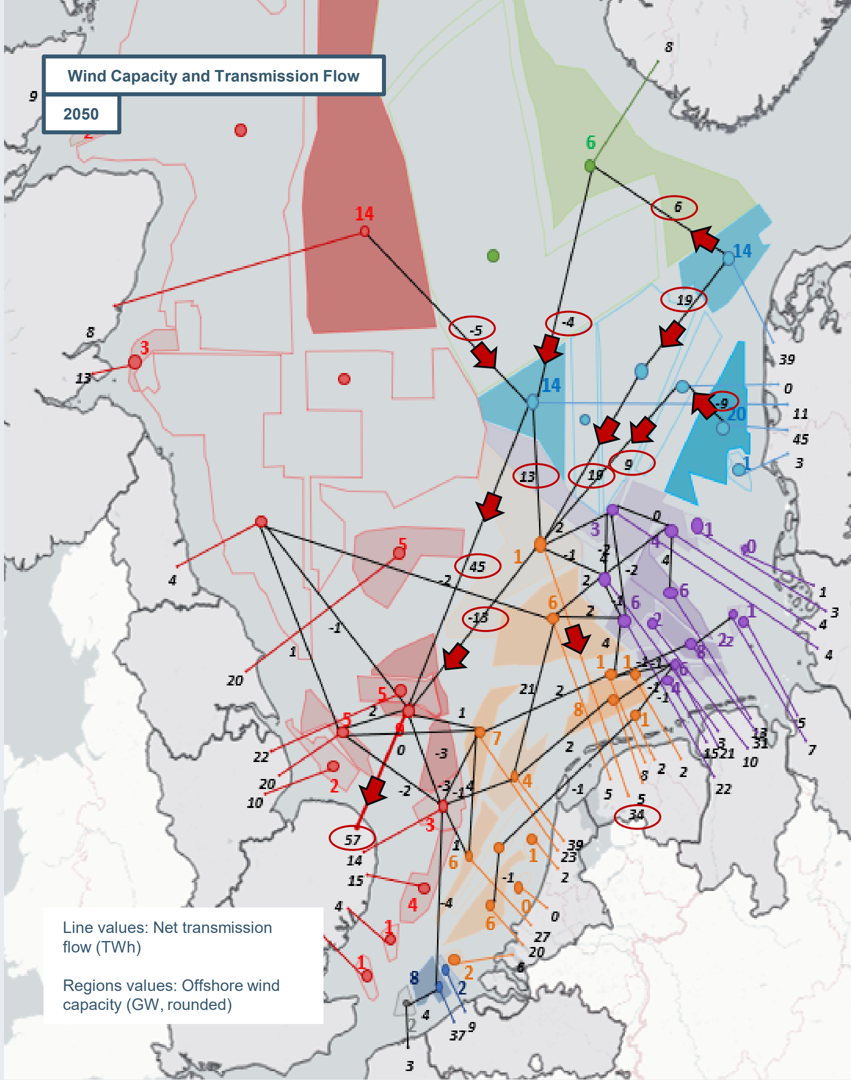


Note: Capacities outside the North Sea are also included. Hub-to-Hub (International) A -> B capacities are also included as B -> A in other countries, so the total aggregated capacity is half of the illustrated.



The north-south corridor facilitates large net electricity flows toward UK and the Netherlands

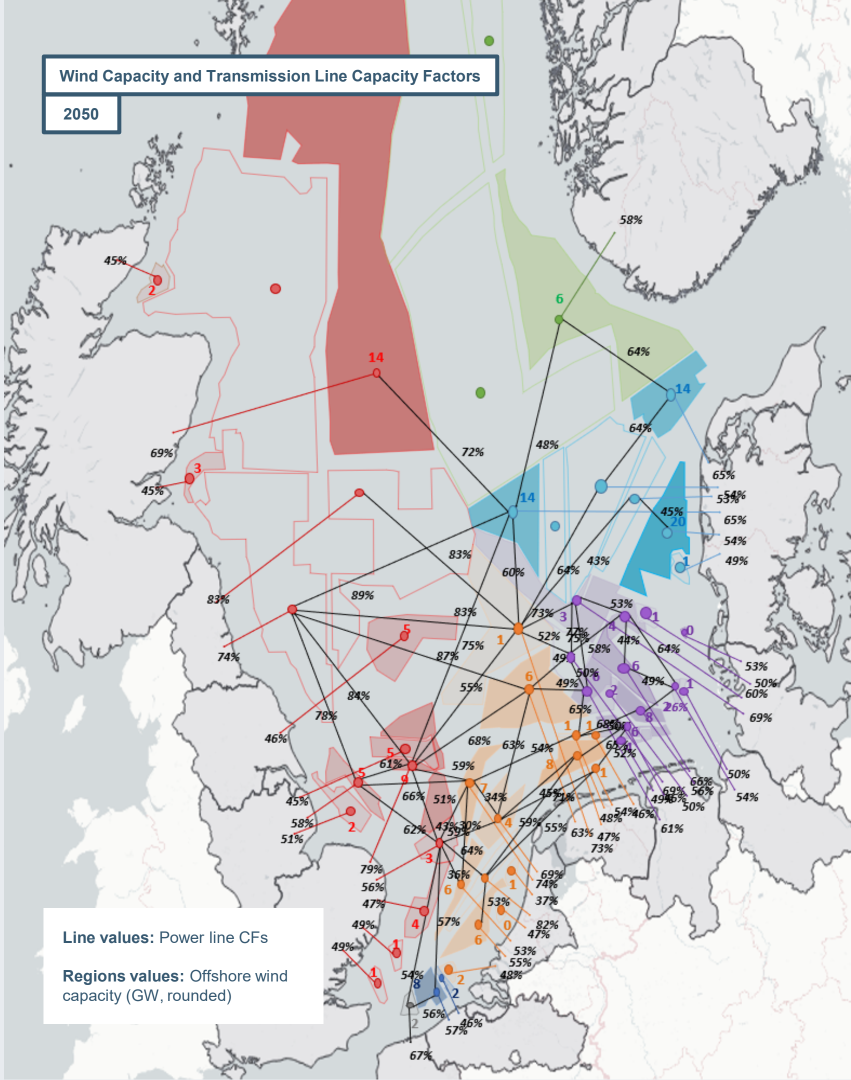
The offshore grid in the North Sea enables flows electricity flows **from mostly the three Danish hubs to the UK and the Netherlands.** The Danish hubs have large wind farms at 20 GW, 14 GW and 14 GW. In total, **~44 TWh flows from the Danish hubs to the UK and ~41 TWh flows from the Danish hubs to the Dutch hubs**. This is equivalent to approximately 20 GW turbine capacity. The overall hub-to-hub grid has several smaller flows in all directions utilising differences in generation profiles across the North Sea. The German hubs export some electricity towards the Netherlands, but the major share is exported to the German shore.



Note: Overview of country-based power flows in the North Sea across scenarios can be seen in the Appendix (table, illustration).

Higher transmission capacity factors reflect steadier flows, while lower ones signalise occasional but important for the system balancing needs

The utilisation of the electricity corridors illustrate one of the advantages of the hubs-and-spokes concept: Many grid elements are used at higher capacity factors, than the capacity factors of offshore wind farms. Higher capacity factors (CF) indicate a relatively constant use of each power line close to the invested capacity, while lower capacity factors show more flexible operation for occasional balancing purpose spikes. For existing or planned radially connected wind farms, the utilisation factor of the transmission-to-shore line matches the experienced OWF FLHs, as transmission and WT capacities are conventionally matching (some overplanting can be beneficial).

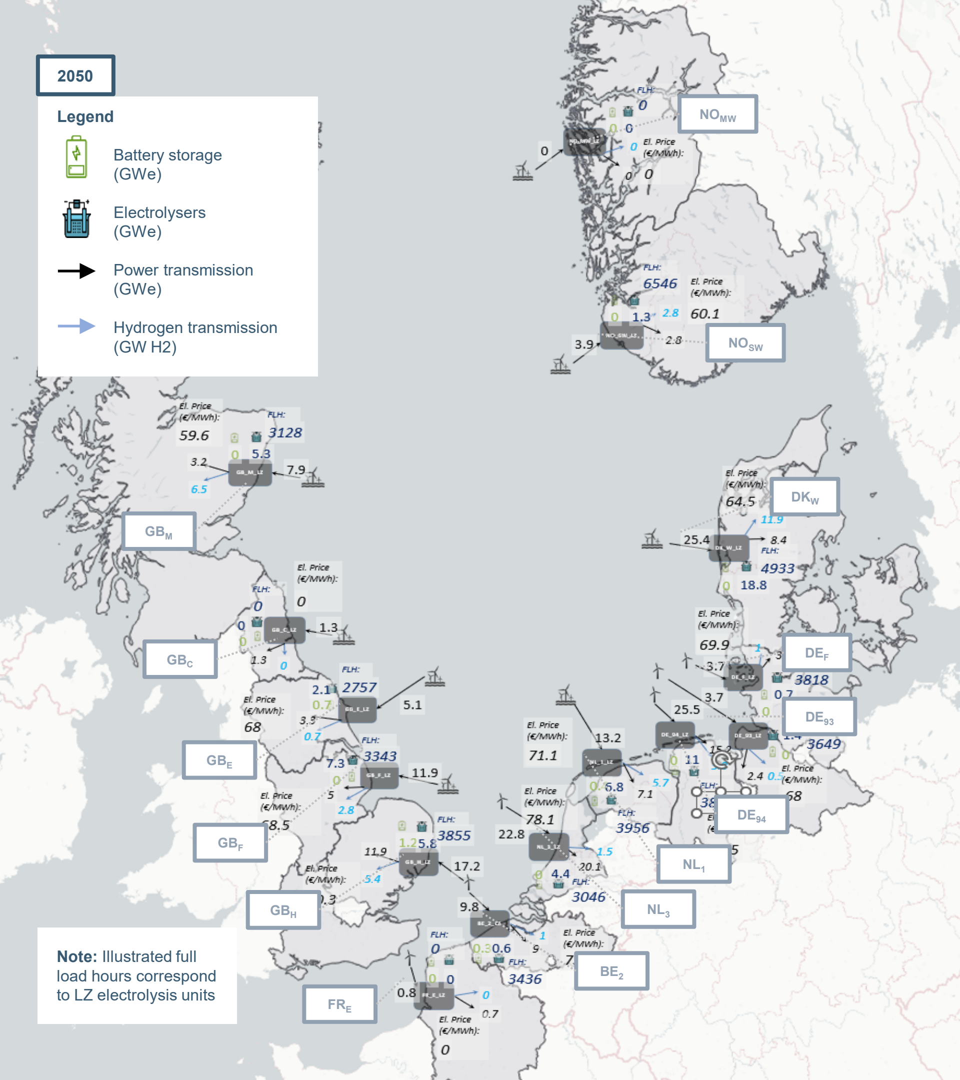


Landing zones (LZs) support the integration of offshore wind to the onshore system. Electrolysers on LZs can relieve onshore infrastructure system needs when connecting offshore and onshore systems

Landing Zones electrolysers (LZ) aim to harvest the benefits collecting electricity from multiple offshore sites, but also from power coming through the mainland. Therefore, the operation of the installed electrolysers on LZs reflects mostly higher FLH's when compared to the corresponding parent region's capacities.

Electrolysers can operate as flexible units during hours with low power prices or when the available onshore VRE generation surpasses the local demand but interconnection to other demand regions are congested.

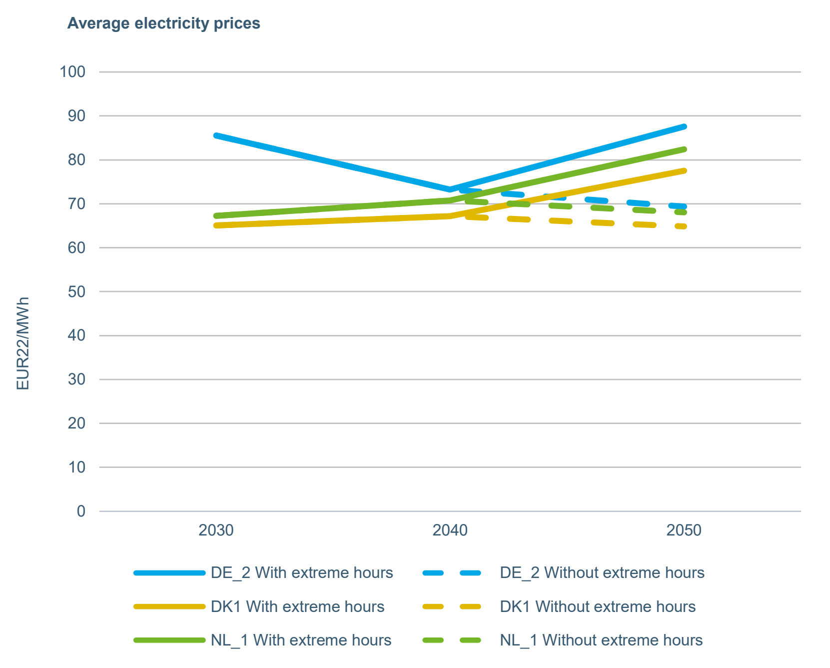
An overview of the NS integration system is illustrated on the right. The role of landing zones on the integration of the offshore system to the onshore one, as well as the role of electrolysers on relieving pressure from the onshore grid is evident. LZ electrolysers operate on average 570 FLHs above the inland units, while transmission lines from LZ to mainland reflect on average 690 more FLHs versus lines from offshore to the LZ.



Average Electricity Prices

Average marginal electricity prices increase by around 10% over the period from 2030 to 2050. The underlying distribution of prices show a general tendency towards few high price hours (around 50 hours/year), impacting the average prices. Without high price hours, average price levels are stable across the analysed period. Reduction of cost for renewable energy on the one side can lead to decreasing average prices, while the massive electrification leads to using marginal renewable resources and increases the need for interconnection on the other side.

Price levels are not directly comparable to today's spot markets for two main reasons:
- Price levels are based on simulation of high-resolution bidding zones, compared to today's setup
- Price levels include the need for transmission grid buildout



Notes: DE 2 is in Southern Germany (Bayern). NL 1 is the northern provinces of the Netherlands. Prices are not consumption weighted, it's the average clearing price in bidding zones. For weighted prices, refer to upcoming slides. Extreme hours are defined as hours where the price is reaching the price ceiling of 3000 €/MWh.

The main power flows in 2050 are heading to central Europe

Main power flow patterns:

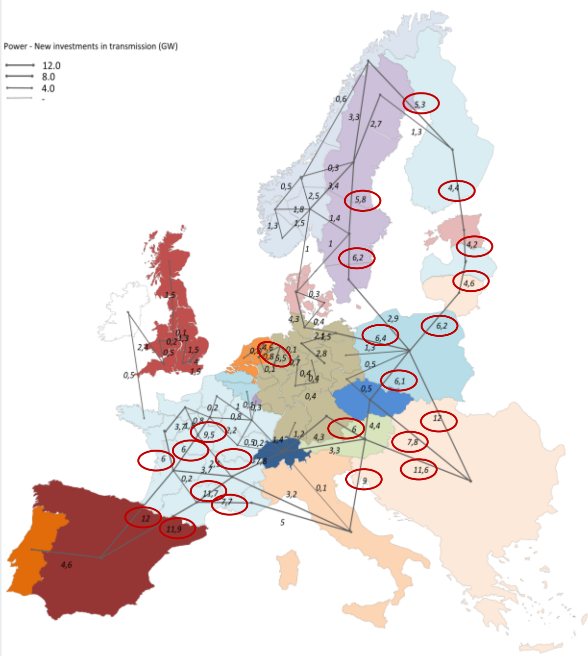
- Nordics to DE, NL, UK
- Nordics to PL
- South-western Europe to central Europe.

The exogenously defined **NTCs within Germany** (starting grid, TYNDP DE 2030) **prove a strong adequacy** which directly affects the modelled results. The internal grid in Germany shows relatively low **investment needs**, and integration of offshore wind is not hindered to a very significant extent by inner-German congestions. A different situation could drive need for further alternative investments, e.g. in hubs-and-spokes.

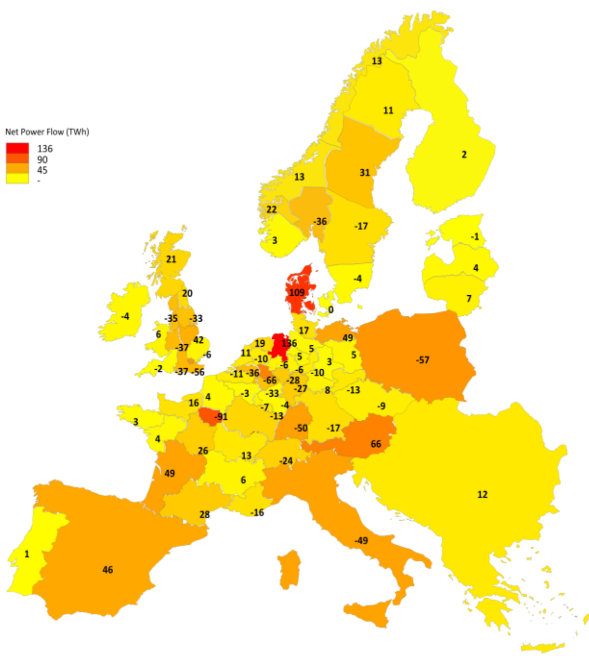
The UK on the other hand can utilise existing lines towards BE, NL and DE, while building additional hub-to-hub options according to need.

Putting side by side both power and H2 flows (upcoming slides), showcases that the northern regions develop power transmission to take advantage of the strong central European system and then converts power to H2 in the target countries, while the south reaches limits for buildout of the electrical grid and applies H2 transmission to export energy to central Europe.

New Investments from 2030 to 2050



2050



Note: Region colouring on the left map serves the sole purpose of country borders and no numeric information is associated to it. Negative values signalise net imports. For power grid deployment information, please refer to the upcoming Appendix.

Hydrogen is mostly produced locally in Europe

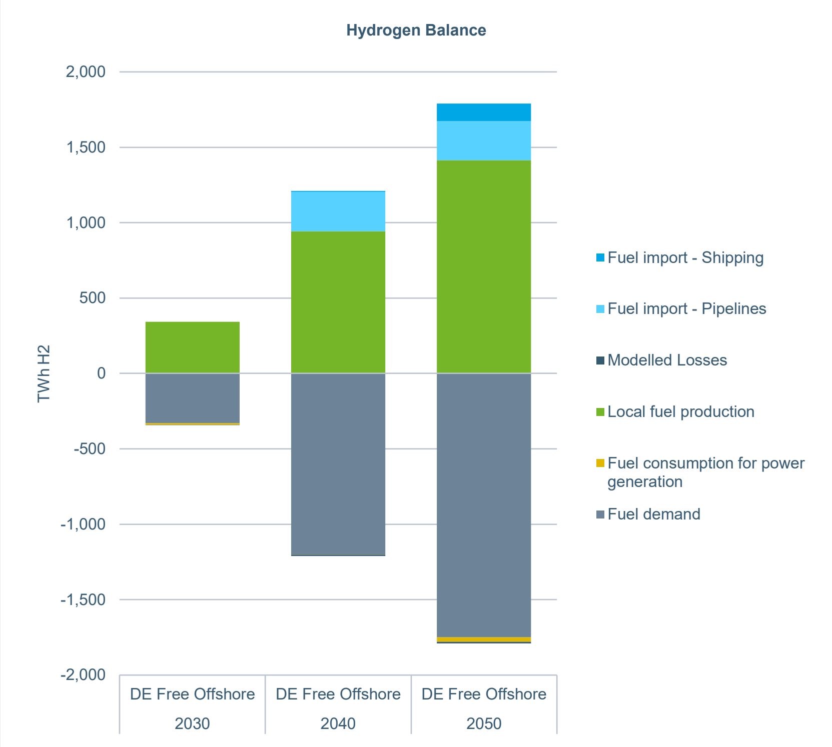
There are two ways of supplying the hydrogen demand in Europe, producing locally, importing through either pipelines from North Africa or via shipping to all coastal areas.

The pipeline imports from North Africa are significantly cheaper than shipping imports and will always be fully utilised before shipping imports. The pipeline imports are limited to around 260 TWh H2.

In 2030, all hydrogen is produced locally in Europe. In 2040, the demand increases and some of it is served from pipeline based imports through North Africa.

The results show that offshore wind is the marginal electricity producer to supply electricity for additional hydrogen production, since the solar PV and onshore wind turbine capacities are fixed and do not provide enough generation to cover both electricity and H2 demands.

In 2050, there is some additional shipping imports in the Balkans and the UK of around 89 TWh and 24 TWh respectively. This means that the marginal cost of producing hydrogen locally with mostly offshore wind turbines cannot compete with the price of shipping imports to fulfil the entire demand.



Note: In this study, we assume a H2 demand alone. There is no modelling of what the H2 used for such as ammonia and e-fuels.

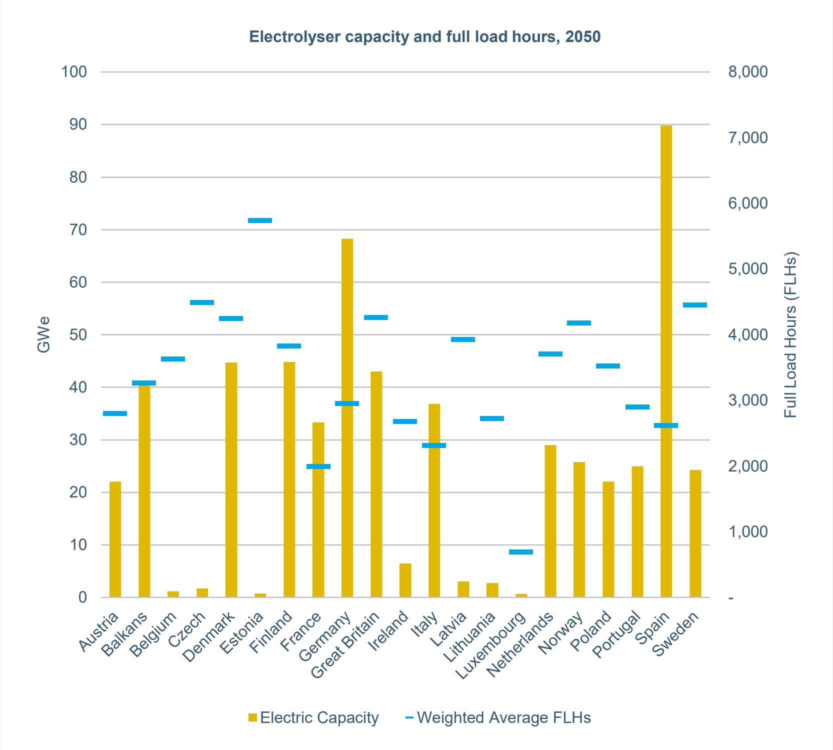
Electrolyser Full Load Hours

The full load hours and capacity of electrolysers in each country is shown in the figure to the right for 2050.

The weighted full load hour average of the system is 3,270 hours. However, there quite a variation between countries.

Solar PV heavy countries such as France, Italy, Portugal and Spain show full load hour averages of around 2000-2600 hours.

Northern countries with high wind capacity, such as Denmark, Finland, UK, the Netherlands, Norway and Sweden, show higher full load hour averages of around 4000.



The H_2 network development complements the exogenously defined EHB network, leading flows to central Europe. Development is strong close to onshore VRE locations

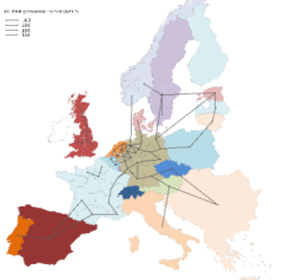
Main H2 flow patterns:

- Nordics to DE and NL
- Nordics to PL
- South-western Europe to central Europe.

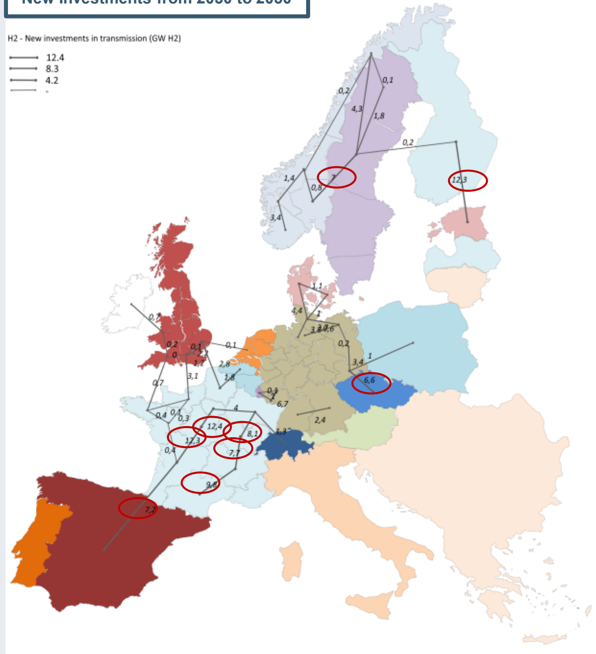
The exogenously defined **NTCs across the modelled geography** (starting network, EHB 2030) decisively dictates the development of the main H2 transmission corridors.

Spain is the only VRE-heavy country injecting large H2 quantities to the central European system, while Italy and the Balkans consume their own but also imported quantities on their net accounts.

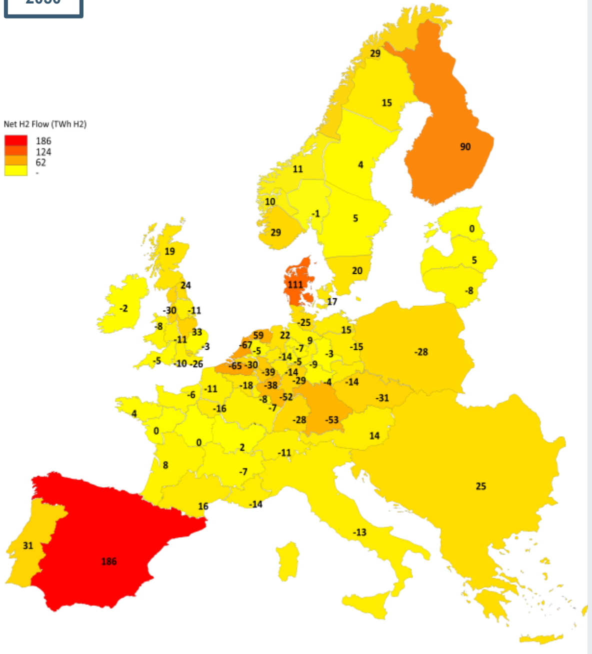
EHB 2030 (10GW$_{H2}$ per connection)



New Investments from 2030 to 2050



2050



Note: Region colouring on the left map serves the sole purpose of country borders and no numeric information is associated to it. Negative values signalise net imports. For H_2 network deployment information, please refer to the upcoming Appendix.

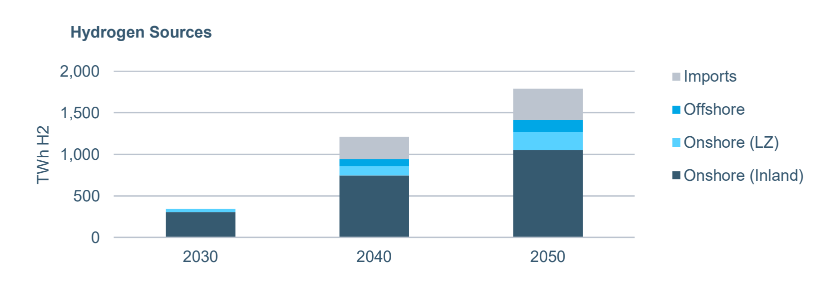
Two South – Central and one North – Eastern onshore H_2 corridors emerge

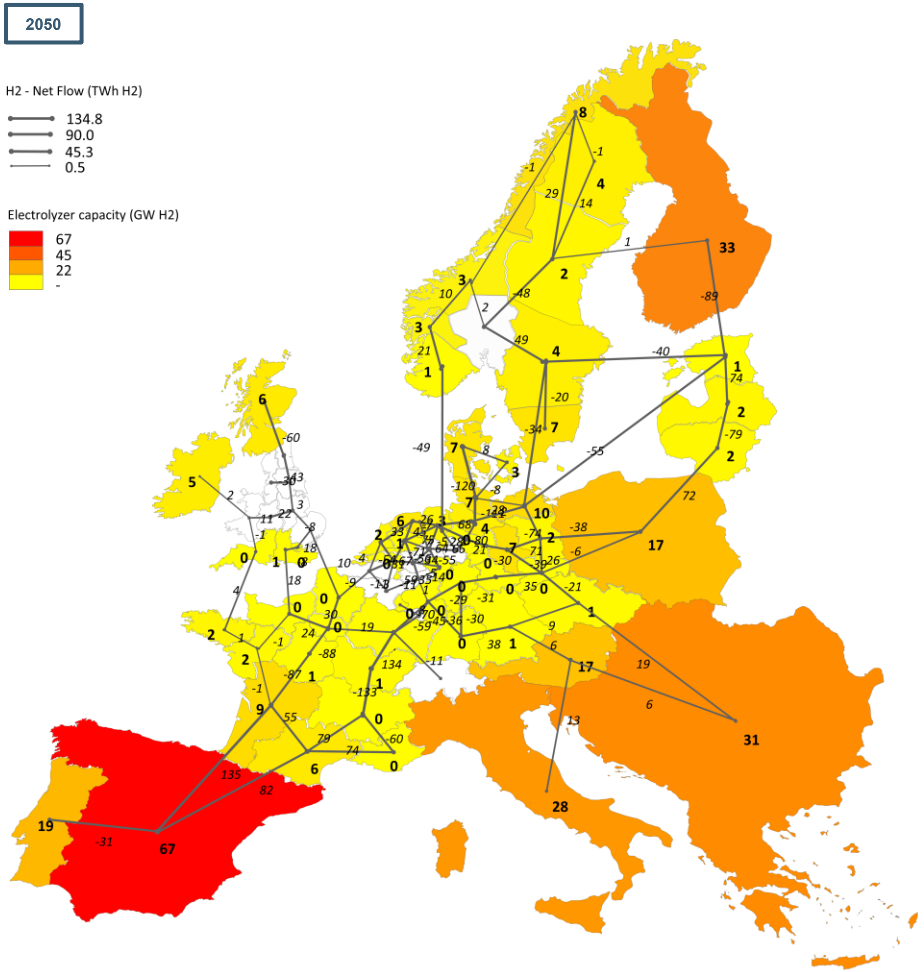
As discussed already, the hydrogen network development complements the existing EHB network and aims to transport H2 flows towards the main sinks of the modelled geography.

2 main south-to-north corridors can be observed, bringing H2 to central Europe and 1 Nordic corridor aiming to support the high Polish H_2 but also German and Dutch demands, partially supported by inflows from south-eastern countries. New investments revolve around the exogenously defined network, avoiding in this way excessive new investments but also lower utilisation of transmission assets.

Notably, North African imports to Spain and Italy don't surpass the local H2 demands, thus no extreme pipelines are developed towards the north. **Pipeline investments are renewable potential driven.**

A breakdown of the sources of circulated H2 in the system across the years can be found below.



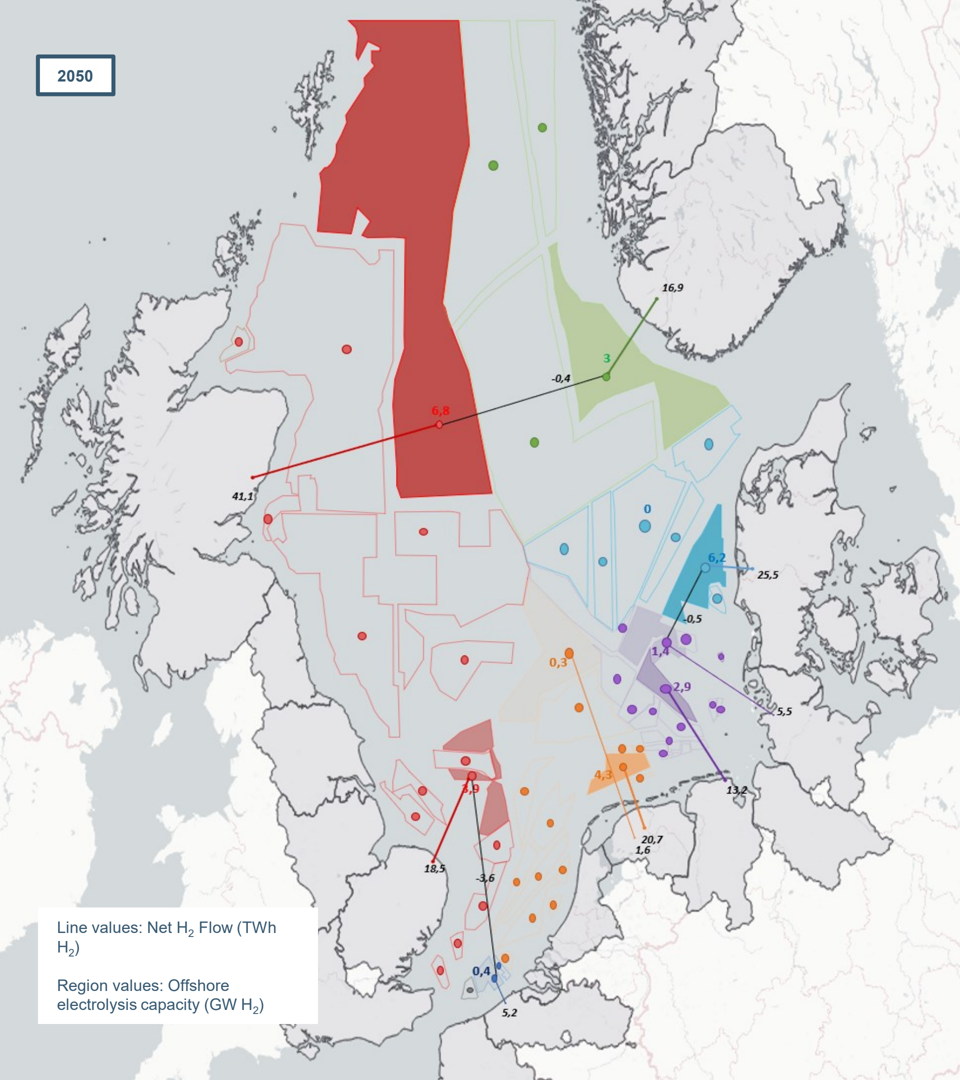


Note: The map showcases results in terms of GW H2 output to match the transmission units. Electrolysis capacities from LZ are not included on the map. Further breakdown can be found in the Appendix.

Limited presence of a hub-to-hub offshore H_2 network, with a versatile distribution of offshore electrolysis

The distribution of offshore electrolysis capacities is not heavily skewed towards one NS country. In contrast, capacities are distributed amongst countries, locating electrolysers in regions with high FLHs and good power connectivity, in order to ensure a high operational level of the electrolyser when taking advantage of asynchronous power generation from neighbouring wind farms.

While Hub to Hub connections with the UK reflect one-sided (mostly) flows, the interconnection between DE and DK hubs showcases a less monotonous flow pattern with approximately 2 TWh H2 flowing towards each way (2.2 TWh H2 towards DK and 1.7 TWh H2 towards DE). The connection from NO to the UK injects 0.6 TWh H2 in the Norwegian system, while 1 TWh H2 heads towards the opposite way. Finally, approximately 4.4 TWh H2 are directed towards Belgium from the GB Hub, with only 0.8 sent backwards.



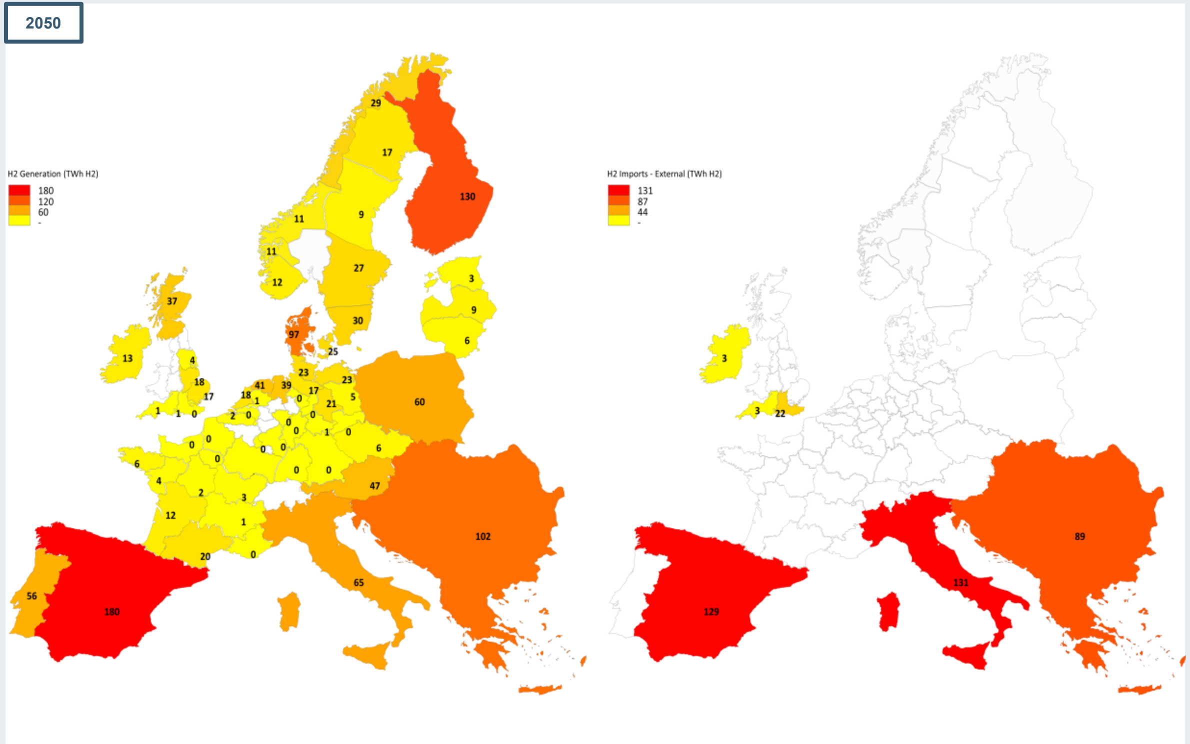
25% of European hydrogen production is located in synergy with offshore wind – either offshore or in landing zones

The vast majority of the locally produced H2 amounts are originating in regions with high electricity generation from VRE, with large amounts located in the periphery of the modelled geography.

In 2050, 149 TWh H2 (~10% of total) are generated in offshore regions and then injected to shore, while 216 TWh H2 (~15% of total) are produced in Landing Zones (LZ), highlighting the benefits harvested from both representations.

The marginal additional hydrogen quantity is served in the model either through offshore wind power or via shipping imports. Countries such as the Balkans, southern UK and Ireland, located far away from considerable offshore wind capacities, turn to more shipping imports due to the significant additional costs that would be required for transferring H2 from the North Sea (centre of offshore wind development) to the corresponding demand centres.

As there is a small amount of shipping, it means that the marginal cost of supplying the H2 demand hits the shipping price.



Note: Regional values are rounded to the nearest integer. Showcased H_2 generation includes quantities produced within the corresponding regions' LZ (if applicable).

Batteries and G$_2$P are used for system balancing (2050)

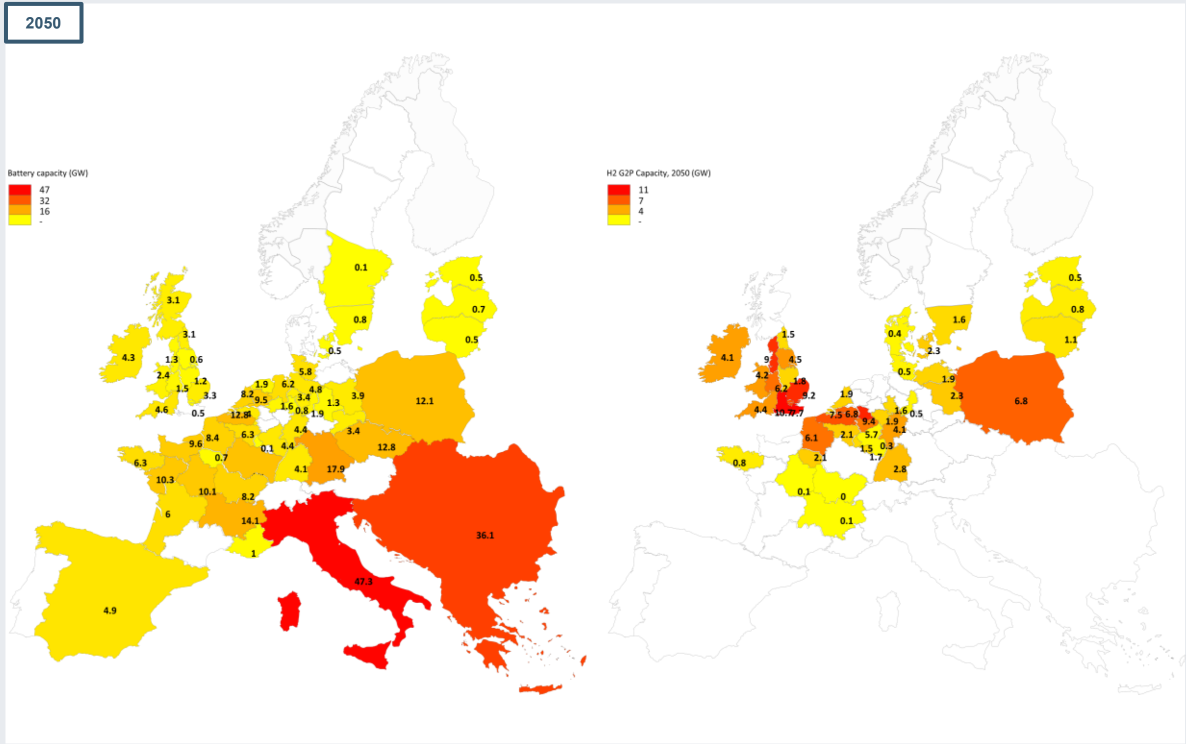
As the system is heavily supplied by renewable generation, **there is need for balancing** in hours of low wind and solar generation.

The model has several options for balancing the system. It can invest in batteries, G2P plants (re-purposing or new), building out transmission capacity as well as flexibly operating electrolyser units.

The results show that batteries are useful in solar heavy regions such as Italy, Balkans, France and Southern Germany.

Re-purposing natural gas fired plants is utilised in the UK, Belgium, France, west Germany and Poland. Only a few new G2P units are installed, 2 GW in Lithuania and Latvia respectively.

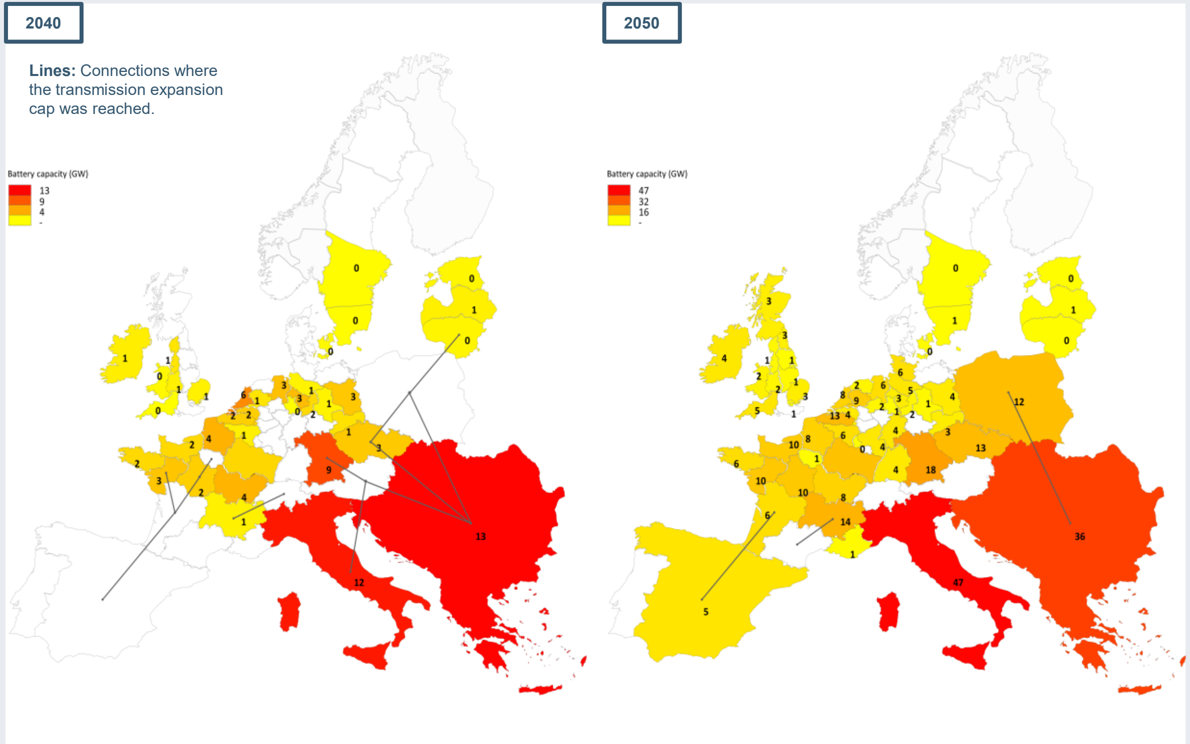
The impacts of the absence of battery storage capacities across sensitivities have been evaluated, with the negative impact on the overall annualised system costs not exceeding 1.22 percentage points (figure). This can conclude that the modelling considerations around electricity storage in the present report would not affect the overall result takeaways.



Battery investments are subject to high VRE integration and limitations on the development of the existing transmission grid

Electric storage serves the purpose of power shifting from timesteps with high and cheap regional generation to hours with higher demand, satisfaction of which would translate to higher costs, than investing and utilising batteries. **Naturally, battery investments are primarily high in locations with large solar PV investments, due to the PV generation pattern fluctuations across the day**. **Therefore, south-easter Europe presents considerably higher total battery capacities.**

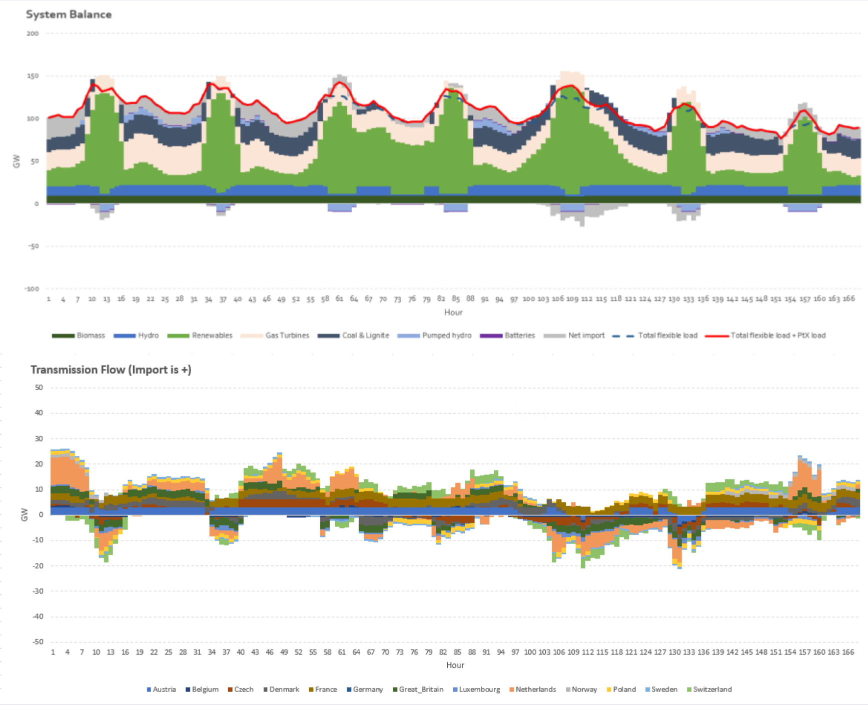
Investment decisions in batteries seem to be subject to effects of both high VRE integration but also limitations on the possible expansion of the power grid network, especially in 2040 where a large amount of south to north power corridors hit the imposed transmission cap of 6GW expansion pet 10 years. **The effects of solar PV additions, and power shift needs, according to the DE scenario data in both Italy and the Balkans seem to be compounding in 2050**, thus taking the lead on being the main battery investment drivers.



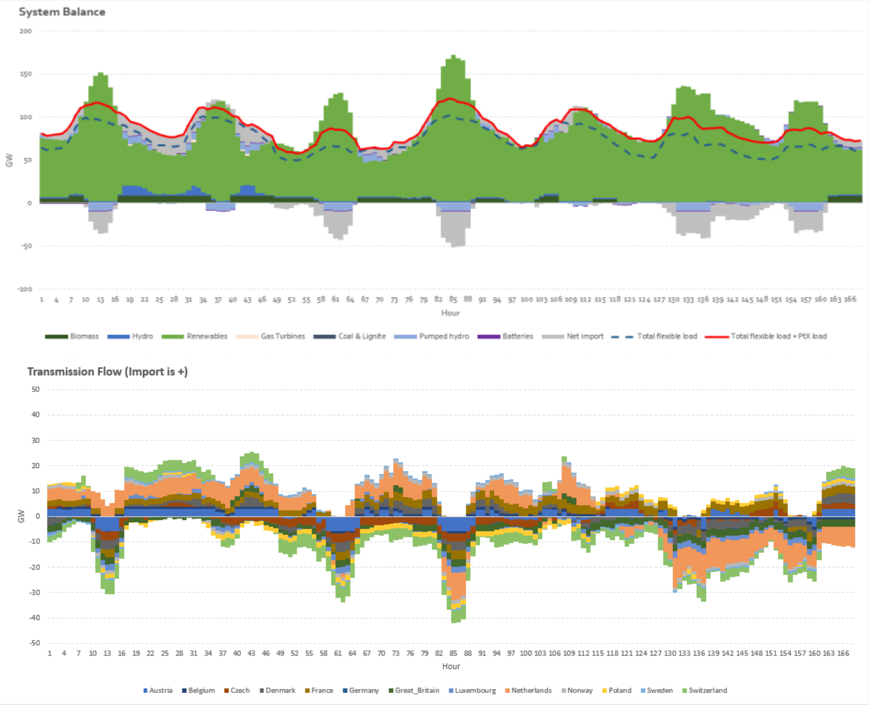
Note: Values are rounded to the nearest integer. Cross-regional lines on the maps signalise that the power transmission expansion between the connected regions reached the imposed cap.

System balancing is ensured in every timestep via thermal generators (when allowed), imports/exports and general flexibility. Example for the aggregation of all German regions, in 2030

Low VRE Week

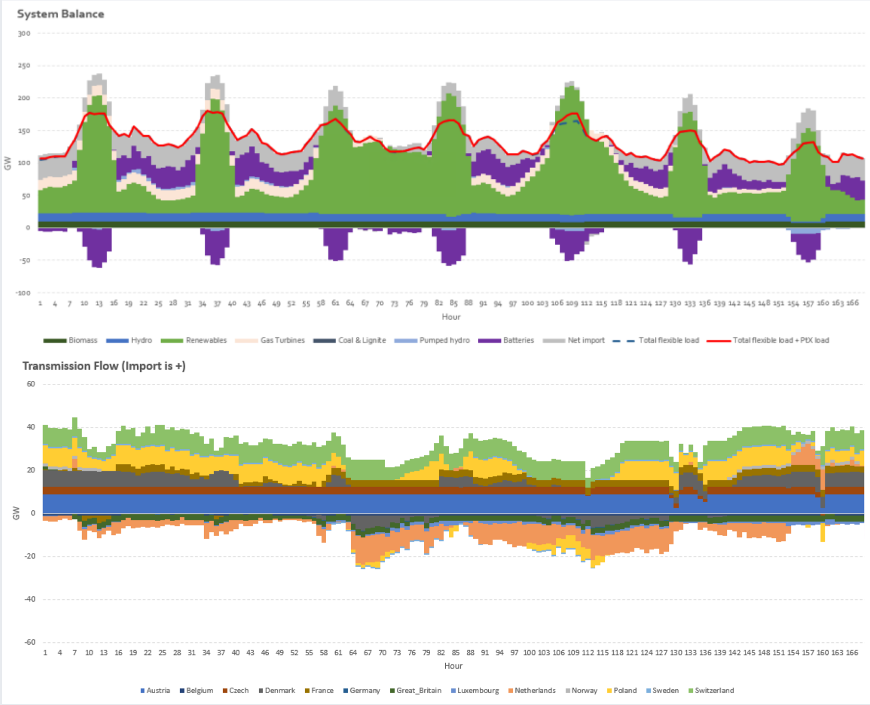


High VRE Week

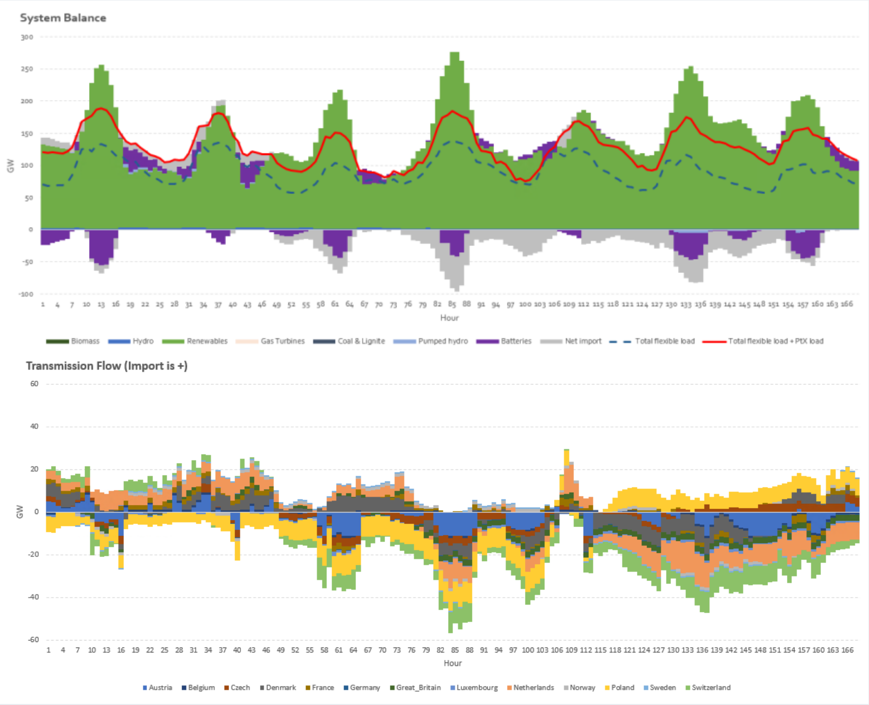


System balancing is ensured in every timestep via thermal generators (when allowed) imports/exports and general flexibility. Example for the aggregation of all German regions, in 2050

Low VRE Week



High VRE Week

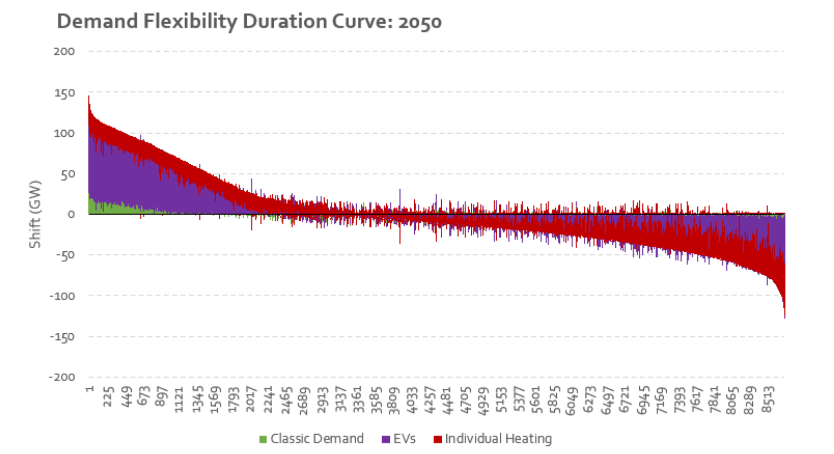


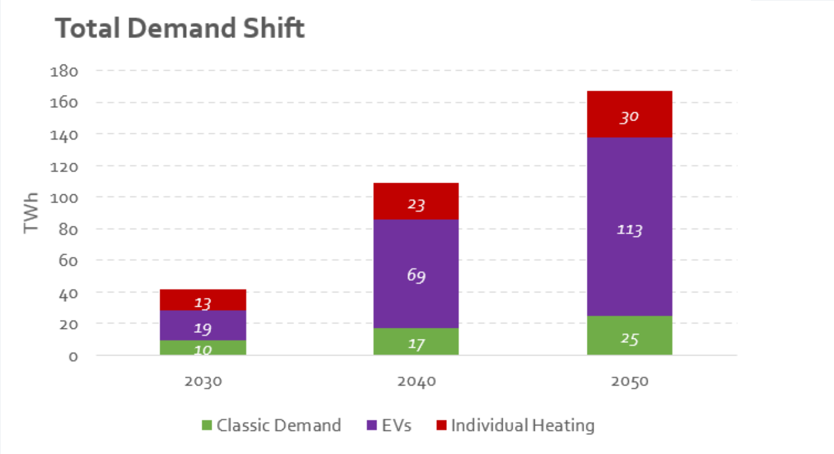
Demand response options of flexible power consumers can shift energy of up to 18% of the total hourly load, summing up to 167 TWh in 2050

The resulting flexible load in the model, consists of 3 demand categories which based on price signals are able to alternate their original profile (natural load) to a revised profile (flexible load) which the model serves from hour to hour. Those categories are:

- Classic demand
- Electric vehicles (EVs)
- Individual heating

This demand side flexibility is always utilised to its maximum extent by the model (following the predefined possible extents as discussed in previous slides), however in an asynchronous manner between categories. The total demand shift between 2050 and 2030 almost quadruples, with prominent effects originating in the harvested flexibility from EVs.





Note: Positive values reflect increased demand vs the expected natural profile, while negative a decrease.

Batteries provide flexibility in the power system, while hydrogen's role is focused to peak demand supply with significantly lower FLHs

Investment in flexible generators reflects the decision between the cost of demand curtailment versus the cost of installing new units that might operate for few hours to cover peak demand deficits. This can be evidently seen in the case of **H2 based G2P generators** which can be found across the modelled geography but operate for a number of hours in 2050 **ranging up to only ~250 FLHs**, operating as a peak generator.

Such a fact differentiates the purpose of flexible generators vs flexibility measures like batteries, which have a considerably more active role in the power system (shifting power around time slices). **Battery FLHs across the modelled geography range between ~ 1,550 and ~3,500** operational hours per year, when considering both their charging and discharging flows, divided by their capacity.

	H_2 G_2P			Batteries		
2050	Capacity (MW)	Generation (GWh)	FLHs	Capacity (MW)	Total Flow (GWh)*	FLHs*
Austria (AT)	-	-	-	-	-	-
Balkans (BK)	-	-	-	36,053	91,787	2,546
Belgium (BE)	9,619	295	31	19,044	37,266	1,957
Czech Republic (CZ)	-	-	-	12,790	28,134	2,200
Denmark (DK)	2,646	181	69	484	1,348	2,785
Estonia (EE)	498	63	126	467	1,102	2,360
Finland (FI)	-	-	-	-	-	-
France (FR)	9,230	1,503	163	86,140	195,280	2,267
Germany (DE)	32,579	6,121	188	63,877	134,755	2,110
Great Britain (GB)	59,267	4,479	76	21,715	38,962	1,794
Ireland (IR)	4,085	1,038	254	4,253	7,731	1,818
Italy (IT)	-	-	-	47,304	136,373	2,883
Latvia (LV)	785	41	52	749	1,160	1,549
Lithuania (LT)	1,115	45	41	497	1,067	2,147
Luxembourg (LX)	1,533	280	183	141	390	2,766
Netherlands (NL)	8,688	1,238	142	23,583	47,014	1,994
Norway (NO)	-	-	-	-	-	-
Poland (PL)	6,816	372	55	12,057	23,967	1,988
Portugal (PT)	-	-	-	-	-	-
Spain (ES)	-	-	-	4,853	16,735	3,448
Sweden (SE)	1,609	73	45	936	2,047	2,187
Switzerland (CH)	-	-	-	-	-	-

Note: FLHs for batteries account for both charging and discharging flows.

Average electricity prices considerably decrease when not accounting for the few hours of extraordinary pricing

The illustrated average electricity prices per modelled region may skew the perception of hourly experienced prices due to not being accompanied by a standard deviation and also due to accounting for all extraordinary high price occurrences. Price duration curves (PDCs) usually serve as a good indicator of such effects, however compiling 74 such curves in a graph would not allow for easy sense checking.

Therefore, some simple statistics are presented in the showcased table. **With the demand cut-off limit set at 3,383 €/MWh, the number of such occurrences can be collected across all regions.** In total, 383 instances of demand curtailment can be counted in 2050 across the modelled geography, across 177 timesteps in the modelled year.

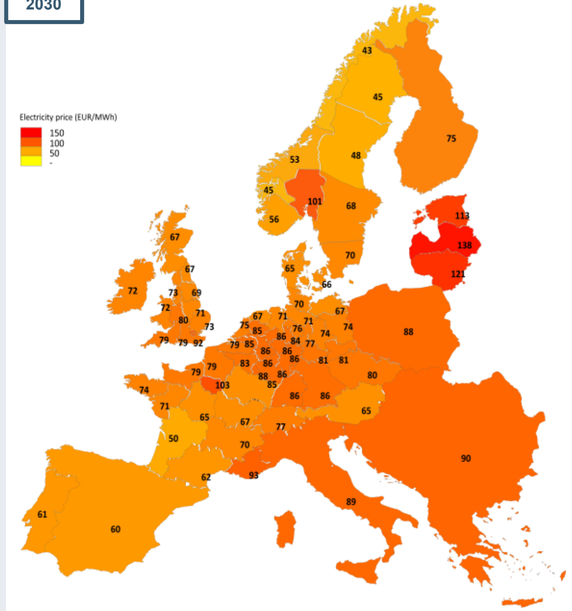
Averaging all prices below 3,000 €/MWh already results in average annual prices dropping by 14-35 €/MWh in contrast to the simple overall average metric.

2050	Number of Regions	Average Instances of Demand Curtailment (Across Modelled National Regions)	Total Demand Curtailment (GWh/y, (% of Total Demand))	Peak Demand Curtailment (GW, (% of Hourly Demand))	Average Instances with Electricity Prices > 2,000 €/MWh (Across Modelled National Regions)	Average (€/MWh)	**Average (≤ 3,000 €/MWh)**	**Average (≤ 2,000 €/MWh)**
Austria (AT)	1	-	- (-)	- (-)	57	82	66	62
Balkans (BK)	1	-	- (-)	- (-)	57	81	63	61
Belgium (BE)	2	2	12 (0.009%)	7.2 (42%)	50	88	73	70
Czech Republic (CZ)	1	-	- (-)	- (-)	57	83	64	62
Denmark (DK)	2	-	- (-)	- (-)	59	78	76	61
Estonia (EE)	1	1	0.2 (0.001%)	0.2 (12%)	68	84	60	59
Finland (FI)	1	53	126 (0.040%)	7.1 (30%)	94	91	56	55
France (FR)	12	1	17 (0.002%)	3.4 (3%)	14	68	65	64
Germany (DE)	20	5	230 (0.021%)	17.5 (15%)	57	88	68	67
Great Britain (GB)	11	9	184 (0.024%)	10.3 (13%)	38	80	70	67
Ireland (IR)	1	12	34 (0.036%)	5.7 (60%)	24	75	66	66
Italy (IT)	1	-	- (-)	- (-)	57	84	67	63
Latvia (LV)	1	-	- (-)	- (-)	56	78	60	58
Lithuania (LT)	1	-	- (-)	- (-)	51	78	63	60
Luxembourg (LX)	1	20	14 (0.089%)	1.2 (50%)	57	92	70	70
Netherlands (NL)	4	1	9 (0.002%)	5.8 (20%)	53	86	71	68
Norway (NO)	5	9	82 (0.026%)	7.4 (16%)	33	71	64	60
Poland (PL)	1	-	- (-)	- (-)	57	83	64	62
Portugal (PT)	1	-	- (-)	- (-)	0	54	54	54
Spain (ES)	1	-	- (-)	- (-)	0	55	55	55
Sweden (SE)	4	4	28 (0.010%)	4.6 (16%)	58	77	69	59
Switzerland (CH)	1	-	- (-)	- (-)	57	85	68	65

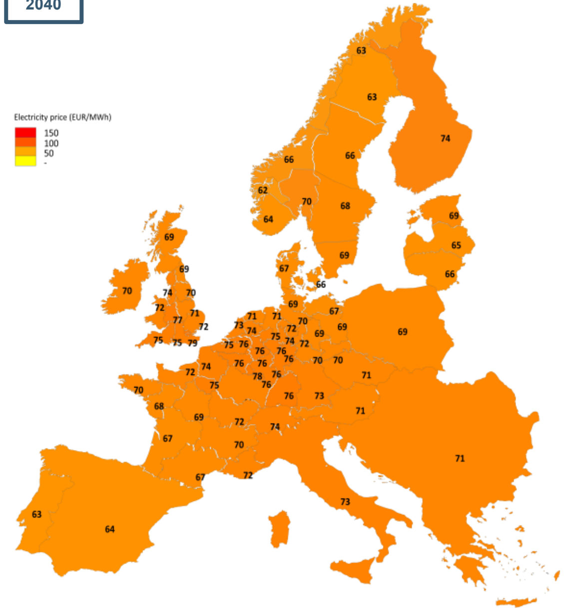
Electricity price duration curves get flatter, with most hours of the years experiencing lower electricity prices than the previous year

The observed Price Duration Curves (PDCs) across regions get flatter (more stable prices) and cheaper with new RE capacity. Nevertheless, a quick glimpse over the illustrated average electricity prices would wrongly signalise tendencies towards the other direction. The reason for such increased average prices is that during the operational year, instances with electricity prices rising to the imposed demand curtailment threshold (3,383 €/MWh) emerge, during the electricity market clearing. 2050 seems to experience such extreme hours for more hours than 2040, thus creating the scene illustrated below (2040 average prices lower than 2050). **Drawing an average without such extremes would create a uniform dropping tendency from year to year.** For more information, a more detailed breakdown of the national average electricity prices will be presented in the next slide.

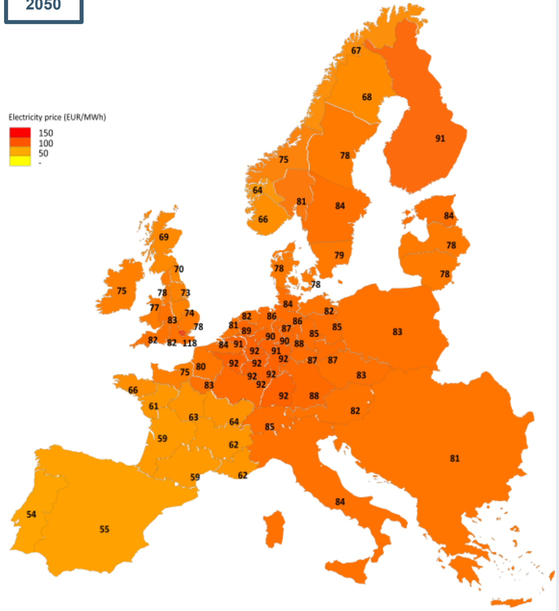
2030



2040



2050

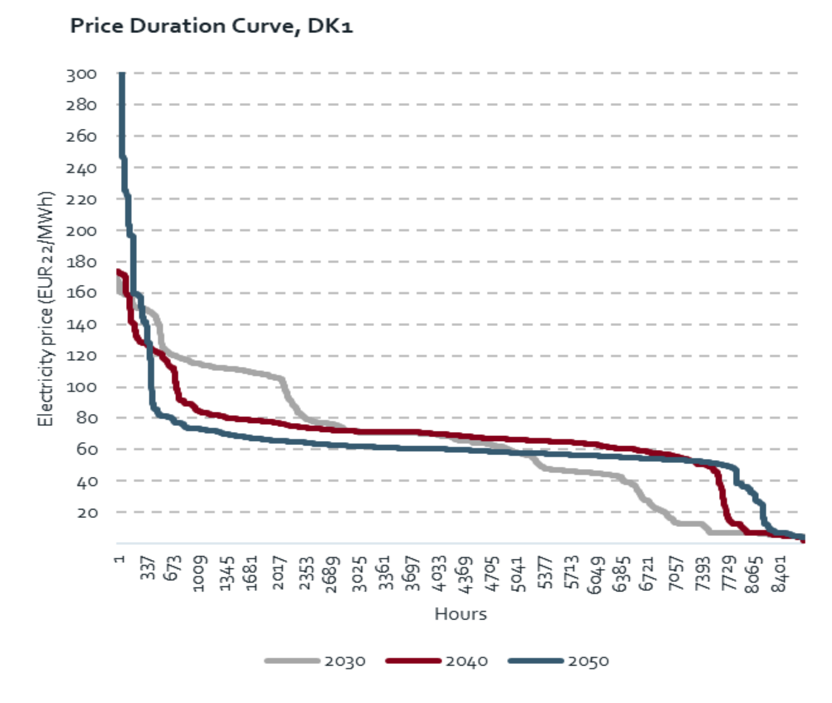


Flexibility limits general price volatility, but number of hours with very high prices increase

In 2030, **higher amounts of VRE but limited system flexibility lead to increasing price volatility compared to recent years.** Towards 2050, increased system flexibility from transmission buildout, electrolyser capacity and flexible demand evens out the duration curves in the middle part.

The average price is around 65-67 €/MWh in 2030 and 2040. In 2050, there is 67 hours where the price is above 2000 €/MWh, which significantly increases the average to 78 €/MWh. Without these hours, the average would be 62 €/MWh.

DK1	2030	2040	2050
Average price (EUR22/MWh)	65	67	78
Average price without extreme price hours (EUR22/MWh)	65	67	62

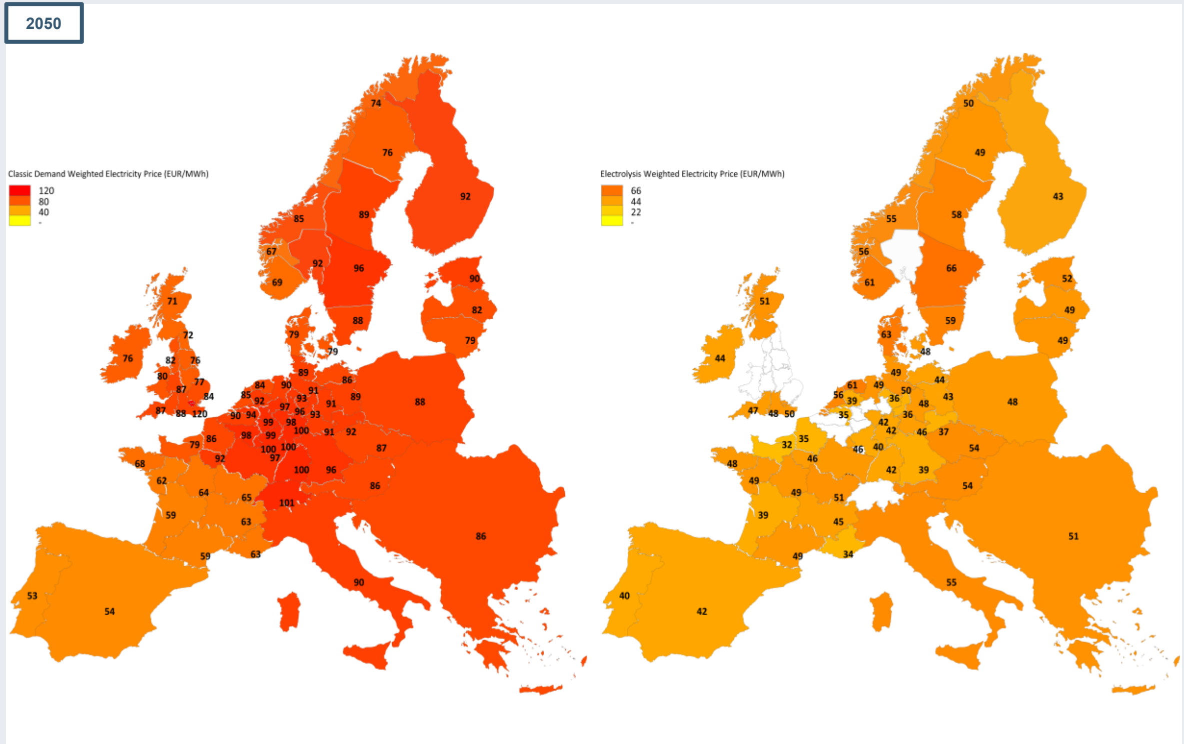


Note: Extreme hours are defined as hours where the price is reaching the price ceiling of 3000 €/MWh.

Demand weighted electricity prices reveal the overall system’s operation patterns

An approximation of the level of electricity pricing, which acts as the turning point of local H_2 generation, can be seen in the figure on the right. This turning point varies (on average) from 34 €/MWhe to 66 €/MWhe. This fact also reveals the stress level of the system when H_2 demand is rising per region. **Regions with high average electricity prices but low electrolysis weighted prices (see central Germany) reveal asynchronous production needs and lower stress levels, due to either uncongested interconnections, storages or high VRE penetration in the hours of H_2 need.**

Electrolysis weighted electricity prices dictate the production cost of local hydrogen production and its competitiveness with external imports from 3rd countries. **These prices, in conjunction with the cost of installing electrolysers or/and laying H_2 piping ultimately drive the investment decisions of the model.**



Dynamics Between DK, DE, UK and NL

Denmark:

- Denmark becomes a significant source of electricity (110 TWh) and H2 (130 TWh H2).
- Most of the electricity export is dispatched to the UK, around 55 TWh, 44 TWh to NL and 14 TWh to DE.
- Denmark also becomes a significant source of H2. All 130 TWh H2 export is fed directly to Germany.

Germany:

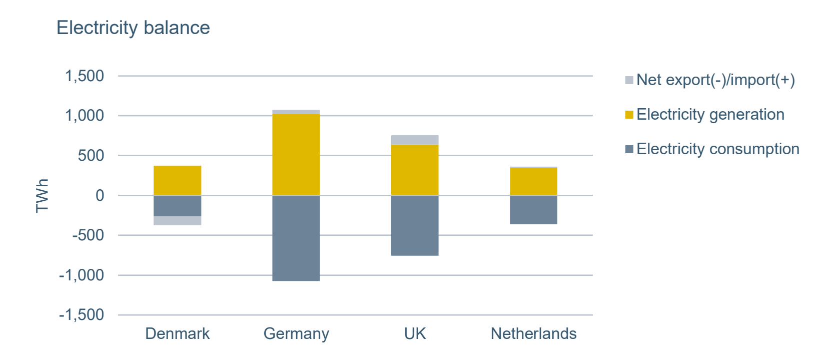
- Germany becomes a significant H2 sink, 2/3's of the H2 demand is imported
- But Germany can supply most of the remaining electricity demand locally, importing only 45 TWh of a 1070 TWh demand.

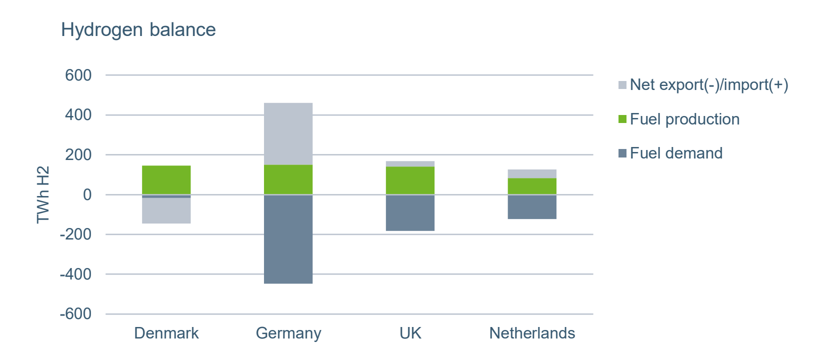
UK:

- The UK is a significant electricity sink, importing 115 TWh, about 15% of the resulting electricity demand. Of which 55 TWh comes from Denmark.
- There are also some H2 imports, about 27 TWh.

Netherlands:

- The Netherlands acts a transit country for Danish electricity export, importing 44 TWh from Denmark, but forwarding 20 TWh to UK, and 8 TWh to Belgium.
- On the hydrogen side, NL receives 105 TWh H2 from Germany (including northern transit flows) of which 61 TWh H2 is forwarded to Belgium.



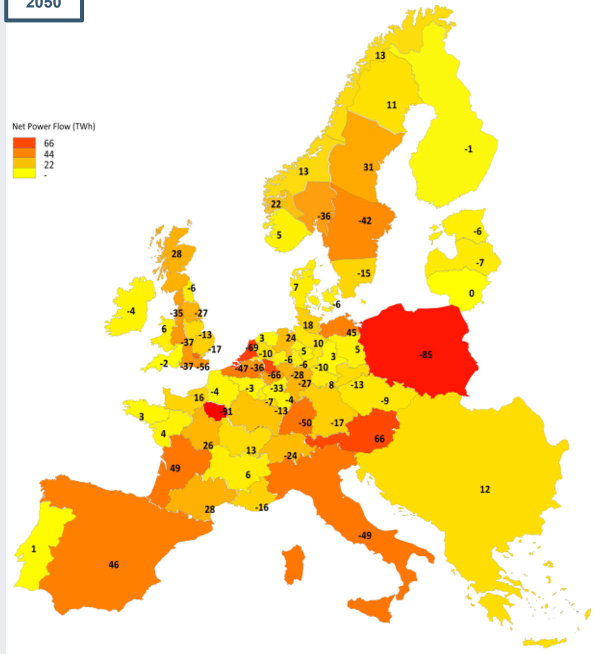


Note: For further country to country flow information, refer to the next slide.

Electricity and H_2 Flow from DK, DE, NL and UK

Electricity

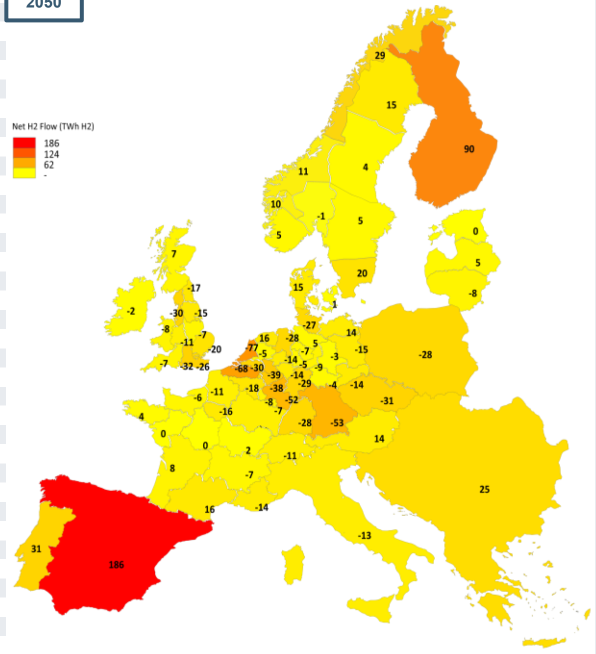
2050



2050	Electricity flow - net out (TWh)	H2 flow - net out (TWh)
From Denmark / to	**109**	**128**
Denmark	0	0
Germany	14	128
Great_Britain	53	
Netherlands	44	
Norway	-2	0
Sweden	-2	
From Germany / to	**-46**	**-311**
Austria	-22	-6
Belgium	-2	11
Czech	-3	12
Denmark	-14	-128
Estonia		-55
France	-14	-130
Germany	1	0
Great_Britain	8	
Luxembourg	4	8
Netherlands	-2	105
Norway	-4	-49
Poland	22	-44
Sweden	-1	-34
Switzerland	-19	
From Great Britain / to	**-116**	**-27**
Belgium	1	4
Denmark	-53	
France	-26	-33
Germany	-8	
Great_Britain	1	0
Ireland	2	2
Netherlands	-21	0
Norway	-11	0
From Netherlands / to	**-16**	**-44**
Belgium	8	61
Denmark	-44	
Germany	2	-105
Great Britain	21	0
Netherlands	0	0
Norway	-3	

Hydrogen

2050



Note: + is an export.

Sensitivity Scenarios

Description of Sensitivities

On the basis of DE Free Offshore scenario, 5 sensitivities have been made.

1. **DE Fixed Offshore**: A scenario with the same onshore wind turbine and solar PV capacities, but also with fixed offshore capacities from DE scenario.
2. **Geo-optimised VRE**: The model is free to locate all new solar PV, onshore and offshore wind turbine investments, limit being technical potential per region and a restriction that total system generation from solar PV and wind turbines is set to match DE scenario.
3. **No Hubs-and-Spokes**: Same as DE free offshore scenario but with no hubs-and-spokes connections allowed, offshore wind can only be connected radially
4. **Unrestricted Solar**: Onshore wind turbine investments is fixed as equal to DE scenario, but solar PV is only limited by technical potential per region.
5. **IC Limits**: Both power transmission and pipeline buildouts are limited from Spain, Italy and Balkans to central Europe.

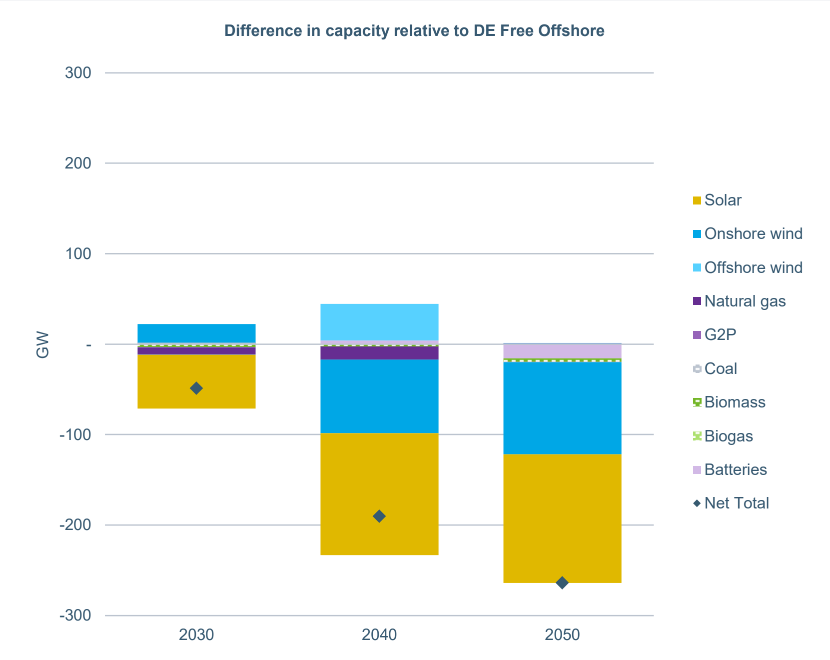
Assumptions per Scenario	Geo-optimised VRE	DE Free Offshore	DE Fixed Offshore	No Hubs-and-Spokes	Unrestricted Solar	IC Limits
Solar PV	DE scenario as a total generation, but location is free. Subject to technical potentials. This means restricting total capacity more than DE scenario.	DE scenario	DE scenario	DE scenario	DE scenario as minimum, with allowed additions subject to technical potentials	DE scenario
Onshore WT	DE scenario as a total generation, but location is free. Subject to technical potentials. This means restricting total capacity more than DE scenario.	DE scenario	DE scenario	DE scenario	DE scenario	DE scenario
Offshore WT	Free	Free	DE scenario	Free	Free	Free
Power Transmission	From 2030, 6 GW per onshore corridor per 10 years	From 2030, 6 GW per onshore corridor per 10 years	From 2030, 6 GW per onshore corridor per 10 years	From 2030, 6 GW per onshore corridor per 10 years. Offshore: no hubs-and-spokes allowed	From 2030, 6 GW per onshore corridor per 10 years	From 2030, 6 GW per onshore line per 10 years. But lines from ES, IT and Balkans is only 3 GW per 10 years. H2 pipelines limited to 10 GW_{H2} expansion in total per corridor on top of existing

Geo-optimised VRE scenario

The Geo-optimised VRE approach results in lower necessary installed onshore VRE capacities for generating the same amounts of renewable electricity

With Geo-optimised VRE allowing redistribution of onshore VRE capacities across the modelled geography, while complying approximately with the total onshore VRE generation of DE Free Offshore, **savings on total installed capacities are achieved. Of course, longer transmission corridors have to be built in order to allow flow circulations**.

The expansion of offshore wind capacities earlier on in the modelling horizon (+40 GW in 2040) is evident, however still resulting in similar 2050 total installed capacities.



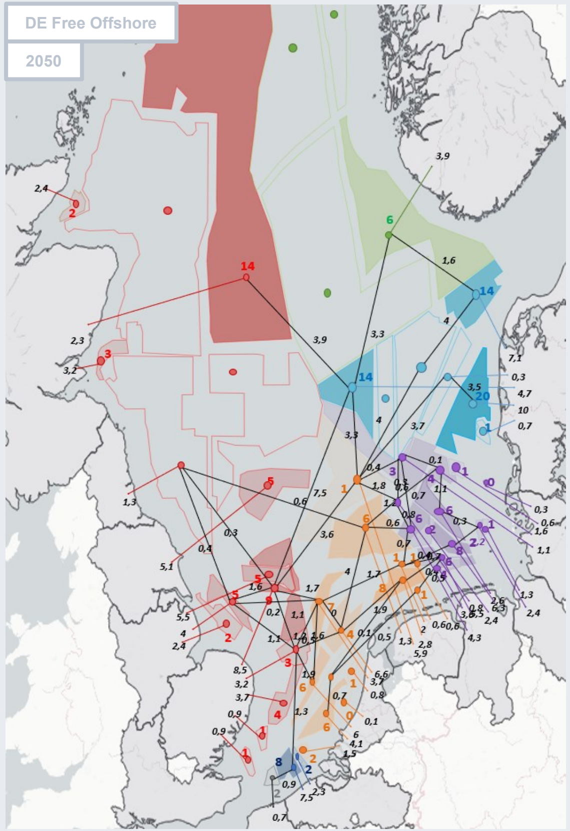
Note: Positive numbers represent additional capacities in the current scenario vs DE Free Offshore, and vice versa.

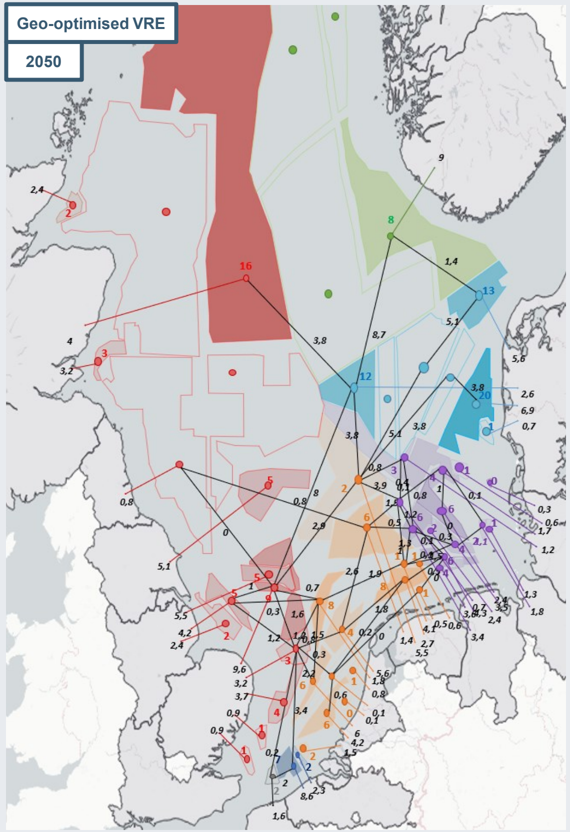
Geo-optimised VRE scenario

Higher importance of Hubs-and-Spokes

Migrating solar PV to southern countries and onshore WT to Norway and France results in stronger offshore power corridors across the North Sea.

Resulting offshore wind capacities remain similar in 2050, with minor redistributions towards the UK and Norway.





Line values: Power transmission capacity (GW)

Region values: Offshore wind capacity (GW, rounded)

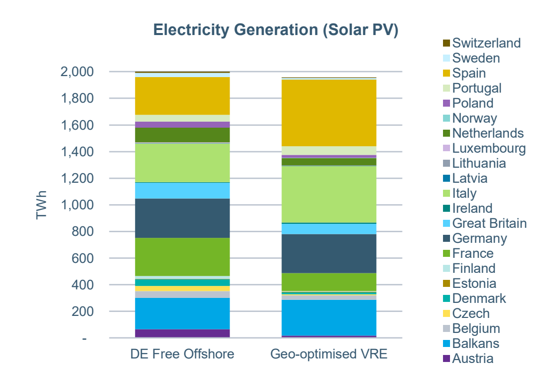
Note: Overview of country-based power flows in the North Sea across scenarios can be seen in the Appendix (table, illustration).

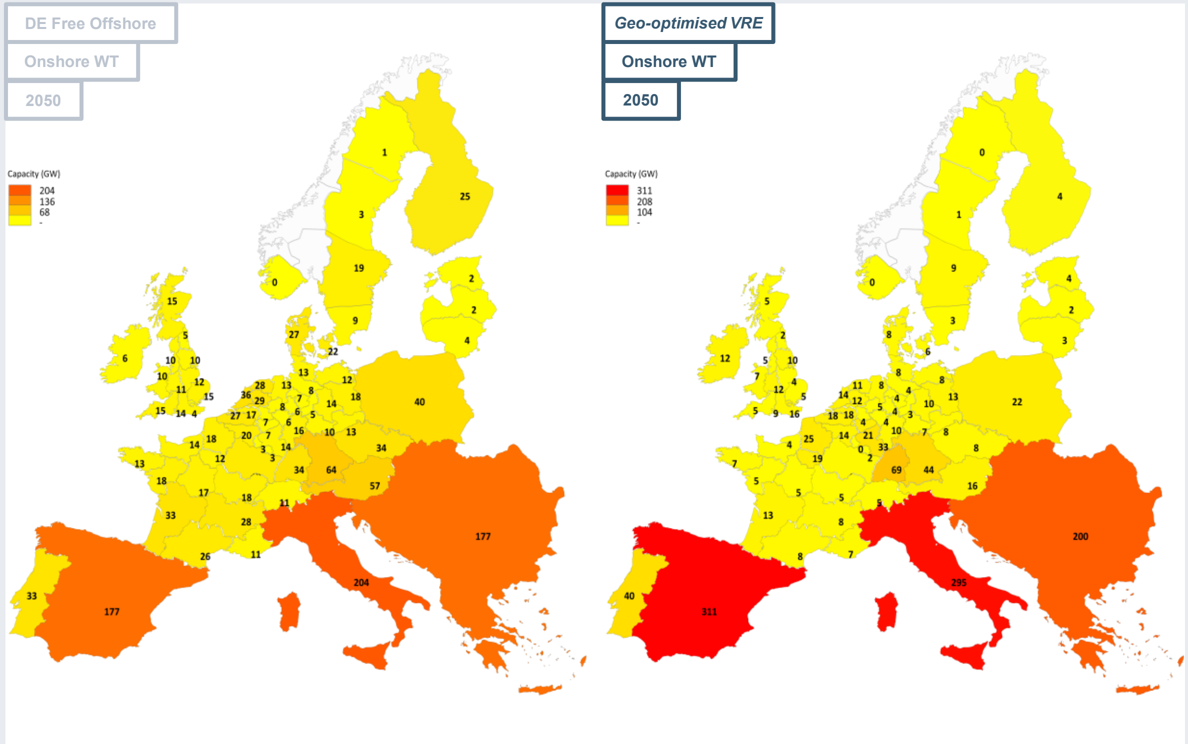
Total installed PV capacities decreased by 9% due to utilisation of better regional FLHs. Capacities are moving south

Due to the allowed capacity redistribution within the modelled geography, similar total electricity generation from solar PVs is injected in the system with **approximately 150 GW less capacities**. Main redistribution effects:

Major decrease
- France: 232 -> 114 GW
- Netherlands: 109 -> 55 GW

Major increase
- Italy: 204 –> 295 GW
- Spain: 177 -> 311 GW



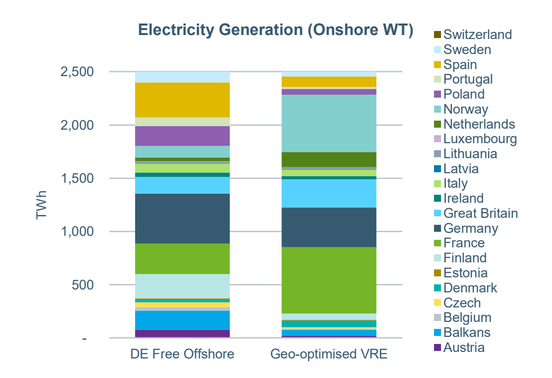


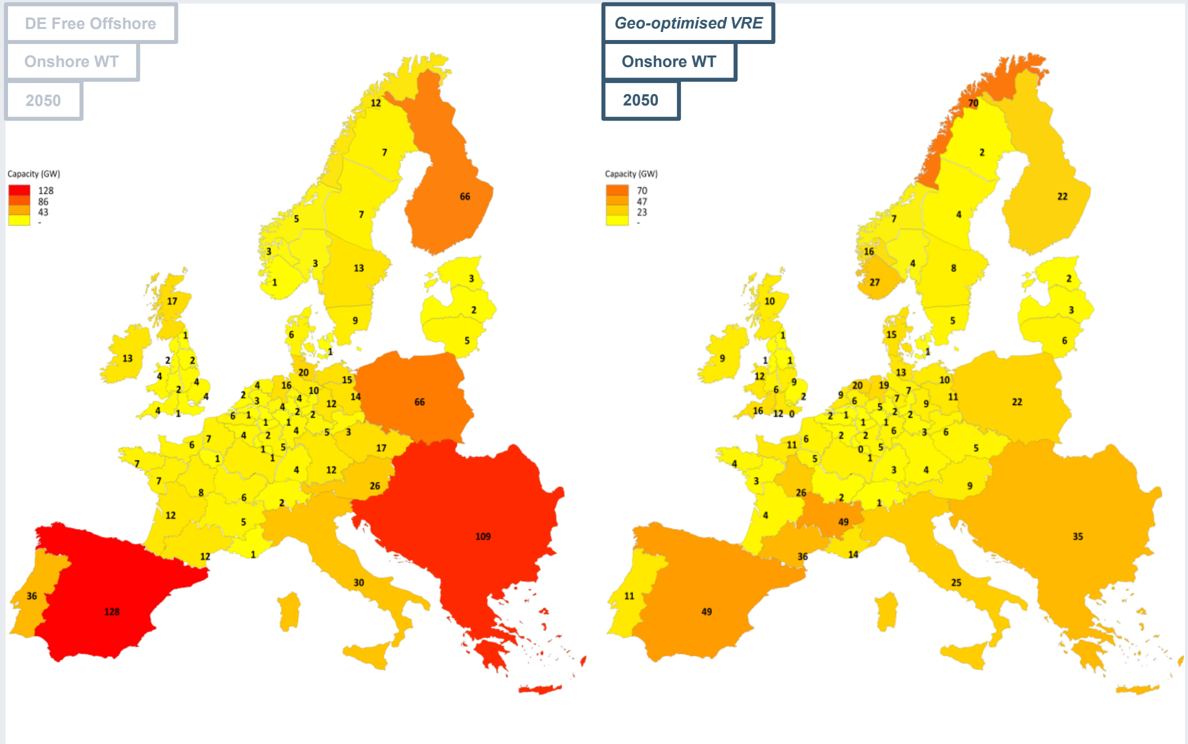
Total installed WT capacities decreased by 12% due to utilisation of better regional FLHs. Capacities moving to central-northern Europe

Alike solar PV, **onshore WT redistribution** can be observed across the modelled geography, while providing similar total electricity generation from onshore WT to the system with **approximately 100 GW less capacities**. Main redistribution effects:

Major decrease
- Balkans: 109 -> 35 GW
- Spain: 128 -> 49 GW

Major increase
- France: 83 –> 168 GW
- Norway: 23 -> 124 GW



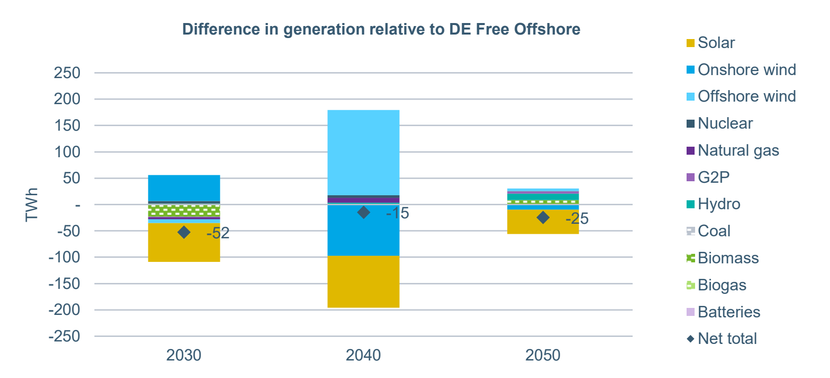


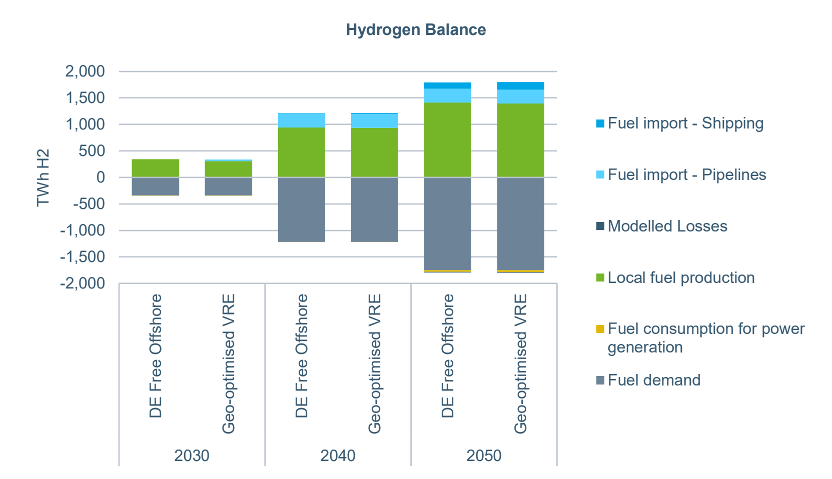
Geo-optimised VRE results in similar locally generated H_2 quantities, fed by different RE sources based on redistribution

The Geo-optimised VRE scenario results in **slightly lower locally produced H2 quantities, replaced by further shipping imports**. Optimally installed onshore wind capacities (model optimised redistribution), led to **capacities located farther away from the centre of the modelled geography and therefore resulted in higher transmission expansion needs**. The considerable **decrease of onshore wind capacities in the Balkans, significantly contributed to the higher experienced H2 imports via shipping**, as transporting generated H2 quantities from other European regions would require an expensive H2 network expansion.

Some **redistribution effects** are observed across the modelled geography. The **north of Norway emerges as a main hydrogen but also power exporter due to the highly beneficial observed FLHs of onshore wind in the region**. However, the additional electrolysis capacities in the Norway roughly match the decrease of Swedish and Polish H2 production. **In parallel, a decrease of hydrogen production is experienced in south-eastern regions**, but with Spain and Italy ramping up their own production.

In terms of onshore transmission networks, regions with higher installed VRE capacities, naturally **required expansion** of the existing power grid and H2 network capacities in order to circulate power and hydrogen to the rest of the regions.





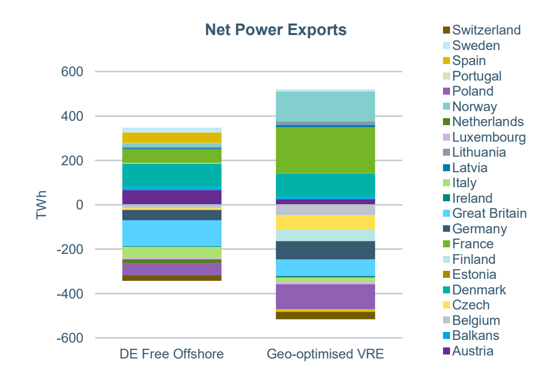
Geo-optimised VRE scenario

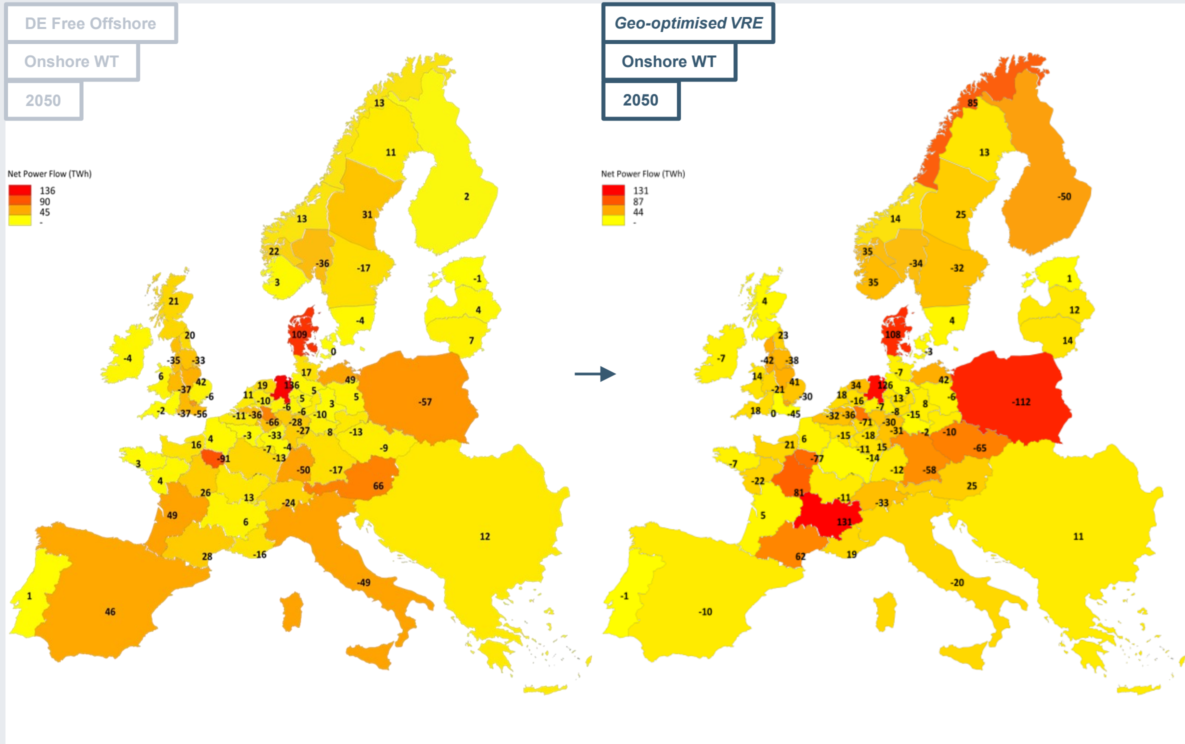
Increased power flows are observed across the system, with the main powerhouses moving away from the south

The redistribution of mainly onshore wind capacities seem to significantly affect the modelled geography's net sources and sinks. Notable examples:

- France: 63 -> 207 TWh
- Norway: 16 -> 136 TWh

- Spain: 46 –> -10 TWh
- Finland: 2 -> -50 TWh
- Poland: -57 -> -112TWh



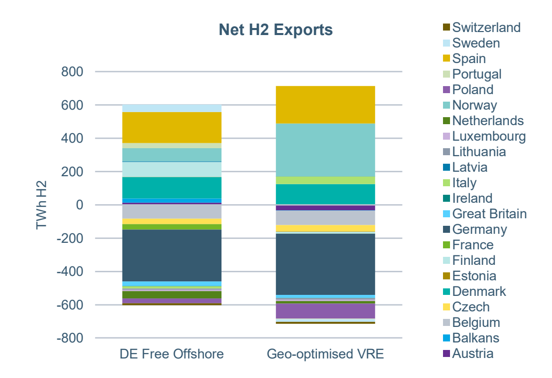


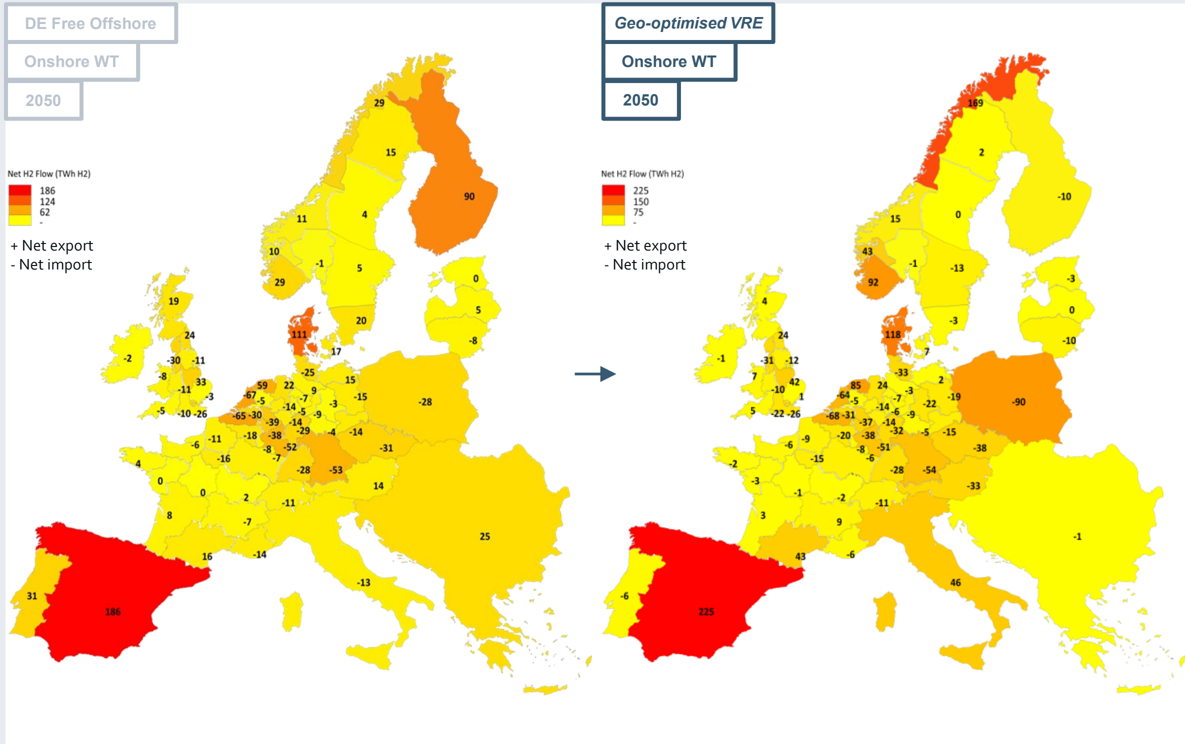
Relatively similar circulation of H_2 quantities in the system, following the placement of both PV and onshore WT capacities

Norway emerges as a main H2 supplier for the system, due to the increased onshore wind development, taking over quantities previously generated via other northern countries. In parallel, southern regions with heavy PV deployment maintain a high level of H2 injection in the central European system.

- Norway: 78 -> 318 TWh H2
- Italy: -13 -> 46 TWh H2

- Finland: 90 -> -10 TWh H2
- Poland: -28 -> -90 TWh H2
- Sweden: 44 -> -15 TWh H2

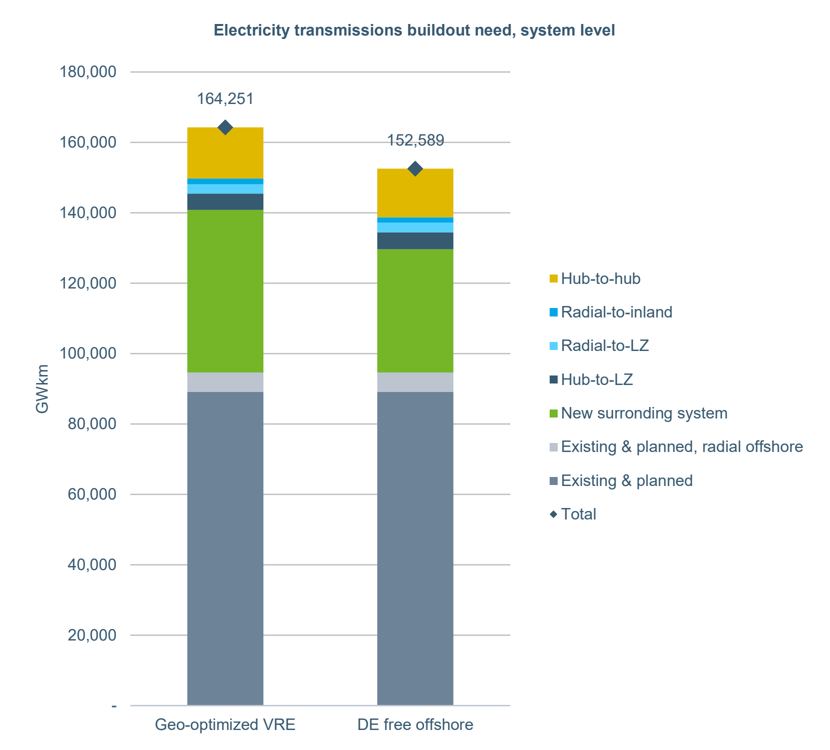




Grid buildout is much higher in Geo-optimised VRE scenario

The Geo-optimised VRE scenario sees a need for much higher grid buildout, as solar PV and onshore wind turbines are relocated to regions with higher full load hours. The grid is increased 12% relative to the DE free offshore scenario in 2050.

The Geo-optimised VRE sensitivity highlights the trade-off between better utilisation of onshore RE capacities and a cost of higher grid buildout.



DE Fixed Offshore scenario

DE fixed offshore results in higher offshore capacity

The DE Fixed Offshore scenario build out a lot more offshore wind capacity. An additional 147 GW is installed across Europe in 2050.

The additional offshore wind is mostly installed in:

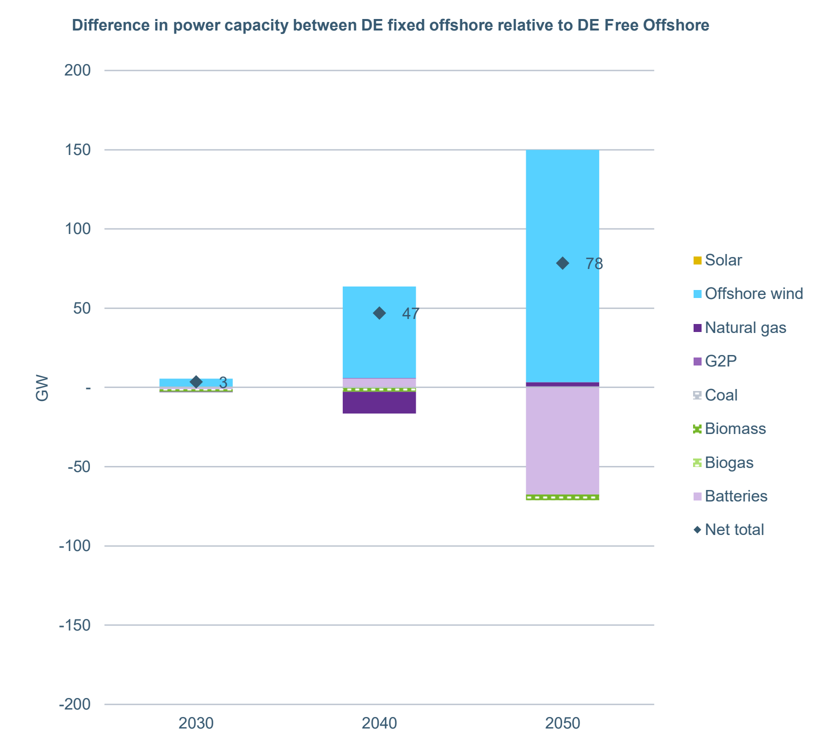
- +58 GW in France
- +39 GW in the UK
- +33 GW in Germany
- +18 GW in the Netherlands
- +19 GW in Ireland
- +12 GW in Norway

Some countries have reduced offshore wind:

- -21 GW in Denmark
- -9 GW in Sweden
- -8 GW in Balkans

Furthermore, the additional offshore wind capacity reduces the need for batteries by 67 GW in 2050, as less balancing capacity is needed.

Some natural gas and biomass capacity is decommissioned on market terms, especially in 2040 and 2050.



Note: Positive numbers represent additional capacities in the current scenario vs DE Free Offshore, and vice versa.

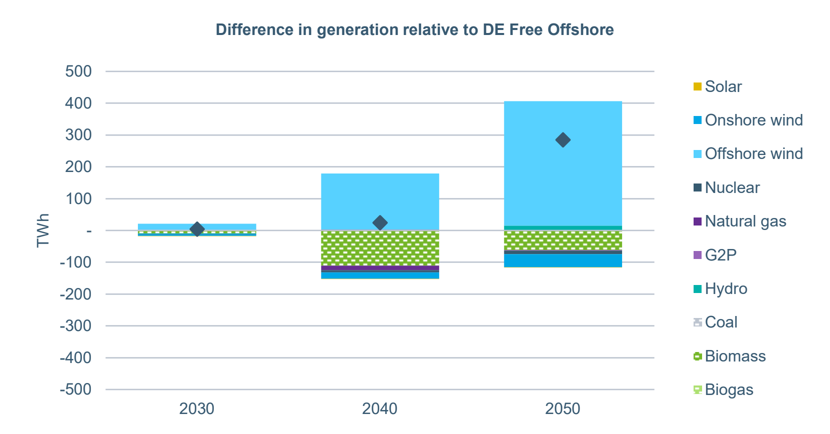
Additional offshore wind is used for H_2

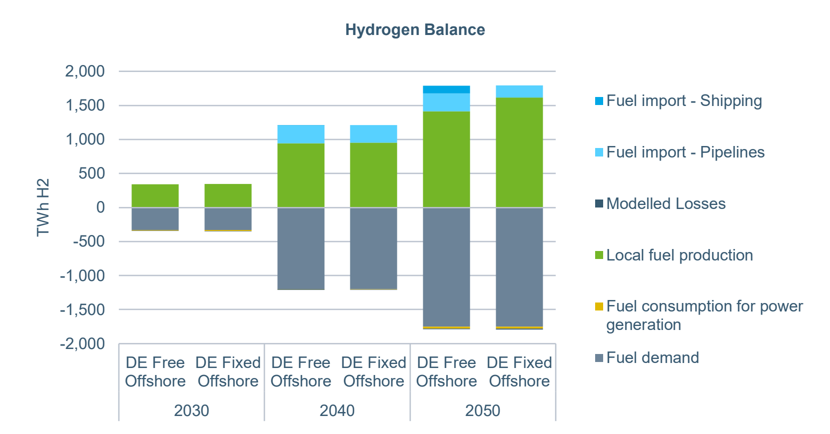
There is an increase of offshore wind generation of about 180 TWh in 2040 and 390 TWh in 2050 in the system. The additional generation from offshore wind replaces mostly biomass-based generation across years. This additional net generation is used for hydrogen production, replacing H2 imports from Northern Africa.

However, the system also have increased curtailment of around 192 TWh from offshore wind generation. Most of this curtailment is in:

- 52 TWh in Germany
- 43 TWh in the Netherlands
- 36 TWh in the UK
- 15 TWh in Denmark

The H2 balance shows that we have reduced hydrogen imports compared to DE free offshore. The remaining import is the cheapest pipeline option directly from North Africa, not any shipping. It appears that the cost of hydrogen imports is lower than building out electrolysers locally to replace this.



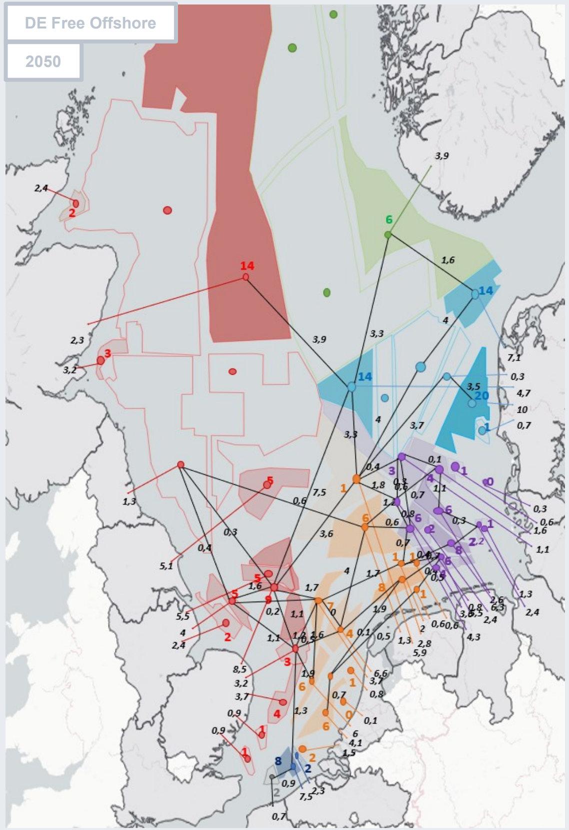


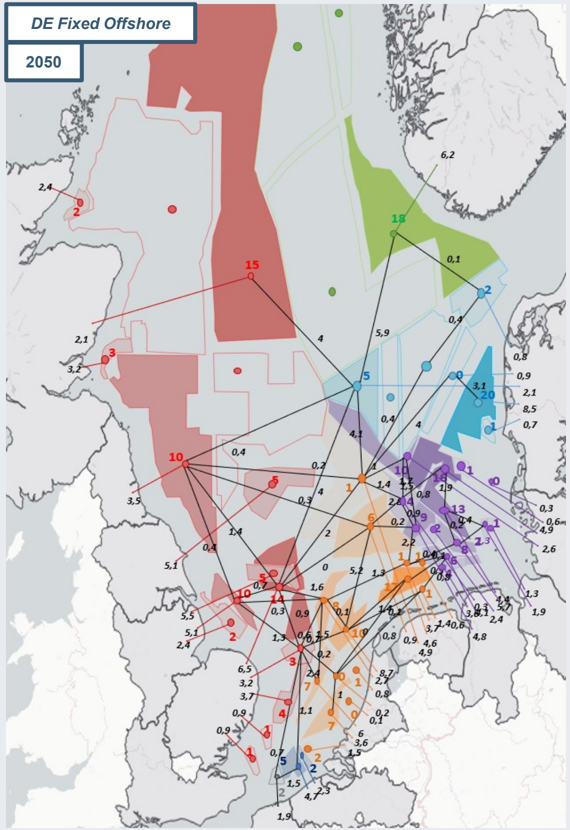
DE Fixed Offshore scenario

Hubs-and-spokes are reduced with fixed offshore

Fixing offshore capacity to DE scenario has a reducing effect on the corridor from DK to the UK and the Netherlands. Around 4 GW less transmission capacity is installed from the DK hubs to NL and the large corridor of 7,5 GW to UK is reduced to 4 GW. The reason is simply that the model is fixed to certain offshore capacities within countries. This results in the low LCOE areas of Denmark, not being utilised.

All in all, the length of the hub-to-hub transmission system is reduced 2,300 GWkm, approximately reduced by 12%.





Line values: Power transmission capacity (GW)

Region values: Offshore wind capacity (GW, rounded)

Note: Overview of country-based power flows in the North Sea across scenarios can be seen in the Appendix (table, illustration).

No Hubs-and-Spokes scenario

No Hubs-and-Spokes results in less offshore capacity

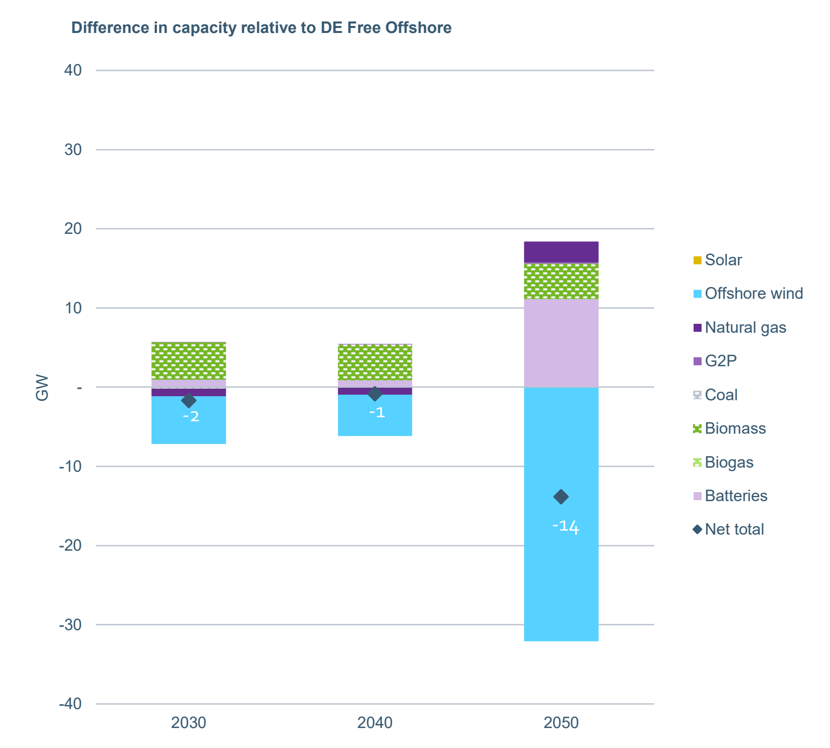
Radial replace hub-to-hub connections.
Overall reduction in offshore capacity.

- + 9 GW in the Netherlands
- -27 GW in Denmark
- -8 GW in the UK
- -5 GW in Norway

The strongest impact is on the Danish offshore capacity.

There is around 5 GW new biomass capacity installed around the system in 2030, while some 3 GW old gas turbines is not decommissioned in 2050, instead re-purposed for hydrogen fuelled generation.

11 GW higher battery capacity in 2050 is also needed to offset less offshore generation.

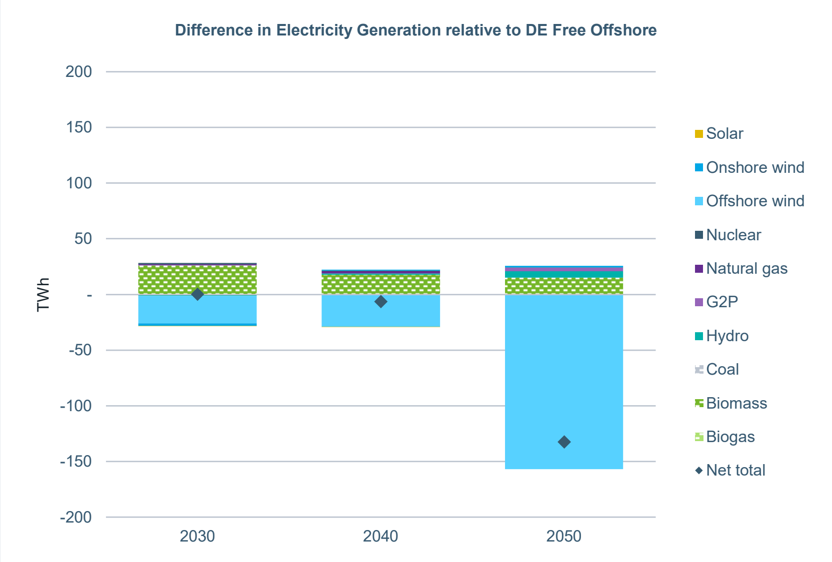


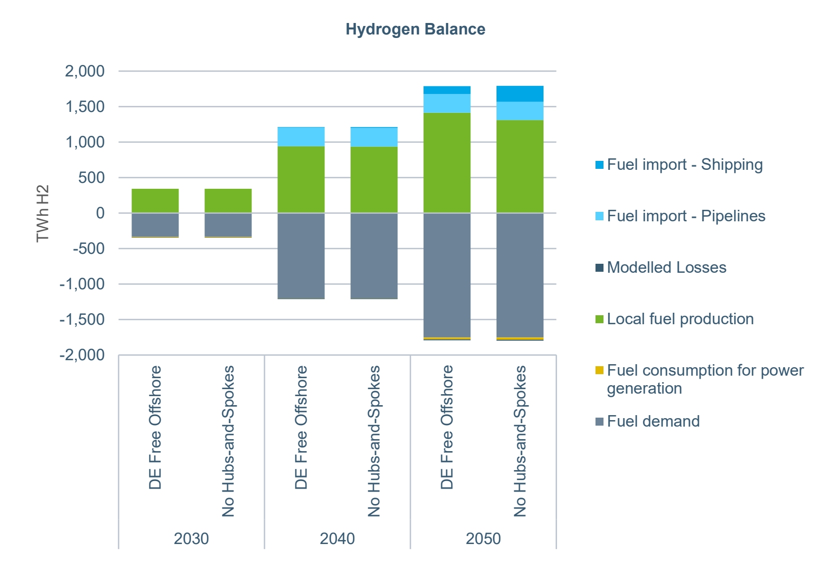
No Hubs-and-Spokes scenario

Absence of hubs-and-spokes results in lower offshore generation and higher H_2 imports

The generation overview shows that offshore wind production is reduced, being replaced by biomass-based generation in 2030 and 2040.

In 2050, lower offshore wind capacities & generation drive higher hydrogen import needs, as shown in the hydrogen balance.





No Hubs-and-Spokes reduces capacity in the North Sea

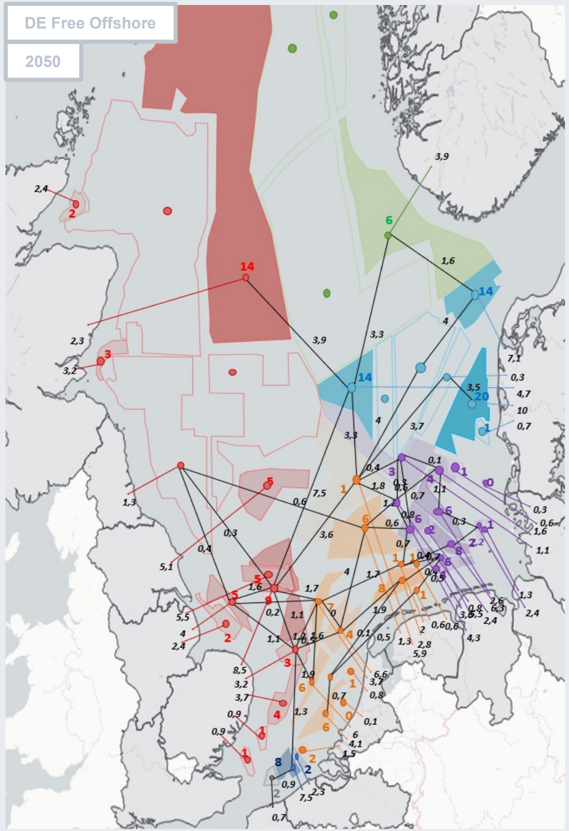
If no hubs-and-spokes are allowed, the model opts for reducing offshore wind capacity and build close to shore radial connections while also importing more hydrogen.

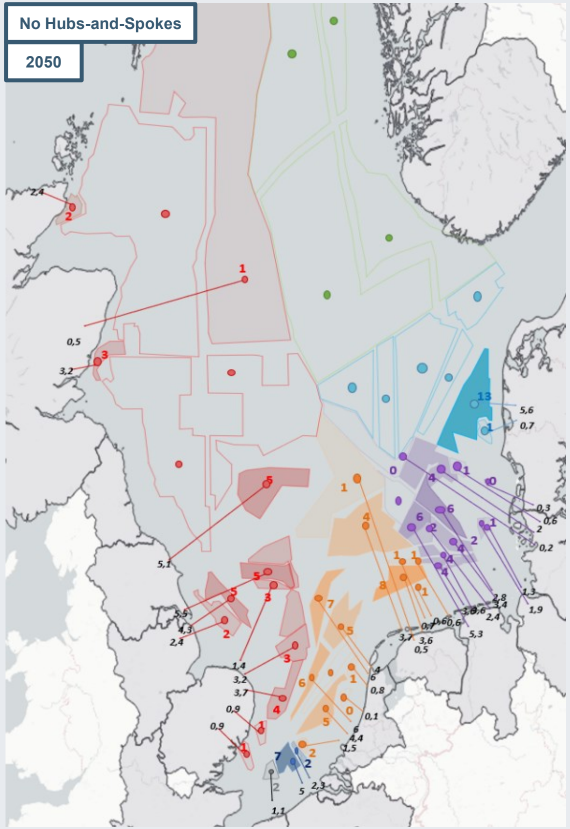
Note that much of the offshore capacity is moved to near shore locations (below 22 km sites), which is not shown on map.

Only two cross-North Sea changes are observed between DE Free Offshore and No Hubs-and-Spokes scenarios, in the absence of a North Sea grid in 2050. The power interconnection between continental NO and UK is increased by 500 MW, while the NO to DE connection is expanded by 900 MW[i].

Line values: Power transmission capacity (GW)

Region values: Offshore wind capacity (GW, rounded)





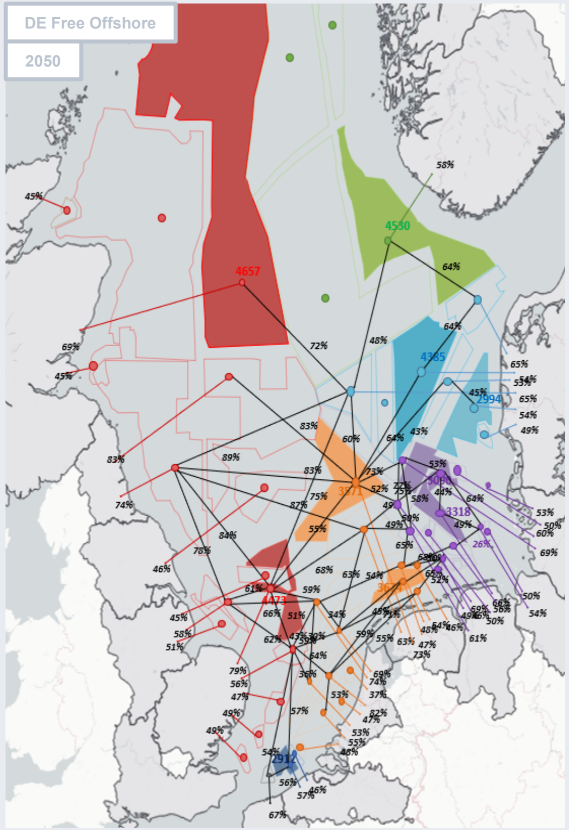
Note: Overview of country-based power flows in the North Sea across scenarios can be seen in the Appendix (table, illustration).

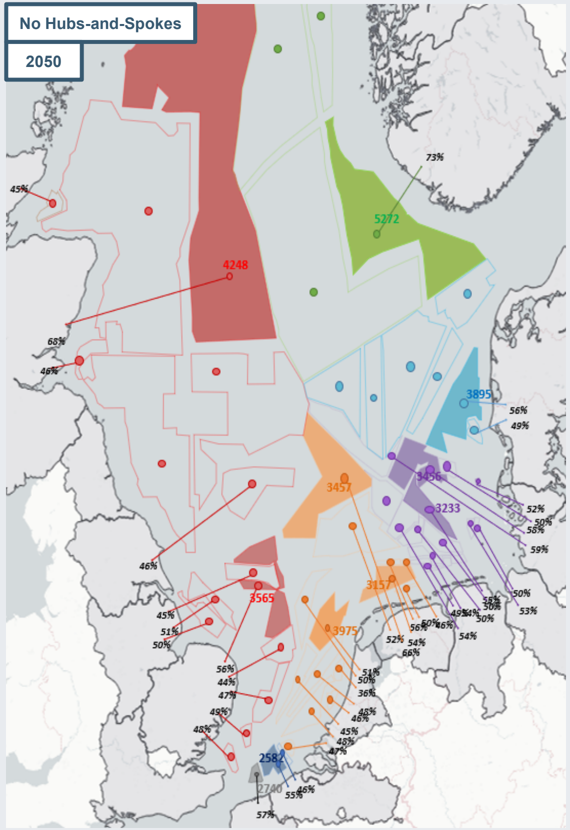
No Hubs-and-Spokes scenario

The utilisation of transmission to shore is dropping

The decrease of installed offshore wind capacities in the North Sea in the No-Hubs-and-Spokes scenario leads to lower capacity factors of power transmission lines.

Electrolysers located on the eastern side of the NS (Norway, Denmark, Germany), reflect higher FLHs when compared to the reference case, while the rest of offshore electrolysis experiences lower operation patterns. Such a fact can highlight the power flow patterns of the system, where absence of a North Sea grid doesn't allow for flows towards the NL and the UK. Higher offshore electrolysis FLHs can benefit the model by yielding savings on power transmission investments.





Line values: Power transmission CFs

Region values: Electrolysis FLHs

No Hubs-and-Spokes scenario

The absence of a North Sea grid roughly results in a similar onshore power system size

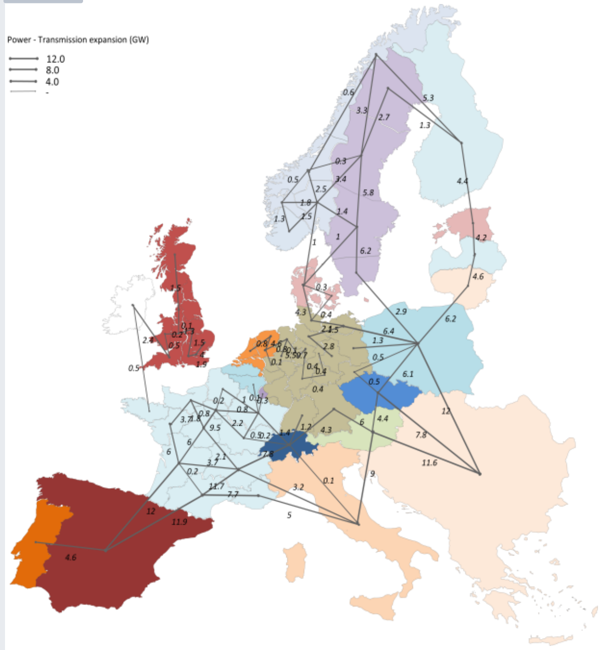
The overall power transmission system in 2050 is reduced by 0.4% (in terms of GWkm) against the reference case), while in terms of pure capacity it is expanded by 7.5 GW.

The main capacity changes against the reference case are located within the main demand centres of the modelled geography (Netherlands and Germany), while direct country to country connections across seas emerge.

Line values: Power transmission invested capacities between 2030 and 2050.

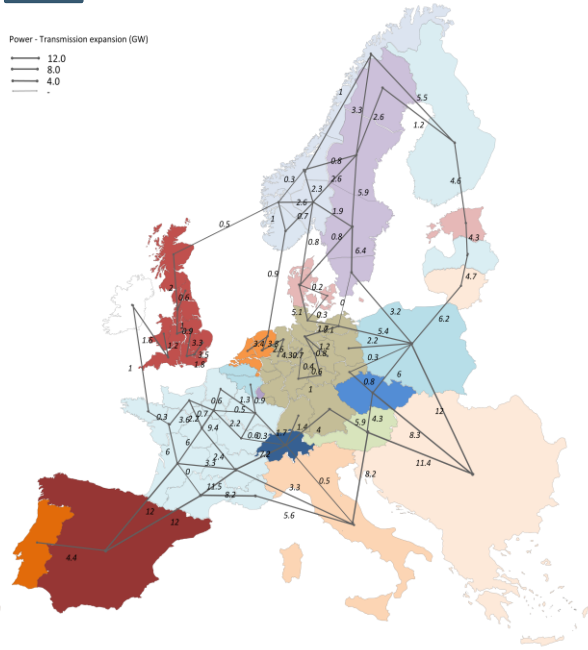
DE Free Offshore

2050



No Hubs-and-Spokes

2050



Unrestricted Solar scenario

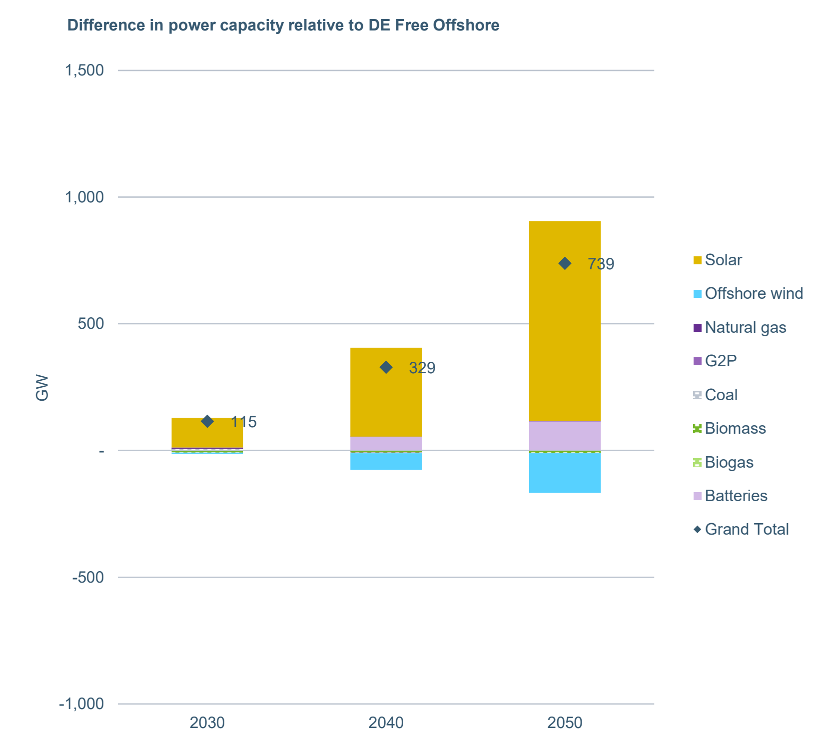
Unrestricted Solar scenario results in solar PV replacing offshore wind

The Unrestricted Solar scenario build out a lot more solar than in the DE Free Onshore scenario. An additional 789 GW is installed across Europe in 2050 with 114 GW more batteries, at the expense of 157 GW offshore wind capacity.

The additional solar PV is mostly installed in Southern Europe:
- +260 GW in Spain
- +160 GW in Balkans
- +150 GW in Italy
- +75 GW in Germany
- +46 GW in the UK
- +41 GW in Portugal
- +34 GW in France

The replaced offshore wind is mostly in Northern Europe:
- -49 GW in Denmark
- -28 GW in the UK
- -25 GW in Germany
- -14 GW in the Netherlands
- -12 GW in Sweden
- -10 GW in Balkans

As less offshore capacity is installed, more battery capacity is needed to cope with increased balancing needs.

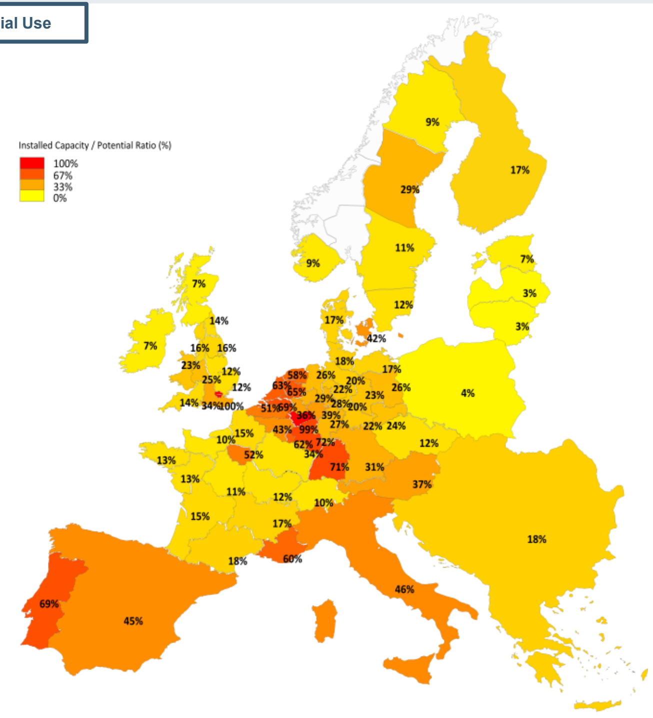


Note: Positive numbers represent additional capacities in the current scenario vs DE Free Offshore, and vice versa.

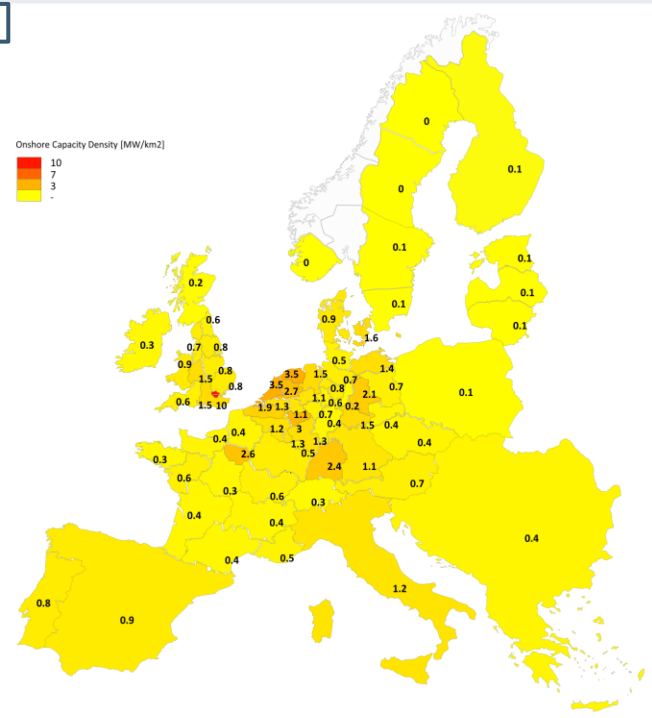
Solar PV Capacity Density (Unrestricted Solar, 2050)

With the main additional solar PV capacities located in southern Europe, the question of spacing naturally emerges. It becomes evident that even though capacities on the south approximately doubled in the present scenario, no southern region stretched up to its total solar potential (technical potential).

Potential Use



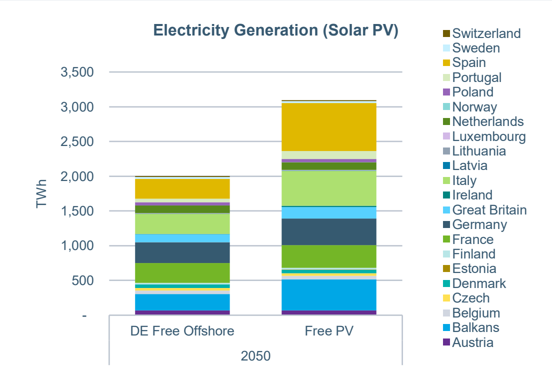
Spacing

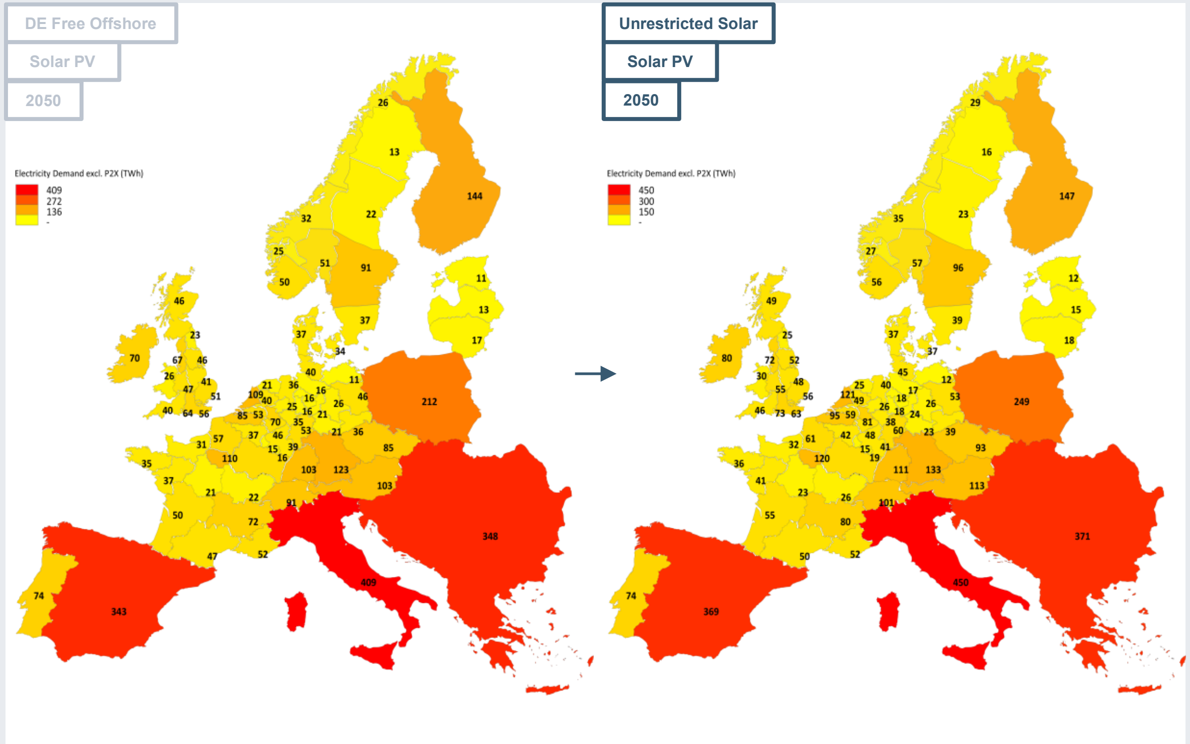


Total installed PV capacities increase by 48%, generation increases by 54%

The main capacity additions are distributed mainly amongst the Balkans, Italy, Spain and partially south of Germany, due to the experienced high FLHs. More specifically:

- Spain: 177 -> 437 GW. Equivalent to 2.5% of agricultural land.
- Italy: 204 –> 335 GW. Equivalent to 2.3% of agricultural land.
- Balkans: 177 -> 336 GW
- Germany: 278 -> 352 GW



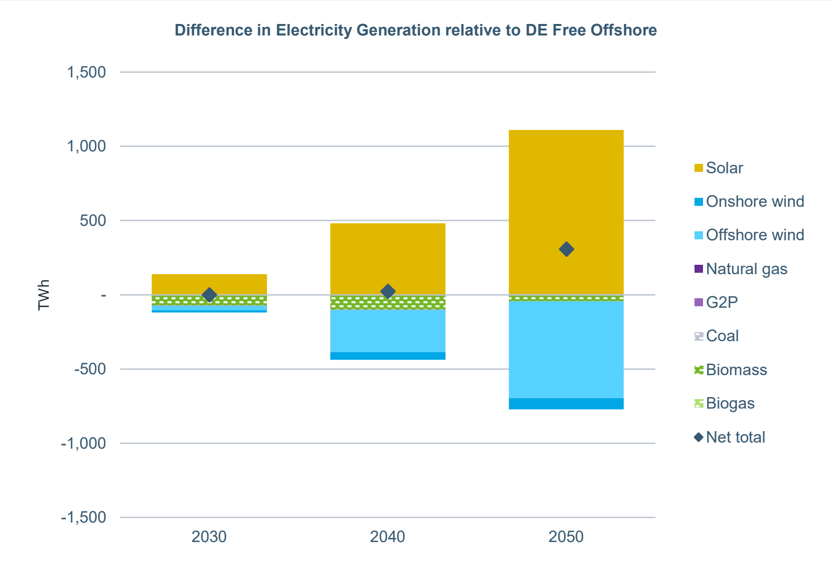


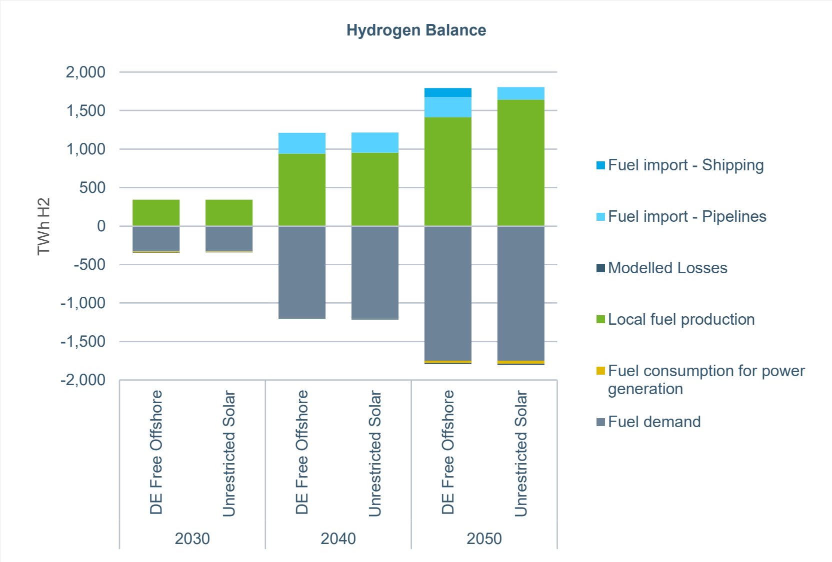
Unrestricted Solar scenario

Additional solar PV generation is used for H_2

The additional generation from solar PV does not only replace offshore wind generation, there is also a 308 TWh increase in the total generation of the system in 2050.

This additional generation is used for hydrogen production, as shown in the hydrogen balance. The additional generation replaces shipping imports.





Unrestricted Solar scenario

Unrestricted Solar results in heavy reduction of hub-to-hub transmission

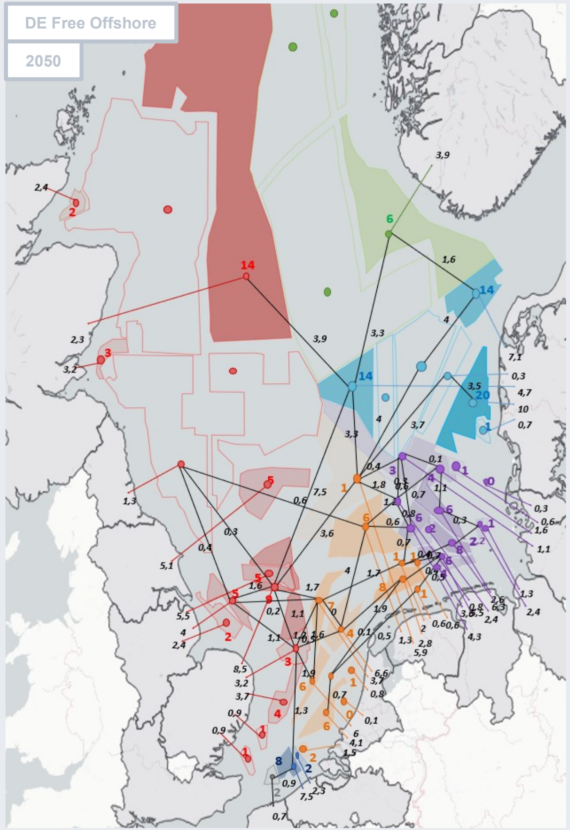
As much of the hydrogen production is moved south, the need for offshore wind capacity is significantly reduced, as are the overall hub-to-hub connections.

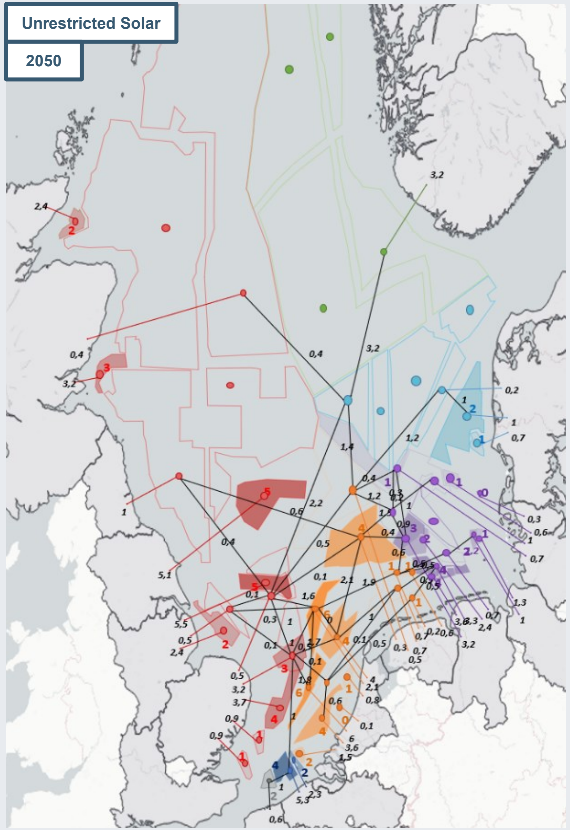
The model sees a need for a 3 GW corridor from Norway down to the UK and the Netherlands, however no offshore wind capacity is installed.

All in all, the length of the hub-to-hub transmission system is reduced to 12,700 GWkm, reduced by approximately 68% (all hub-to-hub lines are included even though they don’t have wind capacity).

Line values: Power transmission capacity (GW)

Region values: Offshore wind capacity (GW, rounded)



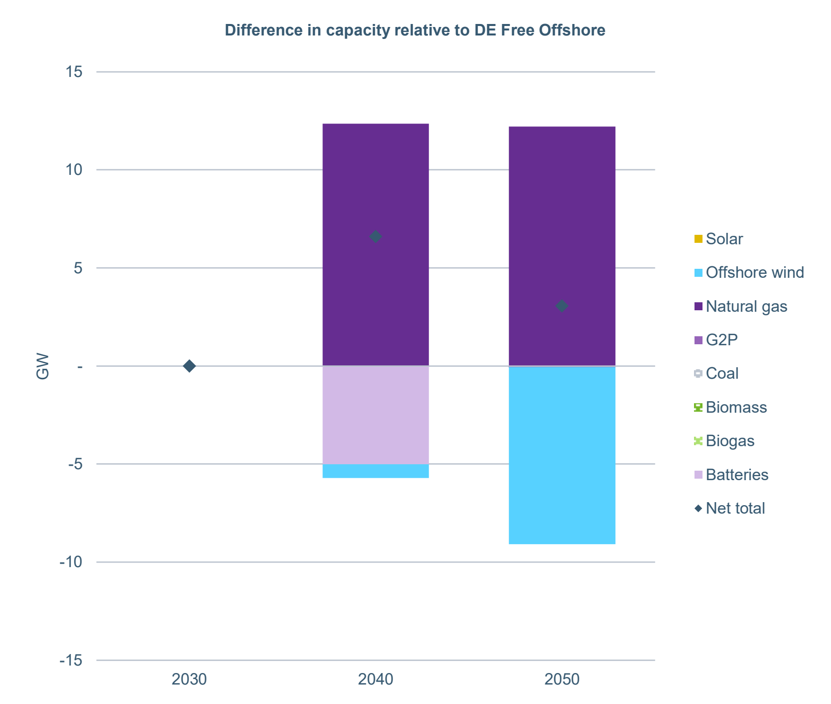


Note: Overview of country-based power flows in the North Sea across scenarios can be seen in the Appendix (table, illustration).

Interconnection (IC) Limits scenario

Interconnection limitations of south Europe lead to partial replacement of offshore wind with natural gas units

A decreased overall offshore wind capacity is observed, mainly due to lower installation in the Balkans. The existence of higher natural gas generator capacities correspond to lower decommissioning rate of the existing fleet. In 2040, natural gas usage is allowed and used instead of power transmission capacity expansions, while capacities in 2050 reflect retrofitted operations based on hydrogen. In parallel, naturally, more flexible generators correspond to lower levels of existing storage.

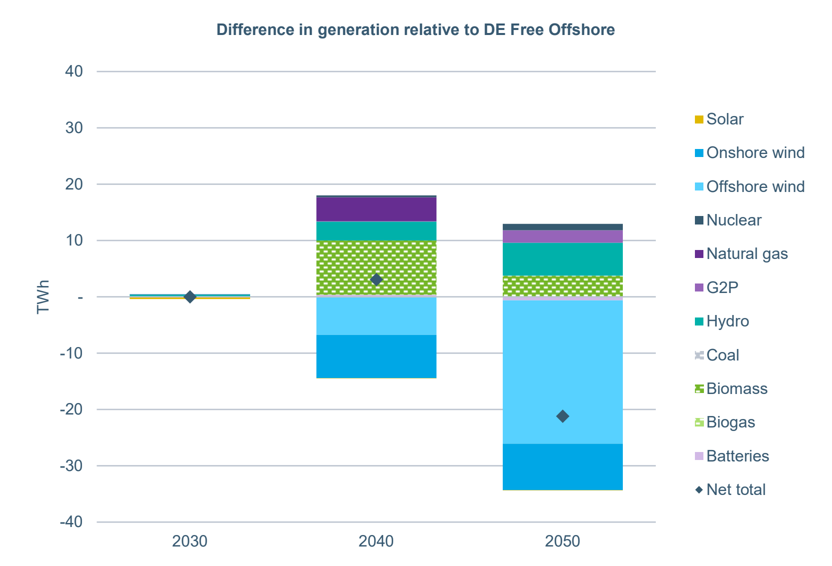


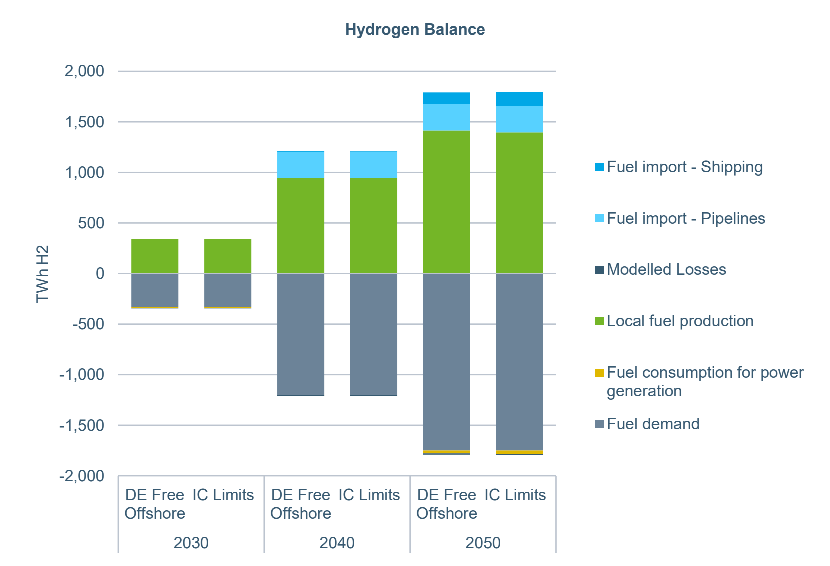
Note: Positive numbers represent additional capacities in the current scenario vs DE Free Offshore, and vice versa.

Interconnection expansion limitations lead to higher H_2 imports for local use in southern countries

Limiting the interconnection expansion of southern Europe results in higher curtailment of onshore VRE quantities, which therefore require replacement by flexible generators based on natural gas, biomass, nuclear and hydrogen. Adding on top the fact of lower total offshore wind capacities, leads to some replacement of locally produced with imported H2 quantities.

Italy, unable to expand its grid to the north, decreases its locally produced H2 (from 65 to 56 TWh H2) while allowing further H2 imports (131 to 166 TWh H2) for own use but also some flows to the north.



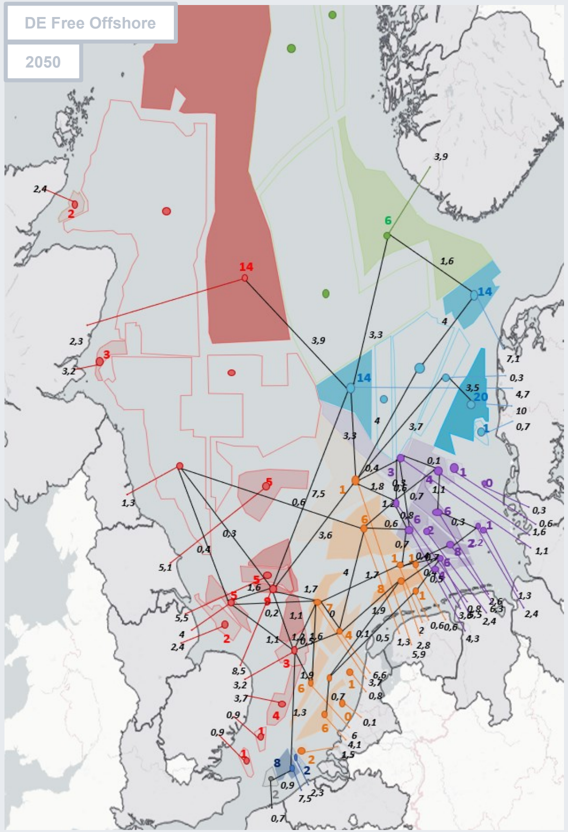


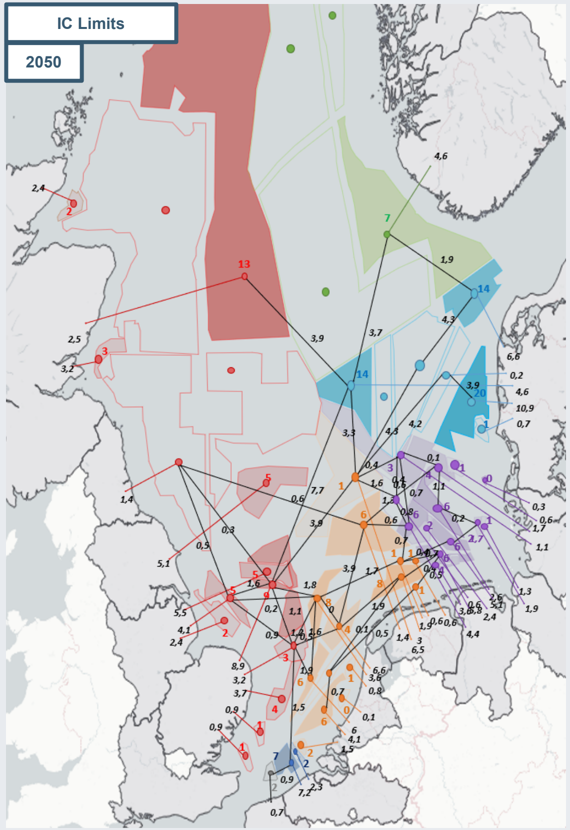
IC Limits scenario

Interconnection constraints on southern Europe, do not heavily impact the structure of hubs-and-spokes

The placement and capacities of offshore wind farms as well as their hybrid interconnections does not seem to be a subject of available electricity from the south.

Small additions to the main south-to-north corridor, assisting better electricity flows are evident. Higher impacts can be seen scattered across the onshore network.





Line values: Power transmission capacity (GW)

Region values: Offshore wind capacity (GW, rounded)

Note: Overview of country-based power flows in the North Sea across scenarios can be seen in the Appendix (table, illustration).

Summary of Sensitivity Impacts

Summarised scenario impacts – simple

Impact per Scenario relative to DE Free Scenario	Geo-optimised VRE	DE Free Offshore	DE Fixed Offshore	No Hubs-and-Spokes	Unrestricted Solar	IC Limits
Offshore capacity	Unchanged	Used as reference	**Increased**	**Decreased**	**Decreased**	**Decreased**
Onshore capacity (wind and solar)	**Total capacity is reduced as it is moved to regions with higher FLH. Results in slightly lower total generation due to calibration.**	Used as reference	Unchanged	Unchanged	**Increased, total solar PV capacity and generation is heavily increased.**	Higher VRE curtailment
Local hydrogen production	Slightly decreased due to lower total generation.	Used as reference	**Increased**	**Decreased, higher imports are needed as offshore wind generation is reduced.**	**Increased, all shipping imports are removed.**	Decreased
Total system costs	**Lower costs,** less capacity is needed for roughly the same generation.	Used as reference	**Higher cost,** as H_2 shipping can be cost competitive to excessive exogenous offshore wind capacities. Additionally, a high wind curtailment is observed.	**Higher costs**, no hubs-and-spokes makes the costs increase as synergies cannot be utilised for local hydrogen production.	**Lower costs,** solar PV is much cheaper source of electricity than offshore wind.	**Higher costs**, mainly because of lower offshore capacity and higher curtailment, resulting in higher H_2 imports.

Summarised scenario impacts vs Base Case (DE Free Offshore)

Some of the main impacts evaluated via the undertaken sensitivities are listed on the present table. These revolve around the **total amount and siting of installed VRE capacities** across the modelled geography, the consequent effects on the development of the **surrounding infrastructure** (transmission networks, flexibility units) and the **competition of the local H2 production price against H2 inflows** from third regions. **The significance and therefore robustness of the Hubs-and-Spokes concept is set under the microscope**. The identified main offshore corridors are set side by side in the upcoming 2 illustrative slides, with further explanations listed on a scenario basis versus the assumed base run (DE Free Offshore) in the rest of the present section's slides. **Impacts on regional capacity redistribution, imported H2 quantities, as well as the necessity for higher amounts of system balancing via flexible generators is being discussed**.

2050	Geo-optimised VRE	DE Free Offshore	DE Fixed Offshore	No Hubs-and-Spokes	Unrestricted Solar	IC Limits
Offshore Wind (GW)	350	350	496	318	193	341
Onshore Wind (GW)	750	852	852	852	852	852
Solar PV (GW)	1,500	1,642	1,642	1,642	2,431	1,642
Offshore Wind Generation (TWh)	1,392	1,386	1,778	1,230	734	1,361
Onshore Wind Generation (TWh)	2,515	2,525	2,484	2,527	2,448	2,517
Solar PV Generation (TWh)	1,958	2,004	2,004	2,004	3,110	2,004
Offshore Wind Curtailment (TWh)	33	35	192	33	34	36
Onshore Wind Curtailment (TWh)	14	36	62	36	95	43
Solar PV Curtailment (TWh)	-	-	-	-	12	-
Battery Capacity (GW)	319	335	67	346	449	335
H_2 G_2P Capacity (GW)	138	139	142	141	140	151
Total Demand Curtailment (GWh)	722	737	225	919	373	1,171
Electrolysis (GW H_2)	435	424	408	407	514	422
H_2 Production (TWh H_2)	1,394	1,414	1,614	1,310	1,643	1,398
H_2 Import - Pipelines (TWh H_2)	261	260	179	261	163	260
H_2 Import – Shipping (TWh H_2)	144	116	-	226	-	136
H_2 Storage Volume (TWh H_2)	120	113	119	110	156	118
Power Transmission (GW, Total)	1,098	977	981	889	819	943
Power Transmission (GW, Hubs-and-Spokes)	87	75	73	-	38	77
H_2 Transmission (GW H_2)	1,033	973	1,008	958	1,041	971
Annualised System Cost (bn.€)	554	574	575	575	558	576

Note: Values rounded to the nearest integer.

Need for hubs-and-spokes is conditional on the need for offshore wind

The present analysis explored 6 different sensitivities, varying the development conditions of renewable energy and transmission networks.

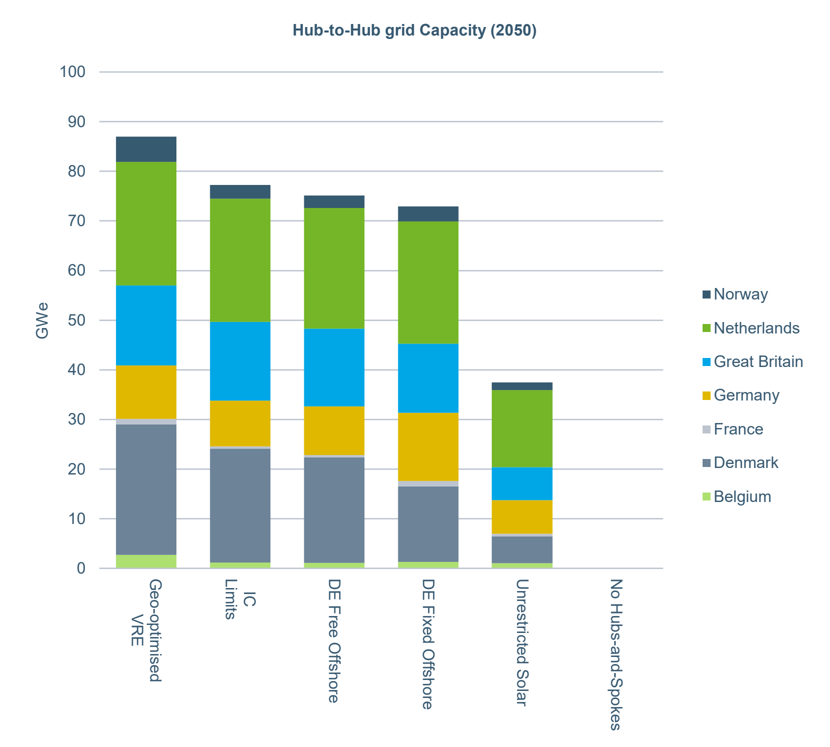
Hubs-and-spokes prove beneficial across a number of sensitivities.

- Most sensitivities show a two main corridors from the DK hubs, one to UK ranging from 2 to 8 GW, and one to the Netherlands ranging from 3 to 13 GW (as seen in detailed maps[1,2]).
- Fewer restrictions on distribution of onshore and offshore renewable capacity increase the value of the transmission system in general and of the hubs-and-spokes (Geo-optimised VRE).

Need for hubs-and-spokes is conditional on the need for offshore wind.

- Reduced need for offshore wind could be the result of higher potentials for solar PV or onshore wind, as well as a conditional decreased cost competitiveness of locally generated H2 vs external imports.

2050	Geo-optimised VRE	IC Limits	DE Free Offshore	DE Fixed Offshore	Unrestricted Solar	No Hubs-and-Spokes
Total System Cost (bn. €)	554	576	574	575	558	575
% Savings against DE Free Offshore	3.55%	-0.25%	-	-0.04%	2.90%	-0.17%
Power Transmission Savings (bn.€)	-4.1	0.8	-	0.1	4.4	2.0
H2 Transmission Savings (bn.€)	-0.5	-0.1	-	-0.2	-0.6	-0.0



Notes: Savings are (+). Transmission costs reflect the whole geography incl. onshore

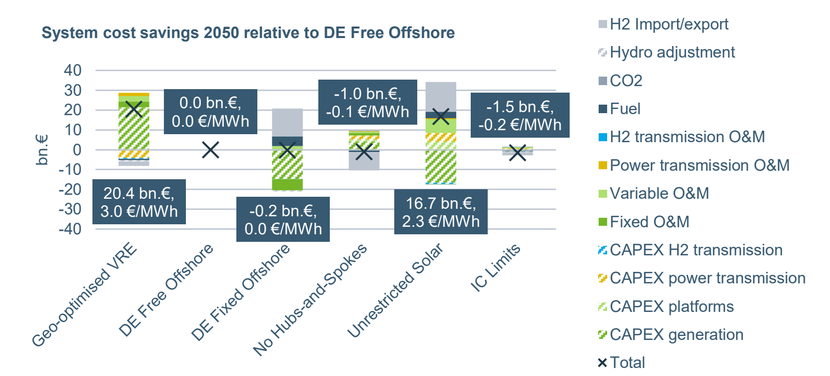
Possible future pathways don’t lead to highly fluctuating system costs. However, the conditions and implications of each scenario vary

There are different socio-economic implications in each future pathway against the base case scenario (DE Free Offshore).

- **The Geo-optimised VRE sensitivity** results in considerable supply side savings due to the optimal redistribution of capacities across the modelled geography, harvesting therefore higher FLHs which lead to lower capacity needs. Of course, with capacities moving to the outskirts of Europe, additional transmission costs are emerging. Considerations of unsatisfied political targets, VRES capacity density in some countries, as well as geolocational obstacles of energy transmission could challenge such a solution.
- **The DE Fixed Offshore sensitivity** calls for higher amounts of offshore wind in the system, matching political ambitions on all renewable fronts, at high additional supply side costs. This fact naturally drives the available cheap electricity to higher levels increasing European hydrogen production and eliminating H2 imports via shipping while also challenging the cheaper pipeline options. Savings on cost for imported hydrogen are to offset the higher supply side cost to a large extent. While the European H2 self-sufficiency is getting strengthened at an almost unchanged system cost, it is worth considering the real-world dynamics, which could include long term price responses from electricity and hydrogen.
- **The No Hubs-and-Spokes sensitivity** leads to a drop of the overall offshore wind capacity in the system with consequent transmission savings, something overturned by the increasing needs of H2 imports from North Africa emerging as the least cost solution of the residual H2 demand. In other words, Hubs-and-Spokes (as well as higher offshore wind buildout illustrated by the DE Fixed Offshore scenario), can increase energy independence at limited costs.

2050	Geo-optimised VRE	DE Free Offshore	DE Fixed Offshore	No Hubs-and-Spokes	Unrestricted Solar	IC Limits
Total System Cost (bn. €)	554	574	575	575	558	576
% Savings against DE Free Offshore	3.55%	-	-0.04%	-0.17%	2.90%	-0.25%

- **The Unrestricted Solar sensitivity** replaces a large amount of offshore wind with more solar PV in southern Europe due to their considerably lower LCOE. Expectedly, this translated to higher local H2 generation volumes (thus higher generation costs vs the base case) and large savings on H2 imports, leading to a highly self-sufficient Europe. The public acceptance of solar PVs in southern European countries, the land use competition with other sectors (e.g. agriculture) and the vulnerability of such centralised power regions can be subject to further scrutiny.
- **The IC Limits sensitivity** doesn’t lead to considerable scenario changes as the effects are mostly concentrated in southern European countries which act as H2 sinks (Italy, Balkans), and therefore getting addressed by further H2 imports than the base case.



Note: Positive values correspond to savings of the indexed (x-axis) scenario against the referenced scenario within the figure’s title. Values are annual. Savings per MWh reflect savings in terms of total power demand.

Socio-economy of sensitivities (Detailed Annualised System Costs)

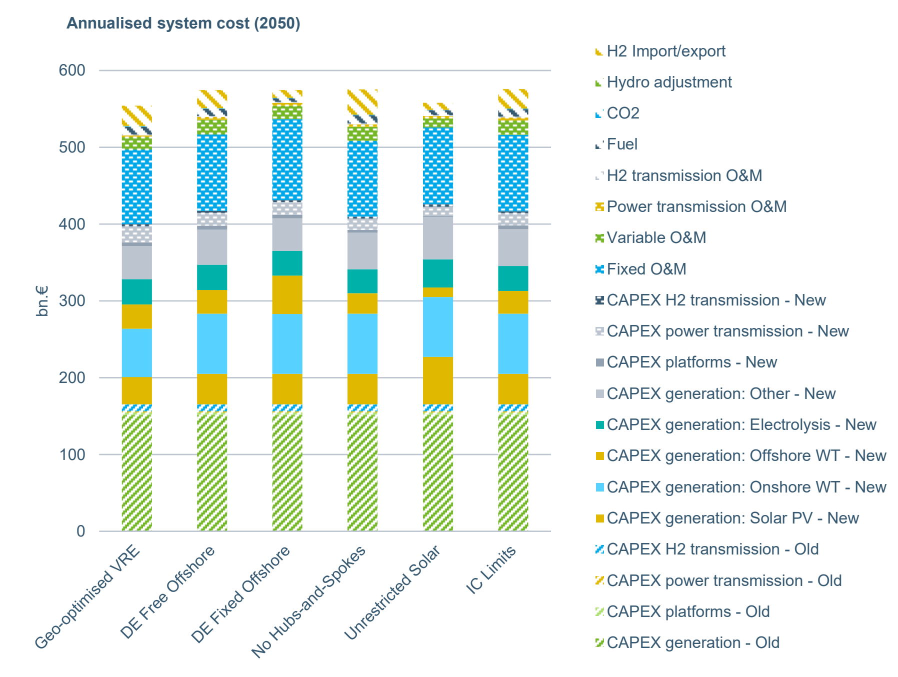
The DE Fixed Offshore and the Unrestricted Solar sensitivities has a similar impact on the system, as the DE Fixed Offshore results in higher offshore generation and higher local hydrogen production, while Unrestricted Solar results in higher solar PV generation and higher local hydrogen production. However, as offshore generation is forced into the system through a constraint in the DE Fixed Offshore sensitivity, it is more expensive than the baseline, while the Unrestricted Solar results in cost savings, because it was initially cheaper to build PV in Southern Europe to produce hydrogen than building offshore wind in Northern Europe and produce hydrogen.

The Geo-optimised VRE sensitivity has the expected impact of being cheaper than the baseline, as the model is free to optimise the location of solar PV and onshore wind turbine capacity between countries, while the baseline is fixed to the DE scenario capacities.

The No Hubs-and-Spokes sensitivity is more expensive than the baseline, as the North to South backbone corridor of the North Sea cannot be realised. The result is that capacity is moved from Denmark to the Netherlands and UK which have a higher LCOE. The difference between the baseline and no hubs-and-spokes can be used to assess the value of the offshore hub-to-hub connections in the North Sea. This sensitivity also less the higher external H2 imports.

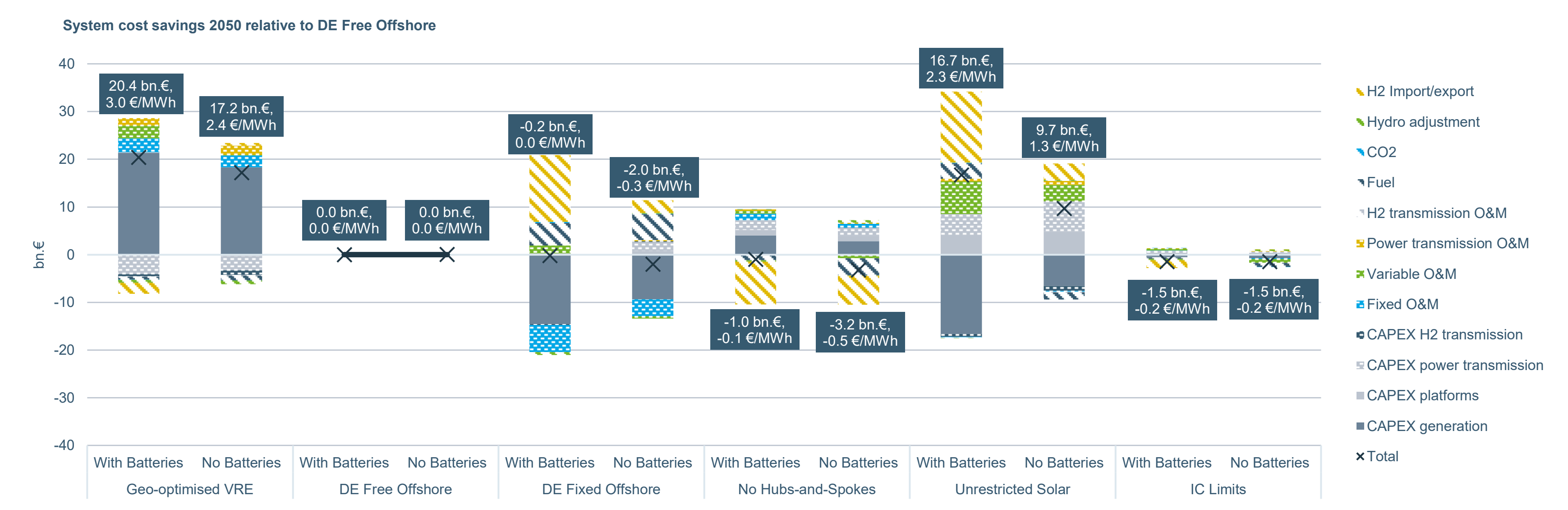
The IC Limits sensitivity is more expensive than the baseline, as the corridors from Southern Europe(Spain, Italy and Balkans) is more limited than in the baseline, resulting in solar PV capacity in the South being more limited.

2050	Geo-optimised VRE	DE Free Offshore	DE Fixed Offshore	No Hubs-and-Spokes	Unrestricted Solar	IC Limits
Total System Cost (bn. €)	554	574	575	575	558	576
% Savings against DE Free Offshore	3.55%	-	-0.04%	-0.17%	2.90%	-0.25%



Note: The illustrated system cost only accounts for the annualised equivalents of all active costs in 2050. The overall system cost would require summation of all annualised active costs across years. The notation "Old" refers to pre-existing units before the start of the optimisation period. "New" to investments during the optimisation horizon.

Socio-economy of sensitivities: Low impact of Batteries' presence across sensitivities



	Geo-optimised VRE		DE Free Offshore		DE Fixed Offshore		No Hubs-and-Spokes		Unrestricted Solar		IC Limits	
2050	**With Batteries**	**No Batteries**	**With Batteries**	**No Batteries**	**With Batteries**	**No Batteries**	**With Batteries**	**No Batteries**	**With Batteries**	**No Batteries**	**With Batteries**	**No Batteries**
Total System Cost (bn. €)	554	559	574	576	575	578	575	580	558	567	576	578
% Savings against DE Free Offshore	**3.55%**	**2.98%**	–	–	**-0.04%**	**-0.35%**	**-0.17%**	**-0.56%**	**2.90%**	**1.68%**	**-0.25%**	**-0.25%**

Capacity overview across sensitivities

	Offshore WT			Onshore WT			Solar PV			Electrolysis		
GWe	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
Geo-optimised VRE	169	296	350	453	618	750	669	1,123	1,500	107	378	580
DE Free Offshore	169	256	350	433	699	852	729	1,258	1,642	126	378	566
DE Fixed Offshore	174	314	496	433	699	852	729	1,258	1,642	128	361	546
No Hubs-and-Spokes	163	251	318	433	699	852	729	1,258	1,642	125	380	545
Unrestricted Solar	163	189	193	433	699	852	846	1,608	2,431	123	408	683
IC Limits	169	255	341	433	699	852	729	1,258	1,642	126	381	564

	Onshore			Landing Zones (LZ)			Offshore		
Electrolysis (GWe)	2030	2040	2050	2030	2040	2050	2030	2040	2050
Geo-optimised VRE	92	295	462	16	50	74		33	43
DE Free Offshore	112	318	458	14	39	70		22	38
DE Fixed Offshore	112	299	426	16	42	68	0.1	20	53
No Hubs-and-Spokes	111	320	457	14	39	54		21	34
Unrestricted Solar	111	390	662	12	17	21		0	0
IC Limits	112	320	456	14	40	71		21	37

Note: Values rounded to the nearest integer.

LCOH (€/MWh H_2): Modelled Geography

Year	Technology	Geo-optimised VRE	DE Free Offshore	DE Fixed Offshore	No Hubs-and-Spokes	Unrestricted Solar	IC Limits
2030	30-39 Onshore	156	156	98	154	106	156
	30-39 Offshore			85			
	Overall	156	156	98	154	106	156
2040	40-49 Onshore	105	100	68	99	74	100
	40-49 Offshore	95	92	63	102	80	92
	40-49 Overall	103	99	68	99	74	99
	Overall	112	109	75	109	82	109
2050	50 - Onshore	87	83	56	83	59	83
	50 - Offshore	84	81	55	90		82
	50 - Overall	87	83	56	84	59	83
	Overall	99	95	66	97	69	95

Note: The illustrated LCOHs consist annual weighted averages across modelled regions and timesteps. A fluctuation of those is experienced on an hourly level, due to system dynamics, therefore making local generation cost competitive to H2 imports from North Africa:
- Pipeline imports: 81 €/MWh (2030), 62 €/MWh (2040), 51 €/MWh.
- Shipping imports: 108 €/MWh (2030), 88 €/MWh (2040), 77 €/MWh (2050).

LCOH (€/MWh H_2): Country Specific

Year	Scenario	Balkans	Belgium	Denmark	France	Germany	Great Britain	Italy	Netherlands	Norway	Spain
2030	Geo-optimised VRE		78	88	98	91	88		92	81	102
	DE Free Offshore			87	94	90	89		93	74	89
	DE Fixed Offshore			86	92	90	85		93	75	88
	No Hubs-and-Spokes			88	95	89	85		89	75	90
	Unrestricted Solar			83	87	84	85		87	74	85
	IC Limits			87	94	90	89		93	74	89
2040	Geo-optimised VRE		99	97	96	95	97	114	96	88	93
	DE Free Offshore	105	90	96	101	94	93	115	95	92	92
	DE Fixed Offshore	92	84	78	84	81	82	98	82	78	79
	No Hubs-and-Spokes	105	90	99	101	95	87	116	95	94	94
	Unrestricted Solar	93	85	82	87	85	86	98	88	85	75
	IC Limits	107	89	96	101	94	93	117	94	94	89
2050	Geo-optimised VRE	96	80	88	84	89	83	103	90	81	85
	DE Free Offshore	86	81	87	83	81	81	95	88	81	77
	DE Fixed Offshore	61	57	62	56	60	50	68	61	54	52
	No Hubs-and-Spokes	86	91	95	84	88	82	96	91	82	77
	Unrestricted Solar	66		62	61	57	58	67	60	60	53
	IC Limits	90	84	87	83	81	82	95	88	81	75

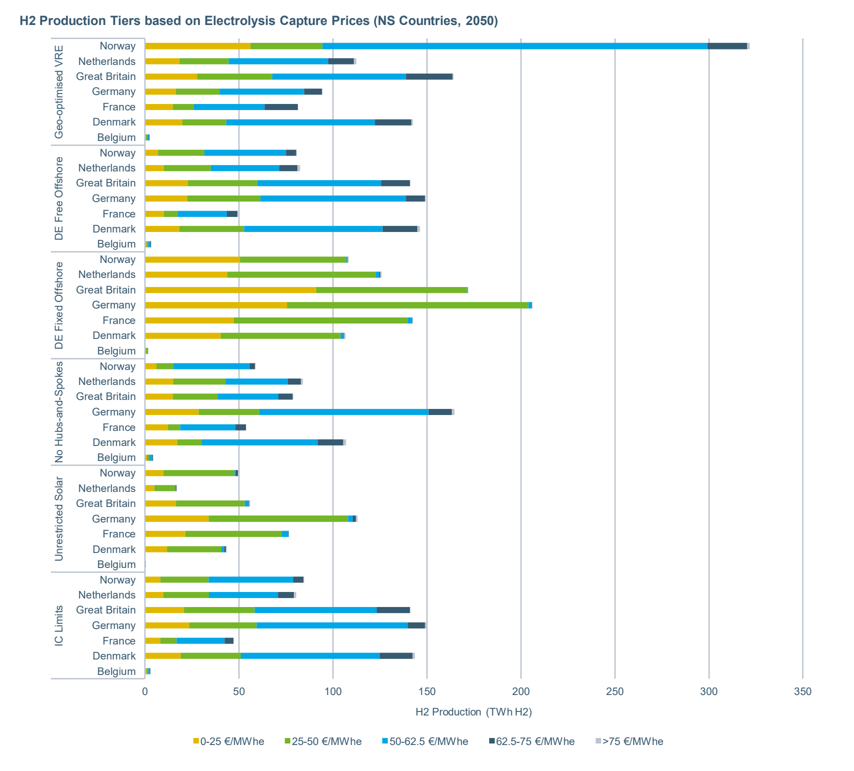
Note: The illustrated LCOHs consist annual weighted averages across modelled regions and timesteps. A fluctuation of those is experienced on an hourly level, due to system dynamics, therefore making local generation cost competitive to H2 imports from North Africa:
- Pipeline imports: 81 €/MWh (2030), 62 €/MWh (2040), 51 €/MWh. - Shipping imports: 108 €/MWh (2030), 88 €/MWh (2040), 77 €/MWh (2050).
The listed LCOHs represent the LCOH of the year specific technologies only. For example, LCOHs in 2050 represent the costs of a 2050 technological maturity.

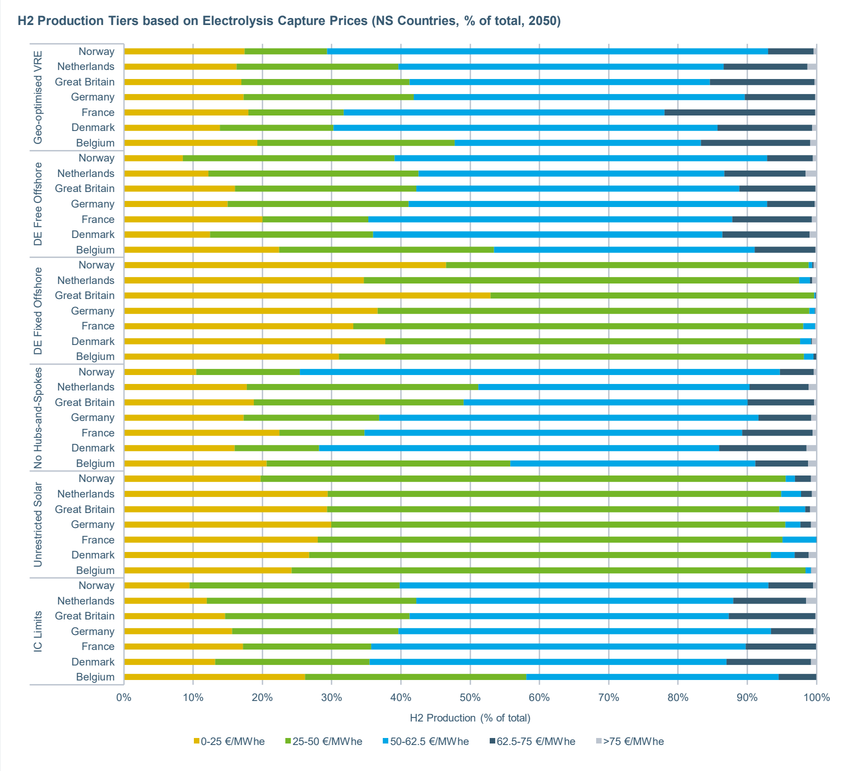
Electrolysis FLHs

Year	Technology	Geo-optimised VRE	DE Free Offshore	DE Fixed Offshore	No Hubs-and-Spokes	Unrestricted Solar	IC Limits
2030	30-39 Onshore	4,117	3,914	3,870	3,933	3,985	3,914
	30-39 Offshore			4,537			
	Overall	4,117	3,914	3,870	3,933	3,985	3,914
2040	40-49 Onshore	3,570	3,769	3,990	3,739	3,406	3,751
	40-49 Offshore	5,403	5,295	5,678	5,095	5,913	5,172
	40-49 Overall	3,796	3,900	4,136	3,851	3,407	3,866
	Overall	3,389	3,423	3,638	3,391	3,210	3,407
2050	50 - Onshore	4,484	4,969	5,433	4,869	4,222	4,964
	50 - Offshore	6,406	6,188	5,994	5,782		6,207
	50 - Overall	4,578	5,079	5,531	4,939	4,222	5,074
	Overall	3,202	3,336	3,952	3,218	3,193	3,311

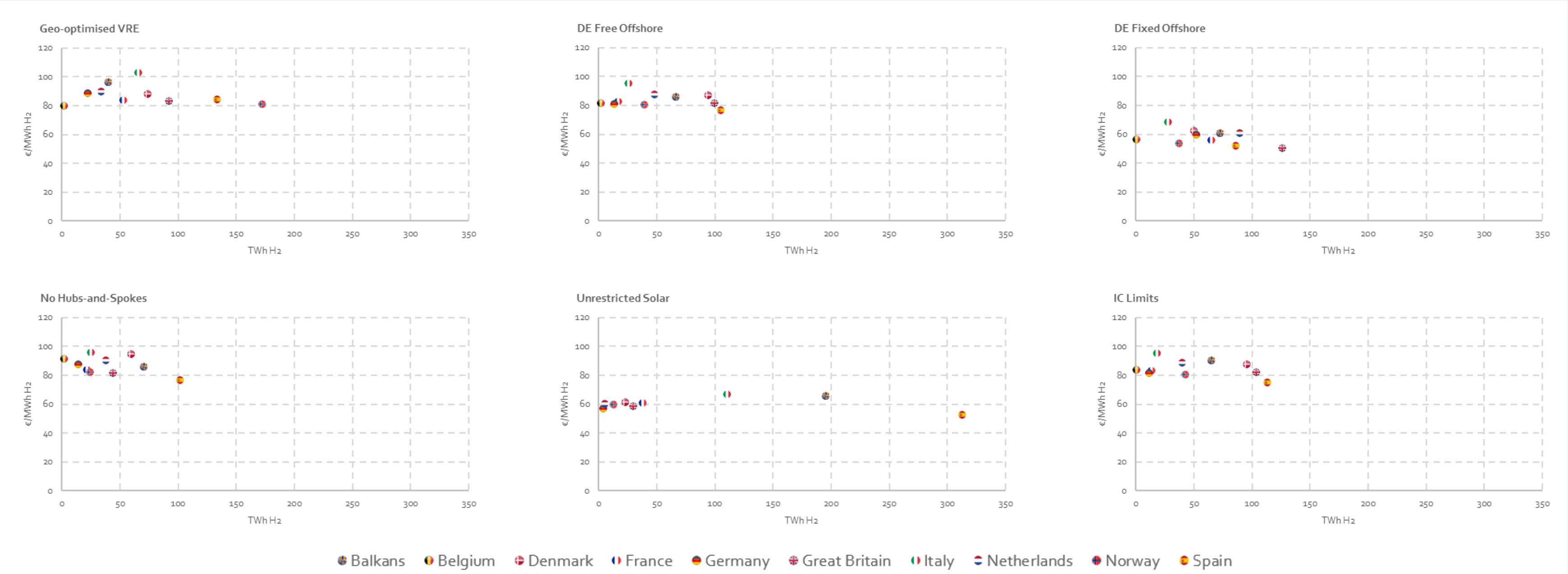
Note: The illustrated FLHs consist annual weighted averages across modelled regions and timesteps.
A fluctuation of those is experienced across installed units among regions.

H_2 production from North Sea countries ranges between 66% (Geo-optimised VRE) and 22% (Unrestricted Solar) of the total European generation. Production during electricity price hours <50 €/MWhe accounts for at least 38% of the total





The average annual production cost of Hydrogen across the most VRE dominated countries does not surpass 3.0 €/kg H_2 (~90€/MWh H_2) in 2050 in all sensitivities. A negative correlation between the produced H_2 quantities and the production costs is evident



The powerhouses of Europe change according to each Pathway. Electrolysis centres follow the adjusted VRES siting

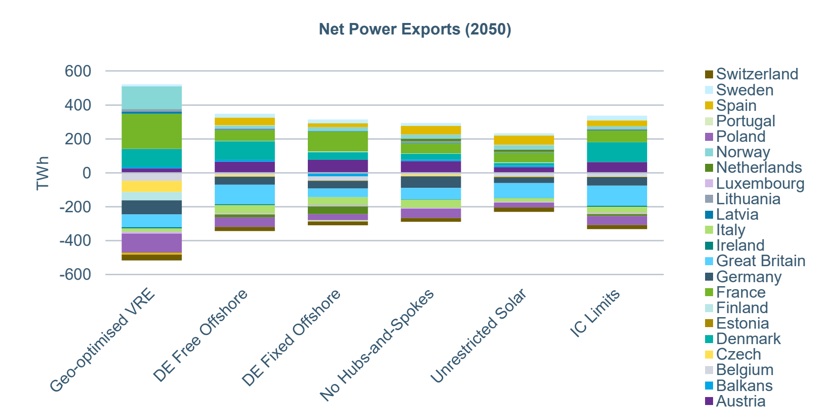
2 main south-to-north corridors are identified, bringing power and H2 to central Europe and 1 Nordic corridor aiming to support the high Polish but also German and Dutch demands. Those corridors are partially supported by inflows from south-eastern countries. Great Britain emerges as a major power sink across all pathways, benefiting from the deployment of hubs-and-spokes, while also heavily utilising existing power lines to NO, DK, FR, BE, NL and DE (CFs: 65-85%).

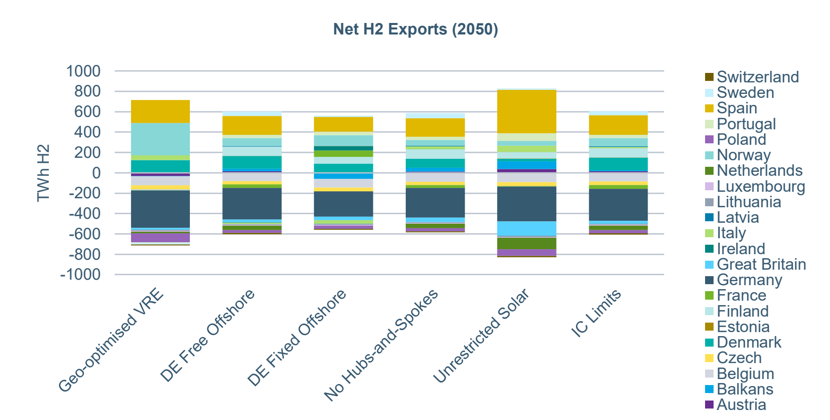
Nordic countries and Spain are the main power and H2 exporters for the modelled geography across most scenarios. France and Austria also strongly contribute to power exports.

H2 pipeline investments are located around regions with heavy VRES deployment. North African pipeline imports to Spain and Italy (cap of 263 TWH H2) don't surpass the local H2 demands, thus no extreme pipelines are developed towards the north to circulate external pipeline imports.

A small international offshore H2 network emerges in some pathways, connecting Great Britain to Norway & Belgium and Denmark with Germany. Most of the connections are utilised to a similar extent towards both directions.

On the whole, northern regions develop power transmission to take advantage of the strong central European system, converting power to H2 in the target countries, while the south utlises H2 transmission to export energy to central Europe, benefiting from the existing hydrogen backbone and lower deployment cost of hydrogen networks.

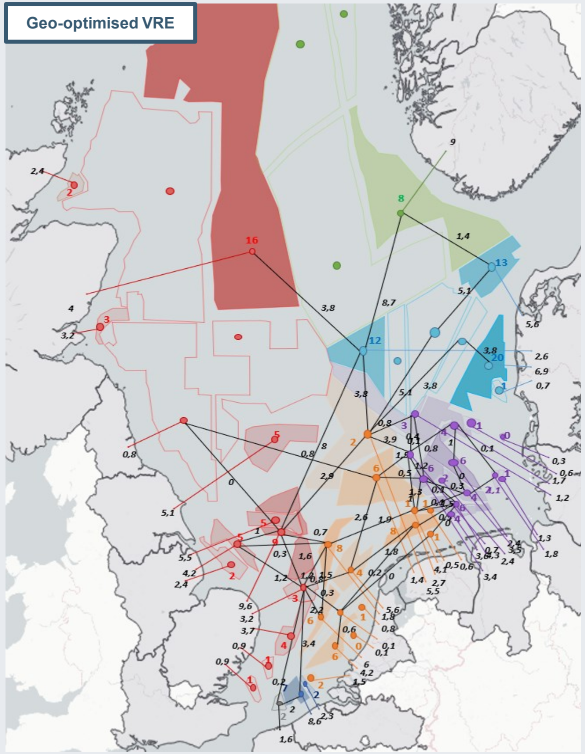


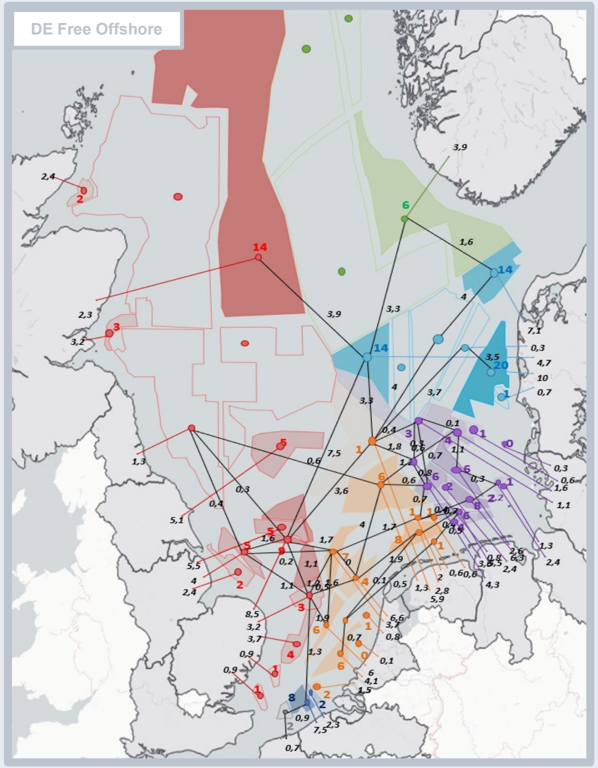


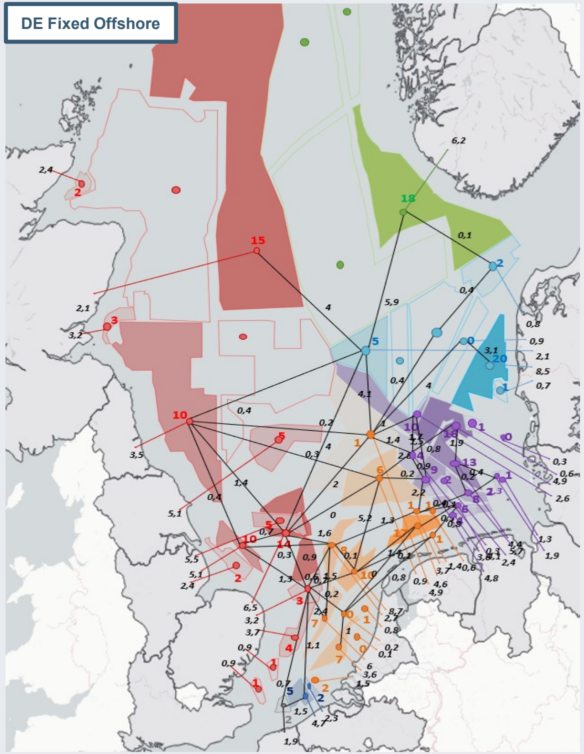
Note: Negative values correspond imports.

Overview of offshore transmission corridors, 2050 (1/2)

Line values: Power transmission capacity (GW)
Region values: Offshore wind capacity (GW, rounded)

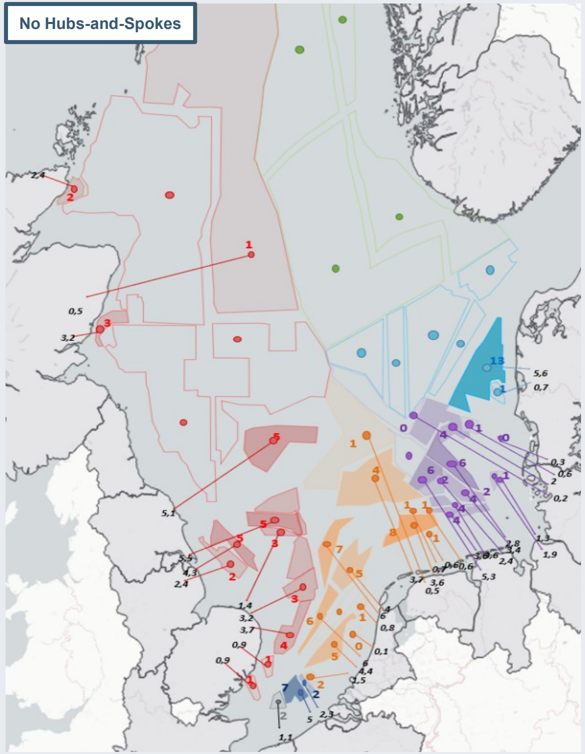


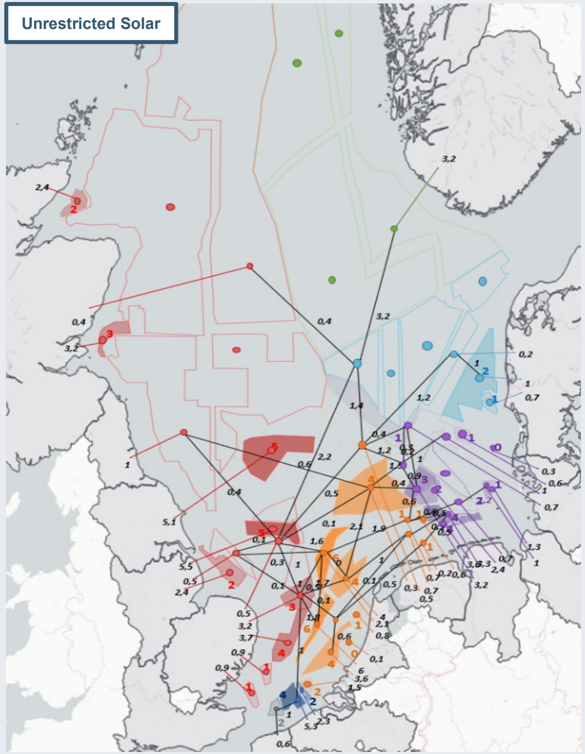


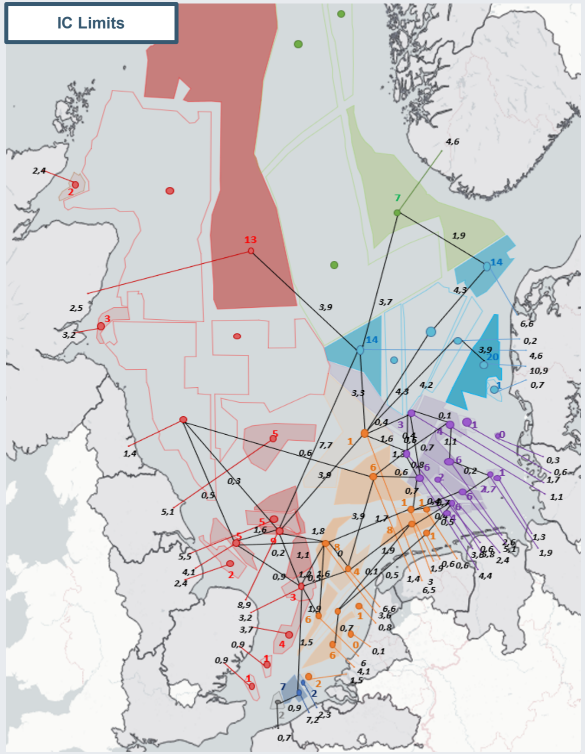


Overview of offshore transmission corridors, 2050 (2/2)

Line values: Power transmission capacity (GW)
Region values: Offshore wind capacity (GW, rounded)







Appendix IV – Further Insights

Electricity Demand

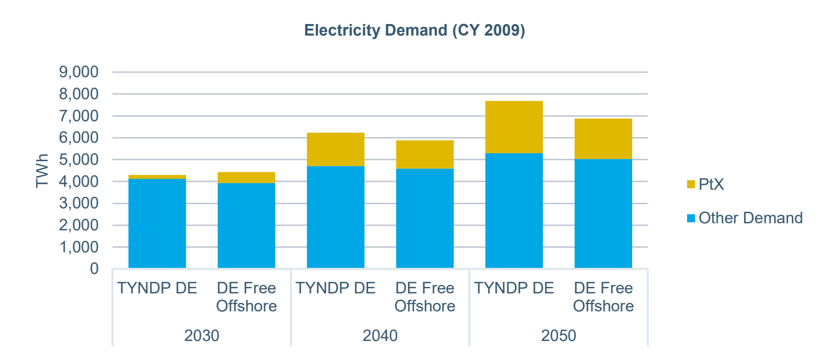
Pathway 2.0 vs TYNDP Distributed Energy (DE)

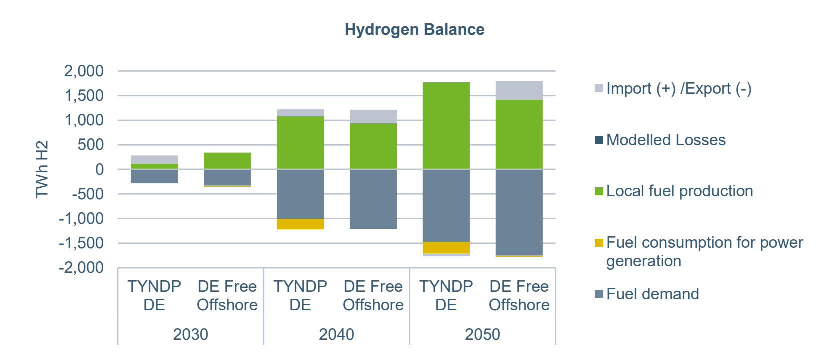
The **resulting electricity demand in Pathway 2.0 vs the TYNDP Distributed Energy scenario** can be seen on the right. Note that the PtX bar reflects the amount of electricity for European hydrogen production and does not account for external H2 import.

The TYNDP DE scenario has a higher locally served electricity to PtX demand (~+537TWh), mainly due to lower levels of H2 imports (higher self sufficiency):

- ***TYNDP includes approximately 240TWh H2*** *or about 350TWh electricity in 2050* ***towards power generation****, 8 times of that of the present Pathway 2.0 scenario.*
- ***Different levels of external H2 imports*** *and differences in electrolysis efficiencies cover the rest, when accounting for the different levels of assumed fuel demands.*
- *Minor demand level differences may be attributed to data aggregation of TYNDP's NUTS 1 data.*

Demand comparison to TYNDP serves the purpose of upcoming generation graph differences.





Notes: *Electricity to PtX quantities in Pathway 2.0 are approximated on the basis of the respective year's PEM electrolysis LHV efficiencies (2030 – 70.0%, 2040 – 75.5%. 2050 – 79.0%).* The Hydrogen Balance figure sets side by side results for TYNDP EU27 countries against the whole model geography of the present study. UK, Norway, Switzerland, Albania, Serbia, Montenegro, North Makedonia, Bosnia Herzegovina and Kosovo are additionally included in the "DE Free Offshore" figures. The TYNDP DE scenario H2 balance is based on rough approximations via publicly available TYNDP data. The electricity for H2 production and the total fuel demand come from raw data, while the import is estimated based on the difference. TYNDP DE import assumptions (Total Potential) are 259 TWh H2 from North Africa, and 217 TWh H2 from Norway.

Note: CY 2009 reflect the analysed data of TYNDP DE. DE Free Offshore represents climate year 2012.

Demand Breakdown

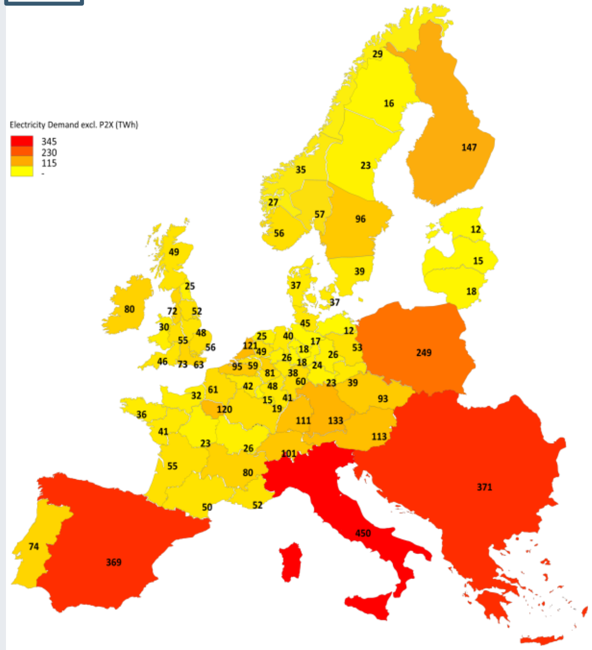
	Electricity excl. hydrogen (TWh)			Hydrogen (TWh H2)		
Country	2030	2040	2050	2030	2040	2050
Modelled Geography	**3,851**	**4,491**	**4,928**	**331**	**1,202**	**1,750**
Austria (AT)	88	101	110	6	25	33
Balkans (BK)	291	343	369	33	125	165
Belgium (BE)	102	120	134	7	54	86
Czech Republic (CZ)	70	83	91	7	28	37
Denmark (DK)	56	64	70	2	9	17
Estonia (EE)	10	11	12	1	2	3
Finland (FI)	116	139	144	6	24	39
France (FR)	524	580	624	31	47	80
Germany (DE)	693	785	860	93	330	448
Great Britain (GB)	381	496	557	30	120	183
Ireland (IR)	58	69	78	3	10	16
Italy (IT)	339	401	443	38	153	208
Latvia (LV)	11	13	14	1	3	4
Lithuania (LT)	15	17	18	4	10	13
Luxembourg (LX)	9	15	15	1	6	8
Netherlands (NL)	181	217	250	21	71	124
Norway (NO)	158	177	196	0	1	2
Poland (PL)	182	208	245	25	60	87
Portugal (PT)	58	73	73	2	13	23
Spain (ES)	284	338	363	12	76	122
Sweden (SE)	147	155	164	7	28	38
Switzerland (CH)	80	89	98	1	6	11

Total Electricity Demand excl. P2X (TWh) – Mapping

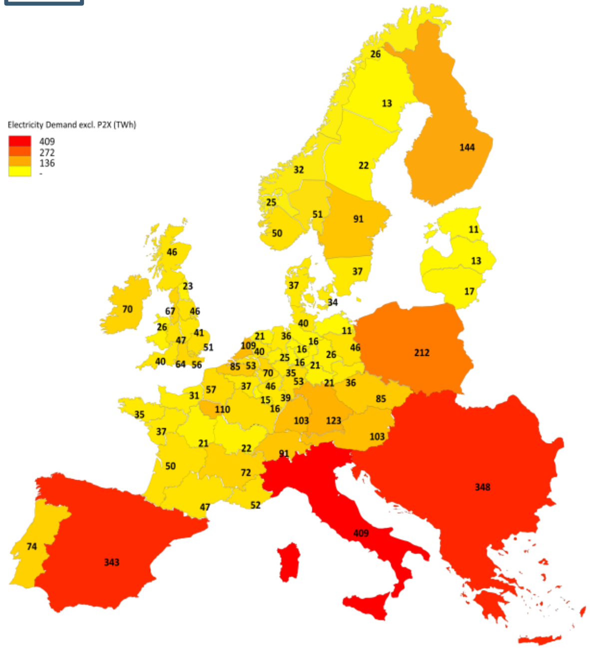
Main Electricity Demand Centres (2050):

DE: 872 TWh
FR: 635 TWh
UK: 573 TWh
IT: 449 TWh
NL: 254 TWh
ES: 368 TWh
PL: 249 TWh

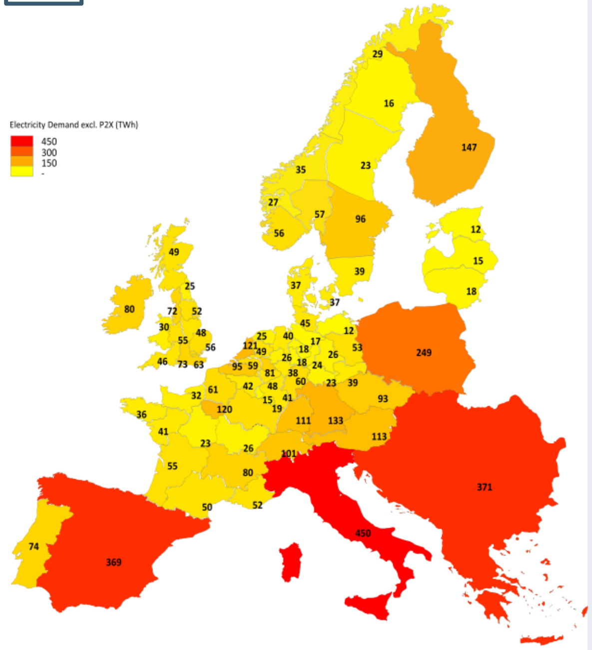
2030



2040



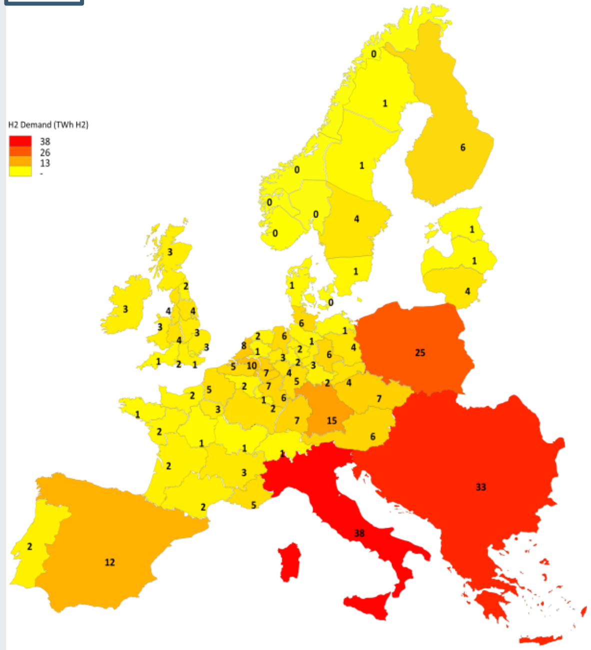
2050



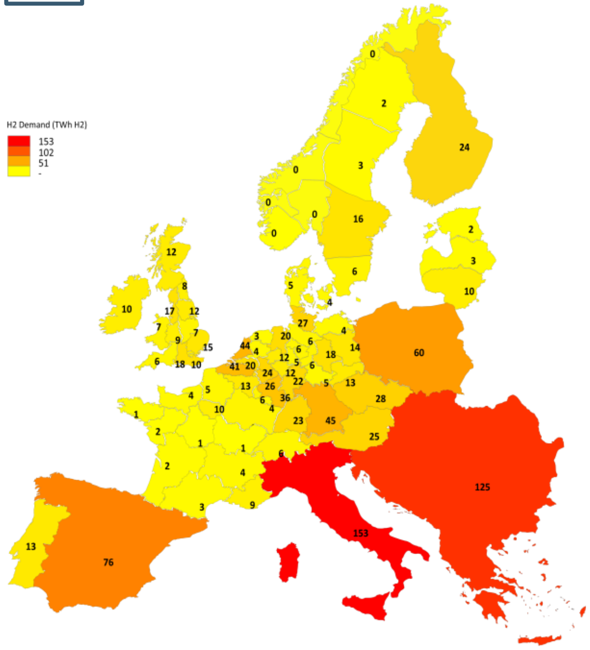
Total H_2 Demand (TWh_{H_2}) – Mapping

Main H_2 Demand Centres (2050):	DE: 448 TWh	IT: 208 TWh	ES: 122 TWh	FR: 80 TWh
	UK: 183 TWh	NL: 124 TWh	PL: 87 TWh	

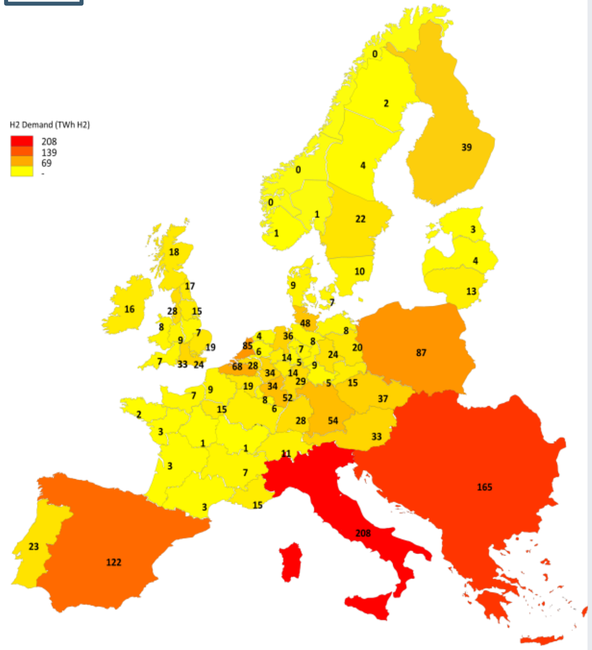
2030



2040



2050



Power Capacity & Generation

Pathway 2.0 vs TYNDP Distributed Energy
The current study (PW 2.0) bases central assumptions on ENTSO-E's Distributed Energy (DE-scenario) scenario yet shows important differences.

Important similarities in assumptions

- Same end demand for electricity and hydrogen
- Similar deployment of onshore wind and solar power (adjusted for differences in full load hours)

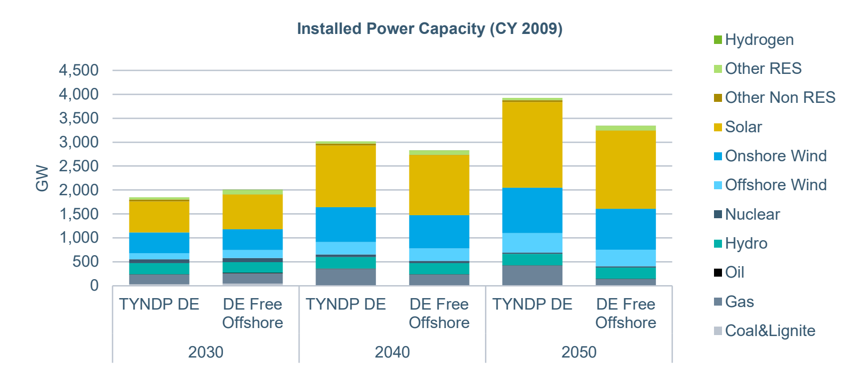
Important differences in assumptions

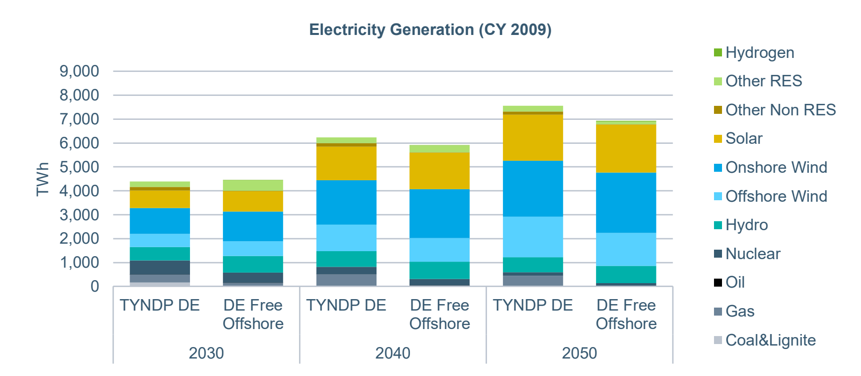
- VRE profiles and full load hours. The applied VRE profiles reflect higher full load hours for solar PV and onshore turbines against those in the DE-scenario. While the defined buildout does account for this difference by reducing the capacities, the resulting **power contribution from onshore WT and solar PV in Pathway 2.0 is higher by ~261TWh (6% of onshore VRE, 3% of total)**.
- Technology cost
- Power prices
- Model optimised buildout of offshore wind and flexibility measures (Electricity and hydrogen grids, electricity and hydrogen storage, backup power plants, electrolysers)
- Model optimised hub-to-hub connections (hubs-and-spokes) in the North Sea in the current study

As a result of the above, the scenarios differ on two main overall points:

- The pathway study shows higher amounts of imported hydrogen, reducing the need for local generation and thus reducing total European power generation compared to the DE-scenario. This is a result of the economic optimisation, showing especially lower buildout of offshore wind
- The pathway study shows lower amount of thermal based generation, especially gas. The current study applies the assumption, that marginal gas is priced based on fossil gas and CO2. TYNDP's DE-scenario shows a mix of different gases used for power generation, including biogas and synthetic gas. The pricing of these can be one reason for the different gas generation levels. Hydrogen based power generation is modelled separately from this.
- Other differences include resulting electrolyser and grid buildout. A full comparison of operational differences of the two systems has not been carried out.

Note: Hydrogen based electricity generation (bottom graph) reflects generated amounts from both newly installed (H2 G2P) and retrofitted natural gas units. The top graph, however, differentiate the capacities where Hydrogen values reflect only new units with the rest incorporated into the Gas category. Use of natural gas in the power mix is disallowed in 2050, while for coal and lignite already from 2040 and on.





Note: CY 2009 reflect the analysed data of TYNDP DE.
DE Free Offshore represents climate year 2012.

Total Onshore VRE Capacities Breakdown (DE Free Offshore)

	Solar PV (GW)			Onshore Wind (GW)		
Country	2030	2040	2050	2030	2040	2050
Modelled Geography	**729**	**1,258**	**1,642**	**433**	**699**	**852**
Austria (AT)	21	47	57	12	22	26
Balkans (BK)	60	113	177	44	84	109
Belgium (BE)	19	35	47	4	8	10
Czech Republic (CZ)	10	22	34	6	13	17
Denmark (DK)	17	35	49	5	5	7
Estonia (EE)	1	1	2	1	1	3
Finland (FI)	5	13	25	27	56	66
France (FR)	91	176	232	34	65	83
Germany (DE)	189	273	278	87	134	138
Great Britain (GB)	48	90	120	17	28	41
Ireland (IR)	2	5	6	7	13	13
Italy (IT)	86	148	204	20	26	30
Latvia (LV)	1	1	2	2	2	2
Lithuania (LT)	3	3	4	5	5	5
Luxembourg (LX)	1	1	3	0	0	1
Netherlands (NL)	54	78	109	7	9	10
Norway (NO)	0	0	0	21	22	23
Poland (PL)	9	20	40	25	46	66
Portugal (PT)	14	24	33	16	29	36
Spain (ES)	77	141	177	69	97	128
Sweden (SE)	13	22	32	23	31	36
Switzerland (CH)	6	9	11	1	2	2

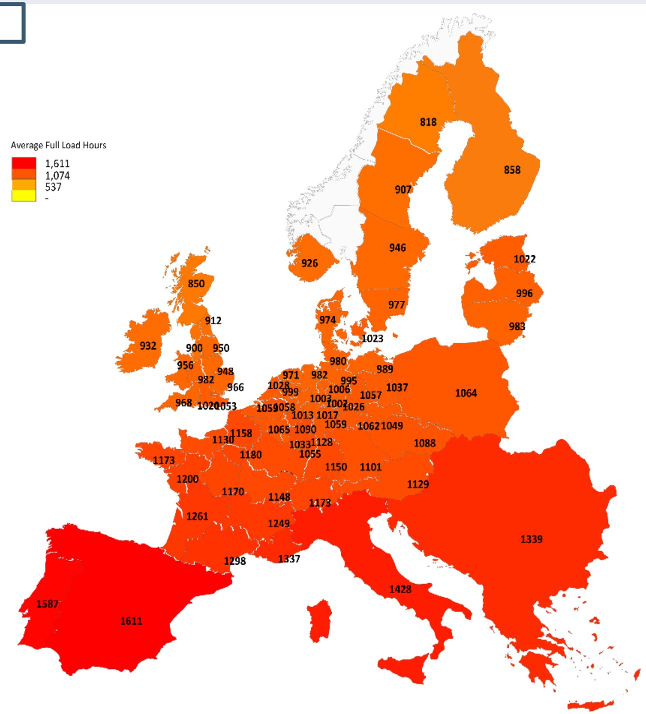
Total Power Generation and Flows (DE Free Offshore)

	Total Electricity Generation (TWh)			Total Net Power Exports (TWh, - is imports)		
Country	2030	2040	2050	2030	2040	2050
Modelled Geography	**4,427**	**5,880**	**6,886**			
Austria (AT)	143	215	241	44	64	66
Balkans (BK)	317	403	516	21	-7	12
Belgium (BE)	69	101	127	-34	-24	-14
Czech Republic (CZ)	60	82	92	-11	-3	-9
Denmark (DK)	94	218	373	15	38	109
Estonia (EE)	10	9	16	0	-2	-1
Finland (FI)	176	279	321	0	1	2
France (FR)	681	755	764	81	96	63
Germany (DE)	703	1,002	1,026	-68	-31	-46
Great Britain (GB)	405	508	639	-24	-81	-116
Ireland (IR)	61	89	93	-2	0	-4
Italy (IT)	315	419	487	-31	-57	-49
Latvia (LV)	16	19	30		2	4
Lithuania (LT)	21	32	33		9	7
Luxembourg (LX)	6	6	9	-6	-10	-7
Netherlands (NL)	241	290	345	35	4	-16
Norway (NO)	270	311	327	20	33	16
Poland (PL)	172	198	270	-14	-46	-57
Portugal (PT)	71	116	147	-2	-1	1
Spain (ES)	327	509	650	-16	7	46
Sweden (SE)	**199**	246	303	2	26	22
Switzerland (CH)	71	76	77	-11	-15	-24

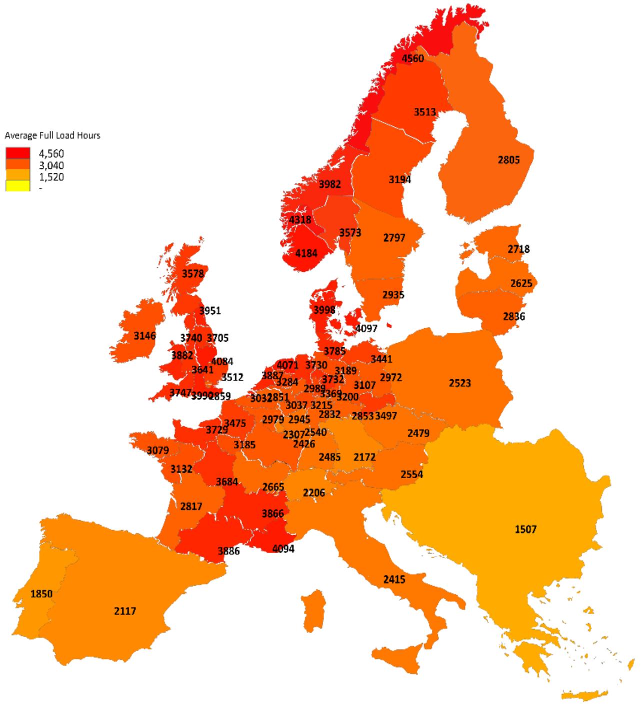
Onshore VRES Full Load Hours (2050)

Illustrated Full Load Hours represent the operation of the active fleet in the given year. Both utilised generation but also curtailment are included in the calculation. Regions with large numbers of older technologies in 2050 (pre-existing fleet or earlier investments in the simulated period) showcase lower FLHs that the FLHs that the marginal addition would experience in the specific year.

Solar PV



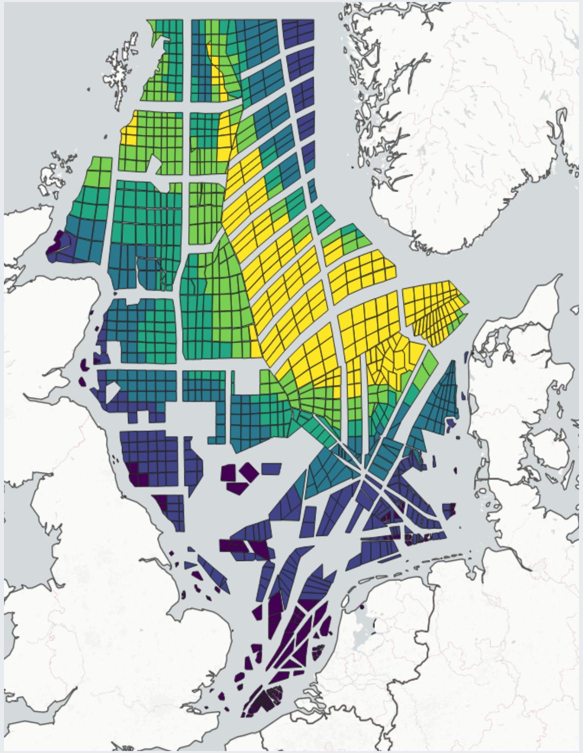
Onshore WT



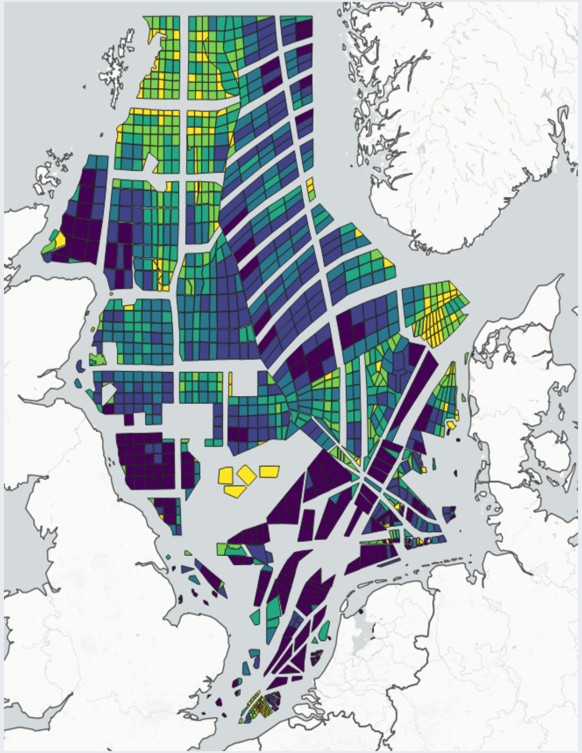
Notes: FLH shown only in places with respective installed tech capacities after the baseline run (Reasoning for e.g. blank solar in Norway). Results based on Geo-optimised VRE.

Resource Mapping – North Sea FLHs (2030)

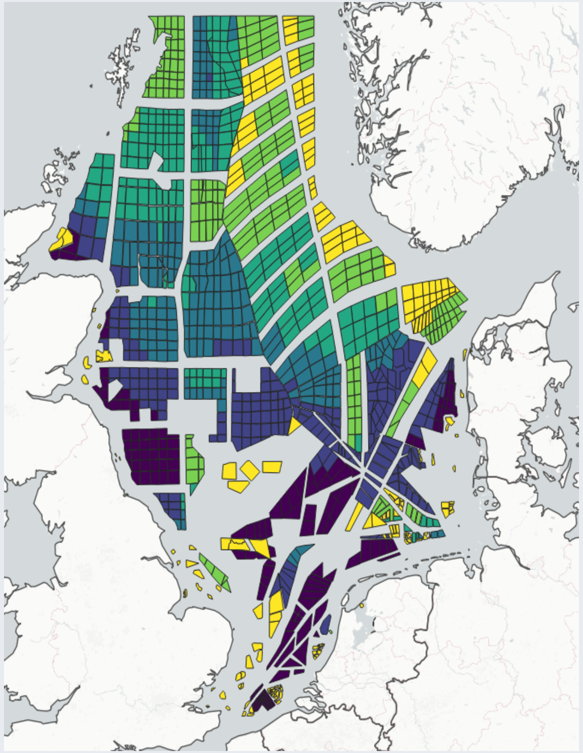
No Wake Losses



Engineering Wake Losses



Mesoscale Wake Losses



Notes: Data provided by the Technical University of Denmark (DTU Wind). Scales differ.

Cross-Scenario International Offshore Power Exchange (North Sea, 2050)

TWh	From	To	Geo-optimised VRE	DE Free Offshore	DE Fixed Offshore	No Hubs-and-Spokes	Unrestricted Solar	IC Limits
Offshore to Offshore	**Belgium (BE)**	**France (FR)**	-6	-4	-2	-	-5	-4
		Great Britain (GB)	-13	-4	-3	-	-3	-5
	Denmark (DK)	**Great Britain (GB)**	44	40	4	-	4	43
		Netherlands (NL)	45	42	26	-	4	45
		Norway (NO)	-3	2	-8	-	-3	4
	France (FR)	**Belgium (BE)**	6	4	2	-	5	4
		Great Britain (GB)	-0.2	-	-1	-	-	-
	Germany (DE)	**Netherlands (NL)**	11	13	40	-	4	12
	Great Britain (GB)	**Belgium (BE)**	13	4	3	-	3	5
		Denmark (DK)	-44	-40	-4	-	-4	-43
		France (FR)	0.2	-	1	-	-	-
		Netherlands (NL)	-21	-17	-1	-	-14	-19
	Netherlands (NL)	**Denmark (DK)**	-45	-41	-26	-	-4	-45
		Germany (DE)	-11	-13	-40	-	-4	-12
		Great Britain (GB)	21	17	1	-	14	19
	Norway (NO)	**Denmark (DK)**	3	-2	8	-	3	-4
Offshore to Home Landing Zone	**Belgium (BE)**	**Belgium (BE)**	-56	-46	-35	-38	-36	-45
	Denmark (DK)	**Denmark (DK)**	-83	-110	-70	-48	-13	-110
	France (FR)	**France (FR)**	-2	-3	-3	-5	-2	-3
	Germany (DE)	**Germany (DE)**	-126	-142	-169	-150	-75	-136
	Great Britain (GB)	**Great Britain (GB)**	-206	-201	-195	-160	-123	-203
	Netherlands (NL)	**Netherlands (NL)**	-176	-174	-200	-161	-105	-181
	Norway (NO)	**Norway (NO)**	-13	-8	-28	0	3	-10

Note: - signalises imports. Figures are rounded.

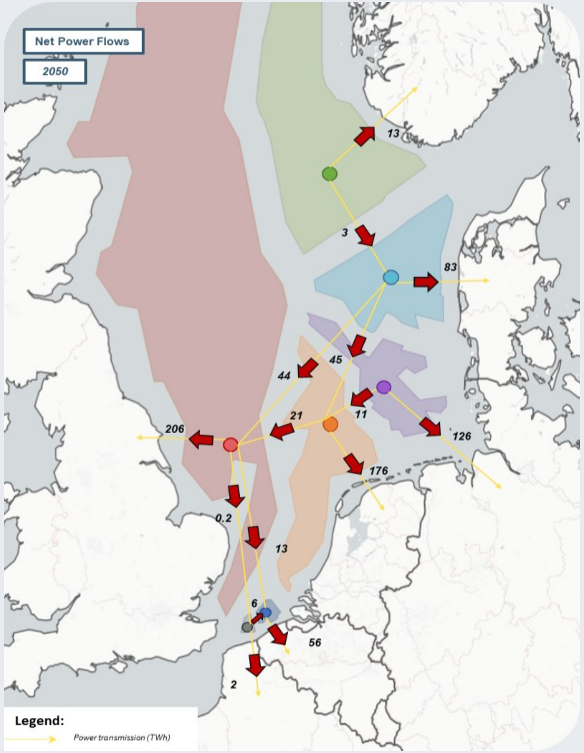
Cross-Scenario System Integration of North Sea Offshore Wind

Year	Side	Element	Geo-optimised VRE	DE Free Offshore	DE Fixed Offshore	No Hubs-and-Spokes	Unrestricted Solar	IC Limits
2030	Generation (TWh)	Generation[1]	435	455	470	438	448	455
		Electricity Imports[2]	24	20	21	3	21	20
		Curtailment	28	28	33	29	35	28
	Use Breakdown (%)	Export to Mainland[3]	88%	89%	88%	88%	90%	89%
		PtX Offshore Hubs[4]	0%	0%	0%	0%	0%	0%
		PtX Landing Zones[5]	12%	11%	12%	12%	10%	11%
2040	Generation (TWh)	Generation[1]	815	714	875	687	479	715
		Electricity Imports[2]	44	35	38	24	26	38
		Curtailment	27	26	53	27	24	28
	Use Breakdown (%)	Export to Mainland[3]	58%	66%	71%	65%	89%	67%
		PtX Offshore Hubs[4]	21%	15%	12%	15%	0%	14%
		PtX Landing Zones[5]	21%	19%	17%	20%	11%	19%
2050	Generation (TWh)	Generation[1]	1006	1011	1309	856	488	1006
		Electricity Imports[2]	50	45	46	24	25	46
		Curtailment	22	19	147	18	16	19
	Use Breakdown (%)	Export to Mainland[3]	56%	57%	59%	62%	88%	58%
		PtX Offshore Hubs[4]	20%	18%	21%	18%	0%	17%
		PtX Landing Zones[5]	24%	24%	19%	20%	12%	25%

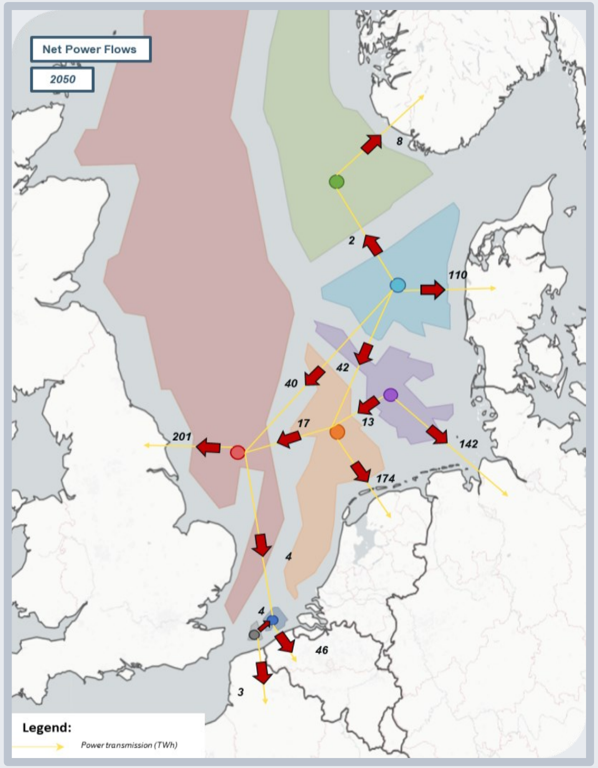
Note: (1): Reflects only offshore wind power generated in the North Sea (BE, DE, DK, FR, NL, NO, GB). (2): Flows from Mainland towards the North Sea Landing Zones. (3): Power flows from North Sea Landing Zones to Mainland. (4): Electricity use for offshore hydrogen production. (5): Electricity use for hydrogen production on North Sea Landing Zones. (3), (4) and (5) consist the % breakdown of the total (1)+(2).

Overview of NS Offshore Power Transmission, 2050 (1/2)

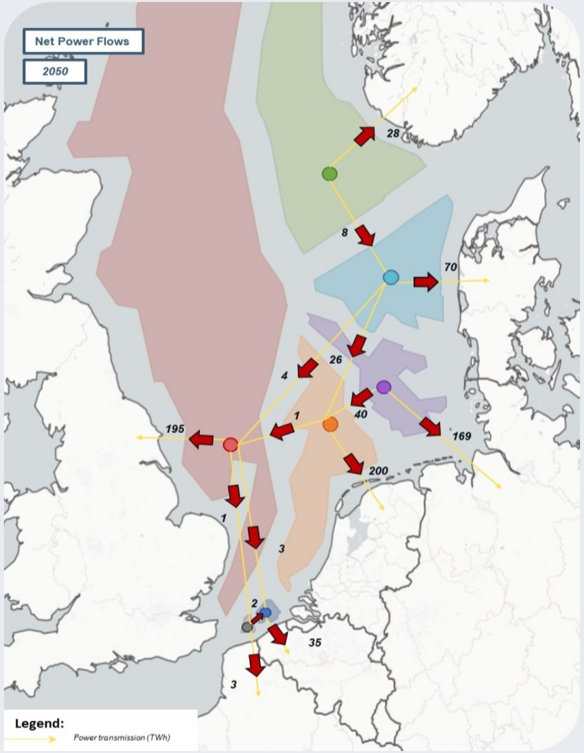
Geo-optimised VRE



DE Free Offshore



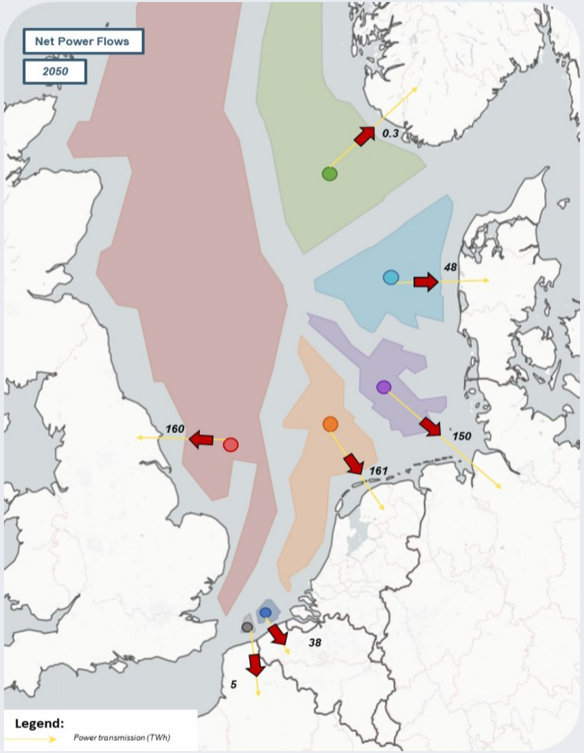
DE Fixed Offshore



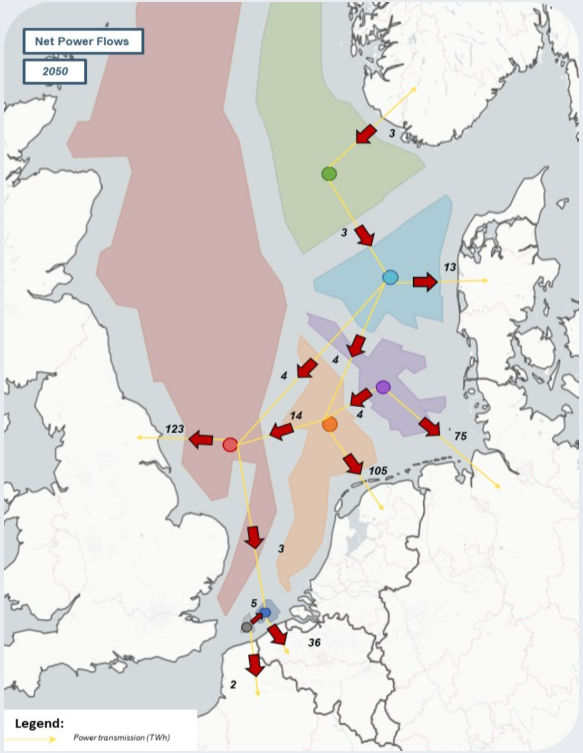
*Note:** The present figures are highly aggregated on a national level

Overview of NS Offshore Power Transmission, 2050 (2/2)

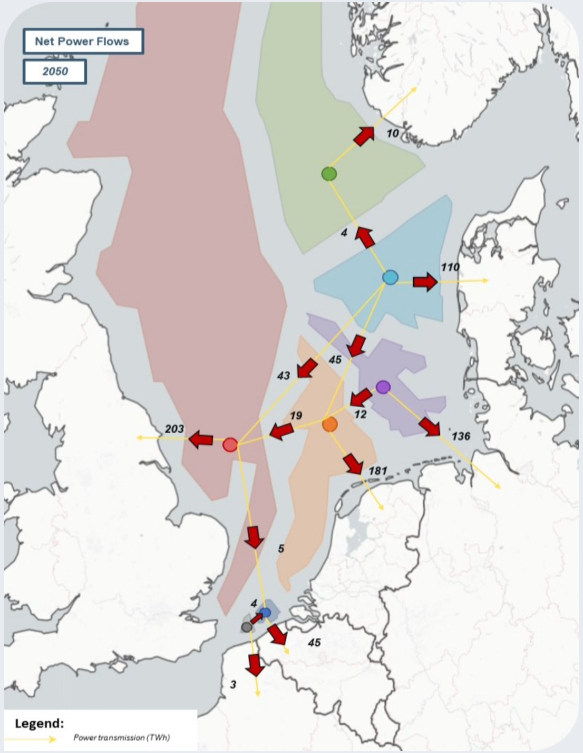
No Hubs-and-Spokes



Unrestricted Solar



IC Limits



***Note:** The present figures are highly aggregated on a national level.

Offshore electrolysers are cost-competitive to onshore for marginal hydrogen production

In 2030, there are no offshore electrolysers while 14 GWe is installed in landing zones. In 2040 however, there is 39 GWe installed in landing zones and 22 GWe offshore electrolysers, meaning that the costs are very close. Transitioning to 2050 capacities almost double, but the synergetic effects seem to be in favour of further additions of onshore electrolysers, harvesting the possible effects of a centrally fed electrolyser from multiple offshore sites. The landing zone electrolysers also have the advantage that it can be supplied by below 20 km radial offshore sites, which are not allowed to connect to other offshore hubs.

In the data assumptions, there is also an example of the relationship between onshore and offshore costs.

	2030			2040			2050		
Electrolysis (GWe, rounded)	Onshore (Inland)	Onshore (LZ)	Offshore	Onshore (Inland)	Onshore (LZ)	Offshore	Onshore (Inland)	Onshore (LZ)	Offshore
Modelled Geography	**112**	**14**	**-**	**318**	**39**	**22**	**458**	**70**	**38**
Austria (AT)	3			15			22		
Balkans (BK)				21			40		
Belgium (BE)								1	1
Czech Republic (CZ)							2		
Denmark (DK)	3	1		9	6	8	13	23	8
Estonia (EE)							1		
Finland (FI)	13			32			45		
France (FR)	17			29			33		
Germany (DE)	19	2		49	10	6	49	13	6
Great Britain (GB)	2	9		4	14	2	9	20	14
Ireland (IR)	1			6			6		
Italy (IT)				28			37		
Latvia (LV)	1			1			3		
Lithuania (LT)	3			2			3		
Luxembourg (LX)	1			1			1		
Netherlands (NL)	4	2		7	7	3	12	11	6
Norway (NO)	14			17		1	21	1	4
Poland (PL)				10			22		
Portugal (PT)	5			15			25		
Spain (ES)	18			58			90		
Sweden (SE)	8			13			24		
Switzerland (CH)									

Cross-scenario Summaries (2050)

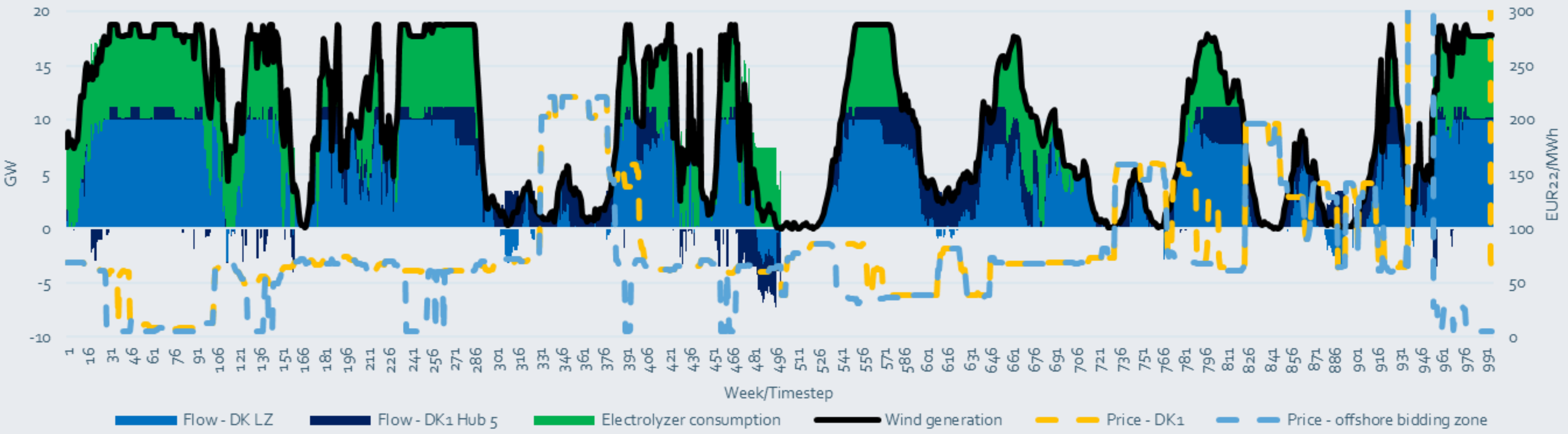
Element	Country	Geo-optimised VRE	DE Free Offshore	DE Fixed Offshore	No Hubs-and-Spokes	Unrestricted Solar	IC Limits
Offshore Wind (GWe)	Belgium (BE)	9	10	7	10	6	9
	Denmark (DK)	64	66	45	39	17	67
	France (FR)	7	7	65	7	7	7
	Germany (DE)	45	49	83	48	24	48
	Great Britain (GB)	75	73	112	65	45	72
	Netherlands (NL)	53	51	68	60	37	51
	Norway (NO)	20	18	30	14	12	19
	Rest	77	76	86	75	44	68
Offshore Electrolysis (GWe)	Belgium (BE)	0.2	1	-	1	-	1
	Denmark (DK)	11	8	7	11	0.1	7
	France (FR)	-	-	1	1	-	
	Germany (DE)	6	6	11	6	-	6
	Great Britain (GB)	14	14	15	6	-	13
	Netherlands (NL)	7	6	10	9	-	6
	Norway (NO)	4	4	8	1	-	4
	Rest	-	-	-	-	-	-
Onshore Electrolysis (GWe) [LZ & Within Grid]	Belgium (BE)	1 & -	1 & -	0.5 & -	1 & -	0.2 & -	1 & -
	Denmark (DK)	17 & 14	23 & 13	14 & 9	7 & 14	3 & 10	23 & 13
	France (FR)	- & 45	- & 33	- & 55	- & 34	- & 41	- & 34
	Germany (DE)	15 & 26	13 & 49	14 & 51	16 & 50	3 & 47	13 & 50
	Great Britain (GB)	27 & 13	20 & 9	21 & 15	15 & 8	11 & 8	21 & 9
	Netherlands (NL)	15 & 20	11 & 12	15 & 11	15 & 10	3 & 6	12 & 12
	Norway (NO)	- & 88	1 & 21	4 & 17	- & 20	- & 17	2 & 21
	Rest	- & 256	- & 321	- & 267	- & 321	- & 533	- & 318

Offshore Electrolyser Site Dispatch, DK Hub 6, 2050

The following graph shows the dispatch from DK Hub 6 (20 GW) in the first 1000 hours of the year. It appears that for hours below approximately 70 €/MWh the hub will opt for producing hydrogen instead of exporting electricity, showcasing the experienced cut-off price. When the price is above 70 €/MWh, the hub will export electricity instead of producing hydrogen.

Furthermore, there are some hours, where this hub actually imports electricity from both the neighbouring hub and from shore to produce hydrogen in around hour 481-496.

In the very last hours on the graph, hours 929 and forward, the DK1 bidding zone hits the price ceiling. The offshore bidding zone also hits the ceiling for a time, but as it regains full wind generation, a bottleneck is created, and the price is heavily reduced at 961 hours. Then this offshore hub shifts to producing hydrogen, even though the DK1 is still hitting the price ceiling.

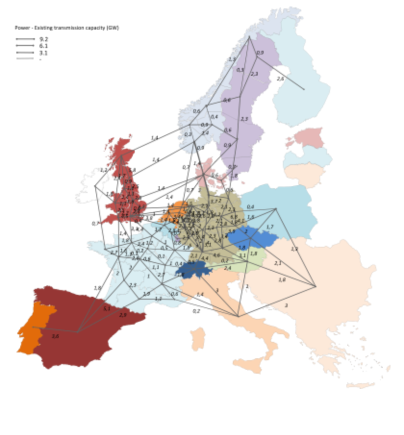


Onshore Power Grid Development: DE Free Offshore

Line values: Power transmission capacity (GW)

Region colours: Country borders

Existing Capacity



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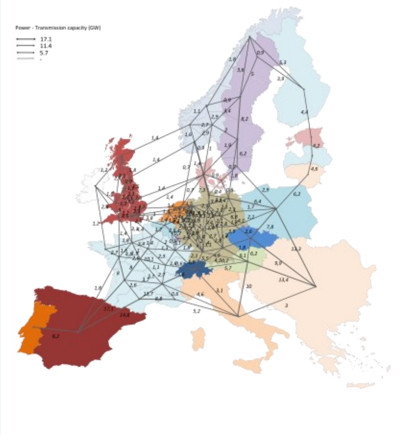
Total Capacity (2050)



Invested Capacity in 2030

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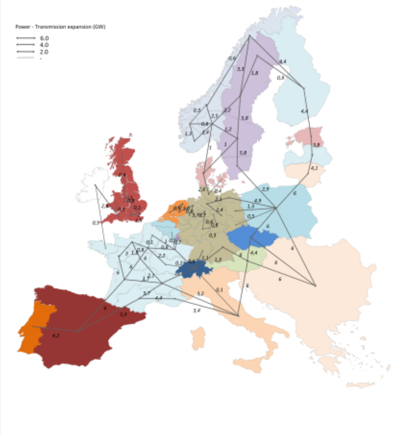
Invested Capacity in 2040



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Invested Capacity in 2050

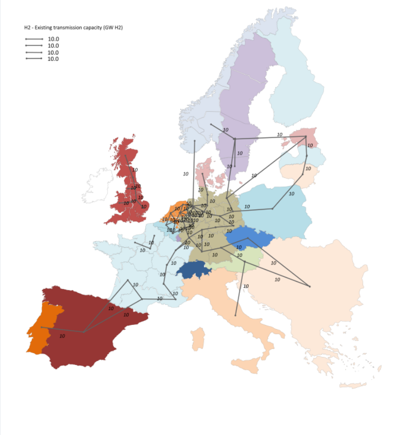
Note: Onshore power grid expansion cap per 10y: 6GW.

Onshore H_2 Network Development: DE Free Offshore

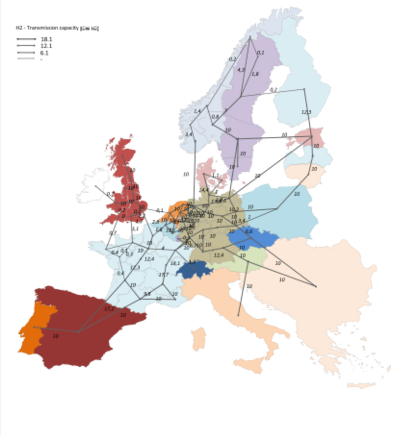
Line values: H_2 transmission capacity (GW_{H2})

Region colours: Country borders

Existing Capacity



Total Capacity (2050)



Invested Capacity in 2030

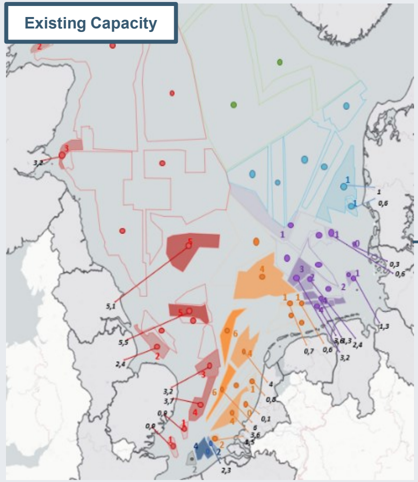
Invested Capacity in 2030

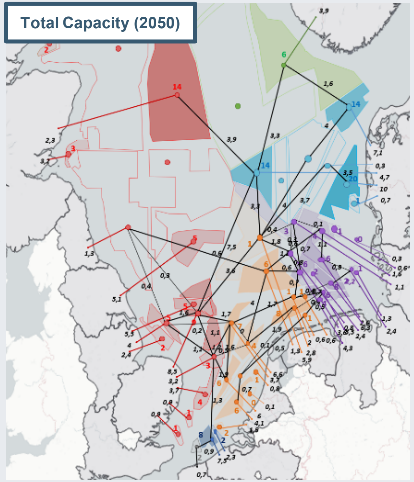
Invested Capacity in 2050

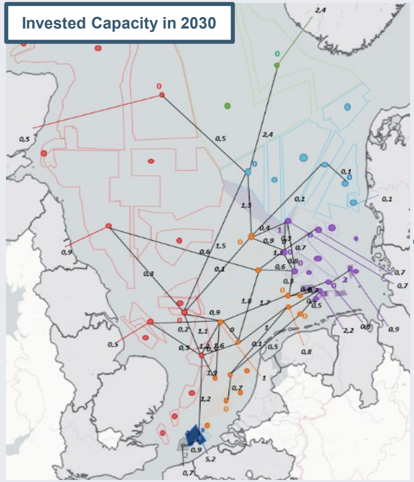
Offshore Power Grid Development: DE Free Offshore

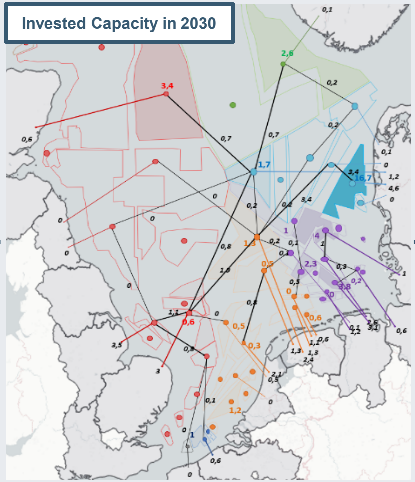
Line values: Power transmission capacity (GW)

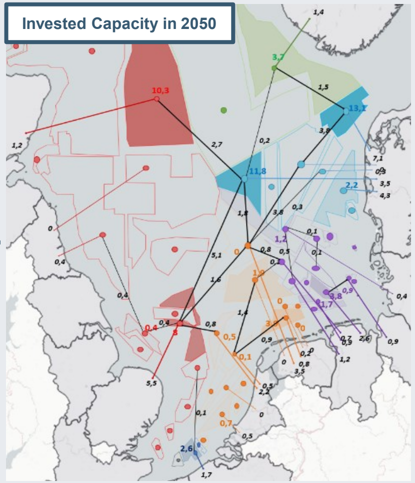
Regions values: Offshore wind capacity (GW, rounded)







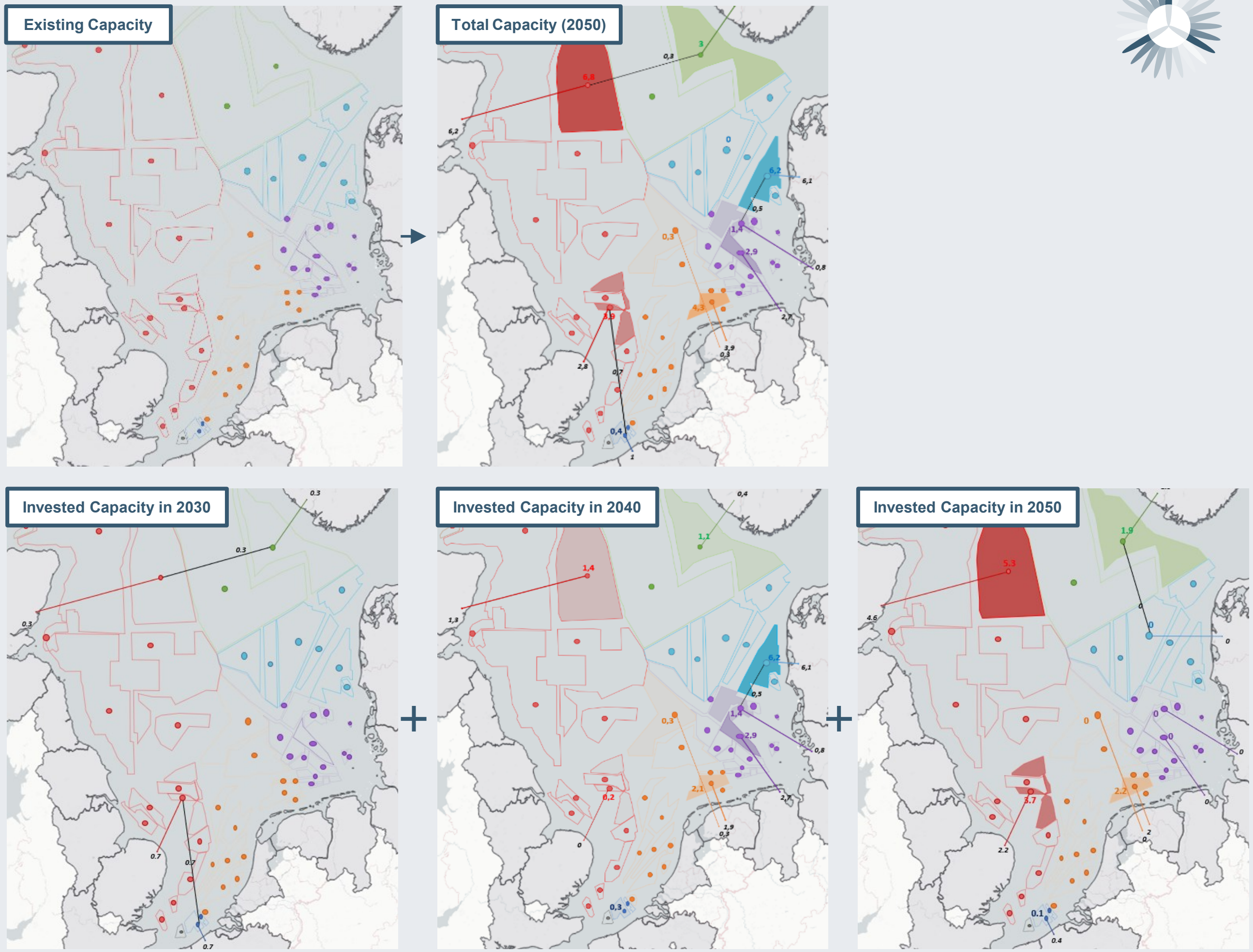




Offshore H_2 Network Development: DE Free Offshore

Line values: H_2 transmission capacity (GW_{H2})

Regions values: Offshore electrolysis capacity (GW_{H2}, rounded)



North Sea
Wind Power Hub
Programme

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