FRAUNHOFER INSTITUTE FOR WIND ENERGY SYSTEMS IWES

INTERNATIONAL SCENARIO CALCULATION FOR OFFSHORE WIND EXPANSION

–

REDUCTION OF POWER DENSITY IN THE GERMAN EEZ AND CROSS-BORDER RADIAL CONNECTION OF OFFSHORE WIND FARMS IN DENMARK AND SWEDEN

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Executive Summary

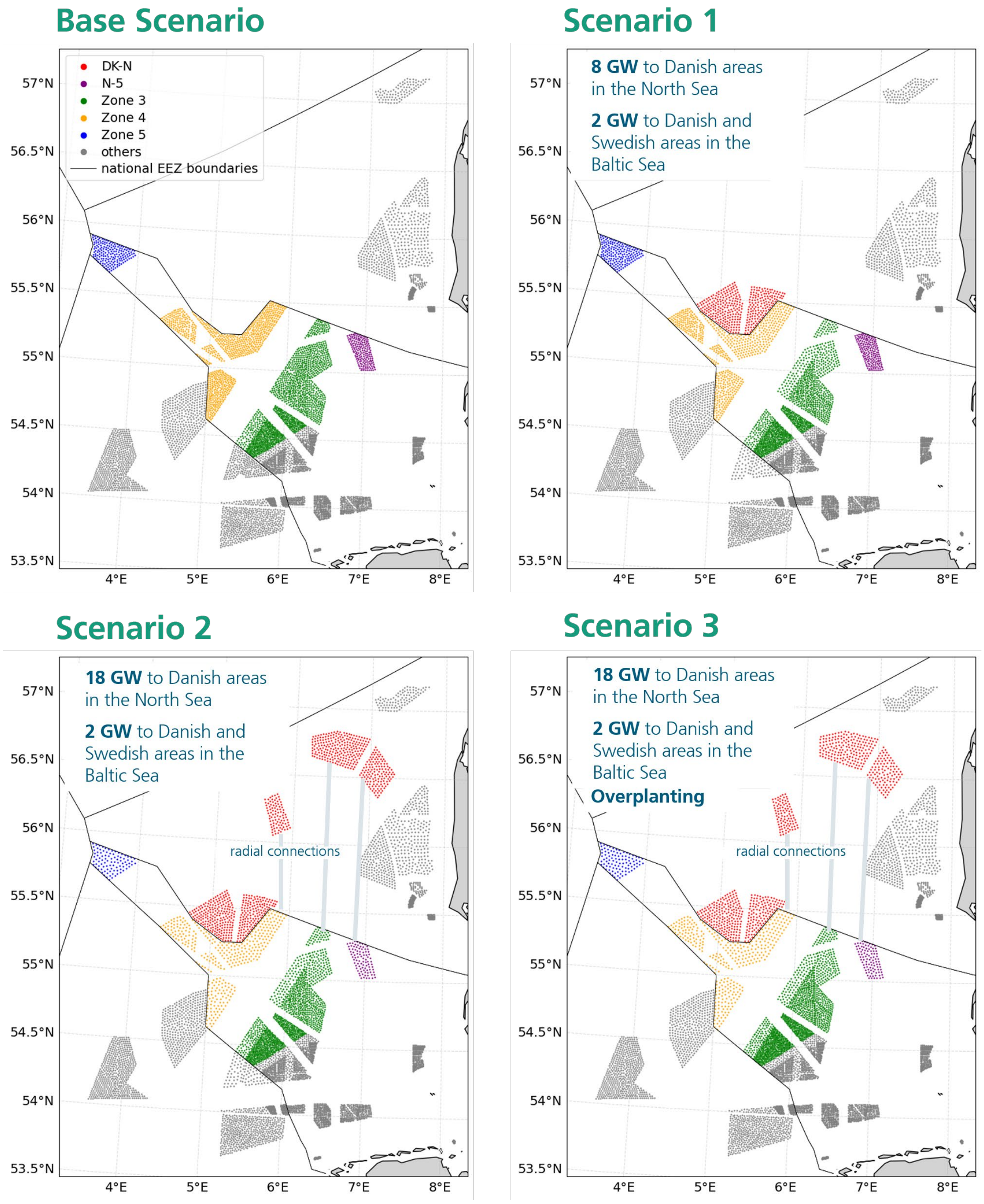

Figure I: Scenario overview of the offshore wind expansion. The images visualize the expansion in the North Sea. The expansion in the Baltic Sea in Scenarios 1 to 3 is shown in Figure 2-2 (Section 2.1).

This study investigates whether the systemic efficiency of offshore wind energy in the German Bight can be increased through an alternative spatial distribution of the future offshore wind expansion. The analysis is based on a reference scenario derived from Germany's Site Development

Plan 2025 draft (in German: Flächenentwicklungplan, FEP) with an installation target of 70 GW by 2045.

Building on this, three alternative scenarios are examined: two comparison scenarios with reduced power density in the German Exclusive Economic Zone (EEZ) and a shift of 10 and 20 GW, respectively, to Denmark and Sweden, as well as an overplanting scenario (based on the 20 GW scenario). The aim is a comparative assessment rather than the optimization of absolute indicators.

The scenarios were calculated using the mesoscale model WRF (weather year 2012) with respect to wind fields and energy yields. Subsequently, technical availability, O&M processes, and operating costs were simulated using the Fraunhofer IWES software OffshoreTIMES. Investment and grid connection costs were determined and allocated over an assumed operating lifetime of 35 years[1] to derive a cost index (cost per unit of electricity generated).

The results show that spatially shifting capacities to Danish and Swedish maritime areas can significantly increase total energy yield (approx. +6% in Scenario 1, +13% in Scenario 2, +8% in Scenario 3; see Table I). In Scenario 2 in particular, the slight increase in operating and grid connection costs is more than offset by higher yields in terms of the cost index. Although the overplanting scenario improves energy yield and grid utilization compared with the reference scenario, it lags behind Scenario 2 due to wake and curtailment losses. All three alternative scenarios exhibit a lower cost index than the reference scenario, with the lowest value found in Scenario 2 (see Table I).

The study thus demonstrates that cross-border spatial planning, while maintaining existing German expansion targets, can lead to macroeconomic efficiency gains.

Table I: Scenario overview of installed capacities, energy yield, full load hours and cost index for the different areas considered in this study.

	Base Scenario				Scenario 1				Scenario 2				Scenario 3			
	Capacity [GW]	Energy Yield [TWh]	Full Load Hours [h]	Cost Index	Capacity [GW]	Energy Yield [TWh]	Full Load Hours [h]	Cost Index	Capacity [GW]	Energy Yield [TWh]	Full Load Hours [h]	Cost Index	Capacity [GW]	Energy Yield [TWh]	Full Load Hours [h]	Cost Index
N-5	4	16.0	4000	0.840	4	16.2	4060	0.829	2	9.3	4650	0.729	2	9.4	4680	0.743
Zone 3	28	89.2	3190	1.106	24	79.8	3330	1.062	24	80.6	3370	1.052	26	82.8	3450	1.074
Zone 4	20	73.8	3690	0.939	14	54.9	3920	0.886	8	34.7	4340	0.803	8	33.3	4510	0.805
Zone 5	4	17.0	4260	0.862	4	17.0	4250	0.864	2	9.5	4760	0.778	2	9.6	4820	0.789
Total DE	56	196.1	3500	**1.000**	46	167.9	3650	**0.962**	36	134.1	3730	**0.946**	35	135.0	3820	**0.964**
DK-S-Baltic	-	-	-	-	2	8.9	4430	0.700	2	8.9	4430	0.700	2	8.9	4430	0.700
DK-N	-	-	-	-	8	31.4	3930	0.901	18	79.3	4390	0.829	15	68.4	4680	0.807
Total	56	196.1	3500	**1.000**	56	208.2	3720	**0.941**	56	222.3	3970	**0.894**	52	212.3	4080	**0.903**

[1] This is a theoretical value, that is currently discussed within the industry.

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1 Introduction

The aim of this study is to investigate whether the systemic efficiency of offshore wind energy use in the German Bight can be increased through an alternative spatial distribution of future offshore wind capacities. In doing so, the total installed capacity and the connection to the German electricity grid remain unchanged.

A reference scenario based on the expansion scenario calculations for the update of the Site Development Plan (SDP) serves as the baseline (Bundesamt für Seeschifffahrt und Hydrographie 2025). This reflects the further development of offshore wind energy in accordance with the current planning logic.

Building on this, comparison scenarios are examined in which selected capacities are relocated to neighboring maritime areas of Denmark and Sweden – as part of a possible offshore cooperation between the states. Germany's expansion target of 70 GW by 2045 is maintained in all scenarios; the wind farms continue to be connected radially to the German electricity grid. The analysis is thus conducted under constant boundary conditions and allows an isolated assessment of the effects of different spatial distributions, evaluating relative differences between the scenarios, for example regarding yield and cost efficiency.

The results therefore do not represent an absolute optimization but rather serve as a comparative decision-making basis for possible efficiency gains through cross-border spatial planning.

2 Methodology

The following approach was defined together with the study's steering committee to address the research questions.

Methodological Procedure

1. Definition and establishment of the relevant framework conditions
2. Establishment of the reference scenario as baseline
3. Definition of alternative international expansion scenarios
    - Scenario 1 – Moderate reduction of power density and shift of 10 GW to Denmark and Sweden
    - Scenario 2 – Strong reduction of power density and shift of 20 GW to Denmark and Sweden
    - Scenario 3 – Shift of 20 GW to neighboring countries including area-specific overplanting of grid connection capacities
4. Execution of simulation-based analyses
5. Comparison and evaluation of results using key performance indicators

Assessment Approach
The scenarios are evaluated using a cost index that compares the annual electricity yields to the associated investment and operating costs. A uniform study period of 35 years of operating lifetime [2] is applied for all areas. The electricity yields are determined using simulation and account for wake effects between existing and new wind farms. The detailed definition and formal calculation of the cost index are described in Section 5.2.

Key Research Questions
The analyses focus on the following aspects:

- What effects result from a reduced power density in the German EEZ, particularly regarding wake losses and energy yields?
- What additional costs arise from the connection of offshore wind farms outside the German EEZ to the German electricity grid?
- What macroeconomic effects arise compared to a purely national expansion planning?
- What macroeconomic effects can be achieved through area-specific overplanting of grid connection capacities (so-called "overplanting")?

The detailed design of the scenarios and all underlying assumptions are described in Section 2.1.

2.1 Scenario Calculations

Objective
The scenario calculations serve to comparatively assess the effects of different spatial distributions of future offshore wind capacities on yield and cost efficiency. The starting point is a reference scenario that reflects the expansion areas and capacities envisaged in the SDP Draft 2025. Building on this, three alternative scenarios are considered, in which the power density of future offshore wind farms in the German EEZ is reduced. The capacity no longer realized as a result is relocated to neighboring maritime areas in Denmark and Sweden for compensation.

The scenario specifications were defined within the scope of the research contract in consultation with the client. The motivation lies in investigating possible efficiency gains through lower spatial densities in the German Bight and through a cross-border spatial reallocation of offshore wind capacities.

The total installed capacity remains unchanged in all scenarios.

General Assumptions Applicable to All Scenarios

1. Weather year for yield calculations and availability simulations: 2012
2. Consideration of the other planned offshore wind projects in the EEZs of neighboring countries in Denmark and the Netherlands where there is a relevant influence. This considers the assumed fully expanded state (2045), as in the positions of the OWTs in the reference scenario and Scenario 1 (Figure 2-1) shown.
3. The spatial framework for offshore wind farms in the Netherlands and Denmark is taken from an earlier Fraunhofer IWES study on wind energy yields in the North Sea (Dörenkämper et al.

[2] Theoretical value, currently being discussed within the industry.

2025). The areas consolidated into the zone designated "DK-N" in Figure 2-1 and Figure 2-3, which were identified jointly with the Danish Energy Agency (DEA) and the Technical University of Denmark (DTU) and which Denmark has stated it does not require for its own expansion, and has already identified for possible radial connection to Germany, are used for the reallocation of capacities in Scenarios 1 and 2. The specific cable route alignments were determined by the accompanying advisory committee.

For the spatial framework in the Baltic Sea, the Danish and Swedish areas of Kriegers Flak were selected in close consultation with the consortium and planned with a total of 2 GW (see Figure 2-2).

4. 22 MW OWTs in future installed offshore wind farms in the zones/areas N-9.4, N-9.5, N-10, N-12 to N-20;
5. 15 MW OWTs in future installed offshore wind farms in the zones/areas N-3 to N-7 as well as N-9.1, N-9.2 and N-9.3
6. The basis for the cost model is the Fraunhofer IWES study "Evaluation verschiedener Weiterbetriebs- und Nachnutzungsszenarien von Offshore Windparks und Offshore-Netzanbindungssystemen in der Deutschen Bucht" (Lorenz et al. 2025)
7. In the calculations, the full expansion state for 2045 as specified by the clients of this study is used. This expansion state of 75 GW in total includes a decommissioning buffer of 5 GW, as currently planned by the BSH. Such a decommissioning buffer could ultimately be reduced through coordinated life extension concepts (Lorenz et al. 2025).
8. Existing wind farms whose areas have not yet been designated for repurposing continue operating until the end of the study period for simplicity, and decommissioning is not considered.

All assumptions (e.g. spatial frameworks, assumed turbine technology, wind farm layouts and cost assumptions) were agreed and/or specified with the client. As reference, the parameters from the study "Evaluation verschiedener Weiterbetriebs- und Nachnutzungsszenarien von Offshore Windparks und Offshore-Netzanbindungssystemen in der Deutschen Bucht" (Lorenz et al. 2025), commissioned by BDEW and conducted by Fraunhofer IWES, were selected and confirmed.

Base Scenario

The base scenario maps the planned offshore wind energy expansion according to the Site Development Plan draft 2025 (see Figure 2-1, left). For newly constructed offshore wind farms, this results in an average power density of 10.2 MW/km². The base scenario thus describes the current planning basis and serves as a reference for the evaluation of the alternative scenarios.

Scenario 1 – Moderate Reduction of Power Density

In Scenario 1, the average power density of newly constructed offshore wind farms is reduced to 8.4 MW/km². The reduction in capacity takes place exclusively in Zones 3, 4 and 5. Already auctioned areas remain unchanged; similarly, the capacities of areas N-10.1, N-10.2 and N-9.5 are not adjusted (see Figure 2-1, right). Additionally, the capacity of the designated but not yet tendered Dutch areas Doordewind I and II, which border directly to the southwest of the German areas N-6 and N-9, is reduced from a total of 4 GW to 2 GW, in order to investigate the cross-border effects of a reduction in power density in this area.

The capacity freed up by the lower power density is relocated to neighboring maritime areas. A total of 10 GW of offshore wind capacity outside the German EEZ is considered, of which:

- 8 GW in the Danish North Sea
- 2 GW in the Baltic Sea (Danish and Swedish areas)

The aim of the scenario is to analyze the effects of a moderate easing of area utilization on energy yield and cost structure.

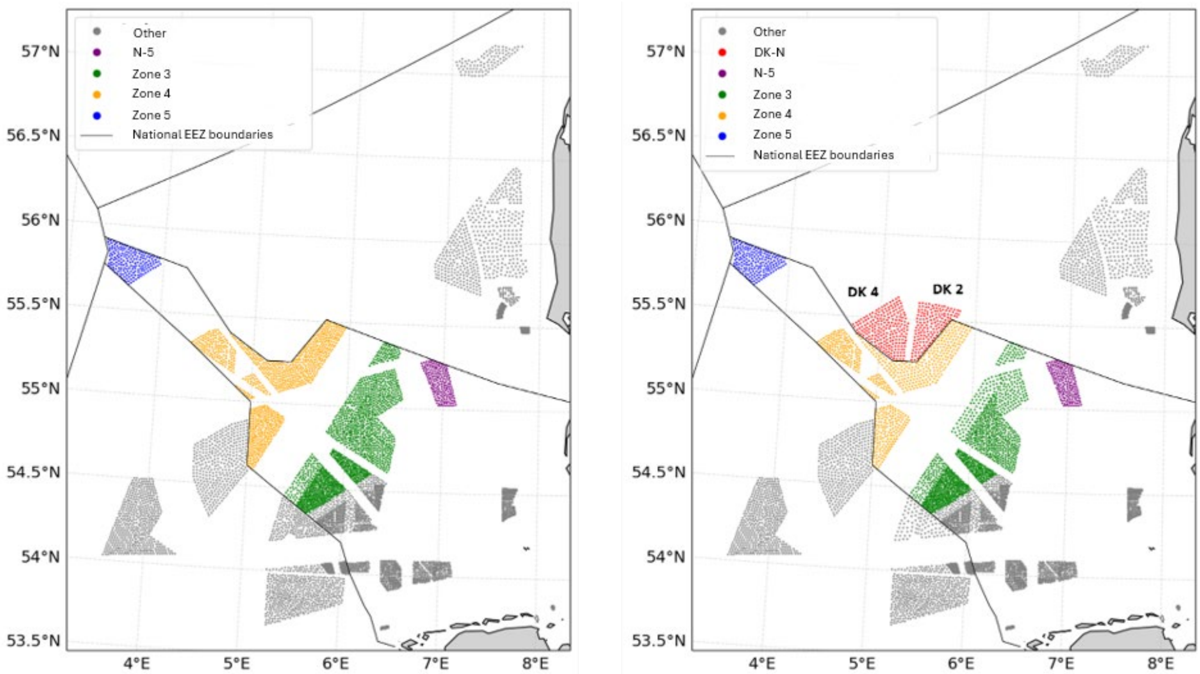

Figure 2-1: Positions of OWTs included in the base scenario (left) and Scenario 1 (right) in the North Sea. Zones 3, 4 and 5 from the Site Development Plan and cluster N-5 are color-coded. The boundaries of the German EEZ and those of neighboring states are also shown.

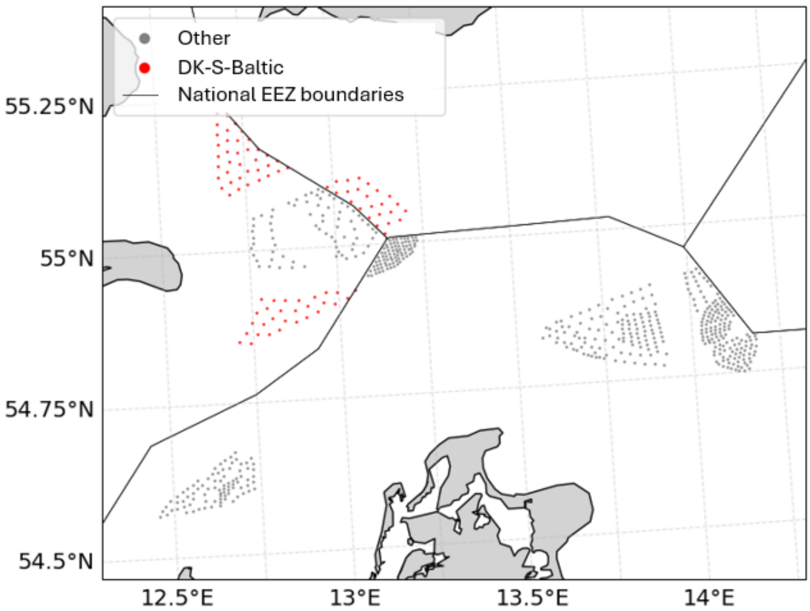

Figure 2-2: Representation of the positions of OWTs installed in Scenarios 1 to 3 in the Baltic Sea. OWTs installed in Denmark and Sweden but connected to the German grid are color-coded. The boundaries of the EEZ of Germany and the neighboring states are also shown.

Scenario 2 – Strong Reduction of Power Density

In Scenario 2, the average power density of newly constructed offshore wind farms in the North Sea is reduced to 6.6 MW/km². Here too, the reduction takes place only in Zones 3, 4 and 5; already auctioned areas and areas N-10.1, N-10.2 and N-9.5 remain unchanged (see Figure 2-3). The expansion in the Baltic Sea takes place as per Scenario 1.

A total of 20 GW of offshore wind capacity is shifted to neighboring maritime areas, of which:

- 18 GW to the Danish North Sea
- 2 GW to the Baltic Sea

This scenario serves to investigate the effects of a significantly stronger spatial easing of offshore wind utilization.

Scenario 3 – Shift of 20 GW to Neighboring Countries plus Overplanting

Scenario 3 combines the relocation of capacities with an additional area-specific overplanting of existing grid connections. The starting point for this is the spatial framework from Scenario 2. Additionally, the capacity of the two designated Dutch areas "Doordewind I" and "Doordewind II" is reduced to 0 GW, to investigate the effects of a further reduction in power density in this area.

The overplanting assumptions used are based on the results of a Frontier Economics study on the optimal overplanting of offshore wind grid connections (Janssen et al. 2026). The starting point was the reference areas examined there and the respectively determined economically optimal overplanting ratios. On this basis, Frontier Economics estimated in simplified form how the optimal overplanting can be classified based on two key area characteristics:

- Full load hours: In areas that already achieve high full load hours, the optimal overplanting is generally reached through a lower overplanting ratio.
- Distance from shore: The optimal overplanting tends to increase with greater distance from shore.

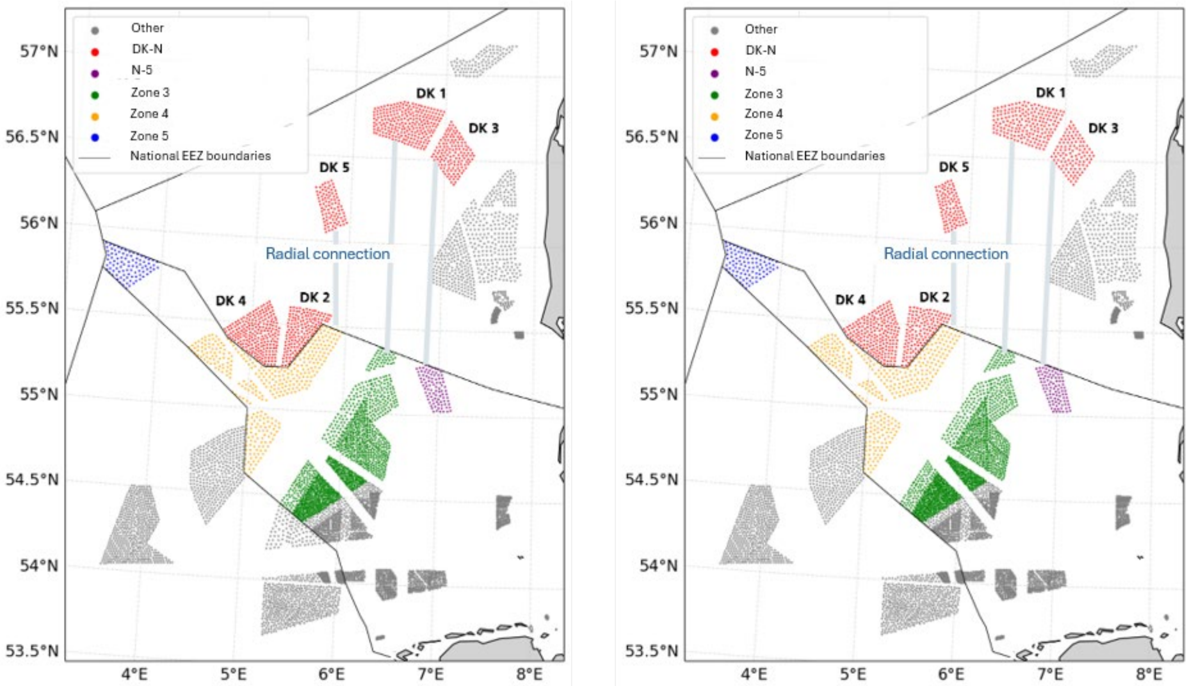

Figure 2-3: Illustration of the positions of the OWTs included in Scenarios 2 and 3. Zones 3, 4 and 5 from the Site Development Plan (offshore spatial development plan) as well as cluster N-5 and OWTs installed in Denmark but connected to the German grid are highlighted in color. The boundaries of Germany's EEZ and those of neighboring states are also shown.

Based on both factors, Frontier Economics approximated the range of optimal overplanting for the areas considered in this study. This simplified approximation does not consider all relevant influence factors. In addition to full load hours and distance from shore, the wind generation profile, wake/shading effects, CAPEX, OPEX, capital costs and electricity prices have a significant influence on the economically optimal overplanting. These factors were incorporated only via the basic assumptions of the Frontiers Economics study considered.

In this way, Frontiers Economics produced overplanting figures for the German offshore wind farms in Zones 3, 4 and 5 as well as area N-5 and the capacities relocated to Denmark in the zone "DK-N"/"DK-North Sea", which are used in the specifications for Scenario 3. For this purpose, these figures were further converted by Fraunhofer IWES into appropriate increments of the capacity of the respective turbine type used. No overplanting was applied in the Baltic Sea for Scenario 3.

The specifications (offshore wind farm capacities, power densities and offshore grid connection systems (OGCS) capacities) for the four scenarios are listed in Table 1 and Table 2. The presentation of the specifications has been split across two tables to maintain readability while simultaneously ensuring traceability of the key differences between the scenarios. The number of OGCS per area in those zones that have a different build-out state depending on the scenario is derived from the respective installed turbine capacity. Exclusively OGCSs with a feed-in capacity of 2 GW are used here.

Table 1: Tabular overview of the assumptions for the Base Scenario, Scenario 1 (reallocation of 10 GW of offshore wind energy capacity from the German North Sea to Danish and Swedish maritime zones) and Scenario 2 (reallocation of 20 GW to Danish and Swedish maritime zones). The total capacity in the Base Scenario of 75 GW in the German EEZ is specified in accordance with the expansion target of 70 GW plus a 5 GW decommissioning buffer (see Section 2.1).

		Base			Scenario 1		Scenario 2	
Area	**Zone**	**Capacity [GW]**	**Power Density [MW/km²]**	**OGCS Capacity [GW]**	**Capacity [GW]**	**Power Density [MW/km²]**	**Capacity [GW]**	**Power Density [MW/km²]**
N-5	**2**	4.0	10.1	4.0	4.0	10.1	2.0	5.1
N-9	**3**	7.7	10.3	7.5	7.7	10.3	7.7	10.3
N-10	**3**	2.5	13.7	2.5	2.5	13.7	2.5	13.7
N-11	**3**	3.5	9.3	3.5	3.5	9.3	3.5	9.3
N-12.1-3	**3**	5.0	10.1	5.0	5.0	10.1	5.0	10.1
N-12.4-6	**3**	4.0	9.3	4.0	2.0	4.6	2.0	4.6
N-13	**3**	5.5	9.9	5.5	3.5	6.3	3.5	6.3
N-14	**4**	6.0	10.4	6.0	4.0	6.9	2.0	3.5
N-16	**4**	10.0	9.1	10.0	6.0	5.5	4.0	3.6
N-17 + N-20	**4**	4.0	8.6	4.0	4.0	8.6	2.0	4.3
N-19	**5**	4.0	7.1	4.0	4.0	7.1	2.0	3.6
Total		**56.2**	**9.5**	**56.0**	46.2	**7.8**	36.2	**6.1**
Other German OWFs		18.9		18.9	18.9		18.9	
Total DE		75.1		74.9	65.1		55.1	
DK North Sea		0.0		0.0	**8.0**	5.2	**18.0**	5.2
DK + SE Baltic Sea		0.0		0.0	**2.0**	8.5	**2.0**	8.5
Total		**75.1**		**74.9**	**75.1**		**75.1**	
Doordewind I and II		4.0	7.3		2.0	3.6	2.0	3.6

Table 2: Tabular overview of the assumptions for Scenario 2 (shift of 20 GW to Danish and Swedish maritime areas) and the overplanting based thereon in Scenario 3. The stated overplanting refers to the ratio of OWF capacity to the respective OGCS capacity.

		Scenario 2			Scenario 3			
Area	**Zone**	**Capcity [GW]**	**Power Density [MW/km²]**	**OGCS Capacity [GW]**	**Capacity [GW]**	**Power Density [MW/km²]**	**OGCS Capacity [GW]**	**Development**
N-5	**2**	2.0	5.1	2.0	2.10	5.3	2.00	5.1%
N-9	**3**	7.7	10.3	7.5	8.11	10.8	7.50	8.1%
N-10	**3**	2.5	13.7	2.5	2.72	14.9	2.50	8.7%
N-11	**3**	3.5	9.3	3.5	3.80	10.0	3.50	8.5%
N-12.1-3	**3**	5.0	10.1	5.0	5.44	11.0	5.00	8.8%
N-12.4-6	**3**	2.0	4.6	2.0	2.13	4.9	2.00	6.4%
N-13	**3**	3.5	6.3	3.5	3.74	6.8	3.50	6.9%
N-14	**4**	2.0	3.5	2.0	2.12	3.7	2.00	6.2%
N-16	**4**	4.0	3.6	4.0	3.58	3.3	3.37	6.4%
N-17 + N-20	**4**	2.0	4.3	2.0	2.11	4.6	2.00	5.7%
N-19	**5**	2.0	3.6	2.0	2.11	3.8	2.00	5.7%
Total		36.2	**6.1**	36.0	37.97	**6.4**	35.37	**7.4%**
Other German OWFs		18.9		18.9	18.90		18.88	0.0%
Total DE		55.1		54.9	56.87		54.25	4.8%
DK North Sea		**18.0**		**18.0**	15.56		14.63	6.3%
DK + SE Baltic Sea		**2.0**		**2.0**	2.00		2.00	0.0%
Total		75.1		74.9	74.43		70.88	**5.0%**
DK Area - 1		5.1	5.2		4.02	4.1	3.78	6.2%
DK Area - 2		3.3	5.2		2.78	4.4	2.60	6.9%
DK Area - 3		3.0	5.2		2.35	4.1	2.22	6.0%
DK Area - 4		4.7	5.2		4.30	4.7	4.03	6.8%
DK Area - 5		2.0	5.2		2.11	5.5	2.00	5.3%
DK North Sea		18.1	5.2		15.56	4.5	14.63	6.3%
Doordewind I and II		2.0	3.6		0.00			

3 Generation of Wind Fields According to the Scenarios

The reference year 2012 was used for the calculation of the wind fields. This weather year has also been used in a joint study with several transmission system operators (Vollmer and Dörenkämper 2025). That study also includes a classification of weather year 2012, as well as a comparison with weather year 2006, which was used for example in the calculations for the Site Development Plan (Bundesamt für Seeschifffahrt und Hydrographie 2025). Under these conditions, the wind fields were calculated in accordance with the assumptions described in Section 2, using the mesoscale model WRF (Skamarock et al. 2019) with a wind farm parameterization, driven by the ERA5 reanalysis data for 2012 provided by the European Centre for Medium-Range Weather Forecasts (Hersbach et al. 2020).

From the scenario specifications (see Table 1), each scenario contained therein yields a build-out state which is calculated with WRF for a simulation period of one year in each case, to determine the energy yields under these conditions. The annual mean wind speeds at 100 m hub height for the various scenarios are shown in Figure 3-1.

The yields calculated in this way apply to uninterrupted plant and grid availability. Therefore, in the following step (see Section 4), technical failures and availabilities during operation are additionally determined by simulation. In this way, a more realistic and comprehensive picture of the expected yields can be established.

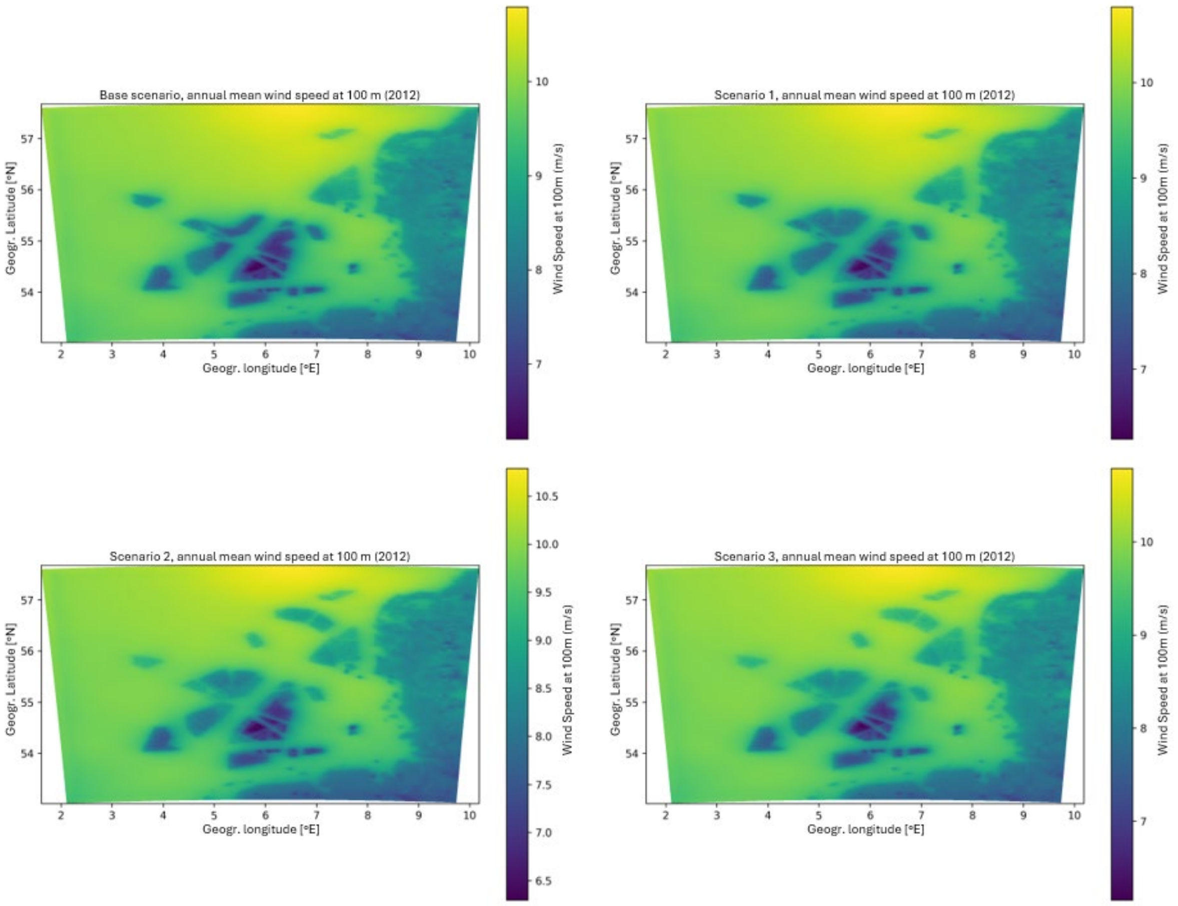

Figure 3-1: The mean 100 m wind speed for weather year 2012 on the model grid of the WRF simulations.

4 Simulation of Offshore Processes with OffshoreTIMES

4.1 O&M Modeling Concept

The preceding energy yield simulation assumes that all wind turbines are operational and able to always feed electricity into the grid. To obtain more realistic estimates of energy yield, the operation of the offshore wind farms is simulated using the Fraunhofer IWES software OffshoreTIMES. This is a holistic, time-series-based software tool for the analysis and planning of offshore wind farms. OffshoreTIMES simulates the execution of maintenance activities and the associated logistics over the entire lifetime of an offshore wind farm, to determine key performance indicators such as wind turbine availability and operating costs (O&M costs). A schematic overview of the input and output parameters of OffshoreTIMES is provided in Figure 4-1.

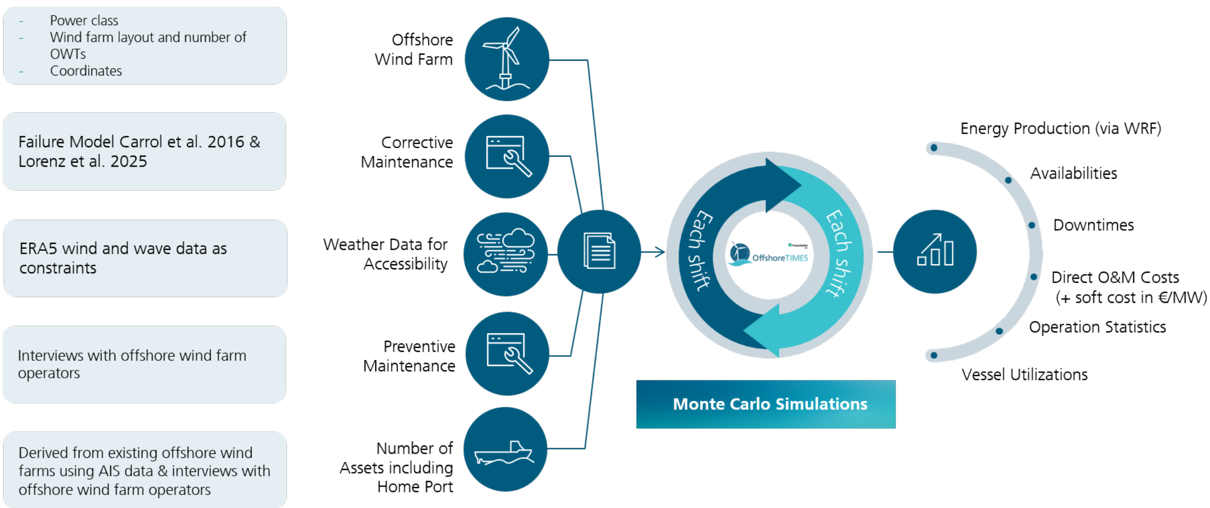

Figure 4-1: Schematic representation of the inputs and outputs of OffshoreTIMES

The failure of systems within a wind turbine and the maintenance and repair work to be carried out have a considerable influence on the operation of an offshore wind farm. The reliability of the technical components of a wind turbine and of the offshore grid connection systems is simulated stochastically in OffshoreTIMES. This means that the failure of a system occurs with a certain probability depending on the nature of the fault. For this reason, OffshoreTIMES follows the principle of a Monte Carlo simulation, in which the maintenance and logistics of an offshore wind farm are simulated over several years in discrete time steps. In this way, a statistically robust analysis of offshore wind farm operation is produced.

The cost model of OffshoreTIMES consolidates the O&M costs of an offshore wind farm into the following cost categories (listed in tabular form in Appendix D):

- Personnel costs: Personnel costs are calculated in the form of day rates, which can be defined for various categories of technical staff.
- Vessel costs: Vessel costs are calculated as day rates established for different types of vessels. The vessel types required for offshore wind farm operation are determined by the requirement profile of the O&M activities to be carried out. Some tasks require only the transport of crew and, where applicable, spare parts (Crew Transfer Vessel, CTV; Service Operation Vessel, SOV), while others

involve specialised requirements such as heavy lift operations (Jack-Up Vessel, JUV), resulting in significantly higher costs. Additional mobilization costs arise for certain vessels, such as the JUV.

- Helicopter costs: If helicopters are deployed as part of the logistics concept, costs are calculated as hourly rates. Helicopters can be used exclusively for personnel transport.
- Repair costs: Repair costs are accounted for as one-off costs depending on the nature of the wind turbine system failure, for example for tools, equipment, or spare parts.

Normally OffshoreTIMES is used for operational modeling, however, the software is also suited to modeling decommissioning and new construction processes. In such a case, the stochastic failure model is deactivated. Instead, a predefined project plan is used, containing a list of tasks that must be worked through by the various vessels. As with operational modeling, it is ensured throughout that the weather restrictions for each individual work step, as well as the weather-related operational limits of the vessels, are always adhered to.

The following section describes the input parameters for the simulation of operations, as well as the assumptions for the new construction of offshore wind farms.

4.2 Specific Assumptions for O&M Modeling

4.2.1 Offshore Wind Turbines

A field data study on average failure rates of wind turbine subsystems, mean repair times, material costs, and the number of technicians required for various types of O&M activities was used as the basis for the input values of the operating cost model (Carroll et al. 2016).

In the modeling within OffshoreTIMES, an offshore wind farm consists of multiple wind turbines, whose subdivision into main systems and subsystems can be flexibly configured within the software. The level of detail of the subdivision influences the simulation, as a separate reliability is defined for each system. In accordance Carroll et al. 2016 , four failure types or severity levels are distinguished for the systems of a wind turbine:

- Major Replacement: An O&M activity in which the system is completely replaced.
- Major Repair: An O&M activity in which an extensive repair is carried out involving larger spare parts.
- Minor Repair: An O&M activity in which a minor repair is carried out using less material and equipment.
- No Cost Data: O&M activities for which no cost data are available.

In the failure model used in this study, an average annual failure rate is defined for each of the four failure types for every subsystem of a wind turbine considered. The corresponding values are shown in Figure 4-2. In addition, for the O&M modeling in this study, the actual on-site working time, material costs, and number of technicians required are also specified for each of the various failure types and components. These assumptions are likewise based on Carroll et al. 2016.

To apply the reliability model to future 22 MW turbines, several adjustments were made. These adjustments correspond to those developed for the same turbine type in a study using a similar methodology (Lorenz et al. 2025). The gearbox failure rate for these turbines is reduced by 50% based on operational experience with more recent turbines. In addition, the failure rate for generator replacement was reduced by 50%, while the failure rate for rotor blade replacement was doubled. Furthermore, hub replacement is excluded as a possible maintenance activity for 22 MW turbines.

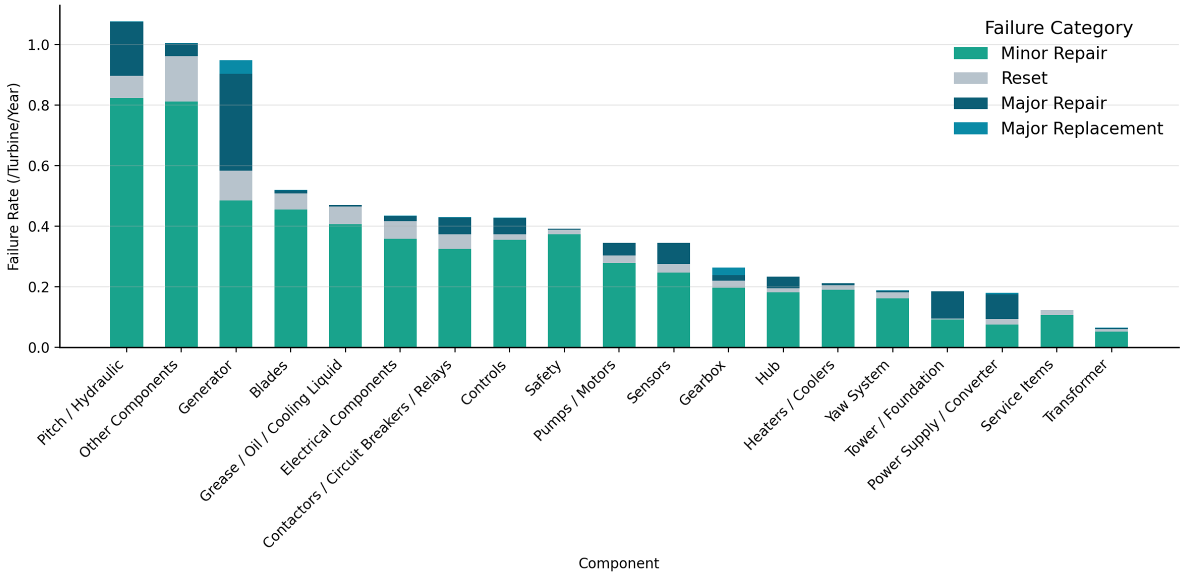

Figure 4-2: Annual failure rates of the individual subsystems of a wind turbine (based on Carroll et al. (2016)).

The failure model of Carroll et al. (2016) contains no information on the extent to which each failure leads to a complete shutdown of turbine operation. There are many failures that do not result in a turbine outage or that cause only a reduction in power output. To address this, the failure model was supplemented with additional data. These are based on estimates from the Technical Reliability group at Fraunhofer IWES.

The material costs presented in the study by Carroll et al. (2016) relate to older turbines (3.6 MW) and are considered appropriate for that size. Higher material costs are generally observed for larger turbines, and accordingly these parameters were adjusted for application to 22 MW turbines. Sufficient data are not available for an analysis of differences by manufacturer (OEM) and availability for 22 MW wind turbines. Since all turbines and all areas are treated equally here, this does not affect the evaluation and discussion of the results.

The detailed assumptions of the complete failure model are provided in the Appendix (Table 11, Table 12 und Table 13), together with inputs for the annual maintenance of offshore wind turbines (Table 14).

4.2.2 Offshore Grid Connection Systems

The transmission networks were likewise included within the scope of the simulations. Based on the studies by Shields et al. (2021) and Warnock et al. (2019), assumptions were defined for the corrective and preventive maintenance activities for the offshore converter platforms and export cables. A distinction is made here between minor corrective maintenance activities on the converter platforms (Table 15), major cable faults (Table 16) and annual maintenance (Table 17).

The annual failure rates of the wind turbine components (see Appendix A, Table 11) and of the maintenance activities for OGCS listed in Table 15 and Table 16 are kept constant over the study period. The effects of failure rates increasing with operational age play a negligible role in the evaluation and discussion in Section 5. In the scenario comparisons of this conceptual study, all scenarios would be equally affected, since an operational lifetime of 35 years is applied uniformly to every offshore wind farm in every scenario, meaning that no differential effect arises when assessing the individual scenarios relative to one another.

4.2.3 Methodology for Determining Operating Costs

In the O&M modeling with OffshoreTIMES, a logistics concept was established for each area under consideration, addressing the required maintenance and repair activities through the deployment of Service Operation Vessels (SOVs) and helicopters. Due to the size of some wind farms, a second SOV is also deployed where necessary to achieve energy-based wind turbine availabilities of 95% on an annual average. In coordination with the operators involved in this study, either Eemshaven or Esbjerg was designated as the base port in each case, depending on which port has the shortest distance to the respective offshore wind farm. OGCS failures were also accounted for in the simulations of the individual areas (see Table 15 and Table 16). However, the resources required for this (vessels and technicians) were not assigned any costs. In this way, the achieved energy yields were simulated, considering possible OGCS failures, while simultaneously only the direct O&M costs incurred for the operation of the respective offshore wind farm were charged.

All simulations use a constant weather year, namely 2012, which also formed the basis for the energy yield simulations (see Section 3). The weather data used are sourced from the ERA5 global reanalysis dataset of the European Centre for Medium-Range Weather Forecasts (Hersbach et al. 2020). In the O&M modeling, the weather data are primarily concerned with near-surface wind speeds and wave heights. These are required to account for the operational restrictions of the various vessel types in the simulation of O&M activities.

In addition to the direct O&M costs determined using OffshoreTIMES, 'soft' operating costs are also budgeted for the analyses in this study. These soft costs include cost items such as financial securities, back-office, insurance, and storage costs. In this study they are estimated at a flat rate of one third of total operating costs. The remaining two thirds are consequently accounted for by the direct O&M costs from the OffshoreTIMES simulations. The total operating costs, including soft costs, are thus determined according to the following equation:

$$\text{Operating costs}_{\text{year}} = 1{,}5 \times \text{direct O\&M costs}_{\text{year}}$$

(Equation 4.1)

In this form, the annual operating costs feed into the calculation of the cost index in Section 5 as a cost item.

Analogous to the operating costs of the wind turbine operators, the transmission network operating costs used in this study are also intended to account for administrative costs, such as back-office engineers, HSE personnel, and inventory management. The total operating costs (logistics, maintenance, operations, and administration) for a 2 GW OGCS are estimated at €30 million per year. These assumptions are based on agreements reached with transmission system operators for an Fraunhofer IWES study on life extension scenarios in the DolWin cluster (Lorenz et al. 2025).

4.3 O&M Modeling Results: Availabilities and Costs

For the logistics concept of the individual areas, an SOV-based service with helicopter support was configured such that the resulting wind farm availabilities achieve industry-standard values of >95%. Only the offshore wind farm considered in the Baltic Sea was modelled with a CTV-based service, due to its proximity to the coast.

As described in Section 4.2.2, the maintenance and repair of the offshore grid connection systems were also represented in the simulations. Considering possible grid connection failures, an overall availability results that was in each case 2–3 percentage points below the pure wind turbine availability.

In addition to availabilities, the direct O&M costs are a further output of OffshoreTIMES, which together with the soft operating costs (see Section 4.2.3) feeds into the economic evaluation in Section 5 as a component of the cost index. The direct O&M costs comprise the charter rates of the vessels and helicopters, the salaries of the technicians, and the costs of spare parts. The O&M costs are determined for each individual area. For each combination of layout and wind farm capacity arising for the individual areas across the various scenarios, a dedicated OffshoreTIMES simulation is carried out to model the operational phase and determine the direct O&M costs and availabilities.

The energy-based availabilities and direct O&M costs calculated using this methodology for the individual offshore wind farms in the respective scenarios are listed in Table 3. The simulated availabilities of the individual areas show no significant differences. The zones N-17+20 and N-19, which are located at a greater distance from the coast, have a slightly lower availability (approximately 0.3 percentage points) compared to zones closer to the coast.

Table 3: Overview of the average availabilities per area. The availabilities represent the overall availability of the wind turbines and transmission networks. For Scenarios 1, 2 and 3, only the areas with changes relative to the preceding scenario are listed.

Scenario	Area	Energy based availability	OWF operating costs per (MW*Year)
Base	N-5	93.8%	36,446 €
	N-9	93.8%	51,762 €
	N-10	93.7%	57,036 €
	N-11	93.6%	39,161 €
	N-12	93.6%	39,758 €
	N-13	93.6%	40,639 €
	N-14	93.7%	38,623 €
	N-16	93.5%	38,620 €
	N-17+20	93.3%	40,045 €
	N-19	93.1%	40,541 €
Scenario 1	N-12	93.6%	40,200 €
	N-13	93.5%	41,180 €
	N-14	93.6%	38,582 €
	N-16	93.5%	38,714 €
	DK-North - 2	93.5%	41,538 €
	DK-North - 4	93.4%	43,278 €
	DK-S-Baltic	93.7%	26,049 €
Scenario 2	N-5	93.8%	38,148 €
	N-14	93.3%	40,050 €
	N-16	93.3%	39,970 €
	N-17+20	93.0%	40,015 €
	N-19	93.0%	42,294 €
	DK-North - 1	93.3%	43,515 €
	DK-North - 3	93.4%	43,541 €
	DK-North - 5	93.4%	38,692 €
Scenario 3	N-5	93.5%	35,796 €
	N-9	93.1%	48,135 €
	N-10	93.6%	55,223 €
	N-11	93.5%	37,993 €
	N-12	93.5%	38,608 €
	N-13	93.3%	40,316 €
	N-14	93.4%	38,738 €
	N-16	93.2%	40,394 €
	N-17+20	93.0%	40,515 €
	N-19	93.1%	40,306 €
	DK-North - 1	93.1%	39,503 €
	DK-North - 2	93.2%	45,061 €
	DK-North - 3	92.9%	49,025 €
	DK-North - 4	93.4%	38,945 €
	DK-North - 5	93.3%	39,051 €
	DK-S-Baltic	93.7%	26,049 €

Considerably larger differences are observed in the direct O&M costs of the individual areas. In particular, the 2 GW offshore wind farm in the Baltic Sea is characterized by significantly reduced operating costs. Due to the very short distance of the wind farm to its service port, the logistics concept in DK-S-Baltic is based on cost-effective Crew Transfer Vessels. These have substantially lower charter costs, resulting in significantly reduced direct O&M costs compared to the remaining offshore wind farms. On the other hand, zones N-9 and N-10 stand out, where operating costs are considerably elevated. This is attributable to the fact that 15 MW turbines are partially installed there. The resulting higher number of turbines per installed capacity leads to a greater need for repair and inspection. The other differences between the zones are attributable to the varying local weather conditions, distances to the coast, and the size of the wind farm area as well as the number of installed turbines.

In summary, the operating costs of all wind farms considered increase slightly in Scenarios 1 and 2, by 0.2% and 2.5% respectively compared to the Base Scenario (Table 4). This is due to the additional installed capacity in the Danish North Sea, which has a greater distance to its respective service port than most offshore wind farms in the German North Sea. In Scenario 3, the wind farm operating costs are lowest (Table 4), because the low operating costs of the 2 GW offshore wind farm in the Danish and Swedish Baltic Sea carry weight, while simultaneously slightly fewer turbines are installed in the Danish North Sea.

Table 4: Tabular overview of the total operating costs of all offshore wind farms considered, per scenario.

Scenario	OWF operating costs per (MW*year)	Change vs Base Scenario [%]
Base	41,693 €	-
Scenario 1	41,791 €	0.2
Scenario 2	42,717 €	2.5
Scenario 3	41,455 €	-0.6

4.4 New Construction Costs

To determine the capital expenditure (CAPEX) for the offshore wind farms, three cost items were summed:

- The logistics costs arising from the results and processes of the OffshoreTIMES simulations were calculated taking into account the vessels deployed and their respective cost structures (further information can be found in Appendix D). To determine these costs more precisely, the process steps listed in Table 19 (in the Appendix), including the associated durations, were carried out in descending order.
- The so-called 'soft costs' encompass various elements, including insurance costs during the construction phase, decommissioning, construction financing, procurement cost contingency, commissioning, and installation contingency. This results in costs of €0.9 million/MW and thus approximately €20 million for the 22 MW wind turbine used in the new construction scenarios (Stehly et al. (2024), Sens et al. (2022) and the Fraunhofer IWES internal cost model).
- The material costs cover monopiles, transition pieces, inter-array cables, and scour protection measures. This results in costs of €2.3 million/MW and thus approximately €50 million for the 22 MW reference turbine (Stehly et al. (2024), Sens et al. (2022) and the Fraunhofer IWES internal cost model).

On the part of the grid operators, the costs for offshore grid connection systems (OGCS) and export cables for the respective areas were compiled from the Network Development Plan Electricity (NDP) 2037/2045 (Übertragungsnetzbetreiber CC-BY-4.0 2023). It should be noted that no OffshoreTIMES simulation was carried out in this case, as the costs from the NDP already include assumptions for logistics costs.

The total costs comprise the expenditure for the cable strings per kilometre of cable laid and the associated 2 GW OGCS. These capital costs amount to €6 million per kilometre for two cable strings and €1 billion per GW for the offshore converter platform (including the onshore substation). For the macroeconomic assessment using the cost index, the CAPEX of the offshore wind farms and the grid-side investments are summed.

Table 5: Tabular overview of the total installation costs of all offshore wind farms considered per scenario, together with the respective change in total costs compared to the Base Scenario.

Scenario	Total installation costs	Change vs Base Scenario [%]
Base	298.81 Bil. €	-
Scenario 1	298.48 Bil. €	-0.1
Scenario 2	302.27 Bil. €	1.2
Scenario 3	292.62 Bil. €	-2.1

The total costs for the installation of all offshore wind farms considered, including offshore grid connection, are listed in Table 5, together with the percentage change in costs compared to the Base Scenario. A more detailed breakdown of the individual CAPEX cost items is provided in

Table 6. As expected, the CAPEX for the wind farms increases proportionally with the number of turbines installed in each case. The grid connection costs per area are higher the more converter platforms need to be connected in each area and the longer the cable routes by which these are connected to the grid.

The values in Table 5 confirm that the specifications of Scenario 1 are associated with a reduction in CAPEX of 0.1% compared to the Base Scenario. This slight reduction is caused primarily by the reallocation of offshore wind farm capacity to the Danish and Swedish Baltic Sea provided for in Scenario 1. This area is characterized by a particularly short distance to the coast compared to the North Sea, and thus by faster offshore processes and significantly shorter and more cost-effective cable routes. In Scenario 2, by contrast, CAPEX increases by 1.2% compared to the Base Scenario. This cost increase is caused by the additional, longer cable routes from the areas in the Danish North Sea to the German mainland (see Table 6). In Scenario 3, the overall CAPEX is lowest. This is because in this scenario two OGCS are saved by using a corresponding share of the installed wind energy capacity as overplanting (see Section 2.1).

Table 6: Overview of the CAPEX components considered for the wind turbine installation of the respective offshore wind farms, including grid connection. For Scenarios 1 and 2, only the areas that have changed compared to the preceding scenarios are listed.

			Wind Farms			Grid Operations		
Scenario	**Area**	**OWF Capacity [MW]**	**Logistics costs**	**Material costs**	**Soft costs**	**Cabel**	**OGCS**	**Total**
Base	N-5	4004	1,457 M€	9,274 M€	3,647 M€	2,532 M€	4,000 M€	20,910 M€
	N-9	7480	3,765 M€	17,326 M€	6,813 M€	4,089 M€	7,500 M€	39,492 M€
	N-10	2490	1,320 M€	5,768 M€	2,268 M€	1,227 M€	2,500 M€	13,082 M€
	N-11	3498	1,214 M€	8,102 M€	3,186 M€	2,193 M€	3,500 M€	18,196 M€
	N-12	8998	3,242 M€	20,842 M€	8,195 M€	6,360 M€	9,000 M€	47,640 M€
	N-13	5500	1,961 M€	12,740 M€	5,009 M€	4,224 M€	5,500 M€	29,434 M€
	N-14	6006	2,278 M€	13,912 M€	5,470 M€	4,230 M€	6,000 M€	31,890 M€
	N-16	10010	3,675 M€	23,186 M€	9,117 M€	7,380 M€	10,000 M€	53,358 M€
	N-17+20	4004	1,515 M€	9,274 M€	3,647 M€	3,444 M€	4,000 M€	21,880 M€
	N-19	4004	1,509 M€	9,274 M€	3,647 M€	4,500 M€	4,000 M€	22,930 M€
Scenario 1	N-12	6996	2,541 M€	16,205 M€	6,372 M€	4,812 M€	7,000 M€	36,930 M€
	N-13	3498	1,221 M€	8,102 M€	3,186 M€	2,688 M€	3,500 M€	18,697 M€
	N-14	4004	1,447 M€	9,274 M€	3,647 M€	2,820 M€	4,000 M€	21,189 M€
	N-16	6006	2,215 M€	13,912 M€	5,470 M€	4,428 M€	6,000 M€	32,025 M€
	DK-North - 2	3256	1,165 M€	7,542 M€	2,966 M€	2,598 M€	3,256 M€	17,526 M€
	DK-North - 4	4730	1,750 M€	10,956 M€	4,308 M€	3,773 M€	4,728 M€	25,515 M€
	DK-S-Baltic	2002	797 M€	4,637 M€	1,823 M€	852 M€	2,000 M€	10,110 M€
Scenario 2	N-5	2002	701 M€	4,637 M€	1,823 M€	1,266 M€	2,000 M€	10,428 M€
	N-14	2002	727 M€	4,637 M€	1,823 M€	1,410 M€	2,000 M€	10,597 M€
	N-16	4004	1,451 M€	9,274 M€	3,647 M€	2,952 M€	4,000 M€	21,324 M€
	N-17+20	2002	767 M€	4,637 M€	1,823 M€	1,722 M€	2,000 M€	10,950 M€
	N-19	2002	745 M€	4,637 M€	1,823 M€	2,250 M€	2,000 M€	11,455 M€
	DK-North - 1	5082	1,975 M€	11,771 M€	4,629 M€	6,261 M€	5,078 M€	29,714 M€
	DK-North - 3	2992	1,118 M€	6,930 M€	2,725 M€	3,294 M€	3,000 M€	17,067 M€
	DK-North - 5	2002	769 M€	4,637 M€	1,823 M€	1,956 M€	2,000 M€	11,185 M€
Scenario 3	N-5	2112	753 M€	4,892 M€	1,924 M€	1,266 M€	2,000 M€	10,835 M€
	N-9	8142	3,962 M€	18,859 M€	7,416 M€	4,089 M€	7,500 M€	41,827 M€
	N-10	2715	1,396 M€	6,289 M€	2,473 M€	1,227 M€	2,500 M€	13,885 M€
	N-11	3806	1,370 M€	8,816 M€	3,467 M€	2,193 M€	3,500 M€	19,345 M€
	N-12	7568	2,737 M€	17,530 M€	6,893 M€	4,812 M€	7,000 M€	38,972 M€
	N-13	3740	1,354 M€	8,663 M€	3,406 M€	2,688 M€	3,500 M€	19,612 M€
	N-14	2134	764 M€	4,943 M€	1,944 M€	1,410 M€	2,000 M€	11,060 M€
	N-16	3586	1,318 M€	8,306 M€	3,266 M€	2,487 M€	3,370 M€	18,748 M€
	N-17+20	2112	773 M€	4,892 M€	1,924 M€	1,722 M€	2,000 M€	11,311 M€
	N-19	2112	809 M€	4,892 M€	1,924 M€	2,250 M€	2,000 M€	11,874 M€
	DK-North - 1	4026	1,568 M€	9,325 M€	3,667 M€	4,661 M€	3,780 M€	23,001 M€
	DK-North - 2	2772	1,016 M€	6,421 M€	2,525 M€	2,075 M€	2,600 M€	14,637 M€
	DK-North - 3	2354	856 M€	5,453 M€	2,144 M€	2,438 M€	2,220 M€	13,111 M€
	DK-North - 4	4312	1,573 M€	9,988 M€	3,927 M€	3,216 M€	4,030 M€	22,734 M€
	DK-North - 5	2112	786 M€	4,892 M€	1,924 M€	1,956 M€	2,000 M€	11,558 M€
	DK-S-Baltic	2002	797 M€	4,637 M€	1,823 M€	853 M€	2,002 M€	10,113 M€

5 Analysis and Discussion

In this chapter, the results of the energy yield modeling (Section 3) and O&M simulations (Section 4) described in the preceding sections are brought together and evaluated with respect to energy yield, full load hours, and the cost index. This evaluation and presentation of results is carried out both at the level of the individual modelled areas (N-5, N-9, N-10, N-11, N-12, N-13, N-14, N-16, N-17+N-20, N-19, DK-North 1, DK-North 2, DK-North 3, DK-North 4, DK-North 5 and DK-S-Baltic) and in summary form. In doing so, the annual offshore wind farm yields are set in relation to the annual operating costs as well as the installation costs. The latter are distributed evenly over an assumed operational lifetime of 35 years for the purposes of this comparison. These results are then discussed considering the aspects of the two scenarios set out in Section 2.

5.1 Energy Yield and Full Load Hours

The annual energy yields and full load hours for all areas considered in this study in the North and Baltic Seas are listed in Table 7. The figures are given for the respective build-out state arising from the specifications for the Base Scenario and Scenarios 1–3 (see Section 2). The table lists both the yields resulting from the pure wind and energy yield modeling (see Section 3), and the yields considering turbine and grid availabilities (see Section 4 und Table 3).

Together with the annual energy yields, the number of full load hours achieved per area is also stated. The full load hours [h] are calculated as the quotient of the annual yield [GWh] and the installed capacity [GW]. Full load hours thus represent a measure of the utilization rate of the wind turbines, for which the highest possible value is sought from both a macroeconomic and a business economics perspective. The theoretical maximum for full load hours for the weather year 2012 used, which is a leap year, is 8,784 h, which would correspond to full turbine utilization at every hour of the year.

When comparing full load hours between different scenarios, it should be noted that these always refer to the offshore wind farm capacity specified in the respective scenario. Differences in full load hours between scenarios therefore do not necessarily lead to proportional differences in the energy yields achieved in each area.

The values in Table 7 show that particularly high full load hours are achieved by those areas that experience little wake effects from other wind farms in the prevailing wind direction of west/south-west. This applies for example to area N-19 in the Base Scenario, the Baltic Sea area DK-S-Baltic in Scenario 1, and areas DK-North 1, DK-North 2 and DK-North 3 in Scenario 2. The reduction in power density in Scenario 1 in areas N-12 to N-16 leads to an increase in full load hours in these areas, because both internal and external wake effects are reduced. Likewise, a general and marked increase in full load hours compared to the Base Scenario can be observed in Scenario 2. This is achieved through the even more pronounced reduction in power density, by installing even more offshore wind farm capacity in the Danish North Sea instead of the German North Sea. This results in even less mutual shading between the German wind farms, particularly through reductions in installation density in areas N-14, N-16, N-17+N-20 and N-19. Area N-5, which does not directly border other areas, also benefits markedly in terms of full load hours through a reduction in its own power density and that of the wind farms located some distance to the west.

Scenario 3 is the scenario in which the highest full load hours are generally achieved for the individual areas. This is because overplanting is applied in this scenario (see Section 2.1). The full load hours here refer to the feed-in capacity at the OGCS and not to the offshore wind farm capacity. In the remaining scenarios this distinction is irrelevant, as in those scenarios the offshore wind farm capacity always corresponds to the OGCS capacity. This means that throughout the offshore wind farms, more turbine capacity is installed than corresponds to the feed-in capacity at the OGCS. This ensures that a high utilization of the OGCS is achieved even in the event of turbine failures and incomplete utilization of the wind turbines. The successful implementation of this strategy is demonstrated by the high full load hours in Table 7.

A summary presentation of the annual energy yields of all areas considered in this study is provided in Figure 5-1. The energy yield is normalized to the total energy yield of the Base Scenario in order to simplify the comparison between the various scenarios.

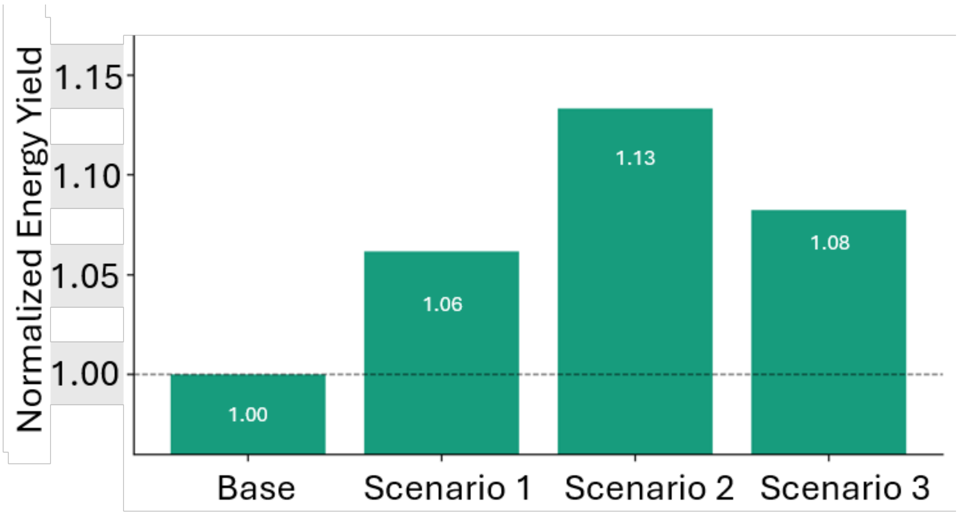

Figure 5-1: The aggregated energy yield achieved in the various scenarios, normalized to the energy yield of the Base Scenario.

Table 7: Overview of the annual energy yields and full load hours for the areas considered. The values are given in each case with and without the influence of turbine and grid availability. The installed capacity of the individual areas follows from the scenario specifications. Due to the overplanting in Scenario 3, the full load hours are given with reference to the OGCS capacity to account for the feed-in limitation of the generated energy.

Scenario	Area	Capacity [GW]	Power density [MW/km²]	Yield [GWh]	Yield [GWh] (incl. Availability)	Full load hours	Full load hours (incl. Availability)
Base	N-5	4	10.1	17,061	16,004	4,265	4,001
	N-9	7.7	10.3	23,755	22,284	3,176	2,979
	N-10	2.5	13.7	8,085	7,579	3,247	3,044
	N-11	3.5	9.3	11,885	11,127	3,399	3,183
	N-12	9	9.7	31,141	29,157	3,464	3,243
	N-13	5.5	9.9	20,397	19,083	3,711	3,472
	N-14	6	10.4	21,966	20,572	3,661	3,429
	N-16	10	9.1	39,298	36,751	3,930	3,675
	N-17+20	4	8.6	17,683	16,500	4,421	4,125
	N-19	4	7.1	18,310	17,047	4,577	4,262
Scenario 1	N-5	4	10.1	17,298	16,227	4,324	4,057
	N-9	7.7	10.3	24,543	23,023	3,281	3,078
	N-10	2.5	13.7	8,201	7,688	3,293	3,088
	N-11	3.5	9.3	12,085	11,315	3,457	3,237
	N-12	7	7.6	25,670	24,025	3,672	3,437
	N-13	3.5	6.3	14,738	13,778	4,216	3,941
	N-14	4	6.9	16,202	15,159	4,051	3,790
	N-16	6	5.5	24,939	23,307	4,157	3,885
	N-17+20	4	8.6	17,594	16,417	4,398	4,104
	N-19	4	7.1	18,265	17,006	4,566	4,251
	DK-North - 2	3.3	5.2	13,685	12,790	4,203	3,928
	DK-North - 4	4.7	5.2	19,918	18,607	4,213	3,936
	DK-S-Baltic	2	8.5	9,470	8,871	4,735	4,435
Scenario 2	N-5	2	5.1	9,910	9,292	4,955	4,646
	N-9	7.7	10.3	24,758	23,225	3,310	3,105
	N-10	2.5	13.7	8,268	7,751	3,320	3,113
	N-11	3.5	9.3	12,161	11,386	3,479	3,257
	N-12	7	7.6	25,935	24,272	3,710	3,472
	N-13	3.5	6.3	14,946	13,973	4,275	3,997
	N-14	2	3.5	9,125	8,513	4,562	4,256
	N-16	4	3.6	18,213	16,991	4,553	4,248
	N-17+20	2	4.3	9,904	9,210	4,952	4,605
	N-19	2	3.6	10,227	9,511	5,113	4,756
	DK-North - 1	5.1	5.2	24,971	23,287	4,917	4,586
	DK-North - 2	3.3	5.2	14,103	13,180	4,331	4,048
	DK-North - 3	3	5.2	14,753	13,778	4,934	4,608
	DK-North - 4	4.7	5.2	20,632	19,274	4,364	4,077
	DK-North - 5	2	5.2	10,435	9,743	5,217	4,872
	DK-S-Baltic	2	8.5	9,470	8,871	4,735	4,435
Scenario 3	N-5	2.1	5.3	10,002	9,354	5,001	4,677
	N-9	8.11	10.8	25,976	24,181	3,463	3,224
	N-10	2.72	14.9	8,528	7,984	3,411	3,194
	N-11	3.8	10	12,387	11,585	3,539	3,310
	N-12	7.57	8.2	26,572	24,836	3,796	3,548
	N-13	3.74	6.8	15,193	14,177	4,341	4,051
	N-14	2.12	3.7	9,389	8,767	4,695	4,384
	N-16	3.58	3.3	16,180	15,087	4,801	4,477
	N-17+20	2.11	4.6	10,111	9,402	5,055	4,701
	N-19	2.11	3.8	10,359	9,643	5,179	4,821
	DK-North - 1	4.02	4.1	20,188	18,795	5,341	4,972
	DK-North - 2	2.78	4.4	12,100	11,276	4,654	4,337
	DK-North - 3	2.35	4.1	11,867	11,025	5,346	4,966
	DK-North - 4	4.3	4.7	18,641	17,405	4,626	4,319
	DK-North - 5	2.11	5.5	10,660	9,944	5,330	4,972
	DK-S-Baltic	2	8.5	9,470	8,871	4,735	4,435

Compared to the Base Scenario, the annual energy yield in Scenario 1 is increased by 6%. This increase is achieved because the areas commissioned in the Danish North Sea in Scenario 1 achieve high yields and attain more full load hours compared to the areas in the German North Sea in the Base Scenario (see Table 7). At the same time, the reduction in installation density in areas N-12, N-13, N-14 and N-16 in Scenario 1 reduces the wake effects within the German North Sea, so that more full load hours are achieved in these areas (Table 7).

In addition, the area DK-S-Baltic, which is commissioned in the Baltic Sea in Scenario 1, is characterized by high yields and high full load hours. This is primarily due to the fact that DK-S-Baltic is surrounded neither by other large wind farms nor by significant onshore topography, resulting in only very minor external wake effects. Accordingly, similarly high and higher values for full load hours are achieved primarily in exposed offshore wind farms in the scenarios with reduced power density (see below).

In Scenario 2, an even higher energy yield is achieved than in Scenario 1. The increase in annual yield, including the influence of turbine and grid availability, amounts to 13% compared to the Base Scenario. This additional increase is achieved through the commissioning of further areas in the Danish North Sea (DK-North 1, DK-North 3 and DK-North 5), which achieve high yields and exhibit high full load hours (Table 7). Analogous to Scenario 1, a further reduction in wake effects within the German North Sea is achieved here through an even more extensive reduction in installation density in the German North Sea. The number of full load hours in Scenario 2 is thus increased even further compared to both the Base Scenario and Scenario 1.

Through the overplanting in Scenario 3, higher electricity yields are achieved than in Scenario 1 (Figure 5-1 und Table 7). However, lower electricity yields are achieved than in Scenario 2. This is due in part to the fact that with overplanting it can occur that under good wind conditions and high turbine availability, not all of the energy produced can be fed into the grid, because doing so would exceed the feed-in capacity of the OGCS. In such cases, generated energy is lost. Furthermore, overplanting increases the density of installed wind turbines per area, which in turn increases the mutual wake effects between turbines and thus reduces the efficiency of individual wind turbines. In particular, in areas where a relatively high power density with stronger internal wake effects already exists, the blanket application of the overplanting figures, which are based on the simplified methodology of Frontier Economics (see Section 2.1), leads to additional losses through internal wake shading.

Overplanting thus leads to an increase in yield compared to the Base Scenario and Scenario 1; however, the increase in yield resulting from the reallocation of installed capacities in Scenario 2 is even greater. Overall, Scenario 2 represents the scenario with the highest annual energy yields.

5.1.1 Separate Analysis of the Influence of the Doordewind OWFs

The Dutch designated but not yet tendered areas Doordewind I and Doordewind II border directly on areas N-6, N-7 and N-9 in the German EEZ. The future development density on these areas and the resulting wake effects are therefore of great significance for the yields in areas N-6, N-7 and N-9.

In order to better quantify this significance, a varying degree of development on the Doordewind areas was specified for the scenarios considered in this study. The differences in yields in these areas between the scenarios can consequently be used to assess the impact of wake shading from Doordewind. Due to the additional scenario differences (possible power reduction in neighboring areas and overplanting in Scenario 3), not all changes in yields can be attributed to the varying development density in Doordewind. Nevertheless, a strong local effect can be assumed.

The varying capacities, yields and full load hours in Doordewind and the directly affected areas in the German EEZ are listed in Table 8. In Scenario 1, the capacity installed in Doordewind is halved compared to the Base Scenario. Areas N-6 and N-9 experience a yield increase of 4% and 3% respectively in this scenario; the yield increase in N-7 amounts to 0.85%. This increase can largely be attributed to the reduction in power density in Doordewind. The only other area in relative proximity that experiences a reduction in power density in Scenario 1 is area N-14.

In Scenario 2 there are only very minor additional yield increases (less than 1% additional yield increase relative to the Base Scenario). These are likely achieved through the reduction in capacity in N-14, from 4 GW in Scenario 1 to 2 GW in Scenario 2.

In Scenario 3, in which no development in Doordewind is planned, areas N-6, N-7 and N-9 experience yield increases relative to the Base Scenario of 6.6%, 1.6% and 9.4% respectively. It should be noted here that in Scenario 3 an overplanting of approximately 9% is applied to area N-9. The effects of overplanting and the reduction of Doordewind on the yields of N-9 cannot be fully separated from one another. If one considers that the reduction of Doordewind in Scenario 1 had approximately the same effect on N-6 and N-9, and transfers this ratio to Scenario 3, this would imply that in Scenario 3 area N-9 experiences a yield increase of approximately 6% through the reduction of Doordewind and of approximately 3% through overplanting.

Table 8: Separate analysis of the yields and full load hours of the areas in immediate proximity to the offshore wind farms Doordewind I and Doordewind II in the Dutch North Sea. Yields and full load hours are given excluding turbine and grid connection availabilities.

Scenario	Area	Capacity [MW]	Yield [GWh]	Full load hours
Base	Doordewind	4,004	15,869	3,963
	N-6	3,982	12,770	3,209
	N-7	1830	6,053	3,307
	N-9	7480	23,755	3,176
Scenario 1	Doordewind	1,980	8,944	4,517
	N-6	3,982	13,288	3,339
	N-7	1830	6,104	3,335
	N-9	7480	24,543	3,281
Scenario 2	Doordewind	1,980	8,962	4,526
	N-6	3,982	13,334	3,350
	N-7	1830	6,123	3,346
	N-9	7480	24,758	3,310
Scenario 3	Doordewind	0	0	0
	N-6	3,982	13,615	3,419
	N-7	1830	6,148	3,359
	N-9	8142	25,976	3,463

5.2 Cost Index

To compare the macroeconomic benefit of the various scenarios with one another, the electricity yields achieved in each scenario are set in relation to the associated costs. This comparison is carried out using the so-called cost index, which is calculated according to the following equation:

$$\text{Cost Index} = \frac{(\text{Operating costs}_{\text{OWF}} + \text{Operating costs}_{\text{OGCS}} + \text{Construction costs})}{\text{Electricity yield}}$$

(Equation 5.1)

The annual yields and operating costs of the individual areas feed into the calculation in accordance with the results presented in Sections 4.3 and 5.1. The construction costs (see Section 4.4) are distributed evenly over an assumed operational lifetime of 35 years for this purpose, so that they can be set in relation to the annual yields and operating costs. The operational lifetime of the newly developed areas is limited to 35 years solely due to current legislation (25 years of regular operation and 10 years of possible life extension) and not for technical reasons.

In the calculation of the cost index $\text{Operating Costs}_{\text{OWF}}$ is derived as the sum of the annual operating costs of all operational offshore wind farms over the simulated year (see Section 4.3). These operating costs comprise the direct O&M costs determined using the OffshoreTIMES simulations and the so-called soft operating costs, as described in Section 4.2.3.

The operating costs of the offshore grid connection systems, $\text{Operating costs}_{\text{OGCS}}$, are derived as described in Section 4.2.3: annual operating costs of €30 million each are estimated for the future 2 GW OGCS.

The Electricity Yield for an area is derived as the annual electricity yield achieved in the respective scenario (see energy yield modeling in Section 3), calculated taking into account turbine availabilities (see OffshoreTIMES modeling in Section 4). In the case of Scenario 3 (overplanting scenario), the feed in capacity of the respective OGCS has likewise been taken into account.

Aspects that contribute to differences in the components of the cost index across the various scenarios include, among others:

- Different locations are associated with different installation costs (different logistics and in particular different cable lengths). This leads to different CAPEX. Furthermore, longer export cables are associated with an increased cable failure rate.
- Different offshore wind farm layouts cause different wake effects within the same offshore wind farm and between offshore wind farms. This leads to different full load hours and electricity yields.
- Different locations are generally associated with different wind conditions, which leads to different electricity yields.
- Direct O&M costs are determined for each offshore wind farm location, layout and number of turbines and will therefore vary between scenarios.
- In Scenario 3, two fewer OGCS are used than in the remaining scenarios. This leads to differences in the construction costs and operating costs of the OGCS.

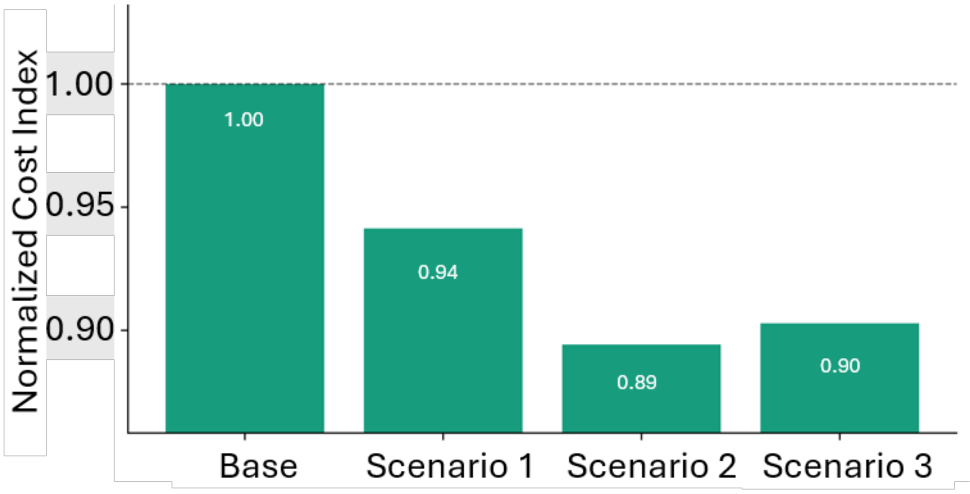

Figure 5-2: The aggregated cost index, calculated across all individual areas, achieved in the various scenarios, normalized to the cost index of the Base Scenario.

A summary presentation of the cost index values in the various scenarios is provided in Figure 5-2. A breakdown of the cost index for the individual areas is listed in Table 9.

The increased energy yield (see Section 5.1) in Scenarios 1 to 3 brings about a general reduction in the cost index compared to the Base Scenario. At the same time, Scenarios 1 and 3 are associated with lower CAPEX than the Base Scenario. Consequently, both of these scenarios exhibit a lower cost index than the Base Scenario. In Scenario 3, the reduced construction costs and operating costs of the two OGCS saved in the North Sea additionally contribute to lowering the cost index. The lowest cost index is achieved in Scenario 2, however. Although higher CAPEX arise in this scenario due to the longer cable routes from the Danish maritime zones to the German mainland (see Section 4.4), these are outweighed by the substantial yield increases in Scenario 2: while CAPEX in Scenario 2 are 1.2% higher than in the Base Scenario (Table 5), yield increases of 13% are achieved (Figure 5-1). The additional costs of the longer cable routes therefore have a far lower macroeconomic significance than the yield increases achieved through the reallocation of capacity to Denmark.

Among the Danish areas, offshore wind farm DK-North-5 achieves the lowest cost index (Table 9). This area is characterized by low operating costs (Table 3) and CAPEX (Table 6). At the same time, high yields and full load hours are achieved due to its exposed location (Figure 2-3) and good wind resource (Table 7).

The 2 GW offshore wind farm in the Danish and Swedish Baltic Sea (DK-S-Baltic) contributes significantly to a reduction in the cost index compared to the Base Scenario in Scenarios 1 to 3. This area is characterized by low O&M costs (Table 3), low CAPEX (Table 6) and high full load hours (Table 7). It thus achieves the lowest cost index of all areas considered.

Table 9: Tabular overview of the normalized cost index per area for the various scenarios.

Area	Base	Scenario 1	Scenario 2	Scenario 3
N-5	0.840	0.829	0.729	0.743
N-9	1.223	1.184	1.174	1.177
DK-North - 1			0.824	0.778
DK-North - 2		0.897	0.870	0.864
DK-North - 3			0.806	0.795
DK-North - 4		0.904	0.873	0.845
DK-North - 5			0.734	0.745
DK-S-Baltic		0.700	0.700	0.700
N-10	1.222	1.205	1.195	1.225
N-11	1.067	1.050	1.043	1.084
N-12	1.065	1.005	0.994	1.018
N-13	1.006	0.888	0.876	0.902
N-14	1.004	0.906	0.812	0.819
N-16	0.939	0.889	0.817	0.811
N-17+20	0.858	0.862	0.769	0.781
N-19	0.862	0.864	0.778	0.789

[3]

A concluding assessment and discussion of the various approaches to improving macroeconomic efficiency - cross-border capacity reallocation and area-specific overplanting - is provided in the summary in Section 5.3.

[3] Since the cost index is normalized to the overall system of all areas considered in the Base Scenario and takes into account area-specific cost and yield parameters, differences arise between individual areas even within the Base Scenario, such that the value at area level deviates from 1.00.

5.3 Summary

Table 10: Tabular overview of the installed capacity, energy yield, full load hours and cost index from the various scenarios, broken down by spatial zone. Due to the overplanting in Scenario 3, the full load hours are given with reference to the OGCS capacity in order to account for the feed-in limitation of the generated energy.

	Base Scenario				Scenario 1				Scenario 2				Scenario 3			
	Capacity [GW]	Energy Yield [TWh]	Full Load Hours [h]	Cost Index	Capacity [GW]	Energy Yield [TWh]	Full Load Hours [h]	Cost Index	Capacity [GW]	Energy Yield [TWh]	Full Load Hours [h]	Cost Index	Capacity [GW]	Energy Yield [TWh]	Full Load Hours [h]	Cost Index
N-5	4	16.0	4000	0.840	4	16.2	4060	0.829	2	9.3	4650	0.729	2	9.4	4680	0.743
Zone 3	28	89.2	3190	1.106	24	79.8	3330	1.062	24	80.6	3370	1.052	26	82.8	3450	1.074
Zone 4	20	73.8	3690	0.939	14	54.9	3920	0.886	8	34.7	4340	0.803	8	33.3	4510	0.805
Zone 5	4	17.0	4260	0.862	4	17.0	4250	0.864	2	9.5	4760	0.778	2	9.6	4820	0.789
Total DE	56	196.1	3500	**1.000**	46	167.9	3650	**0.962**	36	134.1	3730	**0.946**	35	135.0	3820	**0.964**
DK-S-Baltic	-	-	-	-	2	8.9	4430	0.700	2	8.9	4430	0.700	2	8.9	4430	0.700
DK-N	-	-	-	-	8	31.4	3930	0.901	18	79.3	4390	0.829	15	68.4	4680	0.807
Total	56	196.1	3500	**1.000**	56	208.2	3720	**0.941**	56	222.3	3970	**0.894**	52	212.3	4080	**0.903**

This study investigates whether the systemic efficiency of offshore wind energy utilization in the German Bight can be increased through an alternative spatial distribution of future offshore wind capacities. The basis is a reference scenario derived from the 2025 SDP draft, in which the German expansion target of 70 GW by 2045 and the radial connection to the German electricity grid remain unchanged. Building on this, three international comparison scenarios with reduced power density in the German EEZ and a reallocation of 10 and 20 GW respectively to Denmark and Sweden, as well as an overplanting scenario, were defined. The aim of the study is a comparative assessment of these approaches. However, this does not entail an optimization of absolute key performance indicators, nor the determination of an optimized offshore development framework.

Methodologically, the scenarios and boundary conditions were first defined (Section 2.1), after which wind fields and energy yields were calculated using the mesoscale model WRF on the basis of weather year 2012 (Section 3). Technical availabilities, O&M processes and operating costs were simulated using the Fraunhofer IWES software OffshoreTIMES (Section 4). Capital costs of wind farms and grid connections were derived from established cost models and the Grid Development Plan (Section 4.4). These costs were distributed evenly over an assumed operational lifetime of 35 years and combined together with the annual operating costs (Section 4.3) and annual electricity yields (Section 5.1) into a cost index (cost per unit of electricity generated) (Section 5.2). A summary tabular overview of the key results is presented in Table 10. Further tabular listings of the results of the individual aspects considered in this study are provided in the respective sections of this report.

The column "Total DE" shows the respective key figures exclusively for the wind farms located in the German EEZ. These results make clear that an improvement in macroeconomic efficiency can be achieved through the reduction of power density in the German EEZ alone.

The results for the totality of all areas considered show that a spatial dispersal of development and the reallocation of capacities to the Danish North Sea and the Danish and Swedish Baltic Sea significantly increase full load hours and total energy yield (approximately +6% in Scenario 1, approximately +13% in Scenario 2, see Figure 5-1). The slightly increasing operating costs (Table 4) and grid connections costs (Table 5), as well as the higher CAPEX in Scenario 2 arising primarily from the longer cable routes from the German mainland to the Danish maritime zones, are more than offset by the yield gains (Figure 5-2). These yield gains come about because the reduced installation density in the German North Sea diminishes wake effects, and because the Danish and Swedish maritime zones exhibit favorable wind conditions and the offshore wind farms located there achieve high electricity yields and full load hours (Table 7).

The overplanting in Scenario 3 does also improve the fed-in electricity yield (Figure 5-1) and the utilization of the grid connections (Table 7), compared to the Base Scenario and Scenario 1, however, due to wake and curtailment losses it falls short of Scenario 2 in terms of electricity yield (Figure 5-1). In Scenario 3, a total of two OGCS are saved compared to the other scenarios. Through the overplanting in Scenario 3, the power density in the German EEZ (North Sea) is overall increased (see Table 2) and yields are also raised (Table 10). However, due to the simultaneously rising CAPEX, the cost index here is overall higher than in Scenario 2 (likewise Table 10). In the offshore wind farms reallocated to Denmark, a better cost index is achieved in Scenario 3 than in Scenario 2. This is not directly attributable to higher electricity yields, however, but is achieved through lower CAPEX (one OGCS is saved in this area compared to Scenario 2) and higher full load hours (despite overplanting, DK-N overall exhibits a lower power density in Scenario 3 than in Scenario 2; Table 2) (Table 10).

Overall, all three alternative scenarios exhibit a lower cost index than the Base Scenario (Figure 5-2); the most favorable cost index is achieved in Scenario 2.

The study thus demonstrates that cross-border spatial planning, while maintaining the German expansion targets, can lead to macroeconomic efficiency gains. Even in Scenario 3 with overplanting, a cost index is achieved that is almost as favorable as that in Scenario 2 with the greatest cross-border capacity reallocation. Area-specific overplanting of grid connection capacities therefore likewise holds significant potential for macroeconomic efficiency improvement, particularly if the degree of such overplanting were to be determined based on a holistic consideration of all relevant aspects (such as additional internal wake effects).

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Appendix A: Corrective Maintenance Assumptions Part I

Table 11: Detailed inputs of the failure model based on Carroll et al. (2016), operator information and in-house expertise: failure rates and power loss

Component Name	Failure Category	Failure Rate (/Turbine/Year) (0-25 years)	Power Loss
Blades	Major Repair	0.010	20%
Blades	Major Replacement	0.002	100%
Blades	Minor Repair	0.456	10%
Blades	Reset	0.053	0%
Contactors / Circuit Breakers / Relays	Major Repair	0.054	100%
Contactors / Circuit Breakers / Relays	Major Replacement	0.002	100%
Contactors / Circuit Breakers / Relays	Minor Repair	0.326	0%
Contactors / Circuit Breakers / Relays	Reset	0.048	50%
Controls	Major Repair	0.054	100%
Controls	Major Replacement	0.001	100%
Controls	Minor Repair	0.355	100%
Controls	Reset	0.018	100%
Electrical Components	Major Repair	0.016	100%
Electrical Components	Major Replacement	0.002	100%
Electrical Components	Minor Repair	0.358	100%
Electrical Components	Reset	0.059	100%
Gearbox	Major Repair	0.038	100%
Gearbox	Major Replacement	0.050	100%
Gearbox	Minor Repair	0.395	0%
Gearbox	Reset	0.046	50%
Generator	Major Repair	0.321	100%
Generator	Major Replacement	0.045	100%
Generator	Minor Repair	0.485	100%
Generator	Reset	0.098	100%
Grease / Oil / Cooling Liquid	Major Repair	0.006	100%
Grease / Oil / Cooling Liquid	Minor Repair	0.407	0%
Grease / Oil / Cooling Liquid	Reset	0.058	0%
Heaters / Coolers	Major Repair	0.007	100%
Heaters / Coolers	Minor Repair	0.190	0%
Heaters / Coolers	Reset	0.016	50%
Hub	Major Repair	0.038	20%
Hub	Minor Repair	0.182	10%
Hub	Reset	0.014	0%
Other Components	Major Repair	0.042	0%

Other Components	Major Replacement	0.001	100%
Other Components	Minor Repair	0.812	0%
Other Components	Reset	0.150	0%
Pitch / Hydraulic	Major Repair	0.179	100%
Pitch / Hydraulic	Major Replacement	0.001	100%
Pitch / Hydraulic	Minor Repair	0.824	100%
Pitch / Hydraulic	Reset	0.072	100%
Power Supply / Converter	Major Repair	0.081	100%
Power Supply / Converter	Major Replacement	0.005	100%
Power Supply / Converter	Minor Repair	0.076	0%
Power Supply / Converter	Reset	0.018	50%
Pumps / Motors	Major Repair	0.043	100%
Pumps / Motors	Minor Repair	0.278	100%
Pumps / Motors	Reset	0.025	100%
Safety	Major Repair	0.004	0%
Safety	Minor Repair	0.373	0%
Safety	Reset	0.015	0%
Sensors	Major Repair	0.070	100%
Sensors	Minor Repair	0.247	0%
Sensors	Reset	0.029	0%
Service Items	Minor Repair	0.108	0%
Service Items	Reset	0.016	0%
Tower / Foundation	Major Repair	0.089	0%
Tower / Foundation	Minor Repair	0.092	0%
Tower / Foundation	Reset	0.004	0%
Transformer	Major Repair	0.003	100%
Transformer	Major Replacement	0.001	100%
Transformer	Minor Repair	0.052	0%
Transformer	Reset	0.009	0%
Yaw System	Major Repair	0.006	100%
Yaw System	Major Replacement	0.001	100%
Yaw System	Minor Repair	0.162	100%
Yaw System	Reset	0.020	100%

Table 12: Detailed inputs of the failure model based on (Carroll et al. 2016), operator information and in-house expertise: repair time, number of technicians and vessels used

Component Name	Failure Category	Repair Time [Hours]	Number of Technicians	Possible Transport Unit
Blades	Major Repair	21	3	SOV
Blades	Major Replacement	288	21	Jack-Up
Blades	Minor Repair	9	2	SOV, Helicopter
Blades	Reset	28	3	SOV, Helicopter
Contactors / Circuit Breakers / Relays	Major Repair	19	3	SOV
Contactors / Circuit Breakers / Relays	Major Replacement	150	8	SOV
Contactors / Circuit Breakers / Relays	Minor Repair	4	2	SOV, Helicopter
Contactors / Circuit Breakers / Relays	Reset	5	2	SOV, Helicopter
Controls	Major Repair	14	3	SOV
Controls	Major Replacement	12	2	SOV
Controls	Minor Repair	8	2	SOV, Helicopter
Controls	Reset	17	3	SOV, Helicopter
Electrical Components	Major Repair	14	3	SOV
Electrical Components	Major Replacement	18	4	SOV
Electrical Components	Minor Repair	5	2	SOV, Helicopter
Electrical Components	Reset	7	2	SOV, Helicopter
Gearbox	Major Repair	22	3	SOV
Gearbox	Major Replacement	231	17	Jack-Up
Gearbox	Minor Repair	8	2	SOV, Helicopter
Gearbox	Reset	7	2	SOV, Helicopter
Generator	Major Repair	24	3	SOV
Generator	Major Replacement	81	8	Jack-Up
Generator	Minor Repair	7	2	SOV, Helicopter
Generator	Reset	13	2	SOV, Helicopter
Grease / Oil / Cooling Liquid	Major Repair	18	3	SOV
Grease / Oil / Cooling Liquid	Minor Repair	4	2	SOV, Helicopter
Grease / Oil / Cooling Liquid	Reset	3	2	SOV, Helicopter
Heaters / Coolers	Major Repair	14	3	SOV
Heaters / Coolers	Minor Repair	5	2	SOV, Helicopter
Heaters / Coolers	Reset	5	3	SOV, Helicopter
Hub	Major Repair	40	4	SOV
Hub	Minor Repair	10	2	SOV, Helicopter
Hub	Reset	8	2	SOV, Helicopter
Other Components	Major Repair	21	3	SOV
Other Components	Major Replacement	36	5	SOV
Other Components	Minor Repair	5	2	SOV, Helicopter

Other Components	Reset	8	2	SOV, Helicopter
Pitch / Hydraulic	Major Repair	19	3	SOV
Pitch / Hydraulic	Major Replacement	25	4	SOV
Pitch / Hydraulic	Minor Repair	9	2	SOV, Helicopter
Pitch / Hydraulic	Reset	17	3	SOV, Helicopter
Power Supply / Converter	Major Repair	14	2	SOV
Power Supply / Converter	Major Replacement	57	6	SOV
Power Supply / Converter	Minor Repair	7	2	SOV, Helicopter
Power Supply / Converter	Reset	10	3	SOV, Helicopter
Pumps / Motors	Major Repair	10	3	SOV
Pumps / Motors	Minor Repair	4	2	SOV, Helicopter
Pumps / Motors	Reset	7	3	SOV, Helicopter
Safety	Major Repair	7	3	SOV
Safety	Minor Repair	2	2	SOV, Helicopter
Safety	Reset	2	2	SOV, Helicopter
Sensors	Major Repair	6	2	SOV
Sensors	Minor Repair	8	2	SOV, Helicopter
Sensors	Reset	8	3	SOV, Helicopter
Service Items	Minor Repair	7	2	SOV, Helicopter
Service Items	Reset	9	2	SOV, Helicopter
Tower / Foundation	Major Repair	7	1	SOV
Tower / Foundation	Minor Repair	5	3	SOV, Helicopter
Tower / Foundation	Reset	6	2	SOV, Helicopter
Transformer	Major Repair	26	3	SOV
Transformer	Major Replacement	1	1	Jack-Up
Transformer	Minor Repair	7	3	SOV, Helicopter
Transformer	Reset	19	3	SOV, Helicopter
Yaw System	Major Repair	20	3	SOV
Yaw System	Major Replacement	49	5	Jack-Up
Yaw System	Minor Repair	5	2	SOV, Helicopter
Yaw System	Reset	9	2	SOV, Helicopter

Appendix B: Corrective Maintenance Assumptions Part II

Table 13: Detailed inputs of the failure model based on (Carroll et al. 2016), operator information and in-house expertise: material costs and lead times

Component Name	Failure Category	Material Cost [€]	Spare Part Lead Time [days]
Blades	Major Repair	3,000	3.5
Blades	Major Replacement	350,000	3.5
Blades	Minor Repair	340	0
Blades	Reset	0	0
Contactors / Circuit Breakers / Relays	Major Repair	4,600	0
Contactors / Circuit Breakers / Relays	Major Replacement	27,000	0
Contactors / Circuit Breakers / Relays	Minor Repair	520	0
Contactors / Circuit Breakers / Relays	Reset	0	0
Controls	Major Repair	4,000	4
Controls	Major Replacement	26,000	4
Controls	Minor Repair	400	0
Controls	Reset	0	0
Electrical Components	Major Repair	4,000	0
Electrical Components	Major Replacement	24,000	0
Electrical Components	Minor Repair	200	0
Electrical Components	Reset	0	0
Gearbox	Major Repair	5,000	5.8
Gearbox	Major Replacement	460,000	5.8
Gearbox	Minor Repair	250	0
Gearbox	Reset	0	0
Generator	Major Repair	7,000	6.3
Generator	Major Replacement	600,000	6.3
Generator	Minor Repair	320	0
Generator	Reset	0	0
Grease / Oil / Cooling Liquid	Major Repair	4,000	0
Grease / Oil / Cooling Liquid	Minor Repair	320	0
Grease / Oil / Cooling Liquid	Reset	0	0
Heaters / Coolers	Major Repair	2,600	0
Heaters / Coolers	Minor Repair	930	0

Heaters / Coolers	Reset	0	0
Hub	Major Repair	3,000	4.3
Hub	Minor Repair	320	0
Hub	Reset	0	0
Other Components	Major Repair	4,800	0
Other Components	Major Replacement	20,000	0
Other Components	Minor Repair	220	0
Other Components	Reset	0	0
Pitch / Hydraulic	Major Repair	3,800	2
Pitch / Hydraulic	Major Replacement	28,000	2
Pitch / Hydraulic	Minor Repair	420	0
Pitch / Hydraulic	Reset	0	0
Power Supply / Converter	Major Repair	10,600	4.7
Power Supply / Converter	Major Replacement	26,000	4.7
Power Supply / Converter	Minor Repair	480	0
Power Supply / Converter	Reset	0	0
Pumps / Motors	Major Repair	4,000	0
Pumps / Motors	Minor Repair	660	0
Pumps / Motors	Reset	0	0
Safety	Major Repair	4,800	0
Safety	Minor Repair	260	0
Safety	Reset	0	0
Sensors	Major Repair	5,000	0
Sensors	Minor Repair	300	0
Sensors	Reset	0	0
Service Items	Minor Repair	160	0
Service Items	Reset	0	0
Tower / Foundation	Major Repair	2,200	0
Tower / Foundation	Minor Repair	280	0
Tower / Foundation	Reset	0	0
Transformer	Major Repair	4,600	6.7
Transformer	Major Replacement	140,000	6.7
Transformer	Minor Repair	190	0
Transformer	Reset	0	0
Yaw System	Major Repair	6,000	2.8
Yaw System	Major Replacement	25,000	2.8
Yaw System	Minor Repair	280	0
Yaw System	Reset	0	0

Appendix C: Wind Turbines Inspection Activities and OGCS Corrective Interventions

Table 14: Annual maintenance for 22 MW wind turbines

Description	Value
Required vessel type	SOV
Number of technicians required	6
Maintenance time in hours per wind turbine	28
Material costs	20,000 €

Table 15: Corrective maintenance OGCS: minor repairs with outage, to be resolved on the converter platform. The assumptions are based on studies by Shields et al. (2021), Warnock et al. (2019) and Lorenz et al. (2025),

Description	Value
Required vessel type	Helicopter
Number of technicians required	Irrelevant
Working time in hours	8
Material costs	Irrelevant
Annual failure rate	0.45

Table 16: Corrective maintenance OGCS: major repair, cable fault with outage. The assumptions are based on studies by Shields et al. (2021) and Warnock et al. (2019) and coordination with transmission system operators.

Description	Value
Required vessel type	Cable Laying Vessel
Number of technicians required	Irrelevant
Working time in hours	48
Material costs	250,000 €
Annual failure rate	0.003/km

Table 17: Annual maintenance for a converter platform. The assumptions are based on studies by Shields et al. (2021) and Warnock et al. (2019) and coordination with transmission system operators.

Description	Value
Required vessel type	Helicopter (PAX12)
Number of technicians required	Irrelevant
Maintenance time per converter platform	7 Days
Material costs	0 €
Structure/schedule	Four times per year; one of which with shutdown

Appendix D: Offshore Logistics Resources

Table 18: Costs and characteristics of vessels, helicopters and technicians (as of 2024)

Component	Hourly rate	Day rate	Mobilisation costs	Mobilisation time	Speed	Capacity [PAX]	Max, Significant wave height	Max, wind speed	Max, Time offshore
SOV (Shorterm Charter)	-	50,000 €	-	5 Days	12 Knots	60	2.5 m	15 m/s	2 Weeks
SOV (Longterm Charter)	-	30,000 €	-	-	12 Knots	60	2.5 m	15 m/s	2 Weeks
Jack-Up (next-Gen)	-	300,000 €	650,000 €	5 Weeks	10 Knots	60	3.0 m	12 m/s	-
Cable Laying Vessel	-	-	-	1 Week	11 Knots	20	2.0 m	15 m/s	
Helicopter	6,000 €	-	-	-	100 Knots	6	-	20 m/s	-
Helicopter PAX4	3,900 €	-	-	-	100 Knots	4	-	20 m/s	-
Technichian	-	1,000 €	-	-	-	-	-	-	-
Technician (external)		1,250 €	-	-	-	-	-	-	-

Appendix E: New Construction Processes

Table 19: New construction processes for offshore wind turbines, offshore substations and OGCS, as well as the working time required for these processes in hours. The figures are based among others on BVG Associates (2019), Liang et al. (2021) and Kikuchi and Ishihara (2023),

Description	Vessel type	Working time
Seabed preparation	Field Support Vessel	5 h per turbine
OWEA Foundation: Jack-Up	Jack-Up Vessel	32 h
OWEA Foundation: Monopile	Jack-Up Vessel	56 h
OWEA Foundation: Transition Piece	Jack-Up Vessel	42 h
OWEA: Preparation	Jack-Up Vessel	10 h
OWEA: Tower	Jack-Up Vessel	27,5 h
OWEA: Nacelle	Jack-Up Vessel	20 h
OWEA: Rotor blades	Jack-Up Vessel	52,5 h
OWEA: Finish and Hand-Over	Jack-Up Vessel	28,75 h
OWEA: Jack-Down	Jack-Up Vessel	4 h
Array Cable: Pre-Lay Grapnel Run	Field Support Vessel	13 h per turbine
Array Cable: Cable laying	Cable-Laying Vessel	20 h per turbine
OSS: Foundation	Jack-Up Vessel	130 h
OSS: Installation	Jack-Up Vessel	25,25 h
Converter platform: Foundation	Jack-Up Vessel	130 h
Converter platform: Installation	Jack-Up Vessel	49,25 h
Export Cable: Cable laying	Cable-Laying Vessel	8,6 h per km

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