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GERMAN OFFSHORE ENERGY ISLANDS IN THE EUROPEAN ENERGY SYSTEM

A case study analysis

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Study on behalf of Copenhagen Energy Islands ApS

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Disclaimer

This study serves as input for the discussion regarding the optimal expansion of offshore wind energy in the North Sea. It describes three possible expansion scenarios with and without Offshore Energy Islands, which of course cannot represent the entirety of all possible scenarios. For example, the option of electrolysers directly located on the coast is not considered, and the effects on the onshore electricity grid are also not part of the analysis. In addition, the study is based on certain assumptions provided by the customer. It also neglects the operating costs of the electricity grid, which is a conservative assumption, as these would increase the cost savings from the Offshore Energy Islands.

Executive summary

The expansion of the political target to 70 GW of offshore wind in Germany compared to the old German grid development plan (NEP) will lead to an extreme increase in grid costs in order to integrate this higher amount of wind power into the German electricity market. For this reason, the task of this study is to examine the economic advantages and disadvantages of direct use of offshore electricity (e.g. through electromobility, heat pumps and new industrial processes) compared to hydrogen production with electricity from offshore wind.
The results show that Offshore Energy Islands (OEIs), taking into account meshing in the European North Sea grid and electrolyser flexibility, can contribute to the following aspects: Firstly, this results in savings in grid costs both for connecting offshore turbines to the coast and for inland routes. Secondly, they enable efficient hydrogen production without long transportation routes for the electricity. Thirdly, in times of low offshore wind and high solar PV generation, connecting the OEIs on the electricity side can make it possible to convert the surplus solar PV electricity into hydrogen.
In this study, a scenario with two OEIs connected to the electricity grid results in annuity savings of 4 261 MEUR/yr, which is especially due to possible savings in HVDC cables.

Contents

Abbreviations

CCGT combined-cycle gas turbines. 25, 27
CCS carbon capture and storage. 25
CHP combined heat and power. 28

DNK Denmark. 9

GBR Great Britain. 9
GER Germany. 9, 19
GHG greenhouse gas. 8, 25, 26

HVDC high-voltage direct current. 22–24

LP linear programming. 8, 25

NEP German grid development plan. 4, 23
NLD Netherlands. 9
NOR Norway. 9
NSWPH North Sea Wind Power Hub. 7
NTCs net transfer capacities. 9, 22, 27

OCGT open-cycle gas turbines. 25, 27
OEI Offshore Energy Island. 4, 7–24, 27

PtX Power-to-X. 27

SCOPE SD SCOPE Scenario Development. 7–9, 11, 22, 23, 25–27
solar PV solar photovoltaics. 26

TYNDP Ten-Year Network Development Plan. 26, 27

1 Introduction

The interactions of electricity and hydrogen production are crucial for the development of offshore energy infrastructure, especially for large offshore wind energy targets [1]. This is where so-called OEIs come into play. They operate as green power plants at sea and therefore help to phase-out fossil fuel energy sources. With these OEIs, wind turbines can be placed further away from the coast and their generated power can be distributed between several countries more efficiently. In other words, the OEIs serve as hubs that gather electricity from the surrounding offshore wind parks and distribute it to the electricity grid on the mainland [2]. It is also possible to produce hydrogen on the OEIs with electrolysers directly located on them. This means that fewer power transmission lines to the mainland are required [3]. Potential design considerations for OEIs including sheltered docking facilities, laydown areas and the construction of breakwater are described in [4]. The appendix of [5] contains methods for island construction and also a break-down of island construction costs. The world's first energy island is currently being built in the Princess Elisabeth Zone located off the coast of Belgium and is scheduled for completion by 2030 [6].

Europe's first-ever Offshore Network Development Plan, which was recently published by ENTSO-E, is particularly relevant to this topic. According to this development plan, an expansion of up to 496 GW of offshore wind until 2050 is a realistic scenario [7]. A large part of this capacity will be built in the North Sea. The respective market interconnection potential in the North Sea is described in [8].

The topic of OEIs has become more present in the media in recent times. Reports on the project under investigation in this study can be found, for example, in [9, 10, 11]. Reports on similar projects in the North Sea also exist for Denmark [12]. Further projects for the production of hydrogen directly offshore are under discussion [13, 14]. The North Sea Wind Power Hub (NSWPH) consortium has also come to the conclusion that the use of power-to-gas conversion and transmission in combination with coupling with other sectors will be beneficial for the overall energy system [15]. This shows that, despite the German Network Development Plan (NEP) [16] and the German area development plan [17], OEIs are part of the possible solution space for the expansion of wind energy in the North Sea.

With a more scientific perspective, the authors in [18] have used the open-source energy system optimization model PyPSA-Eur to find out how much offshore wind energy can be integrated into the European energy system depending on the grid typology and the amount of hydrogen that is produced offshore. Their results indicate that 310 GW offshore wind can be integrated in the North Sea by using point-to-point connections, while the utilisation of meshed networks and hydrogen could allow the integration of up to 420 GW offshore wind.

The objective of this study is to understand potential system and cost advantages of OEIs and to link the results to the German government targets for efficient grid build out and hydrogen ramp-up. The question of which solution is the most cost-effective for society should also be answered.

The remainder of this study is organised as follows: Chapter 2 introduces the methodology with its three different scenarios built on the integrated energy system modelling and optimisation framework SCOPE Scenario Development (SCOPE SD), including the parametrisation of the OEIs. The results for the European and German energy system as well as for the OEIs in particular are then shown in Chapter 3, followed by Chapter 4, which carries out a cost comparison and discusses existing uncertainties. In the Appendix, Chapter 5 gives an overview of the most relevant scenario assumptions and input data.

2
Methodology

2.1
Integrated energy system model SCOPE SD

The pan-European cross-sectoral capacity expansion planning framework SCOPE SD is a bottom-up techno-economic partial equilibrium model. Recent mathematical formulations and applications of SCOPE SD can be found in [19, 20, 21, 22, 23, 24]. Figure 1 illustrates the structure, components, and typical in- and output data of SCOPE SD (upper section) including the interactions of technology options (lower section) in the corresponding markets or policy instruments (middle section).

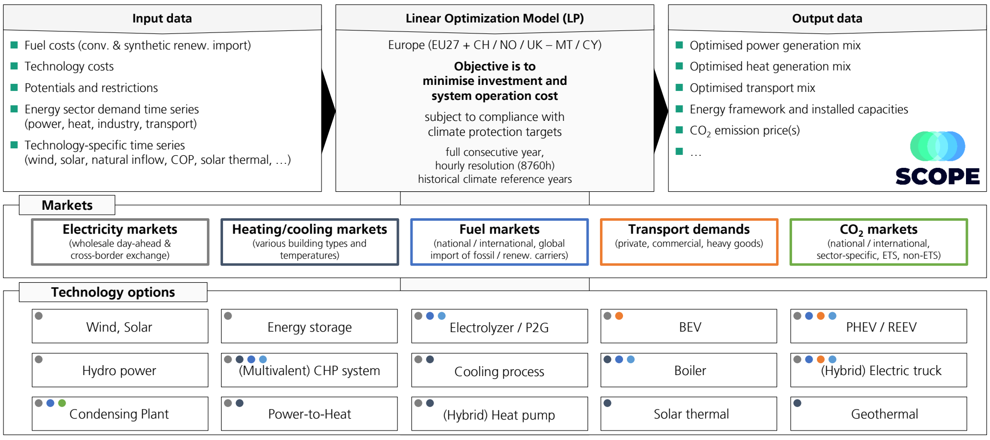


Figure 1 Schematic overview of the pan-European cross-sectoral capacity expansion planning framework SCOPE SD, own illustration. Note that the different dot colours of the technology options indicate the (multi-fold) participation of technology options in the corresponding markets or policy instruments.

The modelling and optimisation framework develops coherent long-term low-carbon energy system scenarios for Europe for a given target scenario year in the future. By minimising the generation, storage, and cross-sectoral consumer technology investment and system operation cost, this large-scale linear programming (LP) approach has representations for the traditional power system as well as for all relevant bi- and multivalent technology combinations at the sectoral interfaces with the building, industry, and transport sectors.
Each market area, i.e. every European country, is usually represented by one node. An exception in this study is the modelling of offshore wind in the North Sea and the modelling of the OEIs, see Section 2.2 and Section 2.3. All units (generation, storage, and cross-sectoral demand technology options), their most important parameters (costs, potentials, and operational characteristics), and their relevant interactions with each other are modelled in hourly resolution. By explicitly modelling national and pan-European fuel markets, it is possible to distinguish between the use of fossil fuels, on the one hand, and synthetic renewables, on the other hand, which are either imported from outside of Europe or produced domestically. In order to account for net-neutrality in future scenarios, national and international greenhouse gas (GHG) emission budgets are implemented as a driving force behind investments in low-carbon technologies.

2.2 Conceptual approach

To address the outlined objectives, this study analyses three different scenarios for a long-term, climate-neutral European energy system with the pan-European cross-sectoral capacity expansion planning framework SCOPE SD. In principle, the model does not contain a detailed representation of electricity grids. However, in order to be able to model an emerging electricity grid in the North Sea region, the offshore wind parks of Germany (GER), the Netherlands (NLD), Denmark (DNK), Great Britain (GBR) and Norway (NOR) that are connected to the North Sea grid are modelled as separate nodes (recall Section 2.1).
Offshore capacity in Germany is set at 70 GW [25], of which 5.1 GW is located in the Baltic Sea [26] and the remaining 64.9 GW in the North Sea. The expansion target for the Netherlands is 58.3 GW [27], of which 36.5 GW can be connected to the North Sea grid [8], the remaining 21.8 GW are connected exclusively to the Dutch mainland. For Norway, 3.8 GW [8] of a total of 30 GW [28] are included in the North Sea grid. In Denmark it is 14.7 GW [8] out of 39.8 GW, in Great Britain it is 42.3 GW out of 105.3 GW [8, 27].
All these offshore wind parks are also connected to their respective national power grid with exogenously given net transfer capacities (NTCs) whose capacity corresponds to the capacity of the offshore wind parks, see the black solid lines in Figure 2 to Figure 4 below. Endogenous expansion of NTCs is permitted between the offshore wind parks in the North Sea grid, see the yellow dashed lines in the following figures. Endogenous electrolyser expansion for the production of hydrogen is only allowed on the mainland and on the two OEIs, but not on the mentioned wind parks. There are further fixed assumptions on NTCs in Europe outside the North Sea region.
The results of the case study for the European energy system focus on the electricity production capacities and quantities as well as on domestic hydrogen generation by electrolysers. For the OEIs in particular, the quantities of electricity and hydrogen generated are evaluated.
The three scenarios differ as follows:

Scenario 1: The European energy system is modelled without any OEIs. 70 GW of German offshore wind parks are directly connected to the German electricity grid. As already mentioned, 5.1 GW of this is located in the Baltic Sea and 64.9 GW is located in the North Sea. Domestic hydrogen production is solely placed on the mainland and therefore also directly included in the German electricity market. A graphical representation of scenario 1 is shown in Figure 2:

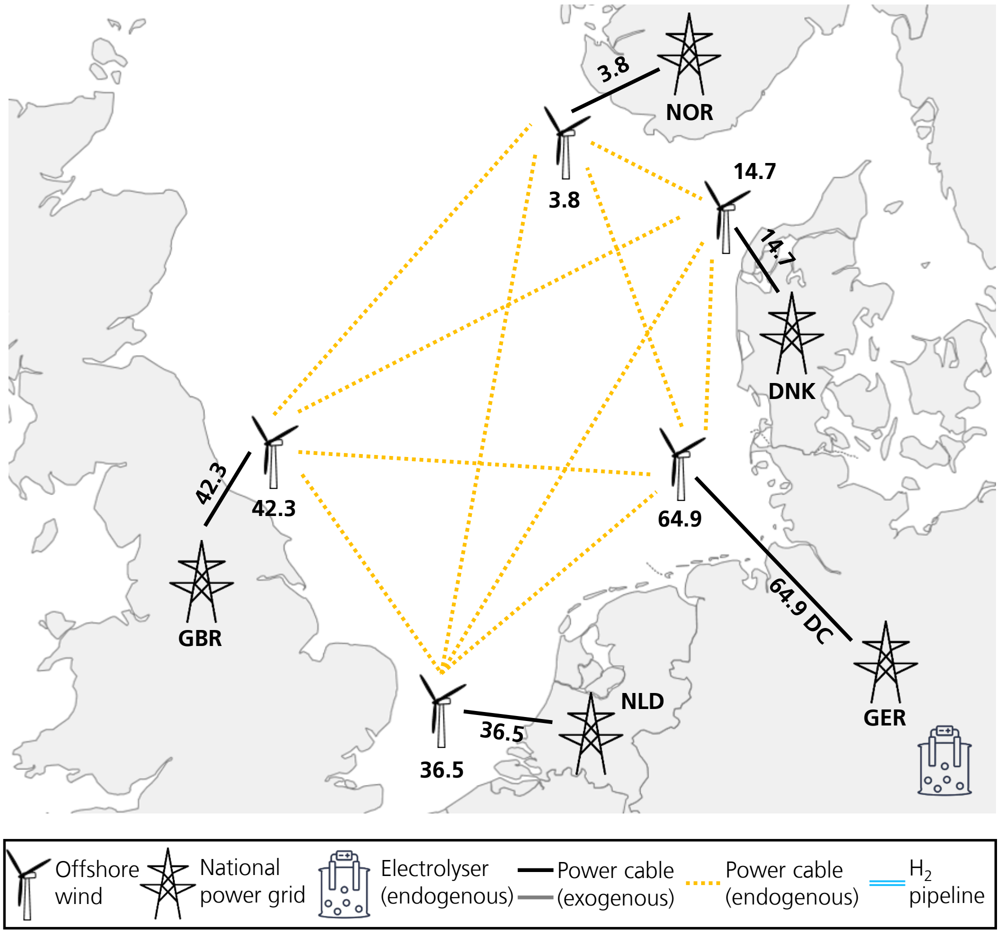


Figure 2 Schematic modelling of offshore wind parks in GW and electrical interconnectors in GW in the North Sea region in scenario 1, own illustration.

Scenario 2.1: The European energy system is modelled with two German OEIs that are further named “OEI 1” and “OEI 2”. 50 GW of German offshore wind parks are directly connected to the German electricity grid (of which 44.9 GW in the North Sea), while another 20 GW of German offshore wind parks are connected with electrolysers on the OEIs via AC power cables. These are further interconnected to the German mainland via pipelines. There is no electrical connection between the OEIs with its 20 GW of offshore wind and electrolysers on the one hand and the German electricity grid on the other hand. Electrolysers can be built not only on the OEIs, but also on the mainland. The electrical connection between the 44.9 GW of offshore wind and the German mainland is set at 44.9 GW DC respectively. A graphical representation of scenario 2.1 is shown in Figure 3:

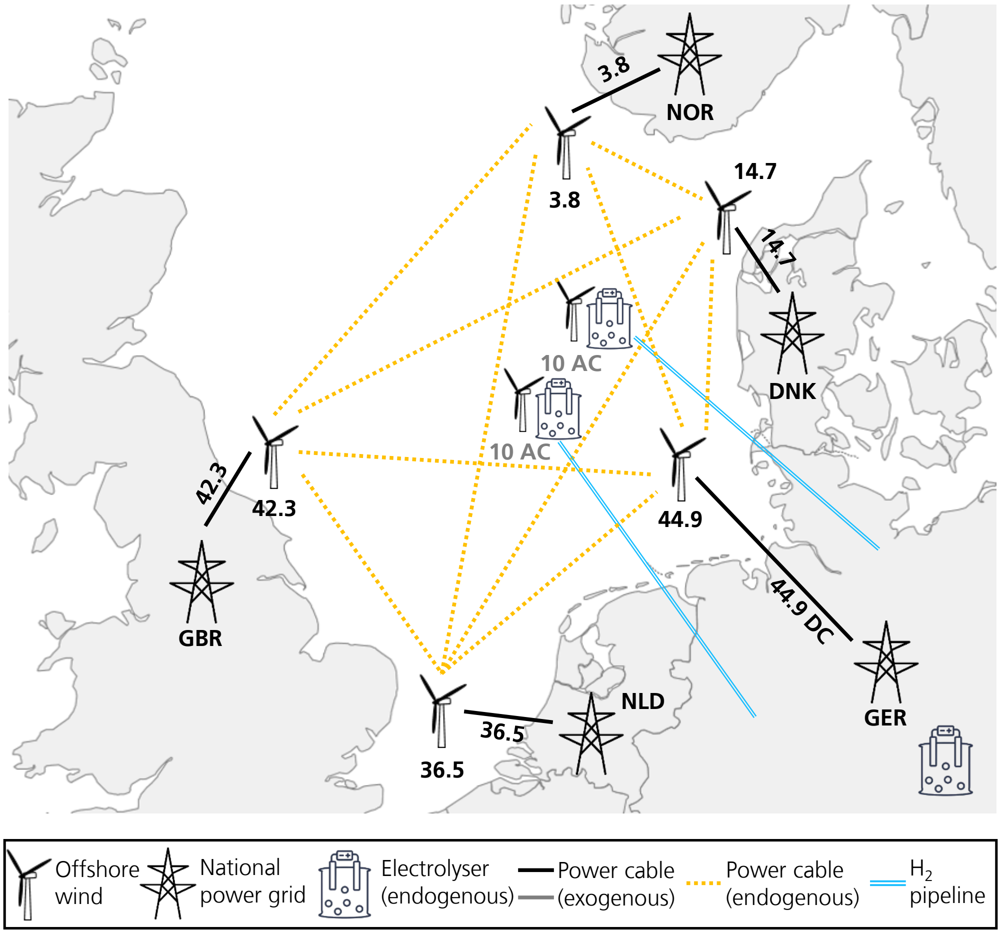


Figure 3 Schematic modelling of offshore wind parks in GW, electrical interconnectors in GW, OEIs, and pipelines in the North Sea region in scenario 2.1, own illustration.

Please note that pipelines are not modelled in SCOPE SD, which is why they are only shown here for illustrative purposes and do not represent a statement about the actual expansion.

Scenario 2.2: The European energy system is again modelled with two German OEIs. In this scenario, they have an electrical connection to the remaining German offshore wind parks in the North Sea. The capacity of the offshore wind parks connected to the OEIs is still 20 GW, their electrical connection to the offshore network is modelled with a capacity of 20 GW AC respectively. Due to that, the offshore wind parks from the OEIs only have 2nd priority access to the 44.9 GW DC connection to the mainland. The power cables between the offshore wind parks (see orange lines in the figure below) are set to the resulting values from scenario 2.1. In this way, the resulting effect and the utilisation of the power cables between the OEIs and the German offshore wind park can be better worked out, as comparability would no longer be possible if the power cable expansion between the scenarios differed. Electrolysers can be built not only on the islands, but also on the mainland. A graphical representation of scenario 2.2 is shown in Figure 4:

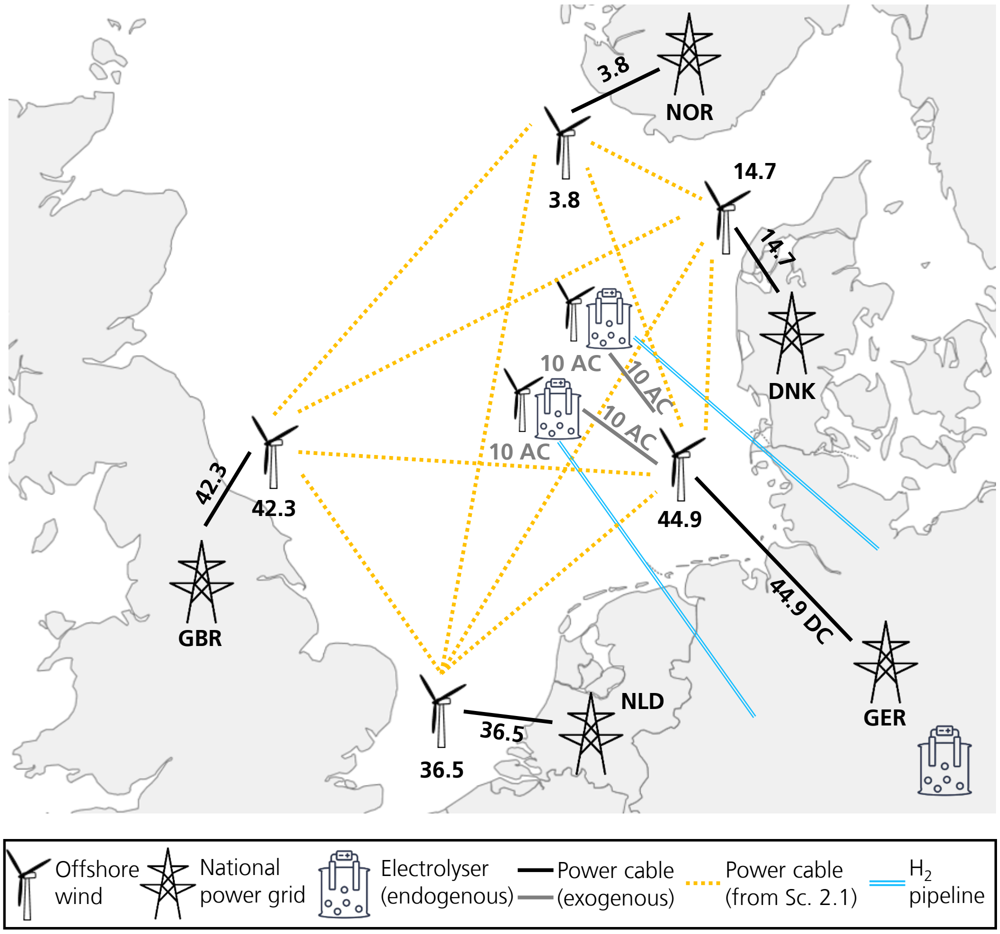


Figure 4 **Schematic modelling of offshore wind parks in GW, electrical interconnectors in GW, OEIs, and pipelines in the North Sea region in scenario 2.2, own illustration.**

2.3
Parametrisation of Offshore Energy Islands

As already stated, two OEIs are considered in this study, referred to as “OEI 1” and “OEI 2”. Some of their general parameters as specified in consultation with the client are given in Table 1.

Table 1 General parameters of the two German OEIs, assumptions in consultation with the client.

Name	Construction costs	Distance to mainland	Lifetime
OEI 1	3.3 bn EUR	150 km	70 years
OEI 2	3.3 bn EUR	200 km	70 years

The lifetime of 70 years assumes that two generations of wind turbines can be connected to the OEIs. This is in line with assumptions from [29].

For a cost comparison later in this study, the construction costs of the two OEIs must be converted into a value to be paid per year. For this purpose, an annuity is calculated based on the lifetime of 70 years, which is dependent on an interest rate to be selected for the capital cost. The resulting annual costs depending on this interest rate are listed in Table 2.

Table 2 Annuity for one OEI in MEUR/yr depending on the interest rate with an assumed lifetime of 70 years.

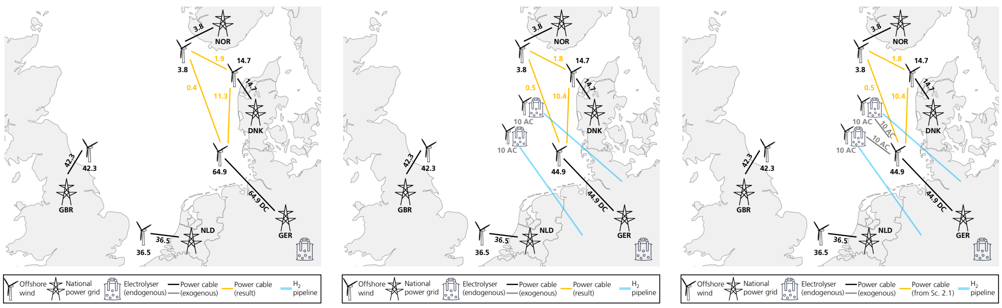
Interest rate	1 %	2 %	3 %	4 %	5 %	6 %	7 %	8 %	9 %	10 %
Annuity in MEUR/yr	65.8	88.0	113.3	141.1	170.6	201.4	233.0	265.2	297.7	330.4

3
Case study results and discussion

In the following, Section 3.1 shows the resulting offshore network in scenario 2.1 which is then transferred as an exogenous assumption to scenario 2.2. Section 3.2 shows the results for the European energy system, Section 3.3 does the same for the German energy system. The resulting characteristics of the two German OEIs are shown in Section 3.4, while Section 3.5 focuses on the utilisation of electrolysers in the different scenarios. Section 3.6 closes this chapter with a special focus on electricity imports and exports to and from the OEIs in scenario 2.2.

3.1
Resulting offshore network

Figure 5 shows the resulting offshore network in each scenario. A kind of triangle is always built between the offshore wind parks of Germany, Denmark and Norway. The wind parks in Great Britain and the Netherlands are not connected to the offshore network by the model, the electricity produced there can only be transferred directly to the respective mainland.



(a) Scenario 1 **(b) Scenario 2.1** **(c) Scenario 2.2**

Figure 5 Resulting offshore network in each scenario in GW, own illustration based on own calculations.

As already stated, the resulting offshore network from scenario 2.1 is used as an exogenous assumption in scenario 2.2. In this way, the additional effect and the utilisation of the power cables between the OEIs and the German offshore wind park can be shown.

In scenario 1, 51.7 % of the power cable from the German offshore wind park to the mainland (64.9 GW) is utilised on average. In the scenarios with OEIs, the average utilisation of the power cable (now 44.9 GW) is 55.8 % in scenario 2.1 and 54.6 % in scenario 2.2.

3.2
Results for the European energy system

The evaluation of the European energy system focuses on the changes between the three scenarios. Table 3 shows the changes in the European electricity production capacities that can be seen in scenario 2.1 and scenario 2.2 in comparison to scenario 1.

Table 3 Changes in European electricity production capacities in GW in comparison to scenario 1.

Technology	Scenario 2.1	Scenario 2.2
Solar PV	+7.0	+2.8
Wind onshore	-	-0.1
Wind offshore	-	-
CHP	+0.2	-
Hydrogen turbines	+3.4	+0.7
Batteries	+3.2	+0.5

In scenario 2.1, more solar PV, hydrogen turbine and battery storage capacities are expanded. This is due to the fact that the 20 GW of offshore wind, which is allocated to the OEIs without a power cable connection, is not available to the electricity market. While onshore wind has already been expanded to its limit and offshore wind is not selected by the model due to its high costs, the missing electricity must be covered by other technology options. In scenario 2.2, this effect is much less pronounced, as there is now a power cable connection to the OEIs so that electricity can be imported from there.

On a general note, the model always calculates the most cost-effective energy system overall. With less offshore wind energy in the market, the energy system is somewhat less efficient and requires more capacity from other technologies to compensate.

Following the same principle, Table 4 shows the resulting differences for the European electricity generation quantities.

Table 4 Changes in European electricity generation quantities in TWh in comparison to scenario 1.

Technology	Scenario 2.1	Scenario 2.2
Solar PV	+9.3	+3.7
Wind onshore	+0.4	-0.8
Wind offshore	-	-
CHP	+2.6	+0.7
Hydrogen turbines	+1.3	+0.3
Nuclear	-0.1	-0.1
Batteries	+6.0	+1.7

The trend in the quantities of electricity produced goes hand in hand with the trend from the evaluation of capacities. In particular, more electricity is being generated from solar PV, and CHP plants are being utilised more. There is also a higher level of production from battery storage systems, whose energy must of course be supplied beforehand.

Finally, Table 5 shows the differences in electrolyser characteristics across Europe.

Table 5 Changes in European electrolyser characteristics in comparison to scenario 1.

	Scenario 2.1	Scenario 2.2
Electrolyser capacities in GW_{el}	+5.6	+0.6
Hydrogen production in TWh_{th}	+11.3	+3.5
Full load hours in h	-16.8	+6.5

In scenario 2.1, there is a significantly higher expansion of electrolyser capacities across Europe, particularly as there is no other option for using the electricity produced from the offshore wind parks that are connected to the OEIs. Accordingly, the quantities of hydrogen produced are higher, which also explains the higher utilisation of the CHP plants mentioned above, as the hydrogen is burned there. It is noticeable that the full load hours are higher in scenario 2.2, as the electrolysers on the islands in particular can be better utilised thanks to the existing power cable connections.

It should be mentioned that hydrogen is not imported from outside Europe in any of the scenarios. However, this is not due to a limitation in the model; importing hydrogen is possible in principle. Instead, the system has a lot of electricity available, particularly due to the high offshore capacities, so that the electricity price is relatively low. The marginal costs of the electrolysers are therefore below the exogenously given hydrogen import price, so that no import takes place and the entire demand is covered by domestic production.

3.3 Results for the German energy system

A similar comparison as for Europe is made for Germany below. Accordingly, Table 6 starts with the German electricity production capacities.

Table 6 Changes in German electricity production capacities in GW in comparison to scenario 1.

Technology	Scenario 2.1	Scenario 2.2
Solar PV	-	-
Wind onshore	-	-
Wind offshore	-	-
CHP	-	-
Hydrogen turbines	+4.9	+1.3
Batteries	+1.7	-0.1

There are no changes in solar PV, onshore and offshore wind and CHP plant capacities. However, more hydrogen turbines are expanded in scenario 2.1 and scenario 2.2 compared to scenario 1. Scenario 2.1 also includes more battery storage, in scenario 2.2 the change is negligible.

In the following, Table 7 shows the resulting differences for the German electricity generation quantities.

Table 7 Changes in German electricity generation quantities in TWh in comparison to scenario 1.

Technology	Scenario 2.1	Scenario 2.2
Solar PV	-	-
Wind onshore	+0.4	-
Wind offshore	-	-
CHP	+1.4	+0.3
Hydrogen turbines	+1.5	+0.4
Batteries	+3.4	+0.6

In addition to the expected changes due to the increased expansion of hydrogen turbines, it is noticeable that the CHP plants are more heavily utilised, which in turn can be explained by the higher amount of available hydrogen. In scenario 2.2, the capacity of battery storage systems is slightly lower than in scenario 1 as mentioned before, but their utilisation is now also higher.

Table 8 shows the differences in electrolyser characteristics in Germany.

Table 8 Changes in German electrolyser characteristics in comparison to scenario 1.

	Scenario 2.1	Scenario 2.2
Electrolyser capacities in GW_{el}	+3.1	-0.2
Hydrogen production in TWh_{th}	+9.6	+4.2
Full load hours in h	+13.5	+97.0

As expected, more electrolyser capacities are expanded in scenario 2.1 and slightly less in scenario 2.2. Nevertheless, the amount of hydrogen produced is higher in both scenarios than in the reference case. The higher number of full-load hours in scenario 2.2, which is almost 100 hours higher than in scenario 1, is remarkable.

Finally, it should be mentioned that the configuration of the scenarios has an impact on the curtailment of German offshore wind power generation in the North Sea. As shown in Table 9, the amount of curtailed electricity is highest in scenario 1, while it is lowest in scenario 2.2. This is due to the direct use of that electricity by the electrolysers on the OEIs.

Table 9 Curtailment of German offshore wind power in the North Sea (including OEIs) in the different scenarios.

	Scenario 1	Scenario 2.1	Scenario 2.2
Curtailment in TWh	4.2	3.6	2.6

3.4
Resulting characteristics of the Offshore Energy Islands

Table 10 and Table 11 show the offshore wind and electrolyser capacities installed on the two OEIs for each scenario, the resulting electricity production and consumption, and the quantities of hydrogen produced.

Table 10 Results for the two OEIs in scenario 2.1.

	“OEI 1”	**“OEI 2”**
Offshore wind capacity in GW	10	10
Electrolyser capacity in GW	7.8	7.8
Offshore wind generation in TWh	36.6	36.6
Electrolyser consumption in TWh	36.3	36.3
Electrolyser full load hours in h	4 673	4 673
Hydrogen production in TWh	25.8	25.8
Curtailment in TWh	0.3	0.3

Table 11 Results for the two OEIs in scenario 2.2.

	“OEI 1”	**“OEI 2”**
Offshore wind capacity in GW	10	10
Electrolyser capacity in GW	9.7	8.3
Offshore wind generation in TWh	36.6	36.6
Electrolyser consumption in TWh	49.6	39.9
Electrolyser full load hours in h	5 099	4 798
Hydrogen production in TWh	35.2	28.3
Curtailment in TWh	0	0

In scenario 2.1, the results are identical for both OEIs, as the only difference between them, namely the distance to the mainland, has no effect without a power cable. Scenario 2.2 shows differences in the capacities and usage of electrolysers between the scenarios and the OEIs: It can be seen that the electrolyser capacities in scenario 2.2 are higher than in scenario 2.1, as additional electricity can now be used through imports. The capacity on “OEI 1” is higher, as it has a shorter distance from the mainland and the electricity transport is associated with correspondingly fewer losses. Accordingly, the quantities of hydrogen produced in scenario 2.2 are also higher than in scenario 2.1.

Table 12 to Table 15 show the operational characteristics for each of the two OEIs in scenario 2.1 and scenario 2.2. The tables show for what application the electricity production from offshore wind is used and where the electricity for the electrolysers on the OEIs comes from.

Electrolysers	99.06 %
Curtailment	0.94 %

(a) Utilisation of offshore wind energy

Offshore wind	100 %

(b) Operation of electrolysers

Table 12 Resulting operational characteristics of “OEI 1” in scenario 2.1.

Electrolysers	99.06 %
Curtailment	0.94 %

(a) Utilisation of offshore wind energy

Offshore wind	100 %

(b) Operation of electrolysers

Table 13 Resulting operational characteristics of “OEI 2” in scenario 2.1.

In scenario 2.1, almost the whole wind power from the OEIs feeds the offshore electrolysers. Less than 1 percent of the available electricity is curtailed. The electrolysers draw their electricity directly from the connected offshore wind parks. As there are no power cables to and from the OEIs in this scenario, no electricity can be transported from the wind turbines to the mainland and no electricity can be transported from the mainland to the electrolysers.

Electrolysers	81.32 %
Export to GER	18.68 %
Curtailment	0.00 %

(a) Utilisation of offshore wind energy

Offshore wind	60.04 %
Import from GER	39.96 %

(b) Operation of electrolysers

Table 14 Resulting operational characteristics of “OEI 1” in scenario 2.2.

Electrolysers	84.90 %
Export to GER	15.10 %
Curtailment	0.00 %

(a) Utilisation of offshore wind energy

Offshore wind	77.88 %
Import from GER	22.12 %

(b) Operation of electrolysers

Table 15 Resulting operational characteristics of “OEI 2” in scenario 2.2.

In scenario 2.2, on both OEIs, more than 80 % of the wind power produced is consumed directly by the electrolysers. There is no curtailment, the remaining wind power is exported via the power cables available in this scenario. There are major differences between the islands when it comes to operating the electrolysers: The electrolysers on “OEI 1”, which is closer to the mainland, obtain 60 % of their electricity from the wind turbines, with the remainder being imported. On “OEI 2”, 78 % of the electrolysers are operated with electricity from the wind turbines, and the imported quantity is correspondingly lower. This is due to the fact that the longer power cable from “OEI 2” to the mainland is subject to higher losses of electricity.

3.5
Utilisation of electrolysers in the different scenarios

Figure 6 shows the standardised usage profiles of German electrolysers in scenario 1 (69 GW) and of electrolysers on the German OEIs in scenario 2.1 (15.5 GW) and scenario 2.2 (18.1 GW).

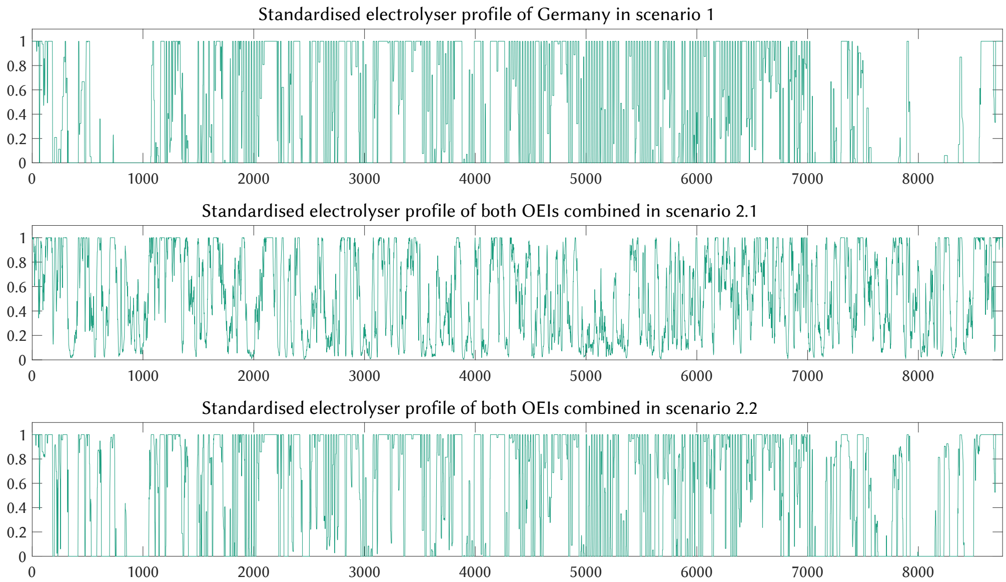


Figure 6 Standardised electrolyser profiles in the different scenarios, own calculations.

In scenario 1, the utilisation of the electrolysers over the year is approximately 45 %. The electrolysers on the OEIs are utilised at a higher rate, namely 53 % in scenario 2.1 and 57 % in scenario 2.2. The profile in scenario 2.1 is almost identical to the profile of the wind power generated, as there is no other way of using the wind power than by electrolysers and, in turn, the electrolysers have no other way of obtaining electricity. The electrolysers in scenarios 1 and 2.2, on the other hand, receive market price signals which is why the profiles look noticeably different than in scenario 2.1. A 100 % utilisation of the electrolysers (value of 1 in Figure 6) occurs in scenario 1 in 2 825 hours, in scenario 2.1 in 1 187 hours and in scenario 2.2 in 2 993 hours.
The behavior during the dark doldrums (shortly before the 1 000th hour of the year) is clearly visible in the profiles: While in scenario 2.1 electricity is converted into hydrogen at this time due to a lack of alternatives, the electrolysers are not used in scenarios 1 and 2.2, as the wind power is needed on the European mainland. On the other hand, the period shortly after the 5 000th hour of the year shows that in times of low wind availability, correspondingly little hydrogen is produced in scenario 2.1, while in scenarios 1 and 2.2, electricity can be used from the European mainland for the purpose of hydrogen production thanks to the power cable connection of the electrolysers.

3.6
Analysis of imports and exports

Net imports from Germany differ very little between the different scenarios. In scenario 1, net imports are the lowest at approximately 50.5 TWh, while in scenario 2.1 they are the highest at approximately 59.7 TWh.

Scenario 2.2 allows imports to and exports from the OEIs. Figure 7 shows these imports and exports of “OEI 1” and “OEI 2” as sorted annual duration lines.

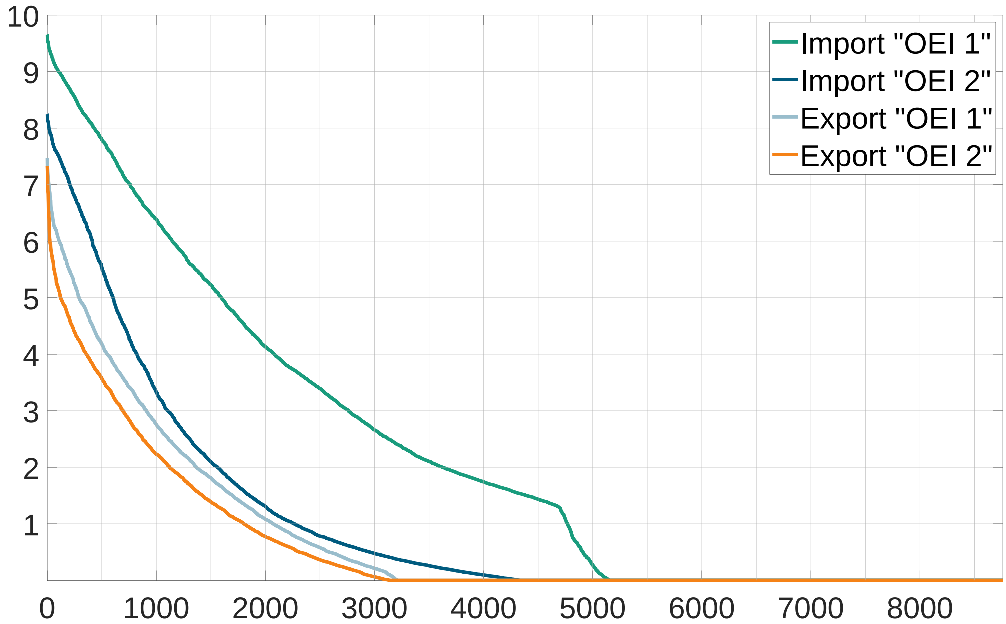


Figure 7 Imports to and exports from the OEIs in scenario 2.2 as annual duration curves in GW, own calculations.

In line with the previous findings, it can be seen that more electricity is imported to the electrolysers on the OEIs than is exported to the mainland. As the power cable to and from “OEI 1” is shorter and therefore less lossy, more electricity is transported to the electrolysers there. The exogenously given capacities of 10 GW AC cables are almost fully utilised at peak times - on “OEI 1” the maximum capacity utilisation is 9.66 GW, on “OEI 2” it is 8.25 GW. The sum of imports and exports per island and subsequent division by the capacity of the respective power cables results in a capacity utilisation of 30.46 % for the “OEI 1” power cable and 16.41 % for the “OEI 2” power cable.

4
Cost comparison, existing uncertainties and conclusion

4.1
Cost comparison between the scenarios

The following Table 16 compares the possible range of annual costs in the different scenarios. Scenario 1 serves as the reference scenario. The calculations for hydrogen pipelines and high-voltage direct current (HVDC) cables have been made using an interest rate of 6 % and a depreciation period of 40 years.

Table 16 Changes in costs between the different scenarios in MEUR/yr, own calculations.

	Scenario 2.1	Scenario 2.2
Change in total annual system costs in SCOPE SD	119	- 777
Annuity for OEIs	403	403
Hydrogen pipelines to the coast (offshore)	193	193
Hydrogen pipelines onshore	342	342
Saved HVDC cables from offshore wind parks to the coast (20 GW)	- 1 095	- 1 095
Connection of offshore wind turbines to OEIs	104	104
HVDC cables from the coast to the south	- 3 431	- 3 431
Cost difference between the scenarios	**- 3 365**	**- 4 261**

4.1.1
Total annual system costs

The change in total annual system costs, which is the differing value of the objective function of SCOPE SD, results directly from the model runs (recall Section 2.1). The costs for the additional electricity connection of the OEIs to the remaining German offshore wind parks and the costs for the exogenously given NTCs between Germany, Denmark and Norway in scenario 2.2 are added up retrospectively.
From the perspective of SCOPE SD, scenario 2.1 is more expensive than scenario 1, as the 20 GW of offshore wind connected to the OEIs can only be used by electrolysers and is not flexibly available to the entire energy system. The savings of 777 MEUR/yr in scenario 2.2 result from efficiency gains through better power cable utilisation.

4.1.2
Annuity for OEIs

The annuity for the two OEIs is calculated using the given sum of construction costs of 6.6 billion EUR, an assumed lifetime range of 70 years and an interest rate of 6 % (recall Table 2).

4.1.3
Hydrogen pipelines

The costs for the hydrogen pipelines are calculated as the sum of the costs for pipes and compressors. The specific costs for the pipes are taken from the “European Hydrogen Backbone” [30], the costs for the compressors are taken from the publication “Extending the European Hydrogen Backbone” [31].

4.1.4
Connection of offshore wind turbines to OEIs

Both scenario 2.1 and scenario 2.2 require 20 GW less wind power to be connected to the German mainland in SCOPE SD due to the construction of the OEIs (recall Figure 2, Figure 3 and Figure 4). In return, the offshore wind turbines must now be connected to the OEIs. The costs for the offshore grid per GW and km have been determined on the basis of [32].

4.1.5
HVDC cables from the coast to the south

The biggest cost savings result from the HVDC cables that are to run from the coast to the south of Germany in the future. According to the second draft of the NEP written by the German transmission system operators [16], the investment costs for the offshore grid plus those cables to the south amount to 145.1 billion EUR for an expansion path of 70 GW and 77 billion EUR for an expansion path of 50.5 GW. The difference between these two paths is around 20 GW, which corresponds to the capacity that would be replaced by the OEIs. The cost difference of 68.1 billion EUR, which corresponds to a saving of 47 %, is converted into an annuity of 4 526 MEUR/yr. The costs for saved HVDC cables from offshore wind parks to the coast are deducted from these two annuities in Table 16 in order to calculate the savings for the HVDC cables from the coast to the south.
It should be noted that the subsequently published confirmation of the NEP assumes higher costs of 160 billion EUR for the offshore grid plus power cables to the south [33, 34]. The approach taken here is therefore more conservative, as the distribution of these cost increases is not known.

4.1.6
Cost difference between the scenarios

Overall, it can be seen that both scenarios with OEIs have cost advantages of around 3 365 MEUR/yr and 4 261 MEUR/yr compared to the scenario without OEIs. This is especially due to the savings in HVDC cables, although the amount is subject to uncertainty.

4.2
Existing uncertainties

4.2.1
Offshore Energy Islands

Uncertainties in the evaluation of the costs exist initially in the annual costs to be estimated for the OEIs. The construction costs of 3.3 billion EUR per island were stated by the client, but the interest rate to be applied to the capital costs cannot be fixed at a single value in practice.

4.2.2
Offshore grid

The costs for the offshore grid are generally subject to very large uncertainties [32, 35]. The distances between the offshore wind parks of the individual countries are based on self-generated point-to-point measurements, which of course only represent reality in a very simplified way. The results of the model show that the selected parameters are robustly expensive, as relatively few power cables are built. A sensitivity model run with changed power cable costs is therefore not considered necessary.

4.2.3
Hydrogen import prices and electrolyser costs

As already mentioned in Section 3.2, there is no import of hydrogen from outside Europe in any of the three scenarios. The import price was set exogenously at 85.00 EUR/MWh_{th}, but is of course subject to uncertainty. Current publications by Fraunhofer IEE assume possible ranges of 72.50 EUR/MWh_{th} to 97.50 EUR/MWh_{th} [24, 36]. Setting a higher price in this study would have no impact on the results, but a lower price could result in a shift from domestic generation to more imports. If the costs for electrolysers are higher than assumed in this study (see Section 5.7 in the Appendix), this could potentially have an effect on the results, the level of which would have to be calculated using further model simulations. However, the differences in the electrolyser capacities of the three scenarios carried out here (see Section 3.2) are relatively small, so that an increase in costs only minimally influences the cost results outlined in Section 4.1.

4.2.4
HVDC routes in Germany

There are major uncertainties with regard to the HVDC routes in the German domestic infrastructure. This applies both to the building costs of the connections themselves and to the time required for approvals and construction, which have a correspondingly expensive impact. The amortization period applied and the interest rate for the capital costs are also very influential in the magnitude of these costs. According to a proposal by the German transmission system operators [37], the construction of overhead lines instead of underground cables could reduce the costs for the HVDC routes by half.

4.3
Conclusion

Despite the high degree of uncertainty, however, it should be noted that based on the findings of this study, Offshore Energy Islands (OEIs), taking into account meshing in the European North Sea grid and electrolyser flexibility, can contribute to the following aspects:
Firstly, the results indicate savings in grid costs both for connecting offshore turbines to the coast and for inland routes. Secondly, OEIs enable efficient hydrogen production without long transportation routes for the electricity. Thirdly, in times of low offshore wind and high solar PV generation, connecting the OEIs on the electricity side can make it possible to convert the surplus solar PV electricity into hydrogen.
In this study, a scenario with two OEIs connected to the electricity grid has resulted in annuity savings of 4 261 MEUR/yr, which is especially due to possible savings in HVDC cables.

5 Appendix: Scenario assumptions and input data

In the long-term scenarios for 2045, Europe is modelled as a net-neutral system, implying that fewer GHG emissions are being produced than absorbed by the system. Note that this study only contains a pan-European GHG emission budget without any additional layer of the country- or instrument-specific budgets. The term “Europe” refers to the current 27 Member States of the European Union without Malta and Cyprus but including Norway, Switzerland, and Great Britain (recall Figure 1).
The SCOPE SD model used for this case study is implemented in MATLAB®. The resulting LP instances in this case study have been solved with the Barrier (interior point) algorithm of Gurobi Optimizer Version 11.0.0 [38] on a medium-range HPCC node (Intel XEON E5-2698v3 16 Cores @ 2.30 GHz, 256 GB RAM).

5.1 General scenario assumptions

To consider meteorological effects and past climate conditions, the historical meteorological reference year 2012 is used to derive weather-dependent input data. The choice for this year is mainly due to the fact that it features a two-week “Kalte Dunkelflaute” period (cold dark doldrums) and is, therefore, well-suited (e.g., see [27]) to represent extreme weather conditions of the integrated energy system in the future and their implication for design choices by the modelling framework.
Several data sources are used to determine the various energy demands in the end-use sectors. The final traditional electricity demand of every country in Europe is based on ENTSO-E data [39]. For the countries of Northern Europe, i.e. Denmark, Finland, Norway, and Sweden, electricity consumption is aligned with an analysis from Statnett [40] to reflect developments of new consumers, e.g. data centres. Final energy demand developments of the European transport and heating sectors are based on the EU Reference Scenario 2016 [41].

5.2 Thermal power generation

For large thermal power plants, a distinction is made between existing or planned plants and new to-be-built ones. In the former category, projections are made using specific lifetime assumptions for the existing and already planned thermal power plants from the PLATTS database [42]. Note that this only affects the remaining nuclear production capacities in Bulgaria (0.95 GW), the Czech Republic (4.18 GW), Finland (1.63 GW), France (18.86 GW), Great Britain (4.58 GW), Poland (1.52 GW), Romania (1.37 GW), and Slovakia (1.73 GW). In addition, nuclear production capacities amounting to 3.5 GW are assumed in Sweden [43]. In the latter category, SCOPE SD can make investment decisions for open-cycle gas turbines (OCGT) and combined-cycle gas turbines (CCGT), both with or without possible cogeneration of heat and power.
Further note that all new to-be-built thermal power plants use hydrogen as their primary fuel source. Solutions involving Carbon Capture and Storage (CCS) technologies are not considered.

5.3
Heat generation

Detailed information on the modelling and input data of heat generation technologies including heat pumps, thermal storage, district heating, and industrial heat generation can be found in [21, 22], which also feature a detailed overview of the required time series data for renewable generation, end-use demands for electricity and heat, and passenger transport demands. Moreover, note that the conventional electricity load profiles in Europe from published ENTSO-E data [44] are adjusted by corrections of today's heat-dependent electricity consumption since the modelling framework has explicit representations of the thermal demand sectors and decides on the optimal supply mix.

5.4
Renewable power generation

For renewable power generation, rooftop and utility-scale solar photovoltaics (solar PV) as well as onshore and offshore wind technology potentials are based on Fraunhofer IEE's internal "satellite models", which combine land-use data [45] with numerical weather prediction information based on the historical meteorological reference year. The European onshore wind capacities are scaled to the capacities of the "Distributed Energy 2050" scenario of the Ten-Year Network Development Plan (TYNDP) 2022 [27]. The same source with its 433 GW is used for offshore wind capacities, with the German capacities rounded to 70 GW [25] and the Norwegian capacities set to 30 GW [28], which then results in 456 GW offshore wind capacities in the European market area. The maximum value of 496 GW offshore wind capacities stated in the Offshore Network Development Plan [7] is therefore slightly undercut.
In the countries of Northern Europe, i.e. Denmark, Finland, Norway, and Sweden, solar PV capacities are adjusted to the values from the Nordic Grid Development Perspective 2021 [46]. As previously mentioned, only green hydrogen is permitted in the model's hydrogen sector. Following the classification of different types and origins of hydrogen in [47], green hydrogen is defined as a result of GHG-neutral production based on water electrolysis powered entirely by renewable electricity from wind and solar PV.

5.5
European hydrogen production

As already mentioned in Section 2.1, SCOPE SD contains endogenous electrolyser investment decisions in every European market area to model domestic production of hydrogen. These electrolyser units do not have any additional flexibility restriction on their dispatch decisions and are assumed to have a general conversion efficiency of 0.71 MWh_{th}/MWh_{el}.
However, a limit on electrolyser consumption per country was imposed to avoid unrealistic electrolyser deployments in small jurisdictions. With this limit, the electricity consumption for domestic electrolysers must not exceed half of the respective country's conventional electricity demand.

5.6
Net transfer capacities

The SCOPE SD framework employs a transport model for cross-border electricity flows. The net transfer capacities (NTCs) are based on the 2040 transmission grid scenario “GCA 2040” of the TYNDP 2018 [48]. In addition, some NTCs in the Nordic region were updated as part of the “HydroConnect” project [49]. Although SCOPE SD can model endogenous transmission expansion planning, this option is only allowed in the North Sea region as explained in Section 2.2.

5.7
Cost assumptions

The assumed investment costs of different technologies in these calculations are based on Fraunhofer IEE’s internal database, which is under continuous development in several research projects, and a current version can be found in [21]. An overview of different cost assumptions for selected renewable technologies can be found in Table 17.

Table 17 Overview of investment costs, fixed operation costs, and depreciation periods for selected renewable technologies assumed in this case study.

Technology	Investment cost in EUR/kW	Fixed operation cost in EUR/kW/yr	Depreciation period in yr
Solar PV (rooftop)	676	0.055	25
Solar PV (utility-scale)	300	0.055	25
Onshore wind (low specific)	1 355 – 1 767	0.054	25
Onshore wind (high-specific)	1 000 – 1 415	0.054	25
Offshore wind	2 800	0.177	20
CCGT	750	30.0	30
OCGT	420	8.0	30
Li-Ion (6 h storage ratio)	372	3.72	8
Electrolyser	470	35.7	20
Methanation	300	9.0	20

In consultation with the client, both investment and operation costs for electrolysers on the OEIs are set 10 % higher than for electrolysers on the mainland.
The price assumptions for green hydrogen from non-European export countries are based on Fraunhofer IEE’s Power-to-X (PtX) atlas [50], which contains a broad assessment of global production and export sites. Further information on the production potential of PtX fuels for all countries outside the European Economic Area and on the import options of these PtX products to Europe can be taken from [51]. Note that the price for green hydrogen from non-European export countries is subject to large uncertainty. All relevant cost assumptions for different fuels in 2045 can be found in Table 18.

Table 18 Overview of assumed fuel costs in the scenario year 2045 in EUR/MWh_{th}.

Fuel	Value
Natural gas	106.33
Uranium	3.55
Hydrogen-Import	85.00
PtL-Import	124.40
$PtCH_4$-Import	124.40

For the long-term scenario year 2045, centralised power plants, including combined heat and power (CHP) backup boilers, no longer use natural gas but only hydrogen (H_2). In addition to imports from outside Europe, it is possible to produce hydrogen domestically using electrolysers (recall Section 5.5). Instead of fossil fuels, renewable liquid fuels (referred to as PtL) and also hydrogen are used in the transport sector in addition to electric vehicles. Natural gas, which is modelled as renewable methane (CH_4) in 2045, is only used in decentralised boiler systems.
Investment decisions incorporate different weighted average cost of capital, which depend directly on the assumed interest rate. These interest rates are given in Table 19.

Table 19 Interest rates for different types of investment decision makers in 2045.

Interest rates	Unit	2045
Decentralised (e.g. private households)	%	6
Centralised (e.g. district heating)	%	6
Industry	%	6

5.8 Hydropower data base

The representation of multi-reservoir hydropower systems across Europe is based on Fraunhofer IEE's internal database, which contains hydropower plants from and reservoir parameters of over 874 hydropower systems, with more than 2 951 single hydro plants and 3 657 individual hydro reservoirs gathered from public data. The parameters of hydropower systems in Norway have recently been updated in close consultation with SINTEF Energy Research based on their detailed models [49].
Figure 8 shows the internal database containing hydropower plants and reservoir parameters of over 874 hydropower systems gathered from public data. Alongside plant- and reservoir-specific data, the database includes complex hydraulic connections, couplings, and information on cross-border market participation.

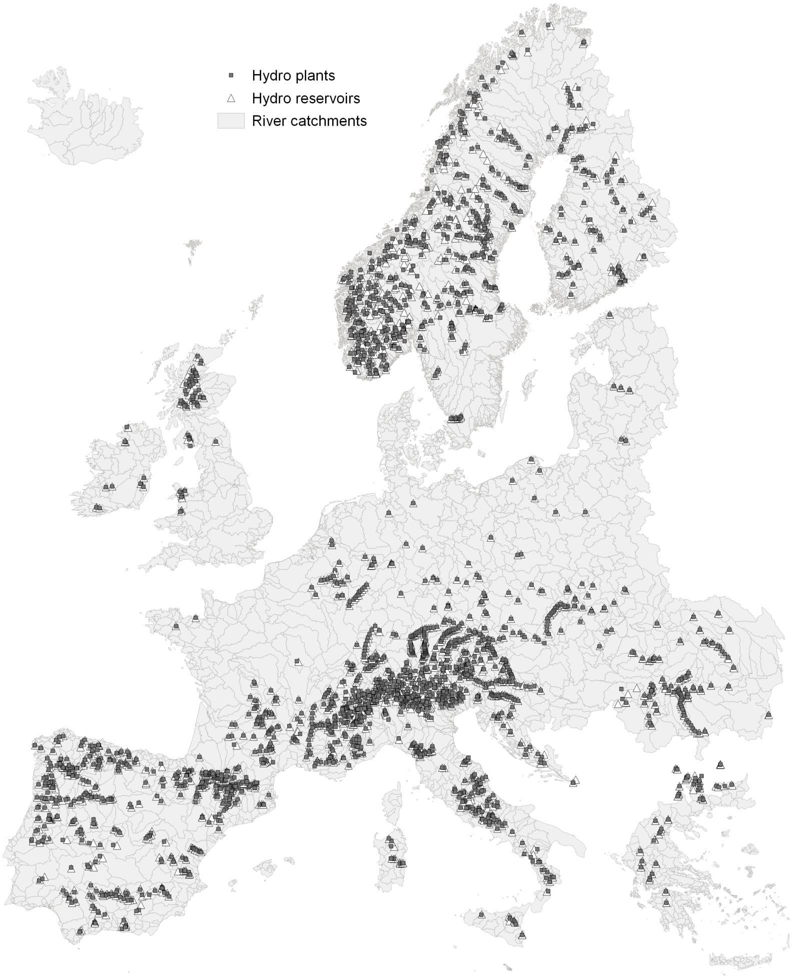


Figure 8 Overview of explicitly covered and modelled hydropower systems across Europe (3 657 hydro reservoirs and 2 951 hydro plants in total), own illustration as already shown in [24, 49] based on updated data sets developed in [52].

Public availability of reservoir inflow data is particularly challenging. The modelling approach employs a generic approach to generate natural inflow profiles of every single hydro reservoir in the considered market areas. The core idea is to infer natural inflows from past climatic and meteorological conditions, i.e. historical runoff data, to create reservoir-specific natural inflow profiles that are then adjusted to individual hydropower plant production data. For a more detailed description of the spatial and temporal interpolation based on the global atmospheric reanalysis ERA-Interim [53, 54], it is referred to [47, 52]. An overview of the modelled hydropower systems across Europe is given in [49].

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