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## The Case of the North Sea

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Copenhagen Business School
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## Working paper 13-2022

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CSEI Working Paper 2022-06

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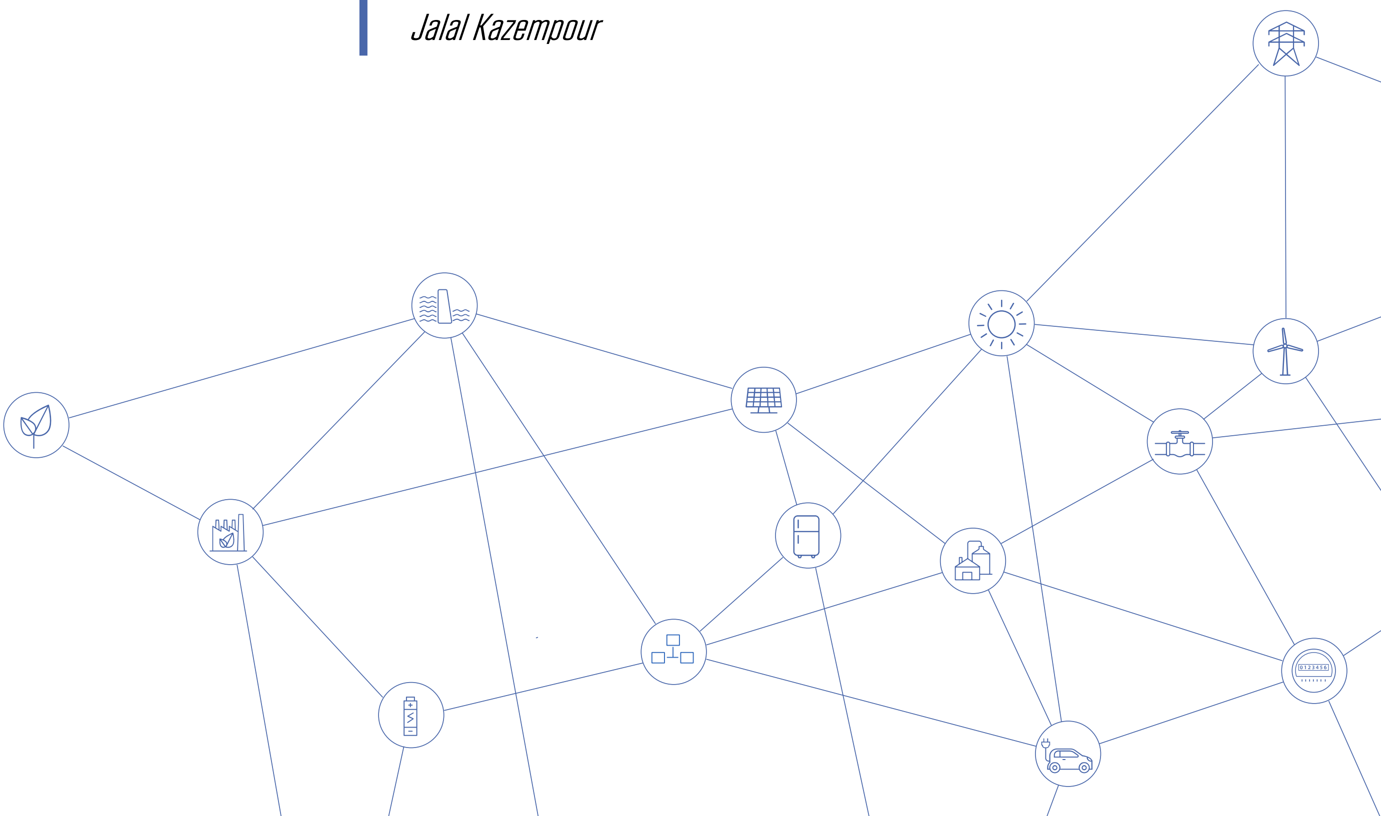

# Electrolysis as a Flexibility Resource on Energy Islands: The Case of the North Sea

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August 29, 2022

**Abstract**

Energy islands are meant to facilitate offshore sector integration by combining offshore wind energy with power-to-x technologies and storage. In this study, we investigate the operation of electrolysers on energy islands: We assess the potential flexibility contribution of the electrolyser and then analyse different market integration strategies of the islands. We develop a two-stage stochastic optimisation model to find the cost-efficient dispatch for an integrated day-ahead and balancing electricity market. For the market integration of the energy island we align our approach to the current debate and compare the case of a single offshore bidding zone to a case where the energy island is integrated into a home market zone. We find that electrolysers on energy islands will run at low capacity factors and provide flexibility in 26–30 % of their run time. In addition, offshore electrolysers produce more hydrogen when they are allocated to an offshore bidding zone, and thus earn higher profits. We conclude that combining offshore wind with electrolysers on an energy island relies on additional economic incentives if their main role is envisioned to be the delivery of balancing flexibility.

**Keywords:** energy islands, offshore energy hub, flexibility resources, bidding zones, hydrogen

**JEL Codes:** C44, C61, C63, D47, L94, L95, Q41, Q42, Q48

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# 1. Introduction

With a rising share of intermittent renewable energy sources in electricity systems, the need for operational flexibility increases. In the meantime, there is a growing demand for low-carbon fuels in sectors where electrification is too expensive or even infeasible. Electrolysis based on green electricity is envisioned as a potential solution to meet both requirements at the same time.

Electricity production from offshore wind in the North and Baltic Seas has developed rapidly over the past years (Wind Europe, 2021) due to its high potential and social acceptance (Kaldellis et al., 2016). The European Commission's strategy on offshore wind further highlights its important role for the future energy system (European Commission, 2020). Despite technological advances and declining costs for power transmission, transferring electricity from offshore wind farms via sub-sea cables to shore remains costly (IRENA, 2019). One way to reduce the required amount of power cables would be to connect offshore and onshore systems to convert a part of the generated electricity into hydrogen close to the offshore wind farms, and then transport the hydrogen to shore via less costly hydrogen pipelines (Singlitico et al., 2021). This idea is incorporated in the discussions around the so-called energy islands (Tosatto et al., 2022). The Danish Government and various industrial consortia are now investigating options to integrate hydrogen production from electrolysis with electricity generation from offshore wind farms out in the sea at potential energy islands.[1]

In our analysis, we assume that the energy islands in the North and Baltic Seas that are currently under consideration will be built and that they will host electrolysers. With this assumption, we investigate two possible drivers: flexibility and profitability. The proximity of the electrolysers to large-scale intermittent wind power generation and the significant distances to load centres and flexibility resources might imply that the offshore electrolysers will serve as operational flexibility providers in addition to producing cheap hydrogen. Exploring the impact of the energy island in the broader energy system, the energy island could potentially constitute its own bidding zone as part of the pan-European electricity market, instead of being integrated into an existing bidding zone. We summarise our research interests in the following two research questions: (1) What is the flexibility potential of an electrolyser on an energy island?, and (2) How does the offshore bidding zone configuration influence the value of offshore electrolysers?

To answer these research questions, we assess operational patterns, market results, and prices

[1]For example, see North Sea Wind Power Hub (www.northseawindpowerhub.eu) and the Danish Islands (www.windisland.dk or www.northseaenergyisland.dk/).

in a setting that incorporates uncertainty in electricity production from renewable energy sources. We do this by developing a two-stage stochastic optimisation model that solves the day-ahead and balancing electricity market clearing problems simultaneously for bidding zones connected by net transfer capacities. Flexibility in our balancing market stage relates to adjustments prior to calling frequency containment reserve and other reserves. Joint market clearing of day-ahead and balancing markets does not happen in today's market operation, and therefore our setup presents an ideal benchmark likely overestimating the effects. Market power, strategic bidding, and network constraints within bidding zones are not taken into account.

We develop the model and apply it to the case of the energy islands in the North and Baltic Seas to answer our research questions focused on the European context. The case study includes the currently planned projects by the North Sea Wind Power Hub consortium, the Danish Energy Island (DEI) and the one at Bornholm (Denmark) with their planned wind energy and cable connection capacities and integrates those into the European energy market zones.

For the year 2030 with a moderate renewable expansion scenario, we find that electrolysers in general do not provide significant balancing flexibility, and that offshore electrolysers do not produce large amounts of hydrogen overall. However, offshore bidding zones do make hydrogen production offshore financially more attractive. For the analysis in 2040, we observe that the reduction in hydrogen prices outweighs the reduction in electricity cost. This leads to overall lower average run times of the electrolysers (which is defined as lower *capacity factors*) and reduces the profitability of electrolysers on energy islands. Despite using a specific case in Northern Europe, we make generic assumptions that are applicable to other potential energy islands. Having restricted interconnection capacity to shore and being placed close to large offshore generation facilities, we expect similar patterns as presented in our results.

The remainder of the paper is structured as follows. Section 2 summarises relevant literature and presents a background for the analysis. In Section 3 we present the modelling framework for the analysis. The case study including data and assumptions follows in Section 4 and then results are given in Section 5. We discuss the economic viability of electrolysers on energy islands, the impact of the assumptions taken, and provide a sensitivity analysis in Section 6. Finally, we present conclusions and policy recommendations in Section 7.

## 2. Background and Literature Review

Scientific literature on energy islands is still scarce. In the following, we collect studies on offshore grids and power link islands—the systemic foundation for energy islands—and present a summary of the few studies on electrolysis offshore and market design for large-scale offshore wind power hubs.

The concept of energy islands emerged around 2016 and was at first driven by the North Sea Wind Power Hub (NSWPH) consortium planning to build an energy island in the North Sea on the Dogger Bank (North Sea Wind Power Hub, 2020). In June 2020, the concept was taken to Danish waters when the government in Denmark officially decided to build two energy islands, one in the North Sea and one in the Baltic Sea[2]. Based on those ideas, other countries have taken up similar discussions about the feasibility of energy islands, for example Norway (Zhang et al., 2021) and Germany[3]. All of these concepts are based on heavy expansion of offshore wind power production, which the European Commission envisions to be a key element in the European energy system transformation (European Commission, 2020).

When expanding power production from offshore wind energy, the infrastructure in the sea needs to be expanded simultaneously. One potential solution to connect large-scale offshore wind to shore is via integrated offshore grids (Trötscher and Korpås, 2011; Strbac et al., 2014). Offshore grids are (potentially meshed) grid structures in the sea connecting countries through wind farms. They can contribute on several levels to support offshore energy access (Gea-Bermudez et al., 2018), enable better interconnection to stabilise a renewable energy based system (Schlachtberger et al., 2017), and increase overall welfare through a higher and more efficient use of renewable energy (Egerer et al., 2013). Furthermore, offshore grids have the potential to connect markets with asymmetric installed renewable power capacities, which can lead to a stabilisation of prices in those markets (Alavirad et al., 2021). At present, no offshore grids are commissioned yet. Guidance on design and topology is needed to construct a technically efficient system (Chen et al., 2018), and the economic framework needs to define operational and ownership rules to incentivise efficient development of offshore systems (Meeus, 2015; Sunila et al., 2019). As an integrating element in offshore grids, Kristiansen et al. (2018) define power link islands as an efficient component in the offshore grid. Power link islands can be seen as the precursor of energy

[2]See Klimaaftale by the Danish Government (2020): https://fm.dk/media/18085/klimaaftale-for-energi-og-industri-mv-2020.pdf.
[3]See AquaVentus: www.aquaventus.org.

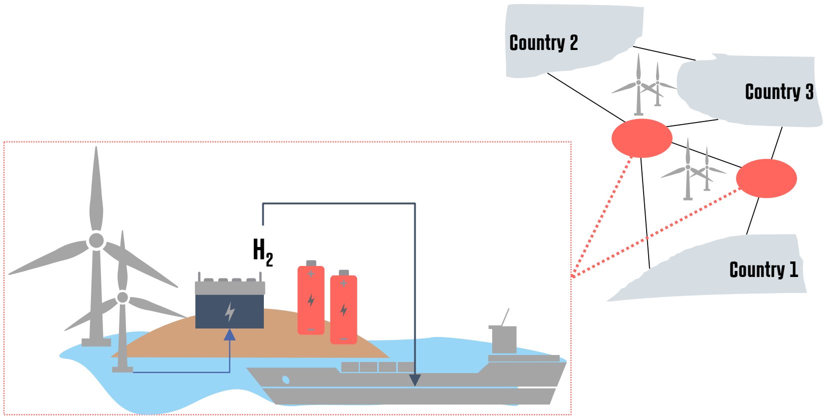


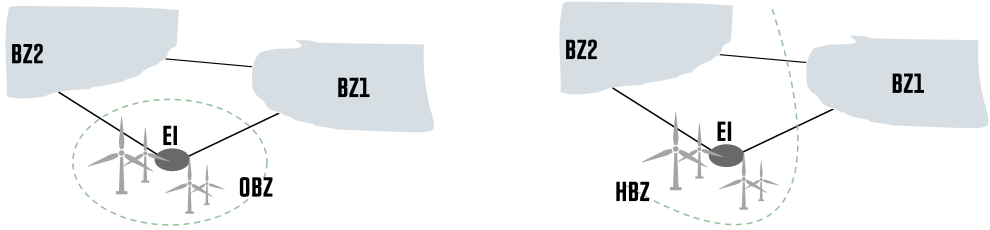

Figure 1: Sketch of an energy island in its most recent vision.

islands, or offshore energy hubs[4]. Such energy island are most often defined by their offshore location, the surrounding large wind capacities, cable connections to one or several countries, and possibly storage or conversion technologies (Lüth, 2022). Generally, energy hubs refer to places where multiple energy carriers are converted or stored (Geidl et al., 2007). In light of discussions about a hydrogen economy, electrolysis or power-to-x may act as a conversion technology offshore, and adding power-to-x to a power link island would turn it into an energy island (Gea-Bermúdez et al., 2022). Figure 1 illustrates how conversion and/or storage of locally or nearby produced renewable electricity can take place on such an energy island.

The concept of energy islands is still at an early stage of development. Some industrial actors have actively discussed sector integration offshore including hydrogen production at sea, whereas techno-economic studies either find that the potential of electrolysis offshore is small (Gea-Bermúdez et al., 2022; Gea Bermúdez et al., 2021) or that offshore electrolysis relies on the benefit of avoided costs for power cable connections (Singlitico et al., 2021). If electrolysers are placed offshore despite higher capital and operational costs and uncertainty in regulatory frameworks, it is favourable to place them at a centralised location, e.g., at a hub, instead of spreading them to decentralised locations (Ibrahim et al., 2022; Singlitico et al., 2021).

Additionally, research on technical feasibility of flexible electrolyser operation has found that, among others, temperature and power consumption influence the efficiency and availability of electrolysers for flexibility provision and system services (Qi et al., 2021; Zheng et al., 2022a,b). They further show that electrolysers are technically capable to quickly adjust their power output in response to fluctuations in renewable power supply. The authors present models and tools to incorporate technical characterstics and temperature dependencies when planning investments

[4]In this paper, we use *energy islands*, but the terms can be used interchangeably.




(a) Offshore bidding zone (OBZ) configuration. (b) Home bidding zone (HBZ) configuration.

Figure 2: Two different bidding zone configurations for offshore wind power hubs and energy islands. In an OBZ, an energy island constitutes its own bidding zone, while in an HBZ the energy island participates in BZ2.

and operational strategies of electrolyser.

Generally, coupling wind farms and hydrogen production increases the cost efficiency and thereby competitiveness of wind power production (Thommessen et al., 2021; Grüger et al., 2019). This is tightly linked to our research questions about the profitability and the operation of electrolysers on energy islands. In this analysis we focus mostly on market outcomes and price impacts in an offshore setting.

For the onshore case, studies show that power-to-gas in connection with re-electrification can be a viable operating strategy (Grueger et al., 2017), stabilise market prices (Li and Mulder, 2021), and benefit congestion management (Xiong et al., 2021). The effect of hydrogen production on flexibility and market prices offshore has not been thoroughly investigated yet.

For offshore power production, several studies have looked into market design and bidding zone configurations for offshore wind energy hubs (without electrolysis). The studies usually compare two concepts: (1) *offshore bidding zones* and (2) *home bidding zones*. In an offshore bidding zone the power hub constitutes its own bidding zone, see Figure 2a, and consequently, its market price will always match the price of the connected bidding zone that has the lowest price. The home bidding zone (Figure 2b) represents the business as usual case where wind farms sell electricity in their home market (Kitzing and Garzón González, 2020; Tosatto et al., 2022). The studies suggest that offshore bidding zones reflect a more efficient electricity market (Kitzing and Garzón González, 2020), but that the distribution of benefits and costs is asymmetrical among the connected actors (Tosatto et al., 2022).

The idea of an offshore bidding zone for power hubs was developed in the context of so-called hybrid projects, where interconnectors between countries also connect to wind farms, for example Kriegers Flak (Marten et al., 2018) which has been operational since 2020. Hybrid projects are fairly new in the system, but in a report for the European Commission, Weichenhain et al. (2019)

identify multiple locations in which a hybrid project can be more beneficial than traditional radial connections to the owner's home market only. In this paper, we make use of the insight that a more cost-reflective offshore bidding zone is preferable and analyse the impact of bidding zone configurations on the operation of the offshore electrolyser.

## 3. The Model

We develop a two-stage stochastic optimisation model to analyse the operation and potential as flexibility resource of offshore electrolysers from a system point of view. The model is based on methods described in Morales et al. (2014) and Conejo et al. (2010). The model allows us to observe market prices and quantities sold on the electricity market in the presence of uncertainty in production from renewable energy.

With the model, we can analyse the value of operating electrolysers for hydrogen production, which function as flexible demands, elastic to the price. All power producing units sell electricity into and electrolysers demand electricity from a day-ahead market, the first trading stage of the model. In addition, the units decide whether or not to bid into a balancing market, the second stage of the model, which is used to compensate for deviations from the day-ahead schedule of renewable power plants. Note that this market is an aggregated and idealised representation of all trading actions between the day-ahead market and the reserve market. This implies that balancing in this analysis excludes primary, secondary and tertiary reserves and thereby differs from the approach by Energinet (2022). We assume that hydrogen can be sold at any time and volume for a given price without any storage or transportation constraints. Capacity of electrolysers is exogenous. To keep the main text succinct, and since large parts of the model are quite standard in the power systems literature, we do not include the mathematical formulation here. Instead, we explain the structure, the objective and the restrictions briefly in text. The full mathematical model including constraints and limitations is presented and explained in Appendix A.1.

| | |
|---|---|
| **min** | Generation costs (day-ahead + balancing market) |
| | - Profits from hydrogen sales |
| **s.t.** | Zonal power balance for each stage |
| | Generator capacity limits |
| | Storage limits |
| | Ramp limits |
| | Electrolyser production limits |
| | Net-transfer capacity limits |

Figure 3: Schematic overview of our model. The mathematical equations can be found in Appendix A.1.

The objective function of the model minimises the expected cost for the day-ahead dispatch and the balancing actions under uncertainty. The uncertainty in the model stems from renewable energy productions. In our day-ahead dispatch, generators only have a forecast of renewable power production available. In the balancing stage, a set of scenarios represents different potential realisations of renewable energy production. In the first stage, conventional power production and hydrogen production incur costs. For the second stage, the expected costs for balancing originate from conventional power plants adjusting their operational schedule as a reaction to deviations in renewable energy production from the forecast. The model has five groups of constraints that limit the solution space. Both stages have a supply-demand balance to ensure that production equals demand. We add a set of capacity restrictions for conventional and renewable energy technology to limit the maximum production to the installed capacities. For storage (battery and hydro power), we introduce charging and discharging restrictions as well as a maximum storage level. To avoid an overestimation of operational flexibility, we include ramping constraints for all conventional power plants. Finally, we add more detail on the electrolysers to restrict their maximum production level and account for efficiency in production. Figure 3 summarises the model as such in text.

## 4. The Case of the North Sea

Our model is suitable for analysing energy islands in any geographical region. The model replicates market zones and transfer capacities between market zones for a day-ahead and balancing stage considering uncertainty in renewable energy production. Although the model framework is generic, we focus on the North and the Baltic Seas and the planned energy islands off the coast

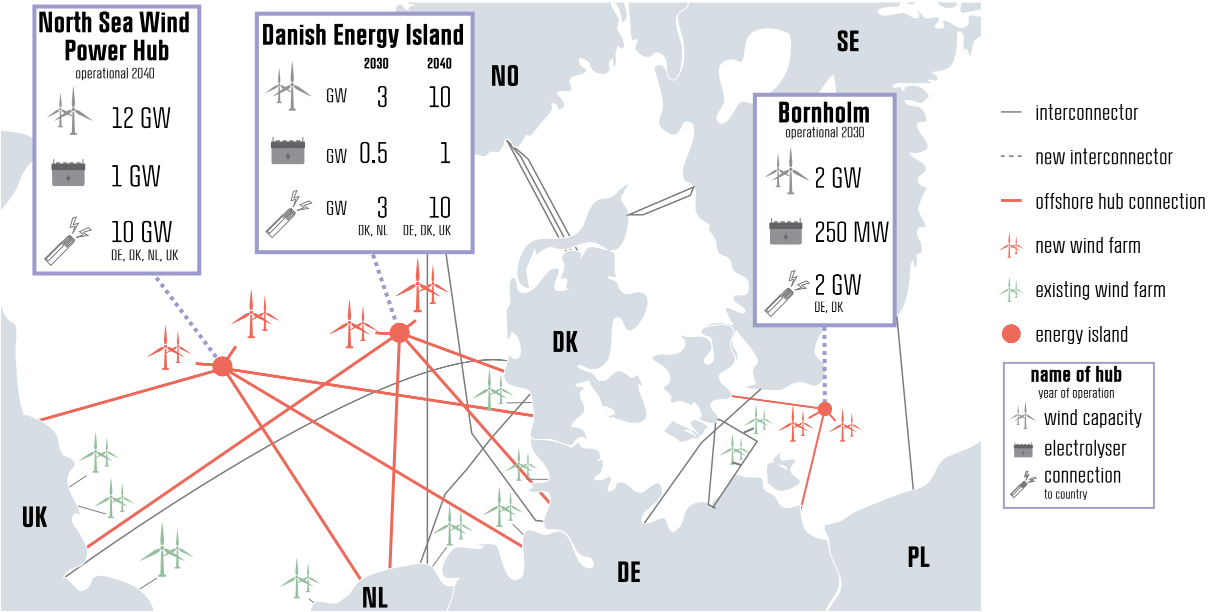



Figure 4: Energy island projects considered in this study.
Source: Own illustration based on COWI (2021) for Energistyrelsen.

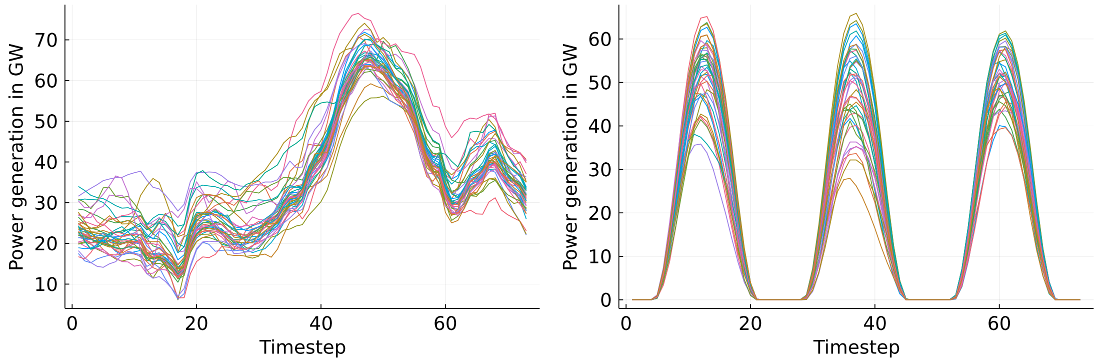
of Denmark and the Netherlands. Figure 4 provides an overview of the three considered energy islands that we include in our analysis. DEI and Bornholm are projects led by Danish partners. The North Sea Wind Power Hub is a project with Danish, Dutch and German partners, and is a Project of Common Interest[5]. The following two sections describe our input data and main assumptions.

## 4.1. Data

We include the 13 countries around the North Sea and the Baltic Sea that comprise 24 bidding zones in total (see Figure 13 in the Appendix). Energy islands are planned to be operational at full capacity in 2040. First milestones in terms of wind power capacity and interconnection will be reached in 2030. We consider both years in separate analyses.

For each country we retrieve estimated future installed capacities for conventional and renewable power plants from the TYNDP 2020 *National Trends* Scenario[6]. To compare and crosscheck values, we made use of the ENTSO-E Transparency Platform and the national system operators websites and data published by Kendziorski et al. (2020). For a sensitivity analysis, we use the $1.5\,^\circ$C scenario *Directed Transition* developed in the openEntrance project[7] as our climate case which shows significantly higher installed capacities of renewables in Europe–about twice as high

[5]See Annex to C(2021) 8409 final by the European Commission: SWD(2021) 335 final.
[6]See TYNDP Data (2020): www.tyndp.entsoe.eu/maps-data/
[7]See openEntrance (2022): www.openentrance.eu/




(a) Onshore Wind



(b) Solar energy

Figure 5: Probabilistic power generation forecast from wind and solar power in Germany for a selected time period. Each of the 40 lines corresponds to an individual scenario.

as in the TYNDP2020 projections (see Figure 12 in the Appendix).

Generation from renewable energy sources is subject to fluctuations and therefore not available at full capacity in all time steps. We use historical generation profiles for wind and solar energy which are retrieved from renewables.ninja[8] for the year 2018 (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016). Based on spatially and intertemporally correlated day-ahead forecasts and real-time realisations taken from Muehlenpfordt (2020), we calculate hourly forecast errors for the years 1980–2019 for wind and solar power for each individual country. Dropping the information about the underlying year, we are able to generate 40 different scenarios, each containing renewable power generation forecast errors for all technologies and countries considered for 8760 hours. We apply those forecast errors to the historical generation profiles from 2018 to generate our second-stage scenarios. The probabilistic power production forecast from onshore wind and solar energy for Germany for a selected time period is shown in Figure 5.

For reservoir hydro power, we derive a limit for the maximum cumulative production during the selected time of a year from historical production data published on the ENTSO-E Transparency Platform[9]. Run-of-river hydro power operates based on historical availability from the EMPIRE model (Backe et al., 2022)[10]. Furthermore, we restrict technologies in their ramping capability based on the technology catalogue by the Danish Energy Agency (2022) and historically observed ramping rates for the aggregated power plant portfolio of each fuel type from ENTSO-E's Transparency Platform.

Electricity demand is expected to increase over the coming years and further towards 2050.

[8]See renewables.ninja (2022): www.renewables.ninja
[9]See: www.transparency.entsoe.eu/
[10]OpenEMPIRE is available on GitHub: https://github.com/ntnuiotenergy/OpenEMPIRE.

We use demand projections from the *National Trends* Scenario of the TYNDP 2020 input data. Within the process of developing the TYNDP, the ENTSOs also gathered data on current net-transfer capacities (NTCs) and establish projections. We use their projections for 2030 and 2040 as our power exchange capacities between zones in the respective years.

Cost assumptions are a significant driver in an energy system model. Conventional energy technology has three cost components in our model: marginal production costs, fuel costs and emission costs. Marginal production costs for conventional power plants can be found in the technology catalogue by the Danish Energy Agency (2022). We use fuel prices for gas, oil, lignite and hard coal from the TYNDP 2018 input data[11]. For the base case, we adopt the $CO_2$ price from the same input data, using €84.3/ton in 2030 and €126/ton in 2040. Our ambitious climate case has a price of €350/ton in 2030 and €700/ton in 2040 based on the *Directed Transition* scenario of the openENTRANCE project (Auer et al., 2020).

Another significant economic component in our model is the income from selling hydrogen. Costs for hydrogen production from renewable energy will depend on the costs for electricity and investment cost of the electrolyser. Investment cost for alkaline electrolysers is estimated to decrease from €750/kW in 2020 to €350/kW in 2050 (Danish Energy Agency, 2022), and variable operations and maintenance cost (VOM) are in a range between €7.2/MWh in 2030 and €5.6/MWh in 2040 onshore. We assume that offshore VOM are 50 % higher with €10.8/MWh in 2030 and €8.4/MWh in 2040. For hydrogen prices, Glenk and Reichelstein (2019) estimate costs of €3.23/kg for 2025 and €2.50/kg in 2040. For production from dedicated wind farms, Meier (2014) estimates hydrogen production cost of €5.2/kg. In later years, assuming existing oil and gas platforms can be reused to base renewable offshore hydrogen production, these costs are projected to decline down to €2.50/kg. We use a value of €4.5/kg in 2030 and €3/kg in 2040. These translate into €150/MWh and €100/MWh, respectively.

All our data and the model are available on GitHub[12]. The model is implemented in Julia 1.6.1 (Bezanson et al., 2017) using JuMP v1.0.0 (Dunning et al., 2017), and solved with Gurobi v9.5.1.

## 4.2. Model Assumptions

We assume that an electrolyser with an exogenously defined size of 0.5 GW (1 GW) and 0.25 GW (0.5 GW) will be placed at DEI and Bornholm respectively, in 2030 (2040) (see Figure 4). The electrolyser on the NSWPH is assumed to be installed with a capacity of 1 GW in 2040.

[11]See ENTSO-E map (2022): www.tyndp.entsoe.eu/maps-data
[12]Find the model here: https://github.com/yannickwerner/EnergyIslands.

Table 1: Parameter values in the model.

| Parameter | Notation | Unit | 2030 | 2040 | Source |
|---|---|---|---|---|---|
| **Fuel prices** | | | | | |
| Lignite | | €/MWh | 8.28 | 8.28 | EUCO: REF 2020 Technology |
| Hardcoal | | €/MWh | 15.48 | 15.48 | EUCO: REF 2020 Technology |
| Natural gas | | €/MWh | 28.84 | 35.28 | EUCO: REF 2020 Technology |
| Heavy oil | | €/MWh | 52.56 | 72.00 | EUCO: REF 2020 Technology |
| Light oil | | €/MWh | 73.80 | 87.84 | EUCO: REF 2020 Technology |
| Biomass | | €/MWh | 11.88 | 14.40 | EUCO: REF 2020 Technology |
| Uranium | | €/MWh | 1.69 | 1.69 | EUCO: REF 2020 Technology |
| $CO_2$ price | | €/ton | 84.3 | 126 | TYNDP 2020 |
| **Electrolyser cost** | | | | | |
| VOM onshore | $mc_{e,y}$ | €/MWh | 7.2 | 5.6 | Danish Energy Agency (2022) |
| VOM offshore | $mc_{e,y}$ | €/MWh | 10.8 | 8.4 | Danish Energy Agency (2022) |
| Electrolyzer efficiency | $\eta_{\mathrm{e}}$ | | 66% | 66% | Danish Energy Agency (2022) |
| Hydrogen price | $p^{\mathrm{H}_2}$ | €/MWh | 150 | 100 | Glenk and Reichelstein (2019) |
| **Onshore electrolyser capacity** | | | | | |
| Denmark | | MW | 3473.4 | 4681.7 | Klima-, Energi-og Forsyningsministeriet (2021) |
| The Netherlands | | MW | 3000 | 6000* | Government of the Netherlands (2020) |
| Germany | | MW | 5000 | 10000 | BMWi (2020) |
| Belgium | | MW | 500 | 500 | FPS Economy Belgium (2021) |
| United Kingdom | | MW | 5000 | 8000* | HM Government (2020) |
| Poland | | MW | 2000 | 4000 | Ministry of Climate and Environment (2021) |
| Sweden | | MW | 5000 | 10000* | Energimyndiheten (2021) |
| Norway | | MW | 750 | 1500* | NVE (2021) |
| France | | MW | 6500 | 13000 | BDI (2020) |

* The values market with * are extrapolated for 2040 based on the estimations given in the sources.

Furthermore, hydrogen can be sold at a fixed price without any quantity restrictions. Costs for transport, storage, or distribution of hydrogen are not taken into account explicitly, irrespective of the electrolyser's location. However, we assume that operational and maintenance costs for the offshore electrolyser is 50% higher than onshore (given in Table 1) to account for these factors, but also space restrictions, environmental conditions, and large distance to shore. We further assume that all electrolysers that are not built on the energy islands are built onshore.

Furthermore, losses on power cables and transmission lines are neglected inside as well as between bidding zones. We consider inflexible, price-inelastic, demand for electricity. Demand-side management is not considered in the current state of the model. Unit commitment and minimum power generation restrictions are generally not included in the model. However, we do include a time-varying minimum load for combined heat and power plants based on heat delivery obligations. We approximate this minimum load by using residential heat demand data from 2013 (Ruhnau et al., 2019; Ruhnau and Muessel, 2022) and increase it by 30 percentage points to account for households that are not connected to district heating grids. Market power, strategic bidding, and network constraints within bidding zones are therefore not taken into account.

It is not possible to run the model for the whole time horizon with a large number of scenarios. To test robustness, we have executed model runs for various numbers of scenarios on a reduced time horizon. We found that neither the balancing service provision nor the capacity factors of the electrolysers change significantly when increasing the number of scenarios to above ten scenarios. Therefore, we only use ten out of 40 randomly selected scenarios to be able to run the model for longer time horizons. We consider the same probability for each of the ten selected scenarios in our optimisation model.

Due to the computational complexity of the model, we need to split up the full time horizon of 8760 hours into six segments with equal length (1460 hours). To avoid depletion of pumped hydro and battery storages at the end of each time segment, we force the initial and final storage levels to be exactly 50% of the storage capacities.

## 5. Results

We run the model with the described data for the years 2030 and 2040. Recall that our two research questions will analyse (1) the flexibility potential of an electrolyser on an energy island, and (2) how bidding zone configuration affects the value of the offshore electrolyser. Along these two research questions, we structure the presentation of the results in two parts: Section 5.1 on flexibility and Section 5.2 on bidding zones and market analysis. We present a discussion of the results and the shortcomings of the model in Section 6.

### 5.1. Flexibility of Offshore Electrolysers

In the model, flexibility is needed to compensate for real-time deviations from the day-ahead schedule of renewable energy sources. The system has a set of flexibility resources available for balancing purposes. These resources are conventional power plants, hydro power reservoirs, biomass, storage technologies (battery and pumped hydro storage), and electrolysers. Looking at a selected period of four days in one of the scenarios, in Figure 6, we observe that hydro power and storage units contribute most to balancing services while the electrolysers' contributions (in red) are marginal.

Taking a more regionally disaggregated perspective, Figure 7 provides a comparison of the capacity factors over the whole time horizon for the years 2030 and 2040 for the total electrolyser capacity in each bidding zone. For the year 2030, we observe that most electrolysers are only used

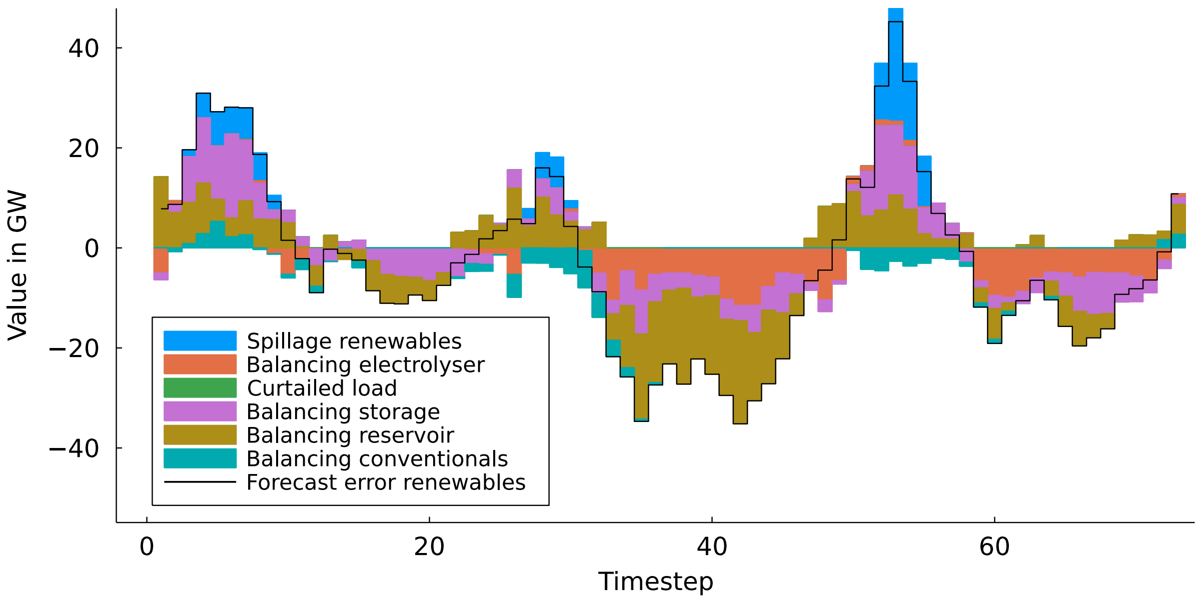



Figure 6: Balancing of the aggregated system-wide deviation from the day-ahead schedule of renewable power generation in a specific scenario.

a few hours in the balancing market. The participation in balancing markets for electrolysers on the energy islands (DEI, NSWPH, Bornholm) is rather modest, and even lower for the onshore electrolysers. This difference occurs due to the availability of cheaper flexibility resources such as hydro power and storage units in most bidding zones onshore. Especially Sweden and Norway have very cheap dispatchable, renewable power generation in the form of hydro power, which results in very low contributions of the electrolysers to the balancing actions in the Norwegian and Swedish zones. When including the day-ahead market, we see that most electrolysers run at rather low capacity factors, on average below 50% and even lower for the offshore electrolysers. Taking a deeper look at the results, we find that offshore hydrogen is produced in fewer hours compared to electrolysis onshore, and the average electricity consumption cost per unit of hydrogen produced are much lower for offshore electrolysers than for onshore ones. This indicates that it is usually of higher value for the system to transfer electricity to shore and use it directly, or convert it into hydrogen there at lower variable cost than producing hydrogen offshore.

Comparing results for 2030 and 2040, we realise that several countries face a decreasing capacity factor for their electrolyser fleet despite significantly higher shares of renewable energy capacity in 2040. While most areas with decreasing capacity factors experience a drop in electricity prices, these cannot compensate for the decrease in hydrogen prices and therefore lead to overall less profitable hydrogen production conditions. This is for example visible in Belgium (zone BE00) and the United Kingdom (zone UK00). One exception is Poland, that experiences very high

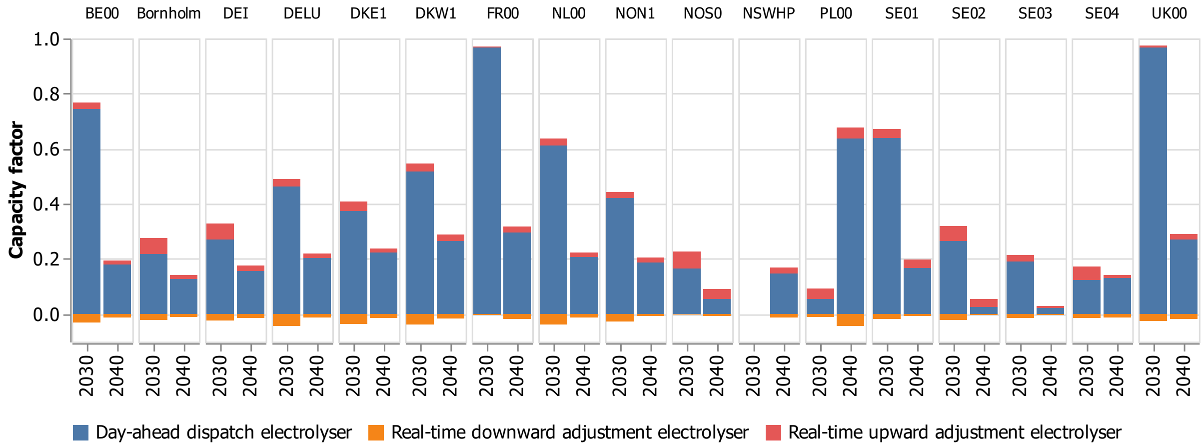



Figure 7: Expected electrolyser capacity factors for the OBZ configuration in the years 2030 and 2040. Each bar corresponds to a bidding zone.

electricity prices in 2030 due to a mostly fossil fuel-based power system but transforms into a renewable based system with low electricity prices in 2040. Therefore, in Poland, we see much higher electrolyser capacity factors and an increased contribution in the balancing market.

Overall, we find that on expectation offshore electrolysers are used for the provision of balancing services in about 26 % to 30 % of their total run time only. Additionally, relatively low capacity factors overall indicate that operators face economic challenges to contribute to meeting European hydrogen demand projections in this market setup. Hence, we analyse in the next section whether an alternative bidding zone configuration would positively influence the value of offshore electrolysers.

## 5.2. Bidding Zone Configurations

With our second research question, we target the impact of bidding zone configuration on the capacity factors and flexibility contributions of electrolysers. We explore whether zonal boundaries change operational patterns for offshore electrolysers, and if so, how. The radial connection of offshore wind farms is the traditional approach to integrate offshore energy, and energy islands in their first operational years can be connected similarly and to their home countries leading to a home market approach. Over the years, this may or may not develop into hybrid projects (see Section 2), or the islands can constitute their own bidding zone in the long run. In the following, we compare the concept of offshore bidding zones to the standard case of home bidding zones to investigate and highlight the role of market zones and their impact on both the market prices in general but also on the energy islands' resources.

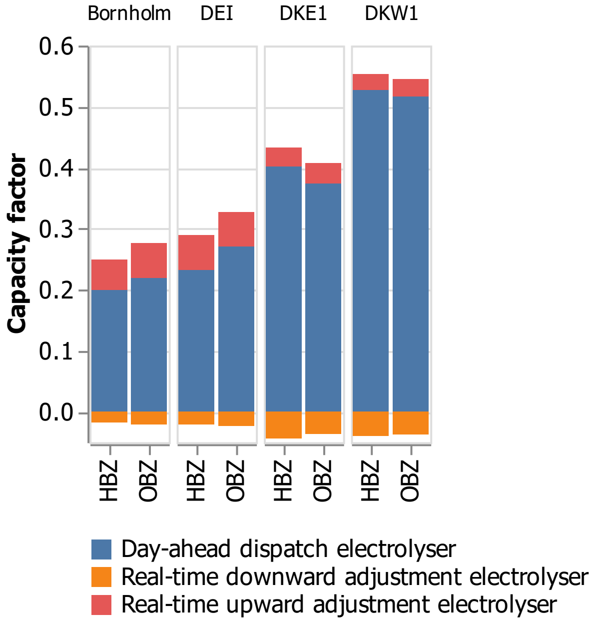


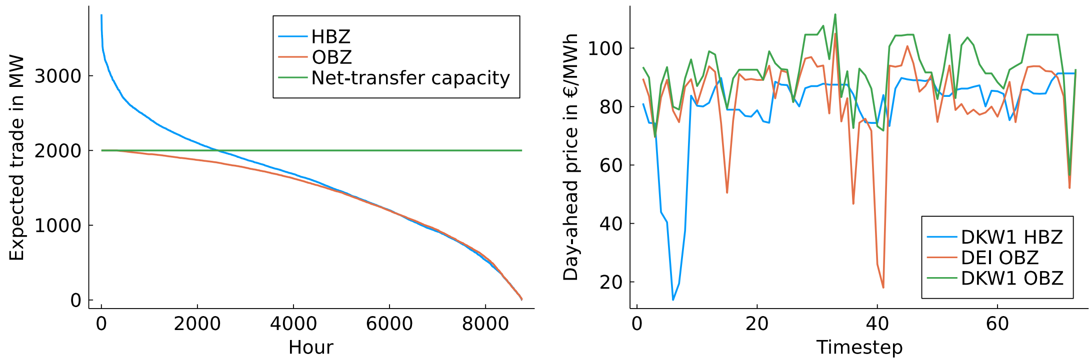

Figure 8: Expected electrolyser capacity factors for 2030 for the OBZ and HBZ configuration.

We recall the two configurations: (1) the offshore bidding zone (OBZ), and (2) the home bidding zone (HBZ)[13]. In HBZ, we add the wind farm capacity and the electrolyser of all three energy islands to their owner country's nearest bidding zone. Figure 8 compares the capacity factors in 2030 for the two configurations. In the HBZ configuration, electrolysers in the zones DKW1 and DKE1 have a slightly higher capacity factors than in OBZ. Looking at the Danish energy islands, DEI and Bornholm, we observe a decrease in offshore electrolyser capacity factors. However, since the electrolyser capacities installed onshore are much larger than offshore, total hydrogen production increases. We identify two reasons. First, electricity generated offshore is transported to and used onshore and preferred over costly offshore electrolysis. Second, in high production hours, none of the hub-shore connecting transmission capacity constraints is binding anymore (as a consequence of the HBZ configuration), and less offshore generation is curtailed. While the flexibility provision by the electrolyser on DEI increases, that of the electrolyser on Bornholm decreases. Those changes are below one percentage point and therefore do not impact the hydrogen production significantly. Nevertheless, there is no strict tendency towards how flexibility provision changes under an HBZ configuration but it seems to depend on the power plant portfolio of the respective countries that the energy island is connected to.

The differences between the two bidding zone configurations are caused by how transmission constraints between the energy islands and the main land are accounted for. While these con-

[13]See Figure 2 in Section 2 above for a visualisation and explanation.

straints impose actual physical limitations in real operations of the power system, the market itself facilitates a higher electricity exchange between the energy island and its home zone when they are neglected (as in HBZ).




(a) Expected electricity flow from DEI to DKW1 over the whole year.

(b) Expected day-ahead prices during the congested hours only.

Figure 9: Interconnector flow and prices during congested hours for DEI and zone DKW1.

We focus the following part of the analysis mainly on one of the three energy islands, DEI in the North Sea, which is integrated into zone DKW1 (Western Denmark) when changing the bidding zone configuration. DEI is chosen because it is currently the first island envisioned to be operational by 2030 and has the most consistent reports and studies available on location, size and interconnection. Figure 9a illustrates the expected export of electricity from DEI to its home zone DKW1 in the OBZ and HBZ configurations. The horizontal line shows the projected physical transmission limit of the corresponding interconnector in 2030. In the HBZ case, this physical transmission limit is violated in 2429 hours on expectation, about 28 % of the time, requiring generally expensive congestion management measures. For the OBZ, the interconnector capacity is only binding in 320 hours (4 %) over the year, indicating that the dispatch changes drastically when the energy islands become part of an HBZ configuration. These findings additionally highlight the sensitivity of the system-wide dispatch towards the capacity of the interconnectors connecting the energy islands to shore. In general, the connection from DKW1 to the energy island is barely used for the export of electricity from DKW1 to the energy island DEI, where it could be further transported to another connected bidding zone.

Relaxing capacity constraints also affects market prices. Figure 9b shows the power prices on DEI and DKW1 in the OBZ and HBZ configurations when there is congestion in the OBZ case. Note that in an HBZ, DEI is part of DKW1 and thus there is a single day-ahead price. One can see from the graph that electricity prices in the integrated bidding zone are less fluctuating than

Table 2: Operational electrolyser statistics for the year 2030 based on the model results.

| **Energy island** | **Configuration** | **Hydrogen production** GWh | **Expected marginal cost** €/MWh | **Expected electricity cost** €/MWh | **Profit** million € |
|---|---|---|---|---|---|
| DEI | OBZ | 1535.22 | 12.06 | 51.79 | 82.88 |
| DEI | HBZ | 1358.11 | 12.20 | 48.64 | 79.57 |
| Bornholm | OBZ | 649.64 | 12.15 | 46.36 | 40.24 |
| Bornholm | HBZ | 584.85 | 12.12 | 46.23 | 36.41 |

in the OBZ case. Furthermore, the price on DEI in the HBZ configuration (blue) is generally higher than in the OBZ configuration (orange) in the same hours. However, for some hours the price on DEI is much lower in the HBZ configuration than in the OBZ. This indicates that the dispatch may be significantly different when the transmission constraint is neglected.

# 6. Discussion

Flexibility and profitability of an electrolyser might work in opposite directions. While for profitability reasons it is desirable that the electrolyser has a high capacity factor, acting as a flexibility resource and participating in the balancing market may be beneficial for the overall system but might reduce overall hydrogen production and eventually the expected profit of the electrolyser. In our cases, flexibility is delivered to the system to some extent by the offshore electrolysers but not as the major service. Generally, the capacity factor of offshore installations is lower than that of their onshore counterparts—independent of the bidding zone configuration.

Based on our findings, we identify three points for further investigation: discussion of the business case for offshore hydrogen production in Section 6.1, a sensitivity analysis on installed capacities and sizing of assets in Section 6.2, and finally a review of model characteristics in Section 6.3.

## 6.1. Business Case

For the business case of an offshore hydrogen producer, it is especially relevant how much hydrogen can be produced and how expensive the corresponding electricity is. Table 2 shows hydrogen quantities produced on the energy islands and the associated expected electricity and marginal[14] cost. Taking a look at DEI, we observe small differences for the two bidding zone

[14] We take 20% reduced and increased marginal cost for upward and downward balancing services, respectively, into account.

configurations. Despite a slightly higher expected electricity cost in the OBZ, a larger hydrogen production leads to a 4 % higher expected profit. To evaluate the expected profit of million €82.88 of the electrolyser on DEI in the OBZ configuration, we compare it to estimated electrolyser investment costs. Based on the investment cost of million €0.45/MW$_{el}$ in 2030 (Danish Energy Agency, 2022), the annuity for the 0.5 GW electrolyser on DEI is million €20.24[15]. This indicates that the investment into an electrolyser under the assumptions taken here might be profitable. Electrolysers onshore face relatively higher expected electricity consumption cost of around €60–90/MWh. Hence, they need a higher number of full load hours to achieve the same return on investment. Note that we neglected any type of infrastructure cost for hydrogen transport and assumed that hydrogen can be sold at any time and quantity for a price of €150/MWh and €100/MWh in 2030 and 2040, respectively.

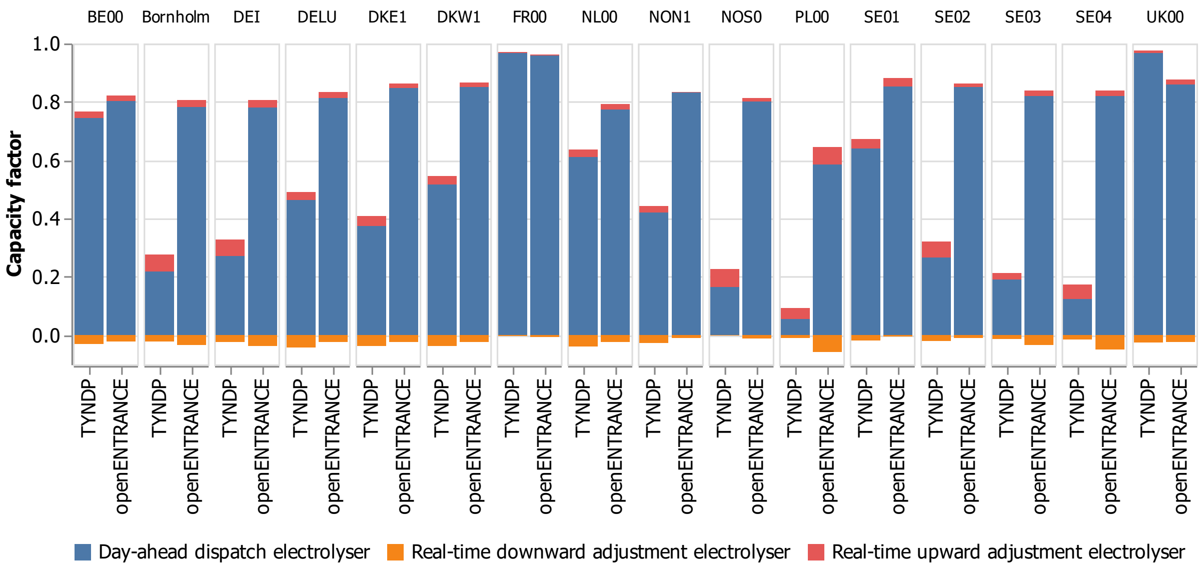



Figure 10: Expected electrolyser capacity factors for 2030 for the TYNDP and the openENTRANCE data set in the OBZ configuration.

## 6.2. Sensitivity Analyses

The results may be sensitive to two main input parameters: installed capacities of conventional and renewable energy technologies as well as sizes of the assets on, and connecting to, the energy islands. We vary the values of these two parameters. As discussed above and due to the better representation of the system and the value of scarcity in the OBZ, we choose to perform the sensitivity analysis for the OBZ configuration only.

[15]We calculate the annuity $a$ based on overnight investment costs $I_0$ for the year 2030 with an interest rate $i$ of 4 % and a lifetime $T$ of 15 years as $a = I_0 \cdot \frac{i \cdot (1+i)^T}{(1+i)^T - 1}$.

#### 6.2.1. Installed Capacities

The data set from TYNDP 2020 provides a rather conservative outlook on the installed renewable energy capacities in 2030 and 2040. To verify our analyses, we contrast the outcomes against results obtained when using the openENTRANCE project input data that feature much higher installed renewable energy capacities (Auer et al., 2020), see Figure 12 in the Appendix. We refer to this case as our *Climate Case*. With significantly higher installed renewable energy capacities but unchanged electrolyser capacities, we observe in Figure 10 that the electrolyser capacity factors increase to around 90 %. In detail, there is an increase of hydrogen production on the energy islands of around 141 % (from 1535 GWh to 3691 GWh) and 183 % (from 650 GWh to 1839 GWh) on DEI and Bornholm, respectively. At the same time, the average expected electricity cost declines by nearly 55–60 % to €21.1/MWh and almost €21/MWh, and the expected profit increases by 350% to million €373.34 on DEI and by 363% to million €186.51 on Bornholm, respectively. Hence, in a climate compatible development of the power system with large-scale deployment of additional renewable energy sources, the business case for offshore electrolysers becomes significantly stronger.

#### 6.2.2. Sizing of Electrolysers and Cable Connections

As shown in Figure 9a, the transfer capacity and the line sizing significantly affect the hydrogen production. The reference cases originate from industry-led studies on the configuration of the energy islands (COWI, 2021; North Sea Wind Power Hub, 2020). To analyse the influence of the chosen interconnector capacities, we consider an increase of 20 % and a decrease of 20 % and 40 % of the capacities of the interconnectors connected to the energy islands. The results are shown in Figure 11 for the OBZ configuration in 2030. We observe that while capacity factors of electrolysers onshore in the connected bidding zones decline, the capacity factors of electrolysers on the energy islands increase. Reducing interconnector capacities by 20 %, the total capacity factors of the electrolysers on DEI and Bornholm increase by 19.8 and 5.2 percentage points, respectively. Similarly, decreasing the interconnector capacity to 60 % of the original value increases the total capacity factors by 31.26 and 15.9 percentage points, respectively. In some peak wind production hours, there is not enough interconnector capacity available to balance fluctuations on the energy islands by solely adjusting trade flows. This leads to an increase of participation in the balancing market of the electrolyser by around 1 percentage point. Increasing the interconnector capacity such that the total line capacity connected to the energy islands exceeds its wind production capacity does not impact the capacity factors of the electrolyser.

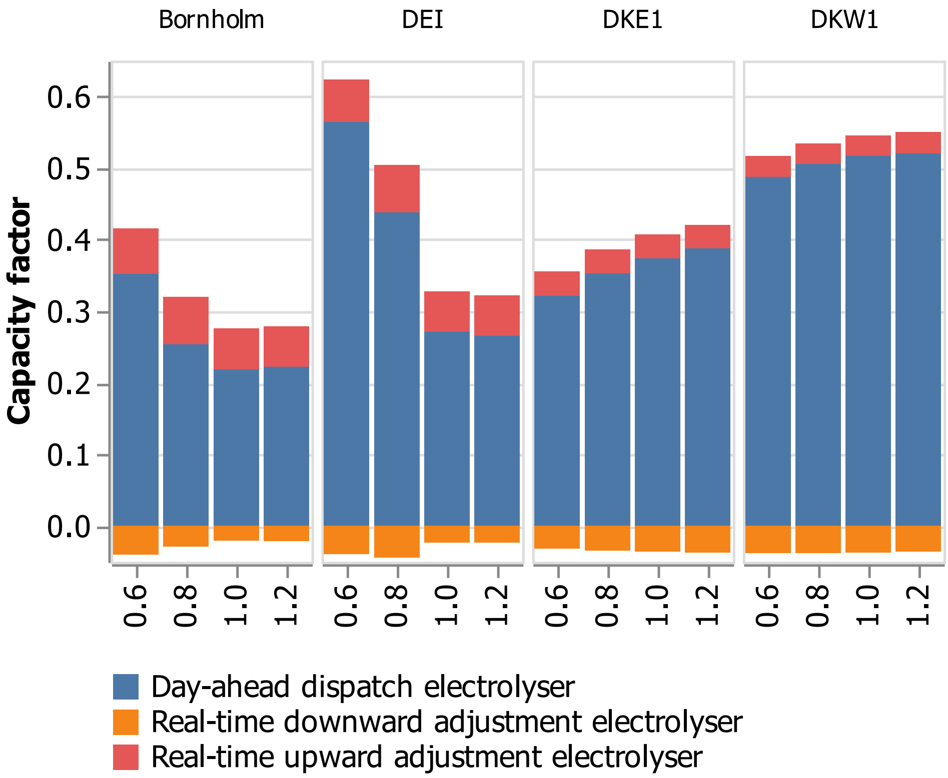



Figure 11: Electrolyser capacity factors for varying energy island interconnector capacities by 20 % for OBZ in 2030.

### 6.3. Model Characteristics

Our model follows a frequently used approach to analyse stochastic infeed from renewable energy sources in electricity markets. Setting up the model, we make a set of assumptions which impact the results. For instance, pursuing computational tractability, we disregard unit commitment constraints. This means that we neglect any minimum power generation limits, down-times, necessary minimum run time requirements and outages, which in turn increases the flexibility of dispatchable units in the model. To compensate for the risk of extensively overestimating flexibility from conventional power plants, we have included restrictions on the maximum ramp rates, based on historical data for the year 2017 taken from the ENTSO-E Transparency Platform.

We use a net-transfer capacity approach to estimate interconnector capacities. In particular, for the cables connecting the energy islands to shore, we assume that their maximum transmission capacity is available at all times. In practice, flow-based market coupling is currently used in Central Western European markets and will likely be adopted across all countries in Europe until 2030 (Tosatto et al., 2022). Flow-based market coupling allocates transmission capacities to those interconnectors that have the highest value for the system in the time period considered. Since energy islands host zero marginal cost power production only, it is very likely that a flow-based market coupling algorithm will allocate the maximum capacity to the interconnectors connecting those energy island to shore. Hence, for the interconnectors connecting the energy islands to shore, flow-based market coupling and the simplified net-transfer capacity scheme adopted here will likely lead to the same outcome. Nevertheless, due to the zonal setup in the model with net-transfer capacities between the zones, we neglect any network constraints within the zones and may overestimate the available grid capacities behind the interconnectors. Refer to, e.g., Seifert (2022) who conclude that the national grid plans for 2030 are not yet fully equipped to accommodate foreseeably large shares of renewable energy, and need upward adjustments following national expansion plans.

Lastly, we simulate two market stages only that do not reflect all stages exist in the current market frameworks of most European countries. The well-established sequences are the day-ahead market, cleared up to 12-36 hours before real-time, the intraday market for adjusting to forecasts, balancing markets for flexibility, and technical reserves as well as for some countries a market-based redispatch or congestion management actions. In this model we consider a day-ahead market clearing and a real-time balancing adjustment only.

The model characteristics influence the results to some extent. Whereas using the full net-transfer capacities between countries for trade may be close to the result of a model with flow-based market coupling, the impact of reduced technical detail of dispatchable technology overestimates their flexibility potential. For all conventional technologies, reservoir hydropower, and biomass, we include ramp rates but neglect unit commitment and must-run obligations. Additionally, for the case of biomass, regulatory frameworks for example in Germany and Denmark, incentivise high capacity factors and a price-inflexible operation. Our model allows full adjustment ranges within ramp rates for all technologies, which can lead to an overestimation of the flexibility potential available in the system.

# 7. Conclusion and Policy Implications

The concept and implementation of energy islands is driven by several players in governments and the industry. Construction of energy islands has not yet started and many details are not yet defined. Assuming that those islands will be a place for wind energy collection and hydrogen production, we have analysed the role of offshore electrolysers.

Our first research question targeted the electrolyser's contribution to flexibility. We conclude that flexibility in the system stems mainly from other, cheaper dispatchable sources than the electrolysers. Offshore electrolysers do have a modest contribution to balancing services on the energy island. Looking at the impact of bidding zone configuration on the operation of the electrolyser, we find that offshore bidding zones lead to slightly higher electrolyser capacity factors and reduced needs for congestion management. Based on our sensitivity analyses, we can summarise that (i) significantly higher shares of renewables onshore lead to much higher capacity factors of all the electrolysers, but especially of those on the energy islands, and make electrolysers a highly profitable investment, and (ii) reducing the size of the cable connections of the energy island significantly increases the capacity factors of the electrolysers and their balancing actions on the island.

Based on our study, we can formulate four policy recommendations impacting the role of electrolysers on energy islands:

1. **Flexibility:** Electrolysers are able to technically react to changes in electricity production and have quite broad potential to provide flexibility. If the potential is to be exploited, there is a need for economic incentives to make a flexibility-oriented operation economically viable. We show that capacity factors are low offshore and investments in electrolysers as flexibility resources only will need to be supported.

2. **Bidding Zone Configuration:** Offshore bidding zones reflect the costs of energy and scarcity of the good more adequately than home bidding zones. For electrolysers on energy islands, the offshore bidding zone configuration facilitates higher hydrogen production levels at lower average electricity cost. Introducing this configuration avoids misalignment between physical network constraints and market solutions, reducing possibly expensive redispatch measures. This suggestion is in line with the conclusion by Kitzing and Garzón González (2020) who considered offshore wind hubs only.

3. **Hydrogen Supply:** Discussions about a hydrogen economy are gaining momentum. The European Commission foresees a production of 10 million tonnes by 2030 in Europe[16]. If hydrogen is to be produced locally as part of the strategy and is to be prioritised, the costs

[16] See COM(2020) 301 final.

of electricity for electrolysis should reflect the local production costs. The implementation of offshore bidding zones can make hydrogen production more viable.

4. **Renewable Energy Targets:** Renewable energy capacity projections presented in the TYNDP 2020 do not succeed to fulfil renewables targets. Our results indicate that the projected capacities are not sufficient to supply the required hydrogen for a low-carbon industry. National and European efforts therefore need to incorporate incentives and plans for dedicated and system-based hydrogen production.

The presented analysis uses an operational model with two stages to analyse the contribution to flexibility provision of an offshore electrolyser as well as the impact of different bidding zone configurations on its profitability. The approach can be extended by including unit commitment to obtain a better representation of operational characteristics for large conventional units. For the representation of the electrolyser operation, Flamm et al. (2021) suggest to use a mixed integer program for higher accuracy, and Zheng et al. (2022b) highlight the importance to include operational details on temperature dependence and change of state in the model. Extending the presented model by adding more technological details to all technologies can provide further insights. Due to uncertainty in hydrogen demand and prices, a further analysis on the impact of both on the viability and the offshore electrolyser will allow to understand how offshore assets can contribute to hydrogen demand and system stability. So far, we have disregarded market power and strategic bidding. However, this might occur around energy islands when operators of wind farms and electrolysers both aim for high profits. In particular, ownership structures may influence strategic behaviour. It can be relevant to analyse the case of different structures and contracts: Owning and operating the wind farm and the electrolyser jointly may lead to a different market outcome compared to having two separate owners and operators. Last, we suggest to investigate the impact of the current and planned future power grid on the role and operation of offshore electrolysers on energy islands. We base this analysis on modelling bidding zones and restrict net-transfer capacities. In a follow-up study, flow-based market coupling as well as performing inner zonal congestion management will provide further insights.

**CRediT authorship contribution statement** **Alexandra Lüth:** Conceptualisation, Data curation, Software, Visualisation, Writing - original draft, Writing - review & editing. **Yannick Werner:** Conceptualisation, Data curation, Software, Visualisation, Writing - original draft, Writing - review & editing. **Ruud Egging-Bratseth:** Conceptualisation, Supervision, Writing

- review & editing. **Jalal Kazempour:** Conceptualisation, Supervision, Writing - review & editing.

**Declaration of competing interest** The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

**Acknowledgements** The authors would like to thank Morten Pindstrup (Energinet), Alessandro Singlitico and Andrea Tosatto for insightful exchanges on energy islands, participants of the energy systems seminar at NTNU for great feedback, and Peter Bogetoft and Marta Victoria for valuable comments to improve this work.

Financial support from the Copenhagen School of Energy Infrastructure (CSEI) is acknowledged. The activities of CSEI are funded jointly in cooperation between Copenhagen Business School and energy sector partners.

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# A. Appendix

## A.1. Model Formulation

The following section describes the modelling framework that we paraphrase in Section 3. The following paragraphs explain the mathematical model and its characteristics. Table 3 provides the nomenclature. Variables are denoted in capital letters, scalars and parameters in small letters.

Table 3: Designated sets, parameters, and variables of the mathematical model.

| **Sets** | |
|---|---|
| $n \in \mathcal{N}$ | zone $n$ in set of zones $\mathcal{N}$ |
| $t \in \mathcal{T}$ | hour $t$ in time horizon $\mathcal{T}$ |
| $i \in \mathcal{I} \subset \mathcal{U}$ | technology $i$ of all conventional technologyies $\mathcal{I}$ |
| e $j \in \mathcal{J}$ | technology $j$ of all renewable plants $\mathcal{J}$ |
| $e \in \mathcal{E}$ | electrolyser $e$ of all electrolysers $\mathcal{E}$ |
| $s \in \mathcal{S}$ | storage unit $s$ of all storages |
| $r \in \mathcal{R} \subset \mathcal{U}$ | technology $r$ of all reservoirs |
| $u \in \mathcal{U} \supset \mathcal{I}, \mathcal{R}$ | technology $u$ of all dispatchable technologies for balancing |
| $d \in \mathcal{D}$ | demand $d$ of all demands $\mathcal{D}$ |
| $f \in \mathcal{F}$ | line $f$ of all lines $\mathcal{F}$ |
| $\omega \in \Omega$ | scenario $\omega$ of all scenarios |
| **Parameters** | |
| $g^{\text{tot}}_{\omega,r}$ | maximum total production for reservoir $r$ in scenario $\omega$ over the whole time horizon |
| $g^{\max}_{u}$ | maximum generation capacity of unit $u$ |
| $r^{\text{down/up}}_{u}$ | maximum downward/upward ramping capacity of dispatchable unit $u$ |
| $r^{\text{down/up},G}_{s}$ | maximum downward/upward ramping capacity of storage $s$ in discharging mode |
| $r^{\text{down/up},L}_{s}$ | maximum downward/upward ramping capacity of storage $s$ in charging mode |
| $g^{\text{real}}_{j,t}$ | renewable energy production of unit $j$ in time step $t$ |
| $l^{\max}_{e}$ | maximum consumption of electrolyser $e$ |
| $l^{\text{el}}_{d,t}$ | demand of load $d$ in time step $t$ |
| $mc_{u/j/e}$ | marginal production cost of unit $u/j/e$ per MWh |
| $p^{\text{H}_2}$ | price per kWh hydrogen sold |
| $p^{\text{up,B}}_{i/e}$ | marginal upwards balancing cost of unit $i/e$ per MWh |
| $p^{\text{down,B}}_{i/e}$ | marginal downwards balancing cost of unit $i/e$ per MWh |
| $p^{\text{LOL}}$ | value of lost load per kWh |
| $ntc_{n,m}$ | net transfer capacity on line from $n$ to $m$ |
| $s^{\min}_{s}/s^{\max}_{s}$ | lower/upper storage level of storage $s$ |
| $\eta^{\text{G/L}}_{s}$ | discharge/charge efficiency of storage $s$ |
| $\eta_{e}$ | conversion efficiency of electrolyser $e$ |
| $\pi_{\omega,t}$ | probability of occurrence of scenario $\omega$ in time step $t$ |
| **Decision Variables** | |
| $F_{f,t} \in \mathbb{R}^{+}$ | flow on line $f$ from zone $n$ and $m$ in time step $t$ |
| $G_{u,t} \in \mathbb{R}^{+}$ | generation by unit $u$ in time step $t$ |
| $G_{s,t} \in \mathbb{R}^{+}$ | generation by storage $s$ in time step $t$ |
| $G^{S}_{j,t} \in \mathbb{R}^{+}$ | scheduled renewable generation from unit $j$ in time step $t$ |
| $L_{e,t} \in \mathbb{R}^{+}$ | load of electrolyser $e$ in time step $t$ |
| $L_{s,t} \in \mathbb{R}^{+}$ | load/charge of storage $s$ in time step $t$ |
| $B^{\text{up}}_{\omega,u/e,t} \in \mathbb{R}^{+}$ | upwards balancing of unit $u/e$ in time step $t$ |
| $B^{\text{down}}_{\omega,u/e,t} \in \mathbb{R}^{+}$ | downwards balancing of unit $u/e$ in time step $t$ |

| | |
|---|---|
| $B^{\text{up,G}}_{\omega,s,t} \in \mathbb{R}^+$ | upwards balancing of discharging storage $s$ in time step $t$ |
| $B^{\text{down,G}}_{\omega,s,t} \in \mathbb{R}^+$ | downwards balancing of discharging storage $s$ in time step $t$ |
| $B^{\text{up,L}}_{\omega,s,t} \in \mathbb{R}^+$ | upwards balancing/reduced consumption of storage $s$ in time step $t$ |
| $B^{\text{down,L}}_{\omega,s,t} \in \mathbb{R}^+$ | downwards balancing/increased consumption of storage $s$ in time step $t$ |
| $F^{\text{adj}}_{\omega,f,t} \in \mathbb{R}$ | adjusted flow on line $f$ from $n$ and $m$ in time step $t$ |
| $G^{\text{CU}}_{\omega,j,t} \in \mathbb{R}^+$ | curtailed renewable energy from unit $j$ in time step $t$ |
| $L^{\text{shed}}_{\omega,d,t} \in \mathbb{R}^+$ | shedded load $d$ in time step $t$ |
| $S_{\omega,s,t} \in \mathbb{R}^+$ | storage level of storage $s$ in time step $t$ |
| $B^{\text{ramp}}_{u/s,t,\omega} \in \mathbb{R}$ | ramping of unit $u/s$ in timestep $t$ and scenario $\omega$ |

**Objective** The objective is to minimise the expected total operational costs for electricity generation adjusted for the profit from hydrogen production for each hour $t \in \mathcal{T}$ in a co-integrated market comprising day-ahead and balancing markets. Let $i \in \mathcal{I},\ j \in \mathcal{J},\ s \in \mathcal{S},\ r \in \mathcal{R},\ e \in \mathcal{E}$ denote the set of conventional, intermittent renewable, storage, hydro reservoir, and electrolyser technologies, respectively. For simplicity, we aggregate all power plants of the same technology in each country to a single unit such that every country hosts at maximum one power plant of each technology. Furthermore, we assume that all power plants of an individual technology have exactly the same operational characteristics, i.e., cost structure, technical constraints and so forth. All inflexible price-inelastic demands denoted by $d \in \mathcal{D}$ are also treated the same and incur the same load shedding cost. We introduce scenarios $\omega \in \Omega$ in the second stage to represent different power production from renewable energy sources.

Eq. (1) minimises the sum of costs for the first stage decision $C^{\text{DA}}_t$ and costs for the second stage balancing $C^{\text{BA}}_{\omega,t}$. The cost in the second stage are represented by the sum over all scenarios $\omega$ weighted by their probability $\pi_{\omega,t}$.

$$\min \sum_{t\in\mathcal{T}} \left[ C^{\text{DA}}_t + \sum_{\omega\in\Omega} \left( \pi_{\omega,t} \cdot C^{\text{BA}}_{\omega,t} \right) \right] \tag{1}$$

Cost in the first stage include the sum of costs for conventional power production and hydrogen production costs related to the day-ahead schedules, Eq. (2). For the day-ahead market, we account for marginal cost $mc_i$ for dispatchable generation $G_{i,t}$ of all conventional generators $i$. Hydro power reservoir and storage technologies are assumed to have zero maginal cost. $L_{e,t}$ denotes the power demand of the electrolyser and $\eta_e < 1$ denotes the power-to-hydrogen efficiency of electrolyser $e$. Term $(\eta_e p^{\text{H}_2} - mc_e)$ expresses the income from producing and selling of hydrogen.

$$C_t^{\mathrm{DA}} = \sum_{i \in \mathcal{I}} (mc_i \cdot G_{i,t}) - \sum_{e \in \mathcal{E}} (\eta_e p^{\cdot}\mathrm{H}_2 - mc_e) \cdot L_{e,t}, \qquad \forall\, t \in \mathcal{T} \tag{2}$$

Costs in the second stage of the model arise from providing balancing energy according to system needs in each scenario $\omega$. Eq. (3) is, thus, built up similar to the first stage costs and adds the costs for upwards and downwards balancing for the available technologies that have non-zero marginal costs of production. For conventional technologies and electrolysers, we include upwards $B^{\mathrm{up}}_{\omega,i,t}$, $B^{\mathrm{up}}_{\omega,e,t}$ and downwards $B^{\mathrm{down}}_{\omega,i,t}$, $B^{\mathrm{down}}_{\omega,e,t}$. For conventional technologies, we assume that upward (downward) balancing costs are 20% above (below) their marginal costs. For electrolysers, we additionally include (losses) revenues for additional (reduced) hydrogen production in the case of downward (upward) balancing service provision. For further explanation of the derivation of the balancing bid prices we refer to Appendix A.2. In the real-time operation, it is additionally possible to shed loads $L^{\mathrm{shed}}_{\omega,d,t}$ at a (sufficiently high) cost $p^{\mathrm{LOL}}$ that ensures that this action is only taken when the supply-demand balance cannot be achieved otherwise. Power production from renewable energy sources is assumed to have zero marginal cost and can be curtailed without a penalty.

$$\begin{aligned} C^{\mathrm{BA}}_{\omega,t} = &\sum_{i \in \mathcal{I}} \left( p_i^{\mathrm{up,B}} \cdot B^{\mathrm{up}}_{\omega,i,t} - p_i^{\mathrm{down,B}} \cdot B^{\mathrm{down}}_{\omega,i,t} \right) \\ &+ \sum_{e \in \mathcal{E}} \left( p_e^{\mathrm{up,B}} \cdot B^{\mathrm{up}}_{\omega,e,t} - p_e^{\mathrm{down,B}} \cdot B^{\mathrm{down}}_{\omega,e,t} \right) + \sum_{d \in \mathcal{D}} p^{\mathrm{LOL}} \cdot L^{\mathrm{shed}}_{\omega,d,t}, \qquad \forall\, \omega \in \Omega, t \in \mathcal{T} \end{aligned} \tag{3}$$

The decisions on day-ahead and real-time power production are restricted by a set of constraints. We introduce a supply-demand-balance for each stage ensuring that electricity supply equals demand at all times. For all technologies, the model includes a constraint to limit their maximum power output to their installed capacity and considers ramping limits for the change of power production between time steps. Exchange capacities between the zones are limited to a maximum net-transer capacity. Storage units have a constraint on maximum storage level and charge and discharge rates. The electrolysers are modelled as power consuming units similar to a storage in charging mode.

**Supply-demand balances** For the first stage, the supply-demand balance given in Eq. (4) needs to hold: in each zone, generation from dispatchable units $G_{u,t}$, scheduled renewables $G^{\mathrm{S}}_{j,t}$, generation from storage $G_{s,t}$, and trade $F_{f,t}$ (incoming and outgoing) have to equal demand for loads $l^{\text{el}}_{d,t}$, hydrogen production $L_{e,t}$, and storage charge $L_{s,t}$.

$$\begin{aligned}
&\sum_{u\in\Delta_n^G} G_{u,t} + \sum_{s\in\Delta_n^S} G_{s,t} + \sum_{j\in\Delta_n^J} G^{\text{S}}_{j,t} \\
&- \sum_{d\in\Delta_n^D} l^{\text{el}}_{d,t} - \sum_{e\in\Delta_n^E} L_{e,t} - \sum_{s\in\Delta_n^S} L_{s,t} \\
&- \sum_{f\in\mathcal{F}_n^{out}} F_{f,t} + \sum_{f\in\mathcal{F}_n^{in}} F_{f,t} = 0, \qquad \forall\, n \in \mathcal{N}, t \in \mathcal{T}
\end{aligned} \tag{4}$$

For the second stage, deviations from forecasted values for stochastic generation need to be balanced. We introduce uncertainty through scenarios $\omega$ in this stage in Eq. (5). In this model, deviations of scheduled intermittent production $G^S_{j,t}$ from $g^{\text{real}}_{\omega,j,t}$ are to be balanced by either curtailing renewables $G^{\text{CU}}_{j,t}$, using balancing services of dispatchable technologies $u$ for up- or downwards adjustments $B^{\text{up}}_{\omega,u,t}, B^{\text{down}}_{\omega,u,t}$, increasing/decreasing the output of an electrolyser $B^{\text{up}}_{\omega,e,t}, B^{\text{down}}_{\omega,e,t}$ or storage units $B^{\text{up,L}}_{\omega,s,t}, B^{\text{down,L}}_{\omega,s,t}, B^{\text{up,G}}_{\omega,s,t}, B^{\text{down,G}}_{\omega,s,t}$. Note that we explicitly allow storage units to not only adjust their day-ahead market schedule in the same direction, but also allow for changing the operational mode in the balancing stage. For example, if a storage is charging in the day-ahead market, we allow the storage to fully revert this action and additionally discharge in the balancing stage. Apart from that, net exchange with neighbouring zones $F^{\text{adj}}_{\omega,f,t}$ can be adjusted and load can be shedded $L^{\text{shed}}_{\omega,d,t}$.

$$\begin{aligned}
&\sum_{j\in\Delta_n^J} (g^{\text{real}}_{\omega,j,t} - G^{\text{S}}_{j,t} - G^{\text{CU}}_{\omega,j,t}) \\
&+ \sum_{u\in\Delta_n^U} (B^{\text{U}}_{\omega,u,t} - B^{\text{D}}_{\omega,u,t}) + \sum_{e\in\Delta_n^E} (B^{\text{up}}_{\omega,e,t} - B^{\text{down}}_{\omega,e,t}) \\
&+ \sum_{s\in\Delta_n^S} (B^{\text{up,G}}_{\omega,s,t} + B^{\text{up,L}}_{\omega,s,t} - B^{\text{down,G}}_{\omega,s,t} - B^{\text{down,L}}_{\omega,s,t}) \\
&+ \sum_{d\in\Delta_n^D} L^{\text{shed}}_{\omega,d,t} - \sum_{f\in\mathcal{F}_n^{out}} F^{\text{adj}}_{\omega,f,t} + \sum_{f\in\mathcal{F}_n^{in}} F^{\text{adj}}_{\omega,f,t} = 0, \qquad \forall \omega \in \Omega, n \in \mathcal{N}, t \in \mathcal{T}
\end{aligned} \tag{5}$$

**Capacity constraints for conventional and reservoir units** Generation capacities for all units are limited in size. To represent these limits, we enforce a series of capacity constraints along the model's stages.

For renewable energy, the scheduled energy production $G^S_{j,t}$ cannot exceed its installed capacity

$g_j^{\max}$. Curtailment $G^{\mathrm{CU}}_{\omega,j,t}$ in the second stage cannot be larger than the realisation of renewable $g^{\mathrm{real}}_{\omega,j,t}$ production.

$$G^{S}_{j,t} \leq g^{\max}_{j} \qquad \forall\, j \in J, t \in T \tag{6}$$

$$G^{\mathrm{CU}}_{\omega,j,t} \leq g^{\mathrm{real}}_{\omega,j,t} \qquad \forall\, \omega \in \Omega, j \in \mathcal{J}, t \in \mathcal{T} \tag{7}$$

For conventional technologies, including hydro power reservoirs, generation $G_{u,t}$ including balancing capacity $B^{\mathrm{up}}_{\omega,u,t}$ and $B^{\mathrm{down}}_{\omega,i,t}$ needs to lie between zero and the maximum installed capacity $g_u^{\max}$, as displayed in Eq. (8) and Eq. (9).

$$G_{u,t} + B^{\mathrm{up}}_{\omega,u,t} \leq g^{\max}_{u} \qquad \forall\, \omega \in \Omega, u \in \mathcal{U}, t \in \mathcal{T} \tag{8}$$

$$G_{u,t} - B^{\mathrm{down}}_{\omega,u,t} \geq 0 \qquad \forall\, \omega \in \Omega, u \in \mathcal{U}, t \in \mathcal{T} \tag{9}$$

**Reservoir** For generation from water reservoirs we restrict the sum of all generation over the time horizon to a scenario-specific maximum $g^{\mathrm{tot}}_{\omega,r}$.

$$\sum_{t \in \mathcal{T}} (G_{r,t} + B^{\mathrm{up}}_{\omega,r,t} - B^{\mathrm{down}}_{\omega,r,t}) \leq g^{\mathrm{tot}}_{\omega,r}, \qquad \forall\, \omega \in \Omega, r \in R \tag{10}$$

**CHP** Let $c \in \mathcal{I}^c \subseteq \mathcal{I}$ denote the set of combined heat and power (CHP) plants that are often subject to heat delivery contracts and are therefore limited in their flexibility. We include a time-varying minimum run requirement in our model to reflect this:

$$G_{c,t} - B^{\mathrm{down}}_{\omega,c,t} \geq g_{\mathrm{c},t}, \qquad \forall\, \omega \in \Omega, c \in \mathcal{I}^c, t \in \mathcal{T} \tag{11}$$

**Exchange constraints and load shedding** In the model, we allow for exchange between different zones $n \in \mathcal{N}$ given a specific line (interconnector) capacity. Let $\mathcal{F}$ denote the set of interconnectors, where interconnector $f$ connects zones $n, m \in \mathcal{N}$. For simplicity, we use $f = (n,m)$ interchangeably. We further define one interconnector for each direction, such that $f = (n,m)$, $\hat{f} = (m,n)$, where $f,\ \hat{f} \in \mathcal{F}$. Additionally, we define subsets $\mathcal{F}^{out}_n$, $\mathcal{F}^{in}_n \subset \mathcal{F}$ that collect all interconnectors $f$ and $\hat{f}$ that start and end at zone $n$, respectively. We use net transfer capacities to limit the maximum flows on interconnectors between zones according to Eq. (12) – Eq. (13).

$$0 \leq F_{f,t} \leq ntc_f \qquad \forall\, t \in T, f \in \mathcal{F} \tag{12}$$

$$0 \leq F_{f,t} + F^{\text{adj}}_{\omega,f,t} \leq ntc_f \qquad \forall\, \omega \in \Omega, t \in T, f \in \mathcal{F} \tag{13}$$

**Electrolyser** Eq. (14) and Eq. (15) restrict hydrogen production from power consumption $L_{e,t}$ including balancing energy $B^{\text{down}}_{\omega,e,t}$ and $B^{\text{up}}_{\omega,e,t}$ to stay between the limits of zero and maximum installed electrical capacity $g^{\max}_e$.

$$L_{e,t} + B^{\text{down}}_{\omega,e,t} \leq l^{\max}_e \qquad \forall\, \omega \in \Omega, e \in E, t \in T \tag{14}$$

$$L_{e,t} - B^{\text{up}}_{\omega,e,t} \geq l^{\max}_e \qquad \forall\, \omega \in \Omega, e \in E, t \in T \tag{15}$$

**Storage Equations** Storage units operate similarly to conventional electricity generation technologies in their discharge mode and similarly to electrolysers in their charge mode. To reflect all of the characteristics of a storage with regard to balancing, expressions Eq. (16) and Eq. (17) restrict power consumption $L_{s,t}$ including activated balancing capacity $B^{\text{down,L}}_{\omega,s,t}$ and $B^{\text{up,L}}_{\omega,s,t}$ to stay between the limits of zero and maximum installed charge capacity $l^{\max}_s$. Further, expressions Eq. (19) and Eq. (18) address the capacity boundaries of generation (discharge) from storage $G_{s,t}$ and the balancing adjustments $B^{\text{down,G}}_{\omega,s,t}$ and $B^{\text{up,G}}_{\omega,s,t}$ to keep within the physical boundaries at maximum $g^{\max}_s$.

$$0 \leq L_{s,t} + B^{\text{down,L}}_{\omega,s,t} \leq l^{\max}_s \qquad \forall\, \omega \in \Omega, s \in S, t \in T \tag{16}$$

$$0 \leq L_{s,t} - B^{\text{up,L}}_{\omega,s,t} \leq l^{\max}_s \qquad \forall\, \omega \in \Omega, s \in S, t \in T \tag{17}$$

$$0 \leq G_{s,t} + B^{\text{up,G}}_{\omega,s,t} \leq g^{\max}_s \qquad \forall\, \omega \in \Omega, s \in S, t \in T \tag{18}$$

$$0 \leq G_{s,t} - B^{\text{down,G}}_{\omega,s,t} \leq g^{\max}_s \qquad \forall\, \omega \in \Omega, s \in S, t \in T \tag{19}$$

Eq. (20) limits the stored energy $S_{\omega,s,t}$ to stay within a lower and an upper storage bound $s^{\min}_s$ and $s^{\max}_s$.

$$s^{\min}_s \leq S_{\omega,s,t} \leq s^{\max}_s, \qquad \forall\, \omega \in \Omega, s \in S, t \in T \tag{20}$$

The storage level $S_{\omega,s,t}$ in each time step and scenario is determined by the storage level of the prior time step $S_{\omega,s,t-1}$, adjusted by charged energy $(L_{s,t} + B^{\text{up,L}}_{\omega,s,t} - B^{\text{down,L}}_{\omega,s,t})$ and discharged energy $(G_{s,t} + B^{\mathrm{up,G}}_{\omega,s,t} - B^{\mathrm{down,G}}_{\omega,s,t})$. The charging and discharging efficiencies are denoted as $\eta^{\mathrm{L}}_s$ and $\eta^{\mathrm{G}}_s$, respectively.

$$\begin{aligned} S_{\omega,s,t} = {} & S_{\omega,s,t-1} + \eta^{\mathrm{L}}_s \cdot (L_{s,t} - B^{\mathrm{up,L}}_{\omega,s,t} + B^{\mathrm{down,L}}_{\omega,s,t}) \\ & - \frac{1}{\eta^{\mathrm{G}}_s} \cdot (G_{s,t} + B^{\mathrm{up,G}}_{\omega,s,t} - B^{\mathrm{down,G}}_{\omega,s,t}) \qquad \forall\, \omega \in \Omega, s \in S, t \in T \end{aligned} \tag{21}$$

**Ramping** Conventional power plants and hydro turbines have technical limits on their capability to adjust their power output. We incorporate these limits by including ramping constraints for all dispatchable power plants $u \in \mathcal{U}$ and storages $s \in \mathcal{S}$:

$$- r^{\mathrm{down}}_u \leq G_{u,t} - G_{u,t-1} \leq r^{\mathrm{up}}_u, \qquad \forall\, u \in \mathcal{U}, t > 1 \tag{22}$$

$$B^{\mathrm{ramp}}_{u,t,\omega} = B^{\mathrm{up}}_{\omega,u,t} - B^{\mathrm{down}}_{\omega,u,t}, \qquad \forall\, \omega \in \Omega, u \in \mathcal{U}, t \in \mathcal{T} \tag{23}$$

$$- r^{\mathrm{down}}_u \leq G_{u,t} - G_{u,t-1} + B^{\mathrm{ramp}}_{u,t,\omega} - B^{\mathrm{ramp}}_{u,t-1,\omega} \leq r^{\mathrm{up}}_u, \qquad \forall\, \omega \in \Omega, u \in \mathcal{U}, t > 1 \tag{24}$$

$$- r^{\mathrm{down},G}_s \leq G_{s,t} - G_{s,t-1} \leq r^{\mathrm{up},G}_s, \qquad \forall\, s \in \mathcal{S}, t > 1 \tag{25}$$

$$B^{\mathrm{ramp},G}_{s,t,\omega} = B^{\mathrm{up},G}_{\omega,s,t} - B^{\mathrm{down},G}_{\omega,s,t}, \qquad \forall\, \omega \in \Omega, s \in \mathcal{S}, t \in \mathcal{T} \tag{26}$$

$$- r^{\mathrm{down},G}_s \leq G_{s,t} - G_{s,t-1} + B^{\mathrm{ramp},G}_{s,t,\omega} - B^{\mathrm{ramp},G}_{s,t-1,\omega} \leq r^{\mathrm{up},G}_s, \qquad \forall\, \omega \in \Omega, s \in \mathcal{S}, t > 1 \tag{27}$$

$$- r^{\mathrm{down},L}_s \leq L_{s,t} - L_{s,t-1} \leq r^{\mathrm{up},L}_s, \qquad \forall\, s \in \mathcal{S}, t > 1 \tag{28}$$

$$B^{\mathrm{ramp},L}_{s,t,\omega} = B^{\mathrm{up},L}_{\omega,s,t} - B^{\mathrm{down},L}_{\omega,s,t}, \qquad \forall\, \omega \in \Omega, s \in \mathcal{S}, t \in \mathcal{T} \tag{29}$$

$$- r^{\mathrm{down},L}_s \leq L_{s,t} - L_{s,t-1} + B^{\mathrm{ramp},L}_{s,t,\omega} - B^{\mathrm{ramp},L}_{s,t-1,\omega} \leq r^{\mathrm{up},L}_s, \qquad \forall\, \omega \in \Omega, s \in \mathcal{S}, t > 1 \tag{30}$$

where $r^{\mathrm{down}}_u, r^{\mathrm{up}}_u$ are the maximum ramping capabilities for downward and upward ramping, respectively, of conventional generator $u$. For storage $s$, $r^{\mathrm{down},G}_s and r^{\mathrm{up},G}_s$ and $r^{\mathrm{down},L}_s, r^{\mathrm{up},L}_s$ are the maximum ramping capabilities for upward and downward ramping in discharge and charging mode, respectively. Furthermore, we define auxiliary variables $B^{\mathrm{ramp}}_{u,t,\omega}, B^{\mathrm{ramp},G}_{s,t,\omega}, B^{\mathrm{ramp},L}_{s,t,\omega}$ to capture the generation adjustments in the balancing stage.

## A.2. Balancing Costs

We assume that the costs of dispatchable units $u$ in the balancing markets are chosen in a way to reflect additional costs of adjusting the power output away from the day-ahead schedule. Hence, we assume that for upward balancing services (generator produces more power), the cost $p^{B,U}_g$ equals $mc_u \cdot (1+\mu)$, where $\mu$ is chosen to be 20%. Similarly, the cost for downward balancing services (generator produces less power) is assumed to be $p_g^{B,D} = mc_u \cdot (1-\mu)$. In contrast to that, the electrolyser faces some gained or lost profits on the hydrogen market in case it produces more or less hydrogen by consuming more or less power. Following a similar argument used for the dispatchable generators, we assume that the bid price for upward balancing services (electrolyser consumes less power) is $p_e^{B,U} = \eta_e p^{\mathrm{H}_2} - mc_e \cdot (1 - \mu)$. Analogously, the cost for downward balancing services (electrolyser consumes more power) is $p_e^{B,D} = -(\eta_e p^{\mathrm{H}_2} - mc_e \cdot (1 + \mu))$. Note that in contrast to dispatchable units, the electrolyser does not only take its marginal production cost into account but further includes its opportunity cost of producing an additional or reduced amount of hydrogen.

## A.3. Additional Graphs and Data

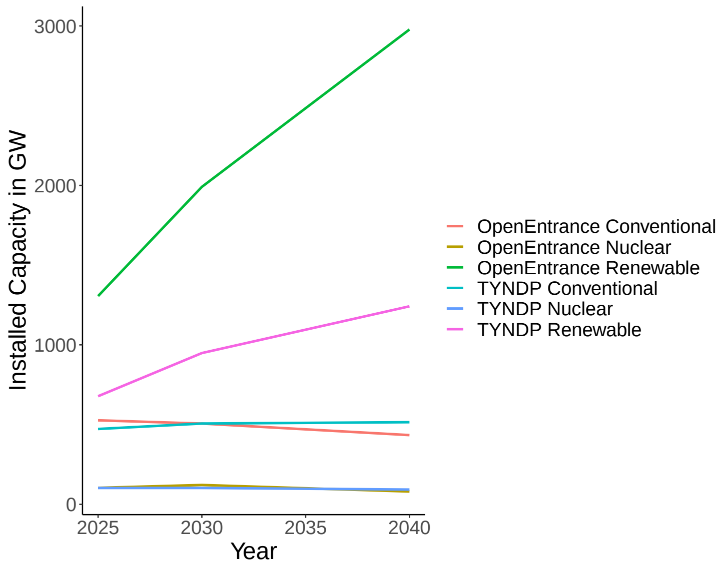


Figure 12: Installed Capacities from TYNDP and OpenEntrance Scenarios.

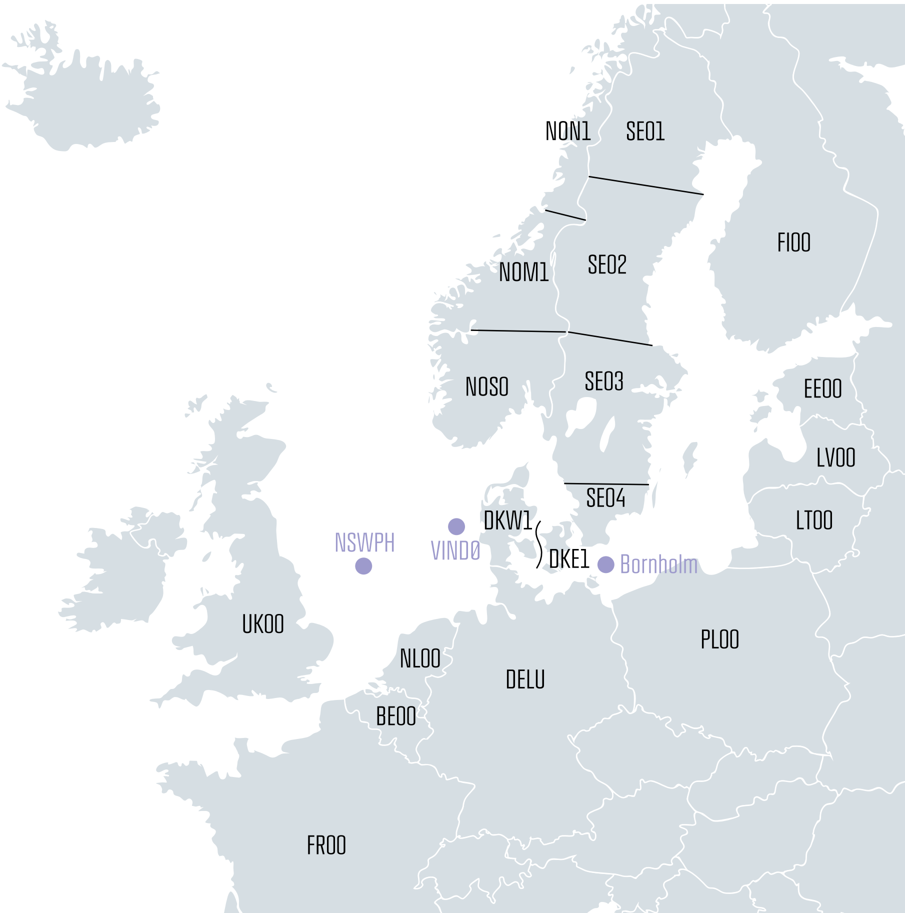


Figure 13: Zones in the model.