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Electrolysis as a flexibility resource on energy islands: The case of the North Sea

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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, assess their potential contribution to flexibility provision, and analyse different market integration strategies of the islands. For this purpose, a two-stage stochastic optimisation model is developed to determine 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 29–36% 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.

1. Introduction

With a rising share of intermittent renewable energy sources in electricity systems, the need for operational flexibility is increasing. At the same time, there is a growing demand for low-carbon fuels in sectors where electrification is expensive or infeasible. Electrolysis based on green electricity is envisioned as a solution to both problems. The required electricity could be sourced from offshore wind.

Electricity production from offshore wind in the North and Baltic Seas has developed rapidly in recent years (Wind Europe, 2021) due to its high potential and social acceptance (Kaldellis et al., 2016). The European Commission's strategy for offshore wind further highlights its importance for the future energy system (European Commission, 2020). Despite technological advances and declining costs of power transmission, transferring electricity from offshore wind farms via sub-sea cables remains costly (IRENA, 2019). One way to reduce the cables required is to convert part of the generated electricity into hydrogen and then transport it to shore via less costly hydrogen pipelines (Singlitico et al., 2021). This idea has been incorporated into the discussions of so-called *energy islands* (Tosatto et al., 2022), which essentially describe interconnected conversion and storage hubs at the centre of large offshore wind farms (Lüth, 2022). So far, energy islands have not been realised in practice. Due to the potential scope of envisioned projects, long investment cycles, and uncertainties in the development of power and hydrogen markets, a carefully designed policy framework is needed. The Danish government and various industrial consortia are currently investigating options for integrating hydrogen production from electrolysis with electricity generated at offshore wind farms on potential energy islands.[1]

In Europe, policymakers intend to foster domestic hydrogen production to be less dependent on imports from overseas. At the same

Abbreviations: CO_2, Carbon Dioxide; DEI, Danish Energy Island; ENTSO-E, European Network of Transmission System Operators for Electricity; HBZ, Home Bidding Zone; NSWPH, North Sea Wind Power Hub; OBZ, Offshore Bidding Zone; TYNDP, Ten-Year Network Development Plan; VOM, Variable Operations and Maintenance

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

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time, conventional power plants that have been providing flexibility will exit the market. Electrolysers may play an important role in the future energy system providing flexibility. On energy islands, which are expected to collect large intermittent offshore wind power generation, electrolysers may constitute a local flexibility resource. This requires a thorough analysis to explore under which market environment electrolysers on European energy islands are incentivised to produce hydrogen and/or flexibility services, facilitating the design of an effective policy framework.

In our analysis, we assume that the energy islands that are currently under consideration for the North and Baltic Seas will be built and host electrolysers. We then 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 suggest that offshore electrolysers will act as operational flexibility providers in addition to producing affordable hydrogen. In the broader energy system, energy islands could also constitute their own bidding zones in the pan-European electricity market instead of being integrated into existing zones. Policymakers will play an important role in setting up a framework that ensures sufficient hydrogen production for the future European demand. We address two research questions, providing insights into hydrogen markets and electrolysis policy with a specific focus on offshore production: (1) What is the flexibility potential of an electrolyser on an energy island? (2) How does the offshore bidding zone configuration influence the value of offshore electrolysers?

To answer these questions, we assess operational patterns, market results, and prices in a setting that incorporates uncertainty into electricity production from renewable energy sources. For this purpose, we develop a two-stage stochastic optimisation model that solves the day-ahead and balancing market-clearing problems for bidding zones connected by net transfer capacities. Flexibility in our study is defined as the ability to balance deviations between forecast and realisation. Joint market clearing of day-ahead and balancing markets does not happen in today's market operations, so our setup presents an ideal benchmark, likely overestimating the effects. Market power, strategic bidding, and network constraints in bidding zones are not taken into account. We also neglect ancillary services for frequency containment.

We apply the model to the case of the energy islands in the North and Baltic Seas to answer our research questions for the European context. Our case study includes the projects currently planned by the North Sea Wind Power Hub consortium, the Danish Energy Island (DEI), and the one at Bornholm (Denmark). Therefore, we consider the wind energy and cable connection capacities planned for those projects, and integrate them into the European energy market zones.

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

The case study results indicate four relevant insights for policymakers about the role of electrolysers as flexibility providers offshore: (*i*) electrolyser technology is generally capable of providing flexibility, but the current economic and regulatory framework incentivises to operate them at high and stable capacity factors; (*ii*) offshore bidding zone configurations reflect scarcity better and influence the price of hydrogen production offshore; (*iii*) the economic framework plays an important role for the economics of locally produced hydrogen; and (*iv*) current renewable energy targets do not succeed in satisfying electricity and hydrogen demand projections for 2030 and 2040.

The remainder of the paper is structured as follows. Section 2 summarises the literature and background of analysis. Section 3 presents the modelling framework. The case study, including data and assumptions, is described in Section 4. Numerical results are given in Section 5, where the economic viability of electrolysers on energy islands and the impact of assumptions are discussed. A sensitivity analysis is provided in Section 6. Finally, Section 7 presents our conclusions and policy recommendations.

2. Background and literature review

The current literature on energy islands is still relatively limited. In the rest of this section, we provide an overview of existing studies on offshore grids, energy and power link islands, offshore electrolysis, and market design for large-scale offshore wind power hubs.

The concept of energy islands emerged around 2016, initially driven by the North Sea Wind Power Hub (NSWPH) consortium, which was 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 of Denmark decided to build two energy islands, one in the North Sea and one in the Baltic Sea.[2] In consequence, other countries started discussing the feasibility of energy islands, for example, Norway (Zhang et al., 2022b), Belgium,[3] and Germany.[4] The idea of energy islands is based on the large expansion of offshore wind power, envisioned by the European Commission as a key part of the energy system transformation (European Commission, 2020).

By growing the offshore wind power production capacity, the transmission infrastructure in the sea must also be expanded. One potentially promising solution to connect large-scale offshore wind to shore is via *integrated offshore grids* (Trötscher and Korpås, 2011; Strbac et al., 2014). These grids with potentially meshed structures in the sea connect countries and support offshore energy access at several levels (Gea-Bermudez et al., 2018) and may increase the market value of offshore wind (Traber et al., 2017). This enables a better interconnection, stabilises the renewable-based energy system more efficiently (Schlachtberger et al., 2017), and increases the overall social welfare through greater and more efficient use of renewable energy (Egerer et al., 2013). Furthermore, offshore grids are expected to connect markets with asymmetric renewable power capacities, helping to stabilise prices in those markets (Alavirad et al., 2021). Note that no meshed offshore grid has been commissioned yet. Nevertheless, guidance on their design and topology is needed to construct a technically efficient and economical system (Chen et al., 2018; Houghton et al., 2016). In addition, an economic framework is required for defining operational and ownership rules and for incentivising efficient development (Meeus, 2015; Sunila et al., 2019). As an integrating element of offshore grids, Kristiansen et al. (2018) describe *power link islands* as an efficient component of offshore grids. Power link islands bundle large wind resources and connect by cable to shore. One may see them as the precursor to energy islands or offshore energy hubs,[5] which are generally defined by their offshore location, large surrounding wind capacities, cable connections to land, and possibly storage and conversion technologies (Lüth, 2022). Energy hubs are places where multiple energy carriers are converted or stored (Geidl et al., 2007). In light of discussions on a hydrogen economy, electrolysis and in general power-to-x systems might act as a

[2] See Klimaaftale by the Danish government (2020): https://fm.dk/media/18085/klimaaftale-for-energi-og-industri-mv-2020.pdf.

[3] See Princess Elisabeth Island: www.elia.be.

[4] See AquaVentus: www.aquaventus.org.

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

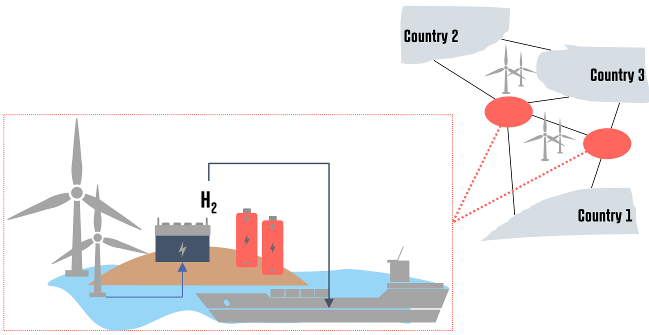


Fig. 1. Sketch of an energy island in the most recent visions.
Source: Lüth (2022, p. 71).

conversion technology offshore, such that adding power-to-x systems to a power link island would turn it into an energy island Gea-Bermúdez et al. (2022). Fig. 1 illustrates how renewable electricity produced locally or nearby can be stored or converted on an energy island.

The concept of energy islands is still at an early stage of development. Lüth and Keles (2023) summarise the recent literature and identify risks, benefits, and opportunities of building energy islands. Some industrial actors have discussed offshore sector integration, including hydrogen production at sea. The techno-economic studies conclude that either the potential for electrolysis offshore is limited (Gea-Bermúdez et al., 2022, 2023) or it relies on the benefits of avoiding the expenditure for power cable connections (Singlitico et al., 2021). We refer the interested reader to Calado and Castro (2021), where a comprehensive literature review on hydrogen production from offshore wind is provided. The first offshore electrolyser has started to being developed in the Dutch pilot project PosHYdon (Peters et al., 2020). If electrolysers are expected to be placed offshore despite their comparatively high capital and operational costs as well as the existing uncertainty in regulatory frameworks, it would be optimal to place them at a centralised location, such as a hub, instead of spreading them out (Ibrahim et al., 2022; Singlitico et al., 2021). An overview of decision-making criteria for offshore hydrogen production is provided in Kumar et al. (2023). It highlights the relevance of nearby renewable energy production, existing offshore infrastructure, and close-by demands as main drivers for the profitability.

Research on the technical feasibility of flexible electrolyser operation has also found that 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). It has been demonstrated that electrolysers are technically capable of quickly adjusting their power consumption in response to fluctuations in renewable power supply. For investment and operational purposes, various models and tools have been developed, incorporating technical characteristics and temperature dependencies of electrolysers.

It is widely acknowledged that coupling wind farms and hydrogen production increases the cost efficiency and competitiveness of wind power (Thommessen et al., 2021; Grüger et al., 2019). This is tightly linked to our research questions about the profitability and operations of electrolysers on energy islands. Literature on coupling offshore wind and electrolysers also gives insights on sizing and technical topology (Sorrenti et al., 2023) as well as expected hydrogen prices (Durakovic et al., 2023). In this paper, we focus on market outcomes and price impacts in an offshore setting. For the onshore case, previous studies show that power-to-gas technologies in connection to re-electrification is a viable operating strategy (Grueger et al., 2017), stabilising market prices (Li and Mulder, 2021), and facilitating congestion management (Xiong et al., 2021).

Regarding the market design and integration aspects, we realise the effect of hydrogen production on flexibility and market prices offshore has not been thoroughly investigated yet. Several studies have looked into the market design and bidding zone configurations for offshore wind energy hubs without electrolysis. It is a common trend for those studies to compare two potential scenarios in terms of the bidding zone configuration: offshore bidding zone (OBZ) and home bidding zone (HBZ). In an OBZ, the power hub constitutes its own bidding zone, as illustrated in Fig. 2(a). Consequently, the market price always matches that of the connected bidding zone with the lowest price. On the contrary, an HBZ, as visualised in Fig. 2(b), represents the business-as-usual case under which wind farms sell electricity in their home markets (Kitzing and Garzón González, 2020; Tosatto et al., 2022). Existing studies such as Kitzing and Garzón González (2020) suggest that the offshore bidding zone leads to a more efficient electricity market in terms of social welfare, but the distribution of benefits and costs might be asymmetrical among parties involved (Tosatto et al., 2022).

The idea of an offshore bidding zone for power hubs was developed in the context of so-called *hybrid projects*, wherein interconnectors between countries are also connected to wind farms. An example is Kriegers Flak (Marten et al., 2018) which has been operational since 2020. Hybrid projects are fairly new to the system. In a report for the European Commission, Weichenhain et al. (2019) identify multiple locations where such interconnections could be more beneficial than traditional radial connections to the owner's home markets only. In this line, we provide policymakers with further insights into the operations of offshore electrolysers. We make use of the findings that a more cost-reflective offshore bidding zone is preferable and analyse the impact of bidding zone configurations on the operation of offshore electrolysers.

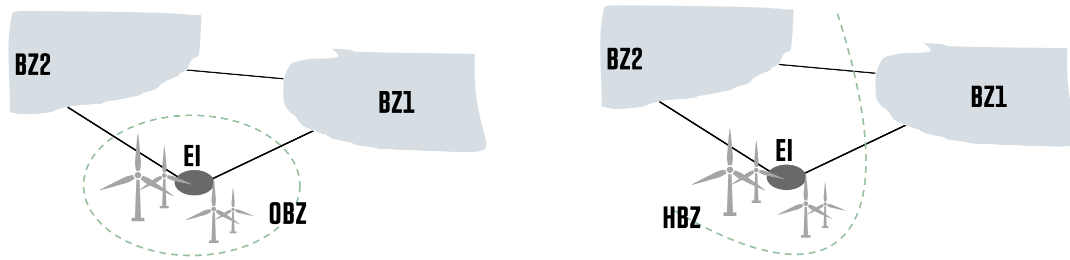
3. The model

We develop a two-stage stochastic optimisation model to analyse the potential of offshore electrolysers as flexibility resources from a system point of view. This optimisation model is aligned with methods already developed by Morales et al. (2014) and Conejo et al. (2010). It allows us to derive market prices and quantities sold on the electricity market, while taking into account uncertainty in the production of renewable energy suppliers. For computational tractability, we limit the representation of technical details and do not consider capacity expansion. Using this model, we analyse the value of electrolysers for hydrogen production while functioning as flexible demands which are elastic to the price. These analyses are valuable to suggest policy frameworks for offshore electrolysis.

min	Total generation costs (day-ahead and balancing markets) minus the profit from hydrogen sales
s.t.	Zonal power balance for each stage Generator capacity limits Storage limits Ramp limits Hydrogen production limits of electrolysers Net-transfer capacity limits

Box 1: Schematic overview of our model. The full mathematical model is available in Appendix.

As the first trading stage of the model, all power production units sell electricity into, and electrolysers demand electricity from, a day-ahead market. As the second stage, the units decide whether to bid into a balancing market, which represents the stage for flexibility (i.e., power adjustment) provision, compensating for deviations from the day-ahead schedule of renewable units. The second stage is an aggregated and idealised representation of all trading actions between



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

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

day-ahead and real-time markets. This implies that our balancing stage excludes the reservation and activation of primary, secondary, and tertiary reserves, and thereby differs from the approach of Energinet (2022). We assume that hydrogen can be sold at any time and volume at a given price without storage or transportation constraints. The capacity of electrolysers is exogenous. For the sake of succinctness, as the model functionality is quite standard in the literature of power markets, we do not include the mathematical formulation here. Instead, we explain the optimisation model structure, objective function, and constraints. The full mathematical model is available in Appendix. Box 1 summarises the model.

The objective function of the model minimises the total expected cost of the system, including the generation cost in the day-ahead and balancing stages, as well as the profit of selling hydrogen. The uncertainty in the model stems from renewable energy production, characterised by a set of scenarios, generated in the day-ahead stage based on the available forecast.

Given all scenarios, the first stage determines the day-ahead schedule of all units and electrolysers. In the second stage, conventional power plants, electrolysers, hydro reservoirs and storage units adjust their operational schedules in response to deviations from the day-ahead renewable power production schedule. The objective function is restricted by five groups of constraints, limiting the solution space. Both stages have a supply–demand power balance to ensure that production equals demand. We add a set of capacity restrictions for conventional and renewable energy technology to limit maximum production to installed capacity. For storage (battery and pumped hydro), we introduce charging and discharging restrictions and 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 hydrogen production level and account for efficiency in production.

4. The case of the North Sea

The optimisation model is suitable for analysing energy islands in any geographical region and helps to gain insights into market frameworks and the role of electrolysers as a flexible asset. Although the model framework is generic, we focus on the North and Baltic Seas considering the planned energy islands off the coast of Denmark and the Netherlands. The goal is to support policymakers in Europe in setting the scene for an efficient electrolyser integration. The chosen countries are advancing quickly to build their own hydrogen production, and have presented ambitious plans for the technology roll-out. Economic and operational frameworks, however, are still to be determined and policy guidance is needed. Fig. 3 provides an overview of the islands we include in our analysis. The Danish energy island (DEI) and Bornholm are projects led by Danish partners. The North Sea Wind Power Hub (NSWPH) involves Danish, Dutch, and German partners and is a Project of Common Interest.[6] In the following two sections, we describe our input data and main assumptions.

4.1. Input data

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

For each country, we have retrieved the estimation of future capacities for conventional and renewable power plants from the Ten-Year Network Development Plan (TYNDP) 2020 *National Trends* scenario.[7] To compare and crosscheck values, we have made use of the ENTSO-E Transparency Platform,[8] the national system operators' websites, and data published by Kendziorski et al. (2020). For a sensitivity analysis, we use the 1.5 °C scenario *Directed Transition* developed in the openEntrance project[9] as our climate case. It shows significantly higher renewable capacities in Europe — about twice the TYNDP 2020 projections (see Fig. 12 in the Appendix).

Generation from renewable energy sources is subject to fluctuations and therefore not available at full capacity in all time steps. For solar energy, we use normalised historical generation profiles for the years 1980–2019, retrieved from renewables.ninja[10] (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016). As solar generation has a characteristic daily pattern, we directly use the realisations from each year to represent a single scenario. Wind energy onshore and offshore does not follow such a daily pattern. Therefore, we use data from Muehlenpfordt (2020) that provides spatially and intertemporally correlated day-ahead forecasts and real-time realisations for the years 1980–2019. We then exploit this data to calculate hourly forecast errors for wind energy onshore and offshore for each country and year. To account for the expansion of wind power sources and the increasing uncertainty in weather prediction due to climate change, we scale these forecast errors by 50%. Afterwards, we apply them to the historical generation profiles from renewables.ninja for the year 2018, which we have chosen as a base year, to build scenarios for wind energy onshore and offshore. We further assume that all scenarios are equally probable. For illustrative purposes, the set of 40 scenarios representing power generation from German onshore wind and solar facilities during a selected three-day time period is shown in Fig. 4.

[6] See the Annex to C(2021) 8409 final by the European Commission: SWD(2021) 335 final.

[7] See TYNDP Data (2020): www.tyndp.entsoe.eu/maps-data/.

[8] See European Network of Transmission System Operators for Electricity (ENTSO-E): www.transparency.entsoe.eu/.

[9] See openEntrance (2022): www.openentrance.eu/.

[10] See renewables.ninja (2022): www.renewables.ninja.

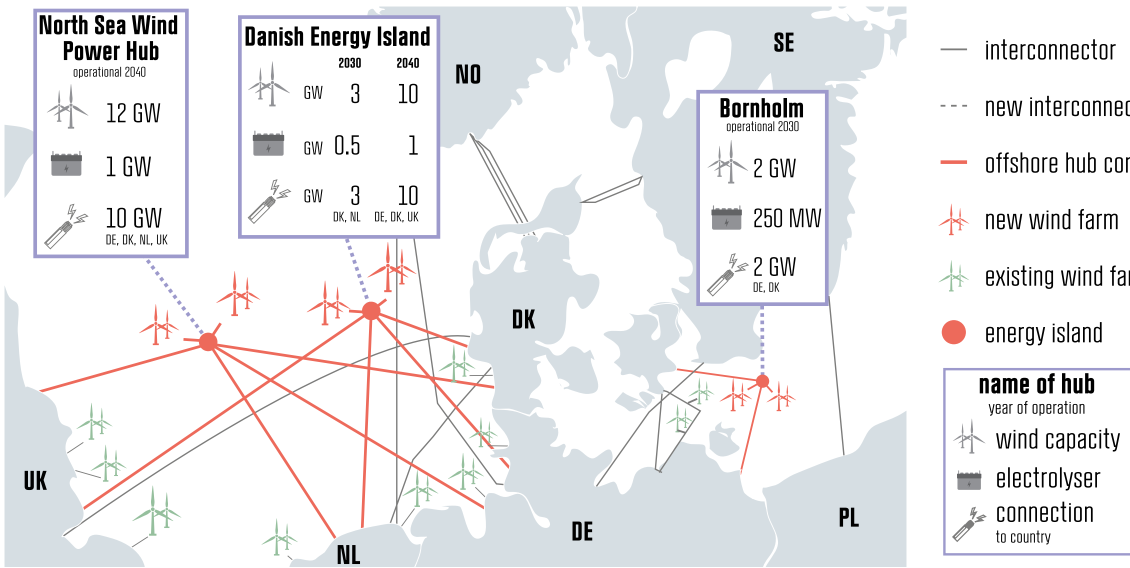
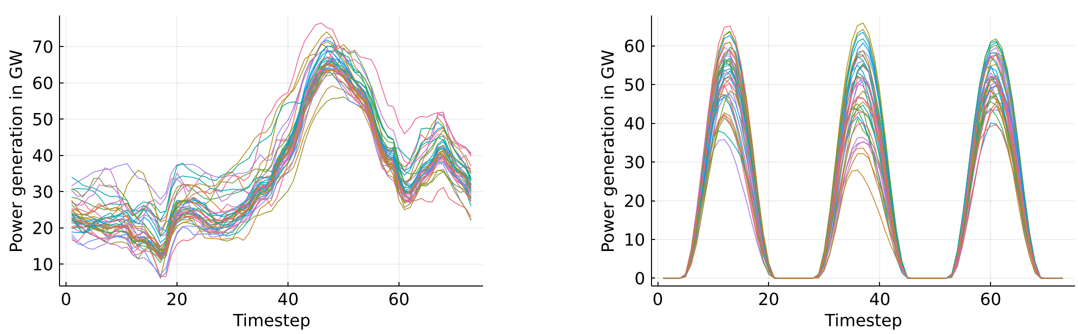


Fig. 3. Energy island projects considered in this study. Authors' illustration based on COWI (2021) for Energistyrelsen.



(a) Onshore Wind.

(b) Solar energy.

Fig. 4. Scenarios for wind and solar power generation in Germany for a selected three-day period. Each of the 40 lines corresponds to an individual scenario.

For reservoir hydropower, we enforce a limit on the maximum cumulative production for every two weeks, reflecting the water inflow over time. This maximum production data are based on historical observations published on the ENTSO-E Transparency Platform. Run-of-river hydropower operates on the basis of historical availability from the EMPIRE model[11] (Backe et al., 2022). We restrict ramping capability of various technologies on the basis of the technology catalogue of the Danish Energy Agency (2022) and of 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 steadily in the coming years towards 2050. We use demand projection data from the *National Trends* scenario of the TYNDP 2020 input data. In the process of developing the TYNDP, the ENTSO-E also gathered data on current net transfer capacity (NTC) and established 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. We list values assigned to cost parameters in Table 1. Conventional energy technologies have 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 of the Danish Energy Agency (2022). We use fuel prices for gas, oil, lignite, and hard coal from the TYNDP 2018 input data.[12] For the base case, we adopt the CO_2 price from the same input data, considering €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 income from selling hydrogen. Costs for hydrogen production from renewable energy depend on the cost of electricity and the investment cost of the electrolyser. Investment costs for alkaline electrolysers are estimated to decrease from €750/kW in 2020 to €350/kW in 2050 (Danish Energy Agency, 2022). In addition, variable operations and maintenance (VOM) costs range between €7.2/MWh in 2030 and €5.6/MWh in 2040 onshore but do not include the preparation of desalinated water. We neglect the desalination process as it only makes up 1% of the total production process if done from seawater (Dokhani et al., 2023). We assume that offshore VOM costs are 50% higher, with €10.8/MWh in 2030 and €8.4/MWh in 2040. For hydrogen prices, Glenk and Reichelstein (2019) estimate €3.23/kg for 2025 and €2.50/kg for 2040. For production from dedicated wind farms, Meier (2014) estimates hydrogen production costs of €5.2/kg. In later years, assuming existing oil and gas platforms can be reused as bases for renewable offshore hydrogen production, this is projected to decline to €2.50/kg. We use

[11] OpenEMPIRE is available on GitHub: https://github.com/ntnuiotenergy/OpenEMPIRE.

[12] See ENTSO-E map (2022): www.tyndp.entsoe.eu/maps-data.

Table 1
Values for various parameters in our model.

Parameter	Notation	Unit	2030	2040	Source
Fuel prices					
Lignite		€/MWh	8.28	8.28	EUCO: REF 2020 Technology
Hard coal		€/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)
electrolyser efficiency	η_e		66%	66%	Danish Energy Agency (2022)
Hydrogen price	p^{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[a]	Government of the Netherlands (2020)
Germany		MW	5000	10 000	BMWi (2020)
Belgium		MW	500	500	FPS Economy Belgium (2021)
United Kingdom		MW	5000	8000[a]	HM Government (2020)
Poland		MW	2000	4000	Ministry of Climate and Environment (2021)
Sweden		MW	5000	10000[a]	Energimyndiheten (2021)
Norway		MW	750	1500[a]	NVE (2021)
France		MW	6500	13 000	BDI (2020)

[a] Value extrapolated for 2040 on the basis of estimates given in the sources.

a value of €4.5/kg in 2030 and €3/kg in 2040, which translate to €150/MWh and €100/MWh, respectively.

All our data and the model itself are publicly available on GitHub.[13] 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 Fig. 3. The electrolyser on the NSWPH is assumed to be installed with a capacity of 1 GW in 2040. Besides, we assume hydrogen is sold at a fixed price without quantity restrictions. We do not consider the origin of the electricity for hydrogen production. Costs for transport, storage, and 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 are 50% higher than onshore (as given in Table 1) to account for such factors, and for space restrictions, environmental conditions, and the distance to shore. We further assume that all electrolysers that are not built on 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. Neither do we include flexible resources beyond battery and pumped hydro storage and electrolysers. Technologies such as heat pumps, electric vehicles, and heating with gas backup may enter the market prior to electrolysers and thus change the need for them to act as flexible components. Unit commitment and minimum power generation restrictions are excluded in the model. However, we 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 not taken into account. Wake effects, which impact the power production of wind farms (Crespo et al., 1999), are not modelled.

It is computationally infeasible 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 the number of scenarios is increased beyond ten. Therefore, we use randomly selected 10 out of 40 scenarios in order to run the model for longer time horizons. We consider the same probability for each of the ten selected scenarios.

Due to the computational complexity of the model, we need to split up the full-time horizon of 8760 h into six segments of equal length (1460 h). Each of these segments needs 1–2 h to be solved on an Intel Xeon Processor 2650v4 with 256 GB RAM, 12 cores and up to 2.20 GHz clock speed. We have tested the robustness of the model results to the length of the segments and observed that they are stable at this length (see Appendix). To avoid depletion of pumped hydro and battery storage at the end of each 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. Offshore electrolysis is envisioned to take up operations at small scale earliest in 2030 and expand significantly towards 2040. First policies therefore need to be set for this time frame and based on the given system. Recall our two research questions are about (1) the flexibility potential of an electrolyser on an energy island, and (2) how bidding zone configuration affects the value of the offshore electrolyser. To properly address these questions, we structure the presentation of numerical results in two parts. Section 5.1 provides results on the flexibility value of electrolysers, whereas Section 5.2 presents results related to the bidding zones and market analysis.

[13] Find the model here: https://github.com/yannickwerner/EnergyIslands.

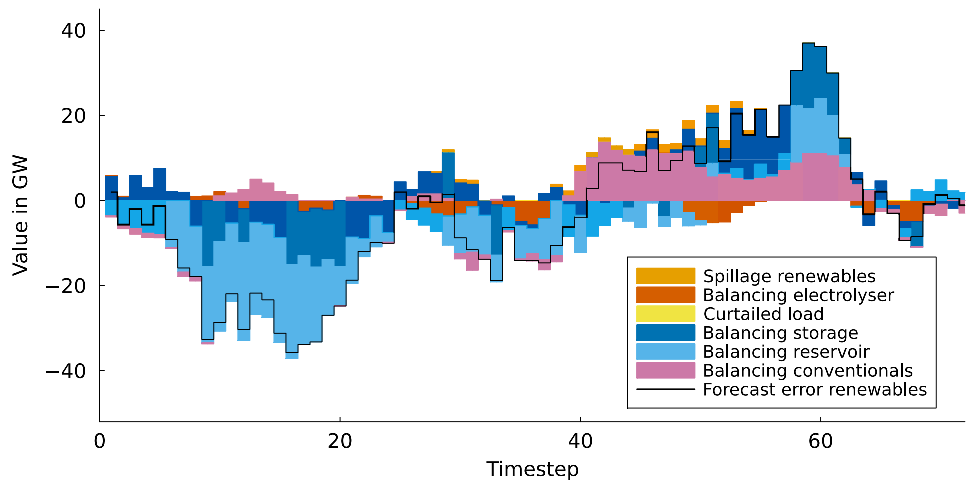


Fig. 5. Balancing actions in response to the aggregated deviation from the day-ahead schedule of renewable power generation in an example scenario.

5.1. Flexibility of offshore electrolysers

Flexibility is needed in the model to compensate for deviations in the real-time power production from the day-ahead schedule of renewable energy sources. Our system has access to the following set of flexibility resources for balancing purposes: conventional power plants, hydropower reservoirs, biomass, storage technologies (battery and pumped hydro storage), and electrolysers. Flexibility in this context relates solely to the ability to balance deviations from the forecast in renewable energy production. Looking at a period of four days in one of the scenarios, Fig. 5 shows that hydropower reservoirs and storage units contribute the most to balancing, whereas the contributions of electrolysers are marginal.

Taking a more regionally disaggregated perspective, Fig. 6 compares the capacity factors over the whole time horizon in 2030 and 2040 for the total electrolyser capacity in each bidding zone. For 2030, we observe that most electrolysers are used only for a few hours in the balancing market. Participation in balancing markets, i.e., upwards and downward adjustments of production, is modest for electrolysers on the energy islands (DEI, NSWPH, Bornholm) and even lower for onshore electrolysers. This is due to the availability of cheaper flexibility resources, such as hydro power reservoirs and storage units, in most onshore bidding zones. Sweden (SE1-SE4) and Norway (NON, NOM, NOS) have especially cheap dispatchable, renewable power generation in the form of hydro reservoirs, which results in low contributions of the electrolysers to the balancing actions in those countries' zones. When we include the day-ahead market, we observe that most electrolysers run at rather low capacity factors, below 50% on average and even lower for the offshore electrolysers, i.e., on the energy islands. Taking a deeper look at the results, we find that hydrogen is produced in fewer hours offshore than onshore, and the average electricity consumption cost per unit of hydrogen produced is much lower for offshore electrolysers. This indicates that it is usually more valuable for the system to transfer electricity to shore and either use it directly or convert it into hydrogen there at lower variable cost, than produce hydrogen offshore–a barrier to reaching large hydrogen production targets.

Comparing the results for 2030 and 2040, we find out that several countries face decreasing capacity factors for their electrolyser fleets despite significantly higher shares of renewable energy capacity in 2040. Most areas with decreasing capacity factors experience drops in electricity prices, but these cannot compensate for the decrease in hydrogen prices and therefore lead to less profitable hydrogen production overall. This is visible in Belgium (zone BE) and the United Kingdom (zone UK). One exception is Poland (PL), which experiences high 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. We, therefore, observe much higher electrolyser capacity factors there, and an increased contribution to the balancing market.

Overall, we find that the offshore electrolysers are used in the provision of balancing services for only about 29%–36% and 18%–23% of their total run-time in 2030 and 2040, respectively. Relatively low capacity factors overall also indicate that operators will face economic challenges to contribute to meeting projected European hydrogen demand in this market setup. Hence, in the next section, we describe our findings on whether an alternative bidding zone configuration would increase 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. Policymakers may consider a change in the set up as a means to ensure affordable and local hydrogen production will meet targets. For this analysis, we explore whether zonal boundaries change operational patterns for offshore electrolysers, and if so how. Radial connection of offshore wind farms is the traditional approach to integrating offshore energy. Energy islands in their first operational years could be connected similarly to their home countries, leading to a home market approach. Over the years, this might develop into hybrid projects (see Section 2), or the islands could come to constitute their own bidding zone. In the following, we compare the case of offshore bidding zones to the standard case of home bidding zones to investigate the role of market zones and their impacts both on the market prices in general and on the energy islands' resources.

In the HBZ, we add the wind farm capacity and electrolysers of each of the three energy islands to its owner country's nearest bidding zone. Fig. 7 compares the capacity factors in 2030 for the two configurations. In the HBZ configuration, electrolysers in the Danish bidding zones DK1 (west) and DK2 (east) have slightly higher capacity factors than in the OBZ. In the Danish energy islands, DEI and Bornholm, we observe a decrease in offshore electrolyser capacity factors. However, because the onshore electrolyser capacities are much greater than offshore ones, total hydrogen production increases. We identify two reasons. First, electricity generated offshore is transported to shore and used there, and is preferred over costly offshore electrolysis. Second, in high production hours, none of the hub-shore connecting transmission

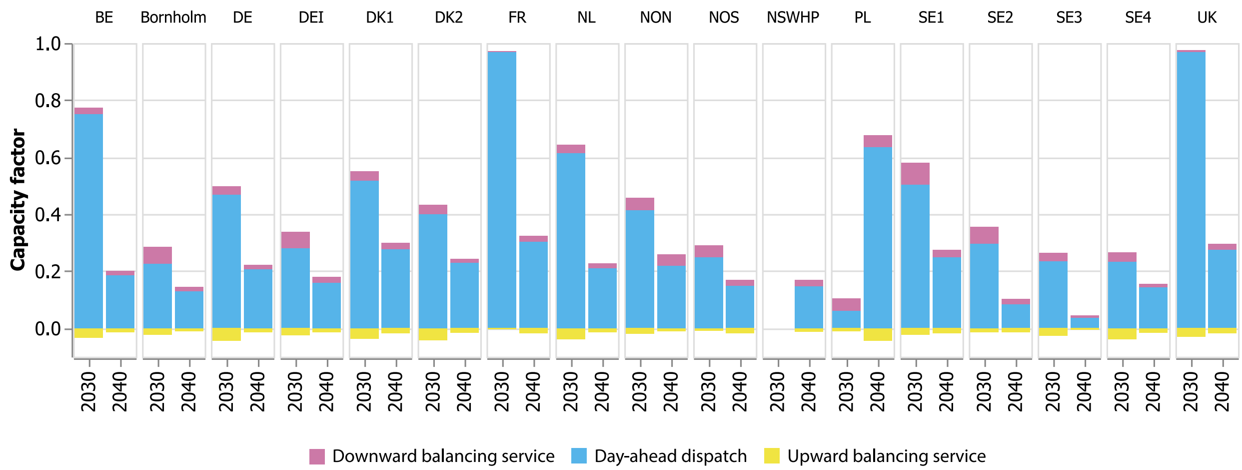


Fig. 6. Expected electrolyser capacity factors for the OBZ configuration in 2030 and 2040 sorted by bidding zones.

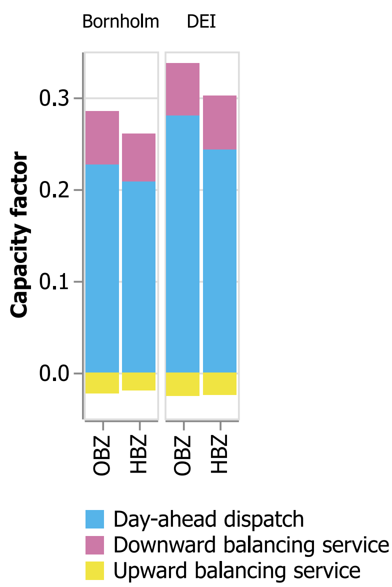


Fig. 7. Expected electrolyser capacity factors in 2030 for the OBZ and HBZ configurations.

capacity constraints is binding (a consequence of the HBZ configuration), and less offshore generation is curtailed. Although the flexibility provision by the electrolyser on DEI increases, that of the electrolyser on Bornholm decreases. Those changes are less than one percentage point and do not affect hydrogen production significantly. Nevertheless, there is no strict tendency in how flexibility provision changes under an HBZ configuration, although it seems to depend on the power plant portfolios of the countries the energy island is connected to.

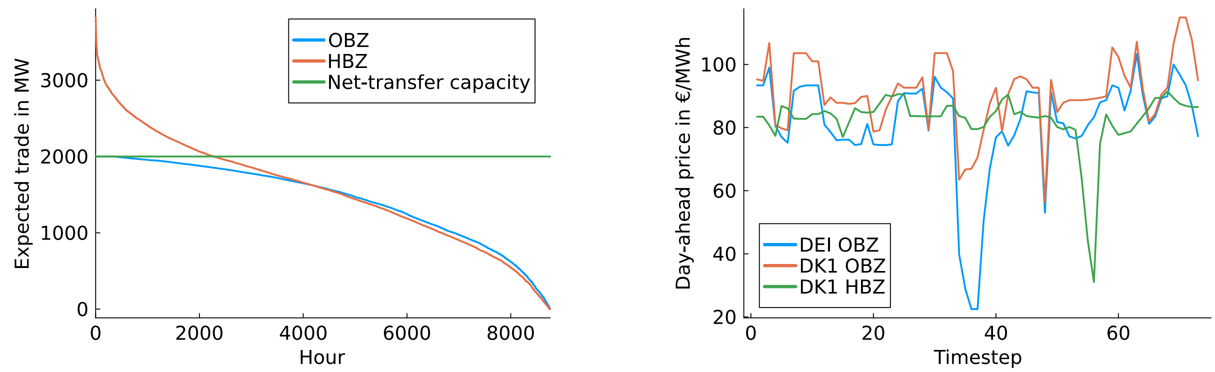
The differences between the two bidding zone configurations are caused by the way transmission constraints between the energy islands and the mainland are accounted for. Although these constraints impose actual physical limitations in the real operations of the power system, the market itself facilitates a higher electricity exchange between the energy island and its home zone when they are neglected (as in HBZ).

In the following part, we focus on DEI in the North Sea, which is integrated into zone DK1 (Western Denmark) when the bidding zone configuration is changed. We choose DEI because it is the first island envisioned to be operational by 2030 and it has the most consistent reports and studies available on location, size, and interconnection. Fig. 8(a) illustrates the expected electricity exports from DEI to its home zone of DK1 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 limit is expected to be violated in 2276 h, or about 26% of the time, requiring generally expensive congestion management. For the OBZ, the interconnector capacity is only binding in 348 h (4%) over the year, indicating that the dispatch changes drastically when the energy islands become part of an HBZ configuration. These findings also highlight the sensitivity of the system-wide dispatch to the capacity of the interconnectors between the energy islands to shore. In general, the connection from DK1 to the energy island is barely used for the export of electricity to DEI, where it could be further transported to another connected bidding zone.

Relaxing capacity constraints also affects market prices. Fig. 8(b) shows the power prices on DEI and DK1 in the OBZ and HBZ configurations when there is congestion in the OBZ case. Note that in an HBZ, DEI is part of DK1, and thus there is a single day-ahead price. One can see from the graph that electricity prices in the integrated bidding zone fluctuate less than in the OBZ case. Furthermore, the price on DEI in the HBZ configuration is generally higher than in the OBZ configuration for the same hours. However, for some hours the price on DEI is much lower in the HBZ configuration. This indicates that the dispatch may be significantly different when the transmission constraint is neglected.

6. Discussion

The flexibility and profitability of an electrolyser might work in opposite directions. Although for profitability reasons it is desirable that the electrolysers have high capacity factors, acting as a flexibility resource and participating in the balancing market could be beneficial for the overall system but also reduce their total hydrogen production and eventually their expected profits. In our cases, some flexibility is delivered to the system by the offshore electrolysers, but not as their major service. In general, the capacity factor of offshore installations is lower than that of their onshore counterparts, independently of bidding zone configuration. These findings allow policymakers to balancing trade-offs. We identify three points for further investigation: the business case for offshore hydrogen production, discussed in Section 6.1, the sensitivity of installed generation capacities, sizing of assets, and hydrogen pricing, analysed in Section 6.2, and finally the model characteristics, reviewed in Section 6.3.



(a) Expected electricity flow from DEI to DK1 over the whole year.

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

Fig. 8. Interconnector flow and prices during congested hours for DEI and Western Denmark (DK1).

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

Energy island	Configuration	Hydrogen production GWh	Expected operational cost €/MWh	Expected electricity cost €/MWh	Expected profit million €
DEI	OBZ	1587.88	11.25	52.87	85.08
DEI	HBZ	1429.18	11.32	50.24	82.08
Bornholm	OBZ	673.44	11.34	47.39	41.54
Bornholm	HBZ	613.13	11.32	47.41	37.82

6.1. *Business case*

For an offshore hydrogen producer, it is important how much hydrogen can be produced and how expensive the corresponding electricity is. Table 2 shows hydrogen quantities produced on the energy islands and their expected electricity and operational[14] costs. Revenues are based on both day-ahead and balancing activities of electrolysers. With DEI, we observe small differences between the two bidding zone 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 €85.08 million of the electrolyser on DEI in the OBZ configuration, we compare it to the estimated electrolyser investment costs. Based on an investment cost of €0.45 million/MW_{el} in 2030 (Danish Energy Agency, 2022), the annuity for the 0.5 GW electrolyser on DEI is €20.24 million.[15] This indicates that investment in an electrolyser under the assumptions made here might be profitable. Electrolysers onshore face higher expected electricity consumption costs, around €70–€90/MWh (except France €45/MWh). Hence, they need more full-load hours to achieve the same return on investment. Note that we neglect any infrastructure costs for hydrogen transport and assume that hydrogen can be sold at any time and quantity for a price of €150/MWh or €100/MWh in 2030 or 2040, respectively.

6.2. *Sensitivity analyses*

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

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

[15] We calculate the annuity a on the basis of 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 of generation technologies*

The data set from TYNDP 2020 provides a rather conservative outlook on renewable energy capacities in 2030 and 2040. To verify our analyses, we contrast the outcomes with those obtained when using the openENTRANCE project data, which feature much higher capacities (Auer et al., 2020); see Fig. 12 in the Appendix. We refer to this as our *Climate Case*. With significantly higher installed renewable energy capacities but unchanged electrolyser capacities, we observe in Fig. 9 that the electrolyser capacity factors increase to around 80%. There is an increase in hydrogen production on the energy islands, of around 125% (from 1588 GWh to 3568 GWh) on DEI and 166% (from 673 GWh to 1788 GWh) on Bornholm. At the same time, the average expected electricity cost declines by nearly 59% to almost €19/MWh, and the expected profit increases by 336% to €370.88 million on DEI and by 348% to €186.30 million on Bornholm. 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 is significantly stronger.

6.2.2. *Sizing of electrolysers and cable connections*

As shown in Fig. 8(a), transfer capacity and line sizing significantly affect hydrogen production. The reference cases originate in industry-led studies of the configuration of 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 decreases of 20% and 40% in the capacities of the interconnectors connected to the energy islands. The results are shown in Fig. 10 for the OBZ configuration in 2030. Although the capacity factors of the onshore electrolysers in the connected bidding zones decline, those of the electrolysers on the energy islands increase. When interconnector capacities are reduced by 20%, the total capacity factors of the electrolysers on DEI and Bornholm increase by 15.1 and 3.5 percentage points, respectively. Similarly, reducing the interconnector capacity to 60% of its original value increases the total capacity factors by 27.4 and 11.6 percentage points, respectively. In some peak wind production hours, there is not enough interconnector capacity available to balance fluctuations on the energy islands solely by adjusting trade flows. This leads to increased participation in the balancing market by the electrolyser, of up to 1 percentage point. Increasing the interconnector capacity so that the total line capacity connected to the energy islands exceeds its wind production capacity does not affect the capacity factors of the electrolyser. These results change when energy islands are integrated into offshore grids, which is shown to be an efficient integration of offshore resources (Lüth et al., 2023).

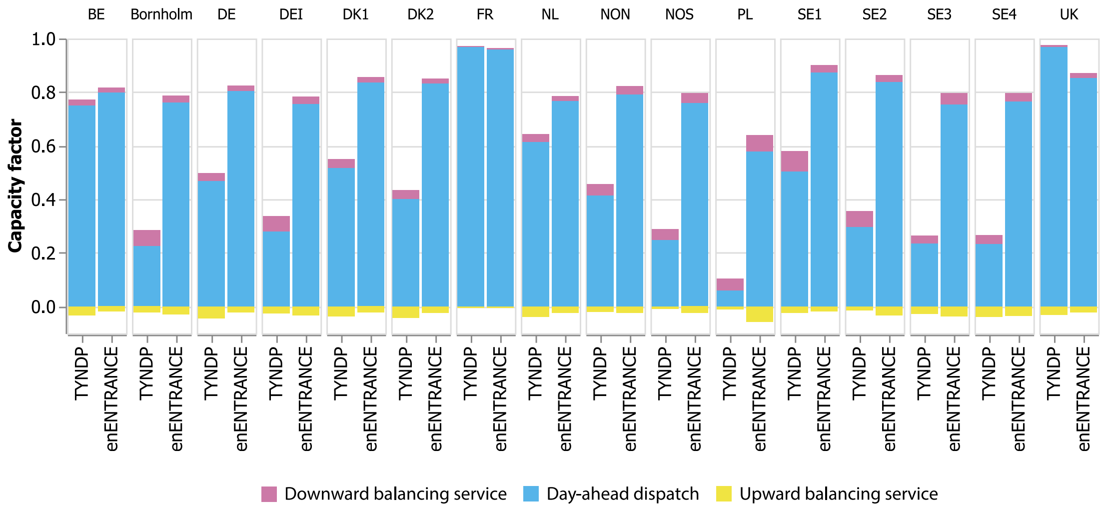


Fig. 9. Expected electrolyser capacity factors for 2030 for the TYNDP and the openENTRANCE data set in the OBZ configuration.

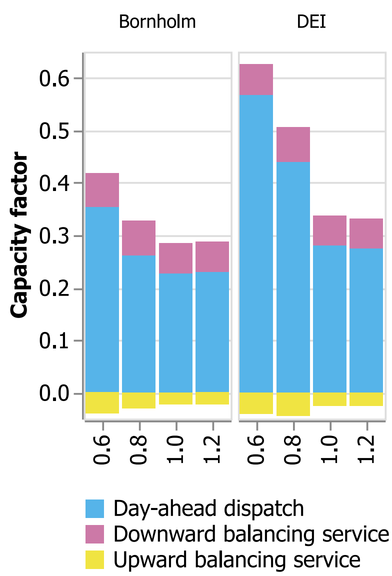


Fig. 10. Electrolyser capacity factors for varying energy island interconnector capacities for the OBZ configuration in 2030.

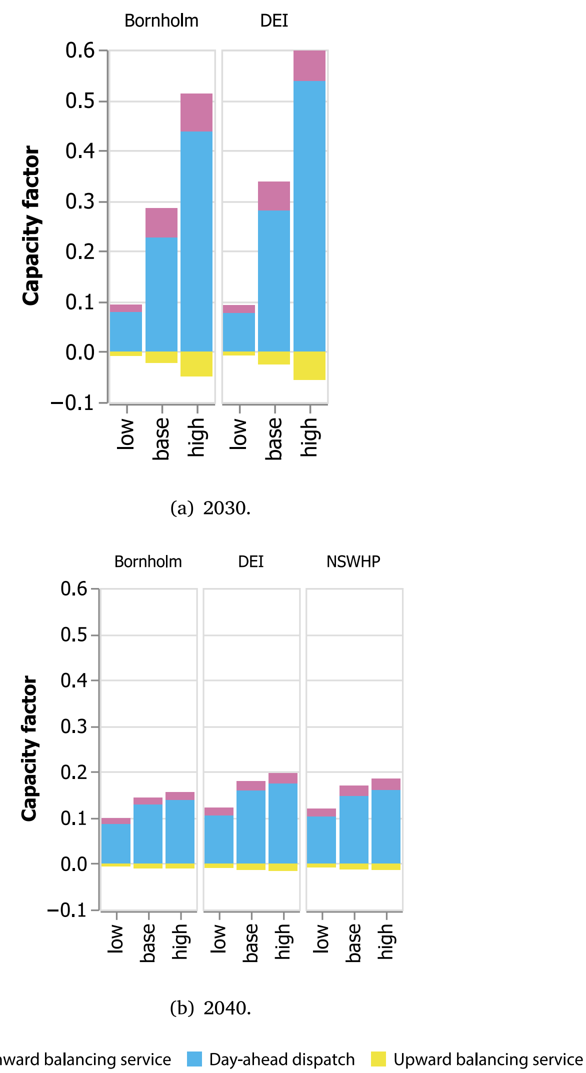


Fig. 11. Capacity factors of offshore electrolysers in a low and high hydrogen price scenario.

6.2.3. Hydrogen prices

In the optimisation model, electrolysers produce and sell hydrogen based on a given hydrogen price. For the base case, we assume a fixed hydrogen price of €150/MWh in 2030 and €100/MWh in 2040 based on a literature survey. In the following, we analyse the sensitivity of the hydrogen production levels to the hydrogen price. For a low hydrogen price scenario that reflects a steeper decrease in electrolyser and electricity prices, we assume a price of €100/MWh in 2030 and €75/MWh in 2040. The high price scenario considers prices of €175/MWh in 2030 and €150/MWh and reflects a conservative cost development of green hydrogen production. Compared to our main analysis, electrolysers produce more hydrogen when prices are high and less when prices are low. The change in production is primarily associated with the day-ahead market while the share of flexibility provision from offshore electrolysers in the balancing market remains at a similar level or even decreases, as illustrated in Fig. 11. The high hydrogen price, however, may drive up thermal power plant usage onshore and increase CO_2 emissions in the system because the setting may invite under specific circumstances to produce hydrogen while at the same time using fossil fuels for power production.

6.3. Model characteristics

Our model follows a frequent approach to analysing stochastic infeed from renewable energy sources in electricity markets. In setting up the model, we make assumptions that affect the results. For instance, to pursue computational tractability, we disregard unit commitment constraints. This means that we neglect any minimum power generation limits, downtimes, necessary minimum run time requirements, and outages, which increases the flexibility of the dispatchable units in the model. To compensate for the risk of having extensively overestimated flexibility from conventional power plants, hydro reservoirs, and biomass, we include restrictions on the maximum ramp rates based on historical data for 2017 taken from the ENTSO-E Transparency Platform. For wind power, neglecting wake effect modelling (Zhu et al., 2018) overestimates the wind production and, thus, if the wind farm capacity projections in our data set are accurate, the results we find for wind generation are likely a bit too high. This does, however, not make our results less generalisable. In addition, for the case of biomass, some 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. This could lead to an overestimation of the flexibility potential in the system and in turn may underestimate the potential contribution of the electrolyser to balancing. On the other hand, we do not consider consumer-based flexibility resources such as heatpumps and electric vehicles in the balancing market. We argue that restricting the current flexibility sources more and adding consumer-based flexibility would lead to similar balancing activity of electrolysers.

We use a net-transfer capacity approach to estimate interconnector capacities. In particular, for 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 Europe until 2030 (Tosatto et al., 2022). Flow-based market coupling allocates transmission capacities to the interconnectors that have the highest value for the system in the time period considered. Because energy islands host only zero-marginal-cost power production, it is very likely that a flow-based market coupling algorithm will allocate the maximum capacity to the interconnectors connecting those islands to shore. Hence for those interconnectors, 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 and the net-transfer capacities between the zones, we neglect network constraints within the zones and may overestimate the available grid capacities behind the interconnectors. Refer to Seifert (2022), for instance, who concludes that the national grid plans for 2030 are not yet equipped to accommodate foreseeably large shares of renewable energy and need upward adjustments following national expansion plans.

Lastly, we simulate two market stages only, which do not reflect all stages of the current market frameworks of most European countries. The well-established sequences are the day-ahead market, cleared up to 36 h before real-time, the intraday market for adjusting to improved forecasts, balancing markets for flexibility, and technical reserves, and 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.

7. Conclusion and policy implications

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

Our first research question targets the electrolysers' contribution to flexibility. We conclude that flexibility in the system stems mainly from other, cheaper dispatchable sources. Offshore electrolysers do make a modest contribution to balancing services on the energy island, however. 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 need for congestion management. From our sensitivity analyses, we conclude in summary that (i) significantly higher shares of renewables onshore lead to much higher capacity factors of all 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 energy islands significantly increases the capacity factors of electrolysers and their balancing actions on the islands.

On the basis of our study, we formulate four policy recommendations affecting the role of electrolysers on energy islands:

1. **Flexibility:** Electrolysers can technically react to changes in electricity production and have a broad potential to provide flexibility. But if that potential is to be exploited, economic incentives are needed to make largely flexibility-oriented operations 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 and scarcity of energy better than home bidding zones. For electrolysers on energy islands, the OBZ configuration allows higher hydrogen production at lower average electricity costs. This configuration also prevents misalignment between physical network constraints and market solutions, reducing possibly expensive redispatch measures. This suggestion is in line with the conclusions of Kitzing and Garzón González (2020) who consider offshore wind hubs only, but it needs to address congestion rent allocations.
3. **Hydrogen supply:** Discussions of a hydrogen economy are gaining momentum. The European Commission foresees production of 10 million tonnes in Europe by 2030.[16] If hydrogen is to be produced locally as part of the strategy and is to be prioritised, the costs of electricity for electrolysis should reflect local production costs. Offshore bidding zones can make hydrogen production more viable.
4. **Renewable energy targets:** The renewable energy capacity projections presented in the TYNDP 2020 do not meet renewables targets. Our results indicate that the projected capacities are insufficient to supply the hydrogen needed by low-carbon industry. National and European efforts must therefore incorporate incentives and plans for dedicated and system-based hydrogen production.

This analysis uses a two-stage operational model to analyse the flexibility provision of an offshore electrolyser and the impact of bidding zone configurations on its profitability. The approach can be extended by including unit commitment to obtain a better representation of the operational characteristics of large conventional units. For the representation of the electrolyser operation, Flamm et al. (2021) suggest using a mixed integer programme for higher accuracy, and Zheng et al.

[16] See COM(2020) 301 final.

(2022b) highlight the importance of including operational details on temperature dependence and changes of state in the model. Extending the model by adding details of all the technologies could provide further insights but may increase computational complexity. A more sector-integrated approach, e.g., by including a technically detailed representation of the heat sector, may help to analyse the role of different flexibility resources and reflect opportunity decisions in multi-energy systems. Due to uncertainty in hydrogen demand and prices, further analysis of the impact both on the viability and on offshore electrolysers will allow a better understanding of how offshore assets can contribute to hydrogen demand and system stability. This can be extended by considering aspects and requirements for green hydrogen production. So far, we have disregarded market power and strategic bidding. However, such bidding might occur around energy islands when operators of wind farms and electrolysers are both aiming for high profits. In particular, ownership structures may influence strategic behaviour. It could be worth analysing the cases of different structures and contracts: Owning and operating wind farms and electrolysers jointly might lead to different market outcomes than when having separate owners and operators. Last, we suggest investigating the impact of current and planned power grids on the role and operation of offshore electrolysers on energy islands. We base our analysis on modelling bidding zones, and we restrict net-transfer capacities. In a follow-up study, an examination of flow-based market coupling and inner-zone congestion management will provide further insights. In addition, the role of congestion rent in the presence of offshore bidding zones needs to be discussed. The allocation of the congestion rent may heavily impact the value of operating wind farms at energy islands.

CRediT authorship contribution statement

Alexandra Lüth: Conceptualization, Data curation, Software, Visualization, Writing – original draft, Writing – review & editing. **Yannick Werner:** Conceptualization, Data curation, Software, Visualization, Writing – original draft, Writing – review & editing. **Ruud Egging-Bratseth:** Conceptualization, Supervision, Writing – review & editing. **Jalal Kazempour:** Conceptualization, 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.

Data availability

The data and code is available here: https://github.com/yannickwerner/EnergyIslands.

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

Sets	
$n \in \mathcal{N}$	zone n in the set of zones $\mathcal{N}$
$t \in \mathcal{T}$	hour t in time horizon $\mathcal{T}$
$h \in \mathcal{H}$	sub-period h in the set of sub-periods $\mathcal{H}$
$i \in \mathcal{I} \subset \mathcal{U}$	technology i of all conventional technologies $\mathcal{I}$
$j \in \mathcal{J}$	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 storage units
$r \in \mathcal{R} \subset \mathcal{U}$	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 ω of all scenarios
Parameters	
$g^{\text{tot}}_{\omega,r}$	maximum total production for reservoir r in scenario ω over all t
$g^{\max}_{u}$	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 ramping capacity of storage s
$r^{\text{down/up},L}_{s}$	maximum upward ramping capacity of storage s
$g^{\text{real}}_{j,t}$	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^{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^{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
η_{e}	conversion efficiency of electrolyser e
$\pi_{\omega,t}$	probability of occurrence of scenario ω 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 ω

Appendix

Model formulation

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

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 sets 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 into a single unit so 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—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 levels from renewable energy sources.

Eq. (1) minimises the sum of costs for the first-stage decision C_t^{DA} and the costs for the second stage balancing $C_{\omega,t}^{\mathrm{BA}}$. The costs in the second stage are represented by the sum over all scenarios ω weighted by their probability $\pi_{\omega,t}$.

$$\min \sum_{t\in\mathcal{T}} \left[C_t^{\mathrm{DA}} + \sum_{\omega\in\Omega} \left(\pi_{\omega,t} \cdot C_{\omega,t}^{\mathrm{BA}} \right) \right] \tag{1}$$

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

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

Costs in the second stage of the model arise from providing balancing energy in response to system needs in each scenario ω. Eq. (3) is thus built similarly to the first-stage costs but 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 $B_{\omega,i,t}^{\mathrm{up}}$, $B_{\omega,e,t}^{\mathrm{up}}$ and downwards $B_{\omega,i,t}^{\mathrm{down}}$, $B_{\omega,e,t}^{\mathrm{down}}$. For conventional technologies, we assume that upward (downward) balancing costs are 20% above (below) their marginal costs. For electrolysers, we additionally include revenues (losses) 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 see . In real-time operations, it is also possible to shed loads $L_{\omega,d,t}^{\mathrm{shed}}$ at a (sufficiently high) cost p^{LOL} to ensure that this action is taken only 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.

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

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-transfer 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 battery storage in charging mode.

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

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

For the second stage, deviations from forecasted values for stochastic generation must be balanced. We introduce uncertainty through scenarios ω in this stage in Eq. (5). In this model, deviations of scheduled intermittent production $G_{j,t}^S$ from $g_{\omega,j,t}^{\mathrm{real}}$ are to be balanced by either curtailing renewables $G_{j,t}^{\mathrm{CU}}$, using balancing services of dispatchable technologies u for up- or downwards adjustments $B_{\omega,u,t}^{\mathrm{up}}$, $B_{\omega,u,t}^{\mathrm{down}}$, increasing or decreasing the output of an electrolyser $B_{\omega,e,t}^{\mathrm{up}}$, $B_{\omega,e,t}^{\mathrm{down}}$ or storage units $B_{\omega,s,t}^{\mathrm{up,L}}$, $B_{\omega,s,t}^{\mathrm{down,L}}$, $B_{\omega,s,t}^{\mathrm{up,G}}$, $B_{\omega,s,t}^{\mathrm{down,G}}$. Note that we explicitly allow storage units to not only adjust their day-ahead market schedules in the same direction but to change the operational mode in the balancing stage. For example, if a storage unit is charging in the day-ahead market, we allow it to fully revert this action and additionally discharge in the balancing stage.

Apart from that, net exchange with neighbouring zones $F_{\omega,f,t}^{\mathrm{adj}}$ can be adjusted and load can be shedded $L_{\omega,d,t}^{\mathrm{shed}}$.

$$\begin{aligned} & \sum_{j\in\Delta_n^J} (g_{\omega,j,t}^{\mathrm{real}} - G_{j,t}^{\mathrm{S}} - G_{\omega,j,t}^{\mathrm{CU}}) \\ & + \sum_{u\in\Delta_n^U} (B_{\omega,u,t}^{\mathrm{U}} - B_{\omega,u,t}^{\mathrm{D}}) + \sum_{e\in\Delta_n^E} (B_{\omega,e,t}^{\mathrm{up}} - B_{\omega,e,t}^{\mathrm{down}}) \\ & + \sum_{s\in\Delta_n^S} (B_{\omega,s,t}^{\mathrm{up,G}} + B_{\omega,s,t}^{\mathrm{up,L}} - B_{\omega,s,t}^{\mathrm{down,G}} - B_{\omega,s,t}^{\mathrm{down,L}}) \\ & + \sum_{d\in\Delta_n^D} L_{\omega,d,t}^{\mathrm{shed}} - \sum_{f\in\mathcal{F}_n^{out}} F_{\omega,f,t}^{\mathrm{adj}} + \sum_{f\in\mathcal{F}_n^{in}} F_{\omega,f,t}^{\mathrm{adj}} = 0, \quad \forall \omega \in \Omega, n \in \mathcal{N}, t \in \mathcal{T}. \end{aligned} \tag{5}$$

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

For renewable energy, the scheduled energy production $G_{j,t}^S$ cannot exceed its installed capacity g_j^{max}. Curtailment $G_{\omega,j,t}^{\mathrm{CU}}$ in the second stage cannot be larger than the realisation of renewable $g_{\omega,j,t}^{\mathrm{real}}$ production.

$$G_{j,t}^S \leq g_j^{\mathrm{max}} \qquad \forall\, j \in \mathcal{J}, t \in \mathcal{T}, \tag{6}$$

$$G_{\omega,j,t}^{\mathrm{CU}} \leq g_{\omega,j,t}^{\mathrm{real}} \qquad \forall\, \omega \in \Omega, j \in \mathcal{J}, t \in \mathcal{T}. \tag{7}$$

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

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

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

Reservoir. We divide the whole time horizon $\mathcal{T}$ into a number sub-periods $h \in \mathcal{H}$ of equal length $\mathcal{T}_h^{\mathrm{sub}} \subseteq \mathcal{T}$. For generation from water reservoirs, we restrict the sum of generation in each sub-period to a scenario-specific maximum $g_{\omega,r,h}^{\mathrm{tot}}$.

$$\sum_{t\in\mathcal{T}_h^{\mathrm{sub}}} (G_{r,t} + B_{\omega,r,t}^{\mathrm{up}} - B_{\omega,r,t}^{\mathrm{down}}) \leq g_{\omega,r,h}^{\mathrm{tot}}, \qquad \forall\, \omega \in \Omega, r \in \mathcal{R}, h \in \mathcal{H}. \tag{10}$$

For our case study, we divide the year into 24 sub-periods such that each sub-period covers 365 h. We chose the length of the sub-periods to reflect the limited inflow of water into the reservoir.

Combined heat and power plants. 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 therefore have limited flexibility. We include a time-varying minimum run requirement in our model to reflect this:

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

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, so that $f = (n,m)$, $\hat{f} = (m,n)$, where $f, \hat{f} \in \mathcal{F}$. We also 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 in accordance with 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. Eqs. (14) and (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 the characteristics of a storage unit with regard to balancing, Eqs. (16) and (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, Eqs. (19) and (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 $S_{\omega,s,t}$ between a lower and upper storage bound $s^{\min}_s$ and $s^{\max}_s$.

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

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

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

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

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

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

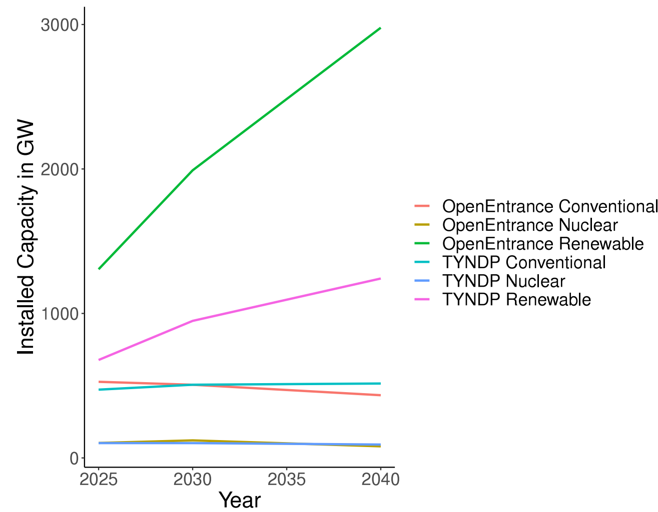

Fig. 12. Installed Capacities from TYNDP and OpenEntrance scenarios.

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

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

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

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

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

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

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

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

Balancing costs

We assume that the costs of dispatchable units u in the balancing markets are chosen in a way that reflects the 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 μ is chosen to be 20%. Similarly, the cost for downward balancing services (generator produces less power) is assumed to be $p^{B,D}_g = mc_u \cdot (1-\mu)$. By contrast, the electrolyser faces some gained or lost profits on the hydrogen market if it produces more or less hydrogen by consuming more or less power. Following a similar argument for dispatchable generators, we assume that the bid price for upward balancing services (electrolyser consumes less power) is $p^{B,U}_e = \eta_e p^{\text{H}_2} - mc_e \cdot (1-\mu)$. Analogously, the cost for downward balancing services (electrolyser consumes more power) is $p^{B,D}_e = -(\eta_e p^{\text{H}_2} - mc_e \cdot (1+\mu))$. Note that in contrast to dispatchable units, the electrolyser not only takes its marginal production cost into account, it further includes its opportunity cost to produce an increased or reduced amount of hydrogen.

Additional graphs and data

Fig. 12 shows the development of installed capacities according to the TYNDP and openEntrance scenarios, that we use for our sensitivity analysis. For all analyses in our case study, we consider the market

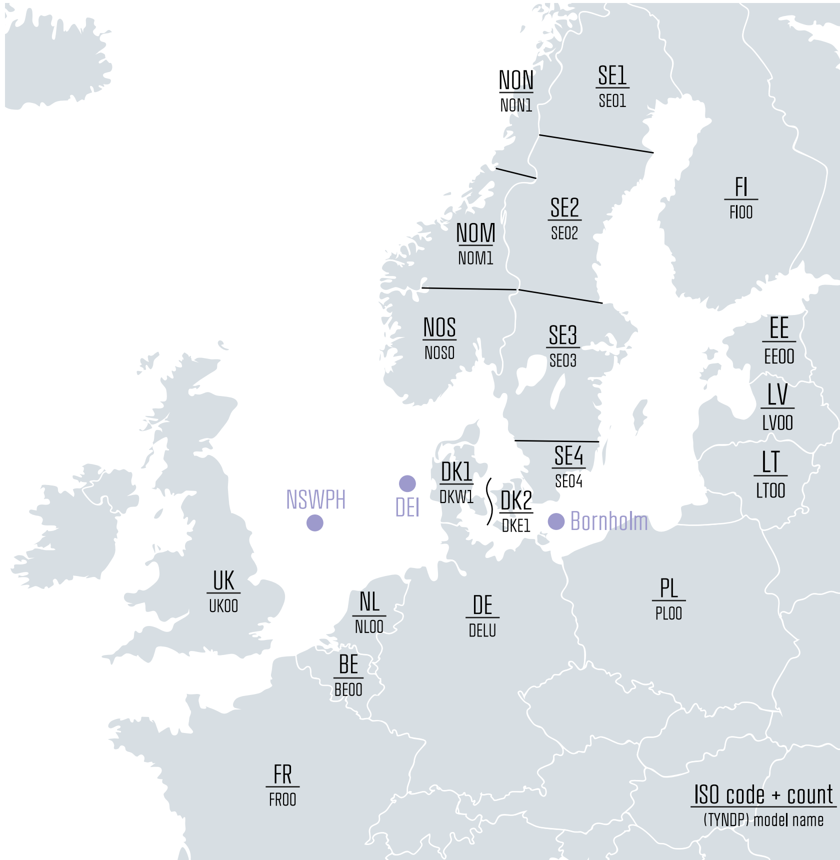

Fig. 13. Zones in the model.

zones depicted in Fig. 2. This configuration follows the convention used in the TYNDP which aggregates the five Norwegian zones into three, and we add the three energy islands to it as separate zones.

Robustness of the results

Due to computational complexity, we consider ten scenarios to reflect the uncertainty in renewable production and split the time horizon of a year into six equally long segments. To verify the robustness of our results to these modelling choices, we test the impact of shorter and longer segments and the number of scenarios. Here, we focus on the impact on day-ahead and balancing capacity factors of electrolysers on energy islands.

For the length of the **time segments**, we observe that results are stable for the chosen length of 1460 h. The day-ahead capacity factors vary neither for longer (2190 h, 12 weeks) nor shorter (730 h, 4 weeks) segments by more than three percentage points. The capacity factors for the balancing market vary by less than 0.5 percentage points.

Increasing the number of **scenarios** significantly impacts the solution time of the model. Tests with 15 and 20 scenarios showcase that the day-ahead capacity factors differ less than 0.3 and 0.4 percentage points, respectively. The capacity factors for the balancing market vary by less than 0.2 and 0.4 percentage points, respectively.

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