Energy Policy 174 (2023) 113382

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Going offshore or not: Where to generate hydrogen in future integrated energy systems?

Juan Gea-Bermúdez [a,*], Rasmus Bramstoft [a], Matti Koivisto [b], Lena Kitzing [b], Andrés Ramos [c]

[a] Technical University of Denmark, Department of Management, Produktionstorvet, Bygning 424, 2800 Kongens Lyngby, Denmark
[b] Technical University of Denmark, Department of Wind and Energy Systems, Frederiksborgvej 399, 4000 Roskilde, Denmark
[c] Instituto de Investigación Tecnológica, Escuela Técnica Superior de Ingeniería, Universidad Pontificia Comillas, Madrid 28015, Spain

ARTICLE INFO

Keywords:
Offshore
Hydrogen
Optimisation
Sustainability transition
Energy system
Modelling

ABSTRACT

Hydrogen can be key in the energy system transition. We investigate the role of offshore hydrogen generation in a future integrated energy system. By performing energy system optimisation in a model application of the Northern-central European energy system and the North Sea offshore grid towards 2050, we find that offshore hydrogen generation may likely only play a limited role, and that offshore wind energy has higher value when sent to shore in the form of electricity. Forcing all hydrogen generation offshore would lead to increased energy system costs. Under the assumed scenario conditions, which result in deep decarbonisatiton of the energy system towards 2050, hydrogen generation – both onshore and offshore – follows solar PV generation patterns. Combined with hydrogen storage, this is the most cost-effective solution to satisfy future hydrogen demand. Overall, we find that the role of future offshore hydrogen generation should not simply be derived from minimising costs for the offshore sub-system, but by also considering the economic value that such generation would create for the whole integrated energy system. We find as a no-regret option to enable and promote the integration of offshore wind in onshore energy markets via electrical connections.

1. Introduction

In relation to the Paris Agreement of 2015 and its corresponding long-term goals (The European Commission, 2015), the European Union (EU) signed the European Green Deal in 2019 (The European Commission, 2019), which details a strategy for the EU to transform into a sustainable economy. The target is to achieve carbon neutrality by 2050 (The European Commission, 2020a).

Previous studies have shown that sector coupling is an important factor to achieving this transition in a cost-efficient way (Gea-Bermúdez et al., 2021b; Brown et al., 2018; Helgeson and Peter, 2020). The concept of sector coupling has also been reflected in the EU strategy for energy system integration (The European Commission, 2020c). A key driver for facilitating energy system integration is Power-to-X and hydrogen (H_2), which can be used as fuel, energy carrier, storage, and feedstock, to decarbonise the hard-to-abate energy sectors, particularly the heavy long-distance transport sector and the industrial sector. Hydrogen is therefore projected to play a prominent role in achieving a carbon neutral energy system, and therefore the EU released its hydrogen strategy in 2020 (The European Commission, 2020b), which promotes the generation of green hydrogen, i.e. hydrogen generated from clean energy sources, to reduce greenhouse gas emissions across the energy sector.

The generation of large amounts of green hydrogen will require massive deployment of variable renewable energy (VRE). Onshore deployment of VRE can face spatial and social constraints, and low social acceptance can impact onshore wind installations (Egelund, 2010). Hydropower could also play an important role in the generation of green hydrogen. However increasing considerably hydropower generation capacity can be complicated due to, among other reasons, limited available locations. To explore and promote offshore alternatives, the EU released in 2020 an offshore renewable energy strategy (The European Commission, 2020d). Previous studies have found that it is cost-effective to develop some future offshore energy in advanced offshore grid configurations (Gea-Bermúdez et al., 2020; Konstantelos et al., 2017; Koivisto et al., 2019b). As a first step in this direction, Denmark announced its intention to build an artificial energy island that bundles several large-scale offshore wind parks as well as grid interconnection to other countries, and for which generation of green hydrogen on the island is considered (DW, 2021). This is a concept that could also become applicable to other countries. However, a

* Corresponding author.
E-mail address: jgeab@dtu.dk (J. Gea-Bermúdez).

https://doi.org/10.1016/j.enpol.2022.113382
Received 18 June 2021; Received in revised form 26 November 2022; Accepted 30 November 2022
Available online 14 January 2023

crucial question still remains: What will the role of offshore hydrogen generation be in future integrated energy systems?

In the literature, two main research fields can be applied to investigate the competition between *(a)* transmitting the power from the offshore wind farms to shore and then generate hydrogen and *(b)* generating hydrogen offshore and send it to shore via pipeline infrastructures. The *first* research field applies detailed project-based techno-economic feasibility calculations to compute the most viable option. The *second* research field applies holistic energy system models, which optimise the competition between the two options from a system perspective and thereby captures the synergies between energy sectors and vectors, as well as the impact of energy transition pathways.

Techno-economic feasibility calculations are strong at encompassing detailed project-based data, which is useful for private/project-based decisions. However, they cannot easily capture the synergies within the energy system, which is important when analysing the cost-effectiveness of the energy system and when proposing strategies towards highly renewable-based energy systems. For instance, the techno-economic feasibility calculations use exogenous electricity price estimates, whereas in holistic energy system optimisations electricity prices are endogenously computed. The prices can be highly affected depending on the transition pathway and defined system conditions. Therefore, the results from each of the two approaches might not lead to identical results given the different perspectives, i.e., project-based against energy system optimality.

Most of the previous research focusing on the competition between generating hydrogen offshore or onshore has applied techno-economic feasibility for different case studies.

Dinh et al. (2020) developed an integrated model to assess the viability of hydrogen generation from dedicated offshore wind farms using an analytical approach. They point out that the model is useful for the assessment of economics and feasibility of dedicated offshore wind and hydrogen systems, from a project-owner perspective.

Babarit et al. (2018) investigated on the techno-economic feasibility of fleets of far offshore hydrogen generating wind energy converters. They showed that shorter distances to shore might be more profitable compared to far offshore wind.

Hou et al. (2017) investigated investment potential of coupling offshore wind farms with different hydrogen system configurations, using a Danish case study. They found that the best configuration is where the generation of hydrogen complements the electricity generation from the wind farm and the hydrogen is sold to the end users directly rather than storing and re-generating electricity when electricity prices are high, as other flexibility measures can provide this service cheaper.

Franco et al. (2021) performed an assessment of pathways for wind-powered offshore hydrogen generation, and found that the transport of the generated hydrogen to shore via pipelines seemed to be the best alternative compared to transporting other energy liquid carriers or transmitting the generated electricity to shore.

On the other hand, McDonagh et al. (2020) simulated the electricity and hydrogen generated by an offshore wind farm including and not including associated power-to-gas system. They explore three configurations, (1) electricity from offshore wind is sold to the market, (2) all electricity from offshore wind is converted to hydrogen and sold to the hydrogen market, and (3) a hybrid system where otherwise curtailed electricity is converted to hydrogen and/or hydrogen is generated when electricity price is low. They find that the most profitable configuration is to sell electricity to the grid. The study is interesting from a project owner perspective. However, it lacks insight into the system dynamics where electricity prices are endogenously generated based on the energy mix, which is an outcome from the transition pathway.

While the research focusing on techno-economic feasibility case studies is useful for determining the profitability of a single project, they do not capture the effects of a large-scale implementation of e.g. offshore wind and electrolysers. This large-scale effect might impact the electricity prices and can result in self-cannibalism.

In order to capture the synergies between energy vectors and sectors, which consequently impacts the competition between technologies and infrastructures, energy system models can be applied. These models are suitable for assessing the central research question of this paper, which is where to generate hydrogen in the future, e.g. onshore or offshore. Despite the obvious benefits of applying energy system modelling tools for assessing the geographical location of hydrogen generation in the future (considering system interactions, multiple energy infrastructures, and time-dependent sectoral energy demands), only a few studies in the literature have applied this approach.

Gils et al. (2021) studied the interaction of hydrogen infrastructures, considering the flexible coupling of energy sectors for a German zero-emission energy system. They identified that hydrogen plays a key role in the transformation of the energy system, even by providing the urgently needed flexibility. However, the study lacks cross country interactions due to the limited geographical scope.

The European Hydrogen Backbone (2022) investigated the potential of a future European hydrogen infrastructure. The study is comprehensive and has a clear focus on the potential hydrogen transmission infrastructure. However, there is little focus on the energy mix behind the results, and the scenarios seem to be an outcome of expert knowledge in the field rather than from applying a coherent energy system optimisation model.

Victoria et al. (2022) applied an energy system model that represents the main energy sectors and its subsequent couplings. They analysed the speed of technological transformations of the European energy system to achieve different climate goals. They focused on the larger picture, and hydrogen generation is included particularly to decarbonise the hard-to-abate sectors. However, they do not particularly focus on offshore wind configurations and the potentials of using offshore energy hubs for hydrogen generation.

Caglayan et al. (2021) investigated a robust design of future renewable-based European energy supply system considering hydrogen infrastructure. The study focused on the system impact of running 38 historical weather years. They identified that hydrogen is mainly generated in the regions with lower electricity prices and that wind and solar are complementing technologies in the system. However, again, the study does not include results or findings related hydrogen generation offshore in connection to wind hubs.

A study by Neumann et al. (2022) focused on the benefits of a hydrogen infrastructure in a future 2050 decarbonised energy system. The comprehensive study shows interesting results related to the potentials for a hydrogen infrastructure in the future, however, they perform a *greenfield optimisation* or *overnight scenario*, and thus do not present the transition pathway towards the decarbonised energy system. Furthermore, the generation of wind and hydrogen related to interconnected offshore energy hubs are not presented.

Therefore, none of the studies using a holistic energy system modelling approach presented results on whether hydrogen should be generated onshore or offshore, and neither did they model advanced offshore grid configurations. All this together leaves the question related to using offshore energy hubs to generate hydrogen unanswered.

We address this research gap, by performing a least-cost optimisation of capacity development and operation of the extended European North Sea energy system towards 2050. The energy system model includes the energy needs of the electricity, heat, and transport sectors and thereby enable synergies between energy sectors and vectors. The model encompasses detailed modelling of advanced offshore grid configurations and simultaneously optimises investment in energy technologies and transmission infrastructure as well as the operational dispatch. Using the holistic energy system model and a scenario approach, we compute the least-cost transition pathways to investigate the socio-economic value of offshore hydrogen generation, and to point out key factors that could have a significant impact on the results.

The paper is structured as follows. Section 2 describes the methodology, data, and optimisation approach for the energy system model

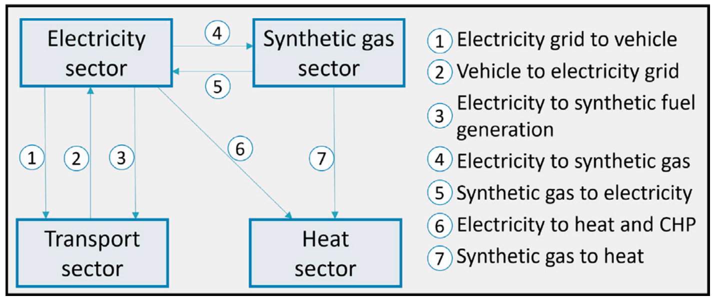

Fig. 1. Possible synergies between the sectors that are included in the model.

applied. The scenarios used in this paper are explained in Section 3. In Section 4, the results are presented and analysed. In Section 5, the results are discussed, and conclusions and policy recommendations are presented in Section 6.

2. Methodology and data

For this study, we have developed new features for the pre-existing energy model Balmorel (Gea-Bermúdez et al., 2021b), that allow us to model in more detail the offshore grid and the possibility for hydrogen transmission, as detailed below. The model and data used are open source (Balmorel Community, 2021b,a).[1] The model includes the energy needs of the electricity, heat, and transport sectors. To reduce model complexity, decarbonisation of the transport sector via increasing electricity demand and synthetic fuel demand towards 2050 is assumed. Demand-side flexibility for these two demand types is allowed, except for rail transport and buses.

2.1. Balmorel

2.1.1. Generic model description

The energy system model Balmorel (Wiese et al., 2018) is open-source (Balmorel Community, 2021a), has a flexible-structure, is deterministic, and has a bottom-up approach. The Balmorel model has been developed for more than twenty years and has recently been compared and validated against other recognised energy system models (Candas et al., 2022; van Ouwerkerk et al., 2022). The model has been developed greatly in the recent years to include more energy sectors (Gea-Bermúdez et al., 2021b), more details on hydrogen and electrofuels (Bramstoft et al., 2020; Lester et al., 2020; Jensen et al., 2020) and the capabilities to model in higher detail system operation (Gea-Bermúdez et al., 2021a).

Balmorel is used to optimise capacity development and operation of the energy system towards 2050 to satisfy the energy demand of selected countries: France, the United Kingdom, Germany, Belgium, Denmark, Netherlands, Sweden, Finland, Norway, and Poland. The optimisation is done using hourly time resolution and from a socio-economic perspective. The socio-economic perspective is mainly reflected in the interest rate and discount rate assumptions used in the optimisations, which attempt to take the perspective of a central planner. The spatial resolution used is based on existing bidding zones. Germany is split into different bidding zones to model intracountry bottlenecks. Bidding zones in the model are defined as regions, and are assumed to be copper plates for electricity transmission.

The energy system used includes the electricity, heat, and transport sectors (Fig. 1). Decarbonisation of the transport sector towards 2050 is assumed in the scenarios.

The objective function is to minimise discounted system costs (Wiese et al., 2018) (Eq. (1)). The different costs of each of the years (y) studied are grouped in fixed operation and maintenance costs (c_y^{fom}), variable operation and maintenance costs (c_y^{vom}), and investment costs (c_y^{inv}). All costs are annualised in the objective function. Investment costs are annualised using an interest rate of 4% (Danish Energy Agency, 2021) for all technologies, assuming this would be the interest rate a social planner would apply. This is done to make a fair comparison of the different technologies, since they can have different lifetimes. Variable costs include fuel costs, operation costs, and CO_2 tax.

The optimisation variables are technology investments (generation units, storage units, electricity transmission, hydrogen pipelines, district heating expansion), and technology operation on an hourly basis (energy generation, storage content, storage loading, energy trade, and electric vehicle (EV) operation). The storage content of hydro reservoirs without pumping is an exception and is modelled on a seasonal basis. Particularly, generation and storage unit mothballing is allowed, which is another variable, before reaching the end of their technical lifetime. Mothballing means that units can be inoperative during one year, to avoid paying the annual fixed costs, and become operative again in future years. The units are forced to decommission at the end of their technical lifetime. The decommissioning costs of exogenous units are not included.

Future years are discounted using a discount rate of 4% (Danish Energy Agency, 2021), which is used to calculate the resulting discount factor (DF_y) of each modelled year, to represent the socio-economic value of time.

$$\min_{c_y^{fom}, c_y^{vom}, c_y^{inv}} \sum_y DF_y \cdot (c_y^{fom} + c_y^{vom} + c_y^{inv}) \tag{1}$$

Other key equations are commodity balances, technology-specific operational constraints, storage balance, and resource potentials equations.

Unit commitment costs, variables and constraints (e.g. start-up costs, on/off unit status, minimum off time constraints, etc.) are not considered in this study. However, the impact of this limitation on results is likely to be low given the high amount of flexibility options included (Poncelet et al., 2020).

2.1.2. Energy system modelling

Generation and storage technologies. Multiple generation and storage technologies are included in the optimisation and compete with each other: generation (dispatchable (hydro reservoirs, electric power-to-heat units (electric heaters, electric boilers, and heat pumps), fuel boilers, combined heat and power (CHP) and non-CHP thermal units, fuel cells, electrolysers, methanation-direct air capture) and non-dispatchable (wind onshore, wind offshore, solar PV, solar heating), storage (electric batteries, hydro pumping, pit thermal storage, heat water tanks, hydrogen tanks, offshore caverns for hydrogen storage). Technology data is mostly based on Danish Energy Agency (2021) (Table 1). More details can be found in Gea-Bermúdez et al. (2021b).

[1] The branch used for the data and code used in this paper is called "H2_Transport_update_2021_JGB" (last access 1st May 2021).

Table 1
Investment costs development assumptions and corresponding sources of selected large-scale technologies in M€$_{2016}$/MW (M€$_{2016}$/MWh for storage) per technology type and year. Other costs, like operational fixed costs, or variable fixed costs are not shown, but can be found in Balmorel Community (2021b). Costs for fuel cells and electrolysers are defined on the electrical side.

Technology	2025	2035	2045	Source
Solar PV (AC side)	0.4200	0.3000	0.2600	Danish Energy Agency (2021)
Onshore wind	1.2728	1.1456	1.0539	Danish Energy Agency (2021)
Offshore wind radial (nearshore, AC, western Denmark)	1.6609	1.5783	1.5140	Koivisto et al. (2019b), Danish Energy Agency (2021), EA Energy Analysis (2020) and EDMOnet-Bathymetry (2021)
Offshore wind radial (far offshore, AC, western Denmark)	2.0662	1.8781	1.7379	Koivisto et al. (2019b), Danish Energy Agency (2021), EA Energy Analysis (2020) and EDMOnet-Bathymetry (2021)
Offshore wind radial (far offshore, DC, western Denmark)	2.7208	2.4829	2.3139	Koivisto et al. (2019b), Danish Energy Agency (2021), EA Energy Analysis (2020) and EDMOnet-Bathymetry (2021)
Hub-connected offshore wind (20 m depth, close to hub)	2.1165	1.9098	1.7839	Koivisto et al. (2019b), Danish Energy Agency (2021), EA Energy Analysis (2020) and EDMOnet-Bathymetry (2021)
Hub-connected offshore wind (20 m depth, far from hub)	2.2025	1.9915	1.8656	Koivisto et al. (2019b), Danish Energy Agency (2021), EA Energy Analysis (2020) and EDMOnet-Bathymetry (2021)
Hub-connected offshore wind (30 m depth, close to hub)	2.2265	2.0098	1.8739	Koivisto et al. (2019b), Danish Energy Agency (2021), EA Energy Analysis (2020) and EDMOnet-Bathymetry (2021)
Hub-connected offshore wind (30 m depth, far from hub)	2.3125	2.0915	1.9556	Koivisto et al. (2019b), Danish Energy Agency (2021), EA Energy Analysis (2020) and EDMOnet-Bathymetry (2021)
Offshore hub (platform and equipment)	0.1860	0.1860	0.1683	Koivisto et al. (2019b)
Electrolyser onshore (alkaline)	0.6500	0.4500	0.3000	Danish Energy Agency (2021)
Electrolyser onshore (alkaline, connected to district heating)	0.6605	0.4605	0.3105	Danish Energy Agency (2021)
Electrolyser offshore (alkaline, with osmosis plant)	0.6505	0.4505	0.3005	Danish Energy Agency (2021) and IEA (2019)
Fuel cell (solid oxide)	1.5000	0.8000	0.6500	Danish Energy Agency (2021)
Lithium battery (electricity storage)	0.4105	0.3284	0.2463	Lazard (2017)
Pumped hydro (electricity storage)	0.2908	0.2908	0.2908	Danish Energy Agency (2021)
Steel tank (H_2 storage)	0.0570	0.0450	0.0270	Danish Energy Agency (2021)
Offshore cavern (H_2 storage)	0.0030	0.0020	0.0015	Danish Energy Agency (2021)

Electricity network. Electricity flow between regions is modelled with net transfer capacity (Gunkel et al., 2020b). Transmission losses per km distinguish between alternate current (AC) and direct current (DC) lines. Distribution losses for generation and storage technologies are defined depending on which part of the electric grid they are located in. Electricity transmission investment costs, calculated using the distance between the centroids of the modelled regions, are based on Nordic Energy Research and International Energy Agency (2016) and Gea-Bermúdez et al. (2020). The lines are assumed to have a lifetime of 40 years (Danish Energy Agency, 2021). Protection or social compensation costs for the lines are not included. More details can be found in Gea-Bermúdez et al. (2021b).

Heat sector. The heat sector is divided into individual users (residential and tertiary sectors), industry, and district heating.

The modelling of district heating is based on network scales inspired from Münster (2012). District heating expansion is assumed to have a cost of 400 000 €$_{2016}$/MW$_{th}$ (Henning and Palzer, 2014) and a lifetime of 40 years (Danish Energy Agency, 2021).

Individual users' modelling takes into account the end purpose of heat demand, i.e. space heating or hot water.

Heat modelling in the industry sector is based on Danish Energy Agency (2021), Rehfeldt et al. (2018) and Wiese and Baldini (2018), and defines three different temperature needs: low (below 100 °C), medium (100–500 °C), and high (above 500 °C).

More details about the modelling of the heat sector can be found in Gea-Bermúdez et al. (2021b).

Synthetic gas. The synthetic gas sector includes the energy balance of synthetic natural gas (SNG) and hydrogen. An illustration of the modelling of the synthetic gas sector is shown in Fig. 2.

The SNG modelling is based on Gea-Bermúdez et al. (2021b) and its energy balance is defined on an hourly basis as an international market. SNG can be generated through methanation-direct air capture units, which consume heat, hydrogen and electricity. SNG can be used in gas units as a perfect replacement of fossil natural gas. The costs and constraints of natural gas networks, where SNG is assumed to be injected, are not included. This means that the generated SNG can be freely distributed around the modelled regions. The CO_2 flows from SNG are ignored because it is assumed to be carbon neutral.

The hydrogen modelling is based on Gea-Bermúdez et al. (2021b), but it has been significantly improved to include more details. The hydrogen balance is defined for each region on an hourly basis. Hydrogen trade between regions is allowed and constrained by the available pipeline capacity. In this paper, hydrogen can only be generated through alkaline water electrolysis units. Other type of electrolysers are not included for computational tractability.

The transport of hydrogen is modelled with transmission pipelines assuming linear bi-directional flow. The existing hydrogen pipeline between regions is not included. The following assumptions are made based on Danish Energy Agency (2021): hydrogen transmission pipes are assumed to have a lifetime of 50 years, an investment cost of 400 €$_{2016}$/km/MW$_{th}$, and hydrogen transmission energy losses of 0.0022 %/km to keep the operating pressure of the hydrogen network, which

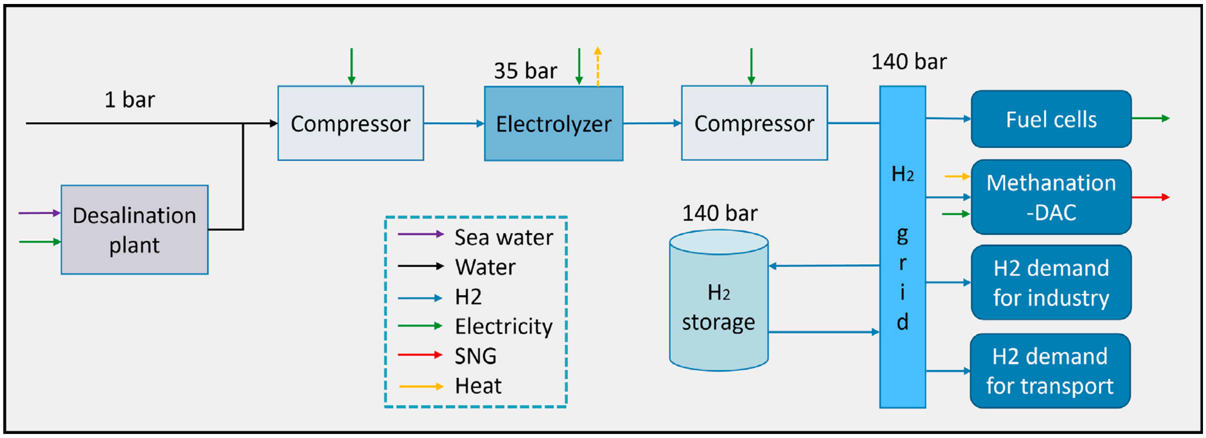

Fig. 2. Illustration of synthetic gas sector modelling. Desalination plants are only relevant if electrolysers are built offshore. Heat coming out from the electrolysers can only be used if built in district heating networks. The hydrogen grid includes the required equipment (compressors, measuring stations, etc.) to keep an operating pressure of 140 bar. "SNG" stands for synthetic natural gas, "H2" for hydrogen, and "DAC" for direct air capture.

is assumed to be 140 bar. The investment cost includes the cost of the compressors and additional equipment to keep the operating pressure.

The energy required to compress the hydrogen generated from the electrolyser to inject it to the network is allocated to the electrolyser and it is assumed to be 2.1%, 1.7%, and 1.5% for investments made in 2025, 2035 and 2045. The same data is assumed for offshore and onshore grid equipment (pipes, compressors, etc.) for simplicity. Other means of transporting hydrogen, e.g. ships, liquid hydrogen, etc., are not considered.

Distribution hydrogen networks and the required equipment to deliver hydrogen to the consumption point are not included, but their corresponding losses are included (1.5% of the exogenous demand based on Danish Energy Agency (2021)). The possibility to reconvert existing natural gas networks into hydrogen ones is not considered.

Fuel cells, methanation-direct air capture units, electrolysers and hydrogen storage are assumed to be connected to the hydrogen transmission network, and hence, are assumed to not incur into distribution losses. Hydrogen storage units are assumed to operate at a similar pressure as the hydrogen transmission grid for simplicity. A round trip efficiency of 99% is assumed for all hydrogen storage technology types to acknowledge possible energy losses in the storing process.

Electrolysers invested offshore are assumed to be built with a reverse osmosis desalination plant, which incurs into additional electricity consumption (0.04 kWh per ton of hydrogen generated) and capital expenditure (4280 $€_{2016}/MW_e$) (IEA, 2019).

Electrolysers built onshore can either be connected or not-connected to district heating networks. If they are built connected to district heating networks, their excess heat can be used in these networks, at the expense of incurring into additional capital expenditure related to the connection to the district heating network. Such cost is assumed to be 105 000 $€_{2016}$ for every MW_{th} of excess heat connected, and mainly corresponds to the cost of the heat exchanger. For every MW of electricity consumed in the electrolyser, a certain amount of thermal energy is generated as recoverable excess heat, which is the one that can be absorbed by the district heating network. This amount depends on the efficiency of the electrolyser and is based on Danish Energy Agency (2021).

We do not model disconnected-from-the-main-grid electrolyser plants. This means that any source (onshore or offshore) of electricity generation can be used, in principle, for the generation of hydrogen (both onshore and offshore). For the case of offshore hydrogen generation, it is required that the model invests in electricity lines connecting the offshore hubs to shore to be able to use onshore generation from e.g. solar PV, onshore wind, etc. to generate hydrogen offshore.

Exogenous hydrogen demand is assumed for industrial purposes and for the decarbonisation of the transport sector (Fig. 3). The hydrogen

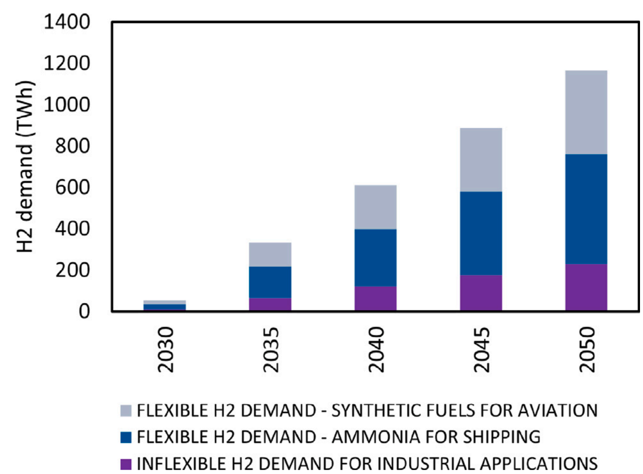

Fig. 3. Annual hydrogen demand assumption split by type (TWh). "H2" stands for hydrogen.

demand for industrial purposes is inflexible and constant along the year, and its demand scenario is based on the European commission's 1.5TECH scenario (European Commission, 2018). The scenario for hydrogen demand for the decarbonisation of the transport sector, which is modelled as relatively inflexible demand, is explained later in this section.

Transport sector. Decarbonisation of the transport sector demand towards 2050 is assumed and its modelling split into inflexible and flexible EVs, and demand for synthetic fuels for transport.

Inflexible EVs include the electrification of buses and rail transport that is not currently electrified based on Transport and Environment (2018). They are modelled with exogenous time series in each region. The demand pattern is assumed constant for trains and time dependent for buses (Philip Swisher, 2020).

Road transport, excluding buses, is modelled as flexible EVs with virtual storage for each region using time series of daily patterns to represent the expected amount of EVs connected to the electricity network (Gunkel et al., 2020a). The number of EVs towards 2050, which is used to calculate the time series used, is not optimised but assumed. The data is taken from Philip Swisher (2020).

The virtual storage content, and the charging and discharging of the EVs are the variables the model optimises in the scenarios. EVs are divided into battery EVs and plug-in hybrid EVs. The use of plug-in hybrid EVs for vehicle-to-grid is not allowed.

The hourly storage balance is the main equation of this technology.

It is assumed that, for each type of EV, the level of the storage at the beginning of the season (in this paper week) must equal the one in the end. The implications of this modelling assumption are discussed in Section 5.

The charger capacity limits maximum charging, whereas inflexible charging limits minimum charging. The daily patterns for road transport assume low availability of the vehicles from the morning to the afternoon, since it is assumed that the vehicles are not connected to the grid during most working hours.

EV charging is penalised with distribution grid losses and a charger loss.

More details about the virtual storage method can be found in Gea-Bermúdez et al. (2021b).

The annual synthetic fuel demand required to decarbonise the shipping and aviation transport sectors of the studied countries is included in the scenarios and based on Transport and Environment (2018). This demand is modelled as an increasing annual hydrogen demand towards 2050 that needs to be satisfied in each onshore region along the year. The hourly distribution along the year of this demand is optimised.

The technologies that consume this hydrogen to generate the synthetic fuels, e.g. ammonia, are not included for tractability purposes. The hourly operation of these units is indirectly restricted though to take into account that these plants are likely to require high capacity factors to maximise their profitability. This is done by adding a constraint that establishes an upper limit to the peak-to-average ratio of the hourly hydrogen demand in each region. This factor is equivalent to defining a minimum average capacity factor per region, which in this paper is set to be 2/3.

The hydrogen demand has been calculated by applying an efficiency assumption of 62.5% to the electricity consumption data shown in Transport and Environment (2018). This efficiency includes distribution losses, which cannot be captured otherwise in the model because distribution networks are not included. Because of adding this hydrogen demand, investments in biomass units are not allowed, since the generation of synthetic fuels is likely to require the use of a large share of the available biomass resources (Sims et al., 2010). The costs and challenges related to the transport of the biomass resources is not included.

The default assumption is that the generation of synthetic fuels to decarbonise the transport sector (modelled as hydrogen demand) cannot be shifted to other regions. This implies that each onshore region needs to consume a certain amount of hydrogen along the year to generate synthetic fuels to satisfy their own demand for these fuels. Hydrogen can be generated in any region, but it needs to be sent ultimately to the onshore regions. This assumption is changed in some of the scenarios and is explained in Section 3.

The capital and operational costs of all the different transportation means (cars, shipping, aviation, etc.) are not included.

Energy efficiency. The European Commission's energy efficiency target of 32.5% reduction of final energy consumption by 2030 (The European Commission, 2020a) is assumed to be achieved. The assumptions on exogenous electricity (excluding the transport sector which already includes efficiency measures) and heat demand development towards 2050 consider this efficiency target. Even though the European Commission uses the year 2007 as a reference for this target, we have used the year 2016 to make this calculation due to data availability limitations.

Wind and solar modelling. To represent that solar and wind resources are not uniform inside the studied countries, the modelling of wind and solar PV technologies is based on several resource grades as it was done in Gea-Bermúdez et al. (2020). The resource grades can differ in investable potential, costs, and time series.

Particularly, radially-connected offshore wind power plants (OWPP) are split into three resource grades: near shore and far offshore connected with alternating current (AC), and far offshore connected with direct current. Hub-connected OWPP are explained later. OWPP costs have been updated to introduce the influence of water depth on foundation costs of offshore wind turbines using data from EDMOnet-Bathymetry (2021) and EA Energy Analysis (2020).

The CorRES model is used to simulate wind and solar PV time series (Nuño et al., 2018; Koivisto et al., 2019a).

The national onshore wind potential for the scenarios (419 GW for the studied countries) is taken from Nordic Energy Research and International Energy Agency (2016). This limit is relatively low, and aims to represent low social acceptance towards onshore wind. Potentials for radially-connected OWPP are based on Nordic Energy Research and International Energy Agency (2016) and Koivisto and Gea-Bermúdez (2018), and large-scale solar PV national potentials are based on Ruiz et al. (2019).

More details about VRE modelling can be found in Gea-Bermúdez et al. (2021b).

Fuel price and CO_2 tax. Fuel prices and CO_2 tax development data towards 2050 comes from Nordic Energy Research and International Energy Agency (2016). The CO_2 tax is assumed to be 29.8, 90.4, 120.6 €$_{2016}$/ton in 2025, 2035, and 2045, respectively. No other tax is included.

Biofuel data is assumed to be carbon neutral and based on Flex4RES Project (2019).

Offshore grid modelling. The modelling and data of offshore power grids is built upon the work of Gea-Bermúdez et al. (2020) and Koivisto et al. (2019b). Introducing the possibility to build an offshore grid allows for multiple configurations of offshore infrastructure. In the offshore grid, apart from hub platforms, hub-connected wind farms, direct-current electricity interconnections, and hydrogen pipelines, investments in electrolysers, hydrogen storage, and fuel cells are also allowed. An illustration of the possible configuration of offshore infrastructure allowed in this paper is shown in Fig. 4.

Offshore regions, which are modelled as individual regions (bidding zones), can then be used to generate and transport electricity and/or hydrogen. Modelling offshore grids as individual bidding zones allows to capture possible congestion issues of the pipes and electrical interconnectors connected to the hubs. Along this paper, offshore regions are also interchangeably called hubs.

The size of the offshore hub platform located in a particular offshore region is defined with its nameplate electrical capacity ($cap_{y,r}^{platform}$), which is modelled with Eq. (2). The equation guarantees that, for each region (r), year (y), and time step (t), the total size of the hub platform in an offshore region is larger or equal to the electricity demand of the different electrolysers ($d_{y,t,r}^{electrolysers}$) located in the offshore region, and the sum of the electricity flows ($f_{y,t,r,r'}$) from the offshore region to other regions (r'), i.e. the total electricity export of the offshore region. This modelling reflects that the size of the offshore hub platform is constrained by the maximum electric power that is dealt with in the offshore region.

$$cap_{y,r}^{platform} \geq d_{y,t,r}^{electrolysers} + \sum_{r'} f_{y,t,r,r'} \tag{2}$$

Hub-connected OWPP are split into two categories: close-to-hub and far-from-hub. This is done to model the influence of the size of the OWPP connected to the hub with respect to transmission investment costs, transmission losses, and wake losses.

The reference size for a cluster of hub-connected OWPP, which is used to calculate the input parameters related to hub-connected OWPP, is 40 GW, with investments modelled in two steps: up to 20 GW, and above 20 GW. The capacity density of hub-connected OWPP is assumed to be 2.8 MW/km^2. Investments up to 20 GW are referred to as close-to-hub OWPP. Compared to close-to-hub OWPP, the capacity factors of far-from-hub OWPP are modelled as 19% lower by downscaling the time series of close-to-hub OWPP, to model the increasing wake losses as more wind turbines are installed (Volker et al., 2017). Wake

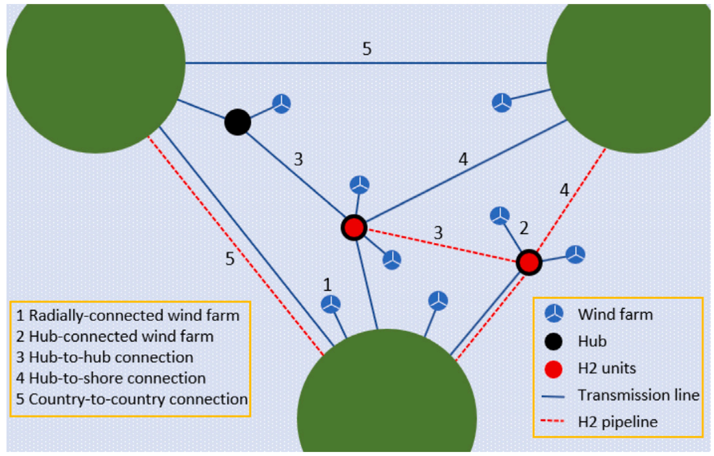

Fig. 4. Possible configurations of offshore infrastructure allowed in the optimisations. Apart from hub platforms, hub-connected wind farms, direct-current electricity interconnections, and hydrogen pipelines, investments in electrolysers, hydrogen storage, and fuel cells are also allowed in the hubs. "H2" stands for hydrogen.

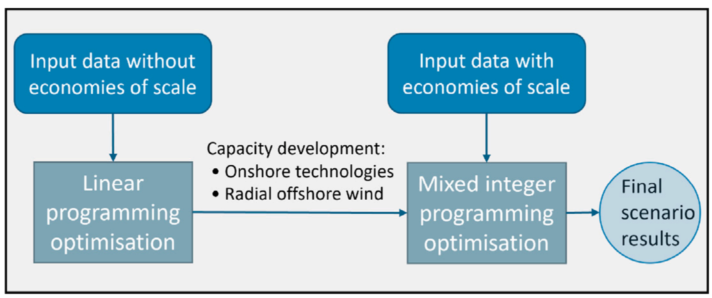

Fig. 5. Illustration of the optimisation approach used to obtain the scenarios of this paper.

losses increase continuously when more GW are installed; however, to keep the model tractable, two steps of hub-connected investments are modelled. With close-to-hub OWPP modelled to have wake loss of 15%, the total loss due to wakes is 23% when 40 GW are installed, matching the efficiency reported in Volker et al. (2017). Compared to close-to-hub OWPP, far-from-hub OWPP are modelled with 36% higher transmission cost and 50% higher transmission loss due to longer cables from OWPP to hub. The transmission loss is based on Negra et al. (2006).

2.2. Optimisation approach

Each scenario is obtained by performing two consecutive optimisations, using some of the results of the first optimisation as input to the second one. The first optimisation is done using linear programming (LP), whereas the second optimisation is performed with mixed integer programming (MIP). The optimisation approach used is illustrated in Fig. 5.

In the first optimisation, economies of scale are ignored when optimising the capacity development and operation of the energy system in each scenario, whereas in the second optimisation economies of scale in offshore grids are considered. This second optimisation, which is inspired by Gea-Bermúdez et al. (2020), avoids unrealistically small investments that can be a result from the linear programming optimisation, which cannot capture economies of scale.

In the second optimisation, investments, mothballing, and/or decommissioning of the different technologies are forced using the results of the first optimisation for almost all the technologies . The exceptions are hub platforms, hub-connected units (OWPP, hydrogen storage, fuel cells, and electrolysers), offshore transmission lines, and hydrogen pipes in the North Sea. Economies of scale are modelled in hubs, offshore transmission lines and hydrogen pipes in the North Sea (Table 2). All this is done to simplify the MIP optimisation, since the complexity of the model increases considerably when including economies of scale.

Both LP and MIP optimisations of each scenario are performed with limited intertemporal foresight (Gea-Bermúdez et al., 2020), following a two-year rolling horizon approach. This means that when planning 2025, 2035 is known, and so on.

Since the optimisations are complex, a reduced amount of time steps are used in the optimisation. These are selected using the approach described in Gea-Bermúdez et al. (2020). In this paper, we use 8 spread-over-the-year weeks, using Thursday, Friday, Saturday but with only 1 every 3 h. This results in 192 time snapshots per year. To test the adequacy of the time representation used in this paper, it would be convenient to run the model using more snapshots and/or different weather years. To test the adequacy of the time representation used in this paper we have simulated the full year operation of the system for scenario **BASE** (scenario explained in Section 3), adding exogenously the resulting installed capacities obtained after performing the optimisations shown in Fig. 5. We have also included additional expensive-to-operate back-up capacity to avoid infeasibilities. The use of this back-up capacity determines the accuracy of the time step selection. To speed-up the full year run, we have used 1 every 3 h. The key results of this run are discussed in Section 5.

Most of the time series are scaled based on the methodology described in Gea-Bermúdez et al. (2020), which uses probability integral transformations to keep annual statistical properties of the time series. Weather data from multiple years is used in the scaling to improve VRE representation in the limited time steps used. Details regarding the scaling approach and the use of different weather years for different technologies is provided below:

- For hydro reservoir seasonal inflow, we use data from several historical years to derive seasonal average energy inflows. Then,

Table 2
Economies of scale data assumptions for hub-connected electricity lines (Koivisto et al., 2019b) and hydrogen pipes (Danish Energy Agency, 2021) in the year 2035. Epsilon means a very small number. Fixed costs related to investments were only easily available for transmission lines, and for this reason, the costs for very small lines (0.1 MW_e) are so high. The costs include the additional equipment to operate pipes and electricity lines, except for protection costs in electricity lines. Costs per MW_e for hub-to-hub electricity lines are cheaper because converters are not needed since the hub and the lines are both assumed to be DC connected. In the linear programming optimisation, the costs used correspond to sizes of 1000 MW_{th} for hydrogen pipes, and 2000 MW_e for electricity lines. “H2” stands for hydrogen.

Hub-connected H_2 pipe		Hub-to-hub electricity line		Hub-to-shore electricity line	
Capacity (MW_{th})	Investment cost (€$_{2016}$/MW_{th}/m)	Capacity (MW_e)	Investment cost (€$_{2016}$/MW_e/m)	Capacity (MW_e)	Investment cost (€$_{2016}$/MW_e/m)
Epsilon	3.7	Epsilon	0	Epsilon	0
250	1.6	0.1	8157.3	0.1	14 094.7
500	0.7	300	2.7	700	2.0
1000	0.4	1000	1.4	1000	1.7
6000	0.2	2000	1.1	2000	1.4
50 000	0.2	50 000	1.1	50 000	1.4

we scale the inflow of the selected seasons used in the runs so it matches the average annual inflow.

- For wind and solar PV hourly generation, we apply the following approach:
  1. We calculate average annual capacity factors. We do so by calculating the average capacity factor of all the weather years for which we have data (40 years in this case).
  2. We select the time series of a given weather year (in this paper 2012).
  3. We extract 192 time snapshots of the time series mentioned in step 2.
  4. We apply probability integral transformation to scale the time series of step 3 so it matches the statistical properties of the time series of step 2.
  5. We scale the resulting time series of step 4 linearly so the average capacity factor of the time series matches the average annual capacity factor of step 1.
- For hydro run of river hourly generation, we use data from several historical years to derive average hourly generation time series. Then, on these time series, we apply steps 3 and 4 of the method described previously for solar PV and wind generation.
- For solar thermal heat generation, demand, and coefficient of performance of heat pumps, we only have data of one weather year, so we apply on these time series steps 3 and 4 of the method described previously for solar PV and wind generation.
- EV profiles are scaled using the average of three-consecutive-hour time steps for simplicity.

3. Scenarios

This paper aims at understanding the potential role of hydrogen generation towards 2050 in a European context. For this reason, several scenarios are designed (Table 3). Analysing different scenarios is of great importance to obtain meaningful insight considering the great uncertainty regarding key input data and modelling assumptions.

The scenarios of this paper are split into main scenarios, which primarily serve as story lines, and detailed sensitivity analysis, which allow to analyse in detail the impact on results of uncertainty in selected parameters.

3.1. Main scenarios

The central scenario of this paper is **BASE**. The rest of the scenarios are derived from this one. In the **BASE** scenario, all the technologies mentioned in Section 2 are included, except for offshore caverns for hydrogen storage.

To understand the influence on the energy system of forcing all hydrogen generation in the system to take place in offshore hubs, scenarios **OFFH2** and **OFFH2-HUB4H2** are created. Compared to scenario **BASE**, investments in electrolysers built onshore are forbidden in these two scenarios. Scenario **OFFH2-HUB4H2** restricts further the energy system with respect to scenario **OFFH2** by forbidding hub-to-shore electricity connection. This means that all the electricity generated in the hubs has to be used to generate hydrogen. The analysis of forbidding electrical connection of potential large-scale is of interest considering the potential technical issues related to the integration of large-scale hubs in the onshore network.

The **BASE** scenario assumes (1) that onshore electrolysers can be connected to district heating networks, (2) that it is not possible to use existing offshore caverns for storage of hydrogen, and (3) that a fast decrease of electrolyser costs will take place towards 2050. All these assumptions reduce the value of offshore hydrogen generation and are not free from controversy and/or uncertainty. Scenarios **NOEXCESSHEAT**, **OFFCAVERN**, and **ELYZERCOST** are designed to dig into these selected uncertainties to analyse to which degree offshore hydrogen generation is affected by them.

Scenario **NOEXCESSHEAT** includes the extreme case of assuming that the electrolysers built onshore cannot be built connected to district heating networks, leading to the waste of their excess heat.

Scenario **OFFCAVERN** allows for the possibility to invest in cheap offshore caverns to store hydrogen.

Scenario **ELYZERCOST** assumes a lower cost reduction rate towards 2050 of the specific investment cost of the electrolysers (Table 4).

The assumptions of scenarios **NOEXCESSHEAT**, **OFFCAVERN**, and **ELYZERCOST** are combined in scenario **ALL**, which aims to analyse the potential synergies between all these modifications.

In most of the scenarios, it is assumed that the required generation of synthetic fuels to decarbonise aviation and shipping sector takes place in each region. The generation of synthetic fuels for this purpose is modelled as hydrogen demand, as explained in Section 2. This means that each region needs to consume a given amount of hydrogen along the year to generate synthetic fuels to satisfy their own demand for these fuels. However, an alternative to this assumption could be to concentrate the generation of synthetic fuels in a few regions, and then export these fuels. With this idea in mind, in scenarios **BASE-H2REDIS** and **ALL-H2REDIS**, compared to **BASE** and **ALL** scenarios respectively, we allow for full redistribution of the hydrogen demand required to generate synthetic fuels. The costs, challenges, and required infrastructure associated to the trade of the resulting synthetic fuels is not modelled, and hence, ignored. Therefore, the results from these scenarios are likely to provide an optimistic view of how synthetic fuel generation could be.

3.2. Detailed sensitivity analysis

Using scenario **BASE** as reference, detailed sensitivity analysis is performed on two highly uncertain and potentially relevant parameters: offshore wind turbine costs and CO_2 tax development. Other uncertainties like onshore wind and solar PV technology development, electricity transmission lines costs, hydrogen pipeline costs, or hydrogen storage efficiency are also be of interest but are excluded to reduce the length of the paper.

Table 3
Scenarios run in this paper. "+" means feature included/allowed, and "−" means not included. "H2" stands for hydrogen, "REDIS" for redistribution, "OFF" for offshore, "HUB4H2" as hub for hydrogen, and "ELYZER" as electrolyser.

Scenario	Redistribution of H2 demand for transport across regions	Onshore electrolyser investments	Hub-to-shore electricity transmission investments	Excess heat utilisation from electrolysers	Offshore cavern investments	Lower cost reduction rate of electrolysers
BASE	−	+	−	−	−	−
BASE-H2REDIS	+	+	−	−	−	−
OFFH2	−	−	−	−	−	−
OFFH2-HUB4H2	−	−	+	−	−	−
NOEXCESSHEAT	−	+	−	+	−	−
OFFCAVERN	−	+	−	−	+	−
ELYZERCOST	−	+	−	−	−	+
ALL	−	+	−	+	+	+
ALL-H2REDIS	+	+	−	+	+	+

Table 4
Specific investment cost development for electrolysers installed onshore (M€$_{2016}$/MW) used in the scenarios of the paper. Electrolysers built offshore or connected to district heating networks have additional investment costs.

Year	Base cost reduction development	Lower cost reduction development
2025	0.65	0.65
2035	0.45	0.565
2045	0.3	0.48

For simplicity, the detailed sensitivity analysis are obtained without running the MIP optimisation mentioned in Section 2.2. Therefore, the results from these runs correspond to the LP optimisations. Not performing the MIP optimisations can have a high impact on the size of electricity transmission lines and hydrogen pipelines, but overall limited in the remaining variables.

The sensitivity analysis on offshore wind cost development is done on a exploratory basis by reducing offshore wind turbine capital expenditure and its corresponding fixed and variable operation and maintenance costs with 10% steps, i.e. 10%, 20%, 30%, …, 90%, 100%. The cost of the required electricity lines to connect the wind turbines to shore (or to the hubs in case of hub-connected wind farms) is not modified in these scenarios.

CO_2 tax development can influence considerably the yearly CO_2 emissions of the energy system, as well as the role of offshore hydrogen generation. To investigate the importance of the uncertainty of CO_2 tax development on the aforementioned factors, two additional sensitivity scenarios are run: **NoFurtherCO2TaxIncrease** and **DelayedCO2TaxIncrease**.

In these two scenarios, the expected increase of CO_2 tax is considerably reduced. In scenario **NoFurtherCO2TaxIncrease**, the CO_2 tax assumed for 2025 is assumed to remain constant along time, i.e. 29.8 €$_{2016}$/ton in all studied years. In scenario **DelayedCO2TaxIncrease**, the tax assumed for 2025 is kept until 2035, and the original tax of the year 2035 is delayed to 2045. These assumptions result in the following CO_2 tax scenario: 29.8, 29.8, 90.4 €$_{2016}$/ton in 2025, 2035, and 2045 respectively.

4. Results

This section summarises the results obtained from the optimisations. An overview of the main insights derived from the scenarios is presented in the following list:

- The energy system of the scenarios experiences strong electrification, VRE deployment, electricity grid reinforcement, and emission reduction towards 2050.
- VRE electricity generation increases its importance towards 2050.
- Generating hydrogen onshore is significantly cheaper than offshore.
- Generating hydrogen following the solar PV generation pattern in combination with extensive use of hydrogen storage is found cost-effective to satisfy the hydrogen demand because operational costs related to hydrogen generation play a larger role than capital expenditure costs.
- The direct integration of offshore wind energy via electrical interconnectors to the onshore system is key to minimise the costs and emissions of the energy system.
- Significant offshore wind cost reduction is required to improve the case for offshore hydrogen generation.
- The expected cost reduction of VRE technologies is likely to play a key role to reduce CO_2 emissions considerably towards 2050.

4.1. Towards an interconnected decarbonised energy system

The combination of technology development assumptions, the increasing CO_2 price assumption towards 2050, and the assumed transformation of the transport sector, lead to a massive electrification of the entire energy system towards 2050. The total electricity generation by 2045 is around 2.5 times the one in 2025 in the scenarios, with the role of wind and solar PV generation increasing towards 2050 (Fig. 6). By 2045 in scenario **BASE**, wind and solar PV generation accounts for 83% of the total electricity generation mix (50% wind and 33% solar PV), with offshore wind accounting for 62% of total wind generation, being 50% of it hub-connected.

Offshore wind increases its importance from 2035 onward, when the best onshore wind locations have already been used. In the scenarios where hydrogen generation is forced to take place offshore, the contribution of hub-connected wind is much higher.

The scenarios also show strong reinforcement of the electricity grid towards 2050, which contributes to the integration of VRE. The accumulated investments by 2045 in electricity interconnectors vary between 110–161 TW_ekm in the scenarios, which correspond to 2.4–3.5 times the exogenous interconnectors assumed to exist by 2025. Hub-connected electricity interconnectors by 2045 correspond to 43%–54% of the accumulated TW_ekm endogenous investments in the scenarios, except for scenario **OFFH2-HUB4H2**, where it only accounts for 2%. The investments in interconnectors in scenario **OFFH2-HUB4H2** correspond to hub-to-hub lines, since hub-to-shore investments were not allowed in this scenario.

The development of hydrogen pipelines is also remarkable. The accumulated investments by 2045 in hydrogen pipelines varies between 6–108 TW_{th}km in the scenarios. The variability in accumulated hydrogen pipeline investments is larger than the electrical interconnectors's one. Hub-connected hydrogen pipelines by 2045 correspond to 6%–52% of the accumulated TW_{th}km endogenous investments in the scenarios.

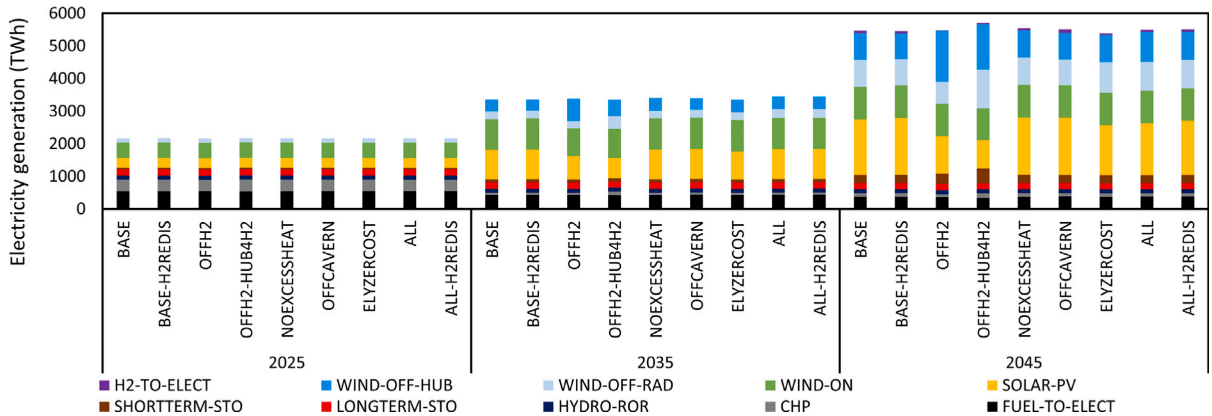

Fig. 6. Illustration of electricity generation increase towards 2050. Results shown for each modelled year, scenario and technology type. Long-term storage includes hydro reservoirs with hydro inflow, and short-term storage aggregates electric batteries (including flexible electric vehicles) and hydro pumping. "H2" stands for hydrogen, "ELECT" for electricity, "OFF" for offshore, "RAD" for radial, "ON" for onshore, "PV" for photovoltaic, "STO" for storage, "ROR" for run-of-river, and "CHP" for combined heat and power.

Table 5
Summary of key results for electricity and hydrogen for selected years. The year 2025 is not shown because there is no hydrogen demand in that year. "H2" stands for hydrogen.

Scenario	Electricity								H_2							
	Total demand (TWh_e)		Hub-connected electrolyser demand (TWh_e)		Hub-connected wind generation (TWh_e)		Hub-connected wind capacity (GW_e)		Total demand (TWh_{th})		Hub-connected electrolyser generation (TWh_{th})		Share of hub-connected electrolyser generation in total demand		Hub-connected electrolyser capacity (GW_{th})	
	2035	2045	2035	2045	2035	2045	2035	2045	2035	2045	2035	2045	2035	2045	2035	2045
BASE	3259	5220	0	30	373	827	82	180	333	1054	0	21	0%	2%	0	10
BASE-H2REDIS	3258	5209	0	13	346	790	77	173	332	1049	0	9	0%	1%	0	4
OFFH2	3277	5171	500	1308	680	1567	147	338	336	918	336	918	100%	100%	63	249
OFFH2-HUB4H2	3251	5254	502	1379	508	1393	111	288	338	962	338	962	100%	100%	64	185
NOEXCESSHEAT	3307	5294	74	156	404	831	89	180	334	1043	49	109	15%	10%	9	36
OFFCAVERN	3295	5256	10	149	353	816	77	174	336	1096	7	105	2%	10%	2	64
ELYZERCOST	3250	5140	0	35	384	837	85	183	333	976	0	25	0%	3%	0	9
ALL	3346	5246	75	366	388	920	84	197	335	1001	51	257	15%	26%	13	84
ALL-H2REDIS	3342	5257	97	325	381	865	82	186	335	1009	65	228	20%	23%	21	80

4.2. Hydrogen generation is preferred onshore over offshore

The contribution of offshore hydrogen generation in the **BASE** scenario towards 2050 is very limited: 0% in 2035 and 2% in 2045 (Table 5).

Not being able to utilise the excess heat from electrolysers (scenario **NOEXCESSHEAT**) or introducing the possibility to use offshore caverns as hydrogen storage (scenario **OFFCAVERN**) significantly impacts the share of offshore hydrogen generation, reaching in both scenarios 10% of the total hydrogen generation by 2045. Despite having a relatively high impact on the share of offshore hydrogen generation, their impact in terms of average system costs is relatively lower. Compared to scenario **BASE**, scenario **NOEXCESSHEAT** leads to average system costs increasing 0.9 b€$_{2016}$/year (0.5%), and scenario **OFFCAVERN** leads to average system costs decreasing 1.0 b€$_{2016}$/year (−0.6%).

Decreasing the cost reduction rate of electrolysers (scenario **ELYZERCOST**) has a much lower impact on offshore hydrogen generation, reaching 3% of total hydrogen generation by 2045. This suggests that the costs related to the generation of electricity to feed the electrolysers are likely to be more important than the capital expenditure of the electrolysers.

The combination of all these changes in scenario **ALL** leads to the highest contribution of offshore hydrogen generation by 2045, i.e. 26%. These results show that onshore hydrogen generation is, overall, preferred over offshore generation from a socio-economic point of view.

4.3. Solar PV generation patterns drives hydrogen generation both offshore and onshore

Generating hydrogen in the electrolysers following the solar PV generation pattern, combined with hydrogen storage, is the most cost-effective way to satisfy hydrogen demand. This does not mean that solar PV is the only source of energy used to feed the electrolysers, since the wind generation in the system in the hours of the middle of the day is far from being negligible. In scenario **BASE** in 2045, the total generation of wind in the modelled hours of the middle of the day (H10, H13, and H16) is 51% of the total solar PV generation.

The solar PV generation pattern influences the generation of hydrogen everywhere, especially in countries with relatively high solar PV generation. Its influence reaches locations without solar PV generation (offshore hubs and the regions in Norway, Sweden, and Finland) because the system becomes highly interconnected electrically, especially by 2045. The solar PV generation pattern leads to low electricity prices in all the regions that are electrically interconnected, favouring onshore hydrogen generation since it is onshore where the exogenous hydrogen demand is assumed to be located, reducing the need for hydrogen transport. Overall, the influence of the solar PV generation pattern is higher everywhere in 2045 than in 2035 due to higher solar PV penetration and higher capacity of electrical interconnectors, which lead to higher volumes of cheap electricity available in the middle of the day.

Solar PV generation influences hydrogen generation in the hubs when connected electrically to shore (Fig. 7). The solar PV generation pattern leads to less need for exporting electricity from the hubs in the hours of the middle of the day, reducing the net export from the hubs in these hours. The electricity that is not exported in these hours is then used to generate hydrogen, or curtailed, as illustrated in the hourly energy balance of electricity of the so-called in this paper central Norwegian hub in 2045 of Fig. 8. When the hubs are not allowed to be connected electrically to shore (scenario **OFFH2-HUB4H2**), then the generation of hydrogen follows the wind generation pattern instead of the solar one (grey line in Fig. 7).

4.4. Hydrogen storage is key to integrate solar PV generation

The rate of use of electrolysers and hydrogen storage of the different scenarios (Table 6) is highly affected by the influence of solar PV

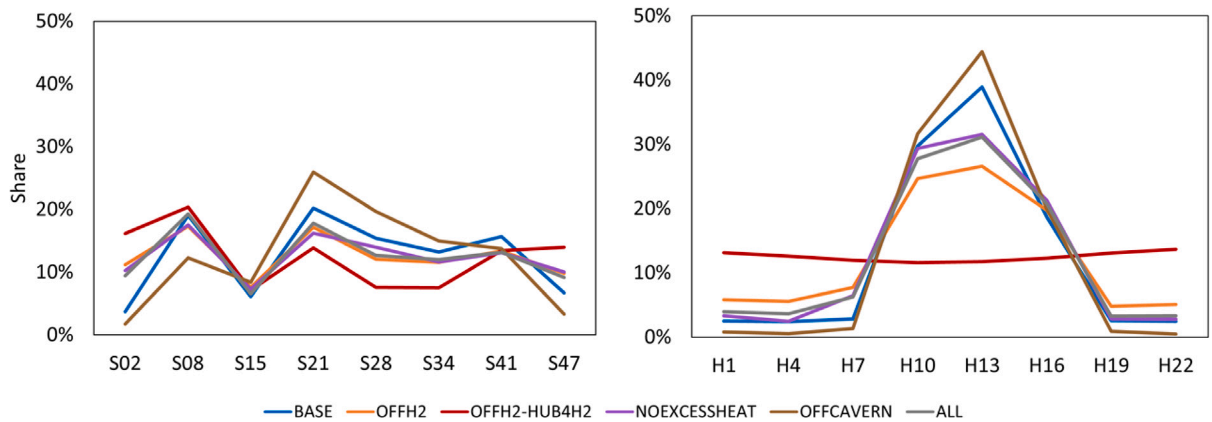

Fig. 7. Seasonality of electricity demand related to offshore hydrogen generation in the year 2045 for selected scenarios. The share of total electricity demand for hydrogen generation in the hubs per modelled season (week) of the year is shown in the left figure, and the share per modelled hour of the day is shown in the right figure. "S02" means week 2 of the year, "S08" week 8, etc. "H1" means hour 1 of the day, "H4" hour 4, etc.

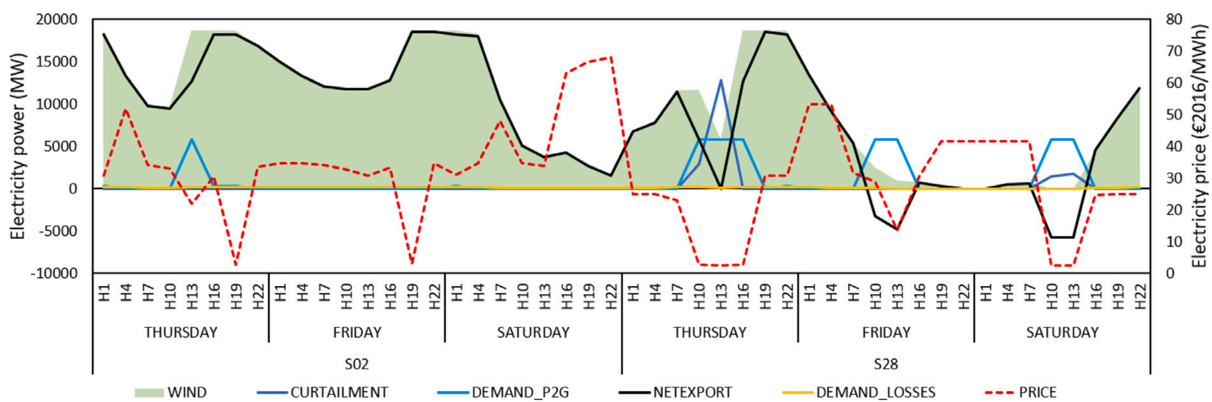

Fig. 8. Hourly electricity balance at the so-called in this paper central Norwegian hub in 2045 in scenario **BASE** for selected modelled seasons (weeks). Wind generation is presented with coloured area, whereas the rest of the variables are presented as unstacked lines. The electricity price (red-dotted line) is linked to the vertical *y*-axis on the right, whereas the rest of the variables are linked to the vertical *y*-axis on the left. DEMAND_P2G corresponds to the electrolyser electricity consumption to generate hydrogen. "S02" means week 2 of the year, and "S28" week 28. "H1" means hour 1 of the day, "H4" hour 4, etc. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

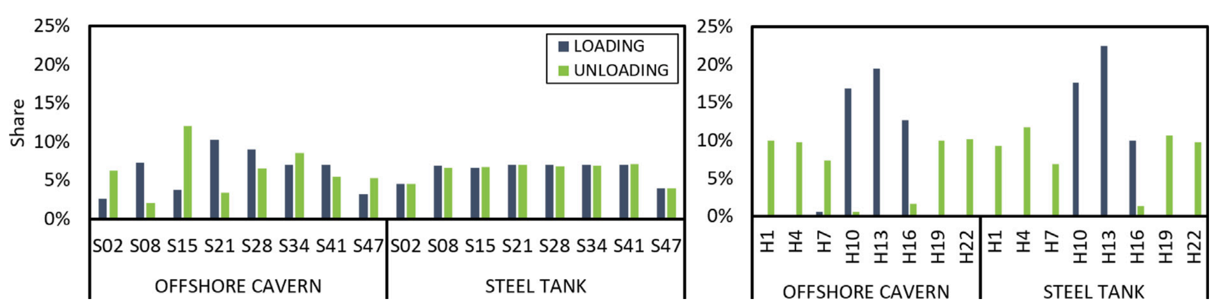

Fig. 9. Use pattern of hydrogen storage loading and unloading in 2045 in scenario **ALL** per storage type. The share of use per modelled season (week) is shown in the left figure, and the share of use per hour of the day is shown in the right figure. "S02" means week 2 of the year, "S08" week 8, etc. "H1" means hour 1 of the day, "H4" hour 4, etc.

generation on hydrogen generation. In the scenarios where the hubs are allowed to be electrically connected to shore, hydrogen generation follows the solar PV generation pattern. This requires extensive use of hydrogen storage to distribute the generated hydrogen, since the hydrogen demand is modelled rather inflexible. Even in the scenarios with offshore caverns allowed, the loading of hydrogen storage, regardless of its type, takes place in the middle of the day, and the unloading, in the rest of the hours (Fig. 9).

Compared to 2035, by 2045 the full load hours of electrolysers decrease considerably in almost all the scenarios both onshore and offshore. By 2045, electrolysers tend to operate mostly following the solar PV generation pattern, which is the reason behind this decrease in full load hours. It is found cost-effective to operate the electrolysers with lower full load hours because (1) there are higher volumes of cheap electricity available in the middle of the day by 2045 than by 2035, and (2) because of cheaper electrolysers by 2045 than by 2035. The fact that the difference between the full load hours in scenario **ELYZERCOST** and scenario **BASE** is lower in 2045 than in 2035 suggests that the influence of the cost of operation (first reason) plays a bigger role than the cost of capital (second reason).

The rate of use of hydrogen storage is highly influenced by the scenario, year, and location. In the scenarios where the solar PV generation pattern has a significant influence on hydrogen generation and the possibility to invest in offshore caverns is not allowed, the equivalent

Table 6
Full load hours of electrolysers and hydrogen storage equivalent full cycles per location (onshore, offshore), scenario, and year. The values shown correspond to weighted averages. "H2" stands for hydrogen.

Location	Scenario	Full load hours of electrolysers		H2 storage equivalent full cycles	
		2035	2045	2035	2045
	BASE	4027	2730	298	262
	BASE-H2REDIS	3895	2697	286	261
	OFFH2				
	OFFH2-HUB4H2			52	80
Onshore	NOEXCESSHEAT	3884	2677	288	262
	OFFCAVERN	3218	2719		318
	ELYZERCOST	4640	2957	322	265
	ALL	3417	2813		322
	ALL-H2REDIS	3412	2813		330
	BASE		2239	158	248
	BASE-H2REDIS	3810	2308		256
	OFFH2	5367	3687	287	232
	OFFH2-HUB4H2	5290	5207	55	79
Offshore	NOEXCESSHEAT	5733	3052	234	266
	OFFCAVERN	2650	1653	11	9
	ELYZERCOST		2643		264
	ALL	3826	3075	10	10
	ALL-H2REDIS	3167	2860	10	8

full cycles of storage tend to be quite high, especially onshore. Overall, the high number of cycles in these scenarios suggests that steel-tank hydrogen storage (the only type allowed in these scenarios) follows daily cycles both onshore and offshore. Compared to the previously mentioned scenarios, when offshore caverns are allowed, hydrogen storage equivalent full cycles decrease offshore, and increase onshore, both significantly. The use of offshore-cavern hydrogen storage as seasonal storage (Fig. 9) is likely to reduce the economic value of onshore steel-tank hydrogen storage to provide seasonal arbitrage, leading to designing onshore hydrogen storage for the main purpose of daily arbitrage. In scenario **OFFH2-HUB4H2** both full load hours of electrolysers and hydrogen storage equivalent full cycles remain in 2035 and 2045 similar due to the hubs not being connected electrically to shore, and hence, not being influenced by the solar PV generation pattern.

Hydrogen storage also plays a role in the need for hydrogen pipeline capacity, by reducing the peak of the transported hydrogen flows, and leading to lower invested pipeline capacity. This purpose is illustrated in Figs. 10 and 11. Fig. 10 shows how the hubs have, in general, a much higher electrolyser capacity than hydrogen transmission pipeline capacity, which becomes feasible due to hydrogen storage. Fig. 11 shows how electrolyser capacity in the hub is higher than the capacity of the hydrogen pipes on the map, and the impact of considering economies of scale with mixed integer programming, which eliminates numerous small pipes and increases the size of a few ones. The diurnal distribution of hydrogen and the congestion issue is illustrated in the hourly energy balance of hydrogen of the so-called, in this paper, central Norwegian hub in Fig. 12.

The contribution of hydrogen storage to the total generation of hydrogen is so important that it accounts for overall 50% of the hydrogen generated with electrolysers in most of the scenarios (Fig. 13). The share of storage usage decreases when hydrogen is forced to be generated offshore because the solar PV generation pattern has a lower influence on hydrogen generation in these scenarios. The large share of the use of hydrogen storage is remarkable compared to the share of electricity storage, which plays a limited role in most of the scenarios (5% in scenario **BASE**, with around 87% of it provided by flexible electric vehicles). The contribution of heat storage is also relatively large and similar in all the scenarios (around 14% on average by 2045), although lower compared to hydrogen storage. In the scenarios where offshore caverns are allowed, more than 50% of the hydrogen storage generation takes place in them.

The alternative solution of having a more constant generation of hydrogen in the electrolysers that would require a more stable electricity input that could come from the combination of wind generation and electricity batteries, i.e. a solution with less need for hydrogen storage, is not found as the least-cost solution by the model. The reason for this result is the combination of technology data assumptions used. Batteries are much more expensive (Table 1) and have a lower lifetime than hydrogen storage, and solar PV becomes significantly cheaper towards 2050.

As shown previously, assuming more expensive electrolysers towards 2050 in scenario **ELYZERCOST** does not lead to significant changes compared to the **BASE** scenario.

4.5. Offshore hubs are mainly used to deliver electricity to shore

Except for the scenarios where offshore hydrogen generation is forced, the total generation and capacity from hub-connected wind farms is rather similar (Fig. 6 and Table 5), being the main purpose of this electricity generation to be sent and consumed onshore, and not to generate hydrogen offshore.

In the scenarios where hydrogen is not forced to be generated offshore, the installed interconnection capacity of each hub is, generally, at least of the size of the installed wind capacity, whereas the electrolyser one is generally lower than the wind capacity in the scenarios (Fig. 14). This implies that the hubs are designed to be able to export their maximum wind generation, and not with an electrolyser capacity that would allow them to consume the maximum wind generation in each hub.

Even though the power curtailment can be as high as the maximum electricity generation in the hub, it is preferred to curtail this excess energy than investing in higher electrolyser capacity to be able to absorb it. Overall, and as long as the hubs are allowed to be electrically connected to shore, the higher the importance of offshore hydrogen generation, the higher the ratio of electrolyser capacity and wind capacity (Fig. 14). In the scenario where all wind generation in the hubs can only be used to generate hydrogen (scenario **OFFH2-HUB4H2**), the ratio of electrolyser capacity and wind capacity is on average 0.92, which suggests that the electrolyser capacity of each hub is roughly in line with the installed wind capacity of the hub.

Most of the electricity demand consumed to generate hydrogen in the hubs, which follows the solar PV generation pattern in most of the scenarios, is coming from the electricity wind generation of the same

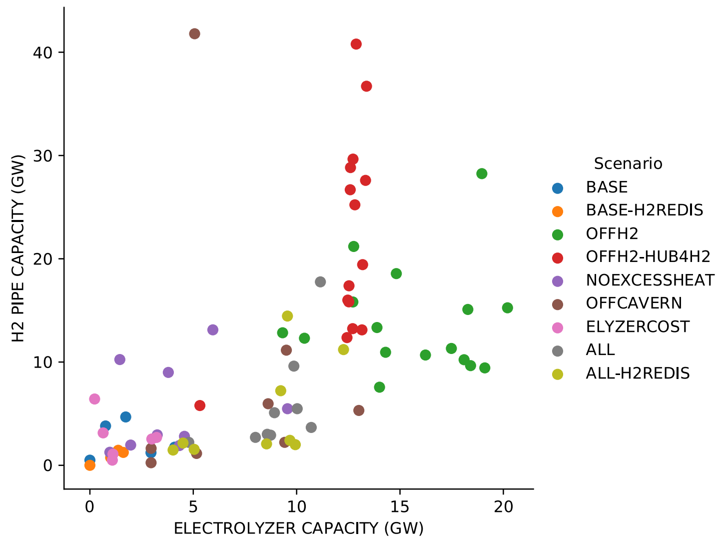

Fig. 10. Installed electrolyser capacity versus aggregated hydrogen pipe capacity in each hub 2045 per scenario. Aggregated hydrogen pipe capacity is calculated summing the capacity of all the pipes connected to each hub. Each dot corresponds to one hub. Units correspond to thermal GW.

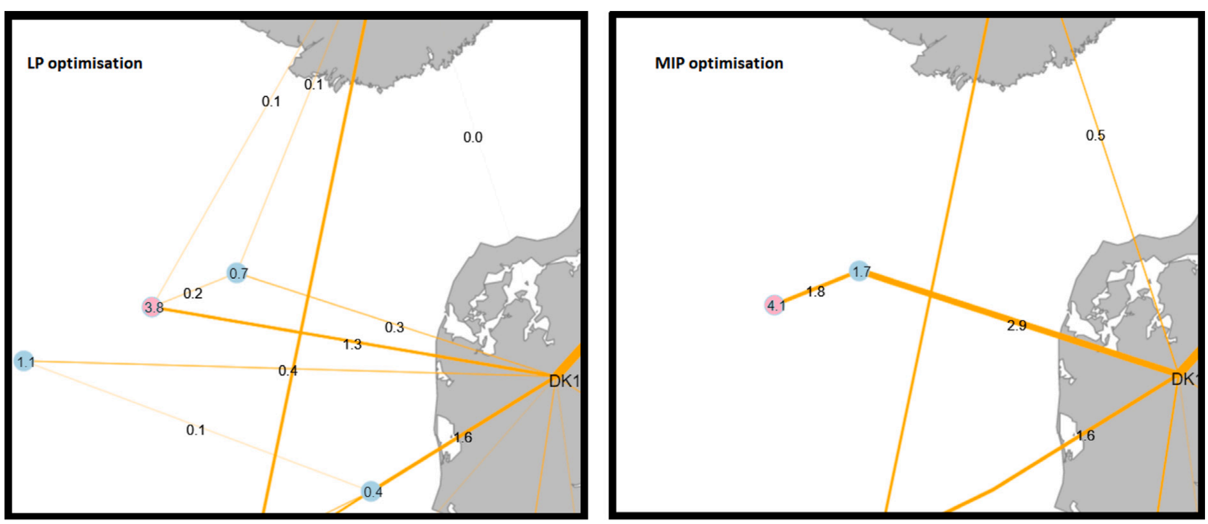

Fig. 11. Influence of linear programming (LP) (left figure) and mixed integer programming (MIP) (right figure) on offshore hydrogen grid in 2045 in scenario **BASE**. Hubs correspond to the blue dots (pink for the so-called in this paper central Norwegian hub) and hydrogen pipes to the yellow lines. Only the hubs with electrolyser capacity investments are shown. The electrolyser capacity in the hubs is the number inside the blue dots, and the number on top of the yellow lines is the hydrogen pipe capacity. All numbers are in GW and have been rounded to the first decimal. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

hub (Fig. 15). The graph also shows that, in general, the lower the electrolyser demand in each hub, the higher the share of electricity that is generated by wind in the same offshore region, which is an intuitive result.

4.6. Forcing hydrogen generation offshore leads to higher costs and higher emissions

The restriction of requiring all hydrogen generation to take place offshore leads to higher costs (Fig. 16). The additional cost of this restriction increases towards 2050, following the increasing need for hydrogen in the system. By 2045 and compared to **BASE**, the additional cost of the system in scenarios **OFFH2** and **OFFH2-HUB4H2** is 9.4 and 27.8 b€$_{2016}$/year, respectively (4.4% and 12.8% of the costs by 2045 in scenario **BASE**). This suggests that forcing hydrogen generation offshore has around 3 times higher impact by 2045 when the electrical connection to shore is not allowed. The cost increase of forcing hydrogen generation to take place offshore is mainly related to the larger costs of hub-connected wind farms compared to solar PV.

In all the scenarios the CO_2 emissions decrease greatly towards 2050, being almost negligible by 2045, which is a consequence of the high CO_2 price assumed. Forcing hydrogen generation to take place offshore leads to higher emissions in the studied period though. Compared to the **BASE** scenario, in the studied 30 year period from 2020–2050 the additional CO_2 emissions in scenarios **OFFH2** and **OFFH2-HUB4H2** are 77 Mtons and 255 Mtons, respectively.

4.7. Significant offshore wind turbine cost could be a game changer

The detailed sensitivity analysis on offshore wind turbine costs shows that significant offshore wind cost reduction is required to improve the case for offshore hydrogen generation. As shown in Fig. 17, up to 20% additional offshore wind cost decrease (compared to **BASE**) have limited impact on the results. On the other hand, to achieve an offshore hydrogen generation share of 20%, costs need to decrease around 40% by 2035, and 50% by 2045. Even in the case where the offshore wind turbine has no cost, the share of offshore hydrogen generation only reaches around 80% in both years. This result is probably related

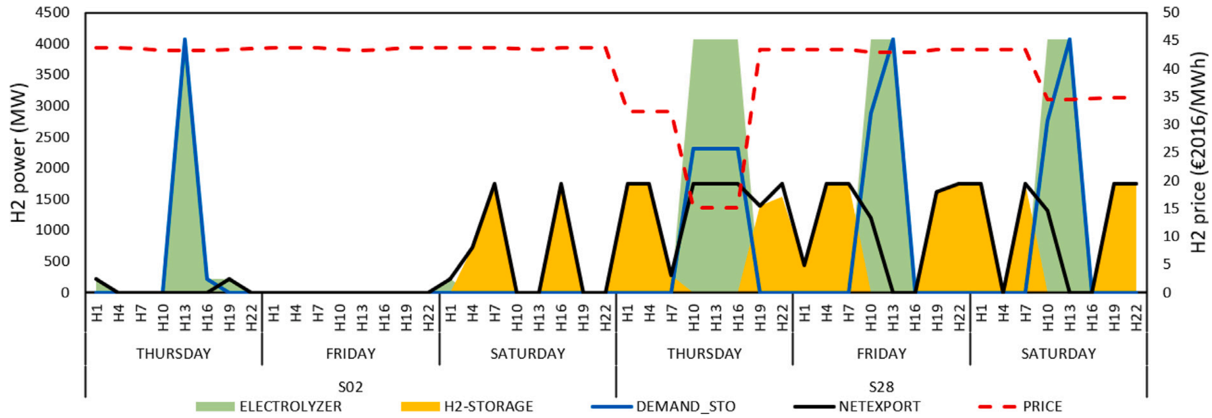

Fig. 12. Hourly hydrogen balance at the so-called in this paper central Norwegian hub in 2045 in scenario **BASE** for selected modelled seasons (weeks). Electrolyser and hydrogen generation is presented with coloured stacked areas, whereas the rest of the variables are presented as unstacked lines. The hydrogen price (red-dotted line) is linked to the vertical *y*-axis on the right, whereas the rest of the variables are linked to the vertical *y*-axis on the left. "H2" stands for hydrogen. DEMAND_STO corresponds to the loading of the hydrogen storage. "S02" means week 2 of the year, "S08" week 8, etc. "H1" means hour 1 of the day, "H4" hour 4, etc. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

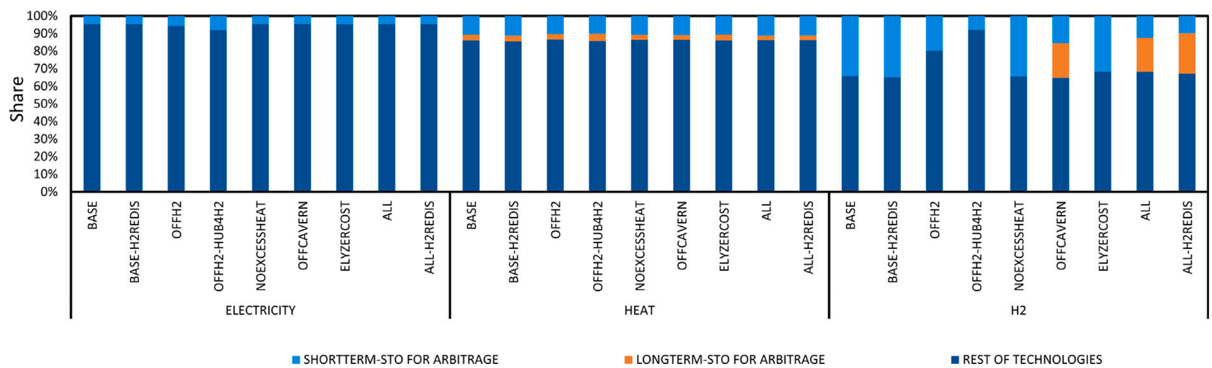

Fig. 13. Share of storage use for price arbitrage in total generation per scenario and commodity in 2045. Hydro reservoir without pumping is not considered storage for price arbitrage, since it can only discharge energy. "H2" stands for hydrogen.

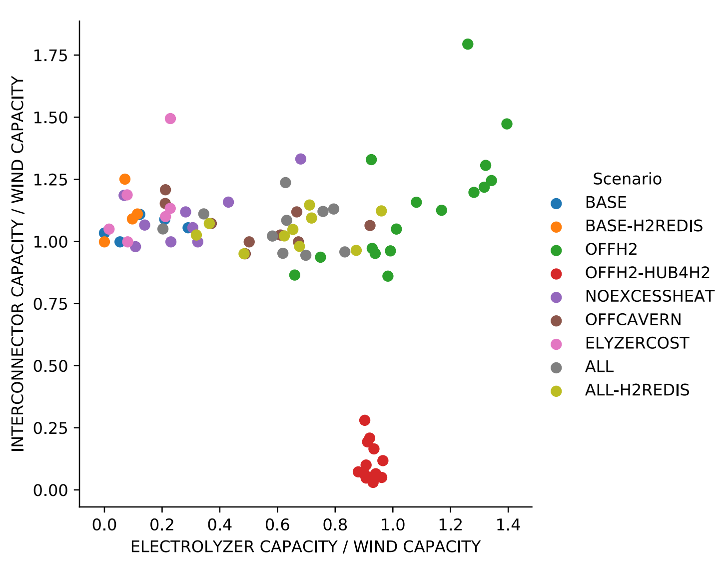

Fig. 14. Ratio of aggregated electricity interconnector capacity and installed wind capacity in each hub versus ratio of installed electrolyser electricity input capacity and wind capacity in each hub per scenario in 2045. Each dot corresponds to a hub. The aggregated electricity interconnector capacity of each hub is calculated summing all the interconnectors connected to that hub.

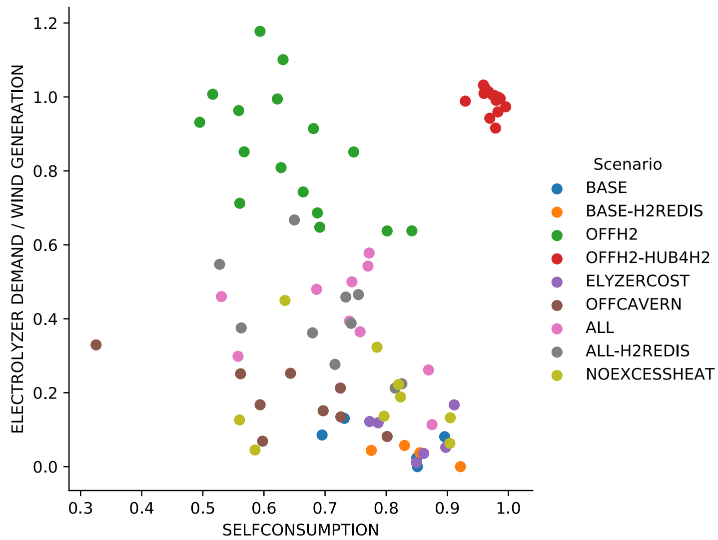

Fig. 15. Ratio of electricity demand in the electrolyser in the hub and the wind generation in the same hub versus selfconsumption in each hub per scenario in 2045. Selfconsumption is defined as the ratio between the electricity demand in the electrolyser that is covered with wind generation in the same hub, and the total electricity demand in the electrolysers of that hub. Data shown only for hubs with electrolyser demand in 2045. Each dot corresponds to one hub.

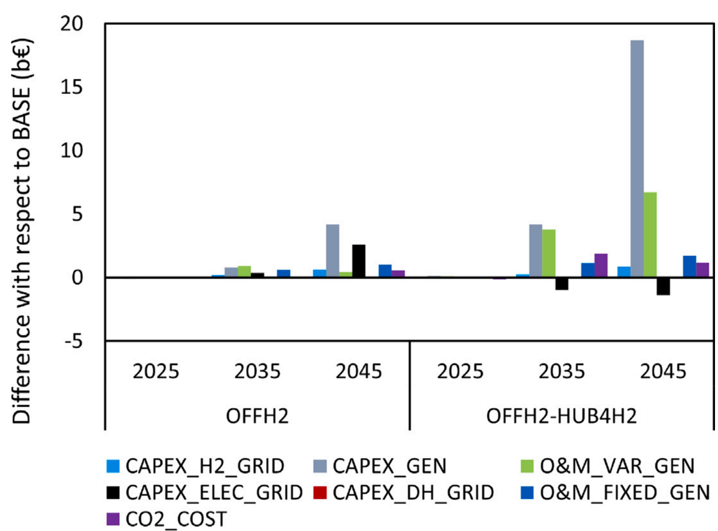

Fig. 16. Difference between energy system costs of selected scenarios and scenario **BASE** per year. GEN stands for generation and storage, DH for district heating, VAR for variable, and ELEC for electricity.

to the non-negligible cost of transporting hydrogen to shore, which is where the demand is assumed to take place.

4.8. Reduced CO_2 tax increase does not influence significantly offshore hydrogen generation

The sensitivity analysis on CO_2 tax development shows limited impact on the share of offshore hydrogen generation. The share of offshore hydrogen generation by 2045 in scenario **DelayedCO2TaxIncrease** is 2.2%, in scenario **NoFurtherCO2TaxIncrease** 2.4%, whereas in scenario **BASE** it is 2.1%. These results suggest that uncertainty in CO_2 tax development is likely to have a limited impact on the role of offshore hydrogen generation.

Despite the limited impact on offshore hydrogen generation, a lower increase of CO_2 tax development towards 2050 results in higher CO_2 emissions. Compared to the **BASE** scenario, in the studied 30 year period from 2020–2050 the additional CO_2 emissions in scenarios **DelayedCO2TaxIncrease** and **NoFurtherCO2TaxIncrease** are 7509 Mtons and 12128 Mtons, respectively.

Despite assuming a less aggressive CO_2 tax development towards 2050, scenario **NoFurtherCO2TaxIncrease** also leads to a significant CO_2 reduction towards 2050. By 2045, compared to the **BASE** scenario, the emissions by 2045 are only 163 Mtons/year higher. These results suggest that, even in a policy scenario without significant CO_2 tax increase, the expected cost reduction of VRE technologies is likely to play a key role to reduce CO_2 emissions considerably towards 2050.

5. Discussion

Our optimisation results suggest that offshore hydrogen generation should play a limited role in the future integrated energy system and that offshore wind should mostly be used to deliver its electricity generation onshore. This is because the generation of hydrogen follows the solar PV generation pattern and combined with hydrogen storage is found cost-effective to satisfy the hydrogen demand.

The costs related to the generation of electricity required to generate hydrogen with the electrolysers play a key role, larger than, for instance, the capital expenditure of the electrolysers. If the capital

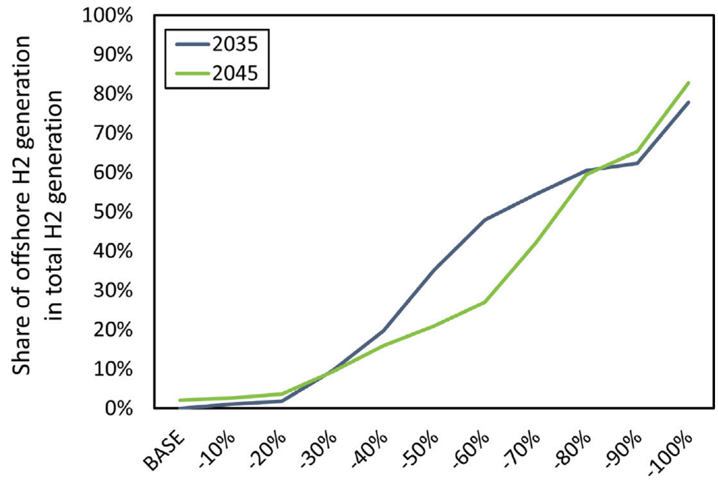

Fig. 17. Share of offshore hydrogen generation in total hydrogen generation pear year and scenario. The year 2025 is not shown because there is no hydrogen generation in this year.

expenditure of the electrolysers had been more decisive, offshore hydrogen generation would have likely become more important because of the higher capacity factor of offshore wind with respect to solar PV. These results are diverging from Franco et al. (2021), who found that inland generation of hydrogen would only be promising for wind farms close to shore and that offshore hydrogen generation transported via hydrogen pipeline was generally preferred. The cost of hydrogen piping is likely to be cheaper than electric sea cables when going far offshore (see Table 2), but just focusing on costs and neglecting the value creation aspect can lead to sub-optimal solutions for the overall integrated energy system. Therefore, using a holistic approach where the synergies and time-dependent value of the technologies in different regions is captured, rather than using for instance techno-economic feasibility analysis based on levelised cost of hydrogen, seems to be key to derive meaningful conclusions on how offshore wind energy should be used and the role of the different players of the energy system.

There are several uncertainties related to our results. First, we expect that actual cost associated with offshore hydrogen generation are likely to be higher than assumed in this paper, as building and maintaining electrolysers offshore will have additional costs as compared to onshore — which we could not consider in the modelling due to lack of reliable data. Hence, we assess that our resulting offshore hydrogen shares may even be optimistic.

Second, we did not include the option to repurpose existing infrastructure for offshore hydrogen transportation. This could increase the value of offshore hydrogen generation, since adapting existing infrastructure is likely to have lower costs than building new pipes. Nevertheless, this argument is also valid for onshore gas infrastructure.

Third, the space requirement for offshore electrolyser capacity could also be an issue. In the scenarios, the installed electricity capacity of electrolysers in the hubs varies from 6–357 GW. Assuming that each electrolyser requires 8 m^2/MW_e (Danish Energy Agency, 2021) leads to requiring a surface of 0.05–2.86 km^2 just for electrolyser equipment. This size is 0.1–6.2 times the size of the energy island that Denmark intends to build. This may become both a cost and a logistical issue. Also, the increased space requirement might be in competition with other sectors, like fishing. This issue could be addressed by adding constraints in the model that limit the total capacity installed in the hubs. Its influence could be investigated in future research.

Other important aspects like the availability of hydro resources onshore have not been included in the modelling. Assuming onshore water scarcity could potentially require using sea water also for onshore electrolysers (when close to shore), and lead to increased cost due to desalination and water transport. This would improve the case for offshore hydrogen generation.

The sensitivity analyses performed in this paper have addressed important data uncertainties, although uncertainties related to onshore wind and solar PV technology development could also be worth investigating in future research. However, modelling assumptions like assuming perfect competition, assuming economic rationality, using linear power and gas flows, using limited time step representation, or using a modelling approach for EVs that can limit their flexibility, could also have influenced the results.

When simulating the dispatch of the entire year (simulation explained Section 2.2) in scenario **BASE**, the share of back-up electricity generation with respect to the total generation is 0% for 2025, 0.01% for 2035, and 0.05% for 2045. In the few regions with back-up generation, the ratio between the maximum regional hourly back-up electricity generation and the regional peak load in the different years is 0% in the year 2025, and varies between 5%–20% for 2035, and 15%–60% for 2045. These results suggest that energy-wise the time resolution used is relatively accurate, whereas capacity-wise, it is less accurate. Using different weather years could have influenced these results, which highlights the importance of accounting for different weather years in systems with high shares of VRE generation.

To investigate the influence of ignoring the link of EV storage levels across seasons (modelling assumption explained in the transport sector part of Section 2.1.2), we have simulated scenario **BASE** assuming that the storage levels are linked across seasons. The impact of this modelling assumption is highly dependent on the year. In terms of system costs, linking seasons leads to higher costs (the increase ranges between 0.1%-4.7%/year). These results suggest that ignoring the link between seasons may have underestimated system costs.

Behavioural and social aspects, which can considerably influence the acceptability of e.g. transmission reinforcement, could be accounted in future research.

Offshore hydrogen generation has recently come into strong focus in the European energy debate, with many proponents of the option. While our paper finds that offshore hydrogen generation would lead to increased socio-economic costs towards 2050, there are many possible reasons for why offshore hydrogen generation could still be a beneficial option to pursue. Discussing them all in detail would go beyond the scope of this paper, but we would like to emphasise a few factors that may need to be weighed against each other for an informed decision.

First, by placing hydrogen generation offshore, substantial reinforcement of the onshore electricity grid could be avoided, which can be hindered and slowed down by social acceptance issues (Battaglini et al., 2012). Modelling the required onshore electricity grid reinforcement with higher accuracy is not an easy task without increasing the spatial resolution of the electricity network, which can make the problem intractable.

Second, market arrangements for offshore electricity generation, tariff and price structures, cross-border interconnection and allocation of congestion rents all have an important role in setting investment incentives, and may make offshore hydrogen generation attractive for some stakeholders.

Third, there may be other value elements and business options, both onshore and offshore, that we simply cannot capture in energy system modelling and that are likely to play a large role in decision making. These could e.g. span from new offshore fuel demand options, over logistical and planning constraints, to spatial and justice considerations.

6. Conclusions and policy implications

By performing energy system optimisation from a socio-economic point of view, this paper has investigated the role of offshore hydrogen generation in the energy system towards 2050. We have used the North Sea region as a showcase, but the general insights are also valid for other regions with large wind and solar PV potentials.

In our scenarios, the most cost-effective solution to cover the expected increasing hydrogen demand towards 2050 is when the generation of hydrogen follows a solar PV generation pattern, combined with the extensive use of hydrogen storage, in a highly integrated energy system with substantial electrical interconnection capacities between regions. The costs associated to the generation of electricity to feed the electrolysers play a key factor in the optimisation. The capital expenditure for the electrolysers are of less importance. As a result, our analysis suggests that it is socio-economically beneficial for most hydrogen generation towards 2050 to take place onshore, where its full flexibility can be utilised better, and offshore hydrogen generation to have a limited role.

For the same reasons, we find that offshore wind generation has higher socio-economic value when sent to shore. Even the (limited) hydrogen generation built offshore in our scenarios follows a solar PV generation pattern as soon as offshore hubs are electrically connected to shore.

Forcing hydrogen generation offshore could lead to a considerable total energy system cost increase (9–28 b€$_{2016}$/year by 2045), and to slightly higher emissions (77–255 Mtons from 2020 to 2050). This is under the assumption that excess heat of onshore electrolysers can be utilised in district heating networks. Restricting this option and/or increasing the possibility to use offshore caverns as hydrogen storage can increase the role of offshore hydrogen generation significantly.

Overall, we conclude that the societal pursuit of substantial offshore hydrogen generation should be supported by other reasons than socio-economic system cost optimisation alone. To us currently unknown technical progress or arising cost and value benefits could, of course, change this conclusion. Other reasons could include logistical, planning, environmental, and social constraints affecting both the hydrogen generation itself or other areas of the integrated system (such as limitations to inter-regional grid expansion).

In any case, a no-regret option in the transition of the European energy system towards sustainability is to enable and promote the direct integration of offshore wind energy via electrical connections to the onshore system, where a large amount of hydrogen generation is expected to be deployed in any case. These electrical connections are likely to be even more important in the case of energy islands.

The following policy implications arise from our analysis:

- Substantial hydrogen generation is expected in a sustainable integrated energy system. Political effort is required to incentivise investment in hydrogen generation facilities — be it onshore or offshore.
- The major argument for policy intervention to incentivise offshore hydrogen generation is most likely not socio-economic system cost optimisation. Other arguments around planning, environmental and social aspects may prevail.
- If offshore hydrogen generation is pursued, a full electric connection to shore is still socio-economically desirable, so that the full economic value of both offshore wind and hydrogen can be captured in the integrated energy system.
- The future energy system with substantial offshore wind and hydrogen generation will depend even more on international collaboration. Action is needed on the expansion of interconnectors across the whole of Europe and on the coordinated expansion of joint offshore infrastructure.
- The full integration of hydrogen generation into the energy system implies that it can be complex to determine the source of electricity used for hydrogen generation. In our scenarios we determine the overall balance of electricity used for hydrogen generation and consider it ‘green’ when using offshore wind and solar PV as input, no matter where the hydrogen generation facility is placed. In reality, legal and regulatory definitions are posing a barrier to this.

Hydrogen is likely to play a large role in the future European energy system. We are at a crossroads today to set the path for how the future system will look like. Our results are a contribution to the discussion about where to place hydrogen generation and we found indications that a pure socio-economic perspective suggests to place most of it onshore — but certainly this discussion is not finally solved and further analysis, especially on the non-economic issues, will shed even more light on the debate.

CRediT authorship contribution statement

Juan Gea-Bermúdez: Conceptualization, Methodology, Software, Resources, Data curation, Writing – original draft, Writing – review & editing, Visualization, Supervision. **Rasmus Bramstoft:** Conceptualization, Methodology, Software, Resources, Data curation, Writing – original draft, Writing – review & editing. **Matti Koivisto:** Conceptualization, Methodology, Resources, Data curation, Writing – original draft, Writing – review & editing, Project administration, Funding acquisition. **Lena Kitzing:** Conceptualization, Methodology, Resources, Writing – original draft, Writing – review & editing, Supervision, Project administration, Funding acquisition. **Andrés Ramos:** Conceptualization, Methodology, Resources, Writing – original draft, Writing – review & editing, Supervision.

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

I have shared the link to data/code in the paper

Acknowledgements

This article is a part of NSON-DK project funded by the Danish Energy Agency, EUDP (grant 64018-0032; previously ForskEL), the Flex4Res project funded by Nordic Energy Research, Norway (grant 76084), and the SuperP2G project financed by the European Union’s Horizon 2020 research and innovation programme (grant number 775970). Matti Koivisto acknowledges support from the PSfuture project (La Cour Fellowship, DTU Wind Energy).

References

Babarit, A., Gilloteaux, J.-C., Clodic, G., Duchet, M., Simoneau, A., Platzer, M.F., 2018. Techno-economic feasibility of fleets of far offshore hydrogen-producing wind energy converters. Int. J. Hydrogen Energy (ISSN: 0360-3199) 43 (15), 7266–7289. http://dx.doi.org/10.1016/j.ijhydene.2018.02.144.

Balmorel Community, 2021a. Balmorel code. URL https://github.com/balmorelcommunity/Balmorel.

Balmorel Community, 2021b. Balmorel data. URL https://github.com/balmorelcommunity/Balmorel_data.

Battaglini, A., Komendantova, N., Brtnik, P., Patt, A., 2012. Perception of barriers for expansion of electricity grids in the European union. Energy Policy (ISSN: 0301-4215) 47, 254–259. http://dx.doi.org/10.1016/j.enpol.2012.04.065.

Bramstoft, R., Alonso, A., Jensen, I., Ravn, H., Munster, M., 2020. Modelling of renewable gas and fuels in future integrated energy systems. Appl. Energy (ISSN: 0306-2619) 268, http://dx.doi.org/10.1016/j.apenergy.2020.114869.

Brown, T., Schlachtberger, D., Kies, A., Schramm, S., Greiner, M., 2018. Synergies of sector coupling and transmission reinforcement in a cost-optimised, highly renewable European energy system. Energy 160, 720–739. http://dx.doi.org/10.1016/j.energy.2018.06.222.

Caglayan, D.G., Heinrichs, H.U., Robinius, M., Stolten, D., 2021. Robust design of a future 100 with hydrogen infrastructure. Int. J. Hydrogen Energy (ISSN: 03603199) 46, 29376–29390. http://dx.doi.org/10.1016/j.ijhydene.2020.12.197.

Candas, S., Muschner, C., Buchholz, S., Bramstoft, R., van Ouwerkerk, J., Hainsch, K., Löffler, K., Günther, S., Berendes, S., Nguyen, S., Justin, A., 2022. Code exposed: Review of five open-source frameworks for modeling renewable energy systems. Renew. Sustain. Energy Rev. (ISSN: 18790690) 161, http://dx.doi.org/10.1016/j.rser.2022.112272.

Danish Energy Agency, 2021. Technology catalogues. URL https://ens.dk/en/our-services/projections-and-models/technology-data.

Dinh, V.N., Leahy, P., McKeogh, E., Murphy, J., Cummins, V., 2020. Development of a viability assessment model for hydrogen production from dedicated offshore wind farms. Int. J. Hydrogen Energy (ISSN: 0360-3199) http://dx.doi.org/10.1016/j.ijhydene.2020.04.232.

DW, 2021. Denmark to construct artificial island as a wind energy hub. URL https://www.dw.com/en/denmark-to-construct-artificial-island-as-a-wind-energy-hub/a-56458179#:~:text=Denmark%20approved%20plans%20on%20Thursday,aviation%2C%20industry%20and%20heavy%20transport.

EA Energy Analysis, 2020. Offshore wind and infrastructure. URL https://www.ea-energianalyse.dk/en/publications/offshore-wind-and-infrastructure/.

EDMOnet-Bathymetry, 2021. EMODnet DTM. URL https://portal.emodnet-bathymetry.eu/.

Egelund, O.B., 2010. Wind energy and local acceptance; how to get beyond the nimby effect. Eur. Energy Environ. Law Rev. (ISSN: 0966-1646) 239–251, URL http://www.kluwerlawonline.com/api/Product/RenderPDF?file=Journals2010017.pdf.

European Commission, 2018. A clean planet for all a European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy. URL https://ec.europa.eu/clima/sites/clima/files/docs/pages/com_2018_733_analysis_in_support_en_0.pdf.

European Hydrogen Backbone, 2022. A European hydrogen infrastructure vision covering 28 countries april 2022. URL https://www.ehb.eu/maps.

Flex4RES Project, 2019. Flexible nordic energy systems summary report. URL https://www.nordicenergy.org/wp-content/uploads/2019/07/Flex4RES_final_summary_report_aug2019.pdf.

Franco, B.A., Baptista, P., Neto, R.C., Ganilha, S., 2021. Assessment of offloading pathways for wind-powered offshore hydrogen production: Energy and economic analysis. Appl. Energy (ISSN: 0306-2619) 286, 116553. http://dx.doi.org/10.1016/j.apenergy.2021.116553.

Gea-Bermúdez, J., Das, K., Koivisto, M.J., koduvere, H., 2021a. Day-ahead market modelling of large-scale highly-renewable multi-energy systems: Analysis of the North Sea Region towards 2050. Energies 14, http://dx.doi.org/10.3390/en14010088.

Gea-Bermúdez, J., Jensen, I.G., Münster, M., Koivisto, M., Kirkerud, J.G., kuang Chen, Y., Ravn, H., 2021b. The role of sector coupling in the green transition: A least-cost energy system development in northern-central Europe towards 2050. Appl. Energy (ISSN: 0306-2619) 289, 116685. http://dx.doi.org/10.1016/j.apenergy.2021.116685.

Gea-Bermúdez, J., Pade, L.L., Koivisto, M.J., Ravn, H., 2020. Optimal generation and transmission development of the north sea region: Impact of grid architecture and planning horizon. Energy (ISSN: 0360-5442) 191, 116512. http://dx.doi.org/10.1016/j.energy.2019.116512.

Gils, H.C., Gardian, H., Schmugge, J., 2021. Interaction of hydrogen infrastructures with other sector coupling options towards a zero-emission energy system in Germany. Renew. Energy (ISSN: 18790682) 180, 140–156. http://dx.doi.org/10.1016/j.renene.2021.08.016.

Gunkel, P.A., Bergaentzlé, C., Grsted Jensen, I., Scheller, F., 2020a. From passive to active: Flexibility from electric vehicles in the context of transmission system development. Appl. Energy (ISSN: 0306-2619) 277, 115526. http://dx.doi.org/10.1016/j.apenergy.2020.115526.

Gunkel, P.A., Koduvere, H., Kirkerud, J.G., Fausto, F.J., Ravn, H., 2020b. Modelling transmission systems in energy system analysis: A comparative study. J. Environ. Manag. (ISSN: 0301-4797) 262, 110289. http://dx.doi.org/10.1016/j.jenvman.2020.110289.

Helgeson, B., Peter, J., 2020. The role of electricity in decarbonizing European road transport – Development and assessment of an integrated multi-sectoral model. Appl. Energy (ISSN: 0306-2619) 262, 114365. http://dx.doi.org/10.1016/j.apenergy.2019.114365.

Henning, H.-M., Palzer, A., 2014. A comprehensive model for the German electricity and heat sector in a future energy system with a dominant contribution from renewable energy technologies—Part I: Methodology. Renew. Sustain. Energy Rev. (ISSN: 1364-0321) 30, 1003–1018. http://dx.doi.org/10.1016/j.rser.2013.09.012.

Hou, P., Enevoldsen, P., Eichman, J., Hu, W., Jacobson, M.Z., Chen, Z., 2017. Optimizing investments in coupled offshore wind -electrolytic hydrogen storage systems in Denmark. J. Power Sources (ISSN: 0378-7753) 359, 186–197. http://dx.doi.org/10.1016/j.jpowsour.2017.05.048.

IEA, 2019. IEA G20 hydrogen report: assumptions.

Jensen, I.G., Wiese, F., Bramstoft, R., Münster, M., 2020. Potential role of renewable gas in the transition of electricity and district heating systems. Energy Strategy Rev. (ISSN: 2211467X) 27 (November 2019), 100446. http://dx.doi.org/10.1016/j.esr.2019.100446.

Koivisto, M., Das, K., Guo, F., Sørensen, P., Nuño, E., Cutululis, N., Maule, P., 2019a. Using time series simulation tools for assessing the effects of variable renewable energy generation on power and energy systems. Wiley Interdiscip. Rev.: Energy Environ. 8 (3), e329. http://dx.doi.org/10.1002/wene.329.

Koivisto, M., Gea-Bermúdez, J., 2018. NSON-DK Energy System Scenarios – Edition 2. DTU Wind Energy, Denmark, https://orbit.dtu.dk/en/publications/nsondk-energy-system-scenarios--edition-2(a12307fd-b045-4d90-a745-38bca211b861).html.

Koivisto, M., Gea-Bermúdez, J., Sørensen, P., 2019b. North sea offshore grid development: Combined optimization of grid and generation investments towards 2050. IET Renew. Power Gener. (ISSN: 1752-1416) http://dx.doi.org/10.1049/iet-rpg.2019.0693.

Konstantelos, I., Pudjianto, D., Strbac, G., De Decker, J., Joseph, P., Flament, A., Kreutzkamp, P., Genoese, F., Rehfeldt, L., Wallasch, A.-K., Gerdes, G., Jafar, M., Yang, Y., Tidemand, N., Jansen, J., Nieuwenhout, F., van der Welle, A., Veum, K., 2017. Integrated north sea grids: The costs, the benefits and their distribution between countries. Energy Policy (ISSN: 0301-4215) 101, 28–41. http://dx.doi.org/10.1016/j.enpol.2016.11.024.

Lazard, 2017. Lazard's levelized cost of storage analysis 3.0. URL https://www.lazard.com/perspective/levelized-cost-of-storage-2017/.

Lester, M.S., Bramstoft, R., Münster, M., 2020. Analysis on electrofuels in future energy systems: A 2050 case study. Energy (ISSN: 03605442) 199, 117408. http://dx.doi.org/10.1016/j.energy.2020.117408.

McDonagh, S., Ahmed, S., Desmond, C., Murphy, J.D., 2020. Hydrogen from offshore wind: Investor perspective on the profitability of a hybrid system including for curtailment. Appl. Energy (ISSN: 0306-2619) 265, 114732. http://dx.doi.org/10.1016/j.apenergy.2020.114732.

Münster, M., 2012. The role of district heating in the future danish energy system. Energy (ISSN: 0360-5442) 48 (1), 47–55. http://dx.doi.org/10.1016/j.energy.2012.06.011, 6th Dubrovnik Conference on Sustainable Development of Energy Water and Environmental Systems, SDEWES 2011.

Negra, N.B., Todorovic, J., Ackermann, T., 2006. Loss evaluation of HVAC and HVDC transmission solutions for large offshore wind farms. Electr. Power Syst. Res. (ISSN: 0378-7796) 76 (11), 916–927. http://dx.doi.org/10.1016/j.epsr.2005.11.004.

Neumann, F., Zeyen, E., Victoria, M., Brown, T., 2022. Benefits of a hydrogen network in Europe. URL http://arxiv.org/abs/2207.05816.

Nordic Energy Research and International Energy Agency, 2016. Nordic energy technology perspectives 2016 report. URL http://www.nordicenergy.org/project/nordic-energytechnology-perspectives/.

Nuño, E., Maule, P., Hahmann, A., Cutululis, N., Sørensen, P., Karagali, I., 2018. Simulation of transcontinental wind and solar PV generation time series. 118, 425–436.

Philip Swisher, 2020. Modelling of political and technological innovation on northern Europe's energy system towards 2050. URL https://findit.dtu.dk/en/catalog/2595776848.

Poncelet, K., Delarue, E., D'haeseleer, W., 2020. Unit commitment constraints in long-term planning models: Relevance, pitfalls and the role of assumptions on flexibility. Appl. Energy (ISSN: 0306-2619) 258, 113843. http://dx.doi.org/10.1016/j.apenergy.2019.113843.

Rehfeldt, M., Fleiter, T., Toro, F., 2018. A bottom-up estimation of the heating and cooling demand in European industry. Energy Effic. 11, 1057–1082. http://dx.doi.org/10.1007/s12053-017-9571-y.

Ruiz, P., Nijs, W., Tarvydas, D., Sgobbi, A., Zucker, A., Pilli, R., Jonsson, R., Camia, A., Thiel, C., Hoyer-Klick, C., Longa, F.D., Kober, T., Badger, J., Volker, P., Elbersen, B., Brosowski, A., Thrän, D., 2019. ENSPRESO - an open, EU-28 wide, transparent and coherent database of wind, solar and biomass energy potentials. Energy Strategy Rev. (ISSN: 2211-467X) 26, 100379. http://dx.doi.org/10.1016/j.esr.2019.100379.

Sims, R.E., Mabee, W., Saddler, J.N., Taylor, M., 2010. An overview of second generation biofuel technologies. Bioresour. Technol. (ISSN: 0960-8524) 101 (6), 1570–1580. http://dx.doi.org/10.1016/j.biortech.2009.11.046.

The European Commission, 2015. The Paris agreement. URL https://ec.europa.eu/clima/policies/international/negotiations/paris_en.

The European Commission, 2019. The European green deal. http://dx.doi.org/10.1017/CBO9781107415324.004.

The European Commission, 2020a. Climate strategies and targets. URL https://ec.europa.eu/clima/policies/strategies_en.

The European Commission, 2020b. Hydrogen. URL https://ec.europa.eu/energy/topics/energy-system-integration/hydrogen_en.

The European Commission, 2020c. EU strategy on energy system integration. URL https://ec.europa.eu/energy/topics/energy-system-integration/eu-strategy-energy-system-integration_en.

The European Commission, 2020d. EU strategy on offshore renewable energy. URL https://ec.europa.eu/energy/topics/renewable-energy/eu-strategy-offshore-renewable-energy_en.

Transport and Environment, 2018. How to decarbonize the transport sector by 2050. URL https://www.transportenvironment.org/sites/te/files/publications/2018_11_2050_synthesis_report_transport_decarbonisation.pdf.

van Ouwerkerk, J., Hainsch, K., Candas, S., Muschner, C., Buchholz, S., Günther, S., Huyskens, H., Berendes, S., Löffler, K., Bußar, C., Tardasti, F., von Köckritz, L., Bramstoft, R., 2022. Comparing open source power system models - A case study focusing on fundamental modeling parameters for the German energy transition. Renew. Sustain. Energy Rev. (ISSN: 18790690) 161, http://dx.doi.org/10.1016/j.rser.2022.112331.

Victoria, M., Zeyen, E., Brown, T., 2022. Speed of technological transformations required in Europe to achieve different climate goals. Joule 6, http://dx.doi.org/10.1016/j.joule.2022.04.016, URl http://arxiv.org/abs/2109.09563.

Volker, P.J.H., Hahmann, A.N., Badger, J., Jørgensen, H.E., 2017. Prospects for generating electricity by large onshore and offshore wind farms. Environ. Res. Lett. 12 (3), 034022. http://dx.doi.org/10.1088/1748-9326/aa5d86.

Wiese, F., Baldini, M., 2018. Conceptual model of the industry sector in an energy system model: A case study for Denmark. J. Clean. Prod. (ISSN: 0959-6526) 203, 427–443. http://dx.doi.org/10.1016/j.jclepro.2018.08.229.

Wiese, F., Bramstoft, R., Koduvere, H., Alonso, A.P., Balyk, O., Kirkerud, J.G., Tveten, Å.G., Bolkesjø, T.F., Münster, M., 2018. Balmorel open source energy system model. Energy Strategy Rev. (ISSN: 2211-467X) 20, 26–34. http://dx.doi.org/10.1016/j.esr.2018.01.003.