2024-10-14

Optimization of reversible solid oxide cell system capacity combined with an offshore wind farm for hydrogen production and energy storage using the PyPSA power system modelling tool

Jessica Guichard *School of Engineering, Computing and Mathematics*

Deborah Greaves *School of Engineering, Computing and Mathematics*

Robert Rawlinson-Smith *School of Engineering, Computing and Mathematics*

Optimization of reversible solid oxide cell system capacity combined with an offshore wind farm for hydrogen production and energy storage using the PyPSA power system modelling tool

Guichard, Jessica; Greaves, Deborah; Rawlinson-Smith, Robert

Published in:
IET Renewable Power Generation

DOI:
10.1049/rpg2.13134

Publication date:
2024

Document version:
Publisher's PDF, also known as Version of record

Citation for published version (APA):
Guichard, J., Greaves, D., & Rawlinson-Smith, R. (2024). Optimization of reversible solid oxide cell system capacity combined with an offshore wind farm for hydrogen production and energy storage using the PyPSA power system modelling tool. *IET Renewable Power Generation*. https://doi.org/10.1049/rpg2.13134

Received: 14 February 2024 | Revised: 13 September 2024 | Accepted: 6 October 2024

IET Renewable Power Generation

DOI: 10.1049/rpg2.13134

The Institution of Engineering and Technology WILEY

ORIGINAL RESEARCH

Optimization of reversible solid oxide cell system capacity combined with an offshore wind farm for hydrogen production and energy storage using the PyPSA power system modelling tool

Jessica Guichard | Robert Rawlinson-Smith | Deborah Greaves

COAST Engineering Research Group, School of Engineering, Computing and Mathematics, University of Plymouth, Plymouth, Devon, UK

Correspondence
Jessica Guichard, COAST Engineering Research Group, School of Engineering, Computing and Mathematics, University of Plymouth, Plymouth, Devon PL4 8AA, UK.
Email: jessica.guichard@plymouth.ac.uk

Funding information
EPSRC, Grant/Award Number: EP/W003732/1

Abstract
Eight scenarios where high efficiency reversible solid oxide cells (rSOC) are combined with an offshore wind farm are identified. Thanks to the PyPSA power system modelling tool combined with a sensitivity study, optimized rSOC system capacities, hydrogen storage capacities, and subsea cable connection capacities are investigated under various combinations of rSOC system capital cost, prices paid for hydrogen, and electricity prices, which give indications on the most profitable scenario for offshore hydrogen production from a 600 MW wind farm situated 60 km from shore. Low electricity prices (yearly average 45 £/MWh) combined with mild fluctuations (standard deviation 6 or 13 £/MWh) call for dedicated hydrogen production when the hydrogen price exceeds 4 £/kg. High electricity prices (yearly average 118 or 204 £/MWh), combined with extreme fluctuations (standard deviation between 73 and 110 £/MWh), make a reversible system economically profitable. The amount of hydrogen which is recommended to be reconverted into electricity depends on the price paid for hydrogen. Comparison of the optimized cases to the default case of a wind farm without hydrogen production improved profit by at least 3% and up to 908%. Comparison to the default case of dedicated hydrogen production, showed that in the case of low hydrogen prices, an unprofitable scenario can be made profitable, and improvement of profit in the case of a profitable default case starts at 4% and reaches numbers as high as 324%.

1 | INTRODUCTION

The Climate Change Act makes achieving net zero greenhouse gas emissions by 2050 in the UK not only a target, but also a legal obligation [1]. One of the methods to reach this target is to increase the amount of low or zero carbon power stations, such as those based on nuclear power and renewable energy.

Wind energy is one of the renewable energy sources expected to contribute significantly in meeting this target [2]. High penetration levels of variable renewable energy sources will require increased energy storage capacity. Furthermore, certain hard to electrify sectors that currently utilise fossil fuels, such as steel production and long-distance and heavy-duty transport will need to find low or zero carbon alternatives. Hydrogen has the potential to provide both energy storage and replace fossil fuels [3]. The UK aims to have 5 GW of green hydrogen production capacity by 2030. Green hydrogen produced via electrolysis from renewable energy can be stored over extended periods of time and either be reconverted into electricity using a fuel cell or a gas turbine, be burned to produce heat, or used for propulsion.

A range of electrolysis technologies have been or are in development. According to [4], "alkaline electrolysis is a mature and commercial technology". Alkaline electrolysers require a minimum load of 10% and can go up to 110%. According to [5], in 2017, alkaline electrolyser systems had the lowest CAPEX amongst electrolyser technologies, at 887 £/kW. Operating pressures of alkaline electrolysers are between 1 and 30 bar, and operating temperature is between 60 and 80°C. Efficiencies in LHV (Lower Heating Value) are indicated to be 63–70% in 2019, and could reach 70–80% in the long term [4].

TABLE 1 Overview of efficiencies achievable with solid oxide cell technologies when combined with waste heat [6].

Temperature of waste heat (°C)	100–200	200–500	500–1000
Efficiency (LHV)	82	86	95

Proton Exchange Membrane (PEM) technologies are gaining in importance. PEM electrolysers have fast response time and can therefore work in fluctuating conditions, in a load range going from 0 to 160% (can work in overload). They are therefore better suited to changing renewable power output when compared to alkaline. PEM electrolysers are also more compact, making them more suitable than alkaline for the offshore use. However, certain platinum group metals (platinum, iridium) required as electrode catalysts are rare and costly. In 2017, according to [5], Capex for PEM was 1120 £/kW, but is predicted to go down to 210 £/kW by 2050. Efficiencies in LHV are indicated to be 56–60% in 2019 but predicted to reach 67–74% in the long term. Operating temperatures are between 50 and 80°C [4]. Operating pressures are between 30 and 80 bar, which means that the hydrogen is delivered at pressures equal or close to pressures required for pipeline transport.

A third emerging technology is reversible solid oxide cells. They are at low technology readiness level for now, and in [5], CAPEX of an electrolyser system for 2017 is indicated to be 1588 £/kW. However, as they use ceramics as the electrolyte, they have low material costs [4]. They operate at high temperatures and have the potential to deliver high electrical efficiencies in electrolyser mode, which can exceed 100% (efficiency being defined as the ratio between energy contained in the hydrogen produced and the electrical energy required to produce it) if combined with waste heat [6]. According to [6], the following efficiencies, when expressed in LHV of hydrogen, can be obtained, depending on the temperature of the available waste heat (Table 1):

In [6], for a cell voltage of 1.15 V, when the temperature exceeds 625°C, the efficiency is indicated to exceed 100%. But even without external heat input, efficiencies are above 80%.

Furthermore, the cell stack can operate both in electrolyser and in fuel cell mode, if the balance of plant required for both modes is present. This allows this type of electrolyser mode to be in operational mode the majority of the time and not be underutilised. One main inconvenience of this type of electrolyser is that it requires high temperatures to function. In [7], two different working temperatures (1123.5 K = 850.35°C and 1023.5 K = 750.35°C) are considered for the modelling of an rSOC technology-based cell stack and thermodynamic model of the balance of plant. Lower temperatures of 520–620°C can be used for the solid oxide cells developed by CERES Power, which uses ceria. A cold start of a typical high temperature electrolyser system requires several hours. In [8], a report from 2018, a cold start for high temperature electrolysers is indicated to be as long as 10 h. This is indicated to go down to 3 h by 2030, and 30 min by 2050, which is indicated as being lower than predicted start up times for alkaline electrolysers in that year. Until those lower start up times can be reached, complete shutdown of such a system should therefore be avoided. As they can work reversibly, when electricity cannot be provided by renewable energy or batteries, making the system function in fuel cell mode, not only allows maintaining the system in operation, but also allows providing heat to the system, thanks to the exothermic reaction happening in fuel cell mode. Switching between the two modes is a matter of changing the ratios of hydrogen and steam that are sent into the system. In [7], for fuel cell mode in the base case operation, the ratio between steam and hydrogen (molar fraction) sent into the system is 0:100, and in electrolyser mode it is 50:50. Modifying those ratios can be done within seconds, but the challenge is dealing with the temperature changes which arise with the change in mode, and which need to be minimised (ideally stay within an interval of 100°C) to avoid premature aging of the cell stack.

Besides that, the current challenge for solid oxide electrolysers is to overcome the "degradation of materials that results from the high operating temperatures" [4].

A report by ORE Catapult [5] presents LCOH calculations for dedicated onshore and offshore hydrogen production from two types of offshore wind farms (bottom-fixed and floating) and using three different types of electrolysers (Alkaline, PEM, and Solid Oxide). For the year 2030, a floating wind farm, a solid oxide electrolyser, and offgrid-offshore hydrogen production, the LCOH is determined to be 4.14 £/kg. It should be noted that this number does not include cost for storage.

Existing or planned projects involving hydrogen production from Offshore Renewable Energy (ORE) use PEM electrolysers preferably. The project called "Surf 'n' Turf" (2015–2017) on the Orkney island Eday [9, 10] used a 500 kW PEM electrolyser by ITM Power. In this project, electricity from an onshore wind turbine as well as a tidal turbine were provided to produce hydrogen onshore subsequently shipped to the Orkney Mainland to provide hydrogen to fuel cell vehicles. The hydrogen was transported in pressurised containers via truck and ship. The cost of hydrogen is determined to be 5.17 £/kg [10] and includes production, transportation and consumption.

The Dolphyn Hydrogen project [11] plans to produce hydrogen using PEM electrolysers on board a floating wind turbine platform in the North Sea and the Celtic Sea using desalinated seawater. Economic modelling [12] indicates that decentralised hydrogen production on a semi-submersible floating wind turbine platform is cheaper than centralised hydrogen production with semi-submersible platforms or onshore hydrogen production. In [12], the undiscounted hydrogen price for a demonstrator project situated 50 km from shore is determined to be likely between 4.68 £/kg and 5.61 £/kg. The size of a Commercial Scale Demonstrator currently planned to be deployed before 2030 is of 10 MW. For a 4 GW wind farm, calculations for three sizes of turbines are indicated (Table 2):

In [13], minimisation of LCOH is conducted thanks to a tool named MegaWatt hybrid optimisation by genetic algorithms (MHOGA) developed by the authors. It is done for green hydrogen coming from wind and solar. This model considers 4 different scenarios. The first one is dedicated hydrogen

TABLE 2 Hydrogen price estimations for decentralised hydrogen production from a 4 GW floating wind farm [12].

Wind turbine size	10 MW	12 MW	15 MW
Undiscounted hydrogen price (£/kg)	1.93 £/kg	1.79 £/kg	1.65 £/kg

production without connection to the grid. The second one allows buying electricity from the grid if the price is below a certain value. The third scenario does not allow buying electricity from the grid but can sell to the grid if the price is above a certain value. The 4th scenario sells electricity to the grid by default and only produces hydrogen if there is surplus electricity. The electrolysers considered are alkaline and PEM, and for both types of electrolysers, a base case, and then a low CAPEX combined with a high efficiency are considered. The effect of a variable efficiency of electrolysis is considered. The lowest value of 4.74 £/kg for LCOH is found for scenario 2, which allows buying electricity from the grid, and a low CAPEX and high efficiency alkaline electrolyser. The highest value of 16.06 £/kg was found for scenario 4 combined with a base case PEM electrolyser. Running the same simulations with the assumption that the electrolyser efficiency is constant instead of variable, leads to differences in LCOH of up to 17.8% and is considered too high to be negligible in those cases.

The Crown Estate has announced a leasing round for 4.5 GW of floating offshore wind in the Celtic Sea by 2035 [14], and had indicated that the region has potential to accommodate up to 24 GW by 2045 [15]. The present paper investigates the use of a reversible system based on rSOC with an offshore wind farm situated in the Celtic Sea. The location of the wind farm is chosen to be in between the lease areas of Petroc and Llywelyn, and the capacity of the wind farm is chosen to be the combined capacity planned for each, that is, 600 MW in total [16, 17].

Modelling scenarios have been identified in which an ORE farm is combined with hydrogen production. The following four operations may be either onshore or offshore, which makes a total of eight scenarios:

1. Dedicated hydrogen production (no fuel cell)
2. Hydrogen production and electricity production in parallel (no fuel cell mode)
3. Pure electricity production—Hydrogen as temporary storage for electricity
4. Hydrogen production with partial reconversion of hydrogen into electricity

Figure 1 illustrates one of the more complex scenarios where both hydrogen and electricity are sent to shore (Scenario 4, offshore version), and in addition, at peak demand times, hydrogen converted into electricity. This is the scenario investigated here. However, depending on the exact parameters used, the model is free to choose any of the offshore scenarios 1 through 3 or to determine that the most economical solution is for no hydrogen production at all (all electricity from wind farm sent to shore, without rSOC plant).

2 | METHODOLOGY

2.1 | Presentation of the PyPSA modelling tool and overview of the model

The PyPSA modelling tool is a code written in Python for energy system modelling and optimization. A detailed description can be found on the PyPSA documentation website [19]. The PyPSA modelling tool allows users to build a network from a collection of predefined elements.

- "buses": nodes of the network where energy flowing in and out needs to be balanced
- "generators": energy sources which can be connected to a bus
- "loads": represent demand, connected to a "bus"
- "stores": represent energy storage, connected to a "bus"
- "links": connections between "buses" which allow energy flow. These typically represent electric cable connections or energy conversion processes.

The following subsections describe each of those elements, and in particular the properties used for the model.

2.1.1 | "Generators"

"Generators" are sources of energy, such as power stations. Power provided can be constant or time-varying. Maximum installed capacity can be fixed or optimized. Power availability may be higher than power actually used. That is, if the optimization determines that it is more cost-efficient to curtail part of the energy coming from a given generator at a given time-step, it will do so, and thanks to the output data the amount of curtailed energy can be determined.

2.1.2 | "Loads"

"Loads" represent demand. Loads can be constant or time-varying. Cost-optimization in PyPSA always requires demand to be met 100%. If the network is defined in a way that this is not possible, the optimization will fail.

2.1.3 | "Stores"

"Stores" represent storage options that can take multiple forms. Amongst the properties which can be defined for a "store" are maximum storage capacity, which can be fixed or optimized by the model, and initial energy stored.

2.1.4 | "Links"

"Links" represent electric cables or energy conversion processes. "Links" are by default directional, and a starting "bus" and a receiving "bus" must be defined. In practice, this can be

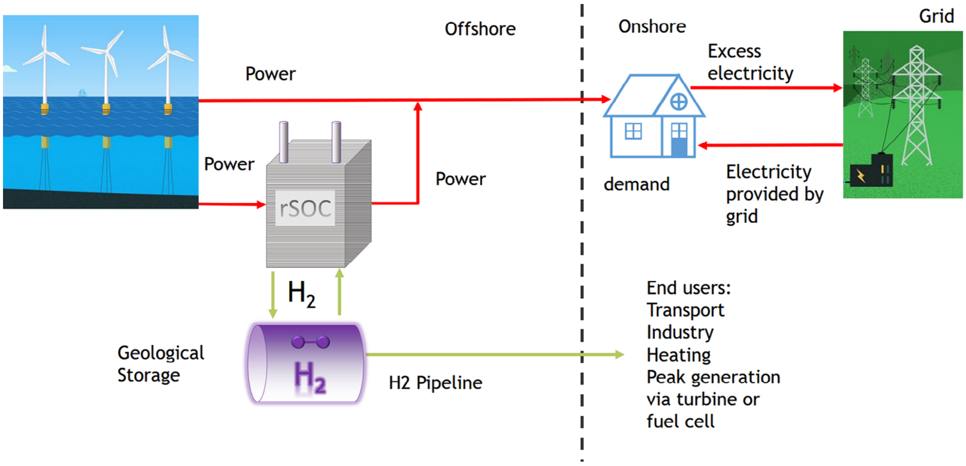

FIGURE 1 Schematic of hybrid offshore hydrogen and electricity production (Images of wind farm and electricity pylon are from [18]. Reproduced with permission from Supergen ORE).

a cable connecting a wind farm to demand, or the energy conversion process, which includes electrolysis, compression, and other processes, which allows going from electricity produced by a wind farm to hydrogen storage. Properties which can be defined for a "link" include efficiency and maximum capacity (maximum power which can be sent from one bus to another). The maximum power can be fixed by the user or optimized by the simulation. Ramp-up and ramp-down limits can also be defined if needed.

2.1.5 | Costs

For each of the above elements, one can attribute "capital_costs" and "marginal_costs". "capital_cost" is the sum total of all the costs needed in order to install 1 MW of a "generator" or a "link" (device allowing the transfer of 1 MW between 2 "buses"). OPEX costs that are independent from the frequency of use of a device need to be included in this cost. For the element called "store", it is the cost for each MWh of storage capacity.

"marginal_costs" are the costs incurred whenever that device is used. That is, for a generator, this would be a cost incurred for every MWh produced. For example, for a gas turbine this could be the cost of the fuel to produce 1 MWh of electricity. For a "link", it is the cost incurred whenever 1 MWh is transferred or converted. For a "store", it is the cost of every MWh taken out of storage.

Figure 2 gives a schematic simplified overview of the PyPSA model used. Four main "buses" are used, one for the wind farm, one for everything related to hydrogen, one for demand, and one for the grid, from which electricity can be obtained or sent to. The "bus" for the wind farm has an element of type "generator" connected to it to represent wind farm production. The "bus" for hydrogen has an element of type "store" connected to it, to represent hydrogen storage. Between the wind farm and the hydrogen, there are two links. The first one represents the whole energy conversion process to go from electricity provided by the wind farm to hydrogen, thus representing electrolyser mode, but also including peripheral processes needed such as desalination, compression, and heating. The second represents fuel cell mode and in a similar manner includes gas expansion and cooling.

Between the wind farm and the demand there is a link which represents the subsea electrical connection and allows transfer of electricity from the offshore electricity production site (which includes the rSOC system) to demand. Demand is furthermore connected to the grid. Details of input data for the elements are given in the next section.

2.2 | Sources for the inputs of the PyPSA model

This section presents the assumptions made for the input data in the PyPSA model, both in terms of energy system modelling and costs. The modelling approach presented here builds on [20], using a more detailed approach for considering the costs involved with offshore hydrogen production, including platform and desalination cost. Calculation of OPEX costs throughout the lifetime of the project have also been refined as well as learning curves and expected cost reduction to predict costs for a future project in 2030.

Costs used in the model are all aimed to correspond to costs for a project starting in 2030, by applying a growth and learning rate or directly making assumptions on yearly cost reductions. OPEX costs are calculated as a percentage (slightly different values for different components) of the CAPEX costs. A discount rate of 6% is applied for every year in the future after 2030, as well as an inflation rate of 2.32%, to determine OPEX costs throughout the lifetime of the project. CAPEX costs and yearly OPEX costs are then added up over 25 years or the lifetime of the component, whichever one is shorter and divided by 25 (or lifetime), to correspond to yearly costs of the project.

Electrolyser and fuel cell mode efficiency are varied to correspond to varying electricity input or output. Heat storage is

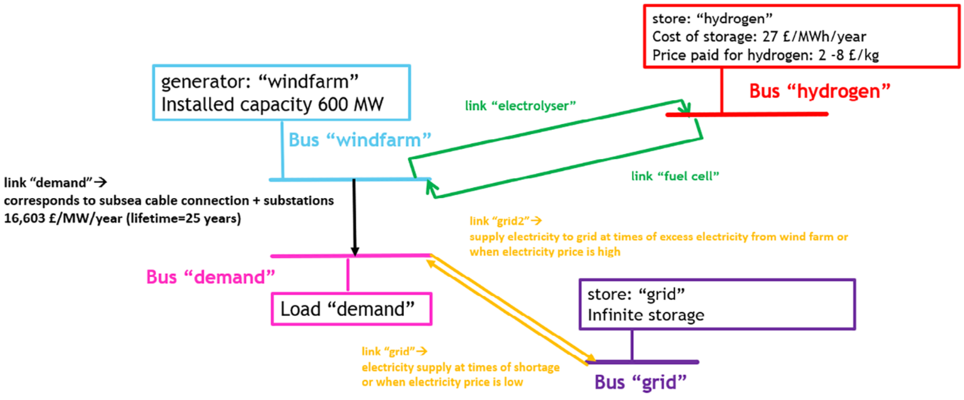

FIGURE 2 Schematic view of model in PyPSA.

included to account for the high dependency of efficiency of solid oxide cells on the working temperature. Daily and hourly fluctuations are considered, as it is expected that the ability to predict those values on a daily or hourly basis would have a significant impact on the energy system modelling.

2.2.1 | General information on costs

For most components, recent literature was consulted for determining costs in a given year. Generally, Equations (1) through (5) are applied to determine the cost to be used in the PyPSA simulation:

$$CAPEX_{2030} = CAPEX_{ypub} \times CF \times (1-x)^{(2030-ypub)}, \quad (1)$$

where $CAPEX_{2030}$ is the Capex cost for a given component in 2030 in pounds, $CAPEX_{ypub}$ is the Capex found in literature for a given component in a given year, CF is a conversion factor for converting foreign currencies into pounds, x is the annual cost reduction percentage, $ypub$ is the year of the publication (or alternatively the year for which the cost is indicated, if different). Yearly Capex $CAPEX_{yearly}$ is determined using Equation (2), necessary to run the simulations for one year only.

$$CAPEX_{yearly} = \frac{CAPEX_{2030}}{lifetime}, \quad (2)$$

where $lifetime$ is the lifetime of the component in years. If a component can last longer than the project duration (25 years), $lifetime$ is considered to be 25 years. The electrolysers and the desalination are considered to only last 20 years, lower than the project duration. Opex costs for the first year $OPEX_{year1}$ are calculated using Equation (3).

$$OPEX_{year1} = CAPEX_{2030} \times perc, \quad (3)$$

where $perc$ is the percentage of Opex for 1 year when compared to the Capex. An average yearly Opex is determined using Equation (4), which is again needed in the model, as it is only running simulations for the duration of 1 year.

$$OPEX_{yearly} = \frac{1}{25}\sum_{y=2030}^{2054} OPEX_{year1} \times \left(\frac{1+infl}{1+dr}\right)^{(y-2030)}, \quad (4)$$

where $infl$ is the annual inflation rate and dr is the discount rate. Lastly, the cost which is used in the model for "capital_cost", $Cost_{PyPSA}$, is determined using Equation (5). As mentioned in Section 2.1.5, "capital_cost" includes Opex, as it is assumed that Opex does not depend on the usage of the component, but rather the total amount of installed capacity.

$$Cost_{PyPSA} = CAPEX_{yearly} + OPEX_{yearly}. \quad (5)$$

For the desalination system, rather than an annual cost reduction, a learning rate combined with a growth rate were employed as found in [21], with the simplified assumption that the growth rate is constant over the number of years.

$$CAPEX_{2030} = CAPEX_{ypub} \times CF \times \left(\frac{production_{2030}}{production_{ypub}}\right)^{-b}, \quad (6)$$

where $production_{2030}$ is the historical global cumulative production output in 2030, $production_{ypub}$ is the historical global cumulative production output in the year where the cost is available in literature, and b is an exponent linked to the progress ratio PR as given in Equation (7).

$$PR = 2^{-b}. \quad (7)$$

The progress ratio is linked to the learning rate LR thanks to Equation (8).

$$LR = 1 - PR. \quad (8)$$

This gives a link between b and the learning rate as shown in Equation (9), or Equation (10).

$$LR = 1 - 2^{-b}, \quad (9)$$

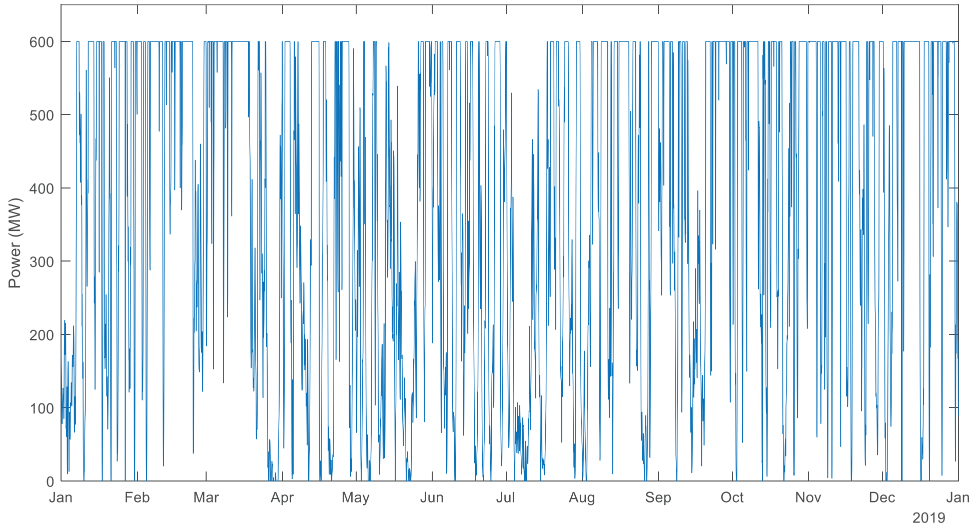

FIGURE 3 Wind farm production assumed for the PyPSA model.

$$-b = \frac{\ln(1 - LR)}{\ln 2}. \tag{10}$$

The cumulative capacities are linked to the growth rate GR thanks to Equation (11).

$$production_{2030} = production_{ypub}\,(1 + GR)^{2030-ypub}. \tag{11}$$

The cost for 2030 and the initial cost can therefore be linked to the growth rate thanks to Equation (12).

$$CAPEX_{2030} = CAPEX_{ypub} \times CF \times (1 + GR)^{-b \times (2030-ypub)}. \tag{12}$$

Equation (13) gives the cost in 2030 calculated directly using the initial cost, the growth rate and the learning rate.

$$CAPEX_{2030} = CAPEX_{ypub} \times CF \times (1 + GR)^{(2030-ypub)\times\frac{\ln(1-LR)}{\ln 2}}. \tag{13}$$

From Equations (1) and (13), it can be deduced that the annual cost reduction percentage can be linked to a growth rate and a learning rate by Equation (14).

$$x = 1 - (1 + GR)^{\frac{\ln(1-LR)}{\ln 2}}. \tag{14}$$

2.2.2 | Wind farm

The production of the wind farm is determined using wind data retrieved from [22]. Wind data is taken for the following coordinates: 51° latitude, −5.6° longitude. This is situated in Search Area 2 [23] of the areas planned for the leasing round in the Celtic Sea. The wind data is taken for 2019, and the power curve of the 15 MW IEA reference turbine [24] used to determine production of a 15 MW wind turbine over a whole year. It is considered that 40 such wind turbines are installed, thus making up a wind farm of 600 MW.

The wind farm production thus used for the PyPSA model can be seen in Figure 3.

The study assumes that the 600 MW wind farm has been installed and that all electricity produced by the wind farm should be utilised. Optimisation of the infrastructure relating to hydrogen production was performed for 144 combinations of different parameters. Collector cables and inter array cables grouping the electricity produced at a central location, are included. From this central location, electricity is either used to produce hydrogen via an electrolyser system or sent to shore via an export cable, or both following [5].

2.2.3 | Subsea cable connection

Costs for subsea cables, offshore and onshore substations, as well as for reactive compensation are calculated using data found in [25]. The wind farm is situated 60 km from shore. Cost is calculated for six grid connection capacities, with a margin of 50% taken for the installed capacity of the subsea cable, related transformers and reactive compensation. To achieve this margin, the grid connection has double the capacity of the maximum power to be transmitted. Figure 4 shows those capacities with the cost associated.

A linear regression is used to determine the cost of the grid connection per MW (Figure 4). As the simulation is run for only a year, the cost provided to the model has to be divided by the lifetime of the project, considered here to be 25 years. This gives a cost of 19,022 £/MW/year in 2021, after applying an annual reduction of 1.5%, this gives a cost of 16,603 £/MW/year in 2030, which is the value given to the variable "capital_cost" in the "link" representing the subsea cable and further equipment needed to send electricity from the wind farm to shore.

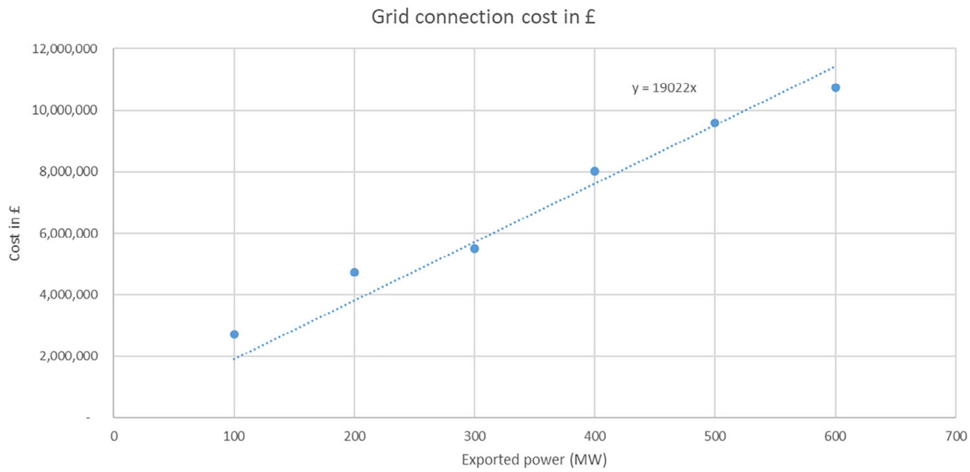

FIGURE 4 Annual subsea cable connection cost as a function of installed capacity (including 50% margin).

Losses in the subsea cable or transformers are not included in the cost, as is done in the cited article [25]. Rather, the losses are calculated using the formulae provided and included in the PyPSA model as the efficiency of the "link" representing the subsea cable. The efficiency used here is 98%.

2.2.4 | rSOC system cost

Cost for reversible systems has not been found in literature at the point of writing. Reference [5] gives learning curves for SOC electrolyser system CAPEX costs, including the balance of plant, varying between 1588 £/kW in 2017 and 585 £/kW in 2050. However, according to [6], a SOC electrolyser system may be available at a CAPEX of 500 £/kW by 2025. These costs include the cost for the cell stack as well as the costs for the balance of plant for an electrolyser. For a reversible system, costs for the added balance of plant, specific to fuel cell mode, need to be added. Discussion with industry [26] provides a cost range for a reversible system between 420 £/kW and 600 £/kW in 2030. Three values are selected to be studied in the model: 420, 500 and 600 £/kW. To this, several other costs need to be added, which are not included in the capital cost of the rSOC system. These are the costs of a platform, AC/DC converters, and a desalination system. Compressors are also needed with the associated cost included in the cost of geological storage (see Section 2.2.12). A certain amount of battery storage is also needed to deal with short term fluctuations in the electricity coming from the wind farm. Indeed, due to the changes in heat production or consumption between the different power levels of the rSOC system, ramp-up or ramp-down times of ~30 min are expected to be required. Energy system modelling here is done for hourly fluctuations, so at this level, short term fluctuations would not be visible, though they would be required to be dealt with. However, the amount of battery storage required is expected to be more directly linked to the amount of wind farm capacity, rather than rSOC capacity, therefore the costs are not included in the optimisation, but rather considered already paid for alongside the infrastructure for the wind farm. It is considered that the lifetime of the electrolyser is 20 years (shorter than the lifetime of the project), and so the value used for the "link" representing the electrolyser mode is obtained by dividing the costs above by 20. This gives values for "capital_cost" of 43,938 £/MW/year, 48,532 £/MW/year and 54,273 £/MW/year for the "link" representing electrolyser mode in the offshore version. It should be noted that for each of those values, a separate simulation was run. It was considered that for each MW of electrolyser capacity installed, a corresponding capacity of fuel cell mode is available.

2.2.5 | Cost of platform for offshore hydrogen production

Costs of the platforms for offshore hydrogen production are determined following reference [27]. In this report, the cost for a jacket platform supporting hydrogen equipment for a 500 MW plant in 30 m water depth is calculated. Using the same methodology, but for a water depth of 100 m, the cost of a platform per MW of rSOC is determined. In addition, as is recommended in [28], a factor of 2 is applied on the amounts of steel required, as according to [28], the numbers found in [27] are too low. After converting costs into pounds from euros, and applying a reduction in costs of 1.3% per year between 2018 (year of the publication of [27]) and 2030, the cost of the platform per MW of rSOC turns out to be £336,560, a sum included in the total costs indicated in Section 2.2.4.

2.2.6 | Cost of desalination

For desalination, reversible osmosis and thermal desalination are available. Reversible osmosis is less energy consuming. However, as reasoned in [29], the input required for a solid oxide cell electrolyser is steam, so the additional energy required for thermal desalination can be offset. Also, the freshwater produced will be of higher quality (purer). According to [29], multi-stage flash distillation requires 12 kWh/m^3 to produce steam at

100°C. To raise the temperature of the steam a further 50°C to 150°C, for delivery to the rSOC system, a further 28 kWh/m^3 are determined to be required (boiler efficiency 99%). From this, it is determined that for every MWh of hydrogen (LHV), 11 kWh are required for desalination, which determines the amount of desalination capacity. According to [29], the energy required for pumping is included. Costs for desalination are also taken from [29]. The article was published in 2014, and the cost given is 1450€/(m^3/d). It is assumed that the cost for pumps is included in this. Converted to pounds and after applying a learning rate of 15%, as well as a growth rate of 20% (as is done in [5]), the cost for 2030 ends up being 3249 £/MW of rSOC. OPEX is considered to be 3% of the CAPEX. Lifetime of the desalination system is considered to be 20 years. This sum is included in the total costs indicated in Section 2.2.4.

2.2.7 | Cost of heat storage

It was determined that heat storage was essential in order for the efficiencies in electrolyser mode to be reasonable. A value for heat storage cost is determined from [30] of 2–4 \$/kWh. After conversion into pounds, this gives a value of 3223 £/MWh of heat storage capacity. No reduction for 2030 is applied, as the technology considered is cited as being low-cost, and due to being based on rock may not be applicable for an offshore case.

2.2.8 | rSOC system efficiencies

Several documents were consulted which describe reversible systems based on solid oxide cell technology. A reversible system described in [31] has an efficiency of 67.1% in fuel cell mode and of 76% in electrolyser mode. In this model, the choice is made to have a low fuel utilisation ratio (20%), but a high recirculation ratio in fuel cell mode. This means that for a given amount of hydrogen sent into the fuel cell, only 20% is converted into electricity. However, the left-over hydrogen is recovered and sent back into the system for future use.

In [7], a reversible system is studied with different assumptions. In the system described in that work, diathermic oil is used to store the heat produced in fuel cell mode to be used in electrolyser mode, thus allowing for a high stack efficiency in electrolyser mode (87% Lower Heating Value, not given in the article but deduced from data given in the article). Furthermore, in fuel cell mode, electricity is produced in addition to the electricity produced by the cell stack thanks to a turbine into which the expanding hydrogen is sent into before being sent into the cell stack. In this way, part of the electricity used for compression in electrolyser mode is recovered in fuel cell mode. This gives different values for efficiency as [31] and illustrates the point that electrolyser efficiency may depend on a number of factors and will be different for different set ups and hence the large variability in efficiency quoted in the literature.

Discussion with industry provides average numbers for system efficiency of 87% in electrolyser mode and 50% in fuel cell mode [26]. However, in practice, efficiency varies with power input and output. Therefore, when running the simulations, for each mode, five different pairs of (power, efficiency) are selected and the efficiency varied depending on the input or output power.

2.2.9 | Ratio of powers between fuel cell and electrolyser mode

As the system described here is assumed to be reversible, this means that for every MW of electrolyser capacity, a given capacity of fuel cell mode is available. Furthermore, within one mode, it is assumed that with varying power, efficiency varies as well. A continuous relation between power and efficiency cannot be implemented. Instead, 5 points are selected from the curve shown in Figure 5, with data extracted from [32].

Table 3 indicates the ratios of powers to the default electrolyser, chosen to have the nominal power, and to which capital costs correspond. It can be seen that is it considered that the electrolyser can be run at a power much higher than the default power, when making a compromise on the efficiency.

For electrolyser mode, energy consumed for desalination of sea water (see Section 2.2.6) and compression needs to be included. In fuel cell mode, additional energy could be produced by sending the compressed hydrogen through a turbine, but this has not been included here.

For the calculation of the energy required to compress hydrogen before sending it into geological storage, a hydrogen delivery analysis model [33] is consulted and formulas and assumptions found in the associated spreadsheet are used. The required pressure is assumed to be 250 bar, as is the case in [34]. Equation (15) allows calculating the electrical power P_{comp} required for compressing hydrogen with a mass flow rate $\dot{m}$ for a compressor with motor efficiency m_{eff} (95%).

$$P_{comp} = Z\dot{m}\,RTn\frac{1}{\eta}\frac{1}{m_{eff}}\frac{k}{k-1}\left[\left(\frac{P_{outlet}}{P_{inlet}}\right)^{\left(\frac{k-1}{nk}\right)} - 1\right], \quad (15)$$

where Z is the mean compressibility factor, R the universal gas constant, T is the inlet gas temperature (assumed to be 298.15 K), n is the number of stages (8), η is the isentropic efficiency (88%), k is the ratio of specific heats ($\frac{C_p}{C_V} = 1.4$), P_{outlet} is the absolute compressor discharge pressure (250 bar), P_{inlet} is the absolute compressor inlet pressure (1 bar).

The number of stages n is determined thanks to Equation (16).

$$n = \left\lfloor \frac{\left[\log P_{outlet} - \log P_{inlet}\right]}{\log Ratio_{comp}} \right\rfloor, \quad (16)$$

where $Ratio_{comp}$ is the compression ratio per stage, chosen to be 2.1 here.

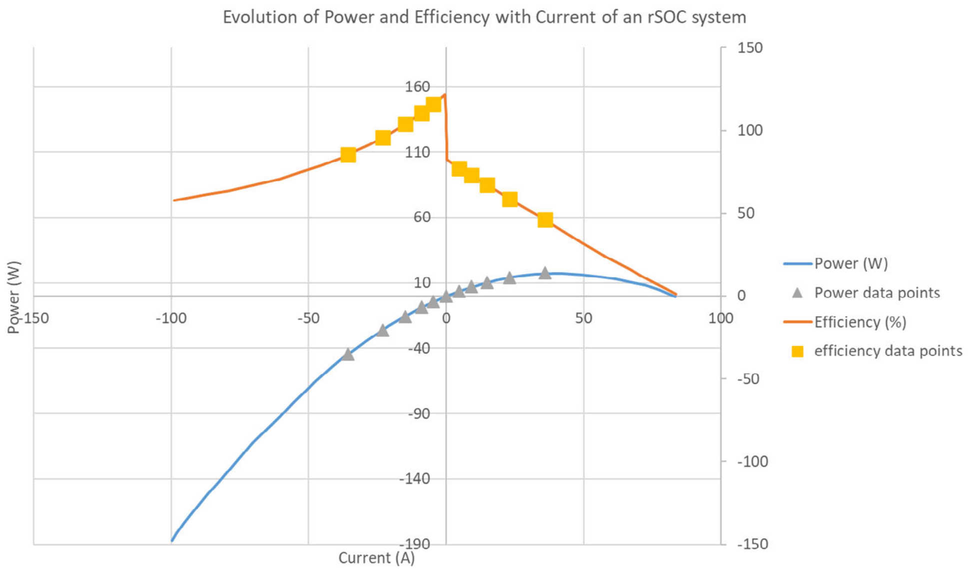

FIGURE 5 Pairs of power and efficiency in electrolyser and fuel cell mode.

TABLE 3 Ratios of power and corresponding efficiencies of rSOC system alone (without desalination and compression).

	Ratio of powers to default electrolyser mode	Efficiency of rSOC system alone
EC mode 1	2.849	85%
EC mode 2	1.686	96%
EC mode 3	1.000	104%
EC mode 4	0.547	111%
EC mode 5	0.280	116%
FC mode 1	0.203	77%
FC mode 2	0.407	73%
FC mode 3	0.610	67%
FC mode 4	0.814	59%
FC mode 5	1.017	46%

The mean compressibility factor Z is determined using Equation (17).

$$Z = \frac{Z_{outlet} - Z_{inlet}}{\ln \frac{Z_{outlet}}{Z_{inlet}}} \cong 1.077, \tag{17}$$

where Z_{outlet} ($\cong 1.159$) is the compressibility factor of the outlet pressure and Z_{inlet} ($\cong 0.998$) is the compressibility factor of the inlet pressure. Z_{outlet} and Z_{inlet} are determined using a table found in [35].

This gives an energy requirement of 2.68 kWh for compressing 1 kg of hydrogen.

Equation (18) defines the electrical efficiency Eff of the electrolyser alone.

$$Eff = \frac{P_{H_2}}{P_{electrolyser}}, \tag{18}$$

where P_{H_2} is the power flow of hydrogen and $P_{electrolyser}$ is the electrical power sent into the electrolyser.

In addition to the electricity sent into the electrolyser, electricity is required for desalination and for compression. The total power P_{elec} required for producing hydrogen is the addition of the power required by the electrolyser, the power required for desalination and the power required for compression (Equation 19).

$$P_{elec} = P_{electrolyser} + P_{comp} + P_{desal}. \tag{19}$$

The efficiency of the whole system Eff_{system} can be recalculated using Equation (20).

$$Eff_{system} = \frac{P_{H_2}}{P_{elec}} = \frac{P_{H_2}}{P_{electrolyser} + P_{comp} + P_{desal}}. \tag{20}$$

Modifying Equation (20) to Equation (21) allows expressing the efficiency of the entire process as a function of the efficiency of the electrolyser alone, as well as $x_{comp} = \frac{P_{comp}}{P_{H_2}}$ and $x_{desal} = \frac{P_{desal}}{P_{H_2}}$. The two ratios x_{comp} and x_{desal} correspond to the amout of power required for compression or desalination per MW of hydrogen flow.

$$\begin{aligned} Eff_{system} &= \frac{P_{H_2}}{P_{electrolyser}\left(1 + Eff \times \left(x_{comp} + x_{desal}\right)\right)} \\ &= \frac{Eff}{1 + Eff \times \left(x_{comp} + x_{desal}\right)}. \end{aligned} \tag{21}$$

After considering the extra energy requirements in electrolyser mode, efficiencies for different power levels are recalculated and are indicated in Table 4.

TABLE 4 Ratios of power and corresponding efficiency between the different modes of electrolyser or fuel cell operation.

	Ratio of powers to default electrolyser mode	Efficiency including desalination and compression in EC mode
EC mode 1	2.799	79%
EC mode 2	1.672	87%
EC mode 3	1.000	94%
EC mode 4	0.550	99%
EC mode 5	0.284	103%
FC mode 1	0.205	77%
FC mode 2	0.410	73%
FC mode 3	0.615	67%
FC mode 4	0.820	59%
FC mode 5	1.025	46%

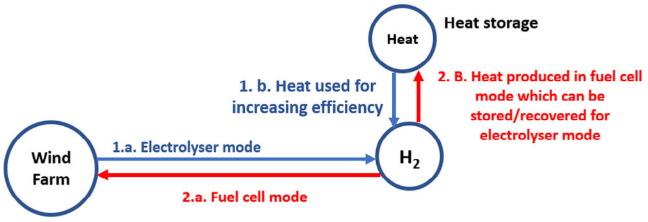

FIGURE 6 Illustration of heat recovery from fuel cell mode for electrolyser mode.

TABLE 5 Table indicating heat input required as a ratio of electricity input for different electrolyser electrical efficiencies.

EC mode	Electrical efficiency (%)	Heat required/ electricity consumed (%)
3	94	4
4	99	11
5	103	16

2.2.10 | Requirements of heat for electrolyser mode and heat recovery from fuel cell mode

As is done in [7], it is considered that part of the heat produced in fuel cell mode can be recovered to be used in electrolyser mode. For this, a double link is used to indicate that whenever hydrogen is converted into electricity, a certain amount of heat can be recovered. Conversely, it is considered that for the cases where electrolyser efficiency is high, heat is required. This is illustrated in Figure 6. For fuel cell mode, it is considered that 10% of the energy in the hydrogen cannot be recovered, which corresponds to the overall efficiency of a Combined Heat and Power (CHP) system, which is indicated to be 90% in [36]. The remaining 90% are partly turned into electricity and the rest stored as heat. In electrolyser mode, the heat input required for the following efficiencies is indicated in Table 5. These numbers are selected based on the reasoning that any energy that causes the efficiency of the rSOC system to be above 100% comes from heat. For the other efficiencies, it is considered that no heat input is required. It is considered that providing extra heat via electricity should be made possible in future models.

TABLE 6 Overview of cost assumptions for rSOC, electrolyser, or fuel cell only.

	Lowest cost (£/kW)	Medium cost (£/kW)	Highest cost (£/kW)
rSOC (reversible, rated in input power of electrolyser mode)	420	500	600
Electrolyser only (rated in input power)	336	400	480
Fuel cell only (rated in output power, considered to be 68% of electrolyser input)	498	592	711

2.2.11 | Fuel cell and electrolyser mode only

Preliminary model runs indicate that for a certain number of the scenarios, the reversible system is not fully put to use, that is, either electrolyser mode is mostly used only, or fuel cell mode requires an installed capacity so high that it exceeds the required installed capacity in electrolyser mode. The model is therefore given the possibility to select one of the modes alone at a slightly lower cost. It is considered that a system which is only able to work in electrolyser mode has a capital cost of 80% of the reversible system. For a system only able to work in fuel cell mode this same cost reduction is applied, but it is considered that the capacity of output power of fuel cell mode is the one available in FC mode 3 (68% of input in EC mode 3, cell stack only). Table 6 summarizes the above.

2.2.12 | Hydrogen storage costs

Hydrogen storage costs are taken from [34]. The CAPEX cost for a salt cavern is indicated to be 180 euros/GJ and the OPEX cost is 0.11 euros/GJ/year. The document indicates that the energy of the hydrogen is given in HHV. In the PyPSA model, the choice is made to express all values of energy contained in the hydrogen in Lower Heating Value (LHV) of hydrogen. Therefore, the costs need to be determined in the case where they are expressed in £/MWh of hydrogen (LHV). This gives a total of 679 £/MWh (using the conversion rate between euros and £ for the year of publication of the report) for a project lasting 25 years, or 27 £/MWh/year, which is the input value in the model for "capital_cost" of the element "store" which represents hydrogen storage. It is assumed that cushion gas is already available in sufficient amounts in the geological storage and the cost included in the CAPEX of the salt cavern. Cushion gas is "the amount of gas that is permanently stored in a natural gas storage. The main function is to maintain sufficient pressure in the storage to allow for adequate injection and withdrawal rates at all times.” [37]. Any amount of energy that is stored shown on graphs corresponds to gas present in addition to cushion gas.

The simulations are run for a year only, which is assumed to represent one out of 25 years. The cost of storage for hydrogen that is sold, rather than reconverted into electricity, makes the assumption that the storage capacity required is equal to what is produced in a year. In reality, regular consumers of hydrogen can make smaller storage capacities sufficient.

Geological storage is a good option for seasonal storage, when large amounts of gas need to be stored at low cost. According to [34], typical storage volume in a salt cavern is 5 PJ (~1389 GWh HHV, 1175 GWh LHV) of hydrogen.

In the North Sea, depleted gas fields could be an option for geological storage, which is not the case in the Celtic Sea. There are halite (salt) deposits in the Celtic Sea, but no plans yet to exploit salt caverns for storage [38].

2.2.13 | Hydrogen price

A sensitivity study is run for the price paid for hydrogen. The element “store” representing hydrogen storage is given four different values for “marginal_cost”, namely 60, 120, 180, and 240 £/MWh. This corresponds to prices of 2, 4, 6, and 8 £/kg of hydrogen when the energy contained in the stored hydrogen is expressed in Lower Heating Value (LHV). This means that any hydrogen left in storage and not used for electricity represents a monetary gain. Separate simulations are run for each of those values being constant throughout the year. It should be noted that this is the price paid for hydrogen before transportation to shore. Optimisation of a pipeline size is not done in the model. To have an idea of added costs for transportation to shore, costs for pipelines found in [39] are used. For a 60 km pipeline with a capacity of 0.3 GWh, Capex (including Capex for compression) for 2030 is determined to be 88 M£. In the case of dedicated hydrogen production, over a period of 25 years, around 2.25 Mt of hydrogen can be produced. This means that per kg of hydrogen, 0.04 £/kg need to be added to the price paid for hydrogen, for hydrogen that is available onshore. An upcoming publication [40] includes optimisation of pipeline size, making the simplifying assumption that the cost of a pipeline increases linearly with capacity. In that publication, as the purpose is to compare onshore and offshore hydrogen production, it is considered important to include the cost for hydrogen transport to shore in the simulation.

2.2.14 | Demand

UK Demand for 2021 is used as the basis for the modelling. Seasonal variation of demand in 2021 is found [41, 42] to be typical of the past decade, although it is noted that mean annual demand is slowly reducing over time. In order to localise the demand to the wind farm location the UK demand is scaled to the peak demand registered at the Indian Queens substation which is chosen due to its proximity to the Celtic Sea.

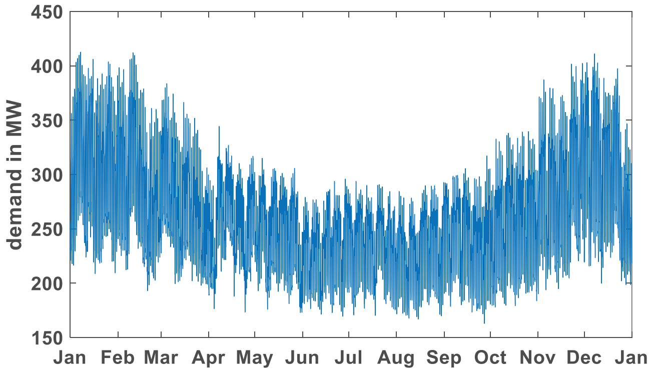

FIGURE 7 Local demand curve used in PyPSA model.

To obtain demand corresponding to local demand, the electricity map produced by nationalgridESO for the Future Energy Scenarios report [43] is consulted. Peak demand for electricity demand around the Indian Queens substation in the scenario called “Leading the way” is taken for the year 2021 and is found to be 413 MW. The demand for the whole of UK is thus multiplied by a factor to correspond to local peak demand. The resulting curve is shown in Figure 7.

2.2.15 | Electricity prices

To ensure that demand is met at all times, the model provides the possibility to receive electricity from the grid, rather than directly from the wind farm or stored hydrogen. The grid is represented using a PyPSA network element “store”. The storage capacity of this element is not predetermined, but rather calculated by the model. The element is allowed to go into negative values. This allows to track whether the wind farm-hydrogen system is able to provide energy in excess or deficit over the whole year. So as not to take electricity from this theoretically infinite source of energy preferentially over the electricity from the wind farm-hydrogen system, a price has to be applied for every MWh supplied. This price could be constant throughout the whole year. However, to ensure that electricity is not taken from the grid at moments when electricity is scarce in the rest of the country, it is chosen to use real past electricity prices. That way, at times of high electricity cost, the model preferentially takes energy from the wind farm—rSOC system. It also provides the model with the possibility to have monetary gain by sending excess electricity to the grid.

Figure 8 illustrates how the electricity price impacts whether hydrogen is produced, kept in storage or used for electricity production. A simplified flow chart is presented here, as some other factors influence the decision-making process. Currently, the price is identical whether electricity is bought or sold. In future versions, a carbon tax will be applied to electricity coming from the grid, in order for the environmentally favourable solution to be prioritized.

Figure 9 shows a graph typical of the cumulative energy sent to the grid over the year. It is negative when more energy has been taken from the grid than sent to the grid.

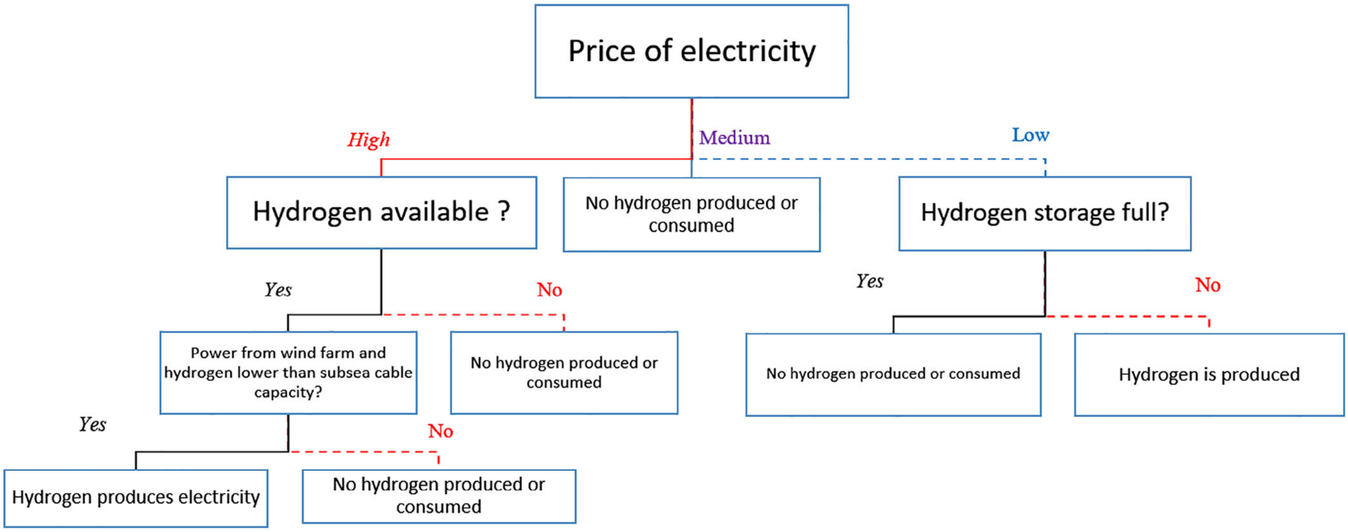

FIGURE 8 Flow chart of decision-making process for hydrogen production or consumption as a function of the price of electricity.

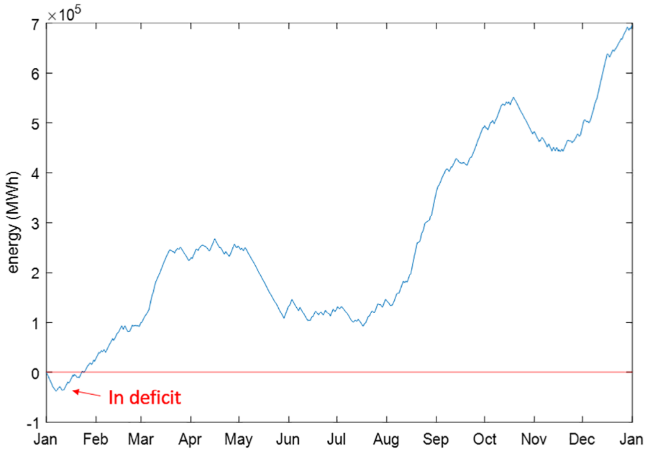

FIGURE 9 Energy deficit or contribution towards grid (cumulated numbers).

Electricity prices are provided by Nord Pool [44]. 2017 is a year with both relatively low prices, but also low fluctuations over the course of a year. The year 2021, on the other hand, is a year with exceptional variations. The year starts with relatively low prices, and towards the end of the year, there is a steep increase. This is due to a combination of factors, between strong economic growth in the wake of the Covid-19 pandemic, a cold and long winter in the Northern hemisphere, a weaker than expected increase in supply, and lower-than-expected wind generation in September and October 2021 [45]. High electricity prices are directly linked to the increase in gas prices, as peak demand in electricity is met by gas turbines, and spot-market wholesale prices are set by the price of the highest generating costs in that timeslot. In 2022, the average electricity price is exceptionally high, which is strongly linked to the conflict in Ukraine. Fluctuations are also extreme, and several peaks over the year can be identified.

Statistics for those 3 years can be seen in Table 7 (daily price) and Table 8 (hourly price). What can be noted is that for some hours, negative electricity prices are observed in 2021 and 2022, as well as prices as high as thousands of £/MWh. Figures 10 and 11 show the fluctuations over a whole year for daily and hourly prices.

TABLE 7 Statistics for daily day-ahead electricity prices in £/MWh of electricity (based on prices obtained by Nord Pool [44]).

Year	Average	Standard deviation	Max daily price	Min daily price
2017	45	6	68	30
2021	118	73	425	25
2022	204	95	571	46

TABLE 8 Statistics for hourly day-ahead electricity prices in £/MWh of electricity (based on prices obtained by Nord Pool [44]).

Year	Standard deviation hourly price	Max hourly price	Min hourly price
2017	13	150	2
2021	104	2500	−19
2022	110	1586	−50

As some simulations call for very large amounts of electricity export, a limitation is provided by applying in the model a cost per MW for a 100 km overhead line. This cost is determined using formulas and costs available in [25].

2.2.16 | Cyclicity

The PyPSA energy system modelling tool includes the possibility to declare a storage to be "cyclic". In this case, the model during the simulation considers that whatever energy is left in storage at the end of the year, is available at the beginning of

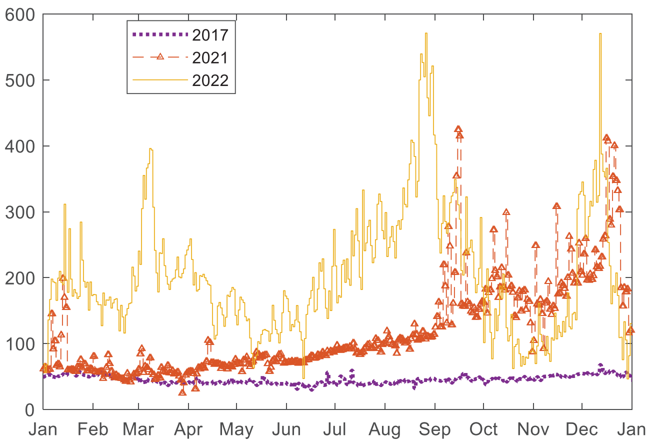

FIGURE 10 Daily day-ahead electricity price for 2017, 2021 and 2022. *Source*: Nord Pool [44].

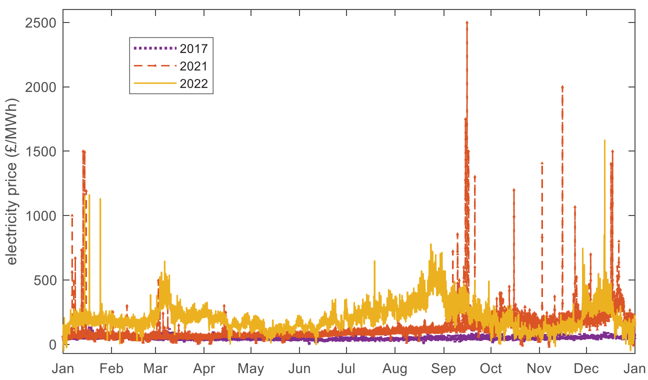

FIGURE 11 Hourly day-ahead electricity price for 2017, 2021 and 2022. *Source*: Nord Pool [44].

the year. In that way, even if the simulation is run for a year only, one can get a better grasp of what happens on a permanent basis. In the case where storage is not cyclic, and by default hydrogen storage is empty at the beginning of the year, hydrogen cannot be converted into electricity, even if electricity prices would make it economic to produce electricity. In the cases of cyclic storage, the model can recommend both using or producing hydrogen, as storage is not empty at the beginning of the year. Ideally, the same would be included for heat storage; however, the current model can only deal with determining cyclic storage needs for one of the two types of storage. The cyclicity of hydrogen storage is prioritized. Without including cyclicity of heat storage, it is considered to be empty at the beginning of the year. In several simulations, fuel cell mode is recommended to be used for short periods of time to provide some extra heat for improving electrolyser efficiency.

2.2.17 | Overview of cases run

A variety of cases are run, all with slightly different parameters. The parameters which are varied were: electricity prices throughout the year, CAPEX cost of rSOC system (as well as

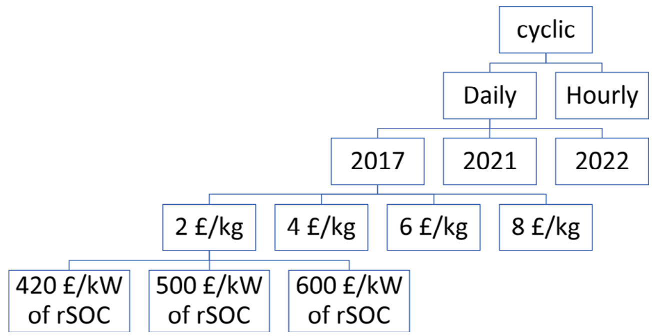

FIGURE 12 Partial tree structure of the cases that are run (cyclic case).

corresponding CAPEX for electrolyser or fuel cell only), price paid for hydrogen, cyclic or non-cyclic hydrogen storage. For the prices of electricity, the prices from three different years are used, namely 2017, 2021 and 2022. For each of these years, the effect of both daily and hourly fluctuations is studied, which gives a total of 6 different cases. For the cost of the rSOC system, three prices are used. For the price paid for hydrogen, 4 different values are investigated. This gives a total of $6 \times 3 \times 4 \times 2 = 144$ cases.

Figure 12 shows a partial arborescence of all the cases considered for the cyclic case.

3 | RESULTS

In order to illustrate the workings of the model, results generated for two short extracts of 3 days and 5 days are shown here. The graphs of Figures 13 and 14 show results obtained for electricity prices from 2021, using hourly and daily fluctuations. The cost of the rSOC system in those examples is assumed to be 420 £/kW. The setting for hydrogen storage is non-cyclic, the price paid for hydrogen is 4 £/kg.

These examples show that, when the electricity price is low, and rSOC capacity is sufficient, all wind farm production is dedicated to hydrogen production. Local demand is met using electricity from the grid. For an hour with a medium price, electricity from the wind farm is used to meet demand, and excess electricity is sent to the grid for extra revenue. During hours with very high electricity prices, even when full wind farm capacity is achieved, hydrogen is converted into electricity to be sent to the grid in addition to the excess electricity from the wind farm. In that way, it can be observed that with a given rSOC system, additional electricity can be obtained at times of scarcity and therefore high cost of electricity.

For the electricity prices of 2017, in the case of cyclic storage, no hydrogen production is installed at all, and all the electricity provided by the wind farm is sent to shore. In the case of the non-cyclic storage, when hydrogen is paid at least 4 £/kg, dedicated hydrogen production is chosen. A small amount of fuel cell capacity is required to provide heat for electrolyser mode, but no electricity is sent to shore. The numbers are identical for the hourly and daily fluctuations of the prices of electricity. The recommended capacity is identical and equal to 324 MW for all

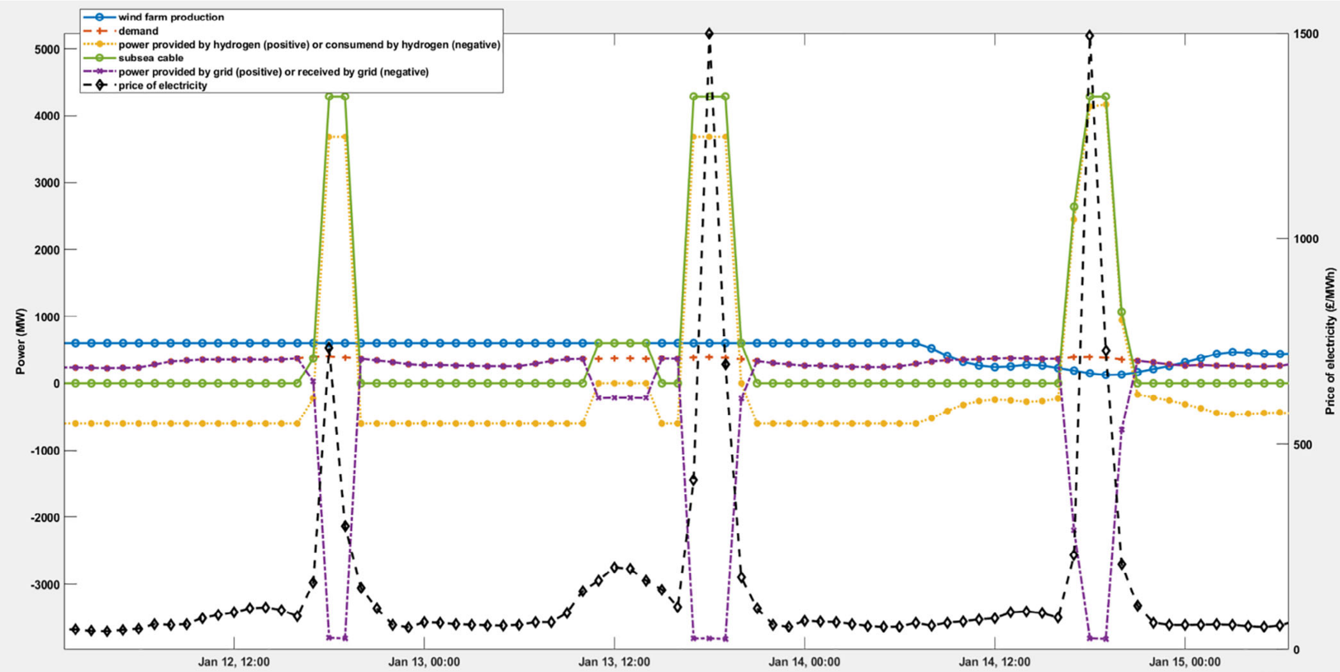

FIGURE 13 Extract of 3 days of the simulation for hourly electricity prices of 2021, a cost of rSOC at 420 £/kW and a hydrogen price of 4£/kg, non-cyclic case.

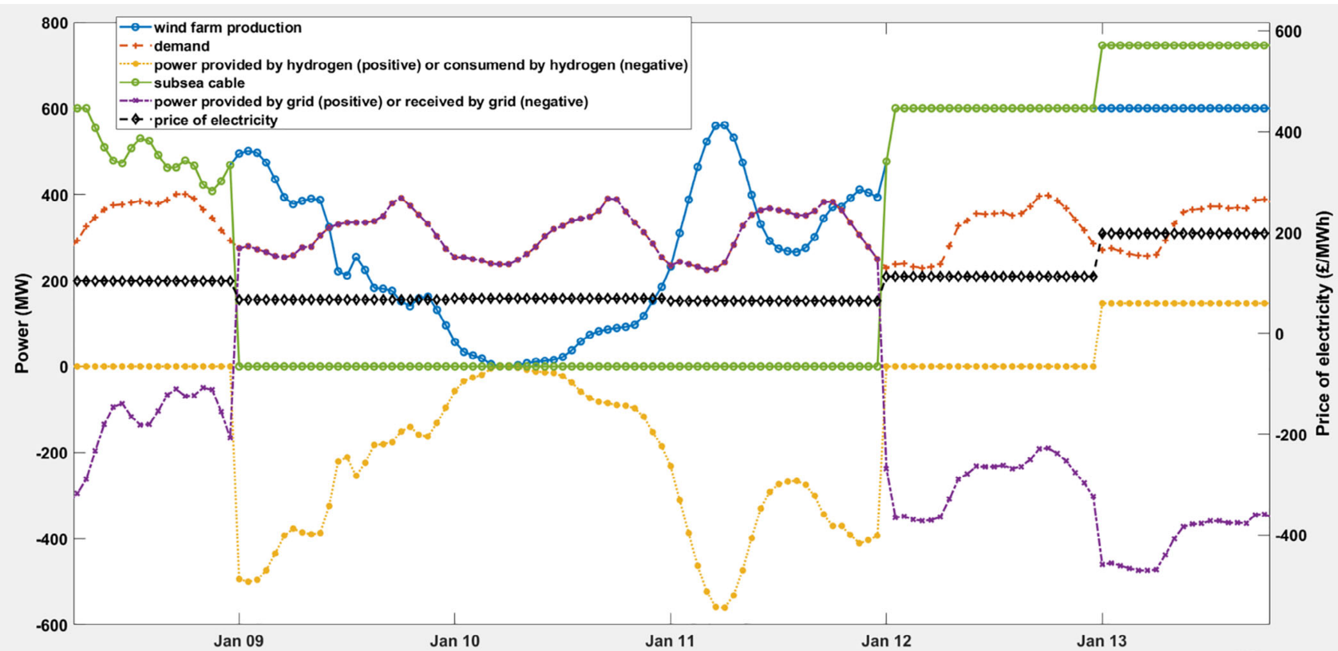

FIGURE 14 Extract of 5 days of the simulation for daily electricity prices of 2021, a cost of rSOC at 420 £/kW and a hydrogen price of 4£/kg, non-cyclic case.

cases except for the combination of lowest price of the electrolyser and a price of hydrogen of 8 £/kg, when it is 342 MW. It should also be noted that the capacity is expressed in a mode with a medium efficiency. That is, when the wind farm provides a higher power, the electricity can still be utilised by running the electrolyser at a higher power but with a lower efficiency.

For the electricity prices in 2021 and 2022, reversible systems are installed in all cases. In many cases, extra fuel cell capacity is required. That is, though the maximum electrolyser capacity needed is limited by the electricity produced by the wind farm, recommended fuel cell capacity is only limited by weighing the gain obtained by extra fuel cell capacity against the added costs

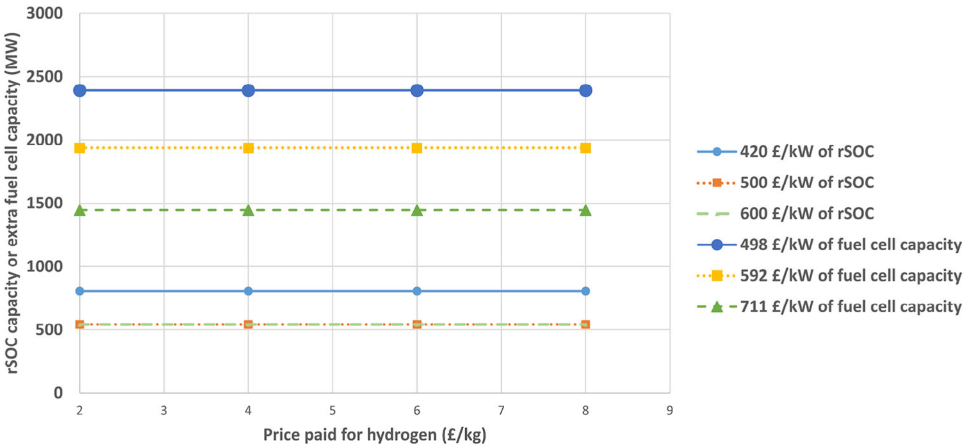

FIGURE 15 Optimized capacities for hourly electricity prices from 2021, cyclic storage, dependency on price paid for hydrogen and rSOC or fuel cell cost.

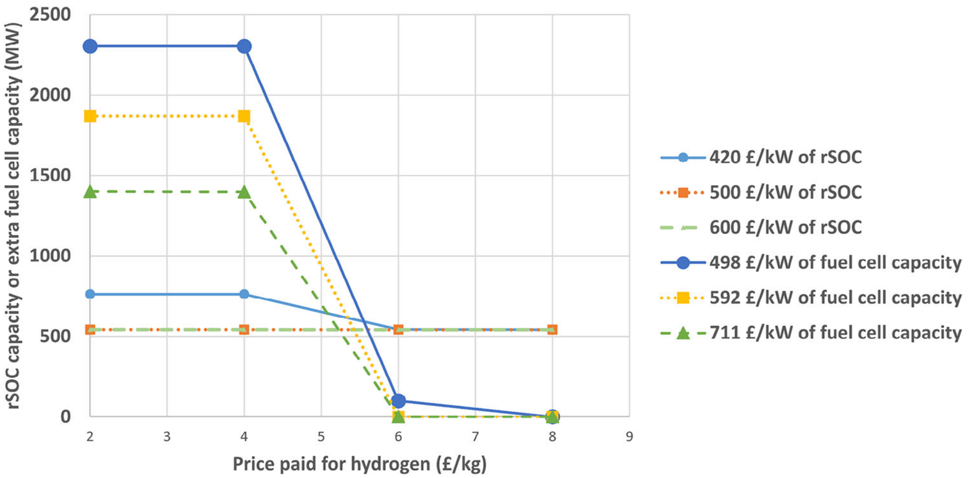

FIGURE 16 Optimized capacities for hourly electricity prices from 2021, non-cyclic storage, dependency on price paid for hydrogen and rSOC or fuel cell cost.

for extra fuel cell capacity, extra subsea cable capacity and extra grid capacity.

For all cyclic cases, rSOC capacity as well as extra fuel cell capacity is dependent on the cost of the rSOC /fuel cell but not on the price paid for hydrogen. Figure 15 shows the optimized values both for rSOC and extra fuel cell capacity, and their dependency on rSOC or fuel cell cost, in the case of hourly electricity prices from 2021, and where hydrogen storage is considered to be cyclic (hydrogen left over at end of year considered to be available at beginning of the year). Contrary to the non-cyclic case described in the next paragraph, due to the fact that the extra hydrogen in the end of the year is made available at the beginning of the year, the price paid for hydrogen does not impact the decision making, as it is not considered interesting to sell the hydrogen.

Figure 16 shows the optimized values both for rSOC and extra fuel cell capacity, and their dependency on rSOC or fuel cell cost, in the case of hourly electricity prices from 2021, and where hydrogen storage is not considered to be cyclic (empty at the beginning of the year). It can be seen that for all hydrogen prices and rSOC costs, a substantial amount of rSOC capacity is recommended to be installed. This amount drops with increased rSOC costs, but also with increased price paid for hydrogen. An explanation of why the rSOC capacity would go down with higher hydrogen prices, is that part of the rSOC capacity is installed for the purpose of having the automatically included fuel cell mode. When the market cost of hydrogen is greater, less hydrogen is converted into electricity, so the need for the fuel cell capacity included in rSOC drops. This can also be seen in the values for the extra fuel cell capacity (which is not reversible). Very high amounts are recommended to be installed in order to convert large amounts of hydrogen into electricity in a short time. This is the case where hydrogen as a gas does not have a high value (2 or 4 £/kg).

Figure 17 shows optimized capacities for the rSOC and extra fuel cell capacities for hourly electricity prices in 2022 and cyclic storage. Optimized values are again independent of the price paid for hydrogen. This time, rSOC capacity recommended is rather high, and extra capacity for fuel cell-only mode, is lower than for the same case for electricity prices from 2021. The system is run in an electrolyser mode with higher efficiencies (and therefore lower power input per installed capacity). In 2021,

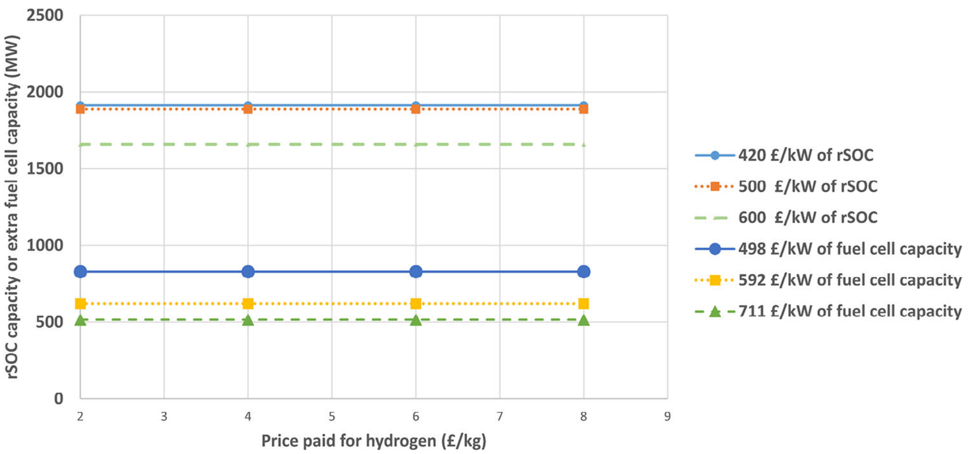

FIGURE 17 Optimized capacities for hourly electricity prices from 2022, cyclic storage, dependency on price paid for hydrogen and rSOC or fuel cell cost.

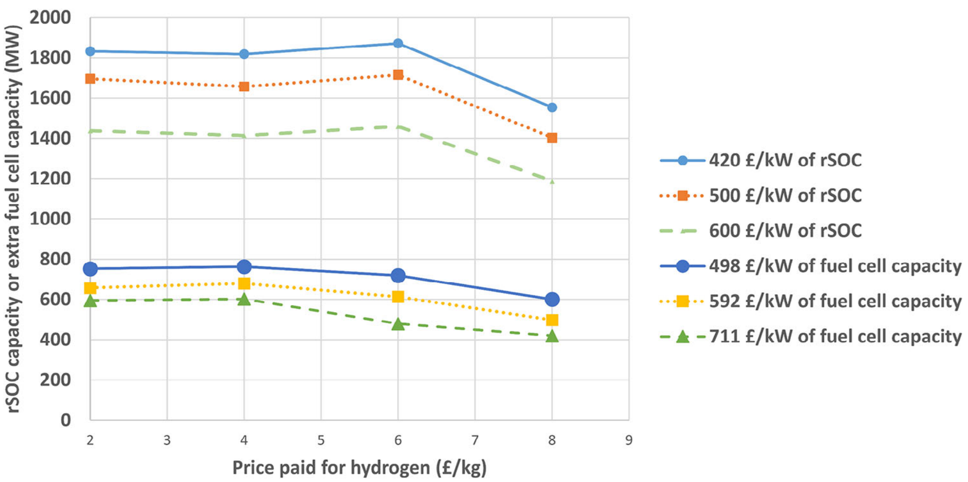

FIGURE 18 Optimised capacities for hourly electricity prices in 2022, non-cyclic storage.

fuel cell mode is mostly only used at the end of the year, and higher amounts of electricity are produced using hydrogen in shorter periods of time, so extra fuel cell capacity is emphasized, whereas in 2022, there are several periods throughout the year where fuel cell mode is used, and maximum electricity produced in an hour is not as high as in 2021. Therefore, more money can be spent on reversible capacity, allowing the use of an electrolyser mode with a higher efficiency.

Figure 18 shows optimised capacities for hourly electricity prices from 2022, in the case of non-cyclic storage. As for the electricity prices from 2021, fuel cell capacity is lower for higher prices for hydrogen, indicating that some of the hydrogen is considered to be "sold" at the end of the year. However, whereas in 2021, fuel cell capacity for the cases of high prices of hydrogen is mostly used to provide heat for electrolyser mode while sending some electricity to shore, in 2022, large amounts of hydrogen are converted into electricity, clearly to provide for extra electricity in the grid at times of high electricity prices.

This can be seen when looking at the amount of hydrogen, as well as heat, stored throughout the year, in 2021 and in 2022. Figure 19 shows what happens for electricity prices of 2022, the highest cost of rSOC considered here and the highest price paid for hydrogen. Large amounts of hydrogen are stored, but also large amounts of hydrogen are reconverted into electricity at moments where electricity prices reach high values. Hydrogen is still available in storage at the end of the year.

Figure 20 shows the same as Figure 19, but for 2021. A lot of hydrogen is stored, but only small amounts are reconverted into electricity. For electricity prices of that year, and with the given assumptions, it looks as though hydrogen has more value as a gas. Heat stored stays at relatively small levels (<12 GWh), fluctuating between 0 and maximum capacity (see Figure 21), which is why it is thought that the main purpose of fuel cell mode here is to provide heat for increased efficiency of electrolyser mode.

In order to determine how the optimisation process improves the profits that can be made from the wind farm—rSOC system, the optimized case is compared to the profits made by a wind farm without hydrogen production, which is considered to be the default case here. Equation (22) shows the variables that allow determining the total profit of the wind farm—rSOC system.

$$T = R_H + R_E - C_{sc} - C_{rSOC} - C_{HS} - C_{wf}, \tag{22}$$

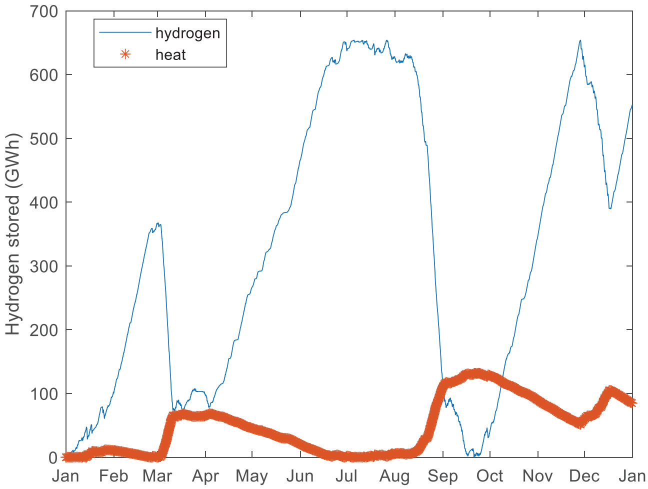

FIGURE 19 Hydrogen and heat stored throughout one year for hourly electricity prices of 2022, rSOC cost of 600 £/kW and price paid for hydrogen at 8 £/kg, non-cyclic storage.

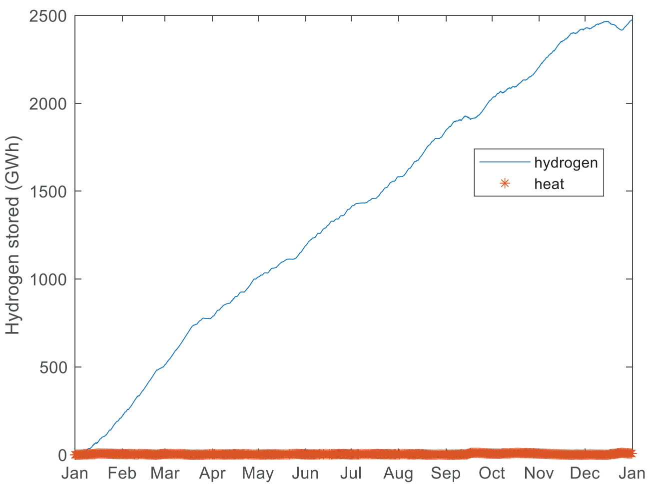

FIGURE 20 Hydrogen and heat stored throughout one year for hourly electricity prices of 2021, rSOC cost of 600 £/kW and price paid for hydrogen at 8 £/kg, non-cyclic storage.

where T is the total profit, R_H the revenue from selling left-over hydrogen, R_E revenue from selling electricity, C_{sc} is the cost of the subsea cable connection (including an offshore and onshore substation), C_{rSOC} is the cost for the solid oxide cell technology based electrolyser, fuel cell or reversible system, including accessories, C_{HS}, is the cost for hydrogen storage and C_{wf} is the cost of the wind farm and electrical cables up until a central offshore platform. All costs include Capex and Opex costs. For C_{wf}, [5] is consulted for the cost predictions for 2030 of a floating wind farm up until a central platform.

In the default case producing electricity only, Equation (22) is simplified to Equation (23).

$$T = R_E - C_{sc} - C_{wf}. \tag{23}$$

Table 9 shows the profit that can be made from a wind farm only in one year depending on whether electricity prices are

TABLE 9 Yearly profit from a wind farm only for various electricity price fluctuations.

Year of electricity prices	2017	2021	2022
Total annual profit	53 M£/year	300 M£/year	590 M£/year
Profit per unit of electricity	16 £/MWh	92 £/MWh	176 £/MWh

identical to 2017, 2021, or 2022. For reference, the profit is divided by the total amount of electricity produced in a year.

Figure 22 shows the relative benefits obtained when using the optimized scenario compared to the default case. For electricity prices of 2017, for a hydrogen price of 2 £/kg, the optimised case is identical to the default case. For electricity prices from the same year, dedicated hydrogen production instead of electricity production only, allows improving profit by at least 221%, if hydrogen is paid at least 4 £/kg. When comparing this finding with alternative studies (Table 10), it can be seen that 4 £/kg is a rather low price at which to be making profit. That is, all alternative studies except for one indicate an LCOH over 4 £/kg. Only one study indicates an LCOH of less than 2 £/kg. For the dedicated hydrogen production case of this study, LCOH is determined to be between 3.10 £/kg and 3.15 £/kg (depending on cost of electrolyser), including the cost of a pipeline as indicated in Section 2.2.13. This is assumed to be due to use of futuristic costs, with for some components rather significant cost reduction assumptions, rather high efficiencies, and the assumption that the electrolyser can be run at loads exceeding the rated power if needed.

A maximum increase in profit of 908% can be seen for the case of daily day-ahead electricity prices from 2017, rSOC Capex of 420 £/kW, and a hydrogen price of 8 £/kg.

For electricity prices of 2021 and 2022, the minimum increase in profit is 3%, and the maximum increase in profit is 90%. It should be noted that though the relative increases in profit look extremely high, this is mainly due to the default profit being low in some cases, thus leading to high percentages, even if the absolute profit is not.

The optimised cases can also be compared to a default case that is dedicated hydrogen production, where all the electricity is used to produce hydrogen and demand is provided by using imported electricity only that is paid for. In this case, Equation (22) is modified to Equation (24).

$$T = R_H - C_{rSOC} - C_{HS} - C_{wf}. \tag{24}$$

Table 11 shows what happens in terms of profit (or deficit) in this default case. Dedicated hydrogen production does not make sense in the cyclic case, dependency on rSOC Capex is small, and results are independent from electricity prices. Which is why results are grouped by hydrogen price.

Figure 23 summarizes the improvements obtained by going from the default case of dedicated hydrogen production to an optimised infrastructure. The benefits are mostly dependent on hydrogen price and year of electricity price, whereas impact of rSOC Capex or daily vs hourly fluctuations does not make a

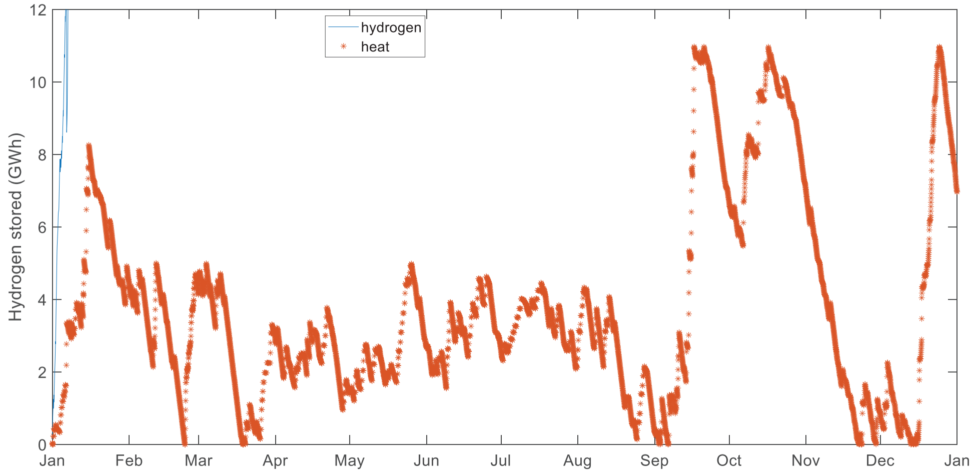

FIGURE 21 Heat stored throughout the year for hourly electricity prices of 2021, rSOC cost of 600 £/kW and price paid for hydrogen at 8 £/kg, non-cyclic storage (zoom of Figure 20).

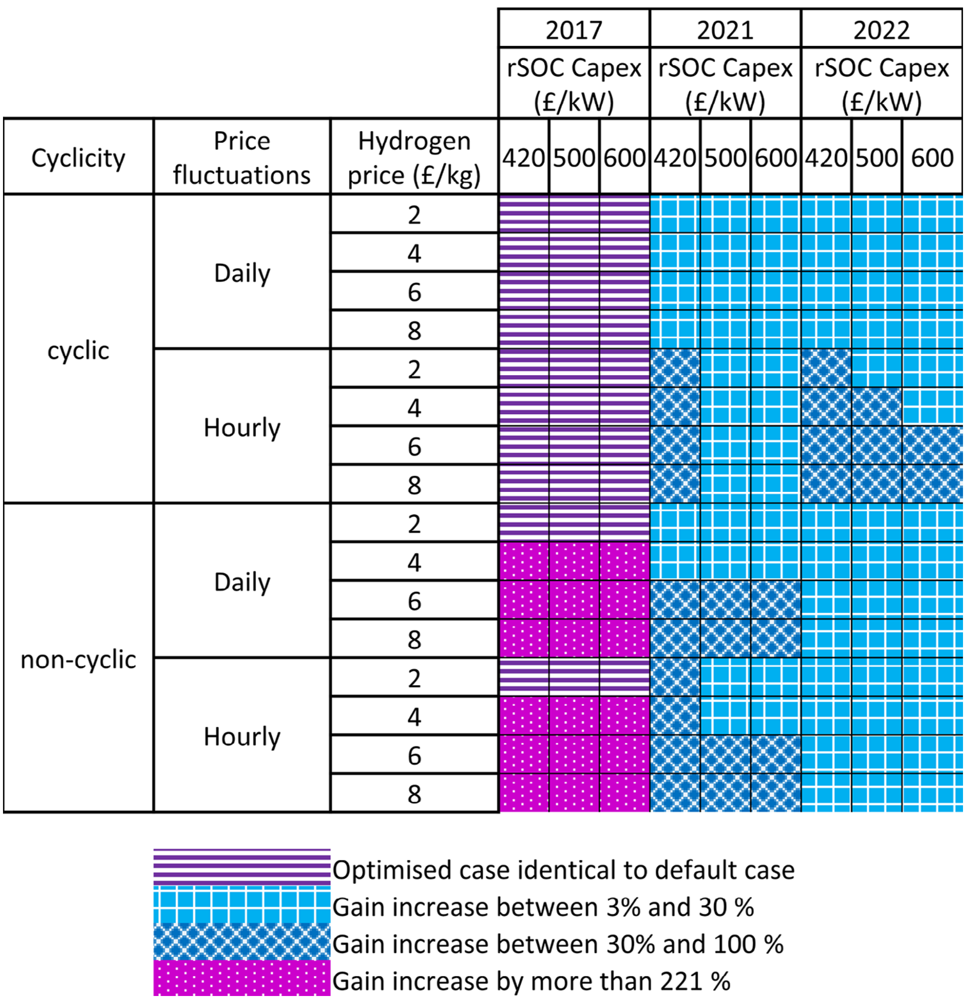

FIGURE 22 Benefits obtained thanks to optimised case when compared to default case (wind farm only).

TABLE 10 Summary of LCOH calculation results for green hydrogen produced using various methods.

Source	[5]	[9, 10]	[12]	[13]		Current study
				Min	Max	
LCOH (£/kg)	4.14	5.17	1.65	4.74	16.06	3.10–3.15 £/kg*
Renewable energy	Floating wind	Onshore wind, tidal	Floating wind, semi-submersible	Onshore wind, solar		Floating wind
Electrolyser	SOC	PEM	PEM	Alkaline	PEM	rSOC
Methodology	Offshore, centralised, dedicated hydrogen production	Limited use of curtailed energy	Offshore, dedicated, decentralised	Optimisation, electricity can be bought from grid	Optimisation, curtailed energy only	Offshore, centralised, dedicated, optimised
Project size	1.2 GW wind farm, 960 MW electrolyser	0.5 MW electrolyser	4 GW			600 MW wind farm, 324 MW electrolyser
Year	2030	2014–2017	2037			2030
Location	UK offshore, undetermined, pipeline (80 km)	Orkney Islands, (hydrogen transport by ship and truck in pressurised container)	North Sea or Celtic Sea, 50 km from shore, pipeline			Celtic Sea, 60 km from shore, pipeline

*Including cost of pipeline and after applying a discount rate and an inflation rate over the project lifetime of 25 years.

TABLE 11 Profits/deficit made from default case of dedicated hydrogen production.

Hydrogen price	2 £/kg	4 £/kg	6 £/kg	8 £/kg
Profit (M£)	−8	172	351	531

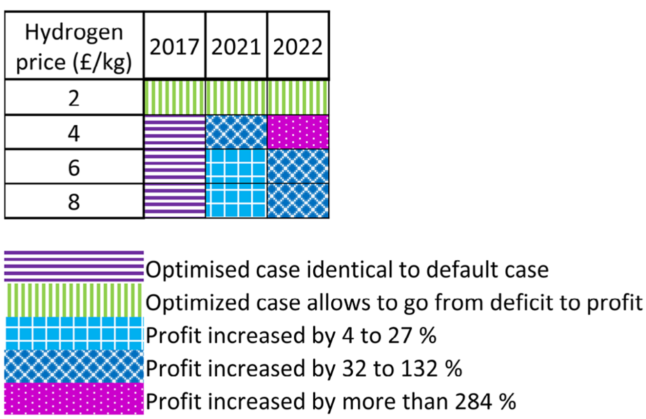

FIGURE 23 Improvement obtained by going from dedicated hydrogen production to optimised scenario.

big difference. Results are grouped in 6 categories. For a hydrogen price of 2 £/kg the optimised scenario allows to go from a deficit to a profit. For all other hydrogen prices combined with electricity prices from 2017, dedicated hydrogen is the optimised case. For hydrogen prices at 4 £/kg at least and electricity prices for 2021 and 2022, optimisation allows increasing the profit by at least 4% and by up to 324% (case of hydrogen price 4 £/kg, hourly fluctuations of electricity prices from 2022 and rSOC Capex of 420 £/kW).

4 | CONCLUSION AND FURTHER WORK

The results obtained illustrate how much the fluctuation of electricity prices can impact the most beneficial way to combine hydrogen with ORE. In years where electricity prices are fairly low and not fluctuating much, dedicated hydrogen production looks like a beneficial way to use the electricity from the wind farm, under the condition that the price paid for hydrogen is sufficiently high (4, 6 or 8 £/kg). In years where electricity prices fluctuate a lot, it is beneficial to have not only hydrogen production capacity, but also be able to convert hydrogen back into electricity at periods of high prices of electricity.

The optimisation was investigated for daily and hourly fluctuations of day ahead electricity prices. It was observed that being able to predict hourly fluctuations, calls for higher amounts of fuel cell capacity, which allows to provide large amounts of electricity during hours of very high electricity prices.

If the hydrogen produced can be sold for at least 4 £/kg, a profit is guaranteed, which makes dedicated hydrogen production a rather fail-safe solution. Having the possibility to convert hydrogen into electricity, can increase the profit in years for electricity prices with high values and fluctuations. There is uncertainty on future electricity prices, but a reversible system allows reducing amounts of imported electricity in the case of a potential energy crisis and could even allow exporting excess electricity.

The comparison of cyclic and non-cyclic storage shows important changes in the results. When hydrogen available at the end of the year is not considered available at the beginning, hydrogen is kept as a gas for the highest prices paid for hydrogen. Both methods do not entirely reflect what happens throughout the whole lifetime of a project of several years. Preliminary calculations run for several years, containing years of both high and low electricity prices indicate the need for both dedicated and reversible hydrogen production.

Future improvements to be made are on the side of the hydrogen market economy. The present paper includes assumptions made for four different constant prices paid for hydrogen throughout the year. A realistic market economy would include fluctuating prices of hydrogen, as well as indications on the hydrogen demand.

In this study, it is assumed that cheap geological storage is available close to the wind farm. This may not necessarily be the case. Simulations with costs for hydrogen storage corresponding to pressurized storage in containers will also be investigated in the future.

Another point for future study is the impact of ramp-up and ramp-down time for the rSOC system on the energy dispatch decisions. Electrolyser efficiencies are rather high, and in particular the heat requirements are too low. Balance of plant calculations for a reversible rSOC are ongoing in the context of an associated EPSRC project (EP/W003597/1) and indicate lower numbers for electrolyser efficiencies or alternatively higher heat input requirements.

In this study, it is considered that the rSOC system is situated offshore. Similar simulations have been run for an onshore rSOC system, in which the subsea cable connection would only transfer electricity to shore coming from the wind farm, and not from the rSOC running in fuel cell mode and comparison to offshore hydrogen production are presented in [40]. Dependency on electricity prices was similar to the offshore version. The main difference to the offshore version is the increased amount of extra fuel cell capacity, as exporting additional electricity does not require as much extra cost as in the offshore case. Unpublished calculations where run where not only rSOC capacity was optimised, but the location (onshore or offshore) as well, and they indicate that dedicated hydrogen production is more interesting offshore, whereas reversible hydrogen production is more interesting onshore.

Simulations run for alternative ORE farms (tidal and wave) indicate similar dependencies of the selection of the type of hydrogen production (dedicated or reversible) on the electricity price and dependency of the installed amounts on the capacity factor as well as the distance to shore.

AUTHOR CONTRIBUTIONS

Jessica Guichard: Conceptualization; investigation; methodology; writing—original draft. **Robert Rawlinson-Smith**: Supervision; writing—review and editing. **Deborah Greaves**: Funding acquisition; project administration; supervision; writing—review and editing.

ACKNOWLEDGEMENTS

The research presented in this paper is part of the EPSRC-funded project on high efficiency reversible solid oxide cells (rSOC) for the integration of offshore renewable energy using hydrogen (EP/W003732/1).

CONFLICT OF INTEREST STATEMENT

The authors declare no conflicts of interest.

DATA AVAILABILTY STATEMENT

The data that support the findings of this study are available from the corresponding author upon reasonable request (except for day-ahead electricity prices which need to be obtained directly from Nord Pool).

ORCID

Jessica Guichard https://orcid.org/0009-0009-4166-5299

REFERENCES

1. UK Government: Climate Change Act (2008). https://www.legislation.gov.uk/ukpga/2008/27/contents
2. HM Government: British Energy Security Strategy (2022). https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy
3. HM Government: UK Hydrogen Strategy (2021). https://www.gov.uk/government/publications/uk-hydrogen-strategy
4. International Energy Agency (IEA): The Future of Hydrogen—Seizing Today's Opportunities. IEA, Paris (2019)
5. Spyroudi, A., Wallace, D., Stefaniak, K., et al.: Offshore Wind and Hydrogen—Solving the Integration Challenge. ORE Catapult, New York (2020)
6. Harman, J., Hjalmarsson, M.J.P., et al.: 1MW-class solid oxide electrolyzer system prototype for low-cost green hydrogen. ECS Trans. 103(1), 383–392 (2021)
7. Wang, Y., Banerjee, A., Wehrle, L., et al.: Performance analysis of a reversible solid oxide cell system based on multi-scale hierarchical solid oxide cell modelling. Energy Convers. Manage. 196, 484–496 (2019)
8. Smolinka, T., Wiebe, N., Sterchele, P., et al.: Studie IndWEDe. Industrialisierung der Wasserelektrolyse in Deutschland (2018)
9. EMEC: Surf 'n' Turf. https://www.emec.org.uk/projects/hydrogen-projects/surf-n-turf/ (2017)
10. Zhao, G.: Business Model and Replication Study of BIG HIT. Department of Energy Conversion and Storage, Technical University of Denmark (2017)
11. Caine, D., Wahyuni, W., Pizii, B., et al.: ERM Dolphyn Hydrogen: Phase 2 - Final Report. Environmental Resources Management, Department for Business, Energy and Industrial Strategy (2021)
12. Caine, D., Iliffe, M., Kinsella, K., et al.: Dolphyn Hydrogen: Phase 1 - Final Report. Environmental Resources Management, Department for Business, Energy and Industrial Strategy (2019)
13. Dufo-López, R., Lujano-Rojas, J.M., Bernal-Agustín, J.L.: Optimisation of size and control strategy in utility-scale green hydrogen production systems. Int. J. Hydrogen Energy 50, 292–309 (2024)
14. Crown Estate: The Crown Estate refines plans for Celtic Sea floating wind. https://www.thecrownestate.co.uk/news/the-crown-estate-refines-plans-for-celtic-sea-floating-wind (2023)
15. Crown Estate: The Crown Estate accelerates plans for floating offshore wind in the Celtic Sea with multi-million pound programme of marine surveys. https://www.thecrownestate.co.uk/news/the-crown-estate-accelerates-plans-for-floating-offshore-wind-in-the-celtic (2022)
16. Petroc: Falck Renewables and BlueFloat Energy looking at early delivery in Celtic Sea. https://petrocwind.co.uk/early-delivery-in-celtic-sea/ (2022)
17. Llywelyn: Falck Renewables and BlueFloat Energy looking at early delivery in Celtic Sea. https://llywelynwind.co.uk/early-delivery-in-celtic-sea/ (2022)
18. Supergen Offshore Renewable Energy: Supergen ORE Hub Research Landscape. https://supergen-ore.net/research-landscape (2023)
19. Brown, T., Hörsch, J., Hofmann, F., et al.: PyPSA: Python for power system analysis. https://pypsa.readthedocs.io/ (2024)

20. Guichard, J., Rawlinson-Smith, R., Greaves, D.: Cost optimization of offshore wind farm combination with reversible solid oxide cell system producing hydrogen using the PyPSA power system modelling tool. In 7th Offshore Energy & Storage Symposium (OSES 2023). IET, Stevenage (2023)
21. Caldera, U., Breyer, C.: Learning curve for seawater reverse osmosis desalination plants: Capital cost trend of the past, present, and future. Water Resour. Res. 53(12), 10523–10538 (2017)
22. Pfenninger, S., Staffell, I.: Renewables.ninja. https://www.renewables.ninja/(2022)
23. Crown Estate: Celtic sea floating offshore wind. https://www.thecrownestate.co.uk/en-gb/what-we-do/on-the-seabed/floating-offshore-wind/ (2022)
24. Gaertner, E., Rinker, J., Sethuraman, L., et al.: IEA Wind TCP Task 37: Definition of the IEA 15-megawatt offshore reference wind turbine (2020)
25. Xiang, X., Fan, S., Gu, Y., et al.: Comparison of cost-effective distances for LFAC with HVAC and HVDC in their connections for offshore and remote onshore wind energy. CSEE J. Power Energy Syst 7(5), 954–975 (2021)
26. CERES Power: (2023)
27. DNV-GL: Power-to-Hydrogen IJmuiden Ver—Final report for TenneT and Gasunie (2018)
28. North Sea Energy: A vision on hydrogen potential from the North Sea (2020)
29. Meier, K.: Hydrogen production with sea water electrolysis using Norwegian offshore wind energy potentials. Int. J. Energy Environ. Eng. 5, 104 (2014)
30. Forsberg, C.: Low-cost crushed-rock heat storage with oil or salt heat transfer. Appl. Energy 335, 120753 (2023)
31. Frank, M., Deja, R., Peters, R., et al.: Bypassing renewable variability with a reversible solid oxide cell plant. Appl. Energy 217, 101–112 (2018)
32. Gamble, S.R.: Reversible solid oxide fuel cells as energy conversion and storage devices. Ph.D. Thesis, University of St Andrews (2011)
33. Argonne National Laboratory: HDSAM—Hydrogen Delivery Scenario Analysis Model. Argonne National Laboratory, Lemont, IL (2023)
34. van Gerwen, R., Eijgelaar, M., Bosma, T.: Hydrogen in the electricity value chain DNV-GL (2019)
35. Hydrogen Analysis Resource Center: Hydrogen compressibility at different temperatures and pressures. https://h2tools.org/hyarc/hydrogen-data/hydrogen-compressibility-different-temperatures-and-pressures (2023)
36. Bloomenergy: Bloom energy announces hydrogen solid oxide fuel cell with 60% electrical efficiency and 90% high temperature combined heat and power efficiency. https://investor.bloomenergy.com/press-releases/press-release-details/2024/Bloom-Energy-Announces-Hydrogen-Solid-Oxide-Fuel-Cell-with-60-Electrical-Efficiency-and-90-High-Temperature-Combined-Heat-and-Power-Efficiency/default.aspx (2024)
37. Kyos: What is cushion gas? https://www.kyos.com/faq/what-is-cushion-gas/#:~:text=Cushion%20gas%20is%20the%20amount,of%20gas%20is%20base%20gas (2023)
38. Williams, J.D.O., Williamson, J.P., Parkes, D., et al.: Does the United Kingdom have sufficient geological storage capacity to support a hydrogen economy? Estimating the salt cavern storage potential of bedded halite formations. J. Energy Storage 53, 105109 (2022)
39. IEA: Global Hydrogen Review 2022 (2022)
40. Guichard, J., Rawlinson-Smith, R., Greaves, D.: Comparison of offshore and onshore hydrogen production from offshore wind. In 6th International Conference on Renewable Energies Offshore. CRC Press/Balkema, Taylor & Francis Group, Lisbon (2024)
41. GridWatch. https://www.gridwatch.templar.co.uk/
42. Elexon. https://www.bmreports.com/
43. National Grid ESO: Regional Breakdown of FES 2022 Data (Electricity). https://www.futureenergyscenarios.com/2022-FES/electricity-maps.html (2022)
44. Nord Pool. https://www.nordpoolgroup.com/
45. IEA: What is behind soaring energy prices and what happens next? https://www.iea.org/commentaries/what-is-behind-soaring-energy-prices-and-what-happens-next (2021)

How to cite this article: Guichard, J., Rawlinson-Smith, R., Greaves, D.: Optimization of reversible solid oxide cell system capacity combined with an offshore wind farm for hydrogen production and energy storage using the PyPSA power system modelling tool. IET Renew. Power Gener. 1–21 (2024). https://doi.org/10.1049/rpg2.13134