Green hydrogen as energy storage and energy carrier in combination with offshore wind power: Production, energy management and techno-economic analysis

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Abstract

The global energy system is in a transition where the intent is to reduce anthropogenic emissions of CO_2 and other greenhouse gases. The general consensus in the scientific community is that these emissions are the main cause of the on-going climate change, and the international community have largely agreed that the magnitude of this climate change must be kept as low as possible. Most of the anthropogenic CO_2 emissions are related to the burning of fossil fuels in the form of coal, oil and natural gas. One of the main priorities to tackle climate change is therefore to reduce the use of fossil fuels by transitioning to technologies that can deliver the same product (electricity, heat, mechanical power, etc.) with lower emissions of greenhouse gases.

One of the technologies that could potentially reduce fossil fuel consumption within several sectors is green hydrogen. This is hydrogen produced through electrolysis of water where the electricity input comes from a renewable energy source like wind, solar or hydro power. Hydrogen is a versatile energy carrier that can be used to reduce emissions of greenhouse gases in several sectors. Suggested applications include using green hydrogen as a component in the refining industry and in the production of ammonia and methanol, green hydrogen as an industrial heat source, as well as green hydrogen as a fuel in the transport sector and as energy storage in electricity systems. The low-hanging fruits are the applications where fossil-fuel based hydrogen is currently used, which is mostly in the refining industry and the production of ammonia and methanol. The other applications could have significant future potential if sufficient technology improvements and cost reductions are achieved.

The first phase of this PhD project focused on hydrogen as energy storage in electricity systems based on renewable energy. The need for energy storage has increased as a consequence of increasing shares of intermittent energy sources like solar and wind power in electricity systems. Batteries are very efficient and well suited for short-term energy storage, but due to self-discharge challenges they are not well suited for long-term (weeks and months) energy storage. Green hydrogen has been suggested as an alternative for long-term energy storage since it can be stored for long periods with minimal hydrogen losses in the storage phase. However, the operational results from the real-world facilities reviewed in the first phase of this PhD project showed that there are significant challenges related to using green

hydrogen as energy storage in electricity systems. The overall energy losses and costs of these systems are currently too high to make them viable large-scale solutions. The reviewed systems showed overall energy efficiencies in the range 15-40%, and this, combined with the high costs of electrolyzers and fuel cells, has so far prevented the commercialization of these systems.

The focus in the main phase of this PhD project was on the combination between green hydrogen and offshore wind power, i.e., hydrogen produced through electrolysis of water where the electricity input is delivered by offshore wind turbines. The specific focus areas within this topic were the hydrogen production (electrolysis) and the energy management (control system) in the wind-hydrogen systems. Computer models were developed to simulate the operation of wind-hydrogen systems, and real-world data sets were used as input to the models to increase the realism of the simulation results. The data included energy production and wind speed from a 2.3 MW floating offshore wind turbine, as well as electricity price data for the wind turbine's location. The models were used in simulation scenarios with different lengths (from 31 days to 25 years), scales (2.3 MW to 1500 MW), system designs, and technology and cost levels (current and future forecasts). Techno-economic analyses were also performed in which the levelized cost of hydrogen (LCOH), levelized cost of energy (LCOE) and net present value (NPV) were calculated for the different scenarios, and a sensitivity analysis was performed to identify the factors with the highest impact on the technical performance and cost of wind-hydrogen systems. The results from the various simulations indicate that green hydrogen production with electricity from offshore wind power is technically feasible, and the LCOH can be competitive with other hydrogen production methods in the scenarios where the conditions are favorable. The most important factors in this respect are the electricity price and the capacity factor of the wind farm, which is mostly determined by the wind speed. Since the electricity price and wind speed are so important for the economic viability of wind-hydrogen systems, a novel model was developed where the wind speed is used to forecast the production of wind energy and hydrogen through polynomial regression, and a control system was designed that used the electricity price to schedule when the wind-hydrogen system should produce hydrogen and when it should sell the electricity directly to the grid. In a real-world wind-hydrogen system the forecast wind speed (e.g., from a weather service provider) and the day-ahead electricity prices (e.g., from the power company) are thus the only required inputs to forecast and optimally schedule wind energy and hydrogen production. The results with and without the novel control system show that the LCOH was reduced by 10-46% in all scenarios where the control system was used, and in some cases the control system constituted the difference between a profitable system and an unprofitable one. This shows that intelligent computer models that can forecast the system processes and optimally schedule the hydrogen production, with regards to both technical and economic parameters, will be a very important factor to make large-scale wind-hydrogen systems a reality.

Sammendrag

Det globale energisystemet har begynt på en overgang hvor intensjonen er å redusere menneskeskapte utslipp av CO_2 og andre klimagasser. Konsensus blant klimaforskere er at disse utslippene er hovedårsaken til de pågående klimaendringene, og det internasjonale samfunnet har i stor grad blitt enige om at omfanget av klimaendringene må begrenses så mye som mulig. Mesteparten av de menneskeskapte CO_2-utslippene er relatert til brenning av fossile brensler i form av kull, olje og gass. En av hovedprioritetene for å håndtere klimaendringene er derfor å redusere bruken av fossile brensler ved å gå over til teknologier som kan levere det samme sluttproduktet (elektrisitet, varme, mekanisk arbeid, etc.) med lavere utslipp av klimagasser.

En av teknologiene som potensielt kan redusere bruken av fossile brensler innen flere sektorer er grønt hydrogen. Dette er hydrogen som er produsert med elektrolyse av vann hvor elektrisiteten kommer fra fornybare energikilder som vind-, sol- og vannkraft. Hydrogen er en allsidig energibærer som kan benyttes til å redusere utslipp av klimagasser i flere sektorer. Mulige bruksområder inkluderer å bruke grønt hydrogen som en komponent i raffineringsindustrien og i produksjon av ammoniakk og metanol, grønt hydrogen som industriell varmekilde, i tillegg til grønt hydrogen som drivstoff i transportsektoren og som energilagring i kraftsystemer (elektrisk strøm). De lavt-hengende fruktene er innen bruksområdene hvor fossilbasert hydrogen brukes i dag, hvorav mesteparten er i raffineringsindustrien og i produksjon av ammoniakk og metanol. De andre bruksområdene kan ha et betydelig fremtidig potensial hvis tilstrekkelige teknologiforbedringer og kostnadsreduksjoner oppnås.

Den første fasen i dette PhD-prosjektet fokuserte på hydrogen som energilagring i kraftsystemer basert på fornybar energi. Behovet for energilagring har økt som en følge av økende andeler variable energikilder som sol- og vindkraft i kraftsystemer. Batterier har veldig høy virkningsgrad og er velegnede til kortidslagring av strøm, men på grunn av utfordringer knyttet til selvutladning er de ikke godt egnet for langtidslagring (uker og måneder). Grønt hydrogen har blitt foreslått som et alternativ for langtidslagring siden hydrogen kan lagres i lange perioder med minimale tap av hydrogen i lagringsfasen. De operasjonelle resultatene fra systemene som ble evaluert i den første fasen av dette PhD-prosjektet viser imidlertid at det er betydelige utfordringer knyttet til å bruke grønt hydrogen som energilagring i

kraftsystemer. De totale energitapene og kostnadene i slike systemer er foreløpig for høye til at de utgjør en levedyktig løsning for storskala prosjekter. Systemene som ble evaluert hadde virkningsgrader i området 15-40%, og dette, kombinert med de høye kostnadene knyttet til elektrolysører og brenselceller, har foreløpig forhindret kommersialiseringen av slike systemer.

Fokuset i hovedfasen av dette PhD-prosjektet var på kombinasjonen mellom grønt hydrogen og offshore vindkraft, det vil si hydrogen som er produsert med elektrolyse av vann hvor elektrisiteten er levert av offshore vindturbiner. De spesifikke fokusområdene innen dette emnet var hydrogenproduksjonen og energistyringen (kontrollsystemer) i vind-hydrogen-systemene. Datamodeller ble utviklet for å simulere driften til vind-hydrogen-systemer og virkelige datasett ble brukt som input til modellene for å øke realismen i simuleringsresultatene. Datasettene inkluderte energiproduksjon og vindhastighet fra en 2,3 MW flytende offshore vindturbin, samt strømprisdata for området hvor vindturbinen er lokalisert. Modellene ble brukt i simuleringsscenarioer med forskjellig varighet (31 dager til 25 år), skala (2,3 MW til 1500 MW), systemdesign, samt teknologi- og kostnadsnivå (nåværende og fremtidige prediksjoner). Tekno-økonomiske analyser ble også utført hvor «levelized cost of hydrogen» (LCOH), «levelized cost of energy» (LCOE) og «net present value» (NPV) ble beregnet for de ulike scenarioene, og en sensitivitetsanalyse ble utført for å identifisere faktorene med størst påvirkning på den tekniske ytelsen og kostnaden til vind-hydrogen-systemer. Resultatene fra de forskjellige simuleringene indikerer at produksjon av grønt hydrogen med strøm fra offshore vindkraft er teknisk gjennomførbart, og LCOH kan være konkurransedyktig med andre hydrogenproduksjonsmetoder i scenarioene der forholdene er gunstige. De viktigste faktorene i så måte er strømprisen og kapasitetsfaktoren til vindparken, som bestemmes hovedsakelig av vindhastigheten. Siden strømprisen og vindhastigheten er så viktige for den økonomiske levedyktigheten til vind-hydrogen-systemer ble det utviklet en datamodell hvor vindhastigheten brukes til å predikere produksjonen av vindenergi og hydrogen ved hjelp av maskinlæring (polynomial regression), og det ble designet et kontrollsystem som bruker strømprisen til å planlegge når vind-hydrogen-systemet skal produsere hydrogen og når det skal selge vindkraften direkte til strømnettet. I et virkelig vind-hydrogen-system er dermed den predikerte vindhastigheten (f.eks. fra en værtjeneste) og neste døgns strømpris (f.eks. fra kraftselskapet) de eneste nødvendige innsatsfaktorene for å predikere og planlegge produksjonen av vindenergi og hydrogen på en optimal måte. Resultatene med og uten kontrollsystemet viser at LCOH ble redusert med 10-46% i alle scenarioene hvor kontrollsystemet ble brukt, og i noen tilfeller utgjorde kontrollsystemet forskjellen mellom et lønnsomt og ulønnsomt system. Dette viser at intelligente datamodeller som kan predikere systemprosessene og planlegge hydrogenproduksjonen på en optimal måte, med hensyn til både tekniske og økonomiske parametre, vil være en veldig viktig faktor for å gjøre storskala vind-hydrogen-systemer til en realitet.

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Preface

This thesis is submitted to the Department of Technology Systems, Faculty of Mathematics and Natural Sciences, University of Oslo, in partial fulfillment of the requirements for the degree of Philosophiae Doctor (PhD). The presented research was conducted both at the Department of Technology Systems, University of Oslo, and at the facilities of the PhD candidate's employers, which were UNITECH Offshore AS for most of the PhD period (2018-2022) and NORCE (Norwegian Research Centre) in the remaining period (2023-2024). The main supervisor in the PhD project was professor Sabrina Sartori at the University of Oslo, and the co-supervisors were Antonie Oosterkamp (PhD) at NORCE and professor Truls Eivind Norby at the University of Oslo. The PhD project was partly funded by the industrial PhD scheme in the Research Council of Norway (50% funding of the period 2018-2022), and the rest was funded by UNITECH Offshore AS (50% in 2018-2022) and NORCE (100% in 2023-2024).

The thesis consists of six chapters and four scientific papers. The research performed in the PhD project is presented in the four papers, and the six chapters of the thesis aim to contextualize the papers and relate them to each other to show the coherence of the thesis. The scientific papers are based on joint work with colleagues, but the PhD candidate performed the majority of the work in all four papers. The overall topic is the role of green hydrogen as an energy carrier in combination with offshore wind power. Specific focus is placed on the production (electrolysis) of green hydrogen from offshore wind, as well as the energy management and techno-economic analysis of wind-hydrogen systems.

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I would also like to thank my co-authors for the great and inspirational collaborations. The co-authors were Amin Hajizadeh (Paper I) at Aalborg University, Øystein Ulleberg (Paper II) from the Institute for Energy Technology (IFE), Jonas Flatgård Jensen (Paper II) at the University of Oslo, Antonie Oosterkamp (Paper IV) from NORCE, who was my co-supervisor, and of course my main supervisor at the University of Oslo, Sabrina Sartori (Papers I-III).

Most of all I would like to thank my family, and more than anyone my amazing wife, Hilde. You are the best thing that has happened to me, my best friend and a constant source of inspiration and motivation. None of this would have been possible without you.

Chapter 1

Introduction

1.1 Background and motivation

The global energy system is arguably the biggest and most complex system that humans have ever built, and most of this system is based on fossil fuels in the form of coal, oil and natural gas. Yearly CO_2 emissions from energy-related human activities reached 36.8 billion tons in 2022 [1], and the general consensus in the scientific community is that this is the main driver behind the on-going climate change. A significant reduction in global fossil fuel usage is therefore needed to minimize the impacts, both immediate and future, of climate change. However, since energy usage is closely tied together with the standard of living and the general functioning of modern societies, it will not be feasible to remove fossil fuel-based technologies without first having other technologies ready to replace them. This will require an energy transition on an enormous scale, away from technologies that rely on fossil fuels (e.g., coal power for electricity generation, oil for transport) and towards technologies that can deliver the same product (e.g., electricity, mechanical power, heat) at the same scale and with the same stability, but with much lower emissions. As expected, this has turned out to be much easier said than done. Even though the growth rates in some low-emission technologies like solar and wind power have been impressive, they have not had a very significant effect when we look at the big picture. In 1995, the year of the first UN Climate Change Conference, the share of fossil fuels in the global primary energy mix was approximately 77% [2–4]. In 2022, after 27 years of global efforts to reduce fossil fuel usage, the share of fossil fuels in the primary energy mix was still 77% [2–4]. This may seem like status quo, but the situation is in fact even worse when we look at absolute energy usage instead of relative shares. In the same 27-year period the global primary energy consumption has increased by almost 60% [2–4] (Figure 1.1), and the result of this is that global energy related CO_2 emissions have actually increased by 64% from 22.4 billion tons in 1995 to 36.8 billion tons in 2022 [1]. The natural conclusion to draw is that global efforts to develop, implement and scale up low-emission technologies that can replace fossil fuel-based technologies must be intensified even further if emissions of CO_2 are going to be reduced in the future.

Green hydrogen is now regularly being suggested as a potential part of the

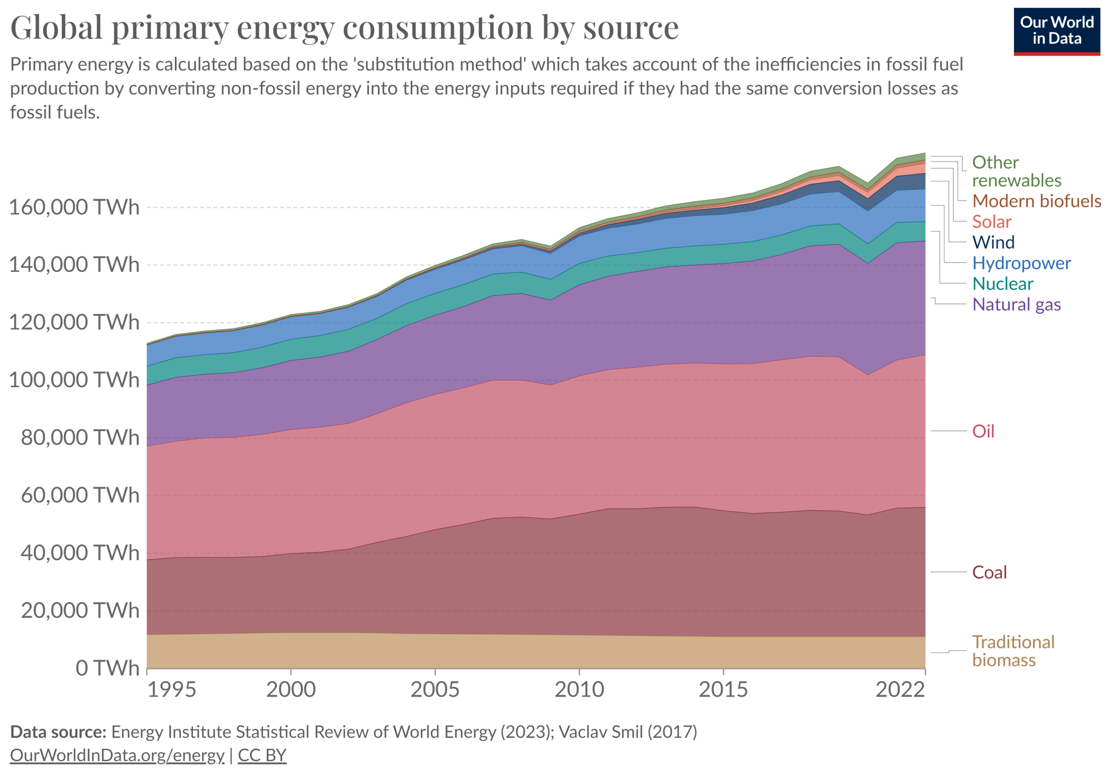

Figure 1.1: Global primary energy consumption by source in the period between the first UN Climate Change Conference in 1995 and the end of 2022 [2–4].

solution to accelerate the transition away from fossil fuels, both from academia, industry and politics. Green hydrogen is defined as hydrogen produced through electrolysis of water where the electricity input comes from renewable (a.k.a. green) energy sources like wind, solar and hydro power. Most of the hydrogen used today is fossil fuel-based hydrogen, which is hydrogen produced from natural gas through steam methane reforming or from coal through gasification. The obvious advantage with green hydrogen vs. fossil fuel-based hydrogen is that the greenhouse gas emissions are reduced from 8.9-9.4 kg CO_2 e/kg H_2 (natural gas) [5] and 16.5-20.2 kg CO_2 e/kg H_2 (coal) [5], down to almost zero for green hydrogen [5]. Green hydrogen can replace the fossil fuel-based hydrogen currently used, mainly in the refining industry and to produce ammonia and methanol, which could almost eliminate current emissions of more than 900 million tons of CO_2 per year from hydrogen production [6]. However, green hydrogen could also be used to reduce CO_2 emissions in other sectors. Applications that are frequently suggested include green hydrogen as energy storage in the electricity sector, as fuel (in fuel cells or combustion engines) in the transport sector and as industrial heat. The successful implementation of large-scale production and consumption of green hydrogen that consequently reduce the global usage of fossil fuels can therefore significantly reduce global CO_2 emissions. However, green hydrogen still faces significant challenges, both related to costs and technical issues (e.g., energy losses, degradation of electrolyzers and fuel cells). The estimated production cost range for green hydrogen is currently 3.2-7.7 \$/kg H_2, compared to 1.9-2.5 \$/kg H_2 for hydrogen from coal and just 0.7-1.6 \$/kg H_2 for hydrogen from natural gas [7]. Therefore, continued research and development on all levels will be crucial to make large-scale green hydrogen systems economically and technically viable.

This summarizes the background and motivation for the work described in this PhD thesis. The work was mostly focused on the production of green hydrogen, with three of the four papers (Papers II-IV) specifically focused on the production of green hydrogen with electricity from offshore wind power, as well as the energy management and costs of such wind-hydrogen systems.

1.2 Knowledge gaps in the research field

The work in this PhD project focused on knowledge gaps identified in previously published research, as explained in more detail in the literature reviews in the first three papers. Specifically, there was a lack of studies that used real-world operational data from offshore wind turbines as direct input to simulation models with green hydrogen production. The work in the second paper, where high-resolution data from the Zefyros floating offshore wind turbine (FOWT) from five different 31-day periods were used in combination with real electricity price data from the same periods, thus provided a novel and more realistic simulation model than previously published research. The work in the third paper of the PhD expanded this work to include polynomial regression to estimate the capacity factor of any wind farm based only on wind speed, as well as a novel control system that utilized the actual electricity price to optimally schedule the production of green hydrogen. This system succeeded in lowering the levelized cost of hydrogen in all test scenarios, both with current technology and costs, and with estimated technology improvements and cost reductions in future scenarios. The work described in these papers resulted in a model that can be used in a real-world wind-hydrogen system, where the forecast wind speed and electricity price can be used to estimate and optimize the production of green hydrogen with respect to both technical and economic factors. A model with these capabilities was lacking in previously published studies, and the work in this PhD project thus filled a knowledge gap that existed in literature.

1.3 Thesis scope and methodology

The main topic of the work in this PhD project was to analyze technical and economic aspects of hydrogen as an energy storage medium and energy carrier in combination with renewable energy. The first part of this work consisted of a critical evaluation of the state-of-the-art in this field, and this review phase was completed with the publication of the first scientific paper of this PhD thesis. It was thereafter decided to focus on the combination between offshore wind power and hydrogen production through water electrolysis. The specific focus areas were hydrogen production (wind turbine-electrolyzer combination), energy management (control systems) and techno-economic analyses (e.g., levelized cost of hydrogen).

Other topics (e.g., other hydrogen technologies) are outside the scope of this PhD project and are therefore not studied in detail in this thesis. They are however included in some parts of the work in less detailed ways, for example as a constant in computer models (e.g., cost per kilogram of hydrogen compression, storage and transport) or as descriptions of other referenced studies/projects. The work in this PhD project included performing a thorough review of published research material, as well as developing computer models and combining these with real-world data sets to answer the following research questions:

1. What are the main advantages and challenges with green hydrogen as energy storage in electricity systems?

2. What are the most important factors that influence the technical performance of green hydrogen production from offshore wind power?

3. What factors have the largest effect on the production cost of green hydrogen from offshore wind power?

4. Is it possible to improve the economic and technical viability of green hydrogen production from offshore wind power by developing a model that uses technical and economic factors to forecast and control the hydrogen production?

The real-world data sets consisted of energy production and wind speed data from Zefyros, a 2.3 MW floating offshore wind turbine (FOWT) owned by the company UNITECH Offshore AS [8], electricity price data from Nord Pool [9], wind speed data from the Norwegian Centre for Climate Services [10] and Renewables Ninja [11–13], and currency conversion rates between US dollar and Norwegian Krone (NOK) from the Bank of Norway [14]. These data sets were used as input to computer models developed in Python [15] and MATLAB/Simulink [16] where hydrogen production through PEM (Proton Exchange Membrane) electrolysis with electricity from offshore wind turbines as input power was simulated. Different models and control systems were developed and tested in various scenarios, and this was combined with techno-economic analyses and sensitivity analyses to answer the research questions listed above.

1.4 Thesis structure

This thesis summarizes my PhD work and consists of six chapters and four papers. The first chapter gives an introduction to the PhD project, including the background and motivation for the work, knowledge gaps in the field, the scope of the project with research questions and methodology, as well as a short introductory summary of each of the four papers. Chapter 2 gives an introduction to green hydrogen and its production and use as an energy carrier. The third chapter contains a description of the simulation models that were developed and used in the PhD project, as well as the data that were used as input to the models. The fourth and fifth chapters discuss the work that was done to answer the four research questions in the PhD project, including a description of previously published work in the field and the contributions made by the work in this PhD project. In these two chapters, chapter 4 focuses on green hydrogen as energy storage in electricity systems while chapter 5 focuses on green hydrogen production with electricity from offshore wind turbines. Chapter 4 focuses on Paper I and chapter 5 discusses Papers II-IV. Chapter 6 gives the most important conclusions from the PhD project along with suggestions for further work. The final part of the thesis consists of four scientific papers. The first three papers (Paper I-III) have been published in peer reviewed scientific journals, while the last paper (Paper IV) has been accepted as a conference paper by *The 34th International Ocean and Polar Engineering Conference* and will be published in the peer reviewed conference proceedings.

1.5 Summary of papers

1.5.1 Paper I

The paper titled "Hydrogen-based systems for integration of renewable energy in power systems: Achievements and perspectives" [17] was the first paper published as part of this PhD project. The PhD candidate (Torbjørn Egeland-Eriksen) was the lead author, and co-authors were Amin Hajizadeh (PhD) from Aalborg University and the PhD candidate's main supervisor at the University of Oslo, Sabrina Sartori (PhD). The paper was published in the *International Journal of Hydrogen Energy* in 2021.

This paper consisted of a critical review of 15 real-world facilities that use hydrogen as energy storage in renewable electricity systems, either alone or in hybrid systems with other energy storage technologies (e.g., batteries, supercapacitors). The main motivation behind this paper was to analyze and map the state-of-the-art within systems of this type, and to identify important challenges related to the technical performance and economics of such systems. The work focused on real-world facilities with operational results, and systems of all scales (from single-digit kW to several MW) were included.

A presentation and discussion of the main results from this paper is given in chapter 4. The original paper published in the *International Journal of Hydrogen Energy* is included in the final part of the thesis.

1.5.2 Paper II

The paper titled "Simulating offshore hydrogen production via PEM electrolysis using real power production data from a 2.3 MW floating offshore wind turbine" [18] was the second paper published as part of this PhD project. The PhD candidate (Torbjørn Egeland-Eriksen) was the lead author, and co-authors were Jonas Flatgård Jensen (M.Sc.) from the University of Oslo, Øystein Ulleberg (PhD) from the Institute for Energy Technology (Norway) and the PhD candidate's main supervisor at the University of Oslo, Sabrina Sartori (PhD). The paper was published in the *International Journal of Hydrogen Energy* in 2023.

This is an original research paper where a MATLAB/Simulink [16] model was used in combination with real-world data sets to simulate offshore hydrogen production via PEM electrolysis with electricity directly from a 2.3 MW FOWT. A Simulink model of a PEM electrolyzer was integrated in a larger model of the whole wind-hydrogen system, and real-world data sets with measured energy production and wind speed from a 2.3 MW FOWT from five different 31-day periods were used as input to the simulation model. Actual electricity prices in the same periods in the region where the FOWT is located were also used as input to the simulation model. Six different system designs were simulated in each of the five time periods, and the model outputs included both technical (e.g., hydrogen production, efficiency) and economic (e.g., production cost) parameters.

A presentation and discussion of the main results from this paper, as well as from Papers III and IV, is given in chapter 5. The original paper published in the *International Journal of Hydrogen Energy* is included in the final part of the thesis.

1.5.3 Paper III

The paper titled "Techno-economic analysis of the effect of a novel price-based control system on the hydrogen production for an offshore 1.5 GW wind-hydrogen system" [19] was the third paper published as part of this PhD project. The PhD candidate (Torbjørn Egeland-Eriksen) was the lead author, and co-author was the PhD candidate's main supervisor at the University of Oslo, Sabrina Sartori (PhD). The paper was published in *Energy Reports* in 2024.

This is an original research paper where a techno-economic model and a control system for large-scale hydrogen production from offshore wind power were developed and tested. The work consisted of four main parts:

1. Real-world data sets with measured energy production and wind speed from a 2.3 MW FOWT were used to develop, train and test a polynomial regression model that can accurately estimate the capacity factor of an offshore wind farm based on wind speed input.

2. The hydrogen production model from Paper II was modified and used to estimate the hydrogen production capacity of an offshore wind farm by using the wind farm capacity factor from the polynomial regression model as input.

3. A novel control system was developed to decide when the wind-hydrogen system will use the wind energy to produce hydrogen and when it will sell it directly to the electricity grid. The outputs from the polynomial regression model and hydrogen production model are used as inputs to the control system, and these inputs are then combined with real-world electricity price data and the average selling price of hydrogen to schedule the hydrogen production in the most cost-optimal way.

4. The outputs from the first three parts were then used to calculate the levelized cost of hydrogen (LCOH), levelized cost of energy (LCOE) and net present value (NPV).

The complete model with all four parts was then tested in various scenarios by using 10 years of historical data of wind speeds, electricity prices and US$/NOK conversion rates. Scenarios with current technology and costs, as well as various future scenarios with forecast technology improvements and cost reductions towards 2050 were tested and compared with each other. A sensitivity analysis was also performed to analyze the effect of changes in the most important variables.

A presentation and discussion of the main results from this paper, as well as from Papers II and IV, is given in chapter 5. The original paper published in *Energy Reports* is included in the final part of the thesis.

1.5.4 Paper IV

The paper titled "Electricity transport vs. hydrogen production from future offshore wind farms" was the fourth paper written as part of this PhD project. The PhD candidate (Torbjørn Egeland-Eriksen) was the lead author, and co-author was the PhD candidate's co-supervisor at NORCE, Antonie Oosterkamp (PhD). The paper has been accepted as a conference paper by *The 34th International Ocean and Polar Engineering Conference* and will be published in the peer reviewed conference proceedings.

This is an original research paper where the simulation model developed in Paper III was used to simulate scenarios with offshore hydrogen production on North Sea wind farms in 2050. In these scenarios the hydrogen gas is transported to the shore through subsea pipelines. This is compared to electricity transport through subsea power cables, as well as alternative onshore hydrogen production methods. The study focused on two main questions:

1. From the point of view of the wind farm, does offshore hydrogen production make sense or is it better to install an export power cable and sell electricity to the grid?

2. If hydrogen *is* produced offshore, can it compete with onshore electrolysis and blue hydrogen?

A presentation and discussion of the main results from this paper, as well as from Papers II and III, is given in chapter 5. The original manuscript that will be published in the peer reviewed conference proceedings to *The 34th International Ocean and Polar Engineering Conference* is included in the final part of the thesis.

Chapter 2

Green hydrogen

Green hydrogen is normally defined as hydrogen produced by electrolysis of water where the electricity input comes from renewable energy sources, a.k.a. green electricity. Global production of hydrogen in 2022 was almost 95 million tons [6], but almost none of this was green hydrogen. More than 99% was made either from natural gas (62%), coal (21%) or as a by-product during naphtha reforming (16%), resulting in emissions of more than 900 million tons of CO_2 per year [6]. Replacing some of this hydrogen with green hydrogen could therefore lead to significant reductions in global CO_2 emissions. In addition to this, green hydrogen has other potential applications that could also reduce emissions. This chapter will describe the theory behind green hydrogen production through electrolysis of water, as well as the potential usage of green hydrogen in the future.

2.1 Water electrolysis

Hydrogen can be produced through electrolysis of water. In this process, electricity is used to split water molecules into hydrogen gas and oxygen gas. The four main types of electrolysis technologies are alkaline, proton exchange membrane (PEM), anion exchange membrane (AEM) and solid oxide electrolysis. The latter two are still in the developmental phase though [20], so commercial facilities currently use either alkaline or PEM electrolyzers. Of these two, PEM electrolyzers are generally best suited for green hydrogen production with wind power as input. The main reason for this is that these electrolyzers have the fastest response times (both ramp-up and cold start-up) [20] which means that they are best equipped to deal with the intermittent in-flows of electricity that you generally get from wind and solar power. PEM electrolyzers also have the most compact design [20], which means that they take up less area per unit of installed power. This can often be an advantage in green hydrogen systems, for example in connection with offshore wind farms. The suitability of PEM electrolyzers for green hydrogen production was also shown in Paper I, where most of the reviewed real-world systems used PEM electrolyzers [17]. The simulation models in this PhD project was therefore based on PEM electrolysis, since the electricity source is offshore wind turbines with highly intermittent power production. The compact design would also be a big advantage in scenarios with offshore elecrolysis. This section will therefore focus on the theory behind PEM electrolyzers.

The overall cell reaction in an electrolyzer is given by Equation 2.1. This overall reaction is the same in all four electrolyzer types, and the required input that drives the splitting of the water molecules is electricity.

$$\mathrm{H_2O} \longrightarrow \mathrm{H_2} + \frac{1}{2}\,\mathrm{O_2} \tag{2.1}$$

The anode and cathode reactions can be different depending on the type of electrolyzer. In a PEM electrolyzer, the anode reaction is given by Equation 2.2 and the cathode reaction is given by Equation 2.3.

$$\mathrm{H_2O} \longrightarrow 2\,\mathrm{H^+} + \frac{1}{2}\,\mathrm{O_2} + 2\,\mathrm{e^-} \tag{2.2}$$

$$2\,\mathrm{H^+} + 2\,\mathrm{e^-} \longrightarrow \mathrm{H_2} \tag{2.3}$$

These reactions and a schematic of the main components and working principle of a PEM electrolyzer cell is shown in Figure 2.1. Electricity is used to split water into oxygen (O_2), protons (H^+) and electrons (e^-) at the anode. The protons are conducted through the membrane while the electrons are conducted through an external circuit, and the two are then recombined at the cathode to form hydrogen gas (H_2). The main components of the cell are the proton exchange membrane (PEM), anode, cathode, gas diffusion layer (GDL), porous transport layer (PTL), separator plates and end plates. The membrane is most commonly made from Nafion®. This material offers high proton conductivity, current density and mechanical strength, while also being chemically stable [20]. The GDL and PTL is usually based on carbon and titanium, respectively. The best anode and cathode materials for PEM electrolyzers are unfortunately based on noble metals, specifically iridium in the anode (IrO_2) and platinum in the cathode (Pt/C) [20]. This is the biggest disadvantage with PEM electrolyzers, i.e., high costs due to expensive materials. For example, just the iridium that would be needed for a 10 MW PEM electrolyzer was estimated to cost around 3 million US$ in 2021 [20]. Adding further to the cost is the fact that the titanium separator plates and end plates are coated with platinum and gold, respectively. Therefore, much of the research on PEM electrolyzers is focused on reducing costs by developing new component designs that do not require the use of noble metals. The other main focus area of current research is to reduce the thickness and further improve the other characteristics of the proton exchange membrane (PEM), which could both improve the energy efficiency and reduce the cost of the electrolyzer [20].

A more detailed description of the dynamic operation of a PEM electrolyzer and the mathematical equations that describe this operation is given in Paper II. In that paper, the mathematical simulation model of the electrolyzer used in this PhD project is described. The model is also described in less detail in chapter 3 of this thesis.

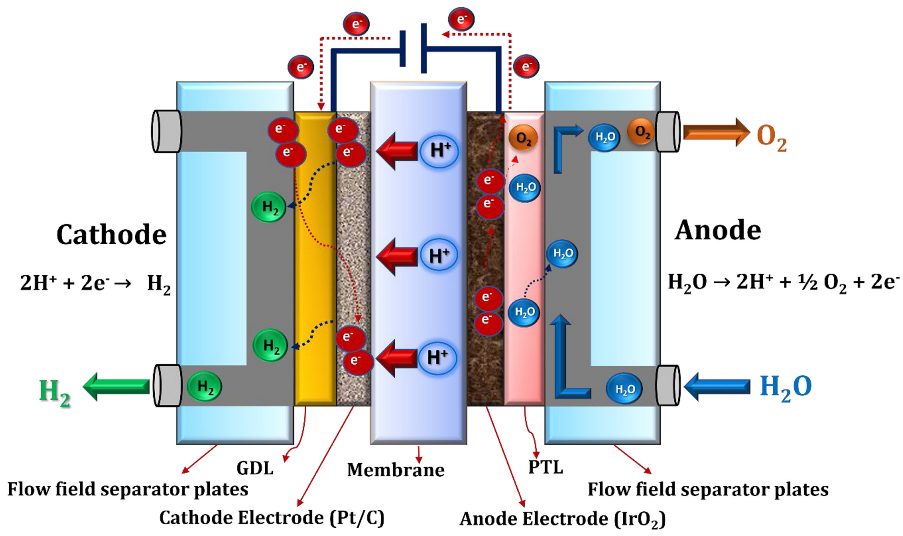

Figure 2.1: Schematic of the main components and working principle of a PEM electrolyzer cell [20].

2.2 Potential usage of green hydrogen

Green hydrogen has many possible applications where it has the potential to significantly reduce emissions of CO_2 and other greenhouse gases. The current yearly hydrogen consumption of almost 95 Mt/year [6], which comes mostly from natural gas, coal and as a by-product in industrial processes, is responsible for emissions of more than 900 million tons of CO_2 per year [6], which translates to around 2.4% of total yearly energy-related emissions. These emissions could be almost eliminated if fossil fuel-based hydrogen is replaced by green hydrogen. In addition to this, emissions could be reduced even further if green hydrogen is used to reduce fossil fuel usage in other sectors as well. Due to hydrogen's versatility, both as an energy carrier and as a component in industrial processes, green hydrogen is frequently presented as a method to reduce emissions in many different sectors. However, not all the suggested applications are equally promising in terms of costs, energy efficiency and reduction of emissions. Therefore, and since the capacity to produce green hydrogen will be limited for a long time still, it will be important to perform careful evaluations of what applications provide the largest total benefits. As an example, electricity generation does not seem like the most promising application for green hydrogen with current technology and costs, as described in chapter 4 and Paper I. However, there are several other applications where hydrogen could make more sense. This is also reflected in *Energy Transition Outlook 2023* by DNV [21]. In this report, hydrogen production is forecast to grow to 350 Mt/year in 2050 [21], and most of this will be consumed within the transport and industry sectors, while electricity generation is predicted to use just 10 Mt/year [21]. However, other analyses that investigate what will be necessary to reach net zero emissions from the global energy sector by 2050 forecast both a much higher total demand for hydrogen, and that a higher share of this will be used for electricity generation. In a net zero scenario, the International Energy Agency

(IEA) estimates that a hydrogen production of 430 Mt/year will be required in 2050 [22], the International Renewable Energy Agency (IRENA) estimates 523 Mt/year [23], the Hydrogen Council estimates 660 Mt/year [24], while DNV estimates that 820 Mt/year will be necessary in their net zero scenario [25]. Most of the hydrogen is used in the transport and industry sectors in the net zero scenarios as well [22–25], but a significant amount of hydrogen is also needed for electricity generation to reach net zero emissions. The Hydrogen Council estimates that around 10% of the total hydrogen production will be used for electricity generation to reach net zero emissions by 2050 [24], IEA estimates 17% [22] and DNV estimates that as much as 26% of the total hydrogen production will be used for electricity generation in their net zero scenario [25]. So it seems that the world will need to use a significant amount of hydrogen for electricity generation if we are going to reach net zero emissions by 2050, although the majority will be used within transport and industry in all scenarios.

Production of green hydrogen has so far been almost non-existent in a global perspective, with a total production below 0.1 Mt in 2022, making up just 0.1% of total hydrogen production [6]. However, it is predicted to grow to become the biggest share of the total hydrogen production in 2050 in all the reviewed analyses [21–25]. In DNV's main scenario they estimate that 35% of total hydrogen production in 2050 will be green hydrogen from dedicated solar and wind power [21]. Additionally, 15% of the production is grid-connected electrolysis [21], which can also be counted as green hydrogen if the electricity grid is based on 100% renewable energy. In the net zero scenarios [22–25], which have electricity grids with net zero emissions, IEA estimates that 76% of total hydrogen production in 2050 will be green hydrogen [22], IRENA estimates 94% green hydrogen [23], the Hydrogen Council estimates 60-80% green hydrogen [24], and DNV estimates that green hydrogen will make up 85% of the total production [25]. Figure 2.2 shows the estimated hydrogen production (both green and total) in 2050 in the different scenarios [21–25] compared to current production [6].

Green hydrogen's share in the total energy mix in 2050 is predicted to increase from the current negligible level, but how much it will increase will depend on which energy scenario becomes a reality. DNV predicts that green hydrogen will make up just 1.8-2.5% of the global energy mix in their main scenario [21]. In IEA's net zero scenario the estimated share of green hydrogen in the global energy mix is 3.5%, which is not that much higher. However, the predicted shares of green hydrogen in the three other net zero scenarios are significantly higher. In IRENA's net zero scenario the predicted share of green hydrogen is 13% [23], in DNV's net zero scenario it is also around 13% [25], and the Hydrogen Council predicts that it will be in the range 13-18% [24]. However, it is important to remember that producing the amount of green hydrogen estimated in these scenarios will require large amounts of green electricity. The predicted green hydrogen production range from the scenarios described above can be used together with the lower heating value of hydrogen (120.1 MJ/kg H_2 [26]), and the most optimistic electrolyzer efficiency of 72% from Paper IV, to estimate the *minimum* amount of electricity that would be needed for green hydrogen production in 2050. With these assumptions, calculations show that the required amount of green electricity will be in the range

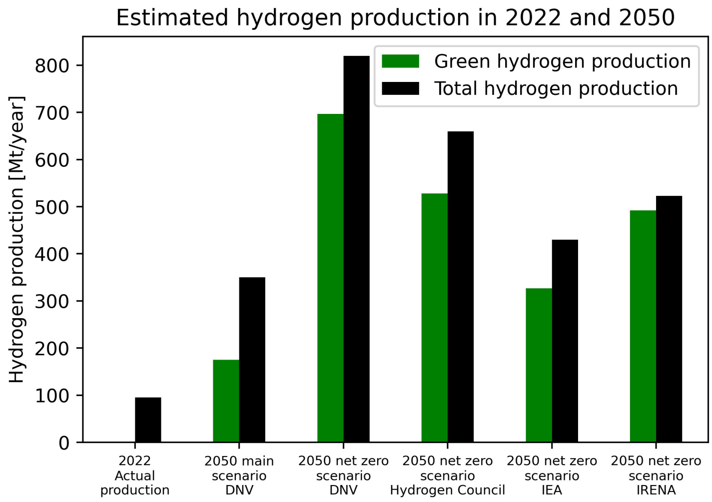

Figure 2.2: Comparison of current (2022) hydrogen production [6] with selected forecasts for various 2050 scenarios [21–25].
Notes: 1) Current (2022) production of green hydrogen is so low (below 0.1 Mt/year [6]) that the bar is not visible in the chart. 2) DNV's green hydrogen estimate in the main scenario for 2050 includes 15% grid-connected electrolysis [21], which means that only grids with 100% renewable energy can be used for this. 3) The green hydrogen estimate by the Hydrogen Council is the high end of their estimate, i.e., 80% of total hydrogen production is green hydrogen [24].

5 700-32 300 TWh, depending on which scenario is used. The global electricity production in 2022 was around 29 000 TWh [3], which means that the equivalent of anywhere from 20% to more than 100% of the entire global electricity production in 2022 will be needed to produce green hydrogen in 2050. If only the electricity that qualifies as green electricity (mainly solar, wind and hydro power) is included, the global production in 2022 was 8 500 TWh [3]. This means that the world could need up to four times the current global production of renewable electricity for green hydrogen production in 2050. Considering that most of the renewable electricity produced in 2050 should (and probably will) be used directly as electricity, the growth rate of renewable electricity will have to be very high in the next 27 years if the most optimistic estimates for green hydrogen are going to be reached. This is also reflected in the reviewed reports, where for example DNV estimates that solar electricity will have to grow by a factor of 27 between 2022 and 2050 in their net zero scenario [25]. Evaluating the probability of achieving such huge growth within renewable electricity and green hydrogen production is outside the scope of this thesis, but it does emphasize the point that green hydrogen should first and foremost be used in the sectors and applications where it makes the most sense, particularly during the first years which will probably see very limited production. The most obvious examples of such low-hanging fruits are to use green hydrogen to replace the hydrogen that is currently produced from fossil fuels without carbon capture, which could reduce global CO_2 emissions by more than 2%, as explained in the beginning of this section.

Chapter 3

Simulating green hydrogen production

The majority of the work in this PhD project has been focused on developing computer models to simulate green hydrogen production with electricity from offshore wind turbines. This was done in two main stages that will be described in this chapter. Section 3.1 describes the first model developed in MATLAB/Simulink [16] and used for the work described in Paper II. Section 3.2 describes the second model developed in Python [15] and used for the work described in Paper III and Paper IV. Both models are described in much greater detail in the attached papers, particularly Paper II (Model 1) and Paper III (Model 2). The results from the simulation work in Papers II-IV are summarized and discussed in chapter 5 of this thesis, which also goes through previously published research in this field.

3.1 Methodology - Model 1

3.1.1 Model overview and structure

The motivation behind the work described in Paper II was to build a model that could simulate offshore hydrogen production in connection with an offshore wind turbine by using real operational data from the wind turbine as input. The data sets from the wind turbine have 10-minute intervals between each data point, so it was decided to use one month (31 days) of data in each simulation scenario to avoid too large computational loads in the simulations. We wanted to investigate how the simulation results would be affected by differences in the wind turbine capacity factor and electricity price, so five time periods with large differences in these two parameters were selected. These periods and the average capacity factor and electricity price for each period are listed in Table 2 in Paper II. The periods were carefully selected so that there would be scenarios with conditions ranging from almost ideal to very unfavorable in terms of hydrogen production. As a rule of thumb, good conditions for hydrogen production are characterized by a high wind turbine capacity factor combined with a low electricity price, while the opposite combination will generally be bad for hydrogen production. Six different system designs were used, where the differences between the designs were the power capacity of the electrolyzer and whether or not a battery was included in the system. The system designs are listed in Table 3 in Paper II. The five time periods and six system designs resulted in 30 simulation scenarios.

The overview of the wind-hydrogen system and the boundaries of the model is shown in Figure 3.1, which is taken from Paper II. The two components inside the blue dashed box (wind turbine and electricity grid) provide the data inputs to the simulation model, as described in the previous section. The components included in the simulation model are the four components inside the green dashed box. These are a PEM electrolyzer, lithium-ion battery, desalination of sea water, as well as compression and storage of hydrogen. The model of the PEM electrolyzer is a detailed mathematical model and the lithium-ion battery is a component included in the Simulink toolbox. These two components respond dynamically to each new data point from the FOWT data sets. The desalination of sea water and the compression and storage of hydrogen are not modelled in such detail. Instead, the energy usage and cost of these two processes are estimated and included in the simulations by using values from literature. These values are listed in Table 1 in Paper II and they give the energy usage and cost per unit of produced water and hydrogen. These simplifications were made to minimize the computational load of the model. Other simplifications in the model are:

- Power electronics are not included in the model, except in the cost estimate for the PEM electrolyzer. This means that both the energy loss and cost would be higher in an actual wind-hydrogen system.

- Ramp-up time and cold start-up time for the PEM electrolyzer are not included in the model. The ramp-up time for a state-of-the-art PEM electrolyzer is so low (below 10 seconds [27]) that the effect on the model results will be very low. The cold start-up time is longer though (5-10 minutes [27]), so this would reduce the hydrogen production in an actual wind-hydrogen system compared to the model.

- Energy usage to keep the electrolyzer in standby mode is not included in the model. This would reduce the energy efficiency and hydrogen production in an actual system.

- The degradation of the electrolyzer during its lifetime is not included in the model. This would reduce the energy efficiency of the electrolyzer over time and increase the total system cost in an actual system.

A schematic illustration of the Simulink model is shown in Figure 3.2, which is taken from Paper II. As shown here, the data from the wind turbine goes to a control system that decides whether the wind energy is used to produce hydrogen, charge the lithium-ion battery, desalinate sea water, or sold to the onshore electricity grid. These decisions are based on a set of rules that are described in detail in Paper II and illustrated in Figures 4 and 5 in the same paper. The main goal of the system is to maximize hydrogen production, so the control system chooses hydrogen production as long as it is possible to do so from an energy perspective. The model has more than 60 different output data

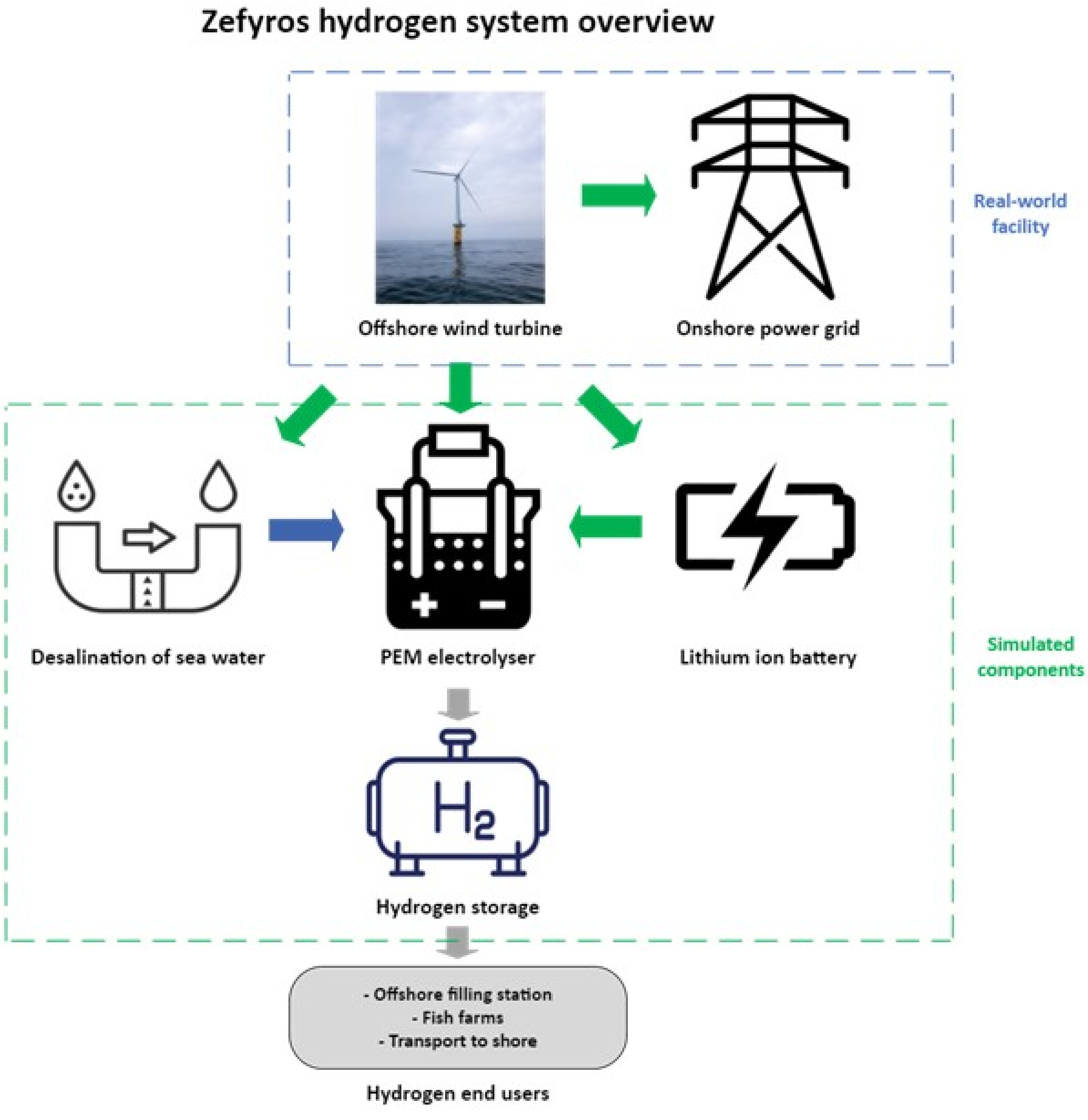

Figure 3.1: Figure from Paper II showing an overview of the wind-hydrogen system modelled in this paper. The real-world facility consists of the components inside the blue dashed box, while the components inside the green dashed box are simulated in MATLAB/Simulink. The green arrows indicate electricity flows, the blue arrow indicates water flow and the grey arrows indicate hydrogen flows. The hydrogen end users are suggestions and are outside the scope of this thesis.

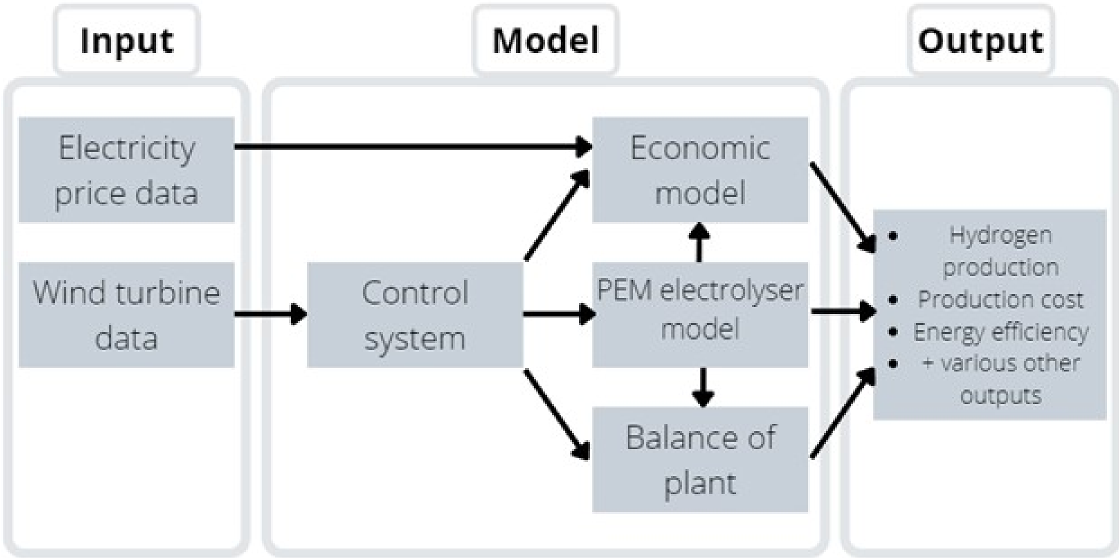

Figure 3.2: Schematic of the Simulink model used in all simulations in Paper II.

flows, but the three focus areas are hydrogen production, energy efficiency and production cost.

3.1.2 Data inputs to Model 1

Model 1 had two data input sources. The first was operational data from a 2.3 MW floating offshore wind turbine (FOWT) owned and operated by UNITECH Offshore AS [8], and the second was electricity price data from Nord Pool [9]. The FOWT data consisted of measured energy production and wind speed on the turbine in five different time periods, each lasting 31 days. Four of the data sets (from 2020 and 2021) have 10-minute intervals between each data point, and the last data set (from 2022) has 1-hour intervals between each data point. Electricity price data sets from the same time periods and region as the FOWT were matched with the data sets from the turbine. The two synchronized data sources were then used as input to the MATLAB/Simulink model used in Paper II. The data sets from the FOWT are owned by UNITECH Offshore AS [8] and are not publicly available. The electricity price data sets are publicly available for download from Nord Pool [9].

3.2 Methodology - Model 2

3.2.1 Model overview and structure

The model described in the previous section (Model 1) simulated five different 31-day time periods with inputs of actual wind energy production, wind speeds and electricity prices for each period, using current technology for all components. It was then decided that the natural next step further would be to develop a larger simulation model that could simulate the operation of a large-scale wind-hydrogen system throughout the project's entire lifetime. It was also decided that the model must be able to simulate wind-hydrogen systems in different locations, and both current and future scenarios in terms of both technical and economical factors must be included. Since the electricity price was shown to have a very large effect on the production cost in Paper II (Model 1), a control system must be included in the new model that optimally schedules the hydrogen production based on the electricity price and other relevant factors. The model was built in three stages, which are described below. The interaction between the three parts are illustrated in the flow chart in Figure 3.3, which is taken from Paper III.

1. Polynomial regression was used with energy production and wind speed data from the 2.3 MW FOWT used in Model 1 as input. This resulted in a regression model that can accurately estimate the capacity factor of an offshore wind farm at any location based on the wind speed at the given location.

2. The hydrogen production model from Paper II (Model 1) was modified and used to estimate the hydrogen production capacity of an offshore wind farm by using the wind farm capacity factor from the polynomial regression model as input.

3. A novel control system was developed that decides when the wind-hydrogen system uses the wind energy to produce hydrogen and when it is sold directly to the electricity grid. The outputs from the polynomial regression model and hydrogen production model are used as inputs to the control system, and these inputs are then combined with real-world electricity price data and the average selling price of hydrogen to schedule the hydrogen production in the most cost-optimal way.

A main scenario was constructed to act as a base case that could later be compared with alternative scenarios. As the base case, it was decided to use a hypothetical 1.5 GW offshore wind farm. This is the same capacity as the intended capacity of the Utsira Nord wind farm [28] that is planned off the west coast of Norway. It was assumed that the wind farm is connected to the onshore electricity grid with a subsea power cable and that the hydrogen production system is located onshore. Current technology and costs were used for all components in the base case. This scenario was simulated both with and without the price-based control system to investigate the effect this system would have throughout the project's lifetime. The base case served as a simulation of what could be possible for a large-scale wind-hydrogen system with current technology, and alternative future scenarios were then constructed to simulate what could become possible in a few decades. Various forecasts from published literature/reports regarding possible improvements in technology and cost reductions were used to develop alternative 2050 scenarios. An optimistic 2050 scenario was constructed by using the most optimistic forecasts for both technology and costs to simulate what could be possible in 2050 if everything goes in the direction most favorable to green hydrogen production, including a low electricity price. This was then compared to a scenario with a significantly higher electricity price, as well as scenarios where

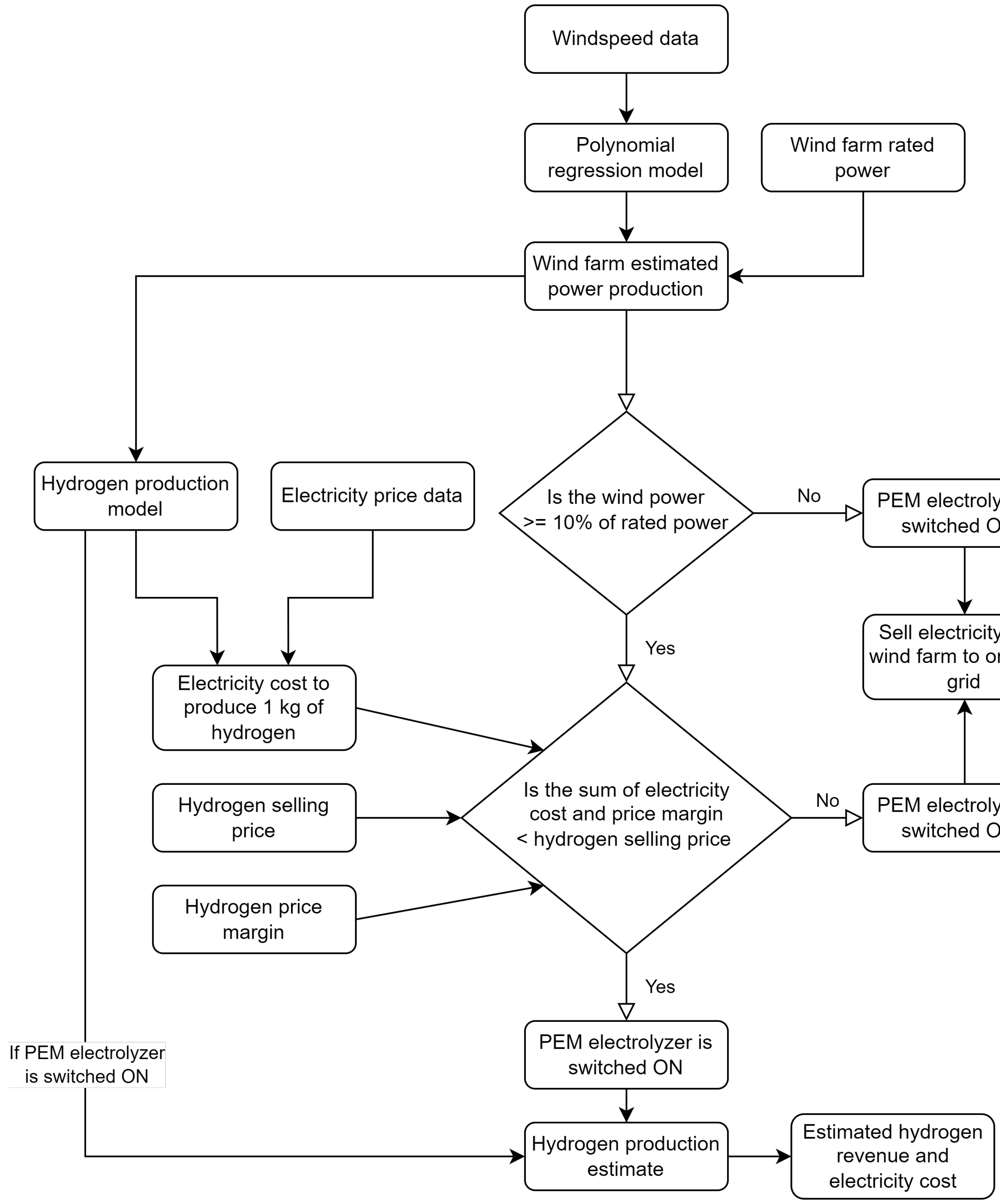

Figure 3.3: Figure from Paper III showing the flow chart of Model 2, which illustrates how the control system interacts with the other two main parts of the model, i.e., the polynomial regression model and the hydrogen production model.

the hydrogen system uses electricity from the onshore electricity grid to produce hydrogen. The same two electricity price profiles were used in the grid-connected configurations. All the scenarios described here were simulated both with and without the price-based control system to evaluate the impact of this system in different scenarios. Finally, an off-grid scenario was constructed where the wind farm is not connected to the onshore electricity grid and the hydrogen production system is placed offshore on a separate platform connected to the wind farm. This scenario also used technology and cost forecasts for 2050, and a lithium-ion battery system was included to act as a buffer between the wind farm and hydrogen system.

3.2.2 Data inputs to Model 2

Model 2 was used for the work described in Paper III and Paper IV, and five different data sources were used:

- Data sets from the 2.3 MW FOWT used in Model 1 were used to train and test the polynomial regression model. These data sets contain values for energy production and wind speed on the turbine. A 12-month data set (1. Nov. 2021 to 31. Oct. 2022) with hourly data points was used to train the model. Two different data sets were then used to test the model: A 12-month data set (Jan. 2020 to Jan. 2021) with 10-minute data points and a 30-day data set (Nov. 2022) with hourly data points. These data sets are owned by UNITECH Offshore AS [8] and are not publicly available.

- Ten years of wind speed data from the period 2013-2022 from the Norwegian island of Utsira were used as input to the simulation model in Paper III. The data set has hourly data points. These data are publicly available for download from the Norwegian Centre for Climate Services [10].

- Ten years of hourly electricity price data from the period 2013-2022 from the Norwegian region where the island of Utsira is located were used as input to the simulation model in Paper III. These data are publicly available for download from Nord Pool [9].

- Ten years of daily NOK/US$ currency conversion data were used as input to the simulation model in Paper III. These data are publicly available for download from the Bank of Norway [14].

- 25 years of wind speed data from the period 1998-2022 from the planned location of the Sørlige Nordsjø 2 wind farm [29] were used as input to the simulation model in Paper IV. The data set has hourly data points. These data are publicly available for download from the Renewables Ninja website [11–13].

Chapter 4

Green hydrogen as energy storage in electricity systems

The first application of green hydrogen investigated in this PhD project was as energy storage in electricity systems based on renewable energy. A schematic overview of a typical system of this kind is shown in Figure 4.1, which is taken from Endo *et al.* [30] and also included in Paper I. The main advantage with hydrogen as energy storage is that it can be stored for long periods with very small losses, contrary to batteries which suffer from self-discharge. The argument made by proponents of hydrogen energy storage is that this can enable a larger share of renewable energy in electricity grids, since large amounts of intermittent renewable energy like wind and solar power could be used to produce hydrogen when the electricity demand is lower than the supply. The hydrogen can then be stored until the electricity demand is higher than the available supply from wind and solar power, at which point the stored hydrogen can be used to produce electricity in a fuel cell. In theory, this could reduce the curtailment of wind and solar power and enable larger shares of renewable energy in electricity grids. However, these systems currently have large challenges that must be solved for them to become economically viable. Even though there are very small hydrogen losses while it is in storage, there are significant energy losses associated with the process of converting electricity to hydrogen and back again to electricity (a.k.a. power-to-H_2-to-power). In Paper I, we performed a critical review of 15 real-world facilities that use hydrogen as energy storage in combination with renewable energy. The results of this work are summarized and discussed in this chapter. For more detailed results, see the attached Paper I.

4.1 Previous work

Several reviews of hydrogen energy systems have been published in recent years. Mazloomi and Gomes [31] reviewed hydrogen production and storage, as well as related risk and safety issues. They concluded that hydrogen is a promising alternative both as energy storage in electricity systems and as a transport fuel [31]. Gahleitner [32] reviewed pilot facilities that produce hydrogen through electrolysis with renewable electricity, while Dutta [33] reviewed hydrogen production and

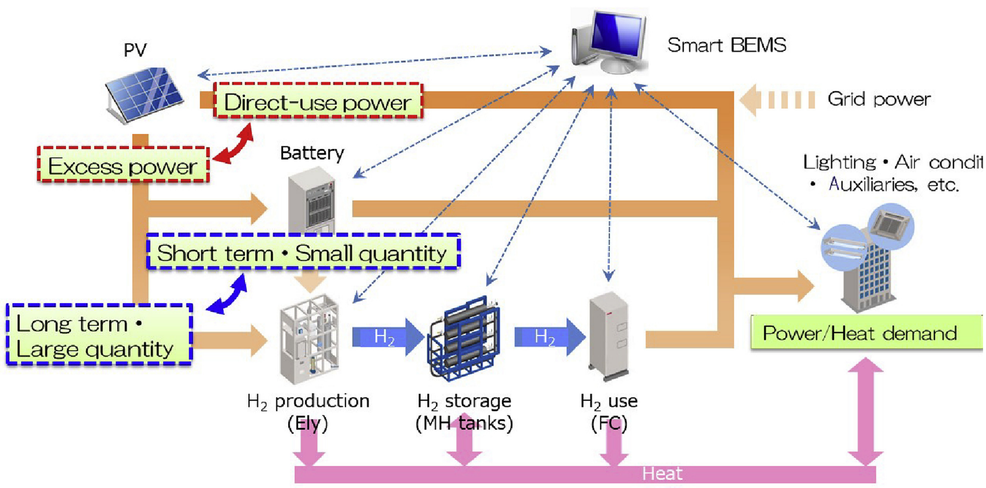

Figure 4.1: An energy flow schematic for a typical energy system that combines renewable energy with hydrogen energy storage. In this case, the renewable energy source is solar energy (PV panels), and the energy storage system includes both batteries and a hydrogen system. The hydrogen system includes an electrolyser, hydrogen storage in metal hydride tanks, and a fuel cell to convert hydrogen into electricity. The whole energy system is controlled by a building energy management system (BEMS) and it is also connected to the main power grid [30].

storage methods, including risk and safety issues. Bailera *et al.* [34] reviewed methods for converting renewable energy to methane, including an overview of real-world facilities. Eveloy and Gebreegziabher [35] reviewed projected power-to-gas scenarios and concluded that significant improvements in efficiency and reliability combined with significant cost reductions are necessary to enable large-scale facilities of this kind. Hanley *et al.* [36] analyzed drivers and policies that could influence the implementation of hydrogen in energy systems and concluded that hydrogen technologies will probably be implemented mostly after 2030. Wulf *et al.* [37] reviewed European power-to-gas projects in 2018 and suggested that these facilities could enable refineries to reduce their emissions of greenhouse gases. In 2020 they performed a second review [38] and found that the implementation of power-to-X projects in Europe had gone faster than projected, and that France and Germany were leading the development. Thema *et al.* [39] performed an analysis and forecast of the cost development within electrolysis and carbon dioxide methanation, including a review of projects that produce either hydrogen or a renewable substitute for natural gas [39]. Abe *et al.* [40] reviewed hydrogen as an energy carrier with a focus on metal hydride storage. Moradi and Groth [41] reviewed hydrogen storage and delivery and analysed risk and safety issues. Parra *et al.* [42] performed a techno-economic analysis of hydrogen energy systems. They recommended focusing on mass production, standardization and favorable policies to accelerate the adoption of hydrogen technologies [42]. Chehade *et al.* [43] reviewed 192 power-to-X projects in 32 countries and found that both electrolysis capacity and the number of hydrogen applications have increased significantly in recent years. Yue *et al.* [44] performed a review and techno-economic analysis of hydrogen energy systems, including real-world projects.

They concluded that technical improvements, political support and up-scaling of projects and production are all necessary factors to make hydrogen technologies economically viable.

4.2 Thesis contribution and discussion

The critical review published in Paper I contributed to the scientific community by providing a detailed overview and critical assessment of existing real-world systems where green hydrogen is used as energy storage in electricity systems. The projects were categorized by system topology (grid-connected or off-grid systems) and hydrogen storage technology (compressed gas or metal hydrides), and the main objectives and results of each project were critically summarized. In addition to this, the novelty of the paper was increased by the inclusion of power electronics and control systems used in hydrogen-based energy storage systems.

4.2.1 Concept

The typical operational profile of a renewable energy system with hydrogen energy storage is shown in Figure 4.2 for a wind power-based system [45] and in Figure 4.3 for a system based on solar power [30]. These figures illustrate very well the basic concept and advantage with these systems, i.e., that you can use excess wind and solar power to produce hydrogen which can later be used to generate power when the wind has died down or the sun has set. Both of these systems also use other energy storage technologies in the form of batteries in Endo *et al.* [30] and both batteries and a flywheel in Ulleberg *et al.* [45]. This enables the system to combine energy storage technologies that are well-suited for short-term storage and rapid fluctuations (batteries, flywheels, supercapacitors) with technologies that are better suited for long-term storage and less rapid fluctuations (hydrogen). Designing hybrid systems like these that are specifically tailored for a given project can increase the energy efficiency of the overall process, but the downside is that the added components and system complexity can also increase the total cost of the system.

4.2.2 Technical factors

All the reviewed systems confirmed the technical feasibility of renewable energy systems with green hydrogen as energy storage, but there is no doubt that there are significant challenges related to both technical factors and costs. The biggest technical challenge is the high energy losses in the conversion processes between electricity and hydrogen (both ways), i.e., the systems have low energy efficiencies. A typical PEM electrolyzer currently has an energy efficiency close to 60% [5, 46] when operating at its rated power. So even under ideal conditions, almost half the energy in the wind or solar electricity will be lost by converting it to hydrogen. To make matters worse, many of the smaller facilities reviewed in Paper I had even lower electrolyzer efficiencies due to fluctuating input power from wind and solar. The only project that achieved an average electrolyzer efficiency close to

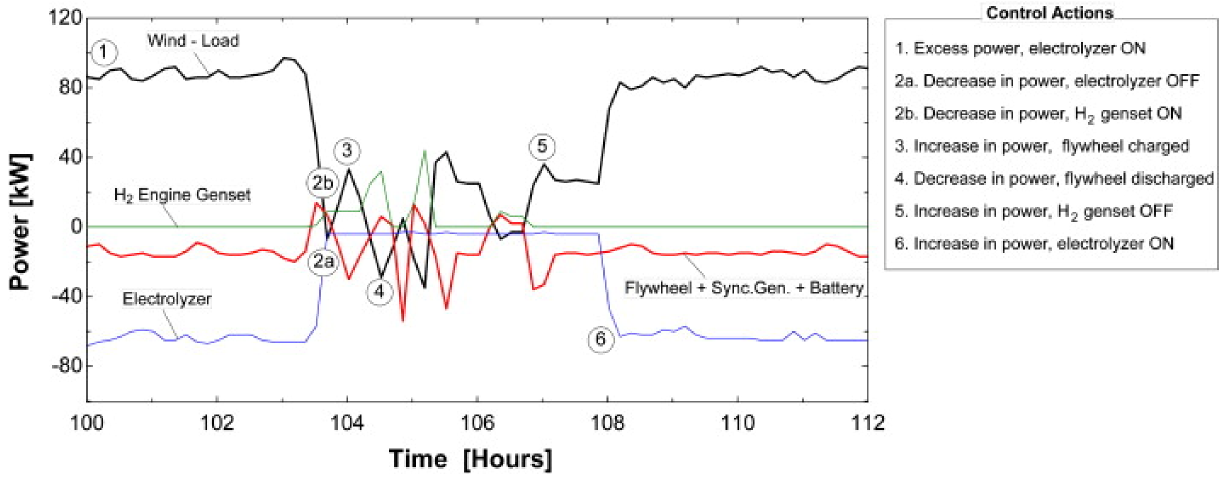

Figure 4.2: Operational profile for a wind power-based renewable energy system with hydrogen energy storage, as described by Ulleberg *et al.* [45].

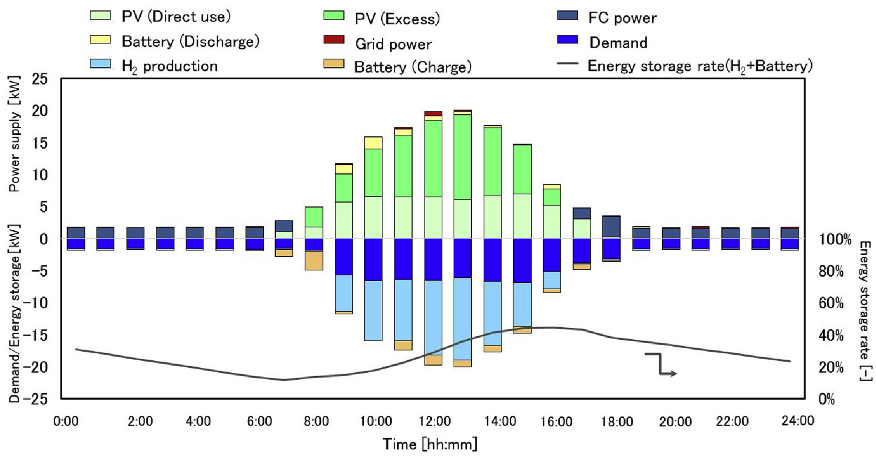

Figure 4.3: Operational profile of a solar power-based renewable energy system with hydrogen energy storage, as described by Endo *et al.* [30].

60% over time was the large-scale facility Energiepark Mainz, where an 8 MW wind farm is combined with a 6 MW PEM electrolyzer system to reach overall efficiencies of 60% in September 2015 and 54% in October 2015 [47]. Several of the other systems that were smaller and more exposed to fluctuating input power had average electrolyzer efficiencies significantly lower than this, for example 40-45% in Lutz *et al.* [48], 41.5% in Maclay *et al.* [49] and as low as 27.2% in Zhang *et al.* [50]. This shows that more research and development is needed within electrolyzer technologies, both to increase the maximum efficiency and to develop electrolyzers that are less sensitive to fluctuating input power. Continued development of energy management systems that optimizes the cooperation between hydrogen and batteries (or other short-term storage technologies) will also be important to reduce the energy losses in hydrogen systems.

More research and development is also needed within hydrogen storage technologies and fuel cells to increase the overall efficiency of the power-to-H_2-to-power process. Hydrogen storage as high pressure gas and in metal hydrides ($TiMn_2$) were compared in a facility at the Spanish National Institute for Aerospace Technology (INTA) [51]. Results showed that the efficiency of high pressure gas storage was as low as 52%, while metal hydride storage achieved an efficiency of 79% [51]. Metal hydride storage was shown to have a lower gravimetric energy density, with 0.31 kWh/kg compared to 0.42 kWh/kg for high-pressure gas [51]. This means that metal hydride storage is currently not a good solution for systems where weight is an issue, for example road transport. It is also a much less mature technology that has not been scaled up to mass production yet. However, metal hydride storage showed a very good volumetric energy density, with 1.22 kWh/L compared to 0.52 kWh/L for high-pressure gas [51]. This shows that metal hydride storage could become a good solution for systems where volume is a more limiting factor than weight.

The efficiency of hydrogen fuel cells is also an important factor in systems where the hydrogen is converted back into electricity. Fuel cells typically have efficiencies around 50% with current technology [46], and this is expected to increase to around 60% with future developments [46]. However, fuel cells can also be sensitive to fluctuating loads, which can reduce the actual efficiency in real systems. The reviewed projects varied in this area as well. A 50% fuel cell efficiency was achieved in Lutz *et al.* [48] and the tests at INTA showed an average efficiency of 48% [51], but other projects showed lower efficiencies, with 40% in Maclay *et al.* [49] and just 29.3% in Zhang *et al.* [50]. The fact that at least half the energy in the hydrogen is lost if it is converted to electricity with current technology is perhaps an indication that it would be better to use green hydrogen directly as hydrogen, instead of converting it back to electricity, at least from an energy efficiency viewpoint.

4.2.3 Costs

Costs in all parts of the green hydrogen value chain constitute large challenges for the large-scale implementation of hydrogen energy storage systems. The projects reviewed in Paper I focus more on technical factors than costs in their studies, but the ones that consider costs conclude that the cost of all components in these systems must be reduced considerably to make them economically viable. None of the projects report that they are cost-competitive when current technology and costs are used. Maclay *et al.* [49] compared the cost of the electricity delivered by their solar-hydrogen system with the price of grid electricity and electricity from a solar-battery system. They calculated that the electricity from the solar-hydrogen system was 933% more costly than regular grid electricity, and also 202% more costly than solar-battery electricity [49]. The high costs of green hydrogen systems are of course also tied to the challenges with low efficiency described in the previous section, since each unit of energy lost will increase the cost of the delivered energy, as long as the system cost is almost fixed. More research and development that can reduce the cost is therefore needed, both for electrolyzers, fuel cells and storage technologies. The cost of green hydrogen *production*, both current and future, was studied in much greater detail in Papers II-IV, which are summarized and discussed in chapter 5.

4.2.4 Discussion

The main conclusion of the critical review in Paper I was that green hydrogen as energy storage in electricity systems have high energy losses and costs, and very few of these systems currently exist because of this. The efficiencies of the power-to-H_2-to-power processes in the real-world systems reviewed in this paper were in the range 15-40%, and it is difficult to justify an energy storage system that loses up to 85% of the energy in the overall process. On the positive side, hydrogen has the advantage compared to batteries that it can be stored for long periods (weeks and months) with minimal losses during the storage period, but unfortunately the energy losses in the conversion processes are too high to make hydrogen a good method for storing energy in electricity systems with current technology. Another challenge for current green hydrogen technologies (electrolyzers, fuel cells) is that they are not well-suited to use intermittent energy flows of the type that solar and wind power typically delivers, so most of the reviewed projects conclude that hydrogen should be combined with short-term energy storage technologies (e.g., batteries) that can smooth out the power fluctuations in the system. Several of the reviewed projects also reported that the current costs of hydrogen energy storage systems are too high to make these systems economically viable. However, the *production* of green hydrogen could be a more viable concept if it is produced for applications where it is not converted back into electricity. Hydrogen fuel cells currently lose around 50% [46] of the energy in the hydrogen gas when converting it to electricity, and this energy loss can be avoided if the hydrogen is used directly, for example as a component in the production of ammonia and methanol. Therefore, it seems that the low-hanging fruit for green hydrogen is not in applications where hydrogen is converted back into electricity. It makes a lot more sense to use green hydrogen to replace the fossil fuel-based hydrogen that is currently used in industrial processes. Subsequently, the next logical step would be to use green hydrogen to replace some of the fossil fuel use in other sectors. Examples of this could be to burn green hydrogen for industrial heat instead of natural gas or coal, or to use green hydrogen to produce fuels (e.g., ammonia, various e-fuels) that could replace some of the fossil fuel use in transport sectors difficult to electrify with batteries, for example shipping. So far, green hydrogen as energy storage in electricity systems is almost non-existent, and it is expected to have significant growth only after 2030, if at all. However, if the world realizes a scenario with net-zero emissions in 2050, significant amounts of green hydrogen could be used as energy storage in electricity systems [22–25], as discussed in chapter 2 of this thesis.

Chapter 5

Simulating green hydrogen production with electricity from offshore wind farms

Most of the work in this PhD project focused on the simulation of green hydrogen production with electricity from offshore wind power. My employer at the time, UNITECH Offshore AS [8], owns and operates a 2.3 MW floating offshore wind turbine (FOWT) with several years of high-resolution (10-minute) data available, including energy production and wind speed. Motivated by the huge fluctuations in Norwegian electricity prices in recent years, UNITECH wanted to investigate the possibility of using electricity from the FOWT to produce green hydrogen when electricity prices are low. Therefore, this became the natural focus area for the next stage of my PhD project. This work resulted in computer models that simulate hydrogen production with electricity from offshore wind farms. The models are described in chapter 3, while the results from the simulations, as well as previously published work by others in this field, are summarized and discussed in this chapter. More detailed descriptions of the models and results can be found in Papers II-IV.

5.1 Previous work

A detailed review of the previous work in this field is given in the literature review sections of Paper II and Paper III and summarized here.

Schnuelle *et al.* [52] modelled hydrogen production from solar and wind power and found that offshore wind power could not compete with onshore wind power or solar power in terms of efficiency and cost. McDonagh *et al.* [53] simulated hydrogen production with electricity from an offshore wind farm and found that it would be more profitable to sell the electricity directly instead of using it to produce hydrogen. Similarly, Baldi *et al.* [54] found that it is currently more profitable to sell the electricity from offshore wind farms to the grid, but hydrogen production could become competitive if the share of wind power in the grid exceeds 40% and the hydrogen price is at least 0.10 £/kg H_2. Dinh *et al.* [55] estimated that offshore wind-hydrogen farms can become profitable in 2030 if the hydrogen price is at least 5 €/kg H_2. Scolaro and Kittner [56] simulated offshore wind-hydrogen farms and found that such systems will need a carbon abatement cost of 187-265 €/ton CO_2 to be profitable. Wei *et al.* [57] used a novel dispatching strategy to optimize the integration of wind-hydrogen systems with the electricity grid, and their simulations achieved a 4.4% reduction in the grid's operational costs. Gea-Bermúdez *et al.* [58] modelled future hydrogen production from offshore wind farms in Northern Europe and concluded that hydrogen should be produced onshore, since offshore production would result in higher costs and emissions. Durakovic *et al.* [59] also modelled green hydrogen production in the North Sea region towards 2060 and found that this could reduce the curtailment of offshore wind power from 24.9% to 9.6%.

Large variations in the levelized cost of hydrogen (LCOH) can be found in previous simulations of wind-hydrogen systems. If the external conditions (for example electricity price) are unfavorable for hydrogen production, the resulting LCOH can become several times higher than when the conditions are favorable, as shown in the simulations in Paper II. However, even if only the best case scenarios from previous works are considered, there are still large variations between the different studies. Grüger *et al.* [60] developed an operating strategy for a wind-hydrogen system and achieved a LCOH of 11.52 €/kg H_2 in their simulations. Lucas *et al.* [61] performed a techno-economic analysis of a large-scale offshore wind-hydrogen farm where the lowest LCOH achieved was 4.25 €/kg H_2. Tebibel [62] analyzed a small-scale decentralized wind-hydrogen system where the resulting LCOH was 33.70 \$/kg H_2. Two studies, Almutari *et al.* [63] and Rezaei *et al.* [64], analyzed hydrogen production from wind power in Iran, and the best case LCOH were 2.1 \$/kg H_2 [63] and 1.375 \$/kg H_2 [64], respectively. Franco *et al.* [65] performed a techno-economic analysis of offshore wind-hydrogen systems where the best case achieved a LCOH of 5.35 €/kg H_2, and they estimate that this could be reduced to 2.17 €/kg H_2 with EU's support to hydrogen deployment. Miao *et al.* [66] analyzed hydrogen production from mixed renewable energy sources and the optimized case achieved a LCOH of 7 \$/kg H_2. The lowest LCOH achieved with an offshore wind-hydrogen system by Jang *et al.* [67] in their study was 13.81 \$/kg H_2. Lamagna *et al.* [68] modelled offshore hydrogen production inside wind turbine towers and estimated that this could achieve a LCOH of 1.95 \$/kg H_2. The lowest LCOH estimated by Groenemans *et al.* [69] in their analysis of offshore wind-hydrogen systems was 2.09 \$/kg H_2. Komorowska *et al.* [70] analyzed future cases with hydrogen production from offshore wind farms and estimated that the best case LCOH will be 3.60 €/kg H_2 in 2030 and 2.05 €/kg H_2 in 2050. More references are included in the literature review in Paper III, all with a LCOH within the same range as the references listed above. The differences in the estimated best case LCOH values are striking. Of course, it must be taken into consideration that there are differences between the studies, e.g., in the assumptions and limitations, system designs, and whether current or future technologies and costs are used in the models and analyses. Nevertheless, such large differences in cost estimates, both current and future, illustrate that the uncertainty is still very high for wind-hydrogen systems, and it is very difficult to evaluate the probability of any future forecasts for these systems.

5.2 Thesis contributions and discussions

5.2.1 Paper II

Model 1, described in chapter 3 and Paper II, was used to simulate the operation of an offshore wind-hydrogen system during five different 31-day periods. Five periods with large differences in wind turbine capacity factors and electricity prices were selected to analyze the importance and impact of these two parameters on both technical and economic factors. The combination of high-resolution real-world data from a FOWT, electricity price data and a detailed simulation model of a green hydrogen production system with a PEM electrolyzer gave very interesting results. The impact the different conditions had on the results demonstrated very well the large variations that a wind-hydrogen system will be subjected to from month to month in a real-world system. Particularly the wind turbine capacity factor and the electricity price have huge effects on these systems. The wind speed is naturally also a very important factor, since this is the variable that usually has the most influence on the wind turbine capacity factor.

The main finding from the work described in the second paper is that a wind-hydrogen system with current technology needs both a high wind turbine capacity factor and a relatively low electricity price to produce green hydrogen at a cost that is competitive with other green hydrogen production methods. Both the total hydrogen production (Figure 5.1) and production cost varied by up to a factor of three between the different periods, which demonstrates that it will be difficult to predict the hydrogen output and economic conditions for real-world systems of this type. The highest hydrogen production and lowest cost were achieved in the same period, which was the period with the most favorable wind turbine capacity factor and electricity price, as expected. This period had a wind turbine capacity factor of 63.6%, the highest of the five periods, and the average electricity price was 0.0091 \$/kWh, which was the second lowest of the five periods. The case with the highest electrolyzer capacity in this period resulted in a total hydrogen production of 17 242 kg with a 1.852 MW PEM electrolyzer, which translates to a utilization/capacity factor of approximately 68% for the electrolyzer. The hydrogen production cost range for the cases in this period was 4.53-5.46 \$/kg H_2, which means that all cases were within the current estimated range of 3.2-7.7 \$/kg H_2 [7] for green hydrogen. In contrast to this, the simulation cases in the period with the least favorable conditions showed very different results. The wind turbine capacity factor in this period was just 21.3% and the average electricity price was 0.0440 \$/kWh. This resulted in a total hydrogen production of just 5649 kg with a 1.852 MW PEM electrolyzer, which translates to a utilization/capacity factor of approximately 22% for the electrolyzer. The hydrogen production cost in this period was in the range 9.55-14.49 \$/kg H_2.

A detailed analysis of the case with the highest hydrogen production showed that the PEM electrolyzer tolerated the fluctuations in the input power from the FOWT well and produced hydrogen with relatively stable efficiency values. This is illustrated in Figure 5.2, which shows the input power and the efficiency of the PEM electrolyzer in a 3-day period in the simulation case with the highest

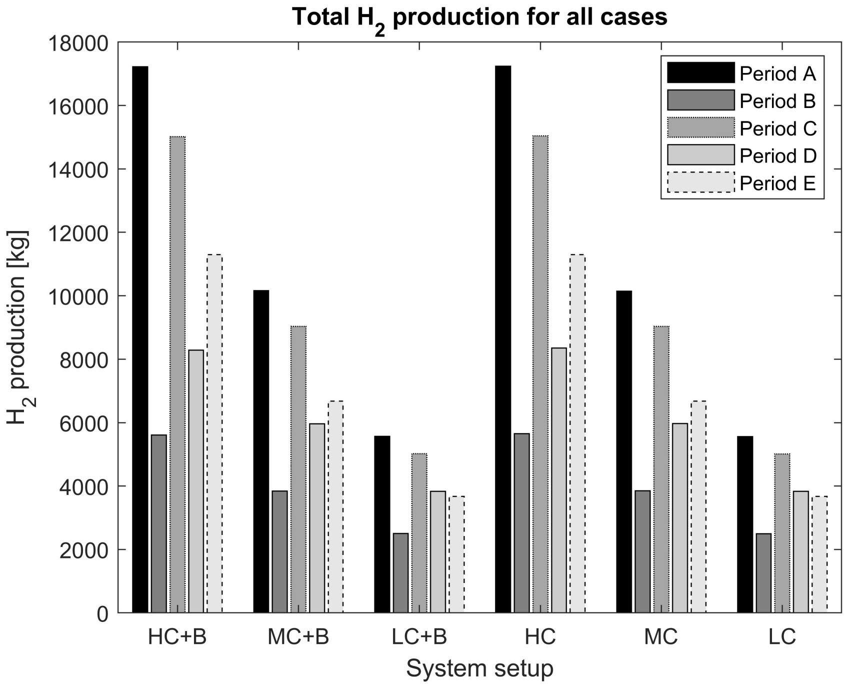

Figure 5.1: Figure from Paper II showing the total hydrogen production for all simulation cases. See Table 2 and Table 3 in Paper II for explanations of the time periods and system setups.

hydrogen production. The efficiency and input power are inversely correlated, and the efficiency is at its minimum when the input power is at its maximum, and vice versa. The efficiency was never below 72% when the electrolyzer was turned on and the average efficiency for the whole 31-day simulation period was approximately 75%. These efficiency values were calculated by using the higher heating value of hydrogen (142.1 MJ/kg [26]). When these are adjusted to the more commonly used lower heating value of 120.1 MJ/kg [26], the minimum efficiency is around 61% and the average efficiency is around 63%. When the energy usage for compression and storage of hydrogen and desalination of sea water is included, the average efficiency for the whole hydrogen production process was around 57% in all simulation cases. These values are considerably higher than many of the reported efficiencies in the reviewed real-world hydrogen systems in Paper I. This is due to the fact that the electrolyzer in Paper II is simulated by a mathematical model, and a model of this kind will never be able to account for everything that could affect the efficiency in a real-world system. There are also other limitations to the model, as described in chapter 3, for example that the model does not include start-up and ramp-up time for the electrolyzer. Therefore, the efficiency values from the simulations should be viewed as ideal values that are unlikely to be achieved in a real-world system with current technology. As the systems reviewed in Paper I shows, real electrolyzers are often more negatively affected by fluctuating input power than simulation models are, resulting in actual efficiencies that are much lower than the expected efficiency at rated input power.

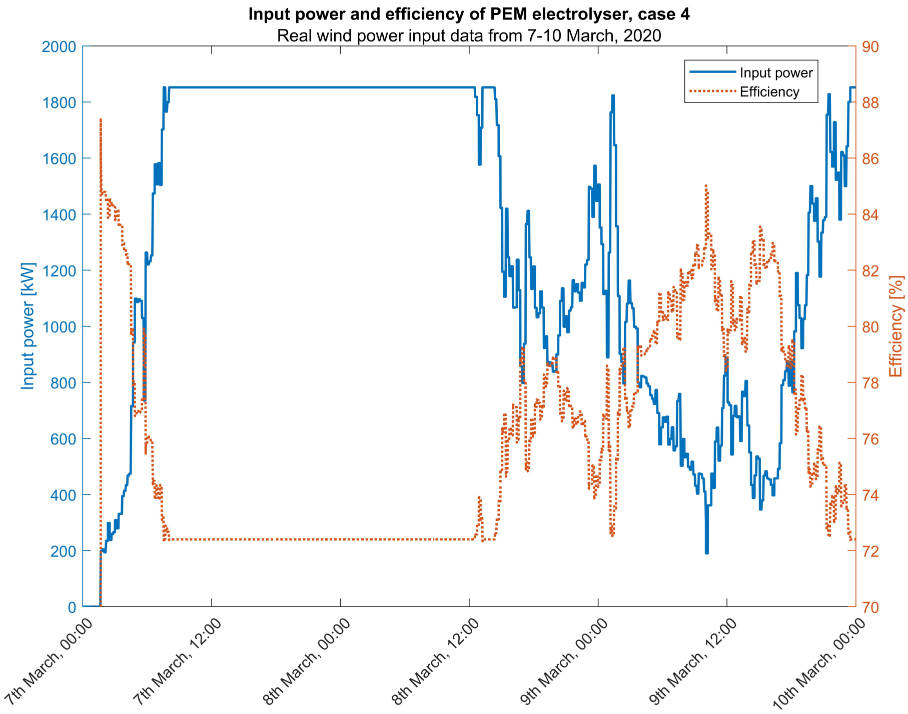

Figure 5.2: Figure from Paper II showing the efficiency and input power for the PEM electrolyzer in a 3-day period of the simulation case with the most favorable conditions. The efficiency values in this chart is calculated using the higher heating value of hydrogen of 142.1 MJ/kg [26].

5.2.2 Paper III

The results from Paper II motivated further research in the field of green hydrogen production from offshore wind power. The next natural step was to expand this work into a much larger model that could simulate large-scale hydrogen production from any offshore wind farm. A new model that can simulate hydrogen production from an offshore wind farm with only the wind speed and electricity price of the location as input was therefore developed, as described in chapter 3 and Paper III. A novel control system was developed to automatically schedule the hydrogen production in the most cost-optimal way for each time interval. Ten years of historical data of wind speeds and electricity prices were used to simulate various test scenarios, both current and future, and the LCOH, LCOE and NPV were estimated for each scenario.

It was decided to keep the hydrogen production onshore in most of the simulation scenarios, but an offshore scenario was also developed to compare with the onshore scenarios. A polynomial regression model was developed to estimate the capacity factor of a FOWT with high accuracy based on the wind speed of the location. The model was tested on two independent testing data sets (a 30-day set and a 1-year set) and the mean absolute error on both data sets were below 1%, i.e., the absolute difference between the predicted capacity factor and the actual capacity factor was on average less than 1%. This is illustrated well in Figure 5.3 (taken from Paper III), which shows the capacity factor estimated

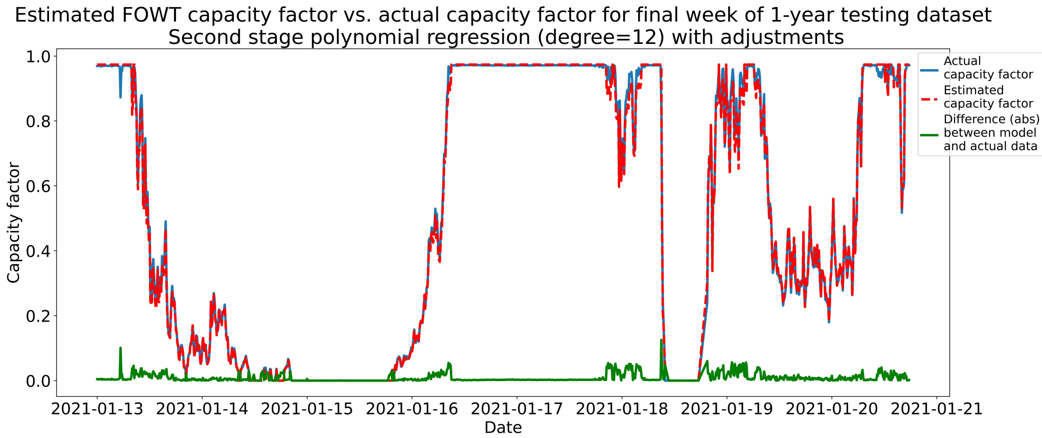

Figure 5.3: Figure from Paper III showing the capacity factor estimated by the polynomial regression model compared to the actual capacity factor in the final week of the largest testing data set. The absolute difference between the capacity factors is also shown.

by the polynomial regression model compared to the actual capacity factor in the final week of the largest testing data set. The absolute difference between the estimated and actual capacity factors is also shown in the chart.

A modified version of the hydrogen production model from Paper II was used to simulate hydrogen production, and this production was scheduled by a control system designed to maximize the profit of the wind-hydrogen system based on the electricity price and average selling price of hydrogen, as described in chapter 3. The results show that the control system decreased the LCOH by 10-46% in all scenarios, both with current technology and costs, as well as with the forecast technology improvements and cost reductions towards 2050. This is shown in Figure 5.4, which presents the LCOH for all simulation cases in Paper III. Each of the cases with even numbers is identical to the case before it, except that the cases with even numbers do not use the control system developed in this paper. For example, case 2 is the same as case 1 except that the control system is only active in case 1, and the same goes for case 4 and 3, and so on. As seen here, the cases that use the control system has a lower LCOH than the same case where the price-based part of the control system is deactivated. This demonstrates that wind-hydrogen systems will benefit greatly from having control systems that are able to schedule the hydrogen production in the most cost-optimal way. With the control system activated, the estimated LCOH with current technology was 6.04 \$/kg H_2 (case 1), which is within the current estimated range of 3.2-7.7 \$/kg H_2 [7] for green hydrogen. Using the most optimistic forecasts of technology improvements and cost reductions for 2050 resulted in a LCOH of 0.96 \$/kg H_2 (case 3). A 2050 scenario with hydrogen production using grid electricity resulted in a LCOH of 0.82 \$/kg H_2 (case 7), but it is important to note that this would not qualify as green hydrogen unless the electricity grid can guarantee that the electricity delivered comes only from renewable energy sources. A 2050 scenario with offshore hydrogen production from an off-grid offshore wind farm resulted

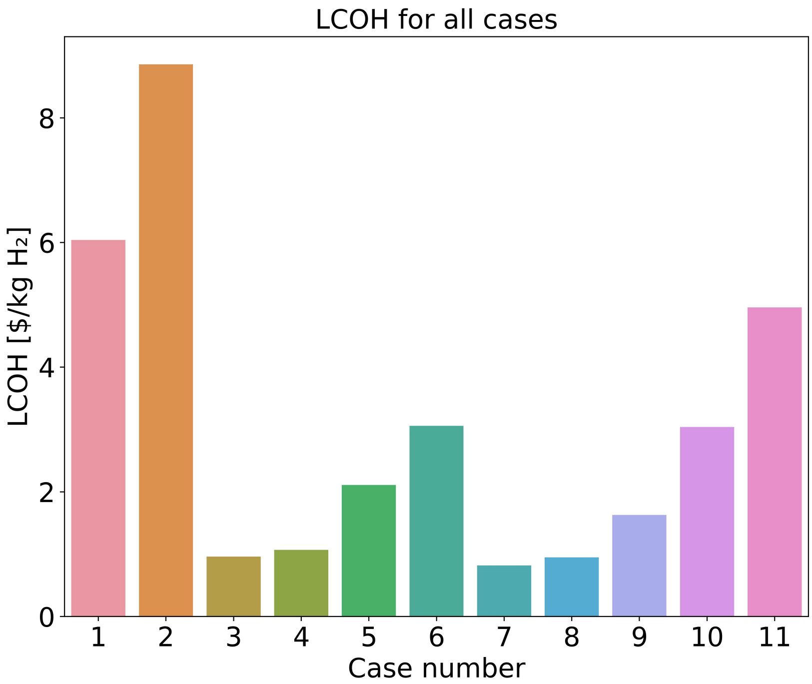

Figure 5.4: Figure from Paper III showing the LCOH for all simulation cases. Cases 1 and 2 used current technology and costs while cases 3-11 used technology improvements and cost reductions forecast for 2050. See Table 10 in Paper III for a description of the cases.

in a LCOH of 4.96 \$/kg H_2 (case 11), which clearly indicates that it will be difficult for a system of this type to compete with onshore hydrogen production. The LCOH of the offshore scenario can be reduced by approximately 50% if new offshore wind turbines with electrolyzers and associated equipment (compressor, desalination plant, etc.) integrated inside the turbine tower are designed and built, however the LCOH would still be higher than all 2050 scenarios with onshore hydrogen production where the control system optimizes the interaction with the electricity grid. All 2050 simulation scenarios except the one with offshore hydrogen production achieved a LCOH within or below the range estimated for green hydrogen in 2050, which is 1.3-3.3 \$/kg H_2 [7].

Revenue estimates showed that a wind farm could potentially increase its yearly revenues by also producing and selling hydrogen compared to a wind farm that only sells electricity. The yearly revenues from hydrogen and electricity sales from the wind-hydrogen system (with the control system) were estimated for a base case with current technology and costs. This was then compared with revenues for the same wind farm without hydrogen production, and the results showed the revenues were higher with hydrogen production than without hydrogen production for every year in the simulation. This is shown in Figure 5.5, where the revenue with hydrogen production is generally 3-6 times higher than the revenue without hydrogen production. The last three years (2020-2022) saw abnormally large

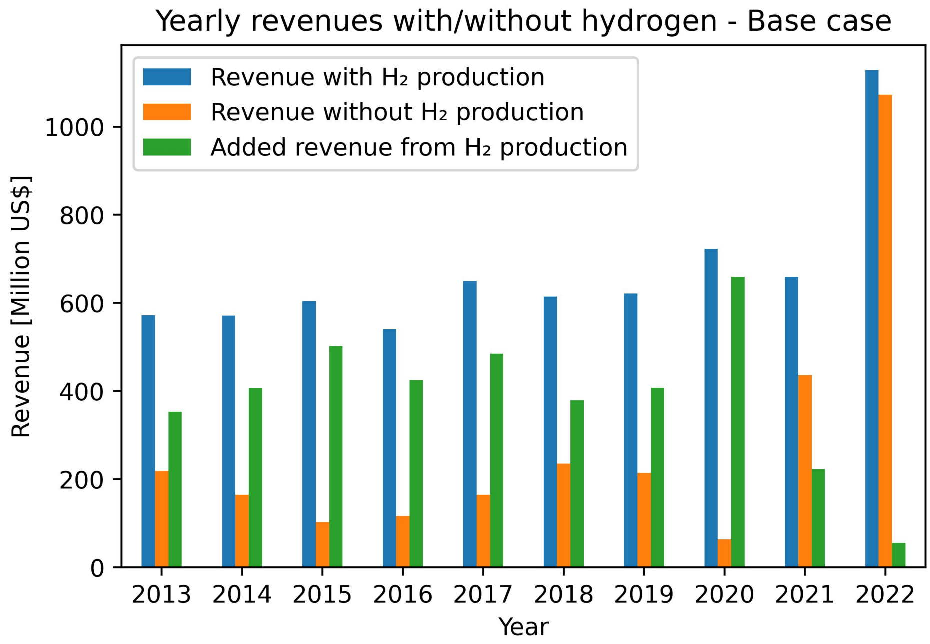

Figure 5.5: Figure from Paper III showing the yearly revenue estimates for a wind farm with and without hydrogen production, as well as the added revenue with hydrogen production. This is for case 1, which is a case that uses current technology and costs and where the control system described in chapter 3 is active.

fluctuations in Norwegian electricity prices. The low electricity prices in 2020 gave results where the revenues with hydrogen production were more than 11 times higher than the revenues without hydrogen production. Then, much higher electricity prices in 2021 and 2022 gave results where the revenues with hydrogen production were just 50% (2021) and 5% (2022) higher than the revenues without hydrogen production. It must also be noted that the control system decided to produce much less hydrogen in the last two years, particularly in 2022 where the hydrogen production was only around a quarter of the average production of the preceding years. These results illustrate that the advantage of combining a wind farm with green hydrogen production can be huge in periods with low electricity prices, but the advantage can almost disappear in periods with high electricity prices. This shows that green hydrogen production will probably not make sense in future scenarios where the electricity price is much higher than the long-term average, as it was in 2022.

A sensitivity analysis was also performed where the impacts from changes within a forecast range in eight of the most important variables were analyzed. The results confirmed what was found in the simulations in Paper II: the electricity price, wind turbine capacity factor and wind speed had high impacts on hydrogen production and the economic results (LCOH and NPV). Additionally, the results showed that the hydrogen selling price and the lifetime of the PEM electrolyzer had high impacts on both hydrogen production and the economic results. The CAPEX of the PEM electrolyzer had a high impact on the economic results. The discount rate and the efficiency of the PEM electrolyzer had relatively low impacts on both hydrogen production and the economic results.

The research described in Paper II and Paper III thus contributed to filling knowledge gaps within research on green hydrogen production in connection with offshore wind farms. The large real-world datasets that the models in this thesis are based upon increases the realism of the simulation results compared to previously published studies, and the novel control system used in Model 2 was able to lower the LCOH in all scenarios, both current and future. The model was developed with future real-world wind-hydrogen systems in mind, where the forecast wind speed and electricity price can be used to continually estimate and optimize the production of green hydrogen with respect to both technical and economic factors.

5.2.3 Paper IV

In addition to the work in Paper III, parts of Model 2 were also used for the work presented in Paper IV, which has been accepted as a conference paper by *The 34th International Ocean and Polar Engineering Conference*. This work used Model 2 to compare electricity transport with hydrogen transport from offshore wind farms in the North Sea in 2050. This paper focused on energy transport (electricity or hydrogen), instead of the hydrogen production and storage which is the focus in Papers I-III. Paper IV is thus not directly focused on any of the four research questions in this PhD project (listed in section 1.3), but it is still so closely connected to the work in Paper II and Paper III that it is included as the final paper in this thesis.

The objective of the work in Paper IV was to investigate whether it could make sense for wind farms in the North Sea to transport the energy it produces to the shore as hydrogen gas in pipelines, instead of electricity through subsea power cables. To answer this, Model 2 was used to perform simulations of wind power and potential hydrogen production from a future wind farm in the North Sea. Techno-economic analyses were then performed for around 150 different scenarios, including offshore and onshore electrolysis, and these were compared with scenarios with power cables and selling of electricity. The effect of different offshore distances was also investigated. The maximum offshore distance in the North Sea will be below 500 km, as explained in Paper IV, but offshore distances up to 5000 km were included in the analysis to investigate if the results change significantly at longer distances. The data input to the simulations was 25 years of hourly wind speed data from a planned North Sea wind farm location (Sørlige Nordsjø 2 [29]), downloaded from the Renewables Ninja website [11–13].

The results of the simulations and techno-economic analyses in Paper IV indicate that offshore hydrogen production on North Sea wind farms will not be competitive with onshore hydrogen production, even with the most optimistic cost reduction forecasts for 2050. The best solution will probably be to connect the wind farm to the onshore electricity grid with a subsea power cable. If green hydrogen is going to be produced, it should be done onshore, either with electricity from the offshore wind farm or with grid electricity from renewable sources. Blue hydrogen, i.e., hydrogen produced from natural gas with carbon capture, is also a relevant option that green hydrogen will have to compete with. The International Energy Agency (IEA) estimates that the cost range for blue hydrogen with 95% carbon capture will be 1.2-2.1 \$/kg H_2 in 2050 [7, 71], which means that green hydrogen will need to get down to the same range to be competitive in such a scenario. Figure 5.6 shows the LCOH for various cases as a function of offshore distance, with the estimated LCOH range for blue hydrogen shown by the shaded blue area. As illustrated in this figure, it is only with offshore distances between approximately 900 and 1400 km that the LCOH curve for offshore electrolysis (green line) is below both the curve for onshore electrolysis (red dashed line) *and* the upper limit of the blue hydrogen price range. In other words, offshore electrolysis could theoretically be competitive with onshore electrolysis and blue hydrogen if the offshore distance of the wind farm is between 900 and 1400 km, but only if the LCOH of blue hydrogen is near the upper limit of IEAs estimate. Additionally, the LCOH of onshore electrolysis could be reduced by 10-46% by using a control system like the one developed and described in Paper III. The purple and yellow dotted lines in Figure 5.6 show 10% and 46% LCOH reductions for onshore electrolysis, which makes onshore electrolysis cheaper than offshore electrolysis in the 900-1400 km range as well. It must also be noted that the LCOH curve for offshore electrolysis assumes that offshore wind turbines with electrolyzers and all associated equipment (battery, compressor, desalination plant, etc.) integrated inside the wind turbine structure have been developed and commercialized. If a separate platform for electrolysis is required, offshore electrolysis will not be competitive in any scenario regardless of offshore distance, as shown in Paper IV.

The simulations and techno-economic analysis in Paper IV thus contribute to answer the question regarding offshore hydrogen production in connection with wind farms, i.e., does this make sense? With the assumptions and limitations used in this analysis (see Paper IV for details), it is very unlikely that offshore hydrogen production in the North Sea in 2050 will be competitive with onshore electrolysis and/or blue hydrogen. The results also indicate that offshore hydrogen production will probably not be competitive anywhere, even in locations where the wind farm is much farther from the shore than what is possible in the North Sea.

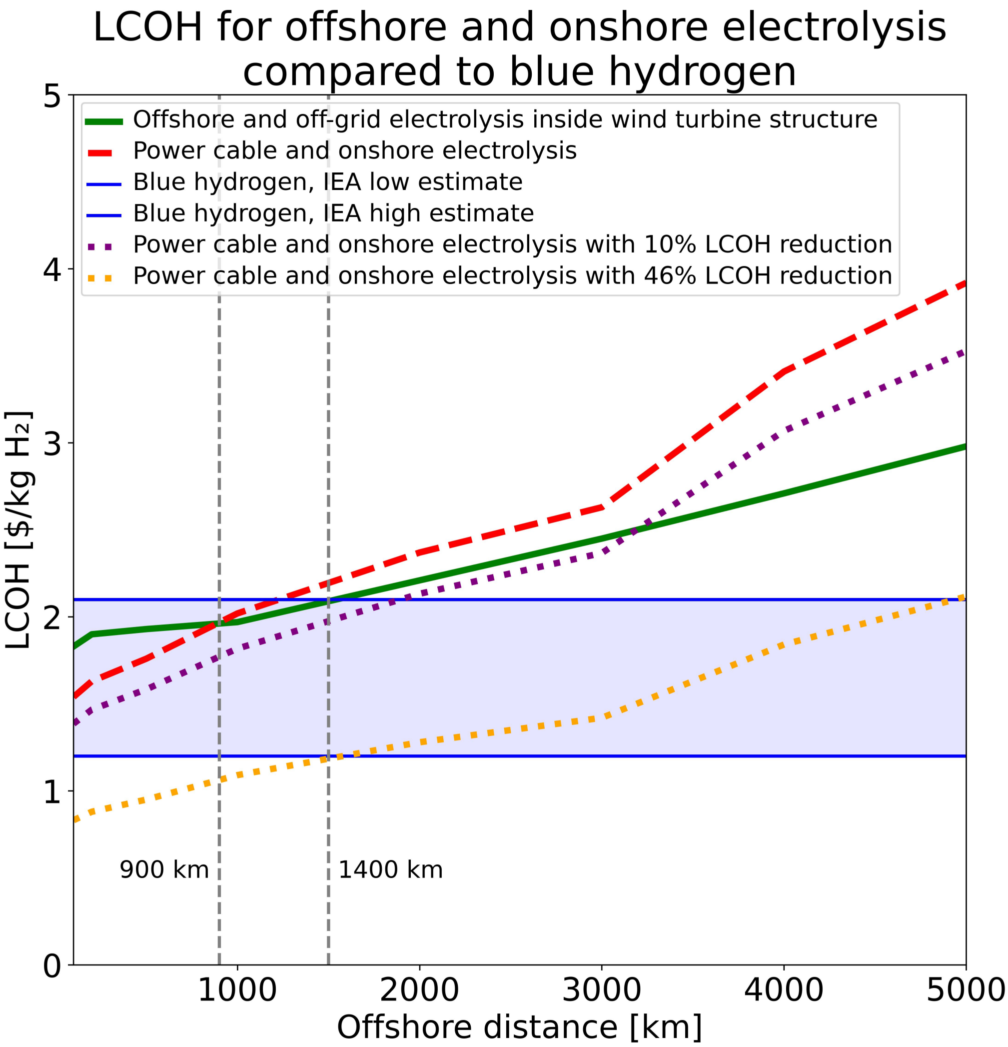

Figure 5.6: Figure from Paper IV showing the LCOH for various cases. The two main cases are offshore and off-grid electrolysis (green full line) and subsea power cable from the offshore wind farm to shore followed by onshore electrolysis (red dashed line). The purple and yellow dotted lines show the latter case with a 10% and 46% reduction in LCOH, which could be achieved with a price-based control system, as demonstrated in Paper III. The blue area marks the range estimated by IEA for blue hydrogen [7, 71], which is hydrogen produced from natural gas with 95% carbon capture. The two vertical dotted lines marks offshore distances of 900 and 1400 km.

Chapter 6

Discussion summary, conclusion and further work

6.1 Discussion summary

Hydrogen technologies could have a significant part to play in the transition away from fossil fuels. The focus in this PhD thesis was on green hydrogen, i.e., hydrogen produced by water electrolysis with electricity from renewable energy sources, and in most of the work in this PhD project the renewable electricity came from offshore wind power. In this section the key points from the PhD project are presented. These are based on the work described in the first three papers to answer the research questions posed in the introduction:

1. What are the main advantages and challenges with green hydrogen as energy storage in electricity systems?

2. What are the most important factors that influence the technical performance of green hydrogen production from offshore wind power?

3. What factors have the largest effect on the production cost of green hydrogen from offshore wind power?

4. Is it possible to improve the economic and technical viability of green hydrogen production from offshore wind power by developing a model that uses technical and economic factors to forecast and control the hydrogen production?

Question 1 was the focus of the work in Paper I. The work in Paper II focused on research questions 2 and 3. The work in Paper III explored research questions 2 and 3 in more detail and on a larger scale, and a simulation model with a novel price-based control system was developed in this paper to explore and answer research question 4.

Regarding research question 1, it was found that the main advantages with green hydrogen as energy storage in electricity systems are the possibility to store hydrogen for long periods with minimal losses, the systems are very flexible in terms of the sizing of energy and power capacity, and there are very few harmful emissions associated with green hydrogen systems. The fact that hydrogen can easily be stored for long periods means that it is not necessarily a competitor to batteries. In fact, they can often be used together in hybrid energy storage systems to the benefit of both technologies. The sizing advantage also makes hydrogen a good match with batteries. In hydrogen systems the total energy storage capacity is determined by the size of the storage vessel (e.g., compressed gas tank) and the maximum power capacity is determined by the rated power of the electrolyzer (input) and fuel cell (output). Therefore, the energy and power capacities are independent of each other, which can be beneficial in some projects. The main disadvantages with green hydrogen as energy storage in electricity systems are that these systems have very high energy losses and are very costly. The green hydrogen systems reviewed in Paper I showed energy losses of 60-85% in the power-to-H_2-to-power process. In addition to this, the performance of electrolyzers is negatively affected when the input electricity comes from intermittent sources (solar and wind), even though some electrolyzer types (e.g., PEM electrolyzers) handle this better than others. These disadvantages, particularly the high energy losses, currently weigh much more heavily than the advantages described above, and because of this there are very few existing projects where green hydrogen is used as energy storage in electricity systems.

The results from the simulation model developed in Paper II showed, as expected, that the most important factor that influences the technical performance of green hydrogen production from offshore wind power is the capacity factor of the wind turbine, and this is mostly determined by the wind speed. The wind turbine used as a data source in the models in this PhD project generates electricity in the wind speed range 4-25 m/s, and the ideal wind speed range where the turbine operates at the rated (maximum) power starts around 13 m/s. The hydrogen production is thus maximized when the wind speed is in the range 13-25 m/s and the turbine downtime (e.g., due to unexpected errors) is minimized. Simulations in Paper II showed that the hydrogen production in the period with the highest wind turbine capacity factor was three times higher than it was in the period with the lowest capacity factor. The capacity factor was also three times higher in the best period compared to the worst period, 63.6% vs. 21.3%, demonstrating the strong correlation between the wind turbine capacity factor and hydrogen production. The results in Paper II also showed that the simulated PEM electrolyzer followed the fluctuations in the incoming electricity from the wind turbine very well. The efficiency of the electrolyzer moved inversely to the input power, i.e., the efficiency was at the maximum level when the input power from the wind turbine was at the minimum level, and vice versa, as explained in more detail in Paper II. However, the efficiency always remained within the expected range when the electrolyzer was producing hydrogen, and the average energy efficiency of the hydrogen production process (desalination of sea water, electrolysis, compression and storage of hydrogen) was close to 57% in all simulations. The model developed in Paper III confirmed that the electrolyzer functioned very well with wind power as input, and that the most important factor for the technical performance of a wind-hydrogen system is the wind speed, since this is the factor that determines the capacity factor of the wind turbine in normal operation. The natural conclusion to draw from this is that it will be very important to build wind-hydrogen systems in the right locations with regards to wind speed, since the output of the hydrogen system is very dependent on the production of wind energy.

In the work described in Paper II and Paper III, the cost of green hydrogen production from offshore wind power was analyzed to identify the most important factors that influence this cost. In Paper II a simplified hydrogen production cost was calculated for each 31-day simulation period. In Paper III, a more detailed economic analysis was performed where the levelized cost of hydrogen (LCOH), levelized cost of energy (LCOE) and net present value (NPV) were calculated for the entire project lifetime (10-25 years), and a sensitivity analysis was performed in which the impacts from changes within a forecast range in eight of the most important variables were analyzed. The results in Paper II show that the most important factors for the hydrogen production cost was the price of electricity and the wind turbine capacity factor (which is mostly determined by the wind speed). The period where the lowest hydrogen production cost of 4.53 \$/kg H_2 was achieved had an average electricity price that was around 20% of the average electricity price in the period with the highest hydrogen production cost (9.55 \$/kg H_2 in the case equivalent to the one with the lowest cost). The wind turbine capacity factor was three times higher in the period with lowest cost compared to the period with the highest cost. The importance of these two factors for the economic parameters (LCOH, LCOE and NPV) in wind-hydrogen systems was confirmed by the results from the large-scale model in Paper III, but other factors were also shown to have significant impacts. The selling price of hydrogen naturally has a large impact on the economics of the system since hydrogen is one of the main products from the system. The lifetime of the electrolyzer had a large impact on the economics since a longer lifetime results in more hydrogen to generate income and more time to spread out the costs. The CAPEX of PEM electrolyzers are still very high, so the most optimistic cost reductions in this area were shown to have a significant impact on the economics of wind-hydrogen systems. The variables having the smallest impact on the economics of the system were the discount rate and the efficiency of the PEM electrolyzer. The simulation case in Paper III that used current technology and costs achieved a LCOH of 6.04 \$/kg H_2, and in the most optimistic 2050 scenario this was reduced to 0.96 \$/kg H_2.

Based on the work in this PhD project, it was found that the most important factor for the cost of green hydrogen production from offshore wind power is the relationship between the electricity price and the selling price of hydrogen. Since electricity is an input factor to the green hydrogen production process and some of the electricity is lost in this production process, the selling price of hydrogen must be higher than the cost of the electricity that was used to make it. Otherwise, the production of green hydrogen will not be economically viable and the wind energy should rather be used directly as electricity. Another very important factor is, as expected, the placement of the offshore wind farm, since the wind speed in the given location will have a very big impact on the wind farm capacity factor, and by extension on both the technical and economic performance of the wind-hydrogen system.

The model developed in Paper III, which also included parts of the model from Paper II, was used to answer research question 4. The model was built, trained and tested by using historical data from a real 2.3 MW floating offshore wind turbine. This was combined with a novel mathematical model of a PEM electrolyzer (described in Paper II), as well as a novel control system developed and described in Paper III. The finished model was used to simulate the long-term (10-25 years) operation of a large-scale (1.5 GW) system that produced green hydrogen with electricity from an offshore wind farm. Both current and future (2050) scenarios were simulated. The results from these simulations showed that the control system lowered the LCOH for the wind-hydrogen system in every scenario. The minimum reduction in the LCOH was 10% and the maximum reduction was 46%. This shows that a well-designed forecasting and control system can indeed improve the economic viability of green hydrogen production from offshore wind power. The model also scheduled the hydrogen production in such a way that the electrolyzer is kept off in periods where it would risk being turned on and off unnecessarily due to low and fluctuating wind power. Minimizing the number of startups and shutdowns in this way could significantly reduce the degradation rate of the electrolyzer.

6.2 Conclusion

It is technically and economically feasible that large-scale production and usage of green hydrogen could play a significant part in the energy transition in the coming decades, but there are challenges related to costs and energy losses that must be tackled before this can become a reality. Green hydrogen as energy storage in electricity systems does not seem to be the most promising application, but there are much more promising applications where green hydrogen can be used directly to replace either fossil fuel-based hydrogen (e.g., production of ammonia) or the fossil fuels themselves (e.g., transport or industrial heat). The green hydrogen for these applications could be produced with electricity from offshore wind farms, but the economic viability of such wind-hydrogen systems will depend greatly on the relationship between the electricity price and the selling price of hydrogen. The work in this PhD project showed that the economic and technical viability of green hydrogen production from offshore wind power can be significantly improved by using a model that forecasts the production of wind energy and hydrogen, combined with a control system that optimizes the hydrogen production based on the electricity price. Such models will therefore be a crucial factor to enable successful large-scale wind-hydrogen systems in the future.

6.3 Further work

Green hydrogen production with electricity from offshore wind farms is a field that still needs substantial research and development to make large-scale implementation of such systems feasible. In terms of the focus area of this PhD project, i.e., computer modelling of wind-hydrogen systems, there are several points that should be explored in future work to expand and validate the results presented in this thesis:

- In terms of the dynamic operation of the PEM electrolyzer, expand the mathematical model to include ramp-up and start-up times, as well as energy usage for standby mode.
- Expand the dynamic hydrogen production model (Model I) to include compression and storage of hydrogen, desalination of sea water and power electronics. The first two are currently included only as constants (per kg hydrogen produced) and power electronics are only included in the cost of the electrolyzer.
- Further develop the control system in Model 2 to also include a dynamic hydrogen selling price instead of a long-term average. A significant increase in hydrogen trade will probably be required before this is possible, since it is currently very difficult to find data on hydrogen selling prices that are updated frequently enough.
- Include the potential feedback effect that large-scale green hydrogen production with price-based control systems will have on the electricity price.
- Include the unexpected downtime of individual wind turbines in the wind farms, for example by using a beta distribution or other probability distributions.
- Expand the large-scale model (Model 2) to also include life cycle emissions of greenhouse gases. This factor will be just as important as the technical and economic factors to the viability of future wind-hydrogen systems.
- Build a pilot facility that produces green hydrogen with electricity from an existing offshore wind farm. Use the forecast wind speed from a weather service provider and the day-ahead electricity prices from the power company together with Model 2 to investigate if the model accurately predicts the production of wind energy (polynomial regression model) and if the control system is able to control the hydrogen production in real time. Use two identical electrolyzers, one where the hydrogen production is scheduled in real time by the control system from Model 2 and one that always produces hydrogen as long as the wind farm delivers electricity. This will show if the control system successfully reduces the LCOH as it did in the simulations in Paper III.
- Integrate Model 2 in an even larger energy system model that can simulate the entire energy system of a region. This can be used to run large simulations to explore the big picture questions regarding what energy technologies should be used, and when and where they should be used. This kind of research will be important to eliminate unviable technologies as early as possible, and thereby focus available time and resources on the technologies that are most promising from an overall perspective.

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Papers

Paper I

Hydrogen-based systems for integration of renewable energy in power systems: Achievements and perspectives

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Review Article

Hydrogen-based systems for integration of renewable energy in power systems: Achievements and perspectives

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HIGHLIGHTS

- Review of 15 projects that use hydrogen as energy storage in a power system.
- Hydrogen is one of very few alternatives for long-term electricity storage.
- Hydrogen storage should in most cases be combined with battery storage.
- Power-to-gas-to-power for hydrogen still has a low energy efficiency (15–40%).
- Intermittent in-flow of energy and high costs are big challenges for these systems.

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Renewable energy

ABSTRACT

This paper is a critical review of selected real-world energy storage systems based on hydrogen, ranging from lab-scale systems to full-scale systems in continuous operation. 15 projects are presented with a critical overview of their concept and performance. A review of research related to power electronics, control systems and energy management strategies has been added to integrate the findings with outlooks usually described in separate literature. Results show that while hydrogen energy storage systems are technically feasible, they still require large cost reductions to become commercially attractive. A challenge that affects the cost per unit of energy is the low energy efficiency of some of the system components in real-world operating conditions. Due to losses in the conversion and storage processes, hydrogen energy storage systems lose anywhere between 60 and 85% of the incoming electricity with current technology. However, there are currently very few alternatives for long-term storage of electricity in power systems so the interest in hydrogen for this application remains high from both industry and academia. Additionally, it is expected that the share of intermittent renewable energy in power systems will increase in the coming decades. This could lead to technology development and cost reductions within hydrogen technology if this technology is needed to store excess renewable energy. Results from the reviewed projects indicate that the best solution from a technical viewpoint consists in hybrid systems where hydrogen is combined with short-term energy storage technologies like batteries and supercapacitors. In these hybrid systems the advantages with each storage technology can be fully exploited to maximize

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efficiency if the system is specifically tailored to the given situation. The disadvantage is that this will obviously increase the complexity and total cost of the energy system. Therefore, control systems and energy management strategies are important factors to achieve optimal results, both in terms of efficiency and cost. By considering the reviewed projects and evaluating operation modes and control systems, new hybrid energy systems could be tailored to fit each situation and to reduce energy losses.

Contents

Nomenclature

Abbreviations

IEA	International Energy Agency
EU	European Union
LNG	Liquified Natural Gas
wt%	weight percent
PEM	Proton Exchange Membrane
DOE	Department of Energy
HPP	Hydrogen Power Park
PV	Photovoltaic
PtG	Power-to-Gas
EPEX	European Power Exchange
DC	Direct Current
AC	Alternating Current
LED	Light Emitting Diode
ZEB	Zero Emission Building
BEMS	Building Energy Management System
INTA	Instituto Nacional de Técnica Aeroespacial
HESS	Hydrogen Energy Storage System
BoP	Balance of Plant
EDLC	Electric Double-Layer Capacitor
PLC	Programmable Logic Controller
DSP	Digital Signal Processing
SCADA	Supervisory Control And Data Acquisition
PC	Personal Computer
FLC	Fuzzy Logic Control
EEMS	External Energy Maximization Strategy
SMCS	State Machine Control Strategy
PI method	Proportional-Integral method
ECMS	Equivalent Consumption Minimization Strategy
MBA	Mine Blast Algorithm
SSA	Salp Swarm Algorithm
DR	Demand Response
IO unit	Input-Output unit

Chemical elements

C	Carbon
O	Oxygen
Li	Lithium
Na	Sodium
Mg	Magnesium
B	Boron
Al	Aluminum
H	Hydrogen
N	Nitrogen
Ti	Titanium
Fe	Iron
Ni	Nickel
Cd	Cadmium
La	Lanthanum
Ce	Cerium
Mn	Manganese

Non-SI units and conversion to SI

kWh (kilowatthour), unit of energy $1\ kWh = 3\,600\,000\ J$
L (liter), unit of volume $1\ L = 0.001\ m^3$

bar, unit of pressure	1 bar = 100 000 Pa
°C (degree Celsius), unit of temperature	n °C = (273.15 + n) K
Nm^3 (Normal cubic meter), unit of volume	1 Nm^3 = 1 m^3 at 293.15 K and 101 325 Pa
h (hour), unit of time:	1 h = 3600 s
kWp (kilo watt peak), unit of power	kWp = kW at peak/maximum power
Ah (Ampere hour), unit of electric charge	1 Ah = 3600 C
atm (atmosphere), unit of pressure	1 atm = 101 325 Pa
SL (standard liter), unit of volume	1 SL = 0.001 m^3 at 273.15 K and 101 325 Pa

Symbols

€ Euro, currency in the European Union

Introduction

One of the great challenges of this century is how to deal with climate change. One of the most crucial aspects to be tackled here is the reduction of CO_2 emissions from transportation, electricity generation, heating, and industrial sectors [1]. Hydrogen has the potential to be a part of the solution. It can potentially be used in vehicles, particularly for long-range heavy transport like trucks, ships and airplanes. It can be used as an additive in natural gas for heating, and it can be used to replace fossil fuel use in industrial processes. The focus of this review paper is on the use of hydrogen in the electricity generation sector. The alternatives to fossil fuels in the electricity sector are mainly hydro power, nuclear power and the so-called new renewables, which are mainly solar and wind power. Of these, both hydro and nuclear power are stable power sources that can cover a large baseload, while both solar and wind power are highly intermittent and need to be combined with either energy storage or other more stable power sources. Hydro power is geographically restricted and will not be an alternative for large parts of the world. Nuclear power could in theory be a very good alternative to replace many coal and natural gas plants, but the reality is that most countries are reducing their nuclear power capacity due to issues related to safety, waste storage, costs and social opposition. That leaves solar and/or wind power as the most realistic alternative to fossil fuels in many regions of the world, with the consequent need of large-scale energy storage when integrating large amounts of renewable energy into power systems.

Batteries perform well for short-term energy storage connected to renewable energy production. An example of this is Tesla's 100 MW (soon-to-be 150 MW) battery facility in Australia [2]. However, batteries are not well suited if energy needs to be stored for longer periods (weeks and months). One of the most realistic alternatives for long-term storage of renewable energy is hydrogen. The basic concept is that excess solar and/or wind power is used to produce hydrogen through electrolysis of water in periods where electricity production from the renewable sources is higher than electricity consumption. Hydrogen is then stored, for instance as a compressed gas or in metal hydrides. When electricity production from wind and/or solar is lower than electricity consumption, the stored hydrogen can be used to produce electricity in fuel cells.

Currently there is very little energy storage connected to power systems because most electricity is generated by sources that do not need energy storage systems. More than 60% of the world's electricity is generated by burning fossil fuels [1]. In addition to this, around 16% is hydro power and around 10% comes from nuclear power [1]. A very small percentage is generated by geothermal power (0.33%) and biofuel power (1,9%) plants [1]. All of these are stable power sources that doesn't require any energy storage. The two intermittent sources with any significance, wind and solar, still only generate around 6% of the world's electricity (a little over 4% for wind and a little under 2% for solar) [1]. Therefore, there hasn't been much need for energy storage in power systems yet, since such relatively small amounts of intermittent renewable energy can be integrated into existing power grids quite easily. However, both wind and solar power are growing rapidly and are expected to supply a larger portion of the world's electricity in the coming decades. The International Energy Agency (IEA) forecasts wind and solar combined to supply between 23% and 42% of the world's electricity by 2040 [3]. Such a high share of wind and solar power could require large amounts of energy storage in many locations, both for short-term and long-term storage. If these forecasts are realized, hydrogen could be the best alternative when it comes to long-term energy storage in power systems. According to the European Union (EU) over 50% of the electricity generation in the EU needs to come from renewables to reach their 2030 objectives, and this has to grow to at least 80% in 2050 [4]. Current estimates are that the electricity grid cannot accept much more than 30% renewables without including additional grid flexibility. Large increases in intermittent energy sources like wind and solar can destabilize the electricity grid if not managed properly. The EU therefore proposes energy storage in the electricity grid as one of the measures to increase the grid's flexibility and state that all types of energy storage are needed, e.g. pumped hydro storage, grid-connected batteries and hydrogen storage [4].

Review papers with different focus areas in the field of hydrogen energy systems have been published in the past. Mazloomi et al. [5] presented hydrogen as a very promising alternative both as fuel for future vehicles and as energy storage in large-scale power systems, taking into consideration production and storage methods, as well as risk and safety issues related to hydrogen technologies. Thema et al. [6] reviewed power-to-gas projects that produce either hydrogen or a renewable substitute for natural gas, providing an analysis and forecast for the cost development of electrolysis and carbon dioxide methanation. Dutta [7] considered production and storage methods for hydrogen with an added focus on risk and safety issues. Abe et al. [8] reviewed hydrogen as a possible primary energy carrier with a focus on storage of hydrogen in metal hydrides. Gahleitner [9] examined power-to-gas pilot facilities where renewable electricity was used to produce hydrogen through water electrolysis. Eveloy et al. [10] reviewed projected power-to-gas scenarios and found that substantial improvements in areas like efficiency, cost and reliability are necessary if large-scale implementation of these types of facilities are going to become a reality. Moradi et al. [11] reviewed alternatives for storage and delivery of hydrogen and analyzed risk and safety issues. Hanley et al. [12] surveyed the implementation of hydrogen in energy systems and analyzed possible drivers and policies that could favor hydrogen over other low-emission energy technologies. They found that the scenario with the highest probability is a scenario where hydrogen technologies are implemented mostly after 2030 [12]. Parra et al. [13] provide a techno-economic review of hydrogen energy systems and highlight measures that they think will accelerate the adoption of hydrogen technologies, including a focus on mass production, standardization and favorable policies. Bailera et al. [14] reviewed the various methods used to convert renewable energy to methane in power-to-gas projects, also providing an overview of real-world projects. Wulf et al. [15] considered power-to-gas projects in Europe, suggesting that power-to-gas facilities will become important for refineries in the future to reduce the emissions connected to their products. Chehade et al. [16] reviewed 192 power-to-X demonstration projects from 32 countries. They found that both the capacity of hydrogen electrolysis and the number of applications for hydrogen has increased significantly over the years [16]. Wulf et al. [17] conducted another review to supplement their earlier work in Ref. [15] to include more recent power-to-X demonstration projects in Europe up until June 2020. Just like Chehade et al. [16] they found that the number of hydrogen applications have increased, they observed that the implementation of power-to-X projects have gone quicker than earlier projections and the development in Europe has been led by France and Germany [17]. Yue et al. [18] surveyed hydrogen technologies in power systems where the various technologies and applications are described using real-world projects as examples. They combined costs and technical aspects in a techno-economic analysis and concluded that continued focus on technical improvements, up-scaling of projects and production, as well as political backing are necessary to make hydrogen technologies cost-competitive [18].

This paper investigates the current state-of-the-art for hydrogen as energy storage in power systems that use intermittent renewable energy sources (wind and/or solar) to generate electricity. This includes a few full-scale facilities in full operation, e.g. the Sir Samuel Griffith Centre at Griffith University in Brisbane, Australia [19] and Energiepark Mainz in Germany [20], some medium-scale test facilities, as well as some lab-scale systems for technology development and testing. Both grid-connected and off-grid systems are included. Some systems use only hydrogen as energy storage, but most of the reviewed systems use a hybrid energy storage system where hydrogen is combined with one or more short-term storage technologies (e.g. batteries). This paper focuses on real systems that have been constructed and tested and the experimental results from these systems, and not on theoretical systems. An example of the main components and energy flow of a typical system that stores intermittent renewable energy in a hybrid energy storage system is shown in Fig. 1 [21]. To enhance the perspective and novelty of this paper we also include a review section on the power electronics and control systems used in projects where hydrogen energy storage is used in combination with renewable energy. More in-depth explanations and analyses of the technical, environmental and political aspects related to hydrogen production, storage and use can be found in the referenced papers [5–18,22–26] and are outside the scope of this paper.

Hydrogen as energy storage in renewable energy systems

Based on IEA forecasts, around a third of the world's electricity will rely on intermittent renewable sources like wind and solar by 2040 [3]. This will require solutions for long-term large-scale storage of electricity, with hydrogen production and storage being a promising technology, as illustrated in Fig. 2 [22]. There are various ways in which hydrogen can be stored for later use. The most common method so far is as compressed gas. Another method is to store it as a liquid at very low temperatures. Hydrogen can also be stored through physisorption, which is physical adsorption on the surface of a solid material, or chemisorption using metal hydrides. Various reviews of the different hydrogen storage technologies can be found [22–26] and are outside the scope of this paper.

Compressed gas storage and metal hydride storage are the most relevant storage methods for stationary power systems, and they are the only two storage methods used in the projects reviewed in this article. Table 1 summarizes the main characteristics of the systems considered in this review. Seven projects use only compressed gas storage, six projects use only metal hydride storage, and two projects use both compressed gas storage and metal hydride storage.

Storing hydrogen as compressed gas is currently the most widespread method. Commercial hydrogen storage tanks like the ones used by Toyota in their Mirai fuel cell car can store hydrogen gas at a pressure of 700 bar [27]. The compression process typically uses 20% of the energy content in the hydrogen [24]. Advantages with storing hydrogen as compressed gas is that it is relatively simple from a technical viewpoint and the cost is relatively low. Disadvantages include relatively low system energy density compared to systems based on fossil fuels and safety issues related to the high pressure.

Hydrogen can also be stored as a liquid. This increases the volumetric energy density significantly compared to storing it as a compressed gas. Liquid hydrogen has a volumetric energy density of 2.2 kWh/L [25], while compressed hydrogen gas contains 1.3 kWh/L at 700 bar and 0.8 kWh/L at 350 bar [25]. However, the volumetric energy density of liquid hydrogen is

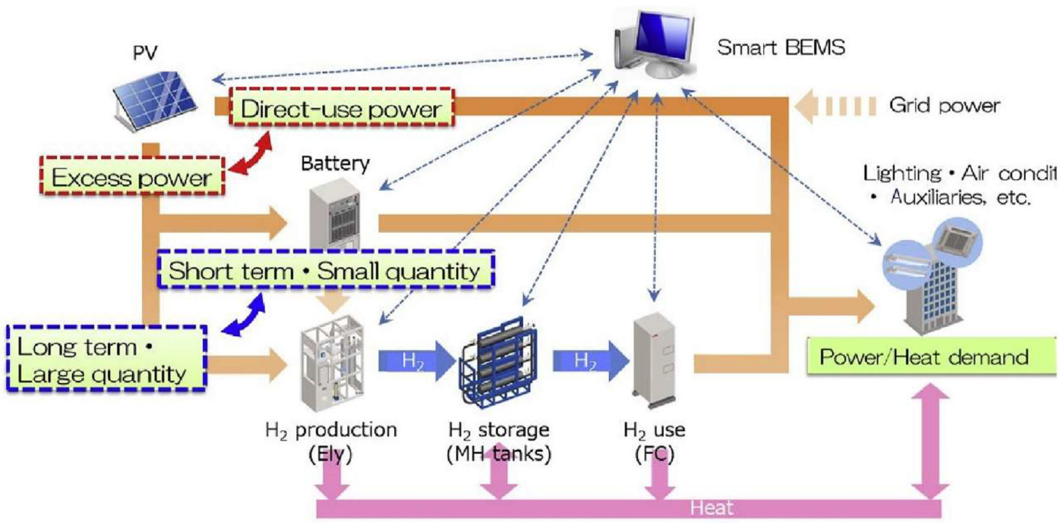

Fig. 1 – An energy flow schematic for a typical energy system that combines renewable energy with hydrogen energy storage. In this case, the renewable energy source is solar energy (PV panels), and the energy storage system includes both batteries and a hydrogen system. The hydrogen system includes an electrolyser, hydrogen storage in metal hydride tanks, and a fuel cell to convert hydrogen into electricity. The whole energy system is controlled by a building energy management system (BEMS) and it is also connected to the main power grid [21].

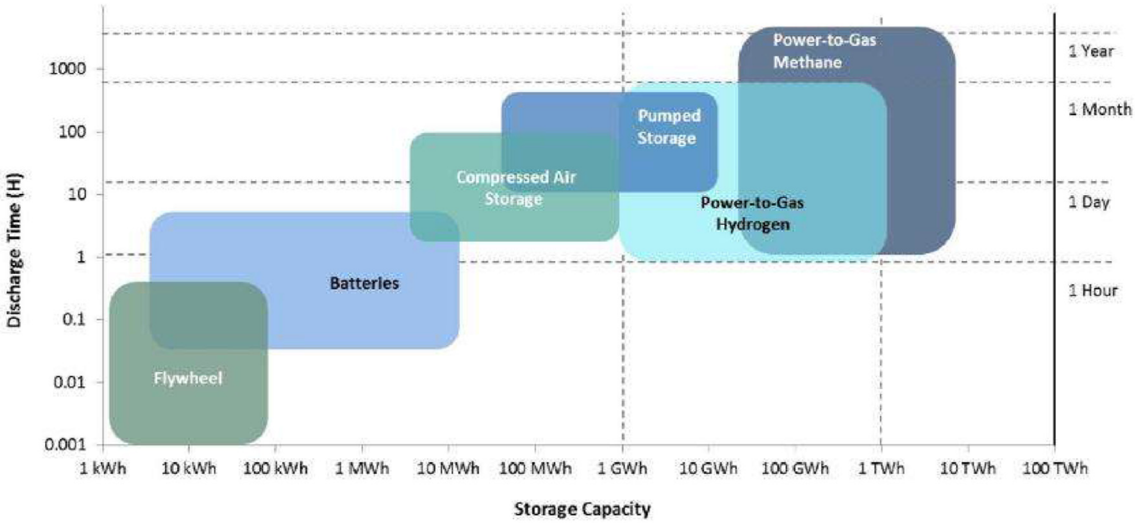

Fig. 2 – Comparison of storage capacity and discharge time for various energy storage technologies [22]. As seen here, hydrogen is one of the best alternatives for large-scale long-term energy storage.

less than 40% of the volumetric energy density of liquified natural gas (LNG), which is 5.8 kWh/L [25]. Disadvantages with liquid hydrogen are the energy required for liquefaction, hydrogen boil-off and very costly storage systems. The consequence of the boil-off issue is that liquid hydrogen is only considered for applications where hydrogen is used relatively quickly after loading (e.g. transport applications with frequent re-filling opportunities) and it is not a good choice for long-term energy storage in stationary power systems.

Physisorption is another method for storing hydrogen. The hydrogen gas molecules are adsorbed onto the surface of a solid material, and then released as gas when hydrogen is needed for use, for example in a fuel cell [24]. The materials most commonly used to adsorb the hydrogen gas are carbon-based materials and metal organic frameworks [24]. While many of these materials are the subject of promising research, they have not been deployed on a commercial scale and none of the projects reviewed in this article uses/used physisorption to store hydrogen. Advantages with hydrogen storage through physisorption includes low system complexity, low pressure and fairly non-expensive materials [23]. Disadvantages include relatively low hydrogen density on carbon and the low temperatures required [23].

Finally, hydrogen can also be stored through chemisorption in metal hydrides. This is a process where hydrogen gas is absorbed and stored in a metal powder, either a pure metal or a metal alloy. Heat is released when the hydrogen gas is

Table 1 – Overview of the reviewed projects, their topologies, storage technologies and objectives. GC = grid-connected, OG = off-grid, CG = compressed gas, MH = metal hydrides.

Ref.	Topology	Storage technology	Objective	Main results/conclusions	Year of publication
[20]	GC	CG	Technical and economic evaluation of full-scale power-to-gas facility	• Average total efficiencies of 60% (Sept. 2015) and 54% (Oct. 2015) for large-scale (6 MW) hydrogen electrolysis and storage as compressed gas (80 bar and 225 bar) • Efficiency of PEM electrolyser is maximum when the power is ca.1 MW (1/6 of peak power) and then decreases slowly with increasing power	2017
[21]	GC	MH	Reduce emissions from buildings	• 24-h operation used almost zero grid power, indicating that it is possible to build zero emission buildings using PV power combined with energy storage as hydrogen and batteries • Full desorption process for metal hydride tank was demonstrated using only waste heat from fuel cell	2019
[28]	GC	CG	Evaluation of full-scale renewable energy system with hydrogen storage operating in a 10-house microgrid	• Stand-alone operation about 50% of the time • Stability issues with fuel cell • Hydrogen system needs load-following electrolysers, increased component efficiencies and reduced costs	2010
[29]	OG	CG	Evaluation of full-scale renewable hydrogen system	• 40–45% electrolyser efficiency • 50% fuel cell efficiency • System functions well, but increased efficiencies and reduced costs are needed	2010
[30]	GC	CG	Evaluate the use of hydrogen as energy storage for residential applications	• 41.5% electrolyser efficiency • 40% fuel cell efficiency • Electrolyser is sensitive to intermittent power (e.g. PV) since it has a minimum power demand (518 W in this case) and will shut down below this • PV-hydrogen electricity was 933% more costly than grid electricity and 202% more costly than PV-battery	2011
[31]	OG	CG	Develop control method for renewable energy system with battery and hydrogen storage	• Battery and hydrogen energy storage in combination can successfully handle both high-frequency (battery) and low-frequency (hydrogen) power fluctuations	2019
[32,33]	GC	CG	Evaluate a renewable energy system with hydrogen storage used for greenhouse heating	• Electrolyser requires minimum power equal to 20% of its 2.5 kW power rating to produce hydrogen • Internal pressure in electrolyser must be in the range 2.8–3.0 MPa for proper function • Mathematical model showed that electrolyser should be operated in the range 1.5–2.5 kW with a minimum production rate of 0.21 Nm^3/h to achieve stable results	2013 and 2014
[34]	OG	CG	Develop and construct small renewable energy system with hydrogen storage for off-grid applications	• A small-scale autonomous solar-hydrogen system is feasible, but it would require more PV power and increased hydrogen production and storage capacity • 10 L of hydrogen at 1.05 atm gave 18 h of continuous operation • Large variations in hydrogen production between sunny and cloudy days	2014
[35]	GC	MH	Optimize operating modes of hybrid renewable energy systems	• Operating mode in a hybrid renewable energy system must be a compromise between energy efficiency and costs, i.e. maximizing efficiency will usually increase the costs and vice versa. • Efficiency and cost of various operating modes will also be greatly affected by the weather profile on the given day, i.e. the energy system should ideally use different operating modes on different days, depending on the weather • Operating hydrogen components with variable power gave highest total system efficiency, but also highest cost • Operating hydrogen components at constant rated power gave lowest cost, but also reduced total system efficiency	2016
[36]	GC	MH	Optimize load sharing for hybrid energy storage systems	• Batteries and ultracapacitors can reduce power fluctuations in the hydrogen components in a hybrid renewable energy system, which in turn can increase the component lifetimes	2016

Table 1 – (*continued*)

Ref.	Topology	Storage technology	Objective	Main results/conclusions	Year of publication
[37]	GC	MH	Evaluate efficiencies in a solar-to-hydrogen integrated microgrid	• The efficiency of the hydrogen conversion and storage (PEM electrolyser and metal hydride tanks) was 35–47% • Electrolyser efficiency varies with input power. Should be operated with constant input power corresponding to max efficiency to minimize losses. • The total efficiency of the complete PV-to-hydrogen chain was 3.4–5.3%	2017
[38]	OG	MH	Off-grid power applications with hydrogen system where fuel cell exhaust is used for hydrogen desorption process in metal hydrides	• A hydrogen system with electrolyser, fuel cell and metal hydride storage without external heat supply is demonstrated, but the fuel cell load must be above a certain minimum to supply enough waste heat for the metal hydride desorption process at 20 °C • Higher electrolyser pressure and/or a hydrogen buffer can decrease the challenge related to the fuel cell load	2019
[39]	OG	MH	Design a hybrid energy storage system with hydrogen and battery with the twin goals of reducing curtailment of wind and solar power, as well as supplying hydrogen to fuel cell buses and the natural gas grid	• Curtailment of solar and wind power was 8.8% during the operation period [39] • The average hydrogen level in the metal hydride tank during the operation period was 71.4% [39]	2020
[40]	OG	MH and CG	Evaluate advantages and disadvantages with different hydrogen storage technologies	• Hydrogen storage capacity: 0.17 wt% for low pressure gas, 1.25 wt% for high pressure gas, 0.93 wt% for metal hydride tank ($TiMn_2$) • Gravimetric energy density: 0.06 kWh/kg for low pressure hydrogen, 0.42 kWh/kg for high pressure hydrogen, 0.31 kWh/kg for metal hydride tank ($TiMn_2$) • Volumetric energy density: 0.01 kWh/L for low pressure hydrogen, 0.52 kWh/L for high pressure hydrogen, 1.22 kWh/L for metal hydride tank ($TiMn_2$) • Hydrogen storage efficiencies: 96% for low pressure gas, 52% for high pressure gas, 79% for metal hydride tank ($TiMn_2$) • Total energy storage and conversion efficiencies (including electrolyser and fuel cell): 32% for low pressure hydrogen, 17% for high pressure hydrogen, 26% for metal hydride tank ($TiMn_2$)	2015
[41]	GC	MH and CG	Create local microgrid that can function as emergency power supply during main grid outages	• The PV/capacitor/hydrogen system was demonstrated to be a reliable solution as emergency power supply, but with efficiency and cost issues • Electrolyser average efficiency 27.2% • Fuel cell average efficiency 29.3% • Efficiency of whole hydrogen system (electrolyser, gas and metal hydride storage, fuel cell) was 22.9% • Reduced efficiency due to electrolyser and fuel cell operating at low and/or fluctuating power • Using a low-pressure hydrogen buffer tank reduced the required heat in the metal hydride desorption process from more than 1.74 kW–1 kW	2019

absorbed in the metal hydride material and heat must be applied for the metal hydride to release the hydrogen again [24]. A drawback with the metal hydride storage method for some of the materials is that the hydrogen bonds so strongly to the metal hydride that relatively high temperatures are needed to release the hydrogen again, for example more than 650 °C in the case of lithium [24]. However, an advantage is that some of these materials have very high gravimetric hydrogen capacities, e.g. 18 wt% for $LiBH_4$ [24]. Other materials such as intermetallics are also possible, like the TiFe-based alloy used by Endo et al. [21]. Though intermetallics have a lower hydrogen storage capacity (1.4 wt% for the alloy in Ref. [21]), they operate at mild temperatures (absorption at 30 °C and desorption at 45 °C for the alloy in Ref. [21]) and pressures, as shown in Fig. 3, thus reducing costs and safety issues. Much of the research in this field is directed towards finding the right metal hydride storage method and material so that low operating pressure and relatively low absorption/desorption temperatures can be combined with the highest possible gravimetric energy density.

Overview of projects and summary of results

15 projects are reviewed in this paper. All the projects use hydrogen as energy storage, either alone or together with other energy storage technologies (batteries, supercapacitors, etc.). Only projects that have built a physical system, either full-scale or some form of test/pilot system, have been considered in this paper. An overview of the projects is given in Table 1. This table summarizes the topology, storage technology, objective and main results/conclusions for each project. Topology states whether the energy system is connected to the local power grid (GC) or if it is a standalone off-grid (OG) system. Hydrogen storage method states whether hydrogen is stored as compressed gas (CG) or in metal hydrides (MH), or both. The objective and main results/conclusions columns should be self-explanatory.

Projects with only compressed gas storage

An energy system based on wind power and energy storage was built and put into operation by Norsk Hydro and Enercon on the Norwegian island of Utsira in 2004 [28]. The system delivered power to ten households on the island and included a 600 kW Enercon wind turbine, an alkaline electrolyser with a production rate of 10 Nm^3/h at 12 bar, an 11 Nm^3/h hydrogen compressor that compresses the hydrogen from 12 to 200 bar, high-pressure hydrogen gas storage tank (200 bar) with a capacity of 2400 Nm^3, a 55 kW hydrogen engine (a modified diesel generator that uses hydrogen) and a 10 kW proton exchange membrane (PEM) fuel cell [28]. Additional energy storage components in the form of a 50 kWh NiCd battery and a 5 kWh flywheel were also included in the total system [28]. The system was in operation for several years and at the time the paper [28] was published in 2010 the conclusion was that hydrogen energy storage systems coupled with wind energy is technically possible, but it is still far from being a realistic solution from a commercial viewpoint [28]. Data from several years of operation showed that 100% stand-alone operation was only achieved around 50% of the time [28]. The electrolyser often had to use power from the grid to produce enough hydrogen to keep the hydrogen storage pressure from becoming too low. Typical operation from a 12-h period for the Utsira power system is shown in Fig. 4 [28]. The control system is programmed to turn on the electrolyser only when the energy production by the wind turbine is higher than the energy consumption. This is the case from point 1 to point 2a in Fig. 4 [28]. At this point the wind power drops, the electrolyser is consequently switched off and the hydrogen engine/generator is switched on. This is followed by a period of rapid fluctuations in wind power where excess wind power is used to charge the flywheel and this is then discharged when the wind power drops again (points 3 and 4) [28]. At the same time the hydrogen engine also produces varying amounts of power based on the needs of the total system. When the wind power remains high for a longer period (point 5) [28], the hydrogen engine is de-activated and the excess power is used to charge the battery. If the power delivered by the wind turbine is still higher than the power usage after the battery is full, this power will be fed to the electrolyser to produce hydrogen (point 6) [28]. During the power system's operating years there were multiple technical difficulties with the fuel cell which resulted in very little operational time for this component (less than 100 h) [28]. This was caused by leaking cooling liquid, assembly damage, issues with the control system/fuel cell communication, as well as very rapid stack degradation (even when the fuel cell was not in use) [28]. The authors recommend some necessary improvement areas for wind/hydrogen power systems. These include technical improvements in fuel cells and hydrogen engines, the development of load-following electrolysers, increased efficiency in all components in the hydrogen system, more advanced wind energy forecasting and energy management system, as well as general cost reductions for all the components [28].

In 2010, more than 90% of the energy used on Hawaii was imported [29], resulting in the highest energy cost in the US [29]. This, combined with the large availability of renewable energy resources on the Hawaiian Islands, prompted the US Department of Energy (DOE) to fund the Hawaii Hydrogen Power Park (HPP) at Kahua Ranch [29]. The facility uses a 7.5 kW Bergy wind turbine and 9.8 kWp photovoltaic (PV) array to produce wind and solar energy. These energy producers are connected to an energy storage system consisting of lead-acid batteries with a storage capacity of 343 kWh as well as a hydrogen system [29]. The hydrogen system includes a PEM

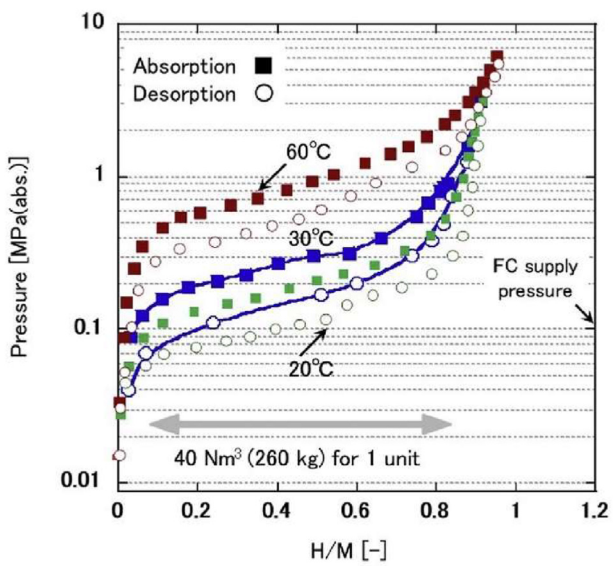

Fig. 3 – Pressure-composition isotherm (PCI) properties at 20, 30 and 60 °C for the TiFe-based alloy used for hydrogen storage in one of the reviewed projects [21]. In the actual project, the hydrogen gas was supplied to the metal hydride tank from the electrolyser at a pressure of 9.7 bar. The hydrogen was then absorbed by the metal hydride at a rate of 5 Nm^3/h at a temperature of 20 °C and the desorption process had a rate of 3 Nm^3/h at a temperature of 60 °C. The hydrogen gas was fed to the fuel cell at a pressure in the range 0.15–0.5 bar.

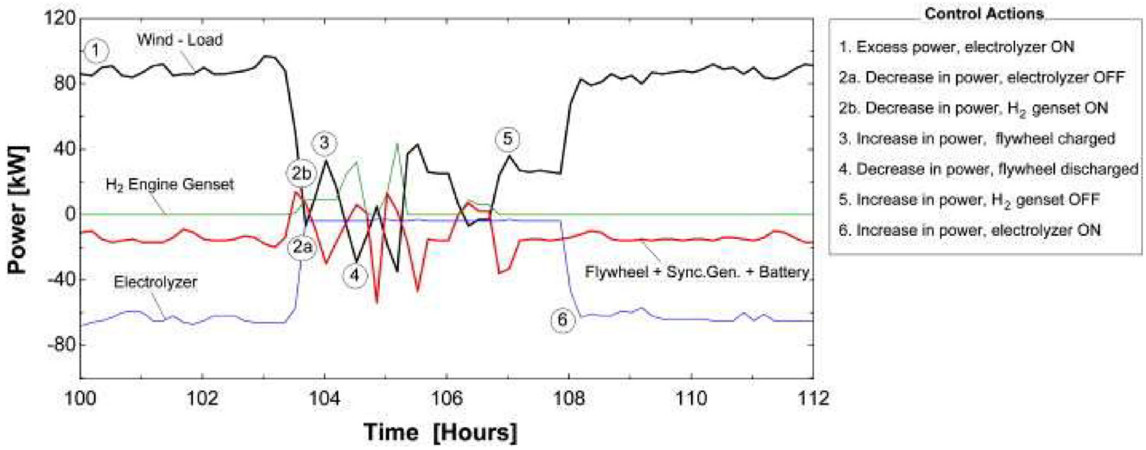

Fig. 4 — Operational data (10-min averages) measured at Utsira on 5 March 2007 [28].

electrolyser with a production rate of 0.2 Nm^3/h at a pressure of 12 bar and a 63% maximum efficiency, low-pressure (12 bar) tanks for hydrogen storage with a combined capacity of approximately 1 kg of hydrogen, and a 5 kW fuel cell system [29]. The power flow from a full day of operation in December 2009 is shown in Fig. 5 [29]. During the night hours, most of the power is supplied by the battery, and the wind turbine takes over during the early morning hours. In the daytime, both the wind turbine and PV array produces power, and the excess power is used to both charge the batteries and produce hydrogen in the electrolyser. During the late afternoon and night hours, the fuel cell system provides some power initially, while the rest of the night is covered by the wind turbine. During the night hours, there is also some excess wind power that is used to charge the battery and operate the electrolyser. The operational data showed that the electrical efficiencies for the various components in the energy system was 40–45% for the electrolyser (steady operation), 50% for the fuel cell system (operation range from ¼ to full load), 10–35% for the wind turbine and 10% for the PV array [29]. The general conclusions drawn from the operation of the HPP at Kahua Ranch is that hydrogen as energy storage offers many

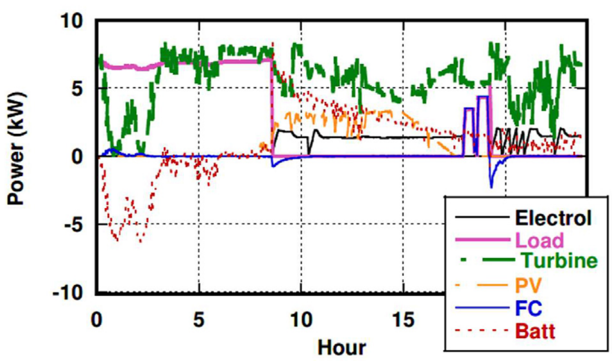

Fig. 5 — Power flow for a full day's operation of the Kahua Ranch facility. The data are from a day in December 2009. Positive values represent power to the bus bar and negative values represent power drawn from it [29].

advantages like zero harmful emissions, low noise, long-term storage with almost no loss of hydrogen, option to use waste heat for heating purposes, high adaptability in terms of sizing since energy and power are independent of each other, as well as long lifetime and low maintenance requirements [29]. However, the study pointed out that it was difficult to justify hydrogen as energy storage economically and technically (at the time of writing in 2010) and that it was necessary to improve the energy efficiency and reduce the cost of these systems to make them commercially attractive [29].

A small-scale experimental solar/hydrogen energy system for residential applications was constructed and tested in 2011 at the National Fuel Cell Research Center at the University of California in Irvine [30]. This was a grid-connected system and it included a 5 kW PV array, an electrolyser that produced hydrogen at a rate of 1 Nm^3/h at a pressure of 13.8 bar and 41.5% efficiency, a compressed gas tank that stored 0.04 m^3 of hydrogen at 13.8 bar, a 1 kW PEM fuel cell and a 5 kW PEM fuel cell [30]. The system also included additional energy storage in a battery and a load bank that simulated a load pattern typical of a residential house. Data from a week in August of 2003 was used to compare the load demand of a residential house in Irvine with the power produced by the 5 kW PV array. The data showed that the electrical energy required by the house for the full week was 108.1 kWh and the energy delivered by the PV array was 224.8 kWh [30]. However, the time mismatch between the PV energy production and the energy usage in the house shown in Fig. 6 [30] clearly demonstrates the need for energy storage. In fact, the data showed that even though the PV array produced more than twice as much energy as the house needed, only 33.6% (36.3 kWh) of the load demand was directly covered by the PV energy [30]. This means that 83.9% (188.5 kWh) of the produced PV energy would have to be stored. Experimental data from a single day of operation showed that the electrolyser used 33.4 kWh of PV electricity and 4.8 kWh of grid electricity to produce hydrogen with an energy content of 17.8 kWh [30]. However, less than half of this energy can be used as electricity in the house since the fuel cell has an efficiency of 40% [30]. Operational data also showed that the electrolyser required an internal pressure of 1380 kPa before it started to produce hydrogen, and this

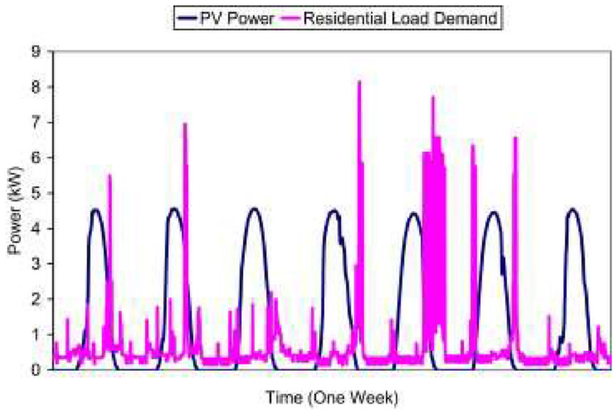

Fig. 6 – Comparison between the power delivered from a 5 kW PV array and the load demand of a residential house in Irvine, California. The data is from the week between the 2nd and 9th of August 2003 [30].

required a minimum PV power of 518 W [30]. The result was that the electrolyser was able to tolerate short fluctuations in solar irradiance, but when there was extended cloud cover it would stop producing hydrogen due to system pressure loss [30]. The 5 kW fuel cell was found to have a power ramp rate capability of 1.7 kW/s and a load shed capability of −4.4 kW/s, which fit relatively well with the measured demand rates of 1.9 kW/s and −1.8 kW/s [30]. The biggest challenge related to hydrogen energy storage was found to be cost. The cost of electricity from the PV/hydrogen system was calculated to be 933% of the average California retail electricity price [30]. Compared to energy storage in batteries, PV/hydrogen electricity was calculated to be 202% more costly than PV/battery electricity [30]. The authors therefore concluded that the cost of both electrolysers and fuel cells must be significantly reduced before hydrogen as electricity storage can become cost-competitive [30].

The full-scale power-to-gas (PtG) plant “Energiepark Mainz” in Germany was constructed to support the local power grid and to perform research on large-scale implementation of PEM electrolysers [20]. Researchers from Rhein-Main University of Applied Sciences, Linde AG, Siemens AG and Mainzer Stadtwerke AG have published a technical and economic analysis of the PtG facility [20]. The facility is connected to an 8 MW wind farm and uses excess wind energy to produce hydrogen gas. This is done through the use of three PEM electrolysers with a peak power of 6 MW and a hydrogen output of 1000 Nm^3/h [20]. The hydrogen is then compressed to a pressure of 80 bar and stored in tanks with a capacity of approximately 10 000 Nm^3 [20]. From these tanks, the hydrogen is either injected into the natural gas grid or it goes through a second compressor stage to a pressure of 225 bar. The hydrogen that is compressed to 225 bar is then filled into trailers and transported either to chemical industries or hydrogen fueling stations [20]. This means that Energiepark Mainz does not use hydrogen to produce electricity in a fuel cell like the other projects reviewed in this article. Instead, hydrogen is used in the three applications mentioned above; as an additive in the natural gas grid, as a reactant in chemical industries, or sold to hydrogen fueling stations [20]. The facility has an annual target output of approximately 200 tons of hydrogen [20]. The analysis shows that there is a slight decrease in the efficiency with increasing load. When the electrolysers are run at the rated power of 4 MW the calculated efficiency is about 64%, while it is about 59% when they are run at the peak power of 6 MW [20]. This is illustrated in Fig. 7 [20] where the production rate and efficiency for the electrolysers is shown. Here it can be seen that the efficiency increases quickly up to its maximum value when the power is around 1 MW (1/6 of peak power), and then the efficiency decreases slowly with increasing power [20]. The hydrogen production rate naturally increases with increasing power. Another thing to keep in mind is that the electrolysers can only run at peak power for 15 min, while they can run continuously at the rated power (or below rated power) [20]. Results for September of 2015 showed an average efficiency of about 60% and for October of 2015 it was about 54% [20]. These efficiencies are the combined efficiencies of the whole PtG facility including all associated equipment (compressors, transformers, pumps, etc.). An economic analysis showed that it was most profitable for the PtG facility to purchase electricity through the market for control reserve rather than use the excess wind energy or purchase from the European Power Exchange (EPEX) [20]. It is concluded that a PtG facility of this type can be a profitable operation if the most favorable power procurement and operation strategy is chosen [20]. The authors state that improvements are needed to reduce capital and fixed costs and increase efficiencies [20]. They also suggest that the implementation of cost premiums for hydrogen produced in a low-emission way would increase the competitiveness of these types of facilities [20].

A distributed control method called “modified DC-bus signaling” for renewable energy systems with hybrid energy storage was proposed by researchers at RIKEN Center of Advanced Photonics and the University of Tokyo in Japan [31]. A lab-scale version of a hybrid energy storage system was developed and used to validate the theoretical work. The storage system included an electrolyser, a 2 m^3 tank that stores hydrogen at a pressure of 7 bar, a hydrogen fuel cell, and a lead-acid battery [31]. DC sources were used in the place of PV panels and loads. The experiments demonstrated that the proposed control method was indeed able to control step-line and random changes in input and output power. It was shown that the battery successfully compensated high-frequency fluctuations in power demand, and the hydrogen system handled the remaining low-frequency fluctuations [31].

A hybrid energy system was constructed to provide power and heat to a greenhouse at the University of Bari in Italy [32,33]. The system combined solar energy production from PV panels, a heat pump, and a hybrid energy storage system with hydrogen and batteries. The PV array consisted of 24 panels of 240 Wp and the battery bank consisted of six 12 V cells with a nominal energy capacity of 900 Ah. The hydrogen energy storage system included an alkaline electrolyser with a power rating of 2.5 kW that produces hydrogen with a nominal production rate of 0.4 Nm^3/h at a pressure of 30 bar when operated at full power, two low-pressure (30 bar) storage tanks with a volume of 0.6 m^3, as well as a 2 kW PEM fuel cell [32,33]. Initial tests showed that the electrolyser operated in an

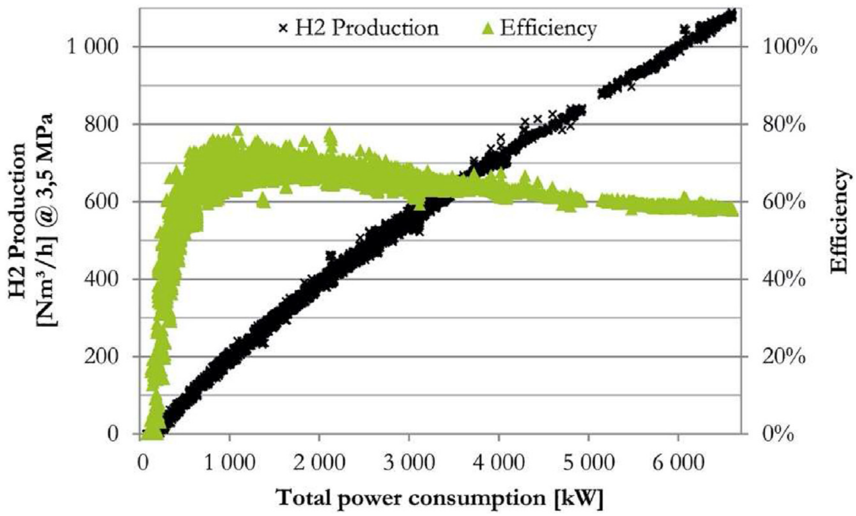

Fig. 7 – Production rate (black) and efficiency (green) for the electrolyser at Energiepark Mainz [20]. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

unstable manner and the performance was not consistent with the theoretically predicted performance [32]. Further tests confirmed the challenges related to the electrolyser/PV combination, which manifested themselves in highly intermittent operation with several breakdowns on partially cloudy days. On clear-sky days the electrolyser could operate continuously, but the hydrogen production was still affected by the variability of the solar radiation and the electrolyser never reached steady-state conditions [33]. These operational issues can be seen in Fig. 8 [33] which shows the hydrogen production for the final week of March 2014, where the first four days have very intermittent production while the production is more stable during the last three days. The experiments showed that the electrolyser only started to produce hydrogen once it received PV power equal to at least 20% of its power rating of 2.5 kW, i.e. 0.5 kW [33]. Since other auxiliary equipment required a power of 0.6 kW to operate, the result was that the electrolyser only produced hydrogen if the delivered PV power was 1.1 kW or higher [33]. Additionally, the electrolyser required an internal pressure of 2.8–3.0 MPa to function properly [33]. A mathematical model showed that the electrolyser should be operated in the range 1.5–2.5 kW with a minimum production rate of 0.21 Nm^3/h to achieve stable results [33].

Researchers at Departamento de Investigación y Desarrollo en Energías Renovables and Escuela Superior Técnica in Argentina built and tested a lab-scale hybrid energy system for off-grid energy supply for low and medium energy consumptions like mountain cabins and military shelters [34]. The system was a solar/hydrogen combination which included two different types of PV panels, an alkaline electrolyser, low-pressure hydrogen and oxygen storage tanks (1.05 atm storage pressure), and two stacks of PEM fuel cells [34]. All the hydrogen components (electrolyser, storage tanks and fuel cells) where designed and constructed by the researchers themselves. To simulate a typical power consumption for the intended applications, a 6 W LED lighting load and an electronic load was connected to the energy system [34]. The energy system was tested in Buenos Aires, Argentina during the month of May, in which the average

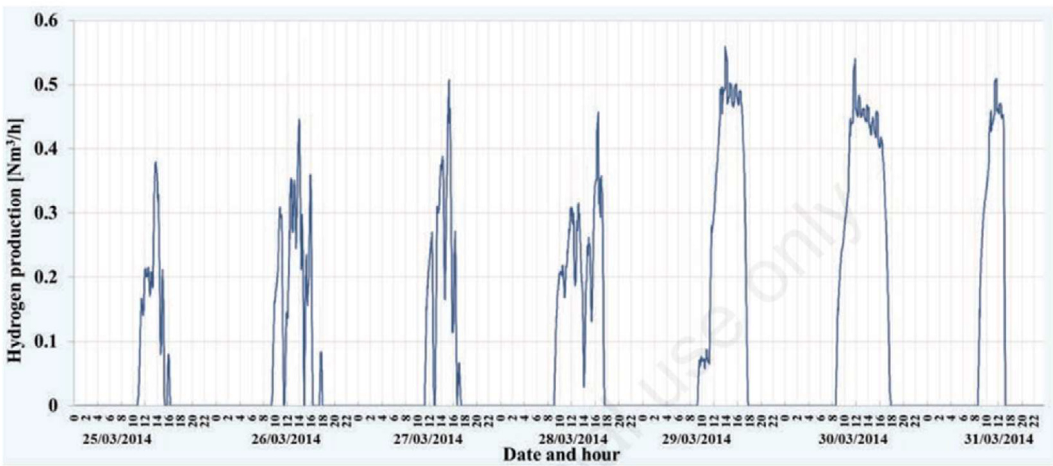

Fig. 8 – Hydrogen production for the final week of March 2014 at the greenhouse facility [33].

recorded solar irradiation is 2.5 kWh/m^2 [34]. On sunny days during this period the PV panels were able to deliver up to 6 W to the electrolyser, while the useable power on cloudy days was observed to be 10–30% of this [34]. The electrolyser was able to produce 5 L of hydrogen on sunny days, while the production on one day that was alternately sunny and cloudy was 3.6 L [34]. The autonomy of the system was tested with the connected loads and 10 L of stored hydrogen and this resulted in 18 h of continuous operation [34].

Projects with only metal hydride storage

A research project at the Universidad de Sevilla in Spain analyzed and performed experiments to identify advantages and disadvantages with various operating modes for energy systems based on renewable energy with hybrid energy storage, including hydrogen [35]. Computer simulations and numerical analyses were performed and the theoretical results were then validated through experiments on a lab-scale energy system. The energy system used in the experiments included a 1 kW PEM electrolyser, a 1.5 kW PEM fuel cell, a 7 Nm^3 metal hydride tank and a 367 Ah lead-acid battery bank [35]. In addition to these components, a 2.5 kW electronic load was used instead of power demand and a 6 kW electronic power source was used instead of power production [35]. Six different operating modes were used and combined with three different simulation scenarios. The six operating modes were: “partial load operation”, “maximize hydrogen production”, “batteries at rated power”, “fuel cell at rated power”, “electrolyser at rated power” and “maximize efficiency” [35]. The three simulation scenarios were: “sunny day scenario”, “cloudy day scenario” and “windy day scenario” [35]. Some of the modes and scenarios were combined in three experimental setups called: 1. Partial load on a sunny day, 2. Maximize efficiency in the cloudy day scenario, and 3. Maximize efficiency in the windy day scenario [35]. The conclusion from the research project was that none of the operating modes have the best performance in every situation [35]. Instead, an “Efficiency-Cost” map can be used to choose the most beneficial operating mode depending on various situations, as shown in Fig. 9 [35]. The experimental work confirmed the results from the theoretical studies and the general conclusion is that operating the electrolyser and fuel cell at variable power achieves the highest energy efficiency [35]. This is indicated by the “P. load” box (black) in Fig. 9 [35] where it can be seen that the total efficiency of the energy path (as defined in Ref. [35]) for this operating mode stretches from 79 to 87% [35]. However, this operating mode can also result in much higher costs. This is indicated by the top side of the “P. load” box in Fig. 9 [35] which represents this operating mode during a cloudy day. There it is shown that the operating cost (as defined in Ref. [35]) in such a situation would be 50€, as opposed to less than 5€ for the same operating mode during a sunny day [35]. One way to lower the costs is to operate the electrolyser and fuel cell steadily at their rated power, but this has the disadvantage that the total efficiency of the energy path could be reduced. This is indicated by the “Max Eff” (green) box in Fig. 9 [35] where it can be seen that this operating mode has very low operating costs (4–5€) for all weather profiles, but it also has a lower total efficiency of energy path (65–77.5%) compared to the “P. load” operating mode [35]. The same experimental setup with a

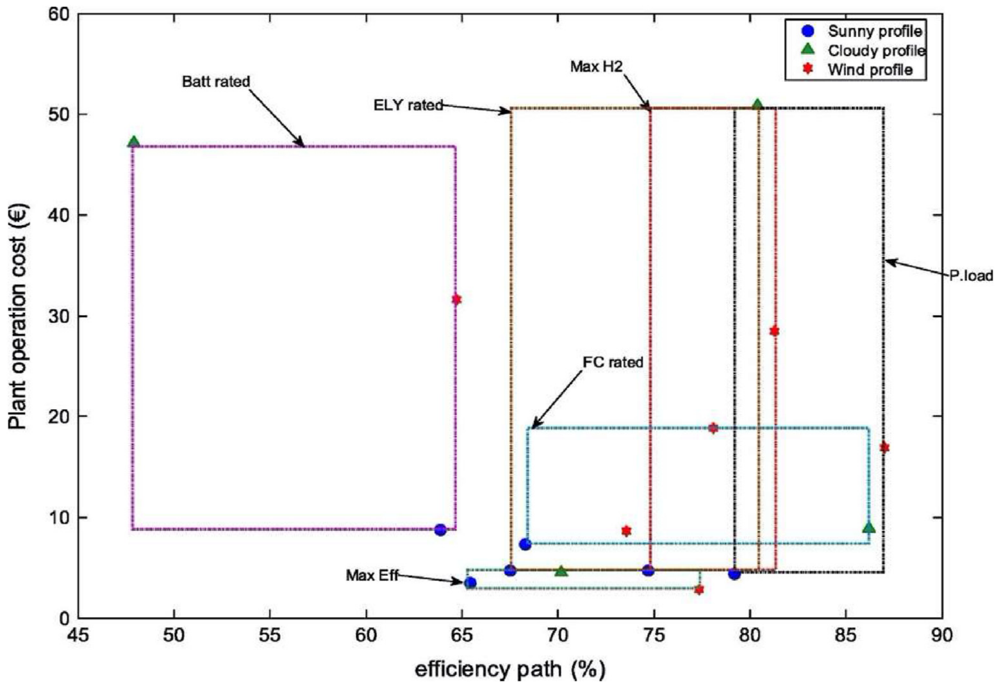

Fig. 9 – Efficiency-cost map showing the various operating modes combined with the three weather patterns. The operating modes are indicated by the boxes, and the different colors are: Black: Partial load, Red: Max hydrogen, Brown: Electrolyser rated, Blue: Fuel cell rated, Purple: Battery rated, Green: Max efficiency [35]. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

3 kW ultracapacitor added to the system was also used in a project where the focus was to develop control algorithms for optimal load sharing in hybrid energy systems [36]. The results from this project showed that definite advantages resulted from the combination of the three different energy storage technologies (hydrogen, battery, ultracapacitor). The use of hydrogen improved the control over the overcharge and undercharge of the battery and ultracapacitor, and it also minimized the high-stress current ratio in the battery, while the use of battery and ultracapacitor made it possible to avoid fluctuating operating conditions in the hydrogen system [36]. The overall conclusion was therefore that the hybrid solution with hydrogen, battery and ultracapacitor in combination with the developed control algorithm can increase the lifetime of the energy storage system [36].

Researchers at the University of Bologna developed a lab-scale microgrid to investigate a solar-to-hydrogen generation chain [37]. The microgrid includes two 220 Wp PV panels, a PEM electrolyser that produces hydrogen at a rate of 30 SL/h (standard liter per hour) and a pressure of 10.5 bar, three metal hydride tanks with a hydrogen storage capacity of 760 SL (standard liter) each, as well as two lead-acid batteries with capacities of 55 Ah at 12 V [37]. The researchers performed experiments with the goal of finding overall efficiency values for the complete solar-to-hydrogen generation chain, and the results showed that this efficiency ranged from 3.4 to 5.3% [37]. Most of the losses in the process is a result of the low efficiency of the PV panels that causes 89% of the total losses [37]. The section of the system that produces hydrogen consists of an AC/DC converter, a PEM electrolyser and the metal hydride storage tanks. The efficiency of this part of the system was in the range of approximately 35–47% during experiments, as shown in Fig. 10 [37]. As shown in the figure the exact efficiency value varied with the input power. The results also showed that the efficiency of the batteries and PV panels depended on the operating conditions. For instance, the battery efficiency was affected by the initial and final state of charge of the battery and the PV efficiency was shown to decrease from 15 to 9% when the solar charge regulator was used to manage the power output to the batteries [37]. The efficiencies of the AC/DC inverter and the solar charge regulator stayed constant during all experiments at 81.4% and more than 99%, respectively [37].

An energy system based on solar energy and with a hybrid energy storage system with both batteries and hydrogen was constructed and tested by researchers from the National Institute of Advanced Industrial Science and Technology and Shimizu Corporation in Japan [21]. The aim was to create a system that would realize a zero-emission building (ZEB) in urban areas, with the main priorities being compactness, safety and mild operating conditions [21]. The system consisted of four containers with PV panels on the roofs, a separate control room container and a ground-mounted PV array. The PV panels from Panasonic had a combined peak power of 23.75 kW (20 kW on the ground, 3.75 kW on the container roofs) [21]. The four containers contained the hybrid energy storage system where the electrolyser, metal hydride tanks, fuel cell and batteries each had their container. The electrolyser was a 26 kW PEM electrolyser that can produce hydrogen at a rate of 5 Nm^3/h at 9.7 bar [21]. Metal hydride storage tanks containing a TiFe-based alloy with an effective hydrogen storage of 1.4 wt% (absorption at 30 °C and desorption at 45 °C) were used, giving the tanks a combined storage capacity of 80 Nm^3 of hydrogen [21]. A 3.5 kW PEM fuel cell with an electrical efficiency of 55% was used to convert stored hydrogen back into electricity when needed [21]. In addition to the hydrogen energy storage, a Li-ion battery system with a combined storage capacity of 20 kWh and an output power of 20 kW was also used [21]. The whole system was controlled by a building energy management system (BEMS) housed in a separate control room. Results from 24 h of operation on a sunny day showed that the system used almost no power from the local grid, which led the researchers to conclude that the system is indeed capable of realizing ZEBs in urban areas [21]. The

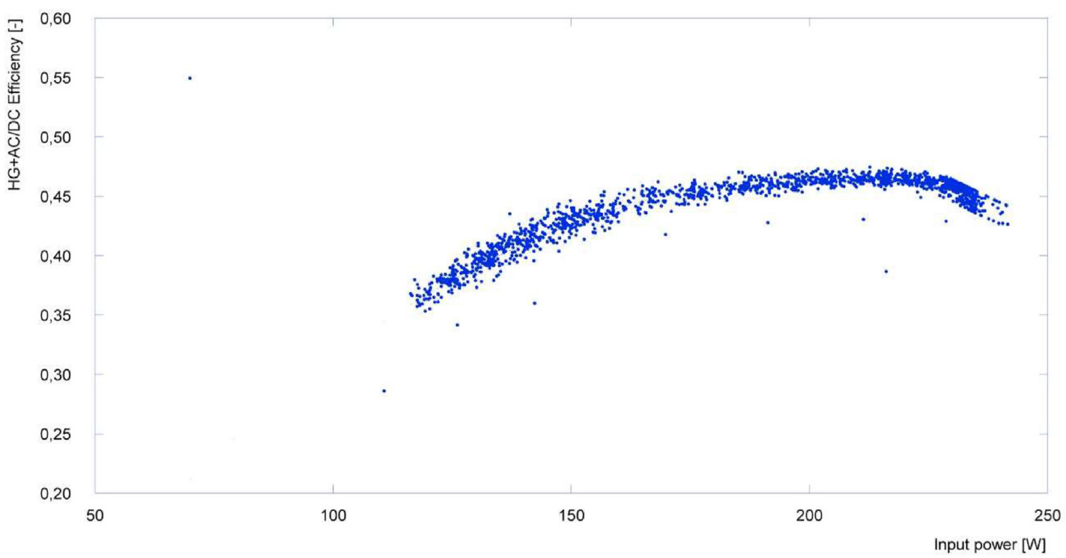

Fig. 10 – Plot of the efficiency vs. input power for the hydrogen part of the system. The hydrogen "section" (AC/DC converter, PEM electrolyser and metal hydride storage tanks) showed a peak efficiency of 47.1%, i.e. an energy loss of 52.9% [37].

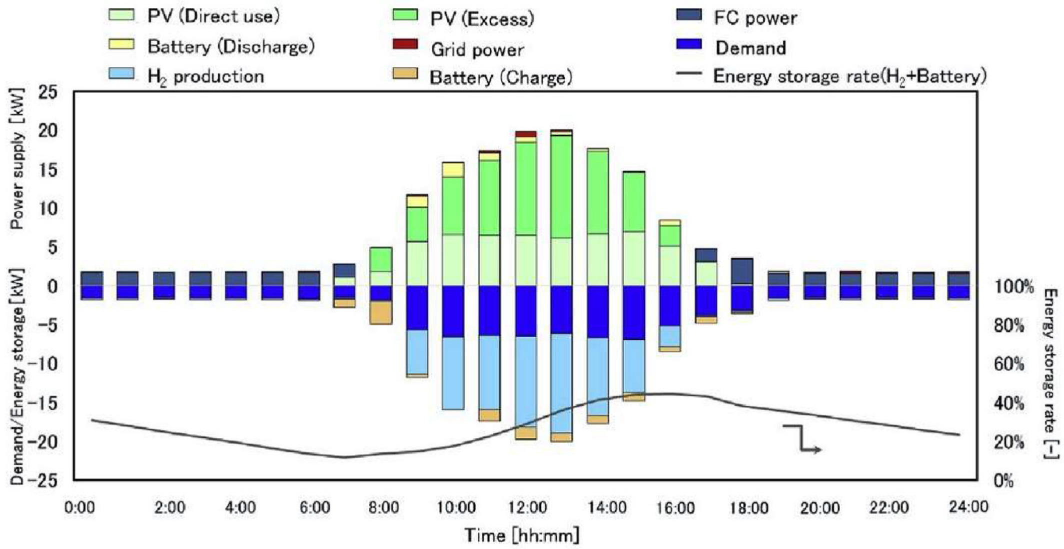

Fig. 11 – Overview of the power supply and demand during 24 h of operation with fine weather conditions. The gray line shows the combined energy storage rate for hydrogen and batteries [21].

power overview for the 24 h is shown in Fig. 11 [21]. This shows that the power demand was covered by the stored hydrogen and the fuel cell during the hours between 0:00 and 7:00. During the daytime hours (between 7:00 and 19:00) the PV panels produced power that was used to cover demand directly, as well as to produce hydrogen and charge the batteries. Only a very small amount of grid power (red in Fig. 11 [21]) was used during this period. During the hours between 19:00 and 24:00 the power demand was again covered by the stored hydrogen and fuel cell. It was also demonstrated that the waste heat from the fuel cell can be used in the desorption process in the metal hydride tanks, thereby making the overall process more energy efficient. In this demonstration, the initial temperature and pressure of the metal hydride tank was 30 °C and 0.15 MPa and the amount of hydrogen stored was 20 Nm^3 [21]. The fuel cell operated with a power output of 3.5 kW and the fuel cell outlet water temperature increased up to 60 °C during the first 20 min and stayed constant at this temperature afterward [21]. This outlet water was used in a heat exchanger to give the heat supply for the metal hydride tanks a temperature of 42 °C [21]. The desorption process in the metal hydride tank was fully completed using only the waste heat from the fuel cell, indicating that it is possible to set up a metal hydride-fuel cell operation without using an external heat supply [21].

A novel kW-scale hydrogen energy storage system was designed, constructed, and tested by researchers at Skolkovo Institute of Science and Technology and Joint Institute for High Temperatures of Russian Academy of Sciences in Moscow, Russia [38]. The system included an electrolyser that produces hydrogen at a rate of 100 SL/h at a pressure of 1.5–3 atm, a metal hydride tank filled with 5 kg of the intermetallic compound $La_{0.9}Ce_{0.1}Ni_5$ with a nominal hydrogen storage capacity of 720 SL, and a 1.1 kW PEM fuel cell [38]. The storage system uses the waste heat from the fuel cell to supply heat to the desorption process in the metal hydride tank, which requires a temperature of 20 °C [38]. This increases the

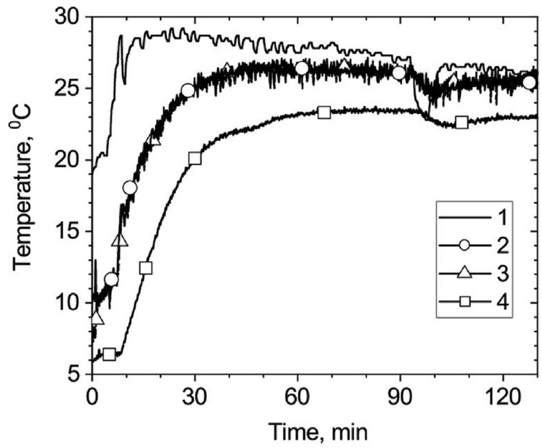

Fig. 12 – Temperature distribution in one of the experiments where fuel cell heat (line 1) was used to supply heat to the desorption process in the metal hydride tank (line 4). Line 2 and 3 shows the temperature of the water flows in the heat exchanger [38].

autonomy of the system and reduces energy losses [38]. Fig. 12 shows the temperatures of the fuel cell waste heat (line 1), water temperatures in the heat exchanger (lines 2 and 3) and the resulting temperature in the metal hydride tank (line 4) [38]. Several experiments were performed and the results indicate that the system requires a certain minimum fuel cell load of around 550 W to achieve stable operating conditions over time [38]. The reason for this is that the fuel cell does not provide the necessary outflow air temperature for the hydrogen desorption process in the metal hydride when the fuel cell is running with a low load or is just starting up [38]. Possible improvements suggested by the authors to remedy this challenge include increasing the pressure from the electrolyser to the metal hydride tank, increasing the load on the fuel cell, adding a buffer that can deliver hydrogen to the fuel cell in the first phase of the process, optimizing heat and mass transfer by improving the design of the metal hydride reactor and the overall system, as well as choosing the metal hydride material that best fits the conditions of the given situation [38]. The authors conclude that the experimental results prove the feasibility of an autonomous hydrogen energy storage system where the use of waste heat from the fuel cell eliminates the need for an external heat supply [38].

A lab-scale hybrid energy system with energy storage was designed, built and tested by Zhang et al. [39] at Hebei University of Technology in China. The main components of the energy system was 1 kW of PV panels, a 0.4 kW wind turbine, a 0.4 kW PEM electrolyser, a metal hydride storage tank with a 500 SL storage capacity, a 1.2 kW PEM fuel cell, and a 55 Ah lead-acid battery [39]. The hydrogen sub-system was not primarily intended to be used as energy storage and load-levelling in the electric power system, but rather as a way of using excess solar and wind energy to produce hydrogen for fuel cell buses or to be added to natural gas pipelines. The main motivation behind this was to reduce the curtailment of renewable power [39]. The fuel cell was only used in cases when the energy production from wind and solar and the energy stored in the battery was not sufficient to cover the load [39]. The researchers designed an operation strategy that would ensure a stable power supply to the hydrogen system and sufficient hydrogen production [39]. The stated results show that the energy system had a utilization ratio of renewable energy of 91.2% [39], which means that 8.8% of the produced renewable power was curtailed during the operation period [39]. This was achieved by operating the electrolyser at the rated power as much as possible, which kept the average hydrogen level in the metal hydride tank at 71.4% during the operation period [39].

Combination of compressed gas storage and metal hydride storage

Instituto Nacional de Técnica Aeroespacial (INTA) in Spain has built a R&D facility at its Renewable Energy Laboratory which includes a hydrogen-based energy storage system (HESS) [40]. The facility has a PV array and a 5 kW wind turbine, and together with the energy storage system this makes up a microgrid which is also connected to the internal grid at the Renewable Energy Laboratory [40]. The HESS includes an alkaline electrolyser with a nominal power of 5.2 kW which delivers hydrogen at a rate of 1.2 Nm^3/h at 6 bar and 80 °C, hydrogen storage system and fuel cells [40]. The storage system consists of three different hydrogen storage technologies: low-pressure gas, high-pressure gas and storage in metal hydrides. The low-pressure storage consists of a 1 m^3 tank that receives hydrogen gas from the electrolyser at 6 bar and stores it at the same pressure [40]. When this tank is full the hydrogen gas can go one of three ways; it can go to a compressor to be stored as high-pressure gas, it can go to the metal hydride storage container, or it can be used directly in the fuel cells to generate electricity. The metal hydride used in the storage system is $TiMn_2$ which accounts for a hydrogen storage capacity of 1.50 wt% for the metal hydride alloy alone and 0.93 wt% for the complete metal hydride container [40]. This tank can store 24 Nm^3 of hydrogen at a maximum pressure of 10 bar [40]. In the high-pressure gas tanks the hydrogen is stored at a pressure of 200 bar [40]. In total, the combined hydrogen storage system can store 65 Nm^3 of hydrogen, which is equivalent to 195 kWh of chemical energy (higher heating value) [40]. According to calculations, the volumetric energy density of hydrogen storage in the metal hydrides (1.22 kWh/L) is much higher than it is in the high-pressure gas tanks (0.52 kWh/L), while the gravimetric energy density is quite comparable for the two technologies (0.31 and 0.50 kWh/kg for metal hydride with and without tank, and 0.42 kWh/kg for high pressure gas) [40]. Hydrogen storage capacity in wt%, as well as gravimetric and volumetric energy density for the various hydrogen storage technologies used at INTA is shown in Fig. 13 [40]. The figure also shows the same values for the complete hydrogen storage system using all technologies. The gravimetric and volumetric energy density of the hydrogen technologies was also compared to three different battery technologies (wet lead acid, valve regulated lead-acid, and Li-ion batteries). In these comparisons, it is also considered that the energy in the stored hydrogen must be converted to electricity in a fuel cell (tested at INTA with an average efficiency of 48%) before it can be compared to the batteries which require no such conversion device [40]. The values for the batteries are stand-alone values (not in combination with hydrogen). The results of these experiments show that hydrogen storage (with fuel cell conversion included) in either the metal hydride tank or as high pressure gas shows equal or higher energy density values than the best battery technology: For gravimetric energy density, high pressure hydrogen has the highest value (200 Wh/kg) while the metal hydride tank (149 Wh/L) and the best battery technology (Li-ion, 150 Wh/L) are almost the same [40]. For volumetric energy density, the metal hydride tank has by far the highest value (586 Wh/L) while the high pressure hydrogen (252 Wh/L) and the best battery technology (Li-ion, 250 Wh/L) are almost the same [40]. The low-pressure hydrogen storage has the highest efficiency (96%) of the three hydrogen storage technologies, but the very low volumetric energy density (6 Wh/L with fuel cell conversion included) makes this an impractical solution for larger facilities [40]. The efficiencies of hydrogen storage in the metal hydride tank and as high-pressure gas was 79% and 52%, respectively [40]. These efficiency values include only storage losses, not losses in the fuel cell [40]. The total average energy efficiency of the whole hydrogen system including electrolyser and fuel cells was also highest when hydrogen flowed straight from the low-pressure storage to the fuel cells, in which case it reached 32%, while it was 26% with metal hydride storage and 17% with high pressure gas storage [40]. The authors state that all these efficiency values for the whole hydrogen plant are much lower than the efficiency in battery storage systems which they report to be 85% for storing renewable energy in lead-acid batteries, although this drops to 69% if the power loads associated to the Balance of Plant (BoP) are included [40].

Researchers from Tohoku University, Chiba University and three Japanese companies developed and tested an energy system that was to function as a reliable emergency power supply [41]. The system included renewable energy generation through solar PV panels and a hybrid energy storage system with a capacitor bank and a hydrogen system. The main

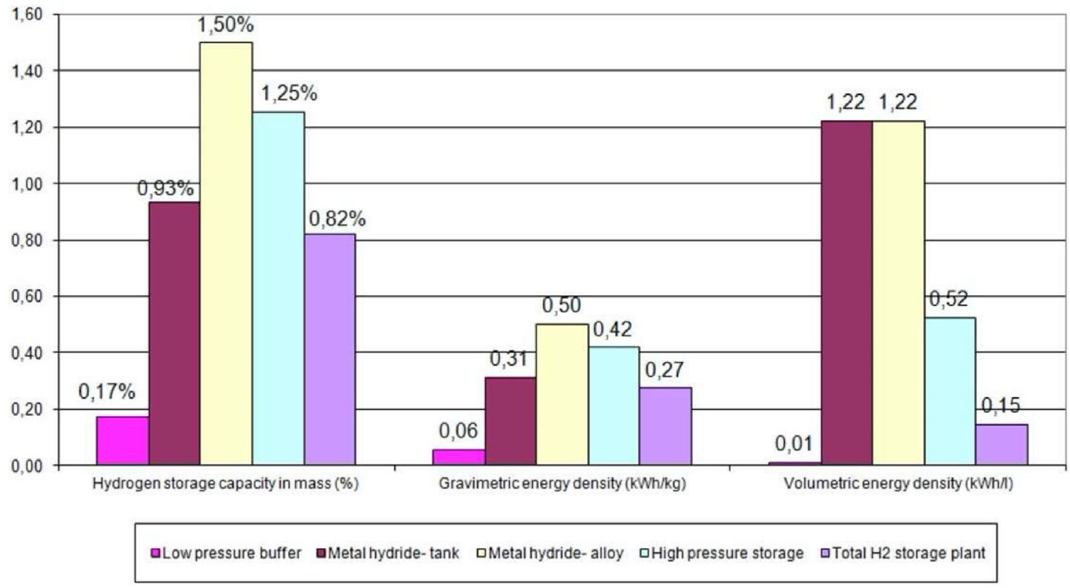

Fig. 13 – Energy densities of the various hydrogen storage technologies tested at INTA. Values for metal hydride storage is given for both the complete metal hydride container and only the metal hydride alloy. Total H_2 storage plant gives the values for the complete hydrogen storage facility using all technologies [40].

targets were: 1. Verify that the system could indeed provide reliable power throughout a long-term blackout, 2. Verify that the use of both low-pressure gas storage of hydrogen and storage in metal hydrides lower power use and show sufficient hydrogen gas flow regulation speed, and 3. Reveal possible ways of increasing system efficiency and decreasing system costs [41]. The PV panels had a nominal power of 20 kW and the hybrid energy storage system included electric double-layer capacitors (EDLC) with a 25 F capacitance and 20 kW nominal power, a 24 kW PEM electrolyser that produces hydrogen with a maximum flow rate of 5 Nm^3/h and a maximum pressure of 8.2 bar, a PEM fuel cell with a nominal power of 15 kW, a 30 m^3 gas tank for storing hydrogen at 8 bar, and $LaNi_5$ metal hydride tanks with a hydrogen storage capacity of 240 Nm^3 [41]. The system was tested through continuous operation for more than three days to verify its suitability for use in long-term blackouts. The results showed that the proposed system is a reliable alternative for use in blackout situations [41]. The hybrid use of low-pressure gas storage and metal hydride storage showed that using the low-pressure gas tank as a buffer effectively reduced the required power for the temperature conditions in the metal hydride tanks [41]. This was achieved by letting the low-pressure gas tank handle fluctuations in power demand which allowed the metal hydride tank to release hydrogen at a stable and relatively low rate [41]. This meant that the heat supply to the metal hydride desorption process could be reduced to 1 kW, while it would have needed to be more than 1.74 kW if there had been no low-pressure hydrogen buffer [41]. The operation also revealed problems related to low energy efficiency and high costs, including insufficient use of EDLC capacity, large energy losses when the electrolyser and fuel cell is operated with low load ratio, and waste of power capacity since the system rarely operated with high power [41]. The low efficiency of the electrolyser and fuel cell at low power conditions is shown in Fig. 14 [41]. The average efficiencies were calculated to be 27.2% for the electrolyser and 29.3% for the fuel cell during experimental operation [41]. These values were calculated from experimental data for the amount of hydrogen produced and energy consumed (electrolyser), and the amount of hydrogen consumed and electric energy delivered (fuel cell) [41]. These efficiencies are much lower than common efficiency values at rated power (above 70% for electrolyser and above 40% for fuel cell) and this was mainly due to the fact that both the electrolyser and fuel cell operated much of the time at low and/or fluctuating power due to the fluctuations in the PV power (in) and power demand (out) [41]. The efficiency of the whole hydrogen energy storage system (electrolyser, storage as low pressure gas and metal hydride, and fuel cell) was calculated to be 22.9% [41]. The authors suggested introducing self-adjusting feed-back control for the EDLC to improve efficiency, as well as shifting the load from the electrolyser and fuel cell to the EDLC when the power demand is low to avoid the large energy losses [41]. The use of peak power shift/shaving could also reduce the necessary power capacity of the electrolyser and fuel cell and thereby reduce costs for the system [41].

Power electronics and control systems in hydrogen-based energy storage systems

Power electronics, control systems, and energy management strategies are very important parts of energy systems with hydrogen energy storage. This is due to the intermittency of renewable energy sources like solar and wind and the combination of these sources with energy storage systems that often include more than one storage technology (hydrogen, batteries, supercapacitors, etc.). Such systems have high complexity and a high number of components. Therefore,

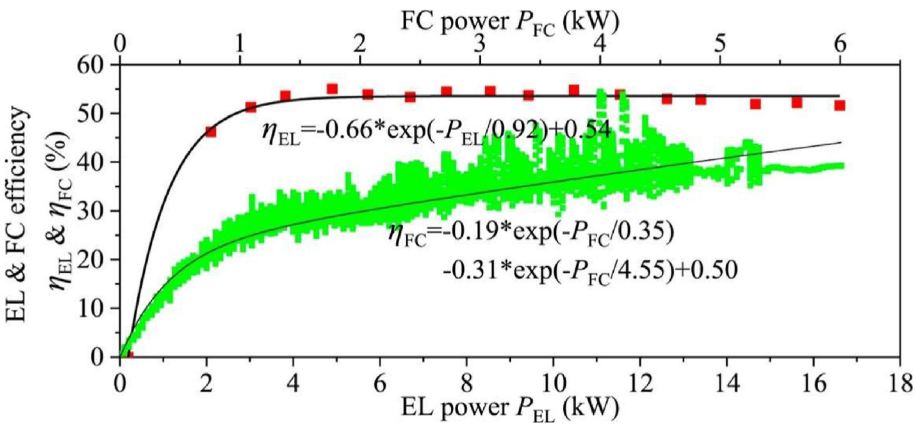

Fig. 14 – Energy conversion efficiencies for the electrolyser and fuel cell (including converter loss) obtained from experimental data [41].

they require advanced energy management systems that are able to respond to the fluctuations in the system, as well as to maximize energy efficiency and lifetime for the various components and the energy system as a whole.

In a study by Bayrak et al. [42], the authors focus on the development of a low-cost power management system for residential power systems based on solar power and hydrogen energy storage [42]. In addition, they also review various control systems used in hybrid power systems. The fundamental control systems are programmable logic controller (PLC) systems, digital signal processing (DSP) systems, microcontroller systems, and supervisory control and data acquisition (SCADA) systems [42]. All these systems have their own advantages and disadvantages. In terms of easy implementation, PLC systems, microcontrollers, and data acquisition systems are the most advantageous [42]. DSP systems have the highest sampling rate, followed by data acquisition systems, while PLC systems and SCADA systems have medium sampling rate, and microcontroller systems have the lowest sampling rate [42]. Data acquisition systems are user-friendly when it comes to the monitoring of the system since they only require a PC or a tablet, while the other systems need extra monitoring devices [42]. Microcontroller systems have the lowest controller costs compared to total power system cost, data acquisition systems also have relatively low costs, PLC systems and SCADA systems have medium costs, while DSP systems have the highest costs [42]. More details regarding the advantages and disadvantages are given in Table 1 in Ref. [42]. To achieve the most beneficial combination of advantages, the authors decided to develop a hybrid control system based on a microcontroller and a Labview data acquisition card [42]. The authors tested the control system experimentally and found that it was relatively easy to implement and suitable for residential power systems based on solar power and hydrogen energy storage [42].

Rezk et al. [43] evaluated and compared various programming algorithms as energy management strategies in a hybrid energy system with a hydrogen fuel cell, supercapacitor and battery [43]. The various algorithms/strategies are fuzzy logic control (FLC) method, external energy maximization strategy (EEMS), state machine control strategy (SMCS), proportional-integral (PI) method, equivalent consumption minimization strategy (ECMS), mine blast algorithm (MBA), and salp swarm algorithm (SSA) [43]. The authors also proposed four novel hybrid strategies. These were MBA-based ECMS, MBA-based EEMS, SSA-based ECMS, and SSA-based EEMS [43]. All energy management strategies are evaluated in terms of efficiency and hydrogen consumption, where the efficiency should be maximized and the hydrogen consumption minimized. The efficiency range for the various strategies was 72.5–85.6%, and the strategy with the best performance was the SSA-based EEMS which resulted in an overall efficiency of 85.6% [43].

Kong et al. [44] propose a modeling and control strategy developed for hybrid energy systems based on solar power and energy storage in hydrogen and supercapacitors [44]. They use a DC bus to control the power of the various modules to stabilize the power fluctuations in the system, and they conclude that the proposed control strategy reduces the fluctuations to an acceptable level [44]. They ignore the constraints of hydrogen storage capacity and state of charge limits for the supercapacitor, but plan to include this in future work [44].

The system built and tested by Zhang et al. [41] has already been described in section Overview of projects and summary of results, but the authors also describe their optimization of the energy management method in this work. The energy management was based on Kalman filtering prediction algorithm [41]. The authors defined the difference between the produced PV power and the power consumed by the loads as power fluctuations, and the Kalman filtering algorithm was used to predict these fluctuations [41]. This prediction was defined as the long-term power fluctuation, and the difference between the prediction and the actual power fluctuation was defined as the short-term power fluctuation [41]. When the long-term fluctuation was positive the excess PV power was used in the electrolyser, and when it was negative the fuel cell was used to produce power [41]. The short-term fluctuations were covered by the EDLC via the bus voltage control of its converter. A state-of-charge feedback control was used to prevent overcharge or over-discharge of the EDLC by regulating the electrolyser and fuel cell power based on the feedback information [41]. As described in section Overview of projects and summary of results, the system used the low-pressure gas tank as a buffer to reduce the external heat demand for the desorption process in the metal hydride tank. The control system did this by making the buffer tank absorb the hydrogen directly from the electrolyser and supply the required hydrogen to the fuel cell, while making the metal hydride tank release hydrogen to the buffer tank according to their pressure difference and absorb hydrogen from the buffer tank when the tank pressure got higher than 0.61 MPa [41]. The control system was also set to heat the metal hydride when the buffer tank pressure got below 0.35 MPa and stop heating when the pressure got higher than 0.45 MPa [41]. Similarly, the chilling of the metal hydride was set to start and stop at 0.68 and 0.65 MPa, respectively [41].

In [45], Maghami et al. constructed and tested a hybrid energy system with a focus on energy management and demand response. The system included a 320 W PV array, 50 W wind turbine, 24 W hydro turbine, 200 W battery, 1600 W converter, and a hydrogen system consisting of an electrolyser, a hydrogen gas tank and a 100 W PEM fuel cell [45]. The authors developed a PLC unit and combined this with a demand response (DR) program to optimize the energy management in the system [45]. All generation units (PV, wind turbine, hydro turbine) have sensors that measure their production and send this to a local controller and a remote input-output (IO) unit. Other sensors also send measurements from other components and the environment to local controllers and the IO unit in the same way. The IO unit acts as a supervisory controller that makes decisions and the local controllers also communicate with each other to make decisions by fuzzy logic (FLC) to achieve specific goals [45]. Four different cases were evaluated: 1. Energy system described above but without hydrogen and DR, 2. Energy system with hydrogen but without DR, 3. Energy system with DR but without hydrogen, and 4. Energy system with both hydrogen and DR [45]. The systems were evaluated with respect to six different variables: 1. The operation cost of battery charging, 2. The operation cost of battery discharging, 3. Operation cost of hydrogen storage charging, 4. The operation cost of hydrogen storage discharging, 5. Cost of Energy Not Supplied, and 6. Cost of excessive energy [45]. The results showed that the hybrid energy system which included both a hydrogen system and a DR program (system 4) achieved the most favorable overall results [45]. This system achieved a total operation cost (sum of the six variables listed above) that was 26% lower than system 3, 32% lower than system 2, and 64% lower than system 1 [45].

Solmecke et al. studied the use of DC-DC converters to increase efficiency and reduce costs in hybrid energy systems based on solar power and hydrogen energy storage [46]. The authors state that by using DC-DC converters with high efficiency (92–95%) between the PV panels and electrolyser and between the hydrogen fuel cell and DC-AC inverter, the use of large and relatively inefficient transformers (75–92%) can be avoided [46]. An analysis of the PHOEBUS demonstration plant at the FZ-Jülich in Germany concluded that the use of DC-DC converters increases the efficiency from 65.2% to 69.6%, while also reducing the cost of the system [46].

Outlook with comparison and perspectives

Hydrogen-based systems in combination with renewable energy are still quite rare. There are a few full-scale facilities like the Sir Samuel Griffith Centre at Griffith University in Brisbane, Australia [19] and Energiepark Mainz in Germany [20], as well as some small- and medium-scale research facilities. In addition to these systems there are numerous micro-scale systems that have been designed, constructed and tested in laboratories. However, these types of hybrid energy systems are certainly not yet a widespread solution compared to more traditional energy systems. Some of the reason for this is that the share of solar and wind energy in power systems is still so low in most parts of the world that energy storage has not been necessary yet. However, with the rapid increase in built capacity for both solar and wind energy that is predicted globally in the coming decades, energy storage will be an increasingly crucial issue. Furthermore, both short-term (seconds to a few days) and long-term (a few days up to several months) energy storage will be necessary in most locations if intermittent renewable energy is going to provide the predicted share of total electricity production. Batteries are quite suitable for short-term energy storage but not for long-term storage. Hydrogen will in many cases be the most feasible alternative if long-term storage of electricity is to be implemented. Consequently, we could see a large increase in both the number and size of hydrogen energy storage systems in the coming decades.

Advantages with hydrogen-based systems emphasized in the reviewed projects are that they enable long-term storage of electricity with almost no loss of stored hydrogen, and they are very adaptable in terms of system sizing in various situations since power and energy are completely independent of each other in hydrogen systems (simply put: maximum power depends on the size of the fuel cell while maximum total energy depends on the size of the storage tank, and of course pressure and temperature). However, even though there is almost no loss of stored hydrogen in these systems, the total *energy* loss in a hydrogen system used for storing electricity is significant, particularly compared to battery systems. Typical efficiencies for electrolysers are in the range 60–80% [47], and typical efficiencies for fuel cells are in the range 40–60% [48]. This means that you lose anywhere from 54 to 72% of the electric energy in the electrolyser and fuel cell combined, and in addition to this you lose about 20% [24] of the energy if hydrogen is stored as high-pressure gas and 25–45% [24] if it is stored as liquid hydrogen. Storing hydrogen in metal hydrides reduces the energy loss compared to high-pressure gas and liquid hydrogen. Nevertheless, you risk losing as much as 85% of the original energy, and in the best-case scenario around 60% of the original energy if waste heat recovery is used in both the electrolyser and fuel cell. The operations at INTA showed a total energy efficiency for the hydrogen energy storage system of 32% when hydrogen was stored as low-pressure gas, 26% for metal hydride storage, and 17% for high-pressure gas storage [40]. This is very low compared to battery systems, particularly Li-ion battery systems which commonly have an efficiency above 90%. This means that hydrogen storage cannot compete with batteries when it comes to short-term storage, but hydrogen could still be an alternative for long-term energy storage since batteries are unsuitable for this due to their self-discharge time.

In terms of energy density, hydrogen storage in metal hydrides has the highest volumetric energy density compared to both compressed hydrogen gas and Li-ion batteries. In Ref. [40], the demonstrated volumetric energy density for metal hydride storage is 586 Wh/L which is more than double the energy density of both compressed hydrogen gas (252 Wh/L) and Li-ion battery (250 Wh/L) [40]. The gravimetric energy densities obtained in the same experiments showed that compressed hydrogen gas has the highest value (200 Wh/kg) with both metal hydride tank (149 Wh/kg) and Li-ion battery (150 Wh/kg) about 25% below compressed gas [40]. An advantage with metal hydride storage is that the waste heat from the fuel cell can be used in the desorption process in the metal hydride tank to reduce energy loss in the overall system, as confirmed in two of the reviewed projects [21,38]. The advantages of hydrogen storage in metal hydrides have become clearer as the technology has developed in recent years and the increasing popularity of this storage technology is shown in the projects presented in this review. While the early projects (beginning in 2004) used only compressed gas, metal hydride storage is more common in the more recent projects. Two projects [40,41] used both compressed gas and metal hydride storage, and one of these [41] found that the use of a low-pressure buffer tank in combination with metal hydride storage slightly reduces the energy loss in the overall process. This was achieved by letting the low-pressure buffer tank handle fluctuating power demands which allowed the metal hydride tank to release hydrogen at a steady and relatively low rate. This reduced the required heat supply in the desorption process by more than 42.5% for this stage of the process [41].

The best solution in many cases seems to be a hybrid energy storage system where hydrogen storage is combined with batteries, and with supercapacitors as a possible third component to handle extremely rapid and large power fluctuations (if there are any). Several of the reviewed projects use some version of these hybrid systems and all of them report significant advantages with the combination of two or more energy storage technologies. Since batteries are very suitable for short-term energy storage and hydrogen for long-term storage, the two technologies combine well in a system where batteries can deal with the high-frequency fluctuations in power demand and hydrogen handles the remaining low-frequency fluctuations. If there are extremely rapid fluctuations in the power demand, then supercapacitors can also be a good addition. The comparison between the various projects indicates that both the overall energy efficiency of the system and the lifetime of the various components increases significantly when a hybrid system is used compared to a system with only hydrogen storage. The operation mode and control system play an important role here and the results show that these should be tailored to fit each situation to reduce energy losses. The most beneficial solution from an efficiency standpoint seems to be a system where the electrolyser and fuel cell are allowed to operate continuously at the rated/ideal power level as much as possible and the battery handles the more rapid power fluctuations. This reduces the energy losses in the hydrogen part of the system and it also increases the lifetime of the electrolyser and the fuel cell. Possible improvements will be obtained with the development of electrolysers that are able to operate more efficiently in a load-following mode.

Power electronics, control systems and energy management strategies are very important factors in hybrid energy systems. Due to the complexity of these energy systems and the natural fluctuations in power production and demand, it is very important that the system is managed in an optimal way with respect to efficiency, costs, lifetime, etc. Reviewed research in this area indicates that it is possible to achieve significantly better results (increased efficiency, reduced costs, increased lifetime, etc.) if the energy management strategy is specifically tailored to the specific conditions in each system. The specific type of control system (PLC, SCADA, etc.), algorithm (FLC, SMCS, etc.) and power electronics (converter, etc.) should therefore be chosen based on the conditions and goals for each system.

The main challenge and frequent showstopper with hydrogen energy storage systems is cost. All the reviewed projects that consider the economic side of the project conclude that significant cost reductions and efficiency improvements for both electrolysers, hydrogen storage and fuel cells will be necessary before hydrogen energy storage systems can approach a point where they are commercially feasible, not to mention profitable. An added challenge here is that some of the system modifications that increases the overall efficiency for the energy system also increases the cost of the hydrogen system. An example of this could be a wind/hydrogen system where you want a large high-power hydrogen system to be able to store as much energy as possible when the wind is really strong and the power consumption is low. However, a hydrogen system of this size would be grossly oversized for most of the operating time and hence a very costly solution. Therefore, it is very important to design and tailor the complete energy system specifically for each situation, so that the most favorable compromise between cost and energy efficiency can be found.

Conclusions

This article has reviewed 15 projects where hydrogen energy storage systems have been constructed and tested. In addition, various studies focusing on power electronics, control systems and energy management strategies for energy systems with hydrogen storage were reviewed. The focus of the review was to provide an overview of the recent developments and current state-of-the-art within hydrogen-based systems and to present the advantages as well as challenges connected to the real-world implementation of hydrogen as an energy storage technology. Results from the projects and papers reviewed in this article show that hydrogen storage systems are technically feasible in many different situations, including large-scale industrial power-to-gas facilities, large commercial/public buildings, residential houses, as well as micro-scale mobile systems. Both the overall energy efficiency of the system and the lifetime of the various components increase significantly when a hybrid system is used. However, there are considerable challenges that need to be dealt with before these systems can be implemented on a commercial scale. The costs of a hydrogen-based system are still high. On the positive side, the predicted increase in demand for long-term energy storage could lead to mass production of the various components of hydrogen storage systems. The economies-of-scale effect from this is predicted by many to significantly reduce the cost of these components and systems in the coming decades. It remains to be seen whether this reduction will be large enough to makethem a commercially attractive option for energy storage in future power systems.

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.

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Paper II

Simulating offshore hydrogen production via PEM electrolysis using real power production data from a 2.3 MW floating offshore wind turbine

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Simulating offshore hydrogen production via PEM electrolysis using real power production data from a 2.3 MW floating offshore wind turbine

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HIGHLIGHTS

- Simulations of H_2 produced with electricity from real-world offshore wind turbine.
- Novel combination of electrolyzer model + wind power and electricity price data.
- H_2 production and cost vary by a factor of three between different periods.
- Highest H_2 production in a 31-day period was 17 242 kg with a 1.852 MW electrolyzer.
- The lowest H_2 production cost achieved was 4.53 $/kg H_2.

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PEM electrolysis

ABSTRACT

This work presents simulation results from a system where offshore wind power is used to produce hydrogen via electrolysis. Real-world data from a 2.3 MW floating offshore wind turbine and electricity price data from Nord Pool were used as input to a novel electrolyzer model. Data from five 31-day periods were combined with six system designs, and hydrogen production, system efficiency, and production cost were estimated. A comparison of the overall system performance shows that the hydrogen production and cost can vary by up to a factor of three between the cases. This illustrates the uncertainty related to the hydrogen production and profitability of these systems. The highest hydrogen production achieved in a 31-day period was 17 242 kg using a 1.852 MW electrolyzer (i.e., utilization factor of approximately 68%), the lowest hydrogen production cost was 4.53 $/kg H_2, and the system efficiency was in the range 56.1–56.9% in all cases.

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Nomenclature:

Abbreviations

BoP	Balance of Plant
CAPEX	Capital Expenditure
FOWT	Floating Offshore Wind Turbine
HHV	Higher Heating Value
LCOH	Levelized Cost Of Hydrogen
LCOS	Levelized Cost Of Storage
LHV	Lower Heating Value
Li-ion	Lithium ion
OCV	Open-Circuit Voltage
OPEX	Operating Expenses
PEM	Proton Exchange Membrane
PV	Photovoltaic
SOC	State of Charge
SOFC	Solid Oxide Fuel Cell
SOEL	Solid Oxide Electrolyzer

Chemical elements

C	Carbon
H	Hydrogen
Li	Lithium
O	Oxygen

Non-SI units and conversion to SI

bar, unit of pressure $1\ \text{bar} = 100\ 000\ \text{Pa}$
h (hour), unit of time $1\ \text{h} = 3600\ \text{s}$
kWh (kilowatthour), unit of energy $1\ \text{kW h} = 3\ 600\ 000\ \text{J}$
liter, unit of volume $1\ \text{L} = 0.001\ \text{m}^3$
minute, unit of time $1\ \text{min} = 60\ \text{s}$
year, unit of time $1\ \text{year} = 31\ 536\ 000\ \text{s}$

Multiples used with SI units

Kilo (k) 10^3
Mega (M) 10^6
Giga (G) 10^9

Currencies

€	Euro, currency in the European Union
$	US dollar, currency in the United States of America
£	British pound, currency in the United Kingdom
CNY	Chinese yuan, currency in China
NOK	Norwegian krone, currency in Norway
AUD	Australian dollar, currency in Australia

Introduction

Climate change and geopolitical issues are key drivers for a faster transition from the use of fossil fuels to the use of renewable energy-based fuels and technologies. There is also an increased focus on the use of hydrogen as an energy carrier. If hydrogen is produced via water electrolysis with power from renewable energy (i.e., “green hydrogen”) and used to reduce fossil fuels, global emissions of greenhouse gases could be significantly reduced. Possible applications include the use of hydrogen as an energy storage in electricity systems (both grid-connected and off-grid systems), hydrogen for the transport sector (both in fuel cells and combustion engines), use of hydrogen in industrial processes (e.g., production of ammonia, steel, and cement), or simply the use of hydrogen as a fuel for heating and cooking (as replacement for or mixed with natural gas).

A specific opportunity that has emerged in recent years is the combination of offshore wind power and hydrogen production via water electrolysis. Several pilot projects that will demonstrate this concept are in the planning phase: TechnipFMC will test a pilot system onshore during the next two years in their *Deep Purple*-project [1] and intend to use the results from this in a subsequent full-scale offshore system; Siemens Gamesa and Siemens Energy are cooperating on the development of a full-scale offshore wind turbine with integrated water electrolysis that they plan to demonstrate by 2026 [2]; Neptune Energy is planning to convert an oil platform into a platform that combines wind power and hydrogen production in their *PosHYdon*-pilot project [3]; ERM Dolphyn is in an early stage of development of a large-scale solution for hydrogen production from offshore wind and is aiming for the first commercial offshore hydrogen wind farm in the mid-to-late 2020's and the first GW-scale farm in the early 2030's [4].

The main objective of the work presented in this paper was to simulate and study the operation of a wind/hydrogen system based on a floating offshore wind turbine (FOWT) and hydrogen production via water electrolysis. A semi-empirical proton exchange membrane (PEM) water electrolyzer system model developed in MATLAB/Simulink in a previous project was used as basis for the technical modeling, while data from an existing 2.3 MW FOWT that has been in operation off the West coast of Norway since 2009 were used as the main input to the simulations. Electricity price data from the same region and time periods were also used as input to further increase the realism of the results.

The main novelty of this study is the combination of using a detailed mathematical water electrolyzer simulation model together with operational data (from five different 31-day periods) from an actual FOWT installation, and the use of actual electricity price data for the same time periods. Hence, the simulation results of hydrogen production and calculations of hydrogen production costs are highly realistic and relevant for industry stakeholders that are considering similar concepts today (2023). This “real-world” approach makes this study different from other published studies (ref. literature survey in Literature review), which mainly focus on estimating hydrogen production capacity and costs for future scenarios (e.g., in 2030 and 2050) using assumed cost reductions and efficiency improvements, or studies that use modelled or estimated values for wind power and/or electricity price instead of real-world data.

This paper is structured in the following way: Literature review contains a review of relevant literature, System design and model-based approach describes the system design and the simulation model, Description of the simulation cases describes the simulation cases, Results and discussion presents the results and discussion, while Conclusions and future work goes through conclusions and suggestions for future work.

Literature review

Several previous academic studies have investigated hydrogen production from offshore wind. In 2014, Meier [5] performed a techno-economic assessment of hydrogen production from offshore wind. A wind profile based on the operation of a wind farm was extrapolated to estimate yearly energy and hydrogen production. The author concluded here that it is technically possible to build large-scale hydrogen production platforms connected to offshore wind turbines, but that it is not economically viable [5]. In 2015, Loisel et al. [6] simulated hydrogen production from offshore wind power based on data from a weather station. Various hydrogen use cases were evaluated and the results show negative profit in all scenarios [6]. In 2020, Schnuelle et al. [7] modelled dynamic hydrogen production from both photovoltaic (PV) power and wind power. A techno-economic assessment was performed and the results show that the onshore wind cases achieved a higher efficiency and lower production cost than the offshore wind cases, while the PV cases were found to be quite competitive with the onshore wind cases [7]. McDonagh et al. [8] simulated hydrogen production from a 504 MW offshore wind farm. The results show that it is more profitable to sell electricity directly to the grid instead of producing hydrogen. However, if hydrogen *is* produced it is most profitable to use a hybrid system that produces hydrogen from wind energy that would otherwise be curtailed [8].

In 2021, several more studies on wind/hydrogen systems were performed. Nguyen Dinh et al. [9] developed a model to assess the viability of hydrogen production from dedicated offshore wind farms. The case study was a hypothetical 101.3 MW wind farm, and the results show that the wind-hydrogen farm would be profitable in 2030 with a hydrogen price of 5 €/kg H_2 and underground storage capacity between 2 and 45 days [9]. Calado and Castro [10] reviewed the current state-of-the-art and future perspectives of hydrogen production from offshore wind, and both offshore and onshore hydrogen production was evaluated. The results show that the offshore alternative may be advantageous due to lower capital cost and transmission loss with gas pipelines vs. power cables. The advantage with the onshore alternative was more economic flexibility since it could sell both hydrogen and electricity [10]. Song et al. [11] analyzed future hydrogen production from offshore wind in China and delivery to Japan. Offshore wind power production was modelled based on meteorological data and hydrogen production and cost were estimated. The results show that it will be possible for China to supply the necessary amount of hydrogen at a cost consistent with Japan's future cost targets [11]. Ibrahim et al. [12] assessed large-scale hydrogen production from offshore wind power and considered three typologies: (1) Centralized onshore electrolysis, (2) Centralized offshore electrolysis and (3) Decentralized offshore electrolysis. It was here concluded that the offshore alternatives with hydrogen transport through pipelines to shore would be economical for large and distant offshore wind farms, while the advantage with the onshore alternative mainly would be the reduced complexity of the system [12]. Settino et al. [13] performed simulations of a system where a hydro-pneumatic energy storage device was used as a buffer between an offshore wind turbine and a hydrogen electrolyzer. The results show that an energy buffer can potentially reduce the on/off cycles of the electrolyzer by up to 70% with no substantial effect on the hydrogen production [13]. Scolaro and Kittner [14] investigated whether an offshore wind/hydrogen system would be cost-competitive in an ancillary service market and determined the optimal size of the hydrogen electrolyzer relative to the offshore wind farm. The results show that a carbon abatement cost between 187 and 265 €/ton CO_2 was needed to achieve profitability. The lowest cost occurred when the electrolyzer capacity was 87% of the wind farm capacity [14]. Lucas et al. [15] performed a techno-economic analysis of onshore hydrogen production from offshore wind power by using the Portuguese *WindFloat* Atlantic offshore wind farm as a case study. Two different wind farm capacities (25.2 MW and 150 MW) and two different hydrogen production cycles (24-h production and production only at night) were analyzed. The results show that only the scenario with 150 MW wind power and 24-h hydrogen production is economically feasible. This resulted in a hydrogen production cost of 4.25 €/kg H_2, and the minimum cost was achieved when the electrolyzer capacity was 30% of the wind farm capacity [15]. Tebibel [16] proposed a multi-objective optimization approach for a system with decentralized hydrogen production from onshore wind power. Wind data were used as input to a simulation model of a decentralized system consisting of a 857.5 kW wind turbine, a 250 kW alkaline electrolyzer, a 719 kW h battery and a 2022 kg hydrogen tank. The results show that the system can produce 8760 kg hydrogen per year. The estimated levelized cost of hydrogen (LCOH) for this system was 33.70 $/kg H_2, while the CO_2 emissions avoided were 87.75 ton/year [16].

Several studies of systems combining offshore wind power and hydrogen production were also published in 2022. Jang et al. [17] analyzed different scenarios for hydrogen production from offshore wind power, including both offshore (centralized and distributed) and onshore hydrogen production. The simulated system included a PEM electrolyzer and a 160 MW wind farm, and a 50% electrolyzer capacity factor was assumed. The results show that distributed offshore hydrogen production achieved the lowest cost when the cost of the wind farm was included, with a cost of 13.81 $/kg H_2. When the wind farm cost was excluded, the lowest cost achieved was the onshore hydrogen production scenario with a cost of 4.16 $/kg H_2. The offshore systems can become profitable with a hydrogen selling price of 14 $/kg H_2, while the onshore system would need a price of 16 $/kg H_2 to become profitable [17]. Luo et al. [18] reviewed possibilities for hydrogen production from offshore wind power in South China with the same scenarios used in Ref. [17]. It is concluded that distributed offshore hydrogen production using PEM electrolyzers is the most promising scenario. The total cost of a 400 MW wind farm with hydrogen production located 60 km offshore was estimated to be CNY2.7 billion, and a comparison analysis shows that it will be more advantageous to sell hydrogen and oxygen from a system of this type than to sell the electricity directly without subsidies [18]. Baldi et al. [19] analyzed hydrogen and ammonia-based pathways for storage, transportation and final use of excess electricity from an offshore wind farm. Wind speed data were used to estimate wind power production and real-world electricity price data were used to estimate electricity price. It was concluded that it is currently more convenient to sell the electricity from offshore wind farms directly to the grid. The results show that hydrogen can be a viable option with a hydrogen price of 0.08 £/kWh and a renewable energy grid penetration of 60%. With a hydrogen price of 0.10 £/kWh or higher it will be favorable to produce hydrogen with an installed wind power grid penetration above 40% [19]. Benalcazar and Komorowska [20] analyzed the prospects for green hydrogen production from PV power and onshore wind in 2022, 2030, and 2050. The results from their techno-economic analysis show that the LCOH in Poland would be in the range 6.37–13.47 €/kg H_2 in 2022, 2.33–4.30 €/kg H_2 in 2030, and 1.23–2.03 €/kg H_2 in 2050 [20]. Lamagna et al. [21] modelled the hydrogen production from a reversible solid oxide fuel cell (SOFC) coupled to an offshore wind farm. Wind speed data and the average electricity price in Sweden in 2021 were used as input to a model that included a reversible SOFC, a sea water desalination plant and an energy management system. It was estimated that the hydrogen system can be placed inside a wind turbine using less than 2% of the turbine tower volume. For a large-scale wind farm, it was estimated that this solution would use 9.82% of the produced wind energy to produce hydrogen at a LCOH of 1.95 $/kg H_2 and a levelized cost of storage (LCOS) of 401 $/MWh [21]. Nasser et al. [22] performed a techno-economic assessment of hydrogen production from PV and wind power at different locations. Climatic data for wind speed, temperature, and solar radiation for each location were used as input to a model of an alkaline electrolyzer that simulated hydrogen production. The system efficiency (including PV and wind turbine efficiencies) was calculated to be in the range 7.69–9.37%, and the LCOH was calculated to be in the range 4.54–7.48 $/kg H_2 for the different locations [22]. Corengia and Torres [23] presented an optimization framework to design hydrogen production processes using grid electricity with or without the addition of wind and/or solar power. Electricity price data and public power data were used as input to a hydrogen production system model where both commercially available and possible future electrolyzer technologies were included. When only commercially available technologies can be used it was concluded that alkaline electrolyzers are a better choice than PEM electrolyzers, since the flexibility of the latter does not fully compensate for the added cost. If any electrolyzer technology can be used (including those not yet commercially available), the optimal solution would be to use a solid oxide electrolyzer (SOEL), either alone or in combination with alkaline electrolyzers and/or batteries, due to the high efficiency of SOELs and their expected relatively low future costs [23]. Groenemans et al. [24] performed a techno-economic analysis of hydrogen production from offshore wind power using PEM electrolysis. Wind data and the power curve of a 14 MW wind turbine were used to estimate wind power production and two hydrogen production scenarios were analyzed: (1) Hydrogen is produced offshore and transported to shore through a gas pipeline and (2) Electricity from an offshore wind farm is transported to shore through a power cable and hydrogen is produced onshore. The results show that the LCOH will be lower with offshore hydrogen production and can be as low as 2.09 $/kg H_2, while the estimated LCOH for the onshore scenario is 3.86 $/kg H_2 [24].

The interest in the combination of offshore wind and hydrogen systems is increasing rapidly and several new studies have already been published in the first quarter of 2023. Dinh et al. [25] developed a geospatial method to estimate the LCOH for a system that produces hydrogen through offshore electrolysis with electricity from offshore wind farms. Distance to port, water depth, distance to hydrogen pipeline injection point and wind characteristics of different locations were used as model inputs. The results show that the LCOH in 2030 varied by more than 50% between the locations; hence, the choice of location for these systems will be crucial for the viability of the concept. A 510 MW system in the best location in 2030 could produce up to 50 000 tons of hydrogen per year with a LCOH below 4 €/kg H_2 [25]. Komorowska et al. [26] analyzed future offshore wind-to-hydrogen production for several locations using a Monte Carlo-based framework. The results show that LCOH values can be in the range 3.60–3.71 €/kg H_2 in 2030 and 2.05–2.15 €/kg H_2 in 2050, with electricity prices and electrolyzer utilization rates having the greatest impact on the LCOH. An analysis of onshore wind-to-hydrogen systems was also performed and the results show that these systems can achieve a lower LCOH in the range 2.72–3.59 €/kg H_2 in 2030 and 1.17–1.36 €/kg H_2 in 2050 [26]. Kim et al. [27] analyzed the feasibility of offshore wind turbines linked with hydrogen production via electrolysis for different combinations of location, offshore distance, hydrogen/electricity transport method, electrolyzer location and electrolyzer type. The results show that offshore hydrogen production and transportation through gas pipelines is generally the most economical option when the distance to shore exceeds 100–200 km, while electricity transport through cables and onshore electrolysis is more economical when the distance to shore is shorter than 15 km. For the distances in between, the choice will depend on the other variables, e.g., windspeed and electrolyzer type. The unit cost ranges were estimated to be 1.64–3.13 $/kg H_2 for alkaline electrolyzers, 2.27–4.17 $/kg H_2 for PEM electrolyzers, and 3.43–4.46 $/kg H_2 for SOELs [27]. Gea-Bermúdez et al. [28] performed optimization modeling of the Northern-central European energy system and the North Sea offshore grid towards 2050 to evaluate whether it will be most beneficial to produce hydrogen (via water electrolysis) onshore or offshore. The main conclusion was that offshore wind power has a higher socio-economic value when it is transported to shore through power cables than when it is used to produce hydrogen offshore. Here it was shown that hydrogen can play a significant role in the future energy system in Europe, and that it should in most cases be produced onshore so that the flexibility of hydrogen as an energy carrier/energy storage can be fully utilized. If hydrogen production is forced offshore it can lead to an increase in total energy system cost of 9–28 billion $€_{2016}$/year by 2045 and an increase in emissions of 77–255 million tons of CO_2 in the period from 2020 to 2050 [28]. Durakovic et al. [29] used the open-source model EMPIRE [30] to model the European power grid towards 2060, and specifically how investments in green hydrogen production in and around the North Sea will impact European grid infrastructure and electricity prices. The results indicate that North Sea hydrogen production hubs can reduce the curtailment of offshore wind power in the region from 24.9% to 9.6%. In this study it was found that the impact on electricity prices by large-scale hydrogen production can be very different from country to country. For example, the yearly average electricity price in Norway is estimated to increase significantly with hydrogen production, while the yearly average price in France and Germany is not expected to increase at all [29]. Kumar et al. [31] reviewed future opportunities related to synergies between large-scale hydrogen systems and various offshore industries. The study shows that small-scale offshore hydrogen production from excess renewable energy is economically unfeasible, while large-scale systems could be economically competitive if the conditions are favorable, i.e., low renewable electricity cost, high utilization factor for the electrolyzer and secure long-term hydrogen demand [31]. Li et al. [32] performed a techno-economic analysis of a simulated hybrid energy system that produces both electricity and hydrogen by using 120 MW of wind turbines, 80 MW of PV cells, 20 MW of batteries and 60 MW electrolyzer capacity. The results show that the renewable electricity production was 584.62 GW h per year, while the hydrogen production was 7432.71 ton/year with an electrolysis ratio of 22.31% and a LCOH of 13.1665 CNY/kg H_2 [32]. Giampieri et al. [33] performed a techno-economic analysis of hydrogen production from offshore wind power. Wind data and the power curve of a wind turbine were used as inputs to a model that calculated future hydrogen production capacity and cost for different scenarios. The results show that the most cost-effective scenario for 2025 would be offshore hydrogen production with pipeline transport, which could achieve a LCOH of 4.53 £/kg H_2 if the distance to shore is not more than 1000 km [33]. Nasser and Hassan [34] analyzed technical, economic, and environmental aspects of hydrogen production via electrolysis powered by PV cells, wind turbines, and waste heat. Weather data were combined with mathematical models to estimate electricity and hydrogen production. The results show large variations in LCOH between 1.19 and 12.16 \$/kg H_2. The lowest cost was achieved when hydrogen was produced from waste heat, followed by grid power, PV cells and wind turbines [34]. Cheng and Hughes [35] analyzed the potential role for offshore wind power in renewable hydrogen production in Australia in 2030. Wind data, solar irradiation data and the power curve of a wind turbine were used as input to a model that simulated hydrogen production via PEM electrolysis, which resulted in an estimated LCOH range of 4.4–5.5 AUD/kg H_2 in 2030. The Australian target of 2 AUD/kg H_2 target could be reached if electrolyzer costs are reduced by 80% and the renewable electricity cost is around 20 AUD/MWh [35].

System design and model-based approach

The system simulation model used in this paper was developed and implemented in MATLAB/Simulink [36]. An overview showing the main components of the hydrogen system modelled in this paper is shown in Fig. 1, while a schematic of the Simulink model is shown in Fig. 2.

The Simulink model was built to simulate an energy system where the electricity from an offshore wind turbine is used to produce hydrogen via water electrolysis. The wind power and wind speed data used as input to the Simulink model are from a 2.3 MW floating offshore wind turbine (FOWT) called *Zefyros* and owned by the Norwegian company UNITECH Offshore AS [37], while the electricity price data were downloaded from Nord Pool [38]. Further details regarding the data sets are provided in Input data. A detailed mathematical model of a proton exchange membrane (PEM) electrolyzer was developed as part of a master's thesis at the University of Oslo [39], in close collaboration with researchers at the Institute for Energy Technology (IFE) that have modeling and experimental experience with PEM water electrolyzer systems [40,41]. This model was then slightly modified for use in this study. In addition to the PEM electrolyzer model, the Simulink model in this study includes a simple control system that regulates the energy flows, a lithium-ion battery system (standard Simulink component), as well as calculations of efficiency, energy use and cost of the various system components. These calculations are based on the values listed in Table 1. More detailed descriptions of the different sections of the model are given in the subsequent sections and in the Supplementary Information.

Assumptions and boundaries for the model

The Simulink model used in this study includes a detailed mathematical model of a PEM electrolyzer, described in PEM electrolyzer. The rest of the model components (balance of plant and economics) are kept very simple to minimize the complexity and computational load of the model. Balance of plant (BoP) includes the lithium-ion battery (standard Simulink component), as well as simple estimations of energy usage and cost for compression and storage of hydrogen and desalination of sea water. However, other BoP components (e.g., power electronics) are not included in the model. The exception is the cost estimate for the PEM electrolyzer which does include BoP (see Table 1). This means that the hydrogen production would most likely be lower in a real-world system since there is energy loss associated with power electronics. This would also increase the hydrogen production cost and decrease the overall efficiency. Furthermore, ramp-up time and cold start-up time for the PEM electrolyzer are not included in the model. However, according to Ref. [43], warm start-up (ramp-up) time for state-of-the-art PEM electrolyzers is less than 10 s, so the exclusion of this feature in the model should not have a great effect on the results. However, the cold start-up time is 5–10 min [43], which could influence the total hydrogen production. This effect would probably be most noticeable for high-capacity electrolyzers since the switch-off limit for the electrolyzers increases with increasing electrolyzer capacity. This effect would also be more noticeable in periods with low and variable wind power input since this increases the number of times the electrolyzer is switched off. A possible remedy to this challenge would be to use power from the onshore grid to keep the electrolyzer in standby mode and thereby avoid any cold start-ups, but this is not considered in this study. Any energy usage to keep the electrolyzer in standby mode is not included in the model. PEM electrolyzer–Control system and the Supplementary Information gives more detailed descriptions of the components included in the model.

The values for energy usage, water usage, costs, efficiency, and lifetime used in the model are listed in Table 1. The electrolyzer CAPEX includes power electronics and balance of plant (BoP).

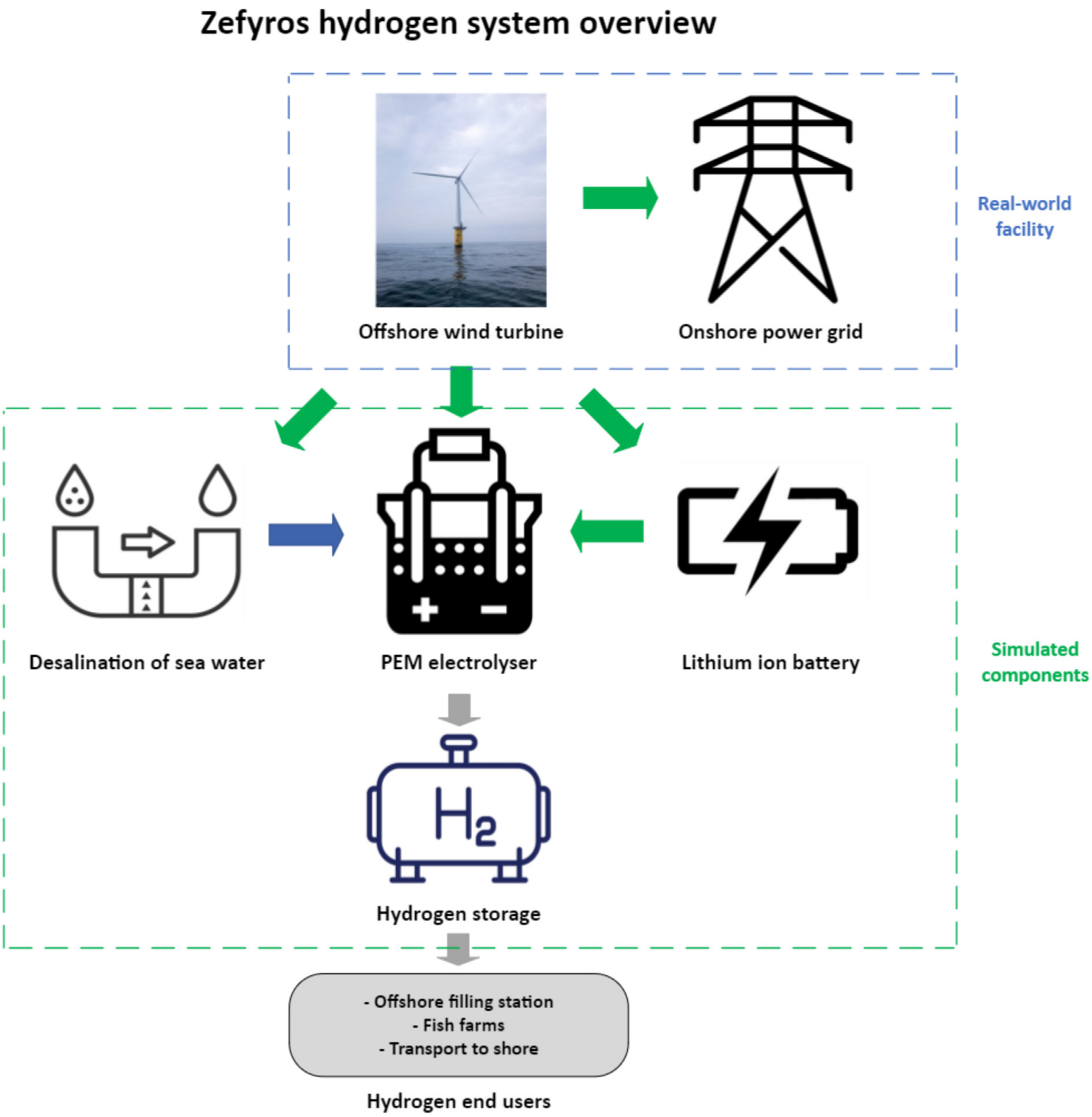

Fig. 1 – Overview of the Zefyros wind/hydrogen system. The real-world facility consists of the components inside the blue dashed box, while the components inside the green dashed box are simulated in MATLAB/Simulink. The green arrows indicate electricity flows, the blue arrow indicates water flow and the grey arrows indicate hydrogen flows. The hydrogen end users are suggestions and are outside the scope of this paper. The picture of the Zefyros wind turbine is courtesy of UNITECH Offshore AS [37] and all other icons are from Shutterstock [42]. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

PEM electrolyzer

A simplified structure of the proposed PEM electrolyzer model is shown in Fig. 3.

The PEM water electrolyzer model is divided into multiple modules, varying in complexity, where the top layer represents the initial conditions for the electrolyzer and the subsequent layers respond to the information generated by the previous modules. The thermal model, which influences all subsequent operating conditions, has a feedback loop. This is due to the stack temperature varying over time and its dependence on the previous and present model inputs. In the proposed model, the electrical response is assumed to be instantaneous, which will lead to behavior deviations from an actual PEM electrolyzer, especially during rapid changes in model inputs. The thermal model is described in more detail in the Supplementary Information available in the online version of this paper.

Product pressure

The pressure on the cathode and anode side of the membrane will be higher than the actual pressure measured in the

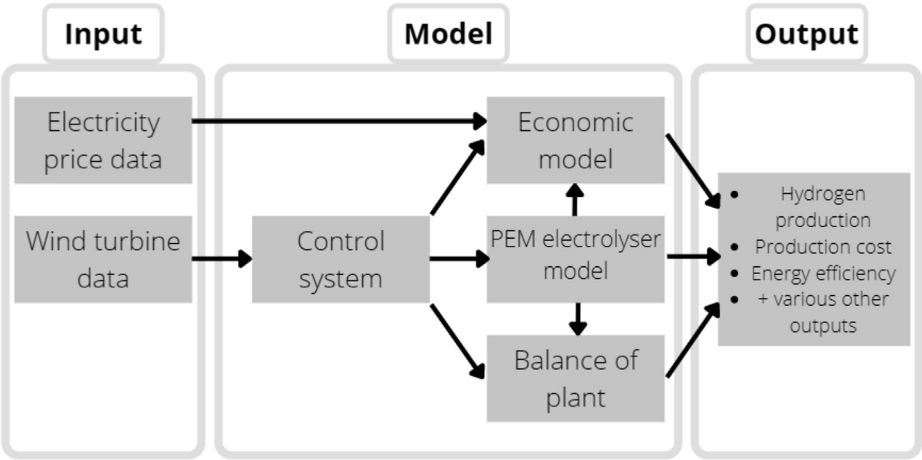

Fig. 2 – Schematic of the Simulink model used in all simulations.

Table 1 – Values used in modeling cases.

Parameter	Value
Desalination of sea water energy usage	4 kW h/m^3 [44]
Desalination of sea water cost	1.26 \$/m^3 [44]
Desalination water amount	283.2 L/h per MW of electrolyzer power [45]
Lithium-ion battery round-trip efficiency	95% [46]
Lithium-ion battery CAPEX	469 \$/kWh [47]
Lithium-ion battery OPEX	10 \$/kW per year [47]
Lifetime of lithium-ion battery	10 years [47]
Hydrogen compression and storage cost	1.73 \$/kg H_2 [48]
Hydrogen compression and storage energy usage	4 kW h/kg H_2 [48]
PEM electrolyzer (incl. BoP) CAPEX	1800 \$/kW [49]
PEM electrolyzer (incl. BoP) OPEX	5% of CAPEX per year [43]
Lifetime of PEM electrolyzer	100 000 h [43]
Cost of platform for electrolysis, desalination and compression	3 000 000 \$/MW of PEM electrolyzer power [44]
Lifetime of platform for electrolysis, desalination, and compression	40 years [44]

product flow channels due to supersaturation in the different layers. The pressures of the products (O_2 and H_2) are also proportional to the current density since it dictates the production rate. The oxygen pressure at the anode side is calculated as the sum of the anode pressure, which is set to 1 bar, and a partial pressure increase factor, minus the vapor pressure of water. This is described in equation (1) [50]:

$$P_{O_2} = P_{an} + \gamma_{O_2} \cdot i - P^{vp}_{H_2O} \quad [bar] \tag{1}$$

Where i is the current density, $P^{vp}_{H_2O}$ is the vapor pressure of water, and the empirical parameter γ_{O_2} is the partial pressure increase factor for an IrO_2 catalyst layer [50].

The hydrogen pressure at the cathode side is calculated as the sum of the cathode pressure, which is set to 30 bar, and the partial pressure increase factor for hydrogen, minus the vapor pressure of water [50]:

$$P_{H_2} = P_{cat} + \gamma_{H_2} \cdot i - P^{vp}_{H_2O} \quad [bar] \tag{2}$$

Cell voltage

The operating potential of the cell during different conditions must be known to calculate the efficiency of the electrolyzer. The cell voltage can be described as the sum of the open-circuit voltage U_{OCV} and three voltage overpotentials: $U_{activation}$, U_{ohmic} and $U_{concentration}$, as seen in equation (3) [51]:

$$U_{cell} = U_{OCV} + U_{act} + U_{ohm} + U_{con} \quad [V] \tag{3}$$

Open-circuit voltage. The Open-Circuit Voltage (OCV) is a measurement of the potential between the two electrodes in the cell. This is often expressed as the sum of the reversible cell voltage and an expression that relates the activity of the products to the reactants involved in the process. The activity of products and reactants is closely related to the concentration of the species and can be expressed through the species' relative pressure difference. The OCV for constant pressure conditions can be described through a modified Nernst equation [51]:

$$U_{OCV} = U_{rev} + \frac{R \cdot T}{2 \cdot F} \ln\left(\frac{P_{H_2}}{P_{cat}} \sqrt{\frac{P_{O_2}}{P_{an}}}\right) \quad [V] \tag{4}$$

Where U_{rev} is the reversible voltage [52,53], R is the ideal gas constant, T is the cell temperature in Kelvin, and F is the Faraday constant.

Activation overpotential. The activation overpotential represents the energetic barrier that needs to be surpassed in order to begin the electrochemical reaction. The total activation overpotential can be expressed as the sum of the anode and cathode activation overpotential, shown in equation (5) [52,54]:

$$U_{act} = U^{an}_{act} + U^{cat}_{act} \quad [V] \tag{5}$$

A catalyst reduces the activation barrier, and thereby decreases the potential that needs to be applied. The anode and cathode activation overpotential can be further described

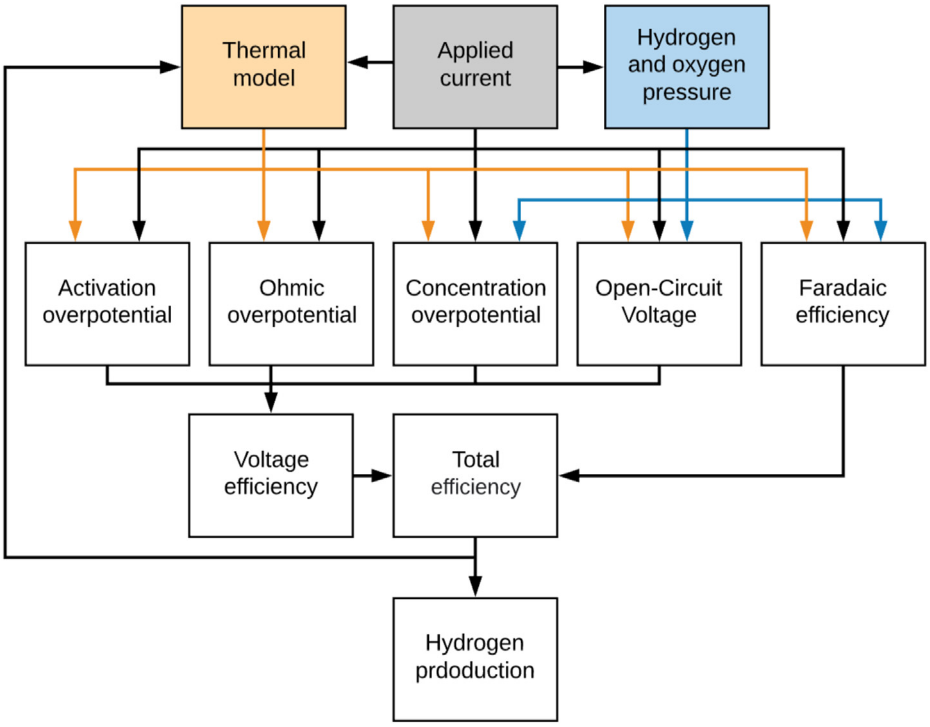

Fig. 3 – Schematics of the proposed PEM electrolyzer model [39].

using the Butler-Volmer equation, shown in equations (6) and (7) for the anode and cathode [51,52,54–56]:

$$U_{act}^{an} = \frac{R \cdot T}{\alpha_{an} \cdot F} \operatorname{arcsinh}\left(\frac{i}{2 \cdot i_{0,an}}\right) \quad [V] \tag{6}$$

$$U_{act}^{cat} = \frac{R \cdot T}{\alpha_{cat} \cdot F} \operatorname{arcsinh}\left(\frac{i}{2 \cdot i_{0,cat}}\right) \quad [V] \tag{7}$$

Where i is the current density, i_0 is the exchange current density and α is a dimensionless charge transfer coefficient. It is common to assume symmetrical behavior between the anode and cathode side, resulting in $\alpha_{an} = \alpha_{cat} = 0.5$ [52,54,55,57], and this assumption is used in this study. The exchange current density is calculated using an expression based on the Arrhenius equation [52,55–58].

Ohmic overpotential. The ohmic overpotential is simplified in the proposed model and contributes only to the ionic loss in the membrane, since the membrane is the dominant source of resistance in the cell. The ohmic overpotential caused by the membrane can be expressed through equation (8) [51,52]:

$$U_{ohm} = \frac{\delta_{mem}}{\sigma_{mem}} i \quad [V] \tag{8}$$

here δ_{mem} is the membrane thickness, i is the current density and σ_{mem} is the membrane conductivity, which can be calculated using an empirical expression for Nafion^{TM} membranes [52].

Concentration overpotential. The concentration or diffusion overpotential arises due to variations in reactant concentration at the electrode surface, both at the anode and cathode side. This occurs when the current density is high enough to impede the surface reaction by overpopulating the membrane with gas bubbles and thereby slowing down the reaction rate. The concentration overpotential is the sum of the contribution at both the anode and the cathode side [52]:

$$U_{con} = U_{con}^{an} + U_{con}^{cat} \quad [V] \tag{9}$$

In order to express the voltage loss due to a surplus of reaction products, the Nernst equation can be combined with Fick's law, which gives an equation valid for static cell pressure. This expression is given in equations (10) and (11) for the anode and cathode side respectively [50,52]:

$$U_{con}^{an} = \frac{R \cdot T}{4 \cdot F} \ln\left(\frac{P_{O_2}}{P_{an} - P_{H_2O}^{vp}}\right) \quad [V] \tag{10}$$

$$U_{con}^{cat} = \frac{R \cdot T}{2 \cdot F} \ln\left(\frac{P_{H_2}}{P_{cat} - P_{H_2O}^{vp}}\right) \quad [V] \tag{11}$$

Efficiency

The electrical efficiency of the electrolyzer can be expressed by multiplying the Faradaic efficiency and voltage efficiency, as shown in equation (12) [59]:

$$\eta_{tot} = \eta_F \cdot \eta_V \quad [\%] \tag{12}$$

The voltage efficiency η_V is defined by equation (13) [59]:

$$\eta_V = \frac{\textit{Thermal neutral voltage}}{\textit{Operating cell voltage}} = \frac{U_{th}}{U_{cell}} = \frac{1.481}{U_{cell}} \quad [\%] \tag{13}$$

The Faradaic efficiency, also referred to as the Coulomb efficiency or current efficiency, defines the efficiency of charge transfer in an electrolyzer. For a PEM electrolyzer this is effectively the efficiency of oxygen production at the anode side and the hydrogen formation at the cathode side. This can be expressed in terms of current density [60]:

$$\eta_F = 1 - \frac{i_x}{i} \quad [\%] \tag{14}$$

Where i_x is the total gas crossover current density [60], which is a sum of the hydrogen and oxygen crossover current densities.

Hydrogen production

The power consumed by the electrolyzer stack can be expressed through Ohm's law, shown in equation (15):

$$P_{in} = U_{cell} \cdot I \cdot N_{cell} \quad [W] \tag{15}$$

Where U_{cell} is the cell voltage, I is the current applied to the cell and N_{cell} is the number of cells in the electrolyzer stack. By knowing the power consumption and the electrolyzer efficiency it is possible to calculate the hydrogen production rate, shown in equation (16) [59,61]:

$$\dot{m}_{H_2} = \frac{P_{in} \cdot \eta_{tot}}{HHV_{H_2}} \quad \left[\frac{kg}{s}\right] \tag{16}$$

Where $\dot{m}_{H_2}$ is the hydrogen production rate and HHV_{H_2} is the higher heating value of hydrogen in J/kg.

Balance of plant

Lithium-ion battery

The lithium-ion battery used in some of the simulation cases is the standard version available in the MATLAB/Simulink software package [36]. Adjustments of the energy and power capacities were made between the different cases. The energy storage capacity for the batteries was set to five times the charging/discharging power (e.g., a charging/discharging power rating of 200 kW gives an energy storage capacity of 1000 kW h). The charging/discharging power and energy storage capacities for the different system designs are shown in Table 3. With the state of charge (SOC) range set to 20–80% the battery can supply energy to the electrolyzer for approximately 3 h at a constant discharge power from 80 to 20% SOC. This means that the battery can only cover power demands over relatively short periods when the wind turbine is not producing enough power for the electrolyzer. Longer periods of low wind power production will require the electrolyzer to shut down. An alternative strategy could be to use power from the onshore grid to keep the electrolyzer running at minimum power (10%), but this has not been considered in this study. The charging/discharging and SOC conditions for the battery are described in Control system.

Hydrogen compression and storage

The hydrogen compression and storage section of the model calculates the energy usage and cost of this part of the system, based on the values listed in Table 1.

Desalination of sea water

The desalination section of the model calculates the energy usage, required water amount and cost of this part of the system, based on the values listed in Table 1.

Cost estimations

The economic section of this model uses the various cost values listed in Table 1 to estimate the production cost of hydrogen for each case. Investment and operating costs (CAPEX and OPEX) are calculated for the key system components, including a PEM electrolyzer, a lithium-ion battery, electricity from the grid, sea water desalination plant, hydrogen compressor, hydrogen storage, and an offshore platform for the electrolyzer and the BoP components. The total CAPEX for a system component is adjusted according to its expected lifetime by using the following method: Total CAPEX is divided by the expected lifetime and multiplied by the length of the simulation period (*Example*: The PEM electrolyzer has an expected lifetime of 100 000 h, so the total CAPEX is divided by 100 000 and multiplied by 744, which is the number of hours in the 31-day simulation period). The cost

Table 2 – The five different time periods used in the simulations. The electricity price is converted from NOK to US $ using 8.74 NOK/$, which was the conversion factor at the time the simulations were performed (February 2022).

Time period	Tag	Wind turbine capacity factor [%]	Average electricity price [$/kWh]
07.03–06.04.2020	A	63.6	0.0091
20.12.2020–19.01.2021	B	21.3	0.0440
01.01–31.01.2022	C	55.1	0.1609
01.06–01.07.2020	D	30.9	0.0018
01.12–31.12.2020	E	41.7	0.0245

Table 3 – Overview of the different system designs used in the simulations.

System design	Electrolyzer power [kW]	Combined electrolyzer and compressor power [kW]	Li-ion battery energy/power [kWh/kW]	Grid-connected
High capacity with battery (HC + B)	1852	2000	1000/200	Yes
Medium capacity with battery (MC + B)	926	1000	500/100	Yes
Low capacity with battery (LC + B)	463	500	250/50	Yes
High capacity without battery (HC)	1852	2000	No battery	Yes
Medium capacity without battery (MC)	926	1000	No battery	Yes
Low capacity without battery (LC)	463	500	No battery	Yes

estimations used in the model do not include discount rate. This will be a subject of future work.

Input data

Measured data for wind power production and wind speed from a 2.3 MW FOWT are used in all models. Five different time periods are used, each lasting 31 days. The time periods are listed in Table 2 together with the simulation cases. All data sets have data points with 10-min intervals, except the data set from 2022 which uses 60-min intervals. The data points give the average value for the given time periods. The data sets from the FOWT are the property of the Norwegian company UNITECH Offshore AS [37] and are not publicly available currently.

Electricity price data from Nord Pool [38] for the five simulation periods are also used as input to the models. These data sets are used to calculate the electricity cost, which is part of the production cost of hydrogen for the system. Nord Pool uses data points with 60-min intervals, and this is used as the average electricity price for each hour in the models. The Nord Pool data is publicly available for download on their website [38].

Control system

Main principle

The control system is based on simple logical switches and relational operators that decide when the various components should receive energy from the wind turbine. These decisions are made based on the magnitude of the incoming wind power and the preset capacities of the various components. The electrolyzer operates when the wind power is $\geq$ 10% of the combined rated power of the electrolyzer and hydrogen compressor. If the wind power is < 10% then either a battery is used or the electrolyzer is switched off. This is to avoid excessive on/off-switching of the electrolyzer when the wind turbine fluctuates in the low power range around its cut-in wind speed. The hydrogen production in this lower power range would in any case be very small, and this power should therefore instead be exported to the electricity grid. Illustrations of the control systems for the simulation cases with and without battery is shown in Figs. 4 and 5, respectively.

Electrolyzer

The electrolyzer produces hydrogen if the power delivered from the wind turbine is more than or equal to 10% of the combined rated power of the electrolyzer and hydrogen compressor. *Example:* If the combined rated power of the electrolyzer and compressor is 2000 kW, the electrolyzer produces hydrogen if the power delivered from the wind turbine is 200 kW or higher.

If the power delivered from the wind turbine is less than 10% of the combined rated power of the electrolyzer and hydrogen compressor, there are several alternatives.

- If the system includes a battery and the battery state of charge (SOC) is higher than 20%, the battery delivers power to the electrolyzer and compressor equal to 10% of their rated power.
- If the system includes a battery and the battery state of charge (SOC) is *not* higher than 20%, the electrolyzer is switched off.
- If the system does *not* include a battery, the electrolyzer is switched off.

Battery

If the system includes a battery, the charging/discharging rules are as follows.

- The round-trip efficiency of the lithium-ion battery is assumed to be 95% [46] and this is applied to the charging of the battery with power from the wind turbine. The power to charge the battery is set to be constant and equal to 10% of the combined rated power of the electrolyzer and hydrogen compressor, divided by 0.95 to include the efficiency of the lithium-ion battery. *Example:* If the combined rated power of the electrolyzer and hydrogen compressor is 2000 kW, the battery will be charged with a power equal to 200/0.95 kW = 210.53 kW
- The SOC range of the lithium-ion battery is set to be 20–80%, i.e., charging is switched off when the SOC reaches 80% and discharging is switched off when the SOC gets down to 20%.
- If the power from the wind turbine is lower than 10% of the combined rated power of the electrolyzer and hydrogen compressor, *and* the battery SOC is higher than 20%, the battery discharges (supplies power to the electrolyzer and compressor) with a power equal to 10% of the combined rated power of the electrolyzer and hydrogen compressor until the SOC is at 20%.*Example:* If the combined rated power of the electrolyzer and compressor is 2000 kW, then the battery delivers a total of 200 kW to the electrolyzer (185.2 kW) and compressor (14.8 kW) if the wind power is below 200 kW *and* the battery SOC is higher than 20%.
- If the power from the wind turbine is higher than the sum of the charging power of the battery and 10% of the combined rated power of the electrolyzer and hydrogen compressor, *and* the battery SOC is lower than 80%, the battery will be charged by wind power equal to the rated charging power of the battery. *Example:* If the combined maximum power of the electrolyzer and compressor is 2000 kW, then the battery will be charged with the charging power of 210.53 kW when the following conditions are met: The wind power is higher than 410.53 kW (200 kW to the electrolyzer and compressor and 210.53 kW to the battery) *and* the battery SOC is lower than 80%.

Desalination of sea water

If the power from the wind turbine is lower than 10% of the combined rated power of the electrolyzer and hydrogen compressor, then some of the wind power will be used to desalinate sea water for later use in the electrolyzer. The power requirement for desalination is very low so it is never an issue to have enough power for this purpose. In the case with the highest hydrogen production (case 4), 2.14 kW is the maximum power and 1.40 kW is the mean power used by the desalination system.

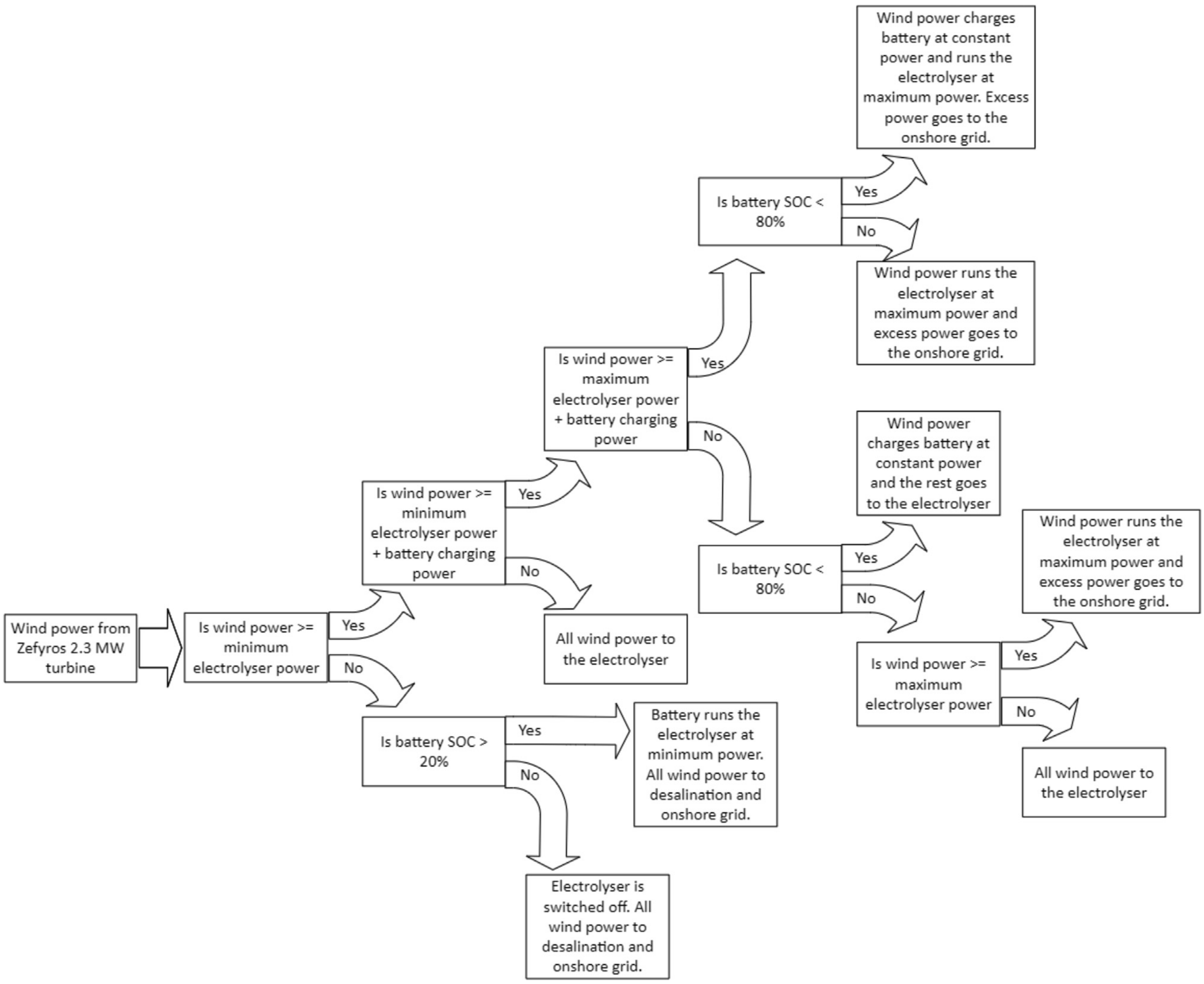

Fig. 4 – Overview of the control system for the simulation cases with a battery. The energy for compression and storage of hydrogen is deducted from the electrolyzer power when it is producing hydrogen, as explained in section *Control system*.

Compression and storage of hydrogen

The energy requirement of this part of the system is listed in Table 1, and the wind turbine delivers this power whenever the electrolyzer is producing hydrogen.

Onshore grid

There are two situations in which some of the wind power is delivered to the onshore grid.

- If the power from the wind turbine is higher than the combined rated power of the electrolyzer and hydrogen compressor, the excess wind power is delivered to the onshore grid, except in the cases that include a battery. In those cases, if the battery SOC is lower than 80%, the battery will be charged up to SOC 80% with some of the excess power. The rest is delivered to the onshore grid.
- If the power from the wind turbine is lower than 10% of the combined rated power of the electrolyzer and hydrogen compressor, the power from the wind turbine is delivered to the onshore grid after the power for the desalination of sea water has been subtracted.

Description of the simulation cases

In the case studies presented in this paper, real-world data from a 2.3 MW FOWT is used as input to a MATLAB/Simulink model to simulate hydrogen production from an offshore wind power system. The main outputs from the simulations are the hydrogen production capacity, production cost, and energy efficiency. The paper presents the results of 30 different simulations. These are divided into five different 31-day periods with six different system designs. The five time periods are listed in Table 2 and the system designs are listed in Table 3. Table 2 also gives the wind turbine capacity factor and the average electricity price for each period. The different time periods were chosen to compare time periods with different wind turbine capacity factors and electricity prices. These are by far the two most important factors for the

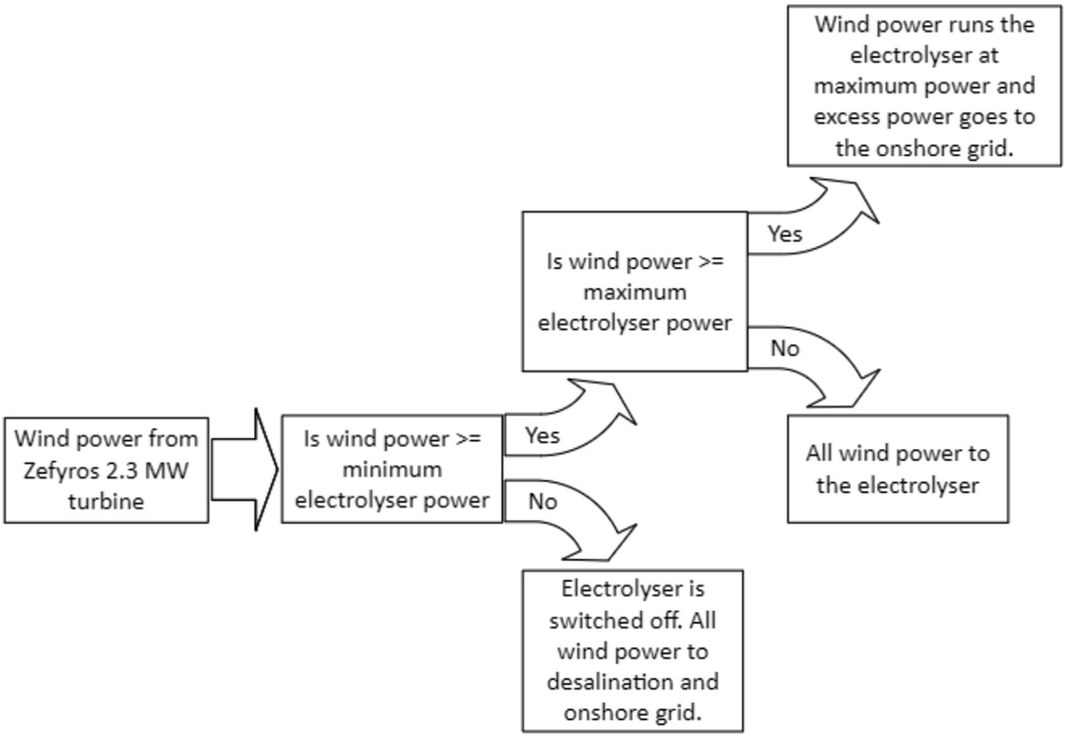

Fig. 5 – Overview of the control system for the simulation cases without a battery.

economic viability of a wind/hydrogen system, and the most favorable conditions are high wind turbine capacity factors and low electricity prices. A low electricity price is favorable because the opportunity cost of producing hydrogen versus selling the wind power as electricity increases with increasing electricity price (i.e., it is better to sell electricity than hydrogen when the electricity price is high).

From Table 2 it can be observed that time period A represents a nearly ideal period for hydrogen production since it has both a very high wind turbine capacity factor and a low electricity price. Period B represents a period with poor conditions for hydrogen production because of the very low wind turbine capacity factor. The electricity price in this period was relatively close to the long-term average price for the period 2016–2021, which was 0.0515 $/kWh (calculated using price data from Nord Pool [38]). Period C was chosen to include a period where both the wind turbine capacity factor and the electricity price is very high, while period D was chosen to include a period where both the capacity factor and electricity price were low. Period E was chosen to include a period where the wind turbine capacity factor was very close to the typical value for offshore wind turbines, and the electricity price was neither extremely high nor extremely low. Period E therefore represents the closest to what would be expected for an average month. However, it should be noted that the electricity price in Norway (where the turbine is located and connected to the grid) has fluctuated wildly in the past couple of years, from almost negative prices in the summer of 2020 to almost five times the long-term average price at the end of 2021 and beginning of 2022. Any electricity price predictions for the future are therefore exposed to extreme uncertainty.

Six different system designs were used in the simulations, and the specifications and abbreviations used are given in Table 3. The first three setups; high capacity with battery (HC + B), medium capacity with battery (MC + B), and low capacity with battery (LC + B) are cases where the electrolyzer and battery capacities are high, medium, and low compared to the maximum wind turbine capacity of 2.3 MW. The next three designs (HC, MC, and LC) are identical to the first three, except that they do not include a battery in the system.

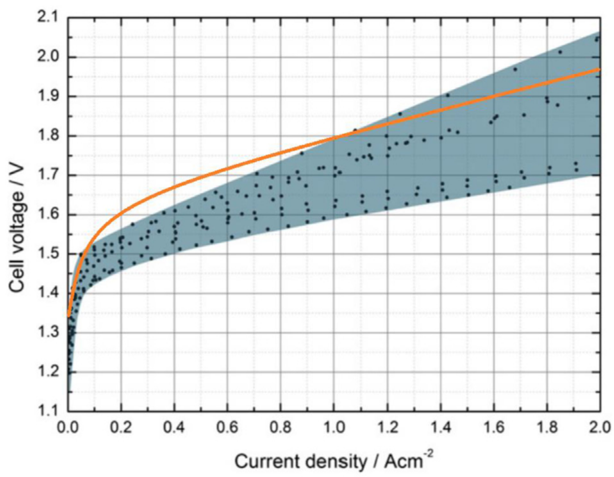

Fig. 6 – Single cell PEM electrolyzer voltage performance published in literature compared to the model in this study. The voltage performance of the model in this study (orange line) has been superimposed on the original figure from Carmo et al. [56]. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

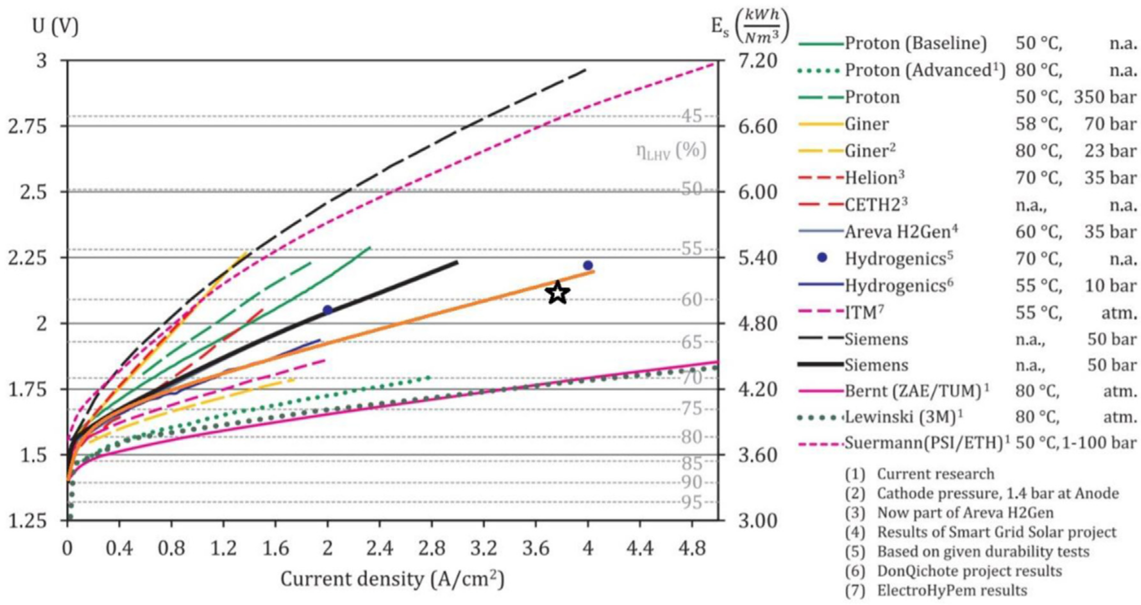

Fig. 7 – Reported commercial PEM electrolyzer voltage profiles compared to the voltage profile of the model in this study. The figure with previously published voltage profiles is taken from Ref. [43], and the voltage profile from this study is shown by the full orange line next to the black star. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

Results and discussion

Electrolyzer model validation

In order to validate the overpotential behavior of the model some comparison to published literature have been made. In Fig. 6 a range of published polarization curve results are given in the shaded area, and these are compared to the curve produced by the model in this study, which is shown by the orange curve.

The shaded area is a range of published polarization curves taken from Carmo et al. [56]. The results are gathered from published results between 2010 and 2012 for single PEM cells. The cells are reported to use an iridium-based catalyst for the anode and a platinum-based cathode catalyst. The cells utilize Nafion™ membranes and are operating at 80 °C. The operating pressure is not disclosed. As seen from the figure, the modeling result in this study (illustrated by the orange line) are slightly higher than previously published results for current densities between 0.1 and 1 A/cm^2, and at the upper end of the range for current densities above 1 A/cm^2.

Fig. 7 shows a range of reported commercial PEM electrolyzer voltage performances compared to the profile from this study (the same profile used in Fig. 6).

As shown in Fig. 7, the voltage profile of the model in this study (full orange line next to the black star) is positioned near the middle of the range of the reported PEM electrolyzer voltage profiles from Ref. [43]. It can be noted here that most of the profiles that have a higher overpotential than the one for the model used in this study are operating at lower temperatures and higher pressures. Most of the voltage profiles that have a substantially lower overpotential are advanced electrolyzers operating at atmospheric cathode pressure.

Summary of simulation results

Table 4 lists all 30 simulation cases (scenarios) for the five time periods and six system designs, as well as the total hydrogen production, total production cost per kg of hydrogen, and overall system efficiency of each case.

Hydrogen production capacity

The total hydrogen production for all cases (Table 4 and Fig. 8) is, as expected, strongly affected by both the electrolyzer capacity (power) and the wind power production for the given time period. The inclusion of a battery has a negligible effect on the total hydrogen production. This can be seen by comparing the production in the cases with equal electrolyzer power in the same time period, where one case includes a battery and one does not (for example cases 1 and 4).

The total hydrogen production increases with increasing electrolyzer capacity, but the specific hydrogen production (kg/kW of rated electrolyzer power) is higher when the rated electrolyzer power is low. This can be seen in all time periods when comparing the hydrogen production for the different system designs in Table 4. For example, the hydrogen production per kW of electrolyzer power for cases 1, 2 and 3 are 9.3, 11.0 and 12.0 kg H_2/kW, and the same pattern can be seen for the other cases. This shows that the utilization of the electrolyzer capacity is higher in the systems with smaller electrolyzers. The reason for this is that the electrolyzers shut down when the wind power is lower than 10% of the combined rated power of the electrolyzer and hydrogen compressor, and this shut-down limit will be higher for the electrolyzers with higher rated power. Therefore, when comparing two electrolyzers with different power capacities during the same time period (with equal wind power

Table 4 – Overview of the main results from all wind/hydrogen system simulations. Case 4 is studied in more detail in section *In-depth study of case 4*.

Case	Time period	System design	Total H_2 production [kg]	H_2 production cost [$/kg H_2]	Efficiency of H_2 production (LHV) [%]
1	A	HC + B	17 218	5.46	56.6%
2	A	MC + B	10 158	4.98	56.7%
3	A	LC + B	5570	4.74	56.7%
4	A	HC	17 242	5.18	56.8%
5	A	MC	10 145	4.74	56.9%
6	A	LC	5561	4.53	56.9%
7	B	HC + B	5612	14.49	56.2%
8	B	MC + B	3841	11.75	56.4%
9	B	LC + B	2503	10.02	56.8%
10	B	HC	5649	13.57	56.7%
11	B	MC	3852	11.10	56.8%
12	B	LC	2497	9.55	56.8%
13	C	HC + B	15 016	13.91	56.6%
14	C	MC + B	9036	13.43	56.7%
15	C	LC + B	5020	13.23	56.8%
16	C	HC	15 041	13.61	56.8%
17	C	MC	9033	13.18	56.9%
18	C	LC	5009	13.00	56.9%
19	D	HC + B	8283	8.54	56.1%
20	D	MC + B	5963	6.50	56.5%
21	D	LC + B	3836	5.46	56.6%
22	D	HC	8353	7.91	56.7%
23	D	MC	5974	6.08	56.8%
24	D	LC	3833	5.15	56.8%
25	E	HC + B	11 298	8.09	56.7%
26	E	MC + B	6677	7.32	56.7%
27	E	LC + B	3676	6.93	56.8%
28	E	HC	11 296	7.66	56.8%
29	E	MC	6675	6.96	56.9%
30	E	LC	3671	6.61	56.9%

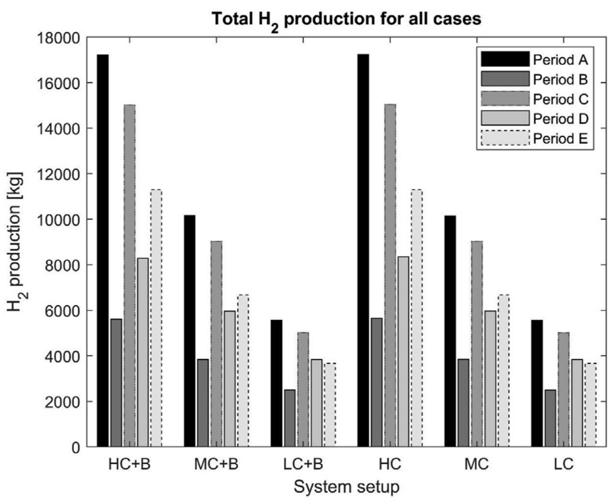

Fig. 8 – Overview of the total hydrogen production in all simulation cases. See Table 2 for information about the different time periods and Table 3 for explanation of the different system designs.

production), the electrolyzer with the highest rated power will have more downtime than the electrolyzer with the lowest rated power. Including a battery in the system has a negligible effect on this issue. However, if the objective is to maximize the total hydrogen production it is beneficial to have an electrolyzer with a rated power close to the rated power of the wind turbine. This is because the total hydrogen production will be much higher for the high capacity electrolyzers compared to the low or medium capacity electrolyzers, even though the high capacity electrolyzer has more downtime.

Hydrogen production cost

The production cost per kg of hydrogen for all cases is provided in Table 4 and illustrated in Fig. 9. It should be noted that the hydrogen production cost does not include the cost of the wind turbine, since the *Zefyros* wind turbine used in these simulation cases is a real turbine already in operation. The hydrogen production cost is therefore only the estimated cost of adding the hydrogen system to the existing turbine.

The hydrogen production cost is strongly affected by the wind turbine capacity factor and the price of electricity. The cases in the time period with the worst conditions (period B) yields hydrogen production costs 2–3 times as high as the period with the most favorable conditions (period A). As expected, this indicates that the profitability of this type of wind/hydrogen system would vary greatly from month to month. The use of a battery does not seem to reduce the production cost per kg hydrogen. In fact, the cases without batteries have consistently lower hydrogen production costs, i.e., adding batteries adds cost to the system without increasing the hydrogen production.

It should also be noted that a battery adds complexity to the system and should therefore not be included unless the

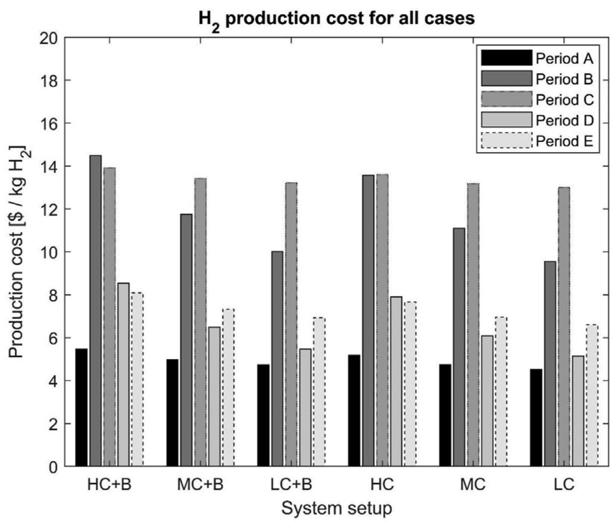

Fig. 9 – Overview of the hydrogen production cost in all simulation cases. See Table 2 for information about the different time periods and Table 3 for explanation of the different system setups.

results are significantly better with a battery than without. However, it should also be noted that the effect of including a battery might be different in a real-world system where the efficiency of the electrolyzer could be more affected by the fluctuating wind power than it is in this mathematical model. In the simulations in this study the efficiency of the PEM electrolyzer is never below approximately 70%, which might not be achievable in real-world systems with existing technology. Another possibility might be to use power from the onshore grid instead of a battery to smooth out the fluctuations in input power to the electrolyzer. These aspects are something that should be tested in future experimental work and are outside the scope of this study.

Other studies [62–65] summarized in Ref. [66] have estimated that the production cost of so-called “green hydrogen”, i.e., hydrogen produced by electrolysis using electricity from renewable sources, with existing state-of-the-art technology is in the range 2.50–6.80 \$/kg H_2 [66]. The cost when using wind power (only onshore) is in the range 4.22–5.76 \$/kg H_2 [66]. When comparing the production cost of the simulation cases in this study with the sources above, all cases in period A fit very well within the estimated range for hydrogen production from wind power. The other periods suffer from a low wind turbine capacity factor and/or high electricity price and most of the cases are therefore well above the estimated upper value of 6.80 \$/kg H_2 from Refs. [62,63]. All cases in period B (very low wind turbine capacity factor) and period C (very high electricity price) have production costs that are much higher than this upper value. Period D and E present more mixed results where some cases are within the estimated range and some cases are above.

Energy efficiency

The overall energy efficiency of the hydrogen production process is calculated by dividing the energy content of the produced hydrogen (using the lower heating value of hydrogen of 33.3139 kW h/kg H_2 [67]) by the wind energy input to the hydrogen system:

$$\eta = \frac{E_{H_2}}{E_{in}} \cdot 100\% = \frac{E_{H_2}}{E_{Zefyros} - E_{grid}} \cdot 100\% \tag{17}$$

The overall efficiency varies very little between the cases. The average efficiency is 56.6% and all cases have an efficiency that is in the range 56.1–56.9%, as shown in Table 4. Both the time period and the system design have very little effect on the overall efficiency. The reason for the small variation in efficiency is that the efficiency of all BoP components (battery, hydrogen compression and storage, desalination of sea water) is assumed to be constant (based on values listed in Table 1) and the dynamic efficiency of the PEM electrolyzer varies very little between the cases. The electrolyzer efficiency is described more closely in In-depth study of case 4. The overall efficiency is slightly reduced when a battery is included in the system. This is because the energy loss is assumed to be 5% [46] when the wind power goes through the battery before it is used to produce hydrogen, and since the total hydrogen production is almost unchanged this reduces the overall efficiency. The efficiency in a real-world system would fluctuate more and would most likely be lower than the estimates in this study due to the simplifications described above. The magnitude of the fluctuations and the difference in overall efficiency will be a subject of future work.

In-depth study of case 4

Simulation case 4 is a scenario where the wind turbine has a high capacity factor (63.6%) and the average electricity price is low (0.0091 \$/kWh), and the wind/hydrogen-system is designed with the largest possible electrolyzer. The system does not include a battery. The results show that this was the case with the highest total hydrogen production (17 242 kg) and the hydrogen production cost of 5.18 \$/kg H_2 is well within the estimated range of 2.50–6.80 \$/kg H_2 [62–66] for green hydrogen. Hence, this is the most favorable case when assuming the main objective is to maximize hydrogen production at the lowest possible cost. As shown in Table 4 and Fig. 9, cases 5 and 6 have slightly lower production costs than case 4 due to less electrolyzer downtime (as explained in Summary of simulation results), so if the demand for hydrogen from the system is low it would be more economical to use a smaller hydrogen system.

The efficiency and input power of the electrolyzer during the first three days of operation in case 4 is shown in more detail in Fig. 10. The modeling results confirm that the PEM electrolyzer system can follow the variable wind power with a relatively high efficiency. The electrolyzer efficiency is in the range 72–88% and it is inversely correlated to the input power (higher input power gives relatively lower efficiency and vice versa). The average efficiency for a 31-day period is approximately 75%.

The explanation for why the efficiency changes inversely with the input power is found in the efficiency equation (equation (12)), which consists of the Faraday efficiency (equation (14)) and voltage efficiency (equation (13)). As seen in equation (14), the Faraday efficiency increases when the current i increases. Since power is directly correlated to current

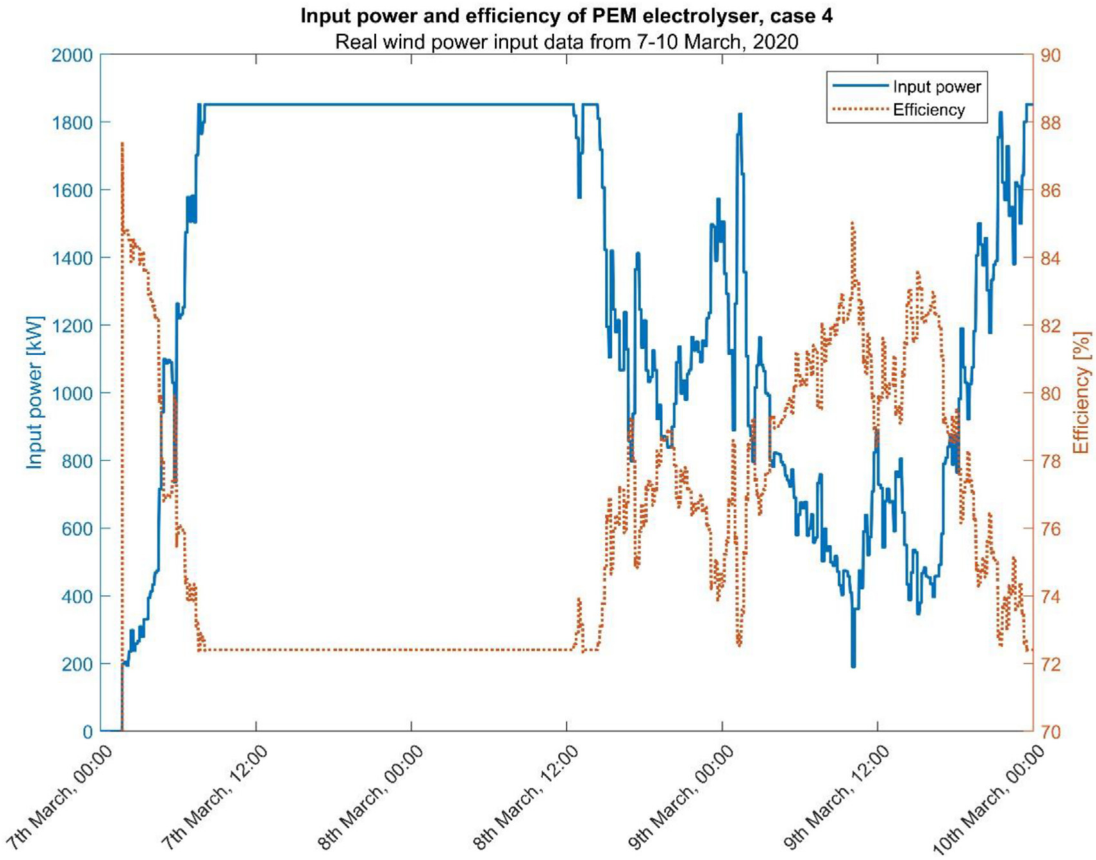

Fig. 10 – Efficiency and input power for the PEM electrolyzer in simulation case 4 during the 3-day period from 7th-10th March 2020. The electrolyzer operation is simulated using real wind power data from the given period as input.

(Power = voltage × current) the Faraday efficiency increases when the input power increases, and it stays in the range 92–99% (92% when the input power is at its minimum and 99% when the input power is at its maximum). However, as seen in equation (13) the voltage efficiency decreases when the input power increases, since the cell voltage is also directly correlated to power (Power = voltage × current). The range of the voltage efficiency is 72–95% (95% when the input power is at its minimum and 72% when the input power is at its maximum), which is a much wider range than the range of the Faraday efficiency. Therefore, the voltage efficiency has a larger effect on the total efficiency than the Faraday efficiency does. The total electrolyzer efficiency will therefore be at the lowest value when the input power is at its maximum, and at the highest value when the input power is at its minimum, as seen in Fig. 10.

Since the electrolyzer can follow the variations in wind power it is not beneficial to include a battery in the system. Most of the scenarios with batteries have higher production cost and slightly lower efficiency without increasing the hydrogen production, as shown in Table 4. However, again it should be noted that the advantage of including a battery in the system could prove to be higher in a real-world system where the wind power input to the electrolyzer will not be constant in each 10-min period, as it is in the simulations. This will be a subject for future experimental work.

Fig. 11 shows how the wind power is used during the same 3-day period of case 4. The electrolyzer uses most of the wind power. The compression and storage of hydrogen uses 7.4% of the total energy to the electrolyzer and storage system. For example, when the electrolyzer and storage system receives a total of 2000 kW of wind power, the electrolyzer uses 1852 kW and the storage system uses 148 kW. This can be seen in Fig. 11 in the period where the wind turbine is at maximum power (2300 kW). The onshore grid receives the excess wind power when the turbine produces more than 2000 kW. The grid also receives all the wind power when the wind turbine produces less than 200 kW (since the electrolyzer is set to shut down when the input power is less than 10% of the rated input power). This can be seen in the first minutes of Fig. 11. The energy for desalination of sea water is included in all simulations, but it is not shown in the figure since it is negligibly small compared to all the other energy usages. It is equal to approximately 0.1% of the energy used by the electrolyzer.

Fig. 12 shows the distribution of the wind energy in the 31-day period in case 4. In this case, 86% of the wind energy is used by the PEM electrolyzer, 7% is used to compress and store the hydrogen gas, and 7% goes to the onshore electricity grid. The desalination of sea water uses less than 1% of the total wind energy.

Fig. 13 shows the percentages of the total time in the 31-day period that the electrolyzer operated in each power interval. The intervals are defined in the following way: 1) **high power** if the input power to the electrolyzer is in the range 80–100% of its rated power, 2) **medium power** in the range 40–80% of rated

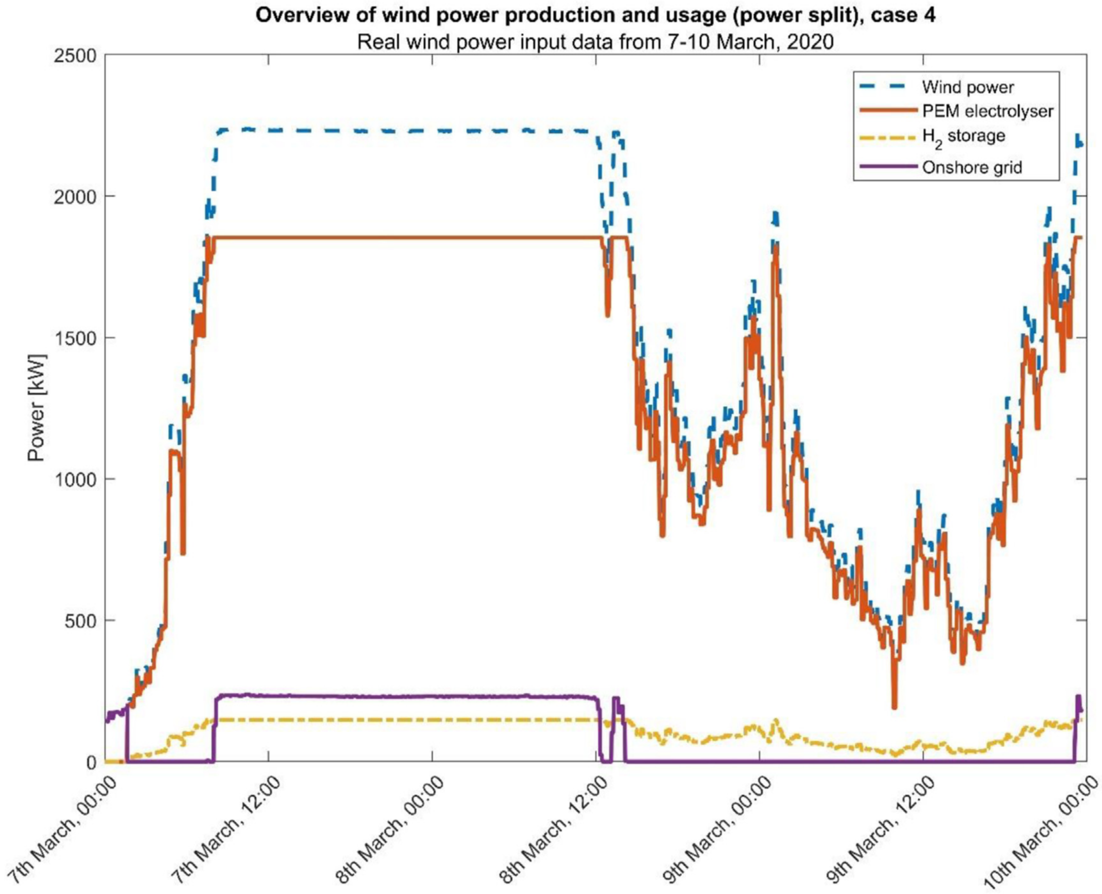

Fig. 11 – Overview of the wind power production and how it is used in simulation case 4 during a 3-day period from 7th-10th March 2020. The wind power production is real data input from the same period.

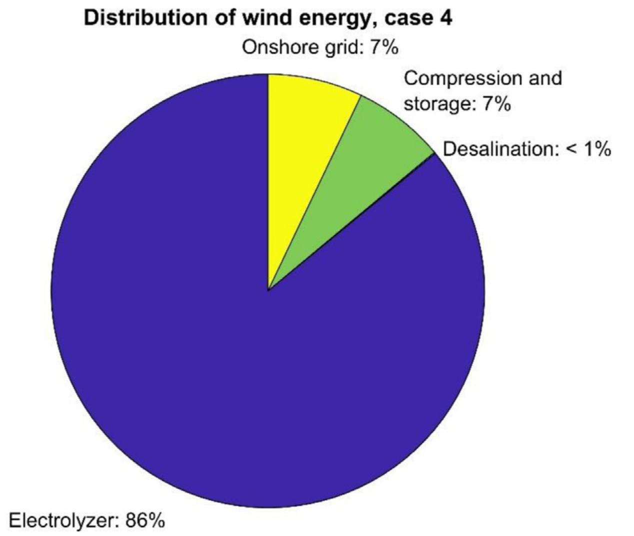

Fig. 12 – Distribution of wind energy in the period 7th March to April 6, 2020 for case 4.

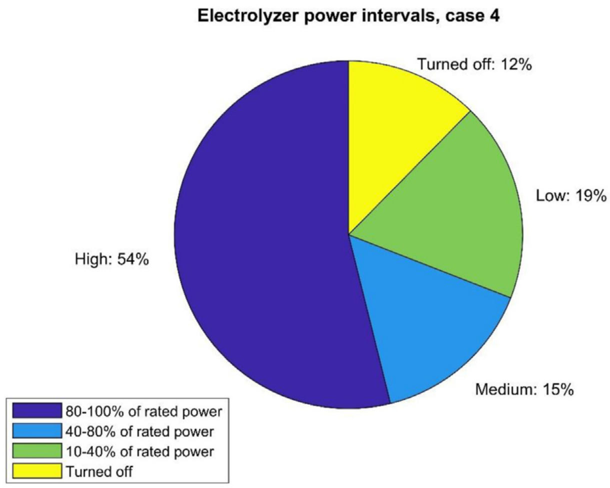

Fig. 13 – Percentage of total time in each power interval for the electrolyzer in case 4.

power, 3) **low power** in the range 10–40% of rated power. If the input power to the electrolyzer is below 10% of its rated power it will be turned off, as explained in Control system. During the 31-day period in case 4 the electrolyzer was switched off 43 times. Many of these were clustered quite closely together in periods were the wind power had large and rapid fluctuations. In case 1, which is identical to case 4 except that a lithium-ion battery is included in the system, the electrolyzer was only switched off 14 times in the same time period. This means that a 67% reduction in the number of shutdowns is achieved by

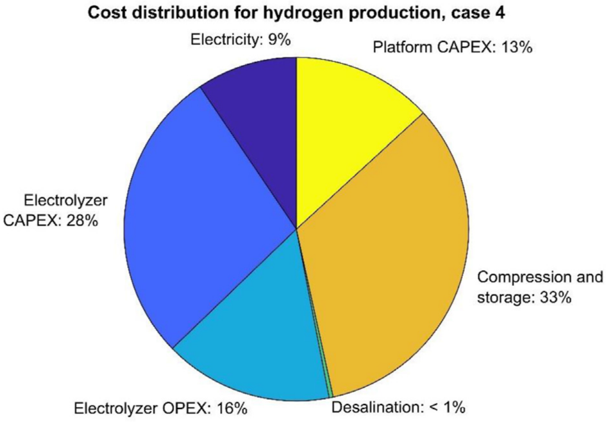

Fig. 14 – Cost distribution in percent for case 4.

including a battery. However, the reduced number of shutdowns did not impact the total hydrogen production or efficiency, as shown in Table 4. This should be tested in future experimental work, since the effect on hydrogen production and overall system efficiency by including a battery could prove to be greater in a real-world system.

Fig. 14 shows the cost distribution percentages in case 4. The electrolyzer costs are the highest with CAPEX (28%) and OPEX (16%) combined making up 44% of the total cost for this period. The cost of compressing and storing the hydrogen gas is also a big part of the total cost with 33%. The platform cost is 13% and the electricity cost is relatively low for this period at only 9% of the total cost. The cost of desalinating sea water is less than 1% of the total cost. The most important thing to note here is related to the electricity cost. The price of electricity in Norway during the 31-day period (7th March to April 6, 2020) used in case 4 was very low (see Table 2) and this cost was therefore a small part of the total cost. However, the electricity price has large fluctuations over time and has increased a lot since then. This is demonstrated very well by looking at case 16 which has an identical system design, but in this period (January 2022) the electricity price was almost 18 times higher (Table 2). This caused the electricity cost to be 62% of the total cost in case 16. The total cost for case 16 was 2.6 times higher than case 4, even though case 16 had a wind turbine capacity factor that was only slightly lower than it was in case 4. This indicates that the price of electricity could be the most important factor for the economic viability of these systems in the future.

Conclusions and future work

This study uses real-world energy production data measured on a 2.3 MW FOWT and Nord Pool electricity price data for the wind turbine's location as input to a detailed MATLAB/Simulink model that simulates offshore hydrogen production via a PEM water electrolyzer. Five different 31-day time periods are used in combination with six different wind/hydrogen-system designs, resulting in 30 unique system simulation cases. The three focus areas in this study are: (1) the total hydrogen production, (2) overall efficiency of the hydrogen production process, and (3) the hydrogen production cost.

The simulation results show how the total hydrogen production and production cost depend on both the wind turbine capacity factor and the price of electricity. The ideal conditions for an offshore hydrogen production system of this type are a high wind turbine capacity factor combined with a low electricity price. The difference between a “good” and a “bad” month can be as high as a factor of three for both the total hydrogen production and hydrogen production cost. As expected, this implies that the profitability of a system of this type will vary greatly from month to month.

The lowest hydrogen production costs are, as expected, achieved in the time period with the most favorable conditions, and are in the range 4.53–5.46 \$/kg H_2. The highest total hydrogen production achieved during a 31-day period was 17 242 kg using a 1852 kW electrolyzer (i.e., an electrolyzer utilization factor of ca. 68%). The overall efficiency of the process was very similar for all the different simulation cases due to the load-following capabilities in the modeling of the PEM water electrolyzer system. The overall efficiency was in the range 56.1–56.9% (LHV) for all the cases.

The results also indicate that it is not favorable to include a battery in the system since this increases the hydrogen production cost without increasing the total hydrogen production. However, this will need to be verified in a real-world system that is not subject to the limitations and simplifications used in these simulations. There are several areas of future work that should be performed to expand and validate the results of this study, including.

- Develop a more detailed economical model that includes the time value of money (discount rate).
- Expand the MATLAB/Simulink model to include:
  - -Power electronics
  - -Ramp-up and start-up times and rates for the electrolyzer (i.e., typical changes in power input to the electrolyzer from one time step to the next. For example, 10% change in power x % of the time, 20% change in power y % of the time, etc.)
  - -Energy usage by the electrolyzer when it is in standby mode
  - -Dynamic models of the hydrogen storage system (e.g., hydrogen compressor) and desalination system instead of using constants from literature
- Build and test a real-world pilot system to validate the simulation results.

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.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2023.03.471.

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Paper III

Techno-economic analysis of the effect of a novel price-based control system on the hydrogen production for an offshore 1.5 GW wind-hydrogen system

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Research paper

Techno-economic analysis of the effect of a novel price-based control system on the hydrogen production for an offshore 1.5 GW wind-hydrogen system

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ABSTRACT

The cost of green hydrogen production is very dependent on the price of electricity. A control system that can schedule hydrogen production based on forecast wind speed and electricity price should therefore be advantageous for large-scale wind-hydrogen systems. This work presents a novel price-based control system integrated in a techno-economic analysis of hydrogen production from offshore wind. A polynomial regression model that predicts wind power production from wind speed input was developed and tested with real-world datasets from a 2.3 MW floating offshore wind turbine. This was combined with a mathematical model of a PEM electrolyzer and used to simulate hydrogen production. A novel price-based control system was developed to decide when the system should produce hydrogen and when it should sell electricity to the grid. The model and control system can be used in real-world wind-hydrogen systems and require only the forecast wind speed, electricity price and selling price of hydrogen as inputs. 11 test scenarios based on 10 years of real-world wind speed and electricity price data are proposed and used to evaluate the effect the price-based control system has on the levelized cost of hydrogen (LCOH). Both current and future (2050) costs and technologies are used, and the results show that the novel control system lowered the LCOH in all scenarios by 10–46%. The lowest LCOH achieved with current technology and costs was 6.04 \$/kg H_2. Using the most optimistic forecasts for technology improvements and cost reductions in 2050, the model estimated a LCOH of 0.96 \$/kg H_2 for a grid-connected offshore wind farm and onshore hydrogen production, 0.82 \$/kg H_2 using grid electricity (onshore) and 4.96 \$/kg H_2 with an off-grid offshore wind-hydrogen system. When the electricity price from the period 2013–2022 was used on the 2050 scenarios, the resulting LCOH was approximately twice as high.

1. Introduction

1.1. Background

Green hydrogen, i.e., hydrogen produced by water electrolysis with electricity from renewable energy technologies (e.g., wind power), is increasingly being mentioned as an important part of the on-going transition towards a more sustainable global energy system. Hydrogen is currently mainly produced from fossil fuel, with annual emissions of approximately 830 million tons of CO_2 (The Future of Hydrogen, 2019). This accounted for approximately 2.3% of the global energy-related CO_2 emissions of 36.8 billion tons in 2022 (Chen et al., 2022). Green hydrogen could abate these emissions, in addition to replacing fossil fuel usage within transport, heating and various industrial processes. Recent reports predict that the production and usage of green hydrogen will need to grow significantly from the current global production of 95 Mt/year (Global Hydrogen Review, 2023) to reach the ambitious target of net-zero emissions by 2050. The prediction is that global hydrogen production will grow by 350–760% by 2050, with green hydrogen production going from the current negligible production of below 0.1 Mt/year (Global Hydrogen Review, 2023) to several hundreds of Mt/year. The International Energy Agency (IEA) estimates that yearly hydrogen production in a net-zero scenario will have to reach 430 Mt/year by 2050 and that 75% of this will be green hydrogen (Net Zero Roadmap: A Global Pathway to Keep the 1.5 °C Goal in Reach, 2023), the International Renewable Energy Agency (IRENA) estimates 523 Mt/year with 94% being green hydrogen (World Energy Transitions

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Nomenclature

Abbreviations

BoP	Balance of Plant
CAPEX	Capital Expenditure (Investment cost)
DNV	Det Norske Veritas
FOWT	Floating Offshore Wind Turbine
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LCOE	Levelized Cost Of Energy
LCOH	Levelized Cost Of Hydrogen
LHV	Lower Heating Value
Li-ion	Lithium ion
MAE	Mean Absolute Error
MAPE	Mean Absolute Percentage Error
MedAE	Median Absolute Error
NPV	Net Present Value
NVE	Norges Vassdrags- og Energidirektorat
OPEX	Operating Expenses
PEM	Proton Exchange Membrane
PV	Photovoltaic
RMSE	Root Mean Squared Error
RoC	Range of Change
SOEL	Solid Oxide Electrolyzer

Chemical elements

C	Carbon
H	Hydrogen
Li	Lithium
O	Oxygen

Non-SI units and conversion to SI

h (hour), unit of time 1 hour = 3 600 s
kWh (kilowatt-hour), unit of energy 1 kWh = 3 600 000 J
liter, unit of volume 1 liter = 0.001 m^3

Multiples used with SI units

Kilo (k) 10^3
Mega (M) 10^6
Giga (G) 10^9

Currencies

€	Euro, currency in the European Union
$	US dollar, currency in the United States of America
£	British pound, currency in the United Kingdom
CNY	Chinese yuan, currency in China
NOK	Norwegian krone, currency in Norway
AUD	Australian dollar, currency in Australia

Outlook, 2023), the Hydrogen Council estimates 660 Mt/year with 60–80% being green hydrogen (Hydrogen for Net Zero, 2021), while DNV estimates 820 Mt/year with a green hydrogen share of 85% (Pathway to net-zero emissions, 2023).

One of the methods that could potentially be used for green hydrogen production is the combination of offshore wind turbines and water electrolysis. An increasing number of scientific studies have been published on the subject (see literature review in Section 1.2) and industrial full-scale projects are being planned by TechnipFMC (Deep PurpleTM Pilot - TechnipFMC plc, 2022), Siemens (Green hydrogen, 2022), Neptune Energy (PosHYdon pilot, Dutch North Sea and Neptune Energy, 2022) and ERM (Dolphyn, 2022). However, both offshore wind farms and green hydrogen systems have high costs compared to many other energy technologies. Control systems that integrate the various components of wind-hydrogen systems and optimize the overall performance, both in technical and economic terms, will therefore be crucial to enable the implementation of these systems on a large scale.

1.2. Literature review

Wind-hydrogen systems have been the topic in many scientific papers in recent years as the interest in hydrogen has increased rapidly. In the following, the main literature related to the topic of this work is presented and will later serve to compare with our findings. Serna et al. (2017) developed an energy management system (EMS) based on model predictive control for an energy system where green hydrogen was produced from offshore wind and wave energy. The results were validated using real data and the EMS was shown to reduce the switching between the connection/disconnection states for the electrolyzer, which increases the continuity of hydrogen production and the lifetime of the electrolyzer (Serna et al., 2017). Schnuelle et al. (2020) modelled hydrogen production from both onshore and offshore wind power and photovoltaic (PV) power. The offshore wind case resulted in lower efficiency and higher production cost than both the onshore wind case and the PV case (Schnuelle et al., 2020). Crivellari and Cozzani (2020) performed a techno-economic analysis of various methods for wind power conversion from remote fields, including green hydrogen production, and found that high electrolyzer capacity and limited offshore distance were most advantageous from an economic viewpoint (Crivellari and Cozzani, 2020). McDonagh et al. (2020) simulated hydrogen production using electricity from a 504 MW offshore wind farm and found that it was more profitable to sell the electricity to the grid instead of producing hydrogen (McDonagh et al., 2020). Mirzaei et al. (2020) developed a flexible bidding strategy for a micro-grid that included wind turbines and hydrogen energy storage and found that the profit of the micro-grid could increase by 2.4% when hydrogen energy storage was included in the system (Mirzaei et al., 2020). Dinh et al. (2021) assessed the viability of dedicated hydrogen production from offshore wind farms and found that a wind-hydrogen farm can be profitable in 2030 with a hydrogen price of 5 €/kg H_2 (Dinh et al., 2021). Calado and Castro (2021) evaluated both onshore and offshore hydrogen production from offshore wind power. Lower capital cost for gas pipelines vs. subsea power cables is an advantage for offshore hydrogen production, but onshore production provides more economic flexibility since the electricity can also be sold to the grid (Calado and Castro, 2021). Song et al. (2021) modelled large-scale hydrogen production from offshore wind in China and delivery to Japan, and concluded that it will be possible for such a scenario to meet Japan's future hydrogen cost targets (Song et al., 2021). Ibrahim et al. (2022) analyzed various typologies, both onshore and offshore, for hydrogen production from offshore wind power. It was concluded that onshore systems will benefit from lower complexity, but offshore production with hydrogen transport through pipelines can become viable for large and distant offshore wind farms (Ibrahim et al., 2022). Scolaro and Kittner (2022) analyzed offshore wind-hydrogen systems and found that a carbon abatement cost of 187–265 €/ton CO_2 will be required to make such a system profitable (Scolaro and Kittner, 2022). Shams et al. (2021) used various machine learning methods to utilize curtailed renewable energy (solar and wind) to produce hydrogen. The gated recurrent unit method was the most efficient and this method was able to utilize 97% of the curtailed renewable energy for hydrogen production (Shams et al., 2021). Wei et al. (2021) developed a novel dispatching strategy to optimize wind-hydrogen systems integration with the electricity grid. The results from electricity grid simulations show that the strategy reduced the operational costs of the grid by 4.4% (Wei et al., 2021). Luo et al. (2022) analyzed different scenarios for hydrogen production from offshore wind in China and concluded that the most promising scenario is distributed offshore hydrogen production with PEM electrolyzers (Luo et al., 2022). Baldi et al. (2022) analyzed hydrogen production with excess electricity from offshore wind farms and concluded that it is currently more profitable to sell the electricity directly to the grid. If the penetration of wind power in the grid exceeds 40% it could be profitable to produce hydrogen with a hydrogen price of 0.10 £/kWh or higher (Baldi et al., 2022). Jiang et al. (2022) analyzed the optimal sizing of offshore wind-hydrogen systems with information gap decision theory and chance constraints programming. The results show that the optimal capacity of the PEM electrolyzer was 336.1 MW when the wind farm capacity was 405.12 MW (Jiang et al., 2022). Javaid et al. (2022) used various machine learning techniques to estimate hydrogen production from wind power in an urban location. The results show that the long short-term memory method was the most accurate (lowest error) and this method estimated an average hydrogen production of 6.76 kg/day for a 1.5 MW wind turbine (Javaid et al., 2022). Cai et al. (2022) used a novel stochastic programming approach to optimize the operation of a power system with wind turbines and a hydrogen storage system. The approach reduced the maximum relative risk by 45% while the operating cost increased by 1.29% (Cai et al., 2022). Gea-Bermúdez et al. (2023) modelled the future electricity grid with hydrogen production from offshore wind farms in Northern-central Europe and concluded that hydrogen should be produced onshore, since offshore hydrogen production would have higher costs and emissions in comparison (Gea-Bermúdez et al., 2023). Durakovic et al. (2023) modelled the European electricity grid towards 2060 to analyze the impact of green hydrogen production in the North Sea region. It was concluded that the production of green hydrogen could reduce offshore wind power curtailment from 24.9% to 9.6%, and the impact on electricity prices will probably vary from region to region (Durakovic et al., 2023). Kumar et al. (2023) analyzed opportunities for future synergies between hydrogen production and offshore industries and found that large-scale hydrogen production systems coupled with offshore renewable energies (e.g., offshore wind) could become economically viable under the right conditions. Important factors will include a low renewable electricity price and a stable long-term hydrogen demand (Kumar et al., 2023). Abadia and Chamorro (2023) modelled green hydrogen production from wind farms by using stochastic modelling of wind farm capacity factors and electricity prices based on Spanish data for these two parameters. The authors estimate that green hydrogen will only be economically viable with a hydrogen price above 3 €/kg H_2, concluding that green hydrogen cannot compete with hydrogen produced from fossil fuels, which has a cost range of 1.5–2.5 €/kg H_2 (Abadie and Chamorro, 2023). Davies and Hastings (2023) analyzed the lifetime emissions of greenhouse gases from various hydrogen production methods. Green hydrogen production with electricity from offshore wind farms was estimated to have yearly emission of 20 Mt CO_2e at a yearly production rate of 0.5 Mt H_2. This was the production method with the lowest emission by far in the analysis, ahead of grid-connected electrolysis (103–168 Mt CO_2e), blue hydrogen (200–262 Mt CO_2e) and the business-as-usual grey hydrogen (250 Mt CO_2e) (Davies and Hastings, 2023). Ghirardi et al. (2023) developed a simulation model to analyze renewable energy systems with batteries and green hydrogen as energy storage. The need for energy storage increases with increasing penetration of renewable energy, and the authors estimate that green hydrogen (power-to-H_2-to-power) will supply 30% of the energy in a 100% renewable energy scenario (Ghirardi et al., 2023). Liponi et al. (2023) performed a feasibility analysis of green hydrogen production from wind power, which included different electrolyzer capacities and number of separate electrolyzer groups. One year of data from a wind farm in Australia were used as input to the model, and the results showed that using a configuration with separate electrolyzer groups increased the hydrogen production. The break-even price of hydrogen for the wind-hydrogen system, referred to as the equivalent hydrogen price (EHP), was reported to be in the range 4.5–6.5 €/kg H_2 (Liponi et al., 2023). Ma et al. (2023) used convex programming to optimize the component sizing and energy management of a hybrid energy storage system with hydrogen and batteries connected to an offshore wind farm. One year of data from a wind farm in China were used as input to the optimization model, and the results showed that the hydrogen-battery storage system could reduce the curtailment of wind energy and thereby increase the net profits of the wind farm by 5.18–13.26% (Ma et al., 2023). Wilberforce et al. (2023) used one year of wind speed data as input to a mathematical model of a wind turbine coupled to a PEM electrolyzer. The results show that the hydrogen production was strongly correlated to the wind speed and the electrolyzer performed best at higher temperatures and lower pressures (Wilberforce et al., 2023). Morton et al. (2023) performed a techno-economic analysis of green hydrogen production in connection with a wind farm in Texas. One year of wind farm data at 5-minute intervals were used as model input and different day ahead market bidding strategies were investigated. The results showed that the optimal bidding strategy will depend on the price of hydrogen, and the minimum hydrogen price to ensure profitability will be 3.58 $/kg H_2 with current costs (Morton et al., 2023).

With regards to the levelized cost of hydrogen (LCOH) produced from wind power, large variations can be seen in the best-case results from different studies. Grüger et al. (2019) proposed an intelligent operating strategy to exploit low electricity prices when producing green hydrogen from wind power. One year of electricity price data and wind farm production data were used to simulate one-year scenarios, and the authors reported that the proposed strategy reduced the hydrogen production cost by up to 9.2%, which resulted in a LCOH of 11.52 €/kg H_2 (Grüger et al., 2019). Lucas et al. (2022) performed a techno-economic analysis of hydrogen production from a large-scale offshore wind farm where the lowest LCOH was 4.25 €/kg H_2 (Lucas et al., 2022). Tebibel (2021) analyzed a small-scale decentralized onshore wind-hydrogen system and calculated a LCOH of 33.70 $/kg H_2 (Tebibel, 2021). Almutairi et al. (2021) analyzed hydrogen production from wind power in several different locations in Iran and the best case had a LCOH of 2.1 $/kg H_2 (Almutairi et al., 2021). Rezaei et al. (2021) also performed a techno-economic analysis of hydrogen production from wind power in Iran, specifically for the city of Lutak. The estimated range of the LCOH in this study was 1.375–1.59 $/kg H_2 (Rezaei et al., 2021). Franco et al. (2021) performed a techno-economic assessment of various pathways for offshore wind-hydrogen systems. The results showed that pipeline transport of hydrogen should be used and this resulted in a LCOH of 5.35 €/kg H_2, but this could be reduced to 2.17 €/kg H_2 with the EU's support to hydrogen deployment (Franco et al., 2021). Miao et al. (2021) analyzed various cases with hydrogen production from mixed renewable energy sources and transport through power cables and pipelines, and the optimized case achieved a LCOH of 7 $/kg H_2 (Miao et al., 2021). Li et al. (2022) performed a techno-economic analysis of an off-grid hybrid renewable energy system with hydrogen production in China where the most cost-effective case resulted in a LCOH of 12.5 $/kg H_2 (Li et al., 2022). Jang et al. (2022) evaluated both onshore and offshore hydrogen production with electricity from a large-scale offshore wind farm. The lowest LCOH when wind farm costs were included was 13.81 $/kg H_2 with distributed offshore hydrogen production, while the lowest LCOH when wind farm costs were excluded was 4.16 $/kg H_2 with onshore production (Jang et al., 2022). Benalcazar and Komorowska (2022) modelled hydrogen production from onshore wind power in Poland. The lowest LCOH in 2020 was estimated to be 6.37 €/kg H_2 and this can potentially decrease to 1.23 €/kg H_2 in 2050 (Benalcazar and Komorowska, 2022). Lamagna et al. (2022) modelled offshore hydrogen production inside the tower of offshore wind turbines, and in a large-scale wind farm this could give a LCOH of 1.95 $/kg H_2 (Lamagna et al., 2022). Groenemans et al. (2022) performed a techno-economic analysis of hydrogen production via PEM electrolysis with electricity from offshore wind power, which resulted in a best-case LCOH of 2.09 $/kg H_2 with offshore hydrogen production and 3.86 $/kg H_2 with onshore production (Groenemans et al., 2022). Cooper et al. (2022) developed a framework for the design and operation of large-scale hydrogen production from wind power and calculated a LCOH of 4.82 €/kg H_2 with a typical wind farm power profile (Cooper et al., 2022). Egeland-Eriksen et al. (2023) simulated offshore hydrogen production via PEM electrolysis with electricity from a floating offshore wind turbine (FOWT). Real-world data from a 2.3 MW FOWT and electricity price data were included in the simulation model and the lowest LCOH in this study was 4.53 $/kg H_2 (Egeland-Eriksen et al., 2023). Dinh et al. (2023) developed a geospatial method to calculate the LCOH of offshore hydrogen production from offshore wind farms. It was estimated that a large-scale 2030 system can achieve a LCOH below 4 €/kg H_2 (Dinh et al., 2023). Komorowska et al. (2023) analyzed future hydrogen production from offshore wind and estimated a best-case LCOH of 3.60 €/kg H_2 in 2030 and 2.05 €/kg H_2 in 2050, while onshore wind cases resulted in a best-case LCOH of 2.72 €/kg H_2 in 2030 and 1.17 €/kg H_2 in 2050 (Komorowska et al., 2023). Kim et al. (2023) calculated the LCOH for different scenarios where hydrogen is produced via electrolysis with electricity from offshore wind. Different electrolyzer technologies were analyzed and the lowest LCOH for each was 1.64 $/kg H_2 for alkaline electrolyzers, 2.27 $/kg H_2 for proton exchange membrane (PEM) electrolyzers and 3.43 $/kg H_2 for solid oxide electrolyzers (SOEL) (Kim et al., 2023). Li et al. (2023) performed a techno-economic analysis of green hydrogen production from a system with wind turbines, PV cells and batteries and calculated a LCOH of 13.1665 CNY/kg H_2 (Li et al., 2023). Giampieri et al. (2023) analyzed scenarios for hydrogen production from offshore wind power and found that the most cost-effective scenario in 2025 would be offshore hydrogen production with pipeline transport. This could achieve a best-case LCOH of 4.53 £/kg H_2 (Giampieri et al., 2023). Nasser and Hassan (2023) analyzed and compared green hydrogen production from PV cells, wind turbines and waste heat for a location in Egypt. It was concluded that wind turbines would be the option with the highest cost with a LCOH range of 8.03–11.60 $/kg H_2 (Nasser and Hassan, 2023). Cheng and Hughes (2023) analyzed the role of offshore wind power in combination with PV power for green hydrogen production in Australia. The calculated LCOH range for 2030 was 4.4–5.5 AUD/kg H_2, which was achieved when the system could use both PV power and offshore wind power without restrictions (Cheng and Hughes, 2023). Burdack et al. (2023) used open-source Python modelling tools and meteorological data to estimate the LCOH for green hydrogen produced from wind and solar power in Colombia. Future LCOH values were estimated to be 1.63 $/kg H_2 in 2030 and 1.11 $/kg H_2 in 2050 (Burdack et al., 2023). Koholé et al. (2023) performed a techno-economic analysis of potential co-generation of wind power and green hydrogen in Cameroon. The best-case LCOH was estimated to be about 4.4 $/kg H_2 (Koholé et al., 2023). Oliva H. and Garcia G. (2023) used one year of data of electricity prices and renewable energy (solar and wind) generation in Chile to investigate the impact that the variable nature of these parameters have on the annualized cost of green hydrogen (ACOH). A model was developed that optimized the capacities of solar power, wind power, electrolyzer and grid energy, and the results showed that both electricity price and location of the energy system had large effects on the ACOH. The location with the highest wind power capacity factor achieved the lowest ACOH of around 2.2 $/kg H_2, and using variable energy prices instead of fixed prices reduced the ACOH by 5.2–10.5% in the different scenarios (Oliva H and Garcia G, 2023). Shin et al. (2023) performed a techno-economic analysis of green hydrogen production from offshore and onshore wind power, as well as from photovoltaic (PV) power. One year of hourly power production data from an onshore wind farm and a PV system were used, and the offshore wind power production was predicted by using a machine learning algorithm trained on onshore wind data. Mathematical models of electrolyzers (PEM and alkaline) were combined with PV and wind power inputs to estimate the LCOH in different scenarios, but variations in electricity price were not considered. The lowest LCOH of 7.25 $/kg H_2 was achieved with onshore wind power and alkaline electrolysis, while the lowest LCOH with offshore wind power was 11.85 $/kg H_2, also with alkaline electrolysis (Shin et al., 2023). Superchi *et al.* developed a simulation framework for green hydrogen production from wind farms based on a one-year data set from a wind farm in Greece, and this was used to simulate scenarios where hydrogen produced from onshore wind power and grid power is used in the steel industry. A sensitivity analysis of the effect of different electricity prices was performed, which was based on average electricity prices since the objective of the system was to maintain constant hydrogen production to ensure reliable delivery to the steel maker. The results showed that the simulated system could deliver hydrogen to the steel industry with a LCOH of 5.7 €/kg H_2 with an 82% reduction in emissions compared to conventional steel making (Superchi et al., 2023b). Emissions could be reduced by as much as 96%, however resulting in a higher LCOH of 7.6 €/kg H_2 (Superchi et al., 2023b). The lowest LCOH achieved for green hydrogen production from onshore wind power, when the steel making application was not considered, resulted in 4.48 €/kg H_2 (Superchi et al., 2023a). Li et al. (2024) analyzed the large-scale integration of offshore wind farms with coal power plants, batteries and green hydrogen production in China. One year of wind data was used in the analysis, and the lowest LCOH achieved was 29.76 CNY/kg H_2 (Li et al., 2024).

1.3. Objective and novelty of this study

The main objective of the work presented in this paper is to develop a complete model that can perform the following tasks quickly and with high accuracy:

- Estimate the energy production of an offshore wind farm based on the wind speed of a specific location.
- Estimate the potential hydrogen production by a PEM electrolyzer using the wind farm electricity as input power.
- Develop a novel control system that optimizes the wind-hydrogen facility by deciding when to produce hydrogen and when to sell wind power directly to the electricity grid based on the electricity price in the region and the average selling price of hydrogen. *Note:* In a real system, the average selling price of hydrogen can either be a chosen price set by the operator/owner of the wind-hydrogen facility, or it can be estimated (for example by a 50-day moving average). Since hydrogen can be stored with relatively small losses, the facility can then sell hydrogen when the price is above the chosen average selling price and store hydrogen when the price is below the chosen average selling price.

These three components (wind energy, hydrogen production, control system) must be integrated in a complete model that is general, accurate and fast enough to work on any time scale. The model can then be used in real wind-hydrogen systems in any location based only on the forecast wind speed and electricity price at the given location. Accurate forecasts of wind speed and electricity price is generally available for at least the next 24 hours in many locations. The model developed in this study can then be used to continuously estimate the production of wind energy and hydrogen, and also schedule in which time intervals hydrogen should be produced to optimize the profitability of the system. Estimates and scheduling can be done on any time frame and are only limited by the time frame of the forecast wind speed and electricity price, i.e., if the wind speed is given with hourly intervals the system will estimate and schedule on an hourly basis. However, the model can also continuously update itself and refine its estimates and scheduling as soon as more accurate short-term forecasts are available. In this way it can ensure the most optimal cooperation between the offshore wind farm and the hydrogen system at all times.

The novelty of this study lies in the proposed price-based control system that optimizes the wind-hydrogen system by successfully lowering the LCOH in all test scenarios. The novelty is further enhanced by the integration of the control system with a polynomial regression model for wind energy estimation and a hydrogen production model based on a previously published paper (Egeland-Eriksen et al., 2023). These three components are combined in a single model that performs the tasks described at the beginning of this section. Furthermore, the model is built in such a way that it can be used in a real-world wind--hydrogen system and require only the forecast wind speed and electricity price of a given location as input. The other required input values (e.g., average selling price of hydrogen, power capacity of wind farm and electrolyzer) can easily be set by the user before running the simulation. The model accurately and continuously forecasts wind energy production and potential hydrogen production on an hourly basis, and the novel control system uses the corresponding hourly electricity prices to control whether the system produces hydrogen or sells electricity to the grid. Additionally, the 10-year data set of hourly wind speed values from the Norwegian island of Utsira used in the simulation cases ensures that these cases and results are particularly relevant for the offshore wind farm planned to be built near this island (*Utsira Nord* (Utsira Nord, 2024)). Models with some similar functionalities have been published in other studies, as described in the literature review in Section 1.2. However, no models that combine all the functionalities described above, and with the level of detail in terms of data set size and resolution (hourly), have been found in previously published research. For example, several of the referenced studies used one year of data instead of 10 years and simulate only one year of operation instead of the whole lifetime of the system. In (Shin et al., 2023), power production for offshore wind was also predicted with a machine learning algorithm, but this was based on input data from an onshore wind farm. The machine learning algorithm in our study is based on data from a real-world floating offshore wind turbine, which should result in a more accurate model for offshore wind. Finally, many of the referenced studies ignore the effect of variations in electricity prices, either by not considering electricity prices at all or by using long-term average values. The novel control system developed in this study used real-world data of hourly electricity spot prices in the same region (Utsira, Norway) and 10-year period as the wind speed data, which effectively reduced the LCOH in all scenarios. A control system of this kind could be valuable for the economic viability of future real-world wind-hydrogen systems, and to our knowledge, no systems equivalent to this can be found in previously published research.

This paper is structured as follows: Section 1 contains a description of the background for the work, a review of relevant literature, as well as the objective and novelty of this study; Section 2 describes the building, training and testing of the polynomial regression model used to estimate the wind farm capacity factor; Section 3 describes the hydrogen production (electrolysis) model and the novel control system developed in this study; Section 4 contains the simulated case studies, results, sensitivity analysis and discussion of results; and Section 5 contains the main conclusions of the work.

2. Regression modelling to estimate wind turbine capacity factors based on wind speed

This section describes the building, training and testing of the regression models used to estimate the capacity factor of the FOWT in this study. The flowchart for the whole process is shown in Fig. 1.

2.1. Linear and polynomial regression

Linear regression is a common machine learning method within the supervised learning category. The mathematical basis for this method is described by Hastie et al. (2017), and the practical implementation in the Python (Python, 2023) programming language is described by Géron

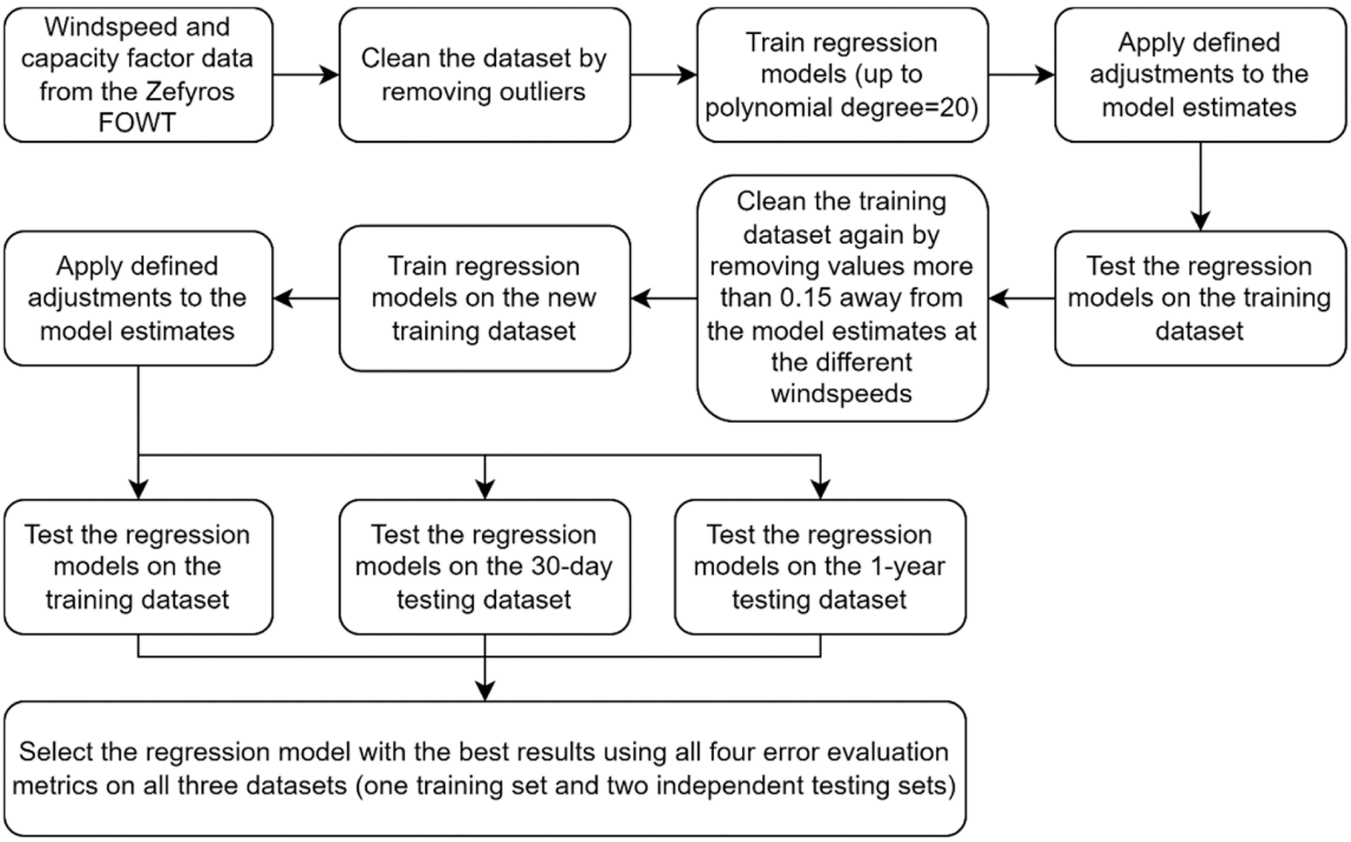

Fig. 1. Flowchart showing the process of building, training and testing the regression model used to estimate the FOWT capacity factor in this study. The process is described in detail in Section 2.

(2017) and (Müller and Guido (2017). Linear regression can be used in cases with a dataset with two variables, where the value of one variable is dependent on the value of the other (independent variable). A dataset containing values for both variables is used to train the regression model, and this results in a mathematical expression that estimates the value of the dependent variable based on the value of the independent variable. The accuracy of the model can then be tested with datasets that were not used for the training of the model. Linear regression is most useful and accurate when the relationship between the dependent variable and the independent variable is linear or approximately linear. In this study the independent variable is wind speed and the dependent variable is the capacity factor of a wind turbine. Since the power of a wind turbine is dependent on the cube of the wind speed, a linear expression will not be very accurate in estimating wind turbine capacity factor values from wind speed input values. Therefore, polynomial regression is used in this study. This method is very similar to linear regression, except that the model will create a polynomial expression instead of a linear expression, as shown in Eqs. 1 and 2 (Géron, 2017):

$$\hat{y} = c + \theta x \tag{1}$$

$$\hat{y} = c + \theta_1 x + \theta_2 x^2 + \ldots + \theta_n x^n \tag{2}$$

where $\hat{y}$ is the estimated value of the dependent variable, c is a constant calculated by the model, x is the value of the independent variable, and the θ values are coefficients calculated by the model. Linear regression has just one coefficient (θ), while the number of coefficients in polynomial regression is equal to the degree of the polynomial, as shown in Eq. 2 where n is the polynomial degree.

2.2. Error evaluation metrics

The Python programming language (Python, 2023) was used to build the regression models, and both linear and polynomial regression were tested. Polynomial regression up to degree 20 was tested ($n = 20$ in Eq. 2). Four different error evaluation metrics were used to select the best regression model. These were mean absolute error (MAE), mean absolute percentage error (MAPE), median absolute error (MedAE) and root mean squared error (RMSE). The first three are described in the online documentation (Scikit-Learn, 2023) to the Python package Scikit-Learn, developed by Pedregosa et al. (2011), while RMSE is the square root of the mean squared error (MSE) described in (Scikit-Learn, 2023):

$$MAE = \frac{1}{n}\sum_{i=0}^{n-1}|y_i - \hat{y}_i| \tag{3}$$

$$MAPE = \frac{1}{n}\sum_{i=0}^{n-1}\frac{|y_i - \hat{y}_i|}{\max(\epsilon, |y_i|)} \tag{4}$$

$$MedAE = median(|y_1 - \hat{y}_1|, \ldots, |y_n - \hat{y}_n|) \tag{5}$$

$$RMSE = \sqrt{\frac{1}{n}\sum_{i=0}^{n-1}(y_i - \hat{y}_i)^2} \tag{6}$$

where n is the total number of samples, $\hat{y}_i$ is the predicted value of the i-th sample, y_i is the corresponding true value, and ϵ used in Eq. 4 (MAPE) is an arbitrary small positive number used to avoid undefined results when y_i is zero (Scikit-Learn, 2023).

2.3. Data input and cleaning

The regression models in this study were trained on a dataset containing hourly values of wind speed and wind turbine capacity factor from a 12-month period (1. Nov. 2021 to 31. Oct. 2022) from a 2.3 MW floating offshore wind turbine (FOWT). The Norwegian company UNITECH Offshore AS (Umbilical & Flying Leads - Unitech Energy GroupUnitech Energy Group, 2023) owns and operates the turbine, which is named *Zefyros*. The wind speed time series for the full 12-month period is shown in Fig. 2, the wind speed distribution is shown in Fig. 3.a) and a boxplot of the monthly wind speed during this period is shown in Fig. 3.b). The dataset is the property of UNITECH Offshore AS and is currently not publicly available.

The monthly average capacity factor of the *Zefyros* FOWT is shown in Fig. 4. A comparison with Fig. 3 shows that the FOWT capacity factor is largely determined by the wind speed, as expected. The most favorable conditions are high wind speeds with relatively low variations, without extremely high wind speeds that cause the FOWT to shut down. This is illustrated very well by looking at February 2022 in Fig. 3 which has the highest wind speeds in the two middle quartiles (shown by the box), but no wind speed values above the cut-out speed of 25 m/s. This resulted in an extremely high average capacity factor of more than 70% for this month, as shown in Fig. 4.

The full dataset showing the capacity factor at different wind speeds is shown in Fig. 5. Most of the data points cluster together to form the typical shape of a wind turbine capacity factor curve: Cut-in wind speed around 4 m/s, non-linear increase in capacity factor from this point until the rated power production starts at a wind speed around 13 m/s and lasts up to the cut-out speed around 25 m/s. However, some data points are well outside the typical range of a wind turbine capacity factor curve, mostly due to unexpected downtime for the FOWT. In this study, the focus is on the ideal operation of the FOWT, i.e., when the turbine produces power “as it should” at different wind speeds according to its specifications. Consequently, outlier data points must be removed from the dataset before the regression model can be trained. This applies to the following data points:

- The single data point above the red dashed line in Fig. 5: This has a capacity factor above 1.0 (above 100%), which is not possible, so there has probably been a malfunction in the measurement system for this data point.
- The data points inside the yellow box in Fig. 5: These data points have a capacity factor equal to zero even though the wind speed is above 4 m/s, so these measurements show the unexpected downtime for the FOWT. In this study the goal is to train a model that shows the ideal operation of a FOWT. The unexpected downtime data points are therefore outliers and were removed before training the model.
- The data points inside the purple box in Fig. 5: These data points have a capacity factor below 0.8 (80%) even though the wind speed is in the ideal range of 13–25 m/s. This is most likely caused by unexpected downtime for the FOWT during parts of the 1-hour periods that these data points represent, which would reduce the total capacity factor of those periods. Since it does not represent ideal operation for the FOWT, these data points are removed before training the model. However, the data points in both the yellow and purple boxes can be useful for future work, for example to analyze the unexpected downtime of FOWTs.

A total of 575 data points were removed when the dataset was cleaned. This is around 6.5% of the original dataset, which means that 93.5% of the dataset was used to train the first part of the regression model. This shows that the capacity factor of the FOWT was within the expected range for a very high percentage of the time throughout the 12-month period. This range will be defined in more detail before the second stage of training the regression model.

2.4. Training the regression models

The regression models in this study were trained in two stages with a second data cleaning between the stages (the first data cleaning is described in Section 2.3). Both linear regression and polynomial regression (up to degree=20) were performed. The model calculates the

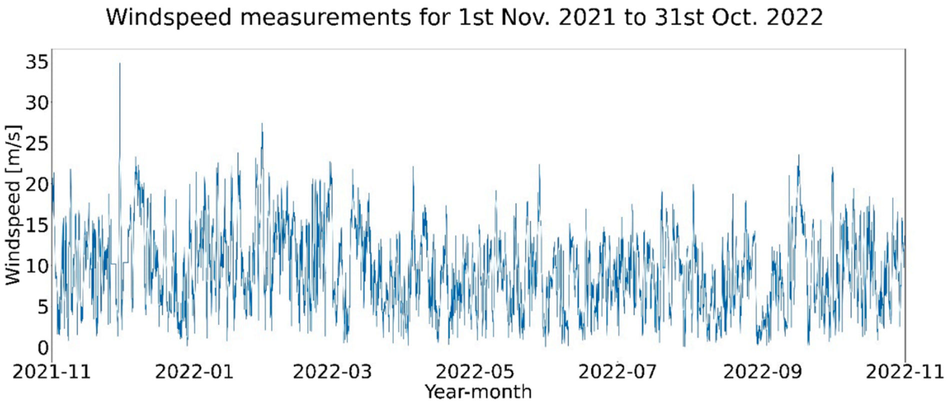

Fig. 2. Hourly wind speed measurements on the Zefyros FOWT in the period 1. Nov. 2021 to 31. Oct. 2022.

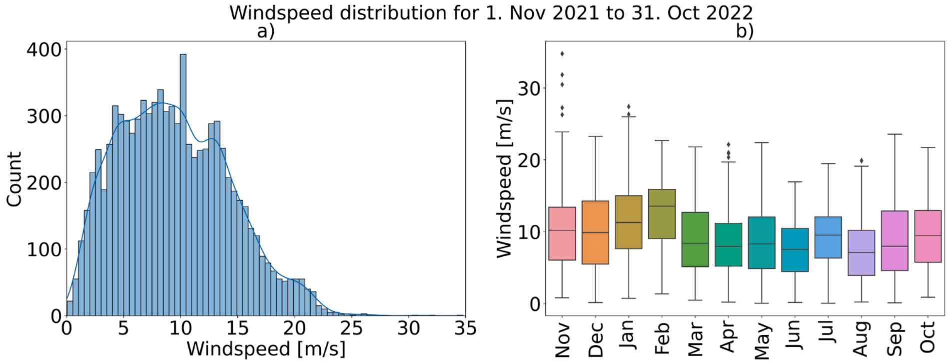

Fig. 3. a) Wind speed distribution for the period 1. Nov. 2021 to 31. Oct. 2022. b) Boxplot showing the wind speed distribution by month in the period 1. Nov. 2021 to 31. Oct. 2022. The boxes show the two middle quartiles of the distribution, and the middle line is the median wind speed for the month. The black lines show the rest of the wind speed range for the month, while the black dots in some of the months (Nov., Jan., Apr., Aug.) are data points classified as outliers.

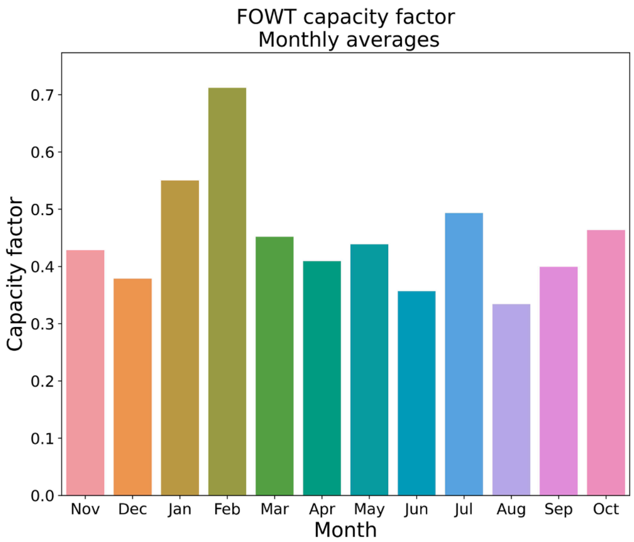

Fig. 4. Monthly average capacity factor of the Zefyros FOWT in the period 1. Nov. 2021 to 31. Oct. 2022.

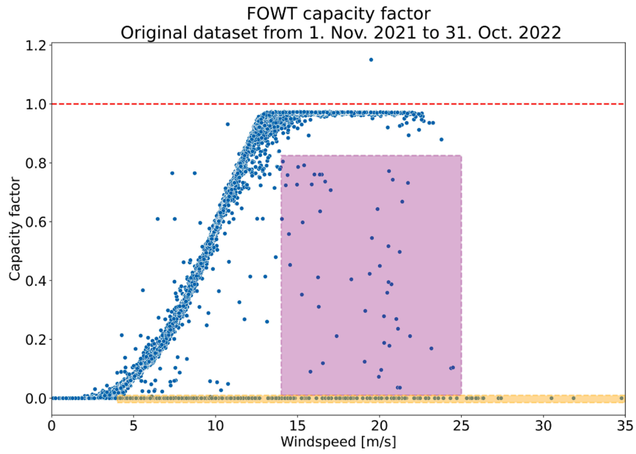

Fig. 5. Measured capacity factor of the Zefyros FOWT at different wind speeds in the period 1. Nov. 2021 to 31. Oct. 2022. The data point above the red dashed line and all data points inside the purple and yellow boxes are considered outliers.

values for the constant c and the θ coefficients shown in Eq. 1 (linear) and Eq. 2 (polynomial), and these values and equations are then used to estimate the FOWT capacity factor based on the wind speed input values. All models were then tested on the training dataset, and more importantly on two separate testing datasets from periods that were not used to train the model. The model with the best results on the testing sets according to the four error evaluation metrics described in Section 2.2 was then used in the rest of the study. The polynomial regression model with degree=12 and some modifications (described below) achieved the best overall results on the testing sets, and it will therefore be used to describe the training and testing process here and in the subsequent section.

The polynomial regression part of the Scikit-Learn Python package (Pedregosa et al., 2011) was used to create an equation that estimates the FOWT capacity factor as a function of wind speed. With the polynomial degree equal to 12, the specific form of Eq. 2 (Géron, 2017) becomes:

$$\hat{y} = c + \theta_1 x + \theta_2 x^2 + \theta_3 x^3 + \ldots + \theta_{12} x^{12} \tag{7}$$

where $\hat{y}$ is the estimated FOWT capacity factor and x is the wind speed input value. The values for the constant c and the θ coefficients in the first stage of the polynomial regression model with degree=12 were calculated by the model based on the 12-month training dataset. The capacity factor curve estimated with Eq. 7 and these values is shown in Fig. 6, together with the actual capacity factor measurements.

A set of rules based on the known operation of the FOWT turbine were then imposed on the model to adjust the estimated capacity factor values in some regions. This is because the polynomial regression model estimates the capacity factor very well when the wind speed is between 4 m/s and 13 m/s, as shown by the area between the vertical dotted lines in Fig. 6. Outside this range it will be more beneficial to use a set of fixed rules (described below) since the focus is the ideal operation of the FOWT at each wind speed (below the cut-in wind speed of 4 m/s and above the rated power wind speed of 13 m/s the capacity factor will be constant when the FOWT operates ideally). Therefore, the polynomial regression model is used to estimate the capacity factor in the wind speed range 4–13 m/s, and outside this range the following rules based on the known operation of the FOWT are used:

- *If the wind speed is below 4 m/s:* This is below the cut-in wind speed of the FOWT, so the estimated capacity factor is set to 0.
- *If the wind speed is in the range 13–25 m/s:* This is the rated power range of the FOWT. Since the focus in this study is the ideal operation of the FOWT, the estimated capacity factor is set equal to the maximum value from the dataset in this range. The actual maximum capacity factor value is used instead of 1.0 to improve the realism of the model, since it is very unlikely that any 1-hour period will have a perfect 1.0 capacity factor in real-world conditions. This is confirmed by the real capacity factor values in the datasets used in this study, which are never a perfect 1.0 in any period.
- *If the wind speed is above 25 m/s:* This is above the cut-out speed of the FOWT, so the estimated capacity factor is set to 0 in this range.
- *If the estimated capacity factor is negative:* A negative capacity factor is not possible, so the estimated capacity factor is adjusted to 0 if the model estimate is negative.
- *If the estimated capacity factor is above the maximum value from the dataset:* The estimated capacity factor is adjusted down to the maximum actual capacity factor in the dataset if the model estimate is above this maximum value.

After completing the first stage of training the polynomial regression model, a second cleaning of outliers from the training dataset followed by a second stage of polynomial regression was performed. This was done to further fine-tune the accuracy of the model by removing data points that are relatively far from the high-density areas at the different wind speeds. The range of accepted data points was chosen to be 0.15 above or below the estimated capacity factor from the first stage polynomial regression (with adjustments). For example, if the estimated capacity factor from the first stage at a given wind speed is 0.6, all data points within the range 0.45–0.75 at this wind speed are included in the second stage polynomial regression model. This range is illustrated by the green shaded area in Fig. 7, and all data points outside this area were removed before the second training stage. A total of 132 data points were removed, which is equal to around 1.6% of the dataset used in the first stage polynomial regression. The capacity factor curve estimated with the second stage polynomial regression model is shown in Fig. 7, together with the actual capacity factor measurements. The same adjustments used on the estimated capacity factor curve in the first regression stage were also used on the capacity factor curve in the second regression stage. The accuracy of the polynomial regression model improved slightly from the first to the second stage. Therefore, and since the added computational load from including the second stage is negligible, it was decided to include both stages in the polynomial regression model used in the rest of the study.

2.5. Testing and validating the regression models

All the regression models (linear and polynomial up to degree=20) were tested on two separate datasets that were not included in the training of the models. These datasets were a 1-year dataset from January 2020 to January 2021 with 10-minute interval data points, and a 30-day dataset from November 2022 with hourly data points. Both datasets contain measured values for wind speeds and capacity factors

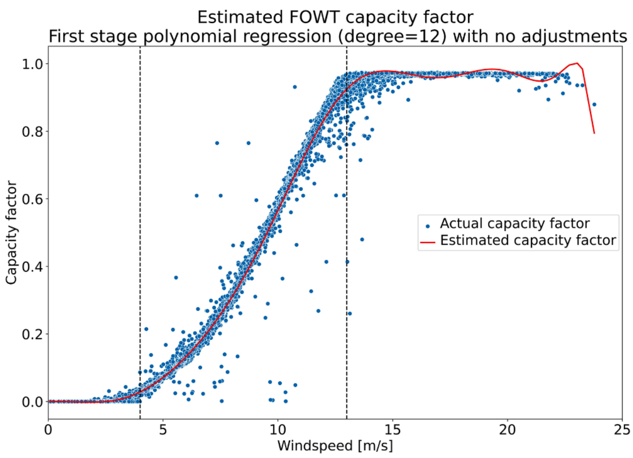

Fig. 6. The blue dots show the actual FOWT capacity factor measurements and the red line shows the capacity factor estimated by the polynomial regression model (degree=12) before any adjustments were made. The black vertical dotted lines are placed at wind speeds equal to 4 m/s and 13 m/s, which are the turbine's cut-in wind speed and lower limit of the rated power wind speed, respectively.

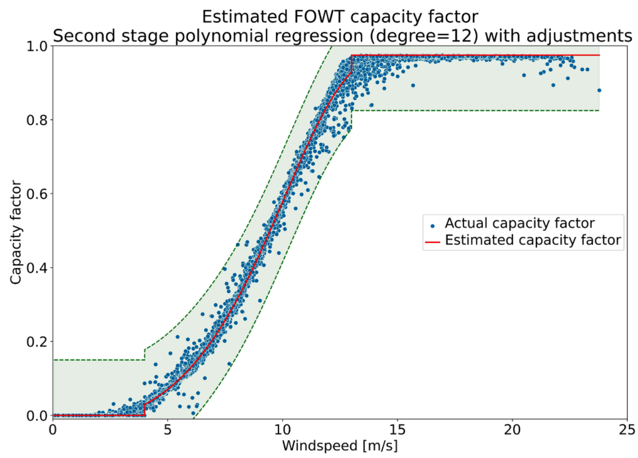

Fig. 7. The red line shows the FOWT capacity factor estimated by the second stage of the polynomial regression model (degree=12) after the adjustments described in Section 2.4 had been made. The blue dots show the actual capacity factor measurements included in the second stage training dataset. The green shaded area shows the range used for this training dataset, and the upper and lower limits are 0.15 above and below the estimated capacity factor curve from the first stage polynomial regression.

for the *Zefyros* FOWT. Before the testing was performed, both datasets were cleaned with the same method used for the training dataset, described in Section 2.4. In this study, the objective is to estimate the capacity factor of a FOWT in periods where it is close to ideal operation. The accuracy of the models must therefore be tested on datasets that contain only data points relatively close to ideal operation. Data points that represent unexpected downtime for the FOWT are therefore removed. The accuracy of the regression models was also evaluated by using the four error evaluation metrics described in Section 2.2 in combination with both the training dataset and the two different testing datasets. The sizes (number of data points) of the datasets used in the error evaluation are 8053 for the training set, 42465 for the 1-year testing set and 603 for the 30-day testing set. The error evaluation results show that the polynomial regression model with a polynomial degree of 12 achieved the highest overall accuracy. The error values for this model are shown in Table 1 and plotted in Fig. 8 (MAE, RMSE, MEDAE) and Fig. 9 (MAPE).

The estimated capacity factor compared to the actual capacity factor measurements for the final week of the 1-year testing dataset is shown in Fig. 10. The week-long plot is used here because it is visually easier to see how close the estimated capacity factor is to the actual capacity factor when a shorter period is viewed. As an example of the accuracy of the model, the MAE for both independent testing datasets (not used in the model training) is below 0.01 (see Table 1). This means that the average difference between the estimated capacity factor values and the actual capacity factor measurements is less than 0.01, in other words less than 1% if the capacity factor is expressed as a percentage where the range 0.00–1.00 is equal to 0–100%.

3. Model and control system for hydrogen production with power from an offshore wind farm

In the following, Section 3.1 describes how hydrogen production via PEM electrolysis with electricity from an offshore wind farm was modelled in this study. Section 3.2 describes the control system that decides when the electricity from the wind farm is used to produce hydrogen and when it is sold directly to the onshore electricity grid.

3.1. Hydrogen production

The hydrogen production estimates in this study is based on the PEM electrolyzer model initially developed in (Jensen, 2021) and modified and described in (Egeland-Eriksen et al., 2023). Based on this model it is possible to estimate the energy consumption of a PEM electrolyzer as a function of the current density. The maximum current density of the electrolyzer used in this study is 2.5 A/cm^2, a value directly correlated to the maximum input power. The energy consumption at this point is calculated to be 54.5 kWh/kg H_2 (Jensen, 2021). This means that when the electrolyzer operates at its rated power (maximum power) it will use 54.5 kWh of wind energy to produce 1 kg of hydrogen. The lower limit for hydrogen production in this study is set to 10% of the electrolyzer's rated power, which is the same limit used in (Egeland-Eriksen et al., 2023). This is to avoid that the electrolyzer turns on and off unnecessarily when the wind speed fluctuates around the cut-in speed of the FOWT. This limit corresponds to a current density of 0.25 A/cm^2 and the energy consumption of the electrolyzer at this point is 46 kWh/kg H_2 (Jensen, 2021), i.e., when the electrolyzer operates with an input power

Table 1
Error evaluation results for the polynomial regression model (degree=12) used in this study.

Dataset	MAE	RMSE	MAPE	MEDAE
Training set	0.01013162	0.01844632	0.08451184	0.0051661
30-day testing set	0.00886017	0.01473975	0.04043656	0.00434783
1-year testing set	0.00837381	0.0140313	0.10712783	0.00422591

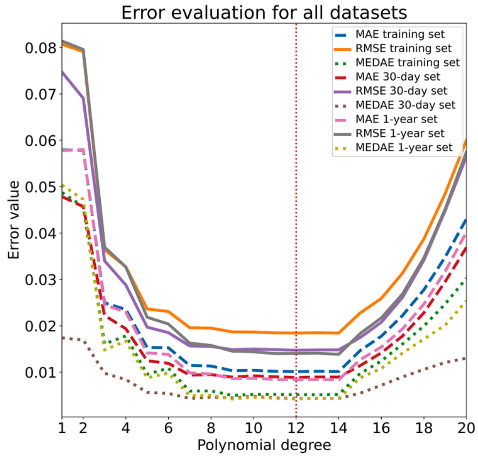

Fig. 8. Error evaluation using MAE, RMSE and MEDAE for all datasets (training set and two testing sets). The best results were achieved by the polynomial regression models with polynomial degrees between 9 and 14. The best overall results (using all four error evaluation metrics on all three datasets) were achieved by the model with a polynomial degree of 12 (vertical red dotted line).

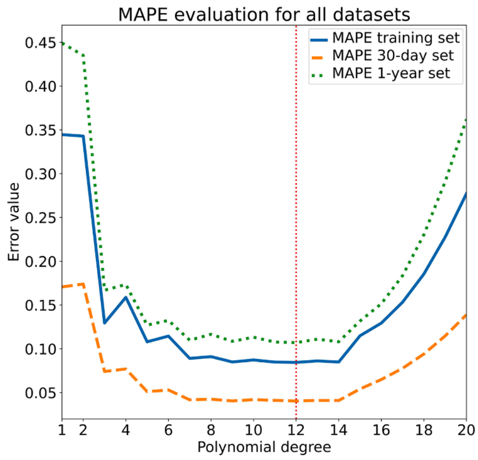

Fig. 9. Error evaluation using MAPE for all datasets (training set and two testing sets). The best results were achieved by the polynomial regression models with polynomial degrees between 9 and 14. The best overall results (using all four error evaluation metrics on all three datasets) were achieved by the model with a polynomial degree of 12 (vertical red dotted line).

equal to 10% of its rated power it will use 46 kWh of wind energy to produce 1 kg of hydrogen. As shown in (Egeland-Eriksen et al., 2023), the efficiency of the PEM electrolyzer decreases as the input power increases from 10% of rated power up towards 100% of rated power. The increase in energy consumption between the two abovementioned current densities (0.25 and 2.5 A/cm^2) is very close to being linear (Jensen, 2021). For this study it is therefore assumed that the increase *is* linear and that the corresponding decrease in efficiency for the electrolyzer between these two points is also linear. This simplification of the model from (Egeland-Eriksen et al., 2023) will most likely mean that the resulting hydrogen production in this work is slightly less accurate than in (Egeland-Eriksen et al., 2023). However, the difference will be minor since the decrease in efficiency is so close to being linear. This simplification is therefore judged to be justified, since it reduces the computational load significantly, which enables the model to simulate the entire lifetime (10–25 years) of the system. By using the energy content (LHV) of hydrogen of 33.3139 kWh/kg H_2 (Energy density, 2022), the following method is used to estimate hydrogen production based on the input power from the FOWT:

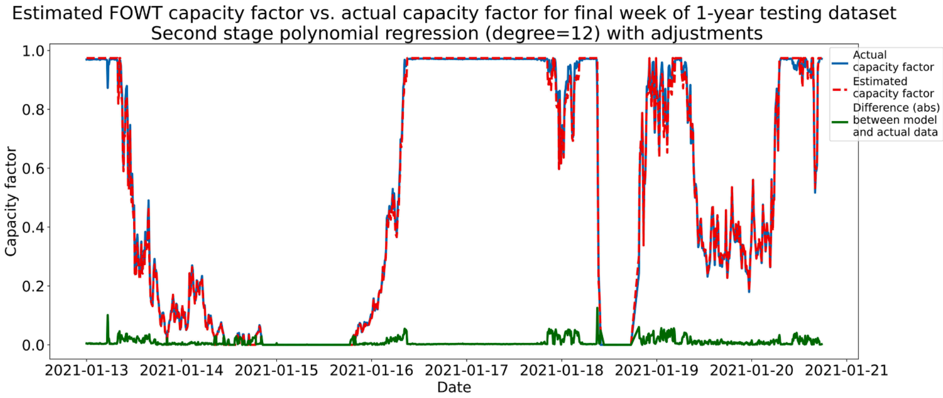

Fig. 10. Estimated capacity factor (red dotted line) compared to actual capacity factor measurements (blue line) for the final week of the 1-year testing dataset. The estimated capacity factor is a result of polynomial regression with a polynomial degree of 12, with the adjustments described in Sections 2.3–2.4. The green line shows the absolute difference between the values estimated by the polynomial regression model and the actual data.

1. When the input power to the PEM electrolyzer is 10% of its rated power the efficiency of the electrolyzer is:

$$\frac{33.3139 kWh/kg \quad H_2}{46 kWh/kg \quad H_2} = \underline{0.724 = 72.4\%} \tag{8}$$

2. When the input power to the PEM electrolyzer is 100% of its rated power the efficiency of the electrolyzer is:

$$\frac{33.3139 kWh/kg \quad H_2}{54.5 kWh/kg \quad H_2} = \underline{0.611 = 61.1\%} \tag{9}$$

3. The decrease in the efficiency of the PEM electrolyzer between 10% of rated power and 100% of rated power is linear, i.e., the efficiency is 72.4% when the input power is 10% of rated power and then decreases linearly as the input power increases up to 100% of rated power, where the efficiency is 61.1%.
4. The rated power of the PEM electrolyzer is set equal to the rated power of the wind farm, and the hydrogen production during each time interval can then be estimated by Eq. 10, where E_{H_2} is the energy in the hydrogen produced by the electrolyzer, WT_{CF} is the estimated capacity factor of the wind turbine, WT_{RP} is the rated power of the wind turbine (and electrolyzer), and η_{PEM} is the efficiency of the PEM electrolyzer at the given power level. The control system overrides this calculation and shuts the electrolyzer off under certain conditions, as explained in Section 3.2.

$$E_{H_2} = WT_{CF} \bullet WT_{RP} \bullet \eta_{PEM} \tag{10}$$

It must also be pointed out that the electrolyzer model described in (Egeland-Eriksen et al., 2023), which the hydrogen production model in this paper is based on, has several simplifications made to limit the complexity and computational time of the simulations. The simplifications and possible consequences are:

- Power electronics are not included in the model, except in the cost estimate for the PEM electrolyzer. Therefore, both the energy loss and cost would be higher in an actual wind-hydrogen system.
- Ramp-up time and cold start-up time for the PEM electrolyzer are not included in the model. The ramp-up time for a state-of-the-art PEM electrolyzer is so low (below 10 seconds (Buttler and Spliethoff, 2018)) that the effect on results will be very low. The cold start-up time is longer though (5–10 minutes (Buttler and Spliethoff, 2018)), so this would probably reduce the hydrogen production in an actual wind-hydrogen system compared to the model.
- Energy usage to keep the electrolyzer in standby mode is not included in the model. This could reduce the energy efficiency and hydrogen production in an actual system.
- The degradation of the electrolyzer during its lifetime is not included in the model. This will affect the energy efficiency of the electrolyzer over time and increase the total system cost in an actual system.

These four points are included in the planned future work to develop the model further and increase its realism, as described at the end of Section 5.

3.2. Control system

The control system illustrated by the flowchart in Fig. 11 decides when the electricity from the wind farm is used to produce hydrogen and when it is sold directly as electricity to the onshore grid. The purpose is to maximize the profitability of the combined wind-hydrogen facility. A wind-hydrogen system of this type, that does not have a control system to decide *when* to produce hydrogen, would run the risk of suffering huge economic losses if hydrogen is produced in periods where the electricity price is very high compared to the hydrogen price. This risk is illustrated well by the huge fluctuations in the price of electricity in Norway and the rest of Europe in the last few years. The model developed in this study evaluates the profitability separately for each time interval (hourly intervals is used in this paper) and the decision is based on the following inputs to the control system:

- **Power produced by the FOWT.** This is estimated by the polynomial regression model based on real-world wind speed data, as described in Section 2.
- **Price of electricity.** This is based on real-world data downloaded from Nord Pool (Market data, 2023) for the region in Norway where the *Zefyros* FOWT is located. The planned 1.5 GW *Utsira Nord* floating offshore wind farm (Utsira Nord, 2024) will also be in this region.
- **Selling price of hydrogen.** This is set to a constant (average) value before each simulation.
- **Price margin between the selling prices of hydrogen and electricity.** This is set to a constant percentage value before each simulation.

Based on these four inputs the model calculates whether it is most profitable to use the electricity from the FOWT to produce and sell hydrogen ***or*** sell the electricity directly to the grid. The calculation is performed separately for each time interval throughout each simulation, with the following decision process:

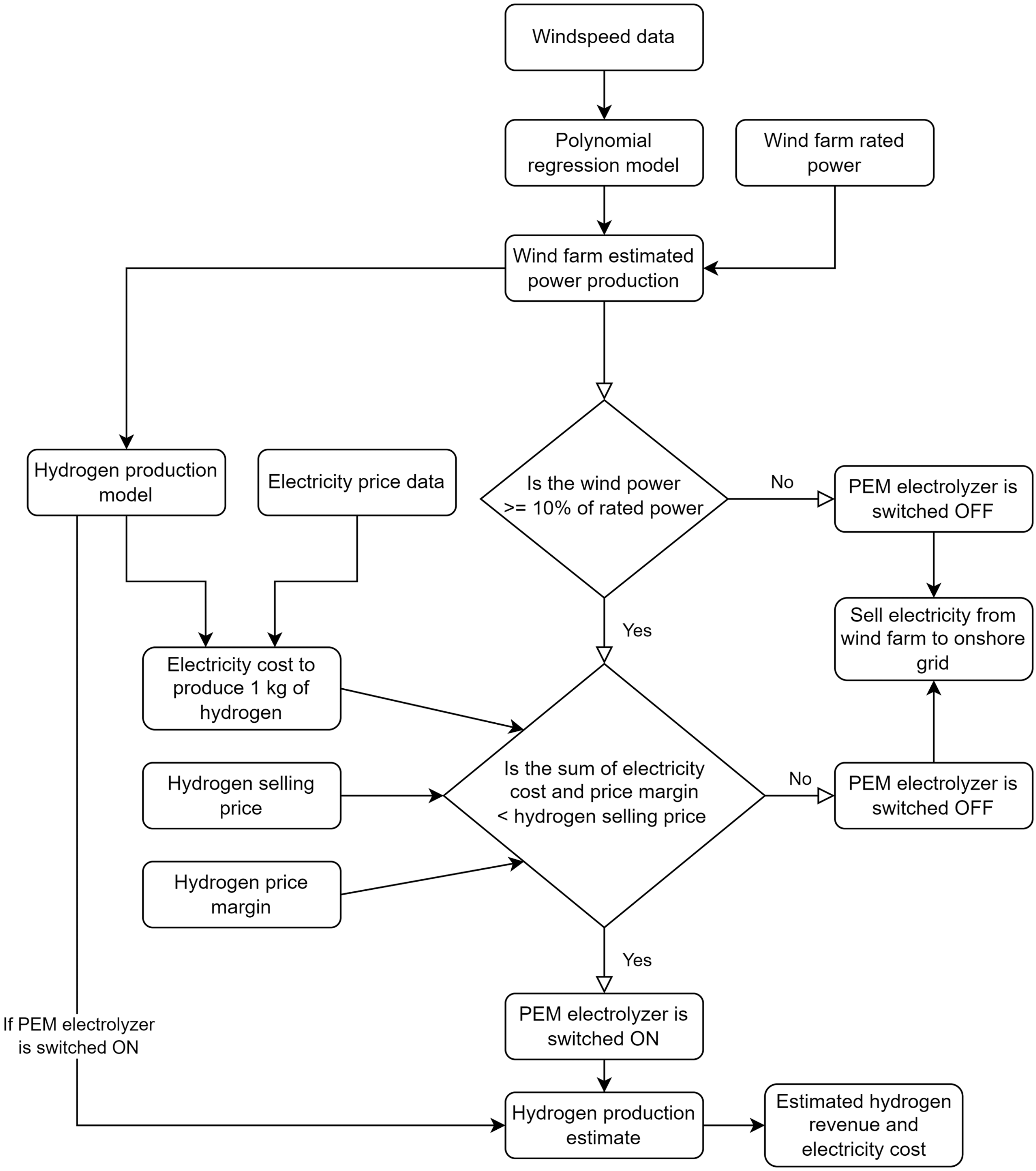

Fig. 11. Flowchart for the control system that decides when the electricity from the wind farm is used to produce and sell hydrogen and when electricity is sold directly to the onshore grid.

1. Is the power from the FOWT higher or equal to 10% of the rated power of the PEM electrolyzer (which is equal to the rated power of the FOWT)?
   a. YES: The electrolyzer produces hydrogen **if** condition 2 is also fulfilled.
   b. NO: The electrolyzer is switched off.
2. Use the process described in Section 3.1 in combination with the price of electricity for the given time interval to calculate the cost of the electricity used to produce 1 kg of hydrogen during this interval. Add the price margin to this cost and compare this with the selling price of hydrogen. Is the sum of the electricity cost and the price margin lower than the selling price of hydrogen?

a. YES: The electrolyzer produces hydrogen <u>**if**</u> condition 1 is also fulfilled.
b. NO: The electrolyzer is switched off.

4. Case study: hydrogen production with electricity from a 1.5 GW offshore wind farm

4.1. Base case conditions and data sources

In this case study the regression model described in Section 2 is combined with the method to estimate hydrogen production and the control system described in Section 3 to simulate the long-term (10 years) operation of a prospective 1.5 GW offshore wind farm producing hydrogen via PEM electrolysis. The hydrogen production facility is assumed to be located onshore, using only electricity from the offshore wind farm for the electrolysis. The rated power of the electrolyzer is set to be the same as the offshore wind farm (1.5 GW) so that all the wind power can be utilized to produce hydrogen when the conditions are favorable. Ten years of historical wind speed and electricity price data from the years 2013–2022 are used as input to the model. The wind speed data are from the Norwegian island of Utsira, which is very close to the planned location of the 1.5 GW *Utsira Nord* floating offshore wind farm. The wind speed data are publicly available for download from the Norwegian Centre for Climate Services (Norsk Klimaservicesenter, 2023). The electricity price data are from the South-West region in Norway (where Utsira is located), and the data are publicly available for download from Nord Pool (Market data, 2023). Historical data of the conversion rate between NOK and US dollars for the same ten years were used to convert the electricity price. These data are available for download from the Bank of Norway (Valutakurser, 2023). The average hydrogen selling price for the period is set to 6.8 \$/kg H_2, which is the upper limit of the production cost range of 2.5–6.8 \$/kg H_2 for green hydrogen given in (Vickers et al., 2020). The hydrogen selling price is assumed to be constant at this level due to the lack of historical data for the selling price of hydrogen for the region. Additionally, since hydrogen can be stored for long periods, the facility can decide when to sell hydrogen as long as the storage system is not full. This should give the facility some price control and reduce the fluctuations in the received selling price. The required margin between the electricity price and hydrogen selling price is set to 5%. This means that the control system described in Section 3.2 will not start hydrogen production unless the electricity cost of hydrogen production in a given time interval is at least 5% lower than the assumed selling price of hydrogen. This margin is included to account for any extra costs related to starting hydrogen production versus selling the electricity directly, and it will thus act as a margin of safety to ensure the profitability of the hydrogen production. Several different price margin values were tested, and the effects that the magnitude of the price margin had on the hydrogen production and economic metrics (which will be described in Section 4.2.3) were negligible, so this is not the most important part of the control system. Nevertheless, it was decided to keep the margin of 5% as a safety factor against the abovementioned extra costs that could occur in a real-world system. All case conditions and data sources are summarized in Table 2. The average values for wind speed, wind farm capacity factor, electricity price, as well as the efficiency and capacity factor of the PEM electrolyzer for the whole 10-year period is given in Table 3. The case study described in this section is the base case. A sensitivity analysis was also performed where the effects of changing different variables (electricity price, hydrogen price, etc.) were investigated. This is described in Section 4.2.4. Additional future scenarios were also simulated, and these are described in Sections 4.3 and 4.4.

4.2. Base case results

4.2.1. Hydrogen production

The results show that the total hydrogen production from the 1.5 GW hydrogen facility in the 10-year period 2013–2022 was approximately 0.81 million tons of hydrogen. The yearly production was relatively similar for most of the years, however the situation in 2020 and 2022 was very different from the rest. The main reason for this is the price of electricity. In 2020 the electricity price was very low, and the control system described in Section 3.2 therefore decided to produce hydrogen more often compared to the other years. In 2022 the exact opposite situation occurred, i.e., the electricity price was very high throughout most of the year, and the control system therefore decided to sell the electricity from the wind farm directly to the grid most of the time. The difference in hydrogen production between these two years is clearly seen when comparing the two charts in Fig. 12. The total hydrogen production for all 10 years is shown in Fig. 13.

Table 2
Data sources and case conditions used in the base case.

Data or parameter	Source and/or value
Wind speed data	Historical data from the period 2013-2022 for Utsira, Norway (Norsk Klimaservicesenter, 2023)
Electricity price data	Historical data from the period 2013-2022 for the South-West region of Norway (Market data, 2023)
NOK/US \$ conversion rate	Historical data for the period 2013-2022 (Valutakurser, 2023)
Wind farm capacity	1.5 GW
PEM electrolyzer capacity	1.5 GW
PEM electrolyzer location	Onshore (connected to the offshore wind farm by a subsea power cable)
Hydrogen selling price (average)	6.8 \$/kg H_2 (Vickers et al., 2020)
H_2 price margin requirement vs. electricity price	5%
Energy density of H_2 (LHV)	33.3139 kWh/kg H_2 (Energy density, 2022)

Table 3
Average values for some key parameters during the 10-year simulation period (data from 2013-2022). The PEM electrolyzer capacity factor gives the percentage of time the electrolyzer was in operation (turned on) during the 10-year period, and the efficiency is the average value for the time that it was operating.

Parameter	Average
Wind speed	8.2 m/s
Wind farm capacity factor	38.4%
Electricity price	58.6 \$/MWh
PEM electrolyzer efficiency	66.8%
PEM electrolyzer capacity factor	61.4%

4.2.2. Added revenue from hydrogen production

The results show that hydrogen production adds substantial revenue to the wind farm with the assumed hydrogen selling price of 6.8 \$/kg H_2. The yearly revenues with and without hydrogen production and the added hydrogen revenues are shown in Fig. 14. For the first seven years (2013–2019) the revenue with hydrogen production was much higher than the revenue without hydrogen production. In the worst year (2013) the revenue increased by a factor of 2.6 with hydrogen production (compared to only selling electricity), and in the best year (2015) it increased by a factor of 5.9. The last three years (2020–2022) show the enormous effect that the electricity price has on this factor. First, in 2020 a very low electricity price pushed the revenue increase factor with hydrogen production up to 11.3. Then the increasing electricity prices towards the end of 2021 and throughout most of 2022 had the opposite effect, and the revenue increase factor with hydrogen production consequently went down to 1.5 in 2021 and just 1.05 in 2022. This shows that despite the very high electricity price in 2022 the control system described in Section 3.2 ensured that the revenue with hydrogen production was 5% higher than it would have been without hydrogen production, and in years with more "normal" electricity prices the

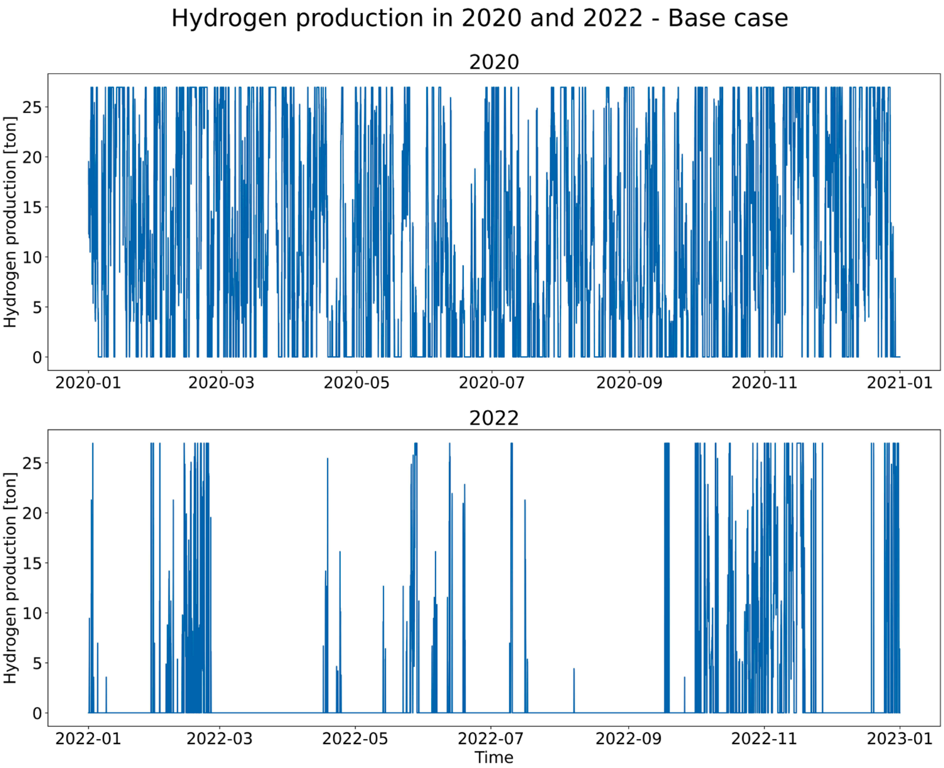

Fig. 12. Hydrogen production in 2020 and 2022 for the base case described in Section 4.1.

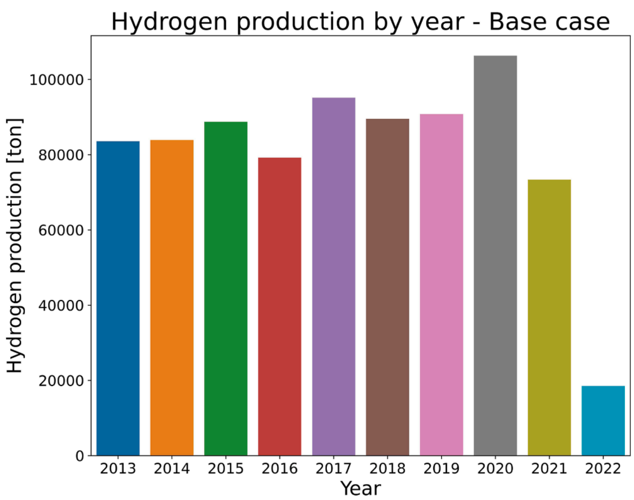

Fig. 13. Yearly total hydrogen production in the base case described in Section 4.1.

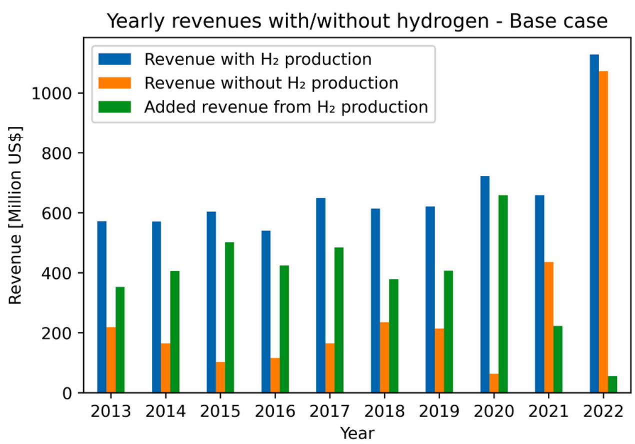

Fig. 14. Yearly revenues with and without hydrogen production, as well as the added revenue with hydrogen production. All revenues are for the base case described in Section 4.1.

revenue was several times higher with hydrogen production than without. The accumulated revenues for the whole 10-year period are shown in Fig. 15. However, it must be emphasized that the revenue does not consider the added cost of the hydrogen production, which must be included when analyzing the lifetime of wind-hydrogen projects. These costs are included in the calculation of net present value (NPV) in Section 4.2.3.

4.2.3. Levelized cost of hydrogen/energy (LCOH/LCOE) and net present value (NPV)

This section presents the calculation of the levelized cost of hydrogen (LCOH), levelized cost of energy (LCOE) and net present value (NPV) of the hydrogen system with the base case conditions described in Section 4.1. LCOH and LCOE are economic calculation methods used to estimate the cost per unit of hydrogen and energy produced, respectively, during a project's lifetime. The formulas used to calculate LCOH and LCOE in this study are given by Eqs. 11 and 12 (Levelized Cost of Energy LCOE, 2024):

$$LCOH = \sum_{t=0}^{n} \frac{I_t + O_t + F_t}{(1+r)^t} \Big/ \sum_{t=0}^{n} \frac{H_t}{(1+r)^t} \tag{11}$$

$$LCOE = \sum_{t=0}^{n} \frac{I_t + O_t + F_t}{(1+r)^t} \Big/ \sum_{t=0}^{n} \frac{E_t}{(1+r)^t} \tag{12}$$

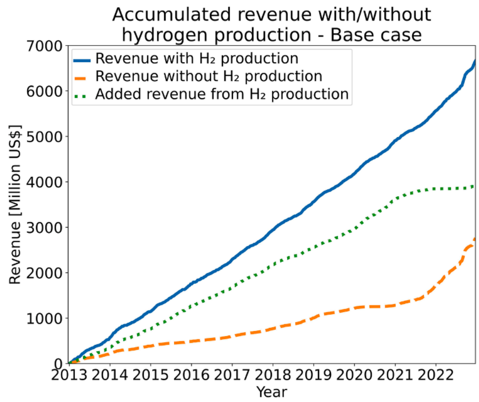

Fig. 15. Accumulated revenues with and without hydrogen production, as well as the added revenue with hydrogen production. All revenues are for the base case described in Section 4.1.

where I_t, O_t and F_t are the investment cost (CAPEX), operating expenses (OPEX) and fuel cost for each year t. Here the fuel is the electricity used by the PEM electrolyzer. The total number of years (lifetime) is given by n, and the assumed discount rate of the project is given by r. H_t and E_t are the hydrogen production and energy production for each year t.

NPV is an economic calculation method used to evaluate the profitability of a project when the whole lifetime of the system is included. The formula used to calculate the NPV is given by Eq. 13 (Net Present Value NPV, 2024):

$$NPV = \sum_{t=0}^{n} \frac{R_t - I_t - O_t - F_t}{(1+r)^t} \tag{13}$$

where R_t is the revenue of each year t. All the other variables are the same as in LCOH (Eq. 11) and LCOE (Eq. 12). The project is estimated to be profitable if the calculated NPV is positive and unprofitable if the NPV is negative.

The current lifetime of PEM electrolyzers was estimated to be in the range 30000–90000 hours in three recent reports by DNV (Hydrogen forecast to, 2050, 2022), IRENA (Taibi et al., 2020) and IEA (The Future of Hydrogen, 2019). The same three reports estimate that this could potentially increase to the range 80000–150000 hours in the long term towards 2050. The number of operating hours in the 10-year base case simulation described in Sections 4.1 and 4.2 was approximately 54000 hours. This is near the middle of the range estimated for current PEM electrolyzer technology in the three reports referenced above. For the base case it was therefore assumed that the lifetime of the PEM electrolyzer is 10 years, i.e., the lifetime of the electrolyzer is equal to the length of the simulation period.

The current range of CAPEX for PEM electrolyzers was estimated to be 700–1800 \$/kW, and this could potentially decrease to the range 200–1000 \$/kW in 2050, according to DNV (Hydrogen forecast to, 2050, 2022), IEA (The Future of Hydrogen, 2019) and IRENA (Taibi et al., 2020). The midpoint of the estimated current cost range was used in the base case simulation in this study, i.e., 1250 \$/kW. The operation and maintenance cost of PEM electrolyzers was estimated to be 2% of CAPEX per year in a Greenstat report (Sæbø et al., 2021), 3% in the abovementioned DNV report (Hydrogen forecast to, 2050, 2022), and IEA estimated 2.2% with a potential to decrease to 1.5% in 2050 (Global average levelised cost of hydrogen production by energy source and technology, 2019). For the base case in this study, the midpoint of the current range was used i.e., 2.5% of CAPEX per year.

The cost of compression, storage and transportation of hydrogen was estimated in a recent report by Bloomberg New Energy Finance (Hydrogen Economy Outlook, 2020). For large hydrogen amounts, defined as more than 100 tons of hydrogen per day, with transport distances up to 1000 km, the estimated cost range is 0.05–0.58 \$/kg H_2 (Hydrogen Economy Outlook, 2020), depending on the transport distance (shorter transport distances is in the lower end of the cost range and vice versa). In the present study, the average daily hydrogen production in the base case was more than 100 tons/day and the transport distance was assumed to be below 1000 km. It was assumed that the exact transport distance will vary, and the midpoint of the cost range was therefore chosen as the average compression, storage and transportation cost in this study, i.e., 0.315 \$/kg H_2.

The discount rate in the base case was set to 6.75%, which was the average unlevered discount rate for offshore wind projects reported by Nordic respondents in a survey by Grant Thornton (Renewable energy discount rate survey results, 2018). No discount rates for hydrogen projects were included in (Renewable energy discount rate survey results, 2018), but in this study it is assumed that these will be similar to those reported for offshore wind. A summary of the economic parameters for the base case is shown in Table 4. Potential changes in the economic parameters and the effects on the results of the case study is presented in the sensitivity analysis in Section 4.2.4. This analysis also includes potential changes in other parameters, e.g., the price of electricity and H_2, efficiency of the PEM electrolyzer and the wind farm capacity factor.

The LCOH, LCOE and NPV for the base case was 6.04 \$/kg H_2, 0.181 \$/kWh and approximately 442 million \$, respectively (Table 5). The LCOH for the base case in this study is within the estimated range of 2.5–6.8 \$/kg H_2 for green hydrogen with current technology given in (Vickers et al., 2020). The NPV is positive, which indicates that the project would be profitable with the conditions and parameters used in the base case. To analyze the effect of the control system, the part that uses the electricity price and hydrogen selling price to decide when to produce hydrogen (described in Section 3.2) was deactivated before running the base case simulation again. This means that hydrogen was produced whenever the power from the wind farm was above 10% of the rated power of the PEM electrolyzer, without any regard for the price of electricity in the given time interval. This resulted in a LCOH of 8.86 \$/kg H_2, LCOE of 0.266 \$/kWh and a NPV of 181 million \$ (Table 5). These results demonstrate the positive effect of the control system developed in this work. The LCOH and LCOE are reduced by 32% and the NPV is increased by 144% when the control system is active compared to when it is deactivated. All other conditions are kept the same, so this effect is solely due to the control system.

4.2.4. Sensitivity analysis

A sensitivity analysis was performed where the effects of changing some of the variables in the base case were analyzed. The changed variables were the hydrogen selling price, electricity price, wind speed, discount rate, wind farm capacity factor, as well as the CAPEX, efficiency and lifetime of the PEM electrolyzer. One variable was changed at a time and all other variables were kept the same as in the base case. The magnitude of the change for each variable is decided based on what is deemed realistic. For example, both the hydrogen price and electricity price have large fluctuations, so these are reduced and increased by up to 80% from the base case. However, the wind speed is only reduced and increased by up to 40% since the average wind speed usually does not vary more than that between different wind farm locations. Other

Table 4
Economic parameters used in the calculations of LCOH, LCOE and NPV for the base case described in Section 4.1. The reasons for choosing these values and the sources that are used are given in the text in Section 4.2.3.

Parameter	Value
PEM electrolyzer lifetime	10 years
PEM electrolyzer CAPEX (incl. BoP)	1250 \$/kW
PEM electrolyzer operation and maintenance cost	2.5% of CAPEX per year
Cost of hydrogen compression, storage and transport	0.315 \$/kg H_2
Discount rate	6.75%

Table 5
Calculated LCOH, LCOE and NPV for the base case (described in Sections 4.1–2) with and without the part of the control system that considers the price of electricity and hydrogen (described in Section 3.2).

Calculation method	Base case with price control system	Base case without price control system
Levelized cost of hydrogen (LCOH)	6.04 \$/kg H_2	8.86 \$/kg H_2
Levelized cost of energy (LCOE)	0.181 \$/kWh	0.266 \$/kWh
Net present value (NPV)	442 million \$	181 million \$

variables, e.g., the CAPEX of PEM electrolyzers, are varied based on future projections from literature sources. The magnitude of the change for each variable is given below.

The analysis focuses on the effect the changing variables have on three metrics: total hydrogen production, NPV and LCOH. The range of change (RoC) is also analyzed as a part of the sensitivity analysis. The RoC is defined here as the percentage range of the change that occurs in the hydrogen production, NPV and LCOH as a consequence of the changes in the eight abovementioned variables. For example, if the lowest NPV in one of the analyses is negative 400 million \$ and the highest NPV is positive 800 million \$, the RoC relative to the base case NPV of 442 million \$ would be −190% to +81%, i.e., from a reduction of 190% up to an increase of 81%.

4.2.4.1. Hydrogen selling price. The effect of different hydrogen selling prices on the base case results was analyzed by running the base case simulation with hydrogen selling prices 20, 40, 60 and 80% higher and lower than the base case price of 6.8 \$/kg H_2, i.e., a hydrogen price range of 1.36–12.24 \$/kg H_2. The lowest price of 1.36 \$/kg H_2 fits very well with the lowest forecast LCOH for 2050 from IEA, which is 1.3 \$/kg H_2 (Global average levelised cost of hydrogen production by energy source and technology, 2019).

4.2.4.2. Electricity price. The effect of different electricity prices on the base case results was analyzed by running the base case simulation with electricity prices that were 20, 40, 60 and 80% higher and lower than the base case price. This price increase/decrease was done for every 1-hour interval throughout the 10-year simulation period.

4.2.4.3. Wind speed. Wind speeds 10, 20, 30 and 40% higher and lower than the base case wind speeds were used in the simulation. The wind speed increase/decrease was done for every 1-hour interval throughout the 10-year simulation period.

4.2.4.4. Discount rate. Simulations were performed with discount rates 10, 20, 30 and 40% higher and lower than the base case discount rate of 6.75%, i.e., a discount rate range of 4.05–9.45%. This fits well with the estimated unlevered discount rate values for any renewable energy technology project in (Renewable energy discount rate survey results, 2018), where 95% of the estimated discount rates are within this range.

4.2.4.5. PEM electrolyzer CAPEX. The effect of changing the CAPEX of the PEM electrolyzer was analyzed by running the base case simulation with CAPEX values 20, 40, 60 and 80% lower and 20 and 40% higher than the base case CAPEX of 1250 \$/kW, i.e., a CAPEX range of 250–1750 \$/kW. The lower end of this range fits well with the lowest forecast for 2050 by IEA (The Future of Hydrogen, 2019) and IRENA (Taibi et al., 2020), while the upper end of the range is the highest CAPEX estimate for current facilities (The Future of Hydrogen, 2019). The CAPEX is not increased by more than 40% in this sensitivity analysis since that would go above 1800 \$/kW, which is deemed unrealistic.

4.2.4.6. PEM electrolyzer efficiency. Simulations were performed with PEM electrolyzer efficiencies increased and decreased by 2.5, 5, 7.5 and 10% compared to the base case efficiency. The choice of this range was based on forecast improvements in PEM electrolyzer efficiency over the next three decades. IEA forecasts that the average efficiency of PEM electrolyzers could increase to 74% (The Future of Hydrogen, 2019) in 2050, which is a 10.8% increase relative to the average efficiency of 66.8% achieved in the base case in this study (see Table 3). IRENA forecasts that the average energy usage of PEM electrolyzers could decrease to 45 kWh/kg (Taibi et al., 2020) in 2050. If the average efficiency of 66.8% in the base case is converted to energy usage, this will result in approximately 49.87 kWh/kg, which means that a decrease to 45 kWh/kg would constitute a decrease of 9.8% relative to the base case in this study. Based on this estimate, the maximum improvement relative to the base case efficiency was set to 10%. A decrease of up to 10% was also included in the analysis to account for cases with lower efficiencies, for example due to very fluctuating input power. This increase/decrease was done for every 1-hour interval throughout the 10-year simulation period.

4.2.4.7. PEM electrolyzer lifetime. The effects of different lifetimes of the PEM electrolyzer on the base case simulation were tested with lifetimes decreased by 30% and increased by 30, 60, 90, 120 and 150% relative to the base case lifetime. The choice of this range was based on forecast improvements in the lifetime of PEM electrolyzers over the next three decades. IEA forecasts that the lifetime of PEM electrolyzers could increase to 150000 hours (The Future of Hydrogen, 2019) in 2050, up from a minimum of 30000 hours today (The Future of Hydrogen, 2019). IRENA forecasts that the lifetime could increase to 120000 hours (The Future of Hydrogen, 2019) in 2050, up from a minimum of 50000 hours today (Taibi et al., 2020). Translating these estimates into years will depend on the electrolyzer capacity factor, i.e., how much of the year the electrolyzer is operating. In this analysis, it was decided to use 7 years as the minimum lifetime (30% reduction from the base case) and 25 years as the maximum lifetime (150% increase from the base case). With the capacity factor of 61.4% (see Table 3) from the base case, this translates into the approximate range of 38000–135000 hours. The decreased lifetime of 7 years was included to account for unexpected degradation of the electrolyzer due to fluctuating operating conditions. For the cases with increased lifetime (more than 10 years), the data from the 10-year simulation were reused. For example, for the case with a lifetime of 25 years, the 10-year datasets were used twice and then the first five years of the dataset were used a third time to account for years 21–25. The 10-year datasets from 2013–2022 (wind speed, electricity price, NOK/US\$ conversion rate) will obviously not repeat in this way in the real world. However, these datasets will still give an estimate of what could be expected in a 10-year period if these three variables act similarly over time compared to the 2013–2022 period. Therefore, these datasets are used as a base case for any 10-year period, including the 2050-cases described in Sections 4.3 and 4.4.

4.2.4.8. Wind farm capacity factor. Simulations were performed with wind farm capacity factor values decreased and increased by 10, 20 and 30% relative to the base case capacity factor. The choice of this range was based on forecast improvements in the capacity factor for floating wind turbines over the next three decades. In a recent report (Energy transition Norway, 2022), DNV estimates that the current capacity factor of floating wind turbines is 45% and that this could be increased to 59% in 2050 (Energy transition Norway, 2022). This constitutes a possible improvement in the capacity factor up to 30% relative to current technology. Improvements of 10–30% were therefore used in this study. The analysis also included a 10–30% decrease in capacity factor to analyze the effect of higher-than-expected downtime for the wind farm. The capacity factor increase/decrease was done for every 1-hour interval throughout the 10-year simulation period.

4.2.4.9. Sensitivity analysis results. The combined results and the most important conclusions that can be drawn from the sensitivity analysis are discussed in this section. Fig. 16 shows the effect on the total hydrogen production from changes in the eight variables included in the sensitivity analysis, and Fig. 17 shows the RoC in the total hydrogen production for the same variables. The most significant negative effects, i.e., reductions in total hydrogen production, occur when either the hydrogen selling price or wind speed are reduced. Changes in the other variables have a much smaller effect in the negative direction on the total hydrogen production, ranging from a 25% reduction in hydrogen production (from reduced PEM electrolyzer lifetime) to no effect at all (discount rate and PEM electrolyzer CAPEX). The most significant positive effect on the total hydrogen production came from the increase in the lifetime of the PEM electrolyzer. This was expected since the lifetime of the system was increased from 10 years in the base case to 25 years in the most optimistic case, and this will naturally have a very large effect on the total hydrogen production. An increase in the wind speed also had a noticeable positive effect on the total hydrogen production, seen by the 43% increase in the most optimistic case. The other variables had a smaller effect in the positive direction, ranging from 16% increase in hydrogen production (wind farm capacity factor) to no effect at all (discount rate and PEM electrolyzer CAPEX).

Fig. 18 shows the effect on the NPV from changes in the eight variables included in the sensitivity analysis and Fig. 19 shows the RoC in the NPV for the same variables. Variations in the selling price of hydrogen had the most significant effect on the NPV, both in the positive and negative direction. The lowest selling price resulted in a 590% decrease in the NPV from the base case, while the highest selling price resulted in a 747% increase in the NPV. The second largest decrease in the NPV came when the wind speed was reduced, which resulted in a 405% decrease in the NPV in the worst case. A higher electricity price and higher CAPEX for the PEM electrolyzer also had a significant negative effect on the NPV with a 191% and 200% decrease in the NPV, respectively. The negative effect on the NPV from the four other variables ranged from a 113% decrease (wind farm capacity factor) to a 56% decrease (discount rate). On the positive side the most significant positive effects came from the hydrogen selling price, followed by the CAPEX and lifetime of the PEM electrolyzer. A lower CAPEX resulted in a 400% increase in the NPV in the most optimistic case, while a longer lifetime resulted in a 363% increase. A lower electricity price and higher wind speed also had noticeable positive effects with up to a 255% increase in the NPV from both variables in the most optimistic cases. The positive effect on the NPV from the three other variables ranged from a 93% increase (wind farm capacity factor) to a 67% increase (discount rate) in the most optimistic cases.

Fig. 20 shows the effect on the LCOH from variations in the eight variables included in the sensitivity analysis and Fig. 21 shows the RoC in the LCOH for the same variables. A decrease in the hydrogen selling price had a very large negative effect on the LCOH in the worst case, shown by the 186% increase in LCOH when the selling price was 20% of the base case selling price. In all the other cases the hydrogen selling price had a very small effect on the LCOH. The second largest negative

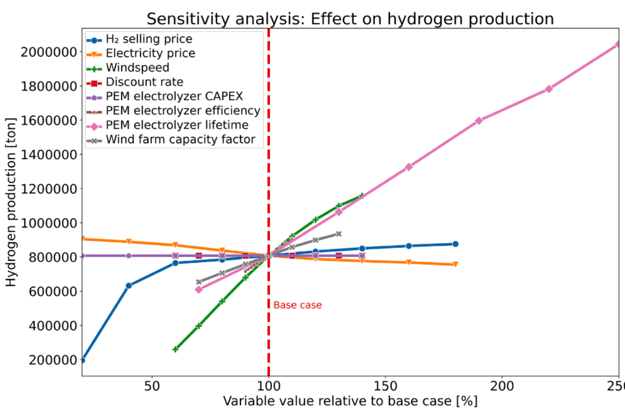

Fig. 16. Effect on the total hydrogen production from variations in selected variables (described in Section 4.2.4).

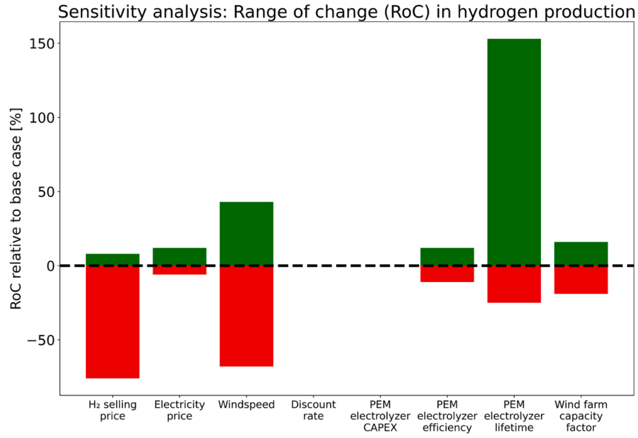

Fig. 17. RoC in total hydrogen production from variations in selected variables (described in Section 4.2.4). Changes in discount rate and PEM electrolyzer CAPEX did not influence the total hydrogen production.

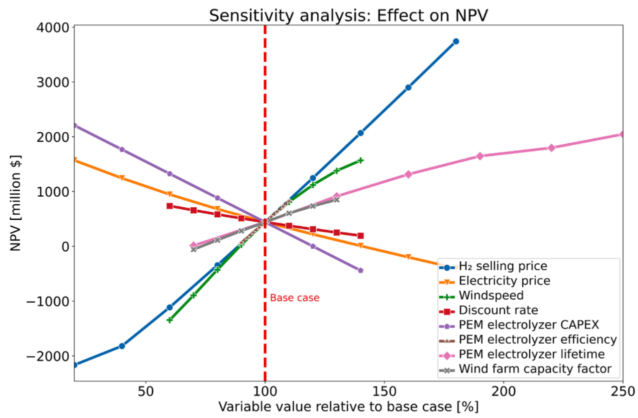

Fig. 18. Effect on the NPV from variations in selected variables (described in Section 4.2.4).

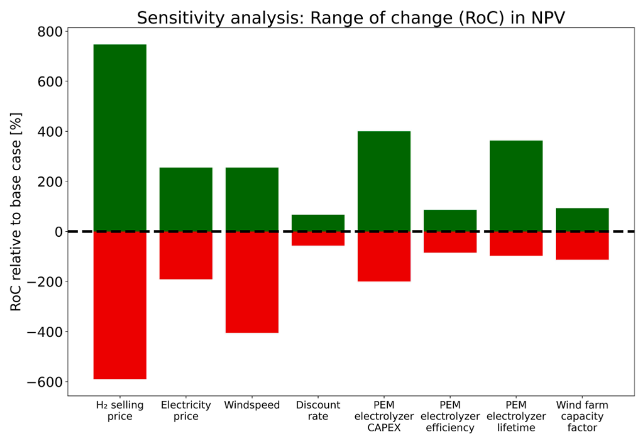

Fig. 19. RoC in NPV from variations in selected variables (described in Section 4.2.4).

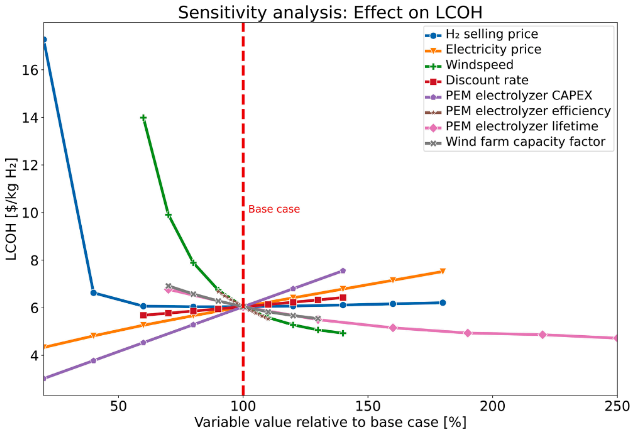

Fig. 20. Effect on the LCOH from changes in selected variables (described in Section 4.2.4).

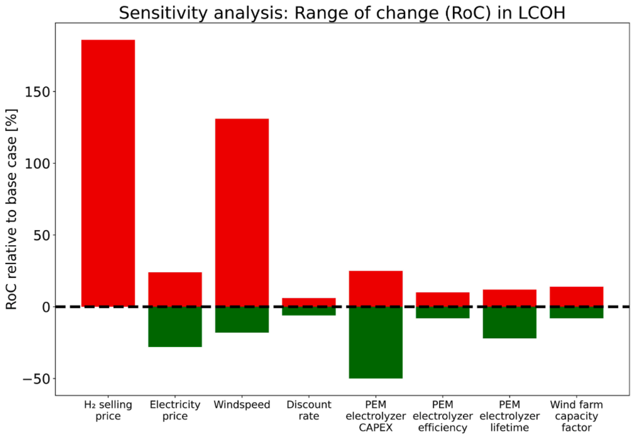

Fig. 21. RoC in LCOH from variations in selected variables (described in Section 4.2.4). In this figure an increased LCOH is colored red and a decreased LCOH is colored green, since a higher cost is considered a negative (red) effect and a lower cost is considered a positive (green) effect.

effect on the LCOH came when the wind speed was reduced, which resulted in a 131% increase in the LCOH in the worst case. The negative effect on the LCOH from the other variables is much smaller, ranging from a 24–25% increase in LCOH (electricity price and PEM electrolyzer CAPEX) to a 6% increase (discount rate). The most significant positive effect on the LCOH came from a reduction in the CAPEX of the PEM electrolyzer, which resulted in a 50% reduction in the LCOH in the most optimistic case. A lower electricity price, longer lifetime for the PEM electrolyzer and higher wind speed also had noticeable positive effects on the LCOH with reductions of 28%, 22% and 18%, respectively. The last three variables had smaller positive effects on the LCOH, shown by the 8% reductions in the LCOH from increased wind farm capacity factor and PEM electrolyzer efficiency, and a 6% reduction in the LCOH with the most optimistic discount rate.

4.3. Optimistic case for 2050

A simulation of a potential case with starting date around 2050 is proposed in this section. This case uses the same basic wind-hydrogen system, control system and data sources as in the base case described in Section 4.1, but many of the variables are changed to the most optimistic setting to evaluate what could be possible in 2050 (Table 6). The three 10-year datasets listed in Table 2 are reused in the same way as described in Section 4.2.4 to reflect that the lifetime of the PEM electrolyzer is extended from 10 to 25 years. All variables from Section 4.2.4 are set to the most optimistic setting/value, except the wind speed. This is kept the same as in the base case since it is assumed that the wind farm would be in the same location in 2050. The OPEX for the PEM electrolyzer was also adjusted to the forecast 2050 value of 1.5% of CAPEX per year (Global average levelised cost of hydrogen production by energy source and technology, 2019). It should be noted that the values/settings listed in Table 6 are very optimistic, and it is very difficult to judge the probability of all these improvements occurring by 2050. Particularly the electricity price has an extremely high uncertainty. NVE forecasts an average electricity price of 510 NOK/kWh in 2040 (Langsiktig kraftmarkedsanalyse, 2021–2040, 2021) for the region used in this study, a value close to the average price of the 10-year base case (503 NOK/kWh, or 58.6 $/MWh). This means that the 80% reduction from the base case used in the 2050 case is also 80% lower than the 2040 forecast by NVE.

Table 6
Values for the variables that were changed for the optimistic 2050 case relative to the base case.

Variable	Value in 2050 optimistic case
Electricity price	80% reduction from base case
Hydrogen selling price	1.36 $/kg H_2
Wind farm capacity factor	30% increase from base case
PEM electrolyzer CAPEX	250 $/kW
PEM electrolyzer OPEX	1.5% of CAPEX per year (Global average levelised cost of hydrogen production by energy source and technology, 2019)
PEM electrolyzer efficiency	10% increase from base case
PEM electrolyzer lifetime	25 years
Discount rate	4.05%

The results from the optimistic 2050 case show that the improvements in technology and reduction in prices causes the wind-hydrogen system to produce more hydrogen per year. The average yearly production in the base case was approximately 80 000 tons while the average yearly production in the 2050 case was approximately 100 000 tons, so the combined technology improvements increased the average production by approximately 25%. The reduced costs and electricity price lowered the LCOH by approximately 84% to 0.96 $/kg H_2 from 6.04 $/kg H_2, but the reduced selling price of hydrogen caused the average added revenue per year from hydrogen production to decline compared to the base case. The average added revenue per year in the base case was approximately 390 million $ while it was approximately 100 million $ in the 2050 case, i.e., around a 74% decline. However, the increased lifetime of the hydrogen facility and the lower discount rate resulted in an increase in the NPV from 442 million $ in the base case to 659 million $ in the 2050 case, i.e., around a 33% increase. These results show that the cost of producing hydrogen (LCOH) via electrolysis can be significantly lowered if the forecast cost reductions and technology improvements are achieved together with a significant reduction in electricity price. However, since the selling price of hydrogen presumably would also be lowered in parallel with this development, the profitability of a wind-hydrogen system might not necessarily be much higher in the future than it would currently be with a higher selling price of hydrogen. With the right price of hydrogen and an appropriate control system, a wind-hydrogen system could be profitable already with today's technology, as shown by the positive NPV in the base case in Section 4.2.3.

The control system (described in Section 3.2) improved the economic results of the wind-hydrogen system in the 2050 case as well, just as it did in the base case (Section 4.2.3 and Table 5). The simulation of the 2050 case was also run without the price-based part of the control system, and this resulted in a higher LCOH and LCOE and a lower NPV (see Table 7). These results again demonstrate the positive effect of the control system developed in this study. The LCOH and LCOE were reduced by approximately 10% and the NPV was increased by approximately 30% when the control system is active compared to when it is deactivated. All other conditions are kept the same, so this effect is solely due to the control system.

4.4. Comparison with alternative 2050 scenarios

This section will compare the base case (Sections 4.1 and 4.2) and the optimistic 2050 case (Section 4.3) with seven alternative 2050 scenarios. The focus of comparison is the LCOH, since this is the most used metric in techno-economic analyses of wind-hydrogen systems. All cases in this section used the same model as described in the previous sections with the same settings/values as the optimistic 2050 case, except for a few modifications. The four cases described in previous sections and the seven new cases are listed in Table 8. The LCOH of all 11 cases included in this study are also summarized in Table 8 and shown in Fig. 22.

Case 11 is the only case where the electrolyzer is located offshore and the wind farm is off-grid, i.e., not connected to the onshore electricity grid. The simulation settings are the same as case 3, except that the electricity cost is substituted with costs related to the offshore wind farm. In addition to the wind farm itself, these costs include desalination of sea water, lithium-ion batteries and a separate platform for the hydrogen production facility. These costs and other information about this case are listed in Table 9. All cost values are the most optimistic forecasts for 2050 from the listed sources. Since the facility is not connected to the electricity grid, the price control part of the control system (described in Section 3.2) is deactivated. The lithium-ion batteries are only intended to act as a buffer in the hydrogen production system, and the capacity is therefore set to provide around 1 hour of back-up power to the electrolyzer at 10% of its rated power with a battery state of charge (SOC) range of 20–80%. This means that the energy capacity of the battery is 250 000 kWh and the power capacity is 150 000 kW. The inclusion of batteries has a negligible effect on the total hydrogen production, as described in (Egeland-Eriksen et al., 2023), but it is assumed that it will be necessary to have batteries in an off-grid system of this type to act as a buffer that can smooth out the most rapid fluctuations in the input power to the electrolyzer.

The results from case 5 show that the price of electricity will have a big effect on the LCOH for future electrolysis systems. Case 5 used the electricity price data without the 80% reduction used in case 3 and 4, and this resulted in a LCOH of 2.11 \$/kg H_2 which is more than double the LCOH of case 3. It is also well above the assumed selling price of 1.36 \$/kg H_2, which means that the facility would not be profitable under those conditions, however, still within the LCOH (from low-carbon electricity) range estimated by IEA for 2050 (1.3-3.3 \$/kg H_2 (Global average levelised cost of hydrogen production by energy source and technology, 2019)). The LCOH of 3.06 \$/kg H_2 from case 6 shows that the control system had a positive effect in the scenario with higher electricity prices as well. The control system caused the LCOH of case 5 to be 31% lower than case 6.

Table 7
Calculated LCOH, LCOE and NPV for the optimistic 2050 case, with and without the price control system for electricity and hydrogen (described in Section 3.2).

Calculation method	Optimistic 2050 case with price control system	Optimistic 2050 case without price control system
Levelized cost of hydrogen (LCOH)	0.96 \$/kg H_2	1.07 \$/kg H_2
Levelized cost of energy (LCOE)	0.029 \$/kWh	0.032 \$/kWh
Net present value (NPV)	659 million \$	508 million \$

Table 8
LCOH for all simulation cases included in this study. Cases 1 and 2 used current technology and costs, while Cases 3–11 used technology improvements and cost reductions that have been forecast for 2050 (see Table 6 and Table 9).

Case description	LCOH
1. Base case (Sections 4.1 and 4.2)	6.04 \$/kg H_2
2. Base case without price control system[a]	8.86 \$/kg H_2
3. Optimistic 2050 case (Section 4.3)	0.96 \$/kg H_2
4. Optimistic 2050 case without price control system[b]	1.07 \$/kg H_2
5. 2050 case without cheap electricity[c]	2.11 \$/kg H_2
6. 2050 case without cheap electricity and without price control system[d]	3.06 \$/kg H_2
7. Straight from grid 2050 case[e]	0.82 \$/kg H_2
8. Straight from grid 2050 case without price control system[f]	0.95 \$/kg H_2
9. Straight from grid 2050 case without cheap electricity[g]	1.63 \$/kg H_2
10. Straight from grid 2050 case without cheap electricity and without price control system[h]	3.04 \$/kg H_2
11. Off-grid 2050 case	4.96 \$/kg H_2

[a] Same as case 1, except the price control part of the control system (described in Section 3.2) is deactivated.
[b] Same as case 3, except the price control part of the control system (described in Section 3.2) is deactivated.
[c] Same as case 3, except the original electricity price data from the base case is used without any price reduction.
[d] Same as case 5, except the price control part of the control system (described in Section 3.2) is deactivated.
[e] Same as case 3, except H_2 is produced with power from the public electricity grid. This enables the PEM electrolyzer to operate constantly at the rated power (1.5 GW) when it is turned on. The control system turns the electrolyzer off when the price of electricity is too high.
[f] Same as case 7, except the price control part of the control system (described in Section 3.2) is deactivated. This means the PEM electrolyzer produces hydrogen at constant rated power (1.5 GW) from the grid throughout the entire project lifetime.
[g] Same as case 7, except the original electricity price data from the base case is used without any price reduction.
[h] Same as case 9, except the price control part of the control system (described in Section 3.2) is deactivated.

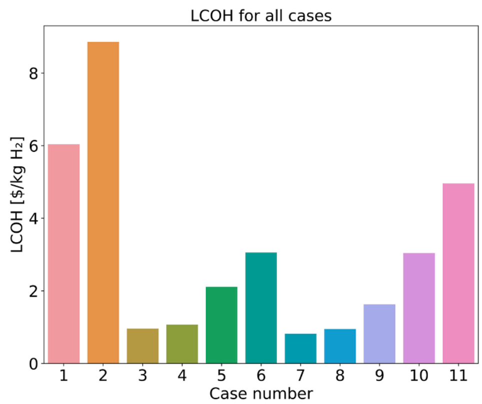

Fig. 22. LCOH for all cases (listed in Table 8). Cases 1 and 2 used current technology levels and costs (listed in Tables 2–4), while Cases 3–11 used technology improvements and cost reductions forecast for 2050 (listed in Table 6 and Table 9).

Table 9
Parameters used in the off-grid 2050 case. A conversion rate between € and $ of 1.11 $/€ was used for the wind farm OPEX.

Parameter	Value
Wind farm CAPEX	1400 $/kW (Future of wind: Deployment, 2019)
Wind farm OPEX	41 €/kW/year (OPEX Benchmark, 2023)
Lithium-ion battery energy capacity	250 000 kWh
Lithium-ion battery power capacity	150 000 kW
Lithium-ion battery CAPEX	87 $/kWh (Cole et al., 2021)
Lithium-ion battery OPEX	5 $/kW/year (Cole et al., 2021)
Desalination of sea water cost	1.26 $/m^3 (Sæbø et al., 2021)
Desalination water amount	283.2 liter/h per MW of electrolyzer power (Series, 2022)
Cost of platform for electrolysis, desalination and compression of hydrogen	3 000 000 $/MW of PEM electrolyzer power (Sæbø et al., 2021)

Cases 7 and 8 were included to compare the wind-hydrogen system to a hydrogen system that receives electricity with constant power from the public electricity grid. This enables the electrolyzer to always operate at the rated power (1.5 GW) when it is producing hydrogen instead of following the fluctuations of the power from the wind farm. The resulting LCOH was 0.82 $/kg H_2, which is almost 15% lower than the LCOH of case 3 (where the power comes from the wind farm). The LCOH of 0.95 $/kg H_2 for case 8 shows that the control system had a positive effect once again, since the LCOH of case 7 is almost 14% lower than case 8. With regards to cases 7 and 8 it should be noted that there are not many locations in the world where the electricity grid is 100% renewable energy. So even though the LCOH can be up to 15% lower with grid electricity compared to the wind farm, this would not be green hydrogen if the electricity grid includes non-renewable energy technologies (e.g., coal, natural gas). However, this could be a good solution in locations that have a grid with only renewable energy. For example, the Norwegian grid is quite close to this due to its very high hydro power share.

Cases 9 and 10 are identical to cases 7 and 8, except that the price of electricity is *not* reduced by 80% from the 2013-2022 dataset like it is in cases 7 and 8. Once again, this shows the impact that the price of electricity has on the LCOH of electrolysis systems. The LCOH of case 9 was 1.63 $/kg H_2. This is double the LCOH of case 7, which was identical except for the 80% reduction in electricity price. The LCOH of case 10 is 3.04 $/kg H_2, which shows that the control system had a very big impact in this scenario. The LCOH was 46% lower with the control system activated (case 9) compared to the case with the control system deactivated (case 10).

Case 11 was included in the study to compare the other cases to a scenario where an offshore wind farm is built without connection to the onshore electricity grid. This wind farm would be solely dedicated to hydrogen production. Therefore, the cost of electricity was removed from this simulation and replaced with the cost of the wind farm and associated components, including desalination of sea water, lithium-ion batteries and a platform for the hydrogen facility. This wind-hydrogen system would be independent of the price of grid electricity since it is not connected to the grid, so the price control part of the control system was not used in this case. The LCOH for this case was 4.96 $/kg H_2, which shows that an offshore off-grid system would not be competitive with an onshore grid-connected system with the conditions used in this study. However, it should be noted that half of this cost is the platform for the electrolyzer, compressor and desalination plant. So, if a new offshore wind turbine is designed where these components are integrated within the turbine structure without increasing the structure cost, the LCOH could potentially be lowered to approximately 2.50 $/kg H_2. This is within the range estimated by IEA of 1.3-3.3 $/kg H_2 (Global average levelised cost of hydrogen production by energy source and technology, 2019) for green hydrogen in 2050. However, it is still above the LCOH of all the other 2050 cases in this study where the price control system is used, which range between 0.82 $/kg H_2 (case 7) and 2.11 $/kg H_2 (case 5). This indicates that an off-grid system of this type would be dependent on a higher selling price for hydrogen to be economically viable, and it would probably not be competitive with onshore hydrogen production.

4.5. Discussion of results

Section 4.2 describes the results of the base case simulation. This simulation used the polynomial regression model described in Section 2, the hydrogen production model and control system described in Section 3, and combined these with current technology and cost estimates to simulate hydrogen production via PEM electrolysis with electricity from a 1.5 GW offshore wind farm. The results show that such a system can be technically and economically viable already with today's technology, *if* a control system like the one developed in this study is used to optimize the interaction between the wind farm and the hydrogen facility. When the control system described in Section 3 was used, the resulting LCOH for the 10-year period 2013-2022 was 6.04 $/kg H_2, which is within the current estimated cost range of 2.5-6.8 $/kg H_2 for green hydrogen given in (Vickers et al., 2020). When the price-based part of the control system was deactivated the LCOH increased to 8.86 $/kg H_2, showing that the control system alone can reduce the LCOH by 32%. This shows that a well-functioning control system will be a vital part of future wind-hydrogen systems. The results also show that the revenue of the combined wind-hydrogen facility was higher than the revenue of the wind farm without hydrogen production when an average hydrogen selling price of 6.8 $/kg H_2 was used. This indicates that a hydrogen production facility with the control system developed in this study could increase the profit for the owner of an offshore wind farm under the given conditions. However, green hydrogen will still have to compete with grey hydrogen, and a LCOH of 6.04 $/kg H_2 is very high compared to the current cost range of grey hydrogen produced from natural gas, estimated to be 0.7-1.6 $/kg H_2 by IEA (Global average levelised cost of hydrogen production by energy source and technology, 2019). This leaves a gap of well over 4 $/kg H_2 between grey and green hydrogen in this case, which shows that green hydrogen production from offshore wind power is not economically viable with current technology and costs. It is therefore likely that green hydrogen projects will be dependent on subsidies for several years, until the costs are reduced to competitive levels. The number of years needed to reduce costs sufficiently to make green hydrogen competitive without subsidies is still very uncertain. The probability and timing of this occurring is outside the scope of this paper.

The results from the sensitivity analysis described in Section 4.2.4 show that several factors can have a large effect on the viability of wind-hydrogen systems of this type. The most important factors for the economic viability of these systems are the prices of hydrogen and electricity, and the general rule is that a low electricity price favors hydrogen production while a high electricity price favors selling the electricity directly to the grid. By producing hydrogen when the electricity price is low and selling this hydrogen when the H_2 price is higher than the cost of the electricity that was used to produce it, the wind farm can increase its total profit. Such optimization could help to increase the pace of the on-going energy transition towards more renewable energy. However, it is important to keep in mind that electricity is the main input to green hydrogen production together with water, which means that the cost of green hydrogen will always be tied to the price of the electricity that was used to produce it. In other words, cheap green hydrogen will *always* require cheap green electricity. This means that large-scale production of green hydrogen might not become a reality until such systems have reliable access to cheap green electricity throughout the whole lifetime of the system. There could probably be several ways to ensure this, e.g., long-term (several years) contracts with a fixed electricity price, or a combination of fixed-price contracts and spot prices so that a price-based control system that exploits price fluctuations can be used. Another important factor that must be explored is the potential feedback effect that large-scale price-based green hydrogen production would have on the electricity price. If many green hydrogen facilities start producing hydrogen every time the electricity price drops, this might stop the electricity price from going further down and perhaps also cause it to increase instead. If this effect gets large enough it would probably reduce and perhaps eliminate the advantage of price-based control systems in the production of green hydrogen. These considerations are outside the scope of this study, but future work is planned to explore these dynamics. While the prices of hydrogen and electricity are very important factors for wind-hydrogen systems, other factors can also have a large effect. The sensitivity analysis shows that the wind speed has a very large effect on the hydrogen production and economics of the system, demonstrating the importance of selecting the right location for the wind farm. The results also show that the potential reduction in the CAPEX of PEM electrolyzers can have a very positive effect on the system, with a potential LCOH reduction of 50% if the most positive cost forecast is achieved. Potential improvements in the lifetime of PEM electrolyzers could also have a significant effect and could reduce the LCOH by 22% in the best case. Improvements in the PEM electrolyzer efficiency and offshore wind farm capacity factor could both reduce the LCOH by 8%, while a lower discount rate could reduce the LCOH by 6%.

Sections 4.3 and 4.4 describe different scenarios where the simulation model and variables were modified to simulate future wind-hydrogen systems. Technology improvements and cost reductions that have been forecast for 2050 were used in these simulations. By using the most optimistic setting on all the variables from the sensitivity analysis, the LCOH of the 1.5 GW wind-hydrogen system was reduced to 0.96 $/kg H_2 with the control system and 1.07 $/kg H_2 without the control system. This demonstrates that even under the most optimistic conditions, the control system developed in this study was still able to reduce the LCOH by 10%. Both these LCOH values are actually *below* the range estimated for green hydrogen in 2050 by IEA, which is 1.3-3.3 $/kg H_2 (Global average levelised cost of hydrogen production by energy source and technology, 2019). The results from the 2050 case *without* electricity price reduction demonstrates the importance of the electricity price for these systems. The LCOH in this case was 2.11 $/kg H_2 with the control system and 3.06 $/kg H_2 without the control system, showing that the higher electricity price doubles and triples the LCOH with and without the control system, respectively. These results also show that the control system developed in this study has an even bigger positive effect when the electricity price is higher. The control system reduced the LCOH by 31% compared to the same case with the system deactivated. These results show that green hydrogen systems need to reach the most optimistic cost reduction forecasts for 2050 *and* have access to cheap green electricity to reach the cost range of grey hydrogen (0.7-1.6 $/kg H_2 (Global average levelised cost of hydrogen production by energy source and technology, 2019)). However, there are other factors that could make green hydrogen competitive with grey hydrogen even if the LCOH of green hydrogen does not reach the cost range of grey hydrogen. Higher CO_2 taxes (price of emissions) and direct subsidies to green hydrogen will both have this effect. These factors are outside the scope of this study and could be included in future work.

Four cases where grid electricity was used in the electrolyzer were also simulated (cases 7-10 in Table 8), two with the control system described in Section 3.2 and two without. The grid electricity enabled the electrolyzer to always operate at the rated power when it was turned on. The LCOH in case 7 (with control system) was 0.82 $/kg H_2 and in case 8 (without control system) it was 0.95 $/kg H_2, which shows that the control system once again had a positive effect by reducing the LCOH by 14%. Comparing these cases to the equivalent offshore wind cases (cases 3 and 4) shows that the LCOH is 15% and 11% lower when the electrolyzer is allowed to use grid electricity compared to when it is restricted to the offshore wind farm. However, it should be noted that hydrogen produced with grid electricity will only qualify as green hydrogen if the electricity grid is based on 100% renewable energy. Most countries will therefore need to drastically increase the share of renewable electricity in the national grid before green hydrogen production with grid electricity can become an option. Cases 9 and 10 used grid electricity without electricity price reduction, and the resulting LCOH were 1.63 $/kg H_2 with the control system (case 9) and 3.04 $/kg H_2 without the control system (case 10). Once again this shows that the control system has an even larger positive effect when the electricity price is higher, and in these cases the control system reduced the LCOH by 46%. These results also show that the LCOH were lower with grid electricity than in the equivalent offshore wind cases (cases 5 and 6). However, the difference between grid electricity and offshore wind was much bigger when the control system was active (23% lower) compared to when the control system was deactivated (less than 1% difference).

The results from the off-grid case (Case 11) indicates that the economics of offshore hydrogen production on a wind farm not connected to the onshore electricity grid will be challenging. In this case the electricity cost was removed from the simulation and the additional costs of offshore hydrogen production (platform, desalination plant, battery) were added to the simulation. All other costs/settings were kept at the most optimistic 2050 settings. This resulted in a LCOH of 4.96 $/kg H_2, which was by far the highest of all the 2050 cases. The LCOH could be reduced by up to 50% if the wind turbines are designed in such a way that the electrolyzer (including BoP), desalination plant and batteries are integrated into the turbine tower or foundation. However, the LCOH would still be higher than all the 2050 cases where the price-based control system is used, indicating that it will be difficult for an off-grid offshore wind-hydrogen farm to compete with onshore hydrogen production. However, other considerations which are outside the scope of this study could be favorable for offshore production, for example limited access to land areas or environmental issues.

The results of this study show that large-scale green hydrogen production using electricity from offshore wind farms can become technically and economically viable if conditions (technical, economical, geographical) are favorable, and a price-based control system is used to optimize the system. This shows that the combination of offshore wind farms and green hydrogen production could have a part to play in the energy transition in the coming decades. However, it must be emphasized that the results will be very different if the conditions for wind-hydrogen systems are unfavorable. A current real-world example of this is the extremely high electricity prices compared to previous years in Norway (and much of Europe) from the end of 2021 up to the time of writing (early 2024). In a future scenario where the electricity price remains high and the most optimistic technology improvements and cost reductions are not achieved, a wind-hydrogen system would need a very high hydrogen selling price to be profitable. It would then probably make much more sense to just sell the electricity from the wind farm directly to the grid. A high hydrogen price would also most likely be a serious obstacle for the demand for hydrogen and the spread of hydrogen technologies. Therefore, significant political and financial support will be needed if large-scale wind-hydrogen systems are to be built, given that it is challenging to accurately forecast any of the variables in this study with 100% accuracy for the entire lifetime of the system.

The LCOH estimates in this paper are within the same range as LCOH estimates in previously published research. As described in the literature review (Section 1.2), there are large variations in the LCOH in previously published research. Different studies use different scenarios, assumptions and modelling tools, so differences in the final results are to be expected. However, most of the reviewed studies are within typical ranges. With current technology and costs the LCOH estimates are mostly in the approximate range between 4 and 9 $/kg H_2, and when future scenarios are simulated the LCOH estimates are mostly in the approximate range between 1 and 4 $/kg H_2 (see Section 1.2 for all LCOH estimates). The LCOH estimates in this paper fit well within these ranges in both current and future scenarios. The exception is Case 11 (off-grid and offshore hydrogen production), which has a LCOH of 4.96 \$/kg H_2. This is higher than most future scenarios in previously published research, and it is also higher than all the other future scenarios in this study. Once again, this indicates that it could be challenging for an off-grid offshore wind-hydrogen system to compete with onshore hydrogen production.

5. Conclusions and future work

This paper presents the results of simulated case studies, analyzing the effects of a novel price-based control system in a 1.5 GW offshore wind-hydrogen facility in Norway. The novel control system was combined with a polynomial regression model that estimates the wind farm capacity factor based on wind speed input and a hydrogen production model based on a previously developed model (Egeland-Eriksen et al., 2023). Real-world wind speed and energy production data from a 2.3 MW FOWT were used to train the 12-degree polynomial regression model. The regression model was then combined with the hydrogen production model and the novel control system, as well as 10 years (2013-2022) of real-world data of wind speeds and electricity prices from a location in Norway, close to the planned location of the 1.5 GW *Utsira Nord* (Utsira Nord, 2024) floating offshore wind farm.

We simulated 11 different case studies of a 1.5 GW wind-hydrogen system, using both current and future (2050) scenarios. The results indicate that large-scale hydrogen production via PEM electrolysis with electricity from an offshore wind farm could become economically and technically viable if a price-based control system is used to decide when the wind power is used to produce hydrogen and when it is sold directly to the electricity grid. The novel control system developed in this study resulted in a LCOH of 6.04 \$/kg H_2 in the base case (current technology and costs), which is within current LCOH estimates for green hydrogen (2.5-6.8 \$/kg H_2 in (Vickers et al., 2020) and 3.2-7.7 \$/kg H_2 in (Global average levelised cost of hydrogen production by energy source and technology, 2019)). This was a 32% reduction in LCOH compared to the same case without the control system. However, this is still more than three times as high as the LCOH of grey hydrogen, currently estimated to be in the range 0.7-1.6 \$/kg H_2 (Global average levelised cost of hydrogen production by energy source and technology, 2019). When using technology improvements and cost reductions forecast for 2050, the resulting LCOH in the most optimistic cases were 0.96 \$/kg H_2 when only electricity from offshore wind was used and 0.82 \$/kg H_2 when the electrolyzer was allowed to use grid electricity. The latter will not qualify as green hydrogen though, unless the electricity grid is based on 100% renewable energy. The novel control system developed in this study had a positive effect in all simulation cases and reduced the LCOH by 10-46% compared to the equivalent cases without the control system. These results show that a control system of the type proposed in this study will be a crucial factor to make wind-hydrogen systems economically viable. Finally, the simulation case where the electrolyzer was located offshore in a 1.5 GW off-grid wind farm resulted in a LCOH of 4.96 \$/kg H_2, which indicates that it will be challenging for off-grid offshore wind-hydrogen systems to compete with onshore hydrogen production systems.

To increase the realism of the model, several aspects can be suggested. These include integration of even more realistic dynamics of PEM electrolyzer usage (ramp-up/cold start-up time, energy usage for standby mode) and its degradation over its lifetime; consider dynamic process simulations of the compression, storage and transport of hydrogen (instead of using a constant per kg of hydrogen) and of the desalination of sea water for the off-grid offshore scenarios (instead of using a constant per kg of hydrogen). The accuracy of the proposed model will also benefit from the addition of power electronics, and the price-based control system could benefit from access to a dynamic selling price of hydrogen instead of using a constant value. Furthermore, an analysis to simulate the effect that large-scale green hydrogen production with price-based control systems will have on the electricity price (feedback effect) will be useful toward the realization of real-world wind-hydrogen systems at the scale necessary to propel a sustainable transition.

CRediT authorship contribution statement

Sartori Sabrina: Conceptualization, Writing – review & editing. **Egeland-Eriksen Torbjørn:** Conceptualization, Formal analysis, Methodology, Software, Validation, Visualization, Writing – original draft, Writing – review & editing.

Declaration of Competing Interest

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

Data Availability

Data from the Zefyros wind turbine is property of UNITECH Offshore. All other data is publicly available on the internet and URLs for download are given in the article references.

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Paper IV

Electricity transport vs. hydrogen production from future offshore wind farms

Electricity transport vs. hydrogen production from future offshore wind farms

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ABSTRACT

This paper presents the results of simulations and techno-economic analyses performed to compare two different methods of transporting energy from North Sea wind farms in 2050, either electricity transport in subsea power cables or hydrogen transport in gas pipelines. Offshore hydrogen production scenarios are compared to various onshore hydrogen production methods, including onshore electrolysis and hydrogen production from natural gas. The simulation model was built with real-world wind turbine data, and 25 years of wind speed data from a future wind farm location in the North Sea were used as input. The work analyzes and compares 150 different scenarios.

KEY WORDS: Offshore wind power; hydrogen; electrolysis; subsea power cables; gas pipelines.

INTRODUCTION

Increased usage of low-emission hydrogen in various sectors is frequently presented as a potential method to reduce emissions of greenhouse gases (GHG). The emissions from hydrogen production are very low if it is produced through electrolysis with electricity from renewable energy sources, or from natural gas with carbon capture. The former is often referred to as green hydrogen and the latter as blue hydrogen. A potential method for large-scale production of green hydrogen is to utilize electricity from the expected expansion of offshore wind power. One of the main questions related to this scenario is whether the hydrogen production systems should be located offshore in connection with the wind farms, or if the wind farms should install subsea power cables to the shore and build the hydrogen production systems onshore. These decisions will be made based on technical, economic, political, environmental, and societal factors, and there are advantages and disadvantages related to both solutions. Firstly, gas pipelines are generally less costly on basis of unit of energy transported than subsea power cables, particularly at long offshore distances, which favors offshore hydrogen production. For hydrogen pipelines to be economical, their transport capacity must be an order of magnitude higher than that of subsea power cables. A necessary condition is that enough electricity is available for producing the large quantities of hydrogen. Secondly, the cost of building and operating a hydrogen production system offshore will inevitably be higher than an equivalent onshore system. Connecting the wind farm to the onshore electricity grid and building the hydrogen production system onshore will also give increased flexibility in terms of electricity prices and input power to the hydrogen system, which could be a huge advantage both from a technical and economic point of view. However, it could be more challenging to get acceptance to build large-scale facilities onshore with respect to political, societal and environmental factors, although not necessarily. In addition to this, green hydrogen production, both offshore and onshore, will have to compete with blue hydrogen. All in all, there are still many uncertain factors connected to green hydrogen production from offshore wind farms.

This study focuses on the technical and economic factors related to the transport of energy from wind farms in the North Sea in 2050, and specifically on the comparison between electricity transport in subsea power cables and offshore hydrogen production followed by transport through gas pipelines. Simulations in a previous study (Egeland-Eriksen et al. 2023) show that green hydrogen production from offshore wind with current technology and costs would have a levelized cost of hydrogen (LCOH) of 4.53 \$/kg H_2 in the period with the most favorable conditions. In the period with the most unfavorable conditions the LCOH was estimated to be as high as 14.49 \$/kg H_2 (Egeland-Eriksen et al. 2023). This LCOH range is not competitive with blue hydrogen, i.e., hydrogen produced from natural gas with carbon capture and storage (CCS). According to the International Energy Agency (IEA) the LCOH range for blue hydrogen is 1.2-2.1 \$/kg H_2, depending on the price of natural gas ("CCUS in Clean Energy Transitions" 2020; "Global Average Levelised Cost of Hydrogen Production by Energy Source and Technology, 2019 and 2050" 2023). This price range is estimated to be the same in 2050 with a carbon capture rate of 95% and a CO_2 price of 180 \$/ton CO_2 ("Global Average Levelised Cost of Hydrogen Production by Energy Source and Technology, 2019 and 2050" 2023; "CCUS in Clean Energy Transitions" 2020). We must therefore assume that the LCOH of green hydrogen in 2050 will need to be reduced to the same range or lower to be competitive with blue hydrogen. Simulations in a second previous study (Egeland-Eriksen and Sartori 2024) show that this is possible to achieve with onshore electrolysis, *if* the most optimistic technology improvements and cost reductions for 2050 are achieved and a control system that exploits low electricity prices is used. The focus in the present study is on the feasibility of offshore electrolysis with electricity from offshore wind farms in the North Sea in 2050. This poses two questions:

1. From the point of view of the wind farm, does offshore hydrogen production make sense or is it better to install an export power cable and sell electricity to the grid?
2. If hydrogen *is* produced offshore, can it compete with onshore electrolysis and blue hydrogen?

METHODOLOGY

To answer the two questions posed in the introduction, simulations of wind power and potential hydrogen production from a future wind farm in the North Sea were performed. Techno-economic analyses were then performed for around 150 different scenarios, including offshore and onshore electrolysis, and these were compared with scenarios with power cables and selling of electricity. The effect of various offshore distances was also investigated. The realism of the results is increased by using the outputs from the novel dynamic wind-hydrogen production model developed in previous own studies (Egeland-Eriksen et al. 2023; Egeland-Eriksen and Sartori 2024) as inputs to the techno-economic analyses. This is done as opposed to techno-economic analyses that use long-term average values for wind energy and hydrogen production as input.

Wind-Hydrogen Model and Data Input

The model described in (Egeland-Eriksen and Sartori 2024) was used to estimate the energy and hydrogen production from an offshore wind farm. The model uses polynomial regression to estimate the wind energy production based on the wind speed of a given location. A simplified version of the mathematical model of a proton exchange membrane (PEM) electrolyzer described in (Egeland-Eriksen et al. 2023) is used to estimate the hydrogen production. For the work described in the present paper, hourly windspeed data from the 25-year period 1998-2022 for a planned offshore wind farm location (*Sørlige Nordsjø 2*) in the North Sea were downloaded from the Renewables Ninja website ("Renewables.Ninja" 2023; Pfenninger and Staffel 2016; Staffel and Pfenninger 2016).

Fig. 1: Planned location of the *Sørlige Nordsjø 2* offshore wind farm ("Sørlige Nordsjø II" 2024).

Sørlige Nordsjø 2 is one of the two areas the Norwegian Government has initially opened for offshore wind. The area is in the first phase expected to be built out with 1.5 GW capacity, and another 1.5 GW will be added in the second phase ("Sørlige Nordsjø II" 2023). It is located in the southern end of the Norwegian area of the North Sea, close to Denmark, as shown in Fig. 1. The area has a size of 2591 km^2 and is 200 km from the Norwegian coastline. Water depth is on average 60 meters and the average windspeed is 10.8 m/s ("Sørlige Nordsjø II" 2023).

The model used the windspeed data from *Sørlige Nordsjø 2* as input to estimate the hourly production of wind energy and hydrogen in the various 2050 scenarios. In other words, it is assumed that the windspeeds in a 25-year period beginning around 2050 will be relatively close to the data collection period beginning in 1998, i.e., that the inevitable day-to-day differences will even each other out over a 25-year period. A techno-economic analysis was then performed using values summarized in Table 1. The analysis estimates the levelized cost of hydrogen (LCOH), levelized cost of energy (LCOE) and net present value (NPV) for the various scenarios. LCOH and LCOE are economic calculation methods used to estimate the cost per unit of hydrogen and energy produced during a project's lifetime. The formulas used to calculate the LCOH and LCOE in this study are:

$$LCOH = \sum_{t=0}^{n} \frac{I_t + O_t + F_t}{(1+r)^t} \Big/ \sum_{t=0}^{n} \frac{H_t}{(1+r)^t} \quad (1)$$

$$LCOE = \sum_{t=0}^{n} \frac{I_t + O_t + F_t}{(1+r)^t} \Big/ \sum_{t=0}^{n} \frac{E_t}{(1+r)^t} \quad (2)$$

where I_t, O_t and F_t are the investment costs (CAPEX), operating expenses (OPEX) and fuel costs for each year t. In the case of electrolysis, the fuel is the electricity used by the PEM electrolyzer. The total number of years (lifetime) is given by n, and the assumed discount rate of the project is given by r. H_t and E_t are the hydrogen production and energy production for each year t.

NPV is an economic calculation method used to evaluate the profitability of a project over its lifetime. The formula used to calculate the NPV is:

$$NPV = \sum_{t=0}^{n} \frac{R_t - I_t - O_t - F_t}{(1+r)^t} \quad (3)$$

where R_t is the revenue of each year t. All the other variables are the same as for the LCOH (Eq. 1) and LCOE (Eq. 2). The project is estimated to be profitable if the calculated NPV is positive and unprofitable if the NPV is negative.

PEM Electrolyzer Model Assumptions and Limitations

The simulation model of the PEM electrolyzer that the hydrogen production estimates in this paper is based on is subject to several simplifications and limitations to limit the complexity and computational load of the model:

- Power electronics are not included in the model.
- Start-up and ramp-up time is not included in the model.
- Energy usage to keep the electrolyzer in standby mode is not included in the model.
- Degradation of the electrolyzer performance during its lifetime is not included in the model.

These factors will in varying degrees reduce hydrogen production and efficiency and increase costs in a real wind-hydrogen system compared to the model. These points are included in planned future work to develop the model further and increase its realism.

Scenarios

All scenarios in this study are set in 2050, i.e., it is assumed that technology improvements and cost reduction forecasts for 2050 have already taken place. Furthermore, for parameters where there is a range of forecast values for 2050, it is assumed that the most optimistic development has taken place, i.e., the most optimistic forecast values are used for all variables. The values used are listed in Table 1 along with their sources, and a more detailed explanation of many of these are given in the previous study (Egeland-Eriksen and Sartori 2024), which this study builds upon. In addition to the parameters listed in Table 1, it is assumed that both the capacity factor of the wind farm and the efficiency of the PEM electrolyzer will be increased by 10% relative to current technology by 2050. This results in a wind farm capacity factor of 60% and an average electrolyzer efficiency of 72% (Table 2), which fits well with the most optimistic forecasts for these two parameters in 2050, as used in (Egeland-Eriksen and Sartori 2024). The average wind speed, wind farm capacity factor, electrolyzer capacity factor (both offshore and onshore), and electrolyzer efficiency from the 25-year simulation scenarios are listed in Table 2. The electrolyzer capacity factor in the scenarios where the electrolyzer produces hydrogen with electricity from the onshore grid is assumed to be 100%, i.e., the electrolyzer operates constantly at its rated power. In a real system it is very likely that there would be some downtime during a 25-year period that would reduce this capacity factor slightly. However, constant electricity prices are used in the onshore scenarios in this study, and a 10% reduction in the electrolyzer capacity factor would therefore have very little effect on the LCOH. Constant electricity prices were used to simplify the simulations and because any long-term forecast of hourly electricity prices for a 25-year period beginning in 2050 would be extremely uncertain. It is also quite possible that a large-scale electrolysis facility would purchase electricity through long-term contracts with a fixed price, thereby making the cost of electricity constant over long periods. However, if the electrolysis facility produces its own electricity in a wind farm that is also grid-connected, it would be possible to use a price-based control system that only produces hydrogen when the electricity price is low and sells electricity when the price is high. Simulations in (Egeland-Eriksen and Sartori 2024) showed that this could reduce the LCOH of the facility by up to 46%, and thereby significantly increase the revenues and economic viability of large-scale wind-hydrogen systems.

Table 1: Values used in the techno-economic analyses.

Parameter	Value	Sources
PEM electrolyzer CAPEX	250 $/kW	(“Hydrogen Forecast to 2050” 2022; “The Future of Hydrogen” 2019; Taibi et al. 2020)
PEM electrolyzer OPEX	1.5% of CAPEX per year	(“Global Average Levelised Cost of Hydrogen Production by Energy Source and Technology, 2019 and 2050” 2023)
Lifetime of PEM electrolyzer	25 years	(Egeland-Eriksen and Sartori 2024; Taibi et al. 2020; “The Future of Hydrogen” 2019)
Compression, storage and transport cost for hydrogen	0.315 $/kg H_2	(Egeland-Eriksen and Sartori 2024; “Hydrogen Economy Outlook” 2020)
Wind farm CAPEX (off-grid, i.e., without export cable)	1260 $/kW	(“Future of Wind: Deployment, Investment, Technology, Grid Integration and Socio-Economic Aspects (A Global Energy Transformation Paper)” 2019)
Wind farm OPEX	41 €/kW/year	(“OPEX Benchmark - An Insight into the Operational Expenditures of European Offshore Wind Farms” 2023)
NOK/$ conversion rate	10.71 NOK/$	Conversion rate between Norwegian Krone (NOK) and US dollar ($) on 13th September, 2023
$/€ conversion rate	1.07 $/€	Conversion rate between US dollar ($) and the Euro (€) on 13th September, 2023
Lower heating value (LHV) of hydrogen	33.3139 kWh/kg H_2	(“Energy Density” 2023)
Desalination water rate	283.2 liter/h per MW of electrolyzer power	(“M Series Containerized PEM Electrolysers | Nel Hydrogen” 2022)
Desalination cost	1.26 $/m^3	(Sæbø et al. 2021)
CAPEX of hydrogen production platform	3 000 000 $/MW of PEM electrolyzer power	(Sæbø et al. 2021)
Lithium ion (Li-ion) battery CAPEX	87 $/kWh	(Cole, Frazier, and Augustine 2021)
Li-ion battery OPEX	5 $/kW/year	(Cole, Frazier, and Augustine 2021)
Hydrogen pipeline CAPEX (500 km offshore)	0.7 €/MW/m	(Gea-Bermúdez et al. 2023)
Hydrogen pipeline OPEX (500 km offshore)	0.00001% of CAPEX per year	(Franco et al. 2021)
Hydrogen pipeline energy loss	2.2% per 1000 km	(Gea-Bermúdez et al. 2023)
Subsea power cable CAPEX	2.0 €/MW/m	(Gea-Bermúdez et al. 2023)
Subsea power cable (HVDC) energy loss	3% per 1000 km	(Gordonnat and Hunt 2020)
Discount rate	4.05%	(“Renewable Energy Discount Rate Survey Results - 2018” 2019; Egeland-Eriksen and Sartori 2024)

Table 2: Average values from the 25-year simulation scenarios.

Parameter	Value
Average wind speed	10.4 m/s
Wind farm capacity factor	60%
Electrolyzer capacity factor, offshore and off-grid scenarios	90%
Electrolyzer capacity factor, onshore and grid-connected scenarios	100%
Average electrolyzer efficiency (using LHV of H_2)	72%

The simulations in this paper are divided into two main stages. In the first stage, a comparison is made between an offshore wind farm that transports electricity to the shore through a subsea power cable, and an off-grid offshore wind farm that uses its electricity to produce hydrogen through electrolysis. In the latter case, hydrogen is transported to the shore through a subsea gas pipeline. These two scenarios were compared using offshore distances in the range 200-5000 km. The focus in this study is the North Sea, which has a maximum width of 580 km ("North Sea" 2023), so the longer distances are not relevant for this area, since the maximum distance to the shore for a North Sea wind farm would probably be well below 500 km. For example, the location of the future *Sørlige Nordsjø 2* wind farm is 200 km from the Norwegian coast ("Sørlige Nordsjø II" 2023). However, scenarios with offshore distances up to 5000 km were included in the techno-economic analysis for readers who are interested in other locations that are farther offshore.

In the second stage, the focus is on the question whether offshore electrolysis can be competitive with other hydrogen production methods. To answer this, hydrogen production from the off-grid offshore wind farm is compared to onshore electrolysis using grid electricity, and both electrolysis scenarios are compared with the estimated cost of blue hydrogen in 2050. All the onshore electrolysis scenarios were run with three different grid emission levels, five different electricity prices and two different CO_2 prices. The three emission levels were the current average emissions of the EU grid at 238 g CO_2/kWh ("The Future of Hydrogen" 2019), a 50% reduction of these emissions by 2050 (i.e., 119 g CO_2/kWh), and an emission-free electricity grid. The electricity prices were 0.10, 0.25, 0.50, 0.75 and 1.0 NOK/kWh, converted to US dollar ($) by using the current (13 Sep. 2023) conversion rate of 10.71 NOK/$. This electricity price range was chosen based on forecasts for 2040 by the Norwegian Water Resources and Energy Directorate (NVE), which have a minimum yearly average around 0.20 NOK/kWh and a maximum around 0.80 NOK/kWh ("Langsiktig Kraftmarkedsanalyse 2021-2040" 2021). We used a slightly lower minimum and higher maximum since our scenarios are in 2050, and we assume that the extra 10 years from 2040 will increase the uncertainty and thereby expand the possible price range. The CO_2 prices were 135 $/ton CO_2, which is the price DNV have forecast for Europe in 2050 ("Hydrogen Forecast to 2050" 2022), and 250 $/ton CO_2, which is the price IEA predicts will be necessary to reach net zero emissions by 2050 ("Net Zero by 2050 - A Roadmap for the Global Energy Sector" 2021).

RESULTS

Around 150 scenarios were run using the values and variations described in the previous section. The most important results are summarized and described in this section. First, a comparison was made between off-grid offshore hydrogen production with pipeline transport and electricity transport through a subsea power cable. Since these two cases use different energy carriers (hydrogen and electricity), the economics can be compared in different ways. The LCOE can be used to compare the cost per unit of energy without considering whether hydrogen or electricity is the desired product. When this metric is used, offshore hydrogen production is not competitive with electricity transport. This is illustrated in Fig. 2a, which shows the LCOE as a function of offshore distance for offshore hydrogen production with separate platform (green line), offshore hydrogen production integrated in the turbine structure (red dashed line), and subsea power cable without hydrogen production (blue dotted line). However, if the desired product is hydrogen, the electricity transported to shore would be used to produce hydrogen in an onshore electrolyzer. In this case it would make more sense to use the LCOH to compare the two cases (pipelines versus cables). This evaluation (Fig. 2b) shows that offshore hydrogen production could be competitive, but only if low-cost wind turbine structures with integrated hydrogen production systems are developed (dotted red line in Fig. 2b). The cost of a separate platform for hydrogen production is so high that this option is not competitive under the conditions considered in this study. With hydrogen production inside the turbine tower, offshore hydrogen production can be competitive with electricity transport and onshore electrolysis if the wind farm is located more than approximately 900 km offshore, as shown in Fig. 2b. This means that offshore hydrogen production will probably not be competitive in the North Sea, since the offshore distances will be much shorter than 900 km. This can also be shown by comparing the NPV of offshore hydrogen production integrated in the turbine structure with the NPVs of transporting and selling the electricity from the wind farm to the onshore grid, onshore electrolysis using grid electricity (with different grid emission levels and CO_2 prices), and onshore electrolysis using the electricity from the offshore wind farm directly. Fig. 3 shows these NPVs when the offshore distance of the wind farm is 200 km, which is the distance for the planned *Sørlige Nordsjø 2* wind farm. This figure shows that there is no electricity price level where the off-grid offshore wind-hydrogen scenario has the highest NPV with a 200 km offshore distance, and simulations with 500 km offshore distance showed negligible differences from the 200 km simulations. If the electricity price is relatively low, the highest NPV is achieved in the scenario where grid electricity is used as input, if the electricity grid is emission free (orange line). If the grid is not emission free, the best solution will depend on the size of the emissions and CO_2 price. With current EU grid emissions and the CO_2 price estimated by IEA to be necessary to reach net zero emissions in 2050 (250 $/ton CO_2) ("Net Zero by 2050 - A Roadmap for the Global Energy Sector" 2021), the best solution is to transport the emission free electricity from the offshore wind farm to the shore through a subsea power cable, and then use it to produce green hydrogen in an electrolyzer. When the electricity price is relatively high, the highest NPV is achieved in the scenario with a subsea power cable and electricity sale (i.e., no hydrogen production at all). However, a price-based control system of the type developed and demonstrated in (Egeland-Eriksen and Sartori 2024) can exploit the fluctuations in electricity price so that LCOH, LCOE and NPV in the scenario with a subsea power cable and onshore electrolysis are significantly improved. Results of simulations with real electricity prices in (Egeland-Eriksen and Sartori 2024) showed a potential LCOH reduction of up to 46%.

If locations with offshore distances longer than what is possible in the North Sea are considered, offshore hydrogen production inside the wind turbine structure (i.e., no extra platform for hydrogen production) can compete with the scenario with subsea power cable and onshore electrolysis (as shown in Fig. 4 when the offshore distance of the wind farm is higher than approximately 900 km). However, the LCOH of the hydrogen produced offshore exceeds the high end of IEAs estimate for the LCOH for blue hydrogen when the offshore distance exceeds approximately 1400 km. This is shown in Fig. 4, where the two vertical grey dotted lines are set at offshore distances of 900 and 1400 km. It is only in the range between these two distances that offshore hydrogen production could be competitive with onshore hydrogen production, i.e., the green line of offshore electrolysis is below both the red dashed line of onshore electrolysis and the upper limit of the blue hydrogen range. However, even in the 900-1400 km range, the competitiveness of

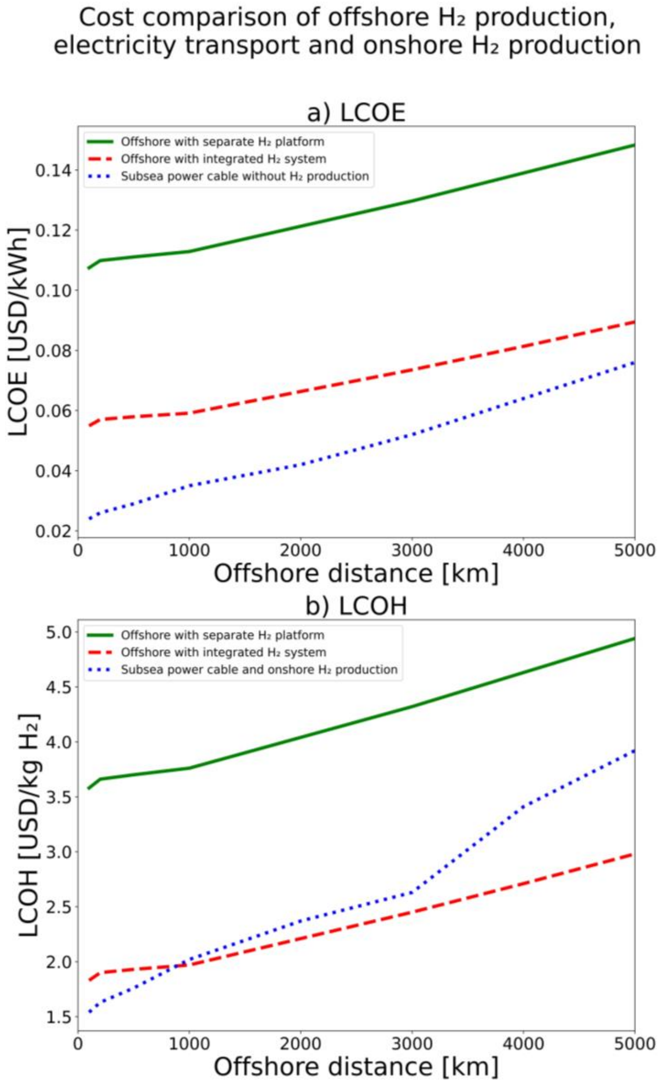

Fig. 2: LCOE (a) and LCOH (b) at different offshore distances for four different scenarios: 1) Offshore hydrogen production on a separate platform connected to the wind farm (full green lines), 2) Offshore hydrogen production inside the wind turbine structures (dashed red lines), 3) Electricity transport in subsea power cable without hydrogen production (dotted blue line in a), 4) Electricity transport in subsea power cable followed by onshore hydrogen production (dotted blue line in b). The wind farm is off-grid in the scenarios with offshore hydrogen production (i.e., without subsea power cable to shore).

offshore hydrogen production will be very uncertain. Firstly, the offshore wind-hydrogen farm would have to be in a region where the price of blue hydrogen is near the high end of IEAs estimate. In regions where blue hydrogen is produced with a LCOH near the low end of IEAs estimate, offshore hydrogen production cannot compete in any scenario. Secondly, the scenario with a subsea power cable to the shore and onshore electrolysis can implement the previously mentioned price-based control system (Egeland-Eriksen and Sartori 2024) to reduce the LCOH significantly. Fig. 4 also shows the LCOH for this scenario reduced by 10% and 46%, which was the minimum and maximum LCOH reductions achieved in (Egeland-Eriksen and Sartori 2024). Thus, if we assume that the control system achieves cost reductions in this range, and we use

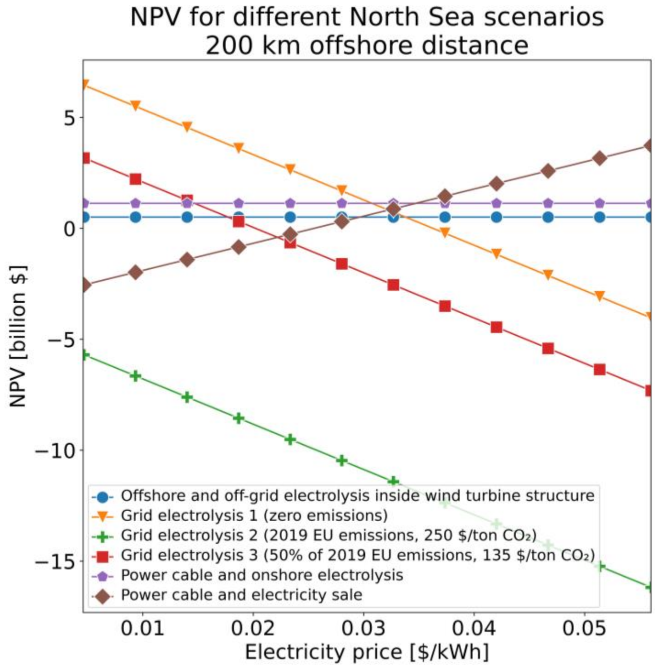

Fig. 3: NPV as a function of average electricity price for different scenarios. The offshore distance is 200 km.

IEAs estimate for blue hydrogen, offshore hydrogen production from off-grid wind farms will not be competitive in any scenario, regardless of offshore distance. This can be seen in Fig. 4 in the following way: At offshore distances above 1400 km, the offshore electrolysis line (green) is above the blue shaded region which shows the price range for blue hydrogen, i.e., offshore electrolysis cannot compete with blue hydrogen in this range. At offshore distances below 1400 km, the offshore electrolysis line (green) is above the lines for onshore electrolysis with 10-46% LCOH reductions (purple and yellow dotted lines), i.e., offshore electrolysis cannot compete with onshore electrolysis in this range. Thus, the best choice for the wind farm will be to either sell the electricity directly or use it to produce hydrogen in an onshore electrolyzer. The choice between these two options will depend mostly on the electricity price and the price of blue hydrogen in the region.

CONCLUSIONS

This study presents the results of simulations performed to investigate whether offshore production of green hydrogen from off-grid wind farms in the North Sea in 2050 will make sense, and whether this green hydrogen would be competitive with onshore production of green and/or blue hydrogen (see questions 1 and 2 in the introduction). Around 150 scenarios were analyzed, and the results indicate that offshore hydrogen production in the North Sea is not the best choice in any of the scenarios. The best solution is to connect offshore wind farms to the onshore electricity grid with subsea power cables and either sell electricity directly or produce hydrogen in an onshore electrolyzer. Offshore hydrogen production through electrolysis on North Sea wind farms cannot compete with hydrogen from onshore electrolysis. Blue hydrogen could also be a better option if it can be produced with a LCOH near the low end of IEAs cost range of 1.2-2.1 \$/kg H_2 ("CCUS in Clean Energy Transitions" 2020; "Global Average Levelised Cost of Hydrogen Production by Energy Source and Technology, 2019 and 2050" 2023). Furthermore, if the offshore wind farm is connected to the onshore electricity grid and the electrolyzer is located onshore, a price-based

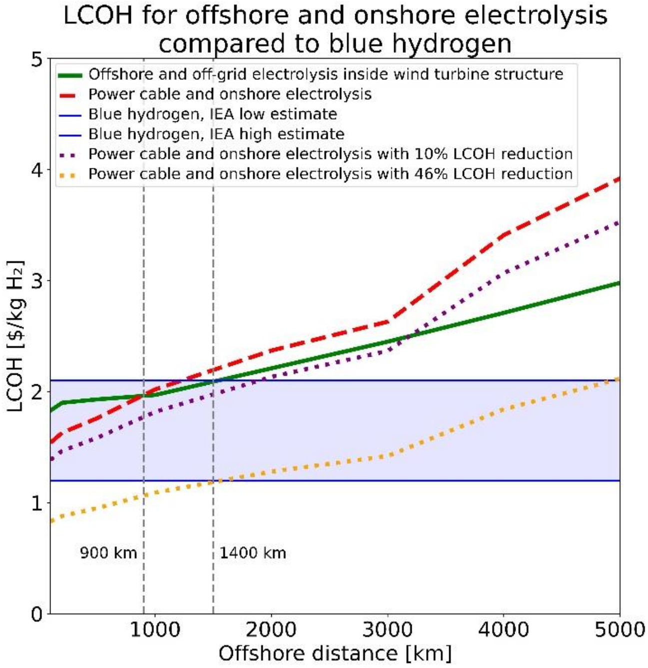

Fig. 4: LCOH for various cases. The two main cases are offshore and off-grid electrolysis (green full line) and subsea power cable from the offshore wind farm to shore followed by onshore electrolysis (red dashed line). The purple and yellow dotted lines show the latter case with a 10% and 46% reduction in LCOH, which could be achieved with a price-based control system, as demonstrated in (Egeland-Eriksen and Sartori 2024). The blue area marks the range estimated by IEA for blue hydrogen ("CCUS in Clean Energy Transitions" 2020; "Global Average Levelised Cost of Hydrogen Production by Energy Source and Technology, 2019 and 2050" 2023), which is hydrogen produced from natural gas with 95% carbon capture. The two vertical dotted lines mark offshore distances of 900 and 1400 km.

control system can be used to reduce the LCOH in this scenario even further, as shown in (Egeland-Eriksen and Sartori 2024). This would make the offshore off-grid scenario even less competitive. Therefore, while the combination between offshore wind farms in the North Sea and green hydrogen production can become beneficial for both wind farm operators and hydrogen producers, all results in this study indicate that the green hydrogen production should be located onshore to be competitive with other hydrogen production methods, and offshore wind farms should be connected to the onshore electricity grid with subsea power cables.

Perhaps the greatest advantage with grid-connected wind farms compared to off-grid wind farms that only produce hydrogen is the flexibility of the grid-connected alternative. A grid-connected wind farm can choose when to produce hydrogen and when to sell the wind energy directly to the electricity grid, which is an economic advantage, as shown in (Egeland-Eriksen and Sartori 2024). It could also reduce the curtailment of energy from the wind farm since there are always two possible paths for the energy to take, compared to an off-grid wind farm which is unlikely to be able to use all the wind energy to produce hydrogen with existing electrolyzer technologies, for example due to the minimum input power of electrolyzers (Egeland-Eriksen et al. 2023; Egeland-Eriksen and Sartori 2024). In addition to this, it seems that the risk associated with building an off-grid wind-hydrogen system is higher than it is in the grid-connected case. Even though the hydrogen demand in Europe is predicted to increase significantly in the decades to come, the magnitude of this increase is very uncertain and will depend greatly on which future energy scenario is realized. The future demand for electricity on the other hand is predicted to increase significantly in all scenarios, for example in ("Energy Transition Outlook 2023" 2023) where the demand in Europe is predicted to approximately double by 2050. From an investor/owner perspective it will therefore be much less risky to invest in a grid-connected wind-hydrogen system where the hydrogen production can act like an economic buffer against very low electricity prices and curtailment issues, in contrast to an off-grid wind-hydrogen system where the investor will essentially be placing a long-term bet on a certain hydrogen demand materializing and that both this demand and a minimum hydrogen price will be maintained throughout the entire project lifetime of at least 25 years. And even then, the hydrogen produced off-grid would have to compete with onshore grid-connected electrolysis and blue hydrogen, which could be difficult according to the results in this study. However, it is important to point out that the results of simulations are always very dependent on its inputs. Significant changes in any of the input variables could tilt results more in favor of off-grid wind-hydrogen systems. An example of this could be material shortages that drive the cost of subsea power cables significantly up relative to gas pipelines. Other factors not considered in this study could also act in favor of offshore systems, for example restricted access to land areas, both for wind farms and hydrogen production facilities. It will therefore be crucial to evaluate and update the simulation models as new information becomes available and developments take place.

Further work can be performed to improve the realism and accuracy of the existing simulation model. This should include the previously described limitations to the PEM electrolyzer model (Methodology section), but other factors should also be included, such as:

- Unexpected downtime for the wind turbines in the wind farm.
- The potential feedback effect that large-scale hydrogen production from wind farms could have on the electricity price.
- Life cycle emissions of greenhouse gases from the wind-hydrogen system.

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