Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Information Technology and Electrical Engineering
Department of Electric Power Engineering

Sander Holt Günther

The Impact of Green Hydrogen Production on the Offshore Wind Business Case

A case study of a North Sea offshore grid

Master's thesis in Energy and Environmental Engineering
Supervisor: Hossein Farahmand
Co-supervisor: Martin Kristiansen
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Abstract

The European Union recently decided to increase its climate ambition for 2030 and aims to reach climate neutrality by 2050. Achieving a climate neutral economy involves a vast expansion of European offshore wind and will require a large amount of hydrogen, especially in hard-to-abate industrial sectors. Such hydrogen will increasingly be produced on the basis of renewable sources, because only renewable-based hydrogen is fully carbon-free. While being essential in tackling emissions, low-carbon hydrogen can also act as a flexibility provider and help balancing seasonal variations in electricity generation from renewables.

In this thesis, a deterministic optimization model for power system expansion planning (PowerGIM) is formulated and demonstrated on a case study. The case study assesses new and effective ways of realizing the potential of offshore wind in the North Sea, through a transnational and cross-sector approach. The TYNDP 2020 Global Ambition scenario for 2040 is used as the main source of input data and included countries are Germany, Denmark, the Netherlands, Belgium, Great Britain, Norway and France. Primary targets are to investigate the utilization and utilization drivers of new transmission and generation capacity. A main focus is also dedicated to investigate the impact of hydrogen on the offshore wind business case.

Obtained results demonstrate that a high level of integration between countries is essential to unlock the full potential of large-scale offshore wind. Connecting new offshore wind capacity to Germany, Denmark and the Netherlands through hub configurations, compared to a radial configuration, is found to provide a higher utilisation of wind assets. However, new transmission capacity has a low value unless connections are included to the Norwegian and British market. It is also found that green hydrogen can serve as a facilitator for offshore wind integration, providing significant reductions in curtailment and increased revenue in the electricity market. Added load through new electrolyser capacity generally leads to a higher utilisation and capture prices for offshore wind. Conversely, when comparing a fixed and price dependent hydrogen load, it is observed that optimal charging from the grid enables the electrolyser to capture low electricity prices, significantly reducing the power costs of hydrogen production. Given the underlying assumptions it is calculated that the levelized cost of hydrogen could come down to €1.2-2.8/kg H_2, provided a low-cost electricity supply and declining capital costs of electrolysers through 2040.

Preface

This Master's thesis concludes my master's degree within Energy and Environmental Engineering at the Norwegian university of Science and Technology (NTNU), and marks the ending of five exciting years as a student in Trondheim.

I want to thank everyone that I have had the pleasure to share my university years with. A special thanks my supervisors Professor Hossein Farahmand and Senior Analyst Martin Kristiansen for your encouragement and support during the work on this master's thesis and the preceding specialisation project. Your sincere dedication and willingness to help have been much appreciated. Gratitude is also extended to my fellow students for a welcoming working environment and rewarding discussions.

My sincere thanks also go to my family and friends, for your unconditional love and support, and all the shared moments that have been thus far.

Trondheim, June 2021
Sander Holt Günther

Abbreviations

AC	Alternating Current
CAPEX	Capital Expenditures
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
DC	Direct Current
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
GB	Global Ambition
GEP	Generation Expansion Planning
G&TEP	Generation and Expansion Planning
HM	Home Market
HVDC	High-Voltage Direct Current
IAEA	International Atomic Energy Agency
IC	Interconnector
IEA	International Energy Agency
LHV	Lower Heating Value
LP	Linear Program
MILP	Mixed-Integer Linear Program
NPV	Net Present Value
NSOG	North Sea Offshore Grid
NSWPH	North Sea Wind Power Hub
OBZ	Offshore Bidding Zone
OPEX	Operating Expenditures
OWF	Offshore Wind Farm
PowerGAMA	Power Grid and Market Analysis
PowerGIM	Power Grid Investment Module
PV	Photovoltaic
RES	Renewable Energy Source
TEP	Transmission Expansion Planning
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
VSC	Voltage Source Converter

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Chapter 1

Introduction

The North Sea holds a vast wind energy potential and offshore wind technology is maturing rapidly. To help meet the goal of climate neutrality by 2050, the European Commission (EC) recently arrived at firm new targets, aiming to increase Europe's offshore wind capacity to at least 60 GW by 2030 and 300 GW by 2050 [1].

The integration of increasingly large and variable volumes of offshore wind electricity is challenging, and harnessing the power of the North Sea requires a comprehensive rethinking of the energy system. The concept of a North Sea Offshore Grid (NSOG) has been identified as a possible solution in this context, with the twofold purpose of integrating offshore wind resources and integrating markets for increased cross-border trade [2]. Such a development is also supported by an increased focus on international cooperation and joint solutions, utilising the total generation and transmission capabilities in the most efficient way.

Achieving a climate neutral economy is expected to require a large amount of hydrogen, which is reflected by the 2030 EU target of 40 GW new electrolyser capacity, set by the EC [3]. Such hydrogen will be increasingly produced on the basis of renewable energy, because only renewable-based hydrogen is fully carbon-free. While being essential in tackling emissions, hydrogen is also found to be a promising option to unlock the full potential of offshore wind, as it can act as a flexibility provider by storing electricity and help to balance power systems.

To ensure an optimal development of the power system, it is necessary to coordinate the connection of new generation and transmission capacity. Transmission and generation expansion planning (G&TEP) is one of the key strategic decisions in power systems [4]. Transmission and generation facilities are characterized by long lifetimes and investments thus have a long term influence on the operation of energy systems [5]. Moreover, investments are capital intensive and planning of large-scale projects is a complex process. Accurate modeling of future scenarios is key to make informed decisions and usually comprise large-scale optimization problems. Financial investors seeking to invest in energy infrastructure need to take a long-term view, accounting carefully and comprehensively for uncertainty. Uncertainties involve e.g. the evolution of demand, investment costs and carbon price.

A specialisation project [6] prior to this Master thesis studied the concept of scenario generation and investigated optimal transmission expansions in the NSOG. Throughout this thesis, it is explicitly stated when relevant text is adopted from the project work.

1.1 Scope of the report

This report investigates different ways of connecting 12 GW of offshore wind (OWF) in the North Sea, demonstrating its findings through a case study, using the open source deterministic optimisation model for power system expansion planning, called PowerGIM. Countries included in the case study are Germany, Denmark, the Netherlands, Great Britain, Belgium, Norway and France. Five different configurations are tested in a 2040 scenario, including both radial and hub arrangements. The various configurations represent proposed, but not yet installed projects. A summary of the main research objectives are:

- **Future power system and technologies:** Give a general introduction to scenario generation and provide an overview of benchmark scenarios covering the future development of the power system. Discuss historical and future trends within the offshore wind and hydrogen industries.

- **Data processing:** Create a comprehensive data set comprising hourly renewable production profiles, load, generation, operational costs and capital costs. Rely on well documented and open sources to maintain a high level of transparency and reliability.

- **Expansion planning model:** Formulate the expansion planning model and incorporate the input data into PowerGIM.

- **Utilisation of transmission and generation assets:** Investigate the utilisation and utilisation drivers of the interconnector (IC) capacity between the OWF and the onshore systems. Observe and interpret tendencies with regard to OWF capture prices and curtailment.

- **Impact of hydrogen on offshore wind business case:** Investigate how offshore wind can be used to produce green hydrogen, and mutual benefits of co-located wind and hydrogen production.

In the end, the validity and limitations of the work are discussed.

1.2 Contribution

The presented work aspires to highlight new and effective ways to realise the potential of wind power in the North Sea, through a transnational and cross-sector approach. Potential risks related to offshore wind capture prices and curtailment are evaluated, and emphasised through various sensitivity analysis, covering e.g. the impact of variations in future CO_2-price and gas price levels, load and climatic conditions. The work also contributes to the understanding of the impact of hydrogen on the offshore wind business case. A main focus is dedicated to investigate how hydrogen can be used as a facilitator for offshore wind, by co-locating a PEM electrolyser and wind generation assets in a common offshore hub. Optimal sizing and operation of the hydrogen facility are tested and discussed. Important considerations regarding the the technical and economical viability of various solutions are also a primary target in the analysis.

To achieve this, a comprehensive data set is created based on the TYNDP 2020 Global Ambition scenario. Data are gathered to fit the areal resolution of countries surrounding the North Sea and are presented in a transparent fashion, which can easily be reproduced. A significant effort is put into the pre-processing of data to achieve a reliable and accurate basis for analysis given the underlying assumptions. Input data are incorporated into a deterministic optimisation model for power system expansion planning (PowerGIM) and the model is updated to take into account storage and hydrogen solutions.

Results are demonstrated through a case study assessing different ways of connecting 12 GW of offshore wind in the North Sea, which serves as a basis for further research and analysis. Transmission assets connecting new offshore wind generation to the respective national markets are found to have a limited value unless connections to the Norwegian and British market are included. The addition of a PEM electrolyser is found to provide significant reductions in offshore wind curtailment and increased revenue in the electricity market.

Chapter 2

Literature Review

This chapter provides an overview of existing research regarding topics covered in this report. A particular focus is dedicated to expansion planning methodology and applications on the NSOG, and the potential of green hydrogen, due to the high relevance to the case study. The content in this chapter is a continuation of the literature survey presented in the specialisation project that was written prior to this report [6]. All content except Section 2.1.2, 2.1.3 and 2.3, are adopted from the project work, with few modifications.

2.1 Transmission expansion planning

Transmission expansion planning (TEP) can be defined as the exercise of "deciding which new lines will enable the system to satisfy forthcoming loads with the required degree of reliability" [7]. The literature reviews by Lumbreras and Ramos in [4] and Hemmati, Hooshmand and Khodabakshian in [8], provide comprehensive meta studies of recent works on TEP in an European context, focusing mainly on modeling decisions and solution methods. Important considerations regarding TEP are presented in the following subsections.

2.1.1 Modelling assumptions

According to [4], most studies assume a completely centralized market operation, even in liberalized generation markets. Including market considerations, especially in long time horizons, adds to the complexity of the problem and high uncertainties about future market structures and behaviour makes accurate modelling difficult. It is suggested that competitive behaviour should be included only when the study targets competition specifically. Moreover, the objectives in a study should be chosen depending on the decision maker's preferences. Most studies have cost as the only objective in the optimization, although the aggregated cost consists of a number of factors. An aggregated mono-criteria model is the preferable option when relative importance of different factors, and thus weights, are clear. However, when the importance is not clear, a multi-criteria model is usually more adequate.

In [4], DC power flow is considered the overall preferred option for power network models, given the decent level of accuracy and low computational complexity. However, in cases with very large problems, transportation models are the preferred option. HVDC is highlighted as a necessity when studying offshore locations, while Flexible Alternating Current Transmission Systems (FACTS) are relevant in cases of looped flows.

The literature review by Gorenstein Dedecca and Hakvoort in [9] provide a comprehensive overview of existing NSOG (North Sea Offshore Grid) studies. It is observed that the main research questions in most studies are investment and operation of the grid using optimization methods, maximizing net social benefits or minimizing costs. Energy policy is also extensively dealt with in the studies, but are mostly included through scenarios. Moreover, the majority of studies has a final horizon year of 2030, with a few exceptions. The authors emphasize the disadvantage of a too general representation of welfare. When presenting only total welfare, information about internal allocations between congestion rent, consumer and producer surplus are lost.

The various studies in [9] are conducted based on different typology categories (radial, hub or meshed). However, there is no observed relation between typology category and cabling length. Thus, the amount of cables required and environmental impact from cable laying is independent of typology. According to [10], a common system operation horizon in TEP optimization models are one calendar year. Simplified aggregated network representations are used and installed production and transmission capacities are usually based on future scenarios.

2.1.2 Transmission-generation-storage investment coordination

Traditionally, transmission optimization models treat generation investment locations and types as exogenous ”build out” scenarios [11]–[13]. This is termed ”reactive” planning. However, expansion planning can also include generation, through so called ”proactive” transmission planning [14]. In fact, in [4] it is suggested that for certain cases, TEP and generation expansion planning (GEP) should be performed in a joint manner. A proactive approach investigates how generation investments may be affected by grid reinforcements and how more cost effective designs can lead to savings in both capital and operating costs of generation. The simplest proactive models assume perfectly competitive generation markets, which allows proactive transmission planning to be modeled using a single ”co-optimization” model [14]–[17]. However, in the deregulated market, GEP decisions are taken privately based on price signals and there exists no centralized GEP plan. If generators behave strategically, multi-level transmission planning models can be used [14], [18]–[21]. While multi-level models are more accurate, they are also much more computationally intensive. Recently, researchers started to include storage investments as an option in TEP to assess the mutual impacts between transmission and storage investments

[22]. Studies have also extended the scope of TEP beyond the electricity sector to include gas grid expansions in the expansion problem formulation [23].

2.1.3 Generation representation

Expansion models usually involve simple models for generator costs and constraints, by means of traditional load-duration curve/merit-order methods. While a simple approach is often sufficient, a too general representation of generation may lead to unrealistic results. Planning models can be enhanced through the addition of unit commitment modelling. In [24] it is found that representations of commitment and ramp constraints, which limit generation flexibility, can improve estimates of the cost of integrating variable renewables. Moreover, in [25], their results indicate that limiting the flexibility of generators through linearized unit commitment constraints, has more impact on transmission economics in systems with slow baseload units.

2.1.4 Uncertainty

Uncertainty is a major factor that needs to be accounted for in TEP. In [4], it is reported three main tools applied in the treatment of uncertainties: stochastic optimization, robust optimization and fuzzy decision analysis. The most commonly studied uncertainties are found to be generation expansion and generating costs. Other common risks in the short-term are demand, hydro inputs, renewable energy production or element failures. Stochastic optimization, possibly including risk measures such as Value-at-Risk (VaR) or Conditional Value-at-Risk (CVaR), is highlighted as a beneficial method when treating risks. However, it is suggested that robust optimization and fuzzy decision analysis can be a viable option for long-term uncertainties. Sequential static approaches are the most suitable option for longer time horizons, providing a realistic picture and at the same time limiting computational complexity.

An example of what uncertainties that can be accounted for in TEP is provided in [10]. In this study, three main uncertainties are analysed with respect to variability in CAPEX. These are: uncertainty in market conditions (including exchange rates, inflation and cost of labor), uncertainty in copper price and uncertainty in steel price.

2.1.5 Indicators of benefits

Benefits from TEP can be measured in a number of ways, depending on the objective of the analysis. In [10], changes in social welfare is highlighted as an important parameter when evaluating the benefits of integrated grids. Assuming inelastic demand, maximizing social welfare is equivalent to minimizing operational costs of the system. Other indicators on the value of network integration can be capital and operational savings, net present value (NPV) of network integration, impact on electricity prices, impact on market revenue of wind farms, impact on utilization of network assets and impact on network revenue. In [9], the indicators analyzed across the studies are offshore wind capacity by scenario, cabling length vs. offshore wind capacity, net social benefits per scenario and scenario CO_2.

2.1.6 Cost-benefit allocation

The study by Konstantelos et al. (2017) [10] provides a case study on the advantages and development barriers of integrated North Sea grids. The study show that an integrated offshore electricity grid in the North Sea, brings substantial financial and technical benefits to the European power system. However, it is observed a lack of commercial interest in such projects. Asymmetric allocation of costs/benefits is highlighted as a major barrier to the commercial pursuit of integrated offshore wind projects. Different allocation schemes are presented and the authors recommend the Positive Net Benefit Differential (PNBD) method. This method is consistent with the ”beneficiary pays” principle and mitigates free riding.

An important consequence of offshore wind farm (OWF) integration with a cross-border interconnection, highlighted in [10], is the fact that the OWF is exposed to the zone with the lower electricity prices. This is the case when line congestion leads to price differentials between the two connected zones. Due to the low-cost, OWF’s are usually on the exporting side of network constraints, as power flows from the zones with low prices to zones with higher prices. Consequently, the change in average market value of offshore wind farm outputs are substantially negative in certain scenarios. This is an obvious drawback to investors and the effect must be mitigated through proper and strategic cost/benefit allocation schemes.

2.2 Expansion planning applied to the NSOG

A number of specific case studies have been conducted on the topic of optimal expansion planning applied to the NSOG. Some relevant publications in this context are presented in this section.

The paper by Martin Kristiansen et al. (2018) [26] demonstrates the economic and environmental capabilities of the visioned Power Link Island (PLI) in the Doggerbank area in the North Sea. The model used is a mixed-integer linear program (MILP), combining both generation and transmission expansion planning (GTEP). It is structured as a bi-level optimization problem where generators respond to transmission investments, with the ability to co-optimize investments and operational costs. Input data on fuel prices and installed capacities per energy source are based on scenarios for 2030. Covered countries are Norway, Denmark, Germany, The Netherlands, Belgium and Great Britain. The model is documented in detail in [27] and [28]. In short, the model assumes perfect competition, inelastic demand and a welfare-maximizing system planner. Hence, the goal is essentially to minimize total system costs. The initial model setup in [26] includes the planned infrastructure for 2030 without any offshore wind connections. Then, in four steps, the idea is to give the model increasing degree of freedom to invest in additional grid and/or generation. When the overall goal of the model is to quantify the added value of a PLI and the expenses consist of grid connections only. The final result can be viewed as break-even values for the construction of the island. A further assessment of a PLI is made by Kristiansen et al. in [29], which shares a very similar motivation as what we saw in [26]. In this paper they perform TEP and use PowerGIM as the optimization tool [30]. The model shares the same bi-level structure as in the previous paper, co-optimizing investment decisions and market operation.

Another very interesting paper by Kristiansen et al. is fund in [31]. The principle aim in this publication is to evaluate different means of flexibility in future scenario TEP models, emphasising on energy storage and demand-side management (DSM). What separates this paper from previous works are the combination of high resolution weather data and introduction of alternative sources providing system flexibility. Impacts on TEP are quantified in a case study of the North Sea area in 2030. The investment model used in [31] is called NetOp, developed by SINTEF Energy. This is a bottom-up, deterministic MILP programmed in MATLAB minimizing total system cost, both operational and investment costs, assuming perfect competition. Investment decisions are based on the scenarios in year 2030. Hourly resolution of load and generation data over the full year, enables the model to capture different market states. Model input data are based on 2030 scenarios. It is assumed that triggering factors for flexibility are related to the supply side and that the majority part of the flexibility needs are caused by non-dispatchable power generation.

Energy storage is modelled in two ways using energy-sum constraints. Detailed mathematical representation are described in [31]. A fundamental assumption is that the sum of consumed and dispatched energy is equal to zero over one year of operation, plus inflow energy if applicable. In [31], one way to model DSM is to include an elastic demand function. This implies that the demand side is less willing to buy electricity when prices are high, and more willing to buy when prices are low. A more convenient representation is a static approach such as peak shaving or PV-battery systems. Peak shaving is achieved simply by manipulating the demand data, lowering the demand during high load and increasing demand during low load. In the case study, a peak shaving approach based on PV-battery systems is used, taking into account solar irradiation. Due to the seasonality of solar irradiation the potential to store energy and thus the impact of peak shaving is most prominent during summer. Finally, the effects of flexibility in [31] are evaluated for each scenario in two different ways: i) increasing the share of energy storage in Norway (pumped hydro storage), ii) implementing DSM in Great Britain.

2.3 Green hydrogen

Green hydrogen, i.e. hydrogen produced from renewable energy sources (RES), is identified as a key contributor for a successful energy transition. In addition to facilitate the integration and storage of RES, hydrogen is found to be a promising energy carrier which is well capable to effectively link various energy sectors [32].

Kakoulaki et al. (2021) [33] assesses the replacement of grey hydrogen with green hydrogen production through electrolysis powered by renewable energy sources in the EU27 and UK. It is found that switching the current annual EU hydrogen production of 9.75 Mt to electrolysis would require 290 TWh (about 10% of current production). At the same time, the authors conclude that the technical potential of producing green electricity from wind, solar and hydro is easily sufficient, both to cover all current electricity and the additional demand for green hydrogen. Moreover, it is found that the majority of current hydrogen production sites have sufficient wind, solar or hydro resources to cover all current electricity consumption as well as to substitute shift all grey hydrogen to green hydrogen.

Various research has been reported recently, dealing with technical, economic and environmental impacts of green hydrogen as a new energy carrier. As en example, the carbon intensity reduction in the energy sector via green hydrogen is reported in [34]. Electrolyser technologies such as Alkaline (ALK) and proton exchange membrane (PEM) has matured in the past decade and their scale-up is expected soon. Cost-benefit analyses that substantiate that the green hydrogen will be a competitive energy carrier in the near future is provided in [35], [36]. Also, the impact of green hydrogen on electricity prices and the possible demand of wind-generated hydrogen is covered in [37].

Introducing the green hydrogen in the future energy systems has its pros and cons. In fact, new flexible demand will be added to the network in the form of power to hydrogen (P2H) energy conversion. Since the added electricity requirement by the electrolysers is expected to be transferred through the existing transmission corridors, the network is forced to operate even closer to the security limits. In addition, other factors such as demand uncertainty, market, public and environmental restrictions may impose further pressures on the network. On the positive side, green hydrogen enables a reduction in RES curtailment [38] and maximizes revenue in the electricity market [39], [40]. It can also provide grid balancing services such as up/down frequency regulations [39], [41], [42].

Chapter 3

Theory and Background

This chapter provides an overview of future power system scenarios and technologies. It comprises an introduction to the concept of scenarios and the process of developing scenarios. Moreover, it highlights historical and future trends within the offshore wind and hydrogen industries. The content in Section 3.1 is adopted from the specialisation project in [6], with few modifications.

3.1 Scenario generation

To date, there exist numerous scenarios projecting the future development of the energy system towards 2030 and 2040, and we are starting to see more works where the scope is extended all the way to 2050. To understand the development of the energy system is vital, both in an economical, but also in an environmental and social perspective. Scenarios is a valuable resource for anyone who want to make decisions about the future energy system, including financial investors, TSOs, scientists etc. This section presents the concept of future scenarios and how scenarios can be generated. Important aspects in the context of transmission and generation expansion planning (G&TEP) are highlighted. In the end, a selection of major works from leading providers regarding long-term power system scenarios, is presented.

3.1.1 General about scenarios

According to Cambridge Dictionary [43] a scenario is *"a description of possible actions or events in the future"*. What a scenario does is essentially to tell a story of how something will look like in the future and the development that leads to this new future state. Scenarios are not constrained to be realistic or probable, which distinguish them from forecasts. While forecasts try to predict the most likely future outcome, scenarios are free to explore any set of possible future events, regardless of how likely they are to be realized.

An important premise when creating scenarios is the assumption that future development is seldom unambiguous or pre-determined. When conditions are complex and the time perspective is long, it is hard to make accurate predictions. Therefore, multiple scenarios in combination are often used to capture the uncertainty associated with a thought development. By mapping a range of possible futures, stakeholders get to know the potential consequences of different actions. Scenarios are not ready strategies, but they provide a basis to test different outcomes and to make informed decisions about the future.

Development of scenarios can generally be divided into two main exercises as described in [44]. The first step of building a scenario is to create a storyline, describing a set of qualitative attributes. A qualitative description sets the scope and provides a base line for the scenario. A key part in this process is to identify main driving forces and large uncertain trends. Different developments are typically assessed in a political, economical, social, technological, environmental or legal perspective, depending on the context. Often, several storylines are created to investigate a range of future developments. A great example of how to define a storylines in qualitative terms is presented in [45].

The second step of building scenarios is to quantify the storylines defined in the previous step. Important aspects of this work are to ensure consistency and satisfactory resolution of data. Consistency of data implies that there cannot be any contradictions in the data. Resolution, on the other hand, refers to the spacial and temporal properties of the data. Adequate models are used to quantify scenarios.

3.1.2 Scenario generation in the context of G&TEP

The enormous complexity of the energy system and high degree of uncertainty, makes scenario generation in the context of G%TEP a challenging endeavour, and one must be critical when evaluating the accuracy of future scenarios. In the book by A. Conejo et al. [5], they identify three main characteristics of the decision-making process for planning electricity energy systems which are; long-term view, uncertainty and high dimensionality.

Generation and transmission facilities have long operating lifetimes spanning over decades. Grid reinforcements or expansions and investment in new generation are long-term exercises, and decisions today influence the future operation of the system for up to fifty years and beyond [5]. These investment are very capital intensive and building periods can range from months to several years.

Modeling of uncertainty is critical in the decision-making process for investments. Important uncertainties includes the future evolution of loads, investment costs and operational costs of different production technologies. A particularly high degree of uncertainty is associated with renewable power units and the evolution of fuel prices. Moreover, investments in transmission are regulated by central entities, while generation investments are driven generally by private competition. Decisions made by energy producers are unknown to market agents other than those directly involved in the specific investment decision [5].

Models to support decisions in transmission expansion and generation investments need to take into account a huge amount of variables and constraints in order to capture different operating conditions [5]. The development of the energy system is generally a multistage process, hence, decision-making tools need to adopt a dynamic framework. Modelling usually comprise large scale optimization models.

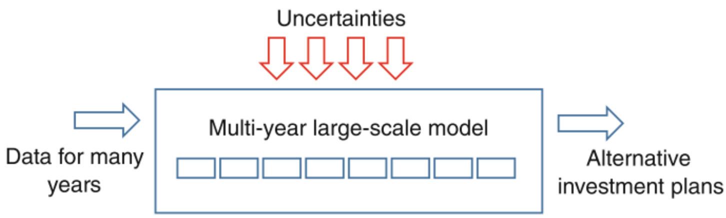


Figure 3.1: Illustration of the nature of long-term expansion problems in power systems [5].

An illustration of the long-term decision-making under uncertainty is shown in Figure 3.1. Data for many years and uncertainties comprise the inputs of the problem, while alternative investment plans are considered as outputs. Several small boxes inside the main box illustrate the dynamic nature of the model, where decisions are made in multiple stages.

3.1.3 Long-term scenarios from various sources

When studying the future development of the power system it is important to be aware of the many scenarios developed and published by various sources. A selection of major works from leading providers, comprising long-term scenarios for the Global, European and Nordic power systems, are listed below:

- **New Energy Outlook (NEO):** BloombergNEF is a trusted provider of data and analysis on carbon and clean energy markets. Every year they publish an extensive report called "New Energy Outlook" (NEO), which is a long-term forecast on the future of the energy economy. This report makes use of scenarios, covering transport, industry and buildings in addition to the power sector. NEO is considered a valuable input to CEO's, investors, strategists and policy makers. BloombergNEF analysis is not open source and complete data sets are only available through subscriptions.
- **World Energy Outlook (WEO):** The International Energy Agency (IEA) is an intergovernmental organization within the Organization for Economic Co-operation and Development (OECD) [46]. IEA is a leading provider of authorative analysis and data on the energy sector. World Energy Outlook (WEO) is a flagship report from IEA that has been an annual publication since 1998. The WEO is an extensive

report covering energy market analysis and projections. A scenario-based approach is used to account for uncertainties in the long term perspective. The most recent publication. Only a snapshot of the results are freely accessible to the public, while full reports must be purchased.

- **Ten Year Network Development Plan (TYNDP):** Every two years ENTSO-E publish a Ten Year Network Development Plan (TYNDP) [47], which is a extensive report that covers the development of the European power grid in the next one to three decades. The most recent publication [48] in the line of TYNDP reports comprise a set of scenarios or visions up to 2050. TYNDP 2020 provide data for each country with a particular focus on the future electricity and gas infrastructures. ENTSO-E works closely with the European Commission, ACER and various stakeholders. All reports, including separate input data files, are freely available to the public.

- **Global Renewables Outlook:** The International Renewable Energy Agency (IRENA) [49] is an intergovernmental organization that aims to facilitate international cooperation, knowledge and adoption of sustainable renewable energy sources. IRENA provide a wide range of research on the topic of renewable integration and a flagship report is the Global Renewables Outlook (GRO). The most recent GRO includes scenarios for the global energy system, highlighting investments and technologies needed to reach targets on decarbonization set in the Paris Agreement.

- **Energy Transition Outlook:** DNV GL is an independent company, specializing in assurance and risk management. Every year since 2017, DNV GL has published their ”Energy Transition Outlook”, forecasting the global energy transition towards a sustainable future. The outlook is focused around the developments in the oil and gas, maritime and energy supply sectors. Core topics are significant risks and opportunities for investment strategies, operating models, safety and fuel choices. The latest edition was published in 2020 and covers the period through 2050.

- **Langsiktig markedsanalyse - Norden og Europa:** Every other year the TSO of Norway, Statnett, publish a long-term market analysis. The 2020 edition [50] of this report investigates scenarios for the Norwegian and European power system with a final time horizon of 2050. The report assess the development and interplay of production, consumption, renewable technologies, grid, CO_2 emissions and power prices. The report, including input data sets, are freely available to the public.

- **Langsiktig kraftmarkedsanalyse:** Similar to Statnett, the Norwegian Water Resources and Energy Directorate (NVE) publish an annual power market analysis. The latest edition [51] of the report assess the development of the Nordic and European power market up to 2040. The presented scenarios include detailed information about average energy prices, production, energy demand, fossil fuel prices and power balances, respective to each country. All previous editions of the report, including input data sets, are freely available to the public.

- **NORSTRAT:** NORSTRAT [52] is a former SINTEF project that developed a ”Nordic Power Roadmap 2050” on how the Nordic system can reach net zero CO_2 emissions by 2050. Multiple scenarios for 2050 is created in this study, with a particular focus on the requirements of the transmission system. Effects from increased electrification of the transport and heating sector, in addition to political measures are main focus areas in this study. Deliverables from the project are freely available to the public.

The aforementioned research is only a snapshot of some of the most recognized research in the field of long-term energy system planning. Additional studies exist in vast numbers. The idea is not to give a complete overview, but rather provide insight to current benchmarks.

3.2 Offshore wind

Offshore wind is an emerging technology and the global offshore wind market is set to expand significantly in the future. To help meet the goal of climate neutrality by 2050, EC recently arrived at firm new targets for offshore wind, proposing to increase Europe's offshore wind capacity to at least 60 GW by 2030 and to 300 GW by 2050 [1]. The following section presents recent trends in the offshore wind industry and important considerations in the development of offshore wind.

3.2.1 Offshore wind industry trends

Offshore wind technology is maturing rapidly. Between 2010 and 2019 the global cumulative deployed capacity grew from 3GW to 28GW, with Europe accounting for 78% of the cumulative installed capacity [53]. In 2019, offshore wind made up just under 5% of global wind (onshore and offshore) deployment. As costs decrease and the technology heads towards maturity, plans and targets for future deployment have been expanding.

Unlike onshore wind projects, offshore wind farms face additional challenges regarding installation, operation and maintenance in harsh marine environments. This tends to increase costs and lead time of offshore wind projects. The planning and development of offshore wind projects is more complex, leading to increased total installed costs. Given their offshore location, they also have higher costs associated with grid connection and construction. According to IRENA [53], installed costs peaked in 2012-2013, due to the siting of projects further from shore, in deeper waters, and the use of more advanced technology.

As the deployment of offshore wind has increased in recent years, cost reductions have been unlocked. Lower costs are driven by technology improvements, economies of scale and increased experience among project developers and turbine manufacturers. Other contributing factors are the standardization of turbine and foundation designs, the industrialisation of manufacturing for offshore wind components and improved installation practices. There has also been a trend towards higher capacity turbines, with higher hub heights and longer blades, enabling turbines to capture more energy from the same wind resource.

Specific designs for the offshore sector has been crucial in reducing the levelized cost of energy (LCOE) of offshore projects. Moreover, specialized ships designed for offshore wind work has reduced the installation effort per turbine unit and helped lower O&M costs. More cost effective solutions in terms of turbine sizes and optimal wind farm designs are also playing a role, as it has increased the availability and efficiency of the wind farm assets.

Over the past two decades there has been a trend with offshore wind farm installations increasingly being located farther from shores and anchored in deeper waters. In 2001, the weighted-average water depth and distance from shore of commissioned offshore wind farms were approximately 7 meters and 5 kilometers. However, in 2019, these same figures had increased to 32 meters and 60 kilometers respectively [53]. Increased water depths and distance from ports both adds the the total installed costs of offshore wind with more expensive foundations and higher O&M and decommissioning costs. Remote locations is also usually correlated with harsher weather conditions making installation more difficult. On the positive side, the location of wind farms further offshore reduces the visual pollution and usually imply stronger and more consistent winds.

While most offshore wind farms today involve conventional bottom-fixed turbines, recent technology developments have also enabled the use of floating foundations. The potential scale of resources that can be unlocked by floating wind is impressive, as they can significantly increase the sea area available for offshore wind farms, especially in countries with limited shallow waters. Since floating wind is still in the prototype stage of development, it is not yet a commercial option. However, it is expected that floating offshore wind will see a strong growth in the long-term [54].

The penetration of offshore wind in the global energy system is believed to increase further in the future. In the Energy Transition Outlook 2020 by DNV GL [54], is is expected that the share of offshore wind in the total wind electricity generation will increase steadily from 5.5% in 2018 to 28% in 2050, with a fifth of this being floating offshore wind. Strengthened support in countries with limited land areas is highlighted as a key driver for this development. It is also expected that Europe will remain in a leading position, both in terms of fixed and floating wind. Moreover, in terms of capacity it is expected that installed volumes will reach 1.3TW globally by 2050, with 255GW being floating wind. This development are the result of larger turbines, ”mega-sized” projects and a more dedicated offshore supply-chain. Significant reductions in installed costs and O&M costs is also emphasised.

3.2.2 Active offshore wind projects in Europe

A summary of key figures from active offshore wind projects in Europe, currently pursued by leading market players are provided in Table 3.1. The data is based on information available at the company’s websites and covers all European offshore wind projects that are either in a late planning phase or under construction, with a set date for start of operations. Included companies are Örsted, RWE, Iberdrola and SSE. The global operational offshore wind portfolio of each of these companies (reported for 2020) was 7600 MW, 5759 MW, 1258 MW and 579 MW respectively. It is important to stress that the data included in Table 3.1 does not include all future planned capacity of new offshore wind in Europe. Several projects are still in an early planing phase and new concessions are granted regularly. Moreover, the four investigated companies represent only a selection of the wind power developers that are operating in Europe. Hence, the amount of pursued projects and countries evaluated for build-out are in reality higher. The intention is not to present a complete overview, but rather to provide a snapshot of current trends.

Table 3.1: Key figures from active offshore wind projects in Europe, pursued by leading market players.

Company	Project size range [MW]	Locations	Planned turbine rating range [MW]	Ready for operation range [year]	Sources
Örsted	242 - 1400	GB, DE	8 - 11	2022-2024	[55], [56]
RWE	342 - 1600	GB, DE, SE	9 - 14	2022-2027	[57], [58]
Iberdola	476 - 3100	GB, DE, FR	7 - 14	2023-2026	[59], [60]
SSE	520 - 4100	GB	9.5 - 14	2025-2027	[61], [62]
Total	21116	GB, DE, SE, FR	7-14	2022-2027	

It is observed that the capacity of projects are ranging between a few hundred megawatts to just above four gigawatts. Great Britain hosts the majority of the projects, followed by Germany. Few projects are also pursued in Sweden and France. Most projects are located in the North Sea, with a few exceptions being built the Baltic Sea. Wind turbine power ratings are ranging between 7 MW and 14 MW, which is high, considering that the weighted-average turbine capacity was 6.5 MW in 2019 [53]. All projects are planned to be set in operation within 2027.

3.2.3 Turbine technology

Over the past two decades, the global weighted-average turbine capacity has increased 114%, form 3 MW to 6.5 MW [53]. In the same time span, the weighted-average rotor diameter of deployed turbines increased from 99 meters to 141 meters. An illustration of how the global weighted-average turbine size has evolved between the year 2000 and 2019, is provided in Figure 3.2. It is observed that China lags Europe in terms of turbine technology, using smaller turbines. Moreover, it becomes clear that Europe is leading the development of wind turbine technology, with the highest turbine ratings in 2019 exceeding 8 MW.

Considering the trend over the last decade and recent developments in terms of turbine technology, it is likely that the size of turbines will increase further in the future. In February 2021, Vestas introduced to the market a new 15 MW turbine [63] with a rotor diameter of 236 meters. At 15 MW, this giant turbine is currently the largest available model in the industry, surpassing the 14 MW rating of the latest models announced by Siemens Gamesea and GE Renewables Energy [64], [65]. Moreover, according to IEA [66], further technology improvements through 2030 could see even bigger turbine sizes of 15-20 MW with rotor diameters up to 250 meters. Larger turbines in the long-term is also anticipated by DNV GL in [54], with continued increases in blade and tower sizes

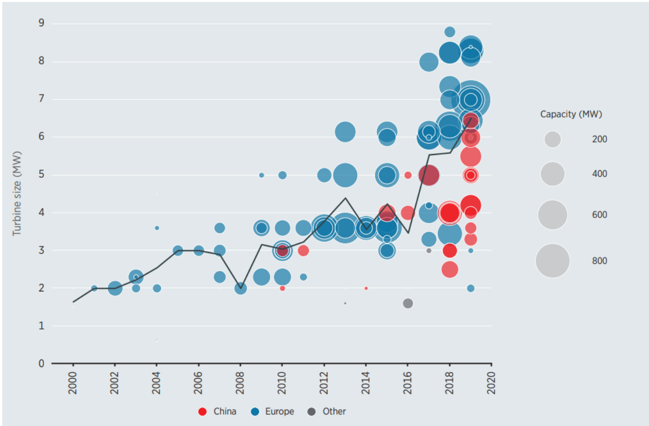


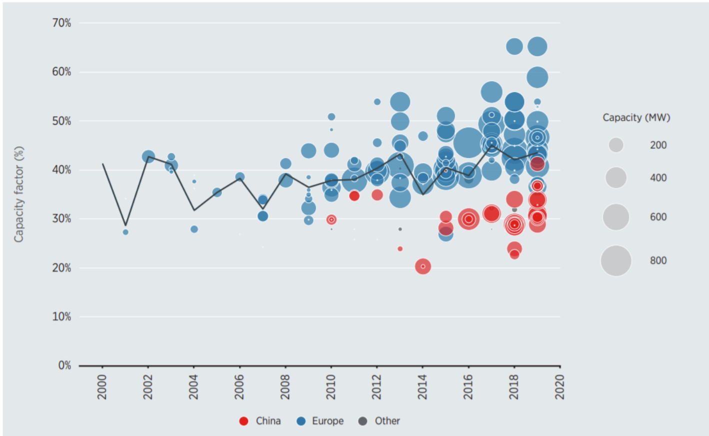
Figure 3.2: Weighted-average turbine size for offshore wind from 2000 to 2019 by region (color) and capacity (dot size). Technology improvement is the main driver for increasing turbine sizes over time [53].

towards 2050. Although some wind farms may experience lower average wind speeds, new turbine types is expected to allow better performance under varying wind conditions.

3.2.4 Capacity factors

The capacity factor (CF) represents the ratio of actual electric energy output over a given period of time to the maximum possible electric energy output over that period. Capacity factors are defined for any electricity producing units and it is an useful tool for examining the reliability of various power plants. This section provides an overview of important aspects for determining the capacity factor for wind power production. First, the historical evolution of capacity factors is covered. Then important considerations and a likely future development of capacity factors is discussed, moving towards 2040 and beyond. The main focus is dedicated to European offshore wind.

The value of capacity factors for wind power production is predominantly determined by two factors: (1) the quality of the wind resources where the wind farm is located and, (2) the turbine and balance-of-plant technology used [53]. Over the past decade, the evolution of capacity factors for wind has been characterized by an increasing trend. Important factors contributing to rising capacity factors are larger wind turbines, with higher hub-heights and larger swept areas that harvest more electricity from the same resource compared to older machines. In addition to turbine technology improvements, better methods for wind resource characterisation and wind farm design, has enabled the selection of better wind sites and improved wind farm layouts that optimise operational output. Another important contributing factor is reduced downtime due to more reliable designs and more efficient O&M practices.



Source: IRENA Renewable Cost Database.

Figure 3.3: Weighted-average capacity factors for offshore wind from 2000 to 2019 by region (colour) and capacity (dot size). Turbine size is the main driver for increasing capacity factors over time as it covers a larger swept area [53].

The global weighted-average capacity factor for onshore wind reported by IRENA [53] increased from just over 27% in 2010 to 36% in 2019. In the same time span, the capacity factor of newly commissioned offshore wind farms has increased from 37% to 44%. Looking at Europe only, the weighted-average capacity factor for offshore wind increased from 39% to 47%. Moreover, for offshore wind projects commissioned in 2019 in Europe, the 5^{th} and 95^{th} percentile capacity factor was 37% and 58%. A visualisation of offshore wind projects and weighted-average capacity factors between the year 2000 and 2019, is provided in Figure 3.3.

In general, as Figure 3.3 illustrate, the range of capacity factors for offshore wind farms is very large. This is primarily due to differences in the meteorology at different locations where wind farms are deployed. As an example, wind farms located close to shore will typically experience lower wind speeds than wind farms located further out to sea. Moreover, the correlation between capacity factors and the size of turbines is clearly illustrated when comparing Figure 3.2 and 3.3. Larger turbines is generally associated with higher capacity factors, while smaller turbines typically have lower capacity factors. Another interesting observation is the fact that capacity factors for Chinese offshore wind are relatively low compared to Europe, which underlines the significant impact of different turbine technologies.

While the historical increase of weighted-average capacity factors for offshore wind appears to be small, it is not insignificant. Considering the large scale of offshore wind deployment that are expected in years to come, only marginal differences in capacity factors will have a tremendous impact on the energy output and economical viability of offshore wind projects. Hence, accurate estimates of the future development of capacity factors is vital when evaluating offshore wind in a financial perspective. In [54] DNV GL expects that the increase in capacity factors will continue in the future, primarily driven by new and improved turbine technology. By 2050, they estimate the global average capacity factor to rise to 51%.

3.2.5 Levelized cost of energy

Between 2010 and 2019, the global weighted-average LCOE of offshore wind went down 29%, from USD 0.161/kWh to to USD 0.115/kWh (real, 2019) [53]. As described in previous sections, increasing experience, advances in wind turbine technology and more efficient operation and maintenance have contributed to lowering the cost of offshore wind. Other important factors reducing the LCOE have been the increasing competition, and strong policy and regulatory support. In [54] DNV GL forsees a further reduction in the LCOE of offshore wind towards 2050. The majority of the cost savings is expected to be from installed costs and O&M costs, as experience of installing and operating offshore wind turbines builds up. Improved capacity factors and reduced turbine costs also contribute to a lower LCOE, however their contribution is less significant. Overall, compared to 2020 levels, the reductions in LCOE for fixed and floating offshore wind are expected to be 56% and 69% respectively, with costs decreasing to USD 0.041/kWh and USD 0.047/kWh (real, 2020). An illustration of the projected cost savings for LCOE of wind, comparing onshore wind, fixed and floating offshore wind between 2020 and 2050, is provided in Figure 3.4.

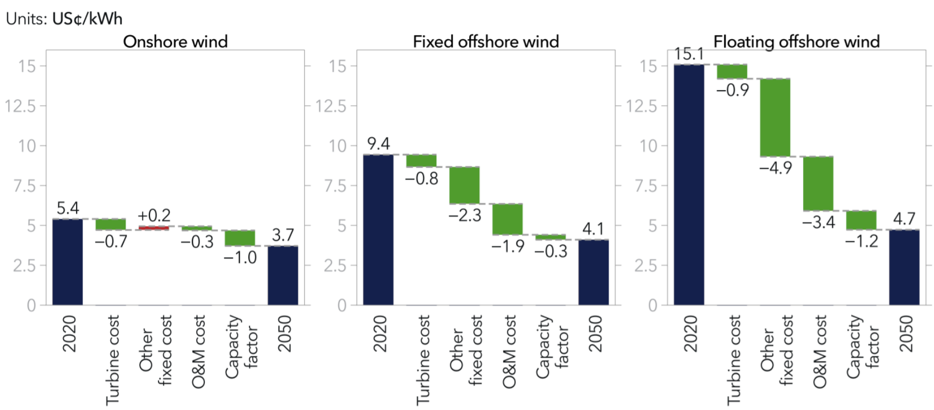


Figure 3.4: Expected costs savings (green) for the LCOE of wind (blue) between 2020 and 2050. Reductions in installed costs and O&M costs are the main drivers for decreasing LCOH over time as experience builds up [54].

3.3 Hydrogen

The European Union (EU) recently decided to increase its climate ambition for 2030 [67] and aims to reach climate neutrality by 2050 [68]. Achieving a climate neutral economy will require a large amount of hydrogen, especially in harder-to-abate industrial sectors. Such hydrogen will be increasingly produced on the basis of renewable electricity, because renewable-based hydrogen is the only carbon-free option. While being essential in tackling emissions, low-carbon hydrogen also has a variety of other applications, as it can act as a flexibility provider by storing electricity and help to balance power systems. The following section covers current and future applications of hydrogen, and provides an introduction to the technical and economical aspects of producing hydrogen.

3.3.1 Hydrogen applications

Hydrogen use today is dominated by industrial applications. The top four single uses of hydrogen today are oil refining, ammonia production, methanol production and steel production, and the vast majority of this hydrogen is supplied by fossil fuels [69]. Hydrogen is primarily used as a feedstock or reaction agent in chemical processes, but also as a combustion fuel for the supply of heat. The demand for hydrogen in industrial applications is expected to increase in the future in line with a growing demand for industrial products [54].

However, maximising the potential of hydrogen in the long-term depends on moving beyond the existing industrial uses of hydrogen. An important path in this development is the increased use of hydrogen as a versatile fuel in various sectors. Hydrogen has for a long time been considered a potential fuel in the transport sector, offering a low-carbon alternative to refined oil and natural gas. Practically all means of transportation could potentially run on hydrogen or hydrogen-based fuels. This includes road transport, maritime, rail and aviation. There is also opportunities for use of hydrogen in buildings sector. While hydrogen is very little used as a source of energy in the buildings sector today, potential uses are being tested. One opportunity is to blend hydrogen in existing natural gas networks. Another is that hydrogen can be used for direct heat production in buildings.

A third sector that could potentially see a growing demand for hydrogen is the power sector. Today, hydrogen plays a negligible role in this sector, as it accounts for less than 0.2% of electricity generation [69]. However, co-firing of ammonia could be an important carbonation measure for conventional coal power plants, and hydrogen-fired gas turbines and combined-cycle gas turbines (CCGT) could be a source of flexibility in electric systems with a higher penetration of variable renewables. As a chemical component in the production of ammonia or synthetic methane in the form of compressed gas, hydrogen could also become a long-term storage option to balance seasonal variations in electricity demand or generation from renewables. The role of so called power-to-hydrogen to accommodate the increasing share of renewables in the power system is highlighted in the Hydrogen for Europe [70] study. Production of hydrogen through electrolysis is emphasised as the main outlet for the generation of solar and wind capacities. Electrolysis is found to provide valuable contributions in terms of power system flexibility, but also in mitigating curtailment and congestion [71].

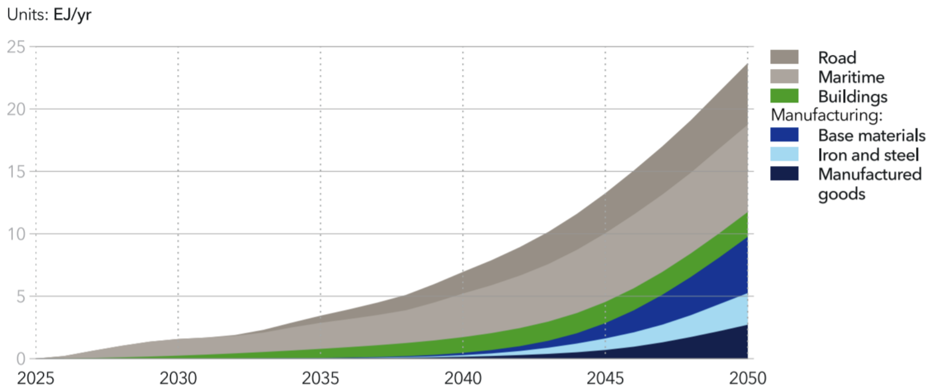


Figure 3.5: Global hydrogen demand by sector forecasted by DNV GL in [54]. Increasing use of hydrogen as a fuel in the transport and buildings sector is the main driver for a growing hydrogen demand towards 2040, while hydrogen use for manufacturing purposes contributes more significantly between 2040 and 2050. Only hydrogen as an energy carrier is included. Maritime synthetic fuels are counted as hydrogen.

An illustration of the global hydrogen demand for hydrogen as an energy carrier, forecasted by DNV GL in [54], is presented in Figure 3.5. It is observed that the use of hydrogen as a fuel in the transport and building sector is expected to be the main driver for a growing hydrogen demand towards 2040. Beyond 2040 the use of hydrogen for manufacturing purposes grows significantly, accounting for about 50% of the global hydrogen demand in 2050.

3.3.2 Hydrogen production

Most hydrogen today is produced from natural gas through either steam methane reforming (SMR) or auto-thermal reforming (AMR). In 2019, hydrogen from natural gas accounted for 76% of the global dedicated hydrogen production, while almost all the rest (23%) was produced from coal, due to its dominant role in China [69]. Oil and electricity account for the reminder of the dedicated production. The high dependence on natural gas and coal means that hydrogen production today generates significant CO_2 emissions and most of this CO_2 is released into the atmosphere. SMR is likely to remain the dominant technology for large-scale hydrogen production in the near-term because of low costs and the large number of SMR units in operation today. Emissions from conventional hydrogen production can be mitigated by introducing carbon capture, utilisation and storage (CCUS) technology. In fact, a reduction in carbon emissions of up to 90% can be achieved by using CCUS in SMR plants [69]. Several low-carbon SMR-CCUS plants are already in operation today.

In order to have a complete elimination of emissions, a switch to carbon-free hydrogen (i.e. green hydrogen) is needed. This can be achieved by producing hydrogen from water and electricity through water electrolysis, splitting water into hydrogen and oxygen. In 2019, less than 0.1% of the global dedicated hydrogen production came from water electrolysis, as production by means of electrolysers are mainly used when high-purity hydrogen is necessary. However, with declining costs for renewable electricity, particularly due to the influence of solar PV and wind, the interest for hydroelectric hydrogen is growing. Three main electrolyser technologies exist today [69]. These are alkaline electrolysis (ALK), proton exchange membrane (PEM) electrolysis and solid oxide electrolysis cells (SOECs). An overview of the various technologies are presented below:

- **Alkaline electrolysis** is the most mature and commercial way of producing hydroelectric hydrogen today. This technology has been used since the 1920s, particularly to supply the fertiliser and chlorine industries. Alkaline electrolysers have an operating range between a minimum load of 10% and their full design capacity. Several alkaline electrolysers were built in the last century, however after the introduction of SMR in the 1970s, almost all of them are now decommissioned. Due to the avoidance of precious metals, alkaline electrolysers are characterized by relatively low capital costs compared to other electrolyser technologies.

- **PEM electrolyser** facilities were first introduced in the 1960s and represents an improved version of the alkaline electrolyser. These electrolysers are relatively small, making them attractive for dense urban areas. They are able to produce highly compressed hydrogen at 30-60 bar (in some systems up to 100-200) without additional compressors, compared to 1-30 bar for alkaline electrolysers. PEM electrolysers also offer flexible operation, including the capability to provide frequency reserve and other grid services. Their operating range is between zero load and 160% of design capacity, hence it is possible to overload the electrolyser for a short time if the overall plant has been designed accordingly. Despite enhanced operational performance, their overall costs are higher than those of alkaline electrolysers, due to expensive electrode catalysts (platinum, iridium) and membrane materials. PEM electrolysers also have a shorter lifetime and are less widely deployed than alkaline electrolysers.

- **SOECs** is the least developed electrolysis technology and it is yet to be commercialized. SOECs operate at high temperatures because they use steam for electrolysis, and unlike PEM and ALK electrolysers they need a heat source. Potential heat sources for SOEC electrolysers are nuclear plants, solar thermal or geothermal heat systems. Heat recovered from the synthesis process can also be used for further SOEC electrolysis. SOECs are characterised by high electrical efficiency and low material costs. Another advantage about SOEC compared to PEM electrolysers, is that they are capable of operating in reverse mode as a fuel cell, converting hydrogen back to electricity. In this way they are able to provide balancing services to the grid in combination with hydrogen storage facilities. However, a key challenge regarding SOEC is the degradation of materials resulting from the high operating temperatures.

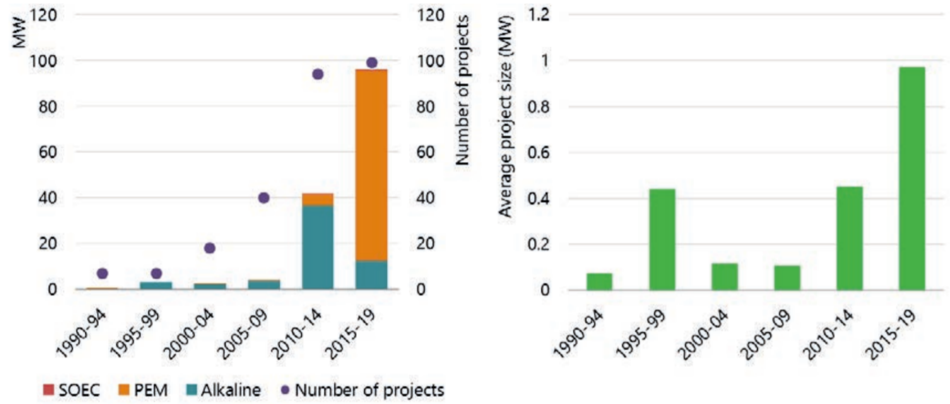


Figure 3.6: Development of global electrolyser capacity additions for energy purposes and their average unit size between 1990 and 2019. Capacity additions refer to already installed capacity additions and are cumulated over the specified 5-year periods. The rapid growth of electrolyser additions should provide cost reductions from economies of scale and learning effects in the future [69].

Over the last decade there has been an increase in new electrolysis installations, particularly by means of PEM technology. To date, most of the projects are located in Europe, although projects have also been initiated in Australia, China and the Americas. The size of electrolyser additions has seen an increasing trend in recent years, as the average unit size grew from 0.1 MW in 2000-2009 to 1.0 MW in 2015-2019 [69]. Today there are several projects under development with capacities of 10 MW or above, and projects with even larger electrolyser sizes above 100 MW are now under consideration. A shift towards commercial-scale applications should start to create economies of scale that can help to bring down capital costs and scale up the electrolyser industry. An illustration of the historical development of electrolyser capacity additions for energy purposes and their average unit size between 1990 and 2019, is provided in Figure 3.6.

3.3.3 Costs of hydrogen from water electrolysis

The production cost of hydroelectric hydrogen are influenced by various technical and economic factors, with the most important being capital costs (CAPEX), conversion efficiency, electricity costs and annual operating hours. In 2019 the International Energy Agency (IEA) reported a CAPEX requirement in the range USD 500-1400/kW for alkaline electrolysers and USD 1100-1800/kW for PEM electrolysers, while the estimated cost for SOEC ranged across USD 2800-5600/kW [69]. The electrolyser stack[1] was accounting for 50% and 60% of the CAPEX of alkaline and PEM electrolysers respectively, while power electronics, gas-conditioning and plant components comprised most of the remaining costs. Future reductions in CAPEX are dependent on advances in technology, e.g. through less costly materials, and economies of scale with regards to the manufacturing processes, e.g. through larger electrolysers.

The impact of CAPEX on the levelized cost of hydrogen (LCOH) is reduced as the amount of operating hours increase. As a result, the impact of electricity costs rises. In order to maintain a low-cost for hydrogen it is therefore essential to have access to low-cost electricity to ensure that the electrolyser can operate at relatively high full load hours. In power systems with a high penetration of variable renewable energy sources, it may be surplus electricity available at low cost. Producing hydrogen through electrolysis and storing it for later use based on surplus energy can be an effective way to take advantage of price variations. However, if surplus energy is only available on an occasional basis it is unlikely that this is not a sustainable business plan. Instead of only relying on surplus electricity with low full load hours, it may actually be cheaper to run the electrolyser at high full load hours and pay for additional electricity.

An alternative to the use of grid electricity for hydrogen production is the use of dedicated electricity generation from renewables or nuclear. Provided that electrolysers are built at locations with excellent renewable resource conditions and declinig costs for technologies such as solar PV and wind, this could become a low-cost supply option for hydrogen. A challenge, however, could be the added transmission and distribution costs of transporting hydrogen from remote renewables locations to the end users.

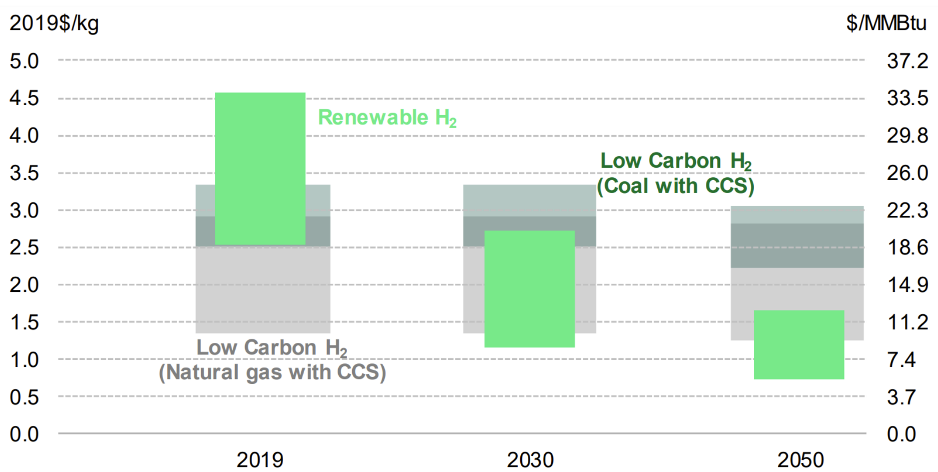


Figure 3.7: Forecast global range of levelized cost of hydrogen (LCOH) production from large projects. Electrolyser manifacturing scale-up and reduced costs are the main drivers for a decreasing LCOH in the long-term. Renewable hydrogen costs are based on large projects with optimistic projections for CAPEX. Natural gas prices range from USD 1.1-10.3/MMBtu, coal from USD 30-116/t [72].

The Hydrogen Economy Outlook study performed by BlombergNEF in [72] provides a

[1]The electrolyser stack represents the primary electrochemical component in a fuel cell electrolysis system. This is the component that converts chemical power to electricity (and vice versa) through an electrochemical reaction involving a cathode and an anode. Source: https://nelhydrogen.com/glossary/cell-stack/

forecast of the global range of the levelized cost of hydrogen production. While renewable hydrogen is expensive today, it is found that significant reductions in LCOH can be achieved in the long-term. If electrolyser manifacruring can scale-up and costs continue to fall, they estimate that renewable hydrogen could be produced for UDS 0.7/kg to USD 1.6/kg in most parts of the world before 2050. According to their calculations this is equivalent to gas priced at USD 6-12/MMBtu, making renewable based bydrogen competitive with current natural gas prices in Brazil, China, India, Germany and Scandinavia on an energy-equivalent basis. At the same time, it makes hydrogen production from renewables cheaper than producing hydrogen from natural gas or coal with carbon capture and storage. A representation of the future LCOH ranges forecasted by BloombergNEF in [72], is provided in Figure 3.7.

Chapter 4

Methodology

The presented methodology includes a representation of the North Sea offshore grid model and the mathematical formulation of the expansion problem used to solve it. Methods for modelling of storage and hydrogen electrolysers, and a description of the case study framework are also presented. All input data, assumptions and simplifications are thoroughly described and discussed. A tabulated presentation of inputs is found in Appendix A. Note that the presented model formulation in Section 4.1 and 4.2 are taken from the specialisation project prior to this thesis in [6].

4.1 Mathematical model formulation

Optimal TEP and GEP are analysed using a tool called Power Grid Investment Module (PowerGIM), presented in [73], [74]. PowerGIM is a module included in the open source PowerGAMA python package, developed by SINTEF Energy Research [75]. The model is built using the open-source optimization modeling package Pyomo [76].

The scope of the following case study (see Section 4.5) is limited to optimize the grid based on pre-determined scenarios for installed generation, transmission and nodes in the system. Consequently, investment opportunities are not presented to the model. However, this section presents the full deterministic capability of PowerGIM, including generation expansion, transmission expansion and the addition of new nodes.

PowerGIM takes the perspective of a supranational system operator, with the objective to minimize the net present value (NPV) of total system costs. Essentially, this implies finding the combination of new connections and production sites, from a set of potential candidates, that minimizes the operational costs of generation and investment costs of lines. Optimal capacity expansion is a problem of dual nature, because the power market equilibrium (i.e. optimal generation dispatch) and the optimal configuration of new interconnectors are solved in parallel. Based on the assumptions of perfect competition in generation investments and operations, completely inelastic demand and discrete transmission investments, the problem is formulated as a mixed integer linear program (MILP). Given the aforementioned assumptions, minimizing total system costs is equivalent to maximizing social welfare. Hence, PowerGIM is a useful tool in the sense that it can establish a threshold for optimal social economic solutions, assuming full cooperation among all involved countries.

With allowance from the authors, the mathematical representation of the model presented in [73] is reproduced here. A detailed description of the notation of the model is provided in Table (4.1).

Table 4.1: Notation used in PowerGIM [73]

Sets & Mappings	
$n \in N$	: nodes
$i \in G$	: generators
$b \in B$	: branches
$l \in L$	: loads, demand, consumers
$t \in T$	: timesteps, hour
$i \in G_n, l \in L_n$	: generators/load at node n
$n \in B_n^{in}, B_n^{out}$	: branch in/out at node n
$n(i), n(l)$	: node mapping to generator i/load unit l
Parameters	
a	: annuity factor
ω_t	: weighting factor for hour t (number of hours in a sample/cluster) [h]
$VOLL$	: value of lost load (cost of load shedding) [EUR/MWh]
MC_i	: marginal cost of generation, generator i [EUR/MWh]
$CO2_i$	: CO2 emission costs, generator i [EUR/MWh]
D_{lt}	: demand at load l, hour t [MW]
B, B^d, B^{dp}	: branch mobilization, fixed- and variable cost [EUR,EUR/km,EUR/kmMW]
CS_b, CS_b^p	: onshore/offshore switchgear (fixed and variable cost), branch b [EUR,EUR/MW]
CX_i	: capital cost for generator capacity, generator i [EUR/MW]
CZ_n	: onshore/offshore node costs (e.g. platform costs), node n [EUR]
P_i^e	: existing generation capacity, generator i [MW]
γ_{it}	: factor for available generator capacity, generator i, hour t
P_b^e	: existing branch capacity, branch b [MW]
$P_b^{n,max}$	: maximum new branch capacity, branch b [MW]
D_b	: distance/length, branch b [km]
l_b	: transmission losses (fixed + variable w.r.t. distance), branch b
E_i	: yearly disposable energy (e.g. energy storage), generator i [MWh]
M	: a sufficiently large number
Primal variables	
y_b^{num}	: number of new transmission lines/cables, branch b
y_b^{cap}	: new transmission capacity, branch b [MW]
z_n	: new platform/station, node n
x_i	: new generation capacity, generator i [MW]
g_{it}	: power generation dispatch, generator i, hour t [MW]
f_{bt}	: power flow, branch b, hour, t [MW]
s_{nt}	: load shedding, node n, hour t [MW]

Total system cost (4.2a) includes investment costs (4.2b) and operation costs (4.2c). Investment costs of new equipment happen in year zero, while operational costs apply through the whole lifetime of the grid. In order to sum the investment costs and operation costs, the net present value of future cash flows related to operational costs is calculated using the annuity factor a given by

$$a = \frac{1-(1+r)^{-n}}{r} \tag{4.1}$$

where r is the discount rate and n is the planning horizon in years. In the single-stage deterministic formulation of the model, cash flows of operational costs are calculated based on one year of operation only. Annual cash flows will thus be identical for each year in the period of analysis. Hence, the net present value of total operational costs are found by multiplying the annual cash flow with the annuity factor a.

In (4.2b) new transmission capacities can be added either by upgrading existing interconnections or by building new interconnections. Building a new interconnector is associated with both fixed costs (4.2d) and variable costs (4.2e). Integer variables are used to include fixed cost associated with new interconnectors, while the capacity dependant costs are linearly dependant on the amount of new transmission capacity. New generation capacities are associated with a fixed capital costs dependant on generator type, and investment costs are linearly dependant on the amount of new generation capacity. The opportunity to extend the grid by new nodes are also included in the model by adding binary variables with associated nodal costs.

The operational cost in (4.2c) is dependant on generation costs and the costs of not supplying load. Generation costs are determined by the level of generator dispatch, and the associated marginal costs and CO_2 emission costs for technologies using fossil fuels. A fixed penalty given by $VOLL$ is added for each unit of unsupplied load.

Equations (4.2f) to (4.2l) represent restrictions. (4.2f) provides the nodal energy balance or market clearing. The demand is set equal to the power generation dispatch, import, export and load shedding. Transmission losses are also included in the equation to ensure that importers pay for the losses. D_{lt} is represented by hourly load profiles included for each aggregated country and the market is cleared for every time state. Equation (4.2g) makes sure the load shedding at respective nodes does not exceed the total demand in any time state.

(4.2h) ensures that generation dispatch is kept within their minimum and maximum limits. The upper limit includes the maximum existing generation capacity and potential new capacity investments, multiplied by a factor γ_{it}. This factor represents production profiles for the intermittent power generation and can take values ranging from 0 to 100% depending on inflow/availability. Profiles at various geographical locations (nodes) and time state are provided in the input data. Equation (4.2i) constrains production units from producing more than their respective disposable energy. This is mainly relevant to production units with storage capabilities, such as hydro power, where annual production is constrained by the amount of energy stored in the reservoirs.

$$\min_{x,y,z,g,f,s} \quad IC + a \cdot OC \tag{4.2a}$$

where

$$IC = \sum_{b \in B}(C_b^{fix} y_b^{num} + C_b^{var} y_b^{cap}) + \sum_{n \in N} CZ_n z_n + \sum_{i \in G} CX_i x_i \tag{4.2b}$$

$$OC = \sum_{t \in T} \omega_t (\sum_{i \in G}(MC_i + CO2_i) g_{it} + \sum_{n \in N} VOLL s_{nt}) \tag{4.2c}$$

$$C_b^{fix} = B + B^d D_b + 2CS_b \qquad \forall b \in B \tag{4.2d}$$

$$C_b^{var} = B^{dp} D_b + 2CS_b^p \qquad \forall b \in B \tag{4.2e}$$

subject to

$$\sum_{i \in G_n} g_{it} + \sum_{b \in B_n^{in}} f_{bt}(1 - l_b) - \sum_{b \in B_n^{out}} f_{bt} + s_{nt} = \sum_{l \in L_n} D_{lt} \qquad \forall n, t \in N, T \tag{4.2f}$$

$$s_{nt} \leq \sum_{l \in L_n} D_{lt} \qquad \forall n, t \in N, T \tag{4.2g}$$

$$P_i^{min} \leq g_{it} \leq \gamma_{it}(P_i^e + x_i) \qquad \forall i, t \in G, T \tag{4.2h}$$

$$\sum_{t \in T} \omega_t g_{it} \leq E_i \qquad \forall i \in G \tag{4.2i}$$

$$-(P_b^e + y_b^{cap}) \leq f_{bt} \leq (P_b^e + y_b^{cap}) \qquad \forall b, t \in B, T \tag{4.2j}$$

$$y_b^{cap} \leq P_b^{n,max} y_b^{num} \qquad \forall b \in B \tag{4.2k}$$

$$\sum_{b \in B_n} y_b^{num} \leq M z_n \qquad \forall n \in N \tag{4.2l}$$

$$x_i, y_b^{cap}, g_{it}, s_{nt} \in \mathbb{R}^+, \quad f_{bt} \in \mathbb{R}, \quad y_b^{num} \in \mathbb{Z}^+, \quad z_n \in \{0, 1\}$$

A transportation model is used to model the power network. Transportation models are simplified formulations where Kirchhoff's voltage laws are disregarded and power flows are restricted by transfer capacities only. This formulation is assumed to be sufficient because the intention is to use the model on an aggregated system, including controllable high voltage direct current (HVDC) grids. Equation (4.2j) and (4.2k) provides constraints for the transportation model, ensuring that branch flows and maximum branch capacity limits are not violated when adding new transmission capacities.

Equation (4.2l) forces new nodes to be built in cases where new branches connect to a nodes that are not all ready existing. In the configuration of PowerGIM that is used in this report, additional cables are defined as positive real variables. Consequently, the model allows for investments in a fractional number of cables. The upside to such a formulation is that if we fix all transmission investment variables (binaries), the model becomes a relaxed linear program (LP) instead of a MILP. This allows electricity prices to be determined by the dual variables of equation (4.2f) in every operational state. In practice, this has no major impact on the results other than the fact that new capacity investments may appear in odd fractional numbers.

4.2 Sampling and operational states

Demand and generation varies, thus the power system will be in a number of different operational states over time. This is an especially important consideration in systems with high penetration of variable RES such as wind and solar, because the power flows do not change uniformly with the loading of the system. Consequently, optimal capacity of interconnectors between nodes are dependant on the joint probability distribution renewable power generation and load at each node.

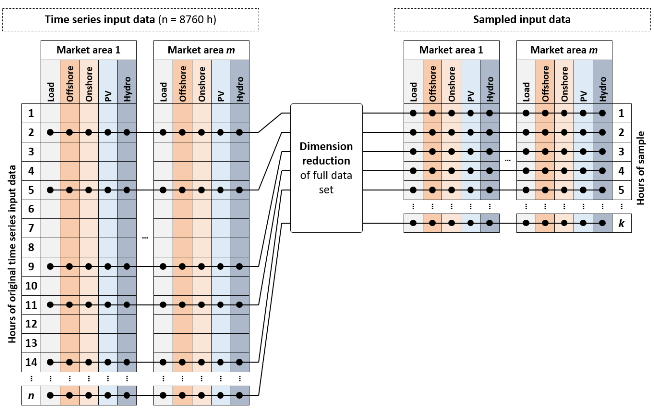


Figure 4.1: Illustration of sampling approach to reduce dimension of the input data [77].

The original wind, solar, hydro power and load data sets which are used, contains values from a full year on a hourly basis (see Section 4.6 about input data). This implies 8760 wind and solar values, and 8760 load values for each node, in addition to 8760 values for Norwegian hydro. This comprise a very large amount of data which leads to long computational time. To keep the computation time within reasonable limits, it is necessary to keep the number of states as low as possible. Random sampling is used to select a subset of states, that provides a sufficiently good description of the full data set. In [78], by comparing sample mean and sample correlation coefficients with those of the original data set, the authors find that 400 randomly selected states constitutes a reasonable compromise between computation time and precision. Consequently, an amount of 1000 random samples are used in this report. This yields an acceptable computational time, while being above 400 samples.

Figure 4.1 illustrates the approach to reduce the dimension of the input data to deal with computational challenges. In this report, k = 1000. More sophisticated dimension reduction techniques do exist, however, the procedure of determining the optimal technique is outside the scope of this report.

4.3 Modelling of batteries and hydrogen electrolysers

Modelling of batteries and hydrogen electrolysers are not an integrated functionality in PowerGIM. Hence, a simple hybrid approach is used to implement these technologies in the model. Battery capacities are included by adding a new "battery" node in each country. These nodes are connected to the respective aggregated country nodes through branches with a fixed loss factor of 10% in each direction, to replicate an assumed round-trip efficiency of 20%. A generator with the capability to run +/- installed capacity (MW) is defined in the each of the "battery" nodes. The annual average capacity factor of these generators are set to 0 to make sure the that they produce and consume equal amounts of energy throughout the year. Moreover, a new constraint is added to the model that limits the maximum annual energy that can be discharged by each battery unit according to a predefined value. All together, these configurations with a "storage" node, generator and branch constitute the battery units in the system.

A similar approach is used to model hydrogen electrolysers. The only difference is that the generator unit in this case is constrained to only produce negative power, i.e. consume power. As the objective in PowerGIM is to minimize total system costs, the model will generally be pessimistic towards negative generation. Hence, without further constraints, a generator with only negative installed capacity will never be dispatched. To resolve this issue it is created a new constraint that forces a minimum annual energy consumption of the electrolyser units.

4.4 North Sea offshore grid representation

The reference grid used in the model is an aggregated representation of the North Sea offshore grid (NSOG). The system consists of 33 nodes, distributed over seven countries surrounding the North Sea. Countries that are included in the model, referred to as the core countries, are Norway (NO), Denmark (DK), Germany (DE), the Netherlands (NL), Belgium (BE), Great Britain (GB) and France (FR). For each country there is one node providing an aggregated representation of the annual load and generation. There are 15 land connection points, connecting the onshore AC grid to the offshore DC grid, and 10 offshore wind clusters. Node 11 represents a wind hub referred to as the North Sea wind power hub (NSWPH). This hub node is used for offshore interconnection between countries and offshore wind production in the following case study. It is also used to host new hydrogen electrolyser capacity. An illustration of the grid is shown in Figure 4.2. Full details of all nodes are provided in Table A.1 in Appendix A.

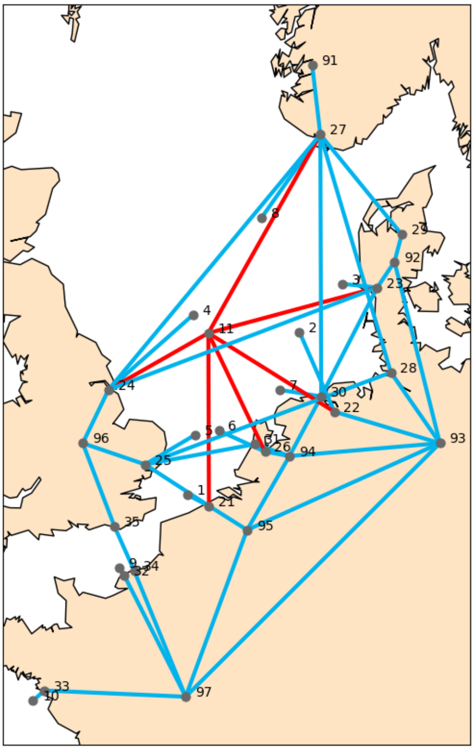


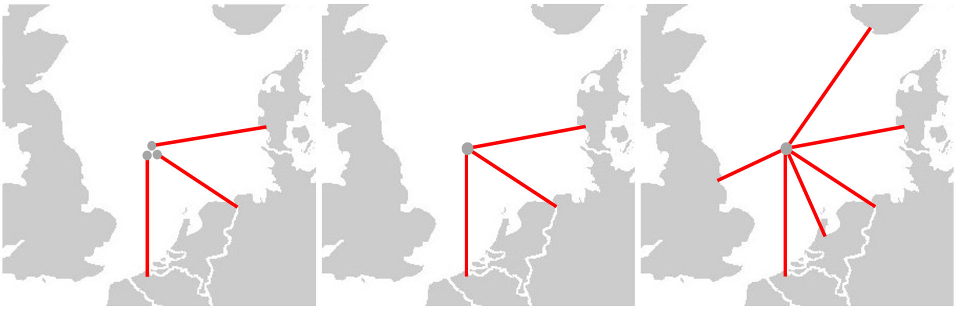
Figure 4.2: Representation of the aggregated North Sea offshore grid infrastructure and nodes used in the model.

The blue lines in Figure 4.2 represent existing interconnections, while the red lines represent the new transmission corridors that are evaluated for expansion in the case study. An accurate representation of all branches are provided in Table A.2 in Appendix A. The red interconnections represent potential pathways for the development of the NSOG as proposed by the North Sea Wind Power Hub programme [79]. These comprise cables connecting DE, DK, NL, BE, GB and NO to the NSWPH. The corridors DE-NSWPH and NL-NSWPH have a capacity of 6000MW and 4000MW respectively, while the remaining cables each have a capacity of 2000MW. A more elaborative description of the case study framework is provided in Section 4.5.

4.5 Case study framework

The aim of the case study is to investigate effective ways to realise the potential of wind power in the North Sea, through a transnational and cross-sector approach. The case study comprise an exogenous capacity analysis, investigating different ways of connecting 12GW offshore wind (OWF) capacity in the North Sea. Different cases are assessed, including both radial and hub configurations. An important source of inspiration is the 2020 study commissioned by the North Sea Wind Power Hub (NSWPH) consortium [79], performed by Afry Managemant Consulting in [80]. A representation of the various connection configurations are provided in Figure 4.3. Five configurations are tested:

- **Wind radial** - The Wind radial configuration investigates the connection of 12GW offshore wind capacity through a radial approach. OWF capacity is split into three separate wind farms, each with a generation capacity of 6GW, 2GW and 4GW, connected to Germany, Denmark and the Netherlands respectively. The ICs between the OWFs and the national systems each have a capacity of 6GW, 2GW and 4GW, matching the respective generation capacities. A home market (HM) setup is assumed, meaning that wind farm dispatches receive the electricity price in the respective HMs.
- **Wind hub** - In the Wind hub configuration, the OWF capacities from the Wind radial case are coupled through internal connections to form a common offshore hub. IC capacities between the hub and the respective national markets remain the same as in the Wind radial configuration. An offshore bidding zone (OBZ) is assumed. Hence, the electricity price is the result of market coupling.
- **Wind hub expanded** - In the Wind hub expanded configuration the hub is expanded to include connections to Belgium, Great Britain and Norway. The IC capacity of the new cables are 2GW each, while the IC capacities to Germany, Denamrk and the Netherlands remain the same as in the two previous configurations. An offshore bidding zone is assumed.
- **Hydrogen: fixed load** - The Hydrogen: fixed load case assumes the same configuration in terms of IC and OWF generation capacity as the Wind hub expanded case, but includes a PEM electrolyser facility at the hub. The electrolyser has a capacity of 5GW, with an assumed annual utilisation rate of 60%. A fixed load operation of the electrolyser is assumed, meaning that the elecrolyser effectively consumes 3GW of power in each sampled hour during the year. An offshore bidding zone is assumed.
- **Hydrogen: price dependent load** - The Hydrogen: price dependent load case assumes the same configuration in terms of IC and OWF capacity as the Hydrogen: fixed load case, the only difference is that it is allowed for optimal charging of the electrolyser. By allowing the electrolyser to see the electricity price in every sampled hour, the charging operation becomes price dependent. Hence, depending on the price, the electrolyser is free to consume any amount of power between 0GW and 5GW in every sampled hour. An offshore bidding zone is assumed.



(a) Wind Radial configuration

(b) Wind hub configuration

(c) Wind hub expanded, Hydrogen: fixed load and Hydrogen: price dependent load configuration

Figure 4.3: Representation of the various case study connection schemes, including one radial and four hub configurations.

4.6 Input data to model

A general goal for the input data is to use reliable open source data. The TYNDP 2020 Scenario Report [81] serves as the main source of input data to the model. Inadequate and lacking data in the TYNDP 2020 are supplemented by external sources whenever needed. Exogenous inputs are carefully selected to maintain a high level of consistency. Consequently, if data are given for different years, 2020 chosen. A discount rate of 5% and a period of analysis of 30 years are assumed. Accurate selection of discount rates is considered outside the scope of this report, hence a ballpark estimate is selected. Transmission and generation assets have a variety of different lifetimes. Transmission assets are likely to be utilised for longer than 30 years, while offshore wind assets are replaced more frequently. Hence, the assumed lifetime of 30 years constitute a viable compromise. The value of lost load (VOLL), i.e. cost for load shedding, is set to 1000 EUR/MWh, while the penalty cost for curtailment of renewable energy is set to zero.

4.6.1 ENTSO-E Ten Year Network Development Plan 2020

Every two years ENTSO-E publishes its Ten-Year Network Development Plan (TYNDP) [47], which is an extensive report that covers the development of the European power grid in the next one to three decades. The 2020 edition [48] is the most recent publication in the line of TYNDP reports and comprise a set of scenarios or ”visions” up to 2040. TYNDP provides data for each country with a particular focus on the future electricity and gas infrastructures. ENTSO-E works closely with the European Commission, ACER and various stakeholders when developing its storylines. All reports, including modelling data, are also freely available to the public. The incredible level of detail, consistency and transparency are the reasons why the TYNDP modelling data is used as the main source of input data.

The TYNDP 2020 Scenario Report presents three different scenarios for 2040. Global Ambition (GA) is the most ambitious scenario with respect to wind power integration. The scenario looks at a future led by a large development in centralised generation, where economies of scale lead to significant cost reductions in emerging technologies such as offshore wind and power-to-X. This constitutes an adequate base for a case study of investment opportunities in renewable North Sea infrastructure. Hence, modelling data from the Global Ambition scenario are used for installed generation capacities, fuel and CO_2 prices, load profiles and generation efficiencies.

Global Ambition is a top-down scenario, driven by the climate targets of the Paris agreement of keeping the temperature increase below 1.5°C. This implies the assumption of a full decarbonization by 2050 and the ambition of net negative emissions after 2050. In terms of transportation, wide adoption of zero-emission vehicles is a key component of decarbonization. Passenger transport is dominated by electric vehicles, and green gas and hydrogen are assumed the main fuels in heavy good transport and shipping. On a residential level, fossil fuels are replaced by electricity with a high penetration of hybrid heat pumps, running both electricity and gas. A transition away from fossil fuels towards renewable and decarbonized gases and electrification are experienced in the industrial sector. Technology improvements and increased energy efficiencies lead to reduced energy demand. Carbon capture and storage (CCS) technologies are adopted to limit emissions from processes where fossil fuels cannot be substituted with electricity or gas. Hydrogen production through P2G is also an applied option. Wind and solar are the leading sources of power generation with high penetration of wind farms in the Northern Europe and large scale solar power plants in the Southern Europe. Nuclear are phased out and gas fired power generation replaces coal. To stay an viable option in the long-term, gas plants run cleaner fuels and are equipped with CCS. Balancing of renewables are achieved mainly through P2G and battery solutions. For further information about the scenarios and their construction, see ENTSO-E [48][82][83].

4.6.2 Generation capacities

Installed generation capacities are based the Global Ambition scenario from the TYNDP 2020 Scenario Report [48] and presented in Table A.3 in Appendix A. Two aggregated categories have been chosen to represent the hydro resources present in the system. The category ”Reservoir” represents all hydro capacities with storage capabilities, including facilities with reservoirs and pumped storage solutions. All remaining hydro capacities are categorized as ”Run-of-river”. Moreover, the category ”Other RES” comprise generation technologies such as marine (wave and tidal), geothermal and small biofuel, while the category ”Other non-RES” contains mainly smaller scale CHP generator capacities. Carbon-based fuels, including oil, lignite, coal and gas, are widely used in CHP plants across Europe today. In accordance with the projections in the Global Ambition scenario, it is assumed a thermal phase-out of oil, coal and lignite by 2040, thus gas plants with heat recovery is used as a reference generation technology for this category. Installed capacities of gas fueled plants are presented in great detail in the Global Ambition scenario. To capture the diversity of different gas technologies, gas is separated into the three categories

”Gas CCGT”, ”Gas OCGT” and Gas conventional”. For the sake of simplicity, coal and oil capacities are represented by one category each. Aggregating different technologies of coal and oil are assumed reasonable due to marginal technological differences and the relatively low penetration in the national systems.

Bio fueled (e.g. biofuel or biomass) generation capacities are not presented as individual categories in Table A.3, because no specific bio fueled production is included in the TYNDP 2020 Global Ambition scenario. Certain coal and gas plants are reported to be running fuels denoted ”gas bio” and ”coal bio”, however the documentation on bio fueled generators are scarce. Consequently, bio fueled generation capacities are included indirectly as part of the categories ”Coal”, ”Gas”, ”Other RES” and ”Other non-RES”.

Battery capacities are included as generation capacities and refers to the aggregated discharge capacity in each country. Note that capacities denoted ”Battery” are not actual generators in the sense that they are not able to produce energy.

4.6.3 Emission factors

CO_2 emission factors for electricity production by combustion fuel product are taken from the *CO_2 emissions from fuel combustion Highlights 2019* report by the IEA [84]. The values are measured in [tCO_2/MWh] and represent average values per electricity produced in OECD member countries between 2011 and 2015. The emission factor for fuel oil is assumed to be a representative common estimate for the fuel products light oil and heavy oil. Input emission factors are presented in Table A.4 in Appendix A.

4.6.4 Cost of generation

In PowerGIM, each generator technology is characterized by a certain generation cost measured in [EUR/MWh]. This cost is composed of two components, which are the marginal operational cost and the CO_2 emission cost. Marginal operational costs are calculated based on fuel costs and variable non-fuel operation costs. CO_2 emission costs are calculated based on CO_2 emission factors and the system CO_2 price.

Fuel costs are calculated based on fuel prices and power plant efficiencies. The TYNDP 2020 Scenario Report [48] provides fuel price estimates on nuclear, natural gas, hard coal, light oil and heavy oil, measured in Euros per unit of electrical energy produced [EUR/GJ]. To obtain one common fuel price for oil it is calculated a volume weighted average price, based on the relative distribution of oil capacities running on light oil and heavy oil. Input fuel prices are presented in Table A.6 in Appendix A.

Power plant efficiencies for different technologies of gas, nuclear and other non-RES (largely CHP) are provided in the TYNDP 2020 Scenario Building Guidelines [82], while efficiencies for coal and oil are taken from the attached input data set for the TYNDP 2018 Scenario Report [81]. Volume weighted average efficiencies are calculated based on the relative distribution of different gas, coal and oil capacities respectively. Resulting input efficiencies are presented in Table A.5 in Appendix A.

It is assumed that all gas plants, including capacities in the category ”Other non-RES”, are fueled by natural gas. Moreover, it is assumed that all coal and oil plants are fueled by hard coal and fuel oil respectively. Fuel prices are converted using the relationship 1 MWh = 3.6 GJ. Input fuel costs are calculated by

$$c_f = \frac{p_{fuel} * 3.6}{\eta_{tech}}, \tag{4.3}$$

where p_{fuel} is fuel price, η_{tech} is plant efficiency and c_f is fuel cost. Resulting input fuel costs are presented in Table A.7 in Appendix A.

Variable non-fuel operation costs are provided in the ASSET Project Report 2018 [85] and presented in Table A.8, column eight, in Appendix A. The fuel cost of renewable energy sources including solar PV, hydro, wind and other RES are all assumed to be zero, thus the marginal cost for these generation technologies are only dependent on the non-fuel operation costs. An exception is made for hydro capacities with reservoirs, because the opportunity to store water represents a value. An arbitrary price of 10 EUR/MWh (like in [21]) is added to the generation cost for reservoir hydro in all countries except Norway to reflect the additional value of storage capabilities. Increasing the generation cost by 10 EUR/MWh ensures that reservoir hydro is below wind and solar in the merit order, while at the same time keeping the cost of generation lower than those for fossil fueled production. A price profile for Norwegian hydro power is included to capture the hydro production more accurately, which is further elaborated under section 4.6.6.

The system CO_2 price is set to 80 EUR/tCO_2 as projected in the Global Ambition scenario. The resulting merit order of generation technologies, without taking into account transmission congestion, system reliability and other system constraints, is presented in Table 4.2.

Table 4.2: Unconstrained merit order of generation technologies, presented as the sum of marginal operational costs and CO_2 emission costs.

Generation Technology	Marginal operational cost [EUR/MWh]	CO_2 emission cost [EUR/MWh]	Marginal cost of generation [EUR/MWh]
Solar PV	0	0	0
Run-of-River hydro	0	0	0
Onshore Wind	0.20	0	0.20
Other RES	0.38	0	0.38
Offshore Wind	0.39	0	0.39
Reservoir hydro (except Norway)	0.32	0	10.32
Nuclear	11.60	0	11.6
Other non-RES	48.50	32	80.5
Gas CCGT	49.81	32	81.81
Gas CCGT CCS	54.88	32	86.88
Gas OCGT	68.31	32	100.31
Gas Conventional	69.31	32	101.31
Coal	60.40	68.8	129.2
Oil	192.76	54	246.76

4.6.5 Investment and operating costs for power generation and storage

For investments in new electricity generation capacities the capital expenditures (CAPEX) are taken from the TYNDP 2020 Scenario Building Guidelines *Annex 2: Cost Assumptions for the Investment Modelling* [86]. Remaining investment costs, including CAPEX of hydrogen production and storage facilities, are taken from the ASSET Project Report 2018 [85]. The chosen CAPEX values reflect a future projected in the Global Ambition scenario, led by economic development in centralized generation, where economies of scale lead to significant cost reductions in emerging technologies such as offshore wind and Power-to-X (hydrogen and methane applications).

Investment costs for new production capacities are measured in euros per unit of capacity [EUR/MW], while the investment cost for new storage capacities are measured in euros per unit of energy stored per year [EUR/MWh]. In [85], long-term cost projections on hydrogen production and storage facilities are denoted by the status ”Ultimate”, rather than a specific year. The ”Ultimate” status for a technology is used when it is difficult to establish the future technology progress. The status is commonly used for immature technologies such as Power-to-X and associated costs represent floor costs. From the range of possible CAPEX the report proposes, the middle value between the year 2030 and ”Ultimate” is assumed for all technologies. To fit the input format in PowerGIM, all CAPEX values are discounted to obtain yearly investment costs. An interest rate of 5% and a payment period of 30 years are assumed. The values from the TYNDP 2020 and the ASSET Project 2018, and calculated input CAPEX data are presented in Table A.9 in Appendix A.

Operational costs of all electricity generation, hydrogen production and storage facilities, are taken from the ASSET Project Report 2018 [85]. Operating expenses (OPEX) of each technology are included through a fixed annual operation and maintenance cost (O&M) per unit of capacity [EUR/MW year] and a variable non-fuel costs per unit of energy produced/stored [EUR/MWh]. The ASSET Project Report presents a wide range of operational costs for wind and solar technologies, reflecting different potentials of wind velocity and solar irradiation. From the range of possible OPEX, the middle value between ”low” potential and ”very high potential” is assumed. Costs of ”Other RES” are assumed to be the average of the technologies ”Waves and tidal”, ”Geothermal” and ”Small biofuel”. For ”Gas OCGT” and ”Gas Conventional” it is assumed equal costs, because the two technologies are not differentiated in the ASSET Project Report. For technologies of hydrogen production and storage facilities, the middle value between year 2030 and ”Ultimate” is assumed. Values from the ASSET Project 2018 and assumed input OPEX data per technology are presented in Table A.8 in Appendix A.

Although PEM electrolysers are the only hydrogen production technology that is used in the actual case study, CAPEX and OPEX data for the technologies Alkaline, SOEC and SME CCS are included for reference in Table A.8 and A.9. The same goes for Gas CCGT CCS.

4.6.6 Renewable production and load profiles

Load and renewable power production vary with time. Input profiles are used to capture the variability of demand and production from wind, solar PV and hydro generation capacities. The TYNDP 2020 provide hourly load profiles in the Global Ambition scenario. Annual energy demand, peak demand and average load for each country are presented in Table A.10 in Appendix A.

Renewable energy generation profiles are not provided by ENTSO-E, thus these profiles are obtained from external sources. Wind and solar profiles are downloaded from the *renewables.ninja* website [87]. Each profile consists of 8760 values between 0 and 1, representing the hourly power output in fractions of maximum output during a full year. The methodology used to generate these profiles are described in Staffell and Pfenninger (2016) [88][89], for wind and solar PV respectively. For solar PV and onshore wind, country aggregated profiles are used. The MERRA-2 simulations are chosen to have consistency in the data and sufficient historical coverage. Another advantage of the MERRA-2 simulations is that they provide both current and future estimated profiles for wind. The simulation called *Long-term future fleet* is used for onshore wind in the model.

For offshore wind it is included specific profiles from each of the offshore node locations presented in Table A.1 in Appendix A. To accurately capture the wind velocity potentials, *renewables.ninja* require a reference hub height and turbine model as inputs. The hub height is set to 140 meters, which is the same height used as a reference in the offshore scenarios investigated by AGORA in [90]. Moreover, the Vestas V164 9500 is used as the reference turbine. This particular turbine model is the largest turbine available at *renewables.ninja*, both in terms of rotor diameter (164 meters) and rated power (9.5 MW). The chosen reference turbine properties are intended to reflect an average offshore wind turbine in 2040 and is based on industry trends as described in Section 3.2.3

All production profiles for wind and solar PV are downloaded in three separate editions, each based on different climate years, to enable the comparison of different solar irradiation and wind velocity potentials. The target climate years are 1982, 1984 and 2007, which are the same years investigated in the scenarios presented in TYNDP 2020.

Norway has a significant amount of hydro resources and the Norwegian electricity prices are highly dependant on the calculated water value of the reservoirs. The water values change with weather conditions, current reservoir levels and expected future inflow and demand. To accurately capture the hydro production, a price profile for Norwegian hydro power is included. Historical prices from 2016 reported by the power exchange Nord Pool are used to represent the water values, under the assumption of marginal cost bidding. Hourly spot prices from the southern bidding area NO2 are used because this is where the interconnections in the model are installed. A major shortcoming in this approach is the presence of prices from 2016 when the time horizon is extended to 2040. Demand and generation portfolios change over time, hence there will be a mismatch between present and future electricity prices. However, in the lack of better open source water value projections, this is the applied method.

Spot prices from 2016 is chosen specifically based on a comparison of historical prices from different years. The 2016 profile was found to provide a decent average, both in terms of prices magnitudes and price volatility. The spot prices are converted to "real 2020-terms" by multiplying the time series with inflation. Assuming an annual inflation rate of 2%, prices p_y are converted to "real 2020-values", p_{2020}, by

$$p_{2020} = p_y * 1.2^{2020-y}, \tag{4.4}$$

where y represents the year from which the prices are taken. Ideally, the year of the reported spot prices should be matched with the reference climate year used for overall inputs. However, because hourly spot prices from 1982, 1984 and 2007 are not open source data, this is considered outside the scope of the report.

4.6.7 Net transfer capacities and transmission cost parameters

The capacity of transmission corridors are expressed through net transfer capacities (NTC). NTC's for the 2040 "Reference Grid" in the Global Ambition scenario, provided in TYNDP 2020, are used for cross-border lines in the model. A useful visualisation of the grid data is available at the TYNDP 2020 Visualisation Platform [91]. Unfortunately, domestic transfer capacities are not provided in TYNDP. However, to reflect the issue of congestion risk, it is necessary to include restrictions on domestic capacities. Consequently, the value of domestic transfer capacities are set such that they can accommodate only 90% of the installed offshore wind capacity at full load operation.

Cost parameters for VSC HVDC transmission infrastructure used in PowerGIM are modeled according to the presented methodology in [92]. Costs are taken from National Grid [93] and input variables are presented in Table A.11, A.12 and A.13 in Appendix A. Transmission losses are implemented by a loss fraction approach and estimated values are provided in the PowerGIM example file [74]. AC/DC converters and inverters have a loss constant of 1.6%. Power loss slope of AC and DC technology is 0.005% and 0.003% respectively. Input grid data are identical to what is used in [94].

4.6.8 Quality of data

While the TYNDP 2020 Global Ambition scenario constitutes a good basis, it has the drawback of not providing all the necessary inputs. The lack of wind and solar production profiles is a particular issue in this regard. This provide a mismatch between the actual input data used and the underlying assumptions. Deviations regarding the offshore wind potential in terms of annual capacity factors is a clear example of this.

The wide range of technology efficiencies, especially with regards to gas production, is another weakness. Depending on the different plant technologies, efficiencies are ranging between 35% and 60%. While this may be representative for the available technologies, it is hard to determine what is the most descriptive values of the aggregated capacities.

Another shortcoming of the TYNDP 2020 data is the generalized categories ”Other RES” and ”Other non-RES”. The relative distribution of different technologies within these categories are hard to determine and the ENTSO-E provide limited documentation regarding their origin. Similarly, there is no dedicated category for bio fueled generation in the TYNDP scenarios, nor is it provided an estimate on biomass price. As a result, bio fueled generation is not included as an individual category in the model.

As previously mentioned, the assumption of using 2016 clearing prices in Norway as estimates for the water values in 2040 is a major flaw in the model. Production and demand change over time, hence there will be a mismatch between historical and future prices. Another challenge about using fixed spot prices as an approximation for Norwegian hydropower, is that the cost will be higher than renewables, such as solar and wind, but lower than fossil fuel. This may result in unrealistic production levels of hydropower compared to the available storage facilities.

A careful selection of input data is crucial for achieving reliable and realistic results. The aforementioned weaknesses represent limitations in the model, which should be considered when evaluating the results.

4.7 Data pre-processing and model validation

A significant effort has been dedicated to the process of selecting reliable input data and validation of the model. The following section highlights important considerations regarding the input data and implemented measures to improve the model performance. A validation of the model against the reference scenario in the TYNDP 2020 Scenario Report [81] is also provided.

4.7.1 Compensation of the external European electricity grid

A challenge when modeling only a subset of the European electricity grid (i.e. Belgium, Germany, Denmark, the Netherlands, Great Britain, France and Norway) is how to compensate the influence of the external European electricity system. When looking at the actual European electricity grid map, it is observed that there are energy flowing between the core countries and the external grid. Consequently, in order to proportionally match production and demand, and to have more realistic market behaviour, it is necessary to modify the model.

The influence of external countries are included by investigating the annual average net energy flows (MW), i.e. leakage flows, between the core countries and the respective adjacent countries. For each core country, these leakage flows are aggregated into one average flow and presented to the model as an external load. These loads are then placed in external country nodes and connected to the respective core country aggregated nodes, through branches with very high transfer capacities to ensure that the loads can be met in every sampled hour. The location of external country nodes are chosen according to which

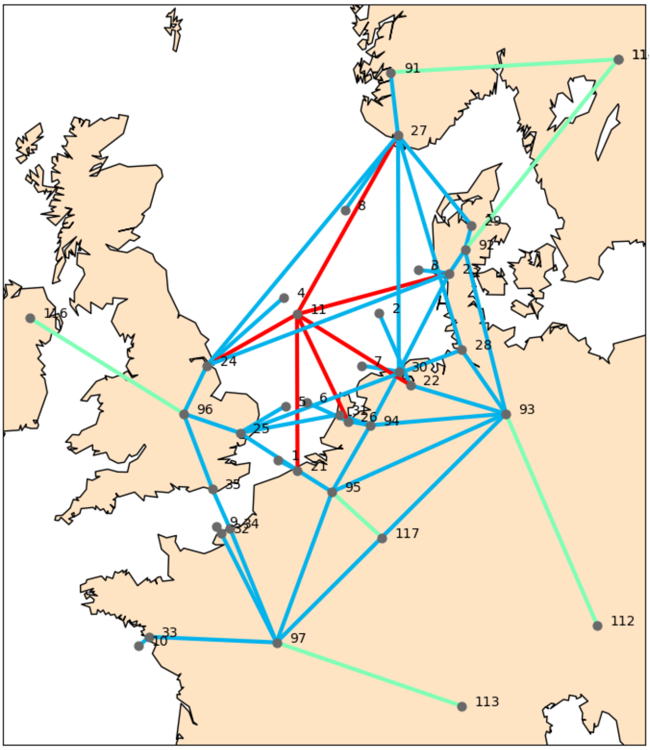


Figure 4.4: Representation of the aggregated North Sea offshore grid infrastructure and nodes, including external connections to non-core countries.

external countries that receive the largest individual flow from each core country. Annual load fluctuations are captured by including dedicated load profiles in countries where external loads are located. Estimated energy flows and load profiles are taken from the Global Ambition scenario in the TYNDP 2020 Scenario Report [48]. A more eleborative description of input data are provided in Section 4.6.

A representation of the aggregated North Sea offshore grid infrastructure, including external connections to non-core countries (green lines), are presented in Figure 4.4. An example of a country that is connected to the external grid is Germany which has net energy flows to Switzerland, Austria, the Czech Republic and Sweden. Net average energy flows between Germany and all four countries are summed up and presented as a single load located in Austria, varying according to the Austrian load profile. Austria is chosen because the net flow to Austria is the largest individual flow among the four. The same approach is adopted for France, Denmark, Norway, Great Britain and Norway. Additional load nodes are included separately for each modelled country. Hence, energy exchange between modelled countries through a common additional load is not possible. An example is Sweden which hosts the additional load of both Norway and Sweden. In this case Sweden is split into the nodes SE (NO) and SE (DK), to ensure that the respective additional loads are supplied solely by Norway and Denmark respectively. An overview of core countries, connected external countries, additional load locations and average load magnitudes are presented in Table 4.3.

Table 4.3: Overview of additional external demand, connected countries, load locations and load magnitudes, when including connections to external non-core countries.

Core country	**Connected external countries**	**External load location**	**Aggregated average external load [MW average per hour]**
France	Spain, Switzerland, Italy	Italy	2430.9
Germany	Switzerland, Austria, Czech Republic, Sweden	Austria	2348.4
Norway	Sweden	Sweden	1071.7
Denmark	Sweden	Sweden	470.4
Belgium	Luxembourg	Luxembourg	156.4
Great Britain	Northern Ireland, Ireland	Northern Ireland	55.3

4.7.2 Capacity factors for renewable energy sources

An embedded functionality in PowerGIM is the opportunity to constrain the annual average capacity factor of generators. Elaborately constraining the annual capacity factor of various generation capacities reduce the flexibility of generators and contribute to a more realistic model [24], [25]. The capacity factors of the generation technologies run-of-river, reservoir hydro, Other RES and nuclear are modified to enhance the model performance. Adjustment of capacity factors are done primarily for renewable generation capacities, because their production are dependent on an intermittent primary energy inflow, making them partly or completely un-dispatchable. While nuclear is a dispatchable energy source, restricting also capacity factor of nuclear are deemed necessary, due to low marginal costs for nuclear. Capacity factors are determined my inspecting output values from the TYNDP market run, reported in the attached TYNDP 2020 - Scenario Data at [95], and by using external sources as reference.

Production from reservoir hydro resources are constrained by a maximum annual capacity factor of 30%. Setting a bar on the annual capacity factor is a simplified way to take into account the storage possibility of reservoirs, in the lack of sufficient water value data. The bar of 30% is set according to the levels of hydro production in the TYNDP market run. An exception is made for the maximum capacity factor of Norwegian reservoir hydro, which is set to 47% based on data provided by NVE [96].

Generation output from run-of-river hydro power is mainly determined by hydro inflows, because there is little or no storage opportunities to regulate the timing and size of inflows. Resulting capacity factors for run-of-river in the TYNDP market run are in the range 22-37%. Hence, the maximum annual capacity factor in PowerGIM is set to 40%. A common default production profile provided in PowerGIM is included for all installed capacities of run-of-river, to take into account seasonal variations in inflow. The capacity factor for Other RES varies between different countries in the TYNDP market run. As the generation capacity within the category Other RES comprise a number of technologies, it is hard to determine the relative contribution from each individual technology. Considering that part of these capacities are tidal and wave, the maximum annual capacity factor of all Other RES capacities are assumed to be 80%.

UK have experienced annual capacity factors for nuclear in the range 60-80% over the past fifty years [97]. Similarly, in 2018, French nuclear was characterized by an annual capacity factor 77% [98]. In addition, French authorities have committed to a target of less than 50% share of nuclear in the country energy mix by 2035 [99]. Based on these observations it is decided to set the maximum annual capacity factors to 80% for nuclear in both Great Britain and France.

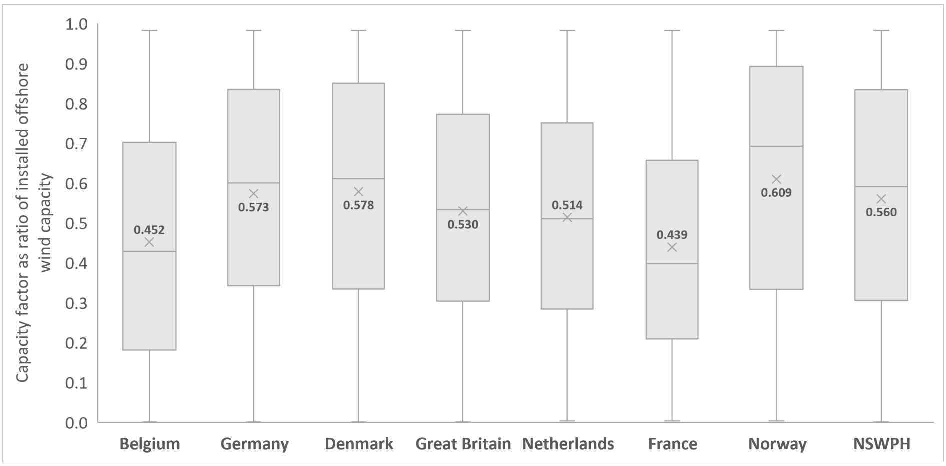


Figure 4.5: Box-plot representation of the annual offshore wind profiles presented to the model (climate year 1984). For countries with multiple offshore wind production sites (see grid representation in Figure 4.2), the average value between different wind profiles is assumed. The horizontal line within each bar represents the median values, while the cross represents the average value, hence, the maximum annual capacity factor in each country. Each box represents the range of values between the the 25^{th} and 75^{th} percentile.

While the maximum annual capacity factors can be set manually, they are indirectly set when including production profiles. This is the case for wind and solar production. As described in Section 4.6.6 these production profiles of wind and solar are associated with a specific location, where each element represent the maximum possible capacity factor on an hourly basis. Hence, the average value of each element in a profile can be viewed as the maximum average annual capacity factor at the respective locations. A box-plot representation of the input profiles for offshore wind used in the model is provided in Figure 4.5. The bars represent the range of values between the first and third quartile, i.e. the 25^{th} and 75^{th} percentile. Moreover, the horizontal line within each bar represents the median values, while the cross is the average value, i.e. the maximum annual capacity factor in each country. The plot provides interesting information about the wind resource in the various national systems. Overall, it is observed that the capacity factors vary greatly in all countries, which highlights the intermittent nature of wind. Moreover, it is observed that Norway has the best wind resources with a maximum capacity factor exceeding 60%, followed by Denmark and Germany. The NSWPH also has an excellent wind resource with a maximum average capacity factor of 56%, while Belgium and France have the weakest wind resources.

Different capacity factors for wind and solar used in the TYNDP simulations compared to the values presented here, represent a potential source of error in the model. However, because the wind and solar profiles used in the TYNDP scenarios are not publicly available, there is no choice but to accept this uncertainty.

4.7.3 Validation of model

A validation of the PowerGIM model is performed to ensure that the model behaves in an expected and realistic manner. The validation is performed by comparing basic model outputs from the PowerGIM model to the results presented in the TYNDP 2020. Inputs from the Global Ambition scenario for 2040 [81], based on the climate year 1984 are used as the reference for comparison. The goal of the validation process is not to achieve a perfect replication of the results presented in the TYNDP scenario, as this would require an extreme effort in terms of time and a level of detail that is not available in the current PowerGIM module. The intention is rather to highlight the most important deviations between the two model outputs. Eventually, the result of the validation process represents a base case which serves as the reference scenario in the following case study. Three main indicators have been assessed in the validation process, which include the country level energy mixes, energy flows between countries and electricity prices. Key observations from the model validation include:

- **Country level energy mixs -** Country level energy mixes obtained from the PowerGIM model are generally very similar to those projected in the Global ambition scenario. The same main characteristics are observed in both models. However, a common observation is the fact that all countries with installed capacities of reservoir hydro experience a slightly higher hydro production in PowerGIM compared to the TYNDP. Without accurate water values, the marginal price of hydro in all countries except Norway are consistently low, making the model optimistic towards hydro production. Moreover, the overall penetration of wind generation is slightly increased, while fossil fueled generation is slightly reduced in the PowerGIM model compared to the TYNDP results. The latter is unlikely to make a considerable impact on the results, considering the limited installed volumes of fossil technologies, particularly in the case of coal and oil.

  Results from the PowerGIM model also show a significantly higher nuclear production compared to the TYNDP scenario. The presence of nuclear is particularly high in Great Britain, but also France is found to have a considerably higher penetration of nuclear in its energy supply. The high penetration of nuclear is the result of low marginal costs for nuclear. The high penetration of nuclear may lead to unrealistic prices and flows in the system, and it is something which should be considered when evaluating the final results.

- **Energy flows between countries -** A drawback of the PowerGIM model is the fact that PowerGIM does not allow the definition of different NTC's on the same corridor depending on direction, which is the case for certain corridors in the TYNDP 2020 scenarios. This becomes an issue on the corridor FR-BE, where it is assumed a 50% higher NTC in the direction France to Belgium than in the direction Belgium to France. Both NTC's have been tested to see which capacity that provides the most similar flow pattern with respect to the TYNDP and it is found that the highest NTC is the best option. The exporting flows from Belgium remains more or less constant for both NTC's. However, compromising the French exporting potential to Belgium have ripple effects on other adjacent countries supplied by France. Relatively low electricity prices in France contributes to a unrealistically large amount of energy flowing to countries such as Great Britain and Germany, which is unfortunate. Taking this into account, it is decided to use the highest NTC on the FR-BE corridor in the PowerGIM model. No further measures are implemented to mitigate the effects of one common NTC. Hence, the relaxed Belgian export constraint is a potential source of error results, which should be considered when evaluating the final modeling results.

  Another important observation is that the net annual flow between Norway and Great Britain in the PowerGIM model is in the opposite direction of what is estimated in the TYNDP. While the net flow in the TYNDP scenarios is in the direction from Norway to Great Britain, Great Britain becomes the net exporter in the PowerGIM model. The reason for this is that British nuclear is competitive with the Norwegian hydro for the majority of the time during the year. The reduced export of energy from Norway to Great Britain must be considered when evaluating the final results.

- **Electricity prices -** Electricity prices obtained from the PowerGIM model are represented as the dual value of the energy balance in each country aggregated node. In order to have a comparable basis, it is assumed that the presented prices in the TYNDP are dual values as well. However, the TYNDP does not provide documentation about how they have calculated the electricity prices. Hence, there could be some uncertainty about the comparison.

  In any case, the resulting electricity prices from running the PowerGIM model are generally found to be higher than the values estimated in the TYNDP, which should be considered in the final results. Resulting prices in Germany, Belgium and Norway are particularly high compared to the TYNDP values. A potential reason why the prices are higher in the PowerGIM model, is the addition of operational costs and CO_2-costs when calculating the marginal cost of generation. As emission factors and operational costs are taken from external sources, there might be deviations in the modelling assumptions that contribute to different prices. Moreover, different assumptions regarding the input water values for Norwegian hydro is likely the reason why significant price differences are observed in Norway.

  Interestingly, unlike all the other prices, the resulting French price in PowerGIM is observed to be lower than in the TYNDP market run. As previously mentioned, low marginal costs for nuclear is the most important reason for this. Because France is not directly included in the following case study, it is assumed that the model is valid despite unrealistically low French prices. However, low French prices and a high French exporting potential should be considered when evaluating the case study results.

As previously stated, the intention of this validation process is not to achieve a perfect replication of modelling results, but rather to provide the most important deviations between the PowerGIM model and the reference TYNDP scenario. A more comprehensive discussion regarding the validity of the model as a whole, is provided in Section 5.3.2.

Chapter 5

Results and Discussion

This chapter provides a presentation of the case study results. Model outputs based on the input data and methodology provided in Chapter 4 are presented first, followed by a sensitivity analysis assessing variations in certain input variables. Finally, a discussion regarding the main findings are presented, including a validation of the results and limitations of the work.

5.1 Case study results

Case study results are provided for each of the five configurations presented in Section 4.5. Prior to the actual case study it is provided an overview of the base case results. The Base case provides preliminary results from running the model without any additional transmission or generation capacities and serves as a reference for comparison in the following case study. Input data based on the climate year 1984 are assumed throughout the entire case study.

5.1.1 Base case

Figure 5.1a shows the resulting national energy mixes in the Base case. Overall, the penetration of renewable energy sources is very large across all countries, primarily driven by offshore wind. Norway has the highest levels of low-carbon penetration, followed by France, Denmark and Great Britain. Germany, Netherlands and Belgium have a lower low-carbon penetration because of higher levels of thermal generation left in the respective national system.

Figure 5.1b provides the resulting time weighted-average baseload prices in all Base case markets. The annual average electricity price in the Belgian market is the highest among the studied countries, followed by the German and Dutch prices. The high prices in these countries are primarily driven by the remaining thermal capacities in the respective national systems. Countries with a significant penetration of carbon emitting generation are also more exposed to higher gas and CO_2 prices, contributing to higher baseload prices. Despite a high penetration of RES, the Danish prices remain rather high due to a strong coupling to the German and Dutch markets. Great Britain, on the other hand, has a more isolated system with a high penetration of offshore wind and nuclear, resulting in low prices. Norway, with the majority of its generation based reservoir hydro, has a marginally lower price than Great Britain, while the French market has the lowest price, primarily due to the high penetration of nuclear capacities.

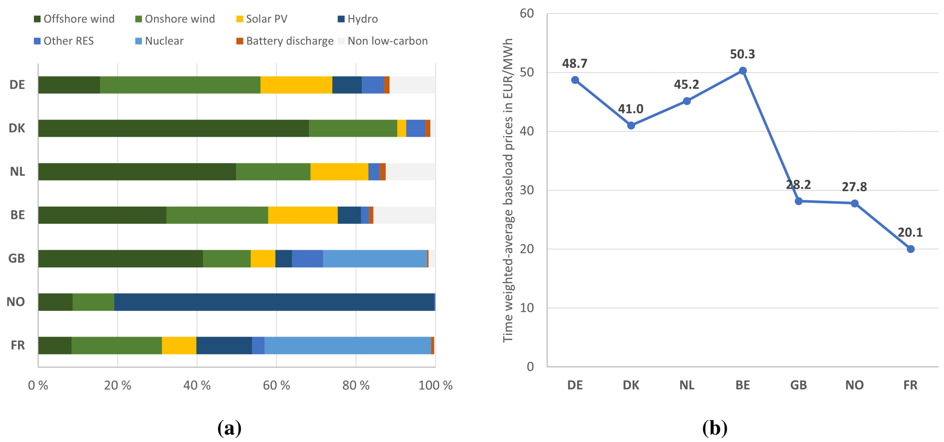


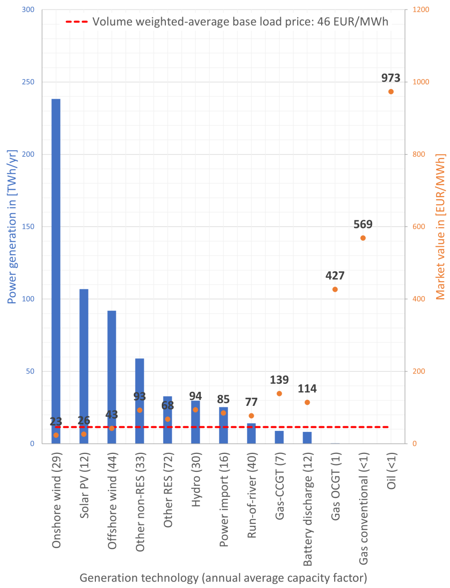
Figure 5.1: Case study results of the Base case configuration: (a) Penetration of each generation technology as a percentage of national energy mix. The category ”Hydro” includes both reservoir and run-of-river capacities, while the category ”Non low-carbon” includes all carbon emitting capacities as defined in Chapter 4, (b) Time weighted-average baseload electricity prices for the Base case markets, real 2020.

A more detailed overview of annual generation quantities, capture prices and capacity factors per generation technology, in the three countries Germany, Great Britain and the Netherlands, are presented in Figure 5.2. It is observed that the renewable generation technologies constitutes the majority of the annual energy mix across all countries, dominated by wind power production, due to the large amount of installed capacities and low marginal costs. The joint contribution of offshore and onshore wind make up 54% (DE), 52% (GB) and 66% (NL) of the national energy mixes. Offshore wind is the leading source of energy in both Great Britain and the Netherlands, while Germany leans heavily on onshore wind resources. Another common observation across all countries is that capture prices for wind and solar are consistently lower than the volume weighted-average base load price, reflecting the merit order of generation units, also known as the cannibalisation effect.

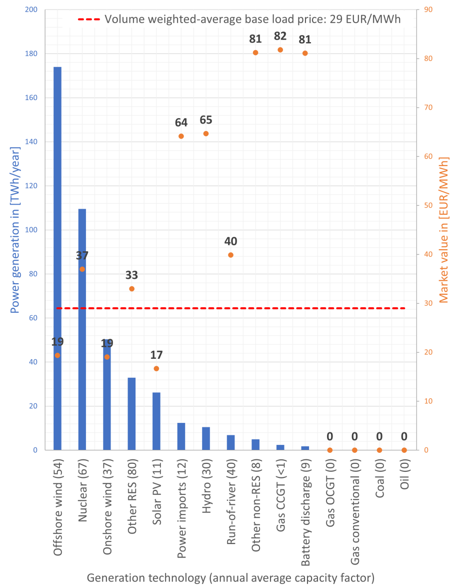
As a consequence of the high renewable penetration, fossil fueled generation technologies are utilized to a low degree. A clear distinction between renewable and fuel based generators, both in terms of capture prices and generation quantities, also highlights the impact of the CO_2-price of €80/tCO_2. Technologies such as oil, coal and expensive gas power plants are used only during peak load hours, reflected by significantly higher capture prices, and their contribution to the overall energy supply are almost negligible.

Among the countries in Figure 5.2 the British market experiences the lowest average wholesale electricity price of 29 EUR/MWh, primarily driven by increasing shares of offshore wind and nuclear towards 2040. Under the assumptions of the Global Ambition scenario, the total installed capacity of British nuclear is expected to double by 2040 compared to current levels [100], increasing from about 9000MW to 18552MW. Considering issues that nuclear is facing today with high capital costs, lack of standardisation and social acceptance, it may be some uncertainty around this level of build-out. Germany has the highest price, driven by remaining thermal capacity in the system, pushing the prices upwards. Among the German thermal capacities there are generally negligible coal and oil capacity due to national phase-out policies prior to 2040. Despite the high share of offshore wind, the Dutch energy supply is still reliant on thermal generators in times of high demand and low production from wind and solar, placing the average price just below the German price.

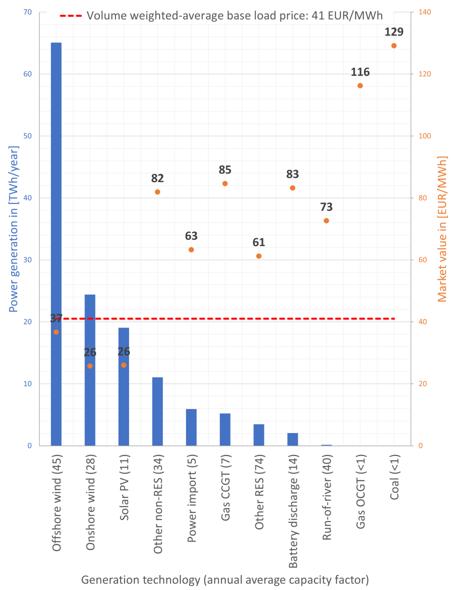
An interesting observation is the formidable capacity factors for British onshore and offshore wind of 37% and 54%, which allows Great Britain to harvest more energy per unit of installed capacity than Germany and the Netherlands. The high capacity factor reflects not only the excellent wind resources off the British coasts, but also the great export potential resulting from low British prices compared to neighbouring markets (see discussion about capacity factors for offshore wind in Section 3.2.4).



(a) Germany



(b) Great Britain



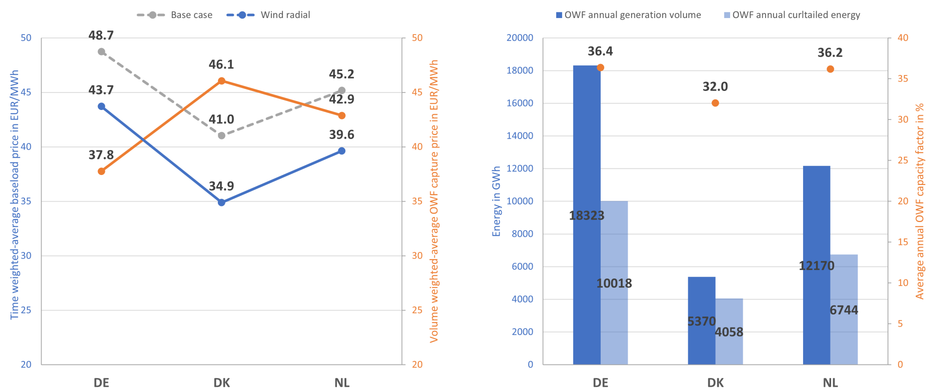
(c) Netherlands

Figure 5.2: Annual generation quantities, capture prices and capacity factors per generation technology in the base case scenario for (a) Germany, (b) Great Britain and (c) the Netherlands.

5.1.2 Wind radial

Figure 5.3a shows the annual average baseload electricity prices in the Wind radial markets, comparing them against the Base case. It also presents the volume weighted-average OWF capacity factors in the Wind radial configuration. The baseload price is defined as the annual time weighted-average wholesale electricity price representative for a "baseload" generator, while the capture price is defined as the weighted-average wholesale electricity revenue of the OWF per MWh accounting for the hourly profile and shape of prices and generation.

Increasing levels of offshore wind generation in the national systems generally put a downward pressure on the wholesale electricity prices in times when wind is generating, resulting in lower baseload prices across all three markets compared to the Base case. The German OWF is observed to capture 86% of the baseload price, while the capture prices of the Danish and Dutch OWF's both exceed the respective national baseload prices. The latter is a surprising observation as capture prices for wind are usually situated below baseload prices, due to low marginal costs. High OWF capture rates in Denmark and the Netherlands are caused by the high penetration of all ready installed renewable energy sources in the respective national systems. On the basis of merit order effects, the new OWF capacities are limited to generate mainly during high load hours when prices are high, resulting in high capture prices.



(a) (b)

Figure 5.3: Case study results from the Wind radial configuration, compared against the Base case: (a) Volum weighted-average annual OWF capture prices and time weighted-average baseload price per market zone, (b) Annual OWF generation volumes, curtailed energy and capacity factors per market zone.

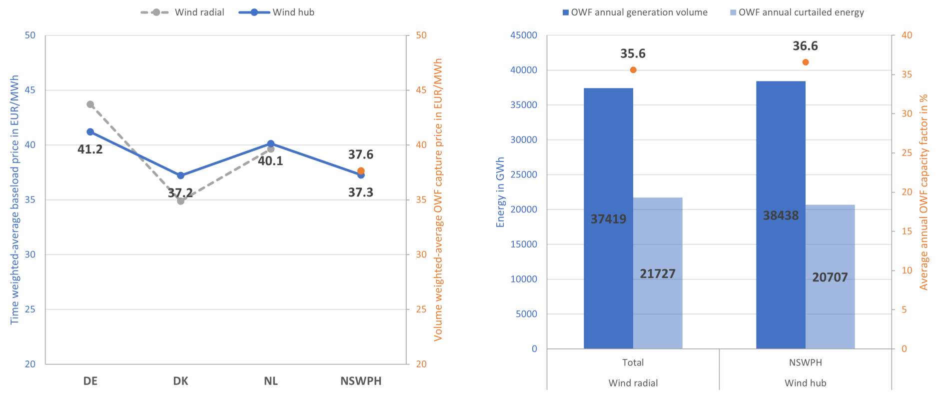
Another point worth mentioning is the fact that the baseload prices are calculated as time weighted-average (flat average) values, while OWF capture prices are volume weighed-average values. As opposed to the volume weighted-average prices, the flat average baseload prices does not capture the value of different generation volumes at different price levels. Hence, the volume weighted-average values and time weighted-average values cannot be compared directly. With the OWF's generating manly during high load hours it is reasonable that the volume weighted capture prices are somewhat higher compared to the baseload price. Another contributing factor to the high capture prices is the fact that wind generation is usually higher during winter when loads and prices are high.

Figure 5.3b provides an overview of the OWF generation volumes, curtailed energy and capacity per bidding zone in the Wind radial case. The generation corresponds to the final generation post transmission losses between the OWF and the national shores. Capacity factors and curtailment levels are calculated based on the assumption of a maximum annual average OWF capacity factor of 56.3%. This value is determined by the input wind profile used for the North Sea Wind Power Hub (NSWPH) location. For details and assumptions regarding input capacity factors for offshore wind, see Section 3.2.4. OWF capacity factors are observed to be in the range 32.0% to 36.4%, reflecting a low utilisation of the OWF assets and very high levels of curtailment. Corresponding annual OWF generation reaching the national shores are 18323 GWh, 5370 GWh and 1217 GWh in the German, Danish and Dutch market zone respectively. As previously mentioned, high levels of curtailment is driven by merit order effects, causing the OWF assets to produce only during high load hours. Another contributing factor in this regard is that the already installed capacities of offshore wind is prioritized over the new OWF capacities. Investigating the grid map in Section 4.4 it is observed that the length of the interconectors (ICs) connecting the new OWF capacity to shore are longer than the ICs connecting excising capacities of offshore wind. Due to the added losses related to transmission, the new OWF becomes marginally more expensive than the existing offshore wind. As a result, the OWF is not dispatched unless the load exceeds all excising renewable capacity in the respective national systems.

5.1.3 Wind hub

Figure 5.4a shows the annual average baseload prices in the Wind hub markets, compared against the Wind radial case. Connecting the OWF capacities in a joint hub leads to a slight decrease in the German and Dutch wholesale prices as more energy is flowing towards the German and Dutch markets. Conversely, the Danish price is found to increase marginally in the Wind hub configuration. The NSWPH electricity price is determined by the prices in the neighbouring markets. The average annual baseload price in the hub is found to be marginally higher than the Danish price and a bit lower than the German and Dutch prices.

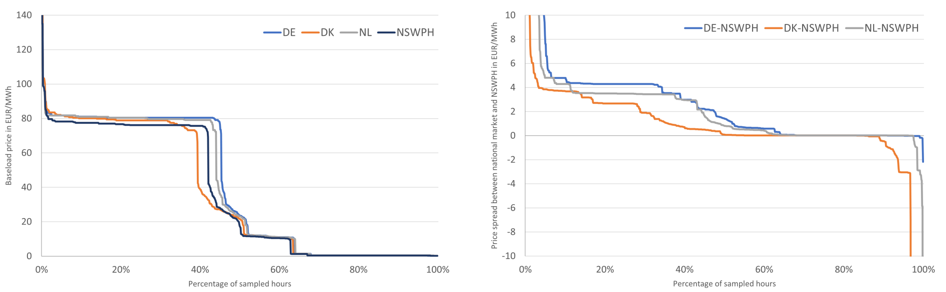
Figure 5.4a also shows the volume weighted-average OWF capture price, calculated based on the overall OWF production and price in every sampled hour. The capture price is found to be marginally higher than the OWF baseload price at €37.6/MWh, which is slightly higher than the Danish wholesale price and lower than the German and Dutch prices. A capture price being close to the national prices reflects the same issue seen in the Wind radial case, were the OWF is generating mainly during high load periods due to the high penetration of cheap renewable energy sources all ready installed in the national systems.



(a) (b)

Figure 5.4: Case study results from the Wind hub configuration, compared against the Wind radial case: (a) Time weighted-average baseload prices per market zone and volume weighted-average OWF capture price, (b) Annual OWF generation volumes, curtailed energy and capacity factors in each configuration.

Resulting OWF generation volumes, curtailed energy and capacity factors in the Wind hub case, compared against the Wind radial configuration, is shown in Figure 5.4b. Increased cross-zonal capacities between the German, Dutch and Danish markets leads to an increase in OWF generation compared to the Wind radial case, however the change is marginal. The utilisation of the OWF remains rather low in the Wind hub case, with a annual average capacity factor of 36.6%.

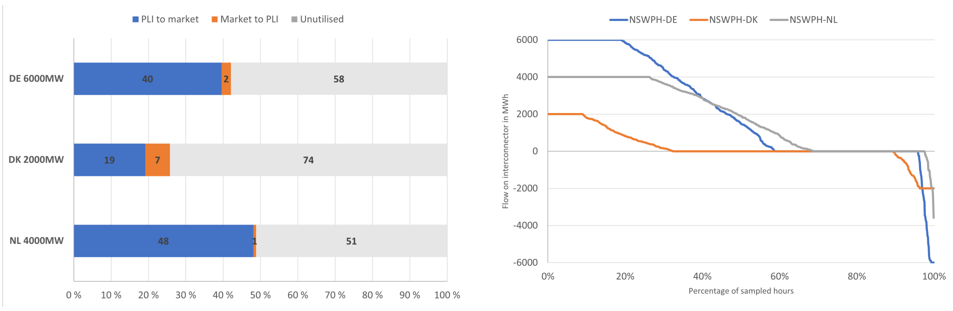


(a) (b)

Figure 5.5: Case study results from the Wind hub configuration: (a) Duration curves of national market baseload prices, (b) Price spreads between national markets and the NSWPH. Price spreads are limited due to a tight coupling between the German, Danish and Dutch markets.

Annual price duration curves for the wholesale electricity prices in the national markets and price spreads between the national markets and the NSWPH are presented in Figure 5.5a and 5.5b respectively. Both figures represent prices based on hourly samples for a full year of operation. Positive values of price spreads represent sampled hours when the national baseload prices are higher than the baseload hub price, while negative values represent hours when national prices are lower than the hub price. Price shapes are very similar between the three markets, with very limited spreads between these markets. Electricity prices remains close to zero for around 30% of the time in all three markets, driven by the high penetration of renewable energy sources as explained previously. Danish prices are generally lower than than the rest across the whole period. Price spreads remains low between the national markets and the NSWPH, with spreads ranging between €0/MWh and €4/MWh for the majority of the time. Interestingly, negative price spreads occur only for a small amount of time. Hence, the export potential from the national systems to the hub is very limited and the hub is not used too much as a transmission hub.

Figure 5.6a shows the utilisation rates of the cables connecting the hub to the national systems in percent by direction of flow. The values are calculated based on the net flow on each cable in every time step, divided by the capacity of each interconnector. Utilisation varies between the different interconnectors, with the respective German and Dutch cables being used the most, due to stronger price signals in the national markets. Moreover, it is observed that the German and Dutch cables almost exclusively used to transport energy from the NSWPH to the national shores. With Danish prices being slightly less correlated compared to the other markets, the Danish interconnector is used to transport energy in both directions, however the volumes are small.



(a) **(b)**

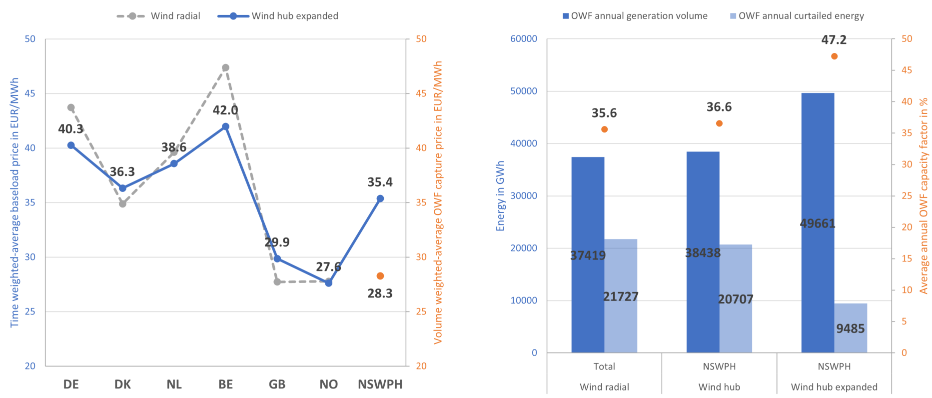
Figure 5.6: Case study results from the Wind hub configuration: (a) Utilisation of interconnectors in percent per direction of flow, (b) Flow duration curves for the interconnectors in MWh. The direction of flows are largely unidirectional due to limited price spreads between the German, Danish and Dutch markets.

Figure 5.6b shows the flow duration curves for the interconnectors between the hub and the national markets in the direction from the hub to the national shores. Positive numbers thus represent flows going from the hub to the national shores, while negative numbers represent flows going from the national systems to the hub. As seen previously, the interconnectors are used mainly to transport energy from the hub to the national shores, while there are very limited flows going from the national markets to the hub. The German and Dutch cables are used between 20% and 30% of the time at their full capacity, while the Danish is used only about 10% of the time at full capacity. Moreover, it is observed that the Danish cable remains unutilised about 50% of the time, while the German and Dutch interconnectors are unutilised about 40% and 30% of the time respectively.

5.1.4 Wind hub expanded

Figure 5.7a shows the annual average baseload price for the Wind hub expanded markets, comparing them against the Wind radial case. With the higher level of integration between the different national markets in the Wind hub expanded configuration, it is observed a converging trend in terms of wholesale prices. The exposure to the British and Norwegian market are putting a downward pressure on prices, leading to decreasing baseload prices in all surrounding markets, including the NSWPH. Conversely, the British price is found to increase by €2.2/MWh compared to the Wind radial case due to net exports, while Norwegian prices are unchanged as reservoir hydro remains the price setting generator for the majority of the time. The most significant change in price is observed in Belgium, were the average baseload price drops €5.4/MWh compared to the radial configuration. NSWPH prices remain below the German, Danish, Dutch and Belgian prices, but higher than the Norwegian and British prices.

Figure 5.7a also shows the average OWF capture price. Interestingly, the capture price in the Wind hub expanded configuration decreases sharply by €9.3/MWh compared to the Wind hub case. Overall lower baseload prices in the system and a higher utilisation of the OFW capacities are important drivers for the low capture rate. The issue of limited participation from the OWF to the national energy supply seen in the Wind radial and Wind hub configurations is now removed due to the exposure to the Belgium, British and Norwegian markets. Instead of generation mainly during peak load periods, the OWF is utilised more frequently in the Wind hub expanded configuration.

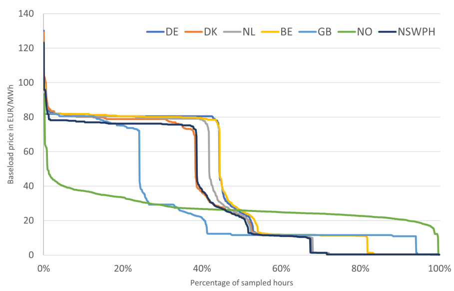


(a) (b)

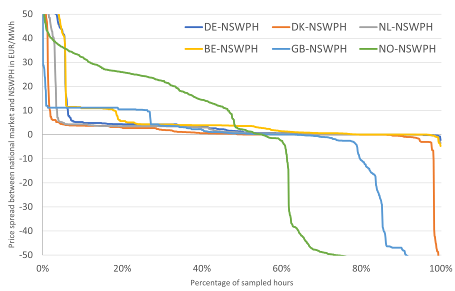
Figure 5.7: Case study results from the Wind hub expanded configuration, compared against the Wind radial and Wind hub case: (a) Time weighted-average baseload prices per market zone and volume weighted-average annual OWF capture price, (b) Annual OWF generation volumes, curtailed energy and capacity factors in each configuration.

Figure 5.7b shows the resulting OWF generation volumes, curtailed energy and capacity factors for the Wind hub expanded case, comparing the values against the Wind radial and Wind hub case. The increased cross-zonal capacities to the Belgian, British and Norwegian markets are reflected through a higher utilisation of the OWF's, with generation volumes increasing nearly 30% compared to the Wind hub configuration. Levels of curtailed energy decrease in line with the increase in generation, resulting in an average OWF capacity factor of 47.2%.

Annual price duration curves for the wholesale electricity prices in the national markets and price spreads between the national markets and the NSWPH are presented in Figure 5.8a and 5.8b respectively. Price shapes are similar between the German, Danish, Dutch and Belgium markets with very limited price spreads between these markets. Norwegian and British prices are generally lower than the rest. However, it is observed that these countries have less low-priced periods than the other countries, due to the high penetration of nuclear in Great Britain and reservoir hydro in Norway. Price spreads remain low between the NSWPH and the German, Danish, Dutch and Belgian markets, while spreads between the hub and the Norwegian and British markets are much higher. Note that the distinct difference in terms of shape between the price duration curve of Norway and all other countries is due to the use of a dedicated price profile for Norwegian hydro. With a specific price for hydro in each sampled hour, the Norwegian curve appears much more smooth than the rest.



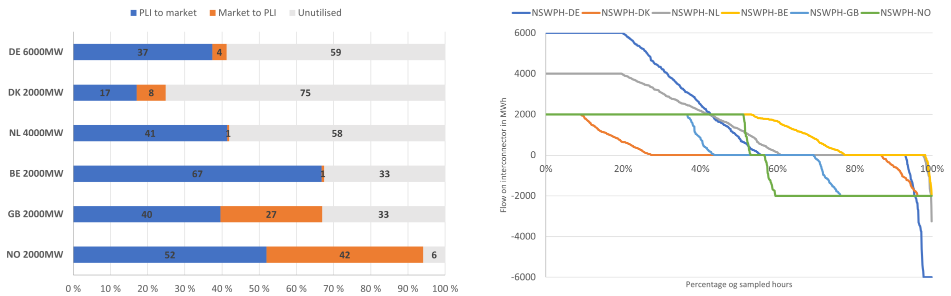
(a)



(b)

Figure 5.8: Case study results from the "Wind hub expanded" scenario: (a) Duration curves of national market baseload prices, (b) Price spreads between national markets and the NSWPH. Higher price spreads between the Norwegian and British market, and the NSWPH are mainly driven by the high penetration of reservoir hydro in Norway and nuclear in Great Britain.

Figure 5.9a shows the utilisation rates in percent by direction of flow for each cable connecting the onshore systems to the hub. Utilisation varies for the different interconnectors. The German, Danish, Dutch and Belgian cables are almost exclusively used to transport energy from the NSWPH to the national systems, with the Belgian cable being used significantly more compared to the other three, due to the stronger price signal in the Belgian market. With prices in Great Britain and Norway being less correlated compared to the other markets the British and Norwegian cables are used to transport energy in both directions, with the Norwegian cable used to transfer energy from the Norwegian national system to the NSWPH over 40% of the time.



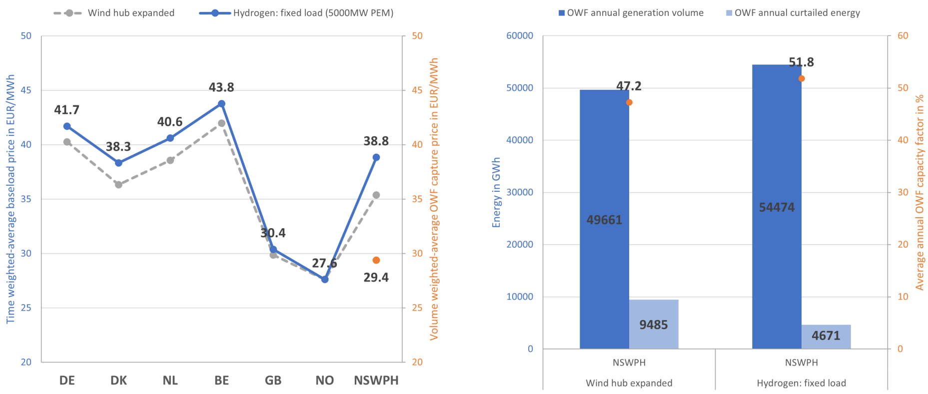
(a) **(b)**

Figure 5.9: Case study results from the Wind hub expanded scenario: (a) Utilisation of interconnectors in percent per direction of flow, (b) Flow duration curves for the interconnectors in MWh. Higher utilisation of the OWF assets is the main driver for increased utilisation of IC capacities. Flows on the Norwegian and British cables are largely bi-directional due to higher price spreads between the Norwegian and British markets, and the NSWPH.

Figure 5.8b shows the flow duration curves for the interconnectors between the hub and the national markets in the direction from the hub to the national shores, where positive numbers represent flows going from the hub to the national shores, while negative numbers represent flows going from the national systems to the hub. As previously seen in Figure 5.9a, there are limited flows from the national markets to the hub, except from Great Britain and Norway. Moreover, it is observed that the German and Dutch interconnectors are used about 20% of the time at their full capacity, while the Danish interconnector is used less frequently at full capacity. The German, Dutch and Danish interconnectors, particularly the latter, remains unutilised for a longer period of time - i.e. around 60% of the time compared to 30% and 5% for the British and Norwegian interconnectors respectively.

5.1.5 Hydrogen: fixed load

Figure 5.10a shows the annual average baseload prices in the Hydrogen: fixed load markets, comparing them against the Wind hub expanded case. It also shows the annual average capture price for the OWF assets. Introducing a 5GW PEM electrolyser with a fixed annual capacity factor of 60% running at fixed load in the hub is observed to put a upward pressure on the electricity prices across the whole system. Average baseload prices in the German, Dutch, Danish and Belgian markets are found to increase between €1.4/MWh and €2.0/MWh as wind production drawn by the hydrogen load are replaced by more expensive thermal generation in the respective national markets. British prices are found to increase only marginally, while Norwegian prices are unchanged as reservoir hydro remains the price setting generator. NSWPH prices remain below the German, Dutch and Belgian prices, but higher than the Danish, British and Norwegian prices. Interestingly, the most significant change in price is observed in the NSWPH market zone, with an increase of €3.5/MWh compared to the Wind hub expanded case. Driven by higher baseload prices in the hub, the capture price for the OWF assets are observed increase marginally in the Hydrogen: fixed load configuration compared to the Wind hub expanded case, averaging at €29.4/MWh.



(a) **(b)**

Figure 5.10: Case study results from the Hydrogen: fixed load configuration, compared against the Wind hub expanded case: (a) Time weighted-average baseload price per market zone and volume weighted-average annual OWF capture price, (b) Annual OWF generation volumes, curtailed energy and capacity factors in each configuration.

Figure 5.10b shows the annual OWF generation volumes, curtailed energy and capacity factors for the Hydrogen: fixed load case, comparing the values against the Wind hub expanded case. Adding a fixed load in the hub leads to higher OWF production, with annual generation volumes increasing by nearly 10% compared to the Wind hub expanded case. Levels of curtailed energy decrease in line with the increase in generation, resulting in an average OWF capacity factor of 51.8%.

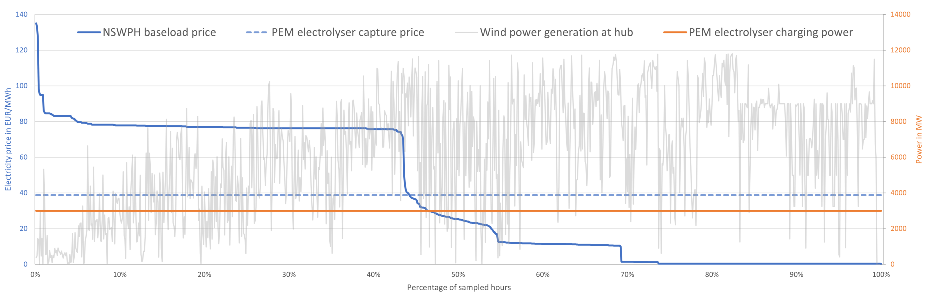
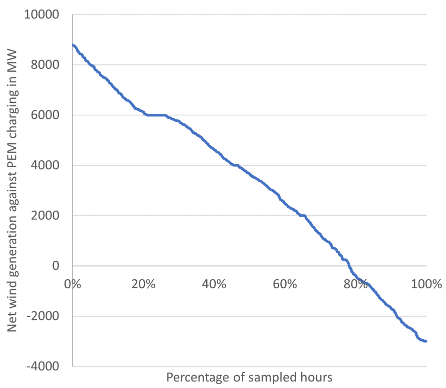


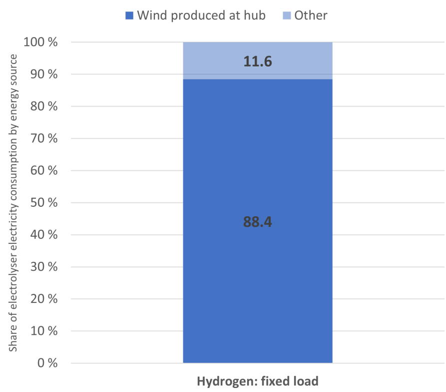
Figure 5.11: Case study results from the Hydrogen: fixed load configuration: annual NSWPH baseload price duration curve and PEM electrolyser capture price, and corresponding PEM electrolyser charging power and wind power generation.

Figure 5.11 shows the NSWPH baseload price duration curve and capture price for the

PEM electrolyser in the Hydrogen: fixed load case. It also shows the corresponding electrolyser charging power and wind power production in MW, in each sampled hour at the hub. A fixed hourly charging power of 3000 MW is observed, following the assumption of a 5000MW PEM electrolyser running fixed load at 60% annual utilisation. With the assumption of fixed load the electrolyser is exposed to the price in every single hour during the year, hence capturing 100% of the annual average NSWPH price of €38.8/MWh. Moreover, it is observed that prices are high when wind generation is low, while prices are low when wind generation is high. This illustrates the impact of wind generation on the NSWPH prices, where large amounts of wind generation generally put a downward pressure on prices. With varying price levels during the year and prices being close to zero about 30% of the time, there exists a great potential to capture lower charging prices through a more selective operation of the electrolyser. However, to exploit this potential it is necessary to allow a less constrained operation of the electrolyser, which is investigated in the next section.



(a)



(b)

Figure 5.12: Case study results from the Hydrogen: price dependent load configuration: (a) Annual net wind power generation duration curve, measured against the charging power of the electrolyser in every sampled hour, (b) Share of PEM electrolyser electricity consumption per energy source.

Figure 5.12a provides the net wind power generation duration curve, measuring wind generation against the charging power of the electrolyser in each hour at the hub. Positive values thus represent the excess power when subtracting the electrolyser charging requirement from the wind generation in a given hour, while negative values represent incidents when the electrolyser charging requirement exceeds the wind generation. The area under the graph on the positive side of the x-axis, represents the annual surplus energy available for export to the national markets. On the other hand, the area under the graph on the negative side of the x-axis, represents the annual amount of energy required to import in order meet the charging requirement of the electrolyser. Due to the large size of the OWF of 12GW and the strong wind resources at the hub site, wind power generation exceeds the charging requirement about 80% of the time.

Figure 5.12b shows the share of the PEM electrolyser electricity consumption per energy

Table 5.1: Input parameters for calculation of Levelized Cost of green Hydrogen (LCOH). Cost parameters are taken from the ASSET Project Report 2018 [85], while the PEM electrolyser efficiency, lifetime and utilisation rate are based on the assumptions provided by IEA in [69]. The energy density of hydrogen is taken from the IDEALHY Project [101].

		PEM electrolyser
CAPEX	[TEUR/MW]	550
Fixed O&M cost	[EUR/kWh year]	12.5
Variable non-fuel cost	[EUR/MWh]	5.6
Efficiency (LHV)	[%]	70
Energy density of hydrogen	[kWh/kg]	33
Lifetime (Capacity factor)	[years] ([%])	25 (60)

source. 88.4% of the charged electricity is supplied by wind produced at the hub, while 11.6% is supplied by other energy sources. The need for external energy import in the supply of the electrolyser is mainly caused by the fluctuating nature of wind generation. When the electrolyser is forced to charge electricity from the grid in all hours during the year it becomes reliant on energy imports in times of low wind.

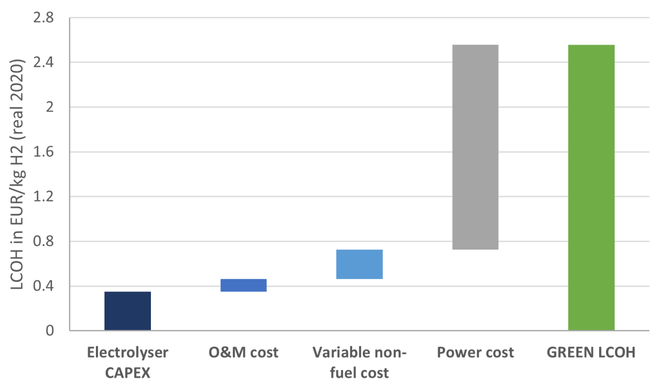
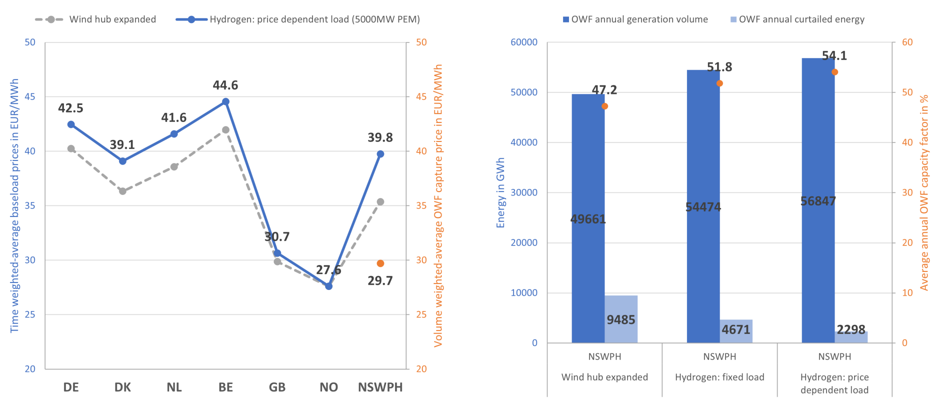


Figure 5.13: Breakdown of Levelized Cost of green Hydrogen (LCOH) measured in Euros per kilo gram H_2 production in the Hydrogen: fixed load case.

Figure 5.13 shows a breakdown of the Levelized Cost of Hydrogen (LCOH) in the Hydrogen: fixed load case, based on the input parameters presented in Table 5.1. An electrolyser efficiency of 70% is assumed, corresponding to the middle value of the long-term efficiency range projected by the IEA in [69]. Based on the projected long-term range of stack lifetime (operating hours) in [69] and the assumption of an annual utilisation rate of 60%, the lifetime of the electrolyser i set to 25 years. One kilogram of hydrogen is assumed to contain 33 kWh of usable energy [101]. Electrolyser cost parameters, including CAPEX and operational costs, are based on values found in the ASSET Project Report 2018 [85]. A linear depreciation of the CAPEX is assumed over the lifetime of the electrolyser, with reinvestment occurring after 25 years. The resulting LCOH is found to be €2.6/kg H_2, with electricity costs determining the largest share of the LCOH (71%). Overall operational costs contribute to 15% of the LCOH, while electrolyser CAPEX determines only 14%.

5.1.6 Hydrogen: price dependent load

Figure 5.14a shows the annual average baseload prices in the Hydrogen: price dependent load markets, comparing them against the Wind hub expanded case. It also provides the annual average capture price of the OWF assets. Introducing a 5GW PEM electrolyser with a fixed annual capacity factor of 60%, allowing the electrolyser to charge electricity in an optimal way, is observed to put an upward pressure on electricity prices across the whole system. Resulting price shapes are very similar to those observed in the Hydrogen: fixed load case, with only marginal differences. Average baseload prices in the German, Dutch, Danish and Belgian markets are found to increase between €2.2/MWh and €3.0/MWh compared to the Wind hub expanded case. As seen previously, higher prices in these markets are caused by the increased use of thermal generation, replacing the wind production drawn by the electrolyser. Similar to the Hydrogen: fixed load case, British prices increase only marginally, while Norwegian prices remain unchanged compared to the Wind hub expanded case. NSWPH prices remain higher than the Norwegian, British and Danish prices, but below the German, Dutch and Belgian prices. The NSWPH prices are observed to increase by €4.4/MWh compared to the Wind hub expanded case, contributing to a marginal increase in the OWF capture price compared to the Hydrogen: fixed case, averaging at €29.7/MWh.



(a) (b)

Figure 5.14: Case study results from the Hydrogen: price dependent load configuration, compared against the Wind hub expanded and Hydrogen: fixed load case: (a) Time weighted-average baseload prices per market zone and volume weighted-average annual OWF capture price, (b) Annual OWF generation volumes, curtailed energy and capacity factors in each configuration.

Figure 5.14b provides an overview of the annual OWF generation volume, curtailed energy and capacity factors for the Hydrogen: price dependent case, comparing the values against the Wind hub expanded and Hydrogen: fixed load configurations. Allowing the electrolyser to consume electricity depending on the price leads to a higher utilization of the OWF assets, with generation volumes increasing about 4% compared to the the Hydrogen: fixed load case. Higher utilisation of the OWF assets are reflected through decreasing levels of curtailment and an OWF capacity factor of 54.1%.

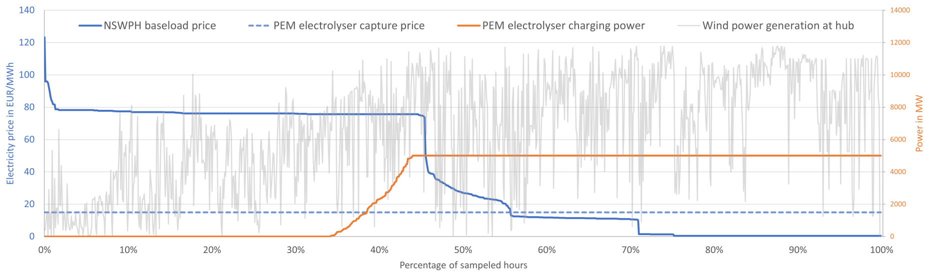


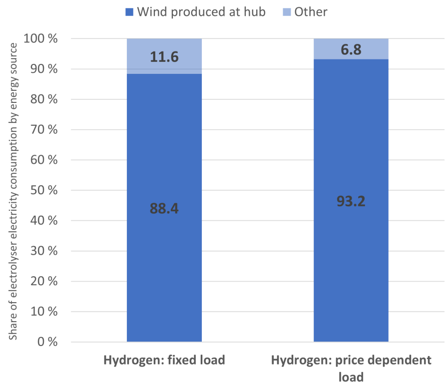
Figure 5.15: Case study results from the Hydrogen: price dependent load configuration: annual NSWPH baseload price duration curve and PEM electrolyser capture price, and corresponding PEM electrolyser charging power and wind power generation. The electrolyser is deliberately charging in low-priced hours in line with the model's objective to minimize total system costs.

Figure 5.15 shows the NSWPH baseload price duration curve and capture price for the PEM electrolyser in the Hydrogen: price dependent load configuration. It also shows the corresponding PEM electrolyser charging power and wind power generation in MW, in each sampled hour at the hub. It is observed that the PEM electrolyser deliberately chooses to charge electricity from the grid in times when prices are low, in line with the model's objective of minimizing total system costs. The PEM electrolyser is charging at full capacity about 55% of the time, while being unutilized just over 30% of the time. The period between 35% and 45% of all sampled hours represents the threshold price period for the electrolyser, with a price of €75.7/MWh. This price represents the highest price accepted by the electrolyser and the charging pattern in this period is characterised by a gradual increase, minimizing system costs.

Allowing price dependent charging from the grid results in an average annual capture price of €14.9/MWh for the electrolyser, corresponding to a capture rate of 37.4%. Comparing against the fixed load case, the capture price is reduced about 60%. Moreover, as seen previously, it is observed that low price periods are characterized by high wind generation, while high price periods are characterized by low wind generation at the hub, which demonstrates the impact of wind generation on power prices and highlights the role of wind in the electricity supply for the electrolyser. Following the correlation between high wind generation and low prices, optimal operation of the electrolyser is to a large degree depending on charging electricity from the grid in hours of high wind production.

Figure 5.16b shows the net wind power generation duration curve in the Hydrogen: price dependent load configuration, measuring the OWF generation against the charging power of the electrolyser in each hour at the hub and compares it to the fixed load case. As

(a)



(b)

Figure 5.16: Case study results from the Hydrogen: price dependent load configuration, compared against the Hydrogen: fixed load case: (a) Annual net wind power generation duration curve, measured against the charging power of the electrolyser in every sampled hour, (b) Share of PEM electrolyser electricity consumption per energy source in each configuration. The increased share of wind in the electrolyser electricity consumption is driven by an increased correlation between OWF production and electrolyser charging.

seen previously, positive values represents the net power in hours when wind generation are higher than the required charging power, while negative values represent net power in hours when the required charging power exceeds the wind generation at the hub. By allowing price dependent charging of the electrolyser, the amount of time when wind generation exceeds the electrolyser charging power increases to 90%, as charging operations are shifted towards periods of high wind and low prices. Moreover, comparing against the fixed load case it is observed that the amount of surplus wind energy available for export to the national markets, is marginally larger in the price dependent load case. At the same time, as the wind production and electrolyser charging becomes more correlated, the need for external energy import to supply the electrolyser are reduced in the price dependent case compared to the fixed load configuration.

Figure 5.16b shows the shares of the PEM electrolyser electricity consumption per energy source in the price dependent load case, comparing them against the fixed load configuration. When allowing optimal charging operation of the electrolyser, the penetration of wind produced at the hub in the electrolyser electricity consumption increases to 93.2% as the electrolyser operates more frequently during hours when wind generations is high. Following the increased contribution from wind to the electrolyser supply, the need for external energy is reduced to only 6.8% in the price dependent case compared to the fixed load case.

Figure 5.17 shows a breakdown of the Levelized Cost of Hydrogen (LCOH) in the Hydrogn: price dependent load case, based on the input parameters presented in Table 5.1. Calculation of the LCOH is based on the same input parameters and assumptions as de-

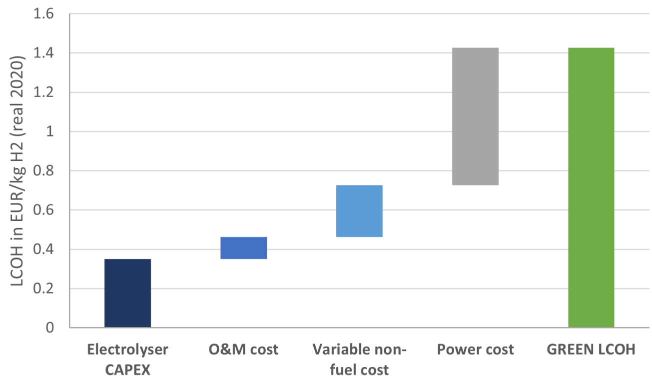


Figure 5.17: Breakdown of Levelized Cost of green Hydrogen (LCOH) measured in Euros per kilo gram H_2 production in the Hydrogen: price dependent load case.

scribed in Section 5.1.5. The resulting LCOH is found to be €1.4/kg H_2, with electricity costs determining the largest share of the LCOH (49%). Overall operational costs contribute to 26% of the LCOH, while electrolyser CAPEX determines 25%. Due to lower capture prices for the PEM electrolyser, the electricity costs share of the LCOH is reduced by 22% in the price dependent load case compared to the fixed load configuration. Moreover, it is observed that by allowing optimal charging of the electrolyser, the total LCOH is nearly halved compared to the fixed load case, highlighting the predominant role of power cost when determining the LCOH.

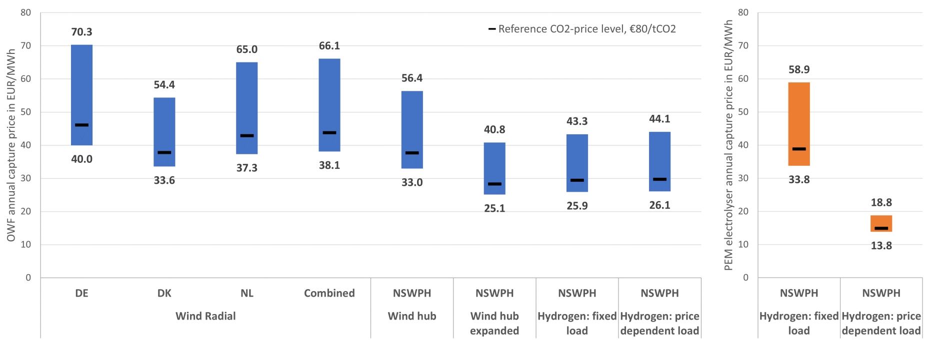
5.2 Sensitivity analysis

The following section investigates how changes in inputs effect the behaviour of the model. The scope of the sensitivity analysis is limited to review the impact on OWF capture prices and curltailment, and PEM electrolyser capture prices, anchored in the case studies previously presented. Sensitivities are studied through separate analyses, changing one input variable at the time. Addressed input variables are CO_2-price, commodity price of natural gas, national loads, wind and solar inflow profiles based on different climate years, and installed capacity of the PEM electrolyser at the hub. Variations in the CAPEX, lifetime and efficiency of the PEM electrolyser and the following impacts on the Levelized Cost of Hydrogen (LCOH) are also investigated at the end of this section.

5.2.1 CO_2-price

The impact of different CO_2 prices is investigated by changing the CO_2 input price in the range between €50/tCO_2 and €200/tCO_2. Resulting OWF capture price ranges for each case study configuration are provided in Figure 5.18a. The maximum OWF capture prices in each case corresponds to a CO_2-price of €200/tCO_2, while the minimum OWF capture prices corresponds to a CO_2-price of €50/tCO_2. It is observed that changes in CO_2-price have a significant impact on the model, with OWF capture prices changing between 63% and 76%. Capture price ranges in the Radial configuration are generally larger than the rest as the radially connected OWF's see only the price in their respective national markets. Moreover, as previously discussed, Germany and the Netherlands both have significant thermal generation remaining in their national systems, making these markets particularly sensitive to changes in CO_2-price. Marginally higher utilisation of the hub connected OWF's replacing thermal generation and tighter market coupling, leads to a slightly decreased capture price range in the Wind hub configuration compared to the Wind radial case.

With increased cross zonal capacity following from the expansion of the hub connecting to Belgium, Great Britain and Norway, the OWF capture price ranges are observed to decrease, primarily due to a significant share of the OWF production being sold in the British and Norwegian markets, characterized by high renewable penetration and low electricity prices. Overall higher access to renewable energy and decreasing electricity prices across all countries in the expanded hub configurations, contribute to a baseload hub price which is more robust against changes in CO_2-price changes. Observed OWF capture price ranges in configurations including a PEM electrolyser at the hub are larger compared to the Wind hub expanded configuration due to a higher electricity demand, however the differences are marginal.



(a) **(b)**

Figure 5.18: Sensitivity analysis results when changing the input CO_2-price between €50/tCO_2 and €200/tCO_2: (a) OWF capture price ranges in each configuration, (b) PEM electrolyser capture price ranges in the Hydrogen: fixed load and Hydrogen: price dependent load case. Underlying data, including capture prices at each CO_2-price level in each case, are provided in Appendix B, Figure B.1 and B.2.

Figure 5.18b shows the resulting PEM electrolyser capture price ranges for the configurations including a PEM electrolyser at the hub. Under the assumption of fixed load operation, the PEM electrolyser capture price is found to be very sensitive to changes in CO_2-price as the electrolyser is forced to charge at any price throughout the year. Conversely, by allowing optimal charging, the capture price range is observed to be very small.

The latter confirms that there are a sufficient amount of low price hours during the year to maintain relatively stable operational costs of the electrolyser, despite changes in CO_2-prices.

Overall, in terms of potential OWF revenues, changing the CO_2-price in the above mentioned range reveals a significant upside and a limited downside of the OWF capture prices with respect to the reference CO_2-price level at €80/tCO_2. Higher CO_2 prices are found to be very beneficial to financial investors seeking to invest in offshore wind, as higher capture prices are associated with higher revenues. Conversely, increasing CO_2-price levels represent a substantial risk for the development of electrolysers, as increased capture prices imply higher power costs. This risk is particularly large in the Hydrogen: fixed load case, with a large upside of the PEM electrolyser capture price. Interestingly, by allowing optimal charging of the electrolyser, most of the risk related to changes in CO_2-price is removed. Because it remains a sufficient number of low price hours in the system, the electrolyser is able to capture low prices despite increasing CO_2-prices.

The merit order of generation and demand remain unchanged when changing the CO_2-price levels. Hence, the OWF generation volumes and curtailment levels are unchanged.

5.2.2 Gas price

The impact of different prices for gas are investigated by changing the input price of natural gas between €15/MWh and €40/MWh. Resulting OWF capture price ranges for each case study configuration are presented in Figure 5.19a. Here, the maximum OWF capture price in each case corresponds to a natural gas price of €40/MWh, while the minimum capture price in each case corresponds to a natural gas price of €15/MWh. It is observed that changes in the price of natural gas have a significant impact on the model, with OWF capture prices changing between 50% and 61%. A similar pattern to what was found when changing the CO_2-price is observed, where the OWF capture prices in the Wind radial case are more sensitive to changes in natural gas prices compared to the hub configurations. Changing the input price of CO_2 and natural gas generally initiates the same response from the model as both impact the cost of carbon emitting generation. However, while the CO_2-price impacts the price of all carbon emitting generation, including coal and oil, the price of natural gas impacts only gas fired generation, including CCGT, OCGT and conventional gas power plants. Consequently, the observed OWF capture price ranges found by changing the natural gas price are slightly more narrow compared to the ranges found when changing the CO_2 price. Another contributing factor to the more narrow ranges is the fact that natural gas prices are changed more moderately compared to the CO_2-price. By not increasing the price of natural gas as aggressively as the CO_2-price, the upside of the capture prices become less significant.

Figure 5.19b shows the PEM electrolyser capture price ranges in the Hydrogen: fixed load and Hydrogen: price dependent configurations. Similar to what was found when changing the CO_2-price, the electrolyser capture price in the fixed load case is observed to be very sensitive to changes in the price of natural gas, due to the direct coupling between the hub baseload price and the capture price of the electrolyser. Conversely, in the price dependent

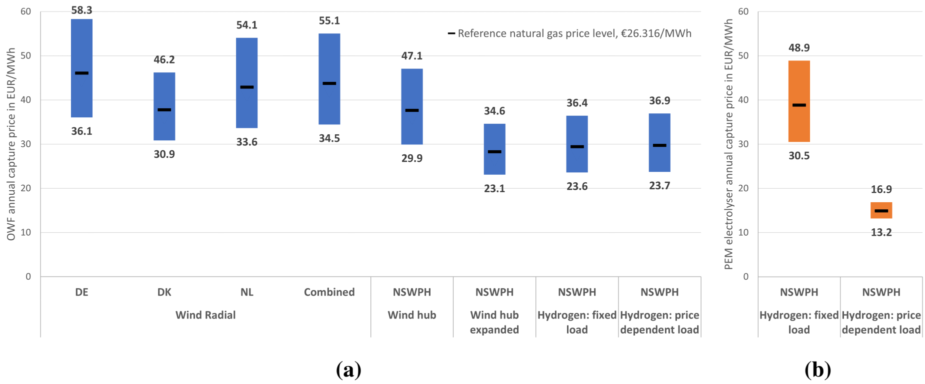


Figure 5.19: Sensitivity analysis results when changing the unit price of natural gas between €15/MWh and €40/MWh: (a) OWF capture price ranges in each configuration, (b) PEM electrolyser capture price ranges in the Hydrogen: fixed load and Hydrogen: price dependent load case. Underlying data, including capture prices at each natural gas price level in each case, are provided in Appendix B, Figure B.3 and B.4.

load case, the capture price is much less sensitive as the electrolyser are able to select low priced hours for charging operation.

The observed maximum and minimum capture prices are evenly distributed around the reference price level in each case, hence the potential upside and downside of the capture prices are approximately the same. This observation implies that the potential risk and benefits from changes in the price for natural gas are equally large. Moreover, the tight correlation between the capture price range patterns observed in when changing the CO_2-price and the price for natural gas, provides some interesting insights about the role of gas power generation. Considering the relatively low penetration of coal and oil in the national systems, it becomes clear that the gas stack is the main driver setting the price. In other words, evaluating the profitability of renewable energy is really a bet on the gas price.

The merit order of generation and demand remains unchanged when changing the input price of natural gas, hence the OWF's generation output and curtailment levels remain unchanged accross all configurations.

5.2.3 National demands

The impact of different electricity demands are investigated by changing the national loads between -10% and +10%, relative to the reference loads. Resulting OWF capture price ranges are presented in Figure 5.20. Here, the maximum OWF capture prices in each case correspond to a relative load increase of +10%, as higher load requires a more frequent utilisation of more expensive thermal generation. On the other hand, minimum capture prices in each case correspond to a relative load decrease of -10%, as larger shares of the national loads are supplied by cheap renewable energy sources. Changing the national loads are observed to have a significant impact on the model, with OWF capture prices changing between 65% and 309%. Radially connected OWF's are observed to capture the highest prices, with maximum values ranging between €64.1/MWh and €67.2/MWh. Lower maximum capture prices are observed in the expanded hub configurations, however the OWF capture price ranges are consistently large across all configurations. The largest capture price range is observed in the Hydrogen: price dependent load case, where the capture price varies between €52.8/MWh and €17.1/MWh.

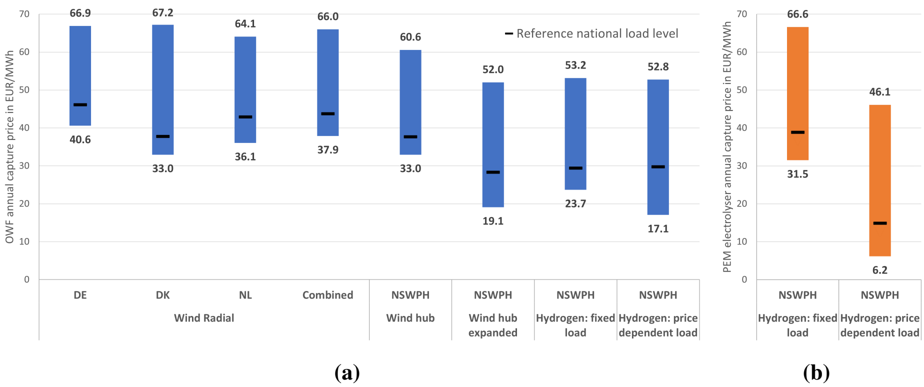


Figure 5.20: Sensitivity analysis results when relatively changing the national loads between -10% and +10%: (a) OWF capture price ranges in each configuration, (b) PEM electrolyser capture price ranges in the Hydrogen: fixed load and Hydrogen: price dependent load case. Detailed results, including capture prices at each national demand level in each case, are provided in Appendix B, Figure B.5 and B.6.

The large upside and small downside of the OWF capture prices represent a great opportunity and limited risk for offshore wind development with regards changes in load. Conversely, the large upside of PEM electrolyser capture prices reveals a major risk for electrolyser development, as power prices are the predominant factor determining the LCOH. Interestingly, the impact of changes in load is found to be equally large in both the Hydrogen: fixed load case and the Hydrogen: price dependent load configuration. With higher load the number of low priced hours in the system decrease, hence the electrolyser is forced to charge at higher prices, resulting in higher capture rates.

Figure 5.21 shows the resulting ranges of OWF curtailed energy when relatively changing the national demands between -10% and +10%. Here, the maximum curtailment in each case correspond to a relative load decrease of -10%, while the minimum curtailment in each case correspond to a relative load increase of +10%. Higher loads generally contributes to reduced levels of curtailment due to a higher utilisation of the OWF assets. Curtailment levels are found to be most sensitive to changes in load in the Wind radial and Wind hub configurations, with curtailed volumes ranging between 16TWh and 26TWh. Less variations in curtailment levels are observed for the more integrated configurations, as the access to multiple markets allows for a more stable utilisation of the OWF's. Configurations including a electrolyser at the hub are observed to be the most robust against changes in national loads. Because a large share of the OWF generation volumes are used

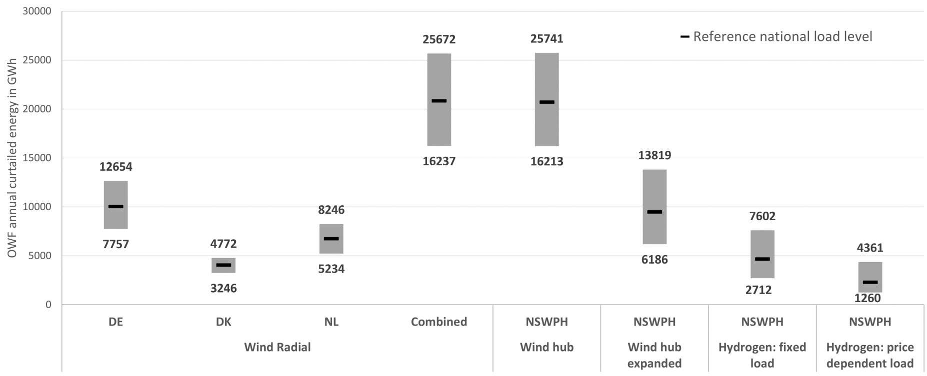


Figure 5.21: OWF curtailed energy in each configuration when relatively changing the national loads between -10% and +10%. Underlying data, including curtailed energy at each national demand level in each case, are provided in Appendix B, Figure B.7.

to supply the electrolyser, the OWF utilisation remains stably high regardless of changes in national loads.

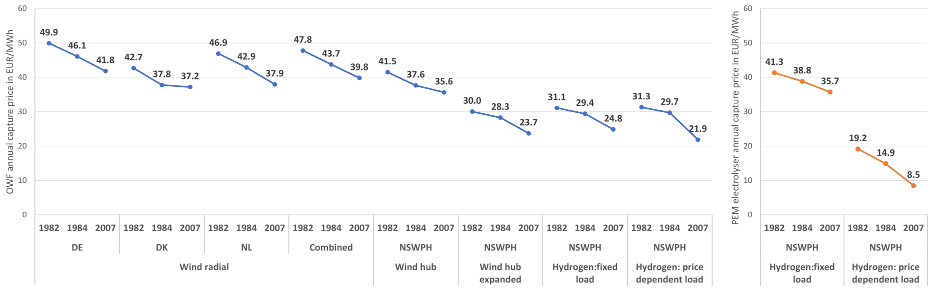
National generation capacities are assumed constant when changing the load. It can be argued that this is an unrealistic assumption, as higher load generally is generally compensated by new generation. An interesting extension of this analysis would be to include a simultaneous changes in load and new generation. However, this approach is considered outside the scope of this report.

5.2.4 Climate years

The impact of changes in wind speeds and solar irradiation are investigated by running the model with different input wind and solar inflow profiles, based on different climate years. The target climate years are 1982, 1984 and 2007, corresponding to the climate years used in the TYNDP 2020 Scenario Report. Input profiles are found using the *renewables.ninja* tool as described in Section 4.6.6.

Resulting OWF and PEM electrolyser capture prices based on each climate year, in each case study configuration, are presented in Figure 5.22a and 5.22b respectively. Using data based on different climate years is found to have a considerable impact on the model results, with the maximum and minimum OWF capture prices in each case study configuration varying between €5.9/MWh €9.4/MWh depending on the climate year. Similarly, capture prices for the PEM electrolyser are observed to vary by €5.6/MWh in the fixed load case and €10.7/MWh in the price dependent load case, depending on the climate year.

Figure 5.23 shows the resulting volumes of OWF curtailed energy calculated based on each climate year, in each case study configuration. Once again, it is observed that cur-



(a) **(b)**

Figure 5.22: Sensitivity analysis results when changing the wind and solar inflow profiles based on the climate years 1982, 1984 and 2007: (a) OWF capture prices in each case study configuration, (b) PEM electrolyser capture prices in the Hydrogen: fixed load and Hydrogen: price dependent load case.

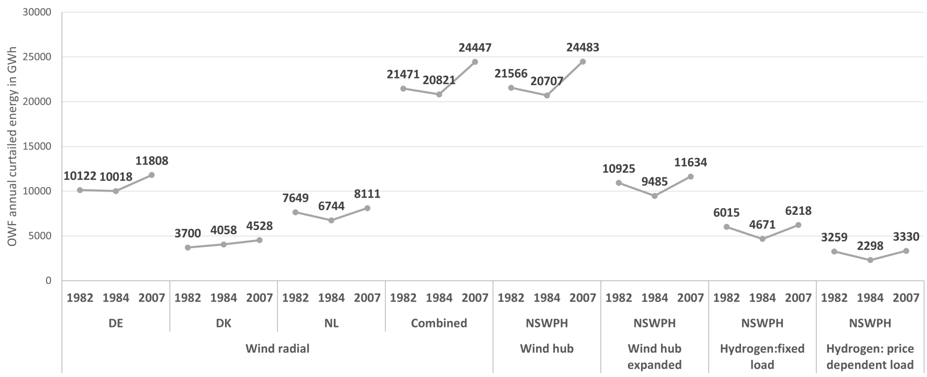


Figure 5.23: OWF curtailed energy in each configuration when changing the wind and solar inflow profiles with respect to the climate years 1982, 1984 and 2007.

tailed energy varies depending on the reference climate year, with minimum and maximum curtailment in each configuration varying between 1032GWh and 3776GWh.

Wind and solar production vary with time as climatic conditions change from year to year. Production vary depending on the quality of the wind and solar resources, but also the temporal timing of inflows at different geographical locations with respect to load. As the results in Figure 5.22 and 5.23 clearly illustrate, considerations with regard to reference climate years is necessary to get accurate results. The intention of this sensitivity analysis is not to explain the specific deviations in the results, but rather to highlight the importance of assessing different climate years. While the observed variations between the different climate years appears to be small, they are not insignificant. Even small margins, both in terms of capture prices and volumes of curtailment, may have a tremendous impact in a financial perspective and they should not be overlooked.

5.2.5 Installed capacity of PEM electrolyser

Resulting OWF and PEM electrolyser capture prices, and volumes of OWF curtailed energy, assessing the impact of different installed capacities for the electrolyser, are presented in Figure 5.24a and 5.24b respectively. Changes in electrolyser capacity are made under the assumption of both a fixed load and a price dependent load operation of the electrolyser, and the investigated installed capacity levels are 3GW, 5GW and 8GW. The chosen installed capacity levels are selected according to EU's 40GW electrolyser target for 2030 in [3]. 3GW and 5GW correspond to the national targets adopted by the Netherlands and Germany respectively, while 8GW represents the joint target for these two countries.

It is observed that OWF capture prices remain more or less constant when changing the electrolyser capacity, with marginally increasing prices as the capacity of the electrolyser is increased. A similar pattern is observed for the PEM electrolyser capture prices, however the increase in price is more significant as the capacity of the electrolyser increase. In the Hydrogen: price dependent load case an increase of €6.1/MWh is observed when increaseing the electrolyser capacity between 3GW to 8GW. Despite stable OWF capture prices, the volumes of OWF curtailed energy drops shapely as the capacity of the electrolyser increases. Increasing the load at the hub generally increases the utilisation of the OWF assets as OWF energy is used to supply the electrolyser.

(a) (b)

Figure 5.24: Sensitivity analysis results when changing the installed capacity of the PEM electrolyser, in the Hydrogen: fixed load and Hydrogen: price dependent load configurations: (a) OWF and PEM electrolyser capture prices, (b) volumes of OWF curtailed energy. Increased energy consumption by the electrolyser is the main driver for decreasing levels of OWF curtailment when increasing the capacity of the electrolyser.

A comparison of the obtained LCOH based on different values of installed capacity for the electrolyser, is provided in Figure 5.25. LCOH is observed to increase as the capacity of the electrolyser is increased, primarily due to rising power prices. Overall, these results represent an interesting trade-off with increased OWF revenues resulting from higher utilisation and stable prices on one side, and more expensive power costs for the electrolyser on the other side. A co-optimization of the size of the wind farm assets and the capacity of the electrolyser will be necessarily to arrive at economically optimal solutions.

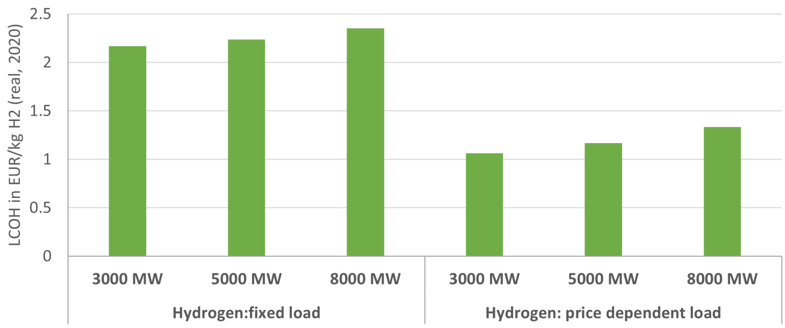


Figure 5.25: Resulting LCOH when changing the installed PEM electrolyser capacity at the hub between 3000 MW and 8000 MW in the Hydrogen: fixed load and Hydrogen: price dependent load configuration. Increased capital costs and electrolyser capture prices are the main drivers for increasing LCOH, when increasing the capacity of the electrolyser.

5.2.6 PEM electrolyser CAPEX, lifetime and efficiency

Impacts on the LCOH are investigated when changing the investment cost (CAPEX), lifetime and efficiency of the electrolyser within reasonable ranges. A reference electrolyser capacity of 5000MW is assumed. First, the electrolyser CAPEX is changed between 200 TEUR/MW and 750 TEUR/MW, corresponding to the future CAPEX range projected in the ASSET Project Report 2018 [85]. Then, the lifetime of the electrolyser is changed between 20 and 30 years, in line with the long-term stack lifetime range projected by the IEA in [69] and the assumption of 60% annual utilisation. Last, the the efficiency of the electrolyser is changed between 65% and 75% (LHV), corresponding to the long-term efficiency range projected in [69]. Resulting LCOH ranges when changing the different input variables are provided in Figure 5.26. Changes in electrolyser CAPEX are found to have the most significant impact on the LCOH, with LCOH varying by €0.4/kg H_2 in both the Hydrogen: fixed load and the Hydrogen: price dependent configurations. A similar sensitivity is observed for changes in the electrolyser efficiency, however, the impact is reduced in the price dependent load case. Changing the lifetime of the electrolyser is observed to have only a marginal impact on the LCOH. Overall, the resulting LCOH ranges are small compared to the impact of changes in electricity price, as seen previously in Section 5.1.5 and 5.1.6. This observation confirms the predominant role of power costs determining the LCOH.

An interesting exogenous reference in terms of LCOH is the Nel ($1.5) €1.23/kg H2 target for green renewable hydrogen by 2025 [102]. The Nel target is situated just below the observed LCOH ranges from the sensitivity analysis. Judging from the model presented in this report this is an ambiguous target. However, with low capture prices for the electrolyser, potentially supported by reduced CAPEX and increased efficiency ratings, and

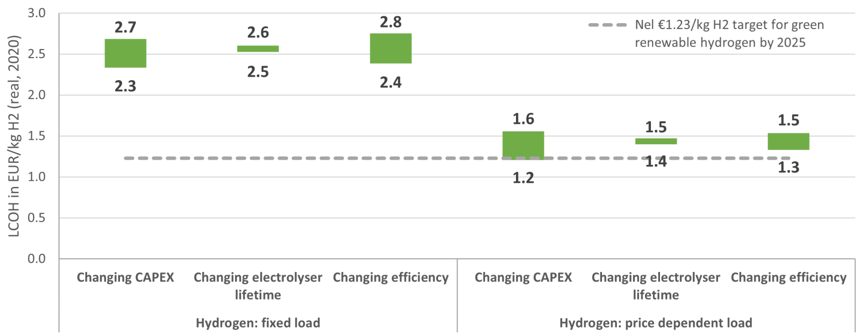


Figure 5.26: Levelized Cost of Hydrogen (LCOH) ranges in the Hydrogen: fixed load and Hydrogen: price dependent load configurations, when changing the input investment cost (CAPEX), lifetime and efficiency of the PEM electrolyser.

optimal charging operation, it can be feasible. It is also worth mentioning that various financial support schemes may contribute to even lower LCOH. Applicable support schemes could be e.g. a power purchase agreement (PPA), contract for difference (CfD) or feed-in-tariff (FiT). Moreover, subsidiaries related to capital and operational costs would help to further reduce the overall costs of the electrolyser. While contributing to a lower LCOH, support through any of the mentioned support schemes would also provide a useful hedge against variable power prices.

5.3 Discussion

This section provides a discussion of the results obtained in the case study and following sensitivity analysis. First, a summary of the case study results is presented. Then, the validity of the results and limitations of the work are discussed.

5.3.1 Summary of case study results

A summary of key results from the case study is provided in Table B.8 in Appendix B. Overall flows and utilisation rates of hub related transmission assets are found to be low. In the Wind radial and Wind hub configurations the transmission assets are mainly used to transfer the OWF generation to the onshore systems, with limited flows going from the national shores. Increasing the cross-zonal capacity between the German, Danish and Dutch markets has a limited value, unless Great Britain, Norway and Belgium are added to the hub. Higher price spreads between the Norwegian/British market and the hub leads to an increase in the overall utilisation of the hub transmission assets, mainly driven by flows from these two national systems. Adding an electrolyser facility at the hub leads to increased generation volumes and reduced curtailment of the OWF assets, as the majority of the energy consumed by the electrolyser is supplied by the OWF.

OWF capture prices in the Wind radial configuration are high due to low capacity factors for the OWF assets and a tight connection to the national home markets. As a result of market coupling and higher utilisation of the OWF assets, the capture prices is observed to decrease in the Wind hub and Wind hub expanded configurations. The price is particularly low in the expanded hub configuration due to the exposure to the Norwegian and British markets. Adding an electrolyser facility at the hub leads to marginally increasing prices as a part of the load imposed by the electrolyser needs to be supplied from the onshore national systems. Allowing price dependent charging of the electrolyser, as opposed to the assumption of fixed load, is observed to result in sharply reduced capture prices for the electrolyser. As a result of decreasing capture prices the LCOH is nearly halved in the price dependent load case compared to the fixed load case.

Despite a low utilisation of the OWF assets, the overall capture revenue in the Wind radial configuration is relatively high, driven by high capture prices. Unless an electrolyser facility is added to the hub, OWF capture revenues are observed to be lower in the hub configurations compared to the Wind radial case, because decreasing capture prices outweighs the benefit of increased OWF utilisation in both the Wind hub and Wind hub expanded configurations. The latter is a great example of how offshore wind and hydrogen electrolysers can compliment each other. On the one hand the wind farm provides cheap energy which serves as a fuel for the electrolyser, while on the other hand the electrolyser impose an additional load which allows for a higher utilisation of the wind farm. Low costs for electricity generally contributes to a lower LCOH for the electrolyser, while higher OWF generation volumes allows the wind farm to sell more energy, leading to higher OWF revenues.

5.3.2 Validity of results

Aggregated input data represents a major challenge with regards to the results, as it will be optimistic towards the benefits of transmission and generation expansions. In reality, generation and demand is dispersed across different domestic locations. This model, on the other hand, assumes that all production are readily available in the respective aggregated national loads, and that demand must be met here as well. In real world operations, countries are likely to experience both internal congestion and losses which is not captured with the current model set-up. It is also worth mentioning that countries are modelled independently, while they in reality are tighter integrated. Less aggregation of nodes would contribute to a more realistic model, capturing the behaviour of the system in more detail.

The scope of the model is limited to include only seven countries (denoted as the core countries), excluding the remaining parts of the European power grid. In reality, the European grid is more meshed and considerable amounts of energy are flowing between the core countries and the external grid. As described in Section 4.7.1, additional load has been included to compensate the influence of the external grid on the core countries. While this is an effective way of balancing supply and demand in the core countries, it is also a significant simplification. Ideally, actual external demand and generation, instead of average net flows, should be included to accurately capture the variations of import and export. However, the inclusion of more countries becomes a trade off between the level of accuracy and the complexity of the model. It is assumed that the selected modelling countries and simple load compensation provides a satisfactory compromise.

Another important consideration is the fact that the results are subject to full flexibility of all generation sources. Beside the maximum generation capacity of each generator, the only active constraints with regard to generation are the maximum annual average capacity factors which are applied to renewable energy sources. In reality, generation dispatch usually involves some kind of start-up behaviour, particularly for less flexible production units such as fossil and nuclear. Hence, allowing generators to turn on and off in any time instant enables certain generators to provide more flexibility than what is possible in real world applications. A potential improvement of the model would be to construct some kind of time dependent constraint that limits the ramp rate of generators. Another solution could be to include a restriction of minimum production. While it does not help with the flexibility issues, one can provide a lower limit of base production which non-renewables has to produce. Another interesting feature about this constraint is to see how the system behaves if the model is forced to supply a minimum amount of renewable production.

Note that Demand Side Response (DSR) is not taken into account in the model formulation in Section 4.1. The decision to exclude DSR is based on challenges related to the modelling aspects of such solutions and the lack of sufficient documentation provided in the TYNDP scenarios. By not including DSR in the system one simultaneously removes a source of flexibility. A simplified way to include DSR in the model could be to expand the generation capacities with respect to the future projected penetration of DSR. While this solution is not completely accurate it does compensate the flexibility loss related to the removal of DSR. More sophisticated ways to model DSR would imply to actually reduce the load. Some major challenges in such approaches are how to valuate each unit of removed load and how to prioritize the disconnection of loads.

Battery capacities are modelled in a very simplified way as described in Section 4.3. Studying the charging/discharging patterns of the battery capacities in the model results show an unrealistic behaviour. Without further constraints, the batteries have no bound on the maximum amount of energy that they can store. Hence, if the model finds it optimal, the batteries might store extremely large amounts of energy. As a result, the system is provided more flexibility than it should have ideally. Potential improvements to the model could be to add constraints for the maximum amount of energy that a battery is allowed to consume in a finite sequence of samples. In this way it is possible to set a maximum storage capacity of the batteries. Another solution would be to force the capacity factor of the batteries to be zero on a shorter time interval, to ensure a more frequent charging/discharging pattern. However, an important aspect to remember is the fact that the results are based on samples. When using 1000 samples to represent a full year (8760 hours) the results become more aggregated and details on an hourly basis are lost. To have an accurate representation of the charging pattern it would be necessary to include all 8760 samples. Another important consideration is the model's ability to see one full year of operation. In this way it is able to make decisions ahead of time and thus find the absolute optimal charging/discharging patterns of batteries and electrolysers. In reality, one can only see backwards in time and make qualified assumptions about the future. While the resulting charging/discharging patterns my not be realistic, they nevertheless provide some interesting upper limits to what is possible to achieve in a social economic perspective.

The model assumes an offshore bidding zone (OBZ) setup, where the studied hubs form a separate offshore zone, in which the offshore wind farms (OWF) submit bids and are dispatched. Via market coupling the offshore generation is matched with onshore demand, and the electricity price within the OBZ is the result of market coupling. An interesting extension of the model would be to investigate how the system behaves if one assumes a different market setup. According to European electricity market principles in [103] there are really only two viable market setup options in the context of offshore wind power hubs, which include the OBZ setup and the home market (HM) setup. In the HM approach the offshore wind farm bids and dispatches into its home market and receives the HM electricity price. The cable connecting the hub and the HM is a so called ”hybrid” asset, while the cables between the different home markets are cross-border interconnectors. It is uncertain which market setup that will be the preferred option in the future. In either case, a rethinking of the existing market structures will be necessary. Exemptions or European regulatory changes are likely required to ensures optimal use of hub connected offshore wind. An important question to be resolved is how to ensure a fair distribution of risk and revenue among the energy market actors.

The levelized cost of green hydrogen (LCOH) is calculated in a simple way as it includes only investment costs (CAPEX), operational costs (OPEX) and power costs. In reality, the LCOH also consists of other items such as balance of the plant, compression and storage and water costs. Considering that certain costs are omitted in the calculation presented in this report, it may be some uncertainty around the resulting LCOH at €2.6/kg H_2 in the fixed load case and €1.4/kg H_2 in the price dependent load case. It should also be mentioned that the assumption of fixed load operation of the electrolyser is unrealistic. In reality, the operation of the electrolyser is dependent on both the hydrogen demand and electricity prices, hence a constant production is unlikely. The exclusive selection of hours with the lowest prices in the price dependent load case is another unrealistic characteristic about the model. By allowing the model to see the full year of operation, the price dependent load case represents the absolute optimum operation of the electrolyser in terms of minimizing power costs. In reality, one cannot know for sure what the future electricity price will be, hence the electrolyser should occasionally capture higher prices as well. Based on the underlying assumptions the actual LCOH is likely to be somewhat lower than €2.6/kg H_2 while somewhat higher than €1.4/kg H_2, reflecting a more realistic charging operation of the electrolyser. Comparing the achieved LCOH against benchmark estimates provides an interesting sanity check of the results. A useful exogenous reference is BloombergNEF which have estimated the LCOH (green) to be in the range of approximately 2.5-1.1 €/kg H_2 in 2030 and 1.5-0.7 €/kg H_2 in 2050 (real, 2019) [72]. It is observed that the resulting LCOH for 2040 are within the ballpark range.

Table 5.2 shows the total system cost, i.e. the objective, from the implementation of each case study configuration, relative to the Base case. Interestingly, the increased penetration of offshore wind and IC capacity contribute to reduced system costs in all configurations. Hence, in the exogenous capacity analysis, all configurations are profitable in a social

Table 5.2: Total system cost in billion Euros for each case study configuration, relative to the Base case. A higher penetration of low-cost offshore wind is the main driver for reduced total system costs.

Case study configuration	**Total system costs [bEUR]**
Base case	264.2096
Wind radial	-26.3600
Wind hub	-29.1715
Wind hub expanded	-43.1499
Hydrogen: fixed load	-25.8550
Hydrogen: price dependent load	-36.1835

economic perspective.

However, when presenting the 12GW offshore wind and corresponding transmission assets as endogenous investment opportunities in PowerGIM, i.e. taking into account the capital expenditures associated with the prospective infrastructure expansions, the model behaviour is changed. Resulting optimal new capacity investments in the endogenous capacity analysis is presented in Table 5.3. Here, each case study configuration has been presented as an investment opportunity in PowerGIM. Capacities that have been evaluated for expansion are the OWF (max 12GW) and the respective IC capacities connecting the OWF to shore. The PEM electrolyser is assumed pre-installed in the Hydrogen: fixed load and Hydrogen: price dependent load cases, hence the electrolyser CAPEX is not taken into account. Overall, it is observed that the amount of new capacity investments is very low. In fact, unless Norway and Great Britain are allowed to connect to the hub, no investments are made. Moreover, it is observed that investments in new OWF capacity occurs only if an electrolyser facility is included at the hub. High capital costs related to the OWF and new cables generally outweighs the operational cost savings from increased transnational trade and higher penetration of RES. These observations provide an interesting insight about the actual profitability of the previously studied case study configurations. Based on the underlying data, neither of the studied configurations are optimal in terms of minimizing the total system costs. The low willingness to expand the grid also gives an indication that there may be some uncertainty regarding the profitability of the prospective case study configurations. The high unit investment cost for offshore wind generation at m€1.345/MW (see Table A.9), is identified as a major hurdle preventing large generation expansions. Unless capital costs for offshore wind decrease even further by 2040, it is not unlikely that financial support schemes will be necessary in order for it to be profitable to invest in such assets in the future.

While the results may not be completely accurate, the overall behaviour of the system is still valid to a large degree.

Table 5.3: Optimal new capacity investments for each case study configuration when taking into account the capital expenditures associated with the planned expansions. The reluctance to invest in offshore wind generation unless an electrolyser is included in the system, is driven by high capital costs for offshore wind.

	New OWF Capacity [MW]	New capacity DE-NSWPH [MW]	New capacity DK-NSWPH [MW]	New capacity NL-NSWPH [MW]	New capacity BE-NSWPH [MW]	New capacity GB-NSWPH [MW]	New capacity NO-NSWPH [MW]
Base case	0	0	0	0	0	0	0
Wind radial	0	0	0	0	-	-	-
Wind hub	0	0	0	0	-	-	-
Wind hub expanded	0	1995.68	0	0	0	91.01	2000.00
Hydrogen: fixed load	1623.94	1304.70	36.51	467.44	0	2000.00	2000.00
Hydrogen: price dependent load	3161.67	2248.15	297.97	780.97	38.06	1408.35	2000.00

5.3.3 The approach and its limitations

As an inevitable fact, when modeling real world operations, one can not cover all aspects and certain simplifications must be made. In the following, shortcomings and critical assumptions related to the methodology used are presented. The content in this section is taken from the project thesis [6] that was written prior to this master thesis.

As described in Section 4.2 operational states are selected by random samples and selected states constitutes only a subset of the full data set. Including the full data set or making use of advanced algorithms for state selection, will generally contribute to a higher precision in the results. However, the increase of samples scales the problem and introduces more variables which may make it computationally challenging to solve. Based on the findings in [78], it is assumed that 1000 random samples constitute a reasonable compromise between computational time and precision of results.

An important simplification in the current problem formulation is the unrealistically static nature of the model. Meshed power grids are usually not built in one step, but rather developed incrementally over many years. A natural improvement of the model would be to make use of the stepwise multiperiod optimization capability embedded in PowerGIM. An even further extension of the model would be to also include stochastic programming in the optimization. In this way it is possible to assess risks in more detail, which is a very important aspect in investment decisions. Relevant uncertainties in the context of grid expansion panning are e.g. generator capacity, energy demand, grid locations, power prices.

A transportation model is assumed to be sufficient because the intention is to use the model on an aggregated system, including a HVDC grid. This simplified representation of the power network reduce the complexity of the model, but provides less accuracy than more sophisticated methods. A reasonable extension of the methodology would be to include linearized power flow equations (e.g. DC power flow), especially in parts of the network that are AC. This would make the model more more applicable also to onshore expansion planning.

Handling of contingencies is another weakness in the current methodology. Optimizing without security constraints can potentially lead to optimal solutions which in reality are infeasible, due to the lack of sufficient redundancy. The decision to disregard security constraints is motivated by the aggregated level of modelling. However, as they argue in

[34], it is conceptually possible to include planning with regard to contingencies, but these approaches will require many more real unknowns.

Chapter 6

Conclusion and Further Work

6.1 Conclusion

This report provides a general introduction to the concept of scenario generation and presents major works from leading market players regarding long-term scenarios of the power system. Historical and future trends within the offshore wind and hydrogen industries are highlighted to provide an adequate basis for the following case study.

A deterministic optimisation model for power system expansion planning (PowerGIM) is described. A comprehensive data set is created using reliable and open sources. The main source for input data is the TYNDP 2020 Global Ambition scenario, which comprise a long-term scenario of the European power system through 2040. After a careful pre-processing of data, the inputs are incorporated into the model.

The methodology is demonstrated on a case study, assessing different ways of connecting 12 GW of offshore wind in the North Sea. Seven countries are treated in the analysis, including Germany, Denmark, the Netherlands, Belgium, Great Britain, Norway and France. Five cases are tested through an incremental approach, including one radial and four hub configurations, two of which include a PEM electrolyser at the offshore hub. First, a radial expansion of 6GW, 2GW and 4GW offshore wind, connecting to Germany, Denmark and the Netherlands respectively, is assessed. Then, the entire capacity (12GW) is placed in a hub, connected to the same three countries, before the hub is expanded to include additional connections to Belgium, Great Britain and Norway, through three separate 2GW interconnectors (ICs). Finally, a 5GW PEM electrolyser is introduced at the hub. The PEM electrolyser is first included under the assumption of fixed hydrogen load operation, before running a price dependent load case.

Low utilisation rates are observed in the wind radial and wind hub configurations. Both cases are characterized by significant curtailment and relatively low capacity factors of the offshore wind farms (OWFs), due to merit order effects and limited price spreads between the national markets and the offshore bidding zone (OBZ). IC capacities are primarily used to transfer energy from the OWF to the national shores, with limited energy going from the national markets to the OWF. Overall, increasing the cross-zonal capacity between the German, Danish and Dutch markets has a limited value, unless Great Britain and Norway are added to the hub. Higher price spreads in the Wind hub expanded case between the Norwegian and British market, and the hub, leads to an increase in OWF utilisation. While flows on the German, Danish and Dutch ICs remain mainly unidirectional, the IC capacity between Norway, Great Britain and the hub are characterized by flows going in both directions. Utilisation of the Norwgian IC is found to be particularly high, as it is unutilised only 6% of the time. While increasing the overall utilisation of new assets, the OWF capture price is found to be at its lowest in the expanded hub case, with an OWF capture revenue declining to m€1404/MWh.

Introducing a PEM electrolyser at the hub is found to provide significant reductions in OWF curtailment and increased revenue in the electricity market. Adding a flexible load allows the OWF to generate on a more regular basis, while the increased load contributes to higher prices. With increased OWF generation volumes and higher prices, the OWF capture revenue increases considerably, peaking at m€1689/MWh year in the Hydrogen: price dependent load case.

Changes in input variables provide considerable variations in the results, with respect to OWF curtailment and capture prices. Changing the CO_2-price, gas price and national loads all reveal a significant upside to capture prices of both the OWF and the electrolyser. Similarly, OWF curtailment is found to be very sensitive to changes in national loads and installed electrolyser capacity. Varying curtailment levels and capture prices resulting from changing the reference climate year, also highlights the importance of accounting for different climatic conditions when modelling future scenarios.

Based on the underlying assumptions in the model, it is found that the cost of producing green hydrogen could come down to €2.6/kg H_2 under the assumption of fixed load and €1.4/kg H_2 in the price dependent load case, with power costs contributing to the majority of the LCOH. Assessing variations in electrolyser CAPEX, lifetime and plant efficiency, the LCOH is found to be in the range of €2.3-2.8/kg H_2 and €1.2-1.6/kg H_2 in the two cases respectively, being most sensitive to changes in CAPEX and efficiency.

6.2 Further work

An interesting objective in further work would be to assess more thoroughly the profitability of the proposed expansions of generation and transmission assets. While the case study in this report is formulated as an exogenous capacity analysis, an endogenous approach would provide valuable insight to the actual feasibility of the required investments. This would also help make the model more applicable to investors who seek to invest in offshore infrastructure. One interesting case would be to observe how the model behaves when changing the input CAPEX of offshore wind. Another would be to evaluate bottom fixed against floating offshore wind. The model could also be updated to take into account financial support schemes. These could e.g. include power purchase agreements (PPAs), contract for difference (CfD), feed-in tariffs (FiTs) or other subsidiary support.

Another extention to the model would be to include a more detailed hydrogen infrastructure. This could e.g. include hydrogen delivery systems, storage and hydrogen demand. Interesting means for hydrogen transportation in offshore applications are for instance ships or pipes. Distribution of hydrogen by road can also be an interesting topic of analysis if load centers are located far from shore. It is also relevant to assess different hydrogen storage opportunities, both as a source of flexibility for renewables and to provide grid balancing services. While the scope of this report is limited to evaluate the impact of PEM electrolysers, there also exist other ways of producing hydrogen. A comparison between different electrolyser technologies would be an interesting assessment. In general, a more accurate representation of the hydrogen value chain is essential to have a better understanding of the role of hydrogen in the future.

In June 2020 the Norwegian government published two concession areas for offshore wind outside the coast of Norway, namely Utsira Nord and Sørlige Nordsjø II. An interesting study would be to apply the methodology described in this report to investigate optimal connection of offshore wind capacity in these areas. Sørlige Nordsjø II is particularly interesting in this case, due to its proximity to other countries than Norway.

Another exciting improvement to the model is to utilize the stochastic programming capabilities in PowerGIM, as described in Section 5.3.3. This will contribute to a more realistic model and enable a more thorough assessment of risks.

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Appendix A

Input Data

Table A.1: Overview of nodes in the grid representation. Node 11 represents the location in which all new offshore wind capacity is located.

Node	Country	Latitude [°]	Longitude [°]	Offshore	Type	Function
1	BE	51.45	2.45	Yes	DC	Offshore wind production
2	DE	54.68	6.16	Yes	DC	Offshore wind production
3	DK	55.59	7.58	Yes	DC	Offshore wind production
4	GB	55.01	2.65	Yes	DC	Offshore wind production
5	GB	52.67	2.72	Yes	DC	Offshore wind production
6	NL	52.75	3.50	Yes	DC	Offshore wind production
7	NL	53.56	5.50	Yes	DC	Offshore wind production
8	NO	56.80	4.90	Yes	DC	Offshore wind production
9	FR	49.92	0.20	Yes	DC	Offshore wind production
10	FR	47.01	-2.64	Yes	DC	Offshore wind production
11	NSWPH	54.66	3.15	Yes	Island	North Sea wind power hub
21	BE	51.22	3.17	No	AC	Land connection point
22	DE	53.13	7.31	No	AC	Land connection point
23	DK	55.52	8.73	No	AC	Land connection point
24	GB	53.56	-0.15	No	AC	Land connection point
25	GB	52.07	1.06	No	AC	Land connection point
26	NL	52.33	5.02	No	AC	Land connection point
27	NO	58.28	6.85	No	AC	Land connection point
28	DE	53.90	9.18	No	AC	Land connection point
29	DK	56.50	9.54	No	AC	Land connection point
30	NL	53.43	6.88	No	AC	Land connection point
31	NL	52.48	4.69	No	AC	Land connection point
32	FR	49.76	0.37	No	AC	Land connection point
33	FR	47.24	-2.27	No	AC	Land connection point
34	FR	49.86	0.70	No	AC	Land connection point
35	GB	50.79	0.05	No	AC	Land connection point
91	NO	59.47	6.58	No	AC	Aggregated country
92	DK	56.00	9.30	No	AC	Aggregated country
93	DE	52.50	10.8	No	AC	Aggregated country
94	NL	52.24	5.83	No	AC	Aggregated country
95	BE	50.72	4.43	No	AC	Aggregated country
96	GB	52.50	-1.00	No	AC	Aggregated country
97	FR	47.10	2.40	No	AC	Aggregated country

Table A.2: Overview of branches in the grid representation, with respect to the net transfer capacities assumed in the Global Ambition scenario in the TYNDP 2020 Scenario Report [48]. Capacity of branches connecting pre-installed generation capacities of offshore wind are set high to accommodate all production.

Node from	Node to	Capacity [MW]	Project Name
21, BE	95, BE	5000	
22, DE	93, DE	15000	
23, DK	92, DK	5000	
24, GB	96, GB	10000	
25, GB	96, GB	5000	
26, NL	94, NL	5000	
27, NO	91, NO	10000	
28, DE	93, DE	5000	
29, DK	92, DK	5000	
30, NL	94, NL	5000	
31, NL	94, NL	5000	
32, FR	97, FR	100000	
33, FR	97, FR	100000	
34, FR	35, GB	4000	
93, DE	94, NL	5000	
93, DE	92, DK	3500	
93, DE	95, BE	1000	
94, NL	95, BE	2400	
96, GB	35, GB	4000	
97, FR	34, FR	4000	
97, FR	95, BE	4300	
97, FR	93, DE	3000	
1, BE	21, BE	100000	
2, DE	22, DE	100000	
3, DK	23, DK	100000	
4, GB	24, GB	100000	
5, GB	25, GB	100000	
6, NL	26, NL	100000	
7, NL	30, NL	100000	
8, NO	27, NO	100000	
9, FR	32, FR	100000	
10, FR	33, FR	100000	
11, NSWPH	22, DE	6000	
11, NSWPH	23, DK	2000	
11, NSWPH	26, NL	4000	
11, NSWPH	21, BE	2000	
11, NSWPH	24, GB	2000	
11, NSWPH	27, NO	2000	
27, NO	24, GB	2800	North Sea Link and NorthConnect
27, NO	28, DE	1400	NordLink
27, NO	29, DK	1640	Skagerakk
27, NO	30, NL	700	NordNed
23, DK	30, NL	700	COBRA
23, DK	24, GB	1400	Viking
31, NL	25, GB	1000	BritNed
21, BE	25, GB	1000	NEMO
28, DE	25, GB	1400	Neuconnect

Table A.3: Input generator capacities from the Global Ambition scenario in TYNDP 2020 [48].

Generation Technology	Installed Capacity [MW] BE	DE	DK	GB	NL	FR	NO
Solar PV	12318	105032	1850	27232	19450	41186	54
Onshore Wind	7130	95401	6329	15508	10100	43855	7948
Offshore Wind	6030	23878	12625	36765	16500	12425	2417
Hydro	1543	15370	0	5973	46	25300	36061
Reservoir	1395	11334	0	4004	0	11700	36061
Run-of-River	148	4036	0	1969	46	13600	0
Nuclear	0	0	0	18552	0	37239	0
Other RES	206	5235	629	4700	540	2549	76
Gas	8685	21176	950	37171	9293	6944	0
Gas CCGT	7606	15299	430	34986	8651	6552	0
Gas OCGT	292	3250	0	2128	642	392	0
Gas Conventional	787	2627	520	57	0	0	0
Coal	615	0	767	3699	3381	0	0
Oil	158	223	412	371	0	0	0
Other non-RES	1324	20565	497	7432	3770	6533	265
Battery	950	8114	1021	2130	1737	7122	0
Total[1]	38959	294994	25080	159533	64817	183153	46821

[1] Note that battery capacities are included in the total generation capacity in each country.

Table A.4: Input CO_2 emission factors from electricity generation by combustion fuel product, reported by the IEA [84] .

Fuel type	**Emission factor** [tCO_2/MWh]
Natural Gas	0.400
Hard Coal	0.860
Fuel Oil	0.675

Table A.5: Input efficiencies for different power plant technologies and capacity volume weighted values. Efficiencies for gas, nuclear and other-non RES are taken from the TYNDP 2020 Scenario Building Guidelines [82], while coal and oil efficiencies are taken from the attached input data set for the TYNDP 2018 Scenario Report [81].

Plant Technology	Aggregated Capacity MW	Efficiency [ratio]	Volume Weighted Efficiency [ratio]
Gas CCGT	73524		0.55
CCGT new	29587	0.60	
CCGT old 1	4410	0.40	
CCGT old 2	22783	0.48	
CCGT present 1	792	0.56	
CCGT present 2	15952	0.58	
Gas OCGT	6704		0.40
OCGT new	4417	0.42	
OCGT old	2287	0.35	
Gas Conventional	3991		0.39
Conventional old 1	1564	0.36	
Conventional old 2	2427	0.41	
Coal	8462		0.43
Hard coal new	3666	0.46	
Hard coal old 1	12	0.35	
Hard coal old 2	4784	0.40	
Oil	1164		0.35
Light oil	291	0.35	
Heavy oil old 1	873	0.35	
Nuclear	55791	0.38	0.38
Other non-RES	40386	0.47	0.47

Table A.6: Input fuel prices and CO_2 price taken from the TYNDP 2020 Scenario Report [48]. The price for reservoir hydro in all countries except Norway, is assumed.

Product	Fuel price [EUR/GJ]	Volume Weighted Price [EUR/GJ]	Other Input Price [EUR/MWh]	[EUR/tCO_2]
Nuclear	0.47	0.47		
Hard coal	6.91	6.91		
Natural gas	7.31	7.31		
Fuel oil		18.45		
Light oil	22.2			
Heavy oil	17.2			
Reservoir hydro (exept Norway)			10	
CO_2				80

Table A.7: Input fuel costs per generation power plant technology, calculated from volume weighted fuel prices and plant efficiencies at optimal load operation. Fuel prices and efficiencies for gas and other non-RES are taken from the TYNDP 2020 [48]. Gas efficiencies are weighted average values, calculated based on the relative distribution of gas plants included in the Global Ambition scenario. Efficiencies for nuclear, coal and oil are taken from the ASSET project report 2018 [85].

Power Plant Technology	Efficiency [ratio]	Fuel Type	Fuel Price [EUR/GJ]	Input Cost [EUR/MWh]
Nuclear	0.38	Nuclear	0.47	4
Reservoir hydro (exept Norway)				10
Other non-RES	0.58			45
Gas CCGT	0.55			48
Gas CCGT CCS	0.51	Natural Gas	7.31	52
Gas OCGT	0.40			66
Gas Conventional	0.39			67
Coal	0.43	Hard Coal	6.91	58
Oil	0.35	Fuel Oil	18.45	190

Table A.8: Fixed operation and maintenance costs (O&M) and variable non-fuel costs per electricity generation, hydrogen and electricity storage technology, taken from the ASSET Project Report 2018 [85]

Technology	Fixed O&M costs [EUR/MW year]			Variable non-fuel costs [EUR/MWh]			Assumed fixed O&M costs [EUR/MW year]	Assumed variable non fuel cost [EUR/MWh]
	2030	2040	Ultimate	2030	2040	Ultimate		
Electricity Generation								
Solar PV	-	11650	-	-	0.00	-	11650	0.00
Onshore wind	-	16750	-	-	0.20	-	16750	0.20
Offshore wind	-	32500	-	-	0.39	-	32500	0.39
Hydro reservoir	-	25500	-	-	0.32	-	25500	0.32
Hydro run-of-river	-	8200	-	-	0.00	-	8200	0.00
Nuclear	-	108000	-	-	7.60	-	108000	7.60
Other RES							47600	0.38
Waves and tidal	-	28000	-	-	0.10	-	-	-
Geothermal	-	96000	-	-	0.32	-	-	-
Small biofuel[1]	-	18800	-	-	0.71	-	-	-
Other non-RES[2]	-	15000	-	-	3.50	-	15000	3.50
Gas CCGT	-	15000	-	-	1.81	-	15000	1.81
Gas OCGT	-	15000	-	-	2.31	-	15000	2.31
Gas Conventional	-	15000	-	-	2.31	-	15000	2.31
Gas CCGT CCS	-	35000	-	-	2.88	-	35000	2.88
Coal	-	25600	-	-	2.40	-	25600	2.40
Oil	-	20700	-	-	2.76	-	20700	2.76
Hydrogen Production								
Hydrogen from PEM	15000	-	10000	6.9	-	4.2	12500	5.6
Hydrogen from Alkaline	14000	-	9000	6.1	-	3.8	11500	5.0
Hydrogen from SOEC	36200	-	39000	16.3	-	13.6	37600	15.0
Hydrogen SME CCS	34000	-	32000	18.3	-	17.2	33000	17.8
Electricity Storage[3]								
Large-scale batteries	15000	-	13100	0	-	0	14050	0
Small-scale batteries	6300	-	5500	0	-	0	5900	0

[1] Operational costs of the category "Very small scale Gas Plant" in the ASSET Project Report are assumed to be representative estimates for "Small biofuel".

[2] Operational costs of the category "Gas turbine with heat recovery" in the ASSET Project Report are used to represent "Other non-RES", because this category consists mainly of CHP plants.

[3] The average value of assumed fixed O&M cost for "Large-scale batteries" and "Small-scale batteries" are used as the input fixed O&M cost for the generator category "Battery" in the PowerGIM model.

Table A.9: Investment costs (CAPEX) per technology. Costs for electricity production facilities are taken from the Global Ambition scenario in TYNDP 2020 [86], while remaining costs are taken from the ASSET Project Report [85]. CAPEX for production units are given per unit of installed capacities [TEUR/MW] and CAPEX for electricity storage technologies are given per unit of energy stored per year [EUR/MWh]. CAPEX is discounted over a period of 30 years, with a fixed discount rate of 5%.

Technology	CAPEX [TEUR/MW]			Assumed CAPEX [TEUR/MW]	Yearly discounted CAPEX [EUR/MW year]
	2030	2040	Ultimate		
Electricity Production					
OCGT New	-	440	-	440	28623
CCGT New	-	750	-	750	48789
Onshore Wind	-	732	-	732	47618
Offshore Wind	-	1345	-	1345	87494
Solar PV (residential)	-	745	-	745	48463
Solar PV (commercial)	-	455	-	455	29598
Hydrogen Production					
Hydrogen from PEM	340	-	200	270	17564
Hydrogen from Alkaline	300	-	180	240	15612
Hydrogen from SOEC	804	-	600	702	45666
Hydrogen SME CCS	850	-	800	825	53667
	CAPEX [EUR/MWh]			**Assumed CAPEX [EUR/MWh]**	**Yearly Discounted [EUR/MWh year]**
Electricity Storage					
Large-scale batteries[1]	253000	-	225484	239242	15563
Small-scale batteries	114000	-	101619	107810	7013

[1] Costs of installation, land cost and grid connection are included in the investment costs of Large Scale Batteries.

Table A.10: Annual electricity demand, peak load and average load, per country from the Global Ambition scenario in TYNDP 2020 [48].

Country	Annual Energy Demand [TWh]	Peak Load [MW]	Average Load [MW]
Belgium (BE)	97.2	14643	11096
Germany (DE)	571.2	82711	65203
Denmark (DK)	59.3	9262	6768
Great Britain (GB)	397.9	62763	45422
Netherlands (NL)	120.0	17651	13698
France (FR)	502.0	88029	57316
Norway (NO)	149.0	27549	17005

Table A.11: Cost parameters per branch for new lines.

Branch type	B^d **[kEUR/km]**	B^{dp} **[kEUR/kmMW]**	B **[kEUR]**
AC	1193	1.416	312
DC-mesh	1236	0.578	312
DC-direct	1236	0.578	312
Converter	0	0	0
AC overhead line	1187	0.394	0

Table A.12: Cost parameters per endpoint per branch for new lines.

Branch type	C_p^L **[kEUR/km]**	C^L **[kEUR]**	C_p^S **[kEUR/MW]**	C^S **[kEUR]**
AC	0	1562	0	5437
DC-mesh	1562	0	5437	
DC-direct	93.2	58209	107.8	453123
Converter	46.6	28323	53.9	20843
AC overhead line	0	1562		

Table A.13: Cost parameters for new nodes.

Node type	N^L **[kEUR]**	N^S **[kEUR]**
AC	1	50000
DC	1	406000
Island	1	1000000

Appendix B

Detailed Results

Table B.1: Detailed results from the CO_2-price sensitivity analysis. OWF annual capture prices at all CO_2-price levels for each case study configuration.

CO_2-price [EUR/tCO2]	**OWF annual capture price [EUR/MWh]**							
	Wind Radial				Wind hub	Wind hub expanded	Hydrogen: fixed load	Hydrogen: price dependent load
	DE	DK	NL	Combined	NSWPH	NSWPH	NSWPH	NSWPH
50	40.0	33.6	37.3	38.1	33.0	25.1	25.9	26.1
80	46.1	37.8	42.9	43.7	37.6	28.3	29.4	29.7
120	54.2	43.3	50.3	51.2	43.9	32.5	34.1	34.5
160	62.2	48.8	57.7	58.7	50.1	36.7	38.7	39.3
200	70.3	54.4	65.0	66.1	56.4	40.8	43.3	44.1

Table B.2: Detailed results from the CO_2-price sensitivity analysis. PEM electrolyser annual capture prices at all CO_2-price levels for each case study configuration.

CO2-price [EUR/tCO2]	**Pem electrolyser annual capture price [EUR/MWh]**	
	Hydrogen: fixed load NSWPH	Hydrogen: price dependent load NSWPH
50	33.8	13.8
80	38.8	14.9
120	45.5	16.2
160	52.2	17.5
200	58.9	18.8

Table B.3: Detailed results from the natural gas price sensitivity analysis. OWF annual capture prices at all natural gas price levels for each case study configuration.

Natural gas price [EUR/MWh]	OWF annual capture price [EUR/MWh]							
	Wind Radial				Wind hub	Wind hub expanded	Hydrogen: fixed load	Hydrogen: price dependent load
	DE	DK	NL	Combined	NSWPH	NSWPH	NSWPH	NSWPH
15.0	36.1	30.9	33.6	34.5	29.9	23.1	23.6	23.7
20.0	40.4	33.8	37.7	38.5	33.3	25.3	26.1	26.4
26.3	46.1	37.8	42.9	43.7	37.6	28.3	29.4	29.7
33.0	52.2	42.0	48.4	49.4	42.3	31.4	32.9	33.3
40.0	58.3	46.2	54.1	55.1	47.1	34.6	36.4	36.9

Table B.4: Detailed results from the natural gas price sensitivity analysis. PEM electrolyser annual capture prices at all natural gas price levels for each case study configuration.

Natural gas price [EUR/MWh]	Pem electrolyser annual capture price [EUR/MWh]	
	Hydrogen: fixed load	Hydrogen: price dependent load
	NSWPH	NSWPH
15.0	30.5	13.2
20.0	34.1	13.9
26.3	38.8	14.9
33.0	43.8	15.9
40.0	48.9	16.9

Table B.5: Detailed results from the demand sensitivity analysis. OWF annual capture prices at all load levels for each case study configuration.

Relative load change [%]	OWF annual capture price [EUR/MWh]							
	Wind Radial				Wind hub	Wind hub expanded	Hydrogen: fixed load	Hydrogen: price dependent load
	DE	DK	NL	Combined	NSWPH	NSWPH	NSWPH	NSWPH
-10	40.6	33.0	36.1	37.9	33.0	19.1	23.7	17.1
-5	43.2	35.5	39.6	40.8	35.2	25.4	26.3	23.5
0	46.1	37.8	42.9	43.7	37.6	28.3	29.4	29.7
5	49.5	41.9	47.1	47.5	41.1	31.3	32.9	33.4
10	66.9	67.2	64.1	66.0	60.6	52.0	53.2	52.8

Table B.6: Detailed results from the demand sensitivity analysis. PEM electrolyser annual capture prices at all load levels for each case study configuration.

Relative load change [%]	Pem electrolyser annual capture price [EUR/MWh]	
	Hydrogen: fixed load	Hydrogen: price dependent load
	NSWPH	NSWPH
-10	31.5	6.2
-5	34.9	8.6
0	38.8	14.9
5	45.5	20.8
10	66.6	46.1

Table B.7: Detailed results from the demand sensitivity analysis. OWF annual curtailed energy at all load levels for each case study configuration.

Relative load change [%]	**OWF annual curtailed energy [GWh]**							
	Wind Radial				Wind hub	Wind hub expanded	Hydrogen: fixed load	Hydrogen: price dependent load
	DE	DK	NL	Combined	NSWPH	NSWPH	NSWPH	NSWPH
-10	12654	4772	8246	25672	25741	13819	7602	4361
-5	11272	4429	7349	23049	22960	11524	6074	3211
0	10018	4058	6744	20821	20707	9485	4671	2298
5	8796	3659	6153	18608	18542	7789	3639	1660
10	7757	3246	5234	16237	16213	6186	2712	1260

Table B.8: Summary of key results from the case study. All presented values are given in annual terms.

		Wind radial				Wind hub	Wind hub expanded	Hydrogen: fixed	Hydrogen: price dependent
		DE	DK	NL	Total	NSWPH	NSWPH	NSWPH	NSWPH
Volumes	**Available OWF generation in the respective bidding zones, accounting for the losses on the transmission cables**	28.34	9.43	18.91	**56.68 TWh**	**59.15 TWh**	**59.15 TWh**	**59.15 TWh**	**59.15 TWh**
Volumes	**OWF generation output at the respective bidding zones**	18.32	5.37	12.17	**35.86 TWh**	**38.44 TWh**	**49.66 TWh**	**54.47 TWh**	**56.85 TWh**
Volumes	**OWF curtailed energy in the respective bidding zones**	10.02	4.06	6.74	**20.82 TWh**	**20.71 TWh**	**9.48 TWh**	**4.67 TWh**	**2.30 TWh**
Volumes	**Average capacity factor of OWF capacities in %**				**35.6%**	**36.6%**	**47.2%**	**51.8%**	**54.1%**
Revenues	**OWF capture price in EUR/MWh (real, 2020)**	€37.8/MWh	€46.1/MWh	€42.9/MWh		**€37.6/MWh**	**€28.3/MWh**	**€29.4/MWh**	**€29.7/MWh**
Revenues	**Overall capture revenue of OWF in million Euros (real, 2020)**				**€1524m**	**€1447m**	**€1404m**	**€1601m**	**€1689m**
Costs	**PEM electrolyser capture price in EUR/MWh (real, 2020)**							**€38.8/MWh**	**€14.9/MWh**
Costs	**LCOH in EUR/kg H2 (real, 2020)**							**€2.2/kg H2**	**€1.2/kg H2**

Sander Holt Günther

NTNU
Norwegian University of
Science and Technology