Mitigating Revenue Losses of a Wind Farm in an Offshore Bidding Zone

A Scenario-Based Modelling Approach

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Master of Science
Engineering & Policy Analysis

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Ministry of Economic Affairs and Climate Policy

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by

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Master's Thesis

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Dear reader,

Before you lies my master's thesis, titled "Mitigating Revenue Losses of a Wind Farm in an Offshore Bidding Zone". This document represents not only the final step in completing my master's degree but also the conclusion of my student life in Delft. Studying at Delft University of Technology, while having a wonderful time living with the best people, spending time with friends, and having the opportunity to travel, presents a period in my life for which I am more than thankful.

This thesis addresses the complex topic of electricity markets, which is increasingly relevant as wind energy becomes a significant part of our future energy supply. However, I don't expect you to read everything. To my family and friends, I suggest reading the introduction, skipping the main chapters, and ending with the first few paragraphs of my conclusion. Other students conducting a similar EPA master's thesis might gain insights from the methodology section or the results. But of course, to all, feel free to read the sections that interest you the most. I hope you enjoy it as much as I enjoyed learning about the complexities of electricity markets and their wind farms.

Before we continue, I would like to thank Laurens de Vries for guiding me through my research process by helping me find the right focus and encouraging me to look further than just the model results. I would also like to thank Enno Schröder for his feedback on defining the right scope for my research and for helping me clarify the most important parts in the right way. Last but definitely not least, I had the great opportunity to write my thesis at the Ministry of Economic Affairs and Climate Policy. Therefore, I would like to thank Martijn Koolen, along with Wieger Wiersema and Pieter Kolstee, and the rest of the team who included me and immersed me in the policy aspects of electricity markets, answered all my questions, and introduced me to other experts in the field. Without this internship, my thesis would not have been the same.

Lastly, I want to thank my family and friends for their interest and support during my studies. Can't wait to drink a beer in the sun with you all!

Vincent Engelhard
Delft, April 2024

Executive Summary

The Netherlands is setting sail again, this time capturing wind with turbine blades and increasing its offshore wind energy from 4.5 Gigawatts to 21 GW by 2030. Yet, this is not without challenges. The higher share of wind brings more volatility into the grid, making it necessary to establish a more integrated electricity system across European countries. A hybrid interconnection combines the connection to two different electricity markets while also connecting an offshore wind farm. Such a hybrid interconnection is generally seen as a promising way to efficiently integrate offshore wind in the EU, allowing electricity prices to decrease. However, current EU legislation is counter-effective. The "70%" rule limits the possibilities of wind farms to transport electricity to their 'home market', their own electricity market.

Offshore bidding zones are proposed as a solution to integrate hybrid projects, while electricity can still be efficiently dispatched into the European energy system. This market setup creates its own offshore electricity market, which lowers energy prices by maximising the dispatch of wind energy. However, current literature indicates a negative impact of offshore bidding zones on the revenues of offshore wind farms. Due to limited transmission capacity and the price differences between markets, congestion rents occur, which reflects revenue losses. Furthermore, if there is no demand within the bidding zone itself, the revenues depend on the characteristics of these markets.

However, the magnitude of revenue losses and the impact of mitigation measures remain vague. This study addresses these knowledge gaps through a scenario-based modelling approach. A model is created to simulate a hypothetical offshore wind farm located in the North Sea, between Norway and the Netherlands, operating with historical electricity prices and wind data. The simulation compares the offshore bidding zone approach with the traditional home market approach to analyse revenues and understand the magnitude of revenue losses for this specific case. Following this, four scenarios with different market setups are designed to analyse the impact of different mitigation measures on revenues, congestion rents, and the amount of compensation. The first and second scenarios introduce market setups with financial support through one-sided and two-sided Contracts-for-Difference, respectively. The third scenario introduces a market-driven rollout in which the wind farm purchases Financial Transmission Rights, and the fourth combines the second and third scenarios. The analysis of these scenarios answers the research question:

How can revenue losses from network congestion of wind farms be mitigated in an offshore bidding zone in the North Sea?

The analysis of the case-specific results indicates revenue losses compared to the traditional home market, which ranged from 8.63% in 2019 to 28.94% in 2021, with an extreme difference of 69.97% in 2020. These losses result from congestion, mostly on the Dutch interconnection. Furthermore, an increase in the volatility and variation of revenues is observed, with the difference between the minimum and maximum average weekly revenues being 52.08 EUR/MWh in the home market versus 59.10 EUR/MWh in the offshore bidding zone during the stable years of 2018, 2019, and 2020.

However, the impact of the offshore bidding zone differs significantly based on the second market to which the wind farm is connected. From the perspective of the government, a trade-off must be made between, on one hand, providing benefits for society by lowering energy prices and increasing the security of supply, and, on the other hand, creating an attractive environment for wind farms and potentially other market parties with governmental support.

Financial support measures succeed in increasing average revenues and stabilising revenue streams. To compensate for the case-specific revenue losses in 2018, 2019, and 2020, a one-sided Contracts-for-Difference should be contracted with a minimum price level of 39 EUR/MWh, while a two-sided Contracts-for-Difference should be contracted with a fixed price of 42 EUR/MWh. However, these

measures do not directly tackle congestion rents themselves.

To ensure a fast rollout of wind farms, financial support can provide the necessary security to receive revenues up to the level of those in a home market. In fact, when the support mechanism is designed with a reference price equal to the price differentials, it might indirectly subsidise grid expansion, which benefits society. This measure could allow the connection to a lower-priced market, which might result in the highest societal benefits, in terms of lower electricity prices. However, the greater the difference in electricity prices between the two markets, the more revenue losses wind farms would face, resulting in higher payments through financial support.

If the goal of the future electricity market is to maximise investment security, this approach might offer a straightforward solution. However, these measures could distort the market, making it less likely to result in an optimally functioning system. A market-driven electricity system is more likely to operate efficiently. Still, there is a need for long-term products that hedge against price differentials in an offshore bidding zone that is market-driven.

While the financial transmission rights potentially result in the highest revenues for the offshore wind farm, they do not provide any predictability of future revenues since this completely depends on the characteristics of the other electricity markets. However, since this measure allows wind farms to hedge the offshore bidding zone price difference between two markets, it could enable them to secure their investments through long-term contracts with participants from the other market. These contracts provide predictability of future revenues, which financial transmission rights themselves do not cover. However, these rights are currently only auctioned for up to one year. A first step to enable a market-driven design would be to create the option to obtain longer-term Financial Transmission Rights.

The most direct way to prevent revenue losses in an offshore bidding zone would be to connect to a market with similar price characteristics. However, the societal benefits of such an interconnection are also lower. This market configuration allows the wind farm to operate more easily within a market-based situation. Financial transmission rights could even potentially lead to higher revenues compared to the home market approach. This makes the environment more attractive for market parties, resulting in an easier rollout of wind farms.

An interesting option to simplify congestion management would be to include the financial transmission rights in the tender process for wind farms. This would remove the step where they pay and then reclaim congestion rents, making the process more straightforward. It would also reduce the complexity of the subsidy process and increase its transparency. Moreover, the tender would become more attractive, likely resulting in lower strike prices if financial support is provided.

To conclude, revenue losses from network congestion can be mitigated through both financial support and market-based measures. However, their efficiency and effectiveness depend on the market to which the Netherlands is connected. Clear long-term objectives for the future electricity market are important to establish a more integrated network and a robust offshore bidding zone market that fits all stakeholders involved.

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List of Abbreviations

BZ	Bidding Zone
CAPEX	Capital Expenditure
CfD	Contract for Difference
EEZ	Exclusive Economic Zone
EPA	Engineering and Policy Analysis
EU	European Union
FTR	Financial Transmission Right
HVDC	High-Voltage Direct Current
LCOE	Levelised Cost of Energy
OBZ	Offshore Bidding Zone
OPEX	Operational Expenditure
OWF	Offshore Wind Farm
PPA	Power Purchase Agreement
SDE++	Stimulering Duurzame Energieproductie Plus
TAG	Transmission Access Guarantee
TSO	Transmission System Operator

1 Introduction

While the sails are set, the goal on the horizon is to increase offshore wind energy from 4.5 Gigawatts (GW) to 21 GW by 2030 (Ministerie van Economische Zaken en Klimaat, 2023b). In doing so, the Netherlands is contributing to the overarching goal of creating the first climate-neutral continent by 2050 (European Commission, n.d.). Yet, this dream is not without challenges. A higher share of wind energy in the energy mix introduces more volatility into the grid, as the amount of electricity generated from wind turbines fluctuates based on wind speed and conditions. To ensure that lights stay on in evenings when the wind is not blowing, it is necessary to establish a more integrated electricity system across European countries (European Commission, 2017). This system enables a breezy exchange of electricity during times when local power generation is not enough to provide sustainable and affordable energy.

However, the cables that connect countries and wind farms are expensive, have a negative ecological impact, and require space to land on the already scarce shore. Therefore, the first cross-border connection from the Netherlands to the United Kingdom (UK), which also integrates a connection with an offshore wind farm (OWF), has been announced (Ministerie van Economische Zaken en Klimaat, 2023b). This approach, referred to as a 'hybrid interconnection' (Figure 1.1), is generally seen as a promising method to efficiently integrate offshore wind in the EU. It allows for lower electricity prices while minimising costs and ecological impacts (NSWPH, 2021). This system contributes to both the Dutch and European goals in that wind farms can be built and connected to shore at the same time as electricity markets are being connected to each other.

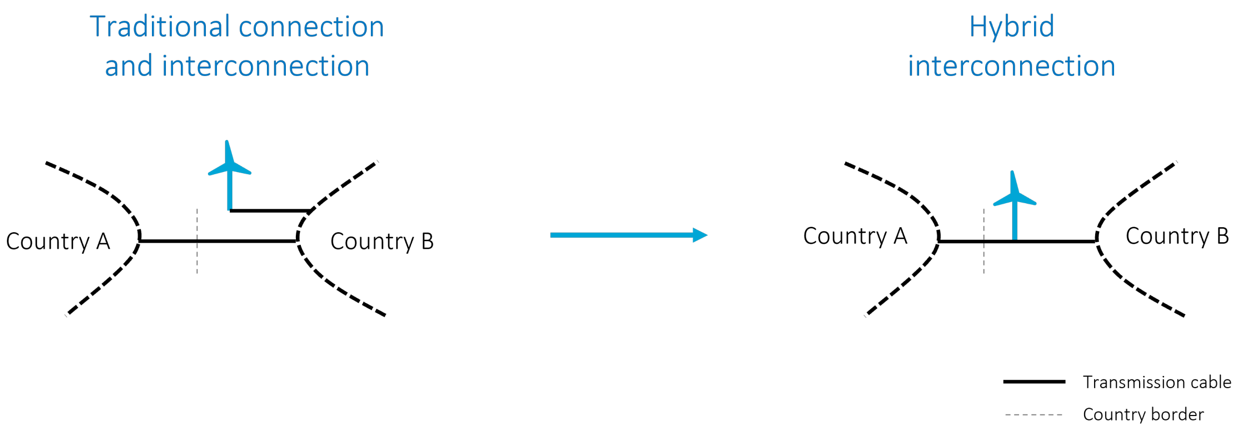

Figure 1.1: Representation of a Hybrid Interconnection

While these hybrid interconnections are promising in many aspects, the current EU legislation that reserves these cables for power exchange between different countries or 'electricity zones' does not support this new setup (European Commission, 2020, European Union, 2019). This "70%"-rule limits the ability of OWFs to transport electricity to their 'home market' (Country B in the case of the OWF in the figure), because this is not a power exchange between countries, but from the OWF to shore. As a result, cross-border electricity trading from one country to another is prioritised over the transfer of electricity from the wind farm to its home market. This could result in a wind farm that can only sell a small portion of its produced electricity.

In other words, integrating hybrid offshore projects while ensuring that OWFs can still sell their electricity to their home market presents a challenge. To address this, a new market setup called the Offshore Bidding Zone (OBZ) has been introduced (Figure 1.2). This setup presents a geographical area where electricity is traded within its own zone (NSWPH, 2022). When there is no demand within the OBZ itself, the OWF transports its electricity to another zone (Country A or B). When electricity is traded from one zone to another, it is considered as cross-border trading. Therefore, the OWF is no longer limited in the use of the electricity cable connected to its home market.

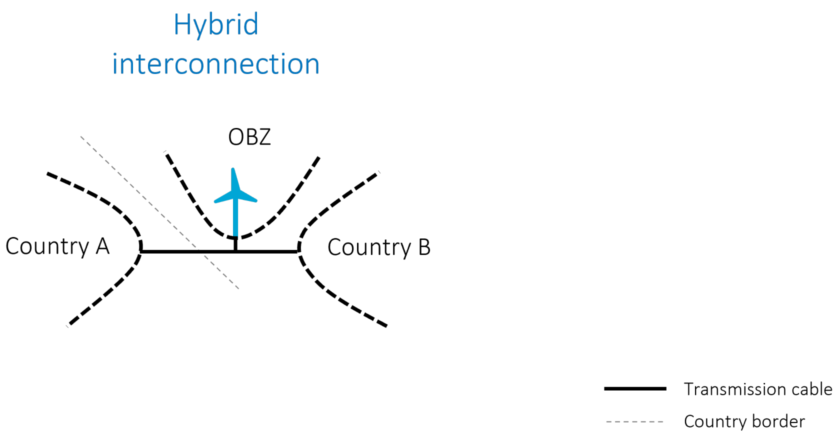

Figure 1.2: Representation of an Offshore Bidding Zone

However, the implementation of an OBZ can lead to revenue losses for the OWF. If the demand for electricity in one country exceeds the capacity of the electricity cable, congestion occurs. To ensure that the OWF can sell its electricity, it will try to offer it at a lower price than that of the neighbouring country. As a result, the price in the OBZ becomes equal to that of this exporting country, which is the lower-priced of both. In contrast, in the traditional approach, the OWF receives the same electricity price as its home country. Therefore, the implementation of an OBZ results in revenue losses for the OWF compared to the traditional home market approach (European Commission, 2022, THEMA, 2022, PROMOTioN, 2020b). These revenue losses create investment uncertainty for OWFs. It is important to address this issue to stimulate the deployment of OWFs in combination with the establishment of hybrid projects.

1.1 Problem Situation

The problem situation is presented as a challenge. On the one hand, implementing an OBZ is an approach that enables an efficient integration of hybrid projects into the European energy system. Hybrid projects minimise the need for transmission cables in the North Sea but since the OWF trades on an interconnection cable, the transport abilities are limited. The introduction of an OBZ makes the transport of electricity to the home market cross-border trading, allowing the OWF to use the full potential of the cable again. This approach maximises the dispatch of wind energy, which lowers energy prices and benefits consumers. Additionally, a better integrated grid is established.

On the other hand, an OBZ is less attractive for OWFs to operate in compared to the traditional home market setup due to revenue losses and higher costs. A hybrid project is more promising for OWFs further from shore since these would otherwise need to be connected with long individual cables. Moreover, these offshore wind farms are expected to experience higher costs as they are built further from shore. This factor, combined with the expected revenue losses, makes it harder to get a return on investment. That is why it becomes less attractive for OWF developers to develop a wind farm in the North Sea.

The challenge is in integrating hybrid projects with the implementation of OBZs, while mitigating the impact on wind farms to stimulate their deployment. This report addresses these challenges by exploring different mitigation strategies within the OBZ market design and their impact on the revenue losses of OWFs.

1.2 Knowledge Gap & Research Question

After reviewing the existing literature on OWFs, OBZs, and mitigation measures implemented, it becomes clear that a better understanding of the revenue losses that occur is required. These revenue losses impact the attractiveness of establishing wind farms. Only after these insights are obtained, the impact of different mitigation measures on the revenues of OWFs can be explored.

Previous research describes a negative impact of OBZs on the revenues of OWFs. Due to the limited transmission capacity available and the price differences between the two markets with which the wind farm is connected, congestion rents occur. These congestion rents reflect the revenue losses for the OWF compared to the home market. Furthermore, if there is no demand inside the OBZ itself, the OWF depends on the characteristics of the neighbouring electricity markets to sell its electricity. Both issues are addressed in the literature, which explores different mitigation measures to support OWFs in this situation. Some measures aim to reduce the volatility of revenues, others aim to increase the average revenues, and still others focus on the risk of not being able to transport electricity.

The problem with the previous literature is that OBZs are mostly studied from a general level. While these studies conclude with 'expected lower revenues,' the specific impact of OBZs on the revenues of OWFs remains vague. The same applies to possible mitigation measures. To explore their impact, a clear understanding of the magnitude of revenue losses is required first. A project-specific study must be carried out that quantifies the impact of the implementation of an OBZ and subsequent mitigation measures.

The following two knowledge gaps are observed:

- **The magnitude of revenue losses:** Because revenue losses are project-dependent, it is difficult to examine the precise impact of an OBZ in the North Seas. A deeper understanding of the magnitude of these revenue losses is important before the need for mitigation measures can be addressed, as described in the literature.
- **The impact of mitigation measures:** Since the magnitude of revenue losses remains unclear, it is difficult to examine the effectiveness and magnitude of the impact of different mitigation measures. Existing literature explores potential mitigation strategies, but often misses a detailed analysis and comparison between strategies.

These knowledge gaps are confirmed by the European Commission (2022) and further academic research (Nieuwenhout, 2022, Dedecca and Hakvoort, 2016). Filling these gaps will help in understanding the need, and the mitigation itself, of the revenue losses for OWFs compared to the home market, resulting in the establishment of offshore wind in the North Sea. To do so, the following research question is designed:

How can revenue losses from network congestion of wind farms be mitigated in an offshore bidding zone in the North Sea?

This question is answered by simulating a hypothetical OWF in the North Sea that operates under historical electricity prices and wind data. By simulating both an OBZ and the traditional home market, revenues can be compared to understand the revenue losses. Subsequently, implementing mitigation measures allows an analysis of their impact on the revenues.

1.3 Relation to the EPA program

This research is in line with the Engineering and Policy Analysis (EPA) program because it tackles the issue of integrating renewable energy, specifically offshore wind, into the energy grid. The research touches upon all criteria (TU Delft, 2022) that characterise an EPA research:

The research is *considered analytical in character* because a scenario-based modelling approach is used to first understand and quantify the impact of OBZs on the revenues of an OWF, and second, to explore mitigation strategies. The research is about understanding market designs for different actors, including OWF operators, policymakers and the Transmission System Operator (TSO).

The research has both a *systems and a multi-actor perspective* because it studies the complex interactions between generators and consumers in a complex electricity market. The exploration of mitigation measures in an OBZ, which forms a solution for integrating offshore wind energy into the energy mix, requires a systems thinking approach. Different parts of the energy system come together as well as multiple stakeholders with each their own needs and goals.

To explore the quantitative impact of the OBZ and the subsequent mitigation measures, *modelling and simulation techniques* are used. A model of a hypothetical OWF is created that operates in an OBZ between Norway and the Netherlands. Simulations are run to obtain the hourly revenues depending on historical data on electricity prices and weather data.

The aim of this research is to *contribute to decision-making* on how to implement OBZs while mitigating revenue losses for OWFs.

1.4 Outline Report

Section 2 of this report consists of the literature review. First, background information is provided, followed by the results of the review. Section 3 presents the Scenario-Based Modelling approach used in this study, together with the sub-questions that arise from the scenarios that are studied. Section 4 gives an overview of how the simplified model is developed, as well as an elaboration on the design of mitigation measures. Section 5 describes and analyses the input data for the model, followed by an analysis of the results in Section 6. Section 7 discusses the findings of this study, followed by the conclusion in Section 8 in which the main-research question is answered.

2 Literature Review

This section explores the state-of-the-art literature in the context of OWFs and the OBZ. First, it provides background literature on the Dutch electricity system. Second, it compares the OBZ market setup to the home market setup. Next, literature on the price formation in the home market approach is discussed, followed by a section on how this is expected to work in the OBZ. Afterwards, a section is devoted to the different risks that a wind farm faces with the implementation of an OBZ, followed by a section on how long-term contracts are required to secure financing for the development of an OWF. This is important to include in the literature review because these might interact with mitigation measures, which are discussed in the last section.

2.1 Background

The following part of the literature review gives an understanding of the current situation regarding the Dutch electricity system, the need for change and why OBZs are a promising solution.

To reach the goal of 21 GW of installed wind power in the North Sea by 2030, different ways are needed to connect these OWFs. The current 4.5 GW is connected via a 'radial connection'. This is a single transmission cable that goes from the OWF to the shore. For each wind farm that is built in the North Sea, a cable needs to connect the wind farm to the shore. These HVDC (high-voltage direct current) cables are cost expensive to build and take space to land on shore. Because of the scarcity of available space to land these cables on shore, this becomes a problem in the future when more wind farms and cables are built.

The wind farms that are connected via these radial connections bid in their home market. They dispatch electricity like any other generators do and get the same price. Due to the large amount of supply and demand in the market, there are most often consumers and producers. This leads to liquidity in the market. Therefore, OWFs can better hedge their risks. These risks refer to both price and volume risks, i.e. revenue that is impacted due to unexpected price differences, and situations where electricity cannot be dispatched due to insufficient capacity available to transport electricity. The presence of these risks decrease investment security.

With the increase of volatile renewable generators (and a decrease in non-renewable flexible power generators), flexibility has become even more important (Neetzow, 2021, Heggarty et al., 2020, Babatunde et al., 2020, Akrami et al., 2019). Flexibility is defined by the Energy Agency (IEA) as "the ability [of a power system] to respond in a timely manner to variations in electricity supply and demand" (IEA, 2019). With the increase of wind and solar, these variations happen faster, and so flexibility becomes more of a daily uncertainty. To ensure this public goal for the energy supply industry (Nations, 2015), there is plenty of attention to new ways to provide this necessary security of supply.

Since the contribution of energy storage is still low, it is important to expand the grid with connections to other countries. When supply is low in one country due to a lack of wind and sun, electricity can be transported from another country where supply is high (or demand is low). This (future) EU-integrated electricity market is better able to cover variations in countries.

Hybrid interconnectors are a promising way of connecting future OWFs, while cost and the use of space are minimised, and flexibility is improved. A hybrid interconnection is an interconnection in which the transmission capacity cannot only be used to transport electricity to other countries, but also to transport the offshore produced electricity to land (European Commission, 2020, European Union, 2019). This combination of transmission capacity reduces the number of cables needed, both minimising costs and used space (both at sea and at shore). As a consequence, it also minimises the ecological impact (THEMA, 2022).

But, while many describe hybrid interconnections as promising to establish more wind energy generation in the North Sea, others warn about current EU legislation on cross-border transmission capacity (Nieuwenhout, 2022). This is the “70%”-rule, which ensures that interconnection capacity is not used to solve internal congestion because that could lead to an economically inefficient dispatch of electricity. More specifically, this EU law ensures that 70% of the interconnection capacity must be reserved for cross-border electricity trading. Consequently, this might limit the possibilities of the OWF to transport electricity to its ‘home market’ to just 30% of the interconnection capacity if export electricity is available. This is because the internal cable is an extension of the interconnection cable, making it automatically also an interconnection cable. The existence of this regulatory barrier is agreed on by more research (Hardy et al., 2023).

In conclusion, radial connections present challenges in terms of cost and land usage to achieve the goal of 21 GW of installed wind power by 2030. At the same time, flexibility has become an important factor in the future electricity system due to the increasing volatility resulting from the growth of renewable energy sources. Since energy storage remains limited and flexible power generators like natural gas plants decrease, grid connections to other countries need to be established to balance supply and demand fluctuations. Hybrid interconnections seem like a promising approach to connect different electricity markets while minimising costs and land usage. However, current EU legislation does not favour the implementation of hybrid interconnections

2.2 *Offshore Bidding Zone vs Home Market*

OBZ is an offshore geographical area where electricity is traded without capacity restrictions (NSWPH, 2022). This leads to a uniform market electricity price across the whole zone. Bidding zones (BZs) in general are created in a way that they stimulate the efficient functioning of electricity markets (Nieuwenhout, 2022). The Dutch electricity market is currently one bidding zone that is equal to its Exclusive Economic Zone (EEZ). An OBZ represents such an area offshore, for example in the North Sea. Figure 2.1 shows an illustration of an OBZ between the Netherlands and Norway. The interconnection connects both countries as well as the OWF. An OBZ differs from a BZ since there is most likely less demand than supply, leading to a big export zone. However, this may change in future, for example with the emergence of electrolysers (Ministerie van Economische Zaken en Klimaat, 2023c). This would increase demand inside the OBZ, lowering the need to transport electricity to neighbouring zones.

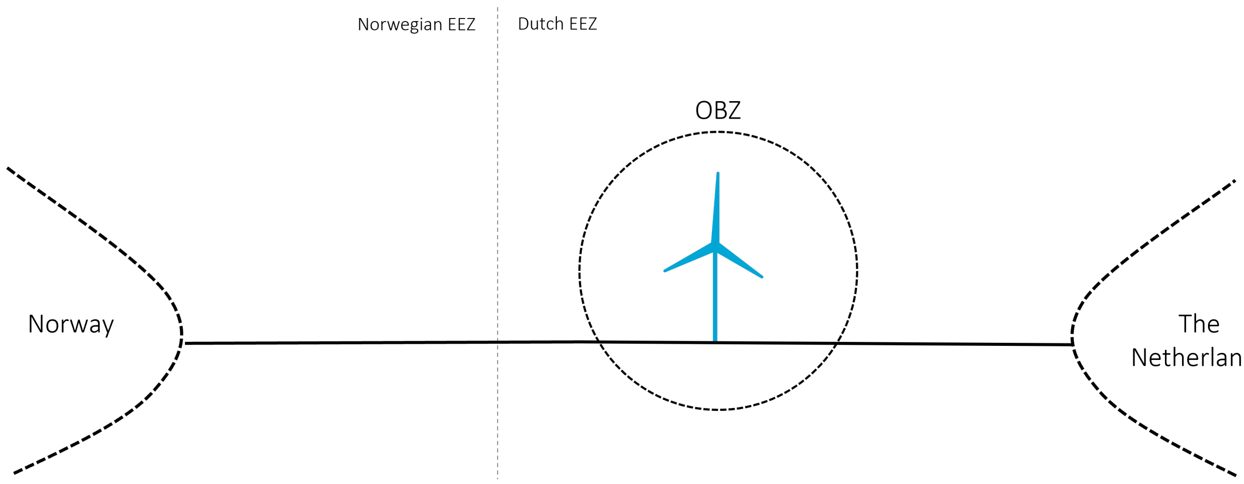

Figure 2.1: Representation of the Offshore Bidding Zone

This new OBZ market setup prevents OWFs from being curtailed due to the 70% rule, as explained in Section 2.1. When an OWF is located in an OBZ, the electricity that is traded to shore is cross-zonal trading, which means that the OWF is not limited anymore by the 70% rule. Therefore, the OWF can use the full capacity of the interconnector instead of only 30%. Through market coupling, the total volume of energy that is generated can be exported from the OBZ to the BZs on shore. Dispatch modelling by European Commission (2020) confirms that this new market setup results in higher overall efficiency compared to bidding into the current home market. This is mostly because the electricity price in an OBZ reflects the actual physical constraints of the network, reducing the need for support by TSOs to match market outcomes with the physical network. This results in lower costs for consumers, which increases the overall efficiency.

The European Commission, ENTSO-E, CEER, ACER, TenneT, and more organisations, together with academic research all adopted the idea that offshore bidding zones are a more efficient way to integrate hybrid projects in the European energy system (Hardy et al., 2023, PROMOTioN, 2020b, Kitzing and Garzón González, 2020). The use of an offshore bidding zone ensures a more effective dispatch of electricity, compared to where OWFs bid in their home market. The introduction of more small offshore bidding zones leads to even bigger social welfare and lower average energy prices, but Hardy et al. (2023) warns of the increasing complexity and the subsequent disadvantages.

However, there are concerns regarding the effectiveness of securing investments in offshore generation that are part of hybrid projects (European Commission, 2020). This is because such a new market concept brings uncertainties for OWF developers and is often subject to new political-technical issues (Nieuwenhout, 2022). Most importantly, it is expected that OWFs have less revenue than they would have when they bid in their home market. The article from THEMA (2022) concludes that the total generator revenues can decrease by 1-11%, depending on the specific project. Other studies state that the impact heavily depends on the home country of the generator. For example, a case study in Norway by Hodt and Hodt (2022) concludes that connection to different markets is more attractive to generator developers from a lower-priced country. The study of Klokgieters (2021) supports this statement by showing that the OBZ has a negative effect on developers from a higher-priced country. Section 2.3.1 elaborates on the decrease in revenues.

To conclude, an OBZ is considered a promising solution to integrate hybrid projects offshore, while electricity can be effectively dispatched into the market. However, the revenues of OWFs are expected to decrease, compared to the current home market. This will probably create investment uncertainty for OWFs. It is important to address this issue to improve investment incentives to attract wind farm developers.

2.3 Price Formation of Offshore Wind Farms in an Offshore Bidding Zone

The previous section described how the revenues of OWFs are expected to decrease in an OBZ market setup compared to the current home market setup. This section elaborates on how these revenues are generated and how the electricity price is formed for the OWFs.

2.3.1 Price Formation

This section explores how prices are formed in the Dutch electricity market.

Producers and consumers trade electricity in the wholesale market. In the Netherlands, most of the electricity is sold directly to the customers in the long-term market. This market gives certainty around the price and volume that will be traded in future. These customers are often large consumers or play as retailers and resell the electricity to smaller consumers. Contracts in this market often have a duration of one year to one day (De Vries et al., 2019). The second market is the spot market, where, for every hour, electricity is traded for the following day (day-ahead). This day-ahead wholesale price is the 'electricity price' and is an important reference value for the electricity system. Depending on the (flexible) demand and the (flexible) supply, the price changes continue. With the increase of intermittent generators, this price becomes more volatile. However, forecasting long-term electricity prices is difficult (Lund et al., 2018). This makes it hard to invest in new generators since it is not sure whether investments are possible to pay back in future. Therefore, generator operators often bid into both long-term and short-term markets. Lastly, producers and consumers can trade in the intra-day market. With different balance mechanisms, the production and consumption are set equal near real-time to bids that are made earlier.

The general 'electricity price' is the price that is established in the spot market. The Dutch spot market is operated by EPEX SPOT, Nord Pool and ETPA. Producers and buyers submit their orders and this operator determines the electricity price and volume that can be traded. To do so, every electricity producer 'bids' into this market by telling what volume can be produced against what price. The price is equal to their variable costs. The spot market operator ranks all bids from low to high (the merit order) and selects all the lowest bids needed to match demand. The last generator is the marginal generator and all generators receive the same electricity price as this marginal generator. Figure 2.2 shows the merit order, in which the marginal generator is the cheapest gas generator. The difference between the spot price and the bids producers bid is revenue surplus for the generator. Since the Netherlands is still one bidding zone, every generator in the Netherlands receives the same price. This price is calculated per hour for the next day.

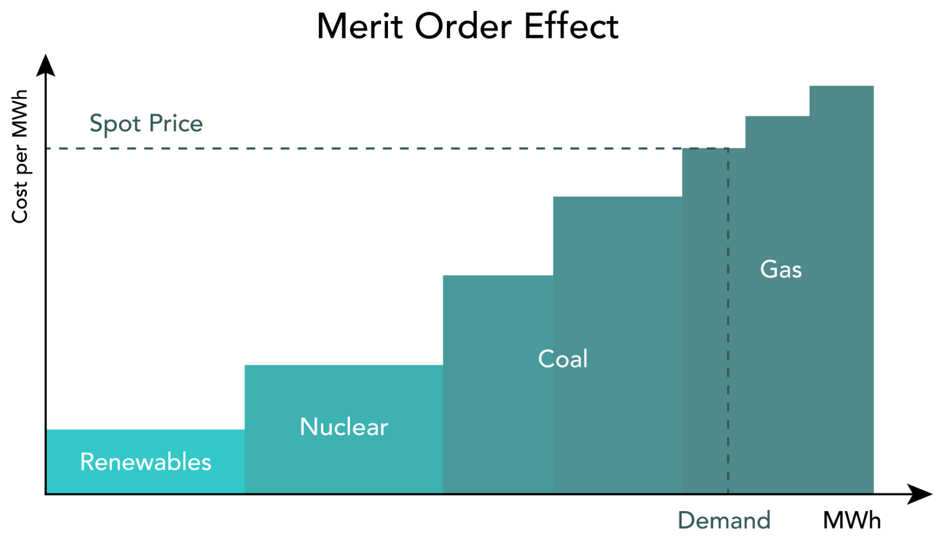

Figure 2.2: Representation of the Merit Order (Bowden, 2023)

The integration of different electricity markets into the European electricity market also affects the wholesale price. The amount of electricity that can be traded cross-zonal and the resulting market clearing price is computed by the algorithm EUPHEMIA (Nordpoolgroup, 2020). It considers the bids that are submitted in the spot market by electricity generators and the offers that are made by large industrial companies and suppliers. Like the spot market, the goal of this algorithm is to maximise socio-economic welfare by finding an optimal allocation of electricity through different electricity markets and suppliers.

Since the OBZ is quite a new concept, it is still unsure how this market will develop and how prices will be formed. However, we do know that there will be no demand (yet). This means that the OWF in the OBZ will sell its electricity cross-border. Therefore, the availability of interconnection capacity determines the amount of electricity an OWF can sell. If there is no demand inside the OBZ, the spot market price will result in a price close to zero since the variable costs of OWFs are almost none. The electricity price that the OWF receives is set by the neighbouring zones. Since EUPHEMIA tries to maximise socio-welfare, i.e. minimising electricity prices, the dispatch of wind energy is maximised since its marginal costs are often lower than the marginal costs of a connected bidding zone (PROMOTioN, 2020a). Therefore, the electricity produced in the OBZ will be favoured to transport over the interconnection over another neighbouring country. This reduces volume risks for the OWF. However, in the case of congestion elsewhere in the grid (onshore), these OWFs may need to be curtailed. Furthermore, it is important to note that this capacity may not be available in case of failure or maintenance on the transmission cable (NSWPH, 2023). Both could result in a loss of revenue for the OWFs. The next subsection will elaborate on how the electricity price is established in OBZs.

2.3.2 Price Formation in an OBZ

As described in the previous subsection, the electricity price in an OBZ is set by the neighbouring countries when there is no demand inside the zone itself. This subsection discusses how prices are established when trading electricity cross-border and explores how these mechanisms work in an OBZ.

The electricity price in an OBZ is set due to congestion on the interconnection. Network congestion occurs when there is more demand for trading electricity over a cable than there is capacity available. When the price of one of the electricity markets connected to the hybrid interconnection is lower than the other, there will be demand for importing electricity from the higher-priced electricity market. The demand will most likely be higher than the interconnection capacity, resulting in cross-border congestion.

The default cross-border congestion managing method in Central Western Europe is market coupling or market splitting (Poplavskaya et al., 2020). In this method, both electricity markets are cleared individually. This results in two markets with each their own electricity price. After market clearing, the market operator buys electricity from the lower-priced electricity market and sells it to the higher-priced market. This results in extra demand in the lower-priced electricity market, which increases the electricity price. On the other side, it also increases electricity production in the higher-priced market, sold by the TSO. This lowers the price in the higher-priced market. As a result, both prices move closer together (De Vries et al., 2019). Nowadays, an enhancement of this method is used: Flow-based market coupling. The algorithm behind this method is different from 'standard' market coupling because it takes into account the physical constraints of the individual electricity grids. Therefore, social welfare is more maximised.

Since the OWF in the OBZ is connected to a cable that connects two bigger electricity markets, there will always be congestion on the cables. However, assumed is that the OWF will most likely be favoured over the other countries to use the cable due to the aim of EUPHEMIA to maximise socio-welfare, as mentioned in the previous section (Section 2.3.1). This assumption is based on the assumption that the marginal costs of OWFs in the day-ahead market are close to zero. However, Giesbertz (2023), who was by the time of writing a representative for the wind park association 'Energie Nederland', describes that this is not specifically true due to costs in the balancing market. For example, when a wind farm sells 100 MW on the day-ahead market, the next day the wind farm has to deliver the actual 100 MW. Since the presence of wind stays uncertain, it could be that the wind farm cannot produce the promised 100 MW. As a consequence, the wind farm has to buy the shortage in electricity in the balancing market, resulting in higher marginal costs.

Continuing on the assumption that the electricity from the OBZ is favoured over electricity from one of the neighbouring electricity markets, the electricity from the OBZ will flow to the highest-priced neighbouring zone through flow-based market coupling. If there is still capacity available on the interconnector, the second-lowest zone (the OBZ is the lowest zone) will transport electricity to the highest-priced zone. When there is no interconnector capacity available anymore, this zone can be seen as the 'marginal zone' and sets the marginal price. The OBZ sells its electricity for this marginal price. This method shows that an OWF should be careful with overplanting (This is when the OWF developer establishes more capacity than the corresponding connection, often done because wind farms rarely operate at full capacity (new offshore wind farms have a capacity factor of 40-50%), resulting in transmission capacity that is not fully used (Hodt and Hodt, 2022).) since the OWF should not exceed the capacity of the interconnection capacity because then the OBZ where this OWF is located could become the 'marginal zone', resulting in an electricity price close to zero.

An important thing to note is that the price formation in an OBZ as described above changes when there is demand in the OBZ (for example with electrolysers). This new demand might become the 'marginal demand'. Furthermore. although assumed that the OWF is always favoured to use the interconnection, other factors might affect the availability of transmission capacity. These are possible grid construction delays, maintenance or failures on the cable, and limited capacity due to operational deratings (The TSO that can reduce capacity to avoid congestion elsewhere in the (onshore) grid) (European Commission, 2022).

Different methods of managing congestion are similar in a way that the seller pays for the interconnection that is used. The price equals the difference in electricity price from both electricity markets around the interconnection. On the one hand, it seems fair that someone pays for usage. On the other hand, the OWF suddenly has to pay for something that physically equals the old situation, in which the OWF is still located inside the economic exclusive zone, but in a different electricity market (the OBZ). From this perspective, the congestion rents could be seen as a lost income. This is why papers often refer to a redistribution of congestion rents, i.e. giving back the income to OWFs inside an OBZ. However, this is a very political debate since another perspective could be that the wind farms have to pay for their cross-border electricity transportation. In that case, congestion rents are not seen as a lost income, but as extra costs of operating in a different market.

To conclude, the electricity price in the OBZ becomes equal to the price in the lowered-priced zone of the two electricity markets. This shows that the electricity price for the OWF in an OBZ is lower compared to the OWF that bids into a single home market. This can be validated with the study from Kenis et al. (2022) that shows that the average day-ahead prices drop in an OBZ compared to a home market. The study also shows the increased congestion rents by the TSOs because of market coupling. This change in income distribution is seen in more studies. However, the quantified economic impact remains difficult to forecast. The combination of reduced revenues and uncertainty about the impact creates investment uncertainty (PROMOTioN, 2020b).

2.4 Risks

As explained in Section 2.3, the OWF faces lower revenues with the implementation of an OBZ due to price differentials between the two connected bidding zones. This difference varies per hour, depending on the price fluctuations in the neighbouring countries. This is one of the price risks that an OWF faces. This section elaborates on the further risks associated with the implementation of an OBZ to better understand its impact on the OWF.

Literature about risks that OWFs might experience in an OBZ is mostly qualitative. The main risks that appear are price, volume, and regulatory risks. These risks are unfavourable for OWFs because they increase uncertainty, which increases the financial costs of offshore development. As is the case with a structurally lower income, this makes it unsure whether OWFs can pay back their investments.

Price and volume risks are systematic risks, also known as market risks. First, price risks relate to the revenue that is impacted due to unexpected price differences with neighbouring BZs (onshore). Second, volume risks relate to situations where electricity cannot be dispatched due to insufficient capacity allocated for the transport of electricity, or because of other factors that limit transmission capacity, such as maintenance or failure. TenneT is responsible for both onshore and offshore transmission capacity. They are required to provide the right onshore transmission capacity to distribute the electricity generated offshore. Assuming they can do so both onshore and offshore, the only remaining volume risks occur when transmission capacity is used to export electricity to another zone.

This happens when the marginal costs of producing electricity are lower in that zone than in the OBZ. Although this is unlikely, as described in Section 2.3, this can occur due to imbalance prices. Additionally, the marginal costs in the neighbouring country might be lower in cases of negative electricity prices. These are all scenarios in which the transmission capacity available might be limited to the OWF. This also results in financial losses, impacting the revenue. Both price and volume risks influence each other. When there is no transmission capacity available, the electricity price will most likely change. Last, regulatory risks refer to changes in policy and regulation that impact prices or volumes, like the change from a home market setup to an OBZ market setup. (NSWPH, 2023)

Risks differ per market where the OWF sells its electricity. The risks have an impact on the financial costs, differ per specific project and depend on many different factors. Most of the studies conclude with the need for further research into the quantitative economic impact of these risks on OWFs.

2.5 Long-term Contracts

Financing of OWFs can be difficult. They have long-expected lifespans and come with significant costs. Therefore, big investments are required. OWF developers either use their own bank balance or approach banks to lend money. Nowadays, the first OWFs are being built without any subsidy support. In other words, their expected revenue is enough to cover their investment costs. It is important to understand how long-term contracts work because they make it possible for an OWF to secure investments in a market-driven rollout.

OWF operators enter into long-term contracts with consumers that guarantee to buy the output. These contracts are so-called Power Purchase Agreements (PPAs). These contracts often range from short-term (1 year) to long-term (15 years).

With a PPA, the OWF has a guaranteed buyer for the produced electricity, making it easier to receive financing for their investments. For the buyer, PPAs reduce price risks because there is a price agreement. However, there is always the risk of setting a price that is higher than the day-ahead price, resulting in higher costs for the buyer than the actual market price. Another risk, as described by Giesbertz (2024) is that the buyer fails to pay the PPA price that is agreed upon, leading to problems in paying back investments.

OWF PPAs are most likely to be 'Off-Site PPAs', meaning that the electricity is consumed at another location than where it is produced. Different types of PPAs exist, as shown in Table **??**.

The most straightforward PPA is the Physical PPA. The strike/PPA price and/or volume are set and the OWF delivers the actual output to the consumer. For example, the PPA price is set at 100 €/MWh. The buyer pays back the difference whenever the day-ahead electricity price (the reference price) is lower and the other way around receives the buyer the difference when the day-ahead price is higher. (Cleary, 2023b)

The PPA price depends on the investment costs of the OWF and the investment rate of return. OWF developers will try to set the price as high as possible and buyers will try to set the price as low as possible (Cleary, 2023a). In the end, the price of a PPA correlates with the day-ahead electricity price. Otherwise, it is not attractive for the buyer to enter this contract since it will be more beneficial to buy electricity in the wholesale market.

Due to a lack of open data on PPA prices, it is difficult to state the exact prices of current OWF PPAs. One of the only studies found mentions that an ideal PPA price for Kriegers Flak, an OWF close to the Danish coast, would be between €75-85 per MWh excluding transport costs (Hughes, 2020). However, this is a hybrid project in a home market and not in an OBZ. Based on the fact that the PPA price is correlated to the wholesale electricity price, this would result in a PPA price of around €92. This is the average electricity price of the past five years (2019-2023) in the Netherlands (calculated with data from (ENTSO-E Transparency Platform, 2023)). however, it is important to note that this calculation includes the peaks in electricity prices during the energy crisis of the last few years.

An important issue arises when considering the structure of PPAs in the context of an OBZ. Section 2.4 notes that OWFs in an OBZ are likely to face higher financial costs compared to those in their current home market. However, this is not a consequence of the OBZ itself, but based on the idea that wind farms in an OBZ are often further from shore in deeper waters. This would require a higher PPA price to recover their investment costs. However, as the wholesale electricity price within the OBZ is expected to be lower than the electricity price in the OWFs' current home market (Section 2.3), buyers will most likely not enter in PPA contracts with higher prices. This is because it would lead to a situation where the wholesale electricity price might often be lower than the PPA price, which means that buyers would need to cover the difference to the OWF. Additionally, with the absence of PPAs, OWFs might not be able to secure their investments resulting in not getting finance. This is an important issue that needs to be addressed.

A second challenge of PPAs is the difficulty of encouraging the conclusion of these contracts by the government since they are created between the OWF and the consumer. This is elaborated on in Section 2.6.

2.6 Mitigation Measures

When OWFs are not able to pay back their investment costs in the future, mitigation measures might be necessary to secure investments in offshore wind projects. Different mitigation measures exist that can be divided into market-driven measures or subsidy mechanisms. Research aims to stimulate offshore wind generation, but since the level of income and risks remain project-dependent and unclear (Section 2.3 and Section 2.4), the results are more qualitative suggestions rather than concrete solutions based on quantified project-based data (Hardy et al., 2023, Sørensen et al., 2020).

2.6.1 Feed-in Premiums

Commonly discussed subsidy mechanisms are feed-in premiums. The goal of this measure is to increase the long-term price stability for OWF operators. A premium that is widely implemented in the Netherlands is the SDE++ (Zhang and Pollitt, 2023) and forms the basis of many other premiums. Under this scheme, also often called a 'one-sided' CfD, usually the government guarantees a minimum price to the generator if the electricity price falls below a certain threshold. This ensures that electricity producers know the minimum revenue they can expect for their generated electricity. Figure 2.3 shows the working of the SDE++. The government pays back the difference whenever the electricity price falls below 65 Euro/MWh. Another feed-in premium, widely adopted in neighbouring countries and prescribed in the recent Electricity Market Reform (Centre for European Reform (CER), 2024), is the 'two-sided' Contract for Difference (CfD). This is similar to the SDE++ but differs in a way that it also sets a maximum price that OWFs can receive. If the market price exceeds this cap, the OWF is required to pay back the difference. So where SDE++ only helps OWFs, the CfD also protects the consumer against price peaks. From the perspective of the OWF, this could be seen as undesirable since (unexpected) price peaks result in extra income. When the 'minimum' and 'maximum' are set at the same level, this is often referred to as the 'strike price'.

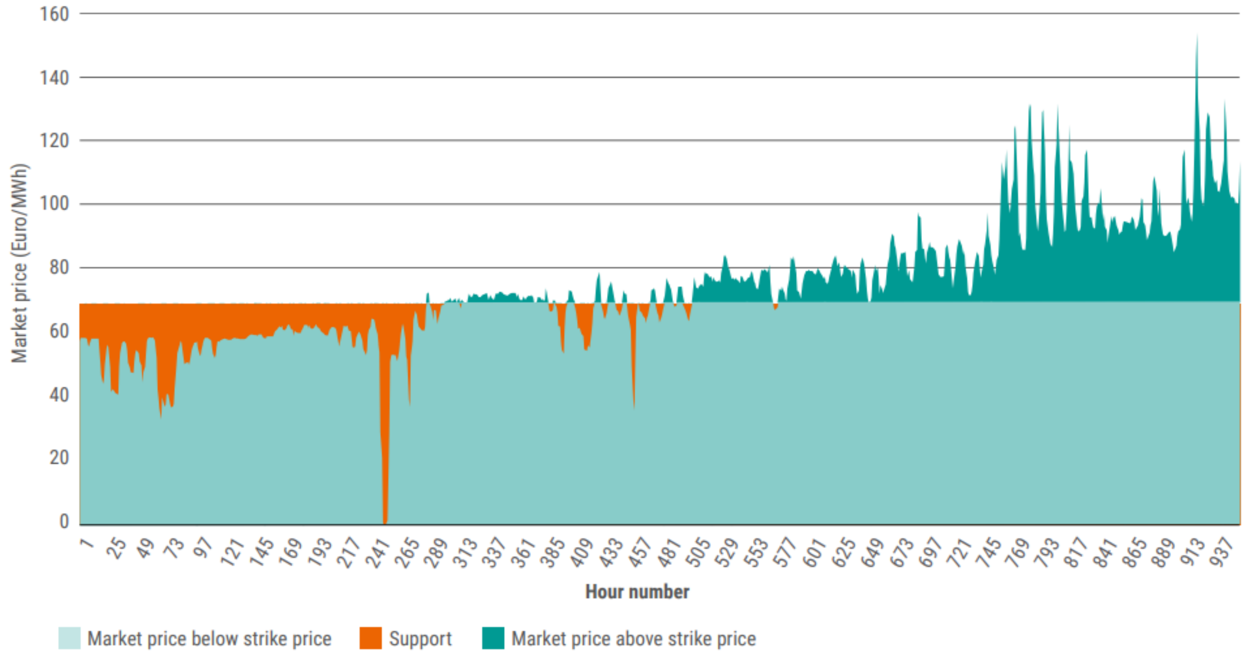

Figure 2.3: Representation of a one-sided CfD (ENTSO-E (2024)

The most basic two-sided CfD is the 'conventional CfD'. This is a CfD in which the strike price is fixed. The payment obligation is calculated for every hour based on the difference between the electricity day-ahead spot price and the strike price, for the volumes that are produced every hour:

$$payment = (strike\ price - spot\ price) * produced\ volume$$

However, there are critiques against this way of compensating OWFs (Schlecht et al., 2024). Since the OWF will always receive the strike price, there is no incentive to adjust the production. However, it would be good to increase output at times of high prices or to schedule maintenance when demand is low. Second, this measure does not fully mitigate revenue risks since the operator still faces volume risks. In case that the OWF cannot transport the electricity to shore, there will be no payment. To counter these problems, many different adjustments are proposed and implemented on the conventional CfD (ENTSO-E, 2024), for example, forms of non-production-based CfDs. These are mechanisms that take volume risks into account. However, this is outside the scope of this research, and therefore not further discussed.

2.6.2 Reallocation of Congestion Rents

Besides subsidy mechanisms, there are also ways to hedge revenue losses by compensating the OWF from the congestion rents itself. As explained in Section 2.3.1, the income decreases while the congestion rents of TSOs go up. The congestion rent is referred to as the volume of electricity that is traded times the price difference between the exporting and importing country (Tosatto et al., 2022). A reallocation of the share of congestion income is often mentioned in the literature. This means that (a part) of the congestion rents that the TSOs receive go to the OWF.

There are different ways in which the TSO can compensate the OWF for its lost revenues. Since the TSO is the operator who receives the congestion rents, measures in which the TSO compensates the OWF could referred to as a reallocation of congestion rents. The first measure is a Financial Transmission Right (FTR). This is a hedging product against price risks in which the OWF gets the right to sell up to a maximum volume of electricity for the price of the corresponding onshore market

(PROMOTioN, 2020a). This right needs to be purchased by the OWF. This can be done for more than one asset, which means that the OWF could buy FTRs on all interconnections. The resulting payment from the TSO towards the OWF equals the price difference between the electricity markets on both sides of the interconnection times the volume of transported electricity up to a maximum that is settled in the contract. However, the payout can never exceed the total congestion rents that the TSO receives. A disadvantage of this rule is that the OWF is only compensated for the electricity that is sold. Although the OWF is most likely to be favoured over exporting countries to use transmission capacity (Section 2.3.1), the OWF will not be compensated by an FTR in case of operational deratings or failures of the interconnection.

Contrarily, the Transmission Access Guarantee (TAG) is a measure that requires the TSO to return congestion rents to the OWF. This compensation should equal the revenue losses that an OWF faces because of operational deratings in transmission capacity. It would stimulate TSOs to minimise limitations in transmission capacity (Hodt and Hodt, 2022, European Commission, 2022). However, a question arises regarding the specific circumstances under which the TSO is required to return these congestion rents. Should this only be the case for congestion for which the TSO is responsible, or also for congestion arising because more profitable trades could be made? And for the first case, deciding when the TSO is responsible for congestion remains very difficult. This is something that is not clearly addressed yet in literature. In the end, both FTRs and the TAG 'reallocate' congestion rents, but they both operate at different times; FTRs hedges price risks and need to be purchased by the OWF, while the TAG hedges volume risks through a regulation that requires the TSO to return the congestion rents.

When comparing these mechanisms to mitigate both price and volume risks, there is an important thing to notice. Both subsidy schemes and FTRs provide a form of compensation ensuring higher revenues, but there is no incentive to invest in the limitations of the system. In contrast, the TAG gives incentives to the TSO to minimise the limitations occurring because of limited transmission capacity.

A problem that might occur around the implementation of mechanisms that redistribute the congestion rents is that TSOs are not allowed to return their congestion rents to OWFs. This is because European regulation says that these rents should only be used to guarantee availability and/or improve cross-border transmission capacity. However, this problem can be avoided with the use of 'put options', in which the volume and price of the FTR or TAG should be included before the financial settlement of the market coupling (European Commission, 2022).

The mitigation measures described above are all based on active compensation or regulatory changes by the government. However, this is not all possible mitigation. As described in Section 2.5, PPAs also offer mitigation in terms of price and volume risks. However, these are agreements created and made outside of the government. Therefore, it is difficult to make this a mitigation measure on where the OWFs can count on in future. However, Giesbertz (2024) describes possible future regulations to reduce the risk that the consumer fails to pay the agreed price. For example, the government could promise to pay the OWF when the consumer is not able to. However, as mentioned earlier, this is a subjective statement written from the perspective of the wind farm.

To conclude, mitigation measures can be divided into subsidies and structural changes in congestion management, the latter tackling the real problem. However, it depends on the specific situation whether and what kind of measure is needed, in combination with the risks that one wants to tackle.

3 Methodology

The challenge addressed in this study is compensating for the revenue losses that an OWF faces in an OBZ. This is done by exploring the implementation of different mitigation strategies in the OBZ market design and their impact on the observed losses. To do so, there is a need for information regarding the revenue streams of OWFs in the OBZ, as discussed in the knowledge gap (1.2). Additionally, an analysis of the impact of different market designs on the revenue streams results in advice for the government on how to minimise revenue losses for OWFs in an OBZ compared to the home market approach. To conduct this analysis, a Scenario-Based Modelling approach is used. This section elaborates on this methodology and how it is performed. Also, the sub-questions are discussed.

3.1 *Scenario-Based Modelling Approach*

The question is answered through a scenario-based modelling approach. The purpose of this study is to gain a better understanding of the revenue losses that OWFs face in an OBZ compared to the current home market setup. Additionally, it is necessary to explore different situations in which the market design changes, to obtain a more robust understanding of how these changes impact OWFs. This exploration involves setting up different scenarios of market designs to see how the mitigation strategies interact with the revenue stream of the OWF. Modelling these scenarios allows to understand the behaviour over time. In the end, numerical examples show how different mitigation measures work, which helps to understand the magnitude of their impact.

3.1.1 Sub-questions

The sub-questions refer to the different situations in which the OBZ market could be designed. The questions are all in the context of the revenue stream of an OWF in an OBZ.

1. How does an OBZ impact the revenue stream compared to the current home market approach?
2. How do different forms of financial support impact the revenue stream?
3. What impact do Financial Transmission Rights have on the revenue stream?
4. How does a combination of financial support and Financial Transmission Rights intervene and impact the revenue stream?

These sub-questions explore different possible scenarios in the design of the OBZ market setup. The first sub-question examines the situation of an OBZ in which the OWF is totally exposed to the market. Since this scenario has a negative impact on the revenue stream of the OWF, sub-questions 2 and 3 explore ways to mitigate this effect. Additionally, sub-question 4 looks into a market design where both mitigation options are implemented.

These questions are answered through a Scenario-Based Modelling approach. To do so, four scenarios are established, each representing the situation described in the sub-questions. The scenarios are simulated using a simplified energy model that is created. Section 4 elaborates on how this model and the scenarios.

3.1.2 Scenario Design

For each sub-question, a scenario is designed. Each scenario represents a different possible OBZ market design. The scope of this research is limited to the historical electricity prices over the past six years. Therefore, the runtime for the simulation of the scenarios equals 2018-2023.

Table 3.1: Scenarios

Scenario	**Situation**	**Note**
Reference scenario	The OWF is totally exposed to the OBZ market	Basic OBZ
Scenario 1	An SDE++ is implemented for the OWF in an OBZ	Financial support, one-sided CfD
Scenario 2	A conventional Contract for Difference (CfD) is implemented for the OWF in an OBZ	Financial support, two-sided CfD
Scenario 3	Financial Transmission Rights (FTR) are purchased by the OWF in an OBZ	Compensation equal to congestion rents
Scenario 4	A CfD is implemented in continuation of FTRs for the OWF in an OBZ	Combination of scenarios 2 and 3

All scenarios represent a possible market design. The scenarios will be simulated to see how the revenue stream of the OWF is impacted. The goal of the model is to show how the different policy measures per scenario work and to show the order of magnitude of both revenue losses and the mitigation options implemented. The scenarios are simulated for a situation in which there is an interconnection capacity of 1.8 GW. In this situation, OWFs can most likely always transport their full amount of generated electricity to one shore since OWFs rarely operate at full capacity. Section 4 elaborates on the design of the hypothetical wind farm.

The **Reference scenario** represents a situation in which the hypothetical OWF is connected to a hybrid interconnection connected to a Norwegian bidding zone and the Dutch bidding zone. This results in a revenue stream of the OWF in which it earns the price of the lowest-priced bidding zone. **Scenario 1 and 2** represent a situation in which financial support is allocated to the OWF via feed-in premiums. This can be done via the SDE++ (one-sided CfD) or two-sided CfD. In **Scenario 3**, an FTR will be allocated to the OWF. This measure provides the OWF operator with the right to sell a maximum of X MW at the price of the bidding zone that is connected with the interconnection on which the FTR is settled. The compensation equals part of the congestion rents that arise on the interconnection. Another measure, which directly reallocates congestion rents, is the Transmission Acces Guarantee (TAG). This measure is not implemented since it is compensation for the OWF in times of operational deratings, and volume risks are outside the scope of this research. Where scenarios 1 and 2 represent the implementation of a financial support mechanism, scenario 3 entails a specific measure based on the price differences between two electricity markets. To see how these two mechanisms intervene, **scenario 4** represents a situation in which a combination of these measures is implemented. Section 4 elaborated on the design of the scenarios.

3.1.3 Model development and Scenario Implementation

A base model is developed to understand the basic operations of a wind farm in an OBZ. Here, the hypothetical OWF is connected via a radial connection to its home market. Next, an interconnection is added to a Norwegian bidding zone which is the default model, representing the reference case. To implement the financial support mechanisms, the right strike price is estimated based on a literature review and historical data on strike prices. To get an understanding of the impact of the level of strike prices, an additional sensitivity analysis is carried out. The FTR in Scenario 3 is added by specifying for which capacity the OWF can sell the electricity against the price of the corresponding electricity market.

3.1.4 Analysis

After the simulations are performed, the results will be analysed. The output of the model is presented in a time series chart that shows the monthly average revenue in (EUR/MWh) of the OWF in the considered scenario. The results will be evaluated based on the criteria shown in Table 3.2. These criteria are obtained based on the relevant stakeholders for this research.

Table 3.2: Evaluation Criteria

Criteria	**Goal**
Revenues in times of high average volatile prices (EUR/MWh)	Maximise
Revenues in times of high average stable prices (EUR/MWh)	Maximise
Revenues in times of low average volatile prices (EUR/MWh)	Maximise
Revenues in times of low average stable prices (EUR/MWh)	Maximise
Predictability of the revenues	Maximise
Lost congestion rents (EUR/MWh)	Minimise
Costs for the counterparty (EUR/MWh)	Minimise

The aim of this study is to provide advice on how the OBZ market can be designed in a way that the revenue losses of the OWF are mitigated, keeping in mind the interests of various stakeholders. The following stakeholders with subsequent criteria are considered:

- **The offshore wind farm operator:** The goal of the OWF is to maximise its revenues and minimise its costs. However, the cost-component is outside of this study. The results will be evaluated on how the OBZ affect the financial viability of OWFs and how the mitigation strategies impact the revenue stream. However, apart from the mitigation measures, the electricity price inside the OBZ also impacts the revenue streams. Therefore, the mitigation measures need to be evaluated for different price scenarios. To do so, the criterion on which the results will be evaluated are **Revenues in times of high average volatile prices (EUR/MWh)**, **Revenues in times of high average stable prices (EUR/MWh)**, **Revenues in times of low average volatile prices (EUR/MWh)** and **Revenues in times of low average stable prices (EUR/MWh)**. The aim is not to give an exact monthly revenue under different scenarios, but to get a sense of the order of magnitude and the impact of these mitigation measures on the revenues of the OWF. Another important criterion for OWFs is the **Predictability of the revenues**. The more predictable the revenue stream, the more investment security OWFs have. All criteria need to be maximised.

- **The transmission system operator:** The goal of the TSO is to ensure a stable and efficient grid. The TSO owns and operates cross-border connections. The TSO earns income in the form of congestion rents for making capacity available. Whenever the interconnection is congested, the congestion rents equal the difference in price between the exporting and importing country per MWh that is transported. These congestion rents cannot be spent freely by the TSO, but they must be used to improve or extend the grid. These congestion rents equal the revenue losses from the OWF in an OBZ compared to the home market. Therefore, the results will be evaluated on **Lost congestion rents (EUR/MWh)**. This criterion only includes the lost congestion rents by the OWF and no other congestion rents that are obtained by the TSO because of the transportation of electricity from other bidding zones. This criterion needs to be minimised.

- **Government:** The Government is the counterparty in a contract with the OWF. Depending on the contract, the provides compensation or receives payment from the OWF. The criterion that measures this payout is **Costs for the counterparty (EUR/MWh)**. Important to note is that an increase in costs is not per se negative. For example, by stimulating OWFs with subsidies, a faster rollout of wind farms might be established. This is elaborated on in Section 7.

3.1.5 Policy Scorecard

After the data is collected for all criteria, the 'Policy Scorecard' tool will be used to illustrate, evaluate and compare the impact of different mitigation strategies per criterion. The grading scale used (–, -, 0, +, ++) or N/A, indicates to which degree the criteria are positively or negatively affected, with "–" indicating a significant negative impact and "++" indicating a significant positive impact. The policy scorecard looks as follows:

Table 3.3: Policy Scorecard

Mitigation Measure	**SDE++**	**CfD**	**FTRs**	**CfD + FTRs**
Criterion				
Revenues during high avg. volatile prices (EUR/MWh)				
Revenues during high avg. stable prices (EUR/MWh)				
Revenues during low avg. volatile prices (EUR/MWh)				
Revenues during low avg. stable prices (EUR/MWh)				
Predictability of the revenues				
Lost congestion rents (EUR/MWh)				
Costs for the counterparty (EUR/MWh)				

4 Model Development and Scenario Design

A description of the simplified model will follow, including the model structure and components, validation and testing, and limitations and assumptions. Next, a description of the scenarios follows on how these are designed and implemented.

4.1 Base Model

This subsection describes the working of the base model. This is done by first describing the scope of the model, followed by its objectives and constraints. Next, a visualisation of the conceptual model is shown, followed by the assumptions and limitations of the model. Last, the methods for calculating revenues and congestion rents are explained. The subsequent subsection explains the method to calculate the payouts by counterparties. The outcome of the base model represents the reference case, as described in Section 3.

4.1.1 Modelling Scope

A simplified energy model is created to simulate the revenue streams of a hypothetical wind farm in the North Sea. The model is used to provide numerical examples to understand the impact of mitigation strategies on the revenue streams in the OBZ. The base model assumes that the OWF is completely exposed to the market. The electricity generated by the hypothetical wind farm is sold through the wholesale market against the day-ahead electricity price of the lower-priced neighbouring bidding zone. The two bidding zones with which the hypothetical wind farm is connected are a Norwegian bidding zone and the Dutch bidding zone. Figure 4.1 shows a representation of the hypothetical OWF.

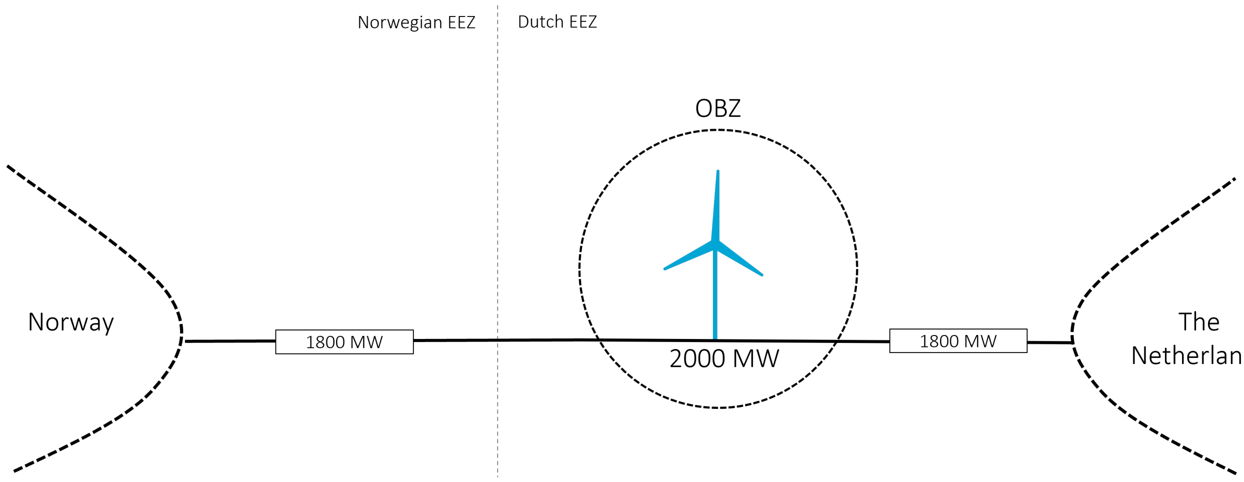

Figure 4.1: Representation of the hypothetical offshore wind farm

The design of the grid has a significant influence on how the system works. The higher the capacity, the less capacity is used from the cable that connects the lower-priced market to the OWF, due to congestion on the other cable. When the capacity is too low, there are chances that the OWF cannot dispatch all the electricity that is produced, resulting in market prices of 0 EUR/MWh. The hypothetical wind farm in this study has a capacity of 2 GW and is connected to the second Norway bidding zone (closest to the Netherlands) and the Dutch bidding zone. The connections have a capacity of 1.8 GW.

To simulate the electricity market and obtain a revenue stream of the hypothetical wind farm inside the OBZ, data on the generated electricity of the OWF as well as data on the electricity price of both neighbouring bidding zones is required. The generated electricity per hour is created by the Virtual Wind Farm (VWF) model of Staffel and Pfenninger. The electricity price for the past six years (2018-2024) is obtained from the ENTSO-E Transparency Platform (2023). This historical data is used rather than future price scenarios because it is transparent and determining future electricity prices is outside the scope of this research. The output of the model is data on the revenue stream over these past six years. Section 5 elaborates on the specific characteristics of the OWF and the input that is used for the model.

4.1.2 Objectives

Now that the scope of the model is known, it is important to understand the goal and the objectives of the model. These objectives are in line with the sub-questions that are provided in Section 3.

- The model must be able to **determine and show the yearly average revenues of the OWF** in all four different scenarios and the reference scenario. This must be shown in EUR/MWh, averaged over the electricity that is sold. This way, the model normalises for capacity of the wind farm. Additionally, a yearly average is preferred to compare against various years where the electricity price differs.
- The model must be able to **determine and show the weekly average revenues of the OWF** in all four different scenarios and the reference scenario. This must also be shown in EUR/MWh for the same reason as the previous objective. The volatility of the revenue stream can be observed by determining the weekly average. This is important to better understand how mitigation measures influence the revenue stream on a shorter notice. For example, how does a mitigation measure behave under specific periods of low or high prices, and how does that impact the revenue stream?
- The model must be able to **determine and show the yearly average congestion rents** in all four different scenarios and the reference scenario. Again, this must be shown in EUR/MWh. These are the congestion rents that arise from the cross-border transportation of electricity produced by the OWF in the OBZ. As explained in Section 1 and 2, these congestion rents represent the 'lost income' for the OWF in an OBZ compared to the home market approach. Several subsidy schemes studied in this research could be paid from these congestion rents. Furthermore, it shows the importance of the presence of mitigation measures. These congestion rents go to the TSO of the corresponding country to where the electricity flows.
- The model must be able to **determine and show the yearly average payout** by counterparties of the mitigation measures per scenario, if applicable. This is also shown in EUR/MWh. This is important because it shows the order of magnitude of subsidy per mitigation measure. In combination with the changes in revenues of the OWF, its effectiveness can be determined.

4.1.3 Constraints

Now that the objectives of the model are defined, it is important to define the boundaries of the model and conditions that must be satisfied for the model to be able to achieve the objectives.

- The model has a **running time of six years** (2018-2023). This timeframe is considered enough to observe how mitigation measures behave over time. This study does not look at investment returns or the costs of CAPEX and OPEX. Therefore, the model does not need to run for the entire lifespan of a wind turbine. Additionally, the last six years cover both a period of stable electricity prices (2018-2020) and a period of volatile electricity prices (2021-2023) because of higher gas prices. As a result, the working of different mitigation measures can be compared and examined for periods in which the behaviour of the electricity price differs.
- The model **generates hourly outcomes**. This is done by using hourly changing data on the

electricity price and hourly changing data on the electricity generation based on hourly wind patterns. This best provides a detailed illustration of the variability of the electricity market and the resulting revenues for the OWF. It allows to distinguish between periods of low and high electricity generation and prices. Additionally, it enables the calculation of the average revenue per MWh of electricity produced, which is needed to achieve the objectives. Another option would be to simulate yearly outcomes with a yearly average electricity price and the yearly average volume of electricity produced, but this might overlook how mitigation measures behave under factors like peak demand and price spikes. This level of detail can help decision-makers in choosing the right mitigation measure based on expected future electricity prices.

- The input data on **the electricity price is based on historical data** of the past six years as described above. It would be optimal to use future electricity prices to represent the behaviour of different market designs, but this requires energy models that simulate all countries surrounding the North Seas, each with their generators and forecasts of future electricity mixes and fuel prices. This is outside the scope of this study. Current research on future electricity prices typically shows a range of prices rather than hourly, weekly or yearly data. To still reflect the most current state, the most recent data from the past six years is selected for input for the model. Section 5 elaborates on the input data.
- The hourly input data on **the generated electricity is yearly averaged** from the past five years (Section 5 elaborates on how this generated electricity is calculated). Consequently, the final dataset contains values, one for each hour of the year, representing the typical wind pattern for that hour based on five years of data. This is done to focus on how different electricity prices over the years influence revenue in combination with different mitigation measures rather than on different generation patterns. Additionally, this is only a small limitation since generation output does not significantly change over the years. This is also shown in Section 5.
- The physical boundaries of the model are set by **two interconnections of each 1800 MW**. This means that the transportation of electricity cannot exceed this capacity. Since the hypothetical OWF has a capacity of 2 GW, it can always transport all of its electricity, given the assumption that the OWF is favoured over exporting countries to use the transmission capacity, as described in the next subsection.

4.1.4 Conceptual Model

Now that the scope, objectives and constraints are clear, a visual representation of the conceptual model is shown in Figure 4.2. A more elaborate description of the input is given in Section 5. A description of the implementation of the scenarios is written below. The output of the model is a volume weighted average of the revenues. This is only done for the presentation of the results. The calculations themselves are performed with hourly data.

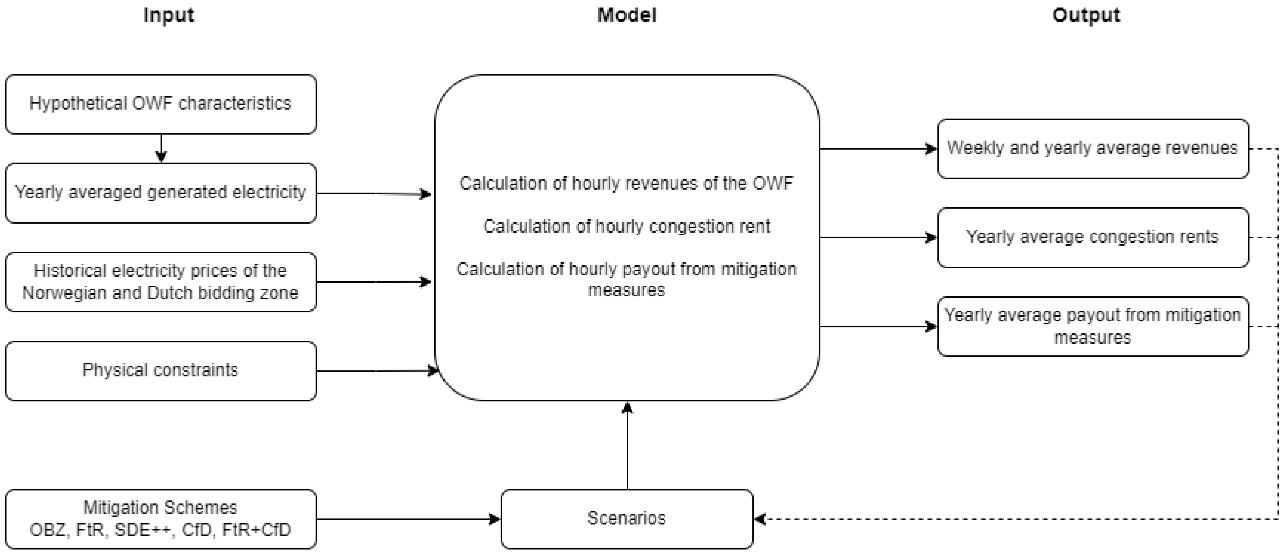

Figure 4.2: Visualisation of conceptual model

4.1.5 Assumptions and Limitations

The following subsection describes the assumptions that are made for this study, together with the limitations of the model.

- **The OWF will always be favoured over the exporting country to use transmission capacity**. As described in Section 2.3.2, the EUPHEMIA algorithm tries to maximise socio-welfare by reserving transmission capacity on the interconnection for the electricity producer who can bid its electricity against the lowest price. In this study, it is assumed that this is always the OWF since its marginal costs are close to zero (Section 2.3.2. However, this is not always true. OWFs have to take operational costs in their variable costs, which is why the marginal costs are higher than zero. If the price of the exporting country would become lower, this country would be the preferred one to use both interconnections, leading to the OWF that must be curtailed.
- Apart from contracts that are studied in this research, **the OWF sells all its electricity through the wholesale market** against the day-ahead electricity price.
- There is **no curtailment from the interconnections** because of operational deratings, failure or congestion on the onshore grid. In combination with the assumption above, the OWF can always transport its electricity to shore. As a result, the OWF does not face any volume risks.
- The **OWF is curtailed with negative electricity prices**. It is assumed that the OWF knows in time when electricity prices turn negative and consequently stops production.
- There is **no demand in the OBZ**. Therefore, the OWF transports all the electricity to the neighbouring countries. In future, demand is expected in OBZ in the form of electrolysers, energy hubs or in the form of shipping activities. This most likely drives up the price in the OBZ. When there is enough demand, the price might become higher than the lower-priced neighbouring bidding zone, resulting in a different revenue stream for the OWF.
- It is assumed that **export and/or import demand of the neighbouring bidding zones is always greater than the interconnection capacity available**. This means that the interconnection cable to the higher-priced bidding zone is always congested. This is either done by the OWF or by exporting demand from the other bidding zone. As a result, the electricity price is always set by the lower-priced neighbouring bidding zone.

- There is **no strategic bidding from the OWF or the exporting bidding zone**. Both could bid at higher prices during peak demand when the day-ahead price is expected to rise or adjust bids near real-time based on updated forecasts. Therefore, the market outcome is considered optimal.
- **Market-coupling does not influence the day-ahead price of the importing country or countries**. However, for example, 2 GW of extra installed capacity above the current 4.5 GW of installed offshore wind capacity in the Dutch North Seas will influence the supply curve in the merit order, resulting in a lower day-ahead price. To take this into account, one needs the merit order of both countries to take into account. This is outside the scope of this study and forms a limitation of the model. This limitation most likely results in higher congestion rents compared to reality. This is important to take into account for the rest of this research.

Due to these assumptions, the OWF operates in a situation in which it can always inject its produced electricity into the grid and sell it to the electricity market with the highest demand. Due to the exporting demand of the lower-priced market, congestion occurs at all times on the interconnection towards the higher-priced market. Therefore, the OWF always offers its electricity at the price of the lower-priced neighbouring bidding zone.

4.1.6 Revenues

The revenues of the OWF depend on the electricity price it receives for the amount of electricity it sells. In the base case, the OWF operates in a basic OBZ as currently defined. This means that the government does not intervene and that there are no contracts between the OWF operator and other parties. As a result, the revenues from the OWF ($R_{\text{owf},t}$) equals the electricity price in the OBZ ($P_{\text{obz},t}$) times the volume of electricity produced by the OWF ($Q_{\text{owf},t}$):

$$R_{\text{owf},t} = P_{\text{obz},t} \times Q_{\text{owf},t} \tag{1}$$

The electricity price in the OBZ ($P_{\text{obz},t}$) is formed through market coupling between the Dutch bidding zone and the Norwegian bidding zone with each their own electricity price (respectively $P_{\text{nl},t}$ and $P_{\text{no},t}$) (Section 2.3.2). Since the assumption is made that the export demand is always greater than the interconnection capacity available, the interconnection to the highest-priced country will always be congested. First, the OWF will transport its electricity over the cable, and in case there is still capacity available, the lower-priced country will sell its electricity to the higher-priced country. Therefore, the price in the OBZ will always be equal to the price of the lower-priced country.

$$P_{\text{obz},t} = \begin{cases} P_{\text{nl},t} & \text{if } P_{\text{nl},t} < P_{\text{no},t} \\ P_{\text{no},t} & \text{otherwise} \end{cases} \tag{2}$$

4.1.7 Congestion Rents

The cause of congestion on interconnections is an ongoing question. This study assumes that the cause of congestion is that there are trades possible between parties on the opposite side of the interconnections (the OBZ and its neighbouring bidding zones), that would result in more profit or welfare maximalisation. In other words, there is more demand for trading electricity over a cable than there is capacity available. As explained in Section 2.3.2, the default cross-border congestion managing method in Central Western Europe is market coupling or market splitting. The two bidding zones connected to the congested interconnection both develop their day-ahead price as if there is no interconnection. The TSO buys electricity from the lower-priced bidding zone (the OBZ) and sells the produced electricity up to a maximum of the capacity of the interconnection to the other bidding zone. Since the OBZ takes over the day-ahead price of the lower-priced neighbouring bidding zone, the OBZ price increases equal to the new marginal price that would have occurred when extra demand was asked in the lower-priced zone. Contrary, the day-ahead price in the higher-priced bidding zone decreases because less supply is needed to match demand. Since the TSO buys electricity against low prices and sells it for higher prices, the TSO earns an income, i.e. congestion rents. These revenues are equal to the difference in price between both zones connected to the congested interconnection times the interconnection capacity.

However, this model does not simulate the change in day-ahead prices of the neighbouring bidding zones as a result of market coupling. In combination with the assumption that there is always interconnection capacity available to offset all produced electricity, the total congestion income ($CI_{\text{total},t}$) equals the produced electricity by the OWF up to a maximum of the congested interconnection times the price difference between the lower priced bidding zone and the higher priced bidding zone. It is important to note that this only includes the rents that are coming from transported electricity from the OBZ, and not from the exporting country. This study only shows this part of the congestion rents because these are the 'lost' congestion rents by the OWF due to the OBZ. The total congestion rent equals the sum of both the congestion rent on the interconnection to the Dutch bidding zone ($CI_{\text{nl},t}$) and the Norwegian bidding zone ($CI_{\text{no},t}$). This results in the following formula:

$$CI_{\text{total},t} = CI_{\text{nl},t} + CI_{\text{no},t} \tag{3}$$

Due to the assumptions made above, there is always only one interconnector congested. Therefore, there is also always only one interconnection on which there are congestion rents. However, it is still interesting to see how much congestion rents each interconnection makes. It can show whether capacity might be increased or decreased in the situation that is simulated. For example, if only a minimal amount of congestion rents is observed on one of the cables, this suggests that congestion is not a significant issue. This could indicate to decrease the capacity of the corresponding interconnection. The congestion rent on the specific interconnection cables is calculated as follows:

$$CI_{\text{nl},t} = \min(Q_{\text{owf}}, Q_{\text{interconnection-nl}}) \times (P_{\text{nl}} - P_{\text{obz}}) \tag{4}$$

$$CI_{\text{no},t} = \min(Q_{\text{owf}}, Q_{\text{interconnection-no}}) \times (P_{\text{no}} - P_{\text{obz}}) \tag{5}$$

4.2 Scenario Design and Implementation

Based on the sub-questions, four scenarios are designed (Section 3.1.2). This section elaborates on the specific design of these scenarios and how these are implemented in the model. All scenarios are simulated in the OBZ environment with an interconnection capacity to shore of 1.8 GW.

4.2.1 Scenario SDE++

Scenario SDE++ represents a scenario that is equal to a Sliding Feed-in-Premium in other countries. This measure could also be called a one-sided CfD. The electricity that is produced and transported to shore is sold on the electricity market and the OWF operator receives a premium that hedges against fluctuations in the electricity price. The OWF receives a premium whenever the electricity price falls below the strike price. Therefore, the revenues of the OWF depend on the volume of produced electricity ($Q_{\text{owf},t}$) and the effective price ($P_{\text{eff},t}$), rather than the average electricity price.

$$R_{\text{owf},t} = P_{\text{eff},t} \times Q_{\text{owf},t} \tag{6}$$

The minimum price that the OWF will receive inside the OBZ is represented by the strike price (presented as the floor price), (P_{floor}). If the price in the OBZ is lower than the strike price, the effective price in the OBZ equals the strike price and vice versa:

$$P_{\text{eff},t} = \begin{cases} P_{\text{floor}} & \text{if } P_{\text{obz},t} < P_{\text{floor}} \\ P_{\text{obz},t} & \text{otherwise} \end{cases} \tag{7}$$

The payout from the SDE++ ($Payout_{SDE,t}$) is based on the production of electricity by the OWF and the difference in price between the strike price and the price in the OBZ whenever the OBZ price is lower than the strike price. There is no payout at negative prices. The following formula represents the total payout that the OWF will receive, which, in theory, could come from several counterparties:

$$Payout_{SDE,t} = \max(0, (P_{\text{floor}} - P_{\text{obz},t})) \times Q_{\text{owf},t} \tag{8}$$

Determination of Strike Price

The strike price of the SDE++ is traditionally set via tenders and differs per specific project. However, these tenders and their resulting strike prices are mostly confidential and therefore often not made public. Planbureau voor de Leefomgeving (Netherlands Environmental Assessment Agency) writes yearly reports on the recommended strike prices inside the SDE++ for different technologies (Lensink et al., 2024, 2023, 2022). However, since the SDE++ is not implemented for offshore wind in the Netherlands, the rapport only includes recommended prices for wind onshore and wind in small waters, for projects with smaller capacity (± 20 MW) and different wind speeds. Table 4.1 shows the strike prices for these wind projects on water barriers for a wind speed of > 8.5 m/s. This is the highest wind speed that the reports include, which comes the closest to wind speeds at sea. Apart from this literature, there is no publicly available information on the level of strike prices, which makes it difficult to determine the right strike price.

Table 4.1: Yearly recommended strike prices for wind projects on water barriers for wind speed > 8.5 m/s

	2022	**2023**	**2024**
strike Price (EUR/kWh	0.0425	0.0576	0.0545

However, at the same time, the first big offshore wind farms are being built in the Netherlands and Germany without any form of subsidy (Jansen et al., 2020). The paper speaks about "*The era of 'subsidy-free' offshore wind turbines* [that] *has begun*", but these offshore wind projects are still radial connected instead of hybrid, which is the case in this study. With the expected lower revenues, it is expected to be unlikely that auctions for these projects will not receive zero-subsidy bids (yet). Therefore, an estimated strike price of 30 EUR/MWh is applied in this study. Since the aim of this study is to provide numerical examples and to show the order of magnitude, rather than the exact changes in revenues, this estimation is considered appropriate. However, it is important to understand how estimating the strike price influences the revenues in this scenario. Therefore, a sensitivity analysis is carried out (Section 4.3).

4.2.2 Scenario CfD

This scenario includes the implementation of a CfD. If the electricity price in the OBZ exceeds the strike price, the OWF operator must pay the counterparty the difference for the volume of electricity produced. The other way around, if the strike price exceeds the OBZ price, the counterparty compensates the OWF for the difference. This results in a situation in which the OWF always receives the strike price for the electricity that it sells.

A lot of different designs of CfDs exist or are under consideration for upcoming projects. The specific design highly influences the effectiveness of hedging price, volume and/or regulatory risks. Price and volume risks refer to the number of negative prices and the situation in which the OWF cannot dispatch electricity due to deratings or congestion on the interconnection. These volume risks are outside of the scope of this study, as explained in the constraints of the model. While implementing a CfD, the aim is to minimise the distortion of the market ((ENTSO-E, 2024, FSR, 2023)). For example, to what extent does the CfD influence bidding behaviour and dispatch of OWFs? The overall incentive of the OWF to bid into the market should be the day-ahead electricity price and not a possible CfD payout. Otherwise, it could be financially attractive to produce and sell electricity in times of negative prices when there is ample of supply.

To implement a CfD, it is important to have a good understanding of how CfDs are designed. ENTSO-E (2024) describes four key elements of the CfD. The first key element is the distinction between a *production-based* or *non-production-based* CfD. In a production-based CfD, the subsidy is based on the actual injection of the asset. Thus, the OWF is only compensated for the electricity that is produced and sold. A non-production-based CfD, on the other hand, provides compensation based on a reference volume that the OWF could have produced, rather than the actual electricity sold. The advantage of the latter is that it also secures the OWF against volume risks, for instance, if the OWF needs to curtail production due to unavailable interconnection capacity, thereby increasing the security of investments. However, apart from its complexity and the fact that this type of CfD is relatively new, with no practical experience yet, it does distort the market more than the production-based CfD, because this option allows the OWF to manage the volume risks itself, which might lead to market-based solutions.

The second key element of a CfD is which *reference market price* is chosen. This price is compared with the strike price to determine the payments between the OWF and the counterparty. Traditionally, this is based on the day-ahead price per hour or averaged over a full year. The advantage of using an average reference price over a longer period is that it provides more incentive to dispatch efficiently into the market. When the reference price is determined per hour, the OWF can forecast the price, leading to bids based on these forecasts rather than on marginal costs. However, towards the end of a longer reference period, the price can still be estimated by the OWF, which might lead to dispatch distortions at the end of the timeframe.

The third key element of the CfD is the *duration of the contract*, indicating how long the OWF receives compensation. This can be based on time or volume. 'Time' refers to the number of years the CfD provides payouts. 'Volume' refers to the amount of electricity produced. This is often established with a cap on the full load hours. This means that the OWF receives payouts only up to a maximum amount of electricity dispatched. The advantage of this approach is that it encourages the OWF to only operate when needed, rather than producing electricity during periods of negative prices or when prices are lower than the marginal costs of the wind farm.

The last key element, to which ENTSO-E (2024) refers, is *whether the CfD pays out at negative prices.* The reason behind not compensating for negative prices is that it removes the incentive to produce 'because the OWF would receive a payment anyway'. Traditional CfDs pay out at negative prices but more recent designs do not.

This study examines a conventional CfD with the following characteristics:

- The reference volume is production-based, because this distorts the market the least.
- The reference price is the spot price in the OBZ per hour, as is the most basic design.

- The duration of the contract equals 6 years (simulation time) and there is no cap on full load hours.
- There is no payout for negative prices in the OBZ, like the most recent CfD designs.
- The strike price is fixed and two-sided, as is the case for a conventional CfD.

In this scenario, the effective price that the OWF receives for electricity, $P_{\text{eff},t}$, is always equal to the strike price (P_{strike}). Thus, the revenue of the OWF can be directly calculated as:

$$R_{\text{owf},t} = P_{\text{strike}} \times Q_{\text{owf},t} \tag{9}$$

The amount of subsidy provided by, or paid back to, the counterparty, ($Payout_{CfD,t}$) is determined based on the difference between the strike price and the price in the OBZ. A negative payout represents the amount that needs to be paid back by the OWF:

$$Payout_{CfD,t} = (P_{\text{strike}} - P_{\text{obz},t}) \times Q_{\text{owf},t} \tag{10}$$

This scenario ensures that the revenue of the OWF is stabilised at the strike price for the volume of electricity generated, regardless of the price in the OBZ. The counterparty compensates the OWF if the market price is below the strike price and vice versa. Similar to the SDE++ scenario, the payout in this scenario represents the total amount received from or paid to a counterparty, which could, in theory, involve multiple parties

Determination of Strike Price

Determining the right strike price for an OWF is a difficult process. Traditionally, the OWF includes a preferred strike price in its tender. The lower the strike price they bid, the greater their chance of securing the project. Choosing the right strike price is of great importance since it highly influences the income for the years of duration of the contract.

To calculate the right strike price, it is important to know both the CAPEX and OPEX costs and the expected electricity production of the OWF. Because the OWF will always receive the strike price, the current electricity price does not influence their bid. However, these prices are significant for the counterparty, which either pays out or receives the difference between the strike price and the market price.

As is the case with choosing the right floor price in the SDE++ scenario, an estimation of the right strike price is considered appropriate since the aim of this study is to provide numerical examples and to show the order of magnitude, rather than providing the exact strike price with which the OWF is expected to be profitable. This estimation is based on the last two auction rounds in the UK in which OWF developers bid (Department for Energy Security and Net Zero and Department for Business, Energy & Industrial Strategy, 2019, 2022). The last auction round took place in 2023; however, there were no bids from OWF developers (Department for Energy Security and Net Zero, 2023). The projects selected to base the strike price for this study are expected to become operational in the next four years (2023-2027) and have a capacity ranging from 1 GW to 2.5 GW (see Table 4.2). The outcomes of all three auctions are reported in 2012 prices. Therefore, the average exchange rate from 2012 is applied to convert the prices into euros (1 British pound = 1.2332 euros) (GBP, 2012). This study uses a rounded average of the auction strike prices, resulting in a strike price of 50 euro/MWh. Again, only information from strike prices in the UK is available, which makes it hard to estimate the right strike price since these are all project-specific. To understand the impact of the estimation, a sensitivity analysis is carried out on different levels of strike prices (Section 4.3). It is important to acknowledge this in the analysis of the results.

Table 4.2: UK Auction Results for Strike Price CFD

Project Name	**Capacity**	**Strike Price (EUR/MWh)**
Hornsea Project Three	2852	46.03
Norfolk Boreas	1396	46.03
EA3	1372	46.03
Inch Cape	1080	46.03
Dogger Bank Creyke Beck A	1200	48.83
Dogger Bank Creyke Beck B	1200	51.33
Dogger Bank Teesside A	1200	51.33
Sofia	1400	48.83

4.2.3 Scenario FTR

An FTR gives the OWF the right to sell a maximum volume of electricity at the price of the neighbouring bidding zone. This agreement is made with the TSO that owns the interconnection between the OBZ and the onshore market. The OWF can establish these FTRs with both TSOs, therefore on both interconnections. It is important to know that these FTRs have no impact on the dispatch of electricity or the actual use of the interconnection. The OWF is only compensated for the electricity that is actually delivered. Therefore, in case of curtailment of the interconnection, the OWF does not receive the income. Given that the OWF is always favoured over exports from the neighbouring bidding zones and that volume risks are outside the scope of this study, curtailment will not occur and the OWF can always use FTRs. This has a great influence on the results. Due to the specific layout of the system in this study, the payout of the FTR equals the congestion rents if the FTR would give the right over the full capacity of the interconnection. This is normally not always the case. For example when an FTR is established over a long distance between several interconnections in a massed grid. However, after acknowledging this fact, one could say that, for this specific layout, the FTR 'reallocates' congestion rents for a specific capacity on the interconnection. Still, the FTR is a hedging product that the OWF buys from the TSO, rather than a 'rule' that the TSO has to pay back the congestion rents. This implementation only shows the increase in operational revenues, rather than the costs of purchasing the FTRs. Next to the fact that this model allows the OWF to always use the FTRs, this is also important to realise in the discussion of the results.

Under this scenario, the revenue of the OWF consists of two parts. First, the revenue obtained from selling electricity under FTR contracts ($R_{\text{FTR},t}$), and second, the revenue obtained from selling any excess electricity through normal market coupling at the OBZ price ($R_{\text{excess},t}$):

$$R_{\text{owf},t} = R_{\text{FTR},t} + R_{\text{excess},t} \tag{11}$$

The revenue obtained from selling electricity through FTR contracts is equal to the volume of electricity produced by the OWF, up to the maximum volume specified in the FTR contract, sold to the higher-priced bidding zone, at the corresponding price ($P_{\text{high},t}$). This is calculated by the volume contracted on the Dutch interconnection ((FTR_{nl}) or the volume contracted on the Norwegian interconnection (FTR_{no}) times the respective electricity price:

$$P_{\text{high},t} = \max(P_{\text{nl},t}, P_{\text{no},t}) \tag{12}$$

$$R_{\text{FTR},t} = \begin{cases} \min(Q_{\text{owf},t}, FTR_{\text{nl}}) \times P_{\text{high},t} & \text{if } P_{\text{high},t} = P_{\text{nl},t} \\ \min(Q_{\text{owf},t}, FTR_{\text{no}}) \times P_{\text{high},t} & \text{otherwise} \end{cases} \tag{13}$$

The revenue obtained from selling the excess electricity through normal market coupling at the OBZ price is calculated in the same way as revenue in the basic OBZ. However, the volume of electricity equals the total volume produced minus the volume contracted on the congested interconnection:

$$R_{\text{excess},t} = \begin{cases} (Q_{\text{owf},t} - FTR_{\text{nl}}) \times P_{\text{obz},t} & \text{if } Q_{\text{owf},t} > FTR_{\text{nl}} \text{ and } P_{\text{nl},t} > P_{\text{no},t} \\ (Q_{\text{owf},t} - FTR_{\text{no}}) \times P_{\text{obz},t} & \text{if } Q_{\text{owf},t} > FTR_{\text{no}} \text{ and } P_{\text{nl},t} < P_{\text{no},t} \\ 0 & \text{otherwise} \end{cases} \tag{14}$$

Determination of FTR Volume

FTR contracts are sold through FTR auctions, where the capacity of the interconnection is offered in different rounds. Not all capacity will be offered to keep capacity reserved for transporting electricity by other participants. Since these contracts are often confidential, the contracted volume per project is often not published. For this study, a contracted volume of 500 MW on both interconnections is assumed, which represents almost one-third of the total interconnection capacity.

4.2.4 Combined FTR and CfD

In this scenario, a combination of selling electricity through FTR contracts in a market with CfDs is examined. This combination of mitigation measures is also mentioned in (PROMOTioN, 2020a). This combination represents the implementation of both a financial support mechanism and a measure based on the price differential between the OBZ and the higher-priced electricity market. It makes sure that there is a predetermined capacity available for the OWF on which it can receive the subsidy from the CfD. Only a CfD could result in a situation in which the interconnection cannot be used, resulting in no compensation through the CfD.

A combination of these measures can be implemented in different ways. The revenues of the OWF depend on whether the payout of the CfD contract is calculated before or after the FTR is included. In the case that the CfD first pays out, the subsidy will only be based on the OBZ price. Next, the OWF will receive an extra income via the congestion rents by the TSO, which equals the price difference between the subsidised price and the higher-priced neighbouring bidding zone. Effectively, this means that the subsidies from the counterparty of the CfD end up being congestion rents, instead of subsidies for the OWF. On the contrary, the payout from the counterparty of the CfD will be lower and the payout from the congestion rents will be higher if the height of the CfD is calculated over the effective price that the OWF receives in which the FTRs are included.

In this scenario, the second implementation of the combination is used. This means that the payout from the CfD is calculated over the effective price that the OWF receives after the FTR is included. This will most likely result in much lower payouts by the counterparty of the CfD compared to the scenario in which only the CfD is implemented. The revenue of the OWF will stay the same as in the CFD scenario since the OWF will always receive the strike price for the electricity produced:

$$R_{\text{owf},t} = P_{\text{strike}} \times Q_{\text{owf},t} \tag{15}$$

The payout by the counterparty of the CfD is now split into two parts. The first payout ($Payout1_{(CfD+FTR),t}$) represents the compensation for the part of electricity covered by FTR contracts. The second payout ($Payout2_{(CfD+FTR),t}$) represents the compensation for the excess electricity produced beyond the FTR capacity. The total payout ($Payout(CfD + FTR), t$) equals the sum of the two:

$$Payout(CfD + FTR), t = Payout1_{(CfD+FTR),t} = +Payout2_{(CfD+FTR),t} = \tag{16}$$

The electricity produced and covered by the FTR is sold at the price of the higher-priced neighbouring bidding zone. Whenever this price falls below the CfD strike price, the payout is calculated as the difference between the two.

$$Payout1_{(CfD+FTR),t} = \begin{cases} \min(Q_{\text{owf},t}, FTR_{\text{nl}}) \times (P_{\text{strike}} - P_{\text{high},t}) & \text{if } P_{\text{high},t} = P_{\text{nl},t} \\ \min(Q_{\text{owf},t}, FTR_{\text{no}}) \times (P_{\text{strike}} - P_{\text{high},t}) & \text{otherwise} \end{cases} \tag{17}$$

The excess electricity sold receives the OBZ price. The payout again equals the difference whenever this price falls below the CfD strike price.

$$Payout2_{(CfD+FTR),t} = \begin{cases} (Q_{\text{owf},t} - FTR_{\text{nl}}) \times (P_{\text{strike}} - P_{\text{obz},t}) & \text{if } Q_{\text{owf},t} > FTR_{\text{nl}} \text{ and } P_{\text{nl},t} > P_{\text{no},t} \\ (Q_{\text{owf},t} - FTR_{\text{no}}) \times (P_{\text{strike}} - P_{\text{obz},t}) & \text{if } Q_{\text{owf},t} > FTR_{\text{no}} \text{ and } P_{\text{nl},t} < P_{\text{no},t} \\ 0 & \text{otherwise} \end{cases} \tag{18}$$

4.3 Sensitivity Analysis on the Strike Price

This section provides a sensitivity analysis to better understand the impact of different designs for the SDE++ and the CfD on the revenues of OWFs. This analysis is important because the price levels in the scenarios are partly estimated, while they have a significant impact on the effectiveness of these measures. The goal is to answer the following questions:

- What is the difference in revenues and payout between the SDE++ and the CfD with the same strike price implemented?
- How do both measures change in relation to each other when the strike price increases?
- What strike price must be implemented to compensate for the revenue losses in the OBZ?

The revenues of the OWF with the CfD implemented equal the strike price. Therefore, a linear relation is expected between the revenues and the strike price. The SDE++ will show higher revenues when the average OBZ price stays below the strike price. When the strike price increases, the revenues will converge towards the revenues obtained through the CfD.

4.3.1 Experiment Design

The previous section on the results showed that the SDE++ and the CfD offer the most predictable revenues. The SDE++ resulted in higher average revenues but was more expensive compared to the CfD. But different from the FTR, in which compensation is based on the price difference between two markets, the height of the compensation through the SDE++ and CfD is highly influenced by the level of strike price. First, these experiments need to give clarity on how the revenues and payouts change when the strike price is adjusted. Second, they need to give insights into how the measures relate to each other when they have the same strike price.

Two different experiments are run. The first experiment is simulated over the data of 2018-2020. 100 simulations are run with a strike price ranging from 0 to 100 EUR/MWh. The second experiment is simulated over the data of 2021-2023. In this case, 200 simulations are run with a strike price ranging from 0 to 200 EUR/MWh. This is done because the difference in electricity prices observed for that period is higher. Furthermore, both measures are implemented as described above.

5 Data Collection and Preparation

This section describes how the right data is collected and prepared to use for simulation. The data that will be used for the model is data on electricity generation and data on electricity prices.

5.1 *Electricity Generation*

As described in Section 2.3.1, the electricity that an OWF can produce depends on the wind profile of the respective location, the design of the wind turbine and the capacity of the OWF. To calculate this generated electricity, the Virtual Wind Farm (VWF) model of Staffell and Pfenninger (2016) is used. This model simulates the power output from wind farms per year based on the given input as described above. The output provides the generated electricity per hour for the specific location and characteristics of the wind farm. Table 5.1 shows the precise input that is given to the model.

Table 5.1: Offshore wind farm characteristics

Variable	Input
Latitude	54.0633
Longitude	5.2944
Dataset	MERRA-2 (global)
Year of data	2018 - 2023
Capacity (kW)	2.0×10^6
Hub height (m)	125.5
Turbine model	Vestas V90 2000

Latitude and Longitude

The chosen location for the OWF is Doordewind ((Windopzee, 2024)). This area is already reserved for the development of two offshore wind farms with each a capacity of 2 GW. The first of these OWFs at this site is expected to become operational by 2031. This is the most northern location and therefore suitable to connect to a hybrid interconnection.

Dataset

The model uses data from NASA's MERRA-2 reanalysis (Global Modeling and Assimilation Office (GMAO), 2015). This dataset contains weather data and more from the time period of 1980 till present which with the wind speed can be calculated. This is the default dataset that is selected when using the model.

Year of data

The model generates output from the past five years, based on the respective historical wind data. This period of five years is selected under the assumption and the observation that wind profiles stay relatively consistent over the years. Although there will be annual fluctuations, it is generally stable across this timeframe.

This is the only variable that changes over time. Based on the year, different weather data are taken from NASA's dataset. Therefore, any differences in electricity output by the wind farm, for the same hour in a different year, are accountable to different weather data. Using this year and hour-specific data might influence the results in revenues for the wind farm. Section 5.1.1 elaborates on how the influence from the difference in electricity output over the years is removed to be better able to analyse the results.

Capacity (kW)

The OWF in the model has a capacity of 2.0×10^6 kW, or 2 GW. This capacity is the same as the capacity of the sides in Nederwiek, the upcoming wind farm zone that will be tendered within the Dutch Exclusive Economic Zone Ministerie van Algemene Zaken (2022). This ensures that the simulation outcomes are indicative of the performance of the latest generation of offshore wind farms in this region.

Turbine type

Different wind turbines have different power curves. This power curve describes the relationship between wind speed and the power output of the turbine. A study focusing on wind turbines in the North Sea shows that Siemens and Vestas are the most popular turbine brands, with Siemens turbines constituting 64% and Vestas turbines 24% of the total installations. These turbines differ in capacity, ranging from less than 1 MW to 6 MW. However, this data only reflects installed turbines in wind farms operational at that time. In contrast, newer wind farms developed in the Dutch EEZ after 2022 have capacities up to 11 MW (Windandwaterworks, 2024).

To ensure the model reflects the most recent advancements in wind turbine technology, for this study is chosen to use the wind turbine with the highest capacity available in the VWF model. This is the Vestas V164-9.5, a turbine with a capacity of 9.5 MW (Vestas, 2023).

The hub height of this turbine is site-specific. Therefore, the same hub height is chosen as the turbines of Hollandse Kust Noord, the newest OWF installed in the Dutch EEZ. This hub height is equal to 125.5 meters (CrossWind, 2023).

5.1.1 Generation Data

This subsection presents the data that is achieved with the use of the Virtual Wind Farm model as explained in the section above.

Figure 5.1 shows the monthly average electricity production of a hypothetical OWF with specified characteristics as described in 5.1. It is important to note that the representation is a monthly average, but that the actual data that will be used for calculations is on an hourly basis. The data is obtained using The Virtual Wind Farm Model by (Staffel and Pfenningner, 2016). It shows seasonal patterns, with higher electricity generation in winter and lower in summer. Both 2020 and 2021 show similar patterns. 2022 shows a significant peak in the beginning months, followed by more fluctuations in the middle months. In contrast, 2019 shows more stability, remaining higher in the latter months compared to other years.

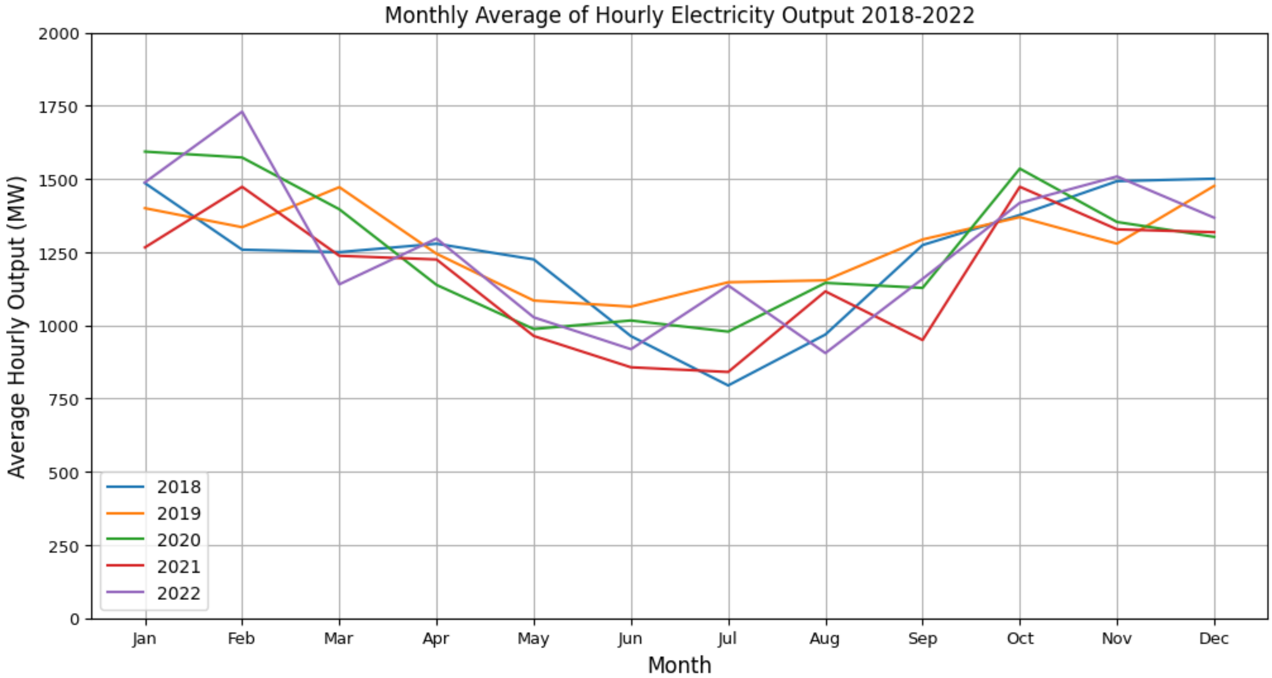

Figure 5.1: Monthly Average of Hourly Electricity Output 2018-2022

The differences in electricity generation over the years are only dependent on changes in weather data (the availability of wind), since other factors remain constant. Together with electricity price data, this data will be used to calculate the revenues of the wind farm. To compare revenues across different years and attribute observations to changing electricity prices, it is chosen to standardise the data on electricity output for each year. Therefore, the electricity output over the five years is averaged into a single year, resulting in an hourly dataset that represents the most accurate electricity output for each hour of the year. Additionally, this approach smooths out short-term fluctuations. Therefore, any single hourly outliers in the results are most likely explainable by extreme values in electricity prices.

A disadvantage of this approach is that differences in wind patterns over the years most likely influence the corresponding electricity price. The harder the wind blows, the more wind energy is generated, which most likely lowers the electricity price. However, this is not a linear correlation since the electricity price is not only set by wind turbines.

Figure 5.2 shows the final data on electricity output as explained above. The data shows seasonal patterns as seen in the individual years. Peaks and troughs are less noticeable than in the yearly data, as expected. This figure is an average representation of the final dataset that will be used as input for the model. The dataset that will be used for calculating the revenues of the wind farm consists of hourly electricity generation.

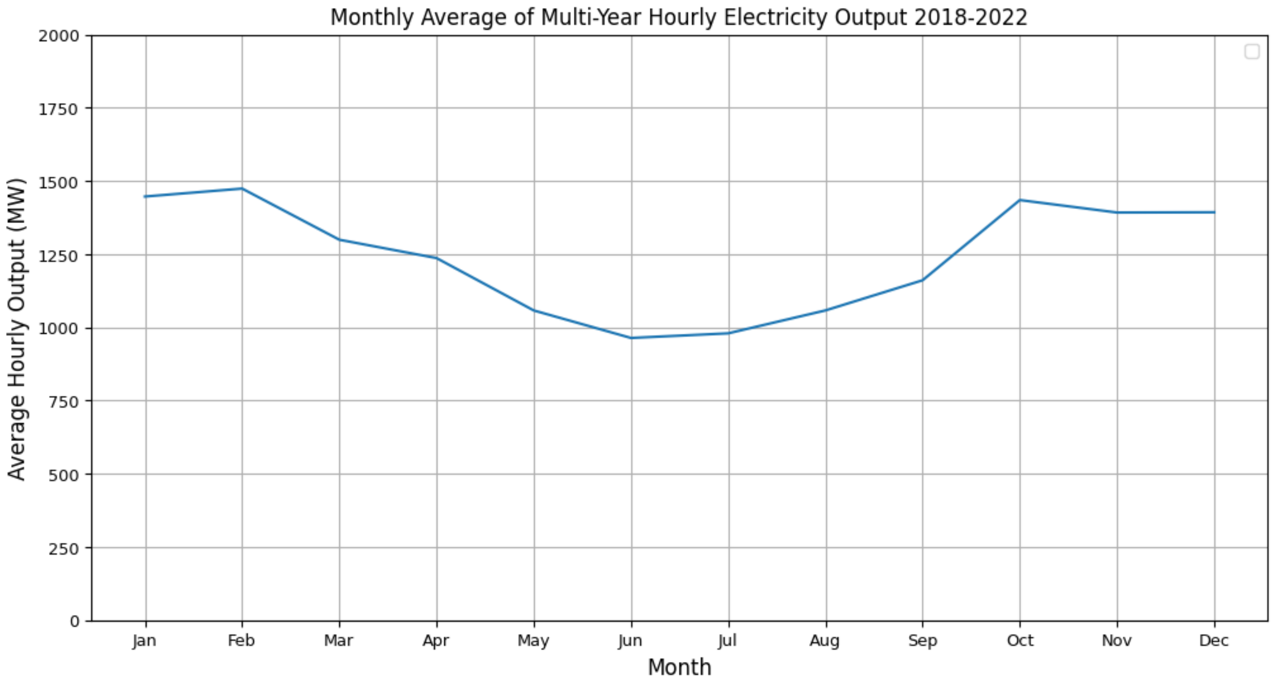

Figure 5.2: Monthly Average of Multi-Year Hourly Electricity Output 2018-2022

5.2 *Electricity price*

This study examines a hypothetical hybrid interconnection between The Netherlands and Norway. First, it is explained why Norway is a good fit for a hypothetical hybrid interconnection. Second, both electricity prices are examined.

5.2.1 Correlation between Electricity Markets.

The choice for a hypothetical hybrid interconnection is based on the assumption that the impact of an interconnection is maximised between electricity markets with a low electricity price correlation. This is because a high electricity price correlation indicates similar electricity markets. Therefore, they could benefit less from each other. Therefore, Pearson's correlation coefficient is used to compare the day-ahead electricity prices of The Netherlands with the European countries around the North Sea over the past five years (2019-2023). The analysis excludes France due to a lack of data. For Denmark, Norway, and Sweden, the electricity prices from the closest bidding zones to the North Sea are used. The correlations per year between the Netherlands and these countries were calculated and averaged over the five years. The electricity prices of all countries are obtained from ENTSO-E Transparency Platform (ENTSO-E Transparency Platform, 2023) for the period of 2019 to 2024. The results are shown in Table 5.2.

Table 5.2: Average Correlation Coefficients of Hourly Electricity Prices NL Compared with North Sea Countries.

Country	Correlation Coefficient
Denmark (BDZ 1)	0.82
Norway (BDZ 2)	0.70
Sweden (BDZ 4)	0.69
Belgium	0.90
Germany	0.73

The results show a relatively strong correlation between electricity prices in Belgium and Denmark, a moderate correlation with Germany and the lowest correlation with Norway and Sweden. This ranking aligns with the findings of an older study by Bobinaite et al. (2006). Additionally, a rapport by TenneT (2023) examines the usage of interconnection capacities on various borders during hours of shortages. It appears that a high contribution of 88% is expected from the interconnection between the Netherlands and Norway. However, this study does not consider an interconnection with Sweden. This is probably the case since there is no interconnection established (yet). Considering these studies, the observed correlation, and costs because of the distance between the Netherlands and these countries, Norway looks like a good fit for this study.

5.2.2 Analysis of the Dutch Electricity Prices

This research is focused on compensating for price risks in offshore wind farms in the context of an offshore bidding zone. Therefore, the aim is to select historical electricity price data that best illustrates the variability and risks associated with future electricity prices. Therefore, the most current data over the past six years (2018-2023) on electricity prices is chosen to work with, because it reflects the most current state of the market.

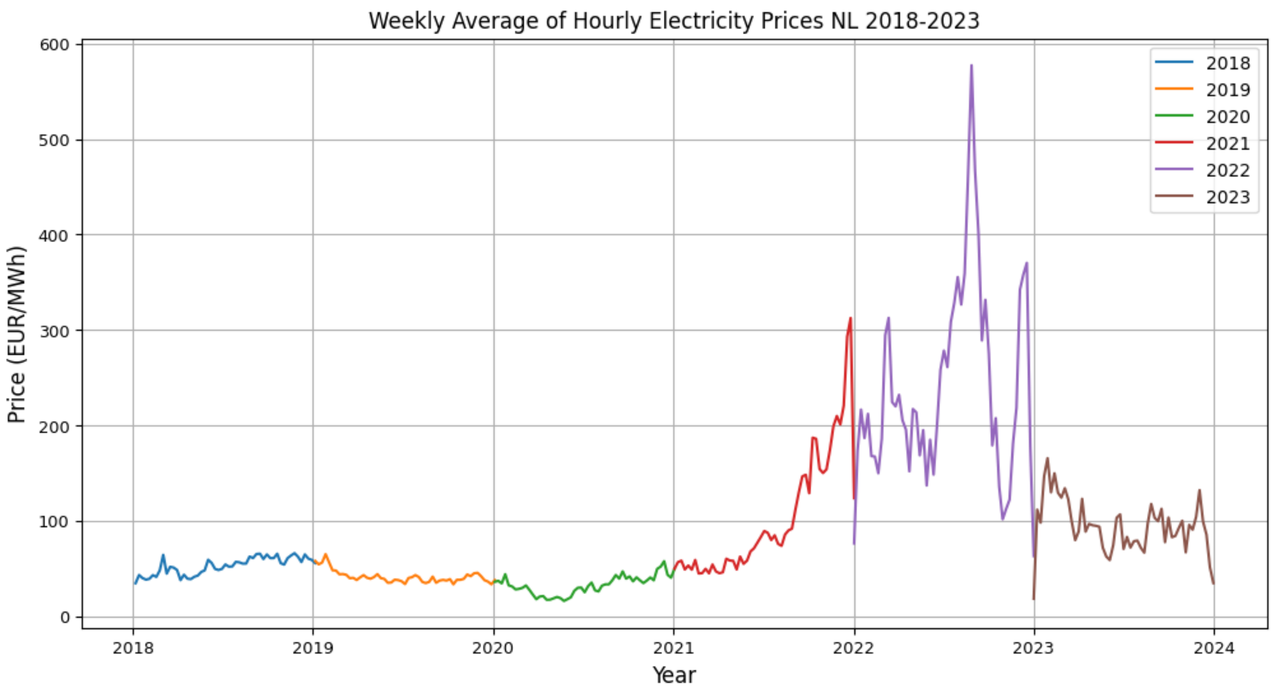

Figure 5.3: Weekly Average of Hourly Electricity Prices NL: 2018-2023

The graph shows relatively stable trends in the years before 2021. The years 2021 and 2022 show an increase in price and volatility with significant spikes. This change can be explained geopolitically by the Russian invasion of Ukraine, leading to higher gas prices, which often result in higher electricity prices (Zakeri and Staffell, 2023). Additionally, the peak in prices observed in the summer of 2022 can be explained by the heatwaves that occurred, affecting demand and supply dynamics (European Council, 2023). The year 2023 shows the most current situation regarding the electricity price. Still, the overall electricity price is higher and more volatile compared to the years before 2021, reflecting the ongoing geopolitical tension and higher fuel prices. The same trends and patterns are also seen in the electricity prices of Norway (see Appendix A.1).

In this study, the time frame is divided into two periods. The first period, referred to as the 'Stable Period', covers the years 2018 to 2020. In this period, the electricity prices range from 10 to 70 EU-

R/MWh. The second period, referred to as the 'Volatile Period', is ranging from 2021 to 2023. In this period, higher price fluctuations are observed with prices reaching between 300 and 400 EUR/MWh, and one peak reaching almost 600 EUR/MWh. This division is used to examine how OBZ impacts the revenue of OWFs under different market conditions.

Figure 5.4 presents the yearly average day-ahead electricity prices of the past six years from both Norway and the Netherlands. As expected, the same trend of higher prices towards the last three years is observed. It is noticeable that on average, the Dutch prices are higher than the Norwegian prices. This means that in the OBZ, the OWF will most often take over the Norwegian electricity price. Therefore, the difference in revenue income of the OWF will most likely be the highest when compared to an OWF that is connected to the Dutch home market, Furthermore, the electricity prices differ the most in the year 2020 and 2022, which are the years with respectively the highest and lowest average prices (See Table 5.3 for the specific averages prices). These are also the most volatile years from the past six years.

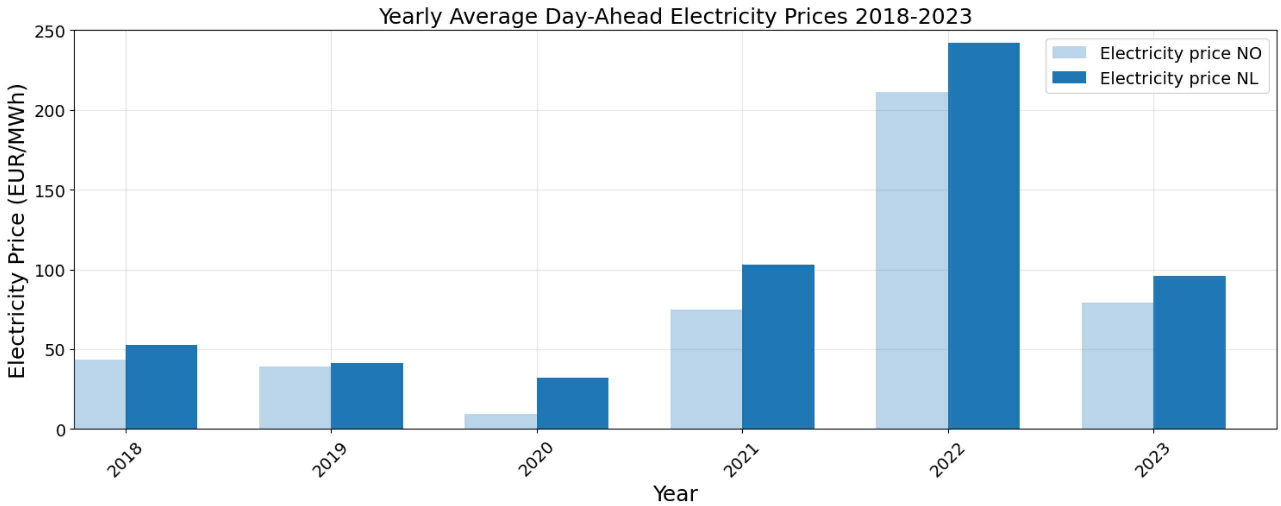

Figure 5.4: Yearly Average Day-Ahead Electricity Prices 2018-2023

Table 5.3: Yearly Average Day-Ahead Electricity Prices (EUR/MWh) 2018-2023

	2018	**2019**	**2020**	**2021**	**2022**	**2023**
NO	43.25	39.27	9.29	75.09	211.25	79.43
NL	52.53	41.19	32.25	102.95	241.89	95.79

Figures 5.5 and 5.6 present the same data as Figure 5.4, but in weekly averages. It is important to note that both figures show averages derived from the actual dataset. The dataset used for the final calculations of revenues is based on the hourly data over the same period of six years.

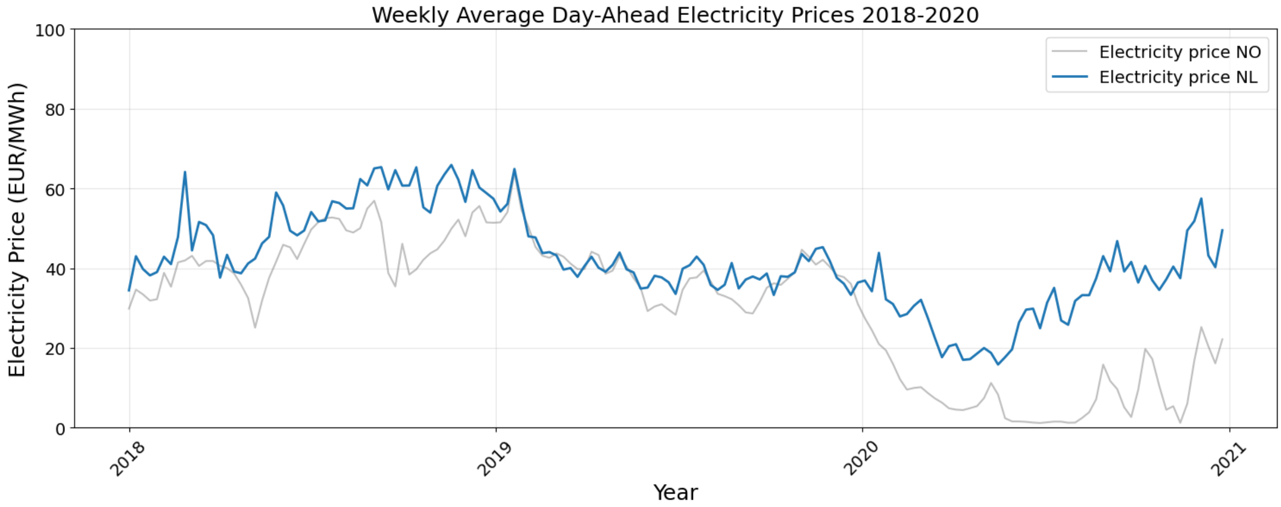

Figure 5.5: Weekly Average Day-Ahead Electricity Prices 2018-2020

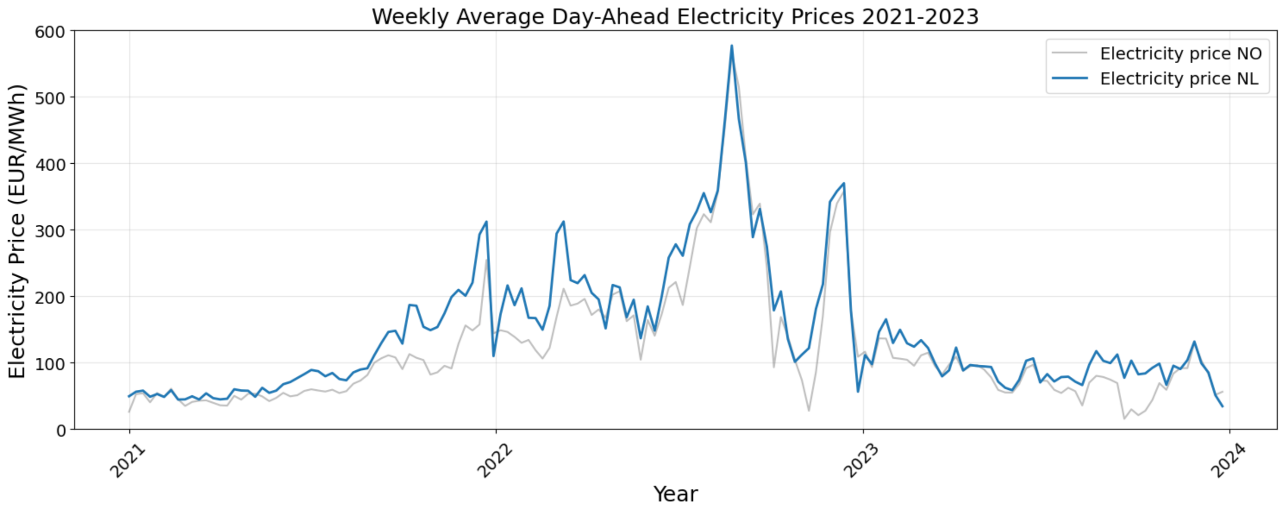

Figure 5.6: Weekly Average Day-Ahead Electricity Prices 2021-2023

6 Simulation and Results

This section reflects on the results of the simulation. First, a detailed analysis is given for each scenario that is simulated. Second, these findings are compared with each other. Together, this should give a complete overview of how the mitigation measures work and how they impact the revenues of an OWF. Last, a policy scorecard is filled in that gives an overview of the impact of the mitigation measures on the criteria discussed in Section 4. The findings are interpreted and discussed in the section after. It is important to note that the results are presented in volume weighted averages. However, the calculations themselves are based on hourly data. Furthermore, these results are primarily described from the perspective of the wind farm. However, the mitigation measures affect more stakeholders, which all have their own wants and needs. Section 7 elaborates on the results from different perspectives.

6.1 *Detailed Analysis for Each Scenario*

The aim of this section is to explore the implications of the different market designs and the corresponding mitigation measures. The analysis is presented with the help of bar plots which show the yearly average revenues, congestion rents and payouts. Line plots show the weekly average revenues, which allows to discuss the volatility of the revenue stream. All plots present hourly data averaged over the total volume of produced electricity by the OWF per year or week (3). Hourly data is required to take hourly fluctuations in the electricity price into account. Otherwise, potential troughs would be smoothed out by higher averaged data, which would impact the working of mitigation measures. Small tables support the bar plots with exact numbers. The analysis is structured based on the scenarios to understand the impact of each mitigation measure individually.

6.1.1 OBZ compared to home market

The home market and OBZ represent two different ways of integrating and managing the electricity that is generated by an OWF. In both approaches, the OWF is completely exposed to the market. In the home market approach, the OWF is directly integrated into its electricity market. Therefore, the OWF is dependent on the supply and demand dynamics of the home market. The OWF bids its electricity like all other generators and receives the same electricity price. They are connected to the shore and the electricity grid through radial connections. This approach leads to higher costs and it makes more use of space since every OWF needs an individual transmission cable.

The OBZ, on the other hand, is a specific geographical area, typically inside the economic exclusive zone of one of the countries, which forms its own electricity market. The electricity is traded based on the supply in the zone itself and demand from the connected bidding zones. The network congestion that occurs between the OBZ and the neighbouring bidding zones reflects the physical constraints of the interconnections. The OBZ allows for a more flexible and efficient dispatch of electricity between the connected countries. The electricity will flow to where it is needed the most against the lowest price. Although this maximises socio-welfare because electricity prices decrease, generators inside the OBZ face revenue losses as a result of congestion rents. The TSO receives the congestion rents, which equal the price difference between the electricity markets on both sides of the interconnector for the volume of transported electricity.

Figure 6.1 shows the results of a comparison of the yearly average revenues of the hypothetical OWF over the past six years between the OBZ and the home market.

As expected, a peak in revenues is observed in 2022 in both the home market approach and the OBZ. This is a result of the unexpectedly high prices in both markets during that year (Section 5. This pattern is visible in all other scenarios except the CfD because there is a cap on the revenues.

Furthermore, the average revenues of the OWF in the OBZ are always lower than the average revenues in the home market, where the last four years show a greater difference in revenues than the first two years. This is a result of low Norwegian day-ahead prices compared to the Dutch prices in the corresponding years (see Figure 5.5 and 5.6).

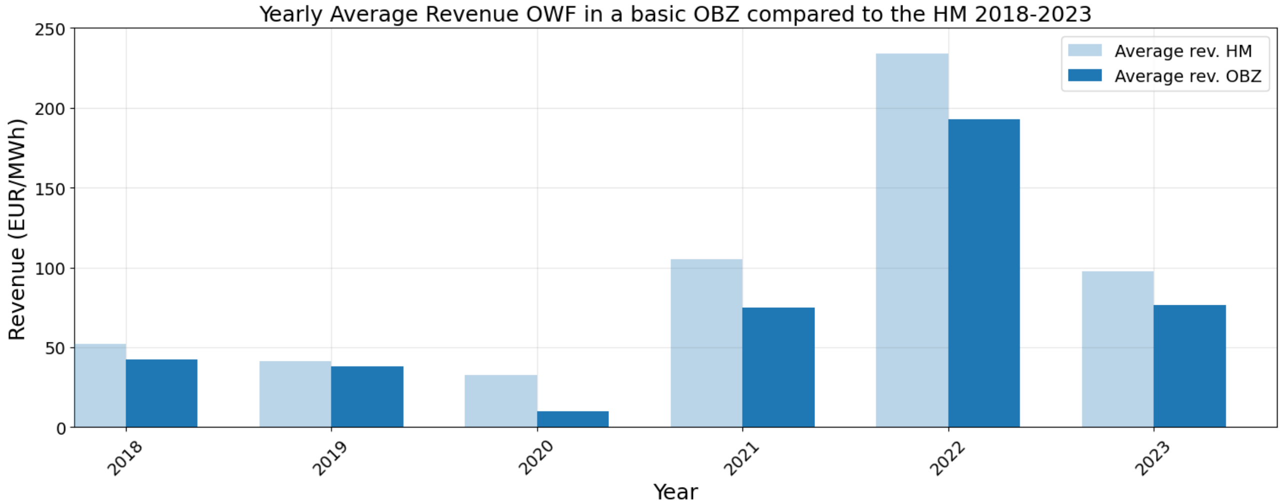

Figure 6.1: Yearly Average Revenue OWF in a basic OBZ compared to the home market 2018-2023

Table 6.1 shows the exact revenue losses. The decrease in revenue percentages ranges from a minimum of 8.63% in 2019 to a maximum of 69.97% in 2020. This variance does not only show the height of the revenue losses but also the volatility of these impacts over different years.

Table 6.1: Yearly Average Revenue OWF in OBZ and home market (EUR/MWh) 2018-2023

	2018	**2019**	**2020**	**2021**	**2022**	**2023**
Home market	52.23	41.50	32.53	104.99	233.80	97.34
OBZ	42.18	37.92	9.77	74.61	193.06	76.51
Decrease	19.24%	8.63%	69.97%	28.94%	17.43%	21.40%

Figures 6.2 and 6.3 show the weekly average revenues of the hypothetical wind farm over the years 2018-2020 and 2021-2023. This different representation of the same data allows for the analysis of the volatility of the revenue stream.

The results show longer times of troughs in the revenues for the OWF in the OBZ compared to the home market. For example, the year 2020 shows significant reductions in revenues from June to mid-August, where the average revenues range from 0.23 to 2.47 EUR/MWh. As explained above, this is a result of low day-ahead prices in the Norwegian electricity market. The difference between the maximum and minimum weekly average revenue in the home market over the years 2018 to 2020 is 52.08 EUR/MWh, while the difference in the OBZ is 59.10 EUR/MWh. Overall, the revenue stream is more volatile compared to the revenue stream of the home market. These results show that the revenues inside the OBZ are subject to the volatility of the lower-priced bidding zone.

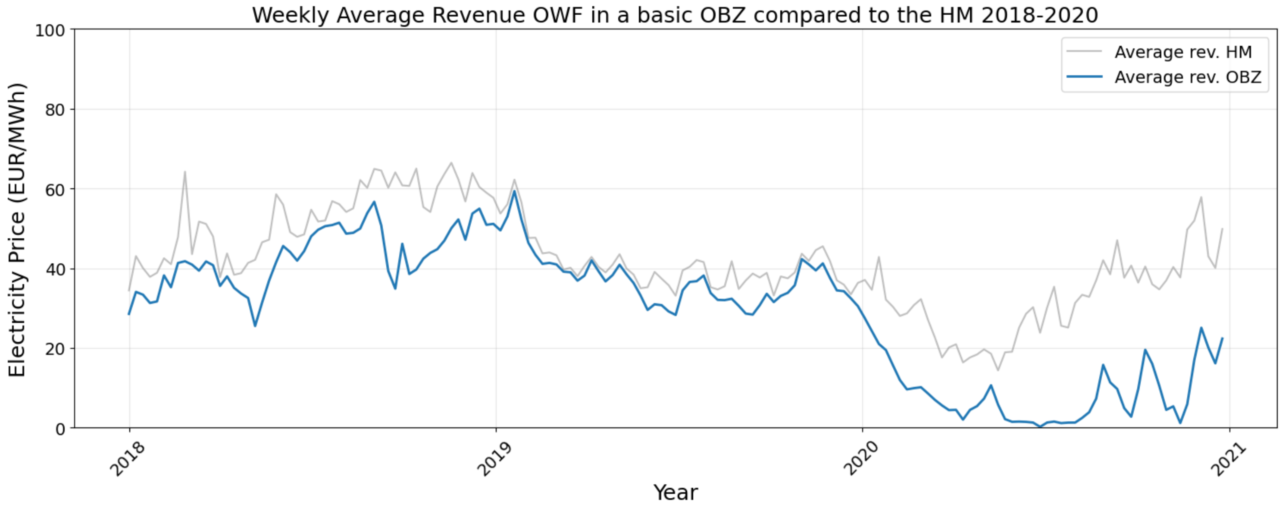

Figure 6.2: Weekly Average Revenue OWF in a basic OBZ compared to the home market 2018-2020

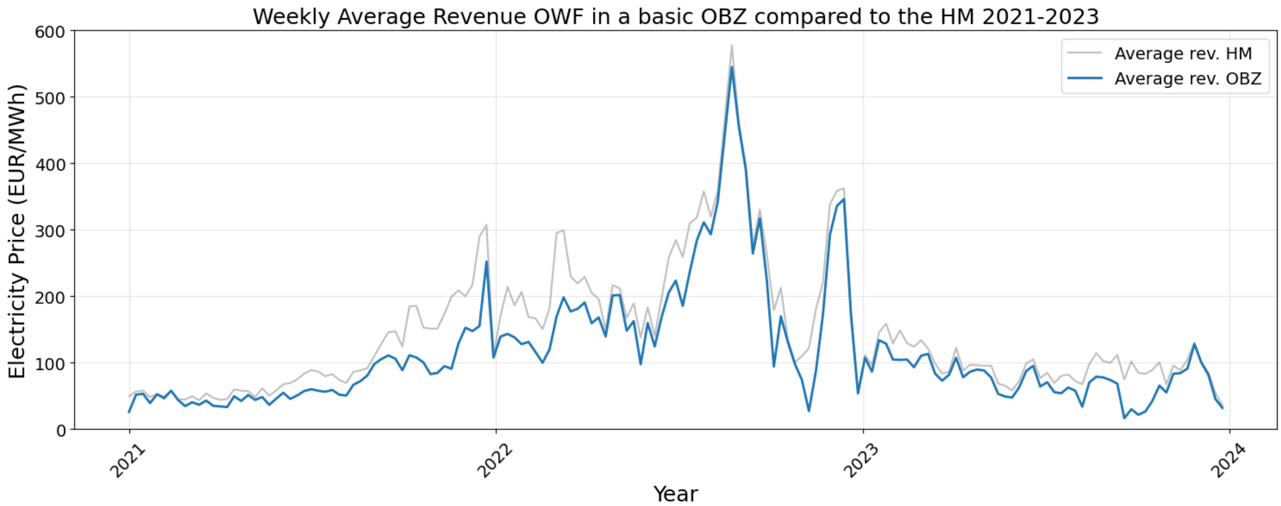

Figure 6.3: Weekly Average Revenue OWF in a basic OBZ compared to the home market 2021-2023

Figure 6.4 shows the yearly average congestion rents in the basic OBZ per interconnection. These congestion rents only include rents that arise from the electricity that is transported cross-border from the OWF inside the OBZ. During the analysis of the congestion rents, it is important to realise that the assumption is made that market coupling does not influence the day-ahead price of other electricity markets (Section 4.1). As a result, the congestion rents will most likely be higher compared to reality. Furthermore, they do not reflect the actual physical limitations of the interconnections.

Higher congestion rents are observed on the Dutch interconnection compared to the Norwegian interconnection. This means that more electricity flows from the OBZ into the Dutch electricity market than the Norwegian market. Furthermore, the results show that both Norway and the Netherlands have the highest congestion rents in 2022, with an average of 9.54 EUR/MWh and 40.70 EUR/MWh respectively. This is a result of the more volatile price in that year, which results in higher differences between both prices.

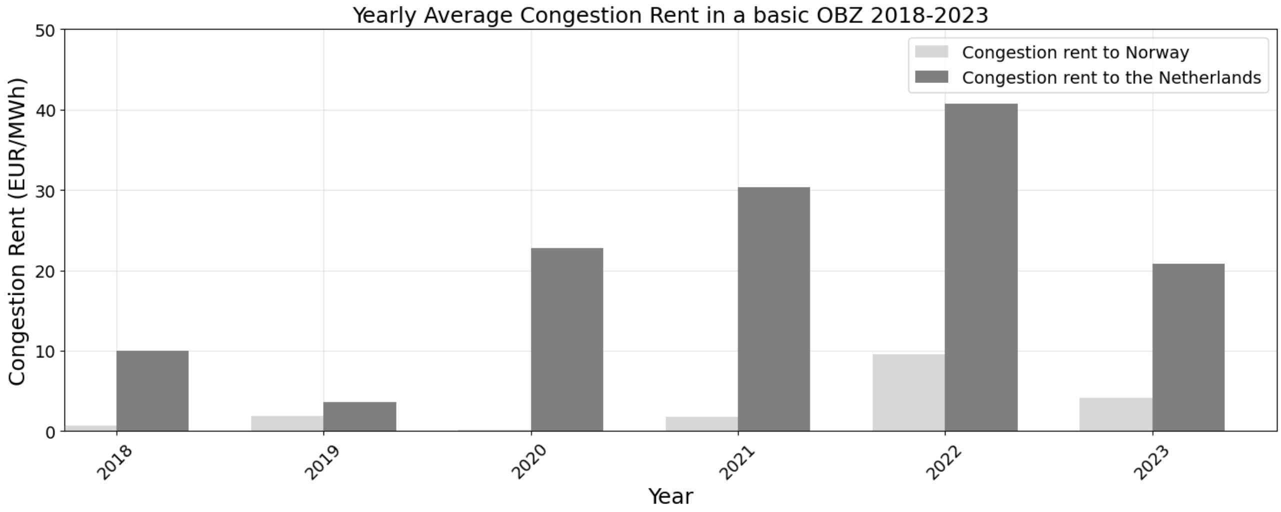

Figure 6.4: Yearly Average Congestion Rent in a basic OBZ 2018-2023

The results of the comparison between the OBZ and the home market show the need for the implementation of mitigation measures. In summary, the following results were observed:

- The OWF in the OBZ has consistently lower average revenues compared to the home market. The years that differ more can be attributed to greater differences in the Norwegian day-ahead price compared to the Dutch day-ahead price. This shows that the height of the average revenues of the OWF relies on the electricity prices of the lower-priced bidding zone.
- The OWF in the OBZ is exposed to longer periods of low revenues compared to the home market. The OWF in the OBZ is subject to the volatility of the lower-priced bidding zone.
- More congestion occurs on the interconnection towards the higher-priced electricity market (the Dutch bidding zone). This means that the OBZ has more impact on the higher-priced market.

6.1.2 SDE++

The SDE++ scenario simulates the impact of an SDE++ subsidy measure on the revenue stream of an OWF in an OBZ. The SDE++ is a one-sided CfD in which the OWF receives a premium if the electricity price falls below the determined strike price. This ensures a minimum revenue for the electricity that is produced and sold. There is no payout in times of negative electricity prices and the strike price equals 30 EUR/MWh (Section 4). It is important to take in mind that a different strike price would change the results significantly. Therefore, the impact of different strike prices is examined in Section 4.3.

Figure 6.5 shows the yearly average revenues of the hypothetical OWF in an OBZ with an SDE++ implemented over the past six years, together with the revenues observed in the basic OBZ scenario. The implementation of the SDE++ results in higher revenues for all years. It follows the same pattern as observed in the OBZ scenario, with high peaks in 2022. In 2020, an increase of 208% is observed (Table 6.2. This is the result of an average OBZ price below the strike price of the SDE++ (9.77 versus 30 EUR/MWh). The OWF faces in the other years an increase in average revenue ranging from 0.71% in 2022 to 4.94% in 2023.

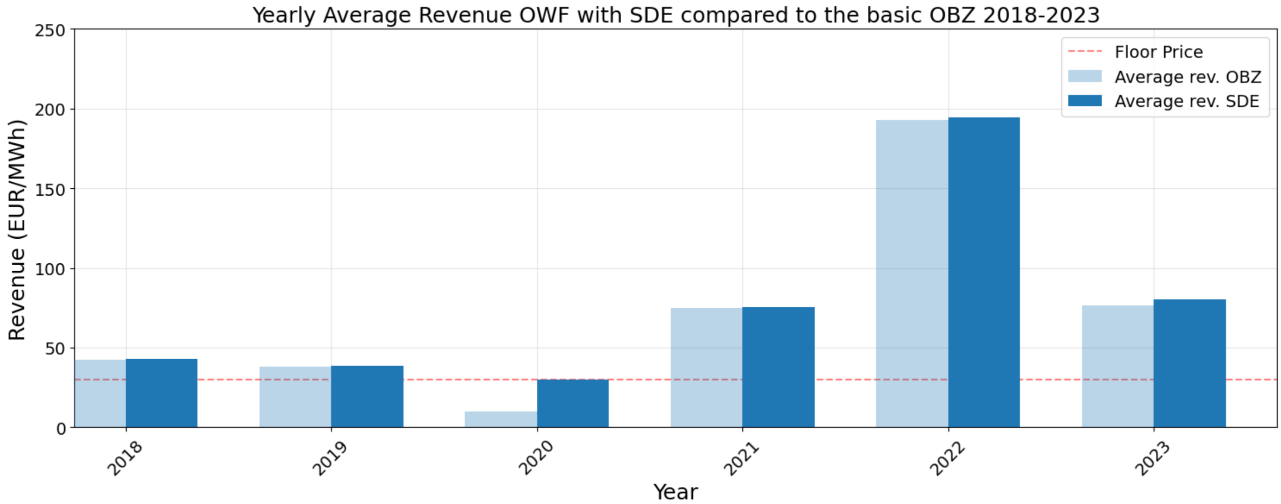

Figure 6.5: Yearly Average Revenue OWF with SDE compared to the basic OBZ 2018-2023

Table 6.2: Yearly Average Revenue OWF in OBZ and SDE 2018-2023

	2018	2019	2020	2021	2022	2023
OBZ	42.18	37.92	9.77	74.61	193.06	76.51
SDE	42.75	38.59	30.10	75.63	194.44	80.29
Increase	1.35%	1.77%	208.09%	1.37%	0.71%	4.94%

Figure 6.6 shows the yearly average payout by the counterparty of the SDE++ contract. Except for the year 2020, more compensation is paid towards the OWF compared to the first two years (1.02, 1.37 and 3.77 EUR/MWh in 2021, 2022 and 2023 respectively vs. 0.58 and 0.67 EUR/MWh in 2018 and 2019 respectively). This is not in line with the average revenues that are obtained in the OBZ, which shows an average revenue increase between the first two years and the last three years of 234.17%. It shows that the OWF receives compensation from the counterparty regardless of the height of the average revenues. This is explainable by the volatility that is observed in the electricity prices in the last three years.

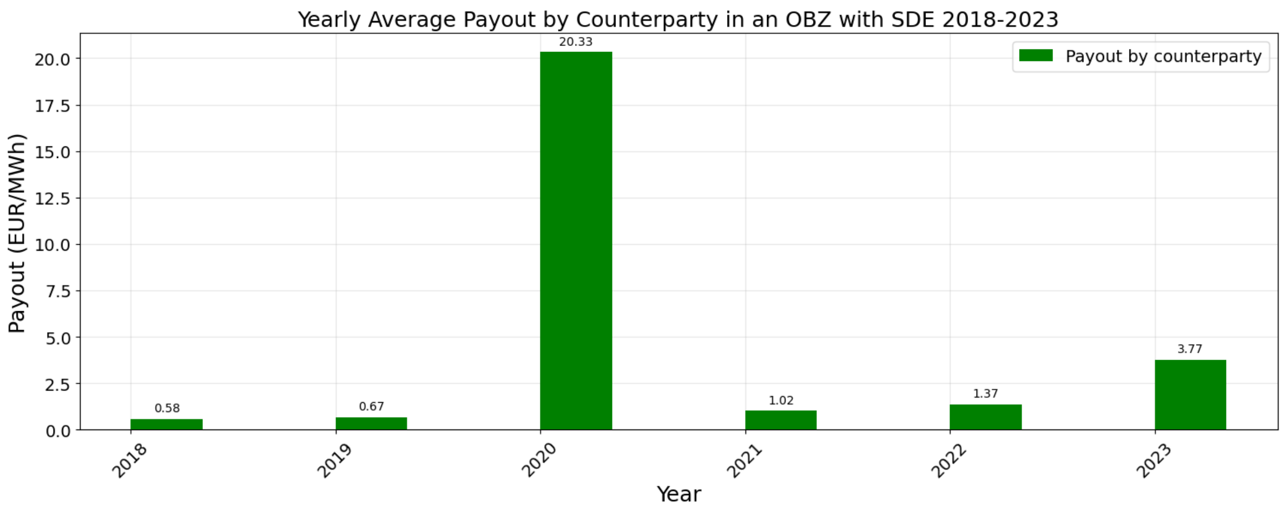

Figure 6.6: Yearly Average Payout by Counterparty in an OBZ with SDE 2018-2023

In summary, the following results were observed:

- The SDE++ results in more stable and increased average revenues.
- The SDE++ has more impact on the revenues if the OBZ price falls below the strike price or if the OBZ price shows a volatile pattern.
- If the SDE++ is implemented with an hourly price as the reference price, overcompensation might emerge in times of high average but volatile prices.

6.1.3 CfD

The CfD scenario represents an OBZ in which the OWF is contracted a two-sided CfD. If the OBZ price falls below the strike price, the counterparty pays the OWF the difference. Vice versa, the OWF pays back the difference if the OBZ price exceeds the strike price. Therefore, the OWF receives a revenue that equals the strike price for the volume of electricity sold (See Figure B.3). Due to the agreed strike price, the OWF can predict its revenues better, which reduces investment risks. For this analysis, a strike price of 50 EUR/MWh is implemented (Section 4). Similar to the SDE++ scenario, it is important to realise that a different implemented strike price has direct consequences for the results. Therefore, Section 4.3 elaborates on the impact of different strike prices.

This mitigation measure takes away all uncertainty around price volatility, as shown in Table 6.3. This is also clearly illustrated in Figures B.4 and B.5 in Appendix B.2.

Table 6.3: Yearly Average Revenue OWF in OBZ and CfD 2018-2023

	2018	**2019**	**2020**	**2021**	**2022**	**2023**
OBZ	42.18	37.92	9.77	74.61	193.06	76.51
CfD	50.00	50.00	50.00	50.00	50.00	50.00
Increase	18.54%	31.86%	411.77%	-32.98%	-74.10%	-34.65%

Depending on the prices in the OBZ and the strike price, the OWF receives compensation or has to pay back the extra income. This is shown in Figure 6.7, where the positive values represent the payout that has to be done towards the wind farm. The negative values are the received incomes from selling electricity to the market by the OWF that have to be paid to the counterparty of the contract. Due to the high electricity prices in 2022, the payout towards the counterparty of the CfD becomes significant, being 143.06 EUR/MWh. When the CfD would have been established, these prices were not foreseen. In this case, the counterparty benefits from it. On the other hand, the OWF would benefit from unexpectedly low prices.

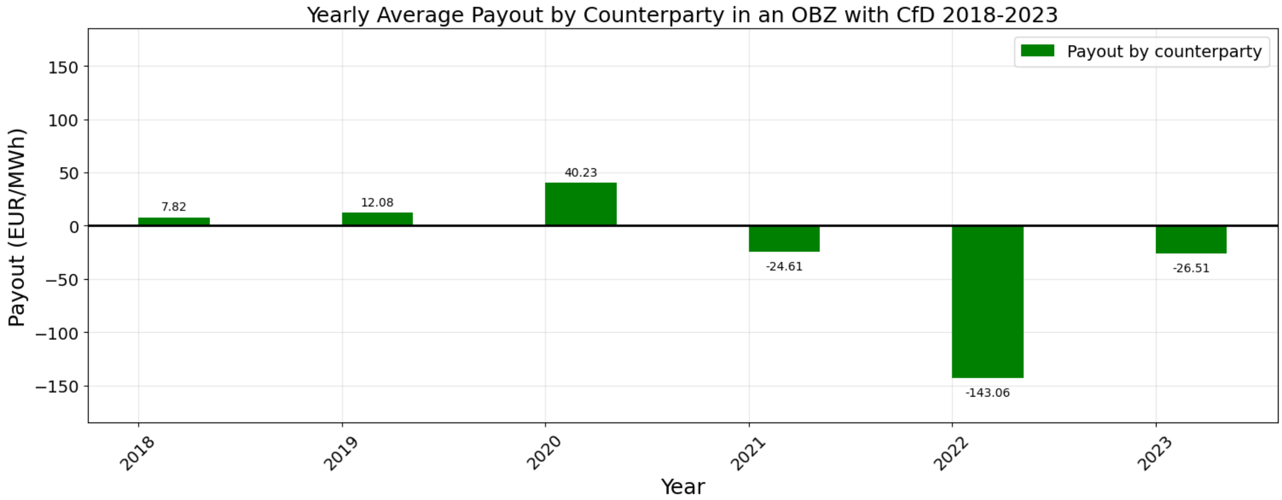

Figure 6.7: Yearly Average Payout by Counterparty in an OBZ with CfD 2018-2023

In summary, the following results were observed:

- The CfD removes uncertainty around price volatility, which results in stable revenues.
- The counterparty of the CfD benefits during high prices.

6.1.4 FTR

The FTR scenario represents an OBZ in which the OWF has the right to transport a maximum of 500 MW on both interconnections towards the neighbouring bidding zones at the price of the corresponding zone. The FTR has no impact on the dispatch or the actual use of the interconnector. Therefore, the OWF is only compensated for the electricity that is transported. The FTR is purchased by the OWF from the TSO. The payment toward the OWF equals the congestion rents for the volume of electricity transported up to the contracted volume.

Table 6.4 shows an overall increase in average revenues, with the highest increase in 2020, where the revenues almost doubled (96.62%). Other than different scenarios, this increase is explained by the price difference between the two electricity markets. The OWF receives the price of the higher-priced market for a maximum of 500 MW, which equals on average 1/3 to 1/2 of the output of the OWF (Figure 5.1). The other years show an increase in average revenue ranging from 5.83% in 2019 to 16.89% in 2021. Logically, the FTR has the most impact in years where the most revenue losses are observed. last, the revenue losses that occurred with the implementation of the OBZ decreased by 43.78% in the stable years from an average revenue of 29.96 EUR/MWh in the OBZ compared to the 42.09 EUR/MWh in the HM to 35.27 EUR/MWh in the OBZ with FTRs purchased (average over 2018, 2019, 2020).

Table 6.4: Yearly Average Revenue OWF in OBZ and FTR 2018-2023

	2018	**2019**	**2020**	**2021**	**2022**	**2023**
OBZ	42.18	37.92	9.77	74.61	193.06	76.51
FTR	46.46	40.13	19.21	87.21	213.17	86.82
Increase	10.15%	5.83%	96.62%	16.89%	10.42%	13.48%

Figure 6.8 shows the yearly average congestion rent and payout in the OBZ with FTRs contracted from 2018 to 2023. Here, a difference is made between both interconnections. Since the electricity

flows more often to the Dutch electricity market, the Dutch FTRs are of more importance to the OWF. As observed, more compensation is paid by the Dutch TSO. Although this compensation only returns revenue losses, it does not solve the congestion rents. However, it creates an incentive for TSOs to reduce them, as discussed in Section 7.

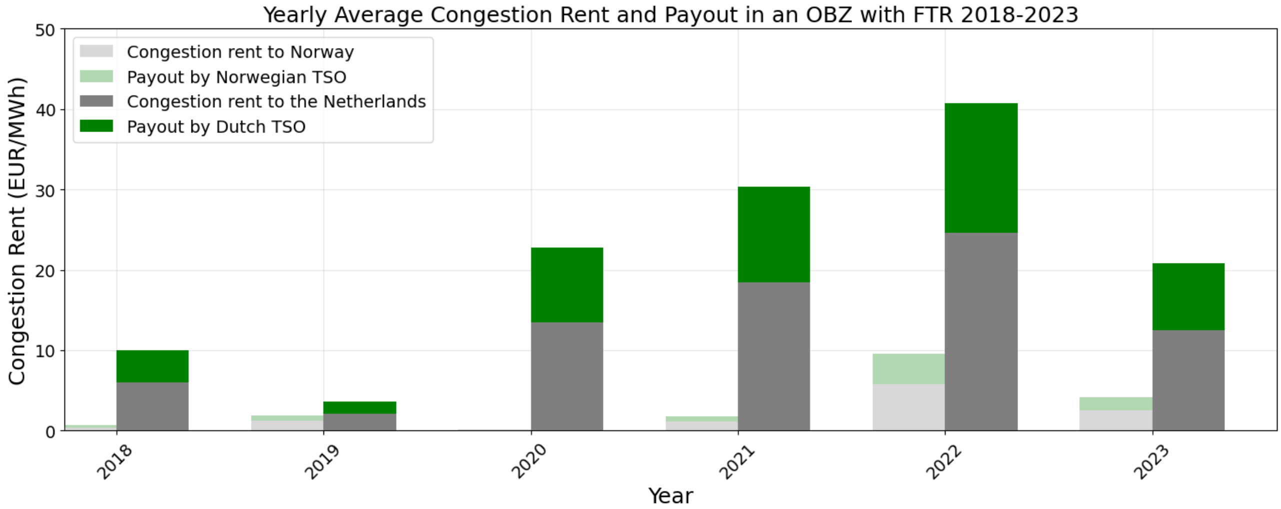

Figure 6.8: Yearly Average Congestion Rent and Payout in an OBZ with FTR 2018-2023

Under FTR contracts, the same volatility is observed as in the basic OBZ scenario. Figures B.7 and B.8 show that the same pattern is followed, but with slightly higher revenues. The year 2020 shows a slightly different pattern. Instead of following the revenue stream of the OBZ, the revenue stream is more volatile. This can be explained by the fact that in the OBZ, the revenue is almost only dependent on the Norwegian electricity price, but with the FTR contract, 1/3 to 1/2 of the electricity is sold at the Dutch price. Thus, the revenue stream takes over the volatility of both electricity markets.

Since the OWF receives partly the electricity price of the higher-priced market, and for the other part of the lower-priced market, a more volatile revenue stream is observed. In other words, the revenue stream is subject to the volatility of both electricity markets. This is slightly visible in Figures B.7 and B.8.

In summary, the following results were observed:

- The FTR has more impact during periods in which the electricity prices of both neighbouring markets differ more.
- The FTR on the interconnection towards the higher prices neighbouring bidding zone has more impact on the revenues of the OWF compared to the second interconnection.
- Volatility in both neighbouring electricity markets affects the revenue stream of the OWF under FTR contracts.

6.1.5 CfD + FTRs

In this scenario, the CfD is implemented in continuation of FTRs. This means that the CfD is calculated over the effective price that the OWF receives from selling electricity through FTRs and the normal market. Since the OWF receives a different price, for the first 500 MW that is sold, than the rest of the electricity, the payment from the CfD also differs for the first 500 MW compared to the rest of the electricity. For example, if the price of the higher-priced market exceeds the strike price of the CfD, the OWF pays back the difference to the counterparty up to 500 MW. If the price of the lower-priced market falls below the strike price, the OWF receives a payment for the rest of the electricity. The strike price in this scenario equals 50 EUR/MWh and FTRs are sold on both interconnections for a capacity of 500 MW. In the end, the revenues of the OWF equal the strike price for the volume of electricity sold. This is equal to the revenues obtained in the standalone CfD (Figure B.3).

Figure 6.9 shows the yearly average payout by the counterparty of the CfD. Payouts in the first three years range from 3.54 EUR/MWh in 2018 to 30.85 EUR/MWh in 2020. During the last three years, the payment goes to the counterparty, ranging from 36.47 and 37.15 EUR/MWh in 2023 and 2021 to 162.97 EUR/MWh in 2022. For this pattern, the same explanation applies as the one provided in the CfD scenario. However, the average payouts towards the OWF are lower compared to the CfD scenario, while the return of income towards the counterparty is higher. This is elaborated on in the next section.

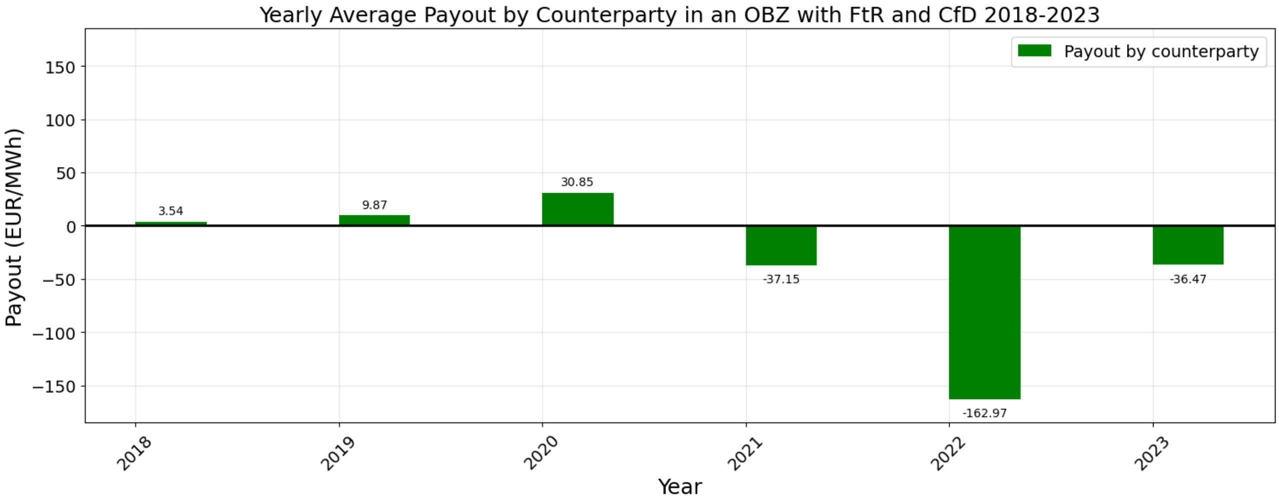

Figure 6.9: Yearly Average Payout by Counterparty in an OBZ with FTR and CfD 2018-2023

6.2 Mitigation Measures Compared

The goal of this subsection is to compare the outcomes of each scenario to get a better understanding of the impact of the mitigation measures. The average revenues of the mitigation measures are shown in Table 6.5.

6.2.1 SDE++ vs. CfD

Both the SDE++ and CfD aim to stabilise the revenues. The SDE++ ensures a minimum price whenever the electricity price falls below a certain level, while the CfD results in a fixed revenue per MWh. Here, the market price does not matter anymore. Therefore, the CfD offers more stability in average revenues since it sets the price. However, the SDE++ secures a minimum income and a variety of revenues based on the volatility of the price in the lower-priced neighbouring bidding zone and its frequency of high prices. Therefore, in periods of high average electricity prices, the SDE++ offers a higher revenue stream. However, since the minimum price level in an SDE++ is often lower than the set price in the CfD, it also brings more uncertainty, and lower revenues in periods where the electricity price is lower.

The payment by the counterparty of the contracts works the same in times of low average prices, i.e. when the OBZ price falls below the strike price. However, since the strike price of the SDE++ is often set lower compared to the strike price of the CfD, the payment towards the OWF is higher in the CfD scenario, as can be seen in the years 2018, 2019 and 2020 in Figures 6.6 and 6.7.

A big limitation in the analysis of these results is the fact that both SDE++ and the CfD are significantly influenced by the height of the strike prices. As discussed in Section 4.2, these levels are estimated. Since the estimation resulted in two different levels, a comparison between the mitigation measures remains difficult. To tackle this problem, additional experiments are done in the form of a small sensitivity analysis (Section 4.3.

6.2.2 FTR vs. SDE++/CfD

The results show that FTRs directly return the revenue losses. This is because the OWF benefits from higher prices in neighbouring zones, which is not the case with the other mitigation measures. This can lead to higher revenues compared to other mitigation measures in years where the prices of the connected electricity markets differ more. However, the results also suggest that the OWF is exposed to more volatility in its revenues. Therefore, compared to the FTR, SDE++ and CfD provide more predictable revenue streams because they offer a strike price. The effectiveness of the FTR is more dependent on the price differences between the connected zones, but it does not target the volatility of the electricity prices.

6.2.3 FTR + CfD vs. Other Mitigation Measure

The combined scenario also returns revenue losses. However, they partly end up at the counterparty of the CfD. In this case, the counterparty benefits from the FTR contracts because the CfD payments decrease if the counterparty has to pay out. On the other side, whenever the OBZ price exceeds the strike price of the CfD, the FTR results in an even greater difference between the initial price that the OWF receives and the strike price. This means that the payout from the OWF towards the counterparty increases compared to the not-combined scenario. As a result, the counterparty receives the congestion income that is generated by the OWF. This is shown in Figure 6.7 where the payout towards the counterparty equals 24.62, 143.06 and 26.51 EUR/MWh for the years 2021, 2022 and 2023 respectively, compared to the payout in Figure 6.9 of 37.15, 162.97 and 36.47 EUR/MWh for the same years.

Still, the OWF benefits from the more predictable revenue streams by receiving the same price for the electricity that is sold throughout the time of duration of the contract, as is the case in the not-combined CfD scenario. In other words, the same effect is obtained in the combined measure compared to the not-combined CfD scenario, while the payment for the counterparty is less. This is elaborated on in Section 7.

Table 6.5: Yearly Average Revenue of OWF across Different Scenarios (EUR/MWh) 2018-2023

	2018	**2019**	**2020**	**2021**	**2022**	**2023**
HM	52.23	41.50	32.53	104.99	233.80	97.34
OBZ	42.18	37.92	9.77	74.61	193.06	76.51
SDE++	42.75	38.59	30.10	75.63	194.44	80.29
CfD	50.00	50.00	50.00	50.00	50.00	50.00
FTR	46.46	40.13	19.21	87.21	213.17	86.82
FTR + CfD	50.00	50.00	50.00	50.00	50.00	50.00

6.3 *Results Sensitivity Analysis*

This section provides the results of the sensitivity analysis. The aim is to better understand the impact of different price levels for the SDE++ and the CfD on the revenues of OWFs.

Figure 6.10 shows the results of the average revenues in the first experiment. The average revenues increase from 29.99 EUR/MWh at a strike price of 0 EUR/MWh, to 100 EUR/MWh at a strike price of the same height. At a strike price of 50 EUR/MWh, the revenues of the SDE++ converge towards the revenues of the CfD. From the perspective of the OWF, the SDE++ is more beneficial up to a strike price of 50 EUR/MWh.

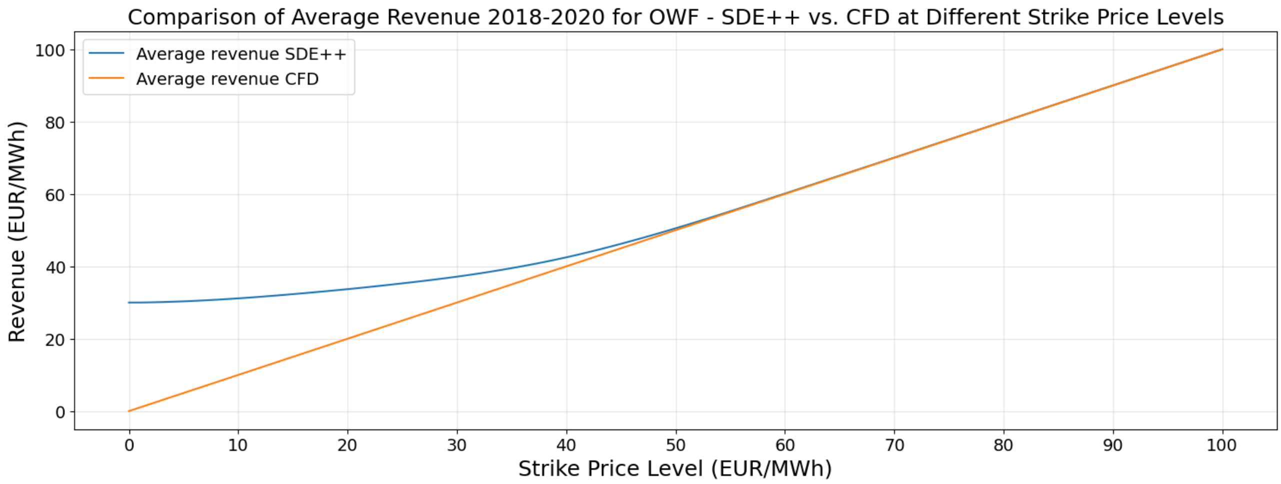

Figure 6.10: Comparison of Average Revenue 2018-2020 for OWF - SDE++ vs. CFD at Different Strike Price Levels

The results of the average payout of both measures in the first experiment are illustrated in Figure 6.11. The pattern of the impact of increasing the strike prices on the payments equals the pattern of the impact on the average revenues. A strike price of 0 EUR/MWh does not incur any payments for the SDE++, as expected. The negative payments for the CfD at a strike price of 0 EUR/MWh equal the revenues obtained in the SDE++ scenario with the same strike price. While the strike price increases, the height of the payments converge together. Although a CfD with a strike price of 0 EUR/MWh will not happen, it shows the maximal average difference possible between payments in the SDE++ and CfD. After a strike price of 50 EUR/MWh, the payments are equal between both measures.

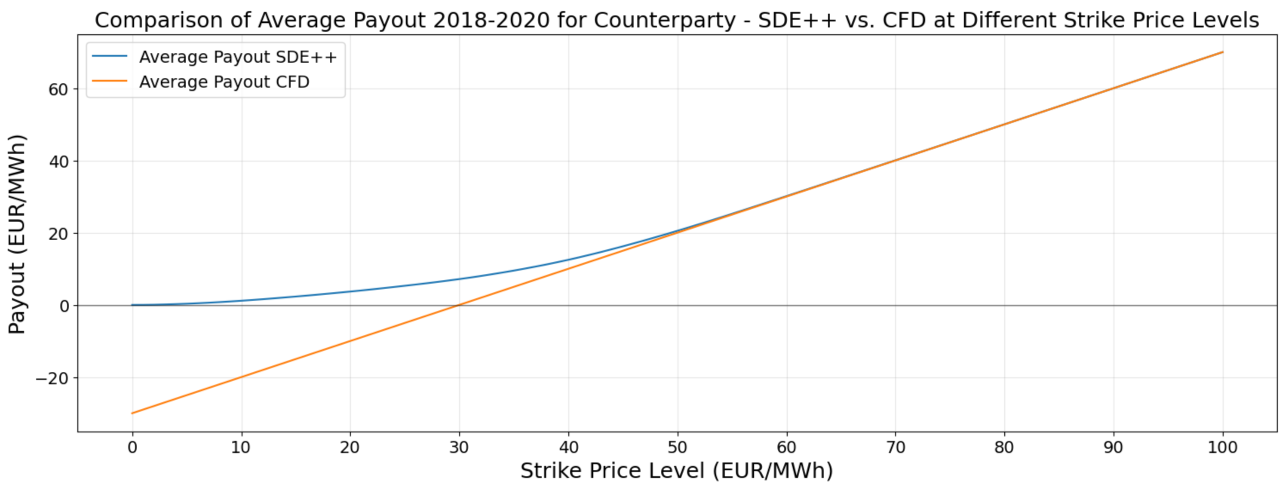

Figure 6.11: Comparison of Average Payout 2018-2020 for Counterparty - SDE++ vs. CFD at Different Strike Price Levels

The average revenue of the OWF that would have been obtained in the home market over the years 2018-2020 equals 42.08 EUR/MWh. To get these same results, the OWF should contract an SDE++

with a strike price of 39 EUR/MWh, while the strike price in a CfD needs to be 42 EUR/MWh. The payment towards the OWF equals 11.88 EUR/MWh and 12.04 EUR/MWh, respectively. Although a small difference, it shows that the payout from the SDE++ is higher than the CfD to get the same results for the OWF.

To understand this little difference in payments, it is important to realise that the SDE++ is implemented over an hourly reference price (as described in Section 4 and mentioned earlier in this section). This means that payments are also made in times of high average prices as long as there is volatility and the price drops under the strike price. When the SDE++ is implemented with a yearly average reference price, the payments better reflect the actual need for compensation by the wind farm. This most likely results in less payments, making the difference in costs between both measures more significant.

The results of the second experiment set are shown in Figures B.9 and 6.11. These results show a similar pattern to the results in the first experiment. However, both the revenues and payouts do not converge after a strike price of 200 EUR/MWh. This is most likely a result of the high price in 2021 and 2022.

In general, the sensitivity analysis indicates that if tenders for financial support work correctly, the choice per mitigation measure does not differ significantly for both the revenues and the payments. However, if unexpected extreme situations occur, like the high electricity prices in 2022, the difference in impact between both measures differs significantly. In the SDE++, the high prices result in extra revenues for the OWF, while in the CfD, they end up at the counterparty.

The additional experiments showed that if tenders for financial support work correctly, the choice per mitigation measure does not differ significantly for both the revenues and the payments. However, if unexpected extreme situations occur, like the high electricity prices in 2022, the impact between both measures differs significantly. In the SDE++, the high prices result in extra revenues for the OWF, while in the CfD, they end up at the counterparty.

6.4 Policy Scorecard

The 'Policy Scorecard' tool is used to show and compare the impact of different mitigation strategies per criterion. The grading scale (–, -, 0, +, ++, or N/A), indicates to which degree the criteria are positively or negatively impacted, with "–" showing a significant negative impact and "++" showing a significant positive impact. The policy scorecard is shown in Table 6.6. An explanation per cell is included in Appendix B.4.

Table 6.6: Policy Scorecard

Mitigation Measure	**SDE++**	**CfD**	**FTRs**	**CfD + FTRs**
Criterion				
Revenues during high avg. volatile prices	+	0	++	0
Revenues during high avg. stable prices	+	0	+	0
Revenues during low avg. volatile prices	++	+	0	+
Revenues during low avg. stable prices	++	++	0	++
Predictability of the revenues	+	++	-	++
Lost congestion rents	N/A	N/A	++	N/A
Costs for the counterparty	–	0	N/A	+

6.5 Summary of the Results

The key findings of the results are summarised as follows:

- The SDE++ and CfD offer the most predictable revenues. In times of low average electricity prices among one of the neighbouring bidding zones, the CfD results in higher revenues because it is implemented with a higher strike price. When both have the same strike price, the revenues will be more or less the same due to the limited paybacks. The SDE++ allows for receiving higher prices for the electricity that is sold in times when the electricity price of the lower-priced neighbouring bidding zone is higher than the strike price.
- The FTR offers the highest average revenues in times when the OBZ electricity price exceeds the strike prices of the SDE++ and CfD. This compensation is paid from the congestion rents that arise from cross-border electricity trading.
- In times of volatile prices, both the SDE++ and the FrR allow the OWF to benefit from high peaks in electricity prices. However, under the SDE++ measure, the OWF only receives a 'peak price' if the price of the other neighbouring bidding zone also peaks. During troughs, the SDE++ protects the revenues of the OWF by securing a minimum price, while the FTR only impacts the revenues if the price in the higher-priced electricity market differs. Therefore, this measure is more significant if the higher-priced zone does not go through a trough.
- In times of low average prices, the CfD yields the highest revenues and secures the OWF of a stable revenue stream for the years equal to the time of duration of the contract.
- In times of high average prices, the SDE++ does not significantly impact the revenue stream of the OWF. The FTR increase the average revenue more.
- The combined CfD and FTR scenario results in less payout by the counterparty in times of low average prices and more payout towards this counterparty in times of high average prices while the revenues of the OWF stay the same compared to a normal CfD scenario.

7 Discussion

This section discusses the findings of the study. Throughout this discussion, a bridge is built from the specific model results to the general conclusions, providing long-term insights for the government and OWF developers. It begins with an interpretation of the results from the model itself, offering case-study-specific numerical examples of the implementation of the OBZ and its mitigation measures. Next, the discussion includes the role of long-term contracts to understand how they influence the effectiveness of these measures. Then, it discusses the broader perspectives of different stakeholders, providing insights into various market configurations based on different objectives for each stakeholder. This is followed by a section on future alternative market connections. This explores the consequences of connecting to different markets, and highlights the trade-offs involved in selecting market connections and the implications of these choices on the broader energy market and its participants. Afterwards, a section on the limitations of the study describes how these might influence the findings. The section concludes with answers to the sub-research questions.

7.1 *Interpreting Model Findings*

This section dives into the interpretation of the model results. These are specific to the case study performed in this research. It provides quantitative insights into the magnitude of the impact of implementing the OBZ and mitigation measures. First, the findings on the OBZ are compared to those of the home market. Next, financial support mechanisms and the FTRs are discussed. Lastly, the findings on different combinations of these measures are discussed. Throughout this section, comparisons are made with grey literature.

7.1.1 The Impact of an Offshore Bidding Zone

Organisations and academic research adopted the idea that OBZs are an efficient way to integrate hybrid projects into the European energy system (Hardy et al., 2023, Nieuwenhout, 2022, NSWPH, 2022, PROMOTioN, 2020b). However, as a result of higher congestion rents, revenue losses of OWFs appear with the implementation of this new market setup. The model results on the impact of the OBZ are in line with these findings. It shows significant revenue losses compared to the home market approach. Different from the literature, these results show the magnitude of the impact of the OBZ on a hypothetical OWF of 2 GW between Norway and the Netherlands.

This study shows that the revenues from a hypothetical OWF of 2 GW within an OBZ between Norway and the Netherlands decreased from 8.63% in 2019 to 28.94% in 2021 compared to the home market, with an extreme difference in 2020 of 69.97%. Additionally, the revenue stream is more volatile over the six years observed, with an increase in volatility in the last three years when electricity prices skyrocketed. While these general findings are supported by the literature above, lower revenues and more volatility were also found in a more quantitative study conducted by Kenis et al. (2022). However, a direct comparison of the results between the two studies is difficult due to differences in their methodological setups. Kenis et al. (2022) modelled a fictive power system with several nodes to simulate demand and supply, while this study uses historical data on electricity prices and an hourly variance in electricity output for only one OWF.

The results show more congestion on the Dutch interconnection compared to the Norwegian interconnection (9.54 EUR/MWh versus 40.70 EUR/MWh in 2022, the most extreme year). This suggests that the OWF has a more significant impact on the Dutch electricity market. As a result, the impact of an OBZ is more significant to the OWF with higher electricity prices in its home market. This is also mentioned in the findings of Hodt and Hodt (2022), which designed a hypothetical OWF between Norway and the UK.

While the impact of the OBZ is more significant to the higher-priced country in lowering electricity prices, a notion worth mentioning is that the exporting country is likely to experience a decrease in welfare since the electricity prices will increase. This is not directly observed in the results of this study but supported by the study of Tosatto et al. (2022), who researched a case study with multiple countries connected. Due to exporting demand, more generators will supply energy, leading to a higher price. Therefore, a trade-off occurs for the exporting country in whether an interconnection is worth the decrease in welfare.

The congestion observed in the results suggests an opportunity for more efficient electricity dispatch between Norway and the Netherlands. In the summer months, the average electricity production falls below the interconnection capacity. Therefore, the congestion occurs mostly from exporting electricity from Norway. This suggests that a better dispatch could have been possible between the two countries. However, this suggestion is mostly based on the difference in electricity prices and the resulting congestion observed. This study does not simulate this effect because of the assumption that market-coupling does not affect the market prices of the corresponding markets. Consequently, the calculated congestion rents are higher compared to the real situation. Therefore, this congestion does not show the right signals for increasing capacity.

While more studies adopt the idea that an OBZ signals transmission scarcity (Kenis et al., 2022), a question can be asked about whether this has any impact. The idea of a bidding zone is to set its borders where congestion arises in the grid. Furthermore, after the hybrid interconnection is built, the cable will most likely not be expanded in the near future.

7.1.2 Financial Support Measures

The model results on financial support show a more stabilised revenue stream, which is an improvement in terms of predictability. Furthermore, the average revenue increases depending on the height of the strike prices.

However, the results also show the importance of the right design of the measure. For example, the SDE++, as it is implemented in the model, shows higher compensation in periods of higher average revenues compared to periods with lower average revenues, which is not the intended result of the measure. This is likely due to the reference price being equal to the hourly day-ahead price in the OBZ, combined with a higher frequency of troughs observed in the years with higher average revenues. This suggests a different implementation of the SDE++ where compensation is based on the average electricity price over a longer period. ENTSO-E (2024) proposes a design in which the reference price equals the average yearly OBZ price. This most likely results in payments that better reflect the actual need for compensation. With this design, the most compensation will be provided in 2020, and no compensation in 2021, 2022, and 2023. This issue will not affect the working of the two-sided CfD, since extra revenues from prices above the strike price are returned.

Where both financial support measures succeed in increasing average revenues and stabilising the revenue stream, they do not directly address the congestion rents. A report by the European Commission (2022) introduces a new concept of CfDs where the strike price equals the day-ahead price of the home market. Here, the compensation would equal the revenue losses that occur due to congestion rents. This would equal what could be received with the FTR if all produced volume of electricity would be contracted. The difference is that the compensation is paid by the government, which does not receive any congestion rents. Besides, this approach still does not directly tackle the underlying problem of congestion rents.

In general, the financial support measures show a problem in that the government compensates for congestion rents via the OWF, without addressing the actual problem. Consequently, the subsidy ends up at the TSO. The TSO is not allowed to decide how it can use these rents. The Netherlands Authority for Consumers and Markets (ACM) decides that a part must be spent on the grid. Due to this restriction, the TSO is also not allowed to earn an income from these congestion rents. Therefore, it cannot charge grid fees for these expenditures. This means that the subsidy by the government indirectly supports the expansion of the grid. Additionally, the height of this subsidy is dependent on the bids from OWFs in the tender process.

If the expansion of the grid occurs on the interconnection, the subsidies of the government could be seen as indirectly tackling congestion rents. However, the pathway of the subsidy is far from transparent. These findings suggest that the government subsidises the grid under the name of 'subsidising the OWF'.

7.1.3 Financial Transmission Rights

FTRs differ from financial support measures in that the OWF benefits from the price of the higher-priced market. Therefore, higher revenues are obtained if the markets show price differentials. FTRs do not provide any predictability of future revenues since this completely depends on the characteristics of the other electricity markets. The compensation paid by the TSO to the OWF equals the congestion rents resulting from transporting electricity from the OWF. Although not simulated by the model, this measure might even result in higher revenues compared to the home market if the two neighbouring electricity markets show opposite fluctuations in the electricity price.

Since the model of this study does not take the costs of purchasing FTRs into account, the positive findings of the FTRs might overestimated the actual benefits. The payments from the TSO to the OWF could be seen as the value of the contract, which can form an indication of the amount that the OWF is willing to pay for the FTRs. With this in mind, the OWF would not receive any net revenues from the FTR if it buys the rights for its most expensive offer. This means that the OWF still pays the congestion rents that occur in the OBZ by purchasing the FTRs. This is difficult to validate due to missing information about auction prices. However, in case of unexpectedly high and volatile revenues, as was the case in 2021, 2022, and 2023, the payments to the OWF are most likely higher than the price paid for the rights.

Some literature refers to FTRs as a reallocation of congestion income (European Commission, 2022). This might be understood as giving back the congestion income, while this is not exactly the case since the OWF must purchase the rights to be compensated for the price difference between the two neighbouring markets. This suggests that other studies also do not consider the costs of FTRs, while this is crucial for the overall effectiveness of the measure.

As is the case with financial support measures, FTRs do not directly tackle congestion rents. While the compensation to the OWF equals the congestion rents as long as the FTRs are contracted for the full volume of produced electricity, the initial congestion rents do not decrease. However, the prices of FTRs do signal where congestion is expected to occur. Furthermore, the higher the congestion rents itself, the higher the need for extra transmission capacity. Although not shown in the results of the study due to the assumption that market coupling does not influence the day-ahead prices of the corresponding markets, the significant congestion on the Dutch cable shows that there is still a big price differential between the two neighbouring bidding zones. This would suggest a larger transmission capacity between these countries.

7.1.4 Combination of Measures

The implementation of financial support measures with FTRs can take different forms. Since this combination within the OBZ is relatively new in the literature, the specific design is not yet clear. The model looks at a scenario in which the CfD is implemented in continuation of FTRs. However, this scenario alone is not enough to understand the possible impact of combining these measures. Therefore, a second scenario is discussed in which the CfD is implemented next to the FTR where both measures function independently from each other.

The first scenario presents a situation in which the OWF receives the strike price from the CfD, while the government only subsidises low prices that are not a result of congestion rents. This occurs because the government compensates based on the effective price, as a result of the FTR. If the FTR is established with the higher-priced market, the effective price reflects the higher price of both markets. As a result, the compensation from the government to the OWF decreases, and the payment from the OWF to the government increases. These lower costs and higher income (or the difference between payments without or with an FTR) equal the congestion rents. If the FTRs are purchased for the full amount of electricity produced by the OWF, this combination would result in the same revenues for the OWF and payments by the government as in a home market with only the CfD implemented.

However, in this market design, there is no incentive for the OWF to purchase the FTRs. The government could potentially purchase the FTRs for the OWF. However, in that case, the government indirectly pays for the congestion rents through the FTRs.

The same structure might be possible with the SDE++ implemented in continuation with FTRs. This would allow the OWF to benefit from a higher effective price as a result of the FTRs, while the subsidies would be lower. Since this combination results in shared benefits, the question arises: who has to purchase the FTRs?

The second scenario presents a situation in which both measures are implemented next to each other and function independently. This is a more likely scenario to occur since both contracts are established with different counterparties. The total revenues of the OWF would be the same as in the CfD scenario, plus the extra revenues obtained through the FTRs. This would make it the most attractive scenario for the OWF, as it benefits from the stability of the CfD while obtaining additional revenues through the FTRs. However, with a high strike price from the CfD, the OWF would benefit twice from the congestion rents, which sounds unlikely to happen. If the CfD tender works correctly, this situation will not occur.

7.2 Long-term Contracts in Future OBZ Markets

After discussing the case-specific results, this section dives into the role of long-term contracts in future OBZ markets. Including this part is important because long-term contracts influence the effectiveness of other mitigation measures. They were not included in the model simulations due to the high presence of uncertain variables and the limited amount of information available on contract prices.

As discussed in Section 2.5, long-term contracts, or PPAs, are important for securing investment for OWFs through stable and predictable revenues. PPAs are similar to a two-sided CfD in a way that they guarantee the OWF with a certain electricity price. However, PPAs are contracted with market participants instead of the government, with the corresponding day-ahead price as the reference price. Long-term PPAs for over 15 years help OWFs in the home market to receive financing from investors due to the security of revenues.

Since PPAs are mostly contracted in the bidding zone of the counterparty, a significant extra risk appears with the implementation of an OBZ. The payments from the PPA are calculated as the difference between the day-ahead price and the PPA price. However, this day-ahead price does not match the OBZ price. If the market price, in which the counterparty is situated, exceeds the PPA price, the OWF has to return the difference. However, the OWF does not receive this market price since the OWF operates in another market. This might result in payments that the OWF is not able to make.

For example, the OWF conducts a PPA contract at the price of 50 EUR/MWh in the Dutch market. If the Norwegian price equals 40 EUR/MWh and the Dutch price equals 80 EUR/MWh, the OWF has to return 30 EUR/MWh for the contracted volume to the counterparty. Since the OWF receives the Norwegian price, only 10 EUR/MWh is left after returning the difference. This presents the possible impact of an OBZ on long-term contracts established in another market.

Since the FTRs compensate for the price difference between these markets, a combination with PPAs might allow the OWF to still secure its investments in an OBZ. The FTR would compensate the 40 EUR/MWh difference between the Dutch and OBZ price. From this compensation, the difference in the Dutch and PPA price can be 'returned', and the OWF is left with a compensation of 10 EUR/MWh which equals the difference between the PPA and OBZ price.

However, a problem is that FTRs are currently only contracted for a maximum of 1 year, while PPA contracts range from 1 to 15 years. Therefore, FTRs do not secure the price risks that arise with long-term PPAs in an OBZ. A solution would be a product that offers longer-term protection from these risks, ensuring that OWFs can enter into PPAs. This is elaborated on in Section 7.3.2. It is important to note that financing through PPAs is only possible with sufficient demand. The question of whether there is enough demand for PPAs in the future electricity market is not addressed in this study.

7.3 Stakeholder Implications

After discussing the case-specific results and the role of PPAs in the OBZ market, this section steps back from the objective findings and explores the OBZ market design through the lens of different stakeholders. The main stakeholders involved in this multi-actor problem are the government, the wind farms, and the TSO. However, since this research focuses more on the relationship between the government and the wind farm, the TSO is only little addressed. For the other two, various perspectives are considered. This provides a wide range of objectives from which the OBZ market can be designed or operated.

7.3.1 Perspective of the OWF

In the scope of this study, it is assumed that the overarching goal of the OWF developer is to make sure that the project is financially viable. It depends on the project and the corresponding strategy of the wind farm developer, which goals are more important than others. This depends on the specific project, the system layout and the electricity markets in which the OWF operates. Therefore, it is important to evaluate how different goals affect the choice of market design. In this section, a distinction is made between four different goals.

The first goal focuses on creating a **stable and predictable revenue stream** during the lifespan of the OWF. This is about minimising the uncertainty around the income that is generated. This goal becomes more important with the implementation of an OBZ due to the higher volatility that is observed in the revenues. The second goal is to make sure that **investments are secured** from the beginning of the development of an OWF. Although both goals are closely related, the first goal is more about being able to forecast an income during the operational phase of the OWF, while the second goal is about making sure to have enough revenues throughout the whole project to find financing from investors. The third goal is to **minimise price risks**. In the context of the implementation of the OBZ, this is about the risks of revenue losses and the volatility of the price differences between the two markets. This goal differs from the other goals in that it directly targets dynamics that negatively impact revenues. The last goal is to **maximise revenues**. This goal is not only about ensuring that the project works but is about making the highest revenues possible.

Stable and Predictable Revenue Stream
The most stable and predictable revenue stream results from a market design with a two-sided CfD implemented. The OWF will always receive the price that is agreed on in the contract. There will not be any incentive for the OWF to purchase FTRs as a continuation after the CfD since it does not influence the revenues. However, when these contracts can be implemented next to each other, not influencing each other, it can result in higher averages. However, it is important to realise that the

potential possibility of including FTRs might influence the strike price. If OWFs are able to purchase FTRs, the wind farm becomes more profitable. This might result in OWF developers that offer lower strike prices in the tender process. If these strike prices are below the minimum price required to return investments, the peak prices become more important. This results in electricity prices that might be volatile of which the OWF is dependent. Whenever the investment costs are expected to be returned with the strike price of the financial support level, these levels of electricity prices are less important, resulting in volatility observed that is less significant.

The SDE++ also offers a form of stable and predictable revenues. However, the same consideration has to be made as with implementing the CfD in continuation of the FTR. If the OWF is dependent on the electricity price whenever it exceeds the strike price, there might be volatility that has to be taken into account. If the OWF is able to secure a level of strike price with which expected investment costs can be returned, the volatility of higher prices is less important. In that case, the SDE++ might be able to provide the necessary stable and predictable revenue stream.

Whenever financial support is not granted, the OWF is exposed to the market. To still secure stable and predictable revenue streams, conducting PPAs might offer a solution. However, without a product that mitigates the price difference between the two markets for a longer period, this option becomes too risky, as discussed in Section 7.2.

Secured Investments
The development of OWFs is highly influenced by the level of security to return on investments. If the OWF developer is able to show contracts that make sure that the OWF has a certain income, there is more chance of getting financed.

The first simple way to secure a return on investments is through financial support by the government. This can be a different form of CfDs, as discussed above. The level of strike price reflects the risk an investor is willing to take.

When the OWF is exposed to the market, long-term contracts like PPAs could offer investment security. Again, this would only be possible with FTRs for a period that equals the lifespan of the OWF, or the duration of the PPA contract. The existence of these new long-term FTRs is dependent on the government or the TSO (Section 7.3.2).

Minimise Price Risks
The price risks are related to the risks that occur with the implementation of the OBZ. This is the risk of facing revenue losses and the corresponding volatility of the price differences between the two markets. If the goal of the OWF is to minimise these risks, regardless of the market characteristics of the other markets, a measure is required that specifically targets these price differences. This might apply to an OWF developer who has experience in the Dutch home market and only wants to tackle the differences that occur with the implementation of the OBZ.

In this case, the FTR would be sufficient. If the FTR is purchased for a capacity that equals the produced electricity, the OWF can operate as if the OWF is situated in a home market. This would remove all price risks that are associated with the OWF (with the assumption that there are no volume risks).

Maximise Revenues
A market design with FTRs allows for the highest revenues, but only if one of the markets has higher prices than the other. In the case of the Netherlands and Norway, it would be sufficient to purchase FTRs on the Dutch interconnection since the Dutch market is often the higher-priced market. Whenever both markets show peaks that are higher than the other market, FTRs on both interconnections could even result in higher revenues compared to the home market. This shows an opportunity for OWF operators to benefit from the OBZ.

Furthermore, the SDE++ allows the OWF to benefit from high peaks in the OBZ price, therefore maximising revenues, while also being secured from troughs. This measure would be more beneficial with lower electricity prices of the connected markets.

7.3.2 Perspective of the Government

An important question currently addressed is what does the future energy system look like? By implementing the OBZ, the government replies to one of the overarching goals of enhancing operational efficiency. This allows OWFs to use the full transmission capacity, making sure that wind energy is not curtailed when there is demand. While the first OWFs are established without financial support, this is less likely to happen with the presence of congestion rents in an OBZ. To still comply with the goals set by the government, the OBZ market has to be designed in a way that allows OWFs to operate in a healthy economic environment. This is discussed from the perspective of four different objectives. The first is **maximising investment security and market stability**, which aims at creating an environment that attracts OWF investments. The second, **stimulating a market-driven rollout**, focuses on reducing financial support while stimulating a market in which OWFs can operate. The third, **ensuring goal realisation**, is about ensuring that the ambitions and targets set by policy are met. The last objective is **enhancing efficiency and effectiveness**, which is making sure that the measures are allocated and utilised in the right way.

Maximising Investment Security and Market Stability
In terms of maximising investment security and market stability, financial support like the SDE++ and the CfD provides the most predictable revenues for the OWFs. Where the SDE++ results in a minimum guaranteed price, the CfD fully covers all volatility in prices in the OBZ by providing a single strike price. However, it is important to realise that the risks of the OBZ price end up at the government. A decision has to be made on whether the government wants to be subject to these prices that might be lower and more volatile. A reason to disagree would be that the financial support does not incentivise market participants to find other ways to secure their investments, which might result in higher financial support than would actually be needed.

An option for how the government might hedge against these OBZ price risks could be to obtain FTRs for the OWF. If the financial support is implemented in continuation with the FTRs, the OWF receives a higher effective price, resulting in lower payments from the government. However, if the FTRs are still purchased by the government, this combination might not result in a net decrease in payments, but the optic subsidy is lower, and it protects the government from extreme situations.

Continuing on these extreme situations, an advantage of the CfD compared to the SDE++ is that OWFs do not make exceptionally high revenues at the expense of the consumer. In fact, the European Commission implemented a tax on the high profits of electricity producers above electricity prices of 130 EUR/MWh as a reaction to the high prices in 2022 (Ministerie van Economische Zaken en Klimaat, 2022). A two-sided CfD would prevent the need for such an intervention.

Stimulating a market-driven rollout
If the objective is to stimulate a market-driven rollout where financial support is minimised, OWFs will be more exposed to the OBZ-, and neighbouring markets, and the corresponding revenue losses.

FTRs mitigate the price differences between the OBZ and the higher-priced market. Furthermore, the FTRs allow the OBZ to conduct PPAs, which secure revenues. Especially in the new OBZ approach, long-term contracts increase the chance that OWFs are being financed and developed. However, current FTRs are only auctioned for up to one year. This does not secure the OWF against the risks resulting from conducting PPAs in another bidding zone. Therefore, a long-term product must be developed that mitigates these risks. An option might be to stimulate long-term FTR auctions with a duration equal to the lifespan of the OWF or the duration of the PPA contract.

Another option might be to simplify the congestion management through FTR allocation in the tender process for OWFs. This removes the step of OWFs that pay and reclaim the congestion rents, which makes the process more straightforward. This reduces the complexity and makes the process more transparent. The same capacity can be contracted through PPAs, securing stable revenues. Consequently, the tender becomes more attractive, resulting in more competitive bids and lower strike prices for financial support mechanisms.

This approach simplifies the subsidy process and increases its transparency. The OWF is assured of higher electricity prices, which directly decreases the congestion rents and the revenue losses. As a consequence, it reduces the need for subsidies by the government.

This option results in a less complex and more transparent process for granting subsidies. Since the OWF sells the electricity against the higher price, the OWF faces less revenue losses. As a consequence, the government is not subsidising congestion rents. Furthermore, it does not impact the TSO since the income from congestion rents can not be spent freely.

Ensuring Goal Realisation
The Dutch government has set goals to expand its current 4.5 GW of installed wind capacity to 21 GW by 2030 (Ministerie van Economische Zaken en Klimaat, 2023b). To achieve this, areas in the North Sea are being reserved for the development of wind parks. A balance has to be made between the added value of an extra wind farm to achieve the goals and the commitment of the government to stimulate such developments. This objective is closely aligned with maximising investment security and stability. The greater the assurance that wind farms will receive a return on investment, the higher the chance of their establishment. Therefore, both financial support measures are straightforward methods to ensure the realisation of these goals.

However, this objective differs from that of maximising investment security and stability in that as long as there is one bidder in each tender process, wind farms will most likely be developed and the set targets will be met. Therefore, the tender process should be designed to ensure there is always a bidder, for example by avoiding a set maximum strike price. Ultimately, the most attractive bidder will be selected to build the OWF.

It must be noted that this approach of ensuring goal realisation leads to a situation where there is no market-driven rollout. This presents a significant political debate.

Enhancing Efficiency and Effectiveness
The objective of enhancing efficiency and effectiveness is to ensure that the investments of the government in wind energy are made wisely and that they achieve the desired outcomes without overcompensation. This mostly refers to the right allocation of subsidy through financial support.

From this perspective, it is important to understand that there are two different price risks that can be mitigated through financial support measures. The first is the basis price risk, referring to low prices in an electricity market, which corresponds to the price risks in a home market. The second risk is the OBZ price differential risk, which is the risk of significant price differentials between the two neighbouring electricity markets. A basic implementation of financial support measures might lead to compensation for these basic price risks, which are normally hedged with PPAs in the home market. This could be seen as overcompensation, although it will be welcomed by the OWFs since PPAs are not yet possible to conduct in the OBZ due to the price differentials between the PPA price and the OBZ price.

To effectively subsidise the OWF for the revenue losses, as mentioned in the research question, financial support should be designed to compensate only for the price differentials between the two countries. For example, the compensation could be equal to these price differentials. Interesting about this approach is that the final compensation does not end up at the wind farm but with the TSO in the form of congestion rents. Since the TSO is restricted by the ACM on how to spend these rents, they do not form a direct income for the TSO. If the ACM decides to allocate these rents for grid expansion, the subsidy ultimately benefits society.

While this method of subsidy is beneficial to society, it represents a non-transparent way of granting subsidies. An alternative approach that could achieve similar results would be to directly provide the TSO with a sum of money that must be spent on grid expansion. However, this does not hedge against the OBZ price differential risks for the OWF. This issue could be solved by requiring the TSO to provide FTRs to the OWFs. Ultimately, this has the same results in that the OWF is hedged against the OBZ price differentials, and the government subsidises grid expansion, which benefits society. Additionally, the inclusion of FTRs enables the wind farm to conduct PPAs to hedge their basic price risk.

7.3.3 Perspective of the TSO

In theory, the TSO is not allowed to make revenues from congestion rents. The ACM ensures that these revenues are spent correctly. Otherwise, there would be a stimulus to increase congestion rents. Part of the rents are spent to reduce congestion. The TSO is not allowed to incorporate these costs into the grid tariffs. This also applies to the revenues obtained from selling FTRs.

If this is all regulated correctly, there will not be an incentive to disagree with selling or giving away long-term FTRs. However, there is a risk for the TSO regarding FTRs. If an interconnection needs to be curtailed, it might limit the OWF to transport all its electricity, resulting in a price drop to zero. If the TSO compensates the OWF through FTRs, the TSO is required to compensate equal to the price of the corresponding market.

In practice, the TSO has more objectives concerning the future OBZ market design. However, since this study primarily focuses on the relationship between the government and market parties, the opinions of the TSO are not covered and must be explored in further research.

7.4 *Exploring Future Market Connections*

Now that the magnitude of the impact of an OBZ and mitigation measures is quantified, the role of PPAs is discussed, and the OBZ market design is explored from various perspectives, the last step is to discuss future alternative market connections and the incentives to connect to them. This part highlights trade-offs that must be made between providing benefits for society and offering governmental support. These choices have significant implications for the broader future energy market and its participants.

The design of the OBZ market depends on the characteristics of both electricity markets. In fact, the objective behind implementing a hybrid interconnection and a corresponding OBZ could determine which other markets the Netherlands should connect to. One could identify three different types of connections from the Dutch market to another: to a market with lower average electricity prices, to a market with similar price characteristics, and to a market with the same average price but different fluctuations over time. A connection to a higher-priced market is less likely to be initiated by the Netherlands since this would only result in exporting electricity without benefiting society.

A connection to a lower-priced market is attractive for the Netherlands because it would lead to lower electricity prices, thus benefiting society. This scenario is similar to the case study in this research, with Norway representing the lower-priced market. However, the greater the price difference between the two markets, the more revenue losses wind farms would face. While these losses could be mitigated by purchasing FTRs, the revenues would not equal those that could have been received in the home market, assuming that the price in the lower-priced country never exceeds the price in the Netherlands. This makes it more attractive for developers to build their wind farms in another market, where higher revenues can be obtained. If a hybrid interconnection is still preferred, governmental support might be needed to attract wind farms.

A connection towards a market with similar price characteristics could increase the security of the electricity supply. Although it would not significantly lower electricity prices, society would benefit in the case of unexpectedly low supply, such as the failure of important generators. Since both markets show similar electricity prices, less congestion will occur. This situation would be more attractive for an OWF than the situation described above since it will face fewer revenue losses. Therefore, its operation and revenues will be similar to those of a radial connection to one of the markets. The wind farm would be less dependent on FTRs or financial support. Since both markets would benefit from the wind farm, it is also important to consider how costs are shared. This issue is noticed by more research (Nieuwenhout, 2022, Kitzing and Garzón González, 2020, Sørensen et al., 2020).

The last situation is to connect the Netherlands to a market with the same average price but different price characteristics. For example, this could be a market with a high share of hydropower and/or nuclear energy in its energy mix, which would lead to more stable prices compared to the Netherlands, where the amount of renewable generators is increasing. The Netherlands could benefit from lower peaks and troughs in their electricity prices. Besides, this presents a promising situation for wind farms that could receive higher revenues compared to the revenues in a home market approach, if the right amount of FTRs is obtained. This scenario would allow the wind farm to benefit from the higher-priced market rather than from the price of only one market. This is a more attractive situation in which governmental support is likely less required.

7.5 Study Limitations

The following subsection discusses the limitations of the study. While the model limitations are already addressed in Section 4, this section elaborates on them in the context of the results and their interpretations.

A significant limitation of the model and the study is that volume risks are not taken into account. Volume risks refer to situations where electricity cannot be dispatched due to insufficient capacity that is allocated for the transport of electricity, or because of other factors that limit transmission capacity, such as maintenance or failure. In the context of this study, this limitation impacts both the comparison between the OBZ and the home market approach, as well as the impact of the mitigation measures.

First, the OWF in an OBZ might be subject to a limited transmission capacity. Although unlikely (Section 4.1), the OWF might not be included in the merit order to use the interconnection. As a result, the OWF can not sell its electricity. This would result in lower revenues. Volume risks are less likely to happen on the transmission cable of an OWF that is established in its home market since the cable is not shared. Therefore, the difference in revenue losses between an OBZ and a home market would be higher if volume risks were taken into account.

Second, the positive impact of the mitigation measures might be overestimated due to the exclusion of volume risks. All mitigation measures have the constraint that compensation is only paid for the electricity that is injected into the interconnection. Therefore, compensation would be paid less often than observed in this study.

Another significant limitation of the model is that it does not simulate the price difference in the electricity markets after market coupling. If this would have been simulated in the real situation, the day-ahead price in the lower-priced market would have increased since there is more supply required to match the demand for the interconnector. Contrary, the price in the higher-priced market would decrease due to the reduction of supply in its merit order. The presence of this limitation results in higher observed congestion rents, more revenue losses and higher differences between the electricity prices. Additionally, when the correct way of market coupling is simulated, the congestion rents would reflect the physical limitations of the transmission system, which is important information in the design of the OBZ.

Furthermore, the analysis for this study is done for a hypothetical OWF that is established in an OBZ and connected to Norway and the Netherlands. Therefore, the quantitative results are only valid for a project with this specific layout. The study would be of more value when more neighbouring countries would have been explored, and different configurations could have been been studied. This gives a better overview of the impact of mitigation measures on the revenues of OWFs in an OBZ. The model that is created in this study allows the input of different electricity markets and configurations.

Another limitation of the study is that only a small number of criteria are used to study the impact of the mitigation measures. Additionally, five out of seven criteria (lost congestion rents excluded) are criteria that examine the impact on the revenue stream of the OWF. The other two reflect the costs that are made by the TSO and the counterparty. To fully examine the impact of the revenue stream, more criteria should be taken into account.

Furthermore, the input data that is used for the model is historical data. Therefore, it does not take any future installed capacity into account, while the discussion is about the future OBZ market design. With more installed wind and solar, it is likely that prices become more volatile, which has an effect on the impact of the mitigation measures. For example, a bigger effect of FTRs is expected.

The final limitation that should be mentioned in this study is that it does not consider any regulatory framework around the implementation of OBZs in the Netherlands. Potential barriers may arise that need to be addressed first.

7.6 Sub-questions Answered

This section answers the sub-questions from this research, based on the findings from the discussion. The first sub-question focuses on the core problem, and the subsequent questions explore potential solutions. Together, the answers to these questions provide the foundation for addressing the main research question, 'How can revenue losses from network congestion of wind farms be mitigated in an offshore bidding zone in the North Sea?'. This is discussed in the conclusion in Section 8.

1. *How does an OBZ impact the revenue stream compared to the current home market approach?*

Traditionally, OWFs are radially connected to their home market and dispatch electricity like all other generators, receiving the same price. In this study, the "home market" refers to the Dutch electricity market, which shows relatively stable electricity prices during 2018, 2019, and 2020, compared to the three years after. Due to the gas crisis, these prices significantly increased, with the most extreme values observed around August 2022.

The day-ahead price of the Netherlands shows quite similar patterns to Belgium and Germany, while the Scandinavian countries show different patterns, with lower average prices. Therefore, an interconnection with one of these countries seems to be the most beneficial for the Netherlands.

To maximise the dispatching of electricity from an OWF connected to this interconnection, an OBZ must be implemented. This market setup ensures cross-border transportation to both countries and bypasses the 70% rule that limits the available capacity for OWFs on an interconnection. Since there is currently no demand within the OBZ, the OWF transports its electricity to the neighbouring electricity market where it is needed the most. If the sum of both interconnection capacities exceeds the capacity of the wind farm, and there is always export demand, congestion will occur on the interconnection towards the higher-priced market. Consequently, the OWF receives the price of the lower-priced market.

The specific results of the case study performed in this research showed a significant decrease in average revenues from 8.63% in 2019 to 28.94% in 2021 compared to the home market, with an extreme difference in 2020 of 69.97%. Additionally, the revenue stream became more volatile over the six years observed, with an increase in volatility in the last three years. The more stable years show an increase in variation of average revenues with the OBZ implemented. The difference between the minimum and maximum average weekly revenues in the home market equals 52.08 EUR/MWh, while the OBZ shows a difference of 59.10 EUR/MWh.

While the results of the case study succeed in exploring the magnitude of the impact of an OBZ on the revenues of a wind farm, this research question is broader than that. The findings of this study show that the impact of the OBZ depends on the characteristics of the connected market. Connecting to a market with lower average electricity prices, like Norway, or to a market with opposite fluctuations in electricity prices, leads to a significant decrease in revenues, but also results in overall lower electricity prices, which benefits society. A connection to a market with similar electricity prices would likely result in fewer revenue losses, although it would also result in fewer societal benefits. This shows that each scenario has different impacts on the stakeholders involved and that careful consideration of trade-offs is required when designing a future offshore electricity market. A balance must be made between providing benefits to society and creating an attractive environment for wind farms.

2. *How do different forms of financial support impact the revenue stream?*

This study explored two forms of financial support. The first is the SDE++, which guarantees a minimum electricity price for the OWF. The second is a two-sided CfD, which sets both a minimum and maximum price. Revenues that arise from higher prices are returned to the government.

During periods of high average prices, the SDE++ provides a higher revenue stream since the OWF benefits from price peaks in the OBZ price. Conversely, the CfD offers a more stable revenue stream and will most likely be contracted against a higher strike price. If the tenders for these financial support measures work correctly, the choice of mitigation measure does not differ significantly for the revenues or payments.

In the system layout of this study, the SDE++ demonstrates higher revenues and payments during the stable years, up to a strike price of 50 EUR/MWh. As the strike price increases further, the revenues and payments from the SDE++ converge towards the levels of the CfD. To compensate for the revenue losses during the stable years, due to congestion in the OBZ, the SDE++ should be contracted with a strike price of 39 EUR/MWh, while the CfD should be contracted with 42 EUR/MWh. This results in payouts of 11.88 EUR/MWh and 12.04 EUR/MWh respectively.

While financial support measures succeed in increasing average revenues and stabilising the revenue stream of the wind farm, their implementation might play a much bigger role in the future OBZ market design. These measures enable connections to markets with much lower electricity prices, which benefits society. If the financial support is designed correctly, it will compensate only for the OBZ price risks. Wind farms themselves might hedge their basic price risks with market-driven measures, as in the traditional home market approach. Additionally, the compensation for the OBZ price differentials indirectly subsidises grid expansion because it ends up at the TSO as congestion rents. Although this approach is far from transparent, it does benefit society.

Overall, the findings highlight the potential importance of financial support in attracting wind farms within the OBZ market design. However, the right design, which enhances efficiency and effectiveness, is of great importance to ensure that these measures meet their intended goals without leading to any form of overcompensation.

3. *What impact do Financial Transmission Rights have on the revenue stream?*

FTRs differ from financial support measures in that they are market-driven. The amount of compensation is based on the price differentials between the OBZ price and the price of the market with which the FTR is established. Therefore, the compensation equals the congestion rents that arise from cross-border electricity transportation from the OWF for the electricity volume that is contracted.

While FTRs potentially result in the highest revenues for the OWF, they do not provide any predictability of future revenues since this completely depends on the characteristics of the other electricity markets. With enough capacity purchased through FTRs, revenues can become even higher compared to the home market. However, this depends on the price characteristics of the connected market. If the OBZ is established between two markets that both show low average electricity prices with little variance, the FTRs have less impact.

In this case study, the FTRs showed a decrease in revenue losses from the implementation of the OBZ by 43.78% in the stable years. The average revenue in the OBZ, initially 29.96 EUR/MWh compared to 42.09 EUR/MWh in the HM, increased to 35.27 EUR/MWh in the OBZ with FTRs purchased. This increase is mostly due to the FTR on the Dutch interconnector.

Looking beyond the specific model results, the findings in this study indicate that FTRs can play a significant role in future OBZ market designs by enabling a market-driven rollout. When OBZ price risks are hedged with FTRs, wind farms can secure their investments through long-term contracts outside their bidding zone. With the right amount of FTRs, wind farms might even experience higher revenues compared to the home market approach, depending on the price characteristics of the other market.

However, a current significant drawback is that the rights cannot be obtained over a longer term, making it uncertain for wind farms to hedge OBZ price risks. Enabling the options to obtain these rights over a longer period, or even including them in the tender process, would be a good step toward adopting market-based mitigation measures.

4. *How does a combination of financial support and Financial Transmission Rights intervene and impact the revenue stream?*

The combination of a financial support measure with FTRs can take different forms. Since both contracts are conducted with different stakeholders, it is most likely that they do not directly influence each other. However, the inclusion of FTRs might impact the tender process, resulting in lower strike prices. In this scenario, the OWF receives stable and predictable revenues equal to the strike price, plus additional revenues from FTRs. Depending on the strike price level and the amount of capacity contracted in the FTR, this could result in the most attractive scenario for the OWF.

The second option presents a scenario in which the CfD is implemented in continuation of the FTR. While the revenues of the OWF remain equal to the strike price, the payments are calculated based on the effective price resulting from the FTRs, leading to lower subsidies. In fact, if the FTRs cover enough capacity, the government only subsidises for the basic price risks, comparable with those in the home market approach. If that is the case, these risks could also be hedged with PPAs, removing the need for governmental support.

However, since the OWF does not benefit from the FTRs anymore, there will be no incentive to purchase these rights. It might be an option for the government to buy the FTRs for the OWF to hedge against the OBZ price risks that the government faces through the CfD. This would result in a similar indirect payment for the congestion rents, as is the case with CfDs with a reference price that equals the price difference between both markets.

The same structure might be possible with the SDE++. This would allow the OWF to benefit from the higher effective price resulting from the FTRs, while keeping the subsidies lower, if applicable. However, due to the shared benefits, a question arises about who should purchase the FTRs.

8 Conclusion

This study addresses the revenue losses from network congestion of an Offshore Wind Farm (OWF) resulting from the implementation of an Offshore Bidding Zone (OBZ) and explores potential measures to mitigate these effects. The quantitative analysis involves a model that simulates a hypothetical OWF located in the North Sea between Norway and the Netherlands, operating with historical electricity prices and wind data. The OBZ approach is compared with the traditional home market approach to analyse revenues and explore the magnitude of the losses. The implementation of mitigation measures provides insights into their impact on revenues, congestion rents, and compensation. Additionally, the role of long-term contracts is examined to clarify how they influence the effectiveness of these measures. This is followed by an exploration of the different perspectives of the wind farm and the government to understand how these could shape the OBZ market design. Finally, an analysis of different future alternative market connections is conducted to understand their implications and the trade-offs that must be made for designing the OBZ market.

This section first answers the main research question. This is followed by a reflection on the academic and societal relevance of this study. A section on future work discusses suggestions on how to expand this research. The very last section of this thesis is reserved for my personal reflection.

8.1 Main Question Answered

The answer to the research question is based on case-study-specific results that address the knowledge gaps, as well as broader findings that explore the future OBZ market design through the lens of different stakeholders. The following research question was formulated:

How can revenue losses from network congestion of wind farms be mitigated in an offshore bidding zone in the North Sea?

The findings of the study indicate revenue losses for a Dutch wind farm within an OBZ compared to the traditional home market approach, as well as an increase in the volatility and variation of revenues. However, the impact differs significantly based on the second market to which it is connected. From the perspective of the government, a trade-off must be made between, on the one hand, providing benefits for society by lowering energy prices and increasing the security of supply, and, on the other hand, creating an attractive environment for wind farms and potentially other market parties with governmental support.

The highest societal benefits, in terms of lowering electricity prices, are most likely to be achieved with the connection to a lower-priced market. However, the greater the difference in electricity prices between the two markets, the more revenue losses wind farms would face. To ensure a fast rollout of wind farms, financial support can provide the necessary security to receive revenues up to the level of those in a home market. In fact, when the support mechanism is designed with a reference price equal to the price differentials, it might indirectly subsidise grid expansion, which benefits society.

While financial support provides a stable and predictable revenue stream for the wind farm, these measures might distort the market. If the goal of the future electricity market is to maximise investment security, this approach might offer an easy solution, but it is less likely to result in an optimally functioning system. A market-driven electricity system is more likely to operate efficiently. However, there is still a need for long-term products that hedge against price differentials in an OBZ that is market-driven.

The most direct way to prevent revenue losses in an OBZ would be to connect to a market with similar price characteristics. However, the societal benefits of such an interconnection are also lower. This market configuration allows the wind farm to more easily operate in a more market-based situation.

FTRs could even potentially lead to higher revenues compared to the home market approach. This makes the environment more attractive for market parties, resulting in an easier rollout of wind farms.

A first step to enable a market-driven design would be to create the option to obtain longer-term FTR contracts. This could allow wind farms to hedge the OBZ price difference over a longer period and secure investments through long-term contracts. These contracts provide predictability of future revenues, which is not covered by the FTRs themselves. Congestion management might even be more simplified with the inclusion of FTR contracts in the tender process for OWFs. It would remove the step where OWFs pay and then reclaim congestion rents, making the process more straightforward. This would reduce the complexity of the subsidy process and increase its transparency. Moreover, the tender would become more attractive, likely resulting in lower strike prices if financial support is provided.

To conclude, revenue losses from network congestion can be mitigated through both financial support and market-based measures. However, their efficiency and effectiveness depend on the market to which the Netherlands is connected. Clear long-term objectives for the future electricity market are important to establish a more integrated network and a robust OBZ market that fits all stakeholders involved.

8.2 Reflection on Academic Relevance

Research into the implementation of an OBZ in the North Sea and the impact of OWFs is not new. It is recognised that the OBZ can lead to lower revenues, which is a result of congestion rents when an OBZ is situated between two other bidding zones. The congestion rents differ per specific project and the surrounding electricity markets. This makes it difficult to quantify the revenue losses precisely. Therefore, a first knowledge gap was found in the magnitude of revenue losses for an OWF that appear with the implementation of an OBZ.

The same research elaborates on mitigation measures to mitigate these losses. Financial support can provide stable revenue streams and market-based measures compensate actual losses. However, the effectiveness of these measures remains uncertain due to missing data on the revenue losses. Therefore, the second knowledge gap lies in the magnitude of the impact of mitigation measures on the revenue losses that OWFs face in the OBZ.

This existing research provides the foundation for understanding the risks that occur with the implementation of an OBZ and the possible ways to mitigate them. This study contributes to the existing research by providing a more detailed understanding of how an OBZ impacts the revenues of an OWF compared to the home market. With this knowledge, the effectiveness of mitigation measures can then be explored.

Understanding the specific impact of the OBZ on the revenues of the OWF was made possible by creating a simplified energy model. This model simulated a hypothetical offshore wind farm that operates in both a home market and an OBZ. To provide realistic revenue streams, data on historical electricity prices was used. The results are on an hourly basis, which enables the implementation of mitigation measures that also operate on an hourly basis. These findings validate the existing knowledge but also provide more in-depth insights into the magnitude of impact.

Furthermore, this research provides a new approach to performing a simulation-based modelling technique, using historical data on electricity prices and wind patterns. This is relevant because it allows to study the impact of both the OBZ and mitigation measures as if they were implemented in 2018, which is the starting point of the simulation. therefore, this study stays close to the real situation. It shows the effects of these measures during periods of unexpectedly high electricity prices. For example, the findings suggest that providing financial support on an hourly basis could lead to high subsidies during times of high average electricity prices. Scenarios for future electricity prices before 2018 do not cover these situations (CE Delft, 2017).

The study also contributes to the academic field by providing a foundation for performing the same study for different system layouts or for different electricity markets. The model can be used as a basis or as a whole if there is electricity data available for the market under study. Changing the characteristics of the wind farm will lead to different outcomes. The same policy scorecard and its criteria can be used to evaluate these results.

8.3 Reflection on Societal Relevance

First and most importantly, this study shows the need for new market designs with the implementation of an OBZ. The results can inform policymakers about the challenges faced with implementing an OBZ market setup and how different measures can mitigate revenue losses faced by OWF. This study provides different market designs dependent on the objectives of the stakeholders.

Second, this study contributes to the broader discussion on the transition towards renewable energy sources. Although the focus of this study is on wind energy, the mitigation measures discussed might be applied to other energy sources as well.

Furthermore, this study examines the different objectives of stakeholders involved in the implementation of the OBZ. This can help with the implementation of policies that consider the different objectives of all stakeholders. Additionally, this analysis helps in understanding the different perspectives.

Although the consumer is not included in the analysis on different stakeholders, the main goal of an OBZ is the efficient dispatch of electricity, which results in lowering electricity prices for consumers if done correctly. This study helps in achieving this situation.

Although the analysis does not directly include consumers in the different stakeholders, the main goal of an OBZ is to efficient dispatch electricity. If implemented correctly, the OBZ leads to lower electricity prices for consumers, therefore benefiting them.

8.4 Future Work

A significant limitation of the model and this study is that volume risks are not taken into account. These volume risks refer to situations where electricity cannot be dispatched due to insufficient capacity allocated for the transport of electricity or due to maintenance or failure. This limitation impacts the analyses of the impact of an OBZ on revenue losses and the effectiveness of mitigation measures. Future work could elaborate on this study by incorporating these risks into the model. ENTSO-E Transparency Platform (2024) provides data on the unavailability of existing transmission grids. Based on this data, an estimation could be made of how often volume risks occur. Mitigation measures, like a Transmission Access Guarantee (TAG) (European Commission, 2022), which compensates for volume risks, could be included in the analysis. This will provide a broader understanding of the impact of an OBZ and its potential mitigation measures. A possible research question might be *"How can volume risks of wind farms be mitigated in an offshore bidding zone in the North Sea?"*.

A broader understanding of the role of an OBZ in the European Electricity Market could be achieved by performing similar research with different configurations of the system layout. This layout can vary both in the countries to which the OBZ is connected and in the capacity of the interconnections. The research could even be expanded with a multi-country, multi-terminal model. However, with the inclusion of multiple countries and wind farms, the model becomes more complex. Such a configuration would likely result in interconnection with less capacity. This means that congestion can occur on more than one cable, which is different from the current study. Therefore, the wind farm can receive different electricity prices at the same time. Additionally, if the OWF needs to be curtailed, the OBZ price drops to zero, which could have a significant effect on the revenues of the OWF. A possible research question might be, *"How do different configurations of an offshore bidding zone contribute to* *an efficient dispatch of electricity throughout Europe?"*, or *"How does a multi-country, multi-terminal configuration of an offshore bidding zone contribute to an efficient dispatch of electricity throughout Europe?"*

A study on the cost components of an OWF in an OBZ could contribute to this research in a way that the business case can be explored. To do so, future work should explore the capital and operational expenditures of the OWF (Swamy et al., 2022). This should aim to determine the Levelised Cost of Energy (LCOE), which reflects the revenue that is required to cover the investment costs over the lifespan of the wind farm (OREC, 2019). Together with the findings of this research, advice can be given on how to design the OBZ market to ensure that wind farms achieve the right return on investment. This could result in one of the following research questions: *"What is the impact of an offshore bidding zone on the levelised cost of energy for a wind farm?"* or *"How can the offshore bidding zone market be designed to meet the levelised cost of energy of a wind farm?"*.

Future research should clarify how to share the costs of mitigation measures or infrastructure associated with an OBZ. Since two (or more) countries experience both the positive and negative impacts of an OBZ, the costs should be shared too. However, as found in this research, the higher-priced markets experience more impact than the other market. Therefore, an equalshare in cost allocation might not be fair. This issue could be even further explored by including more countries that indirectly benefit from the OBZ. This might lead to the following research question: *"How should the costs of mitigation measures and infrastructure related to the implementation of an OBZ be distributed across different countries?"*.

This study showed that the government might indirectly cover part of the congestion rents through subsidies for the OWF. If these costs contribute to grid expansion, it suggests that the government is subsidising the reduction of congestion. This non-transparent route could be further explored by using a system dynamics approach, which allows the creation of a model to examine cash flows. It would be interesting to see where the subsidy ends up, to decrease the complexity of the subsidy process and to potentially lower the (optic) subsidies. This could be explored with the following research question: *"How does compensation for congestion rents indirectly influence congestion and contribute to grid expansion?"*.

Future demand within the OBZ is expected to emerge, for example, due to the presence of electrolysers (Ministerie van Economische Zaken en Klimaat, 2023a). This would reduce the need to transport electricity to neighbouring zones. As a result, the price formation inside the OBZ changes. Furthermore, the OWF is less subject to price and volume risks in the OBZ. Therefore, it would be interesting to study the role of electrolysers in the OBZ with the following research question: *"What is the role of electrolysers within an offshore bidding zone?"*.

8.5 Personal Reflection

The field of electricity markets is a complex subject. It was challenging to make myself comfortable with it, as I had little to no experience. From the start, I learned to understand and analyse electricity data from different markets, which is important for understanding why certain results are observed. Furthermore, I learned how electricity prices are formed in a general electricity market and in an offshore bidding zone. This understanding was needed for the correct implementation of the OBZ in the model and the subsequent mitigation measures. Through discussion papers and interviews, I became familiar with the different objectives of the stakeholders involved, which improved my analysis of the impact of an offshore bidding zone and the mitigation measures on the revenues, congestion rents, and the amount of compensation paid.

Given the complexity and the amount of information on electricity markets, scoping the project to answer the research question within the time constraints of this was challenging. Initially, I tried to examine both price and volume risks, but in the end, I only focused on the specific revenue losses.

The process of writing this thesis and receiving feedback helped me realise the importance of choosing the right wording in such a complex subject. For example, there is a difference between price risks and revenue losses.

If I would write a thesis again, I would spend more time selecting the right methodology and fully understand the different steps involved from the beginning. This approach would have provided me with a better guidance throughout my process. I spent too much time trying to understand the subject before continuing. However, I now believe that performing all steps from the methodology itself is required to gain a better understanding.

During the analysis of the results, I realised that simulating a hypothetical wind farm alone was insufficient to fully answer my research question. Market design is not decided only on the optimal outcomes for one configuration. Different stakeholders have different objectives. For example, the preferred mitigation measure for a wind farm depends on its desired balance between accepting risk, which might lead to higher prices and having a stable and predictable revenue stream. This is also the case for the government objectives, where there is a choice between providing support for stable revenues through compensation and stimulating a market-driven rollout, which might increase future uncertainties. I realised the importance of answering my research question from these different perspectives. A conclusion only based on the model findings was not sufficient.

I conducted my thesis research at The Ministry of Economic Affairs and Climate Policy, which offered me the chance to tackle a question that is relevant to today's policy-making. I am grateful for the time spent there, as it gave me the opportunity to discuss my topic with professionals in the field. I was invited to many meetings within the ministry and with external stakeholders, which provided important context for situating the problem.

Apart from writing my thesis, I had the opportunity to be part of a team that addresses critical questions about the current and future electricity market. It was interesting to see and experience how everyone works on multiple subjects, ranging from the transition of natural gas plants to future principles of cost-sharing for cross-border connections. Working on various subjects within the electricity market team requires smooth collaboration with other teams in the energy markets department. This internship gave me my first experience with how it is to be a public servant. However, I also learned that there is no single answer. The variety of subjects offers a wide range of choices in technical, legislative, and other areas. I am looking forward to seeing how this internship influences my future career choices.

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A Data Collection

This appendix contains figures from the analysis of electricity prices in Norway and the Netherlands.

A.1 *Electricity Prices*

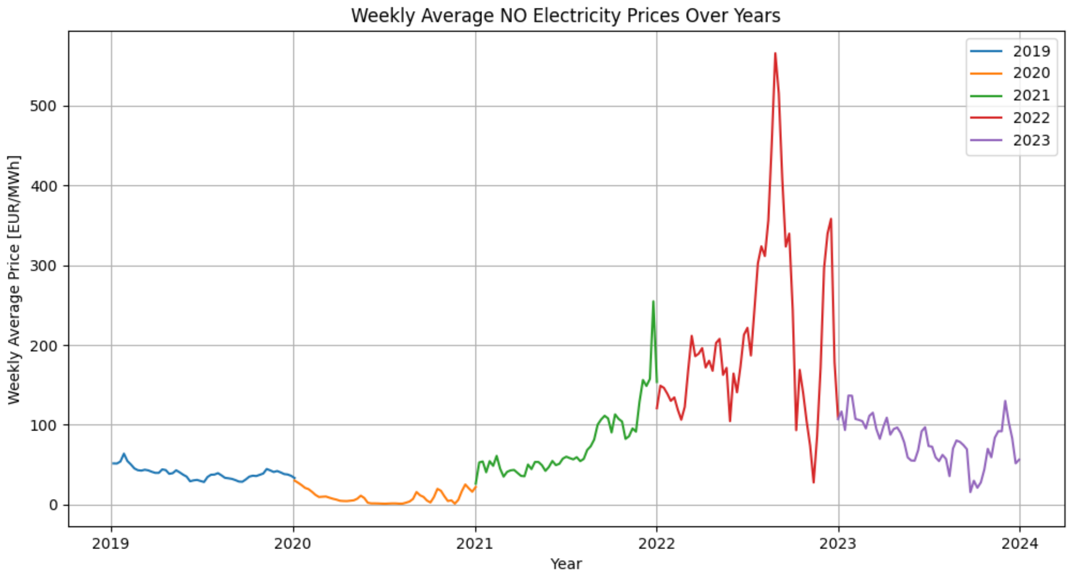

Figure A.1: Weekly Average of Hourly Electricity Prices NO: 2019-2023. Yearly data extracted from (ENTSO-E Transparency Platform, 2023)

Figure A.1 shows the Norway electricity prices over the past five years.

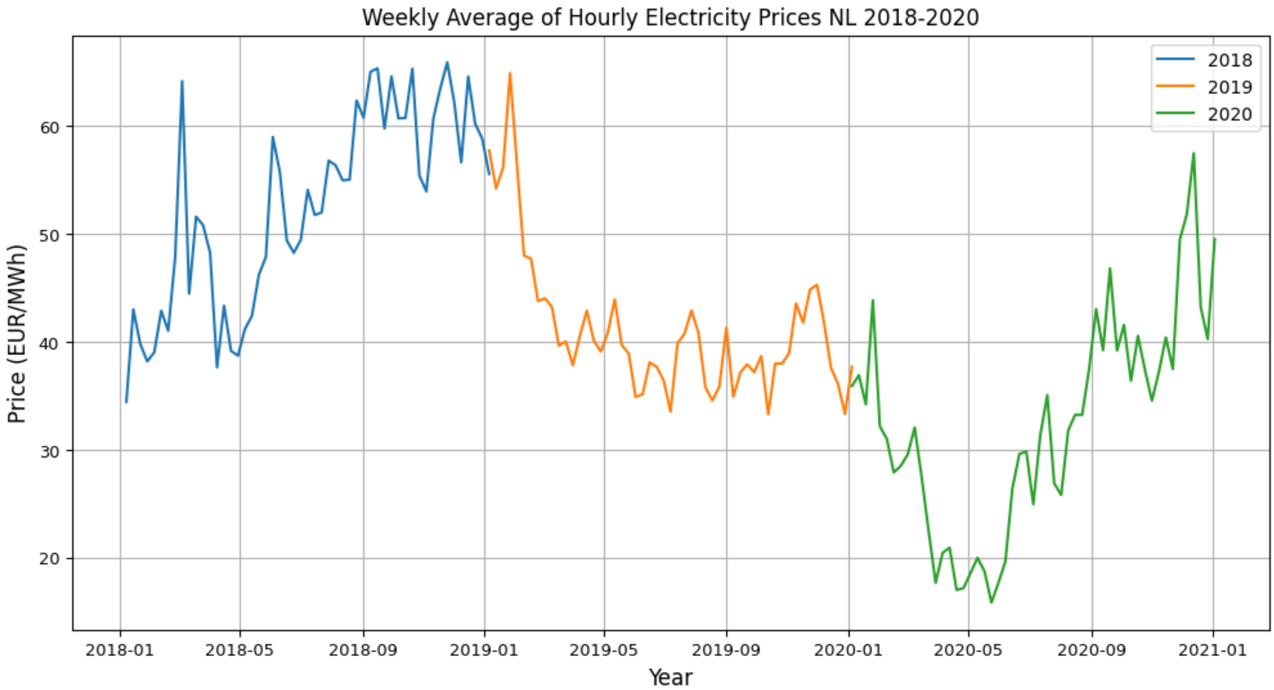

Figure A.2: Weekly Average of Hourly Electricity Prices NL 2018-2020. Yearly data extracted from (ENTSO-E Transparency Platform, 2023)

Figure A.2 shows the Dutch day-ahead electricity prices over 2018-2020. The electricity price stays between 10 and 70 EUR/MWh. These are relatively stable trends compared to the electricity prices in the next period (see Figure A.3).

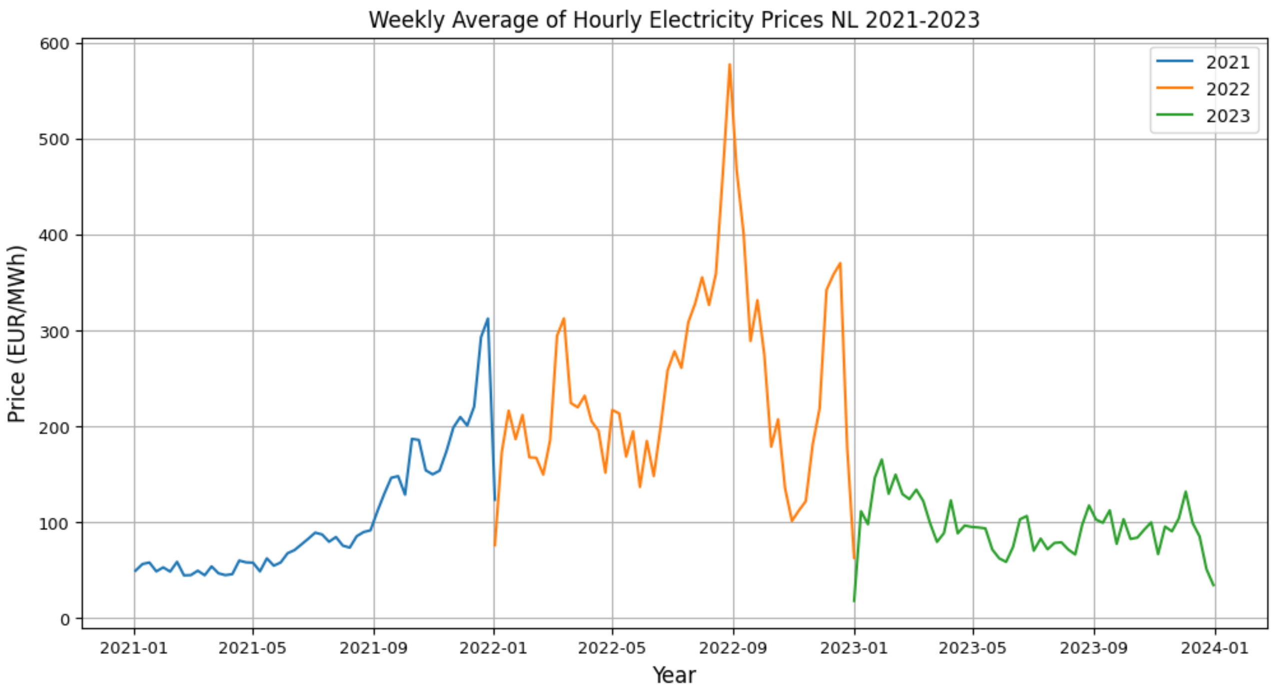

Figure A.3: Weekly Average of Hourly Electricity Prices NL 2021-2023. Yearly data extracted from (ENTSO-E Transparency Platform, 2023)

Figure A.3 shows the Dutch day-ahead electricity prices over 2021-2023. The prices show a volatile pattern with price peaks between 300 and 400 EUR/MWh and one of almost 600 EUR/MWh.

B Additional Results

B.1 SDE++

Figures B.1 and B.2 show the weekly average revenues of the OWF with the SDE++ implemented compared to the basic OBZ for years 2018-2023 and 2021-2023.

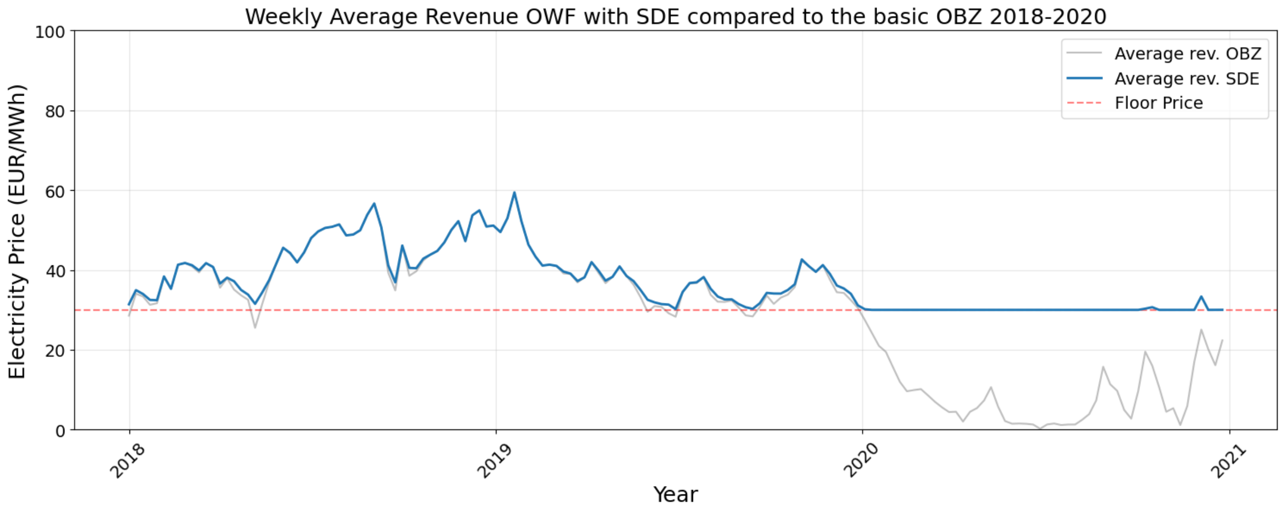

Figure B.1: Weekly Average Revenue OWF with SDE compared to the basic OBZ 2018-2020

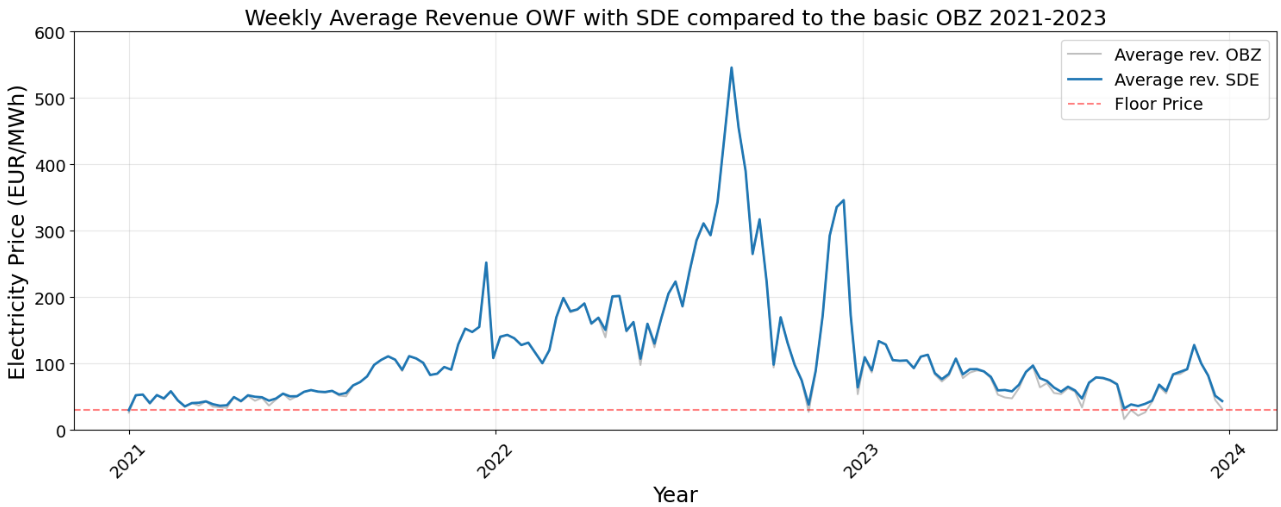

Figure B.2: Weekly Average Revenue OWF with SDE compared to the basic OBZ 2021-2023

B.2 CfD

Figure B.3 shows the yearly average revenues of the OWF with a CfD implemented. As expected, the revenues of the OWF equal 50 EUR/MWh. This mitigation measure takes away all uncertainty around price volatility, resulting in stable revenues.

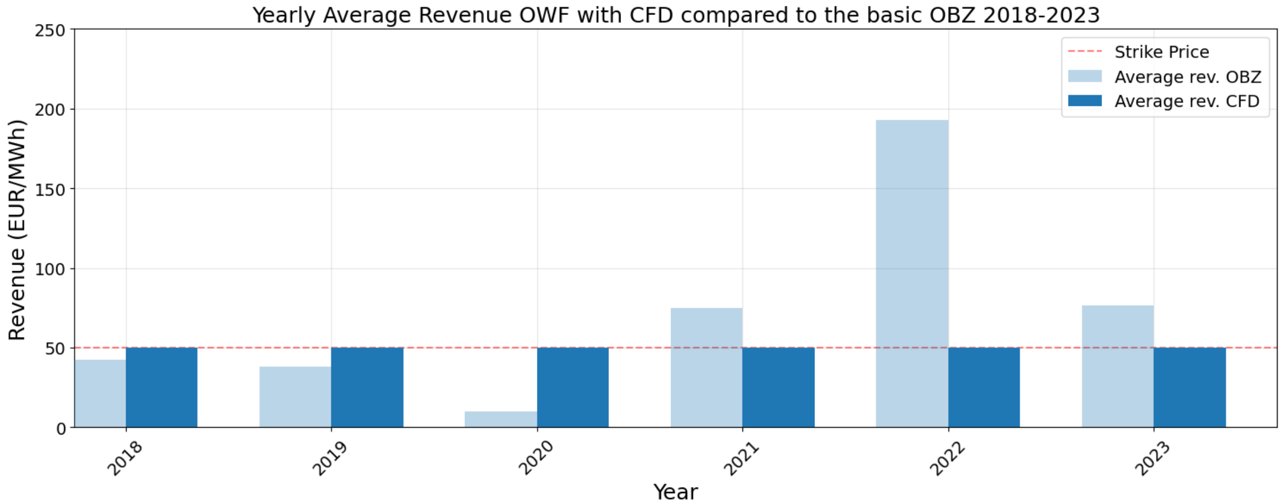

Figure B.3: Yearly Average Revenue OWF with CFD compared to the basic OBZ 2018-2023

Figures B.4 and B.5 show the weekly average revenues of OWF with a CfD implemented. The results show that the OWF benefits from the contract in the years 2018, 2019 and 2020 due to lower OBZ prices. In the years 2021, 2022 and 2023, the OWF receives lower revenues compared to the basic OBZ scenario.

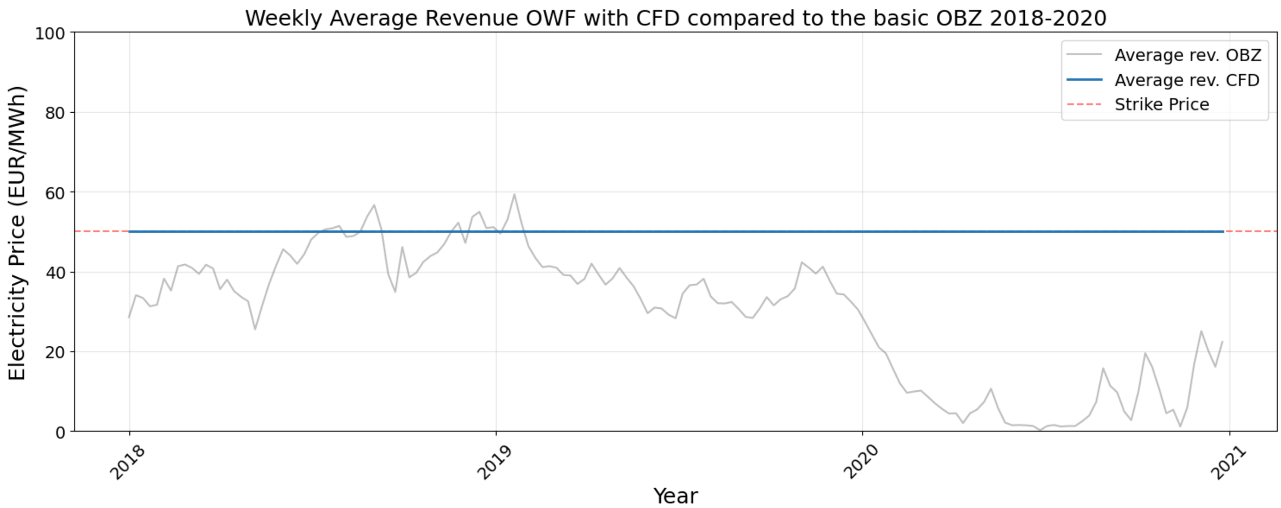

Figure B.4: Weekly Average Revenue OWF with CFD compared to the basic OBZ 2018-2020

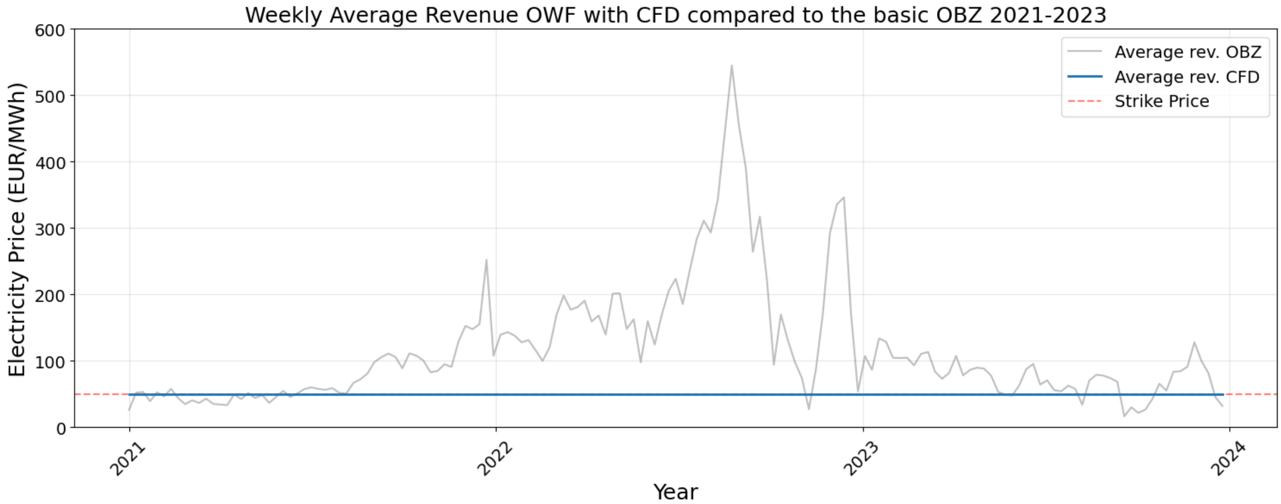

Figure B.5: Weekly Average Revenue OWF with CFD compared to the basic OBZ 2021-2023

B.3 FTRs

Figure B.6 shows the yearly average revenues of the hypothetical OWF in an OBZ with the FTRs implemented over the past six years.

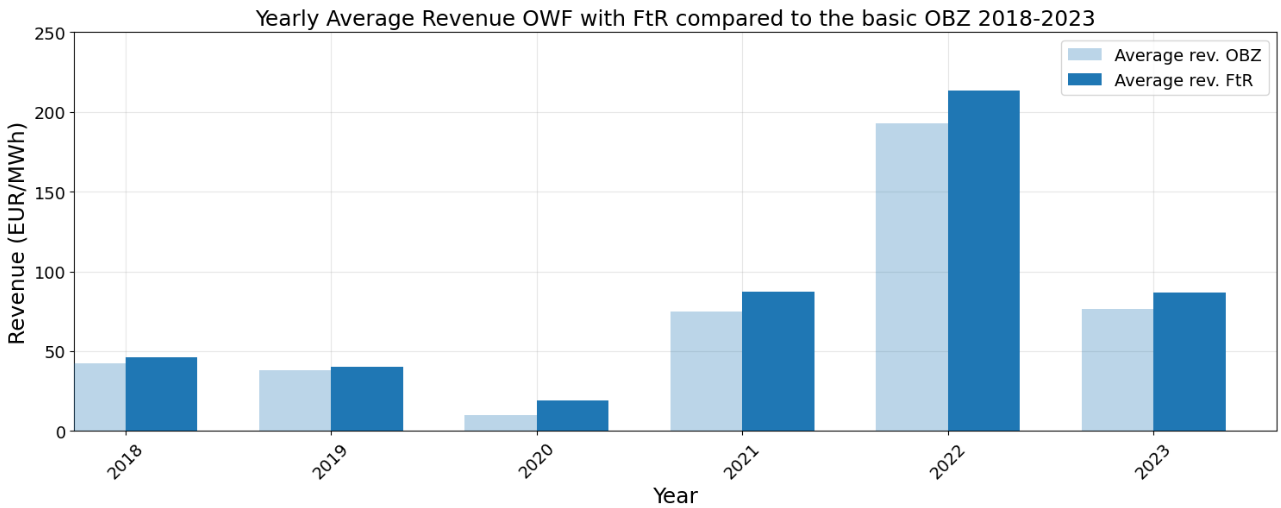

Figure B.6: Yearly Average Revenue OWF with FTR compared to the basic OBZ 2018-2023

Figures B.7 and B.8 show the weekly average revenues of OWF with a CfD implemented.

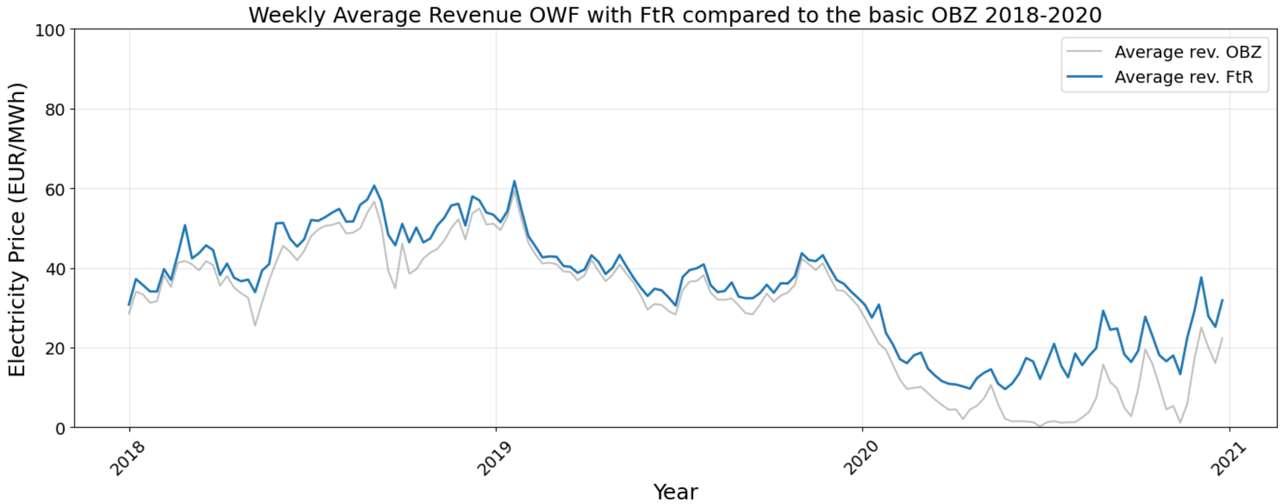

Figure B.7: Weekly Average Revenue OWF with FTR compared to the basic OBZ 2018-2020

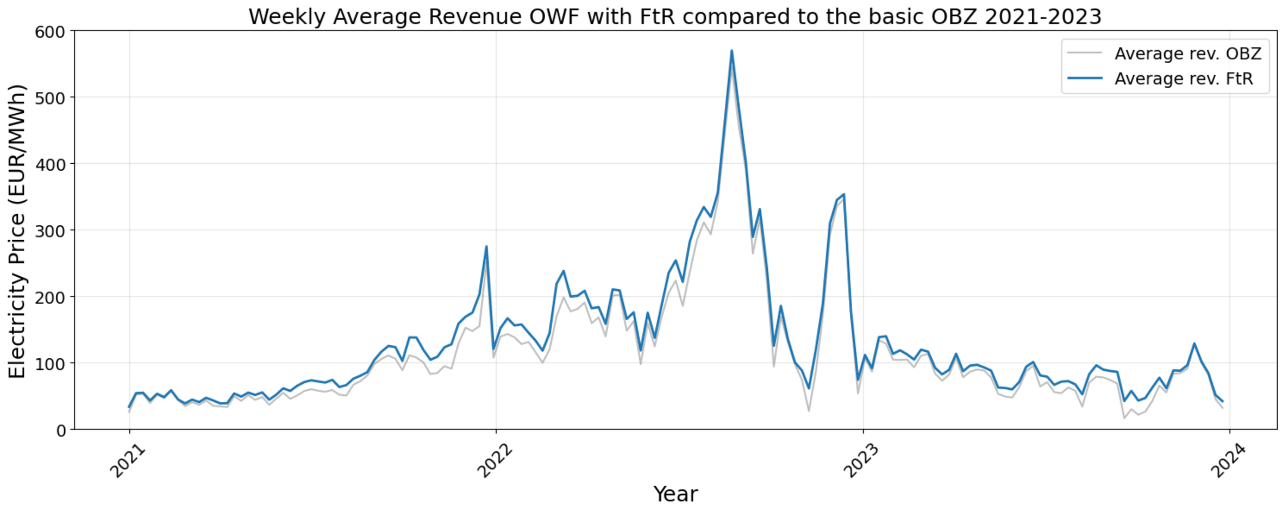

Figure B.8: Weekly Average Revenue OWF with FTR compared to the basic OBZ 2021-2023

B.4 Policy Scorecard Explanation

The 'Policy Scorecard' tool is used to show and compare the impact of different mitigation strategies per criterion. The grading scale (–, -, 0, +, ++, or N/A), indicates to which degree the criteria are positively or negatively impacted, with "–" showing a significant negative impact and "++" showing a significant positive impact. The policy scorecard is shown in Table B.1. A short explanation of how the cells are filled is given below.

Table B.1: Policy Scorecard

Mitigation Measure	SDE++	CfD	FTRs	CfD + FTRs
Criterion				
Revenues during high avg. volatile prices	+	0	++	0
Revenues during high avg. stable prices	+	0	+	0
Revenues during low avg. volatile prices	++	+	0	+
Revenues during low avg. stable prices	++	++	0	++
Predictability of the revenues	+	++	-	++
Lost congestion rents	N/A	N/A	++	N/A
Costs for the counterparty	–	0	N/A	+

Revenues during high avg. volatile prices (EUR/MWh): SDE++ and FTRs score "++" because they allow OWFs to benefit from high peak prices. With FTRs, the OWF receives the higher price up to the contracted volume of electricity. Since prices are volatile, more price differences will occur. CfD and CfD with FTRs result in revenues equal to the strike price, which might be lower than the high average revenues, hence a "0".

Revenues during high avg. stable prices (EUR/MWh): SDE++ and FTRs score "+" because they allow the OWF to benefit from high average prices. The SDE++ does not need to mitigate troughs, and FTRs do not benefit from price differences due to stable prices. The CfD and CfD with FTRs lead to the same revenues equal to the strike price, receiving a "0".

Revenues during low avg. volatile prices (EUR/MWh): SDE++ scores "++" as it provides a minimum price level but also lets the OWF benefit from price peaks. The CfD and CfD with FTRs both secure the OWF with a minimum price, therefore a "+". FTRs do not offer a minimum price, so electricity is sold at low average prices. However, due to volatility, higher price differences might occur, which benefit the OWF with FTRs, resulting in a "0".

Revenues during low avg. stable prices (EUR/MWh): SDE++, CfD, and CfD with FTRs score "++" for providing a minimum price. FTRs score a "0" since there are probably less price differences to benefit from, and they do not offer a minimum price, which is might be needed due to the low average prices.

Predictability of the revenues: CfD and CfD with FTRs are the most predictable, scoring "++". SDE++ is slightly less predictable due to its dependence on market prices, scoring "+". FTRs score "-" due to their variability.

Lost congestion rents: FTRs have a direct impact on congestion rents, scoring "++". They not only return revenue losses due to congestion rents, but also provide an incentive for TSOs to reduce congestion rents after FTRs are purchased. Other measures are scored as N/A since they do not directly affect congestion rents.

Costs for the counterparty: CfD scores "0" since payments are both made to and received from the OWF. SDE++ scores the lowest with "—" since only payments are made. CfD with FTRs score positively with a "+" since FTRs reduce payments to the OWF and increase payments that are received. No payments are made from FTRs since they are covered by congestion rents, and purchased by the OWF.

B.5 *Extra Results Sensitivity Analysis*

Figure B.9 shows the average revenue of the OWF with an SDE++ or an CfD implemented for different strike prices.

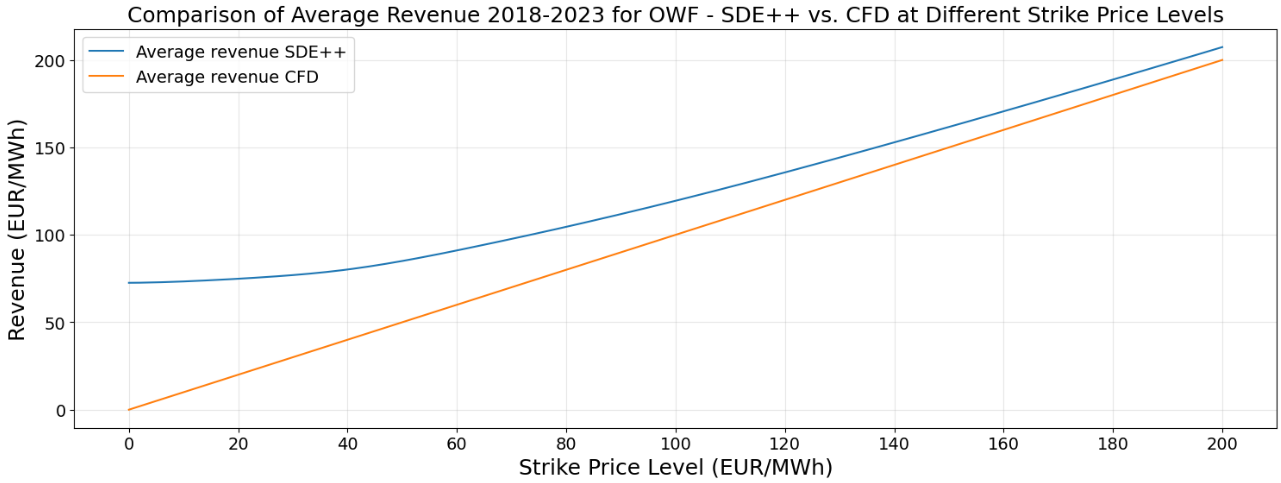

Figure B.9: Comparison of Average Revenue 2018-2023 for OWF - SDE++ vs. CFD at Different Strike Price Levels

Figure B.10 shows the average payout of the OWF with an SDE++ or an CfD implemented for different strike prices.

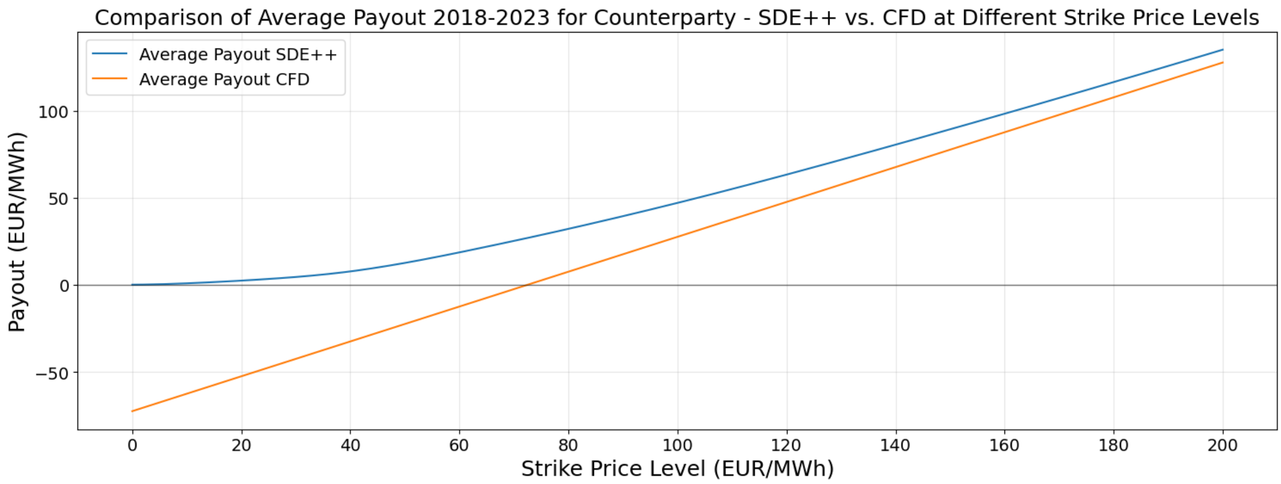

Figure B.10: Comparison of Average Payout 2018-2023 for Counterparty - SDE++ vs. CFD at Different Strike Price Levels