Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Economics and Management
Dept. of Industrial Economics and Technology Management

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A Novel Flexibility Market: Leveraging Distributed Energy Resources to Balance Wind Power Forecast Errors

Master's thesis in Industrial Economics and Technology Management
Supervisor: Pedro Crespo del Granado
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Preface

This master thesis is written as part of the Master of Science in Industrial Economics and Technology Management at the Norwegian University of Science and Technology (NTNU). The specialization of the degree is within Financial Engineering.

First and foremost, I would like to express my gratitude to my two supervisors, Associate Professor Pedro Crespo del Granado and Assistant Professor Felipe Van de Sande Araujo. Throughout this project, they offered invaluable support and guidance. Further, I am thankful for the great commitment and the enthusiasm they showed: On a personal level, they inspired me to do my very best. I would also like to thank SKM Market Predictor AS for supplying intraday market data to be applied in this project.

Abstract

Distributed energy resources (DERs) are a largely untapped flexibility source in power systems. One of the reasons for this, are the barriers to access current power markets. Balancing markets in particular, have strict requirements with respect to availability and reliability. This master thesis proposes a new market design that aims to facilitate the integration of distributed energy resources. The market allows intermittent generators to contract DERs directly through an aggregator. Contracted DERs can be activated to balance production forecast errors of wind producers. A case study is conducted in the Norwegian context to evaluate the market design. It is found that giving wind producers the option to contract DER flexibility, significantly reduces the wind producers' exposure to intraday market illiquidity risk. The revenues that DERs would obtain from offering flexibility to wind producers are however only modest; approximately 30% of the day-ahead price. Examining how system balancing would be affected by introducing the flexibility market, it is found that the median system imbalance would be reduced. The total costs of procuring and maintaining balancing reserves would however not fall considerably, as sufficient reserves are needed to cover peak imbalances. Further research should consider market designs that allow aggregators to trade DERs sequentially in different markets, as this is likely necessary to increase DER remuneration and incentivize the provision of demand-side flexibility.

Sammendrag

Potensialet for å ta i bruk eksplisitt forbrukerfleksibilitet i kraftsystemet er stort, men fremdeles i stor grad uutnyttet. En årsak til dette er at det er vanskelig for aggregatorene som selger forbrukerfleksibilitet å delta i dagens kraftmarkeder. Særlig i balansemarkedet stilles det krav til tilgjengelighet og pålitelighet som vanskelig kan oppfylles av forbrukerfleksibilitet. I denne masteroppgaven foreslås et nytt markedsdesign som er ment å bedre integrasjonen av eksplisitt forbrukerfleksibilitet. Det foreslåtte markedet gjør det mulig for vindkraftprodusenter å redusere sine ubalansekostnader ved å aktivere ressurser på forbrukssiden i kraftsystemet. Markedet testes i et casestudium satt til det norske kraftmarkedet. Resultatene viser at vindkraftprodusenter i vesentlig grad kan redusere sin eksponering mot likviditetsrisiko i intradagmarkedet ved å ta i bruk forbrukerfleksibilitet. Inntektene til tilbyderne av forbrukerfleksibilitet er imidlertid relativt lave; tilsvarende omlag 30% av kraftprisen i Elspot-markedet. Videre undersøkes effekter på balanseringen av kraftsystemet som helhet. Funnene viser at selv om systemubalansene i gjennomsnitt kunne blitt redusert ved å ta i bruk eksplisitt forbrukerfleksibilitet, ville dette sannsynligvis ikke medført at kostnader til balansereverver reduseres betydelig. Dette skyldes at slike reserver må være tilstrekkelige for å dekke toppene i systemubalanser. Videre forskning bør ta for seg handel av eksplisitt forbrukerfleksibilitet i sekvensielle markeder, siden dette trolig er nødvendig for å øke godtgjørelsen og dermed gjøre det mer attraktivt å tilby slik forbrukerfleksibilitet.

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Chapter 1

Introduction

In Homer's The Odyssey, Aeolus is the ruler of winds, and king of the island Aeolia. After escaping from the Island of the cyclops, Odysseus and his men encounter Aeolus. Aeolus gifts Odysseus with a bag containing all the winds; one for each cardinal direction and several more, except the west wind. In this way only the west wind would provide a gentle breeze, and Odysseus could travel home safely. Inadvertently, the winds trapped in the bag get released, and as a result, Odysseus does not arrive home until many years later. Modern technology has not given us abilities to control the winds like Aeolus. Although reliable short-term forecasts of wind speed- and direction can be made, these forecasts come with inaccuracies, and the short-term variability and fundamental uncertainty of wind will remain.

The wide-spread integration of intermittent renewable generation challenges various aspects of secure and reliable power system operation. Firstly, short-term variability and uncertainty of wind and solar-PV production makes maintaining the instantaneous balance between production and consumption more difficult. Further, due to its spatial distribution, wind power production in particular tends to cause line congestion Xiong et al. (2021). Lastly, the feed-in from renewables connected at the distribution system level causes voltage instability. Thus, to accommodate ever-increasing shares of intermittent renewables and enable a low-carbon economy, it is widely established that the flexibility of the power system must be improved (ENTSO-E 2022). One largely untapped flexibility source is at the demand-side: Distributed energy resources (DERs) (Vanderveken and Trzcinski 2014). Distributed energy resources consist of demand-response mechanisms, small-scale energy storage and electric vehicles, to name a few (Newman and MacDougall 2021). They can cover various short-term flexibility needs; both on the distribution system level and system-wide.

To offer flexibility system-wide, it is argued that DERs should have access to electricity markets on the same terms as conventional generation (Xu 2019). Several barriers exist however to trade DERs in wholesale markets, and particularly in balancing markets. To facilitate making DER flexibility available to help balance the system, this work proposes to establish a new market tailored to distributed energy resources. A market dedicated to DERs could be more lenient than balancing markets with respect to requirements on availability, response time, and up- and down regulation rates, which all vary for different types of distributed energy resources. Further, a DER-specific market would provide better transparency about the value that flexible operation of DERs contributes.

The proposed flexibility market allows wind and solar-PV[1] producers to contract DERs. Con-

[1]Wind producers are the focus in this work, as they are likely to have higher uptake in the Nordic markets than solar-PV producers.

tracted DERs can then, through an aggregator, be activated directly by the wind and solar-PV producers themselves, to balance their own forecast errors. The market is designed as a daily, short-term capacity market, named Pre-contracting flexibility market, or PreFlex for short. Using the contracted DERs, wind- and solar PV producers can reduce their exposure to imbalance costs, and illiquidity risk in intraday markets. From the perspective of the DER owners, the PreFlex provides an opportunity to be remunerated for flexible operation of their assets, which is crucial to incentivize increased provision of demand-side flexibility. Lastly, the flexibility market could help reduce system imbalances.

The following research questions are posed, which take the perspective of intermittent (wind) producers, DER asset owners, and the TSO and its system balancing responsibility, respectively:

1. How does having the option to balance forecast errors using DER flexibility impact wind producers?
2. What amount of remuneration could DER asset owners obtain from supplying flexibility to the PreFlex market?
3. What are the effects on system balancing of introducing the PreFlex market?

To answer the research questions, stochastic optimization models that simulate wind producers trading in sequential electricity markets are developed. The models are applied to a case study set in the Norwegian power market context. The potential effects of introducing the PreFlex are evaluated from the perspective of wind producers, DER asset owners, and system balancing respectively.

The main results are as follows: Giving wind producers the option to contract DER flexibility significantly reduces their exposure to intraday illiquidity risk and makes them better equipped to trade profitably trade in intraday markets. The revenues that DER owners obtain from contracting assets to wind producers are however found to be only modest, at approximately 30% of the day-ahead price. The low value is largely driven by the fact that contracted flexibility is not utilized a substantial proportion of the time. Lastly, it is shown that utilizing DER flexiiblity to balance wind power forecast errors could significantly reduce the median system imbalances. This would however likely not result in any substantial reductions in system balancing costs: The size of peak imbalances would remain high, and thus the volume of balancing reserves that must be procured by the TSO would not be reduced considerably by introducing the PreFlex market.

This master thesis is structured as follows: Chapter 2 provides an overview of the Nordic power market. In addition, literature on integrating DERs in balancing markets and intraday markets respectively, is reviewed. Chapter 3 further describes the proposed market design of the PreFlex and establishes the research questions. Chapter 4 details the methodology: Optimization model formulations are developed, and the approach to generate the scenarios that represent uncertainty in wind production and intraday prices is detailed. Chapter 5 introduces the case study and analyzes the data used as input. Chapter 6 presents and discusses the results of the case study. Chapter 7 concludes and suggests topics for further research.

Chapter 2

Background

2.1 Nordic power market overview

To help set the stage for further discussion of DER integration into electricity markets, this section gives an overview of the institutional structure of the Nordic power market. The day-ahead ("Elspot") and intraday ("Elbas") spot markets are presented, as well as the balancing reserve and balancing energy markets. A key element in this work is system balancing, and particularly the consequences for market parties if they have imbalanced positions at the time of delivery. Therefore, an overview of the imbalance settlement process is included as well.

Figure 2.1 shows the timing of Nordic wholesale and balancing markets. The wholesale markets, i.e. the day-ahead and intraday markets, are the primary markets for allocating production and consumption between generators and consumers. Most trade is done in the day-ahead market. The intraday market is used by market participants to make adjustments in their production and/or consumption portfolios in the event of forecast corrections. Both are operated by Nord Pool Spot AS; the power exchange in the Nordic-Baltic system (Khodadadi et al. 2020). The balancing markets however are operated by the individual countries' TSOs. This follows from the "decoupling" or separation of market- and system operation responsibilities in liberalized electricity markets. Balancing power is used to ensure system security, which is the responsibility of the TSO. Although balancing is the responsibility of the individual country's TSO, Nordic TSOs have largely harmonized balancing markets to allow for balancing power exchange (Farahmand 2012).

Overall, substantial efforts are currently put into integrating European intraday markets (Alangi et al. 2022) and balancing markets (Khodadadi et al. 2020). The motivation is to promote effective competition and pricing, and enable more efficient utilization of generation resources across Europe (Alangi et al. 2022). Being somewhat out of scope for this thesis, however, the harmonization of intraday and balancing markets across Europe is not further elaborated on here.

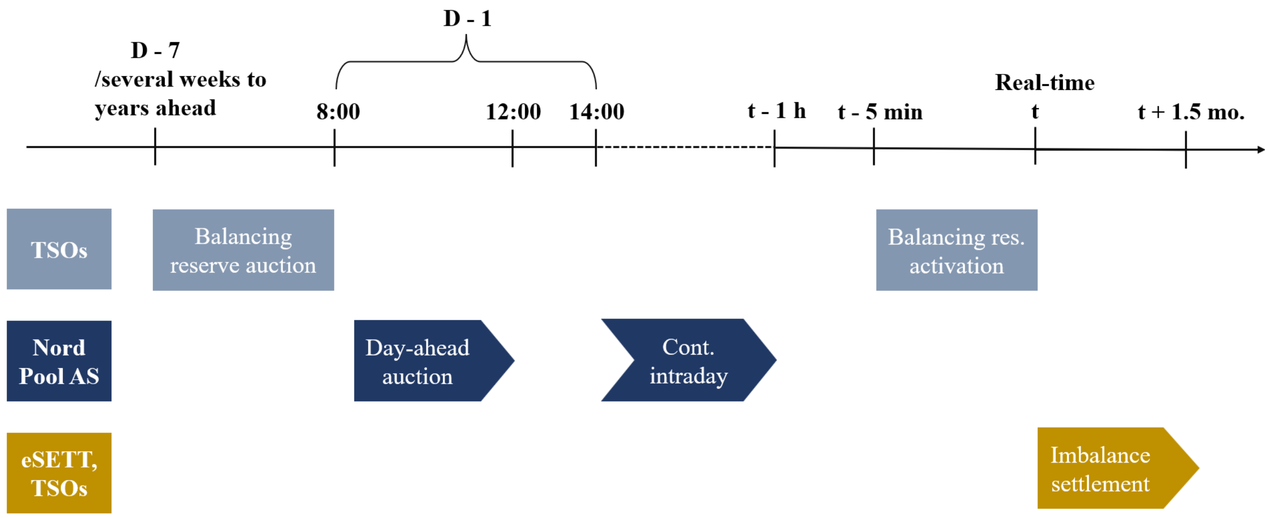


Figure 2.1: Timeline of the Nordic wholesale and balancing markets.

2.1.1 The day-ahead market

The day-ahead market in the Nordic system is Nord Pool's "Elspot". Its purpose is to allocate production and consumption volumes to the various market participants. Contracts are traded for each hour the following day. It is organized as a two-sided, uniform-price auction. Price/quantity bids to purchase and sell power are submitted. These bids are aggregated into hourly supply- and demand curves. The uniform price and total production volume are determined by the point at which these two curves intersect. The uniform price design encourages social surplus-maximizing marginal cost-bidding, as long as there is reasonable competition (Selasinsky 2016). As can be seen in figure 2.1, the day-ahead market clears at 12:00 p.m. Thus, wind producers must forecast production 12-36 hours ahead as part of the process to determine what quantities to bid.

2.1.2 The intraday market

The "Elbas" intraday market allows for trading electricity between the day-ahead market and up until one hour before delivery. Here, market participants can adjust the net volume bought or sold in the day-ahead market closer to real-time. For intermittent producers, this can be advantageous to reduce exposure to imbalance costs. Imbalance costs are incurred by balance responsible parties (BRPs) if less or more[1] power is injected during real-time than sold in the wholesale markets, i.e. in case of an imbalanced position.

The "Elbas" is designed as a continuous two-sided auction. Like with the "Elspot", price/quantity bids both to sell and purchase power are submitted. In contrast to the "Elspot" however, bids are matched continuously on a first-come first-served basis, rather than cleared at a single discrete auction. This implies that no uniform price is set, instead, various market participants trade electricity at different prices which depend on the matching of individual bids using an open order book. An instructive example on the bid matching process in continuous intraday markets such as the Elbas can be found in Selasinsky (2016).

[1] If a Balance Responsible Party (BRP) injects more power into the grid than sold in wholesale markets, the BRP is remunerated for this excess energy according to the surplus imbalance price. Whether this price is beneficial from the perspective of the BRP largely depends on the imbalance pricing rules and the system imbalance.

By reducing the imbalances of intermittent producers going into real-time, intraday markets are considered an important instrument to integrate intermittent renewable production and reduce system imbalances. Due to the fact that balancing markets cover system reliability needs that the intraday market does not, Scharff and Amelin (2016) argue that intraday markets should be considered a complement to balancing markets and not a substitute. Nevertheless, increased intraday market trade can substantially reduce the required volume of balancing reserves, as was observed in Germany (Ocker and Ehrhart 2017).

2.1.3 The balancing market

As previously explained, it is the responsibility of the TSO to ensure a balanced system. To fulfill this obligation, the TSO must procure reserves in balancing markets. Balancing markets are divided into two components: A balancing reserve capacity market and a balancing energy market. The balancing reserve capacity market provides the TSO with a minimum of balancing reserves. The balancing energy market is the market for balancing energy delivery. Reserves procured from the balancing capacity market are obliged to submit bids to the balancing energy market, but other market participants can submit bids as well, given that they satisfy pre-qualification criteria with respect to availability, minimum bid sizes, and symmetric up- and down-regulation (Xu 2019). After the balancing energy market, the TSO activates reserves on short notice if system frequency deviations occur. Reserves are activated according to the merit order determined in the balancing energy market.

2.1.4 Imbalance settlement

In addition to the mentioned TSO, two parties are involved in imbalanec settlement: Balancing Service Providers (BSPs), and Balance Responsible Parties (BRPs). BSPs supply balancing energy which is activated by the TSO in the case of system frequency deviations. All participants in wholesale electricity markets are BRPs or contracted to one. BRPs are obliged to plan in balance, i.e. to sell or buy the same volumes that plan to inject into the grid. As described in Farahmand (2012), the balancing market can be viewed as a platform where Balance Responsible Parties pay indirectly to Balance Service Providers for solving real-time imbalances through the TSO. The imbalance settlement process is key to enabling this: During imbalance settlement, the real-time delivery or consumption of BRPs is compared to their contracted energy for the same imbalance settlement period (ISP). If there is a deviation between the volume delivered and the contracted energy, the BRPs are penalized or remunerated, depending on the sign of the imbalance.

In case of a deficit imbalance on the system level, remuneration is on aggregate paid to the BSPs that supply up-regulation. In the case of a surplus imbalance, the BRPs that have surplus imbalances are on aggregate remunerated. This is done through negative down-regulation prices. Down-regulation prices can be negative, as the BSPs that supply down-regulation are rewarded by the day-ahead price, in addition to paying the (negative) down-regulating price Xu (2019).

Different rules for imbalance pricing have been practiced in different European countries (Chaves-Ávila et al. 2014). The differences mainly consist of whether a single-pricing or a dual-pricing rule is employed. Choosing between these two imbalance pricing rules has implications for whether the BRPs benefit or not from having an imbalance in the opposite direction of the system imbalance. In a dual-price system, the BRP faces the most disadvantageous of the day-ahead price and the balancing energy price. In a single-price system, the BRP is penalized or remunerated with the balancing energy price independent of the sign of its imbalance compared to the system imbalance. As a result, with a dual pricing rule, the BRP never benefits from being in imbalance. With a single-price rule, however, the BRP benefits if its imbalance "aids" the system imbalance, i.e. is in the opposite direction of it (Herre 2020). The assumptions made with respect to imbalance prices in this work are included in chapter 4.

Imbalance settlement in the Nordic system currently undergoes changes as a step in harmonizing European power markets. Two changes specifically were made at November 1, 2021: Firstly, a two-price system for production imbalances was replaced by a one-price system[2]. Secondly, the imbalance settlement period was changed from one hour to 15 minutes. In this work, however, imbalances will be considered for each hour of delivery, to limit modeling complexity.

[2]These changes also involve moving from a two-balance to a one-balance system. This means that imbalance settlement rules will no longer be different for production and consumption imbalances, as they will both be covered by the same single-price imbalance system.

2.2 Literature review on DER market integration

As was discussed in the introduction, the power system would likely benefit from utilizing DERs to help cover the system's needs for flexibility for power. A prerequisite to enable this, however, is to integrate them into power markets. This is a matter of ongoing research. Villar et al. (2018), Xu (2019), Eid et al. (2016), Newman and MacDougall (2021), and IRENA (2019) all agree on the need for TSO-DSO coordination schemes to make the flexibility that the distribution grid-connected DERs could offer, available to the whole system. In addition, the consensus is that aggregators play a key role in reducing transaction costs. The authors disagree, however, on what system-wide markets have the most promise for DERs flexibility: Villar et al. (2018) and Xu (2019) consider trading DERs in ancillary markets and balancing markets in particular. Newman and MacDougall (2021) however, sees the greatest potential in intraday markets.

Villar et al. (2018) reviews the extensive literature on the provision of DER flexibility for various purposes in the power system and defines flexibility located at the distribution grid for use at the transmission grid as one of three types of flexibility products. The asymmetric regulation of DERs and their heterogeneous response times are barriers to trading them in balancing markets. TSOs generally require standard- and symmetric up- and down-regulation rates, which cannot necessarily be guaranteed by a portfolio of DERs. A further barrier is the risk that DERs are unavailable when ancillary services are requested or do not provide the required energy for the entire period.

Xu (2019) and Eid et al. (2016) identify similar barriers to entry for balancing markets as Villar et al. (2018), but highlights an additional vital issue that must be settled for DER flexibility to evolve: As demand-side energy resources are part of a balance responsible party's (BRP) portfolio, activation of these resources by a third-party aggregator could cause imbalances in the portfolio of the mentioned BRP. In light of this, an argument is provided in Xu (2019) for why frequency control reserves in balancing markets have been the first products to become feasible for DERs to offer: Frequency control reserves have a low energy component and high capacity remuneration and are only activated for short periods. As a result, they are more acceptable to the BRP that has these demand-side resources in its portfolio. Although each demand-side resource delivers significant capacity when activated by the aggregator, modifying the operation of the demand-side resource – to offer short term-regulating power – does not substantially contribute to energy imbalances (kWh) for the BRP. Imbalance settlement schemes between aggregators and BRPs are nevertheless needed to utilize DERs beyond offering the most short-term balancing products.

As previously mentioned, so-called TSO-DSO coordination mechanisms are needed to utilize DER flexibility system-wide. Both distribution system operators (DSOs) and the transmission system operator (TSO) could make use of DER flexibility to cover local and regional, and system-wide flexibility needs, respectively. This causes a conflict of interest between the TSO and the DSOs. Briefly summarized, if the TSO activates flexibility for system-wide purposes, such as responding to frequency deviations, it could cause congestion at the distribution system level. The DSO would have to instigate efforts to mitigate this congestion. The result would be that the activation of DER flexibility while solving problems on the system-wide level causes new issues at the local level. Other examples of such conflicts are detailed in dena (2017), and an overview of proposed TSO-DSO coordination schemes can be found in Alazemi et al. (2022).

Contrary to Villar et al. (2018) and Xu (2019), Newman and MacDougall (2021) sees greater potential for DER integration in intraday markets than in balancing markets. It is argued that real-time markets do not offer sufficient lead time for aggregators to schedule their portfolios optimally:

"An EV fleet (scheduled by an aggregator) can better respond to price signals with hours to reroute and shift charging schedules than with minutes to do so. In the real-time market, DERs risk deploying flexibility in moments when they capture neither the most financial value for the resource owner nor the greatest benefit for other grid customers."

Like Newman and MacDougall (2021), IRENA (2019) proposes trading DERs in intraday markets. IRENA (2019) Expect lower price spikes and improved competition if more DERs access these markets. Similar to the aim of the present paper, Garnier and Madlener (2014) evaluate the value that flexible loads in the household segment could provide for wind power balancing. It is found that the relatively higher volatility of intraday markets makes these more attractive to trade flexibility in than in day-ahead markets.

Chapter 3

Problem Description

This chapter sets out the scope of this thesis and provides an overview of the methods applied. It has three sections: Section 3.1 proposes a market design for DER flexibility and presents some hypotheses on the potential effects of making DER flexibility available through such a market. Further, the flexibility market is positioned relative to other existing Nordic electricity markets. In section 3.2 the research questions of this work are further motivated. Lastly, in section 3.3, an overview is given of the methodology and the two main optimization models in this work. The developed models represent two different cases: One case where only current electricity markets are available for wind producers, named ”Business as usual”, and one case where the wind producers have the option to trade in the PreFlex market, named ”PreFlex”.

3.1 Designing a new market for DER flexibility

The literature review on DER integration into wholesale electricity markets showed that intraday markets and balancing markets are considered the most attractive to trade DERs in. ENTSO-E (2022) emphasizes that ”electricity market design should ensure an efficient access to DERs to be used where and when it is most beneficial”. Having markets tailored to DERs would improve transparency about the value that flexible operation of DERs contributes to the system, and could therefore be a path to introduce them into existing electricity markets, particularly in light of the significant entry barriers identified in the literature review. This master thesis proposes and tests a design for a new market that aims to make DER flexibility available to provide *flexibility for power*. The market is provisionally called the “Pre-contracting flexibility market” or simply “PreFlex.” The market is designed as a short-term capacity market where intermittent generators contract DER flexibility directly from aggregators. This could be wind producers or solar-PV producers, but the emphasis is on wind producers in this work as solar-PV only has small uptake in Nordic power markets. Once it is contracted, DER flexibility can be activated by the intermittent generators themselves as real-time approaches and they become aware of errors in their production forecasts. Overall, a flexibility market for forecast error balancing could provide value to the power system in three different ways:

1. **Reduce the restrictions on wind generators.**
   Wind generators currently trade in intraday markets to reduce imbalances caused by forecast errors. When trading in intraday markets, such intermittent producers face several important complications related to both intraday market design and certain technical characteristics of wind generation. More specifically, they face low market liquidity (Shinde and Amelin

2019), systematically worse prices than in the day-ahead market (Selasinsky 2016), and must handle oscillating forecast errors (Henriot 2014). Having access to flexibility would give the intermittent producers more freedom and make them better equipped, specifically to handle the complications that they face when trading in intraday markets.

2. **Provide remuneration for the provision of DER flexibility.**
Currently there is only limited access to trade DER flexibility in conventional wholesale and balancing markets. Therefore, the proposed market structure presents an opportunity for aggregators seeking revenue streams – as a substitute or as a complement to trading in intraday and balancing markets. Lastly, the capacity market element of the PreFlex design could contribute to more predictable revenues to aggregators and DER asset owners, which would lower the barriers to supplying DER flexibility.

3. **Increase power market efficiency by reducing the volume of balancing reserves and committing flexibility at an earlier stage.**
Trade in the PreFlex would help reduce system imbalances, resulting in a reduction in the balancing reserves that the TSO needs to procure. This would likely improve power market efficiency: Firstly, less conventional generation tied up in balancing reserves means that more generation may be traded in other markets, such as the day-ahead and intraday markets. This would improve competition in these markets and increase the supply of energy. Secondly, reducing the volume of balancing reserves would reduce the share of flexibility traded in markets in which the TSO is involved as a market participant. Thirdly, balancing reserves are mostly activated on short term-basis, as the TSO becomes aware of imbalances. As real-time approaches, however, flexibility becomes scarcer. Committing or "activating" flexibility as early as possible is therefore preferred. Wind generators are the first to gain information on their own forecast errors, and if they have access to flexibility, they can commit this flexibility at an earlier stage than the TSO could.

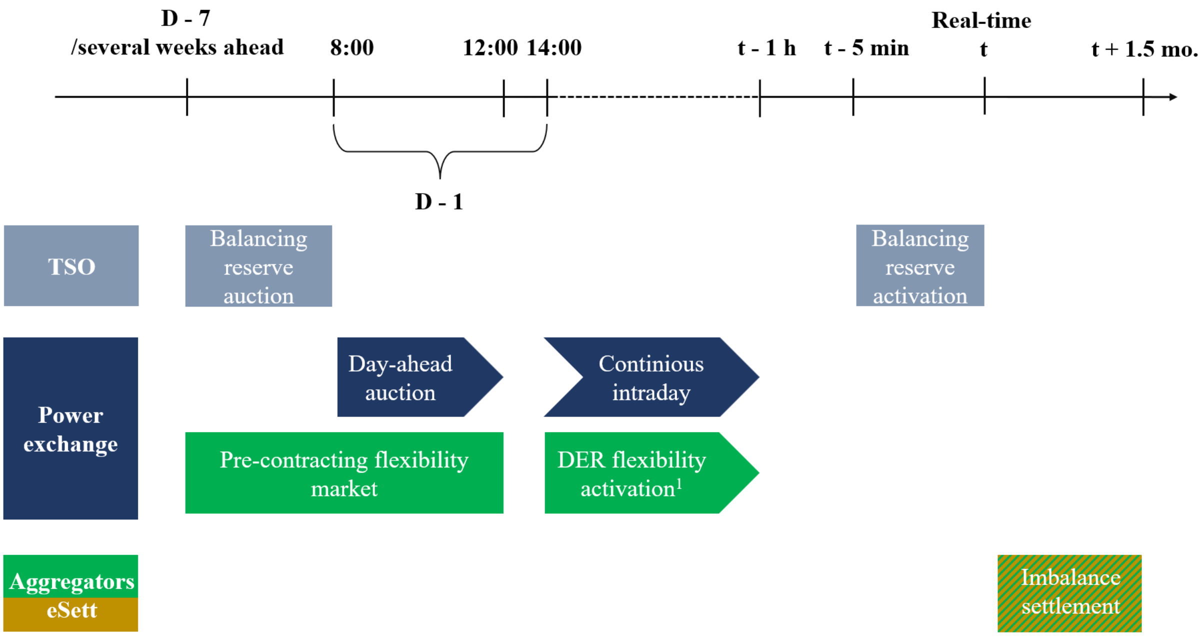


Figure 3.1: The proposed flexibility market positioned relative to the main Nordic power markets. The responsibility of organizing DER flexibility auctions is suggested to be allocated to the power exchange. Notice also the need for imbalance settlement between aggregators and BRPs.
[1]While a request to activate flexibility is made by the wind producer to balance their forecast errors, it is the aggregator that adjusts the operating schedules of these DERs.

Figure 3.1 shows how the proposed flexibility market is positioned relative to Nordic wholesale- and balancing markets. The flexibility market is positioned before and during the day-ahead market. The duration of trade in the flexibility market and its lead time to real-time is an important design variable. In this work, it is assumed that DERs can be pre-contracted daily, and shortly before, or during the day-ahead market bidding phase. The flexibility activation phase is parallel to trade in continuous intraday markets. Lastly, imbalance settlement between aggregators and BRPs is necessary, at least in the case when the DERs activated by the aggregator are part of the portfolio of a separate balance responsible party (BRP) (Xu 2019). Below follows a further discussion of the key design parameters of the proposed flexibility market.

As mentioned previously, the PreFlex is envisioned to be a short-term capacity market where wind producers, or even solar PV producers, can purchase DER flexibility directly from aggregators. The design tested in this work is only provisional, and it is chosen while keeping modeling complexity in mind. Either way, when designing a market tailored to DERs, the entry barriers that DERs currently face in wholesale- and balancing markets should be considered. For balancing markets, some of these barriers are the long lead times of capacity market auctions and high requirements on the duration of availability (Xu 2019). Table 3.1 lists market design variables concerning timing and remuneration for a market tailored to DERs and shows the design choices for the market tested in this work.

Table 3.1: Flexibility design variables considered.

Market design variable	Considerations	Design choice in this work
Auction frequency	Less frequent auctions increase revenue predictability for DERs, but it is substantially more difficult for aggregators to forecast the availability of DERs at longer horizons. Furthermore, at longer horizons, wind producers must rely on average flexibility needs rather than continuously purchasing flexibility according to balancing needs.	**Daily auctions** for a maximum forecast horizon of 36 hours.
Duration for availability	If the period that the DERs must be held available for is longer, the opportunity costs increase as it becomes more difficult for active consumers to adapt their behaviors. On the other hand, a longer availability improves the offering for wind producers.	Availability duration of **one hour**
Remuneration structure	Energy payments could incentivize intermittent producers to use the procured flexibility for a shorter duration. Capacity payments guarantee revenues to DER owners.	**Capacity payment only**

3.2 Research questions

After establishing the Pre-contracting flexibility market concept as an opportunity to trade DER flexibility, this work aims to evaluate the functioning of this market and test some of the hypotheses about its potential impact that were presented above. Before undergoing the relatively cumbersome institutional process of introducing a new market, it is of interest to evaluate its design and its potential impact on market participants. To do this, this work develops models that simulate trade in short-term electricity markets. Further, it explores what effect introducing the PreFlex market could have through a case study set in the Norwegian power market. Various actors are examined; namely wind producers, DER aggregators- asset owners, and the TSO; where the focus is its system balancing responsibility. Only wind producers are considered, as the uptake of solar PV in wholesale electricity markets is still low in Norway. From the wind producers' perspective, it is of interest to explore whether the PreFlex can reduce their exposure to disadvantageous intraday market prices and intraday market illiquidity risk. From the DER perspective, an estimate of the remuneration obtained from trading them in the PreFlex market is found. Taking the perspective of the TSO, the reduction in wind power imbalances obtained using DER flexibility is compared to empirical data on current Norwegian system imbalances. The aim is to evaluate the effect that introducing DER flexibility through the PreFlex could have on the volume of required balancing reserves. The objectives mentioned above of this work are summarized in three research questions:

1. How does having the option to balance forecast errors using DER flexibility impact wind

producers?

2. What amount of remuneration could DER asset owners obtain from supplying flexibility to the PreFlex market?

3. What are the effects on system balancing of introducing the PreFlex market?

In section 3.1, several hypotheses about how the PreFlex could improve the economic efficiency of power markets, and system balancing in particular, were proposed. Discussing social welfare has merit when it comes to introducing a new electricity market, as it perhaps is the main criterion for whether such a market is well-functioning. Quantifying the social welfare effects of introducing a new market, however, is challenging for several reasons. Firstly, different electricity markets are inherently interconnected, so changing the conditions for market participants in one market will invariably affect trade in related markets. Secondly, intraday market trade and activation of balancing reserves are inter-temporal, which makes modeling the efficiency effects of committing flexibility at an earlier stage before real-time difficult. In light of this, it is not attempted to estimate the social welfare effects of introducing the PreFlex market. Instead, the perspectives of three parties are considered individually. The idea is that taking the perspective of wind producers, DER asset owners, and system balancing will provide a relatively holistic evaluation of the impact the PreFlex would have. Importantly, however, conventional generators are not considered explicitly.

3.3 Overview of methodology

In this work, two-stage stochastic optimization models are the primary quantitative tools applied. Models that simulate wind producers trading in day-ahead and intraday markets are developed. Their structure is similar to models deployed in an existing strain of research on wind power trading strategy. In this literature, two- or multi-stage stochastic optimization models are used to obtain optimal trading strategies in short-term electricity markets for individual wind producers. Early examples of this work include Matevosyan and Lennart Soder (2006), Pinson et al. (2007), and Moreno et al. (2012). Further, Morales et al. (2010) considers a three-stage model, where the information flow of improved wind power forecasts is handled more explicitly. Chaves-Ávila et al. (2014) adapts models to the particular imbalance settlement rules in various European electricity markets. Different from the literature mentioned above, the models developed in this master thesis do not consider an individual wind producer but instead group all wind producers within a market area, and analyzes their behavior on an aggregate level. Further, the aim is not to obtain an optimal wind producer trading strategy, but to explore how wind producers' trading behavior would change if they had the option to purchase DER flexibility and use it to balance their forecast errors.

The overall approach to test how the PreFlex affects wind producers, DERs, and system balancing, is to compare two different cases: The first case represents the current setting where the wind producers do not have access to flexibility from DERs. In the second case, the PreFlex market is introduced, and the wind producers have the option to purchase flexibility provided by DERs. The trading behavior of the wind producers in the second case is compared to the first case to answer the first research question on how wind producers are affected by introducing the PreFlex. DER revenues are estimated in a case study on the Norwegian market to answer the second research question. Changes observed in the imbalances of wind producers help answer the third research question on system balancing. The two main cases, one representing trade under current conditions and one where the PreFlex capacity market is introduced, are in this text called "Business as usual" (BAU) and "PreFlex", respectively. Below is a further description of the models representing these two cases and how the models differ.

3.3.1 Business as usual (BAU) model

This model considers wind producers trading in the current Nordic sequential electricity markets. It is a two-stage stochastic optimization model. In the first stage, the wind producers submit bids to the day-ahead market. As real-time approaches, the wind producers can trade in the intraday market as production forecasts are improved, and more information on actual production is obtained. The second stage then represents trade in the intraday market. The wind producers decide on the volume of power to buy or sell in the intraday market, dependent on improved information on actual production, intraday market prices, and expectations of imbalance prices. Uncertainty in wind production and intraday market prices are described using probability-weighted scenarios. These scenarios are constructed from probabilistic wind production forecasts and thus accurately represent the uncertainty about future production at the stage when day-ahead market bids are submitted.

3.3.2 PreFlex model

To model the case where the wind power producers have access to the PreFlex capacity market, the Business as usual model is modified in the following way: In the first stage, the wind producers not only make a decision on what volumes to bid in the day-ahead market but also a decision on what quantity of DER flexibility to contract. In the second stage of the model, the wind producers have the option to activate any DER flexibility previously contracted in the PreFlex to balance forecast errors, in addition to trading in intraday markets. As a result, wind producers have more freedom when handling their forecast errors, and the DERs can trade and be remunerated for their flexibility.

3.3.3 Subcases of the two presented models

Further, various subcases of the Business as usual and PreFlex model are introduced. These subcases aim to test some of the hypotheses on the effects of introducing the PreFlex listed in section 3.1. More specifically, it is tested whether the PreFlex could help mitigate complications that wind producers face concerning disadvantageous intraday prices and low market liquidity. Additionally, a case where the DER flexibility can be traded directly in intraday markets is established as a benchmark for the revenues that DER owners obtain through trading in the PreFlex. More details on how these subcases are implemented can be found in chapter 4.

Chapter 4

Methodology

This chapter presents the methodology applied. The overall approach is to compare the simulated outcomes from two models: One model that represents wind producers trading in the current short-term electricity markets, and one model that expands on this, by allowing wind producers to procure DER flexibility. This section is structured as follows: Section 4.1 presents the mathematical formulations of the stochastic optimization models. Section 4.2 details how production and market scenarios are generated for these models.

4.1 Model formulations

In this section, mathematical formulations of the deterministic equivalents of the two-stage stochastic models are developed. Firstly, the model assumptions are laid out in section 4.1.1. Then, the nomenclature for sets, variables, and parameters is defined in section 4.1.2. Lastly, the formulations for the Business as usual model and PreFlex model are presented in sections 4.1.3 and 4.1.4, respectively.

4.1.1 Assumptions

- **Wind production is known during the late stages of the intraday market**
  Trade in the intraday market occurs before real-time, and thus deviations between the forecasted production volumes at the intraday stage and the actual production can occur. As shown in Scharff and Amelin (2016) however, most intraday trades are made only a few hours before real-time. As a result, although there still is uncertainty about actual wind production at the stage of intraday trade, this uncertainty is substantially lower than at the time of the day-ahead market, at least during the hours when the majority of intraday trade occurs.
- **Wind producers within each market area are homogeneous**
  In this work, wind producers within each market area are grouped together. Their forecast errors and their trading behavior is considered on an aggregate level. This is a reasonable approach given the fact that the forecast errors of wind producers are correlated within individual market areas.
- **The wind producers have no market power**
  Even though the wind producers are grouped together within each market area, this single unit of wind producers should not have any significant price-making ability, as this would

deviate strongly from a realistic situation. Somewhat unrealistically, to avoid that wind producers become price-makers in the model, intraday prices are modeled to be independent of the volume that wind producers trade in the intraday market. Rather, intraday prices are assumed to depend on the aggregate forecast errors of the wind producers, which are beyond their control.

- **Deterministic imbalance prices**
  In reality, imbalance prices are unknown to wind producers during intraday market trade, and decisions to purchase or sell power in the intraday market must be done taking this uncertainty into account. In the models, however, imbalance prices were assumed to be deterministic at the stage of the intraday market.

- **Imbalance pricing rule**
  A single-price imbalance system was implemented. This implies that the wind producers faced an up- or down-regulating price only dependent on their own aggregate imbalance, and independent of the system imbalance. The system imbalance was not integrated in the models.

- **The availability of DER flexibility is independent of the flexibility activation in preceding hours**
  To simplify modeling, it is assumed that the volume of DER flexibility that can be activated in a given hour, is independent of the volume that was activated in the preceding hours. This makes it possible to model the contracting and activation of DER purchases for a given delivery hour as a two-stage optimization problem. To simulate trade throughout a longer period, these optimization models can then be solved iteratively for each delivery hour in the considered period.

4.1.2 Nomenclature

Indices

a Index of market area in the set of market areas $\mathcal{A}$
d Indicates the DER type in the set of DER types $\mathcal{D}$
s Index of scenario in the set of scenarios $\mathcal{S}$

Variables for Business as usual model

p_a^{DA} Total wind power volume bid in day-ahead market in market area a [$\mathrm{MW_{el}}$]

$p_{a,s}^{ID}$ Net volume bought in the intraday market by wind power producers, in market area a and scenario s [$\mathrm{MWh_{el}}$]

$\Delta_{a,s}$ Net imbalance after intraday market gate closure, in market area a and scenario s [$\mathrm{MWh_{el}}$]

$\Delta_{a,s}^{+}$ Surplus imbalance for the wind producers after intraday market gate closure, in market area a and scenario s [$\mathrm{MWh_{el}}$]

$\Delta_{a,s}^{-}$ Deficit imbalance for the wind producers after intraday market gate closure, in market area a and scenario s [$\mathrm{MWh_{el}}$]

Additional variables in PreFlex model

$p_{a,d}^{PF,+}$ Up-regulation capacity contracted of DER type d in the PreFlex market, in market area a [$\mathrm{MW_{el}}$]

$p_{a,d}^{PF,-}$ Down-regulation capacity contracted of DER type d in the PreFlex market, in market area a [$\mathrm{MW_{el}}$]

$p_{a,d,s}^{act,+}$ Volume of up-regulation activated by the wind producers in market area a, of DER type d and in scenario s [$\mathrm{MW_{el}}$]

$p_{a,d,s}^{act,-}$ Volume of down-regulation activated by the wind producers in the delivery hour in market area a, of DER type d and in scenario s [$\mathrm{MW_{el}}$]

$\delta_{a,s}$ Binary variable indicating whether DER up-regulation was activated (0) or not (1)

$\gamma_{a,s}$ Binary variable indicating whether wind producers produce less (1) or more (0) than the forecasted amount, in market area a and scenario s

Parameters

λ_a^{DA} Uniform day-ahead clearing price for the given delivery hour, in market area a and scenario s [$\mathrm{EUR/MWh_{el}}$]

$\pi_{a,s}$ Probability of scenario s occurring, at the time of day-ahead market gate closure [$\mathrm{EUR/MWh_{el}}$]

$\lambda_{a,s}^{ID}$ Volume-weighted intraday market price in market area a and scenario s [$\mathrm{EUR/MWh_{el}}$]

$\lambda_{a,s}^{+}$ Imbalance price in case of a net surplus imbalance for the wind producers in market area a and in scenario s [$\mathrm{EUR/MWh_{el}}$]

$\lambda_{a,s}^{-}$ Imbalance price in case of a net deficit imbalance for the wind producers in market area a and in scenario s [$\mathrm{EUR/kWh_{el}}$]

$\lambda_{a,d}^{PF,+}$ Price to contract up-regulation capacity for DER type d in the PreFlex market, in market area a [$\mathrm{EUR/MW_{el}}$]

$\lambda_{a,d}^{PF,-}$ Price to contract down-regulation capacity for DER type d in the PreFlex market, in market area a [$\mathrm{EUR/MW_{el}}$]

$P_{a,s}^{w}$ Realized wind power production in market area a and scenario s [$\mathrm{MW_{el}}$].

$P_a^{w,max}$ Wind power bid volume upper bound, in market area a [$\mathrm{MW_{el}}$]

4.1.3 Business as usual (BAU) model

This model simulates wind producers trading in short-term sequential electricity markets. Day-ahead markets, intraday markets, and imbalance settlement are considered. Its main purpose is to define a baseline with the current market structure. The outcomes of this model can then be compared to the case where the PreFlex has been introduced.

Objective function. The objective is to maximize the net revenues that wind producers obtain from selling power in day-ahead markets, buying and selling power in intraday markets, and imbalance settlement. Given that prices are positive, selling power in the day-ahead market (p_a^{DA}), in the intraday market ($p_a^{ID} > 0$) and net surplus imbalances $\Delta_{a,s}^{+}$ contribute to increasing net revenues in isolation. Intraday market purchases ($p_a^{ID} < 0$) and net deficit imbalances $\Delta_{a,s}^{+}$ decrease net revenues. The objective can further be divided into two parts: The first part contains the first stage decision of how much to sell in the day-ahead market. The second part consists of the second-stage decisions which are made once information on wind production and intraday prices are unveiled. They are probability-weighted to represent the uncertainty at the stage of the day-ahead market (Eq. 4.1).

$$\max_{p_a^{DA}, p_{a,s}^{ID}, p_{a,s}^{w}, \Delta_{a,s}, \Delta_{a,s}^{+}, \Delta_{a,s}^{-}} \quad \sum_a \left[p_a^{DA} \lambda_a^{DA} + \sum_s \pi_s \left(p_{a,s}^{ID} \lambda_{a,s}^{ID} + \Delta_{a,s}^{+} \lambda_{a,s}^{+} - \Delta_{a,s}^{-} \lambda_{a,s}^{-} \right) \right] \tag{4.1}$$

Day ahead market. Bids in the day-ahead market are upward limited by the total forecasted wind production in the respective market area.

$$p_a^{DA} \leq P_a^{w,for} \quad , a \in \mathcal{A} \tag{4.2}$$

Trading in the intraday market to reduce imbalances. Once more information on actual production is obtained, imbalances in the portfolio of wind producers can be reduced by trading in the intraday market.

$$\Delta_{a,s} = p_a^{DA} - P_{a,s}^{w} + p_{a,s}^{ID} \quad , a \in \mathcal{A},\, s \in \mathcal{S} \tag{4.3}$$

Deficit and surplus imbalances. As deficit and surplus imbalances for balance responsible parties are treated differently at imbalance settlement, separate variables for surplus and deficit imbalance are defined:

$$\Delta_{a,s} = \Delta_{a,s}^{-} - \Delta_{a,s}^{+} \quad , a \in \mathcal{A},\, s \in \mathcal{S} \tag{4.4}$$

Non-negativity. Eq. 4.5 and eq. 4.6 ensure that the day-ahead volume sold, and the surplus and deficit imbalance respectively can never be negative.

$$p_a^{DA} \geq 0 \quad a \in \mathcal{A} \tag{4.5}$$

$$\Delta_{a,s}^{-} \geq 0,\, \Delta_{a,s}^{+} \geq 0 \quad , a \in \mathcal{A},\, s \in \mathcal{S} \tag{4.6}$$

4.1.4 PreFlex model: Enabling procurement of DER flexibility

This model simulates a case where wind producers have the option to contract up- and down-regulation capacity from DERs and use this flexibility to balance forecast errors as an alternative to trading in the intraday market. The model has a structure similar to the Business as usual model, as it also considers wind producers trading in sequential electricity markets. The main modifications made to the Business as usual model are as follows: The decisions on the volume of DER flexibility to contract before the day-ahead market are added as first-stage decisions. Further, it is taken into account that contracted DER flexibility can be used to reduce imbalances. All changes and modifications to the Business as usual model are shown below.

Objective function. The costs of contracting DER up- and down-regulating capacity ($p_{a,d}^{PF,+}\lambda_{a,d}^{PF,+}$ and $p_{a,d}^{PF,-}\lambda_{a,d}^{PF,+}$) are added to the objective of the Business as usual model. This results in the following objective for the PreFlex model:

$$\max_{variables\,\in\,\mathcal{V}} \quad \sum_a \left[p_a^{DA}\,\lambda_a^{DA} + \sum_d \left(p_{a,d}^{PF,+}\lambda_{a,d}^{PF,+} + p_{a,d}^{PF,-}\lambda_{a,d}^{PF,-} \right) + \sum_s \pi_s \left(p_{a,s}^{ID}\,\lambda_{a,s}^{ID} + \Delta_{a,s}^{+}\,\lambda_{a,s}^{+} - \Delta_{a,s}^{-}\,\lambda_{a,s}^{-} \right) \right] \tag{4.7}$$

Where $\mathcal{V}$ is the set of decision variables in the PreFlex model: $\{p_a^{DA},\, p_{a,s}^{ID},\, p_{a,d}^{PF,+},\, p_{a,d}^{PF,-},\, p_{a,d,s}^{act,+},\, p_{a,d,s}^{act,-}$ $\Delta_{a,s},\, \Delta_{a,s}^{+},\, \Delta_{a,s}^{-}\}$

Contracting flexibility. The volume of flexibility that can be contracted is limited by the volume of up-and and down-regulation available in each hour, $p_{a,d}^{PF,+,\,max}$ and $p_{a,d}^{PF,-,\,max}$:

$$p_{a,d}^{PF,+} \leq p_{a,d}^{PF,+,\,max} \quad ,a \in \mathcal{A}, d \in \mathcal{D} \tag{4.8}$$

$$p_{a,d}^{PF,-} \leq p_{a,d}^{PF,-,\,max} \quad ,a \in \mathcal{A}, d \in \mathcal{D} \tag{4.9}$$

Reducing imbalances using DER flexibility. In a given scenario s, realizations of wind production and intraday prices are assumed to be known. The wind producers can now activate previously purchased DER flexibility to balance any forecast errors. This serves as an alternative to trading in intraday markets. In case of a deficit, i.e. the volume bid in the day-ahead market p_a^{DA} is larger than the produced quantity, $P_{a,s}^{w}$, up-regulation capacity can be activated ($p_{a,d,s}^{act,+} > 0$) to reduce the imbalance $\Delta_{a,s}$. Similarly, any down-regulation capacity can be activated in case of a surplus.

$$\Delta_{a,s} = p_a^{DA} - p_{a,s}^{w} - p_{a,s}^{ID} + \sum_d \left(p_{a,d,s}^{act,-} - p_{a,d,s}^{act,+} \right), \quad a \in \mathcal{A},\, s \in \mathcal{S} \tag{4.10}$$

Flexibility activation bounds. The volume of DER up- or down-regulating flexibility activated is limited by the capacity contracted in the PreFlex market ($p_{a,d}^{PF,+}$ and $p_{a,d}^{PF-}$)).

$$p_{a,d,s}^{act,+} \leq p_{a,d}^{PF,+} \quad ,a \in \mathcal{A}, d \in \mathcal{D},\, s \in \mathcal{S} \tag{4.11}$$

$$p_{a,d,s}^{act,+} \leq p_{a,d}^{PF-} \quad ,a \in \mathcal{A}, d \in \mathcal{D},\, s \in \mathcal{S} \tag{4.12}$$

Energy from DERs can not be traded in the intraday market. One of the premises for introducing the PreFlex is the limited access DERs have to intraday markets today. It is therefore assumed that the wind producers can not up-regulate DERs and then sell this power in the intraday market. Eqs. 4.13 and 4.14 ensure that wind producers on aggregate can only buy power from the intraday market, and not sell any power if up-regulation capacity is activated.

$$p^{ID}_{a,s} \geq -M_1 \delta_{a,s} \quad , a \in \mathcal{A},\, d \in \mathcal{D},\, s \in \mathcal{S} \tag{4.13}$$

$$p^{act,+}_{a,d,s} \leq M_2(1 - \delta_{a,s}) \quad , a \in \mathcal{A},\, d \in \mathcal{D},\, s \in \mathcal{S} \tag{4.14}$$

Up-regulating DERs to create an intentional surplus imbalance. An alternative to up-regulating DERs and selling their power in the intraday market, is to up-regulate them to create an intentional surplus imbalance and thereby obtain revenues at imbalance settlement. This would be disadvantageous from the system perspective, as this surplus would have to be balanced by regulating power. This option is barred from the wind producers by imposing the constraints in equations 4.15-4.18.

$$\sum_d p^{act,+}_{a,d,s} \leq p^{DA}_a - p^w_{a,s} + M_3(1 - \gamma_{a,s}) \quad , a \in \mathcal{A},\, s \in \mathcal{S} \tag{4.15}$$

$$\sum_d p^{act,+}_{a,d,s} \leq M_4 \gamma_{a,s} \quad , a \in \mathcal{A},\, s \in \mathcal{S} \tag{4.16}$$

$$p^{DA}_a - p^w_{a,s} \leq M_5 \gamma_{a,s} \quad , a \in \mathcal{A},\, s \in \mathcal{S} \tag{4.17}$$

$$-p^{DA}_a + p^w_{a,s} \leq M_6(1 - \gamma_{a,s}) \quad , a \in \mathcal{A},\, s \in \mathcal{S} \tag{4.18}$$

Non-negativity. The up- and down-regulating capacity contracted, and the up-and down regulating capacity activated are ensured to be non-negative with equations 4.19 and 4.20. Also, the non-negativity constraints of equations 4.5 and 4.6 hold.

$$p^{PF,+}_{a,d} \geq 0,\; p^{PF,+}_{a,d} \geq 0, \quad a \in \mathcal{A},\, d \in \mathcal{D} \tag{4.19}$$

$$p^{act,+}_{a,d,s} \geq 0,\; p^{act,-}_{a,d,s} \geq 0, \quad a \in \mathcal{A},\, d \in \mathcal{D},\, s \in \mathcal{S} \tag{4.20}$$

4.1.5 Subcases of the two models

To test some of the hypotheses presented in section 3 on how wind producers could be affected by introducing the PreFlex market, subcases of the Business as usual model and the PreFlex model are developed. The first case takes into account that wind producers face disadvantageous prices in day-ahead markets. The second case considers the risk that the bids of wind producers are not accepted due to low liquidity in intraday markets. In addition, a subcase where it is possible to trade DERs directly in the intraday market is tested. This last case serves as a benchmark for the revenues that the DER owners obtain from selling DER flexibility in the PreFlex market.

Disadvantageous intraday prices. A topic in the empirical literature on intraday markets is to what extent the difference between the day-ahead and intraday price varies systematically with the forecast error of wind production (Shinde and Amelin 2019). Selasinsky (2016) and Ziel (2017) study the German market. Spodniak et al. (2021) Find a 5-9% price risk between the day-ahead and intraday market, in the case of a one standard deviation sized aggregate wind power forecast error. The theoretical basis for this is as follows: If wind producers overestimated wind production, they will on aggregate be interested to purchase electricity in the intraday market. This implies a shift in the day-ahead market supply curve to the left and an increase in the intraday price compared to the day-ahead price, see for example Kulakov and Ziel (2019). The opposite holds for a net surplus, i.e. that intraday prices are lower than corresponding day-ahead price. As the production and forecast error of wind producers within a market area tends to be correlated, wind producers will systematically tend to purchase power when intraday prices are higher, and sell power when intraday prices are lower than the corresponding day-ahead price. To take into account this effect, a subcase is tested where intraday prices are disadvantageous from the perspective of the wind producers. This subcase is named "Wind-dependent ID (intraday) price".

Intraday market illiquidity. Intraday markets have been characterized by low liquidity (Shinde and Amelin 2019). For wind producers, this implies an increased probability that submitted bids to the order book are not accepted. Low liquidity has been observed even in markets with high penetration of wind power and may be unavoidable due to the inherent nature of continuous trading (Henriot 2014). To represent illiquidity in intraday markets, a case is designed where there is a probability that bids submitted to the intraday market are not accepted. Similar to the approach in Wellnitz and Pearson (2022), constraints are imposed so that in some scenarios the volume of intraday trade is forced to zero:

$$p_{a,s}^{ID} = 0 \quad , a \in \mathcal{A},\ s \in \mathcal{S}' \tag{4.21}$$

Here $\mathcal{S}'$ is the subset of probability-weighted scenarios $\mathcal{S}$ in which the bids of the wind producers are not accepted. To avoid a systematic relation between wind production and the non-acceptance of intraday bids, these scenarios are sampled, and new are selected for each hour.

Trading DER energy in the intraday market. To estimate the value that could be obtained by selling DER energy in intraday market, a case is tested where the constraints that bar the trade of DERs in intraday markets are removed. The formulation of this subcase is therefore identical to the PreFlex model formulation, but with the constraints in equations 4.13-4.18 omitted.

4.2 Scenario generation

Here follows a description of the method to generate the probability-weighted scenarios, which are input to the two-stage stochastic models. The value of two stochastic parameters defines the scenarios: The realized total wind production in each market area, $P_{a,s}^{w}$, and the intraday market price, $\lambda_{a,s}^{ID}$. Distributional forecasts are used to generate scenarios for wind production. Quantile regression, introduced by Koenker and Bassett Jr (1978), is used for this purpose. Being a non-parametric method, it does not specifically assume errors to be normally distributed. As we will see later in this text, wind forecast error distributions show clear skewness and kurtosis. Thus, quantile regression is argued to suit the application of distributional wind power forecasts (Bremnes 2004). For each market area, a quantile regression model is fitted with the following specification to predict the qth quantile of the production forecast error distribution:

$$P_{forecast\ error,\ q}^{w}\left(t\right) = \beta_{0,\,q} + \beta_{1,\,q}\, P_{forecast,\,point}^{w}\left(t\right) + \beta_{2,\,q}\, season\left(t\right) + \epsilon_t \tag{4.22}$$

Where $P_{forecast\ error,\ q}\left(t\right)$ is the ex-post calculated forecast error in delivery hour t, and $P_{forecast,\,point}^{w}\left(t\right)$ is the wind production forecast for delivery hour t at the stage of the day-ahead market. The expected absolute forecast error should depend on the production forecast, as larger errors – all else equal – are more likely with larger production. $season\left(t\right)$ is a categorical variable to take into account seasonality in wind production.

To generate wind production scenarios, the model is estimated and evaluated for the following quantiles:

$$0.001, 0.025, 0.05, 0.10, 0.20\ , ...,\ 0.80, 0.90, 0.95, 0.975, 0.999$$

Evaluating the model at each quantile defines a discrete distribution of the *forecast error* in a given hour. This follows from the fact that the dependent variable in the regression in equation 4.22 is the wind production forecast error, not the wind production. To obtain the probability distribution for wind *production* at the stage of the day-ahead market, the *point production forecast* is added to each predicted quantile of the forecast error:

$$P^{w}_{forecast,\, q}\,(t) = P^{w}_{forecast\ error,\, q}\,(t) + P^{w}_{forecast,\, point}\,(t)$$

Where $P^{w}_{forecast,\, q}\,(t)$ is the qth quantile wind production forecast, $P^{w}_{forecast\ error,\, q}\,(t)$ is the qth quantile of the production forecast error distribution, and $P^{w}_{forecast\, point}\,(t)$ is the point production forecast.

Wind production scenarios are then generated by calculating the average predicted value for two adjacent quantiles and assigning a probability of 2.5% or 5% for the two smallest and largest quantiles and 10% to the rest of the pairs of quantiles. The approach to define wind production scenarios is described explicitly in the below equations, and the probability of each scenario is displayed in table 4.1. The process is done separately for each market area in question.

$$P^{w}_{a,s=1} = (P^{w}_{forecast}(t) + P^{w}_{forecast\ error,\, q=0.001}\,(t)) * \frac{1}{2} + (P^{w}_{forecast}(t) + P^{w}_{forecast\ error,\, q=0.025}\,(t)) * \frac{1}{2}$$

$$P^{w}_{a,s=2} = (P^{w}_{forecast}(t) + P^{w}_{forecast\ error,\, q=0.025}\,(t)) * \frac{1}{2} + (P^{w}_{forecast}(t) + P^{w}_{forecast\ error,\, q=0.05}\,(t)) * \frac{1}{2}$$

$$P^{w}_{a,s=3} = (P^{w}_{forecast}(t) + P^{w}_{forecast\ error,\, q=0.05}\,(t)) * \frac{1}{2} + (P^{w}_{forecast}(t) + P^{w}_{forecast\ error,\, q=0.10}\,(t)) * \frac{1}{2}$$

$$\left[... \right]$$

$$P^{w}_{a,s=12} = (P^{w}_{forecast}(t) + P^{w}_{forecast\ error,\, q=0.90}\,(t)) * \frac{1}{2} + (P^{w}_{forecast}(t) + P^{w}_{forecast\ error,\, q=0.95}\,(t)) * \frac{1}{2}$$

$$P^{w}_{a,\, s=13} = (P^{w}_{forecast}(t) + P^{w}_{forecast\ error,\, q=0.95}\,(t)) * \frac{1}{2} + (P^{w}_{forecast}(t) + P^{w}_{forecast\ error,\, q=0.975}\,(t)) * \frac{1}{2}$$

$$P^{w}_{a,\, s=14} = (P^{w}_{forecast}(t) + P^{w}_{forecast\ error,\, q=0.975}\,(t)) * \frac{1}{2} + (P^{w}_{forecast}(t) + P^{w}_{forecast\ error,\, q=0.999}\,(t)) * \frac{1}{2}$$

Table 4.1: The probability assigned to each of the scenarios. “Quantiles averaged” refers to what quantiles of the distributional wind forecasts are averaged to generate the given production scenario.

Scenario	Probability	Quantiles averaged
1	2.5%	0.1%, 2.5%
2	2.5%	2.5%, 5%
3	5%	5%, 10%
4	10%	10%, 20%
...	...	...
11	10%	80%, 90%
12	5%	90%, 95%
13	2.5%	95%, 97.5%
14	2.5%	97.5%, 99.9%

Lastly, attention is turned towards the intraday price component of the probability-weighted scenarios, which are input to the stochastic optimization models. The intraday market is a continuous market where bids are cleared on a first-come, first-served basis. As a result, no single price holds for each delivery hour; different bids result in different prices. Given that wind producers are considered on aggregate, volume-weighted average intraday prices are used. The question then remains how the intraday price should be modeled. Figure A.1 in the appendix shows that there is a strong relation between day-ahead prices and intraday prices across market areas. It is therefore argued that the day-ahead price should be used as the basis to model the intraday price. Further, it is of interest to explore what could explain the deviations between day-ahead prices and intraday prices. As previously discussed, empirical literature and theoretical arguments suggest that day-ahead- intraday price spreads should be related to aggregate wind production forecast errors. To investigate this relation in the considered dataset, linear regressions with the following model specifications were fitted:

$$ID\_NO1\_WAVG\ (t) = \beta^{C} + \beta^{DA}\, DA\_NO1\ (t) + \beta^{W}\, Wind\_err\_NO1\ (t) + \beta^{L}\, Load\_err\_NO1\ (t) + \epsilon_t$$

$$\begin{bmatrix} ... \end{bmatrix}$$

$$ID\_NO4\_WAVG\ (t) = \beta^{C} + \beta^{DA}\, DA\_NO4\ (t) + \beta^{W}\, Wind\_err\_NO4\ (t) + \beta^{L}\, Load\_err\_NO4\ (t) + \epsilon_t \tag{4.23}$$

Where $ID\_NO1\_WAVG\,(t)\,...\,ID\_NO4\_WAVG\,(t)$ are the hourly volume-weighted intraday prices, $DA\_NO1\,(t)\,...\ DA\_NO4\,(t)$ the hourly day-ahead prices, $Wind\_err\_NO1\,(t)\,...\,Wind\_err\_NO4\,(t)$ the hourly aggregate wind forecast errors, and $Load\_err\_NO1\,(t)$ $...Load\_err\_NO4\,(t)$ the hourly aggregate load forecast errors.

The model summaries for the above specifications can be found in the appendix. Overall, no systematic relation between day-ahead intraday price spreads and wind power forecast errors was found in the data, except for in NO3. A significant relation between load forecast errors on the intraday price was identified. It was however neglected in the scenario generation, as there is little or no systematic relation between wind forecast errors and load forecast errors. As a result, the intraday price in the base case, Fixed ID price, is set equal to the day-ahead price.

Despite that no such relation was found in the dataset, the Wind-dependent ID price case was tested to explore the effect of a systematic dependence between wind forecast errors and day-ahead intraday price spreads. It assumes that in each market area, a one standard deviation deficit in wind production compared to the day-ahead forecast results in a 5% price increase in the intraday price. A 5% decrease in the intraday price occurs in the case of one standard deviation net surplus in wind production. The 5% figure was selected because it is in the low part of the 5-9% intraday price risk range identified in Spodniak et al. (2021), and wind power shares are expected to remain lower in Norway compared to Denmark and some of the Swedish market areas.

Chapter 5

Data and Case Study

The context of the case study is the current Norwegian power market. Data from 2021 on wind production and electricity prices are thus used as input to simulate wind power trade. Estimates on the maximum hourly flexibility volumes that the wind producers can procure from the PreFlex market are obtained from technical reports. The flexibility that is available in a given hour is assumed to be independent of the usage in previous hours. Thus, trade in the PreFlex can be simulated on an hourly basis by iteratively solving the two-stage optimization models presented in section 4, as the optimal solution for one delivery hour would not impact the optimal solution for the next. The case study considers July 2021 and December 2021, to compare outcomes for wind producers and DER owners during two drastically different market conditions.

Three categories of Norwegian power market data are used to simulate the application of DER flexibility to balance wind forecast errors: 1) Wind power production data, 2) data on Norwegian DER flexibility potentials, and 3) electricity price data. Section 5.1 presents the wind power data. Section 5.2 develops assumptions for the case study about hourly quantities of DER flexibility available. Lastly, section 5.3 considers the day-ahead and intraday electricity price data.

5.1 Wind power data

Data on actual wind production and day-ahead wind production forecasts was obtained from the ENTSO-E Transparency Platform. Aggregate wind forecast errors were calculated by subtracting day-ahead wind forecasts from actual wind generation. Only net wind forecast errors are analyzed in this work; any wind production forecast errors that are outweighed by opposite-direction forecast errors for another wind farm would not be apparent in the ENTSO-E data. The Norwegian power market has five market areas: NO1-NO5. However, when examining the wind production data, it was found that the average wind production in NO5 is negligible compared to production in most of the other market areas. As a result, NO5 was excluded from further analysis.

Figure 5.1 visualizes the wind production data applied in the case study using a violin plot. Descriptive statistics for the wind production for the whole year, and for July and December separately, are presented in tables A.2 and A.3 in the appendix. The production was clearly the largest in NO2 and NO3, with an average hourly wind production of 443 MWh and 490 MWh, respectively. Comparing December to July, mean hourly production is twice as high in December as in July in the market areas NO1, NO2, and NO4, and even three times as high in NO3.

Figures 5.2a-5.2d show the distribution of forecast errors for the market areas considered. Imme-

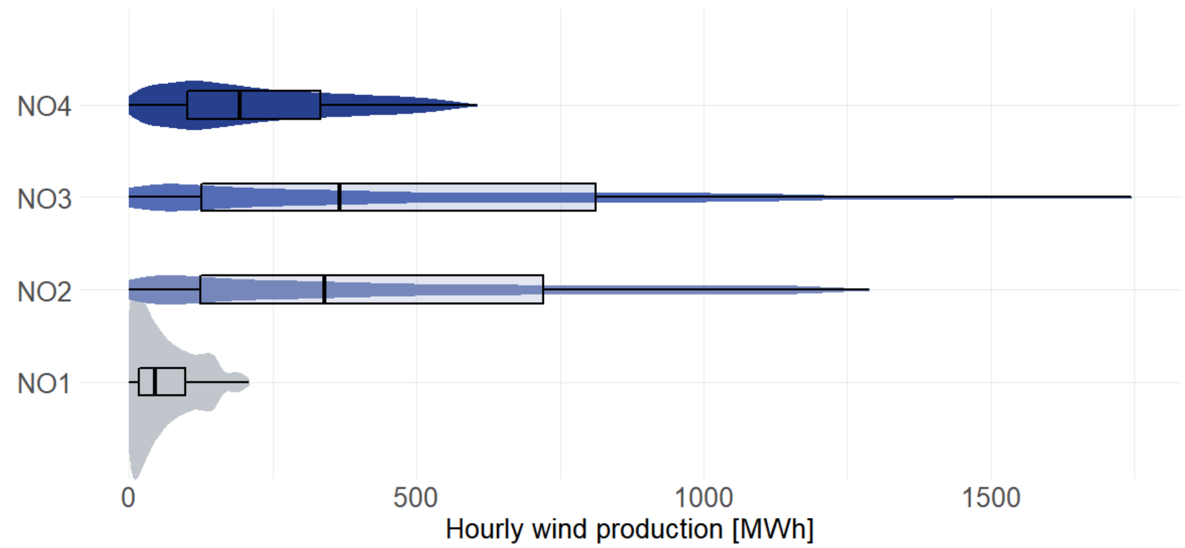
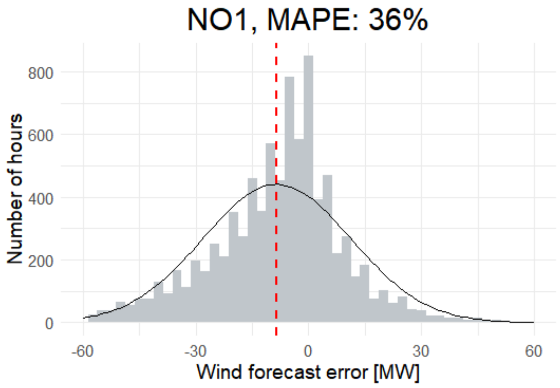


Figure 5.1: Violin plot of the wind production in market areas NO1-NO4 for the whole year of 2021.

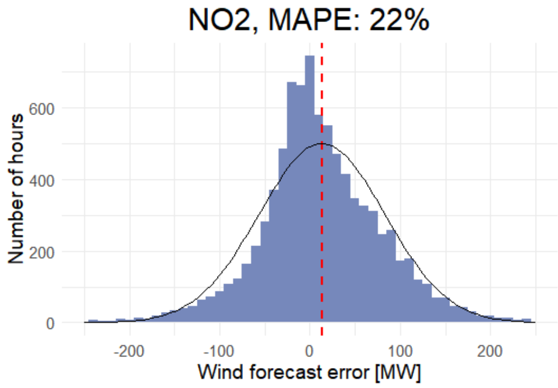
diately, the unusual shape of the NO3 distribution should be noticed. It is highly skewed towards the negative forecast error side. In addition, the mean forecast error in NO3 clearly deviates from zero. Generally, forecast errors should have a mean close to zero: If there is a significant systematic bias, point forecasts could be shifted upwards or downwards to account for it. Although various approaches could be attempted to obtain a distribution with a mean equal to zero for NO3, instead, to avoid more complexity layers, this work will deal with the raw data from the ENTSO-E platform.

To analyze the forecast error distributions in more detail, the histograms in figure 5.2 are displayed together with normal distributions with the same mean and standard deviation. Further, the mean, μ, the standard deviation, σ, the skewness, γ, and the excess kurtosis, κ, are presented. Overall, it can be seen that all forecast error distributions are leptokurtic. This is in line with findings such as in Hodge et al. (2012), where it was found in an international comparison that all considered forecast error distributions were leptokurtic. The distributions in NO1 and NO2 have the largest excess kurtosis, of $\kappa = 3.74$ and $\kappa = 3.22$, respectively. Positive excess kurtosis for the forecast error distributions in the four market areas implies that they have thicker tails than the corresponding normal distribution. Further, in figure 5.2, it can be seen that the peaks of all distributions are more pronounced than the peak of the normal distribution. The distributions also show significant skewness, which is a measure of asymmetry. In light of the non-normality exhibited by the forecast errors, quantile regression is selected as the statistical method to generate distributional forecasts in this work. Quantile regression is considered a non-parametric method in the sense that it assumes little about the distribution of conditional errors and is thus well-suited for the application of probabilistic wind power forecasts (Bremnes 2004). Selecting this method is further supported by the claim in Hodge et al. (2012) that assuming normally distributed forecast errors in power system modeling would lead to significant inaccuracies.

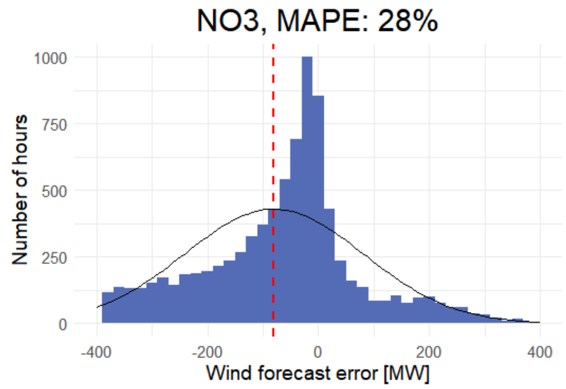
Figures 5.3a and 5.3b show the generated day-ahead distributional wind production forecasts for the first six days in Duly 2021 and December 2021. the distributional forecasts appear to represent the uncertainty in wind production reasonably well and are judged as realistic enough for the case study application. For forecasting applications, distributional forecasts should be evaluated using backtesting methods such as the Kupiec (Kupiec et al. 1995) and Christoffersen (Christoffersen et al. 2001) tests. For the simulation application in this work, however, a visual check is deemed to be sufficient.



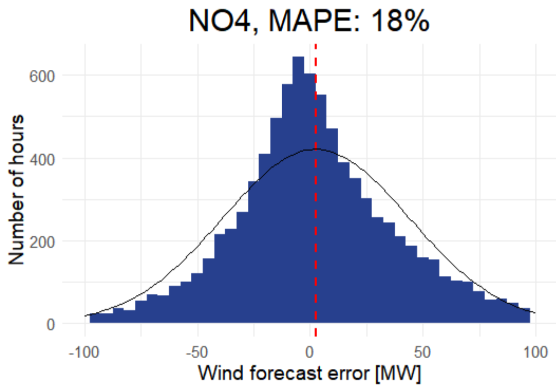
(a) $\mu = -8.42$; $\sigma = 19.9$; $\gamma = -0.970$; $\kappa = 3.74$



(b) $\mu = 13.0$; $\sigma = 70.2$; $\gamma = -0.171$; $\kappa = 3.22$

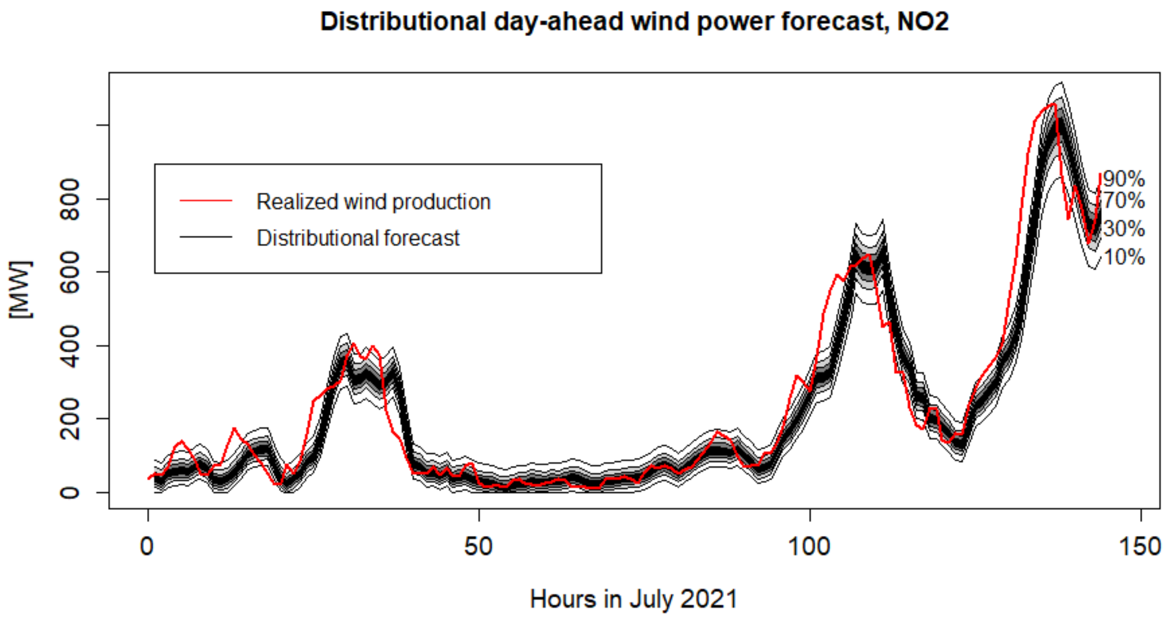


(c) $\mu = -80.0$; $\sigma = 163.2$; $\gamma = -0.726$; $\kappa = 1.13$



(d) $\mu = 2.57$; $\sigma = 41.4$; $\gamma = 0.564$; $\kappa = 1.69$

Figure 5.2: Histograms showing the distribution of aggregated wind power forecast errors in each market area. The mean, μ, standard deviation, σ, skewness, γ, and excess kurtosis κ is calculated to characterize the distributions.



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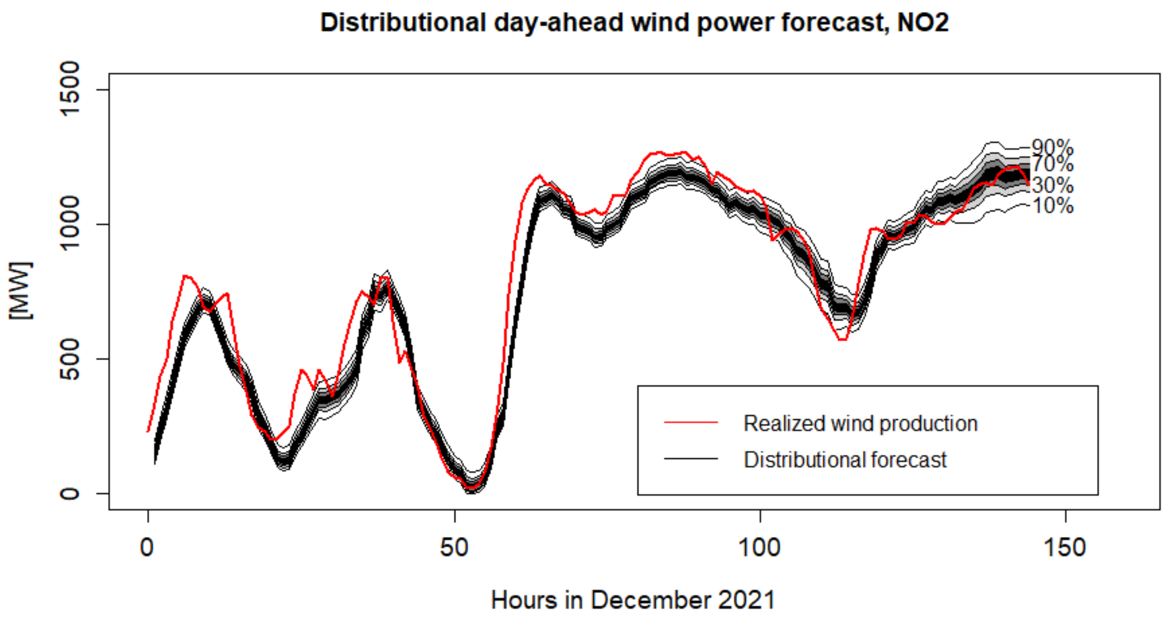

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Figure 5.3: Day-ahead distributional wind production forecast and realized wind production in NO2 for the first six days of July 2021 and December 2021.

5.2 DER data

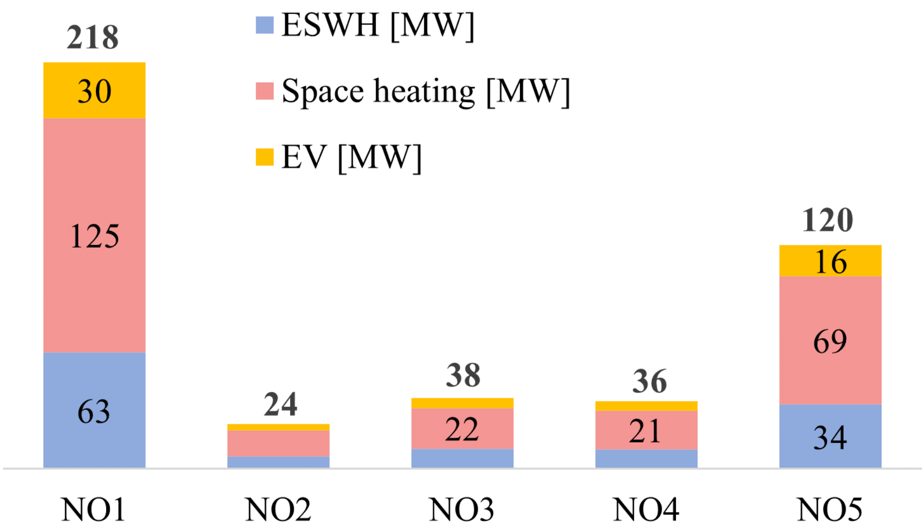
As the case study is set to Norway, the DER types considered are, similarly as in Backe et al. (2021), space heating, electric storage water heaters (ESWHs), and electric vehicles (EVs). Electric storage water heaters are common across the Nordic countries (NVE 2021), and electric vehicles have achieved high market penetration particularly in Norway. Technical reports were consulted to obtain realistic estimates of the amount of demand-side flexibility that could be made available for trade in the proposed flexibility market. Specifically, the volumes of economically viable demand reductions calculated in Statnett (2018), a report on the value of demand-side flexibility in Norway, are the basis for estimates on available DER flexibility used in this work. Further, the volumes presented in Statnett (2018) were compared to the flexibility potentials presented in Söder et al. (2018) for the sake of robustness.

Statnett (2018) calculates economically viable peak-hour demand reductions. This work, however, considers an application of demand response where it is used to continuously balance wind power forecast errors. This implies that demand reductions are assumed to not only occur in a single hour but that they are instead activated in smaller volumes and distributed throughout several hours. NVE (2021) shows that with the user profile and storage capacity of ESWHs, it is possible to shift the charging profiles of ESWHs several hours without any loss of comfort for users. The single-hour demand response estimates in Statnett (2018) must however be reduced to incorporate the assumption in this case study that some flexibility can be used in each hour, independent of the usage in previous hours. Thus, the economic and technical potential estimates in Statnett (2018) are divided by twelve, to represent a situation where available flexibility is distributed throughout the day. Further, the available flexibility potentials in Statnett (2018) are for the whole of Norway. They are therefore distributed among the Norwegian market areas according to population estimates for the corresponding regions in Norway.

The resulting assumptions about the maximum hourly volumes of DER flexibility that can be traded in the PreFlex market are shown in figure 5.4a. DER volumes are further segmented according to DER type and whether they stem from the domestic or commercial sector in figure 5.4b. For simplicity, up-and-down regulating flexibility from space heating is assumed to only be available during winter months, i.e. not in July. Further, up-and-down regulation from EV charging is assumed to only be available when most EVs are connected to charging stations, i.e. in the hours between 10 p.m. and 6 a.m. Lastly, the volume of up-regulation and the volume of down-regulation available are assumed to be equal to each other.

In figure 5.4a, it can be seen that flexibility volumes are distributed quite unevenly among the market areas. This follows from the population distribution in Norway. While NO2, NO3, and NO4 have the most wind production, most of the demand-side flexibility potential is located within NO1 and NO5, i.e. in the Oslo and Bergen regions. To make more flexibility available to wind producers in market areas with lower populations, it is assumed that some of the DER flexibility located in NO1 and NO5 can be procured by wind producers in NO2, NO3, and NO4. Specifically, it is assumed that at maximum, hourly exchange of DER capacity corresponding to the values shown in table 5.1 would be possible. Net exchange is in all cases assumed to occur away from NO1 and NO5, to adjacent market areas. Viewing data for 10 arbitrarily chosen days in the 2020-2022 period from Statnett's power exchange portal (Statnett 2023), it was found that in terms of exchange between NO5 and NO3, and NO1 and NO3, exchange tends to be towards the NO1 and NO5 market areas. Thus, the highest risk for congestion seems to be for exchange *towards* NO5 and NO1 from this market area, not for exchange towards NO3. Further, the assumed volumes of DER capacity are relatively small compared to the capacity commonly exchanged between NO1 and NO5, and NO2, and exchange is likely feasible in most cases.

Table 5.2 presents the maximum flexibility volumes that wind producers in each market area can procure, also including capacity exchanged from other market areas. As mentioned previously, wind producers in NO5 were not considered in this case study, due to the low wind power capacity in this market area.



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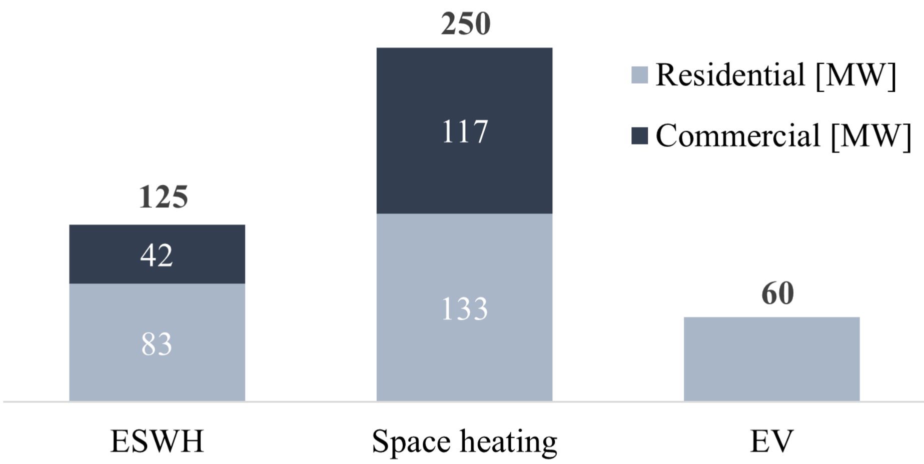

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Figure 5.4: (a) Hourly DER flexibility volumes estimated to be available for trade in the flexibility market in each market area. (b) Hourly flexibility volumes by DER type, in domestic and commercial sectors.

Table 5.1: Assumed maximum DER capacity volumes that can be exchanged between market areas [MW]

To:	NO1	NO2	NO3	NO4	NO5
From:					
NO1	-	50	100	-	0
NO2		-	-	-	-30
NO3			-	50	-30
NO4				-	-
NO5					-

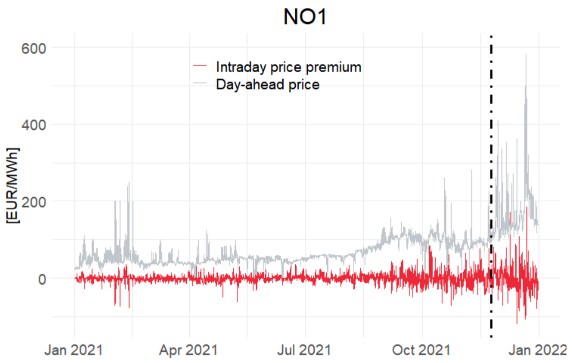
Table 5.2: Maximum hourly DER flexibility volumes that can be procured by the wind producers in each market area [MW]

	NO1	NO2	NO3	NO4
July, 7 a.m. - 21 p.m.	11.7	38.9	42.9	30.4
July, 22 p.m. - 6 a.m.	31.7	58.1	64.1	45.4
December, 7 a.m. - 21 p.m.	56.7	72.6	96.6	71.3
December, 22 p.m. - 6 a.m.	76.7	91.8	117.9	86.3

5.3 Electricity price data

The case study in this work simulates wind producers trading in the short-term Nordic electricity markets. Price data from the 'Elspot' day-ahead market and the 'Elbas' intraday market is thus used as input to the presented optimization models. Hourly day-ahead electricity data was accessed through the ENTSO-E Transparency Platform. Volume-weighted hourly intraday prices were obtained courtesy of power market analysis firm SKM Market Predictor. Figure 5.5 shows day-ahead price time series from 2021, as well as the difference between the volume-weighted hourly intraday price and day-ahead prices, i.e. the "intraday price premium". A dotted line is added to the figures to indicate a possible regime switch: Towards the end of 2021, electricity prices soared due to gas supply disruptions, and price volatility increased drastically as well. Comparing the various market areas, it can be seen that price volatility increased at an earlier point in the NO1 and NO2 market areas than in NO3 and NO4. Further, prices reverted to lower levels in NO3 and NO4, but remained at a high level in NO1 and NO2. This can be explained by the fact that NO1 and NO2 are more exposed to continental European power market prices than NO3 and NO4, due to direct exchange between NO2 and the Danish, Dutch, German, and British power markets.

Table 5.3 displays mean day-ahead prices and day-ahead- intraday price spreads for July and December. A longer list of summary statistics of the price data can be found in tables A.4 and A.5 in the appendix. Overall, the substantial differences between the price conditions in July and December make it interesting to compare the simulated outcomes for trade in the PreFlex market between the two periods. Particularly, it is of interest to evaluate to what extent the value of DER flexibility increases in the high price-volatility period, compared to the low price-volatility period. The proposed DER flexibility market relies on direct activation of DER flexibility to modify load



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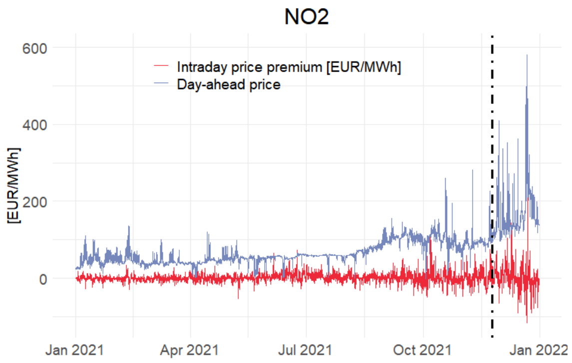

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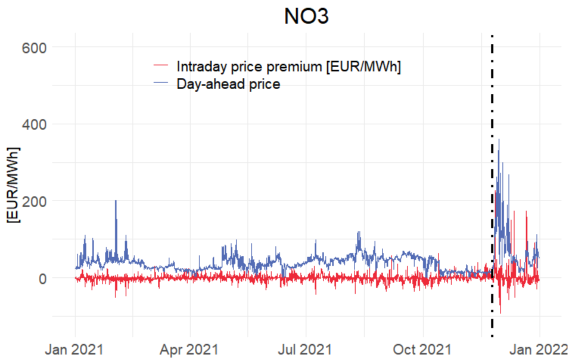

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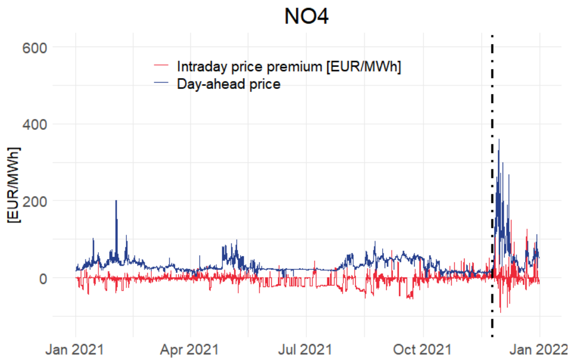

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Figure 5.5: Day-ahead price data considered in the case study for NO1-NO4. The intraday price premium (red) is defined as the difference between hourly volume-weighted average intraday prices, and day-ahead prices for the same delivery hour.

Table 5.3: Mean day-ahead (DA) electricity prices, and mean absolute day-ahead-intraday (ID) price spreads, in July and December [EUR/MWh]

	NO1	NO2	NO3	NO4
Mean DA price, July 2021	55.61	57.48	45.77	22.05
Mean DA price, December 2021	175.79	175.74	60.19	60.09
Mean abs. DA-ID price spread, July 2021	4.76	7.64	4.25	16.66
Mean abs. DA-ID price spread, December 2021	21.38	20.85	13.11	11.50

profiles of DERs, not price signals. As a result, electricity price volatility does not directly impact the optimal usage and the value of DER flexibility. Instead, changes in DER usage between the two price periods would be driven by changes in the wind producers' preferences to contract flexibility.

Chapter 6

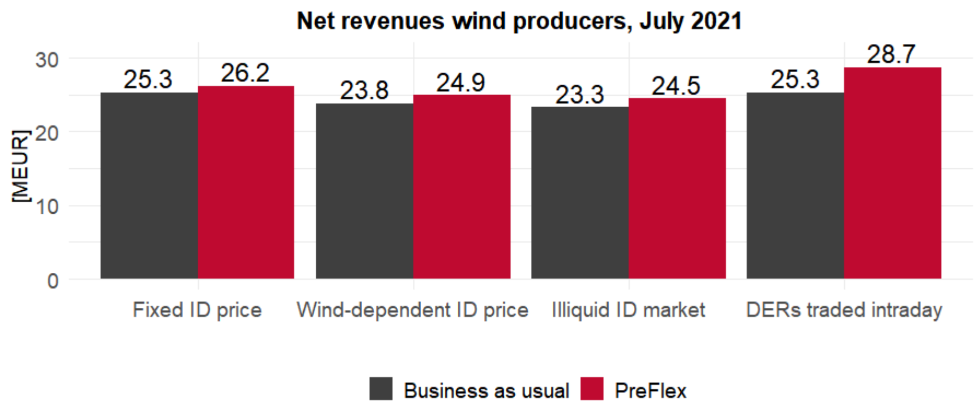
Results and Discussion

The main results of the case study are summarized as follows: Giving the wind producers the option to balance their forecast errors using DER flexibility does not substantially increase the total revenues of the wind producers. It is however found to significantly reduce their costs of managing imbalances; by 8.6% to 19% in the low price-volatility period, i.e. July 2021, and 17.3% to 29.2% in the high price-volatility period, i.e. December 2021. Further, the price that DERs would obtain from trading in the Pre-contracting flexibility market is estimated to be relatively low; 30% of the day-ahead price. Explanations for this and suggestions on how DER revenues could be improved are discussed. Lastly, it is found that using DER flexibility to balance wind power forecast errors could significantly reduce the median system imbalance. The costs of procuring and maintaining balancing reserves would however not be affected considerably.

Section 6.1 takes the perspective of the wind producers and discusses how introducing the flexibility market would impact them. Section 6.2 takes the perspective of the DER asset owners and estimates the revenues that they could obtain from trading in the PreFlex. In section 6.3, the emphasis is on system balancing. Here, modeled reductions in the imbalances of the wind producers are compared to empirical data on system imbalances.

6.1 Wind producer perspective

Figures 6.1a and 6.1b show the simulated net revenues that wind producers obtain from trading in short-term electricity markets. Generally, introducing the PreFlex increases the net revenues of the wind producers. In the Fixed ID price, Wind-dependent ID price, and Illiquid ID market cases, the net revenues of wind producers increase by a modest amount (3.5-5.1% in July, and 1.6-2.3% in December). The DERs traded intraday case shows a higher increase in wind net revenues from introducing DER flexibility. In this case, the wind producers are allowed to trade previously contracted DER capacity in the intraday market, after they have balanced their own portfolios. This yields additional revenues of EUR 2.5M (13,4% increase compared to BAU) in July, and 16.1M (15.3% increase compared to BAU) in December. These are figures obtained under nonrestrictive assumptions about the volumes that actually would be bought in the intraday market from this DER capacity, and the prices that these increased volumes would be sold for. They do however give an indication about the difference that selling power in the intraday market every hour makes, compared to only up-regulating DERs in case of a deficit imbalance for the wind producers. Nevertheless, concluding on how trading DERs directly in the intraday market compares to trading DERs in the PreFlex requires further investigation. This question is further discussed in section 6.2.



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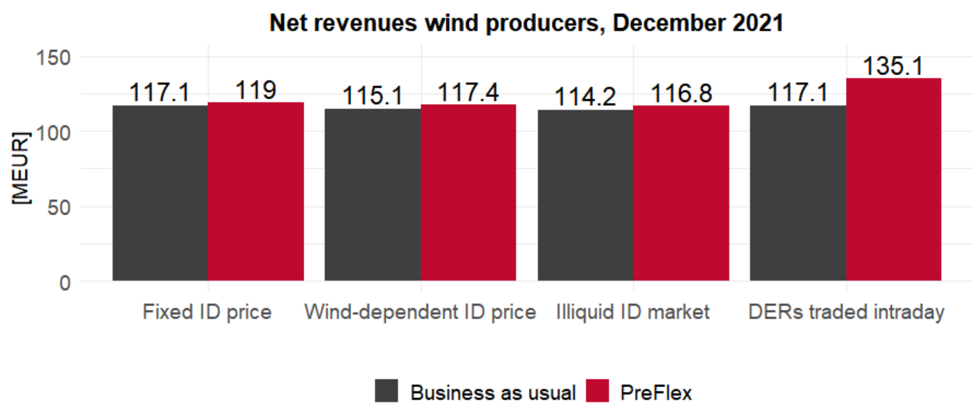

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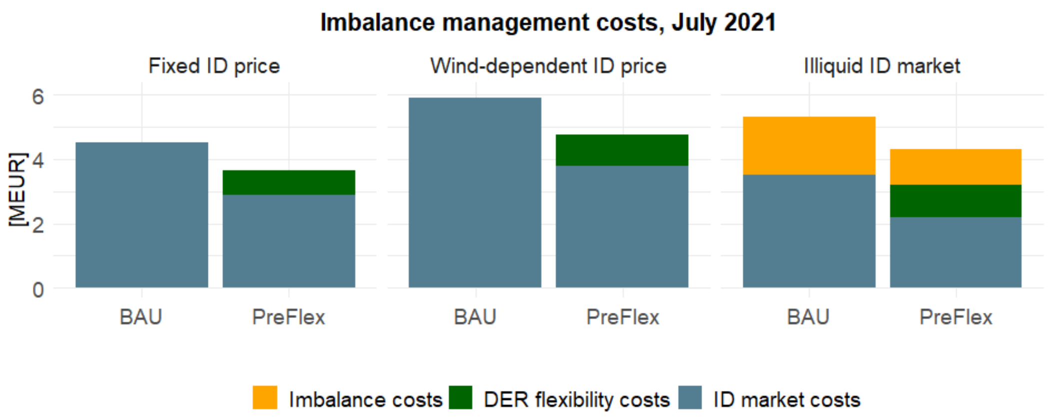
Figure 6.1: Net revenues of wind producers in July 2021 and December 2021.



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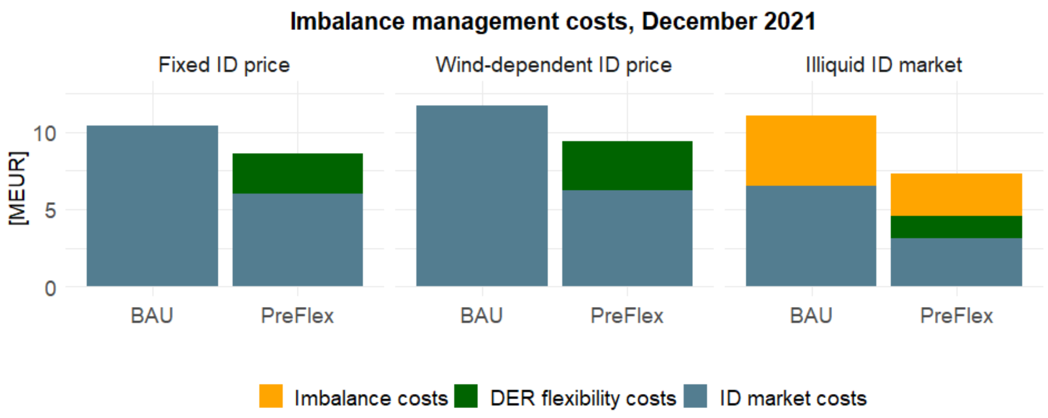


(b)

Figure 6.2: Costs related to managing forecast errors incurred by the wind producers. “Imbalance costs” is the amount owed to the TSO due to any imbalances during delivery hour. “ID market costs” are the costs of purchasing power in in the intraday market. “DER flexibility costs” are the expenditures in the PreFlex market.

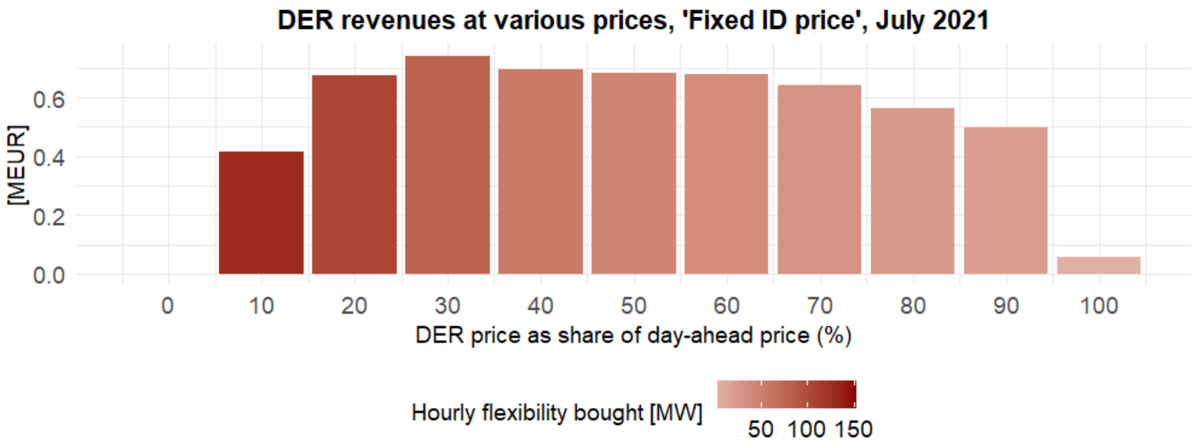
Figures 6.2a and 6.2b show the total costs of the wind producers related to managing forecast errors in the various cases. All calculated values can be found in table A.8 in the appendix. In the Business as usual case (BAU), the “imbalance management costs” consist only of costs related to purchasing power in the intraday market and any imbalance costs owed to the TSO. In the PreFlex case however, costs related to purchasing DER flexibility must also be considered. Overall, the total imbalance management costs are lower in the PreFlex case than in the Business as usual case. Focusing on the expected costs related to purchasing power in the intraday market, i.e. “ID market costs” in figures 6.2a and 6.2b, the wind producers achieve cost reductions of 35.6%-37.1% during July 2021, and cost reductions of 42.3% to 52.3% during December 2021. This reduction is largely driven by replacing intraday trade with activating DER flexibility, which must be purchased periodically through a seperate auction. When also considering the costs of purchasing this DER flexibility, the reduction amounts to 8.6% to 19% during July, and 17.3% to 29.2% during December. This reduction corresponds in absolute terms to the increase in the wind producers’ net revenues shown in figures 6.1a and 6.1b. These figures suggest that given the assumption of a DER flexibility price of 30% of the day-ahead price, and the assumed availability of DER capacity, substantial intraday trade volumes would be displaced.

Various hypotheses were previously presented on how introducing the PreFlex could affect wind producers trading in intraday markets. In the following paragraphs, the impact of disadvantageous intraday prices and intraday market illiquidity on wind producers will be analyzed. Let us first consider the hypothesis that having access to DER flexibility could help wind producers deal with disadvantageous intraday prices. To do this, the Wind-dependent ID price case is compared to the Fixed ID price case. The reduction in total imbalance costs is 19% in both the Fixed ID price case and the Wind-dependent ID price case during the month of July. During December, the reduction in total imbalance costs from introducing the PreFlex is 17.3% in the Fixed ID price case, while being somewhat higher, 19.7%, in the Wind-dependent ID price case. It is concluded that although having access to DER flexibility is advantageous to reduce the volumes of electricity bought at high prices during the intraday market, the effect is not large. Figure 6.2b however, shows that expenditures to contract DERs increase more during December than in July, between the Fixed ID price and the Wind-dependent ID price cases. This is in line with the hypothesis that the value of DER flexibility is larger, even relative to the day-ahead price, in a situation with high price volatility and large day-ahead-intraday price spreads.

Another hypothesis was that introducing the PreFlex would help mitigate complications related to illiquidity in the intraday market. Low liquidity implies that there is a risk that bids at fair prices are not accepted during intraday trade. This then results in imbalances for the wind producers, as they are not able to reduce them sufficiently before real-time. Figures 6.2a and 6.2b provide evidence that the costs due to such real-time imbalances would likely be reduced if a flexibility market such as the PreFlex were introduced. This follows from the fact that once DER flexibility is purchased, the wind producers have reduced their exposure to the risk that low liquidity manifests and no fair-priced bid is accepted. Costs related to delivery hour imbalances fall by 39% in July, and 41% in December. This is a large reduction and a clear indicator that allowing wind producers to pre-contract DER flexibility can aid them in dealing with low liquidity in intraday markets.

6.2 DER perspective

In this section, the emphasis is on DERs and remuneration for the flexibility that they offer. To estimate the value of supplying DER flexibility through the PreFlex market, trade in the PreFlex market is simulated given various assumptions about DER prices to calculate the total revenues that DERs would obtain. The flexibility price is set to a certain percentage of the hourly day-ahead



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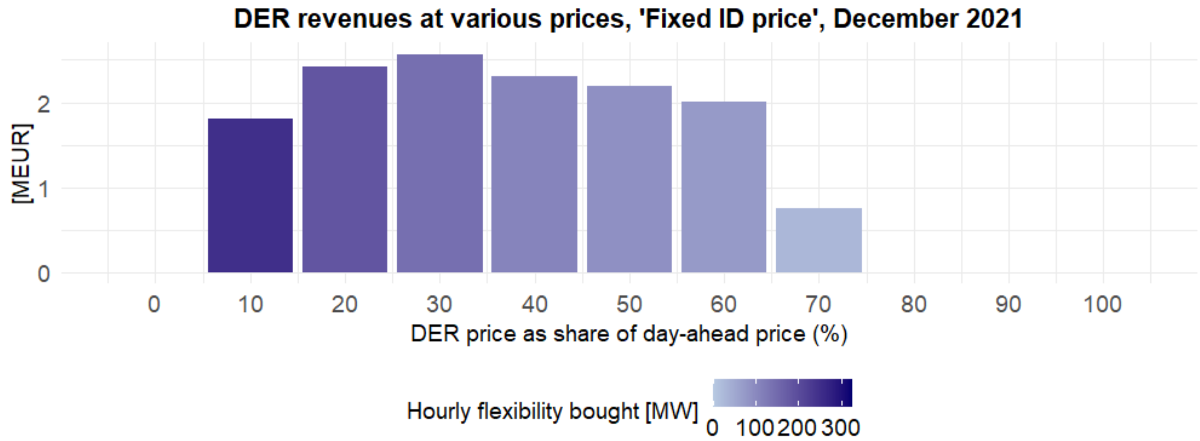

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Figure 6.3: Total revenues that DERs obtain from trading in the PreFlex in July 2021 (a) and December 2021 (b), given various prices payed to contract them. The price to contract DER flexibility is set to a fixed percentage of the hourly day-ahead price. Then, to consider the impact on total DER revenues of changing the flexibility price, this percentage is varied between 0% and 100% of the day-ahead price.

price. Reasonable flexibility prices are difficult to obtain in the literature given that the market structure has not yet been tested. Further, setting the price to a percentage of the day-ahead price has the advantage that it improves transparency about how large the assumed price is relative to the general electricity price level. Secondly, the assumption takes into account that the DER flexibility price in the PreFlex is influenced by prices in other markets. This is realistic at least for a case where aggregators have the option to trade DERs in several different electricity markets.

The price that yields the largest total revenues to the DER owners is used as an estimate of the value that the DERs can contribute within the proposed market design. The DER price is an exogenous input to the optimization models. Therefore, an approach where the assumed DER price is iteratively varied is deemed useful to evaluate how much the wind producers are willing to pay for the DER flexibility. After estimating the value of the DER flexibility traded in the PreFlex market – which is given by the price that wind producers would pay for flexibility – it is of interest to analyze what share of the DER capacity contracted by the wind producers is actually activated.

In figures 6.3a and 6.3b the percentage of the day-ahead price is varied between 0% to 100%. The coloring represents the average hourly flexibility volume bought. Both in July and December, total revenues are maximized when a DER price of 30% of the day-ahead price is assumed.

An important difference between the two months should be commented upon: The total revenues decay substantially quicker with increased DER prices in the simulation set to December than in the simulation set to July. This is judged to be a result of the following: The forecast error data for NO3 has a larger skew towards deficit imbalances in July, compared to December. In July the skewness of the forecast error distribution is -0.97, whereas it for the December data is -0.63. Adding to this is the fact that the mean forecast error in July is -114 MWh, whereas it in December is +137 MWh. This implies that there in the data from July 2021 on average is a deficit of 114 MWh in the total energy produced from wind power compared to the day-ahead production forecast. The result is a much larger demand for up-regulation in NO3 than in the other market areas during July. Further, the demand for up-regulation flexibility is exaggerated, resulting in a high demanded volume even at DER flexibility prices set to 60% of the day-ahead price and beyond in the case of July. This implies that that a DER price of 30% of the day-ahead price should be considered a realistic estimate of the value that DERs contribute when traded in the PreFlex.

Table 6.1: Estimated value of DER flexibility [EUR/MW]

	NO1	NO2	NO3	NO4
July 2021	16.7	17.4	13.2	6.4
December 2021	51.0	53.7	17.9	17.7

Table 6.1 shows the estimated DER flexibility values, in the Fixed ID price case. They are calculated by dividing the total DER revenues in each market area by the total capacity bought. The calculated values are close to 30% of the day-ahead price in each market area and in each month. At first glance, this appears to be a relatively low value. Recall that from the perspective of the wind producers, the alternatives to purchase DER flexibility to balance their forecast errors is either to purchase power in the intraday market or incur imbalance costs imposed by the TSOs. Both of these options come in most cases at prices equal to or higher than the day-ahead price. Explanations for the low value are given in the next paragraph.

Table 6.2 displays the average percentage of procured up-regulation flexibility that is activated. NO3 differs from the other market areas. Here, a substantially larger proportion of the purchased flexibility tends to be activated than in the other market areas. In market areas NO1, NO2, and NO4 however, a common pattern can be seen: 38.7%-56.3% of the purchased capacity is on average activated before real-time. The fact that around or below 50% of the contracted capacity is actually used, can to a large extent be explained by the following: Typically, wind production forecast errors are symmetrically distributed around zero. As a result, it is only around 50% of the time that up-regulation capacity is needed for an individual wind producer. In the case study in this work, wind producers within each market area were grouped together, and aggregated forecast errors were considered. In reality, however, forecast errors of individual producers have some statistical independence, and it is highly unrealistic that absolutely no up-regulation flexibility would be used in a given hour. Still, when relaxing the assumption of grouping all wind producers in each market area together, the average share of activated capacity would be around 50%, as deficit forecast errors only occur around 50% of the time.

Table 6.2: Average percentage of procured DER capacity activated in each market area

	NO1	NO2	NO3	NO4
July 2021	56.3%	41.2%	75.8%	43.7%
December 2021	48.2%	38.7%	61.2%	41.0%

The fact that deficit forecast errors only occur half of the time implies that a substantial proportion of the flexibility bought from the PreFlex market will remain inactivated. This also largely explains the relatively low value of flexibility estimated previously: Wind producers are unlikely to be willing to pay substantially more than 50% of the day-ahead price for flexibility that they do not expect to use more than 50% of the time. While particularly high intraday prices or imbalance prices could increase the willingness to pay for up-regulating DER flexibility, the overall conclusion holds; A substantial proportion of the bought flexibility would on average not be used, which reduces the willingness to pay for this flexibility. As a result, it seems that a key step to improving DER remuneration is to explore how a larger share of any flexibility bought could be utilized.

For the "DERs traded intraday" case, a similar approach is taken as the approach to value the DER flexibility in the previous case where it could not be traded in the intraday market: The price for DER energy is varied in the range of 10% and 100% of the day-ahead price, and the total revenues are examined. Revenues are maximized at a DER price of 90% of the day.ahead price, and the estimated value of DER capacity then becomes 40.3 EUR/MW for July 2021 and EUR 98.6 EUR/MW for December 2021. Both estimates are based on volume-weighted average DER revenues across market areas. This is a substantially higher DER value than the one estimated in the case where it was assumed that DER flexibility could not be traded directly in the intraday market.

When evaluating the "DERs traded intraday" case, the following should be considered: The case implicitly assumes that all available up-regulating DER energy could be sold in the intraday market even after the deficit forecast errors of wind producers are balanced. The following question arises: Who would purchase this additional energy? Given that the wind producers are assumed to already have balanced their forecast errors, the main actors that purchase electricity in the intraday market to balance forecast errors have already covered their balancing energy needs, apart from demand-side BRPs. Thus, it a priori seems unlikely that the full volumes of DER capacity sold in the "DERs traded intraday" case could actually be sold in the intraday market. Examining empirical data on trade volumes on the Nordic Elbas market, it is found that in a relatively high number of hours the traded volumes are low. For instance, the first quartile of Elbas volumes was 1.9 MWh in NO1, 12.9 MWh in NO2, 3.95 MWh in NO3 and 0 MWh in NO4, whereas the median volume traded was 20 MWh in NO1, 40 MWh in NO2, 20 MWh in NO3, and 5.6 MWh in NO4. From this, it is concluded that, although a substantially higher average price could be obtained from trading DER energy in the intraday market than in the PreFlex market, the total revenues obtained would likely not increase that much. This follows from the fact that the volume of DER energy that can be sold in the intraday market varies substantially from hour to hour, and is low for a significant share of delivery hours. The implication is that trading DERs in the intraday market faces a similar complication as trading DERs through the PreFlex: To obtain sufficient remuneration for DER flexibility, it is necessary to trade this flexibility in several different markets, to increase the probability that flexibility is utilized.

6.3 Effects on system balancing

The third research question concerns how using DER flexibility for balancing wind power forecast errors could affect system balancing. In section 6.1 it was shown that supplying additional flexibility could improve the business case for wind producers to reduce their own imbalances. It is however also of interest to examine how such an increase in internal balancing among the wind producers would affect system balancing. The analysis is done given the assumptions on available DER flexibility and wind power forecast errors that were presented in section 5. Further, results from simulating the PreFlex are compared to empirical data on system imbalances across the Norwegian market areas. This data was obtained from the ENTSO-E Transparency Platform. Due to the fact that data on Norwegian system imbalances before November is unavailable on the ENTSO-E platform[1], only simulations for December 2021, and not July 2021, are examined. The system imbalances and the reductions in wind power imbalances that result from introducing DER flexibility are only compared in terms of order of magnitude.

Figures 6.4a, 6.4b, 6.4c, and 6.4d show the hourly imbalances across each of the four Norwegian market areas considered, in December 2021. A positive imbalance implies a surplus in the aggregate power injected into the grid by Balance Responsible Parties, while a negative imbalance implies a deficit. It can be seen that imbalances are distributed fairly equally among surpluses and deficits, although there seems to be a skew toward deficit imbalances in NO1 and NO2. Further, particularly NO2 experienced some very large peaks in both surplus and deficit imbalances, where five individual hours had system imbalances above 750 MWh.

Table 6.3: Median system imbalances in December 2021, and median aggregate wind power imbalances – with and without access to DER flexibility. The system imbalance figures are based on empirical data from the ENTSO-E Transparency Platform, while the wind imbalances result from simulations.

Median imbalances [MWh]	NO1	NO2	NO3	NO4
System imbalances, Dec. 2021	187	157	113	49
Wind producer imbalances, **BAU**	32.5	151.0	305.5	101.9
Wind producer imbalances, **PreFlex**	16.4	141.2	203.1	81.9
Reduction in wind imbalances with DERs	16.1	9.76	102.4	19.9

Table 6.3 Displays wind producers' modeled aggregate deficit imbalances, with and without access to DER flexibility. Further, the median system imbalances are shown for each market area. Reductions in the aggregate imbalances of wind producers are compared to the magnitude of system imbalances: NO3 deviates from the other market areas because the modeled deficit wind power imbalances are very large. As discussed previously, this is caused by the fact that the forecast error data in NO3 is skewed towards a deficit, as can be seen in figure 5.2c, in chapter 5. For market areas NO1, NO2, and NO4, smaller reductions in simulated imbalances are found. These reductions constitute 9%, 6%, and 41% of the median system imbalances in each market area. From this, it is concluded that using DER flexibility to reduce wind power forecast errors in the current Norwegian setting would significantly impact the median system imbalances. Concerning the question of what this implies for the volume of balancing reserves needed in Norway, the reductions in wind power

[1]Imbalance settlement pricing was changed in Norway from a dual-price system to a single-price system in November 2021. This could explain the data discontinuity.

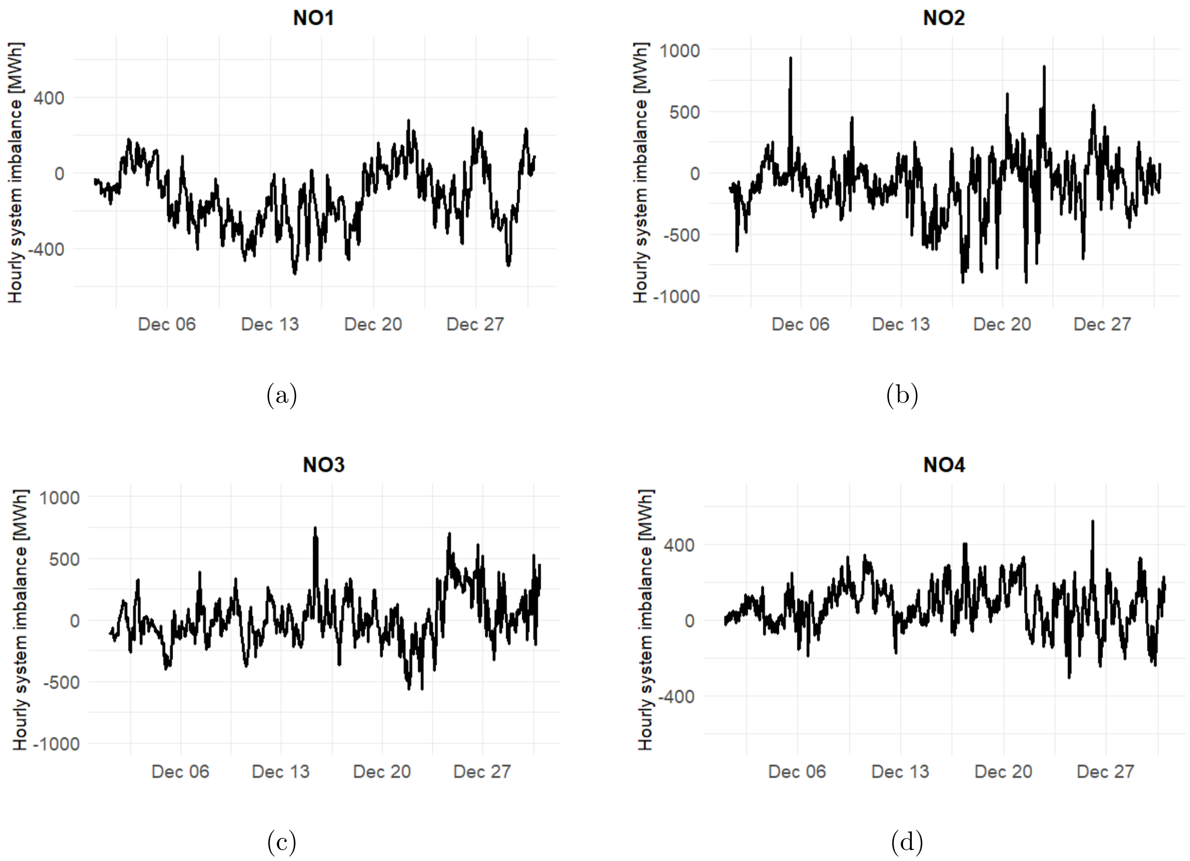

Figure 6.4: Empirical data on total system imbalances in December 2021. Surplus system imbalances are positive, and deficit system imbalances are negative.

imbalances displayed in table 6.3 are compared to the time series on system imbalances shown in figure 6.4.

In extreme hours, deficit imbalances surpassed 400 MWh in NO1, 750 MWh in NO2, 500 MWh in NO3, and 200 MWh in NO4 in December 2021. These peak deficit imbalances are very large compared to the simulated reductions in wind power imbalances. From this, the following is concluded: Although using DER flexibility to balance wind forecast errors could significantly reduce the median system imbalances, the costs related to the procurement of balancing reserves would not be affected considerably. This follows from the fact that balancing reserves must be large enough to correct even the largest imbalances in a given period. The size of peak imbalances would likely not be reduced substantially by using DER flexibility to continuously balance forecast errors, and as a result, the volume of balancing reserves that must be procured by the TSO would not be reduced considerably.

Chapter 7

Conclusion

This master thesis proposes a flexibility market that enables wind producers to contract DER flexibility and use it to balance wind forecast errors. Trade in the market is simulated in a case study set in the Norwegian context. The potential impact of introducing the market is evaluated by considering the perspective of wind producers, DER asset owners, and system balancing.

The case study demonstrates that by contracting DER flexibility and activating it to balance their forecast errors, wind producers could significantly reduce their exposure to intraday illiquidity risk. The price that the wind producers would pay to purchase flexibility from the pre-contracting market, however, is found to be only modest; around 30% of the corresponding day-ahead price. The relatively low value is, to a large extent, a result of the fact that contracted up-regulation flexibility is only activated 38.7%-56.3% of the time. This again follows from the fact that deficit forecast errors only occur around 50% of the time. Increasing the share of hours where flexibility is activated is thus necessary to increase DER remuneration and improve incentives for DER owners to offer flexibility. Lastly, the perspective of the TSO was taken, and the extent to which system balancing in Norway would be affected by utilizing DER flexibility to balance forecast errors. It was found that introducing the flexibility market would likely reduce median system imbalances. Still, the costs of procuring balancing reserves would likely not substantially change since the volume of reserves that the TSO must procure depend on peak system imbalances, and these would remain.

Further research should consider market designs that allow trading DER flexibility sequentially in different markets, as this could increase the utilization of flexibility. The utilization of flexibility, i.e., the share of the time pre-contracted flexibility is activated, was found in this work to be a key driver for what wind producers would pay for it. As a result, increasing the utilization of flexibility can increase the revenues obtained from offering the same capacity and incentivize more provision of demand-side flexibility. In the context of the PreFlex market, enabling trade in sequential markets could involve implementing a deadline for when wind producers must signal to aggregators that they will not use the flexibility in a given delivery hour. Then, this flexibility could be traded in markets with auctions set after this deadline, such as for instance in real-time markets.

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Appendix

Table A.1: Wind production and day-ahead forecast error data for the whole year, 2021.

	N	Mean	St. Dev.	Min	Median	Max
Hourly wind production, NO1	8,735	60.696	52.058	0	45	208
Hourly wind production, NO2	8,735	442.609	363.363	0	340	1,288
Hourly wind production, NO3	8,735	490.204	421.072	0	366	1,745
Hourly wind production, NO4	8,735	222.795	149.742	0	193	605
Day-ahead forecast error, NO1	8,735	-8.53	19.751	-133	-6	107
Day-ahead forecast error, NO2	8,735	12.868	70.229	-661	7	422
Day-ahead forecast error, NO3	8,735	-80.733	162.702	-1,279	-49	594
Day-ahead forecast error, NO4	8,735	2.511	41.375	-192	0	188

Table A.2: Wind production and day-ahead forecast error data for July 2021.

	N	Mean	St. Dev.	Min	Median	Max
Hourly wind production, NO1	742	33.181	30.113	0	26	134
Hourly wind production, NO2	742	324.357	266.097	11	266.5	1,063
Hourly wind production, NO3	742	315.827	340.476	0	149	1,185
Hourly wind production, NO4	742	153.042	128.913	3	113	533
Day-ahead forecast error, NO1	742	-9.865	16.465	-91	-6	52
Day-ahead forecast error, NO2	742	20.499	57.767	-214	18	202
Day-ahead forecast error, NO3	742	-114.201	122.275	-615	-68	89
Day-ahead forecast error, NO4	742	-2.819	37.604	-183	-2	142

Table A.3: Wind production and day-ahead forecast error data for December 2021.

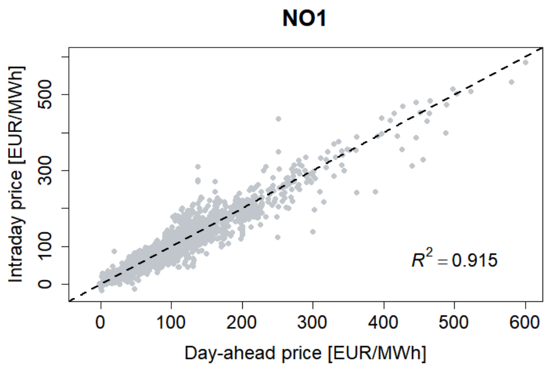
	N	Mean	St. Dev.	Min	Median	Max
Hourly wind production, NO1	718	69.783	66.337	0	41	205
Hourly wind production, NO2	718	642.416	411.837	14	646.5	1,270
Hourly wind production, NO3	718	921.145	508.413	5	974.5	1,745
Hourly wind production, NO4	718	267.028	138.317	13	252	589
Day-ahead forecast error, NO1	718	-4.825	20.193	-86	-4	61
Day-ahead forecast error, NO2	718	41.65	73.973	-356	44	329
Day-ahead forecast error, NO3	718	136.29	126.399	-573	152	594
Day-ahead forecast error, NO4	718	-7.767	39.303	-186	-7	167

Table A.4: Descriptive statistics for day-ahead prices and intraday-day-ahead price spreads in the market areas considered, July 2021.

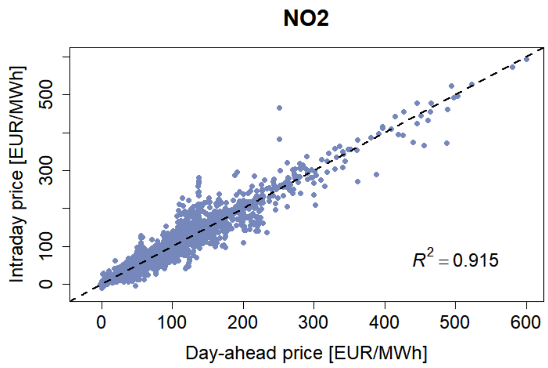
	N	Mean	St. Dev.	Min	Median	Max
DANO1	742	55.611	6.597	2.9	57.835	62.62
DANO2	742	57.481	6.276	2.9	59.06	62.62
DANO3	742	45.765	9.205	17.2	46.305	97.62
DANO4	742	22.051	4.528	17.2	20.71	50.56
DA_ID_dev_NO1_abs	742	4.764	5.237	0	3.085	25.05
DA_ID_dev_NO2_abs	742	7.639	7.058	0	6.035	36.15
DA_ID_dev_NO3_abs	742	4.248	6.213	0	1.31	42.75
DA_ID_dev_NO4_abs	742	16.656	9.579	0	19.99	42.71

Table A.5: Descriptive statistics for day-ahead prices and absolute intraday-day-ahead price spreads in the market areas considered, December 2021.

	N	Mean	St. Dev.	Min	Median	Max
DANO1	718	175.786	72.348	96.94	150.84	600.16
DANO2	718	175.738	72.385	96.94	150.84	600.16
DANO3	718	60.189	40.002	13.75	50.045	299.91
DANO4	718	60.093	39.983	13.75	50.045	299.91
DA_ID_dev_NO1_abs	718	21.382	22.484	0	16.905	185.38
DA_ID_dev_NO2_abs	718	20.847	24.892	0	12.55	214
DA_ID_dev_NO3_abs	718	13.113	24.241	0	5.085	173
DA_ID_dev_NO4_abs	718	11.5	20.154	0	3.94	150.4



(a)



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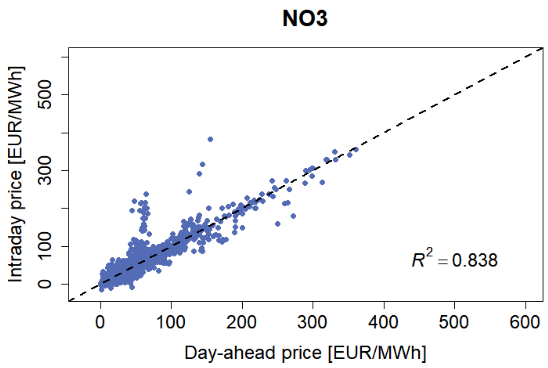

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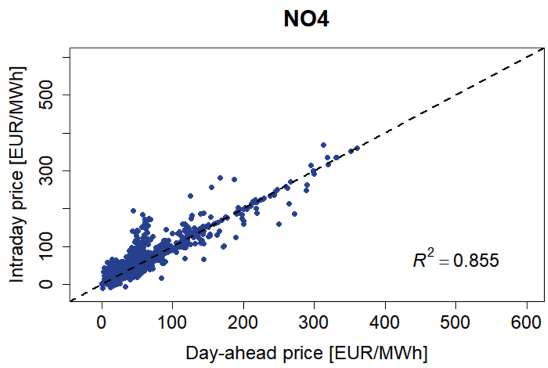

(d)

Figure A.1: Scatter plots showing the relation between day-ahead price, and volume-weighted average intraday price. The plots for NO3 and NO4 contain substantially fewer observations than those for NO1 and NO2, due to the fact that in NO3, and particularly in NO4, more hours had zero intraday trade volume.

Table A.6: Summary for intraday price regression model. Regressions for market areas NO1 and NO2.

Dependent variable:			
ID_NO1_WAVG		*ID_NO2_WAVG*	
DA_NO1	0.970***	DA_NO2	0.993***
	(-0.004)		(-0.003)
Wind_err_NO1	-0.01	Wind_err_NO2	-0.002
	(-0.009)		(-0.002)
Load_err_NO1	-0.003**	Load_err_NO2	0.006***
	(-0.002)		(-0.0004)
Constant	1.049***	Constant	-1.367***
	(-0.345)		(-0.364)
Observations	7,038	Observations	8,215
R2	0.91	R2	0.917
Adjusted R2		Adjusted R2	0.917
Residual Std. Error	15.292 (df = 7034)	Residual Std. Error	14.351 (df = 8211)
F Statistic	23,797.950*** (df = 3; 7034)	F Statistic	30,179.630*** (df = 3; 8211)
Note:			*p<0.1; **p<0.05; ***p<0.01

Table A.7: Summary for intraday price regression model. Regressions for market areas NO3 and NO4. Regressions for market areas NO3 and NO4.

Dependent variable:			
ID_NO3_WAVG		*ID_NO4_WAVG*	
DA_NO3	0.972***	DA_NO4	0.972***
	(-0.005)		(-0.006)
Wind_for_err_NO3	0.005***	Wind_for_err_NO4	0.001
	(-0.001)		(-0.005)
Load_for_err_NO3	0.004***	Load_for_err_NO4	0.013***
	(-0.001)		(-0.002)
Constant	2.295***	Constant	4.394***
	(-0.399)		(-0.408)
Observations	7,311	Observations	4,478
R2	0.839	R2	0.857
Adjusted R2		Adjusted R2	0.857
Residual Std. Error	12.309 (df = 7307)	Residual Std. Error	13.207 (df = 4474)
F Statistic	12,718.230*** (df = 3; 7307)	F Statistic	8,933.978*** (df = 3; 4474)
Note:			*p<0.1; **<0.05; ***p<0.01

Table A.8: Imbalance management costs in the simulated cases.

	Total Imbalance cost	ID market costs	DER flexibility costs	Imbalance costs
July 2021				
BAU, Fixed ID price	4.5	4.5	0	0
PreFlex, Fixed ID price	3.64	2.9	0.74	0
BAU, Wind-dependent ID price	5.9	5.9	0	0
PreFlex, Wind-dependent ID price	4.77	3.8	0.97	0
BAU, Illiquid ID market	5.3	3.5	0	1.8
PreFlex, Illiquid ID market	4.3	2.2	1	1.1
December 2021				
BAU, Fixed ID price	10.4	10.4	0	0
PreFlex, Fixed ID price	8.6	6	2.6	0
BAU, Wind-dependent ID price	11.7	11.7	0	0
PreFlex, Wind-dependent ID price	9.4	6.2	3.2	0
BAU, Illiquid ID market	11.1	6.5	0	4.6
PreFlex, Illiquid ID market	7.3	3.1	1.5	2.7

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