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Fostering Flexibility in Distribution Networks

Through empirical studies, regulatory analyses, and mathematical programs

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Dissertation presented in partial fulfillment of the requirements for the degree of Doctor of Engineering Science (PhD): Mechanical Engineering

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Preface

During the past four years, I have had the pleasure of doing a job that allowed me to learn and be curious every day, leading to personal and professional growth on many levels. However, I believe I could have only truly enjoyed this PhD journey because I was surrounded by many great people, which I would like to thank now.

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Ellen Beckstedde
Florence, November 2023

Abstract

The rise of congestion issues in European distribution grids due to the rapid uptake of distributed energy resources highlights the need for advancements in distribution network operation and planning. Recognizing this need, the Clean Energy Package introduced several provisions to support the development of network planning methodologies to prevent distribution grids from becoming a bottleneck in the transition toward a more sustainable energy system. A crucial element adopted in the legislation involves leveraging the potential of the flexibility that is increasingly present in distribution networks, with an emphasis on the marked-based procurement of these flexible resources. In this context, this dissertation aims to empower the use of flexibility in distribution grids through empirical studies, regulatory analyses, and mathematical programs.

The first part of this dissertation examines the developments in distribution network planning by conducting a stakeholder analysis with European Distribution System Operators (DSOs). The analysis revealed different approaches in the current practices of distribution network planning. While most DSOs are considering flexibility as an alternative to grid investments, developing a robust methodology for cost-effective integration of flexibility in network planning remains an open issue. The level of transparency in distribution network plans also requires further consideration to align DSOs on a common target model in the future.

The second part explores the practical experiences and complexities involved in implementing regulatory tools to source flexibility at the distribution level. Practical implementations of dynamic distribution network tariffs and flexible connection agreements were studied across Europe. While incentives for efficient network usage are being integrated into both flexibility tools, considerable variations in their implementations were observed, raising questions about their compatibility and the impact of their respective design choices.

In this context, regulatory sandboxes can be an important instrument to examine the impact of (combining) flexibility tools in a real environment, leading to regulatory learning by regulators and policymakers. The outcomes of existing sandbox projects reinforce the idea that regulatory sandboxes can be an effective instrument to examine innovations, such as flexibility, in a real environment. However, the analysis of legal frameworks for regulatory sandboxes shows that this potential can only be achieved with effective implementation of administration, derogations, application process and reporting within sandbox frameworks.

The third part considers open issues in the market-based procurement of flexibility for DSO services, also called flexibility markets. A multi-stakeholder analysis considering aggregators, DSOs, market operators, regulators, research institutes and transmission system operators showed that there is not yet a consensus on the optimal approach to flexibility market design. Open issues remain regarding the use cases, incentives, operational timeframes, rules and products, and roles and responsibilities in these markets. However, the need for flexibility market design to consider local grid characteristics, minimize the impact of uncertainty and facilitate secure information exchange was acknowledged by all stakeholders.

Furthermore, a bilevel model was developed to evaluate the concern that grid users might use flexibility markets to deliberately create congestion as they anticipate getting paid to solve it, also known as inc-dec gaming. The results for a stylized test case with renewable energy curtailment at the transmission and distribution network interface show that strategic agents can game flexibility markets. Also, examples of the price-setter game and the inc-dec games using redispatch markets were observed. The derived characteristics of these games can be used to support regulators and system operators to detect and distinguish the different bidding strategies in practice.

Finally, the need for counterbalancing actions of flexibility procurement and its relevance in distribution network planning was assessed. A comparison of flexibility and imbalance data for Germany in 2020 revealed that the counterbalancing costs associated with wind curtailment can be significant, depending on the system's imbalance position. A bilevel model was proposed to evaluate the effect of these counterbalancing costs on the DSO's network investment decision. Results from a stylized test system with wind curtailment indicated that counterbalancing costs influence the DSO's grid investment decision, and flexibility can be a cost-efficient tool in network planning from a system and DSO perspective.

Beknopte samenvatting

De opkomst van congestieproblemen in Europese distributienetwerken als gevolg van de snelle opname van gedistribueerde energiebronnen benadrukt de noodzaak van vooruitgang in de operatie en planning van distributienetwerken. Ter erkenning van deze behoefte introduceerde de Clean Energy Package verschillende bepalingen ter ondersteuning van de ontwikkeling van netwerkplanningsmethodologieën om te voorkomen dat distributienetwerken een knelpunt worden in de overgang naar een duurzamer energiesysteem. Een cruciaal element dat in de wetgeving is opgenomen, omvat het benutten van het potentieel van de flexibiliteit die steeds meer aanwezig is in distributienetwerken, met nadruk op de marktgerichte inkoop van flexibele energiebronnen. In deze context heeft dit proefschrift tot doel het gebruik van flexibiliteit in distributienetwerken te bevorderen door middel van empirische studies, regelgevingsanalyses en wiskundige programma's.

Het eerste deel van dit proefschrift onderzoekt de ontwikkelingen in de planning van distributienetwerken door middel van een belanghebbendenanalyse met Europese distributienetwerkbeheerders (DNBs). De analyse onthulde verschillende benaderingen in de huidige praktijken van distributienetwerkplanning. Hoewel de meeste DNB's flexibiliteit als een alternatief voor netbeheerinvesteringen bekijken, blijft het ontwikkelen van een robuuste methodologie voor kosteneffectieve integratie van flexibiliteit in netwerkplanning een open vraagstuk. Het niveau van transparantie in distributienetwerkplannen moet ook verder overwogen worden tijdens het opstellen van een gemeenschappelijk model voor distributienetwerkplannen in de toekomst.

Het tweede deel analyseert de praktische ervaringen en complexiteiten bij de implementatie van regelgevingsinstrumenten voor het activeren van flexibiliteit op distributieniveau. Praktische implementaties van dynamische distributienettarieven en flexibele aansluitingsovereenkomsten werden bestudeerd in Europa. Hoewel stimulansen voor efficiënt netwerkgebruik worden geïntegreerd in beide flexibiliteitsinstrumenten, werden aanzienlijke variaties in hun implementaties waargenomen, wat vragen oproept over hun compatibiliteit en de impact van hun respectievelijke ontwerpkeuzes.

In deze context kunnen testomgevingen voor regelgeving een belangrijk instrument zijn om de impact van (de combinatie van) flexibiliteitsinstrumenten in een echte omgeving te onderzoeken en om regelgevers en beleidsmakers over de gevolgen van regulatie te laten leren. De resultaten van bestaande projecten ondersteunen het idee dat testomgevingen voor regelgeving een effectief instrument kunnen zijn om innovaties, zoals flexibiliteit, in een echte omgeving te onderzoeken. De analyse van wettelijke kaders voor deze testomgevingen toont echter aan dat dit potentieel alleen kan worden gerealiseerd met een effectieve implementatie van administratie, reglementaire afwijkingen, aanvraagprocedures en rapportering binnen de kaders voor testomgevingen met regelgeving.

Het derde deel behandelt open vraagstukken in de marktgerichte inkoop van flexibiliteit voor DNB-diensten, ook wel flexibiliteitsmarkten genoemd. Een analyse met meerdere belanghebbenden, waaronder aggregatoren, DNBs, marktexploitanten, regelgevers, onderzoeksinstituten en transmissie netwerkbeheerders, toonde aan dat er nog geen consensus is over de optimale aanpak voor het ontwerp van flexibiliteitsmarkten. Open vraagstukken blijven bestaan met betrekking tot gebruiksscenario's, stimulansen, operationele tijdschema's, regels en producten, en verantwoordelijkheden van partijen in deze markten. Niettemin werd door alle belanghebbenden erkend dat het ontwerp van flexibiliteitsmarkten rekening moet houden met lokale netwerkkarakteristieken, de impact van onzekerheid moet minimaliseren en een veilige uitwisseling van informatie moet garanderen.

Bovendien werd een wiskundig model met twee niveaus ontwikkeld om de bezorgdheid te evalueren dat netgebruikers flexibiliteitsmarkten kunnen gebruiken om opzettelijk congestie te creëren omdat ze verwachten ervoor te worden betaald om het op te lossen, ook wel bekend als inc-dec-gamen. De resultaten van het model voor een gestileerde testcase met beperking van hernieuwbare energie op de koppeling tussen het transmissie en distributienetwerk tonen aan dat strategische spelers flexibiliteitsmarkten kunnen manipuleren. Ook werden voorbeelden van prijszetting door marktkracht en inc-dec-gamen met behulp van redispatch-markten waargenomen. De afgeleide kenmerken van deze spellen kunnen worden gebruikt om toezichthouders en systeembeheerders te ondersteunen bij het detecteren en onderscheiden van de verschillende biedstrategieën in de praktijk.

Ten slotte werd de noodzaak van het uitbalanceren van flexibiliteitsinkopen en de relevantie ervan in de planning van distributienetwerken beoordeeld. Een vergelijking van flexibiliteits- en onbalansgegevens voor Duitsland in 2020 toonde aan dat de kosten voor het uitbalanceren van windbeperkingen aanzienlijk kunnen zijn, afhankelijk van de onevenwichtspositie van het systeem. Er werd een wiskundig model met twee niveaus voorgesteld om de invloed van deze tegenbalanskosten op de investeringsbeslissing van de DNB in het netwerk te evalueren. Resultaten van een gestileerd testsysteem met windbeperking gaven aan dat uitbalanceerkosten de netwerkinvesteringsbeslissing van de DNB beïnvloeden en dat flexibiliteit een kosteneffectief instrument kan zijn bij netwerkplanning vanuit een systeem- en DNB-perspectief.

List of Abbreviations

AT	Austria
BR	Brussels
BRP	Balancing Responsible Party
CAPEX	Capital Expenditures
CEER	Council of European Energy Regulators
CEP	Clean Energy Package
DE	Germany
DER	Distributed Energy Resource
DSO	Distribution System Operator
ENA	Association representing Energy Networks in the UK and Ireland
EPN	Eastern Power Networks
ES	Spain
EVs	Electric Vehicles
FL	Flanders
FR	France
GB	Great Britain
GDPR	General Data Protection Regulation
KKT	Karush-Kuhn-Tucker conditions

LPN	London Power Networks
MCP	Mixed Complementarity Problem
MILP	Mixed-Integer Linear Program
MPEC	Mathematical Program with Equilibrium Constraints
NL	the Netherlands
NO	Norway
OPEX	Operating Expenditures
SPEN	Scottish Power Energy Networks
TCC	Total Consumer Costs
TGC	Total Generation Costs
TOTEX	Total Cost of Expenditures (= Capital + Operating Expenditures)
TSO	Transmission System Operator
UKPN	UK Power Networks
WA	Wallonia

Nomenclature

Chapter 6

Indices and sets:

gs (Ω_{gs})	Index (set) of all strategic generation units
gc (Ω_{gc})	Index (set) of all competitive generation units
g (Ω_g)	Index (set) of generation units ($\Omega_{gs} \cup \Omega_{gc} = \Omega_g$)
l (Ω_l)	Index (set) of demand units
i, j, k (N)	Indices (set) of network nodes, with N_d for distribution nodes and N_t for transmission nodes
ij (B)	Index (set) of network branches, with B_d for distribution lines and B_t for transmission lines

Constants and parameters:

C_g	Marginal cost of generation unit g, in €/MWh
$\hat{C}^{max}$	Price cap on each market, in €/MWh
P_g^{cap} (Q_g^{cap})	Active (reactive) power capacity, in GW (GVAr)
P_l^D (Q_l^D)	Active (reactive) demand, in GW (GVAr)
$P_{ij}^{b,max}$	Maximum active branch flow, in GW
$Q_{ij}^{b,max}$	Maximum reactive branch flow, in GVAr
$R_{ij},\ X_{ij}$	Resistance and reactance of the branch
B_{ij}	Susceptance of the branch

v_i^{min}, v_i^{max}	Lower and upper limit of the voltage magnitude
δ_i^{min}, δ_i^{max}	Lower and upper limit of the voltage angle

Variables:

p_g (q_g)	Dispatched active (reactive) power in GW (GVAr), superscripts w, f, up, f, dn, r, up, and r, dn indicate the respective markets
$\hat{c}_{gs}$	Bid price of strategic unit gs in €/MWh, superscripts w, f, up, f, dn, r, up, and r, dn indicate the respective markets
λ	Market clearing price in €/MWh, superscripts w, f, up, f, dn, r, up, and r, dn indicate the markets
p_{ij}^b (q_{ij}^b)	Active and reactive branch flows in GW (GVAr)
w_i	Voltage squared at node i
δ_i	Voltage angle at node i

Chapter 7

Indices and sets:

l (Ω_l)	Index (set) of all wind power levels
g (Ω_g)	Index (set) of generation units
k (Ω_k)	Index (set) of demand units
d (N_d)	Indices (set) of distribution nodes

Constants and parameters:

NB_l	Annual number of occurrences of each power level l
C_{nw}	Annualized incremental network cost, in €/kW
C_g	Marginal cost of generation unit g, in €/MWh
C_g^c	Curtailment cost of generation unit g, in €/MWh
C_g^b	Counterbalancing cost of generation unit g, in €/MWh

P_g^{cap}	Maximum capacity of generation unit g, in MW
P_k^D	Demand of each load k, in MW

Variables:

p_g	Dispatched power of generation unit g in MW, superscripts w, c and b indicate the respective markets
λ_l	Market clearing price for each wind power level l in €/MWh, superscripts w, c and b indicate the markets
f_d	Installed network capacity at distribution node d in MW

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Chapter 1

Introduction

This chapter introduces the research performed in this dissertation. Section 1.1 provides some context on the ongoing developments of flexibility in distribution networks. Section 1.2 discusses the challenges of developing distribution network planning, implementing regulatory tools to source flexibility in practice, and designing flexibility markets. Finally, Sections 1.3 and 1.4 present the research questions and outline of this dissertation, respectively.

1.1 Context

The European Union's ambition to become the first climate-neutral continent by 2050 and reduce at least 55% of greenhouse gas emissions by 2030 places distribution networks at the center of the future European energy system for at least two reasons [1]. First, large capacities of renewable energy sources that come with the decarbonization of the European energy mix will be installed at the distribution level. Second, a large share of heat pumps and electric vehicles that come with the electrification of the heating and transport sectors will be integrated into the distribution network.

The uptake of these so-called distributed energy resources[1] will bring significant network operation and investment challenges for European Distribution System Operators (DSOs) in the coming years. A recent study by Eurelectric and E.DSO estimates that DSOs will need to invest 375-425 €bn in their networks

[1] In the remainder of this dissertation, we assume distributed energy resources refer to smaller-scale generation, storage and demand resources located near the point of electricity consumption.

between 2020 and 2030 [2]. Knowing that distribution and transmission network tariffs accounted for 28.8% of European households' electricity bills in 2020 [3], DSOs are under pressure to keep the costs related to distribution network investments under control and minimize the risk of overinvestment.

Traditionally, European DSOs have dimensioned their networks to handle load peaks by grid users, primarily evening peaks of households, based on historical data and projected demand patterns. This so-called 'fit-and-forget' approach typically did not consider the potential for future changes or uncertainty, such as the emergence of new production and load peaks resulting from distributed energy resources. As the decisions for grid users to invest in renewable generation or switch to an electric vehicle are quicker than network investment decisions, the pace of changes in distributed energy resources has exceeded the typical grid expansion planning and execution processes of DSOs. As a result, several DSOs across Europe have started to experience distribution network congestion, which are grid situations where the demand or supply of electricity exceeds the network capacity. Examples are the long connection queues for new grid users in the Netherlands [4] and the curtailment of renewable energy in Germany [5].

The rise of congestion issues in European distribution grids exposed the limitations of the traditional 'fit-and-forget' approach and highlighted the need for advancements in network planning to prevent distribution grids from becoming a bottleneck in the transition toward a more sustainable energy system. Recognizing this need, the Clean Energy Package (CEP) introduced several provisions to support the development of network planning methodologies that are adapted to this new reality of decentralized energy resources [6, 7]. A crucial element adopted in the legislation involves leveraging the potential of the 'flexibility' that is increasingly present in distribution networks. In this context, flexibility refers to the deviation of grid users from their scheduled consumption or production patterns based on implicit or explicit signals from a third party. Examples of flexibility at the distribution level include pre-heating well-insulated homes, curtailing solar and wind power production and spreading electric vehicle charging over time [8].

By considering flexibility, DSOs can enhance the operation and planning of their distribution grids in two ways. First, flexibility allows DSOs to effectively manage congestion issues and facilitate the connection of new users in heavily congested areas. Second, flexibility gives DSOs the opportunity to delay grid investments to the point that the business case is more certain or to actively reduce grid users' peaks as an alternative to grid investments. It is worth nothing that flexibility at the distribution level can also offer benefits to Transmission System Operators (TSOs) regarding redispatching and balancing services, but this is outside the scope of this dissertation.

The main focus of this dissertation is the market-based procurement of flexibility for DSO services, commonly known as flexibility markets. Flexibility markets are long-term and short-term pools in which the network needs of the DSO are matched with the voluntary offers of flexibility providers in a market-based way. While these markets can potentially integrate with existing intraday and TSO markets, we assume an independent market platform where DSOs act as the sole buyer, either managing the platform themselves or engaging with a third-party market operator. Furthermore, the participation of flexibility providers is usually limited to specific network areas to account for the local characteristics of the DSO's congestion management needs. Technologies that commonly provide flexibility are batteries, electric vehicles, demand side response offered by industrial buildings, commercial buildings, and households, as well as adjustments in electricity generation facilitated by biomass, gas engines and renewables. It is important to emphasize that when this dissertation represents flexibility markets within mathematical models, it focuses on flexibility provided by renewable energy curtailment to relieve congested distribution network areas.

1.2 Motivation

The previous section describes the challenges and opportunities that come with the effective and cost-efficient integration of an increasing amount of distributed energy resources at the distribution level. In the following paragraphs, we summarize the key discussions arising with the developments of distribution network plans, regulatory tools to source flexibility and flexibility markets while highlighting the contributions of this dissertation.

1.2.1 Developments in distribution network planning

The Clean Energy Package's provisions are essential to promote developments, such as flexibility, in distribution network planning. Still, the regulations remain relatively high-level, leaving the detailed implementation to the Member States. Although the EU DSO Entity[2] has been tasked with developing a new methodology for the future investment plans of distribution grids that all DSOs will apply, the first developments in distribution network plans will

[2] The EU DSO Entity [9] represents over 900 European DSOs in the 27 EU Member States. The EU DSO Entity is tasked to share best practices and develop network codes and guidelines for distribution grids in close collaboration with ENTSO-E, the European Association of Transmission System Operators for Electricity. The creation of the EU DSO Entity was legally mandated in Regulation 2019/943 of the Clean Energy Package [7] and formally established in June 2021 [9].

mainly be local or national. Several legislators and DSOs have already started exploring how this trade-off between flexibility and grid investments might be implemented in practice [10, 11, 12]. Also several academics have contributed to this discussion by examining the potential of renewable energy curtailment [13, 14] or demand response [15, 16] to delay network investments.

The ongoing studies by stakeholders and academics on distribution network planning are essential in developing an optimal planning methodology that robustly integrates the use of flexibility. However, the practical implementation of such a common target model for distribution network planning requires engagement and alignment from all stakeholders, which will be a process of sharing best practices and developing network codes to harmonize some aspects of distribution network planning. As DSOs do not commonly make details of distribution network plans publicly available, understanding the current practices of network planning and the alignment of DSOs toward the implementation of the CEP's provisions can be challenging. We contribute towards bridging this knowledge gap by exploring practical examples and stakeholder perspectives on distribution network planning.

1.2.2 Practical experiences with flexibility tools

The Council of European Energy Regulators (CEER) and the associations representing DSOs and TSOs define five main categories of regulatory tools to source flexibility at distribution level: technical solutions, rule-based approaches, network tariffs, connection agreements and market-based procurement [17, 18]. However, the optimal approach to source flexibility for DSO services is still under discussion and the debate is shaped by practical experiences with flexibility tools in two ways.

First, valuable insights can be derived from the practical implementation of flexibility tools across Europe. Similar to the developments in network planning, the high-level description of flexibility in the CEP's provisions led to various practical implementations of regulatory tools to source flexibility. By examining these different practical implementations, we can gain insights into the opportunities and complexities involved with designing and combining flexibility tools. This dissertation makes a first step in this direction by conducting an empirical study.

Second, regulatory learning on the optimal approach to source flexibility at distribution level can be achieved through regulatory sandboxes. Regulatory sandboxes can be defined as a set of regulatory exemptions to test new technologies and business models in a real environment and are recognized as an important tool to let policy and regulation evolve with the changes in our energy system, such as flexibility [19, 20]. Although an increasing number of legal frameworks on regulatory sandboxes are being implemented in Europe, the pioneers in the Netherlands decided to close their sandbox program [21]. These contradictory events raise questions about the potential of regulatory sandboxes to bring innovation to the European energy sector. We contribute to this discussion by performing a regulatory analysis.

1.2.3 Open issues when designing flexibility markets

The Clean Energy Package emphasizes the market-based procurement of flexibility over other flexibility tools as long as these markets are not subject to severe distortions and do not lead to higher levels of grid congestion [6]. As a result, an increasing number of demos and pilot projects on flexibility markets are being developed across Europe. This growth of flexibility markets is mainly driven by three factors. First, DSOs are developing their own market platforms to address (future) congestion issues in their network. Second, third-party market platforms are tapping into the opportunity of flexibility procurement at distribution level. Finally, many demonstration projects are being set up under the European Union's Horizon 2020 research and innovation program. Despite these initiatives, the future development of flexibility markets comes with at least three challenges.

The first challenge lies in determining the optimal approach for flexibility market design. As the CEP's provisions remain high-level on the implementation of flexibility markets, the development of these markets by DSOs, third-party market platforms and European projects leads to diverging design choices. Therefore, open issues persist regarding the future implementation and harmonization of flexibility markets. We contribute to this discussion by conducting a multi-stakeholder analysis on flexibility market design.

The second challenge in the development of flexibility markets is that grid users might use these markets to deliberately create congestion as they anticipate getting paid to solve it [3, 22, 23]. This behavior is often referred to as the inc-dec game and is known as a strategic arbitrage between the zonal day-ahead market and the redispatch market for congestion management at transmission level [24, 25]. There is currently not yet empirical evidence of inc-dec gaming in flexibility markets. However, as flexibility markets come with a similar market set-up as redispatch markets, the practical experience with inc-dec gaming in redispatch markets has evolved into the concern of having similar games in flexibility markets [26]. We aim to evaluate whether this concern is justified by introducing a bilevel optimization model to examine inc-dec games in flexibility markets for a stylized test case.

The third challenge regarding the implementation of flexibility markets is the interaction between the DSO's congestion management services and the system imbalance. With the growth of independent market platforms for DSO services, the effect of flexibility procurement on the system imbalance, and its respective need for counterbalancing measures, can no longer be neglected [27]. This need is reinforced by the fact that the costs associated with counterbalancing might affect the DSO's trade-off between congestion management and network investments. Currently, little is known about the counterbalancing costs that might come with flexibility procurement and their effects on distribution network planning. This dissertation contributes to this discussion by comparing flexibility and imbalance data for a specific test case and developing a bilevel optimization model to capture the effects of counterbalancing on the DSO's network investment decision.

1.3 Research objectives and scope

The main objective of this dissertation is to gain scientific knowledge and empirical information to foster the use of flexibility in distribution networks. We consider the following three aspects: developments in distribution network planning, practical experiences with flexibility tools, and open issues when designing flexibility markets.

Developments in distribution network planning

The first aim of this dissertation is to evaluate the current practices, coordination, and open issues of DSOs with the implementation of the CEP's provisions on distribution network planning. More specifically, an empirical study including practical examples and stakeholder perspectives is performed to answer the following research question:

- What are the current practices and open issues of distribution network planning, and can we move towards a common planning methodology for European DSOs in the future?

Practical experiences with flexibility tools

The second aim of this dissertation is to explore how practical experiences with flexibility tools can support the ongoing discussion on the optimal approach to source flexibility at distribution level. In particular, we examine the following research questions by conducting an empirical study and regulatory analysis:

- What insights can we draw from the practical implementation of flexibility tools across Europe regarding the complexities involved with designing and combining such tools?
- What is the potential of regulatory sandboxes to foster innovation and regulatory learning in the European energy sector, particularly in the context of sourcing flexibility at the distribution level?

Open issues when designing flexibility markets

The final aim of this dissertation is to support the development of flexibility markets by examining challenges regarding the implementation of these markets. To address this objective, the following research questions are answered by performing an empirical study, including practical examples and multi-stakeholder perspectives, and developing mathematical programs.

- What challenges are encountered when designing flexibility markets and what insights can be drawn from stakeholder discussions on the optimal implementation of flexibility markets?
- Is strategic behavior a valid concern during the development of flexibility markets, and can we develop relevant characteristics of these games to support regulators and system operators?
- How can we estimate the costs associated with the counterbalancing of flexibility procurement, and what are the possible effects of incorporating these costs in distribution network planning?

When developing mathematical programs to examine the latter two research questions, three additional scientific challenges arise.

- How can bilevel models designed to capture strategic behavior in electricity markets be extended to include the recent developments of flexibility markets?
- How can we collect and manipulate data resources to develop a relevant and appropriate use case to examine the costs associated with the counterbalancing of flexibility procurement?
- What mathematical model is feasible to represent the DSO's network planning decision while minimizing network investments and the operational costs of flexibility and counterbalancing?

1.4 Outline

We adopt the following outline in this dissertation, which is graphically summarized in Figure 1.1.

Developments in distribution network planning

CH2	Empirical study	What are the current practices and open issues of distribution network planning, and can we move towards a common planning methodology for European DSOs in the future?

Practical experiences with flexibility tools

CH3	Empirical study	What insights can we draw from the practical implementation of flexibility tools across Europe regarding the complexities involved with designing and combining such tools?
CH4	Regulatory analysis	What is the potential of regulatory sandboxes to foster innovation and regulatory learning in the European energy sector, particularly in the context of sourcing flexibility at the distribution level?

Open issues when designing flexibility markets

CH5	Empirical study	What challenges are encountered when designing flexibility markets and what insights can be drawn from stakeholder discussions on the optimal implementation of flexibility markets?
CH6	Mathematical program	Is strategic behavior a valid concern during the development of flexibility markets, and can we develop relevant characteristics of these games to support regulators and system operators?
CH7	Mathematical program	How can we estimate the costs associated with the counterbalancing of flexibility procurement, and what are the possible effects of incorporating these costs in distribution network planning?

Figure 1.1: Outline of the dissertation.

Chapter 2 evaluates the ongoing developments in distribution network planning across Europe. The challenge of grid congestion due to the rapid adoption of distributed energy resources in distribution networks is illustrated using the examples of the Netherlands and Germany. We describe the main Clean Energy Package provisions introduced to address this congestion challenge and foster the planning of distribution grids on five dimensions: planning frequency, coordination with the TSO, digitalization, transparency, and flexibility as an alternative to grid investments. The current practices, alignment, and open issues of European DSOs when implementing these provisions are explored using stakeholder analysis and demonstrated by some recent examples of distribution network plans.

The illustration of the congestion challenge and the examples of distribution network plans are based on:

- Beckstedde, E., and Meeus, L., 2023. From "Fit and Forget" to "Flex or Regret" in Distribution Grids: Dealing with Congestion in European Distribution Grids. IEEE Power and Energy Magazine, vol. 21, no. 4, pp. 45-52. doi: 10.1109/MPE.2023.3269545.

The description of the Clean Energy Package provisions and the findings of the stakeholder analysis contain elements from:

- Beckstedde, E., Meeus, L., Ramos, A., et al., 2021. EUniversal Deliverable 10.1: Business model canvas and comparison of CBA methodologies.

Chapter 3 explores regulatory tools to source flexibility at distribution level. The following six flexibility tools are considered: dynamic network tariffs, flexible connection agreements, flexibility markets, bilateral contracts, cost-based mechanisms, and obligations. Although there is not yet a consensus on the optimal approach to unlock the full potential of flexibility at the distribution level, Member States started adopting flexibility tools in practice. We examine the practical implementation of dynamic distribution network tariffs and flexible connection agreements across Europe and provide some first insights into the complexities and opportunities involved with the implementation and combination of flexibility tools.

The overview of the flexibility toolbox and the analysis of dynamic network tariffs and flexible connection agreements across Europe are based on the following deliverables:

- Beckstedde, E., Meeus, L., et al., 2020. EUniversal Deliverable 1.1: Characterisation of current network regulation and market rules that will shape future markets.
- Beckstedde, E., Meeus, L., et al., 2022. EUniversal Deliverable 10.3: Regulatory recommendations for flexibility options and markets.

The remaining parts contain elements from:

- Beckstedde, E., Meeus, L., Ramos, A., et al., 2022. EUniversal Deliverable 5.4: Evaluation of market mechanisms: challenges and opportunities.
- Meeus, L., Beckstedde, E., Nouicer, A., 2022. Towards a Regulatory Framework for the Use of Flexibility in Distribution Grids. Oxford Energy Forum, Issue 134.
- Beckstedde, E., and Meeus, L., 2023. From "Fit and Forget" to "Flex or Regret" in Distribution Grids: Dealing with Congestion in European Distribution Grids. IEEE Power and Energy Magazine, vol. 21, no. 4, pp. 45-52. doi: 10.1109/MPE.2023.3269545.

Regulatory learnings on the optimal approach to source flexibility at distribution level can also be achieved by developing regulatory sandboxes. In **Chapter 4**, we examine the experiences with regulatory sandboxes in Austria, Belgium, France, Germany, Great Britain, the Netherlands, Norway and Spain. On the one hand, approved sandbox projects are compared based on their scope and regulatory derogations to identify areas of innovation and regulatory learning brought by regulatory sandboxes. On the other hand, the legal frameworks of the concerned countries are examined to develop best practices for implementing sandbox frameworks and promoting innovation.

The content of this chapter is derived from:

- Beckstedde, E., Correa Ramírez, M., Cossent, R., Vanschoenwinkel, J., Meeus, L., 2023. Regulatory sandboxes: Do they speed up innovation in energy?, Energy Policy, Volume 180, 113656. doi: 10.1016/j.enpol.2023.113656.
- Beckstedde, E., Meeus, L., et al., 2022. EUniversal Deliverable 10.3: Regulatory recommendations for flexibility options and markets.

As the Clean Energy Package emphasizes the market-based procurement of flexibility, the remaining chapters of this dissertation focus on open issues when designing flexibility markets. **Chapter 5** describes the evolution and implementation of the three main flexibility market platforms in Europe: NODES, Piclo Flex, and GOPACS. The divergence in the design of these market platforms indicates that although flexibility markets are operational and growing, open issues persist regarding the future implementation and harmonization of these markets. We adopt two approaches to examine these open issues in flexibility market design: a qualitative, multi-stakeholder approach and a quantitative, mathematical programming approach. The multi-stakeholder analysis involves twelve research questions on the use cases and incentives for flexibility markets, the interaction of flexibility markets with existing electricity markets, flexibility market rules and products, and the roles and responsibilities of flexibility market parties. The mathematical programs address the concerns regarding strategic behavior and counterbalancing in flexibility markets and will be further developed in Chapters 6 and 7.

The descriptions of third-party flexibility market platforms include elements from:

- Beckstedde, E., and Meeus, L., 2023. From “Fit and Forget” to “Flex or Regret” in Distribution Grids: Dealing with Congestion in European Distribution Grids. IEEE Power and Energy Magazine, vol. 21, no. 4, pp. 45-52. doi: 10.1109/MPE.2023.3269545.

The findings of the qualitative analysis are based on:

- Beckstedde, E., Meeus, L., Ramos, A., et al., 2022. EUniversal Deliverable 5.4: Evaluation of market mechanisms: challenges and opportunities.

Chapter 6 evaluates the concern that grid users will strategically use flexibility markets to deliberately create and solve congestion, also known as inc-dec gaming. A bilevel model with a three-stage electricity market is proposed to examine the inc-dec game in flexibility markets at distribution level and redispatch markets at transmission level. We demonstrate the proposed model for the stylized example of renewable energy curtailment at the transmission and distribution network interface. Furthermore, we compare our findings with the existing literature to evaluate the impact of strategic behavior on the system and define the main characteristics of the bidding strategies to help regulators and system operators to detect these games in practice.

The chapter is based on the following paper:

- Beckstedde, E., Meeus, L. and Delarue, E., 2023. A bilevel model to study inc-dec games at the TSO-DSO interface. IEEE Transactions on Energy Markets, Policy and Regulation. doi: 10.1109/TEMPR.2023.3292425

Chapter 7 assesses the magnitude of counterbalancing costs related to congestion management, and its relevance in distribution network planning. We examine counterbalancing costs in the context of wind curtailment by comparing flexibility and imbalance data from Germany for 2020. Furthermore, a bilevel model is proposed to account for counterbalancing costs in distribution network planning. Using a stylized test case, we illustrate the possible effects of counterbalancing costs on the DSO's network investment decision.

This chapter contains elements from:

- Beckstedde, E., Meeus, L. and Delarue, E., 2023. Accounting for counterbalancing costs in the DSO's congestion management and network investment decision. ESIM Working paper.

Chapter 8 summarizes the conducted research, presents the main conclusions, and outlines directions for future work.

Chapter 2

Evaluating developments in distribution network planning

This chapter provides an overview of the ongoing developments in distribution network planning across Europe. Section 2.1 illustrates the congestion challenge in European distribution networks and its impact on network planning. Section 2.2 describes the provisions of the Clean Energy Package (CEP) that were introduced to support the development of distribution network plans. In Section 2.3, we conduct a stakeholder analysis to explore current practices, coordination, and open issues of Member States on the implementation of the CEP's provisions. Finally, we provide some examples of recent distribution network plans and develop the conclusions in Sections 2.4 and 2.5, respectively.

This chapter contains elements from:

- Beckstedde, E., and Meeus, L., 2023. From "Fit and Forget" to "Flex or Regret" in Distribution Grids: Dealing with Congestion in European Distribution Grids. IEEE Power and Energy Magazine, vol. 21, no. 4, pp. 45-52. doi: 10.1109/MPE.2023.3269545. © 2023 IEEE.
- Beckstedde, E., Meeus, L., Ramos, A., et al., 2021. EUniversal Deliverable D10.1: Business model canvas and comparison of CBA methodologies.

2.1 Congestion challenge in European distribution grids

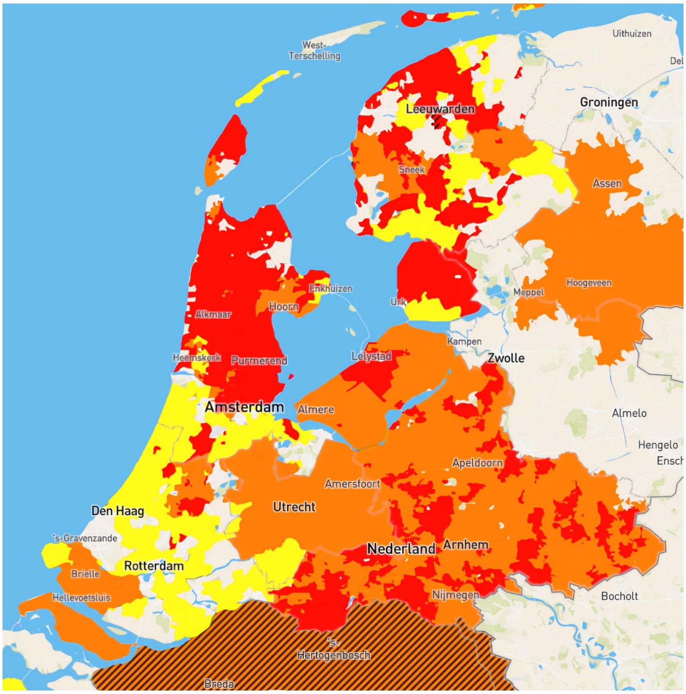
In the first two decades of electricity market reforms, congestion in distribution grids has not been an issue. But recently, it became evident that distribution grids can become a bottleneck for the functioning of the European electricity markets and the transition towards a more sustainable energy system.

It started in 2015 in countries like Germany where injection peaks caused by wind and solar farms created situations with more generation than load in some areas, leading to the curtailment of renewables under the feed-in management regime [28]. It then spread to countries like the Netherlands, where system operators started to announce structural network congestion due to generation peaks from renewables and load peaks from new data centers [29]. The next wave of grid congestion is expected to come from Electric Vehicles (EVs). Leading countries in EV penetration, like Norway, already have distribution grid congestion caused by EV charging. The UK is also experiencing congestion in distribution grids, which is mainly driven by load peaks from EVs and heating, but also by renewable generation peaks depending on the area [30].

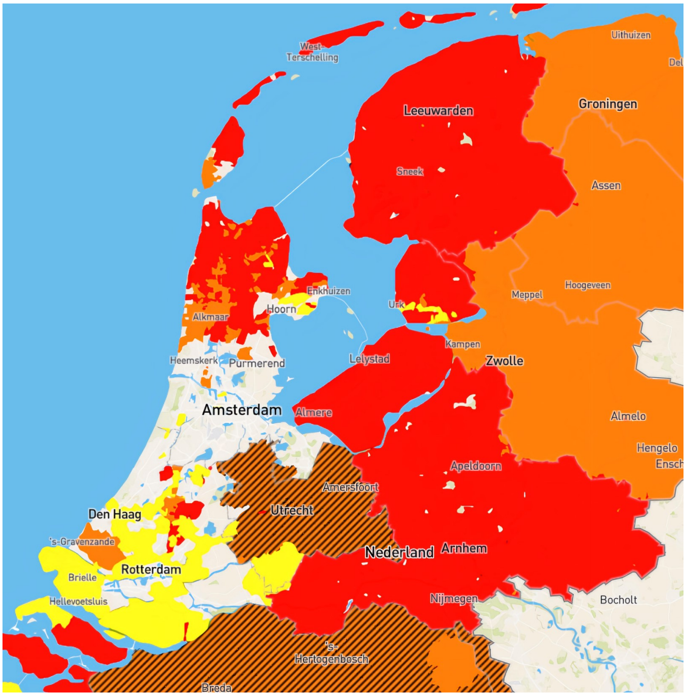
DSOs typically use heatmaps or hosting capacity maps to report on network congestion, but there are different practices. We demonstrate two types of heatmaps using the examples of the Netherlands and Germany.

Figure 2.1 is a picture from the Netherlands for new grid connections of load (top) and generation (bottom) [4]. Red means that all network capacity has been reserved for other grid users, and you cannot connect anymore in that area. Orange indicates that you cannot connect, except if certain congestion management measures are taken. Depending on the case, these measures can be limited capacity contracts or market-based redispatch. The shaded areas indicate where congestion management measures are already in place. Yellow means that the connection is uncertain; there is an application procedure to follow that will tell if you can connect. Only in transparent zones can you connect without capacity limitations.

Figure 2.2 is a picture from the DSO Schleswig-Holstein Netz in Germany [5]. The colors represent the number of hours renewable generators have been curtailed due to network bottlenecks for a selected period. Red means that you can still connect new renewable generation projects, but you have a higher risk of being curtailed if you do. For example, renewable generators located in the dark red zones of Figure 2.2 were curtailed for more than 2000 hours in 2022. Green means that no curtailment was necessary for that area.



(a) New connection of load.



(b) New connection of generation.

Figure 2.1: Network congestion heatmap of the Netherlands [4].

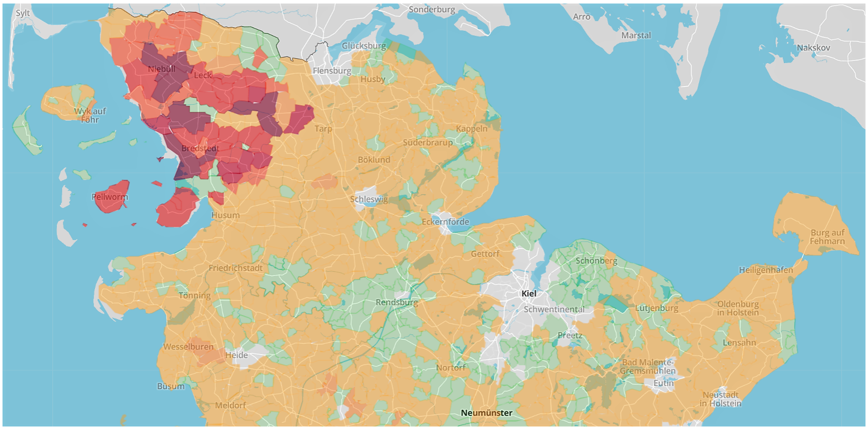


Figure 2.2: Network congestion heatmap of Germany [5].

While these heatmaps show the urgency of congestion issues in the Netherlands and Germany, congestion in distribution grids is still far from a concern for many stakeholders in other European countries. However, the lessons learned from countries like the ones mentioned reveal that congestion can rapidly become an issue in certain zones, catching DSOs unprepared. The decisions for grid users to invest in renewable generation, build a new data center, or switch to an electric vehicle are quicker than the typical grid expansion planning and execution processes. This issue is already well-known in transmission grids, and the same is now happening at the distribution level. The main difference is that including network constraints in market pricing algorithms is more challenging for distribution than transmission. For instance, the IEEE community has already worked on theoretical models for distribution locational marginal pricing[3], but these approaches are not yet considered an actual solution to manage congestion in distribution grids.

As a result, planning distribution grid investments before congestion occurs will be essential in the transition toward a more sustainable energy system. However, minimizing the risks and costs associated with overinvestment will be equally important. Therefore, the CEP introduced several provisions to support DSOs with network planning such that the growing amount of distributed energy resources can be integrated efficiently and cost-effectively.

[3] Relevant references include but are not limited to [31, 32, 33, 34, 35]

2.2 Clean Energy Package provisions on network planning

The CEP includes, among others, the following regulations to support the development of network investment plans for distribution systems.

- Recital (61) of the Electricity Directive: Member States "should introduce network development plans for distribution systems and provide to system users adequate information regarding the anticipated expansions or upgrades of the network. [6]"
- Article 32(1) of the Electricity Directive: Member States "shall provide the necessary regulatory framework to allow and provide incentives to distribution system operators to procure flexibility services in order to improve efficiencies in the operation and development of the distribution system [6]." In this context, the flexibility considered from renewable energy curtailment "shall not exceed 5% of the annual generated electricity of these installations" according to Article 13(5a) of the Internal Market Regulation [7].
- Article 32(3) of the Electricity Directive: distribution network development plans "shall be submitted at least every two years to the regulatory authority and shall set out the planned investments for the next five-to-ten years. [6]"
- Article 55(1a) of the Internal Market Regulation: the EU DSO entity "shall be promoting the operation and planning of distribution networks in coordination with the operation and planning of transmission networks. [7]"
- Article 55(1d) of the Internal Market Regulation: the EU DSO entity "shall be contributing to the digitalization of distribution systems including deployment of smart grids and intelligent metering systems. [7]"

While these new regulations provide some important guidelines on the methodology and features of distribution network plans, the CEP's provisions remain relatively high-level, leaving the detailed implementation to the Member States. In what follows, we will examine the similarities and differences in the transposition of these five planning dimensions: planning frequency, coordination with the TSO, digitalization, transparency, and flexibility as an alternative to grid investments.

2.3 Implementation of the CEP's provisions across Europe

In the context of the EUniversal project, we conducted a stakeholder analysis to (1) gain insights into the current practices of distribution network planning, (2) examine open issues regarding the implementation of the CEP's provisions, and (3) evaluate the alignment of DSOs on a common target model in the future. In what follows, we first describe the two main steps of the stakeholder analysis, then we elaborate on the findings of each dimension in more detail.

First, interviews were conducted with experts from the following European DSOs: Agder Energi (Norway), Energa-Operator (Poland), E-Redes (Portugal), ESO (Lithuania), Fluvius (Belgium), i-DE (Spain), Mitnetz-Strom (Germany), Netz NÖ (Austria) and UK Power Networks (UK). The interviews were semi-structured, containing six pre-defined questions while allowing for additional questions depending on the participant's responses. Also written feedback on the pre-defined interview questions was received from representatives of Enedis (France) and Enel (Italy). The framework used during the interviews aimed to map current practices on network planning and was developed using academic literature [36, 37] and stakeholder reports [2, 10, 11].

Second, an online workshop was organized in June 2021 with participants from Agder Energi, Enedis, Enel, Energa-Operator, E-Redes, ESO, Fluvius, i-DE, Mitnetz-Strom, Netz NÖ and UK Power Networks. During the workshop, the findings of the interviews were debriefed, and participants were encouraged to discuss the future target model of distribution network planning using break-out rooms and polling questions.

2.3.1 Planning frequency

During the interviews, the planning frequency was examined with the question: 'How frequently do you currently report on distribution network planning?' The answers belonged to the following three categories:

- Yearly reporting cycle
- 2 yearly reporting cycle
- 3 yearly reporting cycle

We found that, in current practice, a combination of the reporting cycles is used depending on the type of network development plan. A list of planned investments in the short term is typically published yearly, while network development plans with a five-to-ten-year horizon are mostly reported every two years. An exception to this is the case of Energa-Operator, where these longer-term network development plans are currently submitted every three years, but an update to every two years is expected in the Polish Energy Law.

When a poll was launched on the target model of planning frequency, 75% of participants responded that we should go to a two-yearly submission in the future, and the remaining 25% voted for yearly reporting. Here the comment was raised that an annual frequency is preferred only for certain parts of the network planning process.

2.3.2 Coordination with the TSO

During the interviews, one interesting aspect that came up when asking about coordination with the TSO was the alignment of scenarios used during network planning. On the question 'In creating your scenarios, are you aligned with the TSO?' the following responses could be distinguished:

- Yes, we have alignment meetings with the TSO
- Yes, we use the scenarios of the TSO
- Yes, alignment is ensured by the regulator

These results indicate that alignment with the TSO on the scenarios used during network planning is important for all participating DSOs. However, there are three approaches to how this alignment is reached.

First, alignment meetings can be organized bilaterally between system operators. Most DSOs indicated that their company has alignment meetings with the TSO when defining scenarios. Moreover, these meetings are often expanded to other domains, such as roadmaps and cost-benefit analyses.

Second, scenarios can be aligned between system operators as the DSO uses parts of the TSO's scenarios in their network planning. TSOs typically include data provided by the DSO in their network plans. As a result, the TSO's scenarios contain a good estimation of some aspects of the distribution network and can be used by the DSO in network planning.

Last, the regulator can ensure the alignment between the DSO and the TSO. In this case, the regulator prepares the scenarios to be used by both system operators.

During the workshop, we asked about the regulator's role in aligning the DSOs' and TSOs' planning scenarios in the future target model. 75% of participants voted that the regulator should approve scenarios, 17% answered that the regulator should create scenarios, and 8% responded that the regulator has no role in this alignment. Here it was noted that the regulator also has an important role in approving distribution planning methodologies.

2.3.3 Digitalization

A third question raised to evaluate the degree of digitalization of distribution networks was ‘How do you represent your distribution network during planning?’ The following four network representations could be identified:

- We use a manual representation of our network
- We use representative network models
- We make simulations of critical network areas
- We go towards a full simulation of our network

Before going into more detail, it must be noted that DSOs rarely use only one type of representation, and often a combination of the responses is used during distribution network planning. Two main factors define which representations are used: the kind of analysis performed and the voltage level considered.

First, manual representations are used when digitalization is limited and insufficient information about the network is available. In this case, the network is simplified as a list of assets, load sources, or feed-ins.

Second, higher accuracy of unknown areas can be achieved by using representative network models. Representative network models can also be used to reduce calculation times. Typical examples of representative network models at the distribution level are rural, industrial, suburban and urban areas, but also approximations of the transmission network exist.

Third, simulations with software packages can be used to evaluate critical events such as new connections or obsolete assets. The amount of detail in these simulations is high but limited to a specific grid area or critical network period.

Last, DSOs can have a detailed digital representation of their whole network and move towards a complete simulation of their network.

If we asked whether network planning will evolve toward simulations of the entire distribution grid, 83% of participants answered “yes” and 17% answered “no”. Most DSOs mentioned that they are working towards a full digitalization of their network and that increasing computational possibilities make this feasible. One of the reasons to answer “no” was that always running a full simulation is not the most efficient for all types of analyses and network areas.

2.3.4 Transparency

The dimension of transparency was examined by the question 'How should network investment plans be reported to comply with the Clean Energy Package?' The following four types of reporting were mentioned during the interviews:

- Conversations with stakeholders on scenarios and investment priorities
- Two different plans: a simple public plan and a detailed private plan
- Network capacity heatmaps
- Most information is publicly available

First, reporting of network investment plans can take the form of conversations with partners such as regulators, municipalities, governments, and stakeholders. The information shared during these conversations can range from detailed to high-level results. Security concerns are the main reasons for not making network investment plans publicly available.

Second, two different network development plans can be created to reduce the issue of security: a simplified document that can be shared with the public and a more detailed plan that remains private knowledge.

Third, network capacity heatmaps can be used to share information, such as available network capacity, with grid users. The detail of these heatmaps usually goes up to the level of the transformer substation.

Lastly, DSOs can share most network information publicly using an online data platform. Here it was mentioned that it is important to report on what happened in the past and what is expected in the future.

When asking the participants whether DSOs will make more details of network planning publicly available in the future, 50% of the participants answered "yes" and 50% answered "no". The reporting of a private and public plan was perceived as most interesting by the participants. Besides that, the examples of Germany and the Netherlands in Section 2.1 illustrate the potential of network capacity heatmaps as an instrument to provide network information to grid users.

2.3.5 Flexibility as an alternative to grid investments

The following question was posed during the interviews to examine the trade-off between flexibility and network investments: 'How do you intend to include flexibility as an alternative to investments in your distribution planning methodology?' The answers could be categorized as follow:

- We will follow the requirements of the regulator
- We are testing alternatives and using our experience to go into discussion with the regulator
- We are already convinced that it is valuable to make this trade-off

First, flexibility instruments can be introduced by the regulator. An example mentioned during the interview is the 3% curtailment rule in Germany, which allows DSOs to consider the curtailment of renewable plants' power output by 3% in network planning [10].

Second, DSOs can use pilot projects to test flexibility instruments and use their experience to go into discussion with the regulator. DSOs typically organize these projects in the context of H2020 projects or own initiatives.

Last, DSOs can already be convinced that the trade-off between flexibility and network investments is valuable. Best practices to encourage the growth of flexibility are setting up initiatives even when flexibility providers are still limited, giving long-term economic signals to market players, and reporting detailed information on current and future flexibility needs.

When asking the participants if procuring flexibility should be an alternative to distribution network investment in the future target model, 75% answered they were already convinced before this workshop, 25% replied that they would have to look into it more closely, and 0% reacted that they are still skeptical about this trade-off.

When discussing the results, it became clear that there is a willingness to do tests and that the possibilities are being discovered. However, developing a robust methodology to include a cost-effective trade-off between flexibility and investments in network planning is still an open issue for many DSOs, as the optimal pricing of flexibility remains uncertain. By advancing the use of flexibility in distribution networks, DSOs can gain a better understanding of the costs and benefits involved with flexibility, which can serve as input in future distribution network plans.

2.4 Examples of distribution network planning

The EU DSO Entity will develop a common methodology for the future investment plans of distribution grids that will include the trade-off between flexibility and grid investments. In the meantime, the first distribution network plans are emerging. In what follows, we illustrate two recent approaches in distribution network plans with an example.

First, DSOs gathered via their industry associations and asked consultants to produce a first European plan as a dry-run. The first European plan was developed by Eurelectric, Monitor Deloitte, and E.DSO [2]. The study argues that evening peaks of households will drive congestion and investments in distribution grids and illustrates this with the European version of the so-called duck curve, reflecting the impact of solar production mainly around noon. Figure 2.3, taken from this study, argues that investments in the next 10 years will need to increase annually between 50% and 70% (from an average of 23 billion per year to between 34 and 39 billion per year). Important assumptions for such a plan are the renewable energy objectives and the ambition to electrify transport and heating. Even though most European countries have clear national targets, inferring the future impact on local distribution grids is not always obvious. Another key assumption is the level of flexibility that will be available, which will depend on the incentives in place to manage peaks and the resulting response from end users. The first European plan treats flexibility as an assumption.

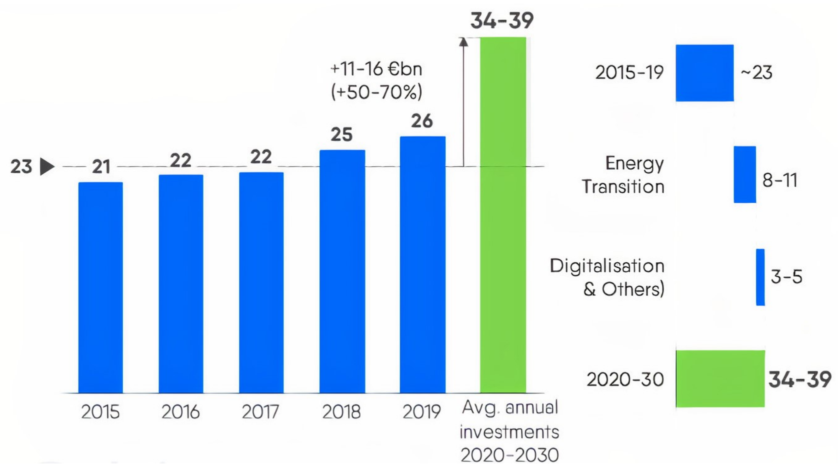


Figure 2.3: Expected increase in annual distribution network investments in Europe and its main drivers [2].

Second, DSOs have already published the first version of their local plans to comply with the new regulations of the Clean Energy Package. An example is Fluvius, the DSO active in the north of Belgium. Figure 2.4 is a picture of this study that shows the level of congestion the DSO expects in each municipality of the region by 2030 if they would not expand the network [38]. Fluvius also qualitatively discuss alternative solutions to manage congestion, such as dynamic network operation, distribution network tariffs, mandatory flexibility services, and market-based flexibility procurement. Although an extensive trade-off mechanism between flexibility and network investment has yet to be included, Fluvius describes the first building blocks of how this mechanism will look like. To further develop their strategy, they will focus on flexibility products for congestion management in their high voltage network with a minimum investment cost of 100 k€ (50 potential projects per year).

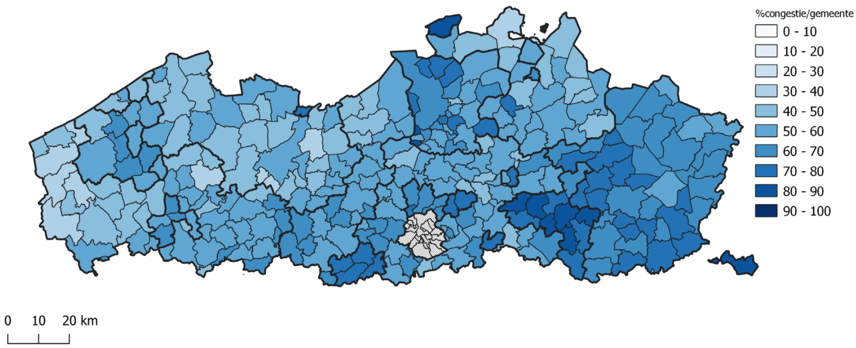


Figure 2.4: Expected share of congestion per municipality by 2035 if the network is no longer expanded [38].

2.5 Conclusions

While congestion in distribution grids is not yet a concern in some European countries, others already face unexpected, extensive congestion issues due to the rapid adoption of distributed energy resources. The latter indicates that evolutions in distribution network planning, such that grid investments can be managed before congestion arises, will become essential in the transition towards a more sustainable energy system.

To support the development of these distribution network plans, the Clean Energy Package introduced provisions across five planning dimensions: planning frequency, coordination with the TSO, digitalization, transparency, and flexibility as an alternative to grid investments. However, the description of these provisions remains relatively high-level, leaving the detailed implementation up to the Member States.

We evaluate the current practices, alignment, and open issues on the implementation of the CEP's provisions by conducting interviews and a workshop with 11 DSOs from different European countries, leading to the following three conclusions. First, the current practices show that there is no single approach to distribution network planning, as for each of the analyzed dimensions multiple answers were given and often different responses were combined within the network planning of a single DSO. Second, DSOs are already well aligned on a future target model covering the dimensions of planning frequency, coordination with the TSO, digitalization, and flexibility as an alternative to grid investments. However, the level of transparency on distribution network plans is still a debatable topic. Finally, including the trade-off between flexibility and network investments remains an open issue. Most DSOs are examining this trade-off in pilot projects but are still looking for the best approach to consider flexibility in network planning.

Although recent examples of distribution network plans illustrate that DSOs are implementing the CEP's provision and evolving the planning of grid investments, there is not yet a consensus on the optimal approach to include flexibility in distribution network planning and operation. Therefore, in the next chapter, we will further explore the different regulatory tools and implementation options that DSOs can use to source flexibility at distribution level.

Chapter 3

Exploring regulatory tools to source flexibility at distribution level

In the previous chapter, we examined the evolving landscape of distribution network planning, including the development of flexibility to enhance the operation and planning of distribution grids.

This chapter further explores the regulatory tools that DSOs can use to unlock flexibility at distribution level. Section 3.1 gives an overview of the flexibility toolbox. In Section 3.2, we examine the practical implementation of flexibility tools across Europe, with a special focus on dynamic network tariffs and flexible connection agreements. Section 3.3 describes some first insights into the risks and opportunities of combining different flexibility tools, and Section 3.4 develops the conclusions.

The contents of this chapter are derived from:

- Beckstedde, E., and Meeus, L., 2023. From “Fit and Forget” to “Flex or Regret” in Distribution Grids: Dealing with Congestion in European Distribution Grids. IEEE Power and Energy Magazine, vol. 21, no. 4, pp. 45-52. doi: 10.1109/MPE.2023.3269545. © 2023 IEEE.
- Meeus, L., Beckstedde, E., Nouicer, A., 2022. Towards a Regulatory Framework for the Use of Flexibility in Distribution Grids. Oxford Energy Forum, Issue 134.

- Beckstedde, E., Meeus, L., et al., 2022. EUniversal Deliverable 10.3: Regulatory recommendations for flexibility options and markets.
- Beckstedde, E., Meeus, L., Ramos, A., et al., 2022. EUniversal Deliverable 5.4: Evaluation of market mechanisms: challenges and opportunities.
- Beckstedde, E., Meeus, L., et al., 2020. EUniversal Deliverable 1.1: Characterisation of current network regulation and market rules that will shape future markets.

3.1 Overview of the flexibility toolbox

DSOs can use six regulatory tools to source flexibility at the distribution level: dynamic network tariffs, flexible connection agreements, flexibility markets, bilateral contracts, cost-based mechanisms, and obligations. Based on [39, 40], we provide the following high-level definitions for each flexibility mechanism.

- Dynamic network tariffs are temporal and locational differentiated network tariffs that can be adjusted to reflect the distribution network's temporal and spatial cost variations.
- Flexible connection agreements are non-firm grid connections, which implies that the system operator can curtail the demand or supply of the grid user for specific energy volumes, connection capacities and peak periods.
- Flexibility markets are long-term and short-term pools in which the network needs of the DSO are matched with the offers of flexibility providers in a market-based way.
- Bilateral contracts are binding, negotiated agreements between two parties, the system operator and the flexibility provider.
- Cost-based mechanisms are used to remunerate the flexibility providers based on the actual costs of providing the flexibility service determined via an acknowledged audit process.
- Obligations are mandatory service provisions from flexibility service providers to the DSO, often without financial compensation.

While the Clean Energy Package emphasizes that flexibility must be procured in a market-based way (i.e., flexibility markets), it leaves the door open for other flexibility tools if they are justified by a cost-benefit analysis [6]. Currently, there is not yet a consensus on the outcome of this cost-benefit analysis and the optimal approach to source flexibility at the distribution level. Nevertheless, some Member States have already started with the practical implementation of regulatory tools to source flexibility, which we will discuss next.

3.2 Practical implementation of flexibility tools across Europe

The regulatory implementation of flexibility tools is challenging and involves several design choices. To gain insight into the design options and complexity involved, we examined the regulatory implementation of the two flexibility tools that are currently most mature in Europe: dynamic distribution network tariffs and flexible connection agreements. A thorough analysis of the ongoing implementation of flexibility markets is given in Chapter 5. Besides that, an analysis of bilateral contracts, cost-based remuneration and obligations can be found in [39].

It must be noted that the regulatory analysis of this section is based on data up until July 2020. Although the general findings on the design choices of dynamic distribution network tariffs and flexible connection agreements are still relevant, some regulatory details of the examined countries might have evolved in the meantime. A recent overview of national implementations on distribution network tariffs and flexible connection agreements can be found in [41] and [42], respectively.

3.2.1 Dynamic distribution network tariffs

Traditionally, European DSOs used distribution network tariffs solely to recover investments and network operation costs from grid users in a regulated way. Over the past years, a second purpose was added to these tariffs: sending implicit price signals to encourage efficient network usage of grid customers. In [43], we examined how distribution network tariffs across Europe meet these two objectives. Our analysis focused on the regulatory frameworks and planned reforms in the following countries and regions: Brussels, Flanders, France, Germany, Norway, Poland, Portugal, Spain, the UK, and Wallonia. An overview of the implementation details of the examined countries can be found in [43] and Appendix A.1. In the context of this chapter, we categorize our findings on dynamic distribution network tariffs into three parts: cost components, granularity, and customer types.

First, three cost components can be distinguished in the implementation of dynamic network tariffs: a fixed charge (€/connection), a volumetric element (€/kWh) and a capacity component (€/kVA). On the one hand, fixed tariff components aim to distribute the costs of past investments that still need to be recovered between grid users. On the other hand, volumetric and capacity components serve to reflect running costs and provide signals to customers for efficient network usage. We observe that the examined countries adopt different combinations of these three cost components in their tariff structures.

Second, DSOs can refine their incentives for efficient grid usage in distribution network tariffs by including temporal granularity in the volumetric and capacity cost components of these tariffs. In the examined countries, time differentiation is applied more frequently in the volumetric component than in the capacity component. Besides that, we observe variations in the number of periods and the occurrence of temporal granularity. The charges of dynamic tariffs can differ for up to four periods during the day, of which the rates and timing can vary regarding the seasons. The occurrence of these tariff periods can be predefined or upon notification. Furthermore, we find that the locational granularity of distribution network tariffs in the examined countries is limited. Although theoretically, network tariffs could be highly granular and based on the nodal representation of the distribution grid, in practice, these charges are currently applied at a regional or national level.

Finally, we observe that distribution network tariffs apply to all grid users by default. However, there are distinctions in the cost components and granularity of grid tariffs among various customer categories. These categories are defined based on the type, magnitude, metering device, and voltage level of the grid user.

In summary, our analysis indicates that distribution network tariffs are evolving to include different incentives for efficient network usage by grid customers through the development of cost components, granularity, and customer types. Nevertheless, there is considerable variation in the implementation of these tariffs across the examined countries, indicating that European grid users currently receive diverging signals from distribution network tariffs. In the future, efforts towards harmonization of dynamic distribution grid tariffs might arise when advancements in the debate on the optimal approach to source flexibility at distribution level are achieved.

3.2.2 Flexible connection agreements

Traditionally, grid users' connection to the distribution network was considered firm, ensuring a reliable and guaranteed availability of network capacity. In recent years, the concept of non-firm network connections gained interest with the rise of grid congestion and discussions on the optimal allocation of the available network capacity among grid users. In [43], we examined the extent to which firm connection agreements are still guaranteed in the following European countries and regions: Flanders, France, Germany, Norway, Spain, the UK and Wallonia. An overview of the implementation details of the examined countries can be found in [43] and Appendix A.2. Within the scope of this chapter, we categorize our findings on flexible connection agreements into four parts: use case, allocation of grid capacity, customer type and compensation schemes.

First, flexible connection agreements can be designed to serve two use cases in distribution grids. On the one hand, these connection agreements aim to respond to critical network situations, ensuring security of supply. On the other hand, connection agreements can be employed to engage flexibility in the operation and planning of distribution networks. We find that the implementation of flexible connection agreements is tailored for each of these use cases and that both applications can be combined within the same country.

Second, the allocation of grid capacity for flexible connection agreements can follow two approaches: a capacity-based or volume-based distribution. In capacity-based agreements, the grid user's connection is typically divided into a firm and a flexible part. While the grid capacity of the firm part is ensured, the grid user can experience curtailment by the DSO on the flexible part. The level of firm capacity of the grid user's connection can be evenly distributed among all grid users, determined using a first-come, first-served principle, or allocated using market-based principles. In volume-based connection agreements, the grid user's flexibility is typically defined as a maximum amount of curtailed energy per year. We observe that capacity-based agreements are more common in the context of critical network situations, while both capacity- and energy-based approaches are being implemented to incorporate flexibility in the operation and planning of distribution networks.

Third, the type of customers entering flexible connection agreements can be implemented into national regulations. Connection agreements can be targeted toward specific technologies, such as renewables and electric vehicles, or toward certain load profiles. Additionally, flexible connection agreements can be either mandatory or voluntary for grid users and can be differentiated between existing and new grid connections. We find that in the context of flexibility, the type of customers entering connection agreements is more tailored towards its application than in agreements related to critical grid situations.

Finally, different compensation schemes exist to reward grid users that provide flexibility through connection agreements. Financial compensations can include reimbursements for curtailed energy, connection discounts, or tariff discounts. However, in some cases, grid users may not receive financial compensation or be rewarded with a faster network connection in grid areas with long connection queues. Overall, we find that the compensations for flexible connection agreements vary across the examined countries, mainly depending on the use case of the agreement and whether the participation of grid users is voluntary or mandatory.

In conclusion, our analysis shows that flexible connection agreements are being developed as a regulatory tool to integrate flexibility in the operation and planning of distribution networks. We observe considerable variation in the implementation of these connection agreements regarding the use cases, allocation of grid capacity, customer type and compensation schemes. In the coming years, we might learn more about the effectiveness of these different design choices and evolve towards a more standardized implementation of flexible connection agreements across Europe.

3.3 Combination of flexibility tools

When implementing flexibility tools in practice, Member States face the challenge of dealing not only with different design choices but also with the effects that might result from combining these flexibility tools. In this regard, we provide some first insights into the risks and opportunities that might arise when implementing and combining different regulatory tools to source flexibility.

As illustrated in the previous section, many European DSOs have adopted dynamic distribution network tariffs to implicitly incentivize network users to align their electricity consumption or production with the needs of the distribution network. While this shift towards cost-reflective distribution network tariff will incentivize grid users to reduce their peaks, we find that there is also a potential for DSOs to contract flexibility of network users for two reasons. First, dynamic network tariffs will always depend on the grid users' voluntary response and be imperfect as they compromise between cost-reflectiveness and other principles, such as fairness and simplicity [44, 45]. Second, as illustrated in Chapter 2.1, investment planning under uncertainty can result in unexpected network congestion. In such cases, DSOs cannot stop all requests to connect to new grid users and will be subjected to significant pressure to overbook the network and manage the congestion resulting from this overbooking.

Our research in [46] showed that DSOs can contract flexibility in the short-term and long-term and in a mandatory or voluntary way. Table 3.1 maps the different flexibility tools on these two parameters. Mandatory flexibility tools are characterized by long-term initiatives, such as obligations and default non-firm connection agreements. Voluntary flexibility tools can be sourced both short-term and long-term. In flexibility markets, system operators can source flexibility in the short-term or long-term depending on the market design and flexibility service providers can typically voluntarily enter. Other long-term voluntary flexibility tools are bilateral contracts, cost-based contracts, and flexible connection agreements.

Table 3.1: Mapping of different flexibility tools on two parameters: mandatory vs. voluntary offering of the service and short-term vs. long-term sourcing of the flexibility.

	Mandatory	Voluntary
Short-term	-	• Flexibility markets
Long-term	• Obligations • Default non-firm connection agreements	• Flexibility markets • Bilateral contracts • Cost-based contracts • Choosing between firm and non-firm connection agreement

At this moment, we are still discovering the risks and opportunities of the different flexibility tools. As discussed in [46], mandatory and long-term flexibility brings more certainty to system operators on the availability, volume and price of flexibility, which can be an advantage in distribution network planning. However, for grid users, mandatory implies that their consumption or generation peaks can get curtailed even if they might not want to be cut short. As a result, regulators typically limit the use of mandatory flexibility or administratively set a compensation price for curtailment, which is a challenging task [37].

Another controversy is the potential of combining different flexibility tools. While incompatibilities between the different mechanisms might exist, there are also arguments for combining them. In [8], we argue that short-term flexibility markets might complement long-term flexibility contracts (voluntary or mandatory) in three ways. First, DSOs can get certainty on the availability of flexibility using long-term contracts and operate short-term flexibility markets to check if cheaper resources are available. Second, grid users can treat short-term flexibility markets as secondary markets to trade flexibility obligations. Finally, regulators can use the price discovery in short-term flexibility markets to adapt the compensation for flexibility under long-term schemes.

To summarize, we find that besides giving implicit flexibility signals to grid users through dynamic network tariffs, there is a potential for DSOs to explicitly contract flexibility using flexible connection agreements, flexibility markets, bilateral contracts, cost-based contracts, or obligations. These explicit tools can be designed to contract flexibility in the short-term and long-term and in either a mandatory or voluntary way. However, a comprehensive examination of the benefits and disadvantages of each flexibility mechanism, as well as the compatibility between different tools, is currently missing and an important subject for future research.

3.4 Conclusions

Different regulatory tools to source flexibility at distribution level exist, such as dynamic network tariffs, flexible connection agreements, flexibility markets, cost-based mechanisms, bilateral contracts and obligations. However, there is not yet a consensus on the optimal approach to unlock the full potential of flexibility at the distribution level. To gain insights into the opportunities and complexities involved with the implementation and combination of flexibility tools, we examine the practical implementation of dynamic distribution tariffs and flexible connection agreements across Europe.

Our analysis of the regulatory implementation of dynamic distribution network tariffs in ten European countries and regions indicates that these tariffs are evolving to include incentives for efficient network usage by grid customers. This evolution is achieved by developing different cost components, granularity, and customer types of grid tariffs. Moreover, we find considerable variations in the implementation of dynamic network tariffs across the examined countries.

In our investigation of flexible connection agreements across seven European countries and regions, we observe the growing use of connection agreements as a regulatory tool to integrate flexibility into the operation and planning of distribution networks. Besides that, we found significant variations in the implementation of these connection agreements in the examined countries regarding the use cases, allocation of grid capacity, customer types, and compensation schemes.

The development and adoption of both flexibility tools raise questions about their compatibility and the impact of their respective design choices. We find that besides giving implicit flexibility signals to grid users through dynamic network tariffs, there is a potential for DSOs to explicitly contract flexibility using flexible connection agreements or other regulatory tools, such as flexibility markets, bilateral contracts, cost-based mechanisms, or obligations. These explicit tools can be designed to contract flexibility for both short-term and long-term periods and can be implemented in either a mandatory or voluntary way. However, a comprehensive examination of the effectiveness of the various design choices of each flexibility mechanism, as well as the risk and opportunities associated with combining different flexibility tools, is currently lacking and represents an important subject for future research.

In this context, regulatory sandboxes can be an important instrument to better understand the impact of (combining) flexibility tools in practice, leading to more informed decision-making by regulators and policymakers. In the next chapter, we explore the potential of regulatory sandboxes to examine innovations, such as flexibility, in a real environment.

Chapter 4

Regulatory sandboxes: a relevant instrument to explore flexibility tools in practice?

The previous chapter provides some first insights into the opportunities and complexities involved with the practical implementation of flexibility tools across Europe.

This chapter examines the potential of regulatory sandboxes as an instrument to experiment with innovations such as flexibility tools in a real environment. Section 4.1 introduces regulatory sandboxes in the European power and gas sector and specifies the contributions of this chapter. Section 4.2 presents the legal frameworks for regulatory sandboxes in the eight examined countries. In Section 4.3, the potential of regulatory sandboxes is evaluated based on the outcomes of approved sandbox projects. Section 4.4 discusses how the implementation and design of the regulatory framework for sandboxes might influence its outcome. Finally, Section 4.5 summarizes the results and gives policy implications.

This chapter is based on the following papers:

- Beckstedde, E., Correa Ramírez, M., Cossent, R., Vanschoenwinkel, J., Meeus, L., 2023. Regulatory sandboxes: Do they speed up innovation in energy?, Energy Policy. doi: 10.1016/j.enpol.2023.113656.

- Beckstedde, E., Meeus, L., et al., 2022. EUniversal Deliverable 10.3: Regulatory recommendations for flexibility options and markets.

4.1 Introduction

In order to reach the ambitious targets of the European Fit for 55 package and REPowerEU Plan, innovations in how we generate, transport, trade and consume electricity will be needed [47, 48]. As most of these activities are regulated in the energy sector, policy and regulation must evolve with the changes in our energy system and create a level playing field for new technologies and business models. The European regulatory entities recognize regulatory sandboxes as an important tool for developing dynamic regulation [19, 20]. These regulatory sandboxes are one way of organizing regulatory experimentation, in which energy actors may propose innovative projects that currently face regulatory barriers. After approval of the sandbox project, regulatory derogations are granted such that these new technologies or business models can be tested in a real environment. In this way, regulatory sandboxes aim to foster innovation[4] and inspire new regulations to support the energy transition.

Regulatory sandboxes have already been adopted all over the world in various regulated sectors such as energy, finance and telecommunications. Although we focus our analysis on regulatory sandboxes in the European power and gas sector, this does not exclude other countries and sectors from inspiring innovation and regulatory learning on this matter. As shown in the timeline of Figure 4.1, we distinguish two implementation waves of regulatory sandboxes in the area of power and gas in Europe. The first wave in 2015 consisted of early movers, such as the Netherlands, Great Britain and Germany. The second wave in 2019 came with the development of regulatory sandboxes in Belgium, Norway, France, Austria and Spain, which is related to the implementation of the Clean Energy Package [49]. In the coming years, we might see more countries picking up regulatory sandboxes with Article 15(2a) of the amendment of the Renewable Energy Directive (EU) 2018/2001 that is proposed as part of the REPowerEU Plan and promotes the use of regulatory experimentation [50]. However, the continuous evolution of technologies and regulation might also be the end of some sandbox frameworks, such as the example of the Netherlands. With the consultation of the New Energy Law in December 2020, the Dutch Ministry decided to close the sandbox regulation on energy sharing to create a level playing field under the new Energy Law that will come with the implementation of energy communities [21]. Currently, no other topics are considered relevant to open a new framework of regulatory experiments. The fact that one of the

[4] What we mean by innovation?

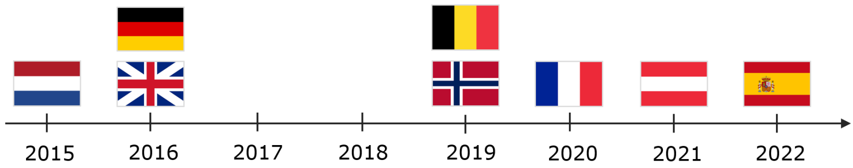


Figure 4.1: Implementation timeline of the examined frameworks on regulatory sandboxes.

pioneering countries has decided to end its sandbox framework raises questions about the effectiveness of regulatory sandboxes in speeding up innovation in the energy sector.

The current academic literature on regulatory sandboxes in the European energy sector lacks conclusions to answer these questions and remains more descriptive on the possible topics and legal implementation frameworks of sandboxes. The work of [51] describes the regulatory experimentation in Italy on smart grids, smart metering and electromobility that was initiated in 2010. As the case of Italy can be seen as a regulatory pilot organized by the Italian regulator ARERA rather than an open framework for regulatory sandboxes, it is outside the scope of this research. Other country-specific cases are analyzed in [52], [53] and [54]. Considering different points of decision-making, [52] examine the dynamics between stakeholders of regulatory sandboxes in the Netherlands. In [53], feasible topics for regulatory sandboxes in Austria are identified based on the analysis of R&D projects and interviews with experts, and [54] evaluate the SINTEG program in Germany based on interviews with experts and participants of the program. Other papers analyze and compare regulatory sandboxes in a collection of countries. The work of [55] discusses the examples of Great Britain, Germany and the Netherlands. The ISGAN casebook describes the different sandbox approaches of Australia, Austria, Germany, Italy, the Netherlands, the United Kingdom and the United States [56]. Based on this analysis, ISGAN brings four policy messages on regulatory experimentation [57]. Also [58] identifies practical limitations of regulatory sandboxes based on the experiences in Great Britain and the Netherlands and is the first to discuss the closure of the sandbox framework in the Netherlands. A comparison of the regulatory frameworks in the Netherlands, Great Britain and Italy was made by [59] using a six-dimension framework. An alternative framework to analyze regulatory experimentation based on the diverging approaches in Great Britain and Italy was proposed in [60] and used to divide worldwide experiences into three experimentation archetypes. Besides that, the report by [61] gives an overview of the main developments on regulatory experimentation in the EU

Member States. Finally, several authors, such as [59] and [62], discuss the need and potential of expanding regulatory sandboxes to European legislation.

This research aims to complement the existing literature on regulatory sandboxes in the European energy sector by examining the outcomes of approved sandbox projects and identifying areas of innovation and regulatory learning brought by these projects. An additional contribution is that we investigate the interaction between the design of the legal framework for regulatory sandboxes and its potential to bring innovation. Finally, we discuss the recent developments on regulatory sandboxes in Belgium, France, Norway and Spain, besides the European countries traditionally covered in academic literature, such as Austria, Germany, Great Britain and the Netherlands.

4.2 Overview of the examined regulatory sandboxes

A literature review using academic work and stakeholder reports was performed for the following eight European countries: Austria (AT), France (FR), Germany (DE), Great Britain (GB), the Netherlands (NL), Norway (NO), Spain (ES) and Belgium, in which the regions of Brussels (BR), Flanders (FL) and Wallonia (WA) were treated separately. In what follows, we introduce the sandbox frameworks of the examined countries using the chronological order of Figure 4.1 and two guiding questions: "Is the legal framework currently in place?" and "Have sandbox projects already been granted under the framework?". Table 4.1 summarizes our findings based on evidence collected until August 2022.

Table 4.1: Introduction of the examined legal frameworks on regulatory sandboxes.

Dimension	Yes	No
Legal framework in place?	AT, BR, DE ('17-'22), ES, FL, FR, GB, NL ('15-'18), NO, WA	DE (>'22), NL (>'20)
Sandbox projects approved?	BR, FL, FR, GB, NL, NO, WA	AT, ES, DE

In 2015, a legal framework for regulatory sandboxes called 'Experimenten Elektriciteitswet en Gaswet' was introduced in the Netherlands [63]. The program focused on projects where participants share electricity and/or operate the distribution network [64]. The government agency RVO approved 14 sandboxes between 2015 and 2018 [65]. However, the Ministry decided to close the regulation in 2020 to create a level playing field under the new Energy Law that came with implementing a legal framework for energy communities

[66]. There is no ongoing consultation to open regulatory sandboxes to other topics and regulations.

Since 2016, innovation in the energy sector has been promoted in Germany and Great Britain. In Germany, the SINTEG funding program was developed to support real experiments on the energy transition [67]. While regulatory experimentation was outside the initial scope of this funding program, the SINTEG-V ordinance of 2017 allowed participants to request regulatory derogations to ensure the experiments could be tested in real environments [68]. With the evaluation of the SINTEG program, it became clear that no projects set up sandboxes under this amendment [69]. In the meantime, the SINTEG-V ordinance expired, but funding programs to promote real experiments are still organized under the concept of Reallabore der Energiewende [70]. However, a general framework for regulatory derogations in the energy sector is currently not in place [71]. In Great Britain, the regulator Ofgem launched its Innovation Link at the end of 2016 and granted its first sandbox projects during the two application windows of 2017 [72, 73]. Since then, Ofgem has worked with over 350 innovators, of which several projects have received regulatory exemptions [74, 75].

In 2019, a legal framework for regulatory sandboxes came into force in Belgium and Norway. In the case of Belgium, the regulation was adopted at the regional level for Brussels, Flanders and Wallonia separately. Over the past years, projects considering energy communities have been approved in each region [76, 77, 78]. The Norwegian regulator NVE-RME developed a framework for regulatory sandboxes after observing an increasing number of project proposals from different market participants in their remuneration program for innovative network investments [79]. Until October 2021, nine projects have been granted derogations, covering alternative tariff models, energy sharing, and flexibility services to DSOs and the TSO [80].

In 2020, a legal framework for regulatory sandboxes was introduced in France. Two project calls have been organized since the implementation of the legislation, which led to the approval of 27 projects by the French Regulator CRE and the Ministry for Energy and Climate DGEC [81, 82].

As of 2021, a legal framework for regulatory sandboxes has been adopted in the Renewable Energy Package of Austria. This framework was implemented after the need for regulatory derogations was identified under the first call of the Energie.Frei.Raum funding program [53, 83]. The second tender of the Energie.Frei.Raum aimed to promote innovation projects on network tariffs and market models for distributed energy resources. Approved projects can request regulatory derogations using the legal framework on regulatory sandboxes. Although the call closed in March 2022, details about the projects and the received derogations have not yet been published until August 2022 [84].

In 2022, a framework for regulatory sandboxes was introduced in Spain by the Royal Decree of 568/2022 [85]. Since the implementation of the framework, no sandboxes have been approved until August 2022.

4.3 Evaluation based on the outcomes of approved sandbox projects

In this section, we evaluate whether regulatory sandboxes bring innovation by looking at the use cases and derogations of existing regulatory sandboxes. We first discuss the methodology used to classify the sandboxes projects, then describe each category in more detail.

4.3.1 Methodology: inductive thematic approach

We analyzed 72 sandbox projects[5] approved under the legal frameworks of Brussels, Flanders, France, Great Britain, the Netherlands, Norway, and Wallonia. Austria, Germany, and Spain were not included in our analysis as no sandboxes have been granted until August 2022. The projects were analyzed using the inductive thematic approach described by [87] and widely applied in qualitative studies. A recent example of another study in energy that applies this method is [88]. This method provides a systematic approach to develop new concepts from qualitative data sources using first-order concepts, second-order themes, and aggregated dimensions. Next, we explain how we applied these elements to the list of approved sandbox projects.

The first step generates first-order concepts of the research data and aims to collect information about the sandbox projects without defining them into categories. The first-order concepts adopted in our analysis are one-sentence summaries of the project's aim and granted derogations. The second step produces second-order themes by aggregating the first-order concepts into larger groups of well-defined research concepts. In our analysis, we selected keywords from the one-sentence summaries of the sandbox topics. These keywords described technologies and activities commonly used in literature on energy transition, such as synthetic methane, energy communities, and dynamic network tariffs. The final step refines the generated second-order themes into

[5]We examined 6 projects in Brussels [76], 1 project in Flanders [77], 27 projects in France [82, 86], 11 projects in Great Britain [72, 73, 75], 14 projects in the Netherlands [52, 65, 66], 8 projects in Norway [80] and 5 projects in Wallonia [78].

aggregated dimensions. In our analysis, the sandbox projects were grouped considering similarities in their second-order keywords and granted regulatory derogations.

An overview of the analyzed projects, first-order concepts and second-order themes can be found in Appendix B.1. Table 4.2 gives an overview of the (sub)categories, geographical scope, and number of examined sandbox projects. Next, we summarize the main characteristics of each category and describe the most prominent project examples.

Table 4.2: Summary of the aim, geographical scope, and number of approved regulatory sandboxes.

Category	Country (number of projects)
Local energy	
- Energy sharing, collective self-consumption, and energy communities	BR (6), FL (1), GB (2), NO (1), WA (2)
- Energy sharing, including dynamic network tariffs	WA (3), NL (5), NO (1)
- Energy sharing, including dynamic network tariffs and network operation	NL (9)
- Peer-to-peer trading	GB (5)
- Consumer rights in microgrids	GB (1)
Flex participation in electricity markets	
- Wholesale markets	FR (1)
- Balancing markets	GB (2), FR (1), NO (3)
Distribution network tariffs	
- Alternative grid connection charges	GB (1)
- Dynamic network usage tariffs	FR (1), NO (3)
Connection to electricity networks	
- Technical solutions	FR (2)
- Flexibility solutions	FR (4)
Connection to gas networks	
- Synthetic methane	FR (17)
- Flexibility solutions	FR (1)

4.3.2 Local energy

The category local energy considers all sandbox projects that enable energy sharing between local grid users. As shown by the subcategories of Table 4.2, local energy can be traded in various ways, such as energy communities, collective self-consumption and peer-to-peer platforms. Besides, local energy projects are often combined with experiments on dynamic distribution tariffs and network operation by grid users. In total, 36 projects on local energy were approved in Belgium, the Netherlands, Great Britain, and Norway, covering half of the examined projects. All sandboxes received similar regulatory derogations, such as exemptions from metering and invoicing rules, network tariff rules, supplier rules and DSO governance rules. Regulators can use the outcomes of these sandboxes as input for the national or regional implementation of (renewable) energy communities. As similar innovations and derogations are tested in the analyzed countries, the learning from these sandboxes might also be relevant for European countries that currently do not have a sandbox framework. Finally, three types of sandbox projects were selected to illustrate this category: the granted sandboxes in Brussels, the approved projects in the Netherlands and the Emergent sandbox in Great Britain.

In Brussels, six regulatory sandboxes on energy communities have been accepted until August 2022 [76]. All projects aim to test new concepts on (renewable) energy sharing between nearby network users and examine alternative methodologies for invoicing network tariffs. In two projects, new tools to optimize the self-consumption rate of participants are also examined. To achieve this, regulatory exemptions regarding the responsibilities of suppliers, the methodology of distribution network and smart meter tariffs, the metering rules of DSOs and the prohibition of DSOs from being involved in activities related to electricity production were required.

In the Netherlands, two types of sandboxes were granted between 2015-2018: ‘big experiments’ and ‘network projects’ [52, 65, 66]. The framework allows participants to share energy, balance the electricity grid through peak shaving and test dynamic electricity tariffs. In ‘network projects’ project promoters could also operate the network. Depending on the project’s needs, participants received derogations from the prohibition of performing DSO tasks, the obligation to have a supplier permit, the rules regarding metering device requirements and data processing, the methodology to determine grid tariffs, and the rules regarding transparency and liquidity of the energy market.

In Great Britain, Emergent Energy Systems was awarded a regulatory sandbox to give the residents of their microgrids the possibility to switch electricity suppliers [89]. To achieve this, derogations were required on the metering of premises and the metered data submission into settlement such that the participants' energy suppliers could settle the correct amount of electricity without entering bilateral arrangements with all other suppliers operating on the site.

4.3.3 Flex participation in electricity markets

The category flex participation in electricity markets refers to all sandboxes exploring alternative business models and market designs to foster the participation of flexibility in wholesale and balancing markets. We find that these sandboxes occur in France, Great Britain and Norway. Although there is a clear trend in the type of innovation, we observe that different regulatory derogations to market rules and TSO responsibilities are needed to develop the projects in the analyzed countries. To illustrate this, three projects are described in more detail: the EDF sandbox in France, the Centrica sandbox in Great Britain, and the NorFlex project in Norway.

In France, the utility company EDF was granted a sandbox to explore the business model of a battery storage [81]. The project aims to combine the battery with a production source for primary frequency reserve provision, aggregate the same battery with other assets to provide secondary frequency reserves and switch the use of the battery between the two services. To achieve this, exemptions were required to allow EDF to combine the battery and production sources as one frequency service provider and to aggregate the battery with two separate production sources that provide different ancillary services.

In Great Britain, the Centrica sandbox [90] aims to enable greater participation in balancing markets from customers that are currently not half-hourly settled and may not have access to half-hour settlement soon. To achieve this, Centrica Business Solutions received several derogations from the Balancing and Settlement Code on the classification and registration of metering systems, the allocation of supplier volumes, and the aggregation of half-hourly data.

In Norway, the TSO Statnett SF has two sandbox projects running on the participation of distributed energy resources in balancing markets [80]. In the NorFlex project [91], Statnett SF collaborates with Agder Energi, Glitre Energi and NODES to access distributed energy resources for manual Frequency Restoration Reserve services through a shared flexibility market with the DSO. However, reaching the minimum bid quantity of this service using aggregated distributed energy sources is often challenging. Therefore, an exemption was required to the guidelines and responsibilities for TSOs regarding the minimum bid quantity.

4.3.4 Distribution network tariffs

The category distribution network tariffs covers all sandbox projects exploring alternative grid connection charges and dynamic network usage tariffs to improve distribution network operation and give signals to network users. We find regulatory sandboxes on alternative grid connection charges in Great Britain and dynamic distribution usage tariffs in France and Norway. Although different innovations on network tariffs are tested, the analyzed projects required similar exemptions: the consent to deviate from regulated tariffing methodologies. This derogation indicates a clear understanding of the regulatory changes required to promote innovation in network tariffing. However, it is still an open discussion of how this innovation is best achieved (e.g., through alternative types of connection or usage charges methodologies). Two sandbox projects were selected to illustrate this category: the Charge Collective trial in Great Britain, and the Aktive Hjem sandbox in Norway.

In Great Britain, the Charge Collective trial [92] by London Power Networks (LPN) and Eastern Power Networks (EPN) aims to examine new connection charges for electric vehicle charging points based on price-point discovery mechanisms. LPN and EPN proposed this innovative methodology to react to the recent measures taken to attract investors of public electric vehicle charging points. Due to these measures, DSOs were fully responsible for the connection costs of these new charging points instead of sharing the costs with the charge point investors. For the implementation of the sandbox, LPN and EPN received derogations on the connection charging methodology of the Electricity Distribution License.

In Norway, the Aktive Hjem sandbox [93] by the DSO Elvia aims to examine dynamic distribution network tariffs. In this way, customers get the opportunity to influence their grid rent and contribute to an optimal utilization of the electricity grid. The tariff structure consists of a fixed component in combination with an energy component that varies between the season and time. To implement this, Elvia received derogations to charge time-differentiated components in the distribution tariffs and differentiate tariffs between network users.

4.3.5 Connection to electricity networks

The category connection to electricity networks covers all projects experimenting with technical and flexible solutions to connect new users to the distribution network or extend the capacity of existing distribution network users. All projects in this category were granted in France and required similar derogations for each subcategory. Projects using technical solutions required derogations to the technical connection documentation of distribution grids, and projects with flexibility solutions were granted derogations on the design and operating requirements of distribution network connections. To illustrate this category, two projects are described in more detail: the Amarenco project and the Boralex sandbox.

In France, the Amarenco project [82] aims to optimize the connection of battery storage. In the connection studies of Enedis, it is assumed that this battery must be able to inject a power equal to its connection power at all times. As this assumption does not capture the countercyclical nature of storage, Amarenco requests Enedis to conduct connection studies based on hypotheses of Amarenco's operating curves. To achieve this, the French regulator CRE granted Enedis to derogate from its technical connection documentation.

In France, the Boralex sandbox [86] seeks to increase the output of two wind farms above the maximum allowed connection capacity to the distribution network using curtailment measures to ensure the injected capacity remains within the required connection limits. To achieve this, derogations from the technical design and operating requirements for connecting to the distribution grids of Enedis were required.

4.3.6 Connection to gas networks

The last category covers innovative projects connecting new production plants to the gas network. We found that regulatory sandboxes in the gas sector are currently dominated by projects considering synthetic gas injection and production in France. Policymakers might learn from sandboxes to reduce the current regulatory barriers to these projects. However, the overall impact of regulatory sandboxes on innovation in the gas sector might be limited as the approved projects are currently restricted in geographical and technical scope. Next, we describe the projects on synthetic gas in France in more detail. Besides that, we explain the SEM Energie Mayenne project, which considers the flexible connection of a biomethane plant in France and therefore illustrates an alternative way for regulatory sandboxes to bring innovation to the gas sector.

In France, 17 projects on synthetic gas production and injection have been approved under the first two calls for regulatory sandboxes [81, 82]. The reason for this is the current legal framework on gas injection into the gas network that only considers the recent developments in biomethane and does not explicitly include other gases such as synthetic methane gas. Therefore, all projects on other gases require derogations to the Energy Code to allow the connection of the project developer, the analysis of the quality of the gas produced and the injection of the gas by the project developer, provided that the feasibility of injecting synthesis gas containing hydrogen residues is proven.

In France, the SEM Energie Mayenne project [82] aims to provide flexibility services with a compressed natural gas station to the public gas network such that the injection of biomethane can be developed without causing additional network investments. To achieve this, derogations from the network operator's obligation to fully reinforce the network to connect this biogas plant are needed. Besides that, the sandbox is required as currently, no legal, technical, contractual or financial frameworks exist for implementing flexibility solutions in the gas sector.

4.4 Evaluation based on the legal implementation of sandboxes frameworks

In this section, we evaluate the interaction between the implementation frameworks for regulatory sandboxes and their potential to bring innovation. We first discuss the methodology used to examine the legal frameworks, then describe to findings for each dimension in more detail.

4.4.1 Methodology: 7-dimensions framework

We examine the implementation frameworks on regulatory sandboxes in Austria, Brussels, Flanders, France, Germany, Great Britain, the Netherlands, Norway, Spain, and Wallonia. It must be noted that we discuss the legal framework of the Netherlands that was in place before its abolishment, and the SINTEG-V ordinance of Germany that allowed projects of the SINTEG funding program to request regulatory derogations. We use the framework of [59] to evaluate the implementation choices in each country. This framework considers the following six dimensions: eligible project promoters, administration, derogations, length of derogations, public funding and transparency. Based on the results of our regulatory analysis, we included one additional dimension considering the application process of the sandbox.

Table 4.3 summarizes the implementation choices of the analyzed countries for each dimension of the regulatory framework. Next, we describe the findings for each dimension in more detail.

Table 4.3: Summary of the dimensions and national design choices for sandbox frameworks. Countries are not included when the dimension is not specified in the framework.

Dimension	Yes	No
Can everyone apply?	BR, DE, FL, FR, GB, NO, WA	AT, ES, NL
Regulator administers (with Ministry)?	BR, GB, NO, WA (AT, DE, ES, FR, NL)	FL
Possible derogations specified?	AT, FL, FR, NL	BR, DE, ES, GB, NO, WA
Dedicated call?	AT, DE, ES, FR, NL, GB (<2020)	BR, FL, NO, WA, GB (>2020)
Length of derogations longer than 5 years, including extensions?	FL, FR, NL	AT, BR, GB, NO, WA
Related to funding program?	AT, DE	ES, FL, FR, GB, NL, NO
Public report at the end of the project?	BR, ES, FL, FR, GB, NL, NO, WA	-

4.4.2 Eligible project promoters

Eligible project promoters are all parties that might propose and organize a regulatory sandbox. Typically, project promoters can be (1) open to all parties or (2) restricted to a certain definition.

First, no definition of eligible project promoters is given in the case of Brussels [94], Flanders [95], France [96], Germany [68], Great Britain [74], Norway [79] and Wallonia [97].

Second, the definition of eligible project promoters is restricted in the case of Austria, the Netherlands and Spain. In Austria, project promoters can be companies of any legal form, research institutions, and other non-commercial institutions [98]. In the Netherlands, several detailed restrictions to project promoters are defined, and overall, the scope of project promoters is limited to homeowner's associations and energy communities [99]. Finally, eligible project promoters in Spain are limited to the lists of the Spanish Electricity Law 24/2013 [100] and the European Directive 2019/944 [85]. This restriction implies, for example, that research institutions may not apply for a regulatory sandbox as they are not considered agents of the electricity system.

We find that in most cases, no restrictions on the eligibility of project promoters are defined, and sandboxes are open to all parties. Even when a definition is given, this is often kept very broad such that eligibility is generally not an issue. Only in the case of the Netherlands eligible project promoters were adapted to the objective of the regulatory sandbox, initially excluding some stakeholders that wanted to participate, such as DSOs [99].

4.4.3 Administration

The dimension administration describes who takes care of the application procedure, approval, monitoring and evaluation of the regulatory sandboxes. The responsibility of the administration of the regulatory sandboxes falls typically under (1) the regulator, (2) the Ministry, or (3) both.

First, the role of the administrator of the regulatory sandbox program is taken up entirely by the regulator in the case of Brussels [101], Great Britain [102], Norway [79] and Wallonia [78]. It is interesting to note that the British regulator Ofgem cooperates with industry to grant derogations from the Balancing and Settlement Code and the Distribution Connection and Use of System Agreement [74].

Second, the Ministry administrates regulatory sandboxes in Flanders. More specifically, the Flemish Energy and Climate Agency VEKA is responsible for the regulatory sandbox program, and the Flemish regulator VREG is only consulted in specific cases [95].

Third, administration tasks are divided between the regulator and the Ministry in Austria, France, Germany, the Netherlands and Spain. In Austria, the following roles are foreseen: the Federal Ministry BMK is the program owner and responsible for providing funding, the funding agency FFG is the program and funding manager and performs the selection of the projects, and the regulator E-Control is involved in the approval of the projects within the sandbox framework [83]. In France, the regulator CRE is in charge of the sandbox program, but the approval of the sandboxes and the division of the project monitoring tasks are divided by the regulator and the Ministry DGEC on a case-by-case basis [81, 82]. In Germany, the German Ministry BMWi is the main administrator of the SINTEG program, and the German Regulator Bundesnetzagentur helps to evaluate the projects on regulatory exemptions [68]. In the Netherlands, the government agency organizes the sandbox program, and the regulator ACM takes up the advisory and monitoring role [52, 59]. In Spain, the Ministry for the

Ecological Transition and the Demographic Challenge MITECO is responsible for organizing the call for regulatory sandboxes. Later, the Secretary of State for Energy and the Spanish regulator CNMC will evaluate the requests depending on the nature of the regulatory exemptions requested [85].

Our analysis indicates that the administration of regulatory sandboxes is typically adopted by the regulator or the regulator together with the Ministry. Depending on who takes up the administrator role, the sandbox framework might bring different opportunities for innovation and regulatory learning. If the Ministry is not involved, this can limit the scope of the sandboxes. An example is the case of France, where the Ministry was required to approve sandboxes on flexible network connections and synthetic methane injections [81, 82]. If the regulator is not involved in the sandbox administration, the regulatory learning from sandbox projects might be reduced. An example is Flanders, where the regulator is not formally involved but is informally consulted [95].

4.4.4 Derogations

Derogations reflect the regulatory exemptions that can be given to the sandbox projects. Typically, derogations are (1) undefined or (2) targeted to a specific list of regulations.

First, the regulatory derogations that can be granted under regulatory sandboxes are not specified in the sandbox frameworks of Brussels [94], Germany [68], Great Britain [89, 90, 102], Norway [79], Spain [85] and Wallonia [97].

Second, a specific list of regulations is targeted in the case of Austria, Flanders, France and the Netherlands. The second call on regulatory sandboxes in Austria focuses on projects regarding grid tariffs, system integration and market models of renewable energy, storage and energy efficiency technologies [103]. In Flanders, the list of regulations to which exemptions can be granted is defined in the Energy Decree [104]. Also in France, each call for regulatory sandboxes specified a list in the Climate Energy Law to which derogations can be granted [96]. Finally, in the Netherlands, exemptions in regulation regarding innovation in energy communities and homeowner's associations were targeted [65].

We find that most sandbox frameworks do not specify which derogations can be granted to sandbox projects. Although the derogations that fall under the sandbox program are undefined, the allowed regulatory derogations might still be limited as they can be restricted to certain sectors, do not apply to European legislation and are strongly related to the responsibilities of the administrator(s) of the program. Examples are the sandboxes in Norway and Spain, which are open but limited to the power sector [79, 85]. Besides that, it can be challenging for sandbox applicants to identify the regulatory barriers of their project, independent of whether derogations are specified or not. This need for regulatory advice was one of the main lessons learned in the first call for sandboxes in France and Great Britain [105, 106].

4.4.5 Application process

The application process describes when and how project promoters can submit a sandbox project to the administrator. When examining the submission of regulatory sandboxes among the countries, we observe that this is typically organized (1) continuously or (2) within a dedicated call.

First, projects can be continuously submitted in Brussels [101], Flanders [95], Great Britain [74], Norway [79] and Wallonia [78]. In Great Britain, it is only since the refreshed Energy Regulation Sandbox in July 2020 that applications can be submitted at any time [74]. Initially, sandboxes were organized in dedicated application windows, such as the two first windows set up in 2017 [72, 73].

Second, regulatory sandboxes are organized in dedicated calls in the case of Austria, France, Germany, the Netherlands and Spain. Under the Energie.Frau.Raum in Austria, two calls have already been organized: the first call in 2019 aimed to define the scope and potential of sandboxes, and the second call in 2021 intends to grant the first projects [107]. The French regulator CRE has already closed two calls for regulatory sandboxes in 2021 and 2022, each attracting around 40 applications [81, 82]. In Germany, regulatory derogations could be granted to projects of the SINTEG innovation program [68]. During the regulatory experimentation in the Netherlands, yearly calls were organized from 2015 until 2018 [63]. Finally, calls for regulatory sandboxes will be scheduled in Spain [85].

Our analysis shows that continuous applications and dedicated calls occur equally in the analyzed countries. There are two lessons learned from organizing sandboxes in dedicated calls. First, dedicated calls typically introduce a regulatory theme in the sandbox invitation. Although this approach might foster regulatory learning, it requires regular updates of the regulatory framework by the administrator. An example of this is the case of the Netherlands, where the Ministry decided to close the regulation on sandboxes with the consultation of the New Energy Law instead of broadening the sandbox program to other areas [21]. Second, dedicated calls might rush innovators into applications, which was the main reason for ending dedicated calls in Great Britain [74].

4.4.6 Length of derogation

The length of derogation represents the maximum number of years that regulatory exemptions will be given to the granted sandbox projects. This is defined by two parameters: the maximum length of the initial project and the possibility of having an extension. Typically, the total duration of the derogations can be (1) up to five years or (2) longer than five years. Here, it must be noted that Germany is not considered as the answer was unclear from regulation. Spain is not yet included as the maximum duration will only be specified during future calls.

First, derogations can last up to five years in the case of Austria, Brussels, Great Britain, Norway and Wallonia. In Austria, the maximum length of the derogations is three years and no details on further continuations seem to be provided [98]. In Brussels, the typical duration of a sandbox project is two years and an extension of another two years may be requested [94]. Also in Great Britain, the derogations granted under the sandbox can last a maximum of two years [74]. In Norway, the duration of the regulatory sandboxes is one to three years in most cases, with a maximum of five years [79] Finally, the maximum length of a project in Wallonia is five years [97].

Second, regulatory sandboxes can close after more than five years in Flanders, the Netherlands and France. In Flanders, the maximum length of derogations is ten years, with a possible extension of another five years [95]. In the Netherlands, the default duration of the derogations granted under the sandboxes between 2015 and 2018 was ten years, with two exemptions of 15 and 20 years [65]. Besides that, exemptions in France can be provided for four years and extended once more under the same conditions [96].

We find that the initial length of the sandbox projects is typically shorter than five years, but extensions can be given. In exceptional cases like Flanders and the Netherlands, regulatory derogations of ten years are allowed. Still, the maximum allowed project duration might not be granted in practice. An example is the sandbox in Flanders that received five years of derogations while applying for the maximum of ten years [77]. Also in Wallonia, the length of derogations is typically shorter than three years instead of the maximum of five years [97].

4.4.7 Funding

Funding reflects to what extent projects can use public financing to develop the regulatory sandbox. When looking at the funding of the sandbox projects, we found that (1) funding cannot be included in the initial scope of the sandbox process or (2) sandboxes can be related to innovation funding programs. Brussels and Wallonia are outside the scope of this analysis as it was unclear from the regulation whether a funding process is in place or not.

First, funding is not included in the initial scope of the sandbox process in Flanders [77], France [96], Great Britain [74], the Netherlands [65], Norway [80], and Spain [85]. However, in all cases, projects are allowed to facilitate financing through other channels.

Second, sandboxes are related to innovation funding programs in Austria and Germany. In the second call for regulatory sandboxes of the Energie.Frau.Raum in Austria, €4.6 million is made available by the Federal Ministry BMK and managed by the Funding Agency FFG [103]. Besides that, regulatory derogations in Germany could only be requested by projects of the SINTEG funding program [68].

Our analysis shows that, in most analyzed countries, regulatory sandboxes are not related to an innovation funding program. However, projects are typically allowed to use external funding sources. An example is Norway, where network companies can request revenue regulations for sandbox projects [80]. Besides that, funding programs can be used to explore the interest of innovators for regulatory sandboxes. An example is the Energie.Frei.Raum in Austria that resulted in a legal implementation of a sandbox framework [83]. A counterexample is the case of Germany, where regulatory derogations were allowed under the SINTEG funding program, but a general sandbox framework in the energy sector is not yet developed [68, 71].

4.4.8 Transparency and reporting

Transparency and reporting describe how the progress and results of regulatory sandboxes are shared with the administrator and made publicly available. We found that all countries have mechanisms for interim reporting in place, and a public report will be made available at the end of the project. Only in the case of Austria, it was unclear from the regulation what type of reporting mechanism is currently present.

In Brussels, project promoters must report every six months to the regional regulator Brugel and provide a final report with the conclusions and learned lessons, which will be published on the website of Brugel [94]. In Flanders, sandbox projects must annually report to the Minister on the progress and results of the project. Besides that, a final report with conclusions and policy recommendations will be published on the website of the Flemish government

[95]. Also in France, projects must send yearly progress reports and a final evaluation report to the French regulator CRE. The CRE will publish this final report as part of its annual report on the sandbox program [96]. In Germany, a final report is made available on the website of the Ministry at the end of each research project of the SINTEG program [68]. Innovators in Great Britain have to report their progress at the most quarterly or at a frequency that reflects the trial's objectives and arrangements. Besides that, a final report containing the experiences and insights of the project will be published by Ofgem [74]. In the Netherlands, projects must submit a progress report every January. Only for the sandboxes granted in 2018, it is explicitly stated that the final document will be publicly available [66]. In Norway, a final report with the project's results will be made available on the website of the NVE-RME to encourage the dissemination of knowledge from the pilot projects. The regulator might request periodic reporting, but this depends from project to project [79, 91, 93, 108]. A steering committee will continuously evaluate sandbox projects in Wallonia, and a final report will be made available on the CWaPE website at the end of the project [97]. Intermediate reporting is only required for some sandbox projects, especially if the project consists of different phases [109, 110]. Finally, project promoters in Spain will send a final report to the Secretary of State for Energy within three months after the completion of the project. The publication of the results is negotiated in the sandbox agreement, but the main finding will at least be integrated into an annual report on regulatory innovation in the electricity sector by the Secretary of State for Energy [85].

We find that most countries have public reporting obligations in place for finished projects. Although these reporting obligations exist, they might be challenging to complete in practice. For example, [65] states that reporting regulatory sandboxes in the Netherlands was not always complete, and various levels of detail could be observed between the different projects. This made it difficult for the RVO to compare the projects and evaluate the sandbox program [65]. As a result, some innovations possible under the sandbox program were not translated to all energy communities under the new Energy law, as adequate regulatory learnings on these innovations were missing.

4.5 Conclusions

Regulatory sandboxes are seen as an essential tool to foster innovation and regulatory learning during the energy transition. As a result, regulatory sandboxes can be an important instrument to examine the optimal approach to source flexibility at distribution level. While legal frameworks for regulatory sandboxes are increasingly introduced in Europe, the pioneers in the Netherlands are closing their sandbox program. These diverging events indicate the need for a thorough evaluation of the current legal frameworks for regulatory sandboxes. Do regulatory sandboxes really speed up innovation? We contribute to this discussion by evaluating the outcomes of existing sandbox projects and examining the interaction between the design of the legal framework for regulatory sandboxes and its potential to bring innovation. We include Belgium, France, Norway and Spain in our analysis, besides the European countries that are generally discussed in regulatory sandboxes.

We examined 72 existing sandbox projects in Brussels, Flanders, France, Great Britain, the Netherlands, Norway and Wallonia. Using an inductive thematic approach, we divided these projects into five main categories of innovation: local energy, flex participation in electricity markets, distribution network tariffs, connections to electricity networks and connections to gas networks. The presence of several projects focusing on flexibility tools, such as dynamic distribution network tariffs and flexible connection agreements, reinforces the idea that regulatory sandboxes can be an effective instrument to examine innovations, such as flexibility, in a real environment.

We also compared the legislation on regulatory sandboxes in Austria, Brussels, Flanders, France, Germany, Great Britain, the Netherlands, Norway, Spain and Wallonia using a 7-dimensions framework. Table 4.4 summarizes the lessons learned for each dimension of this framework. Overall, we came to the following two conclusions. First, the entity responsible for the administration of the sandbox program and the derogations that can be granted to sandbox projects are the most important parameters when designing a sandbox framework, as they directly impact the potential for regulatory learning and the scope of sandbox projects. Second, our analysis indicates that the application process and the reporting of the lessons learned also influence the performance of the sandbox framework. While a call-based application process allows regulators to highlight regulatory themes, it can rush innovators into applications. Furthermore, even though reporting obligations are typically included in sandbox frameworks, effective implementation in practice is essential for both technical and regulatory learning to occur.

We identified two policy implications. First, the outcomes of existing sandbox projects validate the idea of using regulatory sandboxes to examine innovations under REPowerEU Plan in a real environment and indicate important areas for future regulatory learning. More specifically, the projects on synthetic methane injection in the gas network illustrate that sandboxes can promote the diversification of the gas sector. The projects on flexible connections to the electricity network show that regulatory derogations can accelerate the rollout of renewables. Second, to promote innovation and regulatory learning, it is important to make the regulatory scope of the sandboxes as open as possible while keeping it tangible for project applicants. Best practices found in the analyzed regulatory frameworks are twofold: including multiple regulatory entities in the administration process and having an open approach towards regulatory derogations while providing regulatory advice to sandbox applicants. Besides that, administrators should continuously evaluate and update the sandbox program, especially if they organize dedicated calls.

Table 4.4: Summary of the lessons learned for each dimension of the sandbox framework based on the implementation choices of the examined countries.

Dimension	Lessons learned
Eligible project promoters	- Most countries allow everyone to apply - Countries that limit who can apply typically adopt broad definitions, so eligibility has not really been an issue (except for the Netherlands, where DSOs were initially excluded but wanted to participate)
Administrator	- If the ministry is not involved, it limits the scope of the sandbox (the approved sandboxes in France illustrate this point) - If the regulator is not involved, it limits regulatory learning (in Flanders, the regulator is not formally involved but informally consulted)
Derogations	- Specifying derogations might restrict innovators - Not specifying derogations might still restrict innovators to certain sectors or national competencies of the administrator (in Norway and Spain, sandboxes are limited to the power sector) - In both cases, innovators need regulatory advice to identify regulatory barriers (which was one of the main learnings of the sandbox calls in France and Great Britain)
Application process	- Dedicated calls allow regulators to highlight areas for regulatory learning but require updates to remain relevant (an example is the abolishment of the sandbox framework in the Netherlands) - Not having dedicated calls allows innovators to apply at times of need (which was the main reason for ending dedicated calls in Great Britain)
Length of derogations	- Most countries keep the length of derogations down to 5 years - Some countries allow for longer derogations periods (an example is the Netherlands, where projects of 10-20 years were granted) - In both cases, the maximum length of derogations might not be given in practice (the approved sandboxes in Flanders and Wallonia illustrate this point)
Funding	- Most countries do not have a funding program related to sandboxes but allow external funding sources (in Norway, network companies can request revenue regulations to set up sandboxes) - Funding programs can be used as a call for interest for regulatory sandboxes (in Austria this led to the development of a general sandbox framework, in Germany this is not yet the case)
Transparency and reporting	- Most countries have public reporting obligations for finished projects - Although these obligations exist, they might not be met in practice (in the Netherlands, non-consistent reporting was observed when evaluating the sandbox program)

Chapter 5

Examining open issues in flexibility markets

In the previous chapters, we discussed how the uptake of distributed energy resources is evolving the way we plan and operate distribution grids in Europe, introducing different regulatory tools to source flexibility. We explored the opportunities and complexities involved with the practical implementation of these flexibility tools and examined regulatory sandboxes as an instrument for regulatory learning on innovations, such as flexibility.

In the remainder of this dissertation, we will focus on the implementation of a specific flexibility tool - flexibility markets. Section 5.1 describes the recent developments in flexibility markets across Europe. Furthermore, we use two types of approaches to examine open issues of flexibility markets: a qualitative, multi-stakeholder approach and a quantitative, mathematical programming approach. In Section 5.2, we summarize the methodology and key findings of the multi-stakeholder analysis. Section 5.3 introduces the mathematical programs and the examined open issues of the quantitative analysis, which will be further discussed in Chapters 6 and 7. Finally, Section 5.4 formulates the conclusions of this chapter.

The content of this chapter includes elements from:

- Beckstedde, E., and Meeus, L., 2023. From "Fit and Forget" to "Flex or Regret" in Distribution Grids: Dealing with Congestion in European Distribution Grids. IEEE Power and Energy Magazine, vol. 21, no. 4, pp. 45-52, July-Aug. doi: 10.1109/MPE.2023.3269545. © 2023 IEEE.

- Beckstedde, E., Meeus, L., Ramos, A., et al., 2022. EUniversal D5.4: Evaluation of market mechanisms: challenges and opportunities.

5.1 Illustration of recent developments in flexibility markets

In recent years, many DSOs in Europe have set up demonstration projects to test flexibility services to manage (potential) congestion in their grids. Figure 5.1 illustrates some of the biggest projects financed by the European Union's Horizon 2020 research and innovation program and the countries that have hosted the demonstrations.

Figure 5.1: Projects funded by the European Union's Horizon 2020 research and innovation program focused on developing new flexibility services.

DSOs with a lot of congestion in their networks evolved from demonstration projects to full-scale flexibility markets. Some DSOs, such as Enedis (France), have developed their own platforms to tender flexibility services [111], but market platforms owned and operated by third-party companies also entered this space. In what follows, we will discuss three of these third-party platforms that are currently the most relevant ones in Europe in terms of procured volumes or capacities: NODES, Piclo Flex, and GOPACS.

NODES is an independent market platform founded as a joint venture between the Norwegian utility company Agdar Energy and one of the leading Power Exchanges in Europe, NordPool. Today, all shares of NODES are owned by Agder Energi [112]. NODES is an open-market platform that acts as an intermediary between stakeholders for all market-related tasks. The products are adapted to the local characteristics and needs of the involved market parties. Two types of products can be traded on NODES among different time horizons. ShortFlex products are exchanged close to real time in a continuous market.

LongFlex products are reserved by the grid operator for a certain time and awarded via a tendering process [113]. NODES has already proven its market concept in countries such as Norway, Germany, Sweden, and the UK [114]. Table 5.1 shows the traded ShortFlex volumes and reserved LongFlex capacities over the years in their biggest demonstrator, NorFlex, a shared flexibility market between the Norwegian TSO Statnett and the DSO Adger Energi Nett [115]. The traded volumes illustrate the maturity of the NorFlex project and the potential of flexibility markets as a tool for system operators to procure flexibility during peak load situations. Typical flexibility providers in NorFlex are aggregators offering load shifting from industrial buildings, commercial buildings, and households [114].

Piclo Flex, a privately owned start-up mostly active in the UK, is a market platform designed for DSOs to procure flexibility services and operates separately from existing energy markets [116]. Four types of contracts are typically traded on the Piclo Flex platform and are defined by the Association representing Energy Networks (ENA) in the UK and Ireland: (1) sustain products set pre-defined schedules for flexible resources to manage predictable, low-risk network constraints; (2) secure products require flexibility providers to be available at peak times to react to real-time network conditions; (3) dynamic products support DSOs during specific events such as maintenance, and (4) restore products help system operators to activate flexibility services in real time during unplanned network events [117]. DSOs in the UK use Piclo Flex to tender these products for contracts with different lengths, from one-year contracts up to seven-year contracts. Table 5.1 gives an overview of the procured capacities (MW) over the years for UK Power Networks (UKPN) and SP Energy Networks (SPEN), which currently have organized most competitions on the Piclo Flex platform [118, 119]. The procured capacities on Piclo Flex demonstrate the platform's maturity and indicate UKPN's and SPEN's interest in using flexibility markets in network planning and operation. Contracts were typically awarded to technologies such as electric vehicles, gas engines, batteries, biomass, and commercial demand side response [118, 119]. Besides that, it must be noted that no flexibility tenders were coordinated by SPEN in 2022 due to successfully tendered multi-year contracts in 2021, which reduced the need for congestion management services and the availability of flexible service providers in the 2022 tenders [119].

GOPACS was founded in 2019 by the Dutch transmission and distribution system operators [120]. Rather than being an additional market platform, GOPACS acts as an intermediary between the network operators and existing energy markets, such as the Amsterdam Energy Trading Platform ETPA and the European Power Exchange EPEX SPOT. Bids submitted to these intraday market platforms become available on GOPACS if a locational tag is added. In this way, these bids can be activated by system operators to relieve congestion in their network or by other market parties for other purposes. Flexibility providers that are not acting in existing electricity markets can also bid on the GOPACS platform using a specific client portal. Another typical feature of GOPACS is that system operators must counterbalance their activated flexibility with bids outside the congested zone to maintain the balance in the network [120]. Table 5.1 shows the procured volumes (MWh) by the largest DSO buyer, Liander, which are traded as part of their pilot in Neerijnen. The table also contains the traded volumes of the TSO TenneT on GOPACS to illustrate that the congestion management measures of Liander at distribution level are still relatively small in comparison to the congestion measures by TenneT at transmission level [121]. However, the traded volumes by DSOs are expected to grow with the rollout of a new congestion management product for DSOs that was introduced in the Dutch Electricity Network Code at the end of 2022 [122]. This new product has three changes compared to the current redispatch products traded on GOPACS: there is no minimum amount of market participants, there are no counterbalancing measures required, and there is the possibility to close long-term contracts.

Table 5.1: Examples of the contracted flexibility [MW] and traded flexibility volumes [MWh] on the third-party flexibility market platforms NODES [115], Piclo Flex [118, 119] and GOPACS [121].

	2019	2020	2021	2022
NODES (Norflex) [MWh]	-	-	225.2	734.6
NODES (Norflex) [MW]	-	-	-	3.38
Piclo Flex (UKPN) [MW]	19.3	123.0	350.0	367.6
Piclo Flex (SPEN) [MW]	53.3	139.6	555.0	-
GOPACS (Liander) [MWh]	-	69.2	111.3	7.6
GOPACS (TenneT) [MWh]	36 552.1	53 887.8	142 997.6	181 933.1

All third-party initiatives started in countries that were among the first to experience congestion in distribution grids: Norway (and Germany) for NODES, the UK for Piclo Flex, and the Netherlands for GOPACS. However, a fundamental difference in the motivation for the development of flexibility markets in the UK, Norway, the Netherlands, and Germany exists.

- In the UK and Norway, the DSOs really plan for flexibility. They make the trade-off between distribution grid expansions and procuring flexibility. UKPN, for example, recently committed in their RIIO-ED2 Business Plan 2023-2028 to 410 million pounds of deferred load-related investments through the use of low-voltage flexibility [12]. They estimated the cost of the flexibility services based on their experience with flexibility tenders. Also the motivation behind the development of the NODES platform was to defer substantial investments of substations necessary to handle winter peaks [114].

- In the Netherlands, the system operators did not plan to use flexibility. They are forced to overbook the grids as they cannot follow the demand for grid connections and then have to procure flexibility to solve the resulting congestion in their grids [29]. This situation is not the result of a cost-benefit analysis.
- In Germany, DSOs have also been overbooking their grids because there was a bigger demand for grid connection than they could offer, leading to high curtailment rates in certain areas. However, after controlling the most severe capacity issues with network investments, German DSOs can do a cost-benefit analysis to compare the cost of curtailment with the investment cost to expand their grids. In more detail, they can consider a curtailment of 3% of the annual output of each connection point in their network planning [10].

The examples of NODES, Piclo Flex and GOPACS illustrate that different flexibility market implementations are being tested in practice. Different design choices between the three market platforms can be observed in the use cases, operational timeframes, market products, and involvement of system operators. These variations in the implementation of flexibility markets illustrate that although third-party platforms are operational and growing in volume, many open issues still exist in the future development and harmonization of these markets. In what follows, we both qualitatively and quantitatively explore some of these challenges and design choices.

5.2 A qualitative approach

We first discuss the methodology of the qualitative analysis, then summarize the key findings of the examined open issues.

5.2.1 Methodology: multi-stakeholder analysis

In our research of [46], we performed a multi-stakeholder analysis regarding challenges in the implementation of flexibility markets by organizing two types of workshops.

First, we organized, in collaboration with K. Kessels and J. Vanschoenwinkel from VITO, six workshops for the EUniversal partners to support the development of flexibility markets in the project's demos and to align its implementation within the project and with practice. The following topics were discussed during the workshops: timing aspects, product definitions, market-based procurement, allocation of energy volumes and coordination aspects, flexibility markets for reactive power, and roles and responsibilities. The workshops were organized online between September 2021 and May 2022, had a duration of 2 hours and involved experts from the following EUniversal stakeholders: aggregators (Centrica), DSOs (Energa, E.ON, E-REDES, Mitnetz Strom), market operators (NODES, N-SIDE[6]), research institutes (Comillas, INESC-TEC, KU Leuven) and storage associations (EASE). In preparation for each workshop, the EUniversal partners were asked to answer a list of questions on the topic that was developed based on academic literature and past experiences.

Second, we organized a multi-stakeholder workshop for partners of the EUniversal project and the Vlerick DSO Chair [123]. This workshop aimed to build further on the discussions of the internal EUniversal workshops and bring them to a broader audience. The following topics were treated in the workshop: the potential of flexibility in network planning, the optimal approach to contract flexibility, the role of the third-party market operator and the counterbalancing responsibility of the DSO. The workshop was an in-person event at the end of May 2022, took place at the Vlerick Business School's campus in Brussels and had participants from aggregators (Centrica), DSOs (Energa, E.ON, E-REDES, Fluvius, Mitnetz Strom, Netz-Noë, Sibelga, UK Power Networks), market operators (NODES, N-SIDE), regulators (E-Control, VREG), research institutes (Comillas, VITO) and TSOs (APG, Elia). In preparation for the workshop, we interviewed every participant on the workshop's topics.

5.2.2 Debrief of the main insights

In what follows, we summarize the key findings of our multi-stakeholder analysis of 12 open issues on the implementation of flexibility markets. The following research questions on the use cases and incentives for flexibility markets, the interaction of flexibility markets with existing electricity markets, flexibility market rules and products, and the roles and responsibilities of flexibility market parties are treated.

1. Why should we use flexible resources located at the distribution level?

[6] Within the EUniversal demos, the software company N-SIDE adopted the role of market operator.

2. Does incentive regulation need to be enhanced to make sure DSOs consider flexibility as an alternative to investments?
3. Where do flexibility markets fit within the existing wholesale and balancing market sequence?
4. What is the role of TSO-DSO coordination in the organization of flexibility markets?
5. Should competition between flexibility market platforms be allowed?
6. How is the optimal bid selected, and which information needs to be shared to achieve this?
7. What baseline approach should be used?
8. What products should be traded in flexibility markets?
9. How to organize markets for reactive power?
10. What is the future role of the flexibility market operator?
11. Is there a role for the meter data operator?
12. Is there a role for the (independent) aggregator?

All findings are based on the multi-stakeholder analysis of [46], except for the issue of incentive regulation, which was discussed in our research of [124].

1. Why should we use flexible resources located at the distribution level?

We find that the contracting of flexible resources at distribution level can be driven by:

- National and European regulation
- The TSO searching for balancing, reactive power and congestion relief services
- The DSO's need to ensure local balance and to solve congestion or voltage control issues, while also deferring network investments

Furthermore, we identified diverging opinions between stakeholders on the potential for flexibility to defer network investment in the long term. While the majority of the participants saw considerable potential, some indicated that there might be no potential at low voltage levels, or no potential at all, to defer network investments as investments will always be needed alongside flexibility and in order to defer network investments, flexibility solutions should be designed in such a manner that their delivery is reliable. In these cases, national and European regulations and the TSO's need for flexible resources will play a more prominent role in the development of flexibility at the distribution level.

2. Does incentive regulation need to be enhanced to make sure DSOs consider flexibility as an alternative to investments?

Currently, DSOs might experience a financial disincentive to consider flexibility as an alternative to grid investments. The regulated asset base, on which DSOs receive a regulated rate of return, is typically determined based on the DSO's capital expenditures (CAPEX), such as grid investments. Flexibility services, however, are operating expenditures (OPEX), and DSOs typically have efficiency benchmarks for OPEX with rewards if they outperform their OPEX baseline and penalties if they underperform. When DSOs use flexibility as an alternative to distribution grid investments, OPEX (cost of flexibility services) increases and CAPEX (cost of investments) decreases, negatively impacting their efficiency benchmarks and return on investments.

This financial disincentive can be addressed by introducing a TOTEX approach, in which a share of operating and capital expenditures can enter the regulated asset base. However, we observe that advanced methodologies considering this TOTEX approach have reached an inadvisable level of complexity. Therefore, it is still under discussion whether this additional complexity is required to incentivize flexibility in network planning or if the current push of the CEP's provisions and the pressure to keep distribution network tariffs under control will be sufficient.

3. Where do flexibility markets fit within the existing wholesale and balancing market sequence?

We identified four options to integrate flexibility markets in the European electricity market sequence:

- Before the balancing capacity markets and the day-ahead wholesale market
- Between the balancing capacity markets and the day-ahead wholesale market
- After the balancing capcity markets and the day-ahead wholesale market
- A continuous organization of flexibility markets along the balancing capacity and day-ahead wholesale markets

Currently, the optimal approach to integrate flexibility markets is still under discussion, and further research is needed on the benefits and disadvantages of the different market sequence options considering the DSO's access to flexibility and the flexibility providers' bidding possibilities. Also the duration of the market operator's clearing algorithm and the potential imbalance in the flexibility provider's portfolio are important parameters to consider. For the EUniversal demos, the integration of flexibility markets after the wholesale market was preferred such that an appropriate prediction of the network congestion needs can be made.

4. What is the role of TSO-DSO coordination in the organization of flexibility markets?

There are at least two reasons why TSO-DSO coordination is important to consider. First, TSOs and DSOs might want to access the same flexible resources for grid services, such as congestion management and balancing. Second, TSOs and DSOs might impact each other's network when activating flexible resources for their own purposes.

We identified three types of coordination schemes for the DSO's congestion management services and the TSO's balancing and congestion management services:

- Schemes that fully divide the use of flexibility between the services of the TSO and the DSO
- Schemes that fully coordinate the use of flexibility by organizing one integrated market for TSO/DSO services
- Schemes that allow the use of flexibility for multiple TSO/DSO services by organizing a sequence of separate markets for TSO and DSO services

There is not yet a consensus on the optimal coordination scheme, and both DSO flexibility markets, where the DSO is the single buyer, and common flexibility markets, where both the DSO and TSO are buyers, are being developed across Europe. In any case, the interactions and information sharing between the DSO and the TSO will be important to consider for the successful implementation of these coordination schemes.

5. Should competition between flexibility market platforms be allowed?

Allowing competition between flexibility market platforms might bring benefits, such as price reductions, better products and diversified flexibility contracts. However, several disadvantages and conditions of simultaneously entitling multiple market platforms for DSO services were also identified.

Disadvantages include lack of liquidity, risk of gaming, coordination issues (either between more than one market platform or between the market platform and other procurement mechanisms), risk of over and under-procurement by the DSO and increased complexity for the flexibility service provider.

Conditions that might help the development of competition between flexibility platforms while ensuring welfare maximization and safe grid operation are the standardization of the interfaces, the platform's operation by a third party, the assured availability of flexible resources and the coordination between the markets on the network impact.

6. How is the optimal bid selected, and which information needs to be shared to achieve this?

We identified four ways to select the optimal bids during market-based procurement of flexibility:

- Using an economic merit order curve defined by the market prices and quantities
- Using a techno-economic merit order curve defined by the market prices and simplified technical constraints of the network and flexible resources
- Using a complex clearing algorithm deployed by the market operator considering bid prices and the impact of the bid on the network state and flexibility need
- Having a selection of the bids outside the market by the DSO that aims for secure and efficient operation of the grid

We found that stakeholders have diverging views on the optimal methodology for bid selection in flexibility markets. Here, the most debatable aspect is sharing distribution network information with the market operator, as this information is sensitive to share due to data protection (GDPR) and cyber security concerns.

If both efficient flexibility market operation and secure network operation cannot be achieved, DSOs can resort to alternatives to ensure the secure and reliable operation of the network, such as network reconfiguration tools at higher voltage levels and last resort curtailment measures.

7. What baseline approach should be used?

Current practices indicate that the flexibility service provider can choose the baseline methodology to validate the delivery of flexibility. Still, these methodologies can be harmonized across Europe by sharing best practices, procedures and principles. These guiding principles already exist for baselining in frequency services and state that baseline methodologies should be accurate, simple, integer and effective. However, additional criteria might need to be considered in the context of flexibility markets due to the local context of congestion management and voltage control. The following parameters were indicated as important: the local characteristics of congestion management and voltage control, the product and asset types, data availability, and the timing of the baseline submission.

Furthermore, we identified three possible levels of aggregation of baselines:

- At resource level (submeter)
- At smart meter level (behind the meter)
- At feeder or substation level (multiple connection points)

The main challenge is that baselines should be detailed enough to capture the local characteristics of the DSO services and sufficiently aggregated to reduce the impact of uncertainty in the flexibility service provider's portfolio, especially during settlement. Also data privacy and authorization processes play a big role in the calculation and aggregation of baselines.

8. What products should be traded in flexibility markets?

Currently, we observe different practices on product attributes and the implementation of these attributes in flexibility markets across Europe. However, the following four attributes are considered essential when defining flexibility market products:

- The minimum and maximum bid quantity
- The minimum and maximum duration of a delivery time interval
- The activation price
- The location of the flexibility request

Other attributes that might be included depending on the stakeholder's preferences are the possibility to aggregate, the possibility to make partial offers, the full activation time, the granularity of offers, the validity period, the availability price, and the recovery period.

9. How to organize markets for reactive power?

Generally, reactive power is provided through mandatory services by large power plants, capacitor banks, and transformers with automated or manual tap changers. In the coming years, voltage issues in the network might increase, and reactive power services might be provided by more third-party-owned resources, such as renewables, through new market-based systems. Although these markets for reactive power are still immature, and both technological and market barriers exist, we found that the following three aspects must be considered during its development.

First, although reactive power products are typically treated separately from active power products to support their specific characteristics and reduce complexity, the interaction between the two products is important as the active and reactive power output of resources are dependent and voltage control is embedded in congestion management in distribution grids.

Second, the following cost parameters will impact the pricing of reactive power products: the investment cost of the installation to provide reactive power services, the operating costs due to thermal losses in the system and the opportunity cost for active power services.

Third, at least the following aspects must be considered in the aggregation of reactive power products: the local character of reactive power services, the location of the flexible resources, the similarity of sensitivity factors of the aggregated bids, and the steadiness of sensitivity factors of the aggregated bids before and after delivery.

10. What is the future role of the flexibility market operator?

While some DSOs develop their own flexibility platforms, the number of market platforms owned and operated by third-party companies is also increasing. We find that there are both arguments against and in favor of an independent market operator. Arguments against a third-party market operator are the additional layer of complexity, the need for coordination efforts and the increased management costs. Arguments in favor are transparency, the possibility to have multiple system operators as buyers and the know-how of market operation that might not yet fall under the competencies of the DSO.

Furthermore, having a third-party market operator comes with additional discussions on the division of the responsibilities of market activities between the DSO and the independent market operator. While the different stakeholders are aligned on the division of responsibilities of the registration and prequalification phase and the delivery and monitoring phase of flexibility markets, the distribution remains under discussion for the selection of bids and the evaluation of the impact of a bid on the grid need.

11. Is there a role for the meter data operator?

We analyzed the role of the meter data operator in the context of submetering on the consumer side. Currently, submetering data is mainly used to stimulate innovation of flexibility service providers and to inform grid users rather than to settle flexibility services for DSOs. This approach is because, unlike smart meters, a regulated environment for submetering on the consumer side does not yet exist.

In the future, the role of the meter data operator for submeters could be taken up by the flexibility service provider or the DSO, as long as the relevant knowledge to deal with the complexity, security and data protection issues of the validation process is ensured. Furthermore, it is important that the consumer remains the data owner and needs to give consent for its data to be used.

12. Is there a role for the (independent) aggregator?

We found that the (independent) aggregator might develop new competencies with the establishment of flexibility markets, such as evaluating the impact of their bids on the network, optimizing the dispatch of their portfolio over different markets and handling local constraints when providing services to the DSO.

However, the participation of low-voltage customers in electricity markets is also expected to bring challenges to the (independent) aggregator due to high stochasticity at low voltage levels. To reduce the impact of stochasticity, the aggregator needs to smartly include a large number of resources in their portfolio and the rules of the flexibility market must be robust to cope with the impact of these uncertainties. Accordingly, the settlement of aggregated flexibility bids should be done at the portfolio level, as too many uncertainties and errors are involved at the asset level.

Conclusions

This section presents the findings of a multi-stakeholder analysis on twelve open issues regarding flexibility market design, exploring the use cases and incentives for flexibility markets, the interaction of flexibility markets with existing electricity markets, flexibility market rules and products, and the roles and responsibilities of flexibility market parties.

For each question, an overview of design options was presented, for which the stakeholders could not yet define the optimal approach. As a result, our analysis indicates that there are still many open questions regarding flexibility market design and highlights that further research and experimentation on flexibility markets will be essential to reach a common target model in the future. The regulatory sandbox projects of Section 4.3 and the different implementations of the third-party market platforms of Section 5.1 present a first step in this direction. Nevertheless, we can identify three guiding principles on flexibility markets design from the stakeholder discussions.

1. Flexibility market design should consider the local characteristics of distribution networks to deliver congestion management and voltage control services effectively.

2. The design of flexibility markets should minimize the impact of uncertainty, both in the context of determining the network state and providing flexibility services.

3. Flexibility markets should facilitate information exchange between market parties while ensuring the data protection of grid users and the security constraints of network operators.

5.3 A quantitative approach

We first discuss the methodology of the quantitative analysis, then introduce the two open issues that will be further developed in Chapters 6 and 7.

5.3.1 Methodology: mathematical programming and topic selection

The following two open issues will be quantitatively examined in Chapter 6 and Chapter 7: the concern of strategic behavior in flexibility markets and the relevance of counterbalancing procured flexibility services.

The scope of the first topic was defined in early 2020, when flexibility markets were still recently adopted in the Clean Energy Package and the qualitative analysis of Section 5.2 was yet to be performed. At this time, the primary concern when implementing flexibility markets, as highlighted by the Clean Energy Package, was the risk of gaming by flexibility providers due to the local characteristics of these markets. In this context, we aimed to quantitatively explore strategic behavior in flexibility markets to examine the existence of these games and support the detection of such bidding strategies.

The second topic was selected after the research idea of examining the interaction between the TSO's system imbalance and the DSO's flexibility procurement was presented during the multi-stakeholder workshop, which was organized as part of the qualitative analysis of Section 5.2. Given the high level of interest and the multitude of questions raised by stakeholders during the workshops, we considered this topic essential for further quantitative analysis.

To examine the decision-making of agents in flexibility markets, we employ mathematical programs. More specifically, following the approach described by [125], we develop bilevel models that capture the optimization problem of the decision-making agent that is constrained by optimization models representing electricity markets. In analogy with the Stackelberg game [126], these bilevel models are characterized by a specific hierarchy: the decision-making agent in the upper level acts as a leader, anticipating the outcomes of the electricity market problems in the lower levels [125].

5.3.2 Introduction to the examined issues

In what follows, we introduce the two concerns on the implementation of flexibility markets that will be quantitatively examined in the remaining chapters of this dissertation. We refer readers to the chapters dedicated to each open issue for a comprehensive understanding of the mathematical formulations and the employed solution strategies of these models.

1. Is there a risk for strategic behavior in flexibility markets?

The CEP's provisions state that "DSOs shall procure flexibility services in accordance with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that [...] such procurement would lead to severe market distortions or to higher congestion [6]." In this context, regulators and organizations representing DSOs and TSOs expressed concerns that grid users might use flexibility markets to deliberately create congestion as they anticipate getting paid to solve it [3, 20, 22]. This behavior is often referred to as the inc-dec game and is known as a strategic arbitrage between the zonal day-ahead market and the redispatch market for congestion management at transmission level [24, 25]. There is currently not yet empirical evidence of inc-dec gaming in flexibility markets. However, as flexibility markets come with a similar market set-up as redispatch markets, the practical experience with inc-dec games in redispatch markets has evolved into the concern of having similar games in flexibility markets [26].

In Chapter 6, we develop a bilevel model to capture the optimal bidding strategy of a flexibility provider that aims to maximize its profits over the clearing of the wholesale, flexibility and redispatch market. Here, we resolve the scientific challenge of developing a bilevel model with a three-stage electricity market at the lower level, which extends bilevel models designed to capture strategic behavior in electricity markets to include the recent developments of flexibility markets. The proposed bilevel model allows us to examine inc-dec games in flexibility markets for a stylized test case, evaluate the validity of the concern regarding strategic behavior in flexibility markets, and define the main characteristics of these games.

2. How to account for the counterbalancing of procured flexibility services?

When DSOs procure flexibility for grid services after the wholesale market clearing, imbalances at the system level might be created, requiring counterbalancing actions. These actions are typically not considered in current demos and pilot projects as the impact of the activated flexibility is still negligible. However, counterbalancing might become more important when flexibility markets mature and the volumes traded on flexibility markets increase [27]. Yet, limited knowledge exists on the interaction between flexibility and the system imbalance, the costs related to counterbalancing actions, and the relevance of these costs in distribution network planning.

In Chapter 7, we compare flexibility and imbalance data for the example of wind curtailment in Germany. Here, we tackle scientific challenges in data collection and manipulation to arrive at a relevant and appropriate use case to perform the comparison. With this analysis, we aim to gain insights into the costs related to counterbalancing actions and the effect of the interaction between flexibility and the system imbalance on these costs. Besides that, we propose a bilevel model in response to the scientific challenge of holding a mathematical model that represents the DSO's network planning decision while minimizing network investments and the operational costs of flexibility and counterbalancing. The proposed model allows us to examine how counterbalancing costs can be integrated into distribution network planning and to illustrate the relevance of these costs in network planning.

5.4 Conclusions

The examples of NODES, Piclo Flex and GOPACS illustrate how third-party market platforms are tapping into the opportunity of flexibility at the distribution level and are developing different implementations of flexibility markets in practice. More specifically, these market platforms diverge in their design choices regarding use cases, operational timeframes, market products, and involvement of system operators. These variations in flexibility market design indicate that although third-party platforms are operational and growing in traded volumes, open issues persist regarding the future implementation and harmonization of these markets. We contribute to this discussion by performing two types of analyses regarding open issues in flexibility market design.

On the one hand, we conduct a comprehensive multi-stakeholder analysis involving twelve research questions focused on key aspects of flexibility market design. These questions explore the use cases and incentives for flexibility markets, the interaction of flexibility markets with existing electricity markets, flexibility market rules and products, and the roles and responsibilities of flexibility market parties. For each question, an overview of design options was presented, for which the stakeholders could not yet define the optimal approach. This result indicates that there are still many open questions regarding flexibility market design. Nevertheless, we identify three guiding principles from the stakeholder discussions. First, flexibility market design should consider the local characteristics of distribution networks to deliver congestion management and voltage control services effectively. Second, the design of flexibility markets should minimize the impact of uncertainty, both in the context of determining the network state and providing flexibility services. Finally, flexibility markets should facilitate information exchange between market parties while ensuring the data protection of grid users and the security constraints of network operators.

On the other hand, we develop mathematical programs to address concerns regarding strategic behavior and counterbalancing in flexibility markets. This chapter introduces our modeling approach and the examined open issues. In the next chapters, we will elaborate on the relevance, mathematical formulations, findings and conclusions of the quantitative analyses.

Chapter 6

Strategic behavior: a justifiable concern in the development of flexibility markets?

As discussed in Section 5.3, this chapter examines the concern of strategic behavior in flexibility markets using mathematical programming. Section 6.1 introduces the discussion of inc-dec gaming and specifies the contributions of this chapter to the academic literature. In Section 6.2, we propose a bilevel model with a three-stage electricity market to examine the inc-dec game in flexibility markets at distribution level and redispatch markets at transmission level. Section 6.3 discusses the strategic behavior observed for the bilevel model and a stylized test case. Furthermore, the impact of strategic behavior on the outcome of the three-stage electricity market is examined in Section 6.4. Finally, Sections 6.5 and 6.6 present the limitations of the results and the conclusions, respectively.

This chapter contains elements from the following paper:

- © 2023 IEEE. Reprinted, with permission, from Beckstedde, E., Meeus, L. and Delarue, E., 2023. A bilevel model to study inc-dec games at the TSO-DSO interface. IEEE Transactions on Energy Markets, Policy and Regulation. doi: 10.1109/TEMPR.2023.3292425

6.1 Introduction

One of the main concerns in the development of flexibility markets is that grid users might use these markets to deliberately create congestion as they anticipate getting paid to solve it [3, 22, 23]. This behavior is often referred to as the inc-dec game and is known as a strategic arbitrage between the zonal day-ahead market and the redispatch market for congestion management at transmission level [24, 25]. There is currently not yet empirical evidence of inc-dec gaming in flexibility markets. However, as flexibility markets come with a similar market set-up as redispatch markets, the practical experience with inc-dec games in redispatch markets [26] has evolved into the concern of having similar games in flexibility markets. Nevertheless, literature on inc-dec games in flexibility markets remains limited. A statistical test to detect inc-dec games during market monitoring of flexibility markets is proposed in [127] and verified using a stylized example. We introduce a bilevel optimization model to characterize inc-dec games in flexibility markets for a stylized test case.

Bilevel optimization models are generally used to examine strategic behavior in electricity markets. In [128], a bilevel model to capture the bidding strategies of demand response in a two-stage market is developed. Also [129] propose a bilevel model to examine the Nash equilibria of strategic wind producers in a two-stage electricity market. However, the bilevel models of [128, 129] are unsuitable for detecting inc-dec games as network constraints are considered in the first market stage. As a result, the second market stage is typically organized to balance energy rather than to manage congestion. A bilevel model to study the inc-dec game was first developed by [130]. More specifically, [130] propose a solution strategy to find the Nash equilibrium between strategic producers in a zonal day-ahead and redispatch market sequence. In [131], this method is used to examine the impact of inc-dec gaming on the efficiency of nodal pricing and two types of zonal pricing. The bilevel model is also applied in [132] to evaluate the impact of inc-dec gaming under different pricing schemes in redispatch markets.

Inc-dec games have also been studied with other methodologies. In [133], a stylized example is used to illustrate the inefficient character of zonal pricing with counter trading compared to nodal pricing in the context of strategic behavior, especially market power. The game-theoretical analysis of [134] confirms and generalizes these findings, concluding that zonal pricing with counter trading gives inefficient investment signals for generators. Finally, the intuition for the inc-dec game is explained in [135] using a theoretical example of a network with two transmission nodes.

We observe four limitations in the current literature on inc-dec gaming that we aim to address in this chapter:

- The inc-dec game has been studied in the context of redispatch markets at transmission level but has not yet been examined under the recent developments of flexibility markets at the distribution level. In this research, we do add a flexibility market stage to the model.
- Methods to study the inc-dec game are either based on technical optimization techniques or stylized network models. We combine both approaches by applying a bilevel model to a stylized example.
- Most papers analyze the inc-dec game using redispatch markets while paying limited attention to the presence of other games, such as the price-setter game. By applying the proposed model to a stylized example, we can more easily distinguish and analyze different types of gaming.
- The existing literature adopts slightly different definitions of inc-dec games. We provide a comparison of the different types of inc-dec games observed in our test case with those identified by others.

In other words, we provide three main contributions to the existing literature. First, we examine the inc-dec game considering congestion at the interface of the transmission and distribution network. To achieve this, we propose a bilevel model with a three-stage electricity market that consists of a zonal day-ahead market, a flexibility market and a redispatch market. We show that the proposed model can be formulated as a Mathematical Program with Equilibrium Constraints (MPEC) and converted into a Mixed-Integer Linear Program (MILP). Second, we bridge both literature streams by examining the bilevel model for a stylized network example, which allows us to fully understand the mechanisms of the inc-dec game in the complex setting of the three-stage electricity market and the bigger picture of strategic behavior. We discuss three types of games, which definitions are given in Table 6.1. It must be noted that the wording ‘strategic behavior’ and ‘gaming’ does not imply that these different types of bidding strategies are all illegitimate or have the same legal consequences [135]. Finally, we define the impact of the price-setter and the inc-dec games on network congestion, market prices, total consumer costs and total generation costs by comparing the outcomes of our test case with the findings of existing literature.

Table 6.1: Definitions of the three games examined in this chapter.

Game type	Definition
Price-setter game	A strategic producer with market power intentionally drives up (down) market prices to increase profits in an upward (downward) regulating market.
Inc-game	A strategic player adjusts its bid price to pursue activation in the more profitable redispatch (flexibility) market.
Dec-game	A strategic agent makes profits by deliberately creating congestion at the transmission (distribution) level and solving it in the redispatch (flexibility) market.

6.2 A bilevel model to study strategic behavior at the TSO-DSO interface

This section first describes the assumptions of the four main parts of the bilevel model: the test system, the three-stage electricity market, the strategic bidder, and the time horizon. Next, the mathematical formulation and solving procedure of the bilevel model will be given.

6.2.1 The test system

The test system builds further on the power system design of [135, 136] and reflects the issue of renewable energy curtailment due to limited available network capacity in Germany [5]. A schematic outline of the test case is shown in Figure 6.1, and the technical load and generation parameters can be found in Table 6.2, which is the only scenario considered.

The test system comprises a stylized transmission and distribution network within a single bidding zone. Transmission nodes 1-3 are connected by three overly designed network lines, reflecting the meshed transmission grid. Nodes 5-9 represent two branches of the radial distribution network, of which line 6 is limited to a maximum active power $P_d^{b,max}$ of 0.04 GW and reactive power $Q_d^{b,max}$ of 0.03 GVAr. Node 4 and transmission line 4 serve as a transformer connecting the two networks. As different approximation techniques are used for the transmission and distribution network, the transformer is modeled as a snip between the two networks. The generation sources $P_d^{T/DSO}$ at nodes 4-5 ensure the power flow through the transformer. The capacity of the transformer $P_t^{b,max}$ is captured by the maximum power flow through line 4 and equals 15 GW.

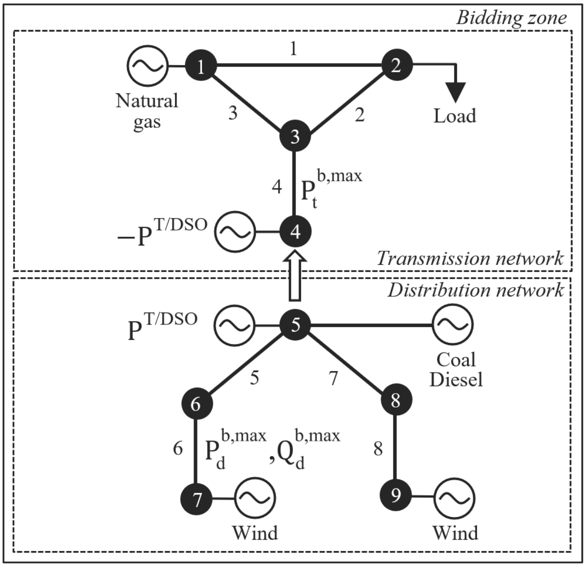


Figure 6.1: The test system and the characterization of the main network flows.

Table 6.2: Generation and load parameters of the test system in order of increasing marginal costs.

C_g [€/MWh]	P_g^{cap} [GW]	Node	Technology
1	0.05	7	Wind
1	0.05	9	Wind
21-40*	20.00	5	Coal
41-60*	20.00	1	Natural gas
62-64*	0.03	7	Biogas
66-70*	5.00	5	Diesel
Inelastic demand	25.50	2	Load

*Range of marginal prices. The marginal price increases by 1 €/MWh for every step of 0.01 GW of biogas and 1 GW of coal, diesel, and natural gas.

6.2.2 The three-stage electricity market

We examine strategic behavior in the three-stage electricity market. We assume that the remaining capacity of the generation units passes from one market to the next.

- The first stage is the day-ahead wholesale market that clears all supply and demand. This zonal market clearing does not consider network constraints within its bidding zone and might result in overloaded network lines and voltage violations in the distribution and transmission network.
- The second stage contains the flexibility market, which the DSO organizes to relieve congestion and voltage issues at distribution level. Three assumptions characterize the functioning of the flexibility market in this chapter. First, due to the design of the test case, the flexibility market is characterized by the down regulation of renewable generation at the export-constrained distribution node 7. An equal amount of generation units are activated on the other side of the congested line to maintain the energy balance. Second, we do not consider flexible resources located in the low-voltage distribution grids beneath the radial branches of the test case. Finally, we assume the DSO does not consider transmission network constraints in the flexibility market clearing.
- The third market stage consists of the redispatch market organized by the Transmission System Operator (TSO) to manage congestion in the transmission network. We make two assumptions. First, the transmission congestion of the test case is characterized by the overloading of transmission line 4 of the transformer that imports energy from the distribution to the transmission network. As a result, the downward redispatch market aims to reduce the generation of units located at the distribution side of the transformer. To maintain the network balance, an upward market is organized to activate the same amount of generation at transmission level. Second, units located at export-constrained distribution nodes are filtered from the upward redispatch market to avoid congestion at distribution level at the end of the market sequence.

Alternative versions of the three-stage electricity market might exist for two reasons. First, flexibility markets can be integrated with other markets, such as the TSO redispatch market [18]. The choice of an independent flexibility market is supported by [137, 138]. Second, the three stages can be placed in an alternative order. The market sequence followed here is in line with the findings of [139].

Finally, we assume that all markets are auction-based and have a pay-as-clear pricing scheme. Besides that, forward and ancillary services markets are not considered.

6.2.3 The strategic bidder

We represent the strategic bidder as a Balancing Responsible Party (BRP). Before the start of the market sequence, a selection of generation units is allocated to the strategic BRP's portfolio. All other units are considered competitive. The BRP maximizes profits by bidding strategic price-quantity pairs into the three-stage electricity market. While the quantity is assumed fixed and equal to the maximum available capacity, the bid price is considered a decision variable of the strategic BRP. As we only consider a single iteration of the optimization problem, the strategic BRP cannot adjust its strategic bid price during the proceedings of the market sequence.

We do not consider the interaction between multiple strategic agents, risk averseness of the strategic player or uncertainty of load and generation parameters. As a result, the strategic BRP will have perfect foresight on the outcomes of the three market stages and will be optimistic about its chances of being selected in the market, even if it chooses a bid price close to the market price. As such, what we consider here is an extreme case (upper bound) in favor of the strategic agent.

6.2.4 The time horizon

We examine the three-stage electricity market for a single timestep, which has three consequences. First, we do not consider the evolution of network topology and weather in time. Second, we discard optimal bidding strategies over multiple time frames. Finally, it is hard to compare the long-term, total risks (e.g., strategic behavior) and opportunities (e.g., efficient network operation and planning) of flexibility markets.

The methods used in [128] and [140] can be used to extend the model to multiple timeframes. However, as the price-setter game and the inc-dec games take place within a single time frame, we believe that our contributions are all valid under this assumption.

6.2.5 The bilevel model

Figure 6.2 gives a schematic overview of the bilevel model, including references to the respective mathematical equations. We now discuss the building blocks of the model, the MPEC formulation and the MILP conversion in more detail.

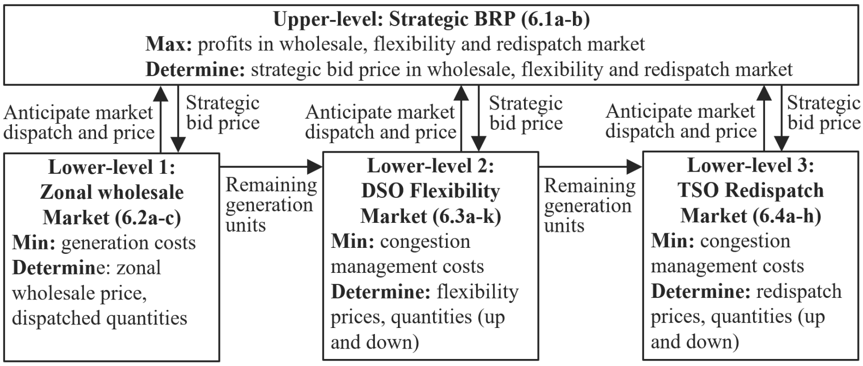


Figure 6.2: Schematic overview of the bilevel model including references to the optimization problems (6.1) – (6.4) of each building block in brackets.

Upper-level problem: the balancing responsible party

The strategic BRP in the upper-level aims to maximize the profits of all generation units gs in its strategic portfolio Ω_{gs} over all markets, which is formulated as follows:

$$\max \sum_{g\in\Omega_{gs}} (\lambda^w - C_g)\, p_g^w + \sum_{g\in\Omega_{gs}} \left(C_g - \lambda_{g\in i}^{f,dn}\right) p_g^{f,dn} + \sum_{g\in\Omega_{gs}} \left(\lambda_{g\in i}^{f,up} - C_g\right) p_g^{f,up}$$
$$+ \sum_{g\in\Omega_{gs}} \left(C_g - \lambda_{g\in i}^{r,dn}\right) p_g^{r,dn} + \sum_{g\in\Omega_{gs}} (\lambda_{g\in i}^{r,up} - C_g)\, p_g^{r,up} \tag{6.1a}$$

where λ^w is the zonal market price of the lower-level wholesale market and $\lambda_{g\in i}$ is, depending on its superscript, the local market price of the downward flexibility f, dn, upward flexibility f, up, downward redispatch r, dn or upward redispatch r, up market organized at the node i. C_g represents the marginal generation cost and p_g the dispatched active power volumes in every market stage, indicated by their superscript.

Two types of profits can be distinguished in the objective function (6.1a). First, the profits in the wholesale, upward flexibility and upward redispatch market equal the market revenues minus the generation costs of the dispatched units. Second, the profits on the downward flexibility and redispatch market consist of the saved generation costs by the down-regulation of units minus the market price that has to be paid to the market operator as compensation for these saved costs.

The strategic BRP maximizes its profits by choosing a strategic bid price $\hat{c}_g$ for every market and unit of its portfolio. Although the strategic bid price is not directly integrated into the objective, the strategic agent influences the market prices of the objective by using the strategic bid price to change the merit order of the market clearings. The bid price must be positive and lower than the market's price cap $\hat{c}^{max}$ of 3000 €/MWh. Equation (6.1b) generalizes this price constraint for every market.

$$0 \leq \hat{c}_g \leq \hat{C}^{max}, \ \forall \ g \in \Omega_{gs} \tag{6.1b}$$

Lower-level problem 1: the day-ahead wholesale market

The first lower-level problem is the zonal, day-ahead wholesale market, which is formulated as follows

$$\text{Min} \sum_{g \in \Omega_{gc}} C_g p_g^w + \sum_{g \in \Omega_{gs}} \hat{c}_g^w p_g^w \tag{6.2a}$$

subject to

$$0 \leq p_g^w \leq P_g^{cap} \ : \ \underline{\mu}_g^w, \ \bar{\mu}_g^w \ \forall \ g \ \in \Omega_g \tag{6.2b}$$

$$-\sum_{g \in \Omega_g} p_g^w + \sum_{l \in \Omega_l} P_l^D = 0 : \lambda^w \tag{6.2c}$$

where p_g^w are the active power volumes dispatched in the wholesale market for every generation unit g in the set of competitive Ω_{gc} or strategic Ω_{gs} units. P_g^{cap} is the maximum capacity of every generator g in the set of generators Ω_g, and P_l^D is the fixed demand of each load l in the set of loads Ω_l. The dual variables of (6.2b) are given after the colon, and the dual variable of (6.2c) reflects the zonal wholesale market price λ^w.

The generation costs of the day-ahead wholesale market are minimized in (6.2a) considering the price-quantity pairs of all competitive and strategic units, the technical capacity of all generation units (6.2b) and the market clearing constraint (6.2c). While the bid price $\hat{c}_g$ is a decision variable of the strategic agent in the upper-level problem, the lower-level problems observe the bid price as a parameter.

Lower-level problem 2: the flexibility market

The second lower-level problem is the flexibility market that the DSO organizes to relieve congestion and voltage violations at minimum cost, which is formulated as follows

$$\text{Min} \sum_{g\in\Omega_{gc}} C_g p_g^{f,up} + \sum_{g\in\Omega_{gs}} \hat{c}_{js}^{f,up} p_g^{f,up} - \sum_{g\in\Omega_{gc}} C_g p_g^{f,dn} - \sum_{g\in\Omega_{gs}} \hat{c}_g^{f,dn} p_g^{f,dn} \quad (6.3a)$$

subject to

$$0 \le p_g^{f,up} \le P_g^{cap} - p_g^w \ : \underline{\mu}_g^{f,up},\ \bar{\mu}_g^{f,up} \forall\ g \in \Omega_g \quad (6.3b)$$

$$0 \le p_g^{f,dn} \le p_g^w \ : \ \underline{\mu}_g^{f,dn},\ \bar{\mu}_g^{f,dn}\ \forall\ g \in \Omega_g \quad (6.3c)$$

$$-Q_g^{cap} \le q_g \ \le Q_g^{cap} : \ \underline{\mu}_g^q,\ \bar{\mu}_g^q \ \ \forall\ g \in \Omega_g \quad (6.3d)$$

$$\sum_{i\in j} p_{ij}^b + \sum_{g\in j} p_g^w - \sum_{l\in j} P_l^D + \sum_{g\in j} p_g^{f,up} - \sum_{g\in j} p_g^{f,dn} - \sum_{k\in j} p_{jk}^b = 0 : \ \lambda_j^f\ \forall\ j \in N_d \quad (6.3e)$$

$$\sum_{i\in j} q_{ij}^b + \sum_{g\in j} q_g \ - \sum_{l\in j} Q_l^D - \sum_{k\in j} q_{jk}^b = 0\text{:}\ \ \mu_j^{qb}\ \forall\ j \in N_d \quad (6.3f)$$

$$-P_{ij}^{b,max} \le p_{ij}^b \le P_{ij}^{b,max} \ : \ \underline{\mu}_{ij}^{pb},\ \bar{\mu}_{ij}^{pb}\ \forall\ ij \in B_d \quad (6.3g)$$

$$-Q_{ij}^{b,max} \le q_{ij}^b \le Q_{ij}^{b,max} \ \ \underline{\mu}_{ij}^{qb},\ \bar{\mu}_{ij}^{qb} \ \ \forall\ ij \in B_d \quad (6.3h)$$

$$(v_i^{min})^2 \le w_i \ \le (v_i^{max})^2 : \ \underline{\mu}_i^v,\ \bar{\mu}_i^v \ \ \forall\ i \in N_d \quad (6.3i)$$

$$w_i \ - \ w_j \ - 2(R_{ij}\ p_{ij}^b + X_{ij}\ q_{ij}^b) = 0 \ : \ \mu_{ij}^v \forall\ ij \in B_d \quad (6.3j)$$

$$w_1 \ = 1 \ : \ \ \mu_1^{v0} \quad (6.3k)$$

where $p^{f,up}$ and $p^{f,dn}$ are the up and down-regulated active power volumes in the flexibility market. q_g reflects the reactive power generation and Q_g^{cap} the reactive power capacity of each generation unit. P_l^D and Q_l^D are the active and reactive loads. p^b and q^b represent the active and reactive branch power flows from all nodes i proceeding node j or all nodes k following the node j depending on their subscript. w_i, v_i^{min} and v_i^{max} are the voltage squared and voltage limits, and R_{ij} and X_{ij} the branch resistance and reactance. The dual variable of (6.3e) reflects the flexibility market price λ_j^f on each distribution node, and the dual variables of all other constraints are given after the colon.

The costs of the flexibility market are minimized in (6.3a) and consist of positive and negative parts. The positive part captures the activation of the cheapest generation units in the upward flexibility market. The negative part represents the downward flexibility market in which the most expensive units are turned off first. The flexibility bids are selected while respecting the unit's available active (6.3b)-(6.3c) and reactive (6.3d) power capacity. We assume that due to its location, flexibility bids cannot participate in both markets at the same time. The distribution network constraints are captured by (6.3e)-(6.3k) using the LinDistFlow formulations [141]. In more detail, (6.3e)-(6.3f) represent the active and reactive power balance at each node in the set of distribution nodes N_d, and (6.3g)-(6.3h) give the active and reactive flow limits of all branches in the set of distribution branches B_d. Finally, (6.3i) reflects distribution network's voltage limits, and (6.3j)-(6.3k) the branch flow constraint and boundary conditions.

Lower-level problem 3: the redispatch market

The final lower-level problem represents the redispatch markets organized by the TSO to resolve congestion in the transmission network, which is formulated as follows

$$\text{Min} \sum_{g \in \Omega_{gc}} C_g p_g^{r,up} + \sum_{g \in \Omega_{gs}} \hat{c}_g^{r,up} p_g^{r,up} - \sum_{g \in \Omega_{gc}} C_g p_g^{r,dn} - \sum_{g \in \Omega_{gs}} \hat{c}_g^{r,dn} p_g^{r,dn} \quad \forall\, g \in \Omega_g \tag{6.4a}$$

subject to

$$0 \leq p_g^{r,up} \leq P_g^{cap} - p_g^w - p_g^{f,up} : \underline{\mu}_g^{r,up},\ \bar{\mu}_g^{r,up}\ \forall\, g \in \Omega_g \tag{6.4b}$$

$$0 \leq p_g^{r,dn} \leq p_g^w + p_g^{f,up} - p_g^{f,dn} \ : \ \underline{\mu}_g^{r,dn},\ \bar{\mu}_g^{r,dn} \ \ \forall\, g \in \Omega_g \tag{6.4c}$$

$$\begin{aligned} &\sum_{i \in j} p_{ij}^b + \sum_{g \in j} p_g^w - \sum_{l \in j} p_l^D + \sum_{g \in j} p_g^{f,up} - \sum_{g \in j} p_g^{f,dn} \\ &+ \sum_{g \in j} p_g^{r,up} - \sum_{g \in j} p_g^{r,dn} - \sum_{k \in j} p_{jk}^b = 0 \text{:} \ \ \lambda_j^r\ \forall\ j \in N_t \end{aligned} \tag{6.4d}$$

$$-P_{ij}^{b,max} \leq p_{ij}^{b} \leq P_{ij}^{b,max} \ : \ \underline{\mu}_{ij}^{pb}, \ \bar{\mu}_{ij}^{pb} \ \forall \ ij \in B_t \tag{6.4e}$$

$$p_{ij}^{b} = \left| B_{ij} \left(\delta_i^t - \delta_j^t \right) \right| \ \forall \ ij \in B_t \tag{6.4f}$$

$$\delta_i^{min} \leq \delta_i^t \leq \delta_i^{t,max} \ : \ \underline{\theta}_i^t, \ \bar{\theta}_i{}^t \ \forall \ i \in N_t \tag{6.4g}$$

$$\delta_1^t = 0 \ \ \theta_1^{t1} \tag{6.4h}$$

where $p^{r,up}$ and $p^{r,dn}$ indicate the upward and downward regulation of generation units in the redispatch markets. B_{ij} is the transmission line susceptance and δ_i^t is the voltage angle on every transmission node. All other variables and parameters are similar to the notations used in problems (6.2)-(6.3); only the subscript d for distribution is replaced by the subscript t for transmission.

The objective function (6.4a) consists of two parts: the activation of the cheapest market bids in the upwards redispatch market and the down-regulation of the most expensive units in downward redispatch market. The markets are cleared while respecting the technical capacity of the resources (6.4b)-(6.4c). The transmission network constraints are respected by (6.4d)-(6.4h) using the DC power flow assumptions. Equation (6.4d) gives the nodal balances, (6.4e)-(6.4f) reflect the branch flow limits, and (6.4g)-(6.4h) define the voltage angle limits and the reference node.

MPEC formulation of the bilevel model

The bilevel model is transferred into its equivalent single-level MPEC by replacing the lower-level problems of (6.2)-(6.4) with their Karush-Kuhn-Tucker (KKT) conditions [125].

First, the day-ahead wholesale market of (6.2) is transferred to

$$0 \leq \ p_{gc}^{w} \perp C_{gc} + \bar{\mu}_{gc}^{w} - \ \lambda^{w} \geq 0 \ \ \forall \ gc \in \Omega_{gc} \tag{6.5a}$$

$$0 \leq \ p_{gs}^{w} \perp \hat{c}_{gs}^{w} + \bar{\mu}_{gs}^{w} - \ \lambda^{w} \geq 0 \ \forall \ gs \in \Omega_{gs} \tag{6.5b}$$

$$0 \leq \ P_g^{cap} - \ p_g^{w} \perp \bar{\mu}_g^{w} \geq 0 \ \ \forall \ \ g \in \ \Omega_g \tag{6.5c}$$

$$(6.2c) \tag{6.5d}$$

Next, the KKT conditions of the flexibility market (6.3) are formulated as

$$0 \leq \ p_{gc}^{f,up} \perp \ \ C_{gc} + \ \bar{\mu}_{gc}^{f,up} + \sum_{j \in gc} \lambda_j^f \geq 0 \ \ \forall gc \in \ \Omega_{gc} \tag{6.6a}$$

$$0 \leq \ p_{gs}^{f,up} \perp \ \hat{c}_{gs}^{f,up} + \ \bar{\mu}_{gs}^{f,up} + \sum_{j \in gs} \lambda_j^f \geq 0 \ \ \forall gs \in \Omega_{gs} \tag{6.6b}$$

$$0 \leq \ p_{gc}^{f,dn} \perp - \ C_{gc} + \ \bar{\mu}_{gc}^{f,dn} - \sum_{j \in gc} \lambda_j^f \geq 0 \ \forall gc \in \ \Omega_{gc} \tag{6.6c}$$

$$0 \leq \ p_{gs}^{f,dn} \perp - \hat{c}_{gs}^{f,dn} + \ \bar{\mu}_{gs}^{f,dn} - \sum_{j \in gs} \lambda_j^f \geq 0 \ \ \forall gs \in \Omega_{gs} \tag{6.6d}$$

$$0 \leq \ P_g^{cap} - \ p_g^w - p_g^{f,up} \perp \ \bar{\mu}_g^{f,up} \geq 0 \ \ \forall \ g \in \ \Omega_g \tag{6.6e}$$

$$0 \leq \ p_g^w - \ p_g^{f,dn} \perp \ \bar{\mu}_g^{f,dn} \geq 0 \ \ \forall \ g \in \ \Omega_g \tag{6.6f}$$

$$0 \leq \ q_g^w + Q_g^{cap} \perp \ \bar{\mu}_g^q + \sum_{j \in g} \mu_j^{qb} \geq 0 \ \ \forall \ g \in \ \Omega_g \tag{6.6g}$$

$$0 \leq \ Q_g^{cap} - \ q_g^w \perp \ \bar{\mu}_g^q \geq 0 \ \ \forall \ g \in \ \Omega_g \tag{6.6h}$$

$$(6.3e) - (6.3f) \tag{6.6i}$$

$$0 \leq p_{ij}^b + P_{ij}^{max} \perp - \ \lambda_i^f + \lambda_j^f - 2R_{ij} \ \mu_{ij}^v + \bar{\mu}_{ij}^{pb} \geq 0 \ \forall B_d \tag{6.6j}$$

$$0 \leq \ P_{ij}^{b,max} - p_{ij}^b \perp \ \bar{\mu}_{ij}^{pb} \geq 0 \ \forall \ ij \in B_d \tag{6.6k}$$

$$0 \leq q_{ij}^b + Q_{ij}^{max} \perp - \mu_i^{qb} + \mu_j^{qb} - 2X_{ij} \ \mu_{ij}^v + \bar{\mu}_{ij}^{qb} \geq 0 \ \forall B_d \tag{6.6l}$$

$$0 \leq \ Q_{ij}^{b,max} - q_{ij}^b \perp \ \bar{\mu}_{ij}^{qb} \geq 0 \ \forall \ ij \in B_d \tag{6.6m}$$

$$0 \leq \ w_j \ - (v_j^{min})^2 \perp \ \mu_{jk}^v - \mu_{ij}^v + \bar{\mu}_j^v + \mu_1^{v0} \geq 0 \ \forall \ j \in N_d \tag{6.6n}$$

$$0 \leq \ (v_j^{max})^2 - w_j \ \perp \ \bar{\mu}_j^v \geq 0 \ \forall \ j \in N_d \tag{6.6o}$$

$$(6.3j) - (6.3k) \tag{6.6p}$$

Finally, the lower-level problem of the upward and downward redispatch markets (6.4) is replaced by

$$0 \leq p_{gc}^{r,up} \perp \ C_{gc} + \bar{\mu}_{gc}^{r,up} + \sum_{j \in gc} \lambda_j^r \geq 0 \ \ \forall \ gc \in \Omega_{gc} \tag{6.7a}$$

$$0 \leq p_{gs}^{r,up} \perp \ \hat{c}_{gs}^{r,up} + \bar{\mu}_{gs}^{r,up} + \sum_{j \in gs} \lambda_j^r \geq 0 \ \ \forall \ gs \ \in \ \Omega_{gs} \tag{6.7b}$$

$$0 \leq p_{gc}^{r,dn} \perp - \ C_{gc} + \ \bar{\mu}_{gc}^{r,dn} - \sum_{j \in gc} \lambda_j^r \geq 0 \ \ \forall \ gc \in \Omega_{gc} \tag{6.7c}$$

$$0 \leq p_{gs}^{r,dn} \perp - \ \hat{c}_{gs}^{r,dn} + \ \bar{\mu}_{gs}^{r,dn} - \sum_{j \in gs} \lambda_j^r \geq 0 \ \ \forall gs \in \Omega_{gs} \tag{6.7d}$$

$$0 \leq P_g^{cap} - p_g^w + p_g^f - p_g^{r,up} \perp \bar{\mu}_g^{r,up} \geq 0 \; \forall \; g \; \in \; \Omega_g \tag{6.7e}$$

$$0 \leq p_g^w + p_g^f - p_g^{r,dn} \perp \bar{\mu} \; {}_g^{r,dn} \geq 0 \; \forall \; g \in \Omega_g \tag{6.7f}$$

$$\sum_{ij} B_{ij}(\lambda_i^r - \lambda_j^r - \underline{\mu}_i^{pb} + \underline{\mu}_j^{pb} + \bar{\mu}_i^{pb} - \bar{\mu}_j^{pb}) - \underline{\theta}_i^t - \bar{\theta}_i^t + \theta_i^t = 0 \; \forall \; i \in N_t \tag{6.7g}$$

$$(6.4d) - (6.4e) \tag{6.7h}$$

$$0 \leq B_{ij} \left(\delta_i^t - \delta_j^t \right) \; + \; P_{ij}^{b,max} \perp \underline{\mu}_{ij}^t \geq 0 \;\; \forall \; ij \in B_t \tag{6.7i}$$

$$0 \leq P_{ij}^{b,max} - B_{ij} \left(\delta_i^t - \delta_j^t \right) \perp \bar{\mu}_{ij}^t \geq 0 \;\; \forall \; ij \in B_t \tag{6.7j}$$

$$0 \leq \; \delta_i^t - \delta_i^{t,min} \perp \; \underline{\theta}_i^t \geq 0 \; \forall \; i \in N_t \tag{6.7k}$$

$$0 \leq \; \delta_i^{t,max} \; - \delta_i^t \perp \; \bar{\theta}_i^t \geq 0 \; \forall \; i \in N_t \tag{6.7l}$$

$$(6.4h) \tag{6.7m}$$

To conclude, the MPEC formulation of the bilevel model can be summarized by problems (6.1), (6.5), (6.6) and (6.7).

MPEC conversion to MILP

Three types of non-linearities are present in the MPEC, which can be linearized in the following way.

First, the non-linearities in the complementarity conditions of KKT-conditions (6.5a)-(6.5c), (6.6a)-(6.6h), (6.6j)-(6.6o), (6.7a)-(6.7f) and (6.7i)-(6.7l) with the form $0 \leq a \perp b \geq 0$ can be replaced by the set of mixed-integer linear conditions $a \geq 0$, $b \geq 0$, $a \leq xM$, $b \leq (1-x)M$ where x is a binary variable and M is a sufficiently large, positive constant [142].

Second, the non-linear term $\Sigma_{gs} \lambda^w p_{gs}^w$ in the objective function (6.1a) of the strategic BRP can be linearized using (6.5a)-(6.5c) and the strong duality theorem [143].

Finally, the non-linear terms $-\Sigma_{gs\in i} \lambda_{gs\in i}^{f,dn} p_{gs}^{f,dn}$, $\Sigma_{gs\in i} \lambda_{gs\in i}^{f,up} p_{gs}^{f,up}$, $-\Sigma_{gs\in i} \lambda_{gs\in i}^{r,dn} p_{gs}^{r,dn}$ and $\Sigma_{gs\in i} \lambda_{gs\in i}^{r,up} p_{gs}^{r,up}$ in the objective function (1a) can be linearized by applying binary expansion to the dispatch quantities $p_{gs}^{f,dn}$, $p_{gs}^{f,up}$, $p_{gs}^{r,dn}$ and $p_{gs}^{r,up}$ [144].

Adopting these linearization techniques brings the benefit of using commercial optimization solvers to approach the bilevel model, here Gurobi [145] in Julia. However, this method comes with two disadvantages. First, an appropriate value of M needs to be selected to find a global optimal solution, which is a non-trivial task [146]. Second, introducing binary and discretized values under the big-M and binary expansion methods brings additional computational complexity to the model.

6.3 Observations of strategic behavior in the test case

This section discusses the bidding strategies observed for the test case and makes the comparison with perfect competition.

6.3.1 Market outcome under perfect competition

First, the zonal wholesale market clears for 46 €/MWh. All generation units with a marginal cost at or below this price are dispatched, including 0.1 GW of wind at nodes 7 and 9, 20 GW of coal units at node 5, and 5.4 GW of natural gas at node 1.

Second, the downward flexibility market reduces the active power flow through the congested line 6, while respecting the distribution network constraints. In total 0.01 GW of wind is curtailed at the export-constrained node 7. The wind generators can keep the revenues created on the wholesale market but have to refund the flexibility market price of 1 €/MWh to compensate for their avoided variable costs. In the upward flexibility market, that is organized at the opposite side of the congested line, 0.01 GW of natural gas is activated at a price of 46 €/MWh.

Finally, the TSO organizes a redispatch market to resolve the congestion on transmission line 4. From the 5.1 GW of congestion created after the wholesale market clearing, 0.01 GW was solved in the flexibility market. The remaining congestion is managed by a downward redispatch market at distribution node 5 and an upward redispatch market at the transmission nodes 1-3. In more detail, 5.09 GW of the most expensive coal units are regulated downward at a market price of 36 €/MWh, and the same amount of natural gas units are activated upward at a price of 51 €/MWh.

6.3.2 Approach to identify strategic behavior

To identify various bidding strategies, we developed a general approach to allocate generation units to the strategic BRP's portfolio, which consists of two steps. First, 13 separate samples of generation units with the same location and technology were placed into the strategic portfolio. Second, the combination of these samples was analyzed. The bidding strategies observed in these two steps could be reduced to the following games:

1. the price-setter game in upward (a) and downward (b) markets,

2. the inc-game using (a) redispatch and (b) flexibility markets, and
3. the dec-game using (a) redispatch and (b) flexibility markets.

The samples leading to the games and a numerical summary of the bidding strategies can be found in Table 6.3 and Table 6.4, respectively. The mechanisms behind each game are described in the remainder of this section.

Table 6.3: Examples of strategic BRPs leading to the price-setter and inc-dec games in the test case.

Game type	Marginal price C_{gs} [MW]	Installed capacity P_{gs}^{cap} [GW]	Node	Technology
1a	48-50*	3.00	1	Natural gas
1b	1	0.05	7	Wind
2a	42-44*	3.00	1	Natural gas
2b	27-29*	3.00	5	Coal
3a	67-69*	3.00	5	Diesel
3b	62-64*	0.03	7	Biogas

*Range of marginal prices. The marginal price increases by 1 €/MWh for every step of 0.01 GW of biogas and 1 GW of coal, diesel, and natural gas.

Table 6.4: Bidding strategy of the strategic brps leading to the price-setter and inc-dec games in the test case.

Game type	Marginal price C_{gs} [MW]	Bid price $\hat{c}_{gs}$ SB [€/MWh]	BRP profits PC [k€]	BRP Profits SB [k€]
1a	48-50*	52↑	6.00	8.00↑
1b	1	0↓	2.25	2.26↑
2a	42-44*	49↑	9.00	24.00↑
2b	27-29*	46↑	54.00	54.00
3a	67-69*	43↓	0.00	21.00↑
3b	62-64*	46↓	0.00	1.35↑

Acronyms: Perfect Competition (PC), Strategic Behavior (SB)
*Range of marginal prices. The marginal price increases by 1 €/MWh for every step of 0.01 GW of biogas and 1 GW of coal, diesel, and natural gas.

6.3.3 The price-setter game in upward and downward markets

In the test system, we observe the price-setter game in upward markets (1a) when allocating the natural gas units of 48-50 €/MWh to the strategic BRP's portfolio. Under perfect competition, these natural gas units are all activated in the upwards redispatch market at 51 €/MWh. Under strategic behavior, the BRP bids these units into the redispatch market at a price above its marginal costs, here 52 €/MWh. As a result, only 2.5 GW of the 3 GW within the strategic BRP's portfolio becomes selected in the redispatch market clearing. The other 0.5 GW is replaced by competitive, more expensive units, driving up the redispatch market price to 52 €/MWh.

The price-setter game in downward markets (1b) is detected in our test system when the strategic BRP holds the wind power plant of node 7 in its portfolio. In this example, the BRP has sufficient market power to reduce the flexibility market price to 0 €/MWh.

In short, by playing the price-setter game, the strategic BRP creates additional income from driving up (down) the market price in the upward (downward) market it is usually dispatched in. The increase in profits is equal to the change in market price and the difference in units dispatched in the market clearing.

6.3.4 The inc-game using redispatch and flexibility markets

The strategic BRP with natural gas units of 42-44 €/MWh engages in the inc-game using redispatch markets (2a) in our test system by seeking activation in the upward redispatch market instead of the wholesale market. The BRP offers its units to the wholesale and upward flexibility market at a price above its marginal costs and the expected market prices. As a result, the natural gas units are cleared in at a redispatch price of 51 €/MWh instead of a wholesale market price of 46 €/MWh.

We can detect the inc-game using flexibility markets (2b) when considering a strategic BRP with coal units of 27-29 €/MWh. Although we observe that the BRP overbids the wholesale market to seek activation in the flexibility market, the strategic agent does not make additional profits compared to perfect competition, as the market price in the wholesale and flexibility market are the same in our test system.

To summarize, we refer to the incremental strategy of the inc-dec game when strategic agents overbid the market clearing to pursue activation in a more profitable redispatch (flexibility) market. The additional profits are proportional to the dispatched volumes and the price difference between the new and initial markets in which the strategic BRP is activated.

6.3.5 The dec-game using redispatch and flexibility markets

We observe the dec-game using redispatch markets (3a) in our test case when allocating diesel units of 67-69 €/MWh to the strategic BRP's portfolio. Under perfect competition, these diesel units are too expensive to be selected in the market sequence, and no profits are made. Under strategic behavior, the BRP offers the diesel units to the wholesale market below the expected market price, here at 43 €/MWh, such that these units clear the market. As a result, the wholesale market price decreases to 43 €/MWh and the congestion at the transmission level increases up to 8.09 GW. Subsequently, this additional congestion is solved in the TSO redispatch market by down-regulating the same diesel units at a market price of 36 €/MWh.

The strategic BRP with biogas units of 62-64 €/MWh engages in the dec-game using flexibility markets (3b) in our test system. The strategic BRP offers these biogas units to the wholesale market below their marginal price, here 46 €/MWh, such that these units clear the market and create 0.03 GW of additional congestion at distribution level. Subsequently, this congestion is solved in the flexibility market by downward activating the same biogas units at a market price of 1 €/MWh.

To conclude, in the decremental strategy of the inc-dec game, a strategic producer gains profits by deliberately creating congestion at the transmission (distribution) level and solving it in the redispatch (flexibility) market. The profits of the strategic BRP are equal to the income of the wholesale market minus the costs of the downward redispatch (flexibility) market.

6.3.6 Discussion of the results

This section discusses the different games of the three-stage electricity market. The following four reflections can be made using the summary of Table 6.5.

Table 6.5: Summary of the price-setter and inc-dec games.

Game type?	Requires market power?	Requires market sequence?	Change in bid price?	Unit selected under PC?
Price-setter	Yes	No	$\uparrow/\downarrow$	Yes
Inc-game	No	Yes*	$\uparrow$	Yes
Dec-game	No	Yes*	$\downarrow$	No

Acronyms: Perfect Competition (PC)
*Inc-game: sequence of two upward regulating markets.
*Dec-game: sequence of upward and downward regulating market.

First, the results show that, in analogy with the inc-dec game using redispatch markets, strategic players can game flexibility markets. This observation indicates that the concern of a market player gaming the flexibility market is valid in some instances, such as in our test system. Moreover, similar bidding strategies are used towards redispatch and flexibility markets. Therefore, in the following paragraphs, we refer to inc-dec games rather than inc-dec games using redispatch (flexibility) markets.

Second, we find that the price-setter game and the inc-dec games hold under different market conditions. While a strategic agent requires market power to perform the price-setter game, this was no prerequisite for inc-dec games in our test system, which is in line with the findings of [135]. In contrast, inc-dec gaming occurs between a zonal market and a local congestion management market, while no such sequence is required for the price-setter game.

Third, Table 6.5 shows that although the inc-dec games are typically treated as one, the strategy behind the incremental and decremental games are significantly different considering the required market sequence, the change in bid price, and the unit's selection under perfect competition.

Finally, we observe that strategic BRPs playing the inc-dec games can also engage in the price-setter game if they hold sufficient market power. In addition, strategic BRPs can engage in a combination of games when having multiple technologies in their portfolio. In our test system, these combinations could be reduced to the three games described in this section.

6.4 Impact assessment of strategic behavior

In this section, we assess the impact of the price-setter game and the inc-dec games on network congestion, market prices, total consumer costs, and total generation costs.

6.4.1 Approach to examine the impact of gaming

We base our analysis on two types of resources: the numerical results of the test system and a literature review.

The numerical results of the test system can be observed in Table 6.6, which contains two new parameters. First, the Total Consumer Costs (TCC) are all costs made by the market operators over the three-stage market sequence and express the internal welfare allocation between producers and consumers.

Second, the Total Generation Costs (TGC) are the marginal costs of the activated units at the end of the market sequence and indicate the total welfare created over the market sequence as demand is inelastic.

Table 6.6: Impact of the strategic BRPs on the outcome of the market sequence in the test case.

Game Type	TSO Congestion [GW]	DSO Congestion [GW]	TCC [k€]	TGC [k€]
PC	5.09	0.01	1249.80	907.35
1a	5.09	0.01	1254.89↑	907.85↑
1b	5.09	0.01	1249.81↑	907.35
2a	5.09	0.01	1326.33↑	907.35
2b	5.09	0.01	1249.80	907.35
3a	8.09↑	0.01	1218.27↓	907.35
3b	5.09	0.04↑	1251.15↑	907.35

Acronyms: Perfect Competition (PC), Total Consumer Costs (TCC), Total Generation Costs (TGC)

The academic references of the literature review are given in Table 6.7, in which we make two observations. First, the interaction between the price-setter and inc-dec game using redispatch markets is only examined in [130] and [135]. Second, both methodological approaches apply slightly different definitions of the inc-dec game. While the stylized examples of [133, 134, 135] consider the incremental and decremental strategy, the bilevel models of [130, 131, 132] only examine the dec-game.

Table 6.7: Academic references used in the general analysis.

Game type	References
Price-setter game	[130, 135]
Inc-game using redispatch markets	[133, 134, 135]
Dec game using redispatch markets	[130, 131, 132, 133, 134, 135]

The impact of each game is explained in the remainder of this section. The conclusions are based on both types of resources unless otherwise stated.

6.4.2 The price-setter game in upward and downward markets

We observe that strategic agents engaging in the price-setter game do not aim to create additional network congestion. However, congestion might be aggravated when part of the strategic units becomes replaced by competitive units located on congested nodes. As the price-setter game deliberately changes market prices, and possibly influences prices in other markets [135], this game increases consumer costs in both upward and downward markets. Also generation costs are increased when the price-setter game changes the merit order, such as in [135] and the upward price-setter game of Table 6.6.

6.4.3 The inc-game using redispatch and flexibility markets

Although congestion is required to perform the inc-game using redispatch and flexibility markets, the results of Table 6.6 suggest that this game does not certainly aggravate congestion. Additional congestion might be created when the inc-game is combined with the dec-game [133] or creates scarcity in the wholesale market [135]. Our test system shows that the inc-game using redispatch markets leads to increased wholesale and flexibility market prices. Besides that, [134, 135] argue that redispatch prices might also converge to nodal prices when considering the Nash equilibrium between multiple players. In contrast, the results of our test system showed no increase in market prices for the inc-game using flexibility market as the volumes traded by the market agent remained small compared to other market stages. When an increase in market prices occurs, this will lead to higher consumer costs. Finally, the total generation costs remain unchanged in our test system, [134], and [135] as the inc-game did not affect the final dispatch. This finding is under the assumption that demand is inelastic.

6.4.4 The dec-game using redispatch and flexibility markets

Grid users profit from the dec-game by deliberately creating congestion at the transmission (distribution) level in the zonal market stage and solving it in the following redispatch (flexibility) market. Here, [135] highlight that the strategic player aggravates existing congestion rather than creating new sources of congestion. As a side-effect, congestion management in other network levels might be affected. We did not observe this effect in our test case but other interactions might exist when considering alternative network topologies or information sharing schemes between system operators. When analyzing the impact of the dec-game on the market prices, we find different outcomes for games using redispatch and flexibility markets. The dec-game using redispatch markets typically leads to lower prices in the zonal market stage, and [134, 135] state that redispatch prices might converge to nodal prices when considering multiple strategic agents. In our test system, we do not observe this effect for the dec-game using flexibility markets as the size of the strategic agent is small compared to the traded volumes in the wholesale market. The impact of the dec-game on the total consumer costs depends on the change in market prices and congestion quantities. In our test case, this interplay results in a slight decrease in consumer costs for the dec-game using redispatch markets and a small increase for flexibility markets. In other references such as [130, 131, 132], the interaction between the price-setter and dec-game using redispatch markets increases the total consumer's costs. Finally, the total generation costs remained the same under the dec-game in our test system, [134] and [135] as demand is inelastic and no change in the final merit order occurs.

6.4.5 Discussion of the results

This section discusses the impact of gaming on the outcome of the three-stage electricity market. Based on the summary of Table 6.8, the following two reflections can be made.

Table 6.8: Summary of the impact of the price-setter and inc-dec games on the outcome of the market sequence.

Game type	Aims to create congestion?	Change in market price?	Increases TCC?	Increases TGC
1a/1b	No	Yes	Yes	Depends
2a	Depends	Yes	Yes	No
2b	Depends	Depends	Depends	No
3a	Yes, TSO level	Yes	Depends	No
3b	Yes, DSO level	Depends	Depends	No

Acronyms: Total Consumer Costs (TCC), Total Generation Costs (TGC)

First, we find that the price-setter game and the inc-dec games have different impacts on the system. While a change in network congestion is a typical feature of inc-dec games, this is not the case for the price-setter game. Besides that, the price-setter game is likely to increase total generation costs due to a change in the final merit order. In contrast, inc-dec games do not cause this change when demand is considered inelastic.

Second, the results indicate that the inc-dec games might affect market prices and network congestion differently depending on their anticipation of the redispatch or flexibility market. While the inc-dec games using redispatch markets influenced market prices in all cases, the volumes traded in the inc-dec games using flexibility markets were too small to observe this effect. Besides that, the inc-dec games using redispatch and flexibility markets aim to aggravate congestion at transmission and distribution level, respectively.

6.5 Limitations of the model

We discuss the three main limitations of this analysis and reflect on their impact on the results, namely the under or overestimation of gaming in our test case.

First, we only examine a simplified test case with inelastic demand and a specific market sequence for a single timeframe. In reality, various network topologies, designs of flexibility markets and time steps exist. Therefore, the existence of the discussed games might be specific to these assumptions. Furthermore, other games might appear when analyzing demand response, multiple time steps, or different market sequences. Similar to the flexibility providers in our case study, demand response units might behave strategically across the proposed three-stage market sequence using market power, seeking price differences across markets or influencing network congestion. The work of [128], which analyzes strategic demand-side response in a wholesale and balancing market sequence, can be a good starting point to extend the model proposed in this chapter. A bidding strategy that the proposed bilevel model does not capture is the optimal dispatch of flexibility providers between markets across different timeframes. Market distortions resulting from this bidding strategy might be captured by extending the proposed model towards multiple timeframes. Here, the methodology proposed in [140], which examines the optimal management of a demand response portfolio over sequential timesteps of wholesale market clearings, can serve as an important reference.

Second, we do not consider multiple strategic players, the risk averseness of the strategic agent, and the uncertainty of load and generation parameters. However, these aspects are expected to decrease the market outcome's predictability and increase the risk of losses for the strategic agent. As stated in [135], this increased uncertainty makes strategic users bid closer to their marginal costs, reducing the likelihood of gaming. In this context, the work of [144] serves as an important reference to include uncertainty in the proposed bilevel model.

Finally, we do not discuss mitigation measures such as price caps, long-term contracts, sanctioning and fixed baselines, which are known to reduce market power and gaming issues and are further discussed in [26] and [147].

6.6 Conclusions

One of the main concerns with the development of flexibility markets is that grid users will use these markets to deliberately create and solve congestion, also known as inc-dec gaming. However, this concern is still to be evaluated for distribution grids. We contribute to this discussion in three ways.

First, we propose a bilevel model with a three-stage electricity market to examine the inc-dec game in flexibility and redispatch markets. We show that the proposed model can be formulated as MPEC and converted into a MILP.

Second, we examine the proposed model for various strategic agents and a stylized example characterized by renewable energy curtailment due to limited available capacity at the transmission and distribution network interface. We find examples of price-setter games and inc-dec games using redispatch and flexibility markets, illustrating the bigger picture of strategic behavior in three-stage electricity markets. When comparing the bidding strategies of our test system, we observe that the price-setter and inc-dec games hold under different market conditions. Moreover, we find that inc-dec games using flexibility markets are similar to the games known from redispatch markets. Also, we clarify the distinction between the incremental and decremental strategy of the inc-dec game, which is typically treated as one. Regulators and system operators can use these characteristics to distinguish strategic behavior in practice.

Finally, we examine the impact of price-setter and inc-dec games on network congestion, market prices, total consumer costs and total generation costs based on the outcomes of our test case and a literature review. While both games lead to changes in market prices and consumer costs, price-setter games have a more prominent impact on total generation costs, whereas inc-dec games affect network congestion. Besides, we find that while the inc-dec games using redispatch markets influenced market prices in all cases, the volumes traded in the inc-dec games using flexibility markets were too small to observe this effect. As a result, monitoring inc-dec games in flexibility markets might be more complex than in redispatch markets.

Chapter 7

Accounting for imbalances: a critical factor when considering flexibility in distribution network planning?

As discussed in Section 5.3, this chapter assesses the need for counterbalancing actions of flexibility measures and its relevance in distribution network planning using mathematical programming. Section 7.1 introduces the matter of counterbalancing and specifies the contributions of this chapter to the academic literature. Section 7.2 describes the data sets, examines the counterbalancing costs related to DSO congestion management and introduces the four cost scenarios. The bilevel model, the test system, and its assumptions are explained in Section 7.3 and the impact of counterbalancing costs on the distribution network planning is illustrated in Section 7.4 for the four cost scenarios. Finally, Sections 7.5 and 7.6 present the limitations of the results and the conclusions, respectively.

This chapter is based on the following working paper:

- Beckstedde, E., Meeus, L. and Delarue, E., 2023. Accounting for counterbalancing costs in the DSO's congestion management and network investment decision. ESIM Working paper.

7.1 Introduction

Conflicts might arise between TSOs and DSOs that both want to use Distributed Energy Resources (DERs) for grid services. On the one hand, these flexible resources connected to the distribution network are entering TSOs' congestion management and balancing markets. On the other hand, DERs can be used for congestion management services by DSOs. To successfully activate large amounts of DERs for grid services of both system operators while maintaining network security, coordination schemes between TSOs and DSOs are gaining importance [18].

While academics are exploring several TSO-DSO coordination schemes [148, 149, 150, 151], the sequential activation of DERs in independent market stages for DSO congestion management, TSO congestion management and TSO balancing services is currently the most dominant scheme in practice [137]. Variations to this scheme exist that consider the TSO's congestion management and balancing services in a single stage or treat the TSO's and DSO's congestion management services as one market [150, 151]. The main reason current demos and pilot projects are adopting different markets for TSO and DSO services is that it facilitates the utilization of DERs by both system operators while minimizing the optimization complexity and the need for information sharing [137]. However, this coordination scheme presents a specific challenge: activating DERs in the independent DSO congestion management market can cause imbalances at the system level, which require counterbalancing actions.

In academic literature and pilot projects, counterbalancing actions of DSO congestion management measures are typically organized in two ways. First, DSOs can implement counterbalancing actions before the TSO balancing market, which can be achieved by designing double-sided congestion management markets or procuring counteractions on the intraday market [151, 152]. Second, the DSO's congestion management actions can be counterbalanced in the balancing market by the DSO, the TSO or the balancing responsible party of the activated DER [46, 150].

Although different approaches to counterbalancing exist, we can assume that, in theory, the DSO will always bear the counterbalancing costs of its congestion management services through direct purchases by the DSO, invoices by the TSO or congestion management prices for DERs. However, in practice, we observe that DSOs may overlook the costs related to counterbalancing when developing congestion management services. For example, under the feed-in management regime in Germany, the costs related to counterbalancing were neglected in the compensation mechanisms for curtailed renewable generators [153]. When DSOs increasingly use DERs for congestion management services, the costs related to counterbalancing might become too important to be neglected [27]. However, little is currently known about the amount of counterbalancing costs that might come with DSO congestion management services. Moreover, these costs are often described under the assumption that the DSO's congestion measures adversely impact the system imbalance, while this might not always be the case. Therefore, the first aim of this chapter is to examine to what extent we need to account for the counterbalancing costs of DSO congestion management services in the future.

Considering that DSOs are expected by Article 32 of EU Directive 2019/944 to adopt congestion management measures when it is cheaper than expanding their network, understanding how counterbalancing costs could be integrated into distribution network planning also gains importance. Over the past years, several legislators and DSOs have examined how the tradeoff between congestion management and distribution network investments might be implemented in practice [10, 11, 12]. Also several academics have contributed to this discussion by examining the potential of renewable energy curtailment [13, 14] or demand response [15, 16] to delay network investments. However, these studies on network planning consider counterbalancing costs to a lesser extent. Therefore, the second objective of this chapter is to investigate how we can incorporate counterbalancing costs in distribution network planning and to evaluate the possible effects of accounting for counterbalancing costs on the DSO's network investment decision.

In summary, our research provides three main contributions to the existing literature. First, we examine to what extent we need to account for the counterbalancing costs of DSO congestion management services for a typical congestion situation in Europe: renewable energy curtailment. More specifically, we compare data on wind curtailment measures and imbalance situations in Germany for 2020. Based on this case study, we develop four scenarios of counterbalancing costs. Second, we illustrate how we can integrate counterbalancing costs in distribution network planning. We propose a bilevel model that captures the DSO's trade-off between congestion management and network investments and show that an iterative algorithm can approach the upper level such that the lower levels can be transferred into Mixed Complementarity Problems (MCPs). Finally, we examine the possible effects of accounting for counterbalancing costs on the DSO's network investment decision by solving the bilevel model for a stylized test case and the four counterbalancing cost scenarios.

7.2 Counterbalancing costs related to wind curtailment in Germany

We examine the counterbalancing costs related to DSO congestion management measures for a typical congestion situation in Europe: the curtailment of renewables due to limited available network capacity at the distribution level. More specifically, we consider the case of wind curtailment in the city of Klixbüll, which is located in the North of Germany and has been particularly affected by congestion management measures [154].

In what follows, we first describe the two datasets needed for this analysis: the curtailment actions by the local DSO Schleswig-Holstein Netz in Klixbüll for 2020 and Germany's imbalance prices and volumes for the same year. We then compare the datasets to estimate the counterbalancing costs related to wind curtailment in our case study, leading to the development of the four counterbalancing cost scenarios.

7.2.1 Germany's feed-in management actions for 2020

In 2020, German system operators were allowed to curtail renewables in real-time at the cost of the lost revenues of these generators, while neglecting counterbalancing costs, under the so-called feed-in management regime[7]. An overview of all curtailment requests by Schleswig-Holstein Netz under this regime can be found on their website [156]. Each request includes information such as the affected power plant, the percentage of curtailment, the start and end date, the network area, the cause of the congestion measure, and the system operator placing the request. Using this information, we can create a dataset that gives for every 15 minutes of 2020 the rate at which the wind powerplant in Klixbüll was curtailed by Schleswig Holstein Netz.

An estimation of the total curtailed wind energy can be derived from the curtailment rate by considering the production of the wind power plant. The power plant in Klixbüll consists of 23 wind turbines with a maximum installed capacity of 3 MW. Following the methodology of [154], we can calculate the hourly power output of the wind plant in Klixbüll for 2020 in four steps.

[7]As of October 2021, the German feed-in management regime was replaced by Redispatch 2.0, which contains four main changes compared to feed-in management: (1) congestion is resolved using a schedule-based process that ends 15 minutes before real-time, (2) all generators with an installed capacity of 100kW must provide congestion management services, (3) generators are selected based on their imputed costs, considering the technical impact of the generator on the congestion issue and the feed-in priority for renewables, and (4) system operators have to compensate the created imbalance costs of congestion measures [155].

1. We acquire the average hourly wind speed at the weather station of Klixbüll from the German Climate Data Center [157].
2. We convert the wind speed at the height of the weather station (10 meters) towards the height of the installed wind turbine (95 meters) using the wind profile power law.
3. We calculate the hourly wind production from the wind speed using the performance curve of the installed wind turbine in Klixbüll [158]. We approximate the performance curve by 85 data points that gives the power output of the wind turbine for each wind speed increment of 0.125 m/s.
4. We determine the hourly power output of the entire wind plant by multiplying the power output of each wind turbine by the total number of turbines in Klixbüll, which is 23.

The curtailment requests by Schleswig-Holstein Netz show that the wind power plant in Klixbüll experienced curtailment for a total of 773 hours in 2020, corresponding to 8.80% of the year. By analyzing the wind speed and curtailment rate at a 15-minute interval, we find that this curtailment resulted in the loss of approximately 36.04 GWh of wind energy per year, accounting for 16.47% of the total potential production of the plant. Figure 7.1 illustrates the wind production in case of no congestion (solid line) and the curtailed wind energy (dotted line) in Klixbüll throughout the year. The months with the most curtailment were May, October, November and December, collectively accounting for 90.84% of all curtailed wind energy.

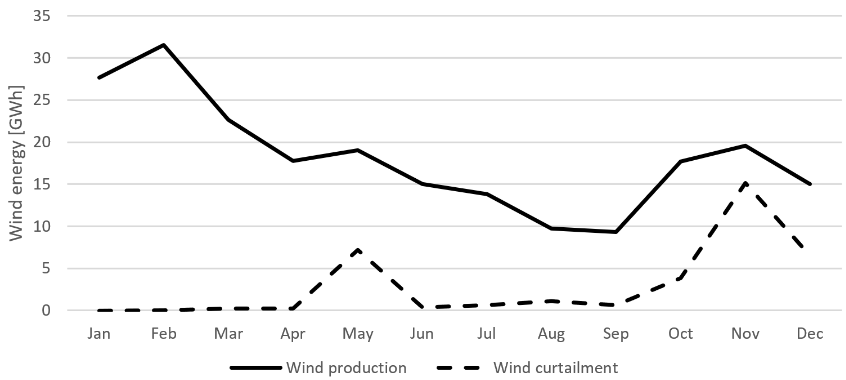


Figure 7.1: Wind production (solid line) and curtailed wind energy by Schleswig Holstein Netz (dashed line) of the wind power plant in Klixbüll, Germany, for 2020.

Although the curtailment data of Schleswig-Holstein Netz indicate that network bottlenecks were responsible for the curtailment measures in Klixbüll, it is difficult to fully identify the effects contributing to these bottlenecks from the data. While the output of the wind power plant will influence the network capacity, the relatively low levels of curtailment observed during months with high wind power production, such as January, suggest the presence of additional factors contributing to congestion measures. These factors can include, among others, peak and off-peak periods of demand and supply sources, weather conditions and maintenance activities by system operators.

7.2.2 Germany's imbalance prices and volumes for 2020

Germany's historical imbalance prices and volumes are available on the ENTSO-E transparency platform [159]. More specifically, the platform reports the imbalance price (€/MWh), the imbalance quantity (MWh) and the imbalance position (short or long) for every settlement period of 15 minutes. The blue points of Figure 7.2 represent the imbalance outcomes in Germany for every settlement period of 2020. The arrows indicate the maximum values, and the percentages present the share of settlement periods in each quadrant.

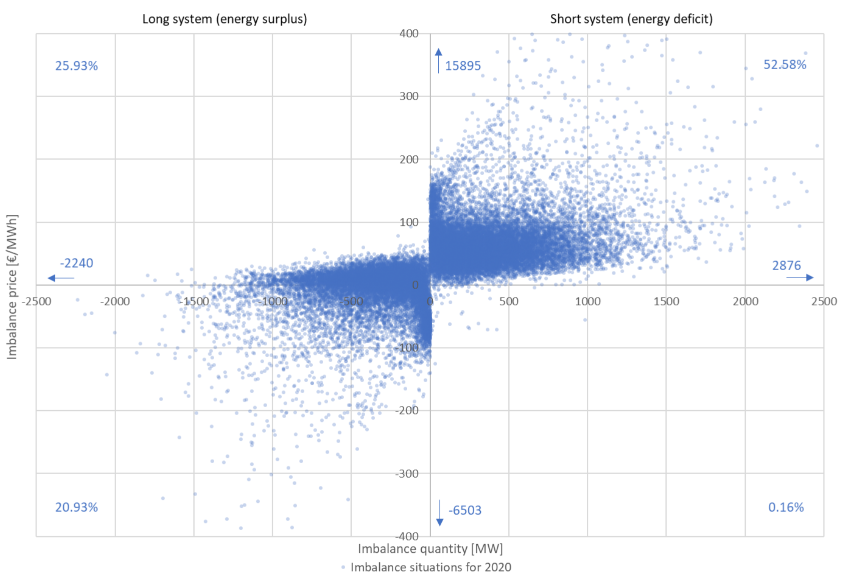


Figure 7.2: Germany's imbalance price and volume for every settlement period of 2020.

In line with [160], we adopt the following sign conventions to describe the imbalance situations.

- A positive imbalance quantity indicates that the system is short (energy deficit), which the TSO can address by activating additional generation or further reducing consumption. These TSO actions typically result in positive imbalance prices as the TSO compensates balancing service providers for their variable generation costs or costs associated with lost load.
- A negative imbalance quantity means the system is long (energy surplus), which the TSO can resolve by placing requests for reducing generation or increasing consumption. On the one hand, these measures lead to positive imbalance prices as the TSO compensates the balancing service provider's opportunity costs, like lost subsidies for unproduced energy. On the other hand, these actions result in negative imbalance prices when the balancing service provider is willing to pay a price to the TSO as the activation leads to avoided fuel costs or increased production outcomes.

7.2.3 Estimation of counterbalancing costs

We can determine the counterbalancing costs associated with the congestion measures by multiplying the curtailed wind volume and the imbalance price for each settlement period. The 36.04 GWh of curtailed wind energy by Schleswig Holstein Netz in Klixbüll results in a total counterbalancing cost of €848 018 for 2020. With a weighted average counterbalancing price of 23.53 €/MWh, our case study indicates that the costs related to counterbalancing can be substantial compared to the average remuneration price for lost revenues due to congestion management, which equals 100 €/MWh under the feed-in management regime[8] [10].

Furthermore, we examine the interaction between the curtailment measures and the system's imbalance by creating a subset of the imbalance data that contains all settlement periods in which curtailment measures were taken. By comparing this subset with the original imbalance dataset, we can gain insights into the state of the system during congestion management periods. Figure 7.3 shows all imbalance outcomes in blue and the subset of imbalance situations that coincide with DSO curtailment measures in orange. For each color, the arrows indicate the maximum values, and the percentages present the share of settlement periods in each quadrant.

[8] It must be noted that only the market premium is considered as lost revenue for renewable generators under the feed-in management regime as the sales revenue can be generated independently of the curtailment measure [153].

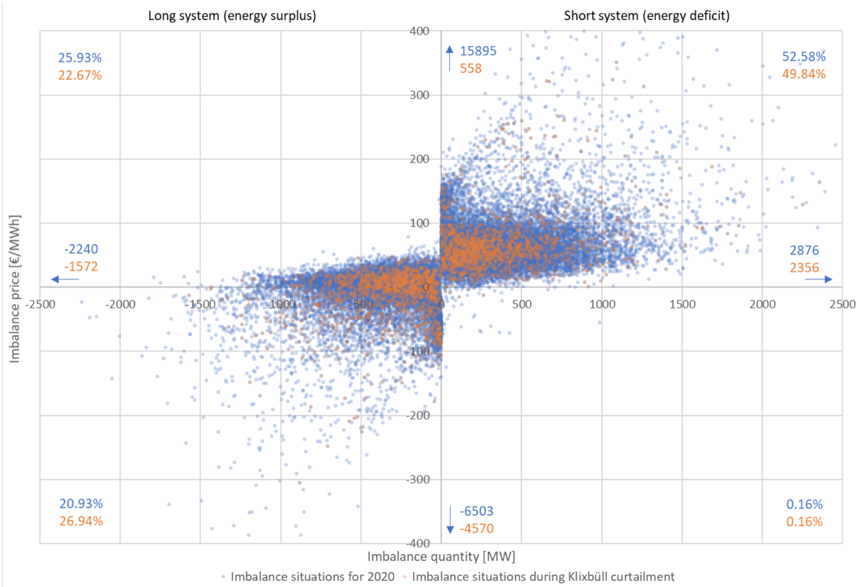


Figure 7.3: Germany's imbalance situations for each settlement period in 2020 in blue, with a subset of imbalance situations during DSO congestion management in orange.

We observe that the settlement periods during curtailment measures follow a similar distribution along the four quadrants as all settlement periods for 2020. Moreover, Figure 7.3 illustrates that curtailment measures by Schleswig-Holstein Netz occur almost evenly during long and short imbalance periods. When the system is short, wind curtailment negatively impacts the system's imbalance. However, when the system is long, the curtailment measures of the DSO can help the TSO to reduce the system's energy surplus. Therefore, the initial assumption that DSO congestion measures adversely impact the system imbalance should be nuanced in some cases, such as our case study.

To include the possible impact of the system imbalance position on the counterbalancing costs related to curtailment measures in distribution network planning, we consider four scenarios.

1. In a worst-case scenario, curtailment measures consistently have an adverse effect on the system imbalance.
2. In a best-case scenario, DSO congestion management always has a beneficial effect on the system imbalance.

3. In a more realistic scenario, such as our case study, the DSO curtails in periods of short and long system imbalances.
4. The balancing costs associated with congestion management measures can be neglected.

We integrate the possible variations in counterbalancing costs into the bilevel model of the next section by considering the weighted average counterbalancing price of the different scenarios. This price is calculated from the orange data points of the case study as the counterbalancing cost divided by the curtailed wind volume for all settlement periods with imbalance positions associated with the considered scenario. Table 7.1 gives an overview of the imbalanced positions and average counterbalancing prices related to the four scenarios.

Table 7.1: Corresponding imbalance positions and counterbalancing prices for each scenario.

	Best case	Neglect case	Average case	Worst case
Associated imbalance positions [-]	Long	None	Long and Short	Short
Average counterbalancing price [€/MWh]	-20.94	0.00	23.53	67.90

7.3 A bilevel model to integrate counterbalancing costs in distribution network planning

This section describes the bilevel model proposed to examine the DSO's tradeoff between network investments and congestion management. First, we discuss the test system. Second, we define the time horizon and the different costs associated with distribution network planning. Finally, we present the mathematical building blocks and solving strategy of the bilevel model.

7.3.1 The test system

The test system, as shown in Figure 7.4, comprises a stylized transmission and distribution node within a single bidding zone and reflects the issue of wind curtailment due to the limited availability of distribution network capacity. The wind power plant at the distribution node is designed after the case of Klixbüll and consists of 23 turbines with a maximum power of 3.075 MW and a marginal cost of 1 €/MWh [154]. To account for the variability of wind, the wind power plant's production is calculated for every hour of 2020 using the methodology of Section 7.2.1. All other parameters are considered constant over the year. The distribution line that connects the distribution node (d) with the transmission node (T) is under construction, and the installed line capacity f_d is a decision variable of the DSO. Finally, an inelastic load source of 500.25 MW and a natural gas power plant of 600 MW with a marginal price of 45€/MWh are connected to the transmission node (T).

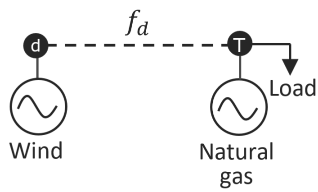


Figure 7.4: The stylized test system.

7.3.2 The time horizon and cost components of network planning

The DSO's investment decision in the test system aims at minimizing the costs associated with network investments, wind curtailment and counterbalancing for one year. The investment costs are a product of the amount of network investments and the annualized incremental network cost. The curtailment and counterbalancing costs are determined in the three-stage electricity market, which is organized for every hour of the year and defined as follows:

- The first stage is the day-ahead wholesale market that clears all supply and demand. While demand is assumed inelastic, supply depends on the power output of the wind plant. The wholesale market is characterized by a zonal market clearing that does not consider network constraints within its bidding zone and might result in congested distribution lines in the test system.
- The second stage is the congestion management market, which the DSO organizes to relieve the overloaded network lines at the distribution level. Due to the test system's design, this market is characterized by wind curtailment at the distribution node (d). The hourly curtailment costs are determined by the curtailment price and the curtailed wind volume. While the curtailment price is considered constant to 100 €/MWh over the year [10], the curtailed wind volume depends on the difference between the power output of the wind plant and the installed network capacity.

- The third stage contains the balancing market, which the TSO organizes. We assume that the TSO will activate the counterbalancing actions of the DSO curtailment measures in the balancing market, but DSO will bear the costs. Due to the design of the test case, the activated units will be located at the transmission node (T) such that congestion at the distribution level at the end of the market sequence is avoided. The hourly counterbalancing costs are a product of the curtailed wind volume and the counterbalancing price, which depends on the considered cost scenario.

We assume that the remaining capacity of the generation units passes from one market to the next and that all markets are auction-based and have a pay-as-clear pricing scheme. Besides that, it must be noted that we do not consider forward markets and congestion management by the TSO.

Instead of solving the three-stage market sequence for every hour of the year in chronological order, we adopt a different approach. We consider the three-stage market sequence once for every wind power level and calculate the yearly curtailment and counterbalancing costs for a certain installed network capacity by multiplying the hourly market results of the wind power levels by their respective number of occurrences in 2020. Table 7.2 gives an overview of the total power output levels of the wind plant in Klixbüll and their respective occurrence in 2020. We adopt this approach to consider the wind production variation throughout the year while maintaining computational efficiency in the model.

7.3.3 The bilevel model

We propose a bilevel model to capture the DSO's network planning decision. Figure 7.5 gives a schematic overview of the bilevel model and its main building blocks. The numbers refer to the respective equations of the mathematical formulation, which we will explain next.

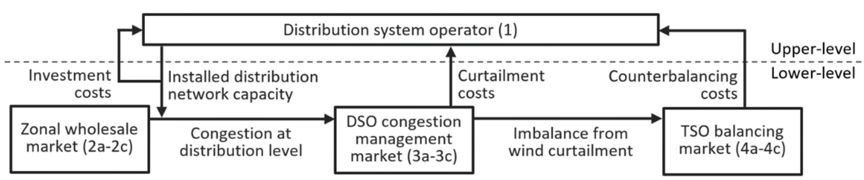


Figure 7.5: Schematic overview of the bilevel model, including references to the optimization problems (1) – (4) of each building block.

Table 7.2: Power output of the wind plant in Klixbüll and its respective number of occurrences in 2020.

Power output [MW]	Occurrence [hours]	Power output [MW]	Occurrence [hours]	Power output [MW]	Occurrence [hours]	Power output [MW]	Occurrence [hours]
0.000	1069	8.269	0	31.671	108	66.654	55
0.132	116	8.941	129	33.264	101	67.689	50
0.265	124	9.614	123	34.857	107	68.724	60
0.397	0	10.413	132	36.449	102	69.058	0
0.529	111	11.213	138	38.042	93	69.391	43
0.788	130	12.012	126	39.767	103	69.725	57
1.047	130	12.811	132	41.492	0	70.058	42
1.305	111	13.748	128	43.217	67	70.167	40
1.564	119	14.686	120	44.942	94	70.277	51
1.921	126	15.623	0	46.771	84	70.386	46
2.277	147	16.560	133	48.599	76	70.495	41
2.634	121	17.664	131	50.428	81	70.541	39
2.990	116	18.768	131	52.256	96	70.587	0
3.427	0	19.872	122	53.981	60	70.633	36
3.864	118	20.976	137	55.706	67	70.679	38
4.301	134	22.230	139	57.431	63	70.691	35
4.738	119	23.483	117	59.156	0	70.702	35
5.284	142	24.737	118	60.513	73	70.714	27
5.831	111	25.990	132	61.870	73	70.725	603
6.377	126	27.410	0	63.227	56		
6.923	121	28.831	125	64.584	55		
7.596	132	30.251	112	65.619	55		

Upper level problem: the distribution system operator

The DSO in the upper level decides on the optimal installed network capacity that minimizes the costs associated with network investments, wind curtailment and counterbalancing for one year, which is formulated as follows.

$$\min C_{nw} f_d + \sum_{l \in \Omega_l} NB_l \; (\lambda_l^c \sum_{g \in \Omega_g} p_{g,l}^c) + \sum_{l \in \Omega_l} NB_l \; (\lambda_l^b \sum_{g \in \Omega_g} p_{g,l}^b) \tag{7.1}$$

Where C_{nw} is the annualized incremental network cost, equal to 150 €/kW/year (as a reference, [44] assume an incremental network cost of 101€/kW/year without sunk costs). f_d represents the installed network capacity at distribution level and is the only decision variable of the DSO. NB_l is the annual number of occurrences of each power level l in the set of wind power levels Ω_l. λ_l^c and λ_l^b are the prices in the congestion management and balancing market for the considered wind power level l. $p_{g,l}^c$ and $p_{g,l}^b$ reflect the dispatched volumes of every generation unit g in the set of generation units Ω_g for the congestion management and balancing market at the analyzed wind power level l.

Lower-level problem 1: the day-ahead wholesale market

The first lower-level problem is the zonal, day-ahead wholesale market, which is organized for every power output level l in the set of wind power levels Ω_l. The generation costs of this market are minimized in (7.2a), considering the maximum capacities of the wind and natural gas units of the test system (7.2b) and the market clearing constraint (7.2c).

$$\min \sum_{g \in \Omega_g} C_g p_{g,l}^w \; \forall \; l \in \Omega_l \tag{7.2a}$$

subject to

$$0 \leq p_{g,l}^w \leq P_{g,l}^{cap} \;\; : \; \underline{\mu}_{g,l}^w, \; \overline{\mu}_{g,l}^w \; \forall \; g \; \in \Omega_g, \; \forall \; l \in \Omega_l \tag{7.2b}$$

$$-\sum_{g \in \Omega_g} p_{g,l}^w + \sum_{k \in \Omega_k} P_k^D = 0 \;\; : \lambda_l^w \; \forall \; l \in \Omega_l \tag{7.2c}$$

Where C_g is the marginal cost of the generation g in the set generation units Ω_g. $p_{g,l}^w$ is the dispatched volume of the generation unit g in the wholesale market for the examined wind power level l. $P_{g,l}^{cap}$ is the maximum capacity of every generation unit g, depending on the wind power level l, and P_k^D is the fixed demand of each load k in the set of loads Ω_k. The dual variables of (7.2b) are given after the colon, and the dual variable of (7.2c) reflects the zonal wholesale market price λ_l^w for the considered wind power level l.

Lower-level problem 2: the DSO congestion management market

The DSO congestion management market is a local, downward market organized to reduce the excess production of the generation units g located at the distribution node N_d at minimum costs for every power output level l in the set of wind power levels Ω_l. The curtailment costs are minimized in (7.3a) while taking into account the technical constraints of the generation units (7.3b) and the constraints of the distribution network (7.3c). We assume in (7.3b) that the maximum curtailed volume of each unit is defined by its dispatched volume in the wholesale market $p^w_{g,l}$. Besides that, we only consider the active power flow through the distribution line in (7.3c).

$$\min \sum_{g \in \Omega_g \cup N_d} C^c_g \, p^c_{g,l} \; \forall \, l \in \Omega_l \tag{7.3a}$$

subject to

$$0 \leq p^c_{g,l} \leq p^w_{g,l} \;:\; \underline{\mu}^c_{g,l},\; \overline{\mu}^c_{g,l} \; \forall \, g \;\in\; \Omega_g \cup N_d, \; \forall \, l \in \Omega_l \tag{7.3b}$$

$$\sum_{g \in \Omega_g \cup N_d} p^w_{g,l} - \sum_{k \in \Omega_k \cup N_d} P^D_k - \sum_{g \in \Omega_g \cup N_d} p^c_{g,l} + f_d = 0 \;:\lambda^c_l \;\; \forall \, l \in \Omega_l \tag{7.3c}$$

Where C^c_g is the curtailment cost of the generation unit g, which equals the average remuneration price under the feed-in management regime of 100 €/MWh [10]. $p^c_{g,l}$ is the curtailed volume of the generation unit g located at the distribution node N_d in the congestion management market for the examined wind power level l. f_d represents the installed distribution network capacity and is defined by the DSO in the upper level. The dual variables of (7.3b) are given after the colon, and the dual variable of (7.3c) reflects the congestion management market price λ^c_l for each wind power level.

Lower-level problem 3: the TSO balancing market

The DSO's curtailment actions are counterbalanced in the balancing market by the activation of generation units that are not located at the distribution node N_d. While the TSO is the balancing market operator, the DSO will bear the counterbalancing costs. The counterbalancing costs are minimized in (7.4a) while considering the technical constraints of the generation units (7.4b) and the system balance constraint (7.4c). We assume in (7.4b) that the counterbalancing volume of each unit is limited by its maximum capacity $P^{cap}_{g,l}$ and its dispatched volume in the wholesale market $p^w_{g,l}$. Furthermore, we only consider the system imbalance caused by DSO congestion management measures in (7.4c).

$$\min \sum_{g \in \Omega_g \cap N_d} C^b_g \, p^b_{g,l} \; \forall \;\; l \in \Omega_l \tag{7.4a}$$

subject to

$$0 \leq p^b_{g,l} \leq P^{cap}_{g,l} - p^w_{g,l} \;:\; \underline{\mu}^b_{g,l},\; \overline{\mu}^b_{g,l} \; \forall \, g \;\in\; \Omega_g \cap N_d, \; \forall \;\; l \in \Omega_l \tag{7.4b}$$

$$-\sum_{g \in \Omega_g \cap N_d} p^b_{g,l} + \sum_{g \in \Omega_g \cup N_d} p^c_{g,l} = 0 \;:\lambda^b_l \; \forall \, l \in \Omega_l \tag{7.4c}$$

Where C^b_g is the counterbalancing cost of the generation unit g, which value depends on the considered counterbalancing scenario. $p^b_{g,l}$ is the activated volume of the unit g, which is not located at the distribution node N_d, in the balancing market for the examined wind power level l. The dual variables of (7.4b) are given after the colon, and the dual variable of (7.4c) reflects the balancing market price λ^b_l for each wind power level.

Solving strategy

As the installed network capacity is the DSO's only decision variable and determines the outcome of the three-stage electricity market for every wind power level, we can approximate the upper level by an iterative algorithm over the installed network capacity. We iterate over 72 levels of network investments, ranging from 0 MW to 71 MW. The iteration with the lowest total costs represents the optimal installed network capacity from the DSO perspective.

For each iteration, we solve the model by transferring the lower levels into Mixed Complementarity Problems (MCP) by using Karush-Kuhn-Tucker (KKT) conditions [125]. The KKT conditions of the day-ahead wholesale market (7.2), the congestion management market (7.3), and the balancing market (7.4) can be formulated as follows.

$$-\sum_{g\in\Omega_g} p^w_{g,l} + \sum_{k\in\Omega_k} P^D_k = 0, \quad \lambda^w_l \ free \ : \forall\, l \in \Omega_l \tag{7.5a}$$

$$0 \leq C_g \ - \lambda^w_l + \overline{\mu}^w_{g,l} \perp p^w_{g,l} \geq 0 \ : \forall\ g \ \in \Omega_g, \ \forall\ l \in \Omega_l \tag{7.5b}$$

$$0 \leq \ P^{cap}_{g,l} - p^w_{g,l} \perp \overline{\mu}^w_{g,l} \geq 0 \ : \ \forall\ g \ \in \Omega_g, \ \forall\ l \in \Omega_l \tag{7.5c}$$

$$\sum_{g\in\Omega_g\cup N_d} p^w_{g,l} - \sum_{k\in\Omega_k\cup N_d} P^D_k - \sum_{g\in\Omega_g\cup N_d} p^c_{g,l} + f_d = 0, \quad \lambda^c_l \ free \ \forall\ l \in \Omega_l \tag{7.5d}$$

$$0 \leq C^c_g - \lambda^c_l \ + \overline{\mu}^c_{g,l} \perp p^c_{g,l} \geq 0 \ : \ \forall\ g \ \in \ \Omega_g \cup N_d, \ \forall\ l \in \Omega_l \tag{7.5e}$$

$$0 \leq \ p^w_{g,l} - p_{g,l}^{\,c} \perp \overline{\mu}^c_{g,l} \geq 0 \ : \ \forall\ g \ \in \ \Omega_g \cup N_d, \ \forall\ l \in \Omega_l \tag{7.5f}$$

$$-\sum_{g\in\Omega_g\cap N_d} p^b_{g,l} + \sum_{g\in\Omega_g\cup N_d} p^c_{g,l} = 0, \quad \lambda^b_l \ free \ : \forall\ l \in \Omega_l \tag{7.5g}$$

$$0 \leq C^b_g + \lambda^b_l + \overline{\mu}^b_{g,l} \perp p^b_{g,l} \geq 0 \ : \forall\ g \ \in \ \Omega_g \cap N_d, \ \forall \ \ l \in \Omega_l \tag{7.5h}$$

$$0 \leq \ P^{cap}_{g,l} - p^w_{g,l} - p^b_{g,l} \perp \overline{\mu}^b_{g,l} \geq 0 \ : \ \forall\ g \ \in \ \Omega_g \cap N_d, \ \forall \ \ l \in \Omega_l \tag{7.5i}$$

As an iterative algorithm approaches the objective of the DSO, the only non-linearities present in the model are the complementarity conditions in the

KKT-conditions of (7.5) with the form $0 \leq a \perp b \geq 0$. These conditions can be replaced by a set of mixed-integer linear conditions $a \geq 0$, $b \geq 0$, $a \leq xM$, $b \leq (1-x)M$ where x is a binary variable and M is a sufficiently large, positive constant [142]. Linearizing these conditions allows us to use commercial optimization solvers such as Gurobi [145] in Julia. However, it must be noted that selecting an appropriate value for M to ensure a globally optimal solution is a non-trivial task that requires careful consideration [146].

7.4 Impact assessment of counterbalancing costs

We illustrate the impact of the counterbalancing costs on distribution network planning for the stylized test case. We first compare the DSO's network investment decision for the four counterbalancing scenarios. Then, we perform a sensitivity analysis. It must be noted that, due to the simplifications and assumptions of the stylized test case, the results of this section do not allow for making detailed recommendations on the optimal level of grid investments in practice. Instead, the analysis is intended to examine the evolutions and interactions of the costs involved with distribution network planning, especially in the context of counterbalancing.

7.4.1 Distribution network planning under different counterbalancing cost scenarios

Figure 7.6 shows the total DSO costs over the installed network capacity for the worst case (yellow), the average case (red), the neglect case (green) and the best case (purple). Moreover, Figure 7.7 shows the different costs components for the average case (red), illustrating the evolution of the DSO's investment (black), curtailment (dark gray) and counterbalancing (light gray) costs over the installed network capacity. Two observations can be made.

First, the evolution of the total costs illustrates the DSO's trade-off between investment, curtailment, and counterbalancing costs. While investment costs increase over the installed network capacity, the costs for curtailment and counterbalancing decrease as less congestion occurs. These two effects lead to an optimal level of installed grid capacity at which the total costs of the DSO are minimized, which is indicated by a cross for each counterbalancing scenario.

Second, as investment and curtailment costs are the same across the four scenarios, the difference between the total cost curves reflects the impact of the counterbalancing costs on network planning. This difference becomes more prominent at lower investment levels, where congestion management measures are more frequent than at higher investment rates.

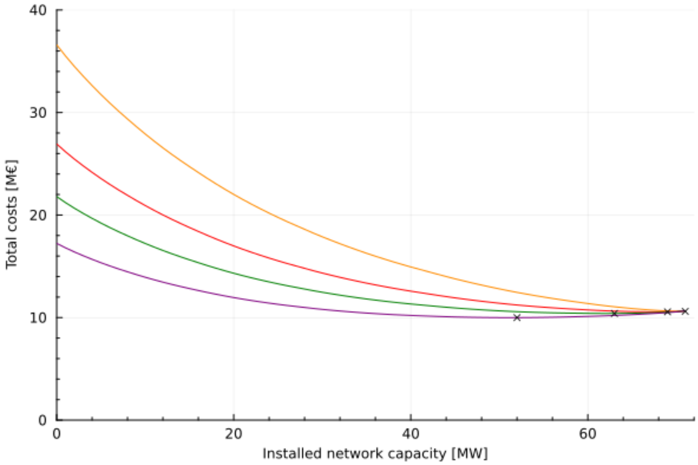


Figure 7.6: The evolution of the DSO's total costs over the installed network capacity for the worst (yellow), average (red), neglect (green), and best (purple) case scenario. The crosses indicate the optimal installed network capacity.

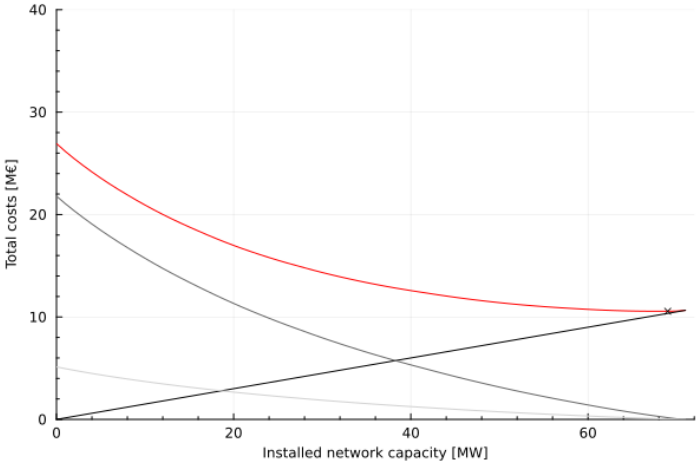


Figure 7.7: The evolution of the DSO's total costs (red) over the installed network capacity for the average scenario, which consist of investment costs (black), curtailment costs (dark gray) and counterbalancing costs (light gray).

The optimal level of installed network capacity for each counterbalancing scenario and the associated curtailment time, curtailment volume and DSO costs are given in Table 7.3. The following three observations can be made.

Table 7.3: The optimal installed network capacity for the four counterbalancing scenarios, with the associated total time and volume of wind curtailment and the total DSO costs with its different cost components at the optimum.

	Best case	Neglect case	Realistic case	Worst case
Optimal installed grid capacity [MW]	51.00	62.00	68.00	70.00
Total curtailment duration [hours]	1896	1464	1193	1033
Total curtailed wind energy [GWh]	29.62	11.01	2.90	0.64
Total DSO costs [M€]	9.99	10.40	10.56	10.60
of which investment costs [M€]	7.65	9.30	10.20	10.50
of which curtailment costs [M€]	2.96	1.10	0.29	0.06
of which counterbalancing costs [M€]	-0.62	0.00	0.07	0.04

First, the optimal level of network investments increases when more counterbalancing costs are considered. Accordingly, the four counterbalancing cost scenarios lead to different investment decisions, with notable variations in installed network capacities. This difference illustrates that the impact of the counterbalancing cost assumption on the DSO's planning decision might be significant in some cases, such as our case study.

Second, the total curtailment time and volume decrease with increasing counterbalancing costs and investment levels. While the curtailment time in the four scenarios is relatively high compared to the actual curtailment duration in Klixbüll for 2020 (equal to 773 hours), the total curtailed wind energy in the four scenarios is significantly lower than the estimated curtailed wind volume in Klixbüll for 2020 (equal to 36.04 GWh). These differences can be explained by the fact that our model consistently curtails wind output exceeding the installed network capacity in a stylized test case, while the curtailment data in Klixbüll results from congestion influences over the whole network area of Schleswig Holstein Netz.

Third, the more counterbalancing costs are considered, the more the total DSO costs increase. It must be noted that this increase primarily reflects the different prices of the counterbalancing scenarios and does not indicate a preference for one scenario over another. When considering the separate cost components of the total DSO costs, we find that investment costs account for the largest share, and the proportion of curtailment and counterbalancing costs depends on the considered scenario.

Alternatively, distribution network planning can be examined by featuring the marginal costs and benefits associated with every additional grid investment.

On the one hand, Figure 7.8 shows that the optimal level of installed network capacity from a DSO perspective coincides with the intersection of the marginal grid investment costs (black) and the marginal benefits of such investments for the DSO, which comprises reduced curtailment and counterbalancing costs. The marginal benefits are considered for the worst case (yellow), the average case (red), the neglect case (green) and the best case (purple) scenario.

On the other hand, Figure 7.8 illustrates the optimal installed network capacity from a system perspective as the intersection of the marginal investment costs (black) and the marginal benefits in generation costs (blue), equal to 24 MW in our test case. This finding suggests that network investments up to the production peak of wind generators might not always be beneficial from a system perspective. Instead, it can be more efficient to allow some degree of congestion management into the system in some cases, such as in our test system.

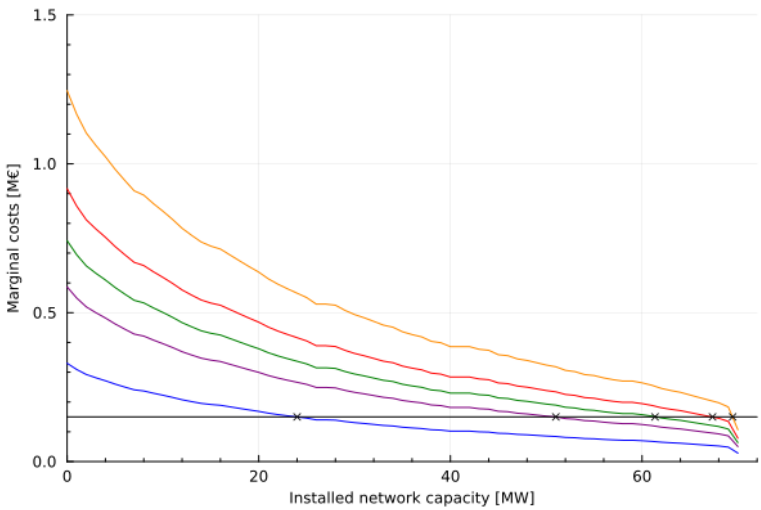


Figure 7.8: Evolution of the marginal investment costs (black), the marginal benefits from the system's perspective (blue), and the marginal benefits from the DSO's perspective for the worst case (yellow), the average case (red), the neglect case (green) and the best case (purple) scenario over the installed network capacity. The crosses indicate the optimal installed network capacity from the system's and DSO's perspectives for each scenario.

7.4.2 Sensitivity analysis

We perform a sensitivity analysis to evaluate the impact of the cost parameters on the DSO's network investment decision. We first examine the influence of the curtailment and the incremental network cost assumptions. Additionally, we introduce a variation to the primary parameter defining the system perspective in our test case: the marginal cost of the natural gas plant.

Curtailment and incremental network costs

We consider three cases with varying curtailment and incremental investment cost assumptions:

1. The curtailment favored system with a curtailment cost of 80 €/MWh and an incremental network cost of 180 €/kW/year.
2. The reference system with a curtailment cost of 100 €/MWh and an incremental network cost of 150 €/kW/year.
3. The investment favored system with a curtailment cost of 120 €/MWh and an incremental network cost of 120 €/kW/year.

Table 7.4 presents the optimal installed capacity with the associated curtailment parameters and DSO costs for the four counterbalancing scenarios and the three sensitivity systems. We make three observations that complement the findings of the reference case in Section 7.4.1.

First, the four counterbalancing cost scenarios result in varying investment decisions, with the optimal installed capacities diverging more in curtailment-favored systems and converging more in investment-favored systems.

Second, the total curtailment time in curtailment-favored and investment-favored systems remains high compared to the actual curtailment duration in Klixbüll for 2020, even at high levels of installed network capacity. Also the total curtailed wind energy remains low compared to the calculated curtailment volumes in Klixbüll for 2020, except in some cases of the curtailment-favored system.

Third, the more balancing costs are considered, the more the total DSO costs increase. This observation is more apparent in a curtailment-favored system and less pronounced in an investment-favored system.

	Best case	Neglect case	Realistic case	Worst case
Optimal installed grid capacity [MW]	29	43	55	68
Total curtailment duration [hours]	3024	2298	1740	1193
Total curtailed wind energy [GWh]	82.0	46.33	22.36	2.90
Total DSO costs [M€]	10.10	11.45	12.22	12.67
of which investment costs [M€]	5.22	7.74	9.90	12.24
of which curtailment costs [M€]	6.62	3.71	1.79	0.23
of which counterbalancing costs [M€]	-1.73	0.00	0.53	0.20

(a) Curtailment favored system

	Best case	Neglect case	Realistic case	Worst case
Optimal installed grid capacity [MW]	51	62	68	70
Total curtailment duration [hours]	1896	1464	1193	1033
Total curtailed wind energy [GWh]	29.62	11.01	2.90	0.64
Total DSO costs [M€]	9.99	10.40	10.56	10.60
of which investment costs [M€]	7.65	9.30	10.20	10.50
of which curtailment costs [M€]	2.96	1.10	0.29	0.06
of which counterbalancing costs [M€]	-0.62	0.00	0.07	0.04

(b) Reference system

	Best case	Neglect case	Realistic case	Worst case
Optimal installed grid capacity [MW]	68	70	70	70
Total curtailment duration [hours]	1193	1033	1033	1033
Total curtailed wind energy [GWh]	2.90	0.64	0.64	0.64
Total DSO costs [M€]	8.45	8.48	8.49	8.52
of which investment costs [M€]	8.16	8.40	8.40	8.40
of which curtailment costs [M€]	0.35	0.08	0.08	0.08
of which counterbalancing costs [M€]	-0.06	0.00	0.01	0.04

(c) Investment favored system

Table 7.4: The optimal installed capacity with the associated total DSO costs and total curtailment time, considering the four counterbalancing cost scenarios and the three sensitivity systems.

Marginal cost of natural gas plant

We introduce an additional sensitivity to the curtailment-favored, reference, and investment-favored system by examining three variations of the natural gas prices. More specifically, we consider the following marginal prices: 45€/MWh (original case), 65€/MWh, and 85€/MWh. While this variation impacts the optimal level of investments from a system perspective, it does not affect the DSO's investment decision.

Table 7.5 presents optimal levels of installed capacity from the system perspective for three natural gas prices. The following three remarks can be made. First, the three sensitivity systems result in varying optimal installed capacities for the same natural gas price as different incremental network costs are considered. Second, higher natural gas prices promote network investments from a system perspective, as the substitution of natural gas by wind brings greater opportunities to reduce generation costs. Finally, in all cases, it remains beneficial to incorporate a certain degree of congestion management into the system. This degree can align with the optimal congestion management rate from a DSO perspective when the marginal generation costs are in the same range as the marginal curtailment and counterbalancing costs.

Table 7.5: Optimal installed capacity from a system perspective for the three sensitivity systems and varying natural gas prices.

Optimal installed capacity [MW]	Natural gas 45 €/MWh	Natural gas 65 €/MWh	Natural gas 85 €/MWh
Curtailment favored system	18	33	46
Reference system	24	40	54
Investment favored system	34	52	63

7.5 Limitations of the model

We discuss the three main limitations of the proposed case study and bilevel model and make suggestions for future work.

First, our study is limited to the case of excess wind production at the distribution level. Other factors influencing the DSO's congestion management decision were not considered, like peak and off-peak periods of demand and production sources, weather conditions and grid works by system operators. For future work, it could be interesting to examine the counterbalancing costs related to DSO congestion management measures for alternative reasons, like consumption peaks (e.g., electric vehicles, evening peaks, ...) or production peaks of other generation types (e.g., PV panels, ...). Moreover, expanding the bilevel model to additional factors influencing network congestion could improve the representation of congestion in the DSO's network investment decision, aligning the duration and volume of curtailment measures more with the characteristics of Schleswig Holstein Netz's curtailment data.

Second, we consider a simplified representation of the distribution network that leaves out transmission losses, distribution losses, and voltage limits. As a result, the proposed model cannot examine congestion issues due to voltage violations or reactive power flows in the distribution network. Adopting a better representation of the distribution network in future research can therefore expand the scope of distribution network planning of the proposed model. Furthermore, the assumptions on the incremental grid costs can be advanced to better capture the dynamics of distribution network investments and planning. Here, the methodology and cost parameters described in [161] might serve as a relevant starting point. The sensitivity analysis of Section 7.4.2 already gives a first indication of the potential impact of alternative cost assumptions on the DSO's network investment decision. More specifically, lower grid costs tend to lead to investment favored systems and increased grid costs toward flexibility favored systems.

Finally, we assume that the DSO can adopt high shares of congestion management in its network planning, while national regulation and consumer rights might limit this. For example, the 3% curtailment rule allows German DSOs to consider the curtailment of renewable plants' power output by 3% in network planning. Higher curtailment rates are only allowed temporarily when the necessary network investments are being made to achieve this maximum curtailment level in the future [155]. Such regulation can significantly impact the DSO's network investment decision, which is an interesting suggestion for future work.

7.6 Conclusions

With the increasing activation of DERs in separate markets for DSO congestion management, the effect of these actions on the system imbalance, and its respective need for counterbalancing measures, can no longer be neglected. This need is reinforced by the fact that the costs associated with counterbalancing might affect the DSO's trade-off between congestion management and network investments. However, the magnitude of counterbalancing costs related to congestion management, and their impact on network planning, remain largely unknown today. We contribute to this knowledge gap in three ways.

First, we examine to what extent we should account for the counterbalancing costs of DSO congestion management measures for a typical congestion situation in Europe: the curtailment of wind due to limited network capacity of distribution level. By comparing data from Germany for 2020, we find that the counterbalancing costs associated with wind curtailment measures can be significant, depending on the system's imbalance position. To incorporate these varying counterbalancing costs in distribution network planning, we develop average counterbalancing prices for four interactions between curtailment and the system imbalance: the neglect case, the best case, the average case, and the worst case.

Second, we investigate how we can incorporate counterbalancing costs in distribution network planning. We propose a bilevel model to capture the DSO's annual trade-off between network investments and congestion management. While the upper level reflects the DSO's investment decision that minimizes network planning and operation costs, the lower levels represent three stages of electricity markets that determine the amount of network congestion and the associated curtailment and counterbalancing costs. We show that the upper level can be approached by an iterative algorithm such that the lower levels can be formulated as Mixed Complementarity Problems.

Finally, we evaluate the effect of counterbalancing costs on the DSO's network investment decision for a stylized test case. Our results show varying investment decisions for the different counterbalancing cost scenarios, illustrating the potential impact of accounting for counterbalancing costs in distribution network planning in some cases, such as our test system. Moreover, we find that network investments up to the production peak of wind generators might not always be beneficial from a system and DSO perspective.

Chapter 8

Conclusions

8.1 Summary and conclusions

This dissertation aims to foster the use of flexibility in distribution grids through empirical studies, regulatory analyses, and mathematical programs. Our analysis consists of three main parts: developments in distribution network planning, practical experiences with flexibility tools, and open issues when designing flexibility markets.

8.1.1 Developments in distribution network planning

While congestion in distribution grids is not yet a concern in many European countries, the long connection queues for new grid users in the Netherlands and the curtailment of renewables in Germany illustrate that the adoption of distributed energy resources at distribution level can quickly lead to congestion issues, catching DSOs unprepared. As a result, developments in distribution network planning are needed such that the growing amount of distributed energy resources can be integrated efficiently and cost-effectively into European distribution grids. To support the development of these distribution network plans, the Clean Energy Package introduced several provisions across five planning dimensions: planning frequency, coordination with the TSO, digitalization, transparency, and flexibility as an alternative to grid investments. However, the description of these provisions remains relatively high-level, leaving the detailed implementation up to the Member States.

Chapter 2 describes the stakeholder analysis that was performed to gain insights into the current practices of distribution network planning, examine open issues regarding the implementation of the CEP's provisions, and evaluate the alignment of DSOs on a common target model in the future. As part of the stakeholder analysis, we conducted interviews and organized a workshop with 11 DSOs from different European countries, leading to the following three conclusions.

First, the current practices indicate that there is no single approach to distribution network planning. DSOs gave diverging answers for each of the analyzed dimensions, and often different responses could be combined within the network planning of a single DSO. This observation indicates the importance of allowing a certain degree of freedom when implementing a common methodology for distribution network planning.

Second, most DSOs establish pilot projects to discover the potential of flexibility in distribution networks and intend to include flexibility as an alternative to grid investments in network planning. However, developing a robust methodology to include a cost-effective trade-off between flexibility and grid investments in network planning is still an issue for many DSOs. Furthermore, the best approach to source this flexibility is still under discussion. This finding indicates that progress on the development of flexibility in distribution grids is being made but acknowledges the need for further research by academics and stakeholders to address this issue comprehensively.

Finally, DSOs are already well aligned on a future target model covering the dimensions of planning frequency, coordination with the TSO, digitalization, and flexibility as an alternative to grid investments. However, the level of transparency of future distribution network plans is still debatable. Security constraints are the main reason for not making details of network investment plans publicly available. The use of heatmaps and the reporting of private and public network investment plans can be solutions to align DSOs on the implementation of the CEP's provision on transparency.

8.1.2 Practical experiences with flexibility tools

Different regulatory tools to source flexibility at distribution level exist, such as dynamic network tariffs, flexible connection agreements, flexibility markets, bilateral contracts, cost-based mechanisms and obligations. However, the optimal approach to unlock the full potential of flexibility at the distribution level is still under discussion. This debate will be influenced by the practical experiences of implementing regulatory tools to source flexibility (as examined in Chapter 3) and the regulatory learning that come with developing sandbox projects on flexibility tools (as discussed in Chapter 4).

Chapter 3 aims to gain insights into the design options and complexities involved with the practical implementation and combination of flexibility tools. We conducted an empirical study of the regulatory implementation dynamic distribution network tariffs and flexible connection agreements across Europe.

Our analysis of the regulatory implementation of dynamic distribution network tariffs in ten European countries and regions indicates that these tariffs are evolving to include incentives for efficient network usage by grid customers. This evolution is achieved by developing different cost components, granularity, and customer types for grid tariffs. Moreover, we find considerable variations in the implementation of dynamic network tariffs across the examined countries. In our investigation of flexible connection agreements across seven European countries and regions, we observe the growing use of connection agreements as a regulatory tool to integrate flexibility into the operation and planning of distribution networks. However, we found significant variations in the implementation of these connection agreements in the examined countries regarding the use cases, allocation of grid capacity, customer types, and compensation schemes.

The development and adoption of both flexibility tools raise questions about their compatibility and the impact of their respective design choices. We find that besides giving implicit flexibility signals to grid users through dynamic network tariffs, there is a potential for DSOs to explicitly contract flexibility using flexible connection agreements or other regulatory tools, such as flexibility markets, bilateral contracts, cost-based mechanisms, or obligations. These explicit tools can be designed to contract flexibility for both short-term and long-term periods and can be implemented in either a mandatory or voluntary way. However, a comprehensive examination of the effectiveness of the various design choices of each flexibility mechanism, as well as the risk and opportunities associated with combining different flexibility tools, is currently lacking and represents an important subject for future research.

In this context, regulatory sandboxes can be an important instrument to examine the impact of (combining) flexibility tools in a real environment, leading to regulatory learning by regulators and policymakers. **Chapter 4** explores the potential of regulatory sandboxes to foster innovations, such as flexibility, in the energy transition. We evaluate the outcomes of existing sandbox projects and legal implementations of sandbox frameworks across Europe in two parts.

First, we examined 72 existing sandbox projects in Brussels, Flanders, France, Great Britain, the Netherlands, Norway and Wallonia. Using an inductive thematic approach, we divided these projects into five main categories of innovation: local energy, flex participation in electricity markets, distribution network tariffs, connections to electricity networks and connections to gas networks. The presence of several projects focusing on flexibility tools, such as differentiated distribution network tariffs for grid users in energy communities and flexible connection agreements to grant faster grid connections to renewable energy resources, reinforces the idea that regulatory sandboxes can be an effective instrument to test innovations and examine open issues on the design of flexibility tools (as defined in Chapter 3), in a real environment.

Second, we compared the legislation on regulatory sandboxes in Austria, Brussels, Flanders, France, Germany, Great Britain, the Netherlands, Norway, Spain and Wallonia. Using a 7-dimensional framework, we developed the following two conclusions. First, the entity responsible for the administration of the sandbox program and the derogations that can be granted to sandbox projects are the most important parameters when designing a sandbox framework, as they directly impact the potential for regulatory learning and the scope of sandbox projects. Second, our analysis indicates that the application process and the reporting of the lessons learned also influence the performance of the sandbox framework. While a call-based application process allows regulators to highlight regulatory themes, it can rush innovators into applications. Furthermore, even though reporting obligations are typically included in sandbox frameworks, effective implementation in practice is essential for both technical and regulatory learning to occur.

Based on our analysis, we defined two policy implications. First, the outcomes of existing sandbox projects validate the idea of using regulatory sandboxes to examine innovations under REPowerEU Plan in a real environment and indicate important areas for future regulatory learning. More specifically, the projects on synthetic methane injection in the gas network illustrate that sandboxes can promote the diversification of the gas sector. The projects on flexible connections to the electricity network show that regulatory derogations can accelerate the rollout of renewables. Second, to promote innovation and regulatory learning, it is important to make the regulatory scope of the sandboxes as open as possible while keeping it tangible for project applicants. Best practices found in the analyzed regulatory frameworks are twofold: including multiple regulatory entities in the administration process and having an open approach towards regulatory derogations while providing regulatory advice to sandbox applicants. Besides that, administrators should continuously evaluate and update the sandbox program, especially if they organize dedicated calls.

8.1.3 Open issues when designing flexibility markets

As the Clean Energy Package emphasizes the market-based procurement of flexibility, the final aim of this dissertation is to examine open issues that arise when designing flexibility markets. The examples of NODES, Piclo Flex and GOPACS illustrate how third-party market platforms are tapping into the opportunity of flexibility at the distribution level and are developing different implementations of flexibility markets in practice. More specifically, these market platforms diverge in their design choices regarding use cases, operational timeframes, market products, and involvement of system operators. These variations in flexibility market design indicate that although third-party platforms are operational and growing in traded volumes, open issues persist regarding the future development and harmonization of these markets. We contribute to this discussion by performing a qualitative analysis using multi-stakeholder perspectives (as examined in Chapter 5) and a quantitative analysis using mathematical programming (as discussed in Chapter 6 and 7).

Chapter 5 debriefs the findings of the multi-stakeholder analysis, which involves twelve research questions on key aspects of flexibility market design. These questions explore the use cases and incentives for flexibility markets, the interaction of flexibility markets with existing electricity markets, flexibility market rules and products, and the roles and responsibilities of flexibility market parties. For each question, an overview of design options was presented, for which the stakeholders could not yet define the optimal approach. The diverging answers to these questions demonstrate that there are still many open questions regarding flexibility market design and might partly explain why the consideration of flexibility in network planning remains a challenge for many European DSOs (as observed in Chapter 2). The following recommendations can help to address the identified challenges in flexibility markets design and network planning: setting up flexibility initiatives even when flexibility providers are still limited (as shared as best practice in Chapter 2), experimenting with flexibility market design and network planning using regulatory sandboxes (as demonstrated in Chapter 4), and addressing financial disincentives for the use of flexibility by system operators (as described in Chapter 5).

Furthermore, we identify three guiding principles from the stakeholder discussions. First, flexibility market design should consider the local characteristics of distribution networks to deliver congestion management and voltage control services effectively. Second, the design of flexibility markets should minimize the impact of uncertainty, both in the context of determining the network state and providing flexibility services. Finally, flexibility markets should facilitate information exchange between market parties while ensuring the data protection of grid users and the security constraints of network operators.

Chapter 6 proposes a bilevel model with a three-stage electricity market to examine strategic behavior in flexibility and redispatch markets. We evaluate the concern that grid users will strategically use flexibility markets to deliberately create and solve congestion, also known as inc-dec gaming, in two ways.

First, we examine the proposed model for various strategic agents and a stylized example characterized by renewable energy curtailment due to limited available capacity at the transmission and distribution network interface. We find examples of price-setter games and inc-dec games using redispatch and flexibility markets, illustrating the bigger picture of strategic behavior in three-stage electricity markets. When comparing the bidding strategies of our test system, we observe that the price-setter and inc-dec games hold under different market conditions. Moreover, we find that inc-dec games using flexibility markets are similar to the games known from redispatch markets. Also, we clarify the distinction between the incremental and decremental strategy of the inc-dec game, which is typically treated as one. Regulators and system operators can use these characteristics to distinguish strategic behavior in practice.

Second, we explore the impact of price-setter and inc-dec games on network congestion, market prices, total consumer costs and total generation costs based on the outcomes of our test case and a literature review. While both games lead to changes in market prices and consumer costs, price-setter games have a more prominent impact on total generation costs, whereas inc-dec games affect network congestion. Besides, we find that while the inc-dec games using redispatch markets influenced market prices in all cases, the volumes traded in the inc-dec games using flexibility markets were too small to observe this effect. As a result, monitoring inc-dec games in flexibility markets might be more complex than in redispatch markets.

It is important to note that because the volumes traded in (early-stage) flexibility markets are still small (but growing, as described in Chapter 5), the occurrence of the games identified in this Chapter might be more frequent as limited market liquidity increases the potential for market power and reduces options to activate alternative flexibility providers. The characteristics of the games defined in Chapter 6 can help regulators and system operators to detect these games in practice. However, our analysis has shown that this monitoring exercise might be more difficult in flexibility markets than in redispatch markets as long as the volumes traded in these markets remain considerably lower.

Chapter 7 performs a data comparison and develops a bilevel model to assess the magnitude of counterbalancing costs related to congestion management and the relevance of these costs in distribution network planning in three ways.

First, we examine to what extent we should account for the counterbalancing costs of DSO congestion management measures for a typical congestion situation in Europe: the curtailment of wind due to limited network capacity of distribution level. By comparing data from Germany for 2020, we find that the counterbalancing costs associated with wind curtailment measures can be significant, depending on the system's imbalance position. To incorporate these varying counterbalancing costs in distribution network planning, we develop average counterbalancing prices for four interactions between curtailment and the system imbalance: the neglect case, the best case, the average case, and the worst case.

Second, we investigate how we can incorporate counterbalancing costs in distribution network planning. We propose a bilevel model to capture the DSO's annual trade-off between network investments and congestion management. While the upper level reflects the DSO's investment decision that minimizes network planning and operation costs, the lower levels represent three stages of electricity markets that determine the amount of network congestion and the associated curtailment and counterbalancing costs. We show that the upper level can be approached by an iterative algorithm such that the lower levels can be formulated as Mixed Complementarity Problems.

Third, we evaluate the effect of counterbalancing costs on the DSO's network investment decision for a stylized test case. Our results show varying investment decisions for the different counterbalancing cost scenarios, illustrating the potential impact of accounting for counterbalancing costs in distribution network planning in some cases, such as our test system. Moreover, we find that network investments up to the production peak of wind generators might not always be beneficial from a system and DSO perspective.

Overall, the findings of Chapter 7 illustrate the complexity and sensitivities involved with setting a price for flexibility in network planning and align with the DSO's open issue to develop a robust methodology to consider the trade-off between flexibility and investments in network planning (as highlighted in Chapter 2). More specifically, the data comparison in Chapter 7 illustrates that the price of flexibility might depend on specific interactions with other electricity markets. Furthermore, the results of the bilevel model in Chapter 7 indicate that this price assumption might influence the outcome of the network development plans. These findings enforce the need for further research by academics and stakeholders to set a suitable flexibility price and develop a robust network planning methodology (as identified in Chapter 2).

8.2 Policy implications

In this section, the findings of this dissertation are discussed in the context of two ongoing developments in the European regulation of the electricity sector: the Electricity Market Reform and the Network Code on Demand Response.

The Electricity Market Reform is Europe's response to the energy crisis experienced in 2022. Once the rules within the Electricity Market Reform receive approval from both the Council and the European Parliament, they transform into European laws that amend the Regulations and Directives under the Clean Energy Package [162]. At the time of writing, the trilogues that will determine these final rules are still ongoing. As a result, our policy implications are based on three topics regarding distribution networks and distribution system operators that were included in the draft texts of the Electricity Market Reform by the Council [163] and the European Parliament [164].

First, the draft texts mention that distribution system operators shall provide new grid users with clear and transparent information on available network capacity [163, 164]. Based on our insights from the stakeholder discussions on the transparency of network planning and the country examples on the reporting of grid congestion in Chapter 2, we acknowledge the importance of providing clear and transparent network information to grid users and flexibility providers, especially in congested areas, and highlight the potential of network capacity heatmaps for this purpose.

Second, the ongoing Electricity Market Reform introduces the possibility to include additional incentives for the use and development of flexibility services in tariff methodologies of distribution system operators. More specifically, the draft texts state that considering operational and capital expenditures, or an efficient combination of both, should be allowed in tariff methodologies [163, 164]. These improvements in incentive regulation might foster progress in the development of flexibility services, which was indicated as an important open issue in Chapter 2, and might address potential financial disincentives for the use of flexibility by distribution system operators, as described in Chapter 5. However, it is important to note that, as highlighted in Chapter 5, such a totex approach should be carefully designed to avoid an inadvisable level of complexity and guarantee efficient incentives toward distribution system operators.

Finally, the draft texts allow distribution system operators to establish flexible connection agreements as a temporary congestion management tool in congested network areas [163, 164]. Based on our insights regarding the complexity and concerns involved with the implementation of flexibility markets from Chapters 5 and 6, and considering the identified interest by Member States for flexible connection agreements in Chapter 3, the findings of this dissertation support the development of a European framework for flexible connection agreements. However, it is important to note that this development might bring new challenges regarding the optimal design of flexible connection agreements and the combination of flexibility tools, as illustrated in Chapter 5. Therefore, the need for further research by academics and stakeholders on the optimal design and possible interactions of flexibility tools, as identified in Chapter 5, might become even more critical in the coming years.

The new Network Code on Demand Response aims to enable market access for demand response and facilitate the market-based procurement of flexibility services by system operators [165]. A proposal for this Network Code, drafted by the EU DSO Entity and ENTSO-E, is currently undergoing public consultation [166]. Once reviewed and adopted by ACER, these network codes will be translated into regulations [167]. While the draft Network Code on Demand Response sets out important European principles and requirements regarding distribution system operators, such as network planning, flexibility procurement and TSO-DSO coordination, it leaves the development of most terms and conditions up to the Member States. Based on the findings of this dissertation, we highlight one benefit and one potential risk of this approach.

On the one hand, formulating terms and conditions at the national level brings the opportunity to acknowledge the diversity in experiences, size and operations between distribution system operators in the regulatory framework. Based on our insights from Chapter 2, which illustrate that there is no single approach to distribution network planning, we acknowledge the importance of allowing a certain degree of freedom when developing methodologies and regulations for distribution system operators.

On the other hand, the development of terms and conditions at the national level following the proposal of system operators, public consultations and the approval by national regulatory authorities also brings a potential risk. As indicated by the stakeholder analyses of Chapters 2 and 5, many open questions remain regarding the implementation of network planning, flexibility procurement and TSO-DSO coordination. As a result, further research on these topics will be essential to support and guide stakeholders and avoid a delayed implementation of the Network Codes.

8.3 Suggestions for future research

This dissertation aims to foster flexibility in distribution networks by exploring developments in distribution network planning, practical experiences with flexibility tools, and open issues in designing flexibility markets. To achieve this, we adopt three different methodologies: empirical studies, regulatory analyses and mathematical programming, each leading to specific suggestions for future research.

8.3.1 Future empirical studies and regulatory analyses

The empirical studies, including the analysis of practical examples and stakeholder perspectives, and the regulatory analyses of this dissertation can be expanded in future research by extending the geographical scope of the analyses, involving additional stakeholder perspectives, and performing frequent updates of practice and regulation. Using these guidelines, a further exploration of the following four topics would be especially interesting.

First, the ongoing experiences with grid congestion in Europe (building further on the examples of Section 2.1), as these congestion issues illustrate the need and use cases of flexibility in distribution networks.

Second, the recent developments in distribution network planning in Europe, especially regarding the trade-off between flexibility and network investments (which was highlighted as an important open issue in Section 2.2). In this way, further insights can be gained into the optimal approach to integrate the increasing amount of distributed energy sources effectively and cost-efficiently in distribution networks.

Third is the implementation of flexibility tools, emphasizing flexibility markets, to learn more about the optimal approach to source flexibility and the compatibility of these flexibility tools. These insights might be used to narrow down the design choices on dynamic distribution network tariffs, flexible connection agreements and flexibility markets (as discussed in Sections 3.2.1, 3.2.2 and 5.2 respectively).

Finally, the ongoing developments and outcomes of regulatory sandboxes (using the frameworks of Sections 4.3 and 4.4), to learn from experiences with sandboxes in countries outside of Europe, such as Australia, and explore the outcomes of approved sandbox projects, of which many will be completed after 2025.

8.3.2 Future mathematical programs

The bilevel models developed in Chapters 6 and 7 of this dissertation can, among others, be extended by incorporating uncertainty in load and generation parameters, considering the equilibrium between multiple strategic agents, using a more detailed representation of the distribution network and introducing additional regulatory measures.

By applying these principles, more accurate and realistic results can be achieved in two key areas of our work. First, quantifying the total impact of gaming in flexibility markets, beyond the examination of the bidding characteristics. Interesting expansions in the context of regulation are the inclusion of mitigation measures in the market rules and objective(s) of the strategic agent(s). Second, a better representation of network congestion and the DSO's investment decision in distribution network planning. Regarding regulatory measures, alternative flexibility tools and additional rules regarding the use of flexibility could be considered.

Besides the proposed modeling extensions, the stylized examples of this dissertation could be improved by considering longer timeframes and alternative network topologies. These alternative grid topologies could involve an extensive set of transmission and distribution nodes and a detailed representation of other grid users such as prosumers, electric vehicles and storage.

In this context, examining the following two topics is particularly interesting. First, the impact of alternative test systems on strategic behavior in flexibility markets, specifically considering the effect on the bidding strategies of existing games and the occurrence of additional games by new grid users. Second, the influence of alternative test cases on the interaction between flexibility and the system imbalance, especially regarding the magnitude of counterbalancing costs and the relevance of these costs in distribution network planning.

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Appendix A

Appendix to Chapter 3

A.1 Overview of examined national regulations on dynamic distribution network tariffs

Figure A.1 gives an overview of the regulatory frameworks and planned reforms on dynamic distribution network tariffs that we examined in [43] and summarized in Section 3.2.1.

	Practice?		Addressed network costs?			Tariff components?			Granularity?			Customer class?
Country	Currently in place	Planned reform	Sunk	Forward looking	No distinction	Fixed	Volume	Capacity	Locational	Temporal energy	Temporal capacity	
Belgium, Brussels	X				X		X	X		2 periods		LV<56 kVA or LV>56kVA w/o metering point
	X				X		X	X		2 periods		Trans MV, MV, Trans LV, LV>56kVA
Belgium, Flanders	X				X		X		X	2 periods		Household and small companies
	X				X	X	X		X	2 periods		Prosumers without smart metering
	X				X		X	X	X	2 periods		Big companies
		X			X		X	X	X			Households and small companies
		X			X			X	X			Big companies
Belgium, Wallonia	X				X		X		X	4 periods		LV<56 kVA or LV>56kVA w/o metering point
	X				X		X	X	X	2 periods		Trans MV, MV, Trans LV, LV>56kVA
France	X				X		X	X		2 periods 2 seasons		LV <36kVA
	X				X		X	X		2 periods 2 seasons	2 periods 2 seasons	LV >36kVA
	X				X		X	X		2 periods 2 seasons + 1period	2 periods 2 seasons + 1period	MV, HV
Germany	X		X	X		X	X		X			All voltage levels without metering of load profiles
	X		X	X			X	X	X			All voltage levels with metering of load profiles
	X		X	X			X		X			Interruptible consumer installations[1]
Norway	X				X	X	X	(X)	X			LV<100kW
	X				X	X	X	X	X			LV>100kW, MV, HV
		X	X	X		X	X	(X)	X	X	(X)	LV<100kW
Poland	X				X	X	X		X	1 or 2 periods		Households and small LV customers
	X				X		X	X	X	1, 2 or 3 periods		Large consumers at LV, all MV, all HV
Portugal	X				X		X	X		1, 2 or 3 periods		LV
	X						X	X		4 periods 2 seasons		MV, HV
		Pilot			X		X	X	X	4 periods	2 periods 3 seasons	MV, HV, EHV
Spain		X			X		X	X		3 periods	2 periods	LV
		X			X		X	X		3 periods 4 seasons	3 periods 4 seasons	MV, HV
The UK	X				X	X	X		X	1, 2 or 3 periods		Domestic and small business
	X				X	X	X	X	X	3 periods		Large business
		X	X	X		X	X	X	X	X	X	LV, MV, HV

[1] Interruptible consumer installations such as electric heating, heat pumps, others defined in the §14a EnWG regulation.

Figure A.1: Overview of examined national regulations on dynamic distribution network tariffs [43].

A.2 Overview of examined national regulations on flexible connection agreements

Figure A.2 gives an overview of the regulatory frameworks and planned reforms on flexible connection agreements that we examined in [43] and summarized in Section 3.2.2.

	Practice?		Addressed network challenge?		Targeted technology?		Curtailment?		Agreement?		Compensation?		
Country	Currently in place	Planned reform	ASM and planning	Critical cases	RES	All generation	Capacity based	Energy based	By default	By consent	Curtailed energy	Other	No
Belgium, Flanders		X	X		X			X		X	X		X
Belgium, Wallonia	X			X		X	X		X		X		X
France		X	X		X		X	X		X		X	
Germany feed-in management	X	X		X		X	X		X		X		X
Germany 3% curtailment rule	X		X		X		X	X	X		X		
Norway	X			X		X	X			X			X
Spain		X		X	X		X			X			X
The UK	X		X			X	X			X		X	

Figure A.2: Overview of examined national regulations on flexible connection agreements [43].

Appendix B

Appendix to Chapter 4

B.1 Overview of examined projects on regulatory sandboxes

Figures B.1-B.6 give an overview of approved sandbox projects and inductive thematic approach of Section 4.3 [169].

Category 1: Local energy		
Subcategory 1.1: Energy sharing, collective self-consumption, and energy communities		
Name (country) duration	Project summary, *with keywords in italic*	Granted regulatory derogations
1. Marius Renard (BR) 21/12/2021-20/12/2023	*Share electricity* from a *cogeneration* plant in the same building and test new concepts of *metering and billing* network tariffs.	Derogations from supplier obligations, present distribution network tariffs, smart meter installation tariffs, billing and metering rules of tariffs.
2. SunSud (BR) 21/12/2021-20/12/2023	*Share solar energy* within a building with social housing and test new concepts in terms of *metering and billing* network tariffs.	Derogations from supplier obligations, present distribution network tariffs, smart meter installation tariffs, billing and metering rules of tariffs.
3. HG Stockel Energy (BR) 29/03/2022-28/03/2024	*Share solar energy* within the same building and test new concepts in terms of *metering and billing* network tariffs.	Derogations from supplier obligations, present distribution network tariffs, smart meter installation tariffs, billing and metering rules of tariffs.
4. ThorPark (FL) 07/02/2020-06/02/2025	*Share energy* between the buildings on the of an industrial site.	Derogations from supplier responsibilities.
5. MikroFlex (NO) 31/10/2019-01/04/2024	*Sharing surplus energy* from self-produced electricity between residents on the same farm and farm number.	Derogations to the definition of a plus consumer beyond the connection point, from billing and metering rules of distribution network tariffs.
6. MéryGrid (WA) 01/03/2019-28/02/2021	Test *energy management system* to improve *collective self-consumption* in a *community* with industry, generation, *batteries.*	Derogations from billing and metering rules of distribution network tariffs.
7. Cannock Chase (GB)	Maximise the participant's benefits by optimizing the *time-of-use retail tariffs*, the *self-consumption* rate of *solar* energy using *storage*, and providing *balancing and flexibility services*.	Unclear from project description.
8. Trent Basin (GB)	Maximise participant's benefits by optimizing the self-consumption rate of solar energy using storage.	Unclear from project description.
9. Tour&Taxis Energy (BR) 29/03/2022-28/03/2024	*Share solar energy* within the same building and test new concepts in terms of *metering and billing* network tariffs.	Derogations from supplier obligations, present distribution network tariffs, smart meter installation tariffs, billing and metering rules of tariffs, the right to choose peak/off-peak grid tariffs for locally produced energy.
10. Les Bambins (BR) 01/07/2020-30/06/2022	Create a *renewable energy community* and test new concepts in terms of *metering and billing* network tariffs.	Derogations from supplier obligations, present distribution network tariffs, smart meter installation tariffs, billing and metering rules of tariffs, the right to choose peak/off-peak grid tariffs for locally produced energy, the prohibition for DSOs to be involved in producing activities.
11. LogisCER (WA) 01/05/2022-31/10/2023	*Energy sharing* in a *renewable energy community* of public housing.	Derogations from metering rules, network tariff rules, supplier obligations, and governance rules for DSOs (e.g., the right to install production and being involved in the sharing of energy).
12. Greenbizz Energy (BR) 09/02/2021-08/02/2023	Create a *renewable energy community*, test new concepts in terms of *metering and billing* network tariffs, develop application to *optimize local self-consumption*.	Derogations from supplier obligations, present distribution network tariffs, smart meter installation tariffs, billing and metering rules of tariffs, the right to choose peak/off-peak grid tariffs for locally produced energy.

Figure B.1: Overview of the approved sandbox projects and the inductive thematic approach for Subcategory 1.1: Energy sharing, collective self-consumption, and energy communities [169].

Category 1: Local energy		
Subcategory 1.2: Energy sharing, including dynamic distribution tariffs		
Name (country) duration	Project summary, *with keywords in italic*	Granted regulatory derogations
13. HospiGREEN (WA) 01/11/2020-01/11/2023	Implementation of a *renewable energy community* and improve *collective self-consumption* (by giving *network tariff discounts* for self-consumed energy).	Derogations from metering rules, supplier obligations, network tariff rules, and invoicing rules of network tariffs.
14. E-Cloud (WA) 01/05/2019-30/04/2020	Implementation of a renewable energy community and improve *collective self-consumption* (by giving *network tariff discounts* for self-consumed energy).	Derogations from metering rules, supplier obligations, network tariff rules, and invoicing rules of network tariffs.
15. Endona (NL) approved in 2015 for 10 years	*Share energy*, balance the electricity grid through *peak shaving* and test *dynamic electricity tariffs*.	Derogations from the prohibition of performing DSO tasks, the supplier obligations, the rules regarding metering device requirements and data processing, the methodology to determine grid tariffs, and the rules regarding transparency and liquidity of the energy market.
16. Aardehuizen (NL) approved 2016 for 10y	See Endona, all 'big experiments' in the Netherlands have a similar project summary.	See Endona, all 'big experiments' in the Netherlands could request the same regulatory derogations.
17. Eemnes (NL) approved in 2017 for 10 years	See Endona, all 'big experiments' in the Netherlands have a similar project summary.	See Endona, all 'big experiments' in the Netherlands could request the same regulatory derogations.
18. MET Amersfoort (NL) approved 2018 for 10y	See Endona, all 'big experiments' in the Netherlands have a similar project summary.	See Endona, all 'big experiments' in the Netherlands could request the same regulatory derogations.
19. Groene mient (NL) approved 2015 for 10y	See Endona, all 'big experiments' in the Netherlands have a similar project summary.	See Endona, all 'big experiments' in the Netherlands could request the same regulatory derogations.
20. ACRus (WA) 01/04/2022-31/03/2025	See Endona, all 'big experiments' in the Netherlands have a similar project summary.	See Endona, all 'big experiments' in the Netherlands could request the same regulatory derogations.
21. Vassinghaugen borettslag (NO) 31/10/2019-31/10/2024	*Sharing surplus production* from self-produced electricity between residents in the same building and test a new *distribution Time-of-Use tariff model*.	Derogations to the definition of a plus consumer, and tariff methodologies to differentiate network tariffs of consumers and add a time of use energy component to the distribution tariff.

Figure B.2: Overview of the approved sandbox projects and the inductive thematic approach for Subcategory 1.2: Energy sharing, including dynamic distribution tariffs [169].

Category 1: Local energy		
Subcategory 1.3: Energy sharing, including dynamic distribution tariffs and network operation		
Name (country) duration	Project summary, *with keywords in italic*	Granted regulatory derogations
22. Parq Green (NL) approved in 2015 for 10 years	*Share energy*, balance the electricity grid through *peak shaving*, test *dynamic electricity tariffs* and *operate* the distribution network.	Derogations from the prohibition to perform DSO tasks, the obligation to have a supplier permit, the rules regarding metering device requirements and data processing, the methodology to determine grid tariffs, and the rules regarding transparency and liquidity of the energy market.
23. Collegepark Zwijsen (NL) approved 2015 for 10y	See Parq Green, all 'network projects' in the Netherlands have a similar project summary.	See Parq Green, all 'network projects' in the Netherlands could request the same regulatory derogations.
24. Noordstraat 111 (NL) approved 2016 for 10y	See Parq Green, all 'network projects' in the Netherlands have a similar project summary.	See Parq Green, all 'network projects' in the Netherlands could request the same regulatory derogations.
25. Schoonschip Amsterdam (NL) 2016 for 10 years	See Parq Green, all 'network projects' in the Netherlands have a similar project summary.	See Parq Green, all 'network projects' in the Netherlands could request the same regulatory derogations.
26. Villa de verademing (NL) approved 2016 for 10y	See Parq Green, all 'network projects' in the Netherlands have a similar project summary.	See Parq Green, all 'network projects' in the Netherlands could request the same regulatory derogations.
27. Republica Papaverweg (NL) 2017 for 20 years	See Parq Green, all 'network projects' in the Netherlands have a similar project summary.	See Parq Green, all 'network projects' in the Netherlands could request the same regulatory derogations.
28. Zevenheuvels, Wezep (NL) 2018 for 15 years	See Parq Green, all 'network projects' in the Netherlands have a similar project summary.	See Parq Green, all 'network projects' in the Netherlands could request the same regulatory derogations.
29. Kleine duinvallei (NL) approved 2018 for 10y	See Parq Green, all 'network projects' in the Netherlands have a similar project summary.	See Parq Green, all 'network projects' in the Netherlands could request the same regulatory derogations.
30. Bad noordzee (NL) approved 2018 for 10y	See Parq Green, all 'network projects' in the Netherlands have a similar project summary.	See Parq Green, all 'network projects' in the Netherlands could request the same regulatory derogations.
Subcategory 1.4: Peer-to-peer trading		
Name (country) duration	Project summary, *with keywords in italic*	Granted regulatory derogations
31. EDF (GB)	*Peer-to-peer* energy trading platform.	Unclear from project description.
32. Empowered (GB)	*Peer-to-peer* energy trading platform.	Unclear from project description.
33. Verv (GB)	*Peer-to-peer* energy trading platform.	Unclear from project description.
34. BP (GB)	*Peer-to-peer* energy trading platform.	Unclear from project description.
35. F&S Energy Ltd (GB)	*Peer-to-peer* energy trading platform.	Unclear from project description.
Subcategory 1.5: Consumer rights in microgrids		
Name (country) duration	Project summary, *with keywords in italic*	Granted regulatory derogations
36. Emergent (GB) 14/07/2022-13/07/2024	Delivering the *right to switch electricity supplier* for residential customers on *microgrids*.	Derogations from the metering, metering data and invoicing rules.

Figure B.3: Overview of the approved sandbox projects and the inductive thematic approach for Subcategory 1.3: Energy sharing, including dynamic distribution tariffs and network operation, Subcategory 1.4: Peer-to-peer trading and Subcategory 1.5: Consumer rights in microgrids [169].

Category 2: Flex participation in electricity markets		
Subcategory 2.1: Wholesale markets		
Name (country) duration	Project summary, *with keywords in italic*	Granted regulatory derogations
37. Eqinov (FR) 01/07/2023-30/06/2027	Enhance the *business model* of demand response by valuing *upward demand flexibility* via the load-shedding block exchange notification mechanism NEBEF.	Derogations to the load-shedding block exchange notification mechanism to allow the valuation of an increase in consumption.
Subcategory 2.2: Balancing markets		
Name (country) duration	Project summary, *with keywords in italic*	Granted regulatory derogations
38. OVO Energy (GB)	Examine an *innovative tariff* for customers with *storage heaters*, allowing the valuation of *flexibility and grid balancing services*.	Unclear from project description.
39. Centrica Business Solutions (GB) 01/09/2022-31/08/2024	Enable *participation in balancing services* from customers that are currently not half-hourly settled and may not have access to half-hour settlement soon.	Derogations from the Balancing and Settlement Code on the classification and registration of metering systems, the allocation of supplier volumes, and the aggregation of half-hourly data.
40. EDF (FR) 31/03/2023-30/03/2027	Explore and optimize the *business model* of a *battery* storage in *ancillary services markets*.	Derogations to allow a battery to aggregate with (multiple) existing balancing service providers and participate in (multiple) ancillary service markets.
41. NorFlex (NO) 01/08/2021-01/04/2022	Access *distributed energy resources* for *manual Frequency Restoration Reserve services* through a shared flexibility market with the DSO.	Derogations from the guidelines and responsibilities for TSOs regarding the minimum bid quantity.
42. eFleks (NO) 17/08/2020-01/11/2020	Stimulate the participation of *flexibility* in *manual Frequency Restoration Reserve services*.	Derogations from the guidelines and responsibilities for TSOs regarding the minimum bid quantity.
43. Fast Frequency Reserves (NO) 21/01/21-03/10/21	Examine the design of *Fast Frequency Reserves* to stimulate the participation of flexibility.	Derogation from responsibilities of TSOs regarding the provision of guidelines on their operation of task and responsibilities.
Category 3: Distribution network tariffs		
Subcategory 3.1: Alternative grid connection charges		
Name (country) duration	Project summary, *with keywords in italic*	Granted regulatory derogations
44. Charge collective (GB) 01/11/2021-30/10/2023	Examine *alternative connection charges* for *electric vehicle* charging points based on price-point discovery mechanisms.	Derogations on the connection charging methodology of the Electricity Distribution License.
Subcategory 3.2: Dynamic network usage tariffs		
Name (country) duration	Project summary, *with keywords in italic*	Granted regulatory derogations
45. Engie B2C (FR) 01/02/2022-31/07/2023	Offer a *new peak tariff* to customers at low voltage levels to reduce/postpone their consumption during peak network periods.	Derogations to the tariff methodologies to offer new tariffs, which consider critical network peaks, to low voltage customers.
46. SmartNettleie (NO) 10/02/2020-31/12/2021	Examine a new *Time-of-Use distribution tariff model*.	Derogations to tariff methodologies to add a time of use energy component to the distribution tariff.
47. Topplastprising (NO) 13/11/2019-30/04/2020	Examine *dynamic distribution network tariffs* using peak load pricing.	Derogations to tariff methodologies to allow the differentiation of network tariffs of consumers that normally belong to the same category.
48. Aktive hjem (NO) 02/10/2020-31/10/2021	Examine *dynamic distribution network tariffs*.	Derogations to tariff methodologies to differentiate network tariffs of consumers and add a time of use energy component to the tariff.

Figure B.4: Overview of the approved sandbox projects and the inductive thematic approach for Subcategory 2: Flex participation in electricity markets and Subcategory 3: Distribution network tariffs [169].

Category 4: Connection to electricity networks		
Subcategory 4.1: Technical solutions		
Name (country) duration	Project summary, *with keywords in italic*	Granted regulatory derogations
49. AFR 20/ Amarenco (FR) 01/07/2023-30/06/2027	*Optimal connection* of *storage* to the *distribution network* of Enedis.	Derogations to the technical documentation of Enedis when carrying out connection studies.
50. WPD (FR) 01/01/2023-31/12/2026	Speed up *connection request* of a *wind power plant* by an alternative connection to the *distribution network* with a direct feeder and a reactive power range that deviates from standards.	Derogations to the technical documentation of Enedis and distribution network tariffs to allow WPD to pay a compensation for the additional grid losses due to deviations in reactive power.
Subcategory 4.2: Flexibility solutions		
Name (country) duration	Project summary, *with keywords in italic*	Granted regulatory derogations
51. Boralex (FR) 02/03/2022-01/03/2026	*Connect wind power plants* with installed capacities above the allowed standards to the *distribution network*, provided that the power injected remains within limits.	Derogations to on the technical design and operating requirements for connection to the electricity grids.
52. BayWa r.e. (FR)	*Connect* three *wind power plants* and one *solar power plant* with installed capacities above the allowed standards to the *distribution network*, provided that the power injected remains within limits.	Derogations to on the technical design and operating requirements for connection to the electricity grids.
53. Fibre excellence Tarascon SAS (FR) 07/02/2022-07/02/2026	*Connect* new production units with installed capacities above the allowed standards to the *distribution network*, provided that the power injected remains within limits.	Derogations to on the technical design and operating requirements for connection to the electricity grids.
54. Enedis Reflex (FR) 23/07/2021-23/07/2025	Testing *flexibility* to *optimize the network sizing* and to allow for more *renewable energy* without additional *network investments*.	Derogations to on the technical design and operating requirements for connection to the electricity grids.

Figure B.5: Overview of the approved sandbox projects and the inductive thematic approach for Subcategory 4: Connection to electricity networks [169].

Category 5: Connection to gas networks		
Subcategory 5.1: Synthetic methane		
Name (country) duration	Project summary, *with keywords in italic*	Granted regulatory derogations
55. SAS HYMOOV 1 (FR) 01/06/2021-31/05/2025	*Injection of synthetic methane* from pyrogasification and methanation into the *gas network*.	Derogations to allow a detailed injection study, the possibility of registering the project in the biomethane capacity register, the connection of the project owner, the analysis of the quality of the gas produced and the injection of the gas produced.
56. SAS GDL/ Quairos (FR) 28/04/2021-27/04/2025	*Injection of synthetic methane* from pyrogasification into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
57. Pau Béarn Pyrénées (FR) 03/12/2021-02/12/2025	*Injection of synthetic methane* from methanation into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
58. PMMCU (FR) 31/12/2021-30/12/2025	*Injection of synthetic methane* from methanation into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
59. Storengy Méthycentre (FR) 24/06/21-23/06/25	*Injection of synthetic methane* from methanation into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
60. Storengy Hycaunais (FR) 04/06/2021-03/06/2025	*Injection of synthetic methane* from methanation into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
61. Energo (FR) 15/11/2021-14/11/2025	*Injection of synthetic methane* from methanation into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
62. SAS HYMOOV 2 (FR) 01/07/2023-30/06/2027	*Injection of synthetic methane* from methanation into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
63. SAS HYMOOV 3 (FR) 01/07/2023-30/06/2027	*Injection of synthetic methane* from methanation into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
64. SAS HYMOOV 4 (FR) 01/07/2023-30/06/2027	*Injection of synthetic methane* from methanation into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
65. SAS HYMOOV 5 (FR) 01/07/2023-30/06/2027	*Injection of synthetic methane* from methanation into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
66. Bordeaux Metropole (FR) 01/07/23-30/06/27	*Injection of synthetic methane* from methanation into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
67. Arkolia Energies (FR) 01/07/2023-30/06/2027	*Injection of synthetic methane* from methanation into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
68. Enosis (FR) 01/07/2023-30/06/2027	*Injection of synthetic methane* from methanation into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
69. CUMA des éleveurs du bergeracois (FR) 01/07/2023-30/06/2027	*Injection of synthetic methane* from methanation into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
70. Siah Croult Et Petit Rosne (FR) 01/07/2024-30/06/2028	*Injection of synthetic methane* from methanation into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
71. SEMARDEL (FR)	*Injection of synthetic methane* from pyrogasification into the *gas network*.	See SAS HYMOOV 1, all projects on synthetic methane in France received the same regulatory derogations.
Subcategory 5.2: Flexibility solutions		
72. SEM Energie Mayenne 01/07/2023-30/06/2027	Provide *flexibility services* with a compressed natural gas station to the public *gas network* such that the *injection of biomethane* can be developed without causing additional *network investments*.	Derogations from the gas network operator's obligation to fully connect new users. Missing legal, technical, contractual or financial frameworks for implementing flexibility solutions in the gas sector.

Figure B.6: Overview of the approved sandbox projects and the inductive thematic approach for Subcategory 5: Connection to gas networks [169].

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Short Curriculum

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Education

2019-2023	PhD candidate at Vlerick Business School, Vlerick Energy Centre and KU Leuven, Department of Mechanical Engineering, Division of Applied Mechanics and Energy Conversion.
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List of Publications

Articles published in peer-reviewed academic journals

- Beckstedde, E., Meeus, L. and Delarue, E., 2023. A bilevel model to study inc-dec games at the TSO-DSO interface. IEEE Transactions on Energy Markets, Policy and Regulation. doi: 10.1109/TEMPR.2023.3292425
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- Beckstedde, E., Meeus, L. and Delarue, E., 2023. Accounting for counterbalancing costs in the DSO's congestion management and network investment decision. ESIM Working paper.
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