Report on market design for micro-grid markets including interaction with the surrounding system and market

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Co-creating with partners that help to understand the needs of relevant stakeholders, we team up with intermediaries to provide an innovation eco-system supporting consortia for research, innovation, technical development, piloting and demonstration activities. These co-operations pave the way towards implementation in real-life environments and market introduction.

Beyond that, ERA-Net SES provides a Knowledge Community, involving key demo projects and experts from all over Europe, to facilitate learning between projects and programs from the local level up to the European level.

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1. Introduction

1.1 Aim and scope of the work

This report summarizes the work performed in Task 5.3 of the m2M-GRID project. In the project application, this task is described as follows:

"Based on the concept of the local flexibility and energy market, this task specifies on the process for energy exchange between different market actors inside a micro-grid, between micro-grids as well as with overlay markets. The local market will not necessarily have the same time frame or objectives and constraints as the overlaying market. The local energy market will also allow system service offers to the distribution as well as transmission system operators."

Therefore, the main topic of Task 5.3 is to study the market-based processes for energy exchange within and between local markets for energy and flexibility. This is a very broad subject that can be analyzed in many different ways. It has therefore been necessary to further concretize the task, which has been achieved in two different ways.

First, in order to provide structure and more precise language to the discussions about local energy and flexibility markets, a high-level analysis has been conducted with the aim of describing and categorizing various market-based (or incentive-based) mechanisms available for the coordination of local electricity systems. This has here been done primarily from the perspective of distribution system operators (DSOs). It attempts to clarify which options are available, in terms of market-based or incentive-based mechanisms, for helping DSOs managing local electricity networks more efficiently. These options are described, and some potential advantages and disadvantages are discussed.

Second, a few specific topics have been chosen and analyzed in more detail. Two of these topics are related to a possible future market landscape where electricity is traded locally to a larger extent than what is the case today. In such a fragmented market landscape, questions arise regarding the interaction between different local markets or microgrids. In this task, we have focused on two aspects of such interactions: energy trading between electricity markets with different market time resolutions, and how forecast errors affect the optimality of market outcomes. Further, as a third topic for more detailed analysis, an empirical investigation of how DSO network fees provide incentives for investments in distributed generation has been carried out.

As a final remark, note that the term "microgrid" in this report is used in a broad sense, encompassing various schemes for local electricity coordination and cooperation. This is consistent with the approaches taken by other tasks in Work Package 5 of the m2M-GRID project. For example, Task 5.1 makes a distinction between physical and commercial microgrids, where the latter can be described as a collection of flexible resources managed by e.g. an aggregator and does not necessarily mean that these resources are capable of being operated in islanded mode [1].

1.2 Outline of the report

Chapter 2 provides an overview and categorization of various local market-based approaches for enabling local flexibility. In addition to providing an overview and categorization, this also includes an analysis of advantages and disadvantages of the various approaches.

The remaining chapters of this report (chapters 3, 4 and 5) each focuses on one of the topics chosen for more detailed analysis. The topics are:

- Impacts of forecasting errors in centralized and decentralized electricity markets, analyzed using a theoretical model and Monte Carlo simulations.
- Arbitrage trades between electricity markets with different time resolution, analyzed using two stylized theoretical models.

- Network fees and incentives to invest in distributed generation, analyzed empirically using data from Swedish DSOs.

Because chapters 3 through 5 each provide a detailed analysis on a specific topic, they are written such that each chapter is self-contained and can be read without reading the rest of the report. Therefore, these chapters contain their own introductions, conclusions and discussions.

2. Approaches for unlocking local flexibility

2.1 Introduction

The electricity markets in Europe today largely follow the same structure since unbundling and liberalization 20-30 years ago. Systems are generally set up to deliver electricity from large, centralized generators, transported through the transmission network, voltage step down to the distribution network to be delivered to consumers. In other words, traditionally, electricity will flow from the transmission network to the distribution network and not the other way around, however, this is now changing.

As a result of the current market structure, the system operator is essentially blind to detailed information on the distribution level. Moreover, wholesale electricity spot markets in Europe and elsewhere typically do not take capacity limitations in distribution systems into account when electricity is traded. This means that it is implicitly assumed that the distribution systems will have sufficient capacity to accommodate whatever amount of electricity is demanded by the end-users, as well as any electricity produced by distributed energy resources (DER). This assumption reflects that electricity distribution systems are typically dimensioned to be able to accommodate any foreseeable load peaks, with substantial margin. In practice, this means that electricity distribution infrastructure such as distribution lines and transformers are generally capable of distributing much more electricity than what is needed on a typical day, such that they can meet the peak loads that may occur under extreme conditions.

The practice of dimensioning distribution systems to be able to accommodate all foreseeable load peaks means that Distribution System Operators (DSOs), as opposed to Transmission System Operators (TSOs), traditionally do not need to actively manage power flows on their networks in real time. Instead DSOs have been able to focus their attention on more long-run activities, such as investing in and maintaining the distribution infrastructure.

Recent developments in electricity systems is putting this practice into new light. Proliferation of DERs, especially solar PV, is changing load profiles and power flow patterns, potentially changing the timing, magnitude and direction of power flows. Further, electric vehicles are creating a new source of intermittent load peaks. These developments, along with continued load growth due to urbanization and population growth, is causing some distribution systems (or parts thereof) to approach their capacity limits. Meanwhile, new options are becoming available that could enable DSOs to more actively manage power flows, as an alternative to traditional grid infrastructure reinforcement measures. These options include demand response, distributed energy storage and active control of DERs.

Against this backdrop, allowing DSOs to take on a more active role in managing power flows using local flexibility resources has been proposed as an alternative and potentially more cost and time efficient alternative to traditional grid reinforcement measures [2]. However, the flexibility available from demand response and DERs is under the control of end-users who likely have preferences concerning how and when their flexibility can be utilized. Further, because of unbundling rules, DSOs may be prevented from directly owning and operating flexibility sources such as energy storage. Therefore, other forms of market-based or incentive-based mechanisms may be needed, where the DSO can financially compensate end-users (or provide end-users with financial incentives) for assisting the DSO in managing the local network. Local flexibility markets can also emerge where actors wish to take more control over how their electricity is generated and when, for example to increase security of supply or uptake of renewable generation [3].

Unlocking local flexibility can help solve issues related to network constraints, balancing and voltage issues, reduce losses, as well as portfolio management. Ref. [4] outlines four categories of flexibility need: flexibility for power, flexibility for energy, flexibility for transfer capacity, and flexibility for voltage. This chapter will outline and discuss some of the many options for how the different flexibility needs can be met, from the perspective of the DSO as the need-owner.

The remainder of this section attempts to provide a description of the main approaches available, including solutions already being used by some DSOs today, as well as more innovative solutions being tested in research projects and demonstration sites. We consider both instruments available to the DSOs and market-based solutions with multiple actors.

This chapter discusses the concept of local flexibility, approaches for organizing flexibility services, and their potential place in the European electricity market landscape. The chapter begins with a brief overview of some key components of the regulatory framework surrounding the European electricity market, focusing on the structure and role different actors which underpin the liberalized electricity market model.

This is followed by a description and analysis of possible approaches that can help unlock local flexibility. Six different approaches are discussed, categorized as either a DSO instrument or as a market-based approach, and assessed based on technical, social, regulatory or transparency barriers. Examples are provided for each of the six approaches.

The identification and assess the different approaches in this report was carried out through a review of research projects, ongoing pilots and demonstrations, and to some extent published academic literature. This work was followed by a workshop with subject matter experts to analyze the six different approaches and potential barriers to implementation.

2.2 The European electricity market model - an overview

This section provides an overview of some of the key components of the European liberalized electricity market model. This market model (or similar) has been in effect in several European countries since the 1990s and has more recently been adopted by the European Union when regulating the European internal market for electricity. It is to a varying degree implemented in most EU countries.

2.2.1 Market actors and unbundling

The European electricity market model is based on an unbundled approach, where each segment of the electricity market - generation, transmission, distribution, and supply - are treated separately. Generation and supply of electricity are competitive segments with multiple actors operating on the market. Electricity networks, on the other hand, tend to operate in separate and distinct regions with only one network owner licensed to operate a certain voltage in each area. This is due to the high upfront and sunk costs that generally characterize electricity network operation. As a result of the high barriers to entry and the economic benefits of limiting the network operators in each area, electricity networks are considered natural monopolies. This means that it would be inefficient to have more than one network owner operating in each area. Due to the lack of competition, electricity networks' revenues are regulated by national regulatory authorities protecting electricity customers from unwarranted prices. The transmission and distribution activities are generally carried out by companies that, with some exemptions, are prohibited from engaging in other segments of the electricity sector, for example buying or selling electrical energy. For a detailed description of how unbundling has been implemented in different European countries, see [5].

The companies that own and operate the high-voltage transmission networks are referred to as Transmission System Operators (TSOs). The TSOs are also responsible for ensuring that the necessary short-run balance between injections and withdrawals is maintained. They are often (but not necessarily) state-owned national enterprises. Ownership of the physical network assets and the responsibility for the operation of the electricity system can be separate, this is for example the case in Great Britain. An Independent System Operator (ISO) can operate the system whilst a separate Transmission Owner (TO) is responsible for owning and maintaining the grid. Responsibility for network planning and development can sit with either the ISO or the TO. For ease, we will use TSO throughout this report. The companies that own and operate the distribution-level grid infrastructure are called Distribution System Operators (DSOs) and are typically either privately or municipally owned.

2.2.2 Balance responsibility

A fundamental principle underlying the competitive trading of electrical energy in Europe is the concept of balance responsibility [6]. This principle means that every consumer who withdraws electrical energy from the grid is responsible for ensuring that an equal amount of energy is injected by a producer somewhere else in the grid during the same time-period. The time-periods are called imbalance settlement periods (ISP) and are typically between 15 minutes and 1 hour long. European regulations stipulate that all TSOs shall apply an ISP of 15 minutes before the end of 2020 [7].

It would be impractical for smaller consumers, such as households, to directly manage their balancing responsibility themselves. Instead, electricity suppliers, as part of the agreement to supply electricity, contract with its customers to manage the balancing responsibility on their behalf[1]. The responsibility of the electricity supplier is then to make a forecast of what they believe that their customers will consume in every ISP and either produce this energy themselves or buy it from other generators. The trading of electricity between suppliers and generators needs to take place in advance to ensure that the generators can plan when and how much to produce.

Generators also have a balance responsibility where the balance responsibility means that they must ensure that, for every ISP, they generate the same amount of electrical energy as they have sold to the electricity suppliers.

The entities who have taken on the balance responsibility for one or more consumers or producers are referred to as balance responsible parties, or BRPs. Each metered connection point to the electrical grid, be it for consumption or production, must be assigned to one (and only one) BRP.

Shortly before the operational hour, all BRPs are required to submit production and consumption plans to the TSO. These plans show how much electricity each consumer and producer has bought or sold for each ISP. At this point, the TSO takes over responsibility for ensuring that injections and withdrawals are balanced in the grid, using balancing services procured from some flexible producers and consumers.

After the operational hour, when the meter values are available, the production and consumption plans of each BRP is compared to the actual meter values for the connection points that belong to each BRP. The BRP is then financially responsible for the imbalance, i.e. the difference between the plan and the metered amount. This imbalance settlement aims at making it financially advantageous for the BRPs to try to get their plans as accurate as possible.

2.2.3 Day-ahead and intraday markets

The balance responsibility requirements and the imbalance settlement system ensure that producers and consumers (represented by BRPs) have financial incentives to trade electrical energy with each other ahead of time.

[1] Alternatively, the electricity supplier could in turn outsource the balance responsibility to a third party.

They could do so directly on a bilateral basis, i.e. without going through a centralized marketplace. However, in a purely bilateral market, it would be difficult for buyers and sellers to find suitable counterparties that are able to match their specific requirements concerning how the production or consumption should be distributed over time. Further, it would be difficult for market participants to find the best available deals for every ISP, leading to suboptimal market outcomes. Therefore, electricity is typically traded via a centralized daily auction, called the day-ahead market, where many consumption and production bids are pooled together to find an efficient match for all ISPs of the next day. The day-ahead auction is then followed by intraday trading, where market participants can adjust their day-ahead position, for example if their production or consumption forecasts change.

The day-ahead and intraday markets are physical markets in the sense that a transaction in these markets involve a responsibility to produce or consume electrical energy during a specific ISP (or else be financially responsible for the imbalance costs). These physical markets, or spot markets, are complemented by more long-run financial markets. In the financial markets, financial products are traded that settle against a specific future spot market price, typically the day-ahead price. This allows market participants to hedge against uncertain price movements in the volatile day-ahead market.

2.2.4 Grid capacity limitations

Electrical grids have capacity limitations. If these are not taken into consideration in the day-ahead and intraday markets, situations may arise where the outcomes from the market trading are not compatible with the physical transfer capacity of the grid. Several different approaches are used to deal with this issue.

One approach is to ignore the issue in the trading process, allowing any producer to sell electricity to any consumer no matter where in the grid they are located, and then let the TSO manage any resulting issues using so called countertrading. This means that the TSO pays producers and consumers that are located in certain areas to change their consumption or production, relative to the market outcomes.

An alternative approach is to try to represent the grid limitations in the market process. One way to do this is to subdivide the grid into bidding zones. Within each bidding zone, market participants can trade freely, and it is assumed that electricity can be delivered from any producer to any consumer. However, trades across bidding zone borders requires access to some form of cross-zonal capacity allocation. This allocation can be an integrated part of the day-ahead auction and intraday trading.

It is also possible to design a centralized marketplace with an even more detailed representation of the transmission system, where an actual model of all transmission lines and substations are included. This essentially means that each connection point to the transmission system has its own bidding zone. This approach, which is sometimes called a nodal market, means that all energy flows must be represented in the market model, which in turn means that bilateral transactions may not be possible.

These three approaches (countertrading, zonal market and nodal market) are all focused on the grid limitations that may arise at the transmission level. They typically do not take grid limitations at the distribution level into account.

2.3 Electricity system flexibility

2.3.1 Flexibility need

The concept of electricity network flexibility is widely used and is currently receiving considerable attention from both industry and the research community. Although there is not one agreed definition of flexibility, it is generally considered to relate to the management of changes in demand or production of electricity [4]. In this paper we define flexibility as modified behavior, in this case, modified consumption or production of electricity, as a result of outside signals or incentives, compared to what otherwise would have occurred. Incentives to modify behavior can come in many forms and are largely based on financial rewards or penalties.

Users of the energy system responding to incentives to modify behavior can allow for safer, more reliable, and efficient operation of the electricity system. [4] identify four different categories of flexibility need, namely;

- Flexibility for power – short term equilibrium between power supply and power demand
- Flexibility for energy – medium to long term equilibrium between energy supply and demand
- Flexibility for transfer capacity – short to medium term ability to transfer power
- Flexibility for voltage – short term ability to keep voltages within predefined limits

Flexibility can be achieved through a range of different approaches and depending on the underlying need defined, some approaches may be more suitable than others. The analysis below primarily focuses on the mechanism used to access flexibility rather than the underlying need for flexibility. A detailed analysis of which mechanism is more suited for a particular flexibility need is beyond the scope of this chapter.

2.3.2 Flexibility models/approaches

Flexibility resources can be organized in several different ways, generally as part of a market solution or through a more regulated system operator-led solution. For many years Ancillary Services (AS) has been available to TSOs as an instrument to ensure short-term balance of the electricity system. The changing dynamic and role of distribution networks call attention to the requirement for similar opportunities to effectively manage the system on a more local level.

We will discuss the following options:

DSO-led approaches

- Non-firm connections
- Direct contracts
- Cost-reflective or time-varying tariffs

Market-based approaches

- Flexibility trading platform
- Energy market with central clearing
- Peer-to-peer bilateral contracts

Whilst the outcome of this discussion and analysis is not intended to identify an optimal approach - an optimal approach is dependent on circumstances specific to individual systems – general advantages, disadvantages and likely timescale for implementation of the different approaches will be considered.

The following criteria and potential barriers to development and implementation, adapted from the barriers identified in [8], will be applied in the analysis:

Technical viability – the analysis will consider the current availability of technical solutions, technological risk, and the need for new innovations.

Regulatory barriers – the electricity market is heavily regulated, particularly the electricity networks and as such, the regulatory and policy frameworks are playing a key part in how any potential flexibility mechanism may be designed. Changes to the framework are generally time-consuming and can therefore act as a barrier or possibly prevent some approaches altogether. However, the regulator is likely to encourage measures that increase efficient use of the electricity network and reduce the need for network extension.

In addition to reviewing potential barriers in the regulatory and policy frameworks, we will also consider market structure (including unbundling and balance responsibility), economic regulation of networks, and market risks.

Social barriers – adoption of new technologies and institutional arrangements depend on social acceptance to be successful, from new large infrastructure [9] to deployment of domestic micro-generation [10]. However, as outlined by [10], whilst an infrastructure project requires mere social consent, domestic micro-generation requires active acceptance by homeowners, as well as positive attitudes, behavior and investments from the households. As a result, social constraints or barriers can include consumer behavior, consumer knowledge, financial, public awareness, and public acceptance.

Transparency – trust between parties reduces transaction costs and therefore encourages more efficient outcomes, from political decision-making [11] to public acceptance of new technologies [12]. Availability of information to all stakeholders in competitive and fair processes is important to increase trust and therefore transparency, including if the approach is open, easy to understand and accessible to the potentially large number of stakeholders will be assessed.

2.3.3 DSO instruments

Non-firm connections or Active Network Management

Through its network license, DSOs generally have an obligation to connect all customers to the network, provided that the customer fulfil certain technical standards and the safe and secure operation of the network can be guaranteed. Traditionally this is a firm connection and the customer can therefore utilize the network up to its connected capacity at any time. When the network is at or nearing its capacity, the safe and secure operation of the network may no longer be guaranteed if more customers are allowed to connect. This means that some customers may have to wait for lengthy network upgrades before being able to connect. Non-firm connections or Active Network Management (ANM) allow generators or consumers to connect to a constrained area of the network on the condition that that the network operator is permitted to control or constrain the flow of electricity as necessary to maintain the safe operation of the grid. Generally, the generator or consumer does not receive compensation for being constrained off, unlike users with guaranteed firm connections, however this may be at the discretion of the DSO or could become part of the wider regulatory framework. Additionally, the user may be able to pay less in terms of connection charges and/or use of network charges [13].

This approach is in use in some places today and can be applied at both transmission and distribution level. It is normally intended as a temporary solution to allow users to connect before necessary, costly and often lengthy upgrades are performed. Ref. [14] find that interruptible or non-firm connections will allow more generators to connect to a constrained area and it can therefore be a solution that can benefit both the operation of the network as well as the network users that may otherwise have not been able to connect.

A notable example of an ANM system is on the Scottish Orkney islands [15]. The islands are rich in renewable resources and supply generally exceeds demand. It is only connected to the mainland via a distribution cable meaning that the potential for exporting excess energy is limited [16]. The ANM area is divided into different zones representing constraint points. The network owner use a system of indicating constraints in each zone by color-codes; green if there are no issues and no generator curtailment, amber if generators in a zone are curtailed, and red in case of generators being stopped altogether or if there are issues with the network or the ANM system. The Last in - First off method is used to determine the order at which generators are curtailed.

The Orkney ANM has allowed a large number of renewable generators to connect to the system, including a significant amount of micro generation. It is however believed that the full potential for renewable generation on the islands will only be realized once a transmission cable connected to the mainland is constructed. The new transmission line is currently with Ofgem, the industry regulator, for decision [17].

Moreover, the uptake of electric vehicles has increased the use of non-firm connections on the demand side. In areas with several EV charging points within a close vicinity, it is common for the supplier to restrict charging at certain points as a result of constraints on the network. The EVs will then charge more slowly compared to what otherwise would have been the case. This kind of responsive charging is sometimes referred to as Smart charging and can be utilized by both network and supply utilities in response to either capacity curtailment or market signals. The EV owners may or may not be offered benefits in exchange for allowing flexible charging [18].

Analysis

Technical viability

ANM and non-firm connections are in use today and therefore the technical challenges can be considered as limited. Issues may however become apparent further up in the system if implemented and applied to solve a local issue without whole system-wide consideration. It is also important that the communication technology is able to meet the requirements of providing accurate and timely information to all the network users participating in the ANM.

Regulatory barriers

If the safe and secure operation of the electricity grid cannot be guaranteed following the connection of new customers, the network owner is prevented from doing so through its license. Non-firm connections or ANM systems are likely to require derogations from the safety and quality standards normally applied and some regulators may be reluctant to allow this. It may also require legislative and regulatory changes, to for example related to network access rights, which are generally part of a lengthy process. Further, it may become a regulatory burden if it is a widely used approach with many applications of derogation are submitted to the same regulatory body.

The application of connection fee will influence the network users' willingness to accept the likelihood of being interrupted. Systems where the connection fee covers a larger share of the work required to connect a new customer to the network rather than being socialized through network charges (a so-called deep connection fee) are likely to be less suited to alternative connection agreements. Whilst the approach may increase flexibility and quicker connections, the customer carries more risk in the form of greater investment costs. If, however, the applicable connection fee only covers the immediate work required (a so-called shallow connection fee), customers may be more open to alternative connection arrangements due to the smaller initial investment and therefore lower risk associated with a non-firm connection.

Social barriers

Offering non-firm connections will require all network users to think about network access in a different way. Today, most producers and consumers in developed countries enjoy access to the electricity network whenever they require. Whilst non-firm connections may be relatively easy to understand for most network users, it would require a change in the way networks are considered.

Moreover, depending on how the system is implemented it may be perceived to be unfair for old vs new users given that some users will have firm connections and some may not. Equality issues could also arise if these types of solutions are not available to all network users, for example, if it is dependent on technology availability or if only applicable in certain areas. It is also likely that larger users are more likely to understand the full process and may therefore be more accepting of alternative access arrangements. Ultimately, any work on the network will be passed on to consumers and it is therefore important that solutions don't benefit one customer at the cost of another.

Transparency

DSOs offering non-firm connections should be able to provide guidelines for the average number of interruptible minutes or occasions per year, however, accurate and long-term forecasting may be difficult. This may generate uncertainty among network users, which could delay investment decisions. It is important the process of how network users are connected and, if needed, interrupted is clear and that the information is available to all users. Customers and network users need sufficient and accurate information to make informed decisions.

DSO direct bilateral contracts

A network operator, a TSO or DSO, can contract directly with suppliers of certain services, without going through a market mechanism [19]. This is most likely, although not necessarily, short-term solutions to immediate network operability issues where the network operator reach out to or call upon potential providers close to real-time and agree the required action or service and price. Short-term bilateral contracts are currently used by some TSOs in systems where grid capacity limitations are not included in the trading process. The price is likely to depend on the prevailing market conditions and availability of service providers. The bilateral contracts agreed without using an explicit marketplace or auction can be settled directly between the network operator and the owner of the flexible asset or they could involve a third-party aggregator.

National Grid, the ISO in Great Britain, use bilateral contracts to procure certain balancing services [20]. The bilateral contracts are agreements between the ISO and the flexibility provider, commonly conventional thermal plants, only and details are therefore not public knowledge. Using this approach, issues in particular areas are solved on a case-by-case basis often for a specific and relatively short time and the agreements are generally settled close to real-time. However, longer-term agreements for service provisions in a particular area with ongoing issues may also be utilized. Longer-term agreements are likely settled through some kind of tendered process or auction. In 2018, GB DSO UK Power Networks launched its procurement for flexibility services through a tender process, inviting bids from companies for 6 month ahead and 18 month ahead contract. The DSO plan to repeat the tender process annually [21].

Analysis

Technical viability

Direct bilateral contracts can come in many different shapes and sizes. There are no general technical barriers to this approach as issues will be solved on a case-by-case basis and the system operator will call on what the flexibility providers that they know depending on what they need. However, not all network users or connected technologies may be able to participate if certain technical specifications are required. The providers of flexibility must be known to the SO and it must have knowledge of the services that can be provided. This is likely to limit innovation and competition.

To ensure that more service providers can participate, advanced communication technology may be required to allow instant and reliable communication between the SO and the flexibility providers. The SO must be able to communicate with many different users to ensure liquidity in service provision.

Regulatory barriers

DSOs should, as part of their role as a monopoly provider of network services and connecting the competitive segments of the electricity sector - producers and end-users of electricity - facilitate competition in these areas. Agreeing contracts on a bilateral basis may hamper the development of market-based procurement and competition and would therefore not be a favored approach by regulators.

With this approach, the flexibility may not be viewed as energy for balance responsibility purposes. Especially not if the actual energy amount is uncertain, and not exactly specified in the contractual arrangement. As such, the DSO direct contracting approach is more likely to be deemed compatible with unbundling requirements in the sector.

Social barriers

Bilateral contracts are likely to be agreed without much involvement from consumers and end-users. As such, without general public awareness, the approach is unlikely to be subject to much public objection.

However, the lack of involvement by the consumers may lead to other issues, for example from a transparency point of view (see below). It is also unlikely that bilateral contracts will be available to smaller users without the introduction of aggregators.

Transparency

There is a risk of low transparency, both to end-users and the market if service contracts for flexibility are agreed bilaterally. Bilaterally agreed contracts, per definition, are not subject to competitive process and will therefore involve limited transparency. This would be reduced somewhat in case of contracts agreed through a tender process or auction, however, it will only be significantly different if the whole process is open to public scrutiny. Due to the commercially sensitive information that will be revealed this is unlikely. Similarly, if the DSO were made to publicly publish the nature of each contract to increase transparency, which is likely only after the contract has been agreed, the impact in terms of increased transparency, is limited.

Cost reflective or time-varying network tariffs

Cost reflective or time-varying network tariffs can be implemented to incentivize a shift in demand loads or 'peak-shaving'. This is an indirect way for a DSO to manage the flows in the distribution network by providing end-users with financial incentives to adjust their consumption and production patterns. While this may not allow for direct control of power flows in real time, it could reduce the need for such interventions by incentivizing a more efficient utilization of the distribution infrastructure in the first place.

DSOs are funded by network fees collected from end-users. While the main purpose of these fees is to collect sufficient revenues to cover the operational and capital costs of the DSO, they can also be used as a tool for providing end-users with various incentives. Therefore, these incentive mechanisms are not intended to affect the total amount of revenues that the DSO collects from its end-users, rather, it simply affects when and how these funds are collected.

DSO network fees, at least for small end-users such as households, typically consists of some combination of a per-kWh fee and a fixed monthly fee, possibly differing by the size of the connection point. This means that the amount of network fees paid by an end-user over a given period of time depends on the total number of kWh consumed during this time period. However, it does not depend on how those kWh were distributed over time within the period. This gives the consumer no financial reason to avoid load peaks or shift consumption to off-peak hours to avoid local grid congestion issues.

There are many possibilities for how network fees can be adapted to provide end-users with financial incentives to shift or smoothen their consumption. One option is to base the fee on the highest power consumption that was recorded over some period of time, for example Triads in GB [22] . This type of fee is sometimes referred to as a "demand charge". [23] analyses the introduction of demand charges for mid-sized consumers (35-63 A) by the DSO Sandviken Energi in Sweden. These demand charges were based on the highest hourly consumption for each month. The analysis in [23] suggests that the introduction of demand charges did contribute to a reduction in peak consumption during the two years following the introduction of the new tariffs.

An alternative to demand charges is volumetric (i.e. per-kWh) fees that vary over time, such that the fee is higher during peak hours and lower during off-peak hours. This type of time-of-use pricing can be implemented for DSO network charges as well as for energy. Because of its applicability also for energy pricing, time-of-use pricing has been implemented by a large number of DSOs and electricity suppliers around the world, as well as by vertically integrated utilities where the grid and energy charges are bundled. [24] provides a meta-analysis of various studies that evaluate the effectiveness of time-of-use pricing and find that most studies show a slight decrease in peak consumption as a result of the pricing scheme.

A more extreme version of time-of-use pricing is critical peak pricing, which means that a relatively low flat volumetric fee is charged for most hours of the year and a very high volumetric fee is charged for a few critical hours. The critical peaks are announced shortly before the event, for example when very high demand is forecasted.

Demand charges, time-of-use pricing and critical peak pricing are all examples of fee structures that DSOs could use to provide their customers with incentives to shift or smoothen demand. However, the fees charged by DSOs may also provide end-users with unintended incentives. For example, a DSO that charges a high volumetric fee and a low fixed fee gives stronger incentives for investments in distributed generation, compared to a DSO with higher fixed and lower volumetric fees. These unintended incentives could therefore also have an impact on local power flows and the likelihood of network capacity issues.

Analysis

Technical viability

The effectiveness of cost-reflective or time-varying tariffs depend on the availability of smart meters and advanced communication technology that can send signals and receive information instantaneously. The rollout of smart meters is progressing across Europe, which would suggest that there are no direct technical barriers, however, effective communication with a wide range of stakeholders may not yet be possible. Smart meters can communicate with DSOs although this does not necessarily mean that communication is effective or that customers receive it in a way to ensure that their response is what was intended from the price signal. Additionally, accurate time-varying tariffs may change quickly, which would further impede effective communication with customers.

Regulatory barriers

Price signals and tariffs tend to be regulated nationally and to some extent at an EU level. As such, tariffs that vary depending on location or time could cause issues from a regulatory point of view.

Ideally, tariffs should be set to recover the costs of the DSO, including a fair level of profit, and be proportional to customers' network impact. However, electricity networks require large investments that will be recovered over a long time and each additional customer only has a small impact, meaning a small marginal cost. This makes defining accurate and proportionate network tariffs difficult, particularly if they are to be dynamic and provide incentives for certain behavior. Furthermore, a cost-reflective tariff may not be strong enough to activate the, from the perspective of the DSO, desired level of flexibility. As a result, regulators may be reluctant to introduce time-varying tariffs.

Social barriers

Cost-reflective or time-varying tariffs can be an issue when considering social aspects such as fairness. Not all customers will be able to respond to price changes or they may be limited in how much their behavior can be modified, for example, consumers living in apartments or vulnerable consumers relying on a certain level of service. Fairness, perceived or otherwise, will also be an issue in that using energy at certain times will only be available to those that can afford it. This can create barriers from consumer protection groups and become a politically unpopular option.

Furthermore, there is also a requirement that consumers have a high understanding of what will impact prices, how prices are likely to move and what they can do the reduce their impact on the network and therefore their costs. This is likely to further equality issues as some consumer groups may have more access to and understanding of this kind of information.

Transparency

Electricity network tariffs can be complicated and must therefore be carefully communicated to ensure that they are transparent. Consumers must be able to understand how the prices are set and what impacts different prices. Tariffs that signal efficient use of the network will by nature be less transparent compared to fixed tariffs or tariffs set in advance since time-varying tariffs will be set closer to consumption, meaning less time for consumers to consider the price change. It is therefore important that the process of how tariffs are set is transparent and well understood by all consumes. If this is the case, time-varying tariffs can be considered a transparent approach.

2.3.4 Market based approaches

Flexibility trading platform

A flexibility trading platform is built on the same idea as existing trading platforms for energy but specifically for flexibility services. Services can be traded for one-off delivery or longer-term partnerships can be agreed. Flexibility can either be traded through a market (exchange with continuous trading) or through auctions, both of which can be either prescriptive, e.g. the buyer lists specific services needed and providers bid in the cost for them to provide this, or take a more open form where the buyer simply lists issues that needs resolving and potential providers submit their solutions and costs for providing these. Trades can take place directly between parties or through aggregators. The buyers of flexibility services are most likely to be the DSO or TSO and the market can cover a wide area or be more localized, for example within one local network area. However, it should be noted that lack of liquidity and non-competitive prices is a risk if access to the market is restricted [25].

The Piclo Flex market [26] is a DSO flexibility marketplace in the UK where DSOs announce requests for tenders according to a standardized format and flexibility providers bid for these tenders in auctions. The contracts are for relatively long periods of time (at least a few months) and typically concern the ability to activate power increases or decreases, stated in MW. The marketplace is currently operational with multiple DSOs requesting tenders. It does not include an activation market or dispatch function and therefore activations need to be arranged bilaterally between DSOs and flexibility providers as part of their contractual arrangements.

The FLECH (FLExibility Clearing House) market concept, developed as part of the iPower project in Denmark [27], includes a reservation phase where long-term capacity contracts for 1-2 years are established between the DSO and flexibility providers. These capacity contracts require the flexibility providers to make flexibility available to an activation market.

Moreover, the NODES-market [28], developed by the Norwegian company Agder Energi, is an example of a flexibility market concept that contains an activation market and a capacity market. The NODES-market is a general market platform that can be adapted to different local circumstances and has been tested in Engene, Norway and Mitnetz, Germany. The product traded is up- and down-regulation in MW, and each flexible resource is attached to a specific grid location, such that the DSO can get activations at the right locations in the network.

Another example of a market concept for a local activation market is USEF (Universal Smart Energy Framework). USEF is a market framework that includes a market design for trading flexible energy use. The USEF framework is used by several research projects and demonstration sites, such as the FUSION project in the UK [29], the Interflex project [30] and the DYNAMO project [31], both in the Netherlands. The framework is adapted to the current European electricity market structure and involves a multistep process where flexibility offers from aggregators are activated by the DSO based on short-term forecasts [32].

Additionally, deliverable 5.1 of the m2M-GRID project also describes a market design for an activation market [1]. As with the USEF framework, it takes the European standard model for wholesale electricity trading into account and provides a complementary market structure where DSOs and balance responsible parties can buy flexibility activations from flexibility service providers.

Analysis

Technical viability

A flexibility trading platform, based on the same model as current energy trading platforms and established capacity markets is not problematic from a general technical point, given that systems are available and functioning already. However, when considering the details of a flexibility market, the technical workings becomes more complex.

The size of the market is an important consideration – it needs to be big enough to ensure the market is liquid whilst also local enough to solve particular issues that a DSO may have. Ideally, both the TSO and DSO would have access to the market, provided that there are rules or a system in place to avoid two flexibility service requests submitted by two different entities in the opposite direction. For example, if the DSO requested a power decrease from service providers in a certain area, and the TSO requested a power increase from the same area. It is therefore likely necessary to specify some priority order for activation requests from different entities, such that, for example, the TSO only can activate flexibility as long as it does not contradict any requests from the DSO.

Regulatory barriers

Roles and responsibilities in the electricity sector may have to be redefined, or at least must be clear and well defined, for a functioning flexibility market. It must be apparent who can sell and buy what and how responsibilities for delivery are considered, bearing in mind unbundling and the balance responsibility processes.

Market surveillance must also be considered as this may prove difficult for the regulator in case many smaller flexibility markets materialize in one jurisdiction. Similar level of surveillance as is common in energy markets today should be implemented to ensure no market abuse.

Social barriers

To actively participate in the market, network users need knowledge of how the market works, what they can offer in terms of flexibility, costs, other participants, strategy, balance responsibility, etc. Therefore, at least initially, a flexibility market is likely to attract participation from actors already involved in trading electricity or some kind of electricity related services – i.e. producers and large consumers, rather than users that today are mainly involved in smaller levels of electricity consumption. Apart from apparent equality issues, this could reduce liquidity in the market since not all available flexibility is utilized. A solution to increase the number of smaller network users in a flexibility market may be aggregators who would take on the responsibility of financial and practical aspects, such as offering services and balance responsibility.

Transparency

An open market with access for all stakeholders does not have obvious immediate transparency issue. This is however likely to depend on the design of the market and how it is governed. A flexibility trading platform is a relatively complex approach, both legally and technically. The additional layer of complexity can be viewed as a transparency issue since it makes the electricity market as whole more difficult to understand.

Energy market with central clearing

One possible approach for handling distribution-level network constraints is to apply the same principle as is sometimes used at the transmission level, namely an energy market that takes network limitations into account. This means that network limitations are explicitly modelled in the energy market model, and that the electricity price is allowed to differ between different locations to reflect congestion [33]. If electricity is traded locally, and distribution constraints are incorporated into the energy market clearing function the energy market can efficiently coordinate flexible resources and manage the distribution network as an integrated part of the energy trading.

A local energy market with central clearing is an automated system based on an algorithm set to clear the market in the most efficient way. All market participants would need to be fitted with a smart meter to ensure that sufficiently granular data is collected and communicated to the market clearing function. For a local energy market to be able to handle local network constraints, it needs to include a detailed model of the local network, and the connection point of all end-users need to be known. Further, the market clearing function needs to be able to "see" all anticipated injections or withdrawals.

One way to ensure this is to mandate that all end-users connected to the distribution network must buy and sell all their electricity via the local market. Otherwise, if participation in the local market is voluntary, the local market must include some representation of the energy injections and withdrawals expected from the non-participating end-users. Since the local market would not be able to influence the consumption and production of the non-participating end-users, this in effect would mean that the non-participators would get preferential access to the distribution network. There must therefore be some other mechanism counteracting this disadvantage for participating in the local market.

The Fossil-free Energy Districts (FED) project in Sweden has designed a local energy market model based on hourly trading with a centralized auction-based market clearing function [34]. The market is designed such that multiple energy carriers in the local energy system can be traded simultaneously, and market participants can place bids that reflect flexibility across energy carriers and over time. The model also takes network constraints into account. The market model is developed and tested in a demonstration at the Chalmers University campus area in Gothenburg, Sweden.

Another example of an energy market with central clearing is EnergyLab Nordhavn, a Danish innovation and research project based in Copenhagen [35]. The project integrates multiple energy infrastructures (electricity, thermal, and transportation) and intelligently controls systems and components. A platform for optimizing production and use of electricity and heating, PowerLab, will be developed as part of the project.

Analysis

Technical viability

To date, this kind of local market with central clearing has only been tested in smaller-scale projects and have proved difficult to make work. To fully automate the trading process, many technical systems (control systems, metering systems, user interfaces) need to be connected to each other in order to send or receive data and control signals. Suitable standards and ICT infrastructure for this information exchange need to be developed. Even with well-defined standards and methods, a significant effort would be needed to adapt existing technical systems to be able to interact with an automated energy trading platform.

The algorithms needed for clearing local energy markets are, at a conceptual level, similar to those currently used at the wholesale level. Nevertheless, some market design development may be necessary to adapt these algorithms to the needs of local markets. For example, concerns regarding market power are likely to be more severe is a local context.

Regulatory barriers

Monitoring and governance of a market with central clearing will be challenging due to the complexities of the market clearing mechanism and algorithms behind it. As such, regulators and decision-makers may be reluctant to allow implementation of this kind of solution.

Further, local energy markets may (depending on their specific design) not be compatible with some of the principles underpinning the European electricity market model. For example, the requirement that end-users should be free to choose electricity supplier means that participation in the local markets may need to be voluntary. But this means that it becomes more difficult to use local markets as a tool to manage network limitations. It is also not obvious how to fit local energy markets into the current system with balance responsible parties. One option is for the market operator to be the BRP for the end-users participating in the local market and therefore take on the role of electricity supplier. If the local market as used by the DSO as a tool for managing network limitations, the dual role of electricity supplier may not be compatible with DSO unbundling rules.

Social barriers

A central market, given the complexities of the mechanism, is likely to be met by skepticism by consumers, particularly those not familiar with the energy market today. Since most end-users would not take the necessary time to learn about and understand the local market model, it could prove politically challenging to implement. This can be especially difficult if the local market creates electricity prices that differ between different locations in the network, since such local price differentiation can be perceived by some end-users as unfair. However, a local market can be viewed as an engaging and community-building institution helping communities achieve their sustainability goals, which can reduce the social barriers.

Transparency

The level of transparency would depend on the openness and availability of the central clearing function and the algorithm behind it. However, the market workings are likely to be complex and therefore difficult for anyone to fully comprehend, meaning that it may be perceived non-transparent even if the information is available. Similarly, the amount of data collected for the trading process is vast, and some of this data can most likely not be openly published due to privacy concerns. This further decreases the transparency of the process. Some transparency concerns can be mitigated by letting an independent, possibly non-profit, entity operate the market.

Peer-to-peer market or bilateral contracts

Peer-to-peer bilateral contracts are agreements between producers and consumers of electricity to purchase and consume specific quantities of electricity or specific flexibility services. When this is done at a local level, it may be referred to as a local peer-to-peer market. This is an alternative to the centralized market models described in the previous two section - consumers and producers trade energy directly with each other, sometimes knowing exactly who they are buying the energy or flexibility service from. Centralized market models tend to either be pooled or the bids and offers anonymized.

The Brooklyn Microgrid project in the US contains a concept for a peer-to-peer local energy market. The marketplace allows market participants to trade with peers locally, or to buy electricity from the main grid. A review of this market model can be found in [36].

Another platform that can be viewed as a peer-to-peer energy market (although not local) is the German sonnenCommunity, operated by the battery company Sonnen. This platform allows members to share self-produced energy with each other. The company operating the scheme, Sonnen, replaces the customers conventional electricity supplier and will both buy and sell electricity [37].

Finally, Powerpeers is a marketplace in the Netherlands that connect domestic energy producers with consumers wanting to buy energy from known sources, for example, solar power from your neighbor or family, even though they live far away. Members pay a monthly subscription in addition to the power itself [38].

From a DSO perspective, it is unclear if a peer-to-peer market can be a useful instrument for accessing local flexibility. Possibly, a peer-to-peer platform can be utilized by a DSO for, for example, countertrading in case of network congestion.

Technical viability

Peer-to-peer markets require a specific platform and software to function. Most peer-to-peer markets that are active today operate as commercial ventures by a platform and software developer, where the users pay for access to the platform or use of the software. The technology is thus available, however, at a small scale. Some platforms claim to utilize blockchain technology for the trading process, but publicly available detailed information about the implementations are scarce, making it difficult to assess the technological readiness of these platforms. Compatibility issues are likely to appear if more peer-to-peer markets are established without consideration of existing platforms, systems and the overlaying electricity market. Additionally, further development is required to establish to what extent peer-to-peer markets can contribute to wider system benefits.

Regulatory barriers

Like other smaller or local markets, peer-to-peer solutions may prove difficult to govern. New roles and responsibilities are likely to have to be identified, which could challenge the existing market structure. EU legislation now recognise citizens and communities as distinct actors in the energy market. This is particularly noticeable through the introduction of 'citizens energy communities' which sets out guidelines for rights and obligations. This is yet to be transferred to national legislation across Europe, however, will support the transition towards more active end-users and communities, including peer-to-peer instruments.

Like local energy markets with central clearing discussed above, it is not clear if peer-to-peer markets are compatible with the current European system of balance responsibility. It may be necessary for the peer-to-peer platform to also act as electricity supplier and take on balance responsibility for the end-users that participate in the market. This means that the peer-to-peer transactions create financial redistributions among users of the platform but are not counted as electricity trades for balance responsibility purposes vis-à-vis the TSO.

Social barriers

Clearer definition of roles and responsibilities regarding consumers and communities' active involvement in the energy market will support the establishment of peer-to-peer instruments. Nonetheless, a shift from today's passive to tomorrow's active end-users will require a high degree of acceptability and adjustment in consumer attitudes. Peer-to-peer solutions will require active participation, which some end-users may object, and may possibly involve private investment costs that some consumers are unwilling or unable to provide. This in turn will cause issues from an equality perspective. On the other hand, a peer-to-peer platform can provide a sense of control and self-sufficiency which certain end-users would welcome.

Transparency

Peer-to-peer markets can lack transparency given that they depend on software that is operated by private commercial entities that depend on keeping the algorithms behind the mechanism private. In this sense, a peer-to-peer market can suffer the same issues as a central market with central clearing, where the workings become too complicated for any entity to efficiently monitor and govern. Further, bilaterally agreed contracts are by nature between two parties only and therefore not open to public scrutiny.

2.4 Discussion

In table 1 we have summarized the analysis above utilizing a traffic-light system, given prevailing market structure and technological development. Red is intended to indicate that the barrier is significant enough to make implementation difficult within the European context within a decade. Yellow indicates that, whilst barriers exist, it should be possible to overcome these barriers within a few years given sufficient political support. Green is meant to reflect that the barriers are limited, and implementation could be achieved today. For the transparency dimension, this time-based interpretation of the colors is less relevant, and the colors should instead be interpreted as whether or not the approach is transparent.

The classification is based on the judgement of the authors of this report, based on the literature review as well as the workshop with subject matter experts.

Assessment	Technical viability	Regulatory barriers	Social barriers	Transpar-ency
Option				
DSO instruments				
Non-firm connections				
Direct contracts				
Cost-reflective or time-varying tariffs				
Market based approach				
Flexibility trading platform				
Energy market with central clearing				
Peer-to-peer bilateral contracts				

Table 1, Summary of analysis of barriers to different flexibility approaches

The approaches outlined and assessed in this report provides a broad overview of options available to access flexibility capacity in the distribution network. The list in not exhaustive; there are other options that may fall in between the options considered or may encompass a combination of several approaches. Flexibility in electricity networks is currently receiving substantial attention from researchers, academics, industry, and policymakers alike. The development of technical solutions and new (local) market structures is however somewhat fragmented. It is unclear how different approaches will fit in the current overlaying energy market or how different solutions might work together. Many approaches developed today are commercial ventures based on a specific technology that may not be compatible with another development by a different company. Increased coordination may alleviate some of these issues from a system wide perspective, however, must not be done in a way that may hamper innovation or competition.

2.4.1 Market fragmentation and efficiency

The above discussion and analysis is intended to provide a starting point for further, and more detailed, discussion and analysis of local flexibility approaches. The remainder of this report is dedicated to a few such attempts. Chapters 3 and 4 are focusing on issues that may arise in a potential future electricity market landscape where many local electricity markets coexists.

Arguments in favor of local electricity markets include that they may be better suited for integrating small-scale distributed generation, that they can be adapted to suit the particular needs or constraints of each local energy system, and that they can be a tool for increasing end-user engagement and market participation.

However, there are also some potential drawbacks. One major potential drawback is that marketplace fragmentation (i.e. replacing a market structure based on a centralized wholesale market by a market structure consisting of many smaller local markets) may lead to an overall less efficient use of available resources. Although each local market may seem efficient from the local system perspective, overall efficiency can be reduced as a consequence of the fragmentation if the local markets are not coordinated in an effective way.

The first fundamental theorem of welfare economics states that, given a set of assumptions, competitive markets produce Pareto efficient[2] outcomes [39]. This can be viewed as a mathematical formalization of Adam Smith's famous invisible hand. Although no real market would ever literally satisfy the mathematical assumptions underlying this theorem, a centralized commodity market such as a wholesale electricity market can be viewed as approximately satisfying the assumptions provided that sufficient competition prevails, and externalities are priced appropriately. In somewhat simplified terms, this means that a well-functioning competitive wholesale electricity market will yield outcomes where it is not possible to improve the outcome for one market participant without harming another, i.e. it exhausts all possible gains from trade.

For the case of wholesale electricity markets, a parallel can be made between Pareto efficiency and short run production cost minimization. If demand is insensitive to prices in the short run, then the market outcome from a wholesale electricity market is going to be (at least approximately) short run cost-minimizing. This follows from the Pareto efficiency, since in this setting an outcome that does not minimize short run costs would also not be Pareto efficient.

Pareto efficiency is in general not sufficient for a market outcome to be considered "good" in a sense that reflects society's preferences. However, one can argue that Pareto efficiency should be considered a necessary condition: irrespective of preferences, it is difficult to argue for the optimality of an outcome if it is not Pareto efficient.

What happens to the Pareto efficiency of a wholesale electricity markets when it is replaced by a system containing many smaller local marketplaces? If the local markets are completely detached from each other without any possibility for exchange across markets, then even if each local market may be internally Pareto efficient, the overall outcome will in general not be. This is simply because there will be gains from trade that are not exhausted between markets participants situated in different market areas. This is essentially the same logic that underlies the traditional arguments for why free trade between countries increases overall economic efficiency - a logic which has been discussed, modelled and analyzed in a vast academic literature that stretches back more than 200 years [40].

In order to restore the overall efficiency, it is therefore crucial that it is possible to trade between the local marketplaces. With an effective process that connects the local markets, it is possible to achieve an overall Pareto efficient outcome. However, this requires that the trading process across markets is as effective as the trading within markets. In the following two chapters we provide two models that illustrate how, although it is possible to trade across the markets, the outcomes are not as efficient as if they were fully integrated. This illustrates that when it comes to restoring overall efficiency by allowing for trade across markets, the outcomes can depend heavily on the details of the market design and trading process.

[2] An allocation is said to be Pareto efficient if it is impossible to improve the outcome for someone without making anyone else worse off.

3. Impacts of forecasting errors in centralized and decentralized electricity markets

3.1 Introduction

With a continued and accelerating growth in distributed energy resources, the current centralized market structure for wholesale electricity markets has come into question [41]. An alternative market structure, consisting of many smaller local electricity markets, may have some advantages in terms of making full use of the flexibility available from distributed resources. However, such marketplace fragmentation may also make it more difficult for market participants to exhaust all possible gains from trade.

Further, forecasts play an important role in electricity markets. Electricity spot markets trade in advance, typically the day before delivery. Therefore, trading is based on supply and demand forecasts. Specifically, most demand and variable renewable generation has to be forecasted, while the capacity available from dispatchable market participants is more predictable. Since forecasting errors are inevitable, schedules for dispatchable market participants that are obtained as market outcomes will often, ex post, turn out to be somewhat sub-optimal.

In this chapter, we compare the current centralized market structure to an alternative decentralized structure with local electricity markets. The comparison focuses on the impact of forecasting errors and how forecasting errors made by market participants are translated into scheduling errors. The comparison is made using Monte Carlo simulations, where we simulate electricity market outcomes using both a centralized and a decentralized approach.

There are many potential reasons for why electricity market outcomes may become more or less efficient with a decentralized structure. In this analysis, we focus on forecasting errors and how they can create sub-optimal market schedules. Other potential issues, such as the exploitation of market power or other types of strategic behavior by market participants, are not considered in this chapter.

3.1.1 Two market approaches

In this chapter, we use the term *centralized market structure* to denote electricity markets where all (or most) market participants submit bids to a single marketplace. The market clearing functionality for the centralized market structure may take transmission limitations into account and produce market prices that differ across locations to reflect network congestion. This market category includes both nodal markets with a relatively high degree of spatial resolution, as well as less granular zonal markets. Some form of centralized market structure is currently used for most liberalized electricity markets today. An overview, with a focus on comparing the nodal and zonal approaches, can be found in [42].

In the following analysis, we compare the currently existing centralized market structure to an envisioned *decentralized market structure*. This decentralized market approach builds on a two-level structure, where smaller local marketplaces are nested within a larger overlaying wholesale market. This structure is, to the best of our knowledge, not in use today, but has been proposed as a possible future electricity market structure for electricity systems based to a large extent on distributed energy resources. Examples of studies that discuss local energy markets include [41], [43], [44] and [45].

For the decentralized market structure to effectively manage transmission limitations, the local market areas could be defined such that transmission limitations can be expressed as constraints in terms of how much electricity that can be transferred in or out of each local market area. Market participants that are located within these local areas trade electricity in the local marketplace, and the transmission limitation is captured through limitations in the amount of electricity that can be exchanged between the local market and the overlaying wholesale market. In the overlying wholesale market, electricity is traded for the market participants that are located outside the congested local areas, along with transfers to and from the local markets.

For the propose of this analysis, we envision the decentralized market structure to share some key features with current centralized electricity markets. Both structures are based on bids submitted by market participants. With the centralized market structure, all market participants submit bids directly to a central marketplace. With the decentralized approach, market participants in local areas submit bids to their respective local markets while market participants outside the local areas submit bids to the wholesale market. Further, both structures are based on uniform marginal pricing, differentiated over time and space.

The decentralized market structure involves one additional type of actor, someone who trades electricity between the local and wholesale markets. We here consider the case where there is a single entity who has balance responsibility for each local area, and therefore is responsible for scheduling the transfers between the local and wholesale markets (see section 2.2.2 for a discussion about balance responsibility in local energy markets). We will here refer to these actors as a transfer traders.

With the centralized market approach, the propagation of forecasting errors is fairly straightforward. Market participants representing non-dispatchable demand and supply submit bids based on their forecasts, and dispatchable resources are scheduled accordingly. Forecasting errors are therefore directly translated into scheduling errors. With the decentralized market approach, the process involves several steps. The non-dispatchable demand and supply located inside the local market areas are represented by two different forecasts. The market participant itself makes a forecast determining the bid in the local market, and the transfer trader for the local market makes a different forecast to determine the amount they buy or sell in the wholesale market. The final schedule for dispatchable resources depends on both these forecasts.

Note that the terminology used in this chapter differs from the use of the terms centralized and decentralized electricity markets in some other electricity market research. For example, [46] refer to electricity markets characterized by bilateral trade between vertically integrated utilities as decentralized markets, and [47] use the term decentralized markets to refer to electricity markets with self-commitment.

3.2 The model

This section presents a stylized model of an electricity system consisting of a number of local transmission-constrained areas as well as an overlaying unconstrained area. The model includes three different methods for finding schedules for dispatchable supply and demand: schedules obtained through a centralized market structure, schedules obtained through a decentralized market structure, and the ex-post optimal schedules that could have been achieved if there were no forecasting errors.

An important assumption in this model is that market participants and transfer traders have access to exactly the same information when making their forecasts, and that their forecasts are random draws from the same probability distribution.

3.2.1 Supply and demand fundamentals

There are N local areas, indexed by $\mathrm{n} \in \{1, \ldots, \mathrm{N}\}$. All local areas are identical to each other in terms of demand and supply characteristics. However, because of forecasting errors, the market outcomes may differ between different local areas.

Across all areas, there are two types of electricity consumers and producers: non-dispatchable consumers and producers who trade electricity based on forecasts, and dispatchable consumers and producers who trade based on a known marginal cost function. For ease of exposition, we will assume that the first group consists of more consumers than producers and we therefore refer to it as *net demand*. Similarly, we assume that the second group consists of mostly producers, and therefore refer to it as *net supply*.

Inside each local area, total net demand is equal to $\delta > 0$. The total amount of net supply that is scheduled from all market participants in local area n is represented by the variable s_n. Note that the amount of net demand is a parameter to the model, whereas the scheduled amount of net supply is a variable that can take on different values for different local areas.

The local net supply function is represented by a linear marginal cost function: $MC_n = \alpha + \beta \cdot s_n$, where MC_n is the marginal cost, and α and β are supply parameters common across all local areas. The amount of electricity that can be transferred in or out of each local area cannot exceed the limit λ.

The area outside of the local areas is referred to as the *unconstrained area*. Supply and demand in the unconstrained area is represented in the same way as for the local areas, but with potentially different parameter values: net demand is $\hat{\delta} > 0$ and the net supply function is given by $\widehat{MC} = \hat{\alpha} + \hat{\beta} \cdot \hat{s}$, where $\hat{s}$ is the amount of net supply scheduled from the unconstrained area, and $\hat{\alpha}$ and $\hat{\beta}$ are the corresponding supply parameters.

Net demand forecasting errors are modeled separately for each area using independent normally distributed random variables. The aggregate net demand forecasting error made by market participants in local area n is represented by X_n, where X_n is normally distributed with mean 0 and standard deviation σ. Similarly, the net demand forecasting error for the unconstrained area is represented by $\hat{X}$, which is normally distributed with mean 0 and standard deviation $\hat{\sigma}$. All forecasting errors ($X_1, \ldots, X_N$ and $\hat{X}$) are independent.

3.2.2 Ex-post optimal schedules

Based on the above supply and demand fundamentals, the ex-post optimal values for the net supply variables ($s_1, \ldots, s_N$ and $\hat{s}$) can be determined by solving a cost-minimization problem, where the total cost to satisfy net demand is minimized, respecting transfer limitations between areas. For the purpose of identifying the ex-post optimal schedules, the true net demand amounts are known and forecasting errors are ignored.

The objective function of this problem is to minimize total costs (from the integrals of the marginal cost functions):

$$\min_{s_1,\ldots,s_N,\hat{s}} \left[\hat{\alpha} \cdot \hat{s} + \frac{1}{2} \hat{\beta} \cdot \hat{s}^2 + \sum_{n=1}^{N} \left(\alpha \cdot s_n + \frac{1}{2} \beta \cdot s_n^2 \right) \right]. \tag{1}$$

This expression is minimized subject to a power balance constraint, ensuring that total supply equals total demand:

$$\sum_{n=1}^{N} s_n + \hat{s} = N \cdot \delta + \hat{\delta}. \tag{2}$$

Finally, the amount transferred in or out of each local area must not exceed the transfer limit λ:

$$-\lambda \leq s_n - \delta \leq \lambda, \qquad \forall\, n \in \{1, \ldots, N\}. \tag{3}$$

This is a linearly constrained quadratic programming problem and can therefore be solved with standard numerical methods, yielding the ex-post optimal net supply schedules.

3.2.3 Centralized market schedules

As previously stated, the analysis in this chapter does not consider strategic behavior by market participants (such as the exercise of market power). We therefore assume perfect competition, which allows us to model electricity market outcomes as the results of a cost minimization problem [48]. The net supply schedules from the centralized market approach are therefore obtained as the solution to an optimization problem similar to that for the ex-post optimal schedules, the only difference being that forecasting errors are introduced for net demand. This means that the objective function is the same as in equation (1), while the power balance constraint becomes:

$$\sum_{n=1}^{N} s_n + \hat{s} = \sum_{n=1}^{N} (\delta + X_n) + (\hat{\delta} + \hat{X}). \tag{4}$$

Similarly, the transfer limit constraints become:

$$-\lambda \leq s_n - (\delta + X_n) \leq \lambda, \qquad \forall\, n \in \{1, \dots, N\}. \tag{5}$$

Given realizations of the random variables $X_1, \dots, X_N$ and $\hat{X}$, this optimization problem problem can be solved in the same way as for the ex-post optimal dispatch, yielding net supply schedules that are influenced by the net demand forecasting errors. Market clearing prices (which may differ by local area) can be obtained from the shadow values of Equations (4) and (5).

3.2.4 Decentralized market schedules

The decentralized market structure is based on two consecutive steps, one for the wholesale market and one for the local markets. In this section, we consider the case where trading takes place in the wholesale market first, and the local markets follow. The alternative ordering, where local markets trade before the wholesale market, is discussed in section 3.5.2.

It is here assumed that the transfer trader who is responsible for the transfers between a local market and the wholesale market knows the underlying marginal cost function for the local area ($MC_n = \alpha + \beta \cdot s_n$). Further, in similarity with market participants representing net demand, the transfer trader needs to make a forecast of the net demand in their local area (δ). We use Y_n to denote the forecasting error made by the transfer trader and assume that Y_n is an independent random variable with the same distribution as the local market participant's forecasting error (X_n).

The transfer trader submits bids to the wholesale market representing the transfer trader's expectation of the net supply function from the local market as a whole (i.e. after accounting for net demand). The expected net transfer supply function for local market n is therefore given by $MC_n = \alpha + \beta \cdot (\delta + Y_n + t_n^w)$, where t_n^w is the transfer scheduled in the wholesale market from local area n (t_n^w is positive for transfers out of the local area, and negative for transfers into the local area).

Given this, the wholesale market can now be modeled by the following cost-minimization problem:

$$\min_{t_1^w, \dots, t_N^w, \hat{s}} \left[\hat{\alpha} \cdot \hat{s} + \frac{1}{2}\, \hat{\beta} \cdot \hat{s}^2 + \sum_{n=1}^{N} \left(\big(\alpha + \beta \cdot (\delta + Y_n)\big) \cdot t_n^w + \frac{1}{2} \beta \cdot (t_n^w)^2 \right) \right]. \tag{6}$$

The power balance constraint for the wholesale market now ensures that the sum of all local market transfers together with net supply from the unconstrained area equals the forecasted net demand from the unconstrained area:

$$\sum_{n=1}^{N} t_n^w + \hat{s} = \hat{\delta} + \hat{X}. \tag{7}$$

Finally, the transfer traders must restrict their bids such that the amount transferred in or out of each local area does not exceed the transfer limit λ:

$$-\lambda \leq t_n^w \leq \lambda, \qquad \forall\, n \in \{1, \dots, N\}. \tag{8}$$

The solution to this minimization problem yields the scheduled net supply for the unconstrained area ($\hat{s}$), as well as the scheduled transfers ($t_1^w, \dots, t_N^w$). A single wholesale market clearing price ($\hat{p}$) is obtained as the shadow value for the power balance constraint in Equation (7).

Step two in the decentralized market approach is the local market trading. Each local market is here modeled as a separate cost-minimization problem with just two variables: the amount of local net supply scheduled (s_n) and the transfer to or from the wholesale market (t_n^l). Local net supply is, as before, represented by the net supply function $MC_n = \alpha + \beta \cdot s_n$, and forecasted net demand is $\delta + X_n$. Finally, the transfer trader offers transfers to or from the wholesale market at the wholesale market clearing price $\hat{p}$. The transfer amount that can clear the local market is not restricted by the transfer amount that cleared the wholesale market, i.e. t_n^l is not necessarily equal to t_n^w. In section 3.5.1 we consider the case where the transfer trader schedules exactly t_n^w in the local market, such that $t_n^w = t_n^l$.

Each local market is therefore represented by a cost-minimization problem of the following form (maintaining the convention that a positive value of t_n^l represents a transfer from the local market to the wholesale market):

$$\min_{s_n, t_n^l} \left[\alpha \cdot s_n + \frac{1}{2} \beta \cdot s_n^2 - \hat{p} \cdot t_n^l \right]. \tag{9}$$

The power balance constraint now becomes

$$s_n - t_n^l = \delta + X_n, \tag{10}$$

and the transfers are limited by the transfer capacity:

$$-\lambda \leq t_n^l \leq \lambda. \tag{11}$$

The market clearing price of each local area can be obtained as the shadow value of Equation (10).

This concludes the description of the market models. We now turn to a description of the simulation algorithm used to compare these market approaches.

3.3 Simulation algorithm

For a given specification of the input parameters ($N, \delta, \hat{\delta}, \alpha, \hat{\alpha}, \beta, \hat{\beta}, \sigma, \hat{\sigma}$ and λ), and a given realization of the random variables ($X_1, \dots, X_N, \hat{X}$ and $Y_1, \dots, Y_N$), the resulting net supply schedules ($\hat{s}$ and $s_1, \dots, s_N$) can be obtained for each market approach. Let $\vec{s}$ be shorthand for the vector of all supply schedules ($\vec{s} = (\hat{s}, s_1, \dots, s_N)$) and let $\vec{s}_{optim}$, $\vec{s}_{central}$, $\vec{s}_{decentral}$ correspond to the ex-post optimal schedules, the centralized market schedules, and the decentralized market schedules, respectively.

$\vec{s}_{optim}$ does not depend on the random variables and is therefore uniquely defined for a given set of input parameters. $\vec{s}_{central}$ and $\vec{s}_{decentral}$ depends on the realization of the random variables and are therefore random vectors of length $N + 1$. We are interested in comparing the schedules from the two market approaches to the ex-post optimal schedules. We refer to these differences as scheduling errors, and define $\vec{e}_{central} = \vec{s}_{central} - \vec{s}_{optim}$ and $\vec{e}_{decentral} = \vec{s}_{decentral} - \vec{s}_{optim}$. We simulate the multivariate distribution of these random scheduling errors using the following algorithm:

1. Values are specified for all input parameters.
2. $\vec{s}_{optim}$ is calculated as described in 3.2.2.
3. One independent random draw is made for each random variable.
4. The corresponding realizations of $\vec{s}_{central}$ and $\vec{s}_{decentral}$ is calculated, according to descriptions in 3.2.3 and 3.2.4, respectively.
5. $\vec{e}_{central}$ and $\vec{e}_{decentral}$ are calculated.
6. Steps 3-5 are repeated k times.

Using this simulation algorithm, simulated distributions are obtained for the scheduling errors. Because all local areas are ex-ante identical, the theoretical probability distribution for the scheduling errors are also identical across all local areas, for a given market approach. In the following analysis, we therefore combine the simulation results for all local markets. The distribution for the unconstrained area is however different, and therefore kept separate.

Finally, summary statistics are calculated for the simulated distributions. Specifically, we calculate sample mean, standard deviation and skewness.

3.4 Results

We here present simulation results for a range of parameter specifications that represent different relative net supply costs. We do this by setting $\hat{\beta} = 1$ and letting β range from 0 to 3. Further, we set $\hat{\alpha} = \alpha = 0$. When $\beta < 1$, net supply in the local areas have a relatively low cost and the local areas can be thought of as "generation pockets". Conversely, when $\beta > 1$, net supply in the local areas is more costly and the local areas become "load pockets".

Further, we here present results for the case where there are two local areas ($N = 2$), net demand is 10 in each local market, as well as in the unconstrained area ($\hat{\delta} = \delta = 10$), and the standard deviation of the forecasting errors is set to 1 ($\hat{\sigma} = \sigma = 1$). Finally, the transfer limit in or out of each local area is 2 units ($\lambda = 2$).

3.4.1 Average scheduling error

Figure 3.1 shows the average scheduling error by market approach and type of area, for a range of β-values.

First, consider the case where β is equal to 1.75. This is the lowest β for which it is ex-post optimal to utilize the full transfer capacity into the local areas. At $\beta = 1.75$, the ex-post cost-minimizing schedule involves transfers of exactly 2 units from the unconstrained area to each local area, but the transfer constraint is not binding and the marginal production cost at the optimal supply schedule is equal across all areas. As seen in Figure 3.1, the market solutions in this case lead to systematic over-scheduling in local areas and under-scheduling in the unconstrained area, compared to the ex-post optimal schedules. This is true for both the centralized and decentralized market approaches.

The reason for this is because of an asymmetry in how forecasting errors affect the market schedules. When market participants over-forecast demand in a local area, then the additional forecasted demand has to be met by local supply schedules since the transfer capacity is already fully utilized. However, if market participants under-forecast demand in a local area, then the supply schedule reduction is be split between supply in both the local and unconstrained areas. Therefore, the scheduling error for the local area supply will on average be larger when demand is over-forecasted than when it is under-forecasted, leading to a positive average error for the local area schedule, even though the forecast itself is unbiased.

The reason for systematic under-scheduling in the unconstrained area when $\beta = 1.75$ is similar, but reverse: under-forecasted demand for the unconstrained area can only be met by a supply schedule reduction in the unconstrained area, while over-forecasted demand will be met by an increase in scheduled supply that is split across the areas.

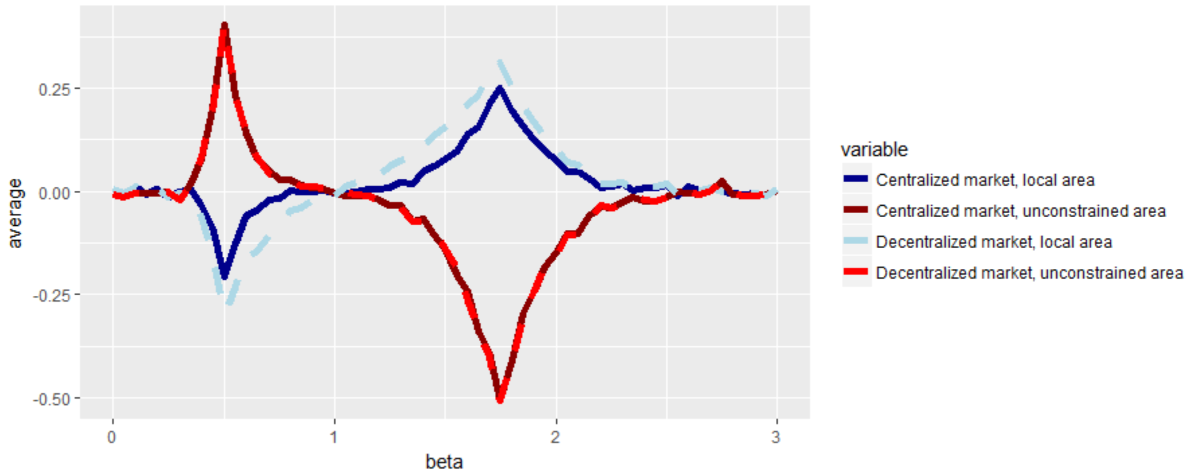

Figure 3.1 Average scheduling error

As β increases above 1.75, supply in the local areas become more expensive and the transfer limit becomes binding. When this is the case, the asymmetry is reduced since under-forecasts in the local area will now be met by a reduction in local supply until the transfer constraint is no longer binding (and vice versa for the unconstrained area). When β is sufficiently large, scheduling errors will follow the corresponding area forecasting errors directly, and the average scheduling error goes to 0.

As β decreases from 1.75 towards 1, the marginal cost functions in the different areas become more similar and the transfer limit does not affect the ex-post optimal solution. Again, this means that the systematic scheduling errors are reduced, since relatively large forecasting errors are required for the asymmetry created by the transfer limit to kick in. For values of β between 0 and 1, we get results that are equivalent to when $\beta > 1$, but with the roles of the local and unconstrained areas reversed.

For both market approaches, the average scheduling errors for the local and unconstrained areas go in opposite directions, for a given value of β. A positive scheduling error for local areas is offset by a negative error for the unconstrained area, and vice versa. For the centralized market approach, the average scheduling errors cancel each other out. This is ensured by the power balance constraint for the centralized market (Equation 4), which implies that there cannot be any systematic scheduling error at an aggregate level.

However, for the decentralized approach, the average scheduling errors do not completely cancel each other out. The scheduling errors for the local areas tend to be somewhat larger in magnitude than the offsetting scheduling errors for the unconstrained area. This result stems from the two-step approach, and that transfers between the markets are represented in the local markets using a wholesale price that does not change with the magnitude of the transfer (as seen from the perspective of the local market).

Again, consider the case where $\beta = 1.75$. When the local market participants over-forecast demand, then (as discussed above) this additional amount has to be fully met by local supply. However, in the other direction, when market participants under-forecast local demand, the local market will, once it hits the wholesale price level, only reduce the transfer from the unconstrained area and not reduce the local scheduled supply. Therefore, the average scheduling error for the local area is greater in magnitude with the decentralized market approach.

3.4.2 Shape of scheduling error distribution

Although the forecasting errors in this model are assumed to follow independent normal distributions, the scheduling error distributions that arise from the market outcomes as a result of these forecasting errors are not symmetric. In this section, we briefly discuss the spread and skewness of these distributions.

Starting with the spread, Figure 3.2 shows the sample standard deviation for the simulated scheduling errors, as a function of β. As seen, the standard deviation is close to 1 (i.e., it is close to σ and $\hat{\sigma}$) when β is either close to 0 or close to 3. This is because, at these extremes, forecasting errors in a given area directly translate into an equivalent scheduling error in that same area and do not affect the schedules of other areas (unless the forecasting errors are very large). At intermediate values of β, the scheduling errors are influenced by forecasting errors from all areas. When forecasting errors are combined, and then distributed across multiple areas, the resulting probability distribution for scheduling errors in a given area has a lower standard deviation. Further, note that in areas where supply is over-scheduled (local areas when $\beta > 1$ and the unconstrained area when $\beta < 1$) the standard deviation for scheduling errors is lower.

Finally (not shown in the figure), the scheduling error distribution is positively skewed for areas where supply is over-scheduled on average, and slightly negatively skewed where supply is under-scheduled on average.

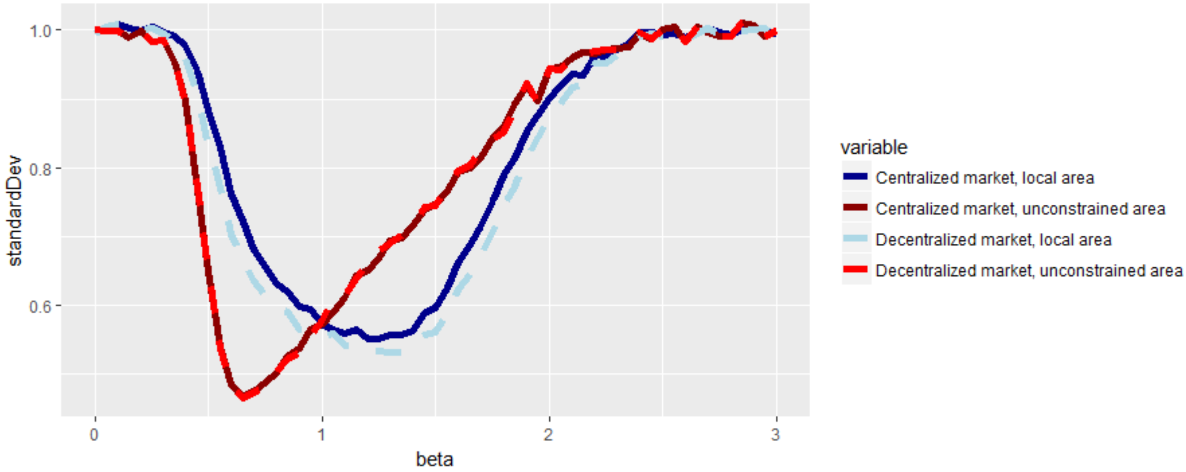

Figure 3.2 Standard deviation of scheduling error distribution

3.5 Model variations

In this section, we consider two variations of the model: one where the amount that the transfer trader buys or sells in the local market is exactly equal to the wholesale market transfer schedule, and one where the timing of the local and wholesale markets are reversed such that trading takes place in the local market before the wholesale market.

3.5.1 Fixed transfer amounts

In section 3.2.4, the transfer trader for local market n first trades in the wholesale market, resulting in a wholesale market schedule for the transfer to or from the local market (t_n^w). Thereafter, in the local market, the transfer trader offers the full transfer capacity (λ) in or out of the local market at the wholesale market price. Therefore, the transfer amount that clears the local market (t_n^l) is in general not going to be equal to the transfer amount that cleared the wholesale market.

Figure 3.3 shows the average scheduling errors for the case where the transfer trader instead simply transfers the amount that cleared the wholesale market, irrespective of the local market clearing price. As seen in the figure, the resulting average scheduling errors then exactly equals those from the centralized market approach, for the unconstrained as well as the local areas.

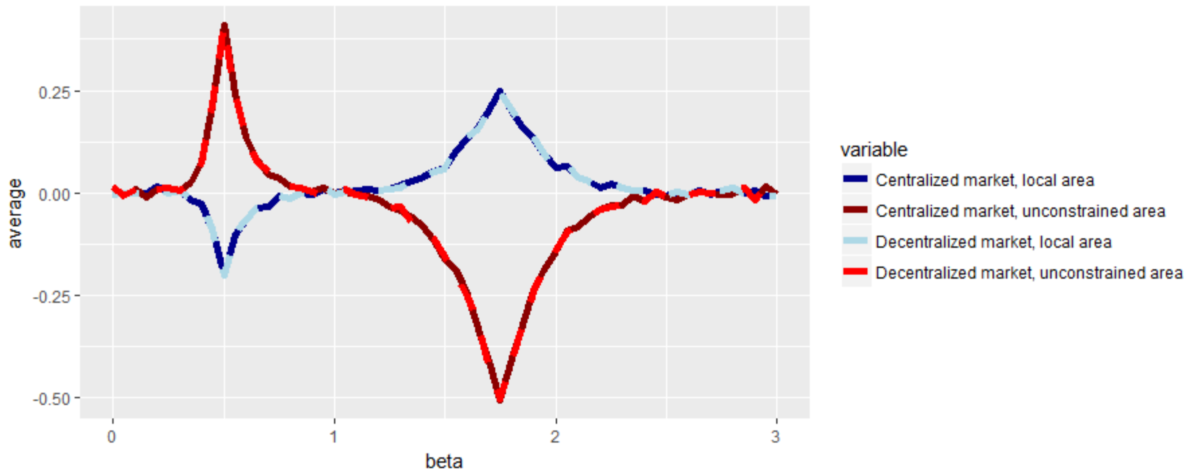

Figure 3.3 Average scheduling error, fixed transfers

However, although the average scheduling errors become identical to the centralized market approach, the scheduling error distributions do not. As shown in Figure 3.4, the standard deviation of the scheduling error distribution is now much higher in the local areas with the decentralized approach, especially when marginal costs are similar across the areas.

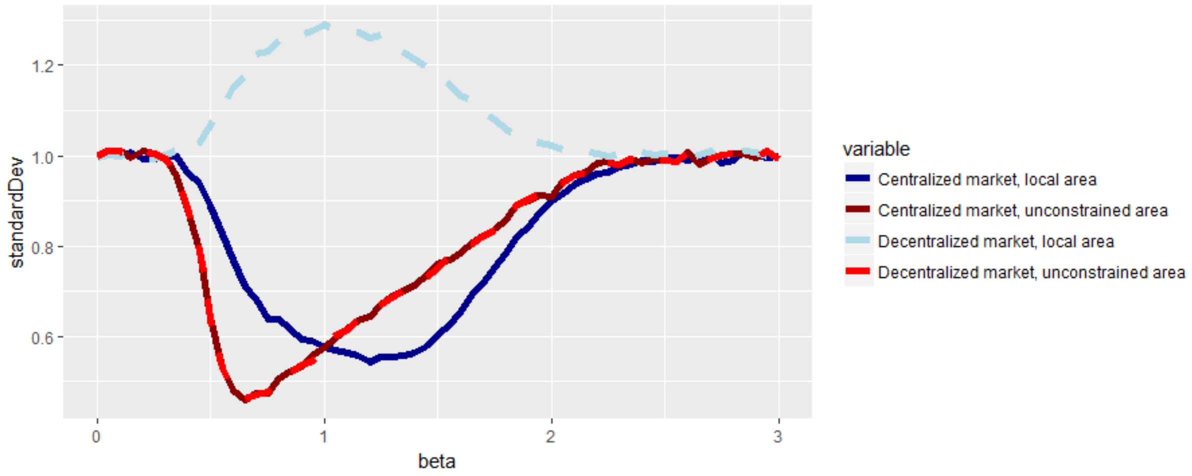

Figure 3.4 Standard deviation of scheduling errors, fixed transfers

The similarity in terms of average scheduling errors between the centralized and decentralized approach when transfers are fixed can be seen mathematically in the following way. With fixed transfers, the local market only has one variable left (s_n), and the local cost-minimization problem described in equations (9) through (11) simplifies to the equation $s_n = t_n^w + \delta + X_n$. Substituting this equation into the optimization problem for the wholesale market (equations (6) through (8)), results in an optimization problem that is similar to that for the centralized market (equations (1), (4) and (5). The only difference is that the objective function now becomes:

$$\min_{s_1,\dots,s_N,\hat{s}} \left[\hat{\alpha} \cdot \hat{s} + \frac{1}{2}\hat{\beta} \cdot \hat{s}^2 + \sum_{n=1}^{N} \left(\alpha \cdot s_n + \frac{1}{2}\beta \cdot s_n^2 + \beta \cdot s_n \cdot (Y_n - X_n) \right) + \kappa \right]$$

where κ is a constant once the random variables are realized and therefore does not affect the solution to the cost-minimization problem. The only consequential difference compared to the centralized approach is therefore the term $\beta \cdot s_n \cdot (Y_n - X_n)$, which has an expected value of 0 and a symmetric probability distribution. Therefore, the average scheduling errors for the local areas with the decentralized approach is the same as for the centralized approach, but the variance is larger.

3.5.2 Reverse market timing

If the market timing is reversed, such that the local market trades before the wholesale market, then the transfer trader must offer the transfer capacity to the local market based on some expectation of supply and demand conditions in the wholesale market.

This makes the task more difficult for the transfer trader compared to when the wholesale market clears first. In section 3.2.4, the transfer trader submits bids to the wholesale market based on an expected local net supply curve. Doing the reverse, i.e. submitting bids to the local market based on an expected wholesale net supply curve would be much more challenging, since it would require the local trader to have detailed knowledge about the supply and demand conditions in all areas, not just its own local area. Further, within our modeling framework, the expected wholesale net supply curve has a more complicated functional form, compared to the linear net supply curve for the local areas.

Therefore, instead of submitting bids that represent an expected net supply curve, we here assume that the transfer trader offers the full transfer capacity to the local market at an expected wholesale market price. It is assumed that the transfer trader has access to a forecast for the wholesale price, which is based on the same model as for the centralized market approach but with independent draws for all random variables. The transfer trader therefore submits the same type of bid to the local market as in section 3.2.4, but now the valuation for the bid is determined by a forecasted wholesale price instead of a realized wholesale price.

To summarize: first, the transfer trader makes a forecast of the wholesale market price. Second, the transfer trader offers the transfer capacity to the local market at the expected wholesale price. Finally, the transfer trader buys or sells whatever transfer amount cleared the local market in the wholesale market.

Figure 3.5 shows the simulation results when the distributed market approach is modeled with this revered order. The results from the centralized market approach is generated using the same algorithm as before and is included in the figure for reference. Comparing Figure 3.5 to Figure 3.1 shows that the average scheduling errors for the local areas are the same, while the average scheduling errors are larger in magnitude for the unconstrained area when the order is reversed. Further, Figure 3.6 shows that the scheduling error distribution for the unconstrained area becomes much more dispersed.

In other words, modifying the decentralized market model by reversing the order between the wholesale and local market in the way described above does not change the simulated scheduling error distribution for the local areas, but it does generate scheduling errors for the unconstrained area that are both on average more biased compared to the ex-post optimal schedules, and have a larger variance.

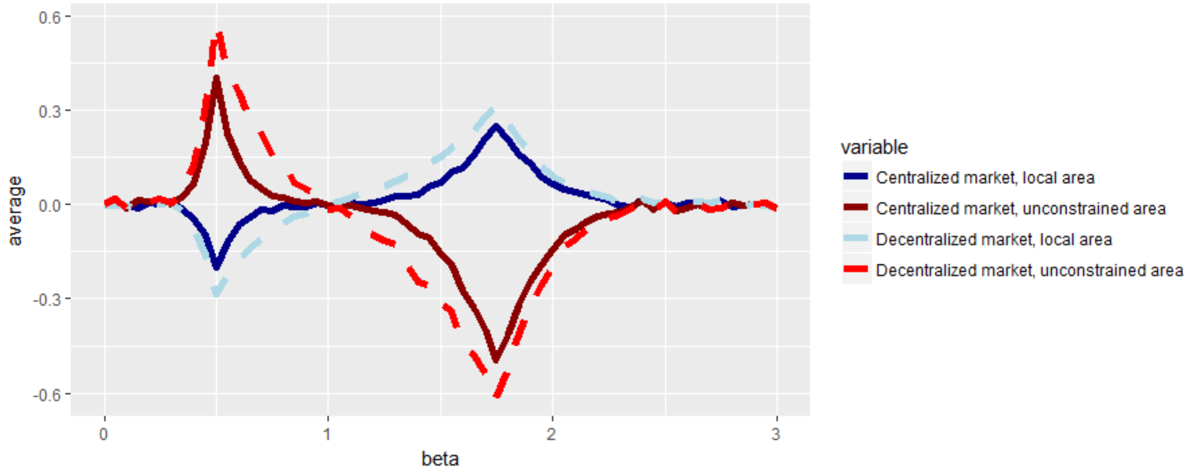

Figure 3.5 Average scheduling error, reversed order

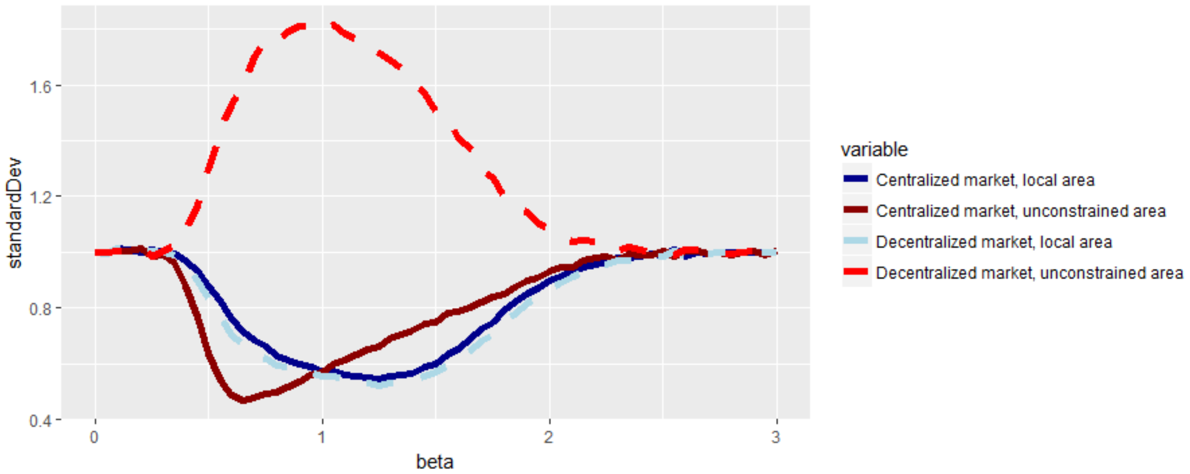

Figure 3.6 Standard deviation of scheduling errors, reversed order

3.6 Discussion and conclusions

This chapter analyzes how forecasting errors influence the schedules obtained from electricity markets, with a focus on comparing centralized and decentralized market approaches. We here discuss the conclusions that can be drawn from this analysis, and some of its limitations.

First, in a market with explicit transfer limitations between areas, market participants' forecasting errors lead to market schedules that *systematically* deviate from ex-post optimal schedules, even if the forecasting errors are drawn randomly from unbiased and symmetric probability distributions. This applies to both centralized and decentralized market approaches.

Second, using Monte Carlo simulations, we have compared the scheduling error distributions under a centralized market structure to those obtained with a decentralized market structure. The simulations show that the scheduling errors are in general larger in magnitude with a decentralized market structure, but the results depend on the details of the decentralized approach.

For example, the flexibility of the transfers between the wholesale and local markets is of great importance for the outcomes. When the transfers are fixed (i.e. when the transfer schedule from the wholesale market is passed on to the local market without flexibility) then the average scheduling errors are equal to those from the centralized approach, but the variance is much higher. With more flexible transfers, the average scheduling errors might be larger in magnitude, but with a lower variance.

Further, the order of trading matters. When wholesale trading takes place before local trading, then the scheduling error distribution for the unconstrained area is unchanged (compared to the centralized approach) while the scheduling errors are somewhat larger in magnitude for the local areas. When the order is reversed, the magnitude of the scheduling errors for the unconstrained area also increases.

There are several important limitations of this analysis to keep in mind when interpreting the results. The transfers between the wholesale and local markets is of great significance for enabling the decentralized market approach to arrive at an outcome that is similar to that of the centralized approach. In this analysis, we have assumed that the transfer trader has complete knowledge about the marginal cost function of net supply within its local area, and that the transfer trader is able to forecast net demand just as well as the market participants themselves. These are strong assumptions. If the transfer trader has a less complete understanding of local market conditions, then the decentralized approach will likely lead to schedules that are even more sub-optimal.

Further, in this analysis we have deliberately avoided any questions related to incentive compatibility of the actors involved. A decentralized market approach may be more vulnerable to exercise of market power and other strategic behavior. The role of the transfer trader is especially important in this regard, as it often may be in a position of market power, and as its behavior is crucial for the outcome of a decentralized market approach.

4. Arbitrage trades between electricity markets with different time resolution

4.1 Introduction

In this chapter, we analyze the social welfare implications of arbitrage trading between two electricity markets where the two markets differ in terms of time granularity. In other words, the market time period length in one market is longer than in the other, such that, for example, one market trades electricity hourly and the other half-hourly.

This analysis is primarily motivated by the recent interest in local electricity markets, see for example [41], [45], [43] and [44]. While an electricity market landscape with many small local electricity markets may be advantageous in a future power system characterized by a large penetration of distributed energy resources, it also raises questions about the interaction of such marketplaces, especially if some market design parameters differ across the local markets. In this chapter we analyze the consequences of one such difference, namely a difference in time period length.

While the primary motivation for this study is an envisioned future market context with local electricity markets, the analysis is also applicable for the interface between existing wholesale electricity markets, assuming that the markets are not explicitly coupled. In a European context, this is of interest since both hourly and fifteen-minute settlement periods are in use across Europe, and that a transition to fifteen-minute trading is gradually under way [49].

When time periods differ across markets, there are two options for how arbitrage trading between the markets may be carried out. The first option is to require traders to match each position in the longer time period market with opposite positions in *each* of the corresponding periods of the market with shorter time periods. For example, to sell 2 MWh of electricity during one hour in an hourly electricity market, the trader must buy 1 MWh in each corresponding half-hour in the half-hourly market. We refer to this option as the constant transfers option.

The second option is to allow the trader to match a position in the longer time period market with opposite positions in *any* of the corresponding periods of the shorter time period market. With this approach, a trader who wants to sell 2 MWh of electricity during one hour in an hourly market, can choose to buy those 2 MWh in either of the two half-hour periods of the half-hourly market. This option is here referred to as the time-varying transfers option.

We are here interested in analyzing what the profit-maximizing transfers would be for an arbitrage trader under these two options, and how they compare to socially optimal transfers based on fundamental cost differences. To do this, we have developed two slightly different models that together allows us to theoretically analyze this topic from several different perspectives.

The first model, presented in section 4.2 below, assumes a linear representation of price-sensitive net supply in each market. With this modelling approach, the arbitrage trader has some market power, which influences the magnitude (and possibly direction) of the profit-maximizing transfer.

In the second model, presented in section 4.3, the arbitrage trader is small relative to the market and cannot influence the market prices. Further, in this model we relax the linearity assumption, such that the underlying marginal cost function in each market is not necessarily linear.

The first model shows that, under the assumption of a linear net supply function, constant transfers never leads to transfers that reduces overall social welfare. However, due to a market power effect, the profit maximizing constant transfer is smaller in magnitude than the socially optimal one. Further, constant transfers prevent the arbitrage trader to respond to price differences within the longer time period, which means that some transfers that would have been social welfare increasing are not carried out.

For time-varying transfers, the profit maximizing transfers could actually go in the opposite direction to the socially optimal transfers and therefore reduce overall social welfare, compared to a case with no transfers at all. However, it is profitable for the arbitrage trader to carry out some of the shorter (and social welfare increasing) transfers that are missed with a constant transfer requirement. Further, the time-varying transfers are, in many cases, larger in magnitude compared to the constant transfers, and therefore closer to the socially optimal magnitude. Effectively, the arbitrage trader can arbitrage between different time periods in the market with shorter time periods and rely on the balancing mechanism in the other market to handle the imbalance. If this balancing mechanism is efficient, this may actually improve social welfare.

The second model illustrates that when the linearity assumption is relaxed for the net supply functions, it is possible for the transfers to reduce overall social welfare, even under the constant transfers option.

4.2 Model with linear marginal cost functions

This section describes and analyzes the linear model, where the underlying production cost in each market is represented by a linear net supply curve. The model setup is presented in section 4.2.1. Sections 4.2.2, 4.2.3 and 4.2.4 characterize the optimal solution for the social welfare maximizing transfers, the profit maximizing constant transfers, and the profit maximizing time-varying transfers, respectively. These results are then analyzed in section 4.2.5.

4.2.1 Model setup

There are two electricity markets, A and B. The market time period length in market A is twice as long as the time period length in market B. We therefore consider a model with two time periods, during which energy is traded jointly as one product in market A and separately for each time period in market B.

Price-insensitive net demand (in average MW) in each market and time period is given by $d_{m,i}$ where $m \in \{A, B\}$ and $i \in \{1,2\}$. For each time period, a trader can transfer t_i (in average MW), where $i \in \{1,2\}$. We adopt the convention that t_i is positive when energy is transferred from A to B.

The price-sensitive net supply in each market is represented by two linear marginal cost functions, $c_A(q_A)$ and $c_B(q_B)$, where q_m represents the amount of electricity supplied from price-sensitive market participants in market m. The marginal cost functions are assumed to be linear and constant across the two periods:

$$\begin{aligned} c_A(q_A) &= \alpha + \beta q_A \\ c_B(q_B) &= \gamma + \delta q_B \end{aligned}$$

Both markets are assumed to be competitive and based on uniform marginal pricing, meaning that we can obtain the market clearing price in each market by replacing q_i by net demand including transfers. However, since energy is traded jointly for both periods in market A, the price in market A reflects the intersection of the marginal cost curve and the average net demand across the two periods, whereas the price in market B reflects the intersection of the supply curve and net demand for each period separately:

$$p_A = \alpha + \beta \left(\frac{1}{2} \sum_i d_{Ai} + \frac{1}{2} \sum_i t_i \right)$$

$$p_{Bi} = \gamma + \delta(d_{Bi} - t_i), \qquad i \in \{1,2\}$$

The trader's position in market B reflects the actual transfer in each time period, but the trader's position in market A equals the sum of the two transfers. The imbalance settlement periods in each market align with the market time period length, such that the trader does not incur any imbalance penalty from either market, even though the transaction may cause imbalances in market A for an individual time period, relative to the market result.

4.2.2 Socially optimal transfer

The socially optimal transfer is the transfer that minimizes the total cost across the two markets to meet the price-insensitive net demand. The total cost for each market is obtained by integrating the marginal cost functions, which yields the following expression for total system costs across both markets and periods:

$$C = \frac{1}{2}\sum_i \left[\alpha(d_{Ai} + t_i) + \frac{\beta}{2}(d_{Ai} + t_i)^2\right] + \frac{1}{2}\sum_i \left[\gamma(d_{Bi} - t_i) + \frac{\delta}{2}(d_{Bi} - t_i)^2\right]. \tag{1}$$

Minimizing this expression with respect to t_1 and t_2 yields:

$$t_i = \frac{\gamma + \delta d_{Bi} - (\alpha + \beta d_{Ai})}{\beta + \delta}, \qquad i \in \{1,2\}. \tag{2}$$

4.2.3 Profit-maximizing constant transfers

We now consider what the profit maximizing trades for our trader would look like, when the transfers are constrained to be the same across the two time periods (i.e. $t_1 = t_2 = t$). The trader wishes to maximize its total profits from two time periods:

$$V = \frac{1}{2}\sum_i [tp_{Bi} - tp_A] = \frac{1}{2}\sum_i \left[t\big(\gamma + \delta(d_{Bi} - t)\big) - t\left(\alpha + \beta\left(\frac{1}{2}\sum_l d_{Al} + t\right)\right)\right].$$

Maximizing this with respect to t yields:

$$t = \frac{\gamma + \frac{\delta}{2}\sum_l d_{Bl} - \left(\alpha + \frac{\beta}{2}\sum_l d_{Al}\right)}{2(\beta + \delta)}. \tag{3}$$

4.2.4 Profit-maximizing time-varying transfers

When the trader is allowed to transfer different amounts across the two periods, the payoff function for a trader is given by:

$$V = \frac{1}{2}\sum_i [t_i p_{Bi} - t_i p_A] = \frac{1}{2}\sum_i \left[t_i\big(\gamma + \delta(d_{Bi} - t_i)\big) - t_i\left(\alpha + \beta\left(\frac{1}{2}\sum_l d_{Al} + \frac{1}{2}\sum_l t_l\right)\right)\right].$$

Maximizing this with respect to t_1 and t_2 yields:

$$t_i = \frac{\gamma + \delta d_{Bi} - \left(\alpha + \frac{\beta}{2}\sum_l d_{Al}\right) + \frac{\beta}{2}(d_{Bi} - d_{Bj})}{2(\beta + \delta)} \tag{4}$$

where $i, j \in \{1,2\}$ and $j \neq i$.

4.2.5 Analysis of transfers

In this section we analyze the profit-maximizing transfers from equations (3) and (4), and compare them to the socially optimal transfers from equation (2). For ease of exposition, we will do this for the case where the price-sensitive net supply functions in the two markets are identical, meaning that $\alpha = \gamma$ and $\beta = \delta$. In this case, all parameters related to the supply functions drop out from equations (2) – (4). The social welfare maximizing transfers are then simply:

$$t_i = \frac{d_{Bi} - d_{Ai}}{2}, \qquad i \in \{1,2\}. \tag{5}$$

The profit-maximizing transfer when the transfer has to be constant across the periods simplify to:

$$t = \frac{d_{B1} + d_{B2} - d_{A1} - d_{A2}}{8}. \tag{6}$$

The profit-maximizing transfers when the transfers are allowed to differ across the time periods simplify to:

$$t_i = \frac{3d_{Bi} - d_{Bj} - d_{Ai} - d_{Aj}}{8}, \qquad i,j \in \{1,2\}, \qquad j \neq i. \tag{7}$$

Illustration of transfers - constant demand in A

Figure 4.1 illustrates the resulting transfers for period 1. The figure shows the transfers for various values of net demand in market B (d_{B1} and d_{B2}), keeping net demand in market A constant at 100 ($d_{A1} = d_{A2} = 100$). Blue represents a transfer from market A to market B, and red represents a transfer from B to A. The intensity of the color shows the magnitude of the transfer.

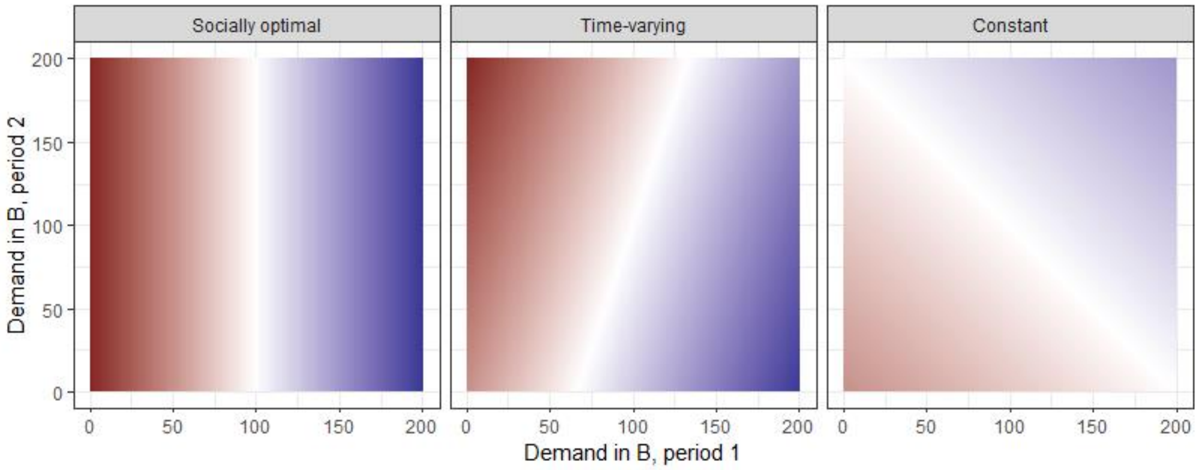

Figure 4.1 Transfers for time period 1

The leftmost panel of Figure 4.1 shows the social welfare maximizing transfer from equation (5). The socially optimal transfer from A to B for period 1 does not depend on net demand in period 2. The optimal transfer for period 1 is therefore straightforward: if net demand in market A (d_{A1}) is greater than net demand in market B (d_{B1}), then it is optimal to transfer energy from A to B, and vice versa.

The rightmost panel illustrates the profit-maximizing transfer for a trader when the transfer has to be constant across the two periods (equation (6)). Because the transfer has to be constant, the trader takes the prices of both periods into account. Therefore, the profit-maximizing transfer depends equally on d_{B1} and d_{B2}.

Finally, the middle panel illustrates the profit-maximizing transfer for period 1 when the transfer is allowed to differ across the two periods (equation (7)). Note that the profit-maximizing transfer for period 1 still depends on d_{B2}. This is because, due to the presence of our trader, d_{B2} affects the price in market A, and this price is constant across the two periods.

To understand how this dynamic works, consider a case at the center-bottom of the middle panel, where d_{B1} is close to 100 and d_{B2} is close to 0. This represents a case where net demand is roughly equal across the two markets for the first period, but where net demand in market B is much lower than net demand in market A for the second period. For the second period, it is profitable for the trader to buy energy in market B and transfer to market A. However, this transaction will reduce the price in market A, which is constant across both periods. Therefore, the price in market A will be lower than the period 1 price for market B. This means that it is profitable for the trader to buy energy in market A and transfer to market B in period 1, despite no difference in net demand across the two markets at that time.

How do these transfers affect total system costs? Figure 4.2 shows the total cost improvements that are obtained with the transfers, compared to a situation with no transfers at all. The total system costs are calculated by substituting the transfers from equations (5), (6) and (7) into equation (1). Note that this includes the total cost improvements from both time periods. The cost improvement is indicated by the intensity of the blue color and white means that there is no cost improvement.

The cost improvements from the socially optimal transfers are straightforward: when net demand in market B is the same as net demand in market A ($d_{B1} = d_{B2} = 100$), then no system cost improvement is possible and the socially optimal transfer is zero in both periods. The cost improvements from the socially optimal transfers increase as the difference in net demand between the markets in either period increases. This is illustrated by the leftmost panel of Figure 4.2.

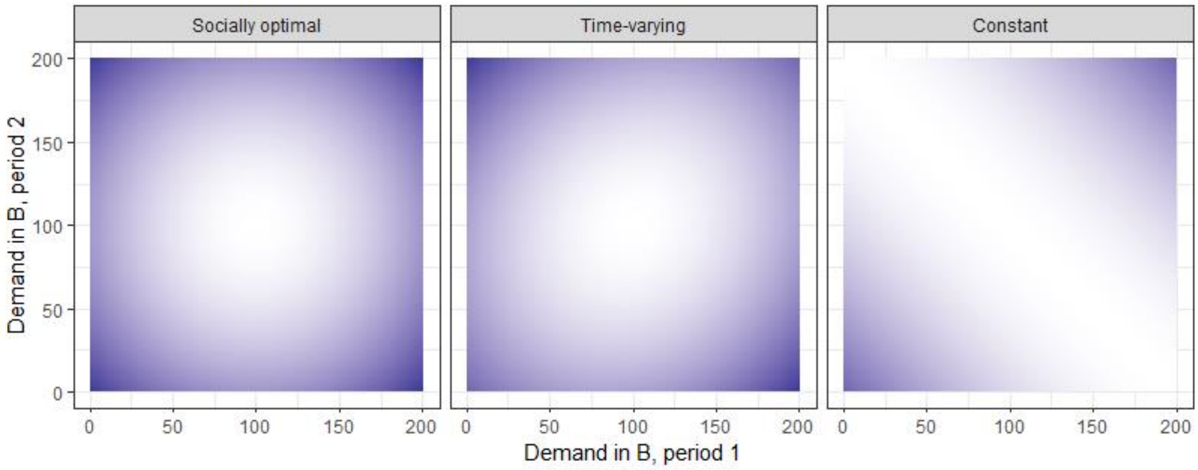

Figure 4.2 *Total cost improvement compared to no transfers*

The rightmost panel in Figure 4.2 shows the cost improvements from the profit-maximizing transfers when the transfers are constrained to be constant across the two periods. Along the diagonal where total demand in market B equals total demand in market A ($d_{B1} + d_{B2} = d_{A1} + d_{A2} = 200$), there is no profitable transfer, and hence no cost improvement. As the difference in total demand increases, the profit-maximizing transfer and resulting cost improvement also increase.

As seen in the middle panel of Figure 4.2, the cost improvements for the case with time-varying transfers look quite similar to the cost improvements for the socially optimal case. The only difference is that the cost improvement is somewhat lower, compared to the socially optimal case, along the diagonal where the demand in market B is equal across the two time periods ($d_{B1} = d_{B2}$). When this is the case, the transfer, and therefore also the cost improvement, is the same for the time-varying and the constant case. When market prices are constant over time, there is no reason for the trader to utilize the ability to vary transfers over time. The transfers do not quite reach the socially optimal level because of a market power effect: it is not profitable for the trader to completely eliminate the price difference between the two markets.

Along the other diagonal, where total demand in market B equals total demand in market A, the profit-maximizing transfer and resulting cost improvement for the time-varying case is identical to the socially optimal case. In this case, the transfers in the two periods are equal in magnitude but go in opposite directions. This means that there is no net impact on market A and the price in market A is unaffected. This removes the market power effect and incentives the trades to transfer a socially optimal amount.

Figure 4.2 shows that, when net demand in market A is constant across the two periods, then the time-varying transfers lead to overall cost improvements that are higher than or equal to the cost improvements from the constant transfers. In fact, the cost improvements from the time-varying transfers are remarkably similar to the cost improvements for the socially optimal case.

However, there is one important caveat to keep in mind when interpreting the results for the time-varying case. Although the transfers are allowed to vary across the two time periods, the trader would only make one trade in market A for the total transfer amount. The fact that the transfer is then going to be different across the two time periods means that the transfers are going to create imbalances relative to the market result in market A. The above analysis of cost improvements implicitly assumes that the method for handling imbalances in market A achieves productive efficiency, such that the marginal cost function still applies.

Illustration of transfers - varying demand in A

We now analyze what the transfers and cost reductions look like when net demand in A is no longer constant across the two time periods. Specifically, we consider the situation where $d_{A1} = 50$ and $d_{A2} = 150$, such that the total demand across the two time periods remain the same as in the previous section.

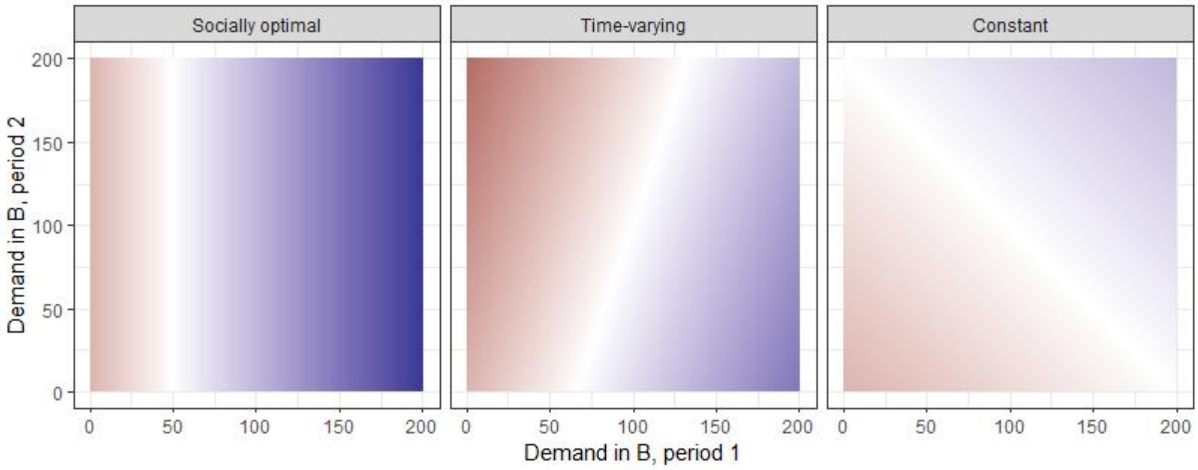

Figure 4.3 Transfers for time period 1

As seen in Figure 4.3, the socially optimal transfer in period 1 has changed relative to Figure 4.1 to reflect the shift in net demand in market A. However, both for the time-varying case and for the constant case, the profit-maximizing transfers remain exactly the same as in Figure 4.1. This is because the price in market A, which only depends on the total demand across the two periods, hasn't changed.

Figure 4.4 shows the corresponding cost improvements. The cost improvements for the socially optimal case shows the same pattern as in Figure 4.2, just shifted to account for the new demand profile for market A. The cost improvements for the case with constant transfers remain exactly the same as in Figure 4.2: the cost improvement is zero whenever the two markets have the same total demand across the two periods, and positive when the total demand differs between the markets.

However, as seen in the middle panel, the time-varying case now looks somewhat different. The red-shaded area corresponds to negative cost improvements, meaning that the profit-maximizing transfers actually lead to higher total production costs, compared to no transfers at all. This occurs when the net demand in the two markets are similar (d_{B1} close to 50 and d_{B2} close to 150). In this case, there is no fundamental reason to transfer energy in any direction. However, it is nevertheless profitable for the trader to transfer energy from B to A in the first period and in the other direction in the second period. This increases total system costs.

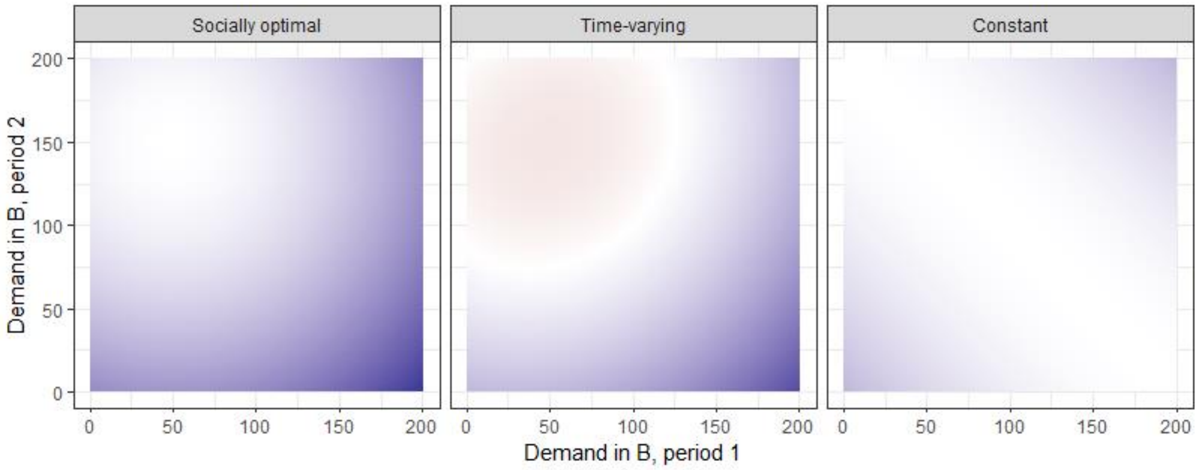

Figure 4.4 *Total cost improvement compared to no transfers*

Conclusions for model with linear marginal cost functions

In this section we summarize the main conclusions that can be drawn from the model with linear marginal cost functions.

When transfers are restricted to be constant across the two time periods, the trader will only respond to the total price difference, i.e. the difference between the price in market A and the average of the prices in market B. Whenever there is such a price difference, the transfer will reduce total system costs. It is possible that the transfer leads to an increase in system costs for an individual time period, but this will then be more than compensated for in the other period.

Constant transfers are accurately reflected in both markets and do not cause imbalances on either side. However, constant transfers are unable to reduce system costs whenever there are cost differences between the markets for individual time periods without any average cost difference across the two time periods.

When the transfers are allowed to vary between the time periods, the transfers will respond to price differences for each individual time period, but the difference in the price difference between the two time periods only reflects fundamental changes in market B. Therefore, the transfers reduce system costs as long as there are no underlying fundamental changes in market A between the two time periods.

When there are fundamental market changes across the time periods in market A, the situation is more complicated. If the fundamental changes in market A are positively correlated to the fundamental changes in market B, and the changes in A are greater than the changes in B, then time-varying transfers increase system costs since the price difference goes in the opposite direction to the actual underlying cost difference. If the fundamental changes in market A are negatively correlated to those in B, then the price difference go in the same direction as the actual underlying cost difference and time-varying transfers reduce total system costs. In either case, the time-varying transfers will lead to imbalances in market A, which means that the above results rely on the existence of an efficient balancing market in A.

4.3 Generalized model with single-unit transfers

In this section we provide an additional model that complements the linear model presented Section 4.2. The main purpose of this is to relax the linearity assumption and allow for an arbitrary functional form for the underlying marginal cost function in each market.

In order to keep the model as tractable as possible, the model presented in this section also assumes that the arbitrage trader is small and cannot influence the market price. This is done by restricting the transfer size to one unit of electricity, and assuming that the price in neither market is affected by this transfer. This means that we are only interested in the direction of the transfer, and not the size.

4.3.1 Model setup

The model setup is similar to the model with linear marginal cost functions. Again, there are two electricity markets (A and B), and the market time period length in market A is twice as long as the time period length in market B. We therefore still consider a model with two time periods, during which energy is traded jointly as one product in market A and separately for each time period in market B.

In contrast to the model with linear marginal cost functions, we here do not explicitly specify the underlying marginal cost functions. Instead, for each market and time period, we specify the underlying marginal cost of electricity absent transfers and consider transfers that are small enough to not influence the market clearing prices. We denote the underlying marginal cost of electricity with $c_{m,i}$ where $m \in \{A, B\}$ and $i \in \{1,2\}$. Note that we include the underlying marginal cost separately for both time periods, also in market A where the two time periods are traded as one.

Both markets are assumed to be competitive and based on uniform marginal pricing. Therefore, the price in market B equals the marginal production cost in market B for the corresponding time period. For market A, where the two time periods are traded jointly, the market price will be somewhere between the underlying marginal costs for the two time periods, such that price can be represented as a weighted average of the two marginal costs. The prices therefore are:

$$\begin{aligned} p_A &= \alpha \cdot c_{A1} + (1-\alpha) \cdot c_{A2}, \qquad && \alpha \in [0,1] \\ p_{Bi} &= c_{Bi}, && i \in \{1,2\} \end{aligned} \tag{8}$$

The parameter α is a function of the shape of the underlying net supply function, where a linear cost function would imply $\alpha = \frac{1}{2}$. Restricting α to be between 0 and 1 means that the underlying net supply function is upward sloping.

We now consider the possibility to trade energy between the markets. It is possible to transfer 1 unit of energy in either direction. We denote the transfer amount for time period i with t_i, where $t_i \in \{-1,0,1\}$, $i \in \{1,2\}$, and adopt the convention that t_i is positive if the transfer goes from A to B.

The direction of the transfer is determined by an arbitrage trader. The trader's position in market B reflects the actual transfer in each time period, but the trader's position in market A equals the sum of the two transfers. The imbalance settlement periods in each market align with the market time period length, such that the trader does not incur any imbalance penalty from either market, even though the transaction may cause imbalances in market A for an individual time period, relative to the market result.

4.3.2 Socially optimal transfer

It is straightforward to characterize the socially optimal transfer in this setting. The transfer is optimal from a societal point of view if the transfer goes from a low-cost market to a high-cost market:

$$t_i = \begin{cases} 1, & \text{if } \mathrm{c_{Ai}} < \mathrm{c_{Bi}} \\ 0, & \text{if } \mathrm{c_{Ai}} = \mathrm{c_{Bi}} \\ -1, & \text{if } \mathrm{c_{Ai}} > \mathrm{c_{Bi}} \end{cases}$$

4.3.3 Profit-maximizing constant transfers

We now consider what the profit maximizing trades for our trader would look like, when the transfers are constrained to be the same across the two time periods (i.e. $t_1 = t_2 = t$). The trader wishes to maximize its total profits from two time periods:

$$max_t \quad t(p_{B1} + p_{B2} - 2p_A)$$
$$s.t. \quad t \in \{-1,0,1\}$$

Using the expressions for the prices in (8), we get the following condition for the profit-maximizing t:

$$t = \begin{cases} 1, & \text{if } 2(\alpha \cdot c_{A1} + (1-\alpha) \cdot c_{A2}) < c_{B1} + c_{B2} \\ 0, & \text{if } 2(\alpha \cdot c_{A1} + (1-\alpha) \cdot c_{A2}) = c_{B1} + c_{B2} \\ -1, & \text{if } 2(\alpha \cdot c_{A1} + (1-\alpha) \cdot c_{A2}) > c_{B1} + c_{B2} \end{cases}$$

Do these transfers increase or decrease social welfare? The change in social welfare, ΔS, is given by:

$$\Delta S = t(c_{B1} + c_{B2} - c_{A1} - c_{A2})$$

Consider the case where $2(\alpha \cdot c_{A1} + (1-\alpha) \cdot c_{A2}) < c_{B1} + c_{B2}$, such that the profit-maximizing transfer goes from market A to market B ($t = 1$). Further, let d represent the profit for the trader, such that $d = c_{B1} + c_{B2} - 2(\alpha \cdot c_{A1} + (1-\alpha) \cdot c_{A2})$. In this case, we get:

$$\Delta S = c_{B1} + c_{B2} - c_{A1} - c_{A2} = d + 2(\alpha \cdot c_{A1} + (1-\alpha) \cdot c_{A2}) - c_{A1} - c_{A2} = d + (2\alpha - 1) \cdot (c_{A1} - c_{A2})$$

From this we get the following condition for the transfer to be social welfare increasing:

$$\Delta S > 0 \Leftrightarrow \begin{cases} \frac{d}{2\alpha - 1} > c_{A2} - c_{A1}, & \text{if } \alpha > \frac{1}{2} \\ d > 0, & \text{if } \alpha = \frac{1}{2} \\ \frac{d}{2\alpha - 1} < c_{A2} - c_{A1}, & \text{if } \alpha < \frac{1}{2} \end{cases} \tag{9}$$

This means that, if $\alpha > \frac{1}{2}$ (such that the price in market A is more influenced by the marginal cost in period 1 than in period 2) then the marginal cost in period 2 (c_{A2}) must not be too large, relative to the marginal cost in period 1 (c_{A1}). Otherwise, it might be that the total price difference between the two markets, and therefore also the profit for the trader, stems from an asymmetry in how the marginal costs influence the price in market A, rather than from a difference in the actual marginal cost between the markets. If this is the case, the transfer may be social welfare decreasing even if it is profitable. When $\alpha < \frac{1}{2}$, the same result holds, but with the time periods reversed. When $\alpha = \frac{1}{2}$, the transfer is always social welfare increasing.

This analysis shows that, while the transfer increases social welfare for most cases, it is possible for the transfer to be profitable and still reduce overall social welfare.

Subtracting d from the expression for the social welfare change in (9) yields the change in social welfare, excluding the profit of the trader. In this case, the following conditions are obtained for when the remaining social welfare increases (when $\alpha = \frac{1}{2}$, the social welfare improvement is completely captured by the trader, and there is no change in remaining social welfare):

$$\Delta S - d > 0 \Leftrightarrow \begin{cases} c_{A1} > c_{A2}, & \text{if } \alpha > \frac{1}{2} \\ c_{A1} < c_{A2}, & \text{if } \alpha < \frac{1}{2} \end{cases}$$

If the price in market A is more influenced by c_{A1} than c_{A2}, then c_{A1} must be greater than c_{A2} for a transfer from A to B to result in an improved remaining social welfare, and vice versa.

4.3.4 Profit-maximizing time-varying transfers

When the trader is allowed to change the transfer between the two time periods, the profit-maximization problem becomes, for each time period:

$$\max_{t_i} t_i(p_{Bi} - p_A)$$
$$s.t. \quad t_i \in \{-1,0,1\}$$

This is maximized by the following t_i:

$$t_i = \begin{cases} 1, & \text{if } (\alpha \cdot c_{A1} + (1-\alpha) \cdot c_{A2}) < c_{Bi} \\ 0, & \text{if } (\alpha \cdot c_{A1} + (1-\alpha) \cdot c_{A2}) = c_{Bi} \\ -1, & \text{if } (\alpha \cdot c_{A1} + (1-\alpha) \cdot c_{A2}) > c_{Bi} \end{cases}$$

The change in social welfare for time period i is given by:

$$\Delta S_i = t_i(c_{Bi} - c_{Ai})$$

Consider the case where $(\alpha \cdot c_{A1} + (1-\alpha) \cdot c_{A2}) < c_{B1}$, such that the profit maximizing transfer in period 1 goes from market A to market B ($t_1 = 1$). Further, let d_1 represent the profit for the trader, such that $d_1 = c_{B1} - (\alpha \cdot c_{A1} + (1-\alpha) \cdot c_{A2})$. In this case, we get:

$$\Delta S_1 = c_{B1} - c_{A1} = d_1 + (\alpha \cdot c_{A1} + (1-\alpha) \cdot c_{A2}) - c_{A1} = d_1 + (1-\alpha) \cdot (c_{A2} - c_{A1})$$

From this we get the following condition for the transfer to be social welfare increasing:

$$\Delta S_1 > 0 \Leftrightarrow \frac{d_1}{1-\alpha} > c_{A1} - c_{A2} \tag{10}$$

From this we see that the transfer is welfare increasing as long as c_{A1} is not to high relative to c_{A2}. If the trade is profitable because of a low c_{A2}, then the transfer in period 1 will not lead to an increase in social welfare.

Subtracting d from the expression for the social welfare change in (10) yields the change in social welfare, excluding the profit of the trader. This shows that the transfer from A to B in period 1 increases the remaining social welfare if $c_{A2} > c_{A1}$. When this is the case, the trader is unable to capture the full value that the trade is creating.

4.3.5 Conclusions for the generalized model with single-unit transfers

The analysis in this section shows that it is possible for the transfers to be overall social welfare decreasing, both when they are required to be constant and when they are allowed to be time varying. For the constant transfers case, this occurs when the underlying marginal cost function in market A is highly non-linear (α far from $\frac{1}{2}$), which means that the price in market A differs substantially from the simple average between the marginal costs of the two time periods in market A. When this is the case, a comparison between the simple average of the prices in market B and the price in market A does not provide a good signal for whether a transfer is socially valuable or not.

For the time-varying case, the transfers could also be social welfare decreasing. However, this occurs under somewhat different circumstances. In this case, the transfers can decrease social welfare even when the underlying marginal cost function in market A is linear. The reasoning is similar as that discussed in more detail in section 4.2: if there is an underlying cost difference across the two time periods in market A, and this cost difference correlates with a similar cost difference in market B, then the transfers might go in a social welfare decreasing direction.

4.4 Discussion and conclusions

As expected, arbitrage trading between electricity markets mostly increases social welfare, even when the markets have time periods of different length. However, as shown by the stylized models developed in this chapter, the welfare implications differ depending on whether the transfers are restricted to be constant or allowed to be time-varying. The analysis shows that it is possible, under certain conditions, for arbitrage trades to be social welfare decreasing even if they are privately profitable for the arbitrage trader. This is theoretically possible for both constant and time-varying transfers. The circumstances under which this occurs are however different between the two options.

An important caveat for the interpretation of these results is that the results for the time-varying approach depend on the existence of a balancing mechanism in the market with longer time periods that achieves productive efficiency. This is a strong assumption that is unlikely to be fully satisfied in a real-world setting. Further, while the total social welfare implications may in some cases be superior for the time-varying approach, the creation of imbalances in the market with longer time periods will likely be perceived as unfair. This is an advantage of the constant transfers option.

Finally, the possible negative effects from arbitrage trades between markets with different time period lengths strengthens the arguments in favor of a harmonization of the market time resolution across European electricity markets, as required by current European regulations [49].

5. Network fees and incentives to invest in distributed generation

Investments in distributed electricity generation, such as rooftop solar photovoltaic, has increased substantially in recent years. However, the popularity of distributed solar generation varies considerably between different countries and regions. These differences are partly related to the geographical variation in solar radiation, but they also depend on the financial incentives given to households and other end-users to invest in these technologies (see for example [50] and [51]).

There are many different components that affect the financial incentives to invest in distributed generation, ranging from investment subsidies to electricity and network prices. For distributed generation installed behind-the-meter, the customer is billed according to their net consumption or production (either keeping time-periods of net consumption and net production apart or aggregating them to a single net position for a longer period of time). The financial value of investing in distributed generation therefore depends both on the price paid for consumed electricity and on the price received for net production [52].

Higher marginal electricity prices increase the financial incentives to invest in distributed generation. One of the components that determine the marginal price is how the costs for the transmission and distribution networks are passed on to consumers. If these costs are added to a volumetric (i.e. the per-kWh) component of the electricity bill then it will be more profitable for consumers to invest in rooftop solar, compared to if the costs are charged as a fixed (e.g. monthly) fee. This effect is especially strong if the same volumetric charge applies to both consumed and produced electricity.

5.1 The Swedish context

DSOs in Sweden must be unbundled from electricity retailing. This means that they own and operate the electricity distribution networks, but they do not generate, buy or sell the electricity that is distributed through the networks. There are over 150 DSOs in Sweden. The ownership varies: some DSOs are private profit-seeking corporations while others are municipality-owned or operated as cooperatives.

DSOs are funded by fees charged to end-users. Because of the natural monopoly aspects of electricity distribution, the fees that DSOs charge are regulated. In Sweden, this is regulated by the Swedish Energy Markets Inspectorate who determines a revenue cap for each DSO. As long as the revenue cap is satisfied, the DSOs have some flexibility in how they choose to design their pricing structure. For smaller low-voltage customers (such as households) most DSOs charge two types of fees: a fixed price and a variable price. The fixed price is unrelated to the electricity usage, and the variable price is a per-kWh price. Other types of pricing schemes also exist, such as fees based on peak electricity use, but these are more common for larger industrial end-users. A DSO may charge different prices for different types of customers depending on, for example, the main fuse size.

Some Swedish DSOs have chosen to rely entirely on fixed charges and therefore have zero or very low variable prices. Others collect the bulk of their revenues through variable charges. This means that consumers that have different DSOs face different marginal (per-kWh) prices for their electricity. As discussed above, the marginal price for buying electricity is key for determining whether it is profitable or not for an end-user to invest in distributed generation. Therefore, DSOs that have chosen to collect their revenues through high variable prices provide stronger incentives for end-users to invest in distributed generation, compared to those that rely more on fixed charges.

Investments in distributed generation in Sweden has so far been quite limited compared to many other countries. However, due in part to generous investment subsidies and income tax deduction possibilities, investments in distributed generation has increased in recent years.

To what extent does the DSOs choice between fixed and variable network prices matter for the investments in distributed generation? This is the topic for the remainder of this section. The wide variation in variable network prices across different Swedish DSOs provide for a good setting to empirically analyze this question.

5.2 Description of data

The analysis in this section is based on DSO-level data obtained from the Swedish Energy Markets Inspectorate [53]. The Inspectorate collect this information from the DSOs as part of their regular monitoring activities. The analysis is based on data for 2016, since this is the latest year for which all relevant variables were available at the time of analysis.

The data contains information about 156 DSOs. The three largest DSOs are subdivided into smaller regional units, where different units are reported separately and may have different prices. For the purpose of this analysis, these regional units are therefore treated as different DSOs. The total number of DSOs in the data then becomes 161.

5.2.1 Prices

Because the DSOs may charge different prices for different types of customers, the Inspectorate collects price information for a set of reference customers. The reference types are defined in terms of main fuse size, annual electricity consumption and whether the customer is in an apartment or in a house. For each DSO and each reference type, the fixed and variable prices are reported as of January 1 of each year.

Many DSOs charge different rates for customers in apartments. However, since the possibilities for apartment-dwellers to invest in distributed generation is often limited, the analysis in this section is focused on non-apartment customers.

For this analysis, variable prices for two types of reference customers are used: a customer in a small house (16A main fuse and 5 000 kWh annual consumption) and a customer in a medium-sized house (20A main fuse and 10 000 kWh annual consumption). Most DSOs charge the same variable price for these two types of costumers, but some DSOs have a somewhat lower variable price for the medium-sized reference customer.

The data contains variable prices for the relevant customer types for 153 of the 161 DSOs. There are an additional 8 DSOs for which this price data is missing. Variable prices for small houses ranged from 3.50 öre/kWh to 50.20 öre/kWh, with an average of 16.59 öre/kWh across all DSOs in the sample. For the medium-sized houses prices ranged from 0 öre/kWh to 47.20 öre/kWh and the average price was 15.09 öre/kWh.

5.2.2 Distributed generation

The DSO-level data from the Energy Markets Inspectorate contains a variable for the amount of energy fed in from micro-producers (Swedish: mikroproduktionsanläggningar). A micro-producer is defined as a customer of the DSO who is both a consumer and a producer of electricity (in the same connection point), who generates electricity using a renewable source, who is a net consumer over a full calendar year, and whose main fuse size is less than 100A. For each DSO, the data includes the amount of energy that was fed in from such micro-producers (in MWh per year), but it does not include the number of such micro-producers.

Values for micro-production are available since 2014, and the amounts have increased substantially since then (from a very low level). It is therefore safe to assume that rooftop solar installations account for a large proportion of this micro-production, although it is possible that some other forms of renewable distributed generation may be included as well.

The amount of energy that is fed in from micro-producers differs widely across the DSOs. In most cases, these differences appear reasonable given the variation in the total number of customers per DSO. A non-missing value for micro-production in 2016 is available from all 161 DSOs. However, 32 DSOs reported a value of 0 MWh. Some of these are very small DSOs, where it may be reasonable that no micro-production occurred. But some are large enough that the value likely should be interpreted as a missing value rather than a true zero. Further, one DSO has reported an amount of micro-production that is extremely high relative to its number of customers.

Among the non-zero values for micro-production in 2016, the amounts range from 1 MWh per year to over 17 000 MWh per year. The average is 522 MWh per year.

5.2.3 Number of customers

The data contains information about the total number of low-voltage customers for each DSO. Further, each DSO reports the number of customers broken down by customer category. To get an approximate measure of the number of customers in each DSO that could potentially become micro-producers, the total number of customers that are homes (i.e. not apartments) and have a main fuse size of 16A, 20A or 25A is calculated for each DSO.

The total number of low-voltage customers per DSO ranged from 20 to over 800 000, with an average of about 34 000. The number of customers that are homes is available for 155 of the 161 DSOs. The smallest DSO has 15 customers that are homes, and the largest has almost 570 000. The average is almost 18 000.

5.2.4 Selection of sample

As noted in the previous subsections, some data is missing for the variables of interest for this analysis. Further, some values for micro-production appear potentially erroneous. Therefore, the sample is restricted as follows: 8 DSOs are excluded from the analysis because of missing price data and 2 DSOs are excluded because of missing data for 2016 due to an accounting year that does not equal the calendar year. The 6 DSOs for which data on the number of homes is missing are all part of the set of DSOs for which price data is missing, so this does not reduce the sample size further.

1 DSO is excluded from the sample due to a suspiciously high micro-production value relative to its size. Finally, an additional 29 DSOs are excluded because of a reported value of micro-production of 0 MWh. There are two reasons for excluding these observations. First, some of these DSOs are sufficiently large that it appears unlikely that no micro-production occurred, which means that some of these values likely should be interpreted as missing values rather than true zeroes. Second, one of the specifications in the regression analysis below involves taking the natural logarithm of each variable, which cannot be done when some variables take on the value zero.

This leaves a final sample of 121 DSOs.

5.3 Regression analysis

The relationship between variable prices and the amount of micro-production in each DSO is analyzed using OLS regressions. The outcome variable is the amount (in MWh) of micro-production in each DSO. The main explanatory variable of interest is the variable price. As noted above, two variables are used for the price data: one for small homes and one for medium-sized homes. In order to avoid issues with multicollinearity in the regression analysis, a single price variable is created by calculating the weighted average of the two prices, weighing by the number of customers in 16A houses and 20A houses in each DSO.

The larger DSOs in the sample tend to have relatively high variable prices. When regressing the amount of micro-production on the variable price, the result would therefore be highly biased if the size of the DSO is not controlled for in some way. The number of homes in each DSO is therefore used as a control variable.

Three different types of OLS regressions are performed:

- **Level regression**: $m_i = \alpha + \beta_1 p_i + \beta_2 h_i + \epsilon_i$. The amount of micro-production (m_i) is regressed on the variable price (p_i) and the number of houses (h_i).
- **Logarithmic regression**: $\log(m_i) = \alpha + \beta_1 \log(p_i) + \beta_2 \log(h_i) + \epsilon_i$. Same as the level regression, but the natural logarithm of all tree variables is used.
- **Per-house regression**: $m_i/h_i = \alpha + \beta_1 p_i + \epsilon_i$. The amount of micro-production per house is regressed on the variable price.

Table 1 below provides a summary of the regression results. The p-values provided in the table are calculated using heteroskedasticity-consistent standard errors, using the HC3-method from [54].

Table 1 Regression results

Model	Variable	Point estimate	p-value
Level regression	Intercept	78.6	0.58
	Variable price	-13.7	0.34
	Number of homes	0.0287	0.00
Logarithmic regression	Intercept	-6.30	0.00
	Variable price	0.471	0.03
	Number of homes	1.07	0.00
Per-house regression	Intercept	0.0115	0.00
	Variable price	0.000448	0.04

As expected, the level regression shows a highly significant relationship between the amount of micro-production and the number of homes in each DSO. However, there is no statistically significant relationship between the variable price and micro-production.

For the logarithmic regression, where the estimated parameters should be interpreted in percentage terms, the highly significant relationship between the number of homes and the variable price remains. Further, the parameter estimate for the variable price is now significant: each percentage increase in the variable price is associated with a 0.47 percent increase in micro-production. Although statistically significant, the explanatory power of the price variable is very low – the R^2 only increases marginally when the variable is included, compared to a similar regression without the price variable.

In the per-house regression, a higher variable price is associated with somewhat higher micro-production. The estimate is statistically significant but the R^2 value is very low – only about 0.02.

5.4 Discussion

The above results show a very weak (if any) association between higher variable prices and more micro-production. When interpreting these correlations, it is important to note that the estimates might be biased for several reasons. There are omitted variables that, if they were available and included in the regressions, could affect the estimates for the variable price. Examples include socio-economic indicators for the customers in each DSO, and geographical information about the DSO service areas. The inclusion of such covariates would only affect the estimates for the variable price if they correlate with both the variable price and the amount of micro-production. Another potential source of bias is the relatively large number of DSOs that were excluded from the analysis due to missing or questionable data.

Since the analysis was performed for 2016 in Sweden, where the uptake of rooftop solar was still quite low, the analysis captures the price-sensitivity among early adopters in rooftop solar technology. Such end-users may be less sensitive to price, and more driven by, for example, environmental and technological factors, compared to the average end-user.

6. References

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