Ine Solsvik Vågane

Local Flexibility Market - TSO and DSO coordination

Master's thesis in Energy and Environmental Engineering
Supervisor: Hossein Farahmand
Co-supervisor: Dmytro Ivanko
June 2022

Master's thesis

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

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Kunnskap for en bedre verden

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Preface

The master thesis was written at the Department of Electric Power Engineering at the Norwegian University of Science and Technology (NTNU). It was written Spring 2022 and was supervised by Professor Hossein Farahmand (NTNU) and Dr. Dmytro Ivanko.

I could not have done this thesis without Dr. Dmytro Ivanko's help and guidance. I want to thank him for helping me when I didn't know how to proceed. I also want to thank Naser Hashemipour for giving advice and discussing my results.

Further I want to thank my sister, Julie, for comforting me when I most needed it, and for proof reading my dyslexic writing.

Trondheim, June 08, 2022

Ine Solsvik Vågane

Abstract

Currently, the energy system in Europe is in transformation. An increasing amount of renewable energy resources and distribution generation is included in the power production. Despite positive environmental effects, these technologies create additional challenges for the market operators in managing the operation of their grids. Therefore, the traditional way of operating the grids are no longer sustainable for the future. New ways of regulating the power system are needed. Using the flexibility assets from distribution grid is an effective way to address potential grid challenges.

First, the thesis explores the different flexibility resources and regulations that are relevant to a flexibility market. It reviews how the operation and main parts of the flexibility market are structured. The review shows that coordination between TSO and DSOs are important for proper and efficient functioning of flexibility market.

Thereafter, the thesis evaluates various approaches from existing materials on TSO-DSO coordination. Several approaches of a power market coordination are compared, and the local flexibility market concept is selected as a basis for this research. The clearing procedure for this type of market using OPF models is introduced and analyzed. Particular attention is given to a method for coordinating TSOs with multiple DSOs in the flexibility market. There are two main methods for clearing the market in these conditions: bi-level optimization and decomposition method. After their comparison, the decomposition method is selected as more suitable for the tasks of the thesis.

The main part of the thesis focuses on the issues related to flexibility market modelling in conditions when coordination between TSO and multiple DSOs is established. For this purpose the Hybrid AC/DC-OPF ADMM model is developed. In this model, the transmission grid is presented by DC-OPF, and distribution grids are presented by AC-SOC OPF. The connection between these grids are established according to Hybrid AC/DC-OPF model. The ADMM method is used to organize the coordination between TSO and multiple DSOs in this OPF problem.

Finally, the Hybrid AC/DC-OPF ADMM model is tested to see how the flexibility resources can benefit the operation of the TSO and DSOs. For this purpose, the test case, which includes transmission and three distribution grids is developed based on Pandapower and Distribution Network Generator (Ding0). The grids are exposed to several grid issues such as voltage violation, congestion in the distribution system, and congestion in the transmission system. The results show that the

flexibility resources benefit from the distribution system they are located at in several ways. The costs, active losses and the voltage profile are improved. Nevertheless, for the considered case with limited number of flexibility resources, the DSOs could not help each other with the extra power when needed.

Sammendrag

Akkurat nå er det europeiske energisystemet i endring. Energien som produseres, kommer i større grad fra fornybar energi og desentralisert generasjon. Selv om dette har miljøfordeler, følger det også med en del tekniske utfordringer for markedsoperatørene. Den tradisjonelle måten å drifte strømnettet på er derfor ikke lenger bærekraftig for fremtiden, og det trengs nye måter å regulere kraftsystemet. Én av løsningene kan være å bruke fleksibilitetsressurser.

Denne avhandlingen utforsker forskjellige fleksibilitetsressurser og reguleringene som er relevante for fleksibilitetsmarkedet. Den undersøker hvordan et fleksibilitetsmarked driftes og hvordan markedsdeltagere organiseres. Analysen understreker viktigheten av god koordinering mellom TSO og DSO-ene for å ha et velfungerende kraftsystem.

Deretter evaluerer avhandlingen forskjellige fremgangsmåter for å koordinere et fleksibilitetsmarked, med utgangspunkt i diverse publikasjoner. Fremgangsmåtene ble vurdert og sammenlignet, og lokal fleksibilitetsmarked ble valgt som basis for forskningen. Hvordan dette markedet skulle blir klarert ved hjelp av OPF modell ble introdusert og analysert, med spesielt fokus på koordineringen mellom TSO og flere DSO-er. Det blir introdusert to hovedmetoder for å håndtere koordineringen; bi-level optimering og dekomponeringsmetoden. Etter sammenligning og vurdering, blir dekomponeringsmetoden valgt som metode for å koordinere TSO og DSO-ene.

Til slutt er Hybrid AC/DC-OPF ADMM modellen testet for å se om fleksibilitetsressursene kan være til fordel for driften av TSO og DSO-ene. Av denne grunn er testforsøket basert på ett transmisjons- og tre distribusjonsnett, som er utviklet og basert på Pandapower og Distribution Network Generator (Ding0). Nettene er utsatt for forskjellige nettproblemer, som spenningsovertredelser, flaksehals i distribusjonsnettet og flaskehals i transmisjonsnettet. Resultatene viser at fleksibilitetsressursene er til fordel på mange måter for det distribusjonssystemet de er plassert i. Kostnadene, aktive tap og spenningsprofilene er alle forbedret med fleksibilitetsressursene. Likevel, for dette testforsøket med begrensede fleksibilitetsressurser, kunne ikke DSO-ene hjelpe hverandre med ekstra kraft når det trengtes.

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Abbrevation

ACOPF AC Optimal Power Flow

ACPF AC Power Flow

ADMM Alternating Direction Method of Multipliers

BESS Battery Energy Storage System

BRP Balancing Responsible Party

DA Day Ahead

DCOPF DC Optimal Power Flow

DCPF DC Power Flow

DER Distributed Energy Resource

DFR Distributed Flexibility Resource

DLMP Distribution Locational Marginal Pricing

DS Distribution System

DSO Distribution System Operator

EU European Union

FR Flexibility Resource

FM Flexibility Market

FMO Flexibility Market Operator

ICT Information and Communication Technology

ISO Independent System Operator

LFM Local Flexibility Market

LFMO Local Flexibility Market Operator

LMP Locational Marginal Prices

LP Linear Programming

MCP Market Clearing Price

OPF Optimal Power Flow

RES Renewable Energy Source

SDP Semi-Definite Programming

SLR Surrogate Lagrangian Relaxation

SOCP Second Order Cone Programming

TDS Turn Down Services

TUS Turn Up Services

TS Transmission System

TSO Transmission System Operator

UC Unit Commitment

VR Voltage regulation

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1 Introduction

To manage to reduce the carbon emissions, and meet the constantly growing energy demand, renewable energy resources are becoming even more important. The power market needs to change rapidly. But how will the market handle the uncertainty that follows with using renewable energy resources? In this thesis, the coordination between transmission system operator (TSO) and distribution system operators (DSOs) with flexibility resources will be the solution in focus. There are several types of flexibility resources [1], and the focus in this thesis are the resources that can provide flexibility to the grid operation. These flexibility resources include load shifting, batteries and distributed generators. The use of the flexibility resources needs to be coordinated in a market with different market participants, and this is where local flexibility market comes in. It is defined as a trading platform for trading flexibility resources in a local area [2]. As the grid used in this thesis has several DSOs, the coordination of local flexibility market was chosen to be cleared based on Hybrid AC/DC-OPF ADMM model. This method can decompose the market problems into sub-problems for TSO and each of the DSOs, and find an optimal solution for the flexibility market in an iterative way [3]. The motivation, scope, aim, objective, contribution and structure of the thesis will be given in this chapter.

1.1 Motivation

Incorporating more renewable generation is crucial for reaching the global climate goals. As there are several challenges that follows, the future power market needs to have the resources that can manage the new energy production. This master thesis wants to highlight the importance of infiltrating flexibility resources into the electricity market and therefore encourage doing more research in this area.

To have a satisfactory flexibility market operation requires well organized TSO-DSO coordination. The downsides of not having adequate cooperation between the TSO and DSO are serious. Not having a thorough communication system can lead to conflicting decision-making between the participants [4]. Furthermore, it could lead to additional, unwanted costs.

A big motivation for developing an acceptable coordination scheme between the flexibility market participants is to reduce costs. To be able to avoid expensive operations, an accurate and reliable modelling approach should be developed. The groundwork has been done by other researchers, including the master thesis by Ole Kjærland Olsen and Damien Sieraszewski at the IEL faculty of NTNU [5]. The Hybrid AC/DC-OPF model this thesis is based on was designed only for the coordination of one TSO and one DSO. Thus, there is an ambition to create a new, improved model for clearing the flexibility market. The main target for this thesis was to develop the model to handle more realistic cases when multiple DSOs with flexibility resources are participating in the flexibility market. Therefore, in this thesis, the Hybrid AC/DC-OPF model was improved with Alternating Direction Method of Multipliers (ADMM). The three distribution grids, where two of which are generated based on real data from German grids, were used to develop a test case in this investigation. And finally, using the test case and the model, the applicability of flexibility resources for solving different challenges in distribution and transmission grids should be tested.

1.2 Scope, aims, objective

The scope of the thesis is local flexibility market, its participants, structure and coordination. It includes the flexibility resources: load shifting, batteries and distributed generators. In addition, it covers the modelling approaches for market operation. The developed Hybrid AC/DC-OPF ADMM model for clearing the local flexibility market will be tested with the test case, which includes one transmission grid connected with three distribution grids.

There are several limitations of the work that should be mentioned. The model was tested based on medium voltage distribution grids with aggregated load and flexibility resources since consideration of a full scale grid system would be too computational heavy and time consuming for the masterwork. In addition, the prices for flexibility resources were considered constant. Depending on a market mechanism, the trading can be organized in a way that these prices could change dynamically, which is not covered in this thesis. The prices were also taken from the Norwegian power market and not the German market, where two of the grids are from. The distributed generators used in this model is of flexible dispatch and not the intermittent nature of renewable energy.

The local flexibility market is still a developing term. The thesis aims to get a better understanding of the flexibility market and how to coordinate it, and additionally to develop a mechanism and model for clearing a flexibility market with coordination of TSO and multiple DSOs.

There is still a demand for knowledge about how to organize and model a local flexibility market.

The objective for this thesis is therefore divided into five parts:

1. Reviewing existing publications on utilisation of the flexibility resources, functioning and coordination of the local flexibility market, and modelling approaches that can be used for the market clearing, and to analyze which one is suited for the tasks of the master investigation.
2. Developing a Hybrid AC/DC-OPF ADMM model, that can be used for clearing the flexibility market with coordination of TSO and multiple DSOs.
3. Creating a test case based on a Pandapower grid and a synthetic grid generated by Ding0 package to test the Hybrid AC/DC-OPF ADMM model.
4. Using the model and the test case, the fourth part aims to answer the question: how can the operation of TSO and DSOs benefit from the flexibility resources?
5. Finally, answering the research question: Can the DSOs help each other with grid issues in a flexibility market?

1.3 Contribution

The existing literature, or the state of the art, was reviewed to identify potential research gaps. The special focus was made on the local flexibility market concept, which is well suited for Norwegian and German conditions. For instance, in the paper [2], an extensive review of concepts, models and clearing methods for a local flexibility market (LFM) was presented. It gives a good overview of the most important elements in a LFM. A proposal for different coordination schemes in a LFM was made in [6]. It introduced and systematized five schemes, which was an important step towards having a clearer framework for the LFM. A characterization of flexibility resources was presented in [1], giving a better overview of the possible flexibility resources and their utilisation for different purposes. The papers [7] and [8] give an overview of two clearing methods that could be used for clearing markets with several DSOs.

These papers combined, give a wide perspective of the LFM. Nevertheless, they do not combine challenges, an overview of flexibility resources, regulations, schemes and modelling approaches into one review; One that ties all the aspects of a LFM together, which is done in this thesis. This thesis' review incorporates a wide variety of the defining parts of a LFM. In addition, it includes a model extension and case study for a LFM.

The thesis contributes with a Hybrid AC/DC-OPF ADMM model and case study. The model is a product of extension work, a continuation of the Hybrid AC/DC-OPF model that was made to coordinate a LFM done by [5]. Their model did not cover TSO coordination with multiple DSOs. Therefore, in this thesis, the model was improved and adjusted with the ADMM method to cover this drawback. The extended model then became capable of handling multiple distribution grids, where there was previously only one. This is an important contribution to simulate more realistic market cases. The work also contributes to developing a realistic test case based on Pandapower and Ding0 grid generators for analysis of the TSO coordination with multiple DSOs in the flexibility market. A final contribution is the analysis and results of the flexibility resources application for solving challenges in transmission and distribution grids.

1.4 Structure of the project

The thesis consists of eight main parts; introduction to the problem, literature review and theory in flexibility markets design, a method for flexibility market modelling, presentation of a test grid, test results and discussion regarding the results, and lastly a conclusion and description of further work.

Chapter 2 reviews the structure of the flexibility market and describes how to operate it. Various grid challenges and solutions with the utilization of flexibility assets are presented. Further, flexibility regulations, resources and main participants in a flexibility market are given. Next, a review of the different TSO-DSO coordinations in a flexibility market is introduced.

Chapter 3 is a continuation of the review, but it focuses on approaches for flexibility market operation. How optimal power flow (OPF) should be implemented for flexibility market modelling is presented. In the last subchapter, different market clearing methods for several DSOs are presented and compared.

Chapter 4 presents the method for coordinating the market operation. The first subchapter introduces the Hybrid AC/DC optimal power flow (AC/DC-OPF) model for TSO-DSO coordination in the power grid from the master thesis [5]. The next subchapter gives an introduction to how the ADMM method works and presents the extension of the AC/DC-OPF model with ADMM for TSO coordination with multiple DSOs.

Chapter 5 introduces the case study of the thesis and describes the state of the German grid. In addition, it presents the German grid that is being used, and how it was developed with Ding0.

Chapter 6 presents the results for the four different cases: voltage violation, congestion in the DS, congestion in the TS and economic dispatch.

Chapter 7 is a discussion of the presented results in Chapter 6. It discusses if the objective is met by the results.

Chapter 8 concludes the project, and establishes if the aim is met. It finalizes how the thesis contributes with a review of flexibility market, how the extended model works for multiple DSOs, and lastly if the extended model can use flexibility resources to solve different grid challenges.

2 Flexibility assets, market structure, regulations and operation

A part of the objective of this thesis is to review the existing publications about flexibility resources, the LFM and coordination of this market. Therefore, is this chapter dedicated to the main aspects of utilizing flexibility resources and flexibility market functioning. Subchapter 2.2 considers grid challenges that can be solved with flexibility resources. Subchapter 2.3 presents regulations regarding flexibility and injection of power from the consumer side. Subchapter 2.1 presents a detailed analysis of different flexibility resources. Subchapter 2.4 discusses the structure and participants of the flexibility market. Finally, Subchapter 2.5 introduces the problem of TSO-DSO coordination in a flexibility market. Subchapter 2.2 and 2.1 are a continuation of the specialization project [9]. They have been modified and new information has been added. Subchapter 2.4 and 2.5 are kept the same and are a presentation of the specialization project [9] as there has not been found new information during the work on the thesis. This chapter gives the background information that will be used in the model extension.

2.1 Flexibility resources in electrical power system

Some of the possible flexibility resources will be described in this subchapter. One of the definitions of flexibility resources (FRs) is that FR is any resource that can provide flexibility to the grid operation [1]. This suggests that a considerable amount of resources can be called a FR. The FRs are organized into two main groups: flexibility assets and operational flexibility. Flexibility assets can be conditionally divided into three sub-groups: demand-side, supply-side and storage assets. The demand side flexibility has three options: shiftable advance, delay or advance/delay combined. Under the storage group, two FRs are defined: stationary and mobile. In the stationary group, there are two alternatives; with generation or stand-alone. Operational flexibility also can be divided into three subgroups: network reconfiguration, dynamic line rating and lastly other innovative operation techniques. Each of the main groups is explored in the following subchapter and is shown in Figure 2.1.

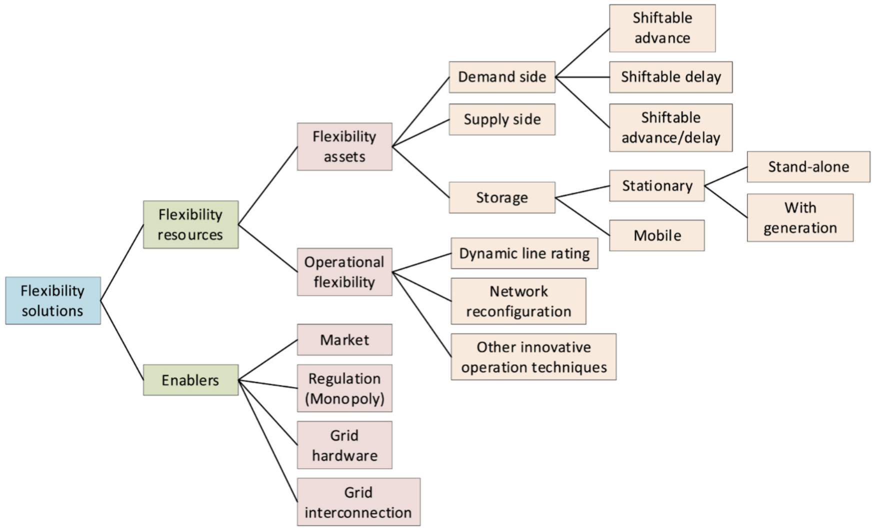

Figure 2.1: *The classification of different flexibility resources from [1].*

In this thesis, load shifting at the demand side is one of the FRs that is used for flexibility market modelling. Therefore, devices that can be used for this purpose in detail will be considered. The first considered subgroup of flexibility assets is the demand side. Electrical vehicles are examples of demand side assets. Using electrical vehicles for a shiftable advance on the demand side can be an advantageous strategy for EU countries, that have a significant share of electrical cars. Another option is a shiftable delay, such as a freezer/refrigerator, water boiler, heating system etc. The energy use of these devices can be temporarily reduced or shifted in time without significantly affecting their operation and the comfort of people, but still improving the performance of the power system. If shiftable delay and advance are combined, another option is made. An example of these devices is washing machines and dishwashers, which have timers that can be used to plan energy use in time [1].

The evident benefit of demand side flexibility is the ability to shift the demand from peak hours to off-peak hours to reduce the stress on the grid. In addition, load shifting can help with congestion problems and voltage violations, reducing the overall costs of the grid operation. Involving residential consumers in flexibility market has great importance for dealing with grid challenges. However, it should be taken into account that the potential for residential load shifting is not constant and varies with the subsistence levels. Subsistence levels mean in this context how much consumption is required to suffice the basic needs of living, and are measured in kWh per hour and are evaluated for an average household in Sweden [10]. In winter, the subsistence level is higher due to the need for heat and light, while the warmer and brighter summers have a lower level. The average level during peak hours is 3kWh in winter and 0,7 kWh in summer. Hence, if the electricity use of a residential is higher than 3kWh, it will respond to a price increase in winter. In summer, residents will respond if the electricity use is higher than 0,7 kWh. The subsidence level also has daily variations, as the demand varies when the residents are home (high energy use) or away (low energy use) [10]. This variation can be seen in the residential demand graph in Figure 5.3. The potential for load shifting is highest when it is summer and the residents are away. Additionally, the electricity prices influence the potential for residential load shifting. At peak hours the price elasticity is -0.8, and -0.6 at off-peak, which implies that consumers are more willing to change consumption during peak hours [10]. In addition to subsistence levels, the prosumers have regulatory challenges hindering them to be included into the active demand side. This is explored more in Subchapter 2.3.

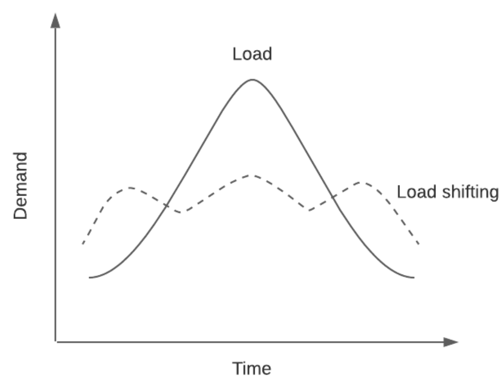

Figure 2.2: *Reducing the peak load demand with load shifting.*

Load shedding is the last possible option the market operators want to apply in the power system [1]. Nevertheless, it is necessary in some cases, which will be shown in later chapters. It is not defined as a FR in this thesis however.

Further, is the second subgroup, the supply side. Hydropower and thermal power, which are dispatchable power plants, can be used as examples for the supply side for flexibility assets [1]. Adding distributed generators can help reduce the stress of the grid. The generators could either use intermittent or non-intermittent energy production. Intermittent generators generate power only for a limited time period. Wind and solar energy sources belong to intermittent generators since their production depends on weather conditions [11]. As these types of power are unpredictable, non-intermittent electricity generators were used as additional flexibility assets in the distribution grids in this work.

Storage is an important contributor to the flexibility of the grid, and there are several options for energy storage. Hydrogen storage or pumped hydro can be essential examples of stationary stand-alone storage. Furthermore, stationary storage with generation is an option, such as a wind power plant or photovoltaic plus battery. The last option presented is mobile storage, and electrical vehicles are an example of a provider with such storage [1]. To take the energy storage flexibility solution into account in this master thesis, the batteries were included in the flexibility market modelling performed.

Including battery storage in the power grid will allow the operators to store energy for when it is needed. A battery energy storage system (BESS) contains an electrochemical device that charges and discharges energy from an electrical grid. The concept is shown in Figure 2.3. The batteries can be of different types and inhabit different abilities. BESS will play an important role in the future power grids with the integration of renewable energy, as this power is unpredictable and may not be produced when needed. Batteries can contribute to enhancing the use of renewable energy by storing it for later use, reducing renewable energy curtailment [12]. However, it may not be the most economic choice of FR.

There are other benefits of using batteries in the power grid. It can provide arbitrage by utilizing the batteries with the increasing and decreasing electricity prices and earning a profit. Incorporating batteries can also secure the system operator's reliability, by providing enough power when the demand is high [12]. Additionally, to ensure grid reliability, several different operating reserves and ancillary services needs to be provided. Batteries can contribute to these services by charging and discharging quickly, providing Primary Frequency Response and Regulation. Lastly, batteries can contribute to delaying transmission and distribution grid upgrades. The grids need to update to meet the new peak demand, however, by including batteries it can defer these costly updates [12].

The grid used in this work has buses that are aggregated from low voltage grids, and electrical vehicles could therefore be used as aggregated batteries.

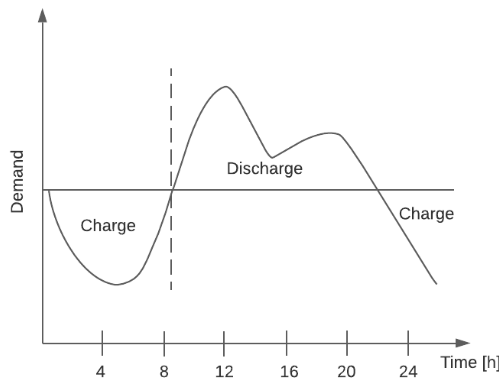

Figure 2.3: *The concept of using battery energy storage system in a grid.*

Lastly, some information about the operational flexibility group must be mentioned. The two subgroups of operational flexibility that are presented here are network reconfiguration and dynamic line rating [1]. Network reconfiguration of the distribution system is the changing of the topology of the distributing feeders [13]. As stated in [2], network reconfiguration can optimize the system and make the power supply more capable in the distribution system. Next, dynamic line rating is a method with the object of maximizing the load on the overhead power lines, while taking the weather and environment conditions into account [14]. As this thesis is focused on flexibility assets, the group of operational flexibility is not taken into consideration in further chapters.

2.1.1 Potential challenges of using flexibility resources

Despite the benefits of FRs there are also potential challenges with the widespread application of FRs. The demand side can not be as easily controlled as the supply side, since it consists of residents, industry, agriculture etc. In this subchapter, the consumers or prosumers are in focus, as they have the biggest amount of individuals, and may be the biggest challenge incorporating into the active demand side.

The demand side FR mentioned in this subchapter is load shifting. In addition, some consumers on the demand side can have batteries available in form of electrical cars. They have the potential of being a source of flexibility, but what is not acknowledged is that the end-users on the demand side need to be able and willing to provide that flexibility. As mentioned in [15], only large-scale industrial and commercial users have the knowledge and experience of being a part of the grid and network management. They have settlements such as interruptible contracts, time-of-use tariffs with interval metering, and storage contracts.

Residents' contribution to flexibility is still not developed enough to reach their full potential. They are yet to become active participants on the demand side. However, by including interval metering, two-way communications, micro-generation, storage and frequency-response-enabled appliances they will be more incorporated into the flexibility market [15].

Another challenge is the issue of privacy. The researchers in [15] highlight the concern people have by letting larger utilities govern and control their domestic activities. Therefore, a big challenge is creating trust in the suppliers which is essential to ensuring the utilization of the available FRs. In addition, many householders are not interested in being a part of an active demand side, as they already have the option of being passive. In the next subchapter, which of the described FRs can help managing grid challenges is explored.

2.2 Solving grid challenges with flexibility resources

In Chapter 6 the model is testing different grid challenges to see how FRs can help the grids. Some of these grid challenges that will be tested are described in this subchapter. The widespread integration of renewable energy resources leads to inconsistent energy production and additional grid challenges. To ensure optimal operation of the grid in these conditions, technical and economic solutions should be explored. Among different solutions, the flexibility assets in distribution grid have great potential to solve grid problems. There are several publications which highlight grid challenges and flexibility solutions to deal with them. For example, [16] describes different challenges with the integration of wind power. One of the problems with using an intermittent energy resource such as wind energy is the unpredictability [16]. No forecasting model is 100% correct, and the wind will not always blow accordingly to the prediction. This gives an imbalance in the power flow. The authors propose to solve this issue by utilizing the potential of charging batteries when there is higher power production than demand, and discharging when the power production is lower than the demand.

Another possible challenge with increased production of wind energy is their consumption of reactive power. The commonly used induction generators in wind power generation systems consume reactive power, unlike synchronous machines that generate reactive power. Imbalance in the reactive power flow caused by induction generators can lead to instability in the grid [16]. However, this characteristic of wind production can also be used as an advantage, as a FR, for the voltage profile by consuming reactive power when it is needed.

In addition, there are problems related to frequency when the share of power produced by wind is increasing. The overall inertia of the power system is reduced with the use of wind power production. To manage the frequency degradation problem load control is suggested, e.g. load shifting or using energy storage like batteries [16]. As reactive power and voltage are interrelated, they both need to be considered when controlling the voltage. It is a critical issue to manage the voltage between operational limits. Including wind power production in the electricity grid will induce flickering and instability in the voltage values [16]. Flexible assets such as load shifting, batteries and distributed generators could help to stabilize the voltage. This theory is tested in Chapter 6, where voltage violations will be investigated in combination with FRs.

Another important grid issue is congestion. In Norway in 2021, approximately 13% of all cars are electrical and this share is constantly growing [17]. The electrical cars can add an additional load on the already high demand at the peak hours, which can lead to congestion in the distribution grid. As more electrical cars and distributed generation is used it will lead to congestion in the distribution system. A solution could be to shift the load to prior to or after the peak hours. These measures are called load shifting [18]. In the testing part of this master thesis, issues regarding congestion in the distribution system and transmission system will be tested.

There are also some other problems regarding grid operation that could be solved with FRs. When transferring electricity over long distances, a share of the power is lost in the lines. The greater the distance, the bigger the loss. By including distributed generators and implementing operational flexibility, transmission losses can be reduced. This would encourage operators to choose suppliers closer to the loads, not the distant, bigger power plants. In addition, the system would be more efficient and economical [18].

Natural disasters or bad weather conditions can contribute to blackouts or damage the power systems. By utilizing backup systems such as stationary storage, the FRs can be imperative to manage the grid in these conditions [18]. There are several FRs that can help reducing the grid challenges described in this subchapter. However, to increase the use of them, there needs to be regulations set. The next subchapter reviews the regulations that the governments should include to increase the use of FRs for the flexibility market participants are described. In addition, the challenges of implementing these regulations are presented as well.

2.3 Regulations for flexibility use

Currently, the power system operation is mostly based on a traditional centralized approach where the power is transferred from the transmission system to the distribution system. As this is changing, the governments need to create new regulations and adjust existing ones to utilize FRs as optimal as possible. The existing regulations from European countries are discussed below.

From the Directive (EU) 2019/944 [19], the DSOs' use of flexibility is established. Rule number 61 states that the DSOs need to try to integrate more distributed energy resources (DERs). More specifically, it mentions energy storage and demand response. In this thesis, the DERs or FRs are load shifting, load shedding, batteries and distributed generators. To aid this change, incentives are suggested as the main form of encouragement. If the DSO wants to include new loads, then heat pumps and electrical cars are suggested, as they can be used as FRs. The Directive states that the Member States (EU) should establish national network codes and market rules that will benefit the expansion of FRs' usage. In addition, it advocates for the Member States to propose the network development plans to the distribution system operators, to aid the transition of the power grid into more renewable energy sources (RESs).

Rule number 10 and 39 in the Directive (EU) 2019/944 [19] concern the consumers in the market. Rule number 10 acknowledges the important role the consumers have in the transition to an active, flexible demand side. It encourages the Member States to empower the consumer by providing them with the means to be a bigger part of the energy market. Rule number 39 states that every consumer group (industrial, commercial and households) must have the opportunity to trade the FRs they have available.

The Directive states in rule number 90 that the Directive should be used collectively with Regulation

(EU) 2019/943. This is because it lays the key principles for the new market design for electricity when regarding the flexibility market. If done so, it will ensure that FRs get the appropriate reward as well as ensuring adequate price signals. In addition, the Regulation (EU) 2019/943 has established new rules in various areas, such as a better cooperative system between transmission system operators.

Article 32, "Incentives for the use of flexibility in distribution networks" [19], states that the Member States need to arrange the required regulatory framework that will establish incentives for the DSOs to procure flexibility services. This applies to congestion management and the progression of the distribution system. The article highlights the importance of having transparent, non-discriminatory and market-based procedures when the DSOs procure the FRs. Moreover, the DSOs should, in collaboration with the TSO and other relevant system users, establish the specifications for the procured flexibility services transparently. These specifications need to include all market participants. The coordination between the TSO and DSOs should be developed in a way that ensures optimal usage of the FRs. In Chapter 3 this coordination is further explored and analyzed.

2.3.1 Challenges regarding the existing regulations

As mentioned, there are several established regulations for FRs in the power market. Most of the FRs are procured as a short-term solution and fall under these existing regulations [20]. However, for medium and long-term demands for flexibility, there is a lack of established regulations. This will be necessary for the future to ensure the maximum utility of FRs.

Even though the Directive for regulations was given in 2019, none of the Member States has made complete facilitation for DSOs' flexibility procurement by 2020 [20]. The reason for the delay could be that the network code for demand side flexibility is not yet published. If the Member States implement a national framework for the demand-side now, it might conflict with the new upcoming network code. Therefore, the already existing products and the new FRs need to be intertwined. If not, it might give services or products that are not compatible. Additionally, as the countries will create their regulatory framework that suits their local circumstances, it might create market barriers. This shows the demand for common structures for all the Member States to follow.

The already existing FRs policy initiatives have given the retail sector, Energy service companies and aggregators a commercial development [21]. However, the policy framework does not cover the specifics of the Energy service companies and will hinder further development. The existing aggregators could face being surpassed by new independent aggregators if the new regulatory framework allows it. Several regulatory challenges needs to be sorted to make it easier for FRs to be included in the LFM. A presentation of the LFM and its participants are described in the subchapter below.

2.4 Local flexibility market operation and its main participants

The local flexibility market has previously been mentioned in this master thesis, however, it has not been defined. A local flexibility market (LFM) is a trading platform to trade flexibility goods in a geographically limited area. These areas could be neighbourhoods, communities or small towns. The market framework for the LFM is a service to be traded (FRs), market operators (DSO, TSO) and other market participants and lastly market clearing mechanism [2]. In this thesis this is Subchapter 2.1, Subchapter 2.4 and Chapter 3, respectively. An important notion to make is that LFM and flexibility market (FM) will both be used to describe the market that is the focus of this thesis. An overview of the roles and responsibilities of a LFM participant is given in Figure 2.4. The roles of the main market participants will be further discussed below.

As the contribution from RES is increasing, the roles of TSO and DSO are changing. However, there are traditional roles that the TSO and DSO are in charge of. The TSO is responsible for the generation side and provides power to the consumers by the DSO. In the planning phase, the TSO predicts consumption and balances the real-time flows. The problem the TSO is currently facing is the unpredictability of renewable energy production. This is caused by the uncertainty in the predictability in weather forecasting for both wind and sun [22], already discussed in Subchapter 2.2. By including FRs such as batteries or load shifting, the uncertainty of renewable generation could be solved by these flexibility assets.

The DSO is responsible for distributing the power to the consumers and maintaining the distribution grid. With the increased use of RES, the coordination between TSO and DSO needs to be adjusted. Now, a growing amount of energy is generated in the distribution system and not just in the transmission system. Before, it was the TSO who planned and provided the generation of power. Now, however, by having a greater amount of distributed generation, the TSO's planning becomes more difficult. The TSO has to receive information from the DSO about the distributed generators, as the DSO is the operator that controls the distributed generation [22]. In this context, the TSO and DSO can be considered as market participants with roles proposed in the Horizon project [23].

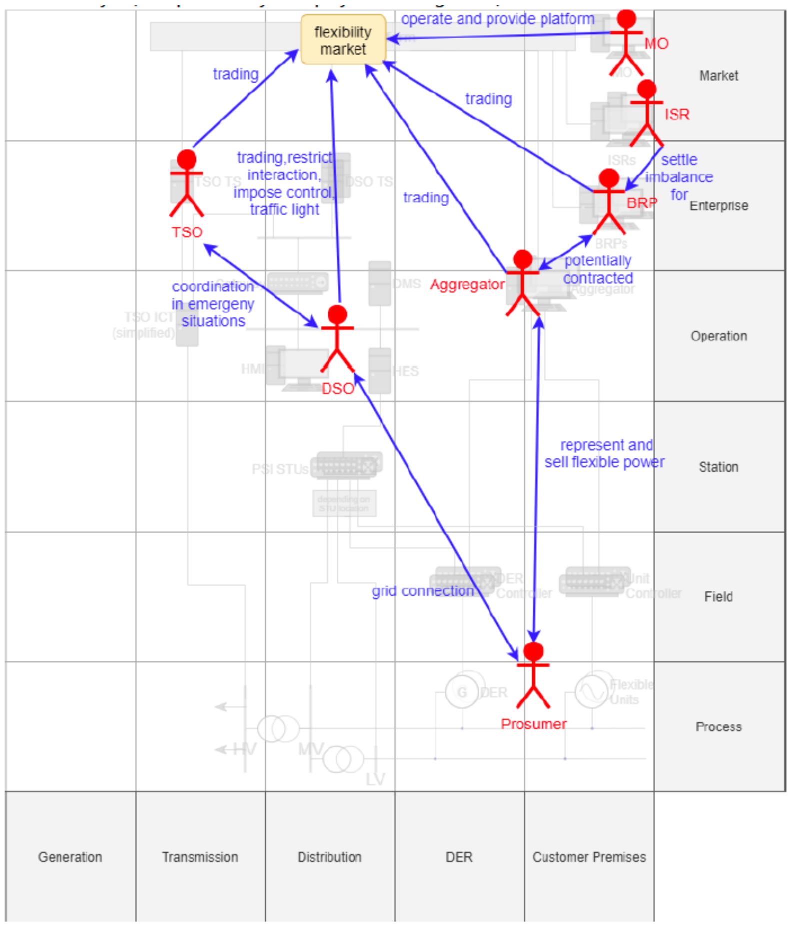

Figure 2.4: *The coordination scheme for the flexibility market from [23].*

The investigation that this master thesis extends on [5], considers the ability of TSO and DSO to act as the balancing responsible party (BRP). A BRP has the responsibility to balance the consumption and supply in the market. To keep the balance more efficiently, the BRP's purchase flexibility from aggregators. The role of the BRP varies with the market's design. In some markets, such as the one in this thesis, the DSO and TSO have the job of keeping the balance in the system. In other types of markets, the BRP can be an independent actor from TSO and DSO [2].

The flexibility market operator (FMO) has the responsibility for creating a trading platform where market clearing can take place. It collects information about the flexibility offers and decides prices as well as the quantity of traded flexibility. The FMO does not have to be an independent participant, sometimes it could be a DSO or an aggregator [2]. Further, the imbalance settlement responsible has an important role in the FM, being responsible for the frequency of settlement, main imbalance pricing mechanism, regulation states, single/dual pricing, one/two price settlement and alternative imbalance pricing [24].

Distributed flexibility resources' (DFRs) and prosumers' role in the FM is to produce and consume/store power according to the need of the grid. The willingness of end-users to provide flexibility depends on the technology they are using. Prosumers with photovoltaic plus battery and prosumers with an electric vehicle are more likely to contribute with flexibility, than owners with a heat pump [25]. Different DFRs are presented in Subchapter 2.1. By having a significant number of small prosumers, they are represented in FM by an actor called an aggregator. The aggregator's responsibility is to forward the flexibility services the DFRs and prosumers can provide to the BRPs. The trading information is given by the aggregators to the FMO. This is beneficial for the DFR's and prosumers since they often provide only small amounts of flexibility [26].

There are several different aggregator types. In this subchapter, an in-depth consideration of aggregators as FM actors in the Dutch electricity system is given. Six types of aggregators are presented: the combined aggregator-supplier, the combined aggregator-BRP, DSO as an aggregator, the aggregator as a service provider, the delegated/broker aggregator and lastly the prosumer as aggregator [26]. Combined aggregator-supplier and aggregator as a service provider are the aggregator types that are best supported in the Dutch system. This is due to their resemblance to the contemporary activities of the suppliers and the electricity market. The combined aggregator-BRP and prosumer as aggregator are however not as well supported by the Dutch electricity market, even though some elements are supported. This is due to their complexity and the expertise needed to function. The delegated/broker aggregator and the DSO as aggregator are not supported at all, due to the complexity, lack of explicit rules and strict DSO regulations [26]. The next subchapter will provide a market framework for how the different market participants work together to coordinate the FM.

2.5 TSO-DSO coordination in flexibility market

There are several ways to coordinate a FM. Some of these will be elaborated on in this subchapter. The markets that are included in the review are Day Ahead (DA), intra-day and balancing market, where FM is between intra-day and balancing market. In this section, various models for coordinating a FM and the market participants' roles are presented and analyzed. The coordination includes the market participants and FRs already described. Smartnet has presented five coordination schemes, where all of the schemes are describing the FM between intraday and balancing market. Some of the schemes are also describing the balancing market. In all of the schemes, FRs are included [6]. These are presented, compared with various articles [5] [27] [28], and lastly the best suited coordination scheme is chosen as the framework for the model presented later.

2.5.1 Centralized AS market model

The first market model [6] is the Centralized AS market model, where the TSO is operating with both transmission level and distribution without an extensive DSO. The DSO is solving the local grid problems and procures flexibility in a different time frame than the Centralized AS market. In this scheme, the involvement of the DSO has been kept at a minimum by being a part of the pre-qualification process.

2.5.2 Shared balancing responsibility model

The second market model is the shared balancing responsibility model, where both the TSO and DSO share the responsibility of balancing the market. The DSO has the power of the resources and must follow the agreement made between the TSO and DSO [6]. The TSO has no power over the FRs located in the distribution system (DS). The coordination scheme paired up with the shared balancing responsibility model is FM with DSO as flexibility provider.

Flexibility Market with DSO as flexibility provider

It is advantageous to utilize FRs for distribution system management for the DSO. Likewise for the TSO, using it to handle congestion and minimize energy costs in the transmission system (TS). DERs, or distributed energy resources, are small-scale electricity supply or demand resources that are interconnected to the electric grid [29]. DERs are a type of FR that can be used when planning the DA market and are included in the FM (intra-day). The proposed coordination scheme starts with the information given from the DA market, and then it describes the FM with a balancing market process with five phases, with the following steps [27]:

1. The distributed energy resources (DERs) or FRs have found their initial self-dispatch from the DA market. This initial point of operation and offers are then submitted to the DSO by the DER.

2. The DSO has to optimize the power flow with the DER that is in the DS and offer collection.

3. The TSO has to balance the market and consider network violations. It must simultaneously consider the offers given to the DSO. Hence, it evaluates both the DSO offers and the resources based on the TS.

4. Verification of the requests. The DSO performs optimal power flow (OPF), this time including the TSO offers. The TSO offers will be evaluated if it is feasible, or if it violates the network constraints. If possible, the verification will be sent back to the TSO.

5. The TSO and DSO present a final plan to the other FMPs, that is optimized and verified.

There are similarities between this coordination scheme, FM with DSO as flexibility provider and Shared balancing responsibilities. The main similarity is that the DSO is responsible for the FRs. Nonetheless, there is a big difference; with the Shared responsibility market, the TSO can not use offers from the FRs situated in the distribution system. In the other market design, this is a crucial part, where the TSO can consider using offers collected from the DSO.

2.5.3 Common TSO-DSO Ancillary Service market model

The third market model is the Common TSO-DSO Ancillary Service market model. Here, the TSO and DSO share a common goal; to decrease the costs while covering their need for resources. This occurs with a joint operation system. Their resources are connected to both the transmission level and the distribution level. The DSO's constraints are taken into account when clearing the market. When concerning the optimization process in this scheme, the alternatives are a centralized or a decentralized variant [6].

2.5.4 Integrated flexibility market model

The fourth market model is the Integrated flexibility market model, where the market is open to different coordination schemes. There could be regulated and non-regulated parties, but this would require an independent market operator. The market operator has to consider the DSO's constraints when clearing the market. It is based on the common market model, but commercial market parties also procure FRs [6]. This market is paired up with the TSO-DSO-Retailer coordination scheme.

TSO-DSO-Retailer coordination scheme

A market participant that is often not included in coordination schemes is the Retailer. It is not included in the description of market participants in Chapter 2.4, as it is often left out in the coordination of FMs. It is however included in [28], and the investigators argue that it is beneficial to have a coordination between TSO-DSO and the Retailers, due to the extra costs that can occur without cooperation. This argument highlights the importance of a thorough coordination scheme. Retailers have the responsibility for contracting their consumers' demands. They are also required to pay for the deviation that occurs between metered consumption and their contracted position [28].

The paper [28] includes three market designs: the sequential design, the TSO-DSO mechanism and lastly TSO-DSO-Retailer design. In all of the designs, the DERs are the sellers and TSO, DSO and Retailers are the buyers. The offers of service from the DER are announced on a trading platform, where the buyers can contract. The DSO presents a linearized model of the network for each round, and the sellers can choose to accept the offers partly or entirely. An important aspect that [28] includes is the prices and triad warnings in the process. All three designs include the FM and the balancing market. The three schemes are:

1. **The sequential:** The process starts with the Retailer procuring turn down services (TDS) if there is a triad warning. Further, the used flexibility TDS must be removed from the services of the DSO. This is crucial as these services are not available for use anymore. While TDS is essential for solving congestion induces by the demand, turn up services (TUS) are for solving congestion due to generators. The job of the DSO is then to minimize the cost, while also taking the grid conditions into account. Furthermore, when the DSO has made its procurement, it has to make the services unavailable for the TSO. The TSO procure what it needs from the set of services. Finally, at the settlement, each of the TSO, DSO and Retailer

has to pay for their procurement of service. The payment is based on "pay-as-bid". Regarding the imbalance settlement, the Balancing & Settlement Code rules are used [28].

2. **TSO-DSO mechanism:** In this design, the Retailer is driven on its own by a private firm. The DSO and TSO, however, are regulated and does not (as the Retailer does) have the goal of maximizing profit. The market is therefore presented as a semi-separated market. The process starts with the Retailer procuring TDS, as is done in the sequential design. It is important to remove the units from the set of services. The coordination mechanism gets valuation and grid constraints from the DSO and TSO. Further, the coordination mechanism clears the market while taking the total welfare of the TSO and DSO into account. When the coordination mechanism clears the market, the DSO valuation is included. This implies that the DSO does not have to ensure that the dispatch is feasible, as the mechanism already takes it into account. The settlement is slightly different from the sequential design; the TSO and DSO will for example share the payment for procurement of a TDS if they both have the equal benefit of it. However, if it exceeds the DSO valuation, the TSO has to pay fully. Regarding the imbalance settlements, the same rules apply as for the sequential design for the Retailer, but the DSO has to pay for its imbalances [28].

3. **TSO-DSO-Retailer mechanism:** This mechanism is quite similar to the second mechanism. However, in this design, the Retailer is included in the market and has to pay for the cost of coordinated services. Regarding the imbalance settlement, both the DSO and Retailer have to pay for their imbalances [28].

The Integrated flexibility market model and TSO-DSO-Retailer coordination scheme have many aspects in common. The TSO, DSO and Retailer/commercial market parties can all procure flexibility. Additionally, both of the schemes include the DSO's constraints in the clearing process. In the TSO-DSO-Retailer coordination scheme, the market is cleared by the coordination mechanism, and the Integrated flexibility market model also uses an independent market operator. However, only the TSO-DSO-Retailer scheme includes the determination of the prices and the ones responsible for paying for the different services.

2.5.5 Local AS Market model

The last market model is the Local AS market model. The DSO handles a local market with the FRs are connected at the distribution level. Here, a solution for the local market is found, and the TSO is offered the bids that are remaining after considering the constraints and aggregators of the local market [6]. This market model is paired up with the Local Flexibility market.

Local Flexibility Market

The LFM coordination scheme differs from the other coordination schemes, as it is presented as a more developed scheme, prepared for the real market. The local market participants are described in Chapter 2.4, and can be seen in Figure 2.4. The coordination scheme takes both the planning and operation phase into account [5]. After the DA market is cleared, the planning phase can start. The LFM lies between intraday and balancing market, and consists of five steps:

1. The aggregators have to forecast the flexibility capacity that the DFR has to offer. Simultaneously, the DSO has to forecast the load scenarios for the distribution network.
2. The DFR's capacity is submitted to the local flexibility market operator (LFMO), providing the offers to the DSO.
3. The DSO performs OPF simulations from the load scenarios. From here, the DSO decides how much FRs are needed to maintain the conditions and restrictions of the grid and gives this information to the LFMO. The result from the OPF made by the DSO is then handed to the TSO. This makes it a decentralized market, as only the needs of the distribution system are taken into account, as a separate market.
4. The LFMO confirms the reservation made by the DSO, and the remaining flexibility capacity is given to the TSO. Now, the TSO can decide how much flexibility it needs or wants, to solve potential problems in the transmission network.
5. Finally, the LFMO has to schedule an operation plan based on their reservation. This scheduling is then given to the aggregators, so they can inform the DFRs on how much to dispatch [5].

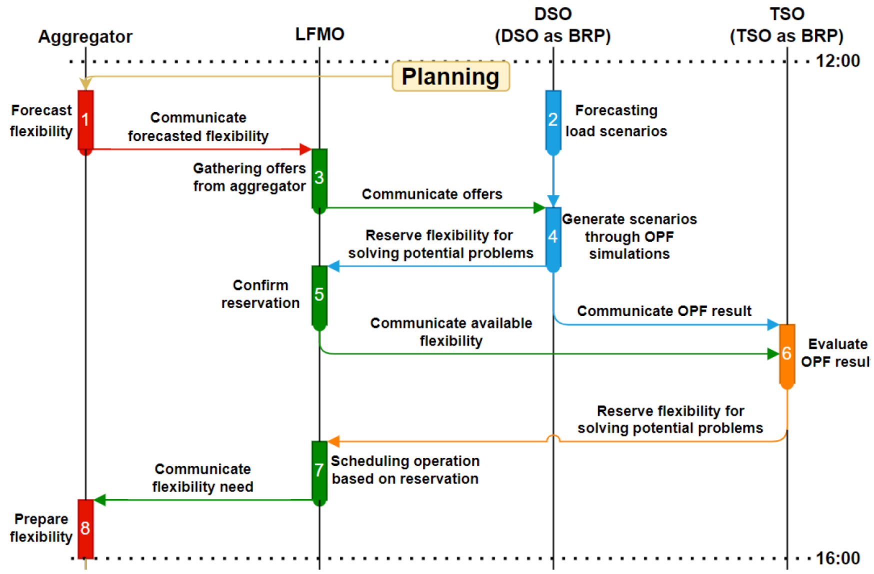

Figure 2.5: *Flowchart over the planning phase for the LFM [5].*

The planning phase can be seen in Figure 2.5. From the planning phase, the operation phase enters at 00:00, as seen in Figure 2.6. The operation phase has five steps:

1. The DSO performs monitoring and metering over the grid. This has to be done before the activation can begin.
2. If there are any changes, the DSO has to conduct a new OPF to acquire the right amount of DFR capacity. The new result will be given to the LFMO.
3. The LFMO performs re-scheduling and activation evaluation. The LFMO then communicates the updated DFR activation to the aggregators. If the DFR cannot provide a sufficient capacity activation, the LFMO must notify the TSO.
4. The TSO can ask the balancing market for missing power.
5. The DSO has to keep performing monitoring and metering to assess the grid's condition [5].

The operation phase is done every 15 minutes from 00:00 to 23:45. It can be seen in Figure 2.6.

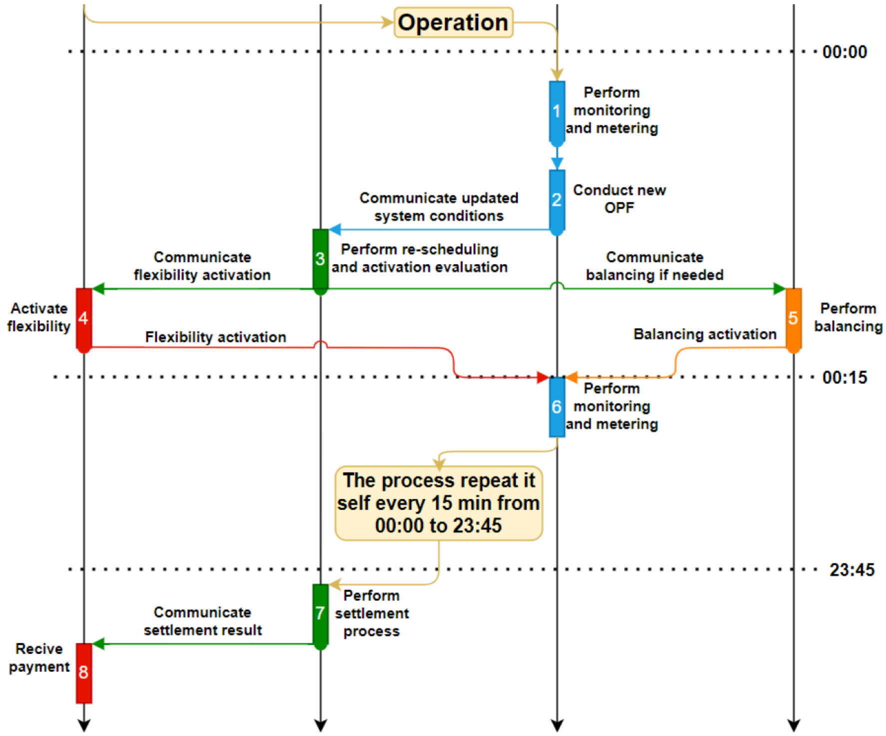

Figure 2.6: *Flowchart over the operation phase for the LFM [5].*

The next phase is the settlement phase, which is done at 23:45 each day. The process consists of two steps:

1. The LFMO performs the settlement process, which is done by getting the metering from the DSO.
2. The LFMO is informed about the power activated at the DFRs by the BRPs, and sends the payment to the aggregators for the provided flexibility [5].

The Local AS market model and LFM have similarities. In both of the models, the DSO procures FRs first, and the rest of the FRs is offered to the TSO. Additionally, the DSO has the responsibility for procuring FRs.

2.5.6 Comparison between different market models and coordination schemes

What are the disadvantages and advantages of these five market models and supplementary coordination schemes? The elements that are compared are the coordination between the participants, which participants are included, roles and responsibilities. What role the DSO plays in procuring FRs in a FM is an important decision to make for the coordination scheme used in this master thesis.

A big difference between the Centralized AS market model and the Local AS market model, is that the Local AS market model encourages the use of local markets that are governed by the DSO, giving more responsibility to the DSO. However, the Centralized AS market model does not have a local market to govern [6]. Another big difference is that the DSO in the Centralized AS market model is procuring FRs in another time frame than the centralized market. In the Local AS market, this happens simultaneously.

Regarding the coordination schemes from the various articles, the process that FM with DSO as flexibility provider is presenting has some differences from the LFM. Nevertheless, if looking at the schemes as a whole, they are quite similar. In both of the coordination schemes, the DSO performs the OPF, and the TSO has the responsibility for balancing the market. However, FM with DSO as flexibility provider does not use FMO, BRP and aggregator as independent units. It only considers the TSO, DSO and DER as flexibility market participants, leading to a difference between the coordination schemes regarding the roles and responsibilities in the market. In the LFM, there is a separate local flexible market operator that collects the offers and demands from the DFRs, and presents the remaining bids to the TSO. However, in the FM with DSO as flexibility provider, the DSO has to collect the offers. Then, the offers are presented both to the DSO and the TSO at the same time. Thus, in one of the schemes, the TSO has equal rights as the DSO to the FRs at the distribution level, while in the other scheme, the DSO has priority to the FRs at the distribution level (local market). A disadvantage is that when both participants give their offers simultaneously, the optimization problem can be intricate.

Various coordination schemes have been presented and analyzed. In this project, LFM or Local AS markets is the approach being used to coordinate the LFM participants. The advantage of using the LFM rather than the others is that the DSO will have priority for the flexibility offers. It is a decentralized market, which makes the optimization problem less computational heavy. However, since it is the TSO's job to balance the market, and the DSO uses FRs to fix grid problems, it might disturb the balance. This requires proper communication between the TSO and DSO, to manage the imbalance. If a market has numerous small distribution systems with corresponding local markets, it could lead to a thin market that operates with high costs. The consequences could be high costs for the DSO to procure FRs, leaving the DSO with no other option than curtailment or load shedding. Another problem related to multiple local markets is the expensive setup for communication with the ICT layer. Still, there could be advantages with a specified and custom-made market product for each of the multiple local markets [4].

The reason for choosing the LFM for this thesis, is because it is a good fit for countries involved in the HONOR project, that being Germany, Norway and Denmark. In the German system, their power market has a long experience with decentralized power sources. They have governmental programs regarding decentralization dating back to the 1990s [30]. This confirms their experience in the field. It is also a developing market that can give many benefits when there is an increased use of RESs, as mentioned above. By having efficient coordination between TSO and DSO, situations where they make conflicting decisions can be avoided. This is a motivation for developing the cooperation between the different market participants. In this thesis, the LFM is chosen as the scheme to coordinate the market participants, with the DSO responsible for the procuring of FRs in the FM and the TSO responsible for the balance in the balancing market. In the next chapter, how to use OPF to clear the market with several DSOs is reviewed.

3 Review of modelling approaches for flexibility market operation and TSO-DSO coordination

A part of the objective for this thesis is to review modelling approaches that can be used for market clearing, and to analyze which one is suited for the tasks of the master investigation. Thus, this chapter gives an introduction to OPF approaches for FM modelling and a review of existing OPF techniques that allow to coordinate the TSO with multiple DSOs. The effective functioning of FM and TSO-DSO coordination require the application of advanced simulation and modelling techniques. The OPF modelling approach is a powerful instrument for planning and analyzing the operation of FMs. The special interest of this thesis is OPF modelling for TSO coordination with multiple DSOs. This chapter is a continuation of the specialization project [9], where the first subchapter has been modified and new information has been added. The second subchapter is a presentation of the specialization project [9] as new relevant materials haven't been found during the work on the thesis.

3.1 Application of Optimal Power Flow approaches for flexibility market modelling

OPF is well established and often used in optimization problems in the power system analysis. Traditionally, it helps reduce operational costs, enhances the performance of the system and improves the system's reliability and security [31]. The important role of OPF in FM is to analyse how the DSO procures FRs and the effect it has on the power grid operation. Naturally, the price, allocation and amount of FRs affect the power flow in the grids. Thus, for proper functioning, the FM has to perform OPF simulations several times throughout the planning and operating phase, as was explained in the previous chapter in Figure 2.5 and Figure 2.6.

There are several formulations of the OPF for energy markets. In this research, the focus is on OPF formulation for finding the optimal steady state operating point that gives the minimum costs for power production, meets the demand and satisfies the operating constraints [32]. Using this OPF formulation, different grid problems will be tested later in the thesis, where the procurement of FRs will be the focusing solution approach. The OPF analysis will then check how the FR use in distribution grids may affect the operation of each other and the TSO.

There are several different approaches for OPF modelling, depending on what kind of power system it is applied. The structure of the grid determines the appropriate method. There are several factors that might affect applicability of the certain OPF modelling approach, amongst others [33]:

1. Grid topology: radial or weak meshed networks
2. R/X ratios
3. Multiphase, unbalanced operation
4. Unbalanced distribution load
5. Distributed generation

In this thesis, the distribution grids are radial and have distributed generation. The OPF problem for this type of grid is non-convex, which makes it difficult to solve. Due to the listed above factors, it can be challenging and time consuming to use Newton Raphson, Gauss-Seidel or fast decoupled methods for the distribution grids. Well known that some of the OPF modelling approaches can have trouble converging and finding the local optimum [34]. For example, commonly used AC Optimal Power Flow (AC OPF) has issues converging, while DC Optimal Power Flow (DC OPF) is too inaccurate for the distribution grid. Therefore, to obtain global solutions, relaxation to the OPF problem is then required. This could be semi-definite programming (SDP), second-order cone programming (SOCP) or linear programming (LP). When using convex relaxation, it provides an upper and a lower bound. This can enable certifying if the problem is infeasible, and it often provides a global optimum for the objective function [34]. Usually, using AC OPF relaxation methods for distribution grids allow us to obtain more accuracy than DC OPF. At the same time, these methods are relatively fast and reliable. The SOCP method is preferred to SDP due to less computational effort in each iteration [35]. Therefore in this project, the SOCP-ACOPF method will be used for solving the problem in the distribution grid.

The transmission grid is often a big scale power system. For this type of grid, a DC OPF method is suited well. This is a simplified iterative and linearized method. In the DC OPF method, the problem is scaled down to a set of linear equations, reducing the computational time tremendously. However, there is a few drawbacks to this method. It does not consider the reactive power flows, and the assumptions that are made can to a certain extent affect the accuracy of the calculated power flow [36]. For the transmission grid, these drawbacks of DC OPF are relatively small since the transmission grid has a low R/X ratio, unlike the distribution grid.

Therefore, it was decided to use DC OPF for transmission grid modelling and AC OPF for distribution grids. To handle the whole FM, both of the methods are implemented in Python program. Later, the connection between the DC OPF problem for the transmission grid and AC OPF for distribution grids is established in the model. This leads to an AC/DC OPF method. The mathematical formulation of the AC/DC OPF method will be presented in Chapter 4. Now when the decision about the OPF model was made, a way of clearing the FM needs to be explored in more detail. Different options for market clearing are presented in the following section.

3.2 Methods for clearing market with TSO and several DSOs

Traditionally, the distribution system is a uni-directional and centralized system, but now, as already mentioned, the distribution system is transforming towards a bi-directional and decentralized power system [2]. In [2], the authors present three main directions for clearing the market; centralized optimization, decomposition method and bi-level optimization, shown in Figure 3.1. In this section, two methods for clearing the market will be presented, and a comparison is made between them. Lastly, as there are several DSOs in this project, one of the methods for clearing the market will be determined as the most suitable.

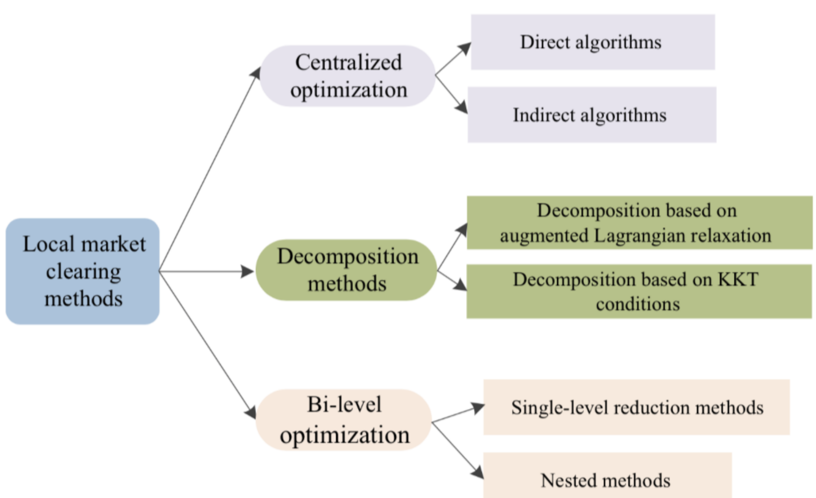

Figure 3.1: *Different market-clearing methods [2].*

Market clearing with multiple DSOs and an ISO

In [8] the authors present a bi-level optimization model for clearing the distribution market with several DSOs and an ISO. An ISO is an independent system operator, coordinating generation and transmission across a wide geographic area. It is responsible for matching generation instantly to the market demand for electricity, much like a TSO [37]. The ISO-DSOs coordination is therefore comparable to TSO-DSOs coordination.

The model proposed in [8], considers the interaction between the distribution and transmission wholesale markets. The wholesale market is a combination of several markets. In these markets, bids are submitted and prices are determined. The wholesale market consists of DA, intraday market and the balancing markets [38]. In the developed model used in this thesis, DA and FM, which is a part of intraday/balancing market, is being used. The model described in [8] is split into two, where the upper-level model represents the DSO market clearing and the lower-level model represents the wholesale market clearing for the ISO. The market clearing is done as generation or consumption bids and corresponding prices are presented to the market operator by the consumers and producers. The market operator will then conduct a market-clearing process shown in Figure 3.2, to determine the market clearing price (MCP) for the corresponding time interval [39].

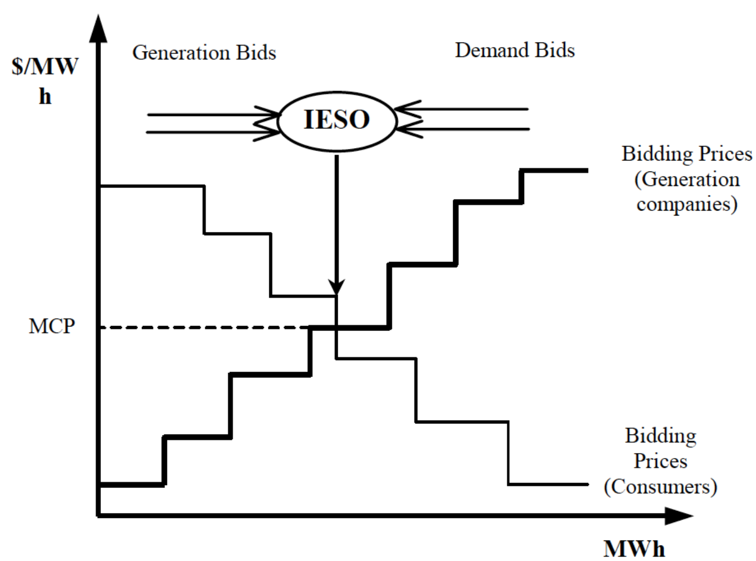

Figure 3.2: *Market-clearing process in an electricity market [39].*

The DERs or FRs will influence the locational marginal prices (LMP), but also visa versa. This will affect the dispatch of the DERs, the power demands from the DSO and the distribution locational marginal pricing (DLMP). Further, the ISO and its LMPs will be influenced by the power demands from the DSOs [8].

In the [8], the bi-level optimization model with equilibrium constraints has been formulated. This formulation is used to find the equilibrium between the DSOs and the ISO. Figure 3.3 shows the framework for DSOs-ISO market clearing. It starts at the lower level where the ISO performs the market-clearing method on the transmission network. When clearing the market, the ISO must consider the offers from the generators and load serving entities. To reach optimal power scheduling, it is crucial that the active distribution networks are considered. The aim at this level is to maximize the social welfare of the transmission network. To set the purchase price for the wholesale market [8] use the LMP at the substation.

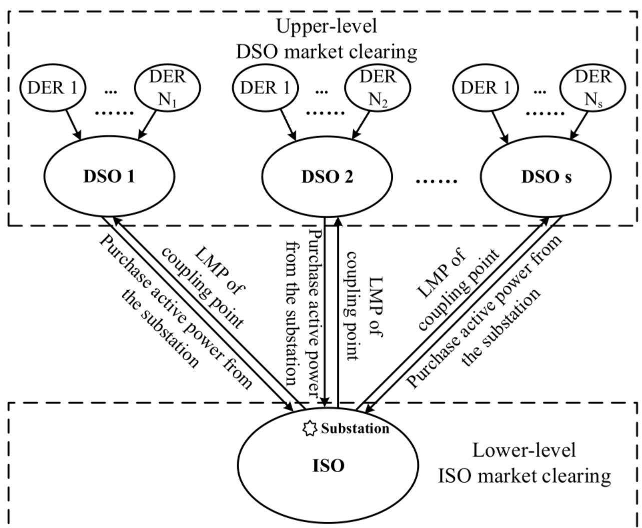

Figure 3.3: *DSOs-ISO market-clearing framework[8].*

Further, at the upper level, each DSO performs the market-clearing of its active distribution network. It considers the offers from the DERs and the LMP decides what the optimal dispatch for the DERs is going to be. From this, it determines the power purchase from the ISO and the DLMP at each of the distribution nodes. Then, the DSO informs the ISO about the new power purchase, and the ISO clears the market with the power demands from the distribution networks. With new LMPs from the market-clearing made by the ISO, the DSOs perform market clearing. From this clearing, the DERs know how much to dispatch and the DSO can adjust the power trade from the transmission network. The ISO is notified about the updated power demand and can adjust the LMPs. For this process to end, an equilibrium between the ISO and DSOs is required. Additionally, the market-clearing solution needs to be the same for each iteration. This is one of the ways to clear the market with several DSOs. Another way is described in the following section.

Market clearing method with DSOs and a TSO

In [7], the authors propose a solution where binary unit commitment (UC) decisions are taken into account. The method presented in [7] coordinates the operations of the distribution and transmission while including UC decisions. The method can be defined as the decomposition method since Surrogate Lagrangian relaxation (SLR) is used, as seen in Figure 3.1. The power system that is considered has multiple distribution systems operated by their own DSO and one transmission system with a TSO. The DSOs and TSO participate in the wholesale electricity market [7].

In [7], the transmission grid is meshed while the distribution grid is radial. The transmission grid is only connected to the root/slack bus of each distribution system. Both the DSO and the TSO aim to maximize the social welfare of the distribution system and transmission system respectively. This is done by fulfilling the demand by using the distribution and market resources that are accessible to the DSO. In this model, it is only operating with a single-period situation. One of the advantages of this method, shown in Figure 3.4, is the reduction in computational time due to not requiring optimality for every sub-problem.

The solution method is based on an iterative SLR, with several steps and is shown in Figure 3.4. First, it has to initialize the variables needed to solve the problems. Then it solves the DSO problem, for each of the DSOs. From here, the TSO receives values for the capacity offered by the DSO in the wholesale. Either the DSO offers to sell the electricity in the wholesale, or the DSO offers to purchase electricity. These values are further used in the TSO problem [7].

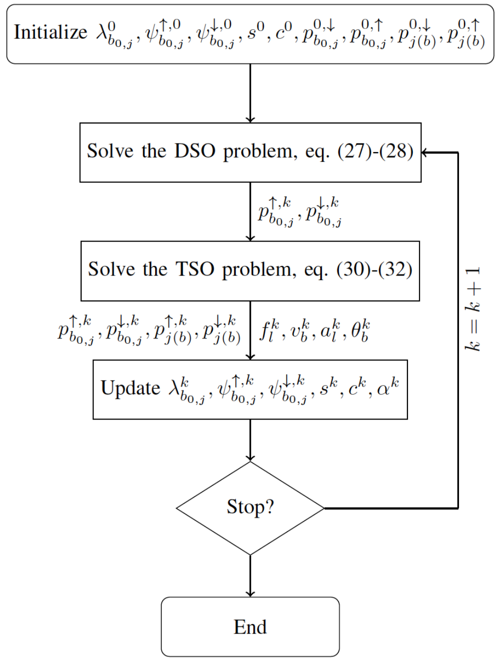

Figure 3.4: *Flowchart of the proposed SLR-based solution technique [7].*

The TSO is then solved and a new set of values is produced; the DSOs sell/purchase electricity, the power exchange with distribution system as seen from the transmission side, active and reactive power flow across a line, voltage squared with defined limits, auxiliary variable and power angle. From the values given by the TSO, a set of values are updated; the LMP at the transmission bus, the Lagrange multiplier, the step-size, the penalty coefficient, and the step-size parameter. This process continues in a loop until a limit is reached. This could be Central Processing Unit time, the value of the surrogate subgradient norm or the duality gap [7].

3.2.1 Comparison between bi-level optimization and decomposition methods

The two methods presented have different approaches to clearing the market. First [8] uses bi-level optimization, while [7] uses decomposition method. In [2], the decomposition method is claimed to be primarily used to clear centralized optimization model based on local markets. The decomposition method presented does not have a decentralized decision-making framework. This leaves it more exposed to a cyber-attack, and it could struggle to protect the DSO and TSO's privacy. Nevertheless, having a centralized framework makes the communication structure easier.

Bi-level optimization is more suitable for clearing local markets that have a hierarchical structure. This involves having a leader at the upper level and a follower at the lower level. In [8], the DSO operates in the upper level, and therefore the DSO is the leader, while the ISO or TSO operates in the lower level. Another similarity is that in both of the models, the ISO or TSO aims to maximize the social welfare of the transmission grid. To maximize the social welfare of a system implies increasing the seller/demand-side cost and decreasing the generating side cost [40].

The market-clearing method with DSOs and TSO that is presented in [7] is the most relevant method presented in this chapter, as it is a decomposition method. The reason decomposition methods are important in this project is their ability to divide the problem into smaller sub-problems and solve them. It is beneficial when solving the problem for TSO and DSO separately but in the same iteration. In such way, the solutions for each TSO and DSOs can be found by using different computers, and after the exchange of information between them can be organized. Another benefit of using decomposition methods is their ability to use a separate computer for solving each sub-problem. In such a way the computation time for solving the entire problem can be reduced [7].

In the work this project extends on, coordination between TSO-DSO was established based on the Hybrid AC-SOC/DC OPF method which connects DC OPF for TSO and SOC OPF for DSO. However, when multiple DSOs are included, the problem becomes complex. Therefore, it is proposed to decompose this complex problem into small sub-optimization problems by using the ADMM method. ADMM is a powerful decomposition method based on augmented Lagrangian relaxation, one of the methods for clearing local markets seen in Figure 3.1. It solves convex optimization problems by breaking them into smaller pieces, which represent sub-problems for TSO and each DSO. The approach method for ADMM has the same structure as SLR-method in Figure 3.4, but this SLR-method is based on a single-period situation while the test case in this thesis is based on a multi-period situation. In addition, the ADMM method used in this work solves the DSO and TSO problem in parallel and not sequentially as presented in the SLR-method. A more thorough explanation of the ADMM method is given in the next chapter.

4 Method for TSO-DSOs coordination in flexibility market

The second part of the thesis' objective is to develop a Hybrid AC/DC-OPF ADMM model that can clear the FM with coordiantion of TSO and multiple DSOs. Thus, in this chapter, the OPF model formulation for FM is presented. First, Subchapter 4.1 presents a mathematical formulation of the Multi-Period Hybrid AC/DC OPF model for coordination of TSO with one DSO. In Subchapter 4.2, the model is expanded with the ADMM method, which allows us to establish TSO coordination with multiple DSOs. Subchapter 4.1 is sourced from [5] and later modified and used in the specialization project [9], and as no new information was found, the subchapter is a presentation from the specialization project. Research of relevant background material was carried out in the project preceding this thesis [9], and Subchapter 4.2 is a continuation of these works where new information has been added.

4.1 Multi-Period Hybrid AC/DC Optimization Model Formulation

The model formulation presented below is a Multi-Period Hybrid AC/DC Optimization model, which is established by Kjærland Olsen and Damian Sieraszewski in [5]. The description is an adaptation of their work.

The objective function is defined by minimizing the total cost of FRs from different sources, as shown in Equation 4.1. Equation 4.2 to 4.22 represents the constraints in the model, more specifically the constraints on SOC-ACOPF, DC-OPF, AC to DC connection, load shedding, flexible generation, flexible load and battery. The mathematical formulation for these constraints will briefly be introduced below. In more details, these equations can be found in [5].

The first set of constraints is the SOC-ACOPF constraints. The two first equations, Equation 4.2 and 4.3, represent the power balance equations. The next equations, Equation 4.4 and 4.5, represent two inequality constraints, and lastly, Equation 4.6 represents an auxiliary variable and is a parameter due to node 1 being assumed known, as it is the slack node.

The second set of constraints is the DC-OPF constraints. The first equation, Equation 4.7, represents the balance of power in a node. Equation 4.8 and 4.9 represent the power flow in a line and the minimum and maximum transfer of power in a line, respectively. The last DC-OPF constraint in Equation 4.10, defines the slack node. The third set of constraints in Equation 4.11 is the AC to

DC connection constraint. This represents the equality constraint and connects the transmission grid to the distribution grid. The load shedding constraint, Equation 4.12, is the fourth set of constraints. It represents the opportunity to shed the load in each node if necessary. The fifth and sixth sets of constraints are flexible generation constraint and flexible load constraints, Equation 4.13, 4.14 and 4.15. The two first constraints represent the minimum and maximum generation and loads in each node, while the last constraint represents the possibility of load shifting in a node. The last set of constraints is the battery constraints. The three first constraints, Equation 4.16, 4.17 and 4.18 represent state of charge, charge capacity and discharge capacity, respectively. The following three equations, Equation 4.19, 4.20 and 4.21 represent the connection that is made between every unit, which is a part of the simulation, and they set the battery's state. The last constraint in this set of constraints is Equation 4.22. It serves the purpose of ensuring the battery's state is the same at the beginning and at the end of the simulation.

The resulting model is shown below, and it consists of numerous variables and their corresponding indices. All variables are explained in detail in [5], and can be found in Appendix A. The five different indices are described in short here. The indices are; the node in the transmission grid, n, the node in the distribution grid, m, time unit, u, hour of the simulation, t, and finally the index that indicates the node that is sending power, j.

Multi-Period Hybrid AC/DC Optimization Model Formulation:

DCOPF Variables: $P^{fl}_{nj,t,u}, \theta_{n,t,u}$

SOC-ACOPF Variables: $u_{m,t,u}, R_{mj,t,u}, I_{mj,t,u},$

Flexibility Variables: $P^{G,Flex}_{m,t,u}, P^{L,Flex}_{m,t,u}, P^{LS}_{m,t,u}, P^{SoC}_{m,t,u}, P^{ch}_{m,t,u}, P^{disch}_{m,t,u}$

Minimize:

$$\sum_{m=2\ldots M}\sum_{t=1\ldots T}\sum_{u=1\ldots U}(P^{G,Flex}_{m,t,u}\cdot c^{G,Flex}_{m,t,u} - P^{L,Flex}_{m,t,u}\cdot c^{L,Flex}_{m,t,u} + (P^{disch}_{m,t,u} - P^{ch}_{m,t,u})\cdot c^{batt}_{m,t,u} - P^{LS}_{m,t,u}\cdot c^{LS}_{m,t,u}) \tag{4.1}$$

Subject to SOC-ACOPF constraints:

$$P^{L,AC}_{m,t,u} + P^{L,Flex}_{m,t,u} - P^{G,AC}_{m,t,u} - P^{G,Flex}_{m,t,u} + P^{ch}_{m,t,u} - P^{disch}_{m,t,u} = \sqrt{2}u_{m,t,u}\sum_{j\in k(m)} G_{mj} + \sum_{j\in k(m)}(G_{mj}R_{mj,t,u} - B_{mj}I_{mj,t,u}) \tag{4.2}$$

$$Q^{L,AC}_{m,t,u} - Q^{G,AC}_{m,t,u} = -\sqrt{2}u_{m,t,u}\sum_{j\in k(m)} B_{mj} + \sum_{j\in k(m)}(B_{mj}R_{mj,t,u} + G_{mj}I_{mj,t,u}) \tag{4.3}$$

$$2u_{m,t,u}u_{j,t,u} \geq R^2_{mj,t,u} + I^2_{mj,t,u} \quad for\ all\ mj\ lines \tag{4.4}$$

$$R_{mj,t,u} \geq 0 \quad for\ all\ mj\ lines \tag{4.5}$$

$$u_1 = V_1^2/\sqrt{2}, u_m \geq 0 \tag{4.6}$$

Subject to DC-OPF constraints:

$$P^{G,DC}_{n,t,u} - P^{L,DC}_{n,t,u} = -\sum_{j\in k(n)} B_{nj,t,u}\theta_j \quad n_{DC} \neq m_{AC} \tag{4.7}$$

$$P^{fl}_{nj,t,u} = B_{nj}(\theta_n - \theta_j) \quad for\ all\ nj \tag{4.8}$$

$$-P^{fl,max}_{nj,t,u} \leq P^{fl}_{nj,t,u} \leq P^{fl,max}_{nj,t,u} \quad for\ all\ nj \tag{4.9}$$

$$\theta^{slack}_{n,t,u} = 0 \qquad n_{DC} \neq m_{AC},\ \exists!\ n_{DC} \tag{4.10}$$

Subject to AC to DC connection constraint:

$$P_{n,t,u}^{G,DC} - P_{m,t,u}^{G,AC} = -\sum_{j \in k(n)} B_{nj}\theta_{j,t,u} \qquad P_{m,t,u}^{G,AC} = P_{n,t,u}^{L,DC} \;\; if \;\; n_{DC} = m_{AC} \tag{4.11}$$

Subject to load shedding constraint:

$$P_{m,t,u}^{LS} = P_{m,t,u}^{L,AC} \tag{4.12}$$

Subject to flexible generation constraint:

$$P_{m,t,u}^{G,Flex,min} \leq P_{m,t,u}^{G,Flex} \leq P_{m,t,u}^{G,Flex,max} \tag{4.13}$$

Subject to flexible load constraints:

$$P_{m,t,u}^{L,Flex,min} \leq P_{m,t,u}^{L,Flex} \leq P_{m,t,u}^{L,Flex,max} \tag{4.14}$$

$$\sum_{m=2...M} \sum_{t=1...T} \sum_{u=1...U} P_{m,t,u}^{L,Flex} = 0 \tag{4.15}$$

Subject to battery constraints:

$$P_{m,t,u}^{SoC,min} \leq P_{m,t,u}^{SoC} \leq P_{m,t,u}^{SoC,max} \tag{4.16}$$

$$P_{m,t,u}^{ch,min} \leq P_{m,t,u}^{ch} \cdot (1 - \delta_{m,t,u}) \leq P_{m,t,u}^{ch,max} \tag{4.17}$$

$$P_{m,t,u}^{disch,min} \leq P_{m,t,u}^{disch} \cdot \delta_{m,t,u} \leq P_{m,t,u}^{disch,max} \tag{4.18}$$

$$P_{m,1,1}^{SoC} = P_{m}^{SoC,init} + P_{m,1,1}^{ch} \cdot \eta^{ch} - \frac{P_{m,1,1}^{disch}}{\eta^{disch}} \tag{4.19}$$

$$P_{m,t,u}^{SoC} = P_{m,t,u-1}^{SoC} + P_{m,t,u}^{ch} \cdot \eta^{ch} - \frac{P_{m,t,u}^{disch}}{\eta^{disch}} \tag{4.20}$$

$$P_{m,t,1}^{SoC} = P_{m,t-1,U}^{SoC} + P_{m,t,1}^{ch} \cdot \eta^{ch} - \frac{P_{m,t,1}^{disch}}{\eta^{disch}} \tag{4.21}$$

$$P_{m,T,U}^{SoC} = P_{m}^{SoC,init} \tag{4.22}$$

For Equation 4.2-4.22:

$$n = 1...N \qquad m = 2...M \qquad t = 1...T \qquad u = 1...U \tag{4.23}$$

4.2 Extension of the AC/DC-OPF Model with ADMM for TSO coordination with multiple DSOs

The Multi-period Hybrid AC/DC optimization model presented in the previous subchapter is working for different kinds of distribution grids, which was tested in the specialization project [9]. However, this model was designed for TSO coordination with only one DSO. In this thesis, however, the whole system includes coordination of TSO with multiple DSOs. This leads to an issue of adjusting Multi-period Hybrid AC/DC optimization model according to a new task when more than one DSO is taken into consideration. In addition, it is necessary to solve the problem of TSO-DSOs coordination without too high computational time and to preserve the distribution grids' privacy. To achieve these tasks, the Hybrid AC/DC OPF model was extended and adjusted with ADMM method, which is presented in the subchapter below.

4.2.1 The ADMM method

Usually, the datasets used for FM modelling when multiple DSOs are involved are complex and of high volume. It is therefore a demand for an algorithm that can handle this type of data. ADMM is short for Alternating Direction Method of Multipliers, and is a powerful algorithm that can handle distributed convex optimization [3]. As our TSO-DSOs coordination problem is a distributed convex optimization problem, ADMM is suited well for improving the existing Hybrid AC/DC OPF model.

The method is based on coordinating the solutions of the separate local subproblems for TSO and each of DSOs to find the solution for the global problem of entire FM coordination. The procedure is called decomposition-coordination. The ADMM method attempts to unify the benefits of dual decomposition and the augmented Lagrangian methods for constrained optimization.

The general mathematical formulation of the ADMM is:

$$\begin{aligned} minimize \quad & f(x) + g(z) \\ s.t. \quad & Ax + Bz = c \end{aligned} \tag{4.24}$$

where both f and g are assumed to be convex, and $x \in \mathcal{R}^n$, $z \in \mathcal{R}^m$, $A \in \mathcal{R}^{pxn}$, $B \in \mathcal{R}^{pxm}$, and lastly $c \in \mathcal{R}^p$. The augmented Lagrangian form of the method of multipliers [3] is:

$$L_\gamma(x, z, \lambda) = f(x) + g(z) + \lambda^T(Ax + Bz - c) + \frac{\gamma}{2}\|Ax + Bz - c\|_2^2$$

The ADMM method inhabits these three iterations:

$$x^{k+1} := \arg\min_{x} L_{\gamma}(x, z^k, \lambda^k) \tag{4.25}$$

$$z^{k+1} := \arg\min_{z} L_{\gamma}(x^{k+1}, z, \lambda^k) \tag{4.26}$$

$$\lambda^{k+1} := \lambda^k + \gamma(Ax^{k+1} + Bz^{k+1} - c) \tag{4.27}$$

In Equation 4.25 to 4.27, γ is greater than 0 and is the penalty parameter. The penalty term adds a quadratic term, so the problem becomes quadratic. The problem needs to be quadratic to make the gradient based method work, it is only gradient if it is quadratic. The penalty term is zero in the optimal point, therefore it does not change the optimal value [41]. As our objective function is linear, as seen in Equation 4.1 the quadratic term is needed.

Equation 4.25 is the x-minimization step, Equation 4.26 is the z-minimization step, while the last one, Equation 4.27, is the dual variable update or Lagrange multiplier update. This update operates with a step size equal to γ [3]. If convergence is reached, λ is not updated to a new value. It is because of Equation 4.27, where the term after γ is zero at the optimal point. Lambda (λ) is the Lagrange multiplier, which can be translated as the shadow price. The shadow price is defined as the rate of change of the objective function from increasing one unit at the right hand side [42]. The TSO and DSOs are independent business entities, and their object is to maximize their profit. The information that is used in OPF modelling can give away information about their private business strategies. Therefore, it is important that this information is unavailable to the public. The benefit of using the ADMM method is that it solves their OPF problems, but does not share their private information. The λ is the exchange of information between agents, which is the price. In Chapter 6, the shadow prices for one of the grids used in this thesis will be presented and discussed.

The ADMM method is closely related to dual ascent and the method of multipliers. However, when regarding the augmented Lagrangian, the iterations x and z are updated in an alternating way. Due to this updating approach and the f and g being separable, it opens up for decomposition. The primal variables (z^{k+1}, y^{k+1}) are a function of z^k and y^k, which are a part the algorithm state. As seen in Equation 4.25 and 4.26, variable x^k is not a part of the state. It represents an intermediate result given from the previous state (z^{k-1}, y^{k-1}). The order of the updates makes the roles x and z slightly asymmetric. First, there is z^{k+1}, then the dual update λ^{k+1}, and lastly x^{k+1} [3].

The Hybrid AC/DC OPF extended with ADMM method is used for solving the DA and FM in this project. The version presented below is developed by a team and with the supervision of Prof. Hossein Farahmand and Dr. Dmytro Ivanko at the Department of Electric Power Engineering of NTNU.

4.3 ADMM method for Day-head market and Flexibility market

The DA market and FM clearing is done separately. When the DA market is cleared, some variables such as $P_n^{G,DC}$, $P_m^{G,AC}$ and $Q_m^{G,AC}$ are used in the FM clearing process. The planned generation from DA market and FRs is used to react to the changing load in the current day. The modelling for each of the markets is divided into subproblems for each of the DSOs and TSO. In the presented model below, there are some new variables, that are only included in the extended model, and they are explained here. The ones that are not explained here, can be found in Appendix A, which was originally used in prior work, article [43]. The first market to be cleared is the DA market.

4.3.1 Day Ahead market

The object of the DA market is to minimize the cost of production in the transmission grid, n, and in the distribution grid, m. It is also worth mentioning that FRs are not included in the DA market, as it is a part of the intraday/balancing market (FM). The mathematical representation of the problem for DA market clearing is as follows:

Minimize:

$$\sum_{n=1\ldots N} P_n^{G,DC} \cdot c_n^{DC} + \sum_{m=2\ldots M} P_m^{G,AC} \cdot c_m^{AC} \tag{4.28}$$

Indices n and m represent the transmission and distribution grid node, respectively. As this is an extension of the Multi-Period Hybrid AC/DC OPF model, for each of the DSO the Constraints 4.2 to 4.6 from the SOC-ACOPF constraints, apply for 4.28. This accounts for the DSOs, while for the TSO, the DC-OPF Constraints 4.7 to 4.10 apply. The connection between each of the DSO and TSO has a similar form, as presented in Equation 4.29. There is one equation for each of the TSO-DSO connections, where i represents each DSO.

$$P_n^{G,DC} - P_{im}^{L,AC} = - \sum_{j \in k(n)} B_{nj}\theta_j \tag{4.29}$$

The index j is used concerning power flow in a line and indicates the node that is sending power. Next, the ADMM method is applied for the DA market, which yields separate problems for the TSO and DSOs. However, they exchange variables to reach an optimal solution that benefits both. As for the general explanation of the ADMM method, there are three updates for each iteration. In this work, it is the χ-update, the ζ-update and lastly the λ-update, which is updated in parallel and are further explained below. The TSO and DSOs subproblems obtained by problem decomposition for the DA, are presented here.

TSO subproblem

The DA market minimization problems are divided into TSO and DSO problems. Equation 4.30 is the augmented Lagrangian relaxation for the TSO subproblem. The first part of the TSO minimization problem is therefore the first part of Equation 4.28. The next part has the Lagrangian multiplier, λ, where Equation 4.29 is included without the distribution grid's term. This is so that the subproblem can be solved independently. The last part represents the penalty term, which ensures the problem to be quadratic, with the constant penalty term γ. The augmented Lagrangian relaxation TSO subproblem is presented in Equation 4.30.

Minimize:

$$\begin{aligned}\sum_{n=1\ldots N} P_n^{G,DC} \cdot c_n^{DC} + \sum_{i=1\ldots I} \Bigg(\lambda_{ti} (P_{ni}^{G,DC} + \sum_{j \in k(n)} B_{nji}\theta_{ji}) + \\ \frac{\gamma_i}{2} \left\| P_{ni}^{G,DC} + \sum_{j \in k(n)} B_{nji}\theta_j - P_{mi}^{L,AC} \right\|^2 \Bigg)\end{aligned} \tag{4.30}$$

For this minimization problem, the DC-OPF Constraints 4.7 to 4.10 apply as well. The λ_t in Equation 4.30 is updated for each iteration. How it is updated is shown later in the iteration process description. The indices t and i indicate the simulation's hour and each of the DSOs connected to the TSO, respectively. For the subproblem regarding TSO, all variables dependent on the DSO, and not the TSO, are parameters.

$$\zeta = P_m^{L,AC} \tag{4.31}$$

As Equation 4.31 is not dependent on TSO, it will be a parameter derived from the previous iteration for the DSO subproblem. When this subproblem is solved, the variables in the Constraint

χ can be updated as they are dependent on the TSO. The χ-update is presented at the end of an iteration:

$$\chi = P_n^{G,DC} + \sum_{j \in k(n)} B_{nj}\theta_j \tag{4.32}$$

DSO subproblem

The next step is to solve the other subproblems regarding the DSOs. For each of the DSOs, the objective function and augmented Lagrangian relaxation becomes Equation 4.33. The first part of the objective function is the part of the AC OPF problem, Equation 4.28 that is related to the DSOs. The second part is the part of the TSO-DSO connection Constraint 4.29 that is related to the distribution grid, according to the ADMM method. The last part, the penalty term, is the same for the DSO and TSO subproblem. The only difference from the other subproblem is which part is given. For the DSO subproblem, the variables related to the TSO are parameters, while the variables related to the DSOs are variables.

Minimize:

$$\sum_{m=2...M} P_m^{G,AC} \cdot c_m^{AC} + \lambda_t(-P_m^{L,AC}) + \frac{\gamma}{2}\left\| P_n^{G,DC} + \sum_{j \in k(n)} B_{nj}\theta_j - P_m^{L,AC} \right\|^2 \tag{4.33}$$

The AC constraints from Equations 4.2 to 4.6 from the Multi-Period Hybrid AC/DC OPF model applies to this objective function as well. The DSO subproblem uses the χ-update from last iteration for the TSO subproblem as parameters. The ζ, Equation 4.31, is updated in this subproblem and given as a parameter to the next iteration for the TSO subproblem. The iteration process of reaching convergence for clearing the DA market is described below.

The iterations:

1. Setting the limit for absolute error, e_{abs}, and relative error, e_{rel}, to a value best suited for the project. To reduce number of iterations, it is set to 0.01 p.u. The initial values for λ_{in}, γ_{in}, χ_{in}, and ζ_i is set to 1. The index i represents each of the DSOs.

2. Sending the initial values to the subproblems for the TSO and DSOs. From the solved subproblems, the value for χ and ζ is updated and presented.

3. Using the updated values for χ and ζ to update the value for λ:

$$\lambda^{(v)} = \lambda^{(v-1)} + \gamma(\chi^{(v)} - \zeta^{(v)})$$

4. Calculating the errors, and checking if the errors are low enough to trigger the stopping criteria. The errors, ε and ξ, are defined as:

$$\varepsilon = \sqrt{\gamma} \cdot e_{abs} + e_{rel} \cdot max(\chi^2, \zeta^2)$$

$$\xi = abs(\chi - \zeta)$$

If $\xi \leq \varepsilon$, then the iteration can stop, and a converging solution is found. If it does not converge, the process continues again from step 2.

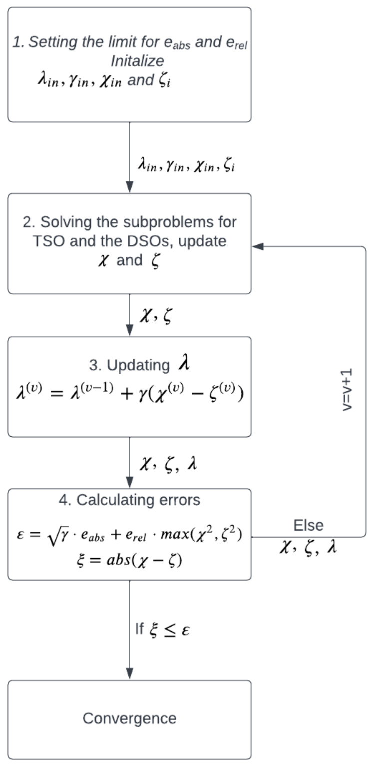

Figure 4.1: *The iterative approach of Hybrid AC/DC OPF ADMM.*

The iterative approach of the ADMM method is presented in Figure 4.1.

4.3.2 Flexibility market

The next market-clearing considered, is the FM optimization. The optimization equations that are necessary as constraints for the objective function 4.34, are Equation 4.2 to 4.11. In this market, load shifting, batteries, distributed flexible generators and load shedding are included.

$$\sum_{m=2\ldots M}\sum_{t=1\ldots T}\sum_{u=1\ldots U}(P^{G,Flex}_{m,t,u}\cdot c^{G,Flex}_{m,t,u}-P^{L,Flex}_{m,t,u}\cdot c^{L,Flex}_{m,t,u}+ \\ (P^{disch}_{m,t,u}-P^{ch}_{m,t,u})\cdot c^{batt}_{m,t,u}-P^{LS}_{m,t,u}\cdot c^{LS}_{m,t,u}) \tag{4.34}$$

The objective function 4.34 is divided into subproblems for the TSO and the DSOs. The object of the FM in this model is to fix the deviation from the predicated operation points made by the DA market with FRs.

TSO subproblem

As FRs are not included for the TSO, the objective subproblem has no constraints that includes them, as seen in Equation 4.35. From the DA market clearing, $P^{G,DC}_{ni}$ is given. The objective function is very similar to the DA objective function 4.30, but it does not include the production, as FM only fix the deviation from the DA market. In addition DA is hourly, while FM is quarterly.

Minimize:

$$\sum_{i=1\ldots I}\left(\lambda_{ti}\left(P^{G,DC}_{ni}+\sum_{j\in k(n)}B_{nji}\theta_{ji}\right)+\frac{\gamma_i}{2}\left\|P^{G,DC}_{ni}+\sum_{j\in k(n)}B_{nji}\theta_{ji}-P^{L,AC}_{mi}\right\|^2\right) \tag{4.35}$$

Similarly to the DA market, the DC-constraint, Equation 4.7 to 4.10, applies here as well. Additionally, χ is updated and the value for ζ is derived from the last iteration for the ζ-update.

DSO subproblem

As the FRs are located in the DSO, and the main power generators are located in the TSO, only FRs are included in the first term. The two following terms are similar to the ones in the DA market. In addition, $P^{G,AC}_m$ and $Q^{G,AC}_m$ are given from the DA market. The objective function for the DSO subproblem can be seen in Equation 4.36.

Minimize:

$$\sum_{m=2\ldots M}\sum_{t=1\ldots T}\sum_{u=1\ldots U}(P^{G,Flex}_{m,t,u}\cdot c^{G,Flex}_{m,t,u}-P^{L,Flex}_{m,t,u}\cdot c^{L,Flex}_{m,t,u}+(P^{disch}_{m,t,u}-P^{ch}_{m,t,u})\cdot c^{batt}_{m,t,u}- \\ P^{LS}_{m,t,u}\cdot c^{LS}_{m,t,u})+\lambda_t(-P^{G,AC}_m)+\frac{\gamma}{2}\left\|P^{G,DC}_n+\sum_{j\in k(n)}B_{nj}\theta_j-P^{L,AC}_m\right\|^2 \tag{4.36}$$

The AC constraints from Equations 4.2 to 4.6, used in the DA market for the DSO subproblem, also apply here. Additionally, χ is a parameter, and the values are derived from the last iteration from the χ-update for the TSO subproblem. The ζ-update is performed in this subproblem at the end of the iteration. To reach convergence for the FM, the same iterative way, as for the DA market is applied, and it can be seen in Figure 4.1.

The presented, extended model needs to be tested to see if it works for a real grid. In the next chapter, a German grid is presented and in combination with a Pandapower grid they are further tested. The results from the testing are presented in Chapter 6.

5 The case study created based on Ding0 and Pandapower Network Generator tools

A part of the thesis' objective is to create a test case based on a Pandapower grid and a Ding0 grid to test the Hybrid AC/DC OPF ADMM model. In this chapter, a description of how the grid that is being tested was developed is given. It is a combination of two German Ding0-grids and a Pandapower grid. The test case was developed to demonstrate if the extended model handles several DSOs. In addition, it was made to test the coordination between the TSO-DSO how FRs help the DSOs and if the DSOs help each other. First, it was only the German grids that were being tested, but to check if the extended model can handle several grids, the Pandapower grid was included as well.

5.1 The current state of the German power grid

Before two of the three test case grids, the German grids, are presented, the state of the German grid is introduced. At present, the power grid in Germany is using the traditional way of operation. Big power plants deliver energy through the transmission and distribution grid to the end users. However, the situation is changing. The German Energy system development creates a significant share of new energy demand, which must be covered by distributed and renewable resources. The energy production development can be seen in Figure 5.1. The installed net power generation capacity in Germany from 2002 to 2021 has increased, especially for RESs. Currently, there are over 1.7 million solar PV installations and over 29,000 onshore wind turbines operating in Germany [44]. The renewable installations are mainly located at the distribution level, where they impose a great amount of power and create a bi-directional power flow. Despite many benefits, such as reduced carbon emissions, the generation from RESs possess some challenges for the grid functioning due to the intermittent nature of generation. In these conditions, managing altering and unpredictable generation of renewable resources, while securing the stability of the power system, becomes crucial for the grid operators.

The German distribution system distributes power on three voltage levels: the high voltage grid, the medium voltage grid and the low voltage grid [44]. In this work, the medium voltage level is in focus. The medium voltage distribution grid and the TSO used in this thesis are exposed to several different challenges, such as voltage violations, congestion in the DS, and congestion in the TS. A solution to these grid challenges is FRs, which was explored in Subchapter 2.2. The model presented in Subchapter 4.2 will be tested in the next chapter, in whether it can fix these challenges with FRs, or not. It will be testing it on the German Ding0-grid presented in Subchapter 5.3.

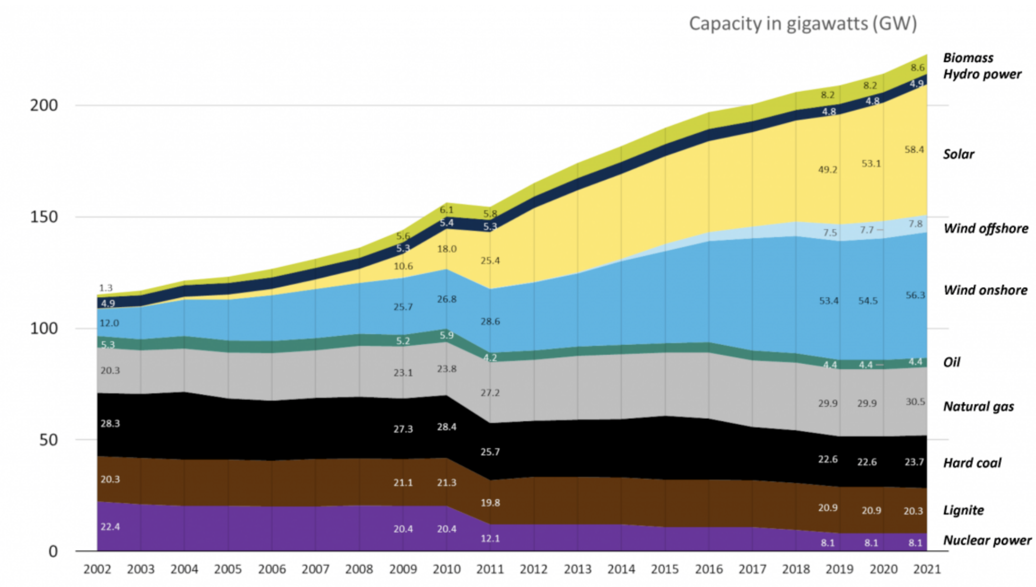

Figure 5.1: *Installed net power generation capacity in Germany 2002-2021 [45].*

5.2 Developing the grid for the case of study

The purpose of the case study is to test and show that the model can handle several DSOs, and that including different FRs are beneficial for the grid. This is done by creating four different cases: congestion in the TS, congestion in the DS, voltage violation in the DS, and economic dispatch. In each case, scenarios are created with different types of flexibility included. The different grids in the case study are from various sources. The transmission grid is from Pandapower [46], named "Case 9", and has a base power of 100 MVA and base voltage of 345 kV. Pandapower is a tool to create a network calculation program and is used to analyze optimization in power systems. It can analyze both transmission system and distribution system [47]. There are three DSOs used in this work. The first is "Case 33bw" from Pandapower and the root node is connected to the transmission grid's bus 2.

The two other grids are identical, synthetic, and are generated from Ding0 [48]. They are connected to the transmission grid's nodes 4 and 7. The reason for choosing two grids with identical topology was to test one of these grids with included FRs and another grid without flexibility. Some scenarios presented in this thesis consider this case. In addition, the most beneficial case when there was FRs at both grids is also taken into consideration. Therefore, the reason for them to be identical is to test how the DSOs help each other when one of them has FRs included and the other does not, and when they both have FRs included. It is also to see how the TSO benefit from the FRs located in the DSOs. The grids can be seen in Figure 5.4.

As distribution system operators generally do not release data about their grids, there was a need for a tool to generate medium and low voltage distribution grids. By using the available data, the Ding0 developers made a dataset of distribution grids in Germany. Ding0 is short for Distribution Network Generator and is used to make synthetic medium or low voltage distribution grids. It is generated from open and available data. The data used is high resolution spatial data of load and generation. It needs to be spatial to get a topology of the grid. The tool uses a routing technique, such that the medium voltage topology is generated. The focus is mainly on medium voltage grids, and therefore the low voltage grids are aggregated as loads and generations [49].

The data for DA market, FM, load shifting, batteries, and distributed generation for the IEEE 9 bus system, or "Case 9", is sourced from [50]. The missing data for the German grid is simulated. The data that was missing, was DA market and FM load profile data. The DA load profiles were extracted from Scientific Data [51]. As there are few appropriate data for energy consumption the article presents load profiles that are a combination of residential, industrial and agricultural, and are represented in Figure 5.3. The data incorporates weather time series, standard load profiles, census data, movement data and employment data. In addition, the data is targeted to an energy system with a great share of renewable energy which is the case in this thesis [51].

The FM load data are randomized, with a base on the DA data, and the differentiation is "noise" to create a more realistic case. It is made so to show the variation between predicted load in DA data and real data that is used in intra-day or FM. The flexible distributed generators in the two German grids are based on the data from [52] seen in Figure 5.2. In both of the grids the generator is placed at bus 26, and is based on voltage level 4, "HV-MV", as the grids are medium voltage grids but are connected to a high voltage transmission system.

Voltage level	Inst. Capacity	Allocation
1 EHV	> 120 MW	Transmission substation
3 HV	$17.5 - 120$ MW	HV Grid
4 HV-MV	$4.5 - 17.5$ MW	Transition point
5 MV	$0.3 - 4.5$ MW	MV Grid
6 MV-LV	$0.1 - 0.3$ MW	Distribution substation
7 LV	< 0.1 MW	Load area

Figure 5.2: *Installed capacity assigned to voltage level based on [52].*

The load shifting data are randomized, are about 4-10% of the load profiles, and are placed on buses 24-38. The battery data are between approximately 0-20% and are placed from buses 26-38. The percentages are based that the research that was done, to create realistic scenarios. This can be seen in Figure 5.5.

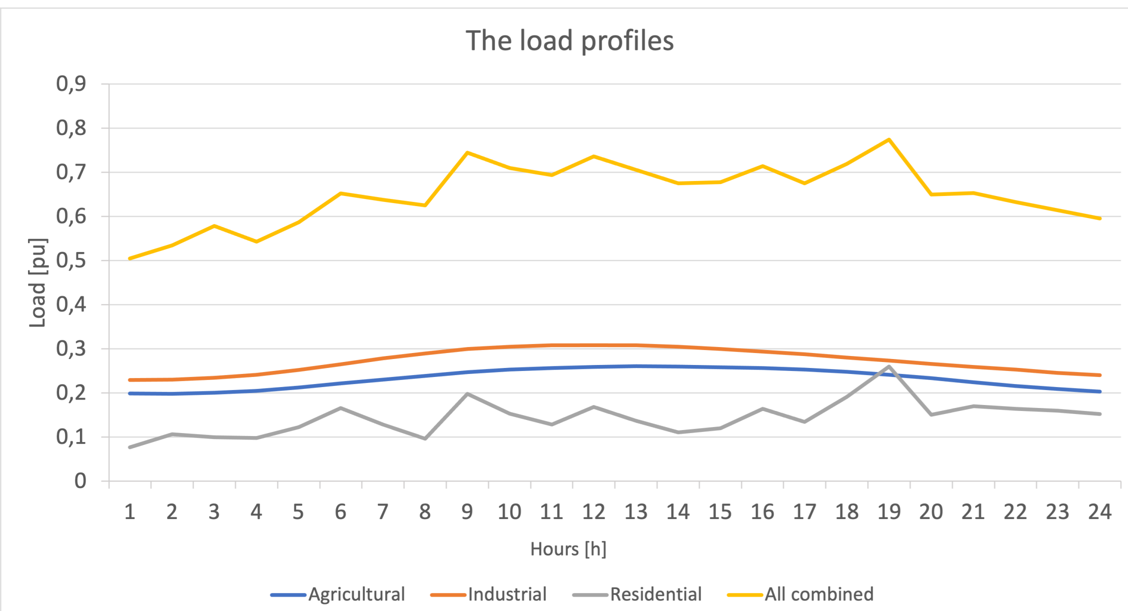

Figure 5.3: *The load profiles in p.u. per hour, residential, agricultural and industrial from [51].*

In creating the two German grids, the low voltage grids were aggregated and represented as load buses in the medium voltage grids, buses 24-38. The transformers were presented as resistances to simplify the model.

5.3 The German test grid

The grid that was explained in the previous subchapter is presented in Figure 5.4. The thicker lines represent the transmission grid lines. The figure represents the base case, where no FRs are included. From this base case, different challenges will be tested, such as voltage violations, congestion in the distribution grid and the transmission grid.

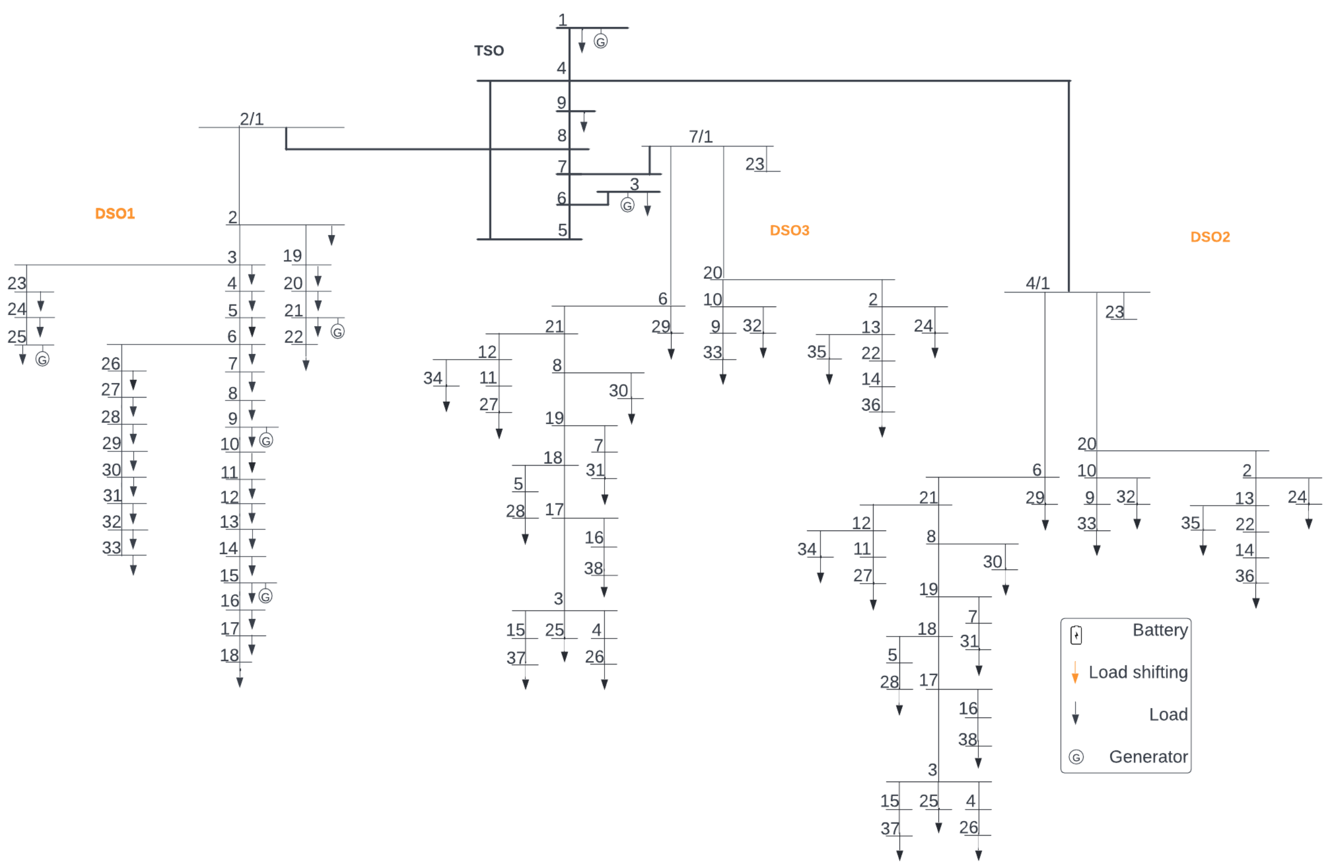

Figure 5.4: *The German grid, from Ding0, with no flexibility resources included.*

5.3.1 Adding flexibility resources

To test the grid, FRs are included. In this thesis, the testing consists of different load shifting, batteries and flexible distributed generators. When every FR is included, the grids look like Figure

5.5. The prices for the FRs that are used in this thesis are based on the previous work done by [5]. The prices are based on the El-spot area (Midt-Norge) on the 26th of April 2021 and they are constant. If the FRs aid the grid regarding the grid challenges explained in Subchapter 2.2, will be tested in the next chapter.

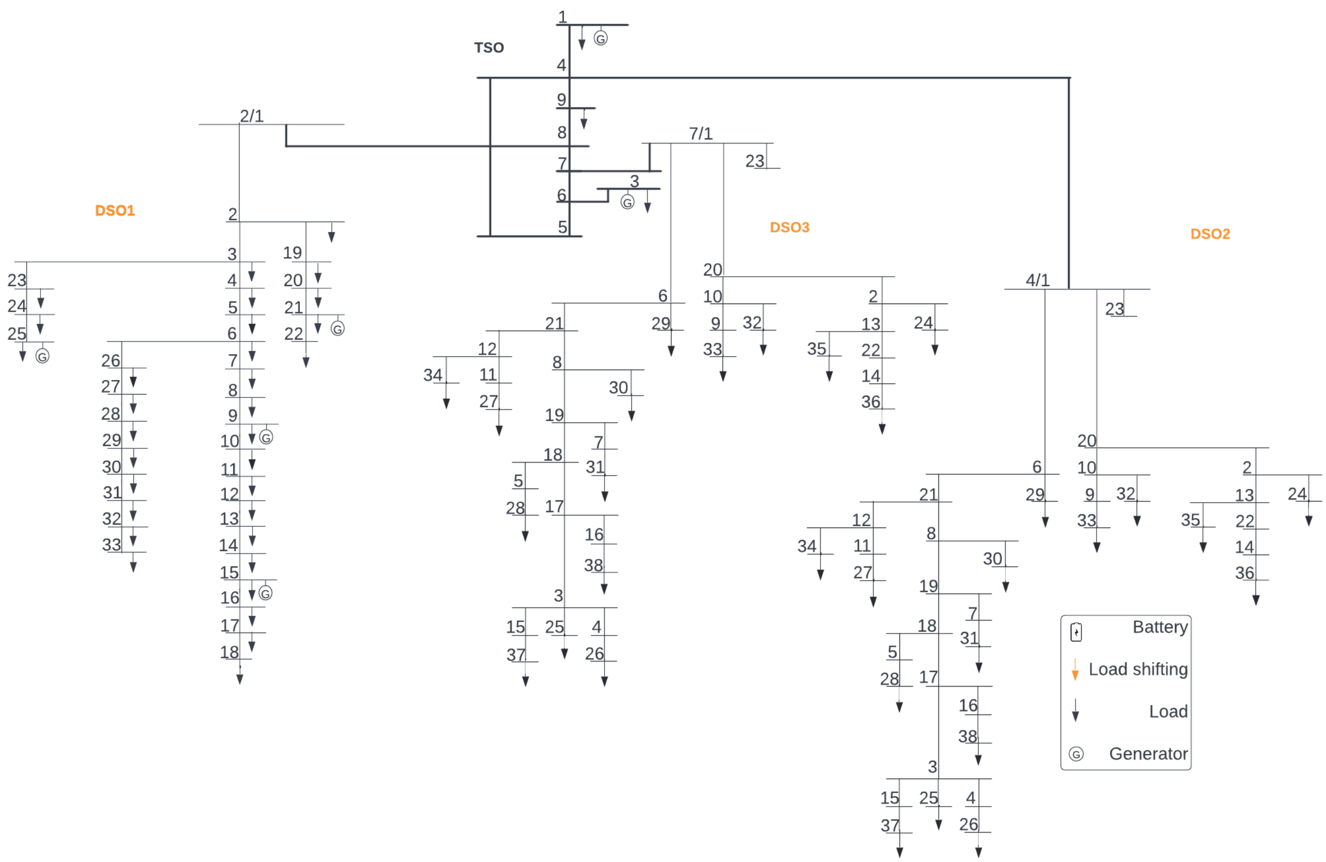

Figure 5.5: *The German grid, from Ding0, every flexibility resource included.*

The available FRs in the distribution grids are presented in the following tables. The first table is an overview of the distributed generators in Table 5.1.

Table 5.1: *Overview of standard for flexible distributed generators in the grids.*

DSO number	Type of flexibility resource	Bus number	Maximum production [p.u.]
1	Distributed generator	10	0,5
2	Distributed generator	26	0,05
3	Distributed generator	26	0,05

The second table describes the load shifting potential in DSO 1, as seen in Table 5.2.

Table 5.2: *Overview of load shifting in DSO 1.*

Bus number	Type of flexibility resource	Maximum decrease and increase [p.u]
5	Load shifting	0,0003
10	Load shifting	0,0003
26	Load shifting	0,0003

The load shifting potential for DSO 2 and 3 looks like Table 5.3. How load shifting, batteries and distributed generators works are presented in Subchapter 2.1.

Table 5.3: *Overview of load shifting in DSO 2 and DSO 3.*

Bus number	Type of flexibility resource	Maximum decrease and increase [p.u]
24	Load shifting	3,35887E-05
25	Load shifting	0,001416322
26	Load shifting	0,004765002
27	Load shifting	0,000509428
28	Load shifting	0,001752209
29	Load shifting	0,001936946
30	Load shifting	0,004501522
31	Load shifting	0,000744549
32	Load shifting	0,004483538
33	Load shifting	0,004388259
34	Load shifting	6,71773E-05
35	Load shifting	4,47849E-05
36	Load shifting	0,000106364
37	Load shifting	4,47849E-05
38	Load shifting	7,27754E-05

The last FR included in the grids, are batteries. For DSO 1, this can be seen in Table 5.4.

Table 5.4: *Overview of batteries in DSO 1.*

Bus number	Type of flexibility resource	Initial state of charge [p.u]	Minimum state of charge [p.u]	Maximum state of charge [p.u]	Maximum charge and discharge capacity [p.u]	Charge and discharge efficiency [%]
22	Battery	0,001	0,0	0,002	0,0002	99
19	Battery	0,002	0,0	0,004	0,0003	99
33	Battery	0,0005	0,0	0,001	0,00025	99

For DSO 2 and DSO 3 the batteries is located at the buses presented in Table 5.5. The battery potential is presented in Table 5.6.

Table 5.5: *Buses with batteries placed in DSO 2 and DSO 3.*

Buses with batteries	26	27	28	29	30	31	32	33	34	35	36	37	38

Table 5.6: *Overview of batteries placed in DSO 2 and DSO 3.*

Type of flexibility resource	Initial state of charge [p.u]	Minimum state of charge [p.u]	Maximum state of charge [p.u]	Maximum charge and discharge capacity [p.u]	Charge and discharge efficiency [%]
Battery	0,0008	0,0	0,001	0,00008	99

The next chapter presents the results from testing the described grids with several grid challenges. The FRs' data introduced will be tested to see the benefit of including them in the distribution grids.

6 The results of the Hybrid AC/DC OPF ADMM model application

The fourth and fifth part of the thesis' objective are to test the modified model to see if the FRs are beneficial for the distribution grids, and if the DSOs help each other with grid issues. In this chapter a series of scenarios was tested to answer these parts of the objective. Previously, in Chapter 2.2, different challenges for the grid were described. The four different cases tested in this model are voltage violations, congestion in the DS, congestion in the TS and economic dispatch. As these are grid issues that will occur even more with the increased penetration of RES, the results would be valuable information to have for the further planning of the power system. The solutions proposed in Subchapter 2.2 were FRs, and the results will show the benefits of using FRs for the different DSOs.

6.1 Voltage violations

The model is first tested with two distribution grids, the 38 node German Ding0-grids. When FRs were not included, the undervoltage problem is created by increasing the loads in the 21-feeder in DSO 3 (see Fig. 5.4) with 50%. When connecting the DSO 1 "Case 33bw" from Pandapower to the TSO, the German distribution grid with increased loads in feeder 21, DSO 3, creates the same undervoltage. The voltage limit is set to 0,95-1,05 p.u. The limit is set by accepting a 5% deviation from the optimal voltage of 1 p.u. The voltages were the same in the two cases. This shows that adding another DSO did not affect the voltages for DSO 3. In both cases, the voltages at bus 4 and 26 is under the voltage limit of 0,95 p.u. The next four scenarios will show if FRs can help with this voltage violation at DSO 3. The different types of FRs that are included in the scenarios, are shown in Table 6.1.

Table 6.1: *Overview over the FRs that are included for the various scenarios with voltage violation, (-) indicates not included, (x) indicates included.*

		Load shifting	Batteries	Generators
Scenario 1				
	DSO 1	-	-	-
	DSO 2	-	-	-
	DSO 3	-	-	-
Scenario 2				
	DSO 1	x	x	x
	DSO 2	x	x	-
	DSO 3	-	-	-
Scenario 3				
	DSO 1	x	x	x
	DSO 2	x	x	-
	DSO 3	x	x	-
Scenario 4				
	DSO 1	x	x	x
	DSO 2	x	x	-
	DSO 3	x	x	x

6.1.1 Results without voltage regulations

In order to see how the FRs help the grids, and if the DSOs help each other, the first applied challenge is voltage violation. The first case has no voltage regulations (VRs) and the various costs for the four different scenarios are shown in Table 6.2. The DA costs are the same for each scenario, because the voltage violation is introduced only in the FM.

Table 6.2: *Costs for the four different scenarios, without VRs.*

	Market operator	**Flexibility Market [EUR]**	**Day ahead [EUR]**	**Total [EUR]**	**Summed up [EUR]**
Scenario 1	DSO 3	32 713,05	89 501,50	**122 214,63**	**605 063,78**
	TSO	47 626,63	435 222,51	**482 849,15**	
Scenario 2	DSO 3	32 713,06	89 501,51	**122 214,57**	**605 063,65**
	TSO	47 626,57	435 222,51	**482 849,08**	
Scenario 3	DSO 3	32 581,01	89 501,51	**122 082,52**	**604 928,64**
	TSO	47 623,60	435 222,51	**482 846,11**	
Scenario 4	DSO 3	31 562,23	89 501,51	**121 063,74**	**603 811,65**
	TSO	47 525,39	435 222,51	**482 747,91**	

In addition to reduction in the total costs for DSO 3 with each scenario, the active power losses for DSO 3 are also mainly reduced for each scenario, shown in Table 6.3.

Table 6.3: *Active power losses for the four scenarios at DSO 3, without VRs.*

	Scenario 1 [p.u]	**Scenario 2 [p.u]**	**Scenario 3 [p.u]**	**Scenario 4 [p.u]**
Flexibility Market	2,976	2,976	2,962	2,729
Day ahead	0,377	0,377	0,377	0,377
Total:	**3,353**	**3,353**	**3,339**	**3,106**

The four scenarios' voltage profiles for DSO 3 can be seen in Figure 6.1. The voltage limit is 0,95 p.u., marked by the blue horizontal line.

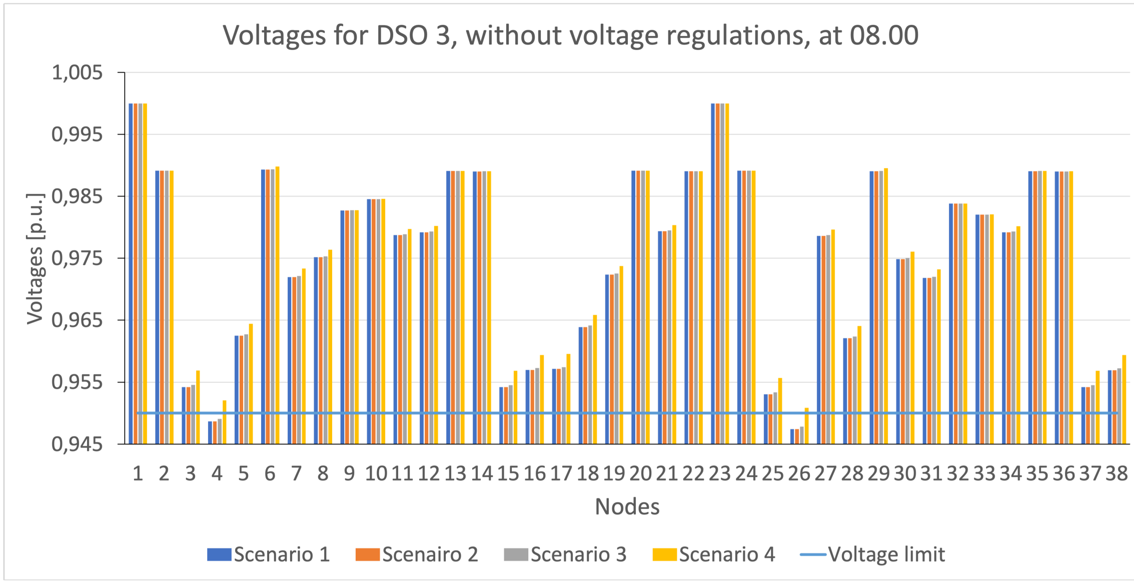

Figure 6.1: *The voltages profiles for the four scenarios, without VRs.*

In addition to voltage profiles, costs and losses, another result can tell us about the solution presented in each scenario: the Lagrangian multiplier, which represent the shadowprice. The Lagrangian multipliers, λ's, are prices made for the DSOs, where the object is to maximize profit by minimizing the costs. The DSOs does not determine the production, but gives the optimum quantity they want produced. The DSOs update the prices for each iteration, as the dispatch is changing. The shadow prices can be related to the peak of the load, as seen in Figure 6.2. Only two lines are visible in the graph, the load profile and scenario 4. The remaining three scenarios are overshadowed by the fourth one, because the shadow prices are nearly identical.

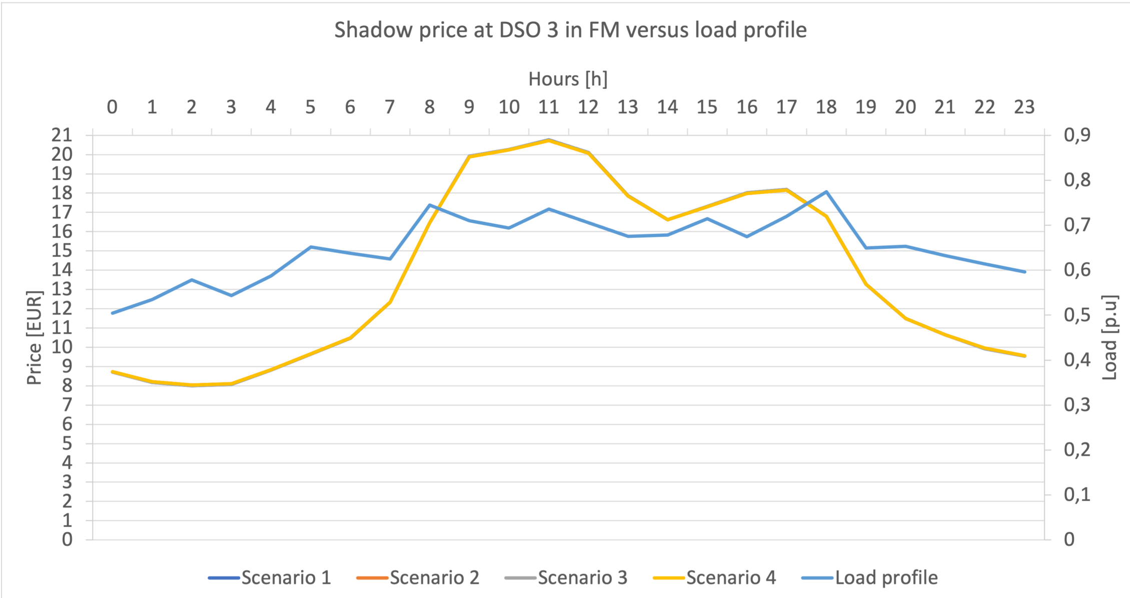

Figure 6.2: *The λ-price versus load profile for DSO 3, without VRs.*

6.1.2 Results with VRs

As the objective of the model is to reduce costs, and not to regulate the voltages, it will not intentionally choose the options that increase/decrease the violating voltages. To ensure voltages within the voltage limits, VRs are added. To meet the voltage requirements, the model will shed the load that creates undervoltage.

The total costs of the four scenarios are presented in Table 6.4.

Table 6.4: *Costs for the four scenarios at DSO 3, with VRs.*

	Market operator	**Flexibility Market [EUR]**	**Day ahead [EUR]**	**Total [EUR]**	**Sum of DSO 3 and TSO [EUR]**
Scenario 1	DSO 3	131 739,61	89 501,50	**221 241,12**	**704 090,27**
	TSO	47 626,63	435 222,51	**482 849,15**	
Scenario 2	DSO 3	131 739,69	89 501,51	**221 241,20**	**704 054,25**
	TSO	47 590,54	435 222,51	**482 813,05**	
Scenario 3	DSO 3	91 604,98	89 501,51	**181 106,49**	**663 925,90**
	TSO	47 596,89	435 222,51	**482 819,40**	
Scenario 4	DSO 3	31 558,74	89 501,51	**121 060,25**	**603 802,59**
	TSO	47 519,83	435 222,51	**482 742,34**	

The active power losses are shown in Table 6.5. For every scenario with VRs the losses are smaller, than the case without VRs.

Table 6.5: *Active power losses for the four scenarios at DSO 3, with VRs.*

	Scenario 1 [p.u]	**Scenario 2 [p.u]**	**Scenario 3 [p.u]**	**Scenario 4 [p.u]**
Flexibility Market	2,925	2,925	2,931	2,727
Day ahead	0,377	0,377	0,377	0,377
Total:	**3,302**	**3,302**	**3,308**	**3,104**

The voltage profiles for DSO 3 with VRs, are presented in Figure 6.3. Table 6.6 shows that there is no load shedding at scenario 4, but the voltage is well within the limits nonetheless. It is also higher than the voltages with load shedding. The determining factor to avoid load shedding is therefore including flexibility generators, such as in scenario 4.

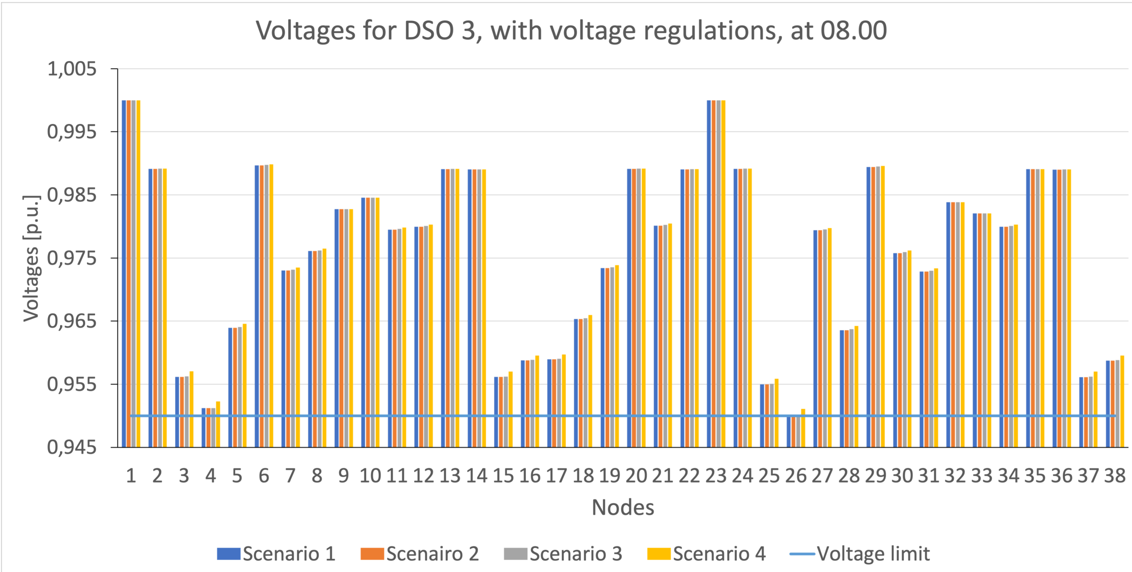

Figure 6.3: *The voltage profile for DSO 3, with VRs.*

The VRs in this model choose to increase the voltages by load shedding. The amount of load shedding is presented in Table 6.6.

Table 6.6: *Load shedding for the four scenarios at DSO 3, with VRs.*

Scenarios	1	2	3	4
Amount of load shedding [p.u]	0,796	0,796	0,474	0,0

6.2 Congestion in the DS

Currently, overvoltage is one of the most critical problems the power system is facing. However, in the future, when there is a higher penetration of renewable energy and EVs, congestion in the distribution grid will become a bigger issue. As mentioned in Chapter 2.2, this is one of the issues FRs might contribute to solve. In this case, a congestion is created in the line between bus 4 and 26 in DSO 2. This is done by putting a limitation of the capacity of the line. The flow between bus 4 and 26 is 0,174 p.u. in normal state, when there is no congestion. Setting a lower limit for the capacity of the line will create a congestion. The different scenarios testing how the FRs can help the congestion in line 4-26 in DSO 2 are shown in Table 6.7.

Table 6.7: *Overview over FRs included in the scenarios tested for congestion in the DS, (-) indicates not included, (x) indicates included.*

		Load shifting	Batteries	Generators
Scenario 1				
	DSO 1	-	-	-
	DSO 2	-	-	-
	DSO 3	-	-	-
Scenario 2				
	DSO 1	x	x	x
	DSO 2	-	-	-
	DSO 3	x	x	x
Scenario 3				
	DSO 1	x	x	x
	DSO 2	x	x	-
	DSO 3	x	x	x
Scenario 4				
	DSO 1	x	x	x
	DSO 2	x	x	x
	DSO 3	x	x	x

The lowest capacity that line 4 to 26 can handle in DSO 2 is presented in Table 6.8. Scenario 0 shows the natural flow, when there is no congestion in the line and no FRs available. The minimum capacity the line can take before it cannot provide enough power, is 0,0625 p.u for scenario 1, 2 and 3. Scenario 4 differs from the other scenarios, as DSO 2 has a distributed generator at bus 26. The system can then converge when the line's capacity is down to 0,0256 p.u. This can be seen in Table 6.8.

Table 6.8: *The lowest capacity for line 4-26 in DSO 2 the grid could take in each scenario.*

Scenarios	Lowest capacity [p.u]	Resulting flow in line 4-26 in DSO 2 [p.u]
Scenario 0	no congestion	0,1740
Scenario 1	0,0625	0,0624
Scenario 2	0,0625	0,0624
Scenario 3	0,0625	0,0625
Scenario 4	0,0256	0,0256

The costs that occur with the congestion in DSO 2 are presented in Table 6.9, showing the cost for DA and FM. The amount of load shedding for DSO 2 is presented in Table 6.10. The reason for the high costs and load shedding are analysed in the discussion (Chapter 7), more specifically in Subchapter 7.2.

Table 6.9: *The costs for DSO 2 with a congestion of 0,0625 p.u.*

Cost [EUR]	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Flexibility Market	1 820 089,671	1 855 026,855	1 607 322,060	948 124,539
Day ahead	89 490,562	89 490,897	89 490,897	89 490,897
Total:	**1 909 580,234**	**1 944 517,753**	**1 696 812,958**	**1 037 615,437**

Table 6.10: *The costs of and amount of load shedding in DSO 2, with a congestion of 0,0625 p.u.*

Load shedding	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Amount [p.u.]	14,416	14,697	12,708	7,423
Cost of load shedding [EUR]	1 802 067,975	1 837 155,026	1 588 510,011	927 894,813

Table 6.11 shows how much power is imported to DSO 2 trough the slack node.

Table 6.11: *Active slack production for DSO 2 in FM.*

Scenarios	1	2	3	4
Active slack production [p.u]	12,365	12,294	12,776	12,900

Table 6.12 shows scenario 4 with various maximum production at generator located at bus 26 in DSO 2. The higher the maximum production is, the lower the load shedding amount and the costs for FM are.

Table 6.12: *The amount of load shedding needed with an increased maximum production for the distributed generator at bus 26 at DSO2.*

Congestion capacity [p.u.]	Maximum production [p.u]	Load shedding amount [p.u]	Cost for FM [EUR]
0,0625	0,05	7,423	948 124,53
0,0625	0,1	2,838	376 096,27
0,0625	0,15	0,262	54 504,36
0,0625	0,2	0,0	21 113,52

6.3 Congestion in the TS

Another grid challenge that is common, introduced in Subchapter 2.2, is the congestion in the transmission system. When there are no FRs included and no congestion in the line 7-8, the normal flow for the 9-bus transmission grid (presented in Figure 5.4) is maximum 0,853 p.u. When limiting the capacity of the line to 0,84 p.u., the model would not converge. To aid the grid, various FRs are added. To see the benefit of the FRs for the TSO, different scenarios are tested and presented in Table 6.13.

Table 6.13: *Overview over the FRs included for the scenarios tested for congestion in the TS, (-) indicates not included, (x) indicates included.*

		Load shifting	Batteries	Generators
Scenario 1				
	DSO 1	x	x	x
	DSO 2	-	-	-
	DSO 3	-	-	-
Scenario 2				
	DSO 1	x	x	x
	DSO 2	x	x	x
	DSO 3	-	-	-
Scenario 3				
	DSO 1	-	-	-
	DSO 2	x	x	x
	DSO 3	x	x	x
Scenario 4				
	DSO 1	x	x	x
	DSO 2	x	x	x
	DSO 3	x	x	x

The costs for the TSO for the four different scenarios are presented in Table 6.14. The prices for DA market stay the same in the four scenarios, while for the FM they are decreasing as more and more FRs are included.

Table 6.14: *The costs for the TSO for the four different scenarios.*

Scenarios	**Flexibility Market [EUR]**	**Day-ahead [EUR]**	**Total DA + FM [EUR]**
1	15 990,806	435 096,360	**451 087,167**
2	15 917,748	435 096,360	**451 014,108**
3	15 655,663	435 096,360	**450 752,023**
4	15 652,484	435 096,360	**450 748,844**

In Table 6.15 the different slack productions of active power are presented. When there is no congestion and no FRs included, the active slack production in the TSO for the FM is 35,232 p.u.

Table 6.15: *The slack production of active power in the TSO for the different scenarios.*

Scenario	**Flexibility market [p.u]**	**Day ahead market [p.u.]**
1	33,911	34,561
2	32,855	34,561
3	33,116	34,561
4	31,812	34,561

The lowest capacity line 7-8 could take for scenario 4, where FRs are included at all the DSOs, are presented in Table 6.16. It also shows if the model converges, and the costs for the TSO and the DSOs.

Table 6.16: *The lowest capacity of line 7-8 in TSO, if it converged and the cost for TSO and the DSOs for scenario 4.*

Capacity of line 7-8	**Converged?**	**Cost for TSO for FM [EUR]**	**Cost for DSO 1 for FM [EUR]**	**Cost for DSO 2 for FM [EUR]**	**Cost for DSO 3 for FM [EUR]**
0,84	yes	15 655,663	4,635	23 500,476	23 407,267
0,83	yes	15 801,259	6,848	23 499,806	23 259,091
0,82	yes	16 103,229	10,643	23 499,003	22 964,934
0,81	no	-	-	-	-

6.4 Economic dispatch

The last case is not a grid challenge, but a test on how the FRs affect the grid when it has no issues, and to see if/how the grids help each other. The five different scenarios are presented in Table 6.17.

Table 6.17: *Overview over the FRs included in the scenarios for economic dispatch, (-) indicates not included, (x) indicates included.*

		Load shifting	Batteries	Generators
Scenario 1				
	DSO 1	-	-	-
	DSO 2	-	-	-
	DSO 3	-	-	-
Scenario 2				
	DSO 1	x	x	x
	DSO 2	-	-	-
	DSO 3	-	-	-
Scenario 3				
	DSO 1	x	x	x
	DSO 2	x	x	x
	DSO 3	-	-	-
Scenario 4				
	DSO 1	-	-	-
	DSO 2	x	x	x
	DSO 3	x	x	x
Scenario 5				
	DSO 1	x	x	x
	DSO 2	x	x	x
	DSO 3	x	x	x

The costs for the different scenarios are presented in Table 6.18.

Table 6.18: *The DA + FM costs for the five different scenarios.*

	Market operator	Costs for DA and FM [EUR]	Summed up [EUR]
Scenario 1	TSO	450 807,2	**686 490,73**
	DSO 1	7 744,37	
	DSO 2	113 985,12	
	DSO 3	113 954,03	
Scenario 2	TSO	450 811,23	**685 924,04**
	DSO 1	7 173,65	
	DSO 2	113 985,12	
	DSO 3	113 954,02	
Scenario 3	TSO	450 738,20	**684 867,99**
	DSO 1	7 173,53	
	DSO 2	113 002,23	
	DSO 3	113 954,02	
Scenario 4	TSO	450 660,48	**684 373,93**
	DSO 1	7 744,37	
	DSO 2	113 000,17	
	DSO 3	112 968,89	
Scenario 5	TSO	450 664,79	**683 807,37**
	DSO 1	7 173,50	
	DSO 2	113 000,17	
	DSO 3	112 968,89	

The differences in costs for the various scenarios are presented in Table 6.19. The costs are decreasing for each of the scenarios.

Table 6.19: *The differences in cost from the different scenarios.*

	Difference in cost [EUR]
Scenario 2 vs scenario 1	-566,69
Scenario 3 vs scenario 2	-1 056,05
Scenario 4 vs scenario 3	-494,07
Scenario 5 vs scenario 4	-566,55

In Figure 6.4, the voltages for DSO 1 for the five different scenarios are presented. For scenario 1 and 4, there is an undervoltage with the basic flow when there are no FRs included in DSO 1. For scenario 2, 3 and 5, DSO 1 has FRs included and there is a large overvoltage.

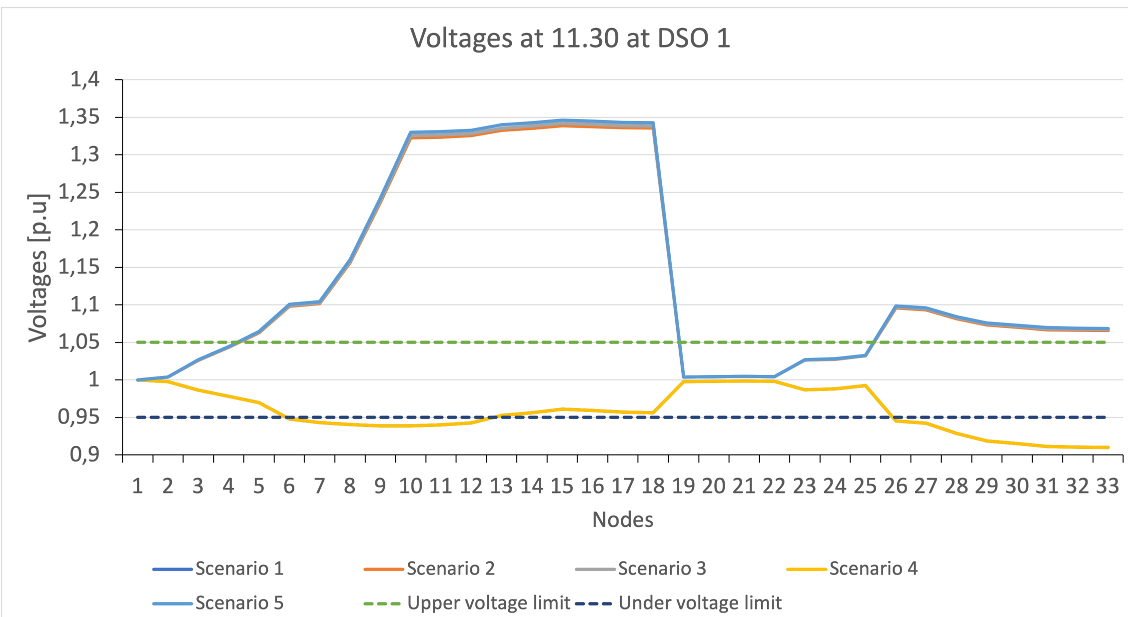

Figure 6.4: *The voltage profile at 11.30 for DSO 1.*

Table 6.20 shows the flow of power in DSO 1 from node 7 to node 18 at 11.30 in scenario 2 without VRs. It shows a surplus of power from node 7 to 18.

Table 6.20: *The flow of power in DSO 1 from node 7 to node 18 at 11.30 for scenario 2 without VRs.*

	Power [p.u.]
Active generation	0,207
Flexible generation	0,183
Discharge/charge battery	0
Load shifting	0
Flow from 6-7	-0,144
Load	-0,029
Active losses	-0,033
Total summed up:	**0,183**

In Table 6.21 the active losses for the three grids are presented.

Table 6.21: *The active losses for the five different scenarios.*

Scenarios	**Market operator**	**Active losses in the FM [p.u.]**
1	DSO 1	0,229
	DSO 2	1,493
	DSO 3	1,492
2	DSO 1	1,933
	DSO 2	1,493
	DSO 3	1,492
3	DSO 1	1,936
	DSO 2	1,347
	DSO 3	1,492
4	DSO 1	0,229
	DSO 2	1,347
	DSO 3	1,346
5	DSO 1	1,943
	DSO 2	1,347
	DSO 3	1,346

For DSO 2 and 3, the losses are reduced when including FRs, while for DSO 1 the active losses are increased with 743 %. The active losses are too high, implying that this is not a realistic case. As the Pandapower grid is a simulated distribution grid, the results may not be in a realistic range.

The active flow at 11.30 in DSO 1 is presented in Figure 6.5. The active flow data is from node x (lower in the grid, can be seen in Figure 5.5) to node y (higher in the grid). When the flow is negative, the flow is moving down the branches of the grid, away from the slack node.

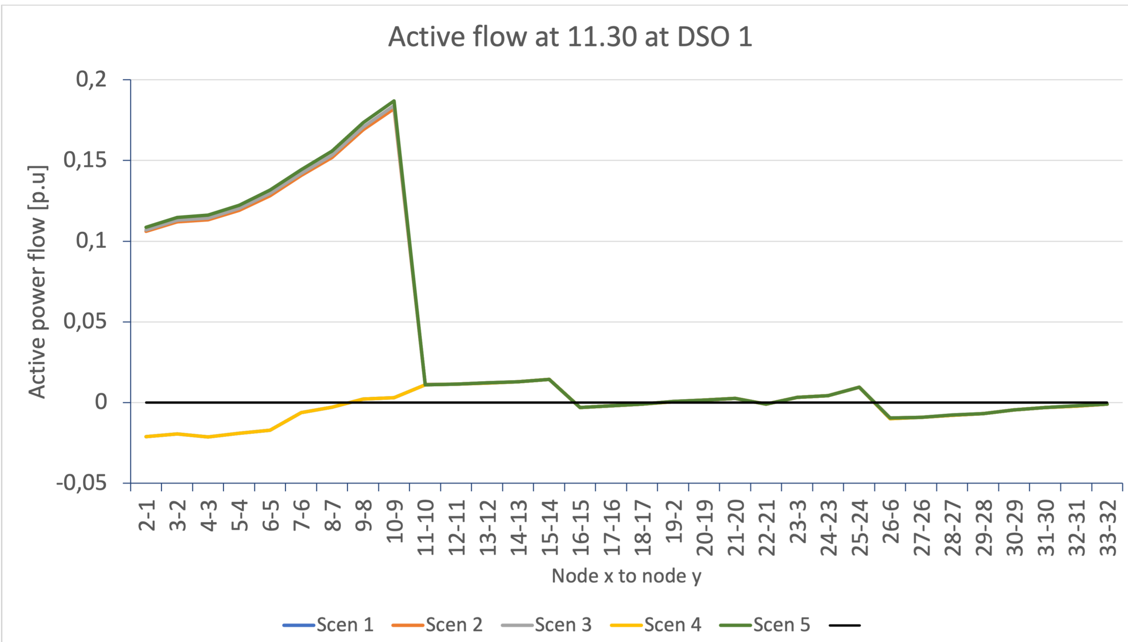

Figure 6.5: *The active power flow at 11.30 for DSO 1.*

The active losses from line 1-10 and 10-33 are presented in Table 6.22, which shows the difference in active losses for DSO 1. In scenario 1, DSO 1 doesn't have FRs, while in scenario 2 FRs are included and tests with and without VRs.

Table 6.22: *The active losses for DSO 1 for scenario 1 and 2 split up into two groups, without VRs and with VRs.*

	Scenario 1	**Scenario 2 without VRs**	**Scenario 2 with VRs**
Active losses from lines from 1 to 10 [p.u]	0,154	1,872	0,321
Active losses from lines from 10 to 33 [p.u.]	0,075	0,061	0,067
Total [p.u.]	**0,229**	**1,933**	**0,389**

In Table 6.23, the power flow in DSO 1 from node 7 to 18 at 11.30 for scenario 2 with VRs is presented. The positive power flows are the injection of power into the small part of the grid, the negatives are the withdraw of power.

Table 6.23: *The flow of power in DSO 1 from node 7 to node 18 at 11.30 for scenario 2 with VRs.*

	Power [p.u.]
Active generation	0,071
Flexible generation	0,048
Discharge/charge battery	0
Load shifting	0
Flow from 6-7	-0,033
Load	-0,029
Active losses	-0,004
Total summed up:	**0,052**

7 Discussing the results

This chapter aims to discuss if the two last parts of the research objective are achieved by the results. This discussion will focus on examining the results from the Hybrid AC/DC OPF ADMM model with the benefits of FRs for the TSO and multiple DSOs, and if the DSOs would help each other when experiencing grid issues.

7.1 Voltage violation

The first challenge that the test grid was exposed to, was voltage violation. The Hybrid AC/DC OPF ADMM model was tested on cases with and without VRs in the grid. In addition, the model was applied for grid configurations with two and three distribution grids connected to the transmission grid. The results showed that the Hybrid AC/DC OPF ADMM model was able to handle both grid configuration and cases that were considered. The results showed that the model could handle the coordination of TSO with multiple DSOs in an efficient way.

7.1.1 Results of the model testing without VRs

As Table 6.2 shows, with an increasing amount of FRs included, the total cost drops. From scenario 1 to 2, the costs for the TSO is reduced, even though the voltage violation happens at DSO 3 and FRs are only included at DSO 1 and 2. This implies that FRs are economically beneficial, and it shows that FRs are valuable for the TSO as well.

From scenario 2 to 3, presented (Table 6.1) and explained in the previous chapter, the load shifting and batteries are also included at DSO 3. This led to a noticeable reduction in active power losses in the considered grid. The activation of local FRs leads to a decreased need for power transfer in each period, explaining the reduction of losses. From scenario 3 to 4, the active power losses are reduced even more, due to a flexibility generator that was placed on bus 26. Thus, in scenario 4 less power needs to be transferred the whole way from the slack node to bus 26, reducing the losses by 6,99 %. The results show that by including FRs, the active losses can be reduced.

There is difference in voltage profiles for DSO 3 in the first two scenarios, as seen in Figure 6.1, where FRs are not included in DSO 3 but are included at DSO 1 and 2 for scenario 2. This can be related to the lines' capacity. Two of the grids used in this work are realistic German distribution grids. Therefore, the lines' capacity has not been increased, to try keeping the data as realistic as possible. This is also a motivation for using FRs, that the grid operators do not need to upgrade their lines. The results show that adding FRs at the other two DSOs doesn't benefit the operation of DSO 3. Thus the other DSOs don't help with their flexibility assets to DSO 3.

In scenario 3, where load shifting and batteries are included for DSO 3, the voltage is a bit higher, showing that the voltage profile benefit from the FRs. The only scenario with a voltage profile higher than the limit for every bus in DSO 3, is scenario 4. In scenario 4, bus 26 has a flexibility generator included which increases the voltage profile not only for node 26, but also for node 4, which is closely located to node 26, as seen in Figure 5.5. The results demonstrate that the voltage profile benefits from the FRs for the DSO where they are located.

The load profile in Figure 6.2 has a peak between hour 8 and hour 18. This is also the case for the shadow price, which is the highest in this time period. It means that the cost can be maximum reduced between hour 8 and hour 18 by reducing the load by one unit. Consequently, reducing the load in peak hours gives the most reduction in the costs. However, the shadow price is about the same for each of the four scenarios. This shows that the FRs don't affect the shadow price significantly for DSO 3.

In sum, the FRs help with the voltage profile, costs and active losses. However, it also shows that FRs only help the DSO where they are located and the TSO.

7.1.2 Results of the model testing with VRs

There is a large change in total FM costs in the case without VRs compared to the case when VRs are included. For scenario 1, the FM cost for DSO 3 is 16,36 % higher than for the case without VRs. The cost for FM for DSO 3 is higher than the TSO FM cost, which indicates that this is not a realistic scenario. The purpose of this case is to create a voltage violation. If the loads were to be decreased to avoid load shedding, it would not create an undervoltage problem. Therefore, there is a high cost caused by the load shedding at DSO 3. In scenario 1 and scenario 2, the DSO 3 does not have FRs to compensate for the undervoltage, and the model must choose load shedding to reduce the load. The load shedding costs are set high, since this is the last, unwanted solution. Therefore, when including VRs, the costs will be high, as the model must reduce the voltage by load shedding to meet the voltage requirements.

In scenario 3, the cost for FM is still higher for DSO 3 than TSO, even though it is reduced from scenario 2 to 3. This shows that FRs reduce costs when load shedding is included as well. The costs for scenario 4 with and without VRs are quite similar. Since a flexibility generator is included in scenario 4, there is less load to be cut for keeping the voltage within limits. For scenario 4, the costs are a bit lower with VRs than without. The reason for the small change in costs might be that the voltage levels are different in the two cases. This results in dissimilar reactive power flow and might lead to lower losses, as seen in Table 6.5. When there are lower losses, less production is needed, and the cost are therefore reduced.

Figure 6.3 shows that including VRs will increase the voltages to reach the voltage limit. There is no load placed at bus 4, but as the load at bus 26 is cut, the voltage at bus 4 is consequently lifted, as it is located near bus 26. In scenario 3 the FRs, load shifting and batteries, are included, but due to the limited volume of FRs, there is still load shedding in DSO 3.

The load shedding presented in Table 6.6 can indicate if the FRs are beneficial. For scenario 1 and scenario 2, the amount of load shedding in DSO 3 is about the same as when FRs are placed in DSO 1 and DSO 2. The voltage violations are positioned at DSO 3. Therefore the results indicate that FRs placed in other DSOs do not benefit the DSO 3 significantly.

To conclude, by including VRs and FRs, the voltage profiles and losses are improved, while the costs are increased when the requirements for voltage limits is set, leading to expensive load shedding.

7.2 Congestion in the DS

In Table 6.8, the minimum capacity the line 4-26 can provide is calculated to be 0,0625 p.u. for scenario 1, 2 and 3. This occurred despite the fact that DSO 2 had load shifting and batteries available in scenario 3. The only scenario that could handle a lower capacity, was scenario 4. In this scenario, DSO 2 has a generator at bus 26, which suggests that line 4-26 could handle a capacity of 0,0256 p.u. A lower capacity would lead to failure. This shows that in the case of congestion in the DS, adding a flexibility distributed generator will give the best results for this distribution grid as it is radial. It will provide more reliability and security for the operation of the power system. Congestion in the DS, as mentioned in Subchapter 2.2, is a grid challenge that is a threat to the grid's optimal operation. The cost for DSO 2 is also changing with the scenarios. With a congestion of 0,0625 p.u. the cost of each scenario is presented in Table 6.9. From scenario 1 to 2, the prices for DSO 2 increase. In scenario 2, FRs are included in DSO 1 and DSO 3, and there is a higher cost for DSO 2. As seen in Table 6.10, there is a higher amount of load shedding in scenario 2 than in scenario 1, leading to a higher cost. This happens as there is less power imported in scenario 2 than in 1, forcing DSO 2 to shed more load. This can be seen in Table 6.11. In this case, including FRs in the other DSOs is a disadvantage for DSO 2.

From scenario 2 to 3 and scenario 3 to 4, there is less load shedding and lower costs, due to the fact that load shifting and batteries are available for DSO 2 in scenario 3. In addition, in scenario 4, DSO 2 has a generator at bus 26 at its disposal, causing less load shedding and the possibility of coping with greater congestion. The cost for FM is about 10 times higher than the DA in scenario 4. Since it is a radial system, the grid must shed the load when there is not enough power to cover the energy demand in the considered node. The cost of load shedding is set high, giving unrealistic costs. However, as load shedding is an unwanted event, the price must be set high to prevent the model form choosing it, as the object of the model is to reduce costs. Load shedding applies only in a case when the model does not have other options to handle the congestion in the grid. In a real grid, other measures can be taken to reduce the load [53].

When increasing the maximum production the generator located at bus 26 in DSO 2 can produce, it provides many benefits. Table 6.12 shows the results for scenario 4 when increasing the maximum production. When the production is increased, it leads to reduced load shedding. At a production of 0,2 p.u., the load shedding is reduced down to zero. Another positive benefit of the increased flexibility generator production, is the decreased costs that can be seen in Table 6.12. The cost for FM was 10 times higher than the DA for scenario 4, which is an unrealistic result. However, the prices for FRs are simplified, as they were used as a fixed value. In the real market, the prices can vary during the day, and can be different for different DSOs and/or buses. In addition, it is not realistic that load shedding is the option the market operators choose when experiencing congestion. In the real market, this would be a very last resort, and the cost would therefore not be so high. As this model does not include all the options a market operator has, it can have a certain inaccuracy in obtained results. In addition, the incentives mentioned in Subchapter 2.3 are also not included in the prices.

To sum up the discussion of congestion in the DS, the costs are reduced for DSO 2 when FRs are included in DSO 2. When FRs are only included in DSO 1 and DSO 3, the costs are higher for

DSO 2. In addition, the load shedding is reduced when including FRs in DSO 2.

7.3 Congestion in the TS

Table 6.14 shows costs for FM and DA for the considered scenarios in the case of congestion in the transmission system. In scenario 1, there is congestion in line 7-8 in the TSO, and FRs are included in DSO 1. The costs are therefore higher than without the congestion, as creating congestion with no FRs was not feasible. However, from the results of modelling, there is a consistent trend that the costs are reduced when FRs are included. In scenario 2 and 3, two DSOs have FRs included. The only difference was which DSO had the FRs included. Table 6.14 shows that having FRs included at DSO 2 and 3 are cheaper than 1 and 2. Nevertheless, in Table 6.15 the slack production in the TSO is higher for scenario 3 than 2. This implies that even though the TSO needs to produce more for scenario 3, this option is still cheaper.

The cheapest option is to have FRs at all DSOs, and this is also where the TSO has the least slack production. In Table 6.15, the trend is that the slack production is reduced from scenario 1 to 2 and from 3 to 4. However, from scenario 2 to 3 the production increases. This means that the slack production for the TSO benefits from the FRs located at DSO 1 the most.

When there were no FRs included, the model could not converge even with just a small reduction of capacity. When including FRs at all DSOs, the model could handle congestion in line 7-8 in the TSO with a capacity down to 0,82 p.u., shown in Table 6.16. This suggests that when including FRs, the grid becomes more resilient to congestion in the TS, which is important to the TSO when operating a changing power system. For the TSO, the prices are increasing with the decreased capacity of line 7-8. The costs for the DSOs are differently affected, which can also be seen in Table 6.16. For DSO 1, which is connected to the TSO's node 8, costs are increasing as the capacity for line 7-8 decreases, and it needs to provide an increasing amount of power to sustain itself, as the import of power is jeopardized. For DSO 2 connected to the TSO's node 4, it is not directly connected to the reduced capacity in line 7-8, but is closely connected to the slack node, which leads to a constant price. The last DSO, DSO 3, has a reduced cost with the decreased line capacity. This happened because it was connected to the TSO's node 7, and when less power is flowing from line 7-8, more power can be provided to DSO 3. Even though the costs for DSO 3 is reduced, the total cost for TSO and DSOs are increased with the reduced capacity of line 7-8 at the TSO.

To summarize, FRs at the DSOs reduce the costs and losses for the TSO. How much the costs are reduced depends on the DSO where the FRs are located. Generally, the TSO doesn't have to produce as much power when FRs are included. The results show that when including FRs at all the DSOs, the TSO gets more resilient towards congestion in the TS. It can handle a lower capacity at line 7-8 when the FRs are included, while when no FRs are included the model could not handle any congestion in the line at all.

7.4 Economic dispatch

When the grids are not experiencing any grid challenges the results show how the FRs affect the operation of a normal grid. The costs for the DA and the FM for the different scenarios are shown in Table 6.18. From scenario 1 to 2, FRs are included at DSO 1. The costs are only reduced for DSO 1 and the TSO. This implies that DSO 1 does not help the other DSOs economically. The same can be seen in the other scenarios, where the costs are only reduced for the DSOs that have FRs included. The TSO, however, does benefit from the DSOs where FRs are used, as it does not need to provide as much power for them. This is why the costs are reduced for each scenario, as shown in Table 6.19. The biggest reduction in cost happens in scenario 2 to 3, where the cost is reduced by 1056,05 EUR. This indicates that is more beneficial to go from FRs included at DSO 1 to FRs at DSO 1 and 2, than going from no FRs to FRs included at DSO 1. In addition, the cost is reduced from scenario 3 to 4, where scenario 3 has FRs included in DSO 1 and 2, while it is included in DSO 2 and 3 in scenario 4. This signifies that it is more economically beneficial to have FRs included in the two grids generated in Ding0, than the Pandapower grid "Case 33bw" and one Ding0 grid. The costs are reduced, as seen in Table 6.18. From scenario 1 to 2, the cost of DSO 1 is reduced by 570,72 EUR, illustrating the economic benefit of FRs.

In Figure 6.4 there are mainly two voltage profiles, because the DSOs do not affect each other. This was already seen in previous analysis, which showed almost the same results when FRs are included at DSO 1. The voltage profiles for scenario 2 and 3 are almost the same, even though FRs are included at both DSO 2 and DSO 1 in scenario 3. The question is why including FRs create an overvoltage. As seen in Table 6.20, there is more power transferred from node 7-18 than used, and the power is flowing from node 7 to 6 and not 6 to 7. It is flowing up towards the TSO, not downwards the branches. The surplus of power, created from the FRs, will lead to an overvoltage, which is shown in Figure 6.4. As the object of the model is not to control the voltages, but to reduce costs, the model will choose options that might only be beneficial for the DSOs in an economical aspect. This is why it chooses the FRs. An overvoltage is unwanted, as it can lead to damage to electrical appliances used in the power grid. Therefore, other measures need to be considered to reduce the voltage, such as VRs. The voltage profiles show that other DSOs do not help with the voltage profile for DSO 1, and that including FRs can lead to unwanted results.

The active losses in Table 6.21 are decreased for DSO 2 and 3, showing that FRs can reduce active losses. However, the losses are increased for DSO 1 when including FRs. As seen in Figure 6.5, when FRs are included the flow is high from node 1 to 9, where the power moves in the direction from node 9 to the TSO connected at DSO 1's node 1. As the power flow is high in these lines, it leads to bigger losses, which explains the losses in Table 6.21. This is confirmed in Table 6.22, where the majority of active power losses occurs in the lines between node 1 and 9 for scenario 2 where FRs are included. Hence, when FRs are included the active losses in DSO 1 are reduced for the lines between 10 and 33, and increased for the lines between 1 and 10. However, if VRs are included, as seen in Table 6.22, the active losses from lines 1 to 10 are decreased by 1,55 p.u. from without to with VRs. How the losses are reduced can be seen in Table 6.23. The active generation and the flexibility generation are reduced as the VRs are added. When there is less power flowing, the active losses are naturally lower, even though the load demands are the same.

The results from economic dispatch show that FRs give lower costs for the DSO where they are located, and for the TSO (with the exception of scenario 1 to 2 for the TSO). The losses are reduced for DSO 2 and 3 when FRs are included, while for DSO 1 the losses are higher, due to the objective of the models to reduce costs. However, by including VRs the losses are reduced for DSO 1.

8 Conclusion and further work

There are five parts in the objective of this thesis. The first is to review materials regarding functioning and coordination of the LFM, modelling approaches that can be used for the market clearing, and to analyze which one is suited for the tasks of the master investigation. This was done in the first chapters, that were dedicated to various FRs, grid challenges, and determining how to solve them with FRs. In addition, regulations for FRs, mechanisms for FM operation and roles of participants in the market were investigated. In Chapter 3, a review was made on two modelling approaches, that could be used for the coordination of TSO with multiple DSOs in the OPF model. The choice landed on the decomposition approach, as it is better suited for the purpose of the research. This brings us to the model development.

The second part of the objective is to develop the Hybrid AC/DC OPF ADMM model, and to see if it can handle the coordination of TSO with multiple DSOs. The mathematical formulation for the Hybrid AC/DC OPF model was described in Chapter 4. The extension of the model with ADMM method was then introduced to include several DSOs, and the iterative approach to reach convergence was given. The developed model converged, indicating that it could handle multiple DSOs.

The third part of the thesis was to develop a test case using a Pandapower grid and two German distribution grids generated by Ding0. This task was described in Chapter 5. The developed grids were then tested with four different cases; voltage violation, congestion in the DS, congestion in the TS and economic dispatch.

The fourth part was to use the model and the test case to answer the research question: how can the operation of TSO and DSOs benefit from the FRs? The results suggested that the use of FRs are partly beneficial for the DSOs and TSO. For the case of voltage violations, FR helps with the voltage profile, costs and active losses. When introducing congestion in the DS, the costs and load shedding amount are lower only when FRs are located in the DSO with the congestion. For the case of congestion in the TS, the costs are reduced for the TSO when more FRs are included in the distribution grids. In addition, the FRs make the TSO more resilient to congestion in the TS. When there are no grid issues, as in the case Economic dispatch, the results show that FRs only help the DSO where they are located and the TSO. The active losses are increased for DSO 1 when

FRs are included in DSO 1, but decreased for DSO 2 and 3 when located in their grid.

The last part of the objective was a research question; can the DSOs help each other with grid issues in a FM? The answer is no for the grids used in this project. The results show that the FRs can only help the DS where they are located and the TSO. To achieve a grid system where the DSOs help each other, the line capacity and grid infrastructure needs to be different. The capacity needs to be higher, the DSOs should be connected in more nodes and the grids should be meshed. As one of the motivations for using FRs is to avoid upgrading the lines, improving the line capacities would contradict that motivation.

The master thesis and results of this investigation contribute to the knowledge in FM operation and modelling, and create a new instruments for TSO coordination with multiple DSOs. This research can be useful for further use of FRs from distribution grids to solve new challenges that TSOs and DSOs are facing.

8.1 Further work

As mentioned in the discussion, more realistic and dynamic prices could be considered in this research. As of today, there is not a lot of data for including FRs in the grid, and using realistic prices for the FRs should therefore be further explored. Adding more scenario-based testing will also check the robustness of the Hybrid AC/DC OPF ADMM model, and investigate if the model can handle other types of grid settings. In addition, including more real data can give a better understanding of how to include FRs in the grids. Another aspect could be to test the model with multiple TSOs and not just DSOs. This will further test the reliability of the model, and give a more realistic view of the power system, as TSOs are also connected and influence each other.

As the results have shown, the DSOs are not helping each other when they are experiencing issues, such as voltage violation. As this is related to the lines' capacity, it could be interesting to test further with grids that do not have that much of a restriction on the lines. In this thesis, a realistic grid is used. However, trying to test more grids with different typologies could be useful. It could also be interesting to try meshed DS grids, where they were connected in several nodes, and test to see if the other DSOs could help with congestion in a DS.

Another aspect that could be a subject of further work, is using intermittent energy production as flexibility distributed generators. As of now, the generators used in the model can be dispatched whenever it is needed, but it would be more realistic if the generators were intermittent such as solar power or wind power. The model needs further work to handle a negative load, which could be the case with prosumers at certain time periods.

As mentioned already, the prices used are from Norway, and they are not dynamic for the FRs. It could be useful to use a profile for the prices and more realistic prices. Further work done on the price aspect of the model could improve the model's certainty.

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Appendix A

Variable	**Explanation**
N/n	Sets/index of nodes in DCOPF model for transmission grid
M/m	Sets/index of nodes in SOC-ACOPF model for distribution grid
T/t	Sets/index for hours in model
U/u	Sets/index for time units in model
j	Index of receiving node
θ	Voltage angle
u	Auxiliary variable equal to: $\frac{V}{\sqrt{2}}$ in distribution grid
R	Auxiliary variable equal to: $V^2\cos(\theta)$ in distribution grid
I	Auxiliary variable equal to: $V^2\sin(\theta)$ in distribution grid
$P^{G,Flex}$	Flexible power generation
$c^{G,Flex}$	Price for flexible generation
$P^{L,Flex}$	Flexible load
$c^{L,Flex}$	Price for flexible generation
P^{disch}	Discharging power of the battery
P^{ch}	Charging power of the battery
c^{batt}	Price for flexible battery
P^{LS}	Load shedding
c^{LS}	Price of load shedding
$P^{L,AC}$	Load in the distribution grid
$P^{G,AC}$	Power generation in the distribution grid
G	Conductance of line
B	Susceptance of line

$Q^{L,AC}$	Reactive load in the distribution grid
$Q^{G,AC}$	Reactive power generation in the distribution grid
$P^{G,DC}$	Active power generation in the transmission grid
$P^{L,DC}$	Active load in teh transmission grid
$P^{fl,max}$	Maximum active power flow
P^{fl}	Active power flow
θ^{slack}	Voltage angle at the slack node
$P^{G,Flex,min}$	Minimum flexible generation
$P^{G,Flex,max}$	Maximum flexible generation
$P^{L,Flex,min}$	Minimum flexible load
$P^{L,Flex,max}$	Maximum flexible load
$P^{SoC,min}$	Minimum state of charge of the battery
P^{SoC}	State of charge of the battery
$P^{SoC,max}$	Maximum state of charge of the battery
$P^{ch,min}$	Minimum charging power of the battery
δ	Binary variable of battery operation
$P^{ch,max}$	Maximum charging power of the battery
$P^{disch,min}$	Minimum discharging power of the battery
$P^{disch,max}$	Maximum discharging power of the battery
$P^{SoC,init}$	Inital state of charge of the battery
η^{disch}	Discharging efficiency of the battery
η^{ch}	Charging efficiency of the battery

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Kunnskap for en bedre verden