Master's thesis

2020

Master's thesis

Marthe Fogstad Dynge

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

NTNU
Norwegian University of Science and Technology

Marthe Fogstad Dynge

Impact of Local Electricity Markets and Peer-to-Peer Trading on Grid Operations in a Norwegian Low-Voltage Distribution Grid

June 2020

NTNU
Norwegian University of Science and Technology

NTNU
Norwegian University of
Science and Technology

Impact of Local Electricity Markets and Peer-to-Peer Trading on Grid Operations in a Norwegian Low-Voltage Distribution Grid

Marthe Fogstad Dynge

Master of Energy and Environmental Engineering
Submission date: June 2020
Supervisor: Magnus Korpås (IE)
Co-supervisor: Dimitri Pinel (IE)
Pedro Crespo del Granado (IØT)

Norwegian University of Science and Technology
Department of Electric Power Engineering

Acknowledgement

This Master Thesis has been written at the Department of Electrical Power Engineering at the Norwegian University of Science and Technology (NTNU) and was concluded during the Spring semester of 2020. It was supervised by Professor Magnus Korpås and co-supervised by Senior Researcher Pedro Crespo del Granado and PhD candidate Dimitri Pinel.

The thesis was in collaboration with the European Projects: BEYOND and Positive Cityx-Change. Thesis inspiration and research discussion with researchers in these projects helped understand better the latest challenges and research frontiers in local markets. With this follows several persons to be acknowledged for their valuable support throughout this project.

First of all, I want to thank my supervisor Magnus Korpås for always being just a Teams-call away, providing both inspiration, knowledge and interesting discussions. I will also express gratitude to my co-supervisors Dimitri Pinel and Pedro Crespo del Granado, for excellent help and availability throughout the semester. A special thanks to the latter, your commitment and passion for the research field has been of great motivation. I also want to direct thanks to PhD candidate Naser Hashemipour for your valuable help with the model development and finalizing of the attached journal paper. Lastly, I want to thank PhD candidate Salman Zaferanlouei for providing relevant data for the project, and Raquel Alonso Pedrero and Erik Næss Guldbrandsøy for great inputs when determining the project direction at the beginning of the semester.

Last but not least, I would like to express gratitude to my friends and loved ones, for patience and motivation during these long months of working from home.

Trondheim, 23.6.2020

Marthe F. Dynge

Marthe Fogstad Dynge

Abstract

Distributed Energy Resources (DERs) are rapidly entering the power system, introducing both new opportunities and challenges for the system operators. Formerly passive consumers are transitioning into the prosumer role, calling for a restructuring of the conventional top-down system. With the simultaneous advancements in Information and Communication Technology (ICT), new frameworks to facilitate a more consumer-centric market and the deployment of DERs, are emerging. Peer-to-Peer (P2P) markets have thus gained attention in academic research and as pilot projects over the recent years, with promising results in terms of economic benefits. The impacts such market structures will have on the grid operations of low-voltage distribution networks are, however, little explored. As the peers are connected to a complex power system with hard technical constraints, such analyses are essential in order to determine the actual feasibility of local electricity trading.

In this thesis, a novel approach is conducted by combining a multi-period market optimisation model with a power flow analysis tool in MATLAB. With this method, all market decisions can be validated, but not necessarily constrained, by the distribution grid's technical specifications. Two system configurations of DER and storage deployment are analysed, with comparative cases of the impacts of establishing a local market or not. Additionally, an innovative pricing mechanism for reducing total system losses is introduced in a final case study.

The main findings indicate that there are no significant impacts on the grid operation of a P2P market when only Photovoltaics (PVs) are installed in the system. With decentralised batteries available, the P2P trade induced more voltage fluctuations and 13.79 % more losses within the neighbourhood than the case with no local market. The proposed pricing strategy in the final case managed to reduce these losses with 4.67 %. Moreover, establishing a local market showed a higher degree of community resilience and effective use of local resources for both system configurations.

Sammendrag

Desentraliserte fornybare energiressurser er raskt på vei inn kraftsystemet, og introduserer både nye muligheter og utfordringer for systemets aktører. Tidligere passive forbrukere inntar prosumer-rollen og den tradisjonelle ovenfra-og-ned-strukturen er i ferd med å endres. Med de samtidige fremskrittene innen informasjons- og kommunikasjonsteknologi, dukker det opp nye muligheter for å legge til rette for et mer forbrukersentrisk marked og investeringer i lokale energikilder. Peer-to-peer-markeder har dermed fått oppmerksomhet innen akademisk forskning og som pilotprosjekter de siste årene, med lovende resultater når det gjelder økonomiske fordeler. Imidlertid har det vært lite fokus på hvilken innvirkning slike markedsstrukturer vil ha på nettdriften i lavspente distribusjonsnett. Da markedsaktørene er koblet til et svært komplekst kraftsystem, med klare tekniske restriksjoner, er slike analyser essensielle for å kunne avgjøre om lokal krafthandel er gjennomførbart.

I denne oppgaven gjøres en ny tilnærming på dette feltet ved å kombinere en flerperiodisk markedsoptimaliseringsmodell med et lastflytanalyseverktøy i MATLAB. Med denne metoden kan alle markedsavgjørelser valideres, men ikke nødvendigvis begrenses, av distribusjonsnettets tekniske spesifikasjoner. To ulike systemkonfigurasjoner med distribuert produksjon og lagring er analysert, med caser som sammenligner virkningen av å etablere et lokalt marked eller ikke. I tillegg introduseres en innovativ prismekanisme for å redusere det totale systemtapet i et endelig casestudie.

Hovedfunnene indikerer at det ikke er noen vesentlig innvirkning på nettdriften av et lokalt marked når bare solcellepaneler er installert i systemet. Med desentraliserte batterier tilgjengelig førte peer-to-peer-handelen til flere spenningssvingninger og 13,79% mer tap i nabolaget, enn tilfellet uten lokalt marked. Den foreslåtte prisstrategien reduserte disse tapene med 4,67 %. Dessuten viste etablering av et lokalt marked en høyere grad av uavhengighet fra det øvrige nettet og effektiv bruk av lokale ressurser for begge systemkonfigurasjoner.

Contents

Figures

Tables

Acronyms

AC Alternating Current.

AMS Advanced Metering System.

DERs Distributed Energy Resources.

DG Distributed Generation.

DR Demand Response.

DSO Distribution System Operator.

ICT Information and Communication Technology.

IRENA International Renewable Energy Agency.

mpc MATPOWER case struct.

NVE The Norwegian Water Resources and Energy Directive.

p.u. Per Unit.

P2P Peer-to-Peer.

PVs Photovoltaics.

SOC State of Charge.

TSO Transmission System Operator.

Chapter 1

Introduction

1.1 Background and Motivation

In light of facing the growing energy demand and necessity of finding low-carbon solutions, more attention has been brought to the development and deployment of renewable energy. With this increased focus, investment costs in DER technology like solar PVs and batteries has been declining exponentially over the recent years [1, 2]. The tendency is thus that small-scale energy technology is starting to get affordable to regular households, creating the transition from consumerism to prosumerism as they simultaneously inhabit the role of consumption and production.

The traditional power system has had a top-down structure, designed to accommodate large, centralized generation units located far from the end-users. The increasing penetration of DERs has thus drastically changed the topology of the system, shifting problems that are faced at transmission-level today down to lower voltage levels. The challenges caused by deploying DERs at low-voltage level are already a well-explored topic, including harmonic distortion, voltage spikes and power output fluctuations [3, 4]. This introduces new challenges and areas of responsibility for the Distribution System Operator (DSO).

With the simultaneous advancement of ICT, enrollment of smart meters, and distributed ledger technology, new frameworks for managing the energy transition are emerging. This allows for closer interaction between end-users, DSOs and other system agents, and introduces the possibility of a more consumer-centric energy system. As a result, the power market needs to undergo a restructuring, dividing the system into smaller entities.

Local markets and P2P trading has thus gained increased focus within academic research, as well as pilot projects in various countries [5–7]. The decentralized management and collaborative principles characterizing these structures allow for the prosumers' preferences to be better implemented in the market [8]. Studies have found P2P trading to reduce total electricity costs, improve self-consumption and promote more effective utilisation of local DERs [9–11]. However, exchange of electricity is different from trade of other goods, as the agents are connected to a complex power system. Accordingly, how such novel market structures will concur with the hard technical constraints of the grid needs to be addressed.

Despite the growing focus on local market designs and challenges occurring with DER deployment, little attention has been brought to explore how a more active operation by the prosumer, when participating in a local market, can affect these challenges. The focus in this thesis will thus be to provide a comparative study of grid impacts of establishing a local market or not when integrating DERs and storage within the low-voltage distribution network.

1.1.1 Problem Description

The thesis aims to touch upon research challenges and questions as follows:

- What is the impact of local markets on voltage variations, grid dependency and losses?
- What cost-benefits provide P2P and local markets compared to "business as usual"?
- How to align P2P and local markets' operational decisions with the low-voltage grid conditions?

In order to address these questions, the main objective of the study has been to develop a model which combines market optimisation and power flow analysis. This way, the impacts on grid operation can be analysed by the power flow results of each market decision. Additionally, being a cost-minimising optimisation problem, the costs and benefits for each case can be obtained from this part of the model. Lastly, to address the third question, a novel market mechanism for reducing system losses is proposed and included in the model.

1.2 Approach

The model developed in this thesis is based on two existing research models, one for multi-stage market optimisation and one for power flow analysis. The main idea has been to modify these models to suit the scope of the study and automatise the interaction between them. The objective has thus been to minimise the electricity costs for a community for 24 hours at a time while conducting a full Alternating Current (AC) power flow analysis for each time step within this period. Excel and MATLAB have been used for modelling, input data adjustments, regressions and external calculations.

1.3 Structure of the Thesis

Chapter 1, *Introduction*, presents the background, motivation and objectives of the thesis.

Chapter 2, *Power Markets*, presents an overview of the wholesale power market from the Norwegian end-user's perspective. Important concepts regarding P2P electricity markets are also introduced, including a brief literature review of previous studies of local power markets with network considerations.

Chapter 3, *Power Flow Theory*, gives a brief overview of the characteristics of Norwegian distribution grids and the theory later used in the thesis for power flow analysis.

Chapter 4, *Methodology*, presents a detailed explanation of the approach of developing the model used for analyses.

Chapter 5, *Case studies*, presents the distribution network and the different case studies analysed in the thesis.

Chapter 6, *Market Results*, provides the results of market behaviour and operational decisions for the different cases.

Chapter 7, *Grid Impact Results*, provides results related to the grid impact of the individual cases. Additionally, it presents the results from the final case study with the novel pricing mechanism.

Chapter 8, *Discussion*, discusses the main findings and analyses from the results.

Chapter 9, *Conclusion and Recommendation for Further Work*, summarises and concludes the main findings and discussions of the study, and provides recommendations for further work within the topic.

In light of the limited existing research on the topic, the results obtained in this study was considered to be of contribution to the field. Thus, a journal paper was written in parallel with this thesis, presenting the key findings of the study. The manuscript for this paper is included in Appendix B.

Chapter 2

Power Markets

As this thesis aims to uncover some of the technical and economic impacts of establishing local markets within low-voltage distribution networks, it is essential to understand how the relevant participants procure their electricity today. The case studies will be based on data from a real distribution grid in Mid-Norway. Hence the focus will be on the Nordic power market principles. The following chapter will thus explain how today's wholesale power market works from the small end-users' perspective. Section 2.2 will present the concepts of P2P trading and a brief review of the research done on grid considerations in such market setups.

2.1 How Do Norwegian End-Users Buy Their Electricity Today?

In the early 1990s, the Norwegian power sector went through an extensive restructuring. The intention was to separate generation and retail from the transmission of electric power and achieve increased social benefits by introducing free competition in wholesale electricity markets [12]. With this followed a more efficient and integrated market between the Nordic countries, with a focus on optimal use of resources and increased security of supply. The transmission and distribution of electricity remain a natural monopoly of the grid operators in its respective area and voltage level. As of this, Norwegian consumers are free to choose their electricity retailer, but not the transmission operator or distributor [13].

The electricity retailer participates in the common Nordic electric power exchange market NordPool, on behalf of their customers. This wholesale market platform offers both a day-ahead and an intraday market, with the day-ahead market being the most relevant for small end-users. Here, all participants, namely retailers, producers, traders and large industries, place their bids and offers of price and quantity for each hour of the following day. These bids reflect the willingness to pay or sell for each of the participants. After the market closes at noon, all bids and offers are aggregated into supply and demand curves, and their intersection point determines the system price. The price is then the same for all participants. [13, 14]

The day-ahead market in NordPool partly takes into consideration the transmission grid constraints by utilising the area pricing method. There are currently 13 predefined pricing areas in the Nordic region, determined by the relevant Transmission System Operator (TSO). Norway is divided into five pricing zones. The TSO submits the transfer capacity between these areas before the bids and offers are placed for the following day, which then are taken into account when NordPool calculates the hourly area prices. If there is sufficient capacity between two areas, the areas will have the same price. If not, the area prices will differ, and the deficit area will end up with a higher price. [14, 15]

2.1.1 Grid Tariff

The price of the delivered electricity covers typically 30 % of the electricity bill for a Norwegian household. The rest of the charge includes grid rent and government taxes, covering respectively around 30 % and 40 % each [16]. This fee covers the operation, maintenance, grid development and taxes and is determined by each DSO. It is, however, regulated by The Norwegian Water Resources and Energy Directive (NVE) as they set a revenue limit for each grid operator. The grid rent traditionally consists of two terms, a fixed-term and an energy term. The fixed-term is a yearly cost [NOK/year] set independently of the energy consumed. As the most widespread tariff scheme in Norway today is the flat rate tariff, the energy term covers the energy delivered [NOK/kWh], but are set to be the same for all consumers, regardless of the time of use or how much power at a time.

In 2019, all households in Norway got installed smart meters, Advanced Metering System (AMS), in their homes. As these measure hourly electricity consumption in real-time, and enhance a bidirectional communication between the grid operator and the consumer, both consumer and operator now have access to more accurate data than ever before. This allows for new utility tariff structures and might lead to a more efficient grid usage and better opportunity for the consumer to take a more active part by, e.g. demand response.

NVE recently published a proposal for a new utility tariff structure for consumers connected to the low voltage distribution grid [17]. The proposal involves a structural change of both the current terms, as well as including a term for peak power. The energy term would be changed so that the consumer no longer cover the fixed expenses for the grid operator, but can include incentives for reducing peak power. The fixed-term would be more differentiated based on the consumer's need for grid capacity. The power term is proposed to be based on the consumer's daily peaks of power demand. The changes are suggested to take effect from 2022 and be gradually implemented until 2027. NVE expects these alterations to have little real changes in the total grid tariff for most consumers. It will, however, reduce some of the current benefits of installing rooftop solar, as this investment rarely reduce the owner's need for grid capacity. They further emphasise that the changes will give incentives for investments in smart technology, for smarter and more efficient use of the grid. This may, in turn, contribute to accelerating the transition to local electricity market structures. [17]

2.1.2 Prosumer Agreement

The Norwegian Energy Regulatory Authority defines a prosumer as a consumer with both consumption and production of electricity behind the grid connection point, where the production exceeds the demand for some hours and can be exported back to the grid [18]. This surplus must never exceed 100 kW and cannot be subject to a concession. By the prosumer agreement, the prosumers are exempted from paying the fixed term of the feed-in tariff and the utility grid tariff of what they export back to the grid.

The agreement also implies that the prosumer cannot trade their surplus directly with other end-users or participate in the wholesale market, but has to sell to an electricity retailer. With the predicted transformation of the power market to become more consumer-centric, however, this will likely change soon.

2.1.3 New Generation Retailers

With the recent advancements in ICT, new possibilities also emerge within power trading. An example is the digital platform Tibber, a fully digital electricity retailer [19]. An automatised smart software buys electricity for the customer at NordPool spot price without the additional costs usually added by the traditional retailers. Tibber has thus zero profit from trading power, but earns its money from a monthly subscription paid by the customer. Through an app, the customer can also get an overview of where their electricity originates and analyses of the composition of their consumption. With a focus on energy efficiency, the platform also provides smart charging and heating control. Through deals with DSOs and Statnett, their customers get discounts on electricity by providing flexibility assets in return. [19, 20]

As the prices of rooftop solar panels are rapidly declining, becoming a prosumer is more achievable for regular households. Otovo is another Norwegian company that aims to handle the whole process from planning to installation of PV panels. Additionally, it created an exchange platform called Nabostrøm, where its PV customers could exchange excess power with their neighbours. In case of deficit of solar generation, Otovo would buy power from the spot market on behalf of Nabostrøm's subscribers. The platform closed in 2019 as its services were merged with Tibber, but it is still considered one of the first steps towards a P2P market in Norway. [21, 22]

2.2 Local Electricity Markets

Theory regarding local electricity markets and P2P trading was covered in earlier work done by the author, exploring the potential of local energy markets between positive energy blocks in Trondheim [23]. The following subsections are thus mostly the same as in the previous project report. Subsection 2.2.4 is added at the end as a review of previous studies analysing the grid impacts of P2P trading, and to clarify the research gaps explored by this thesis.

2.2.1 Motivation behind Local Electricity Markets

As of today, the electricity market is structured with a top-down approach, forcing most prosumers to remain passive receivers. Prosumers will then mainly focus on their own self-sufficiency, with backup procurement from the grid, leading to sub-optimal utilisation of their DER assets. To fully harness the benefits of DERs, one would thus need to restructure the traditional market to be more consumer-centric [24]. This could be achieved through the establishment of local markets, a platform for trading surplus between prosumers and consumers for local balance and to manage load peaks, maximise flexibility assets and optimise the use of DERs, as defined by Backe et al. [25]. This would provide a higher level of energy independence, awareness, and control for the consumers, further enhancing market participation and demand-side management [8].

As for the security of supply, Brudermann and Yamagata [26] argues that local markets would decrease the dependency on the transmission grid, making the participants less vulnerable to potential outages. Both because small scale energy producers can offer emergency backup for others within the local energy community, and because by creating a cooperative energy culture, citizens are more likely to contribute to solving problems occurring in the community.

Another advantage is allowing market participants to choose how and where the electricity they buy is generated, which also allows for product differentiation, as proposed by Sorin et al. [27]. As more consumers would choose to buy low-emission and local energy, this would further boost the investments in renewable DERs.

2.2.2 Market Structures

There have been proposed many different organisational approaches for local energy markets in the literature, but most are primarily based on three main structures; *Full P2P markets, community-based* or *hybrid P2P market*. All these are again based on a P2P collaboration model. Sousa et al. [8] defines a peer to be anyone who owns or operates an asset of production, consumption or storage. In a P2P market structure, all peers can trade directly between each other through a local pricing scheme and then trade through a retailer to cover the remaining deficit or surplus. [8]

Full P2P Market

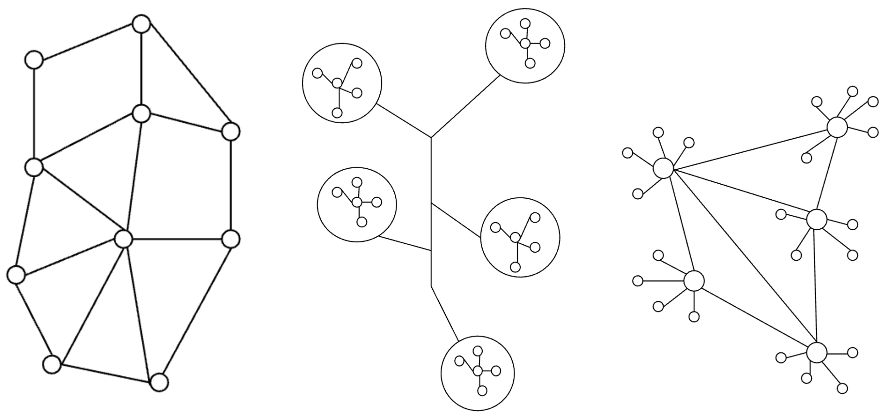
In a full P2P market, all market participants negotiate directly with each other without the need of supervision from a third party. Each of the peers optimises their own assets, minimising their costs of energy. By using such decentralised optimisation techniques, each agent's privacy is maintained as they have control of what information they share with other peers. A disadvantage with this approach is that an optimal solution for one peer is a suboptimal solution for the community [28]. Also, the scalability is a concern, as the computational burden may be too heavy with a large number of market participants [8].

Community Based Market

The community based market concept is based on the same principles as the P2P, but more structured. Here, each peer can choose to trade energy within the community or with other communities through a community manager. This manager optimises the operation for the whole community, using information from each unit. The manager also works as an interface between the local and the wholesale market. These communities' co-operation could be based on geographical location or just shared interests in energy collaboration [29], linked as virtual community energy pools. This strategy enhances citizen engagement, and the community manager can provide services as an aggregator for the grid operators. Also, when combining the surplus from all assets within the community, one could more easily meet the minimum capacity requirements that would otherwise not be possible for small stand-alone prosumers when trading with the global market [30]. A disadvantage with this strategy is the challenge of collecting information from each agent within the community and meeting the preferences of all of them [8].

Hybrid P2P Market

The hybrid P2P market approach is a combination of the two previous designs, also often called the "Russian doll" approach. Here communities and peers within each layer of the trading system may interact directly with each other. Individual, small-scale participants form energy collectives as proposed in the community-based approach, and these communities trade with each other, larger peers, and the wholesale market in a P2P manner. This is the structure that is most applicable to the power system of today [30].



(a) (b) (c)

Figure 2.1: Basic illustrations of the three described market designs. a) Full P2P, b) Community based and c) Hybrid P2P

2.2.3 Real-life Projects

Even though local energy trading is still a relatively new field, there are emerging some pilot projects for consumer-centric market models. One example is the Brooklyn Microgrid, a network of prosumers and consumers in New York who participates in a local energy marketplace through a mobile app. The prosumers are citizens with PVs installed and can choose to sell their excess energy through the local market or feed it back to the grid. The consumers set their daily budgets for energy purchase and buy energy from auction, similar to the traditional energy market. Surplus energy from EV charging stations is also made available for purchase on the local marketplace. The energy transactions are made through a blockchain platform called Exergy. [6]

In the Netherlands, the project PowerMatching City (PMC) has tested smart grid and local P2P trade application in Hoogkerk in different phases since 2007. Forty households are equipped with rooftop PVs, heating installations, energy storage, electric vehicles, and smart metering systems. The unique aspect of this project compared to the Brooklyn Microgrid is the utilisation of thermal flexibility assets, like heat pumps and heat storage, for demand-side management. A fully automated trading platform with dynamic pricing, the Power-matcher, optimises the operation and interests of all participants. This is a community-based approach where consumers, retailers, and the DSO can place bids. The market platform determines a balancing price after taking into account the day-ahead spot price, balancing market price, local transformer loading, and consumer preferences. [7]

2.2.4 Grid Considerations in Previous Studies and Thesis Contribution

Despite the increased focus on local markets in research over the last years, few studies have considered the impacts on grid operation. Zizzo et al. [31] evaluate power loss allocation due to energy exchanges using blockchain technology in a medium voltage network. Others, like Munsing et al. [32] and Baroche et al. [33] have utilised different versions of decentralised optimal power flow and grid utilisation costs strategies. None of these methods, however, explore the actual impacts on the grid, as they mainly focus on the market solutions obtained with the grid constraints integrated into the market optimisation.

Guerrero et al. [34] propose a method based on sensitivity analysis to evaluate the technical impacts caused by the P2P transactions in a low voltage network and to ensure that no network constraints are violated. They utilise sensitivity coefficients for voltage change, system losses and power distribution factors to predict the network state caused by each transaction made in the P2P market dispatch. The study provides an analysis of the network state after the grid constraints have been implemented.

Orlandini et al. [35] have conducted one of few studies performing a full AC power flow in order to analyse the grid impacts of P2P trading. An iterative methodology is proposed, which utilises product differentiation and artificial congestion tariffs to motivate market participants to avoid grid congestion. The study focuses on line congestion and how it changes under the proposed tariff scheme.

Differing from the work of Guerrero et al. [34], this thesis will mainly focus on the technical impacts of a non-interfered P2P market dispatch. An approach similar to the one of Orlandini et al. [35] is applied, but with a different market structure and a broader focus on voltage levels, losses and peak demand values. The study will also analyse different cases of DER and storage integration and perform parallel simulations of the system without local trading. This approach intends to get a more comprehensive understanding of the impacts of implementing a P2P market.

Chapter 3

Power Flow Theory

3.1 Distribution Network

The Norwegian electricity grid is divided into three different levels, depending on voltage; *transmission*, *regional* and *distribution*. The different voltage levels, total lengths and typical topology of the three grid types are presented in Figure 3.1. Traditionally, the transmission grid is what connects the producers with the consumers nationwide. Some high voltage production and consumption radials can also be connected to the regional grid, which connects the transmission and distribution grid. The smaller end-users, like residential and smaller commercial consumers, are supplied by the distribution grid. This grid is separated into a high and a low voltage level, divided at 1 kV, where most regular consumers are connected at 400 or 230 V. [36]

The low voltage distribution grid has several characteristics other than voltage levels separating it from the other parts of the national grid. As stated in Figure 3.1, the distribution grid has a mostly radial topology. The typical radial structure of a grid is illustrated in Figure 3.2. This structure is vulnerable to failure and outages, as all supply beyond the fault gets isolated [38]. As there is usually no generation on the low voltage side of the distribution transformer, the grid is modelled for a purely unidirectional flow, flowing from the transformer connection point and down the radials. This means that the voltages in the radials

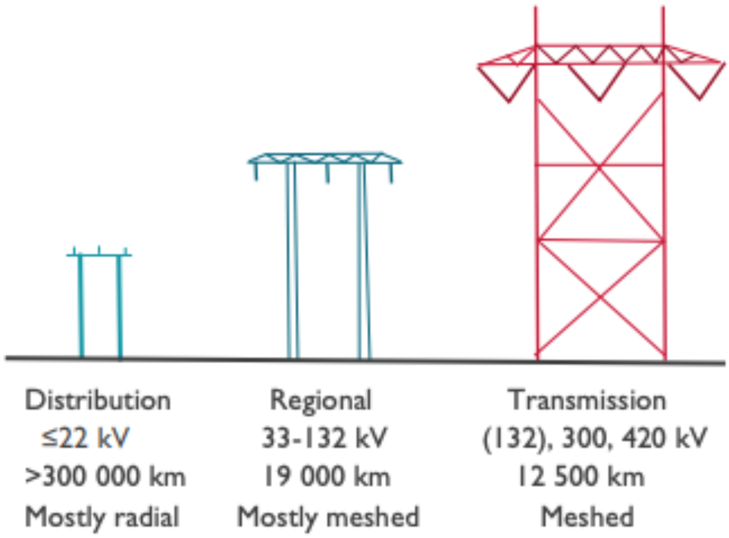


Figure 3.1: Illustration of the main three different electricity grid levels in Norway [37].

never exceed the feeder voltage and a common challenge is the low voltage levels some far-out nodes can experience. With the increasing penetration of local generation and storage, e.g. rooftop solar panels and batteries, new problems will thus arise for the DSO, with bidirectional power flows and higher voltage levels out in the radials.

Another distinct characteristic is its high R/X ratio making resistive terms no longer negligible, as they often are in simplified transmission models. As shown in a study of Szultka et al. [39], this leads to a higher voltage dependency on active power injections and less

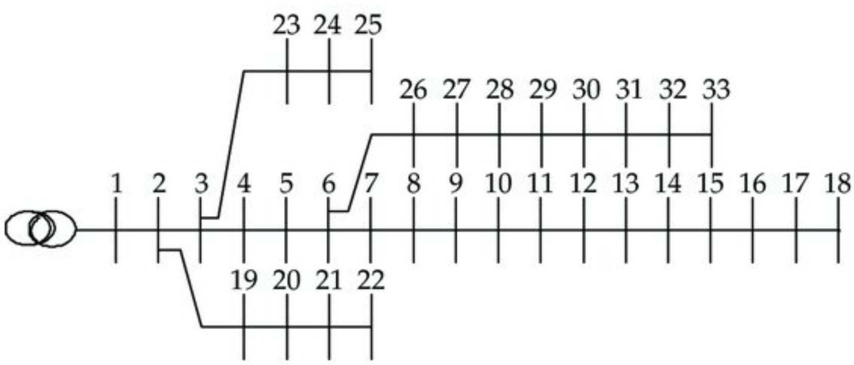


Figure 3.2: Single line diagram of IEEE radial 33-bus grid.

on reactive power, as opposed to the transmission grid where the voltage is assumed to be tightly coupled with reactive power injections.

Today, a large portion of the Norwegian distribution grid is characterised as weak, with high grid impedance levels. According to Kirkeby et al. [40] only 30-40 % of Norwegian grid customers are connected to a distribution grid with an equal or lower impedance than the reference value set by the International Electrotechnical Commission. This makes it vulnerable to big voltage drops between the distribution transformer and the end-user.

3.2 AC Power Flow

3.2.1 The Power Flow Problem

Power flow analysis, sometimes called load flow analysis, is used to evaluate a power system's behaviour under normal balanced steady-state conditions [41]. Standard power flow problems aim to determine the node voltages, active and reactive flows and losses, corresponding to pre-defined load and generation patterns. This is done by solving a set of equations of the form of

$$f(x) = 0 \tag{3.1}$$

expressing the nodal power balance equations as functions of unknown voltage quantities. All nodes in the system are categorised into three different bus types. One bus in the system is chosen to be the *slack bus*, the reference bus, where the voltage magnitude and angle typically are set to be respectively 1 Per Unit (p.u.) and zero. Nodes connected to generators are modelled as PV buses, meaning that the active power and voltage is predetermined and used as input data. The rest of the nodes in the system is referred to as PQ buses, typically load buses, with active and reactive power injections fully specified.

The most conventionally used technique is the Newton Raphson load flow, which is an iterative method of solving the nonlinear algebraic equations in the power flow problem, utilising the Jacobi matrix. This method, as well as its decoupled versions, are well developed for transmission networks. For distribution grids, however, some of these methods have shown to be inefficient due to the grid's distinct topology, with the high R/X ratio and radial structure [42]. To account for the specific nature of distribution grids unique power flow methods have been developed, with the forward/backward sweep method being the most popular. This is thus the chosen method in this thesis, and the next section will be used to describe the method more in detail.

3.2.2 Forward/Backward Sweep Method

The first step of the forward/backward sweep method is to carry out an element ordering process, to determine the calculation sequence of the sweeping procedure. This is done by dividing the network into different layers, starting with the slack node. The forward sweep then starts at the slack node and continues to the last ordered branches, while the backward sweep starts calculating at the last ordered node and goes back to the slack node.

There are three commonly used versions of the forward/backward sweep method; *current summation, power summation and admittance summation*. The chosen strategy determines which power flow equations to be used. In this thesis, the power flow summation method is chosen due to its alleged performance with Distributed Generation (DG) units integrated with the system [42]. This section will thus solely focus on describing the five main specific steps of this strategy. The following steps are based on the algorithm used in MATPOWER [43, 44], as this is the analysis tool further used in this thesis. The branch representation used to derive the power flow equations are depicted in Figure 3.3. Node i represents the sending end of the branch, while node k is the receiving end, meaning that the power flow is defined positive in the direction i to k. The subscripts t, f, d and s represents respectively receiving power, sending power, demand and series impedance.

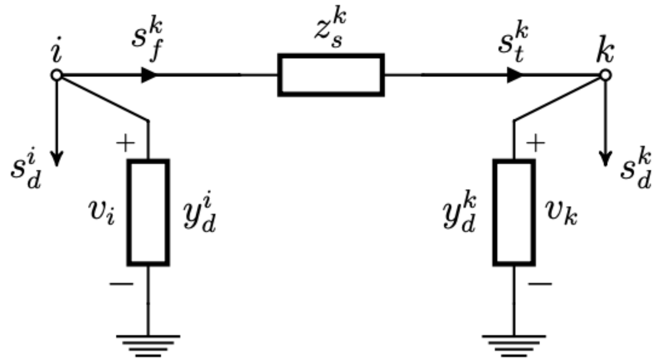


Figure 3.3: Representation of branch between sending bus i and receiving bus k [44].

Step 1: Set all voltages to 1 p.u.

Step 2: The apparent branch power flow at the receiving end (s_t^k) is set to be equal to the total demand at receiving end (s_d^k) and the power drawn by the shunt admittance (y_d^k) connected to bus k. n_b represents the total number of buses in the system.

$$s_t^k = s_d^k + \frac{(y_d^k)^*}{v_k^2}, \qquad k = 1, 2, \ldots, n_b \tag{3.2}$$

Step 3: *Backward sweep*: The sending end branch flows are calculated as the sum of the receiving end branch flows and branch losses by Equation 3.3. Power summation is performed starting from the branch with the biggest index and heading towards the branch connected to the slack node. Equation 3.4 adds the receiving power at bus k to the sending power of the corresponding branch.

$$s_f^k = s_t^k + z_s \cdot \left| \frac{s_t^k}{v_k} \right|^2 \qquad k = n_l, n_l - 1, \ldots, 2 \tag{3.3}$$

$$s_{t,new}^i = s_t^i + s_f^k \qquad k = n_l, n_l - 1, \ldots, 2 \tag{3.4}$$

Step 4: *Forward sweep*: The receiving end bus voltages are calculated with known sending power, voltage and series impedance.

$$v_k = v_i - z_s^k \cdot \left(\frac{s_f^k}{v_i} \right)^* \qquad k = 2, 3, \ldots, n_l \tag{3.5}$$

Step 5: Compare voltages derived in iteration ν with the voltages from iteration $\tau - 1$ using equation 3.6.

$$\max_{i=1,\ldots,n_b} = \left\{ \left| v_i^\tau - v_i^{\tau-1} \right| \right\} < \varepsilon \tag{3.6}$$

If the difference between the voltage magnitudes is greater than the specified error limit ε, more iterations are needed and the process goes back to step 2. In MATPOWER, the default tolerance is set to be 10^{-8}.

Chapter 4

Methodology

In order to analyse the technical impacts of P2P trading on the grid, a model was developed in MATLAB. A flowchart of the complete model structure is depicted in Figure 4.1. The market model is based on the work of Lüth et al. [9], with some modifications made to fit the scope of this thesis. The load flow analysis is performed with the open-source tool MATPOWER. Both these models, and the method for combining and automatise the execution of them, will be explained in detail in this chapter.

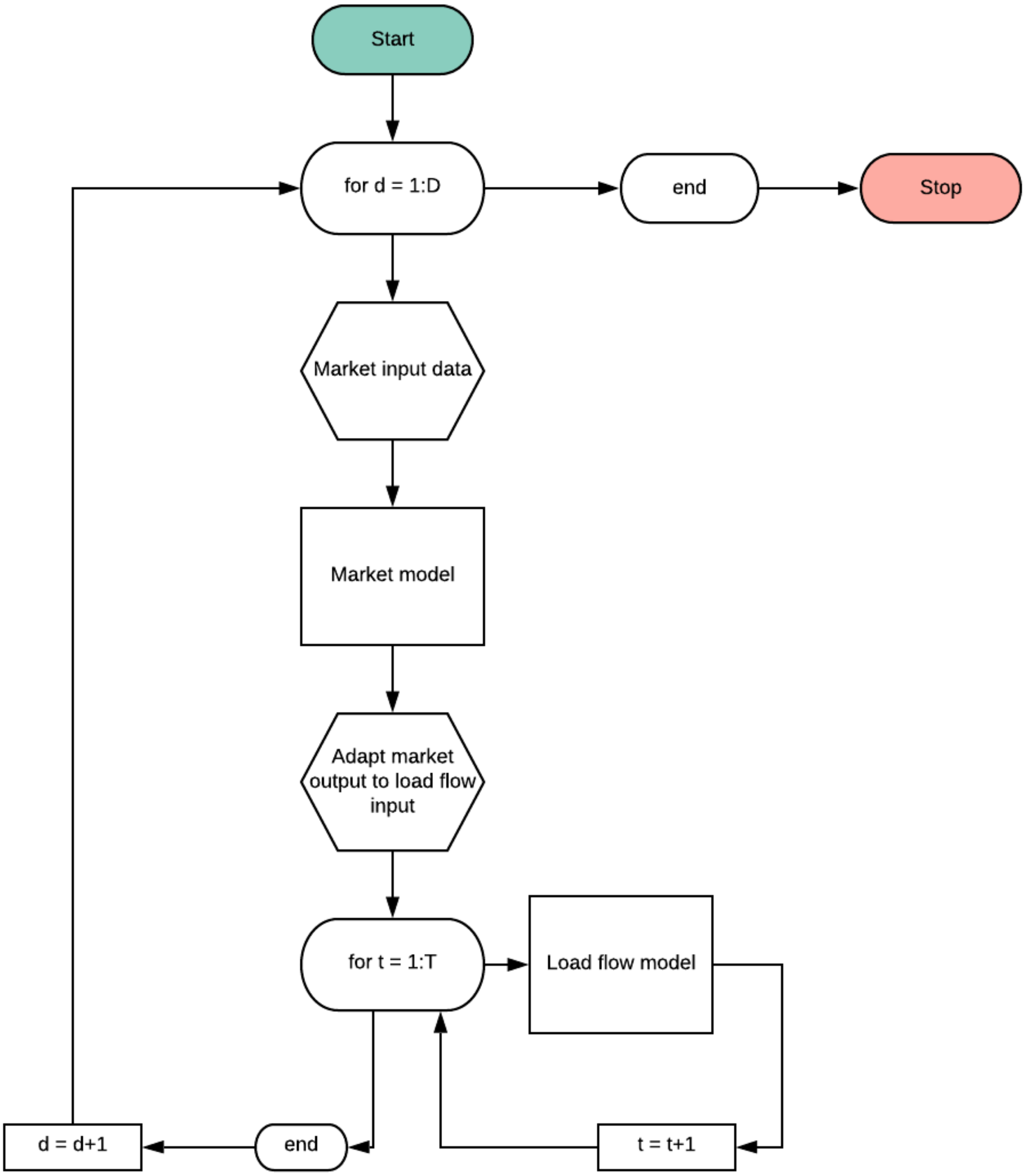


Figure 4.1: Flowchart of overall structure of main model.

4.1 P2P model

The P2P model used in this thesis is a multi-period linear programming model, based on the work of Lüth et al. [9]. With a community based P2P market structure, the objective function comprises the total electricity costs for the whole neighbourhood, subject to supply, demand, trade and storage constraints. Similar to the day-ahead market in the wholesale electricity market, the model finds an optimal solution for the next 24 hours based on predefined demand and supply quantities. The stochastic nature of a household's consumption, wholesale electricity prices or PV panel generation is not considered in this thesis and is assumed to be known for each time step. A nomenclature for the full version of the P2P optimisation model is presented in Table 4.1.

4.1.1 Objective Function

For all versions of the model used in this thesis, the objective function stays the same and is represented in Equation 4.1.

$$min \quad \sum_{h}\Big(\sum_{t}(c_{spot}^{(t)} + c_{en}) \cdot G^{(t,h)} - \sum_{t} c_{spot}^{(t)} \cdot \psi \cdot E^{(t,h)}\Big) \tag{4.1}$$

It aims to minimise the total costs related to the community's electricity consumption. As all P2P trade is happening within the community, and thus the price someone pays cancel out what someone earns, these costs are not included in the objective function. Compared to the objective function in the model of Lüth et al., grid tariff consideration and the possibility to sell electricity to the grid has been added. The fixed-term of the grid tariff is excluded from the total costs, as the peers are subject to this regardless of market structure. The energy term is, however, added to the costs of importing electricity from the grid. As stated in Subsection 2.1.2, prosumers are exempted from paying the feed-in tariff when exporting electricity to the grid. They do, however, have to pay for the possible extra losses occurring in the system due to their export. The total earnings of this action are thus set to be the wholesale spot-price multiplied with a system loss factor ψ. This factor is set to reflect the

Table 4.1: Nomenclature of P2P model

Sets		
$t \in T$	Hours t in time horizon T	hours
$h, p \in H$	Houses h and peers p in community H	-
$d \in D$	Days d in time horizon D	days
Scalars		
ψ	System loss factor	%
$\bar{s}/\underline{s}$	Upper/lower bounds of storage levels in battery	kWh
α/β	Maximum charge/discharge rate of battery	kW
η^C/η^D	Battery charging/discharging efficiency	%
c_{en}	Energy term of grid tariff	øre/kWh
α	Regression coefficient for total demand in time step t	-
β	Regression coefficient for total grid import time step t	-
γ	Regression coeffiecient for total PV generation time step t	-
Parameters		
$dem^{(t,h)}$	Demand of house h in time step t	kW
$res\_pv^{(t,h)}$	Electricity production from PV of house h in time step t	kW
$c_{spot}^{(t)}$	Wholesale spot price for electricity from the grid in time step t	øre/kWh
$S_0^{(d,h)}$	Energy storage level at beginning of optimisation period d	kWh
Variables		
$C^{(t,h)}$	Charge of battery at house h in time step t	kW
$D^{(t,h)}$	Discharge of battery at house h in time step t	kW
$S^{(t,h)}$	Energy storage level in battery of house h in time step t	kW
$G^{(t,h)}$	Electricity consumption from grid of house h in time step t	kW
$E^{(t,h)}$	Export to grid from house h in time step t	kW
$I_{p,p2p}^{(t,h\rightarrow p)}$	P2P electricity purchase of house h from peer p in time step t	kW
$X_{p,p2p}^{(t,h\rightarrow p)}$	P2P electricity sold by house h to peer p in time step t	kW
$I_{p2p}^{(t,h)}$	P2P electricity purchase of house h in time step t	kW
$X_{p2p}^{(t,h)}$	P2P electricity sold by house h in time step t	kW
$Losses^{(t)}$	Total system losses in time step t	kW

marginal loss rate of 5 % ($\psi = 95$ %) used by the DSO Tensio in the summer, which will be relevant for the area of the case studies [45].

Aforementioned, the individual P2P trading prices are not included in this model. With the chosen modelling approach, they are, however, assumed to be between the grid consumption price and the grid feed-in price. As the model optimises for the neighbourhood as a whole, it is more expensive to export the excess DER production, than to utilise it locally. This is due to the ψ factor on the one hand and the grid tariffs on the other for the peers that have to import electricity from the grid instead of using local PV generated electricity.

4.1.2 P2P Trading Rules

The P2P trading set up within the community allows for direct trade of electricity among all peers, regardless of an actual physical connection. The total amount of sold electricity through P2P trade $X_{p2p}^{(t,h)}$ from each house $h \in H$ for each time step $t \in T$ is defined by Equation 4.2.

$$X_{p2p}^{(t,h)} = \sum_{p \neq h} X_{p,p2p}^{(t,h \rightarrow p)} \qquad \forall t \in T, \forall h \in H \tag{4.2}$$

The total amount of purchased electricity through P2P trade $I_{p2p}^{(t,h)}$ is defined similarly by Equation 4.3.

$$I_{p2p}^{(t,h)} = \sum_{p \neq h} I_{p,p2p}^{(t,h \leftarrow p)} \qquad \forall t \in T, \forall h \in H \tag{4.3}$$

Both these equations are based on the assumption of Equation 4.4.

$$I_{p}^{(t,h \leftarrow p)} = X_{p}^{(t,p \rightarrow h)} \qquad \forall p \neq h \tag{4.4}$$

It is assumed that the P2P trade is limited to stay within the community, with the variable $E^{(t,h)}$ defining the potential surplus leaving the community. A constraint to ensure that the sum of sales made by P2P trade equals the sum of purchases is thus defined by Equation

4.5. Compared to the work of Lüth et al., there is no system loss coefficient included in this constraint, or in Equation 4.4. As the actual losses for each trade are found by performing a power flow analysis in this model, it was considered superfluous to have it in the market model as well.

$$\sum_h X_{p2p}^{(t,h)} = \sum_h I_{p2p}^{(t,h)} \qquad \forall t \in T \tag{4.5}$$

A central constraint in the model is the power balance equation, represented in Equation 4.6. This constraint ensures that the supply equals the demand at each house h at each time step t.

$$\begin{aligned} G^{(t,h)} + I_{p2p}^{(t,h)} + D^{(t,h)} + res\_pv^{(t,h)} \\ \geq dem^{(t,h)} + X_{p2p}^{(t,h)} + C^{(t,h)} + E^{(t,h)} \qquad \forall t \in T, \forall h \in H \end{aligned} \tag{4.6}$$

4.1.3 Battery Constraints

For the cases involving batteries, some additional constraints have to be added to the market model to control their behaviour. For each battery, there is an upper and lower bound in both State of Charge (SOC) and charging and discharging rate, represented by Equation 4.7, 4.8 and 4.9.

$$\underline{s} < S^{(t,h)} < \overline{s} \qquad \forall t \in T, \forall h \in H \tag{4.7}$$

$$0 < C^{(t,h)} < \alpha \qquad \forall t \in T, \forall h \in H \tag{4.8}$$

$$0 < D^{(t,h)} < \beta \qquad \forall t \in T, \forall h \in H \tag{4.9}$$

The SOC for each battery in each time step is also a function of the SOC of the previous time step and the charge and discharge of this time step. This is one of the main motivations of performing a multi-period optimisation as the decisions of time step t will depend on the decisions made in time step $(t-1)$.

$$S^{(t,h)} = S_0^{(d,h)} + \eta^C \cdot C^{(t,h)} - \frac{1}{\eta^D} \cdot D^{(t,h)} \qquad t = 1, \forall h \in H, \forall d \in D \tag{4.10}$$

Equation 4.10 represents the SOC calculation for the first time step (t=1) for each period d. Here, d represents the day in the overall time horizon D which are being optimised. At the first day, S_0 is set to be zero for all batteries, while S_0 for all consecutive days are set to be equal to $S^{(t,h)}$ at the last time step t of $(d-1)$. As the market model only finds the optimal solution for each period d, this battery behaviour creates a more realistic dependency between the periods. The SOC for the other time steps t within period d is defined by Equation 4.11.

$$S^{(t,h)} = S^{(t-1,h)} + \eta^C \cdot C^{(t,h)} - \frac{1}{\eta^D} \cdot D^{(t,h)} \qquad \forall t \neq 1 \in T, \forall h \in H, \forall d \in D \tag{4.11}$$

In the original model, the batteries were only assumed to be charged with excess power of the local DERs. In this study, the peers are allowed to perform arbitrage operations and charge their batteries with electricity procured from the wholesale market.

4.2 Power Flow Model

After the P2P model has found the optimal solution for the day d, the main model proceeds to the power flow analysis part. As previously mentioned, this part of the model is based on the open-source analysis tool MATPOWER 7.0 [43, 46]. In order to run a power flow analysis with this tool, a case struct is passed in as an input by one of the main functions *runpf*. This case struct must be set up as a specified MATPOWER case struct (mpc), which contains the necessary information for each node for one time step. The set up of this struct is illustrated in Table 4.2. It should be noted that only the data points used in this project are described in Table 4.2, as the mpc struct can include more information if required.

Table 4.2: Overview of mpc struct setup.

mpc		
bus	**gen**	**branch**
• Bus number	• Bus number	• From-bus number
• Bus type	• Active power generation	• To-bus number
• Active power demand, P_d	• Reactive power generation	• Resistance
• Reactive power demand, Q_d	• Max. reactive power	• Reactance
• Conductance	• Min. reactive power	• Susceptance
• Susceptance	• Rated voltage	• MVA long term rating
• Area	• Base MVA	• MVA short term rating
• Voltage magnitude	• Status	• MVA emergency rating
• Voltage angle	• Max. active power	• Transformer off turns ratio
• Base voltage	• Min. active power	• Transformer phase shift angle
• Zone		• Branch status
• Max. voltage		• Min. angle difference
• Min. voltage		• Max. angle difference

The *runpf* function also invokes the right solver, by taking in an options struct. As it was decided to use the forward/backward sweep method with power summation, based on the reasoning of section 3.2, the solver 'PQSUM' was called upon with the options struct. The load flow problem is then solved by the algorithm described in subsection 3.2.2.

After the *runpf* function is executed, the model returns a *results* struct. This struct contains the same information as the mpc-struct, but with corrected voltage values and additional information about the final branch flows. The discrepancy between the flows in each direction is used to determine the power losses in the system. As one of the terms always is defined negative, the losses in each branch are calculated by Equation 4.12. Here, i and k represents the nodes at each end of the branch, and H is the set of all nodes in the system.

$$P_{loss} = P^{(i \rightarrow k,t)} + P^{(k \rightarrow i,t)} \qquad \forall i,k \in H, \forall t \in T \tag{4.12}$$

4.3 Combining the Models

One of the main ideas in this thesis was to combine the two described models. As illustrated in Figure 4.1, the P2P model finds a global optimal solution for the 24 hours t within period d. The power flow is then executed for each hour of the market solution. As an output from the P2P model, we get the seven first matrices described under 'Variables' in Table 4.1. These must be adapted to fit the input requirements of the MATPOWER model, which is the net active and reactive demand at each node.

The net active power demand is assumed to be the sum of the capacity imported to the node minus the capacity exported from the node. Hence, for each house h the active power demand for each time step t is calculated by Equation 4.13. The battery charging and discharging is assumed to happen behind the connection point at each node and is thus not included in the net power injection calculation.

$$P_d^{(t,h)} = G^{(t,h)} + I_{p2p}^{(t,h)} - E^{(t,h)} - X_{p2p}^{(t,h)} \qquad \forall t \in T, \forall h \in H \tag{4.13}$$

Two of the output matrices from the market model, $I_{p,p2p}^{(t,h \to p)}$ and $X_{p,p2p}^{(t,h \to p)}$, are three-dimensional, indicating the individual trades for each time step. These must thus be summed over the third dimension, finding the total imported and exported for each house h for each time step t. $I_{p2p}^{(t,h)}$ and $X_{p2p}^{(t,h)}$ in Equation 4.13 represents these final sums.

4.3.1 Reactive Power Management

The P2P model only treats the exchange of active power and neglects the changes in reactive power caused by this exchange. However, the reactive power net injection at each node would likely be influenced by the trade as well. The net reactive power demand for each node must thus be calculated for each time step t. For simplicity, it was decided to find an average power factor for each of the nodes, and keep that constant for all time steps. The power factor can be described by the power triangle illustrated in Figure 4.2.

The power factor is given by the cosine of the angle ϕ. By trigonometric rules it can be

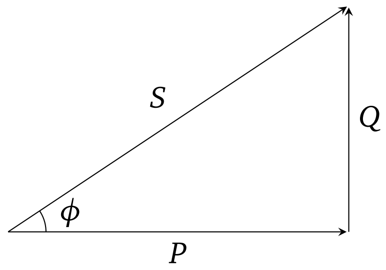


Figure 4.2: Power triangle.

expressed by Equation 4.14.

$$\cos\phi = \frac{P}{S} = \frac{P}{\sqrt{P^2+Q^2}} \tag{4.14}$$

From the given load data, it was obtained that all buses maintained a constant power factor of 0.98. The reactive power demand for each house h for each time step t was thus calculated with Equation 4.15.

$$Q_d^{(t,h)} = \sqrt{\frac{P_d^{(t,h)^2}}{\cos\phi^2} - P_d^{(t,h)2}} = \sqrt{\frac{P_d^{(t,h)^2}}{0.98^2} - P_d^{(t,h)2}} \qquad \forall t \in T, \forall h \in H \tag{4.15}$$

The output matrices from the market model include all operation decisions for each time step t within period d, for each node h. As the overall model is meant to perform a power flow analysis for each time step t, one individual mpc struct has to be made for each. Equation 4.13 and 4.15 is thus used to calculate the active and reactive demand for each node h for one time step t at a time, and update the mpc struct.

4.4 Pricing for Loss Reduction

As a final case study, it was important to investigate and test how market signals regarding system losses would affect the peers' decisions. The idea was to affect the decision of importing electricity from the grid in order to minimise the total system losses by finding an adequate relation between the two. As such, a regression was performed based on the loss time series obtained from the previous case simulations with the model described above. With this novel approach, a new constraint was included in the market model. Accordingly, the losses are computed empirically within the market model in a linear regression. These losses are a function of the dynamics of demand, grid imports (variable in the optimisation model) and PV generation. Hence, they will have the coefficients α, β and γ, respectively, based on the regression. Equation 4.16 represents this new constraint in the local market model.

$$Losses^{(t)} = \alpha \cdot \sum_h dem^{(t,h)} + \beta \cdot \sum_h G^{(t,h)} + \gamma \cdot \sum_h res\_pv^{(t,h)} \qquad \forall t \in T \tag{4.16}$$

The overall market model aims to minimise the total community costs. In order to minimise the system losses, they are thus included in the objective function, with allocated costs. It is assumed that the costs should reflect the costs of additional power needed to be imported from the wholesale market in order to cover the losses. Accordingly, the same costs are allocated to the losses as for the grid import. The updated objective function is given by Equation 4.17.

$$min \quad \sum_h \left(\sum_t (c_{spot}^{(t)} + c_{en}) \cdot (G^{(t,h)} + Losses^{(t)}) - \sum_t c_{spot}^{(t)} \cdot \psi \cdot E^{(t,h)} \right) \tag{4.17}$$

4.5 Completing the Loop

As the model performs a complete load flow analysis of each time step, it was also intended that it should be able to do a redispatch of the market if any of the technical constraints were violated. The concept is illustrated in the flowchart in Figure 4.3. In each time step, after the load flow analysis is complete, the node voltages are checked against the rated upper and lower limits. If any of the voltages falls outside of the admissible regulation band (typically ±0.1 p.u. from 1 p.u.), a set of new constraints are derived for that specific bus using sensitivity coefficients. These constraints are intended to limit the net injection of active power in that node, thus also constraining how much it can trade in that particular time step.

In this project, however, no such violations ever occurred in any of the simulations. It was thus not necessary to go through with the complete modelling of the loop. As this is likely just an exception due to the characteristics of the particular simulated cases in this thesis, the complete callback concept is included here for completeness of the model description.

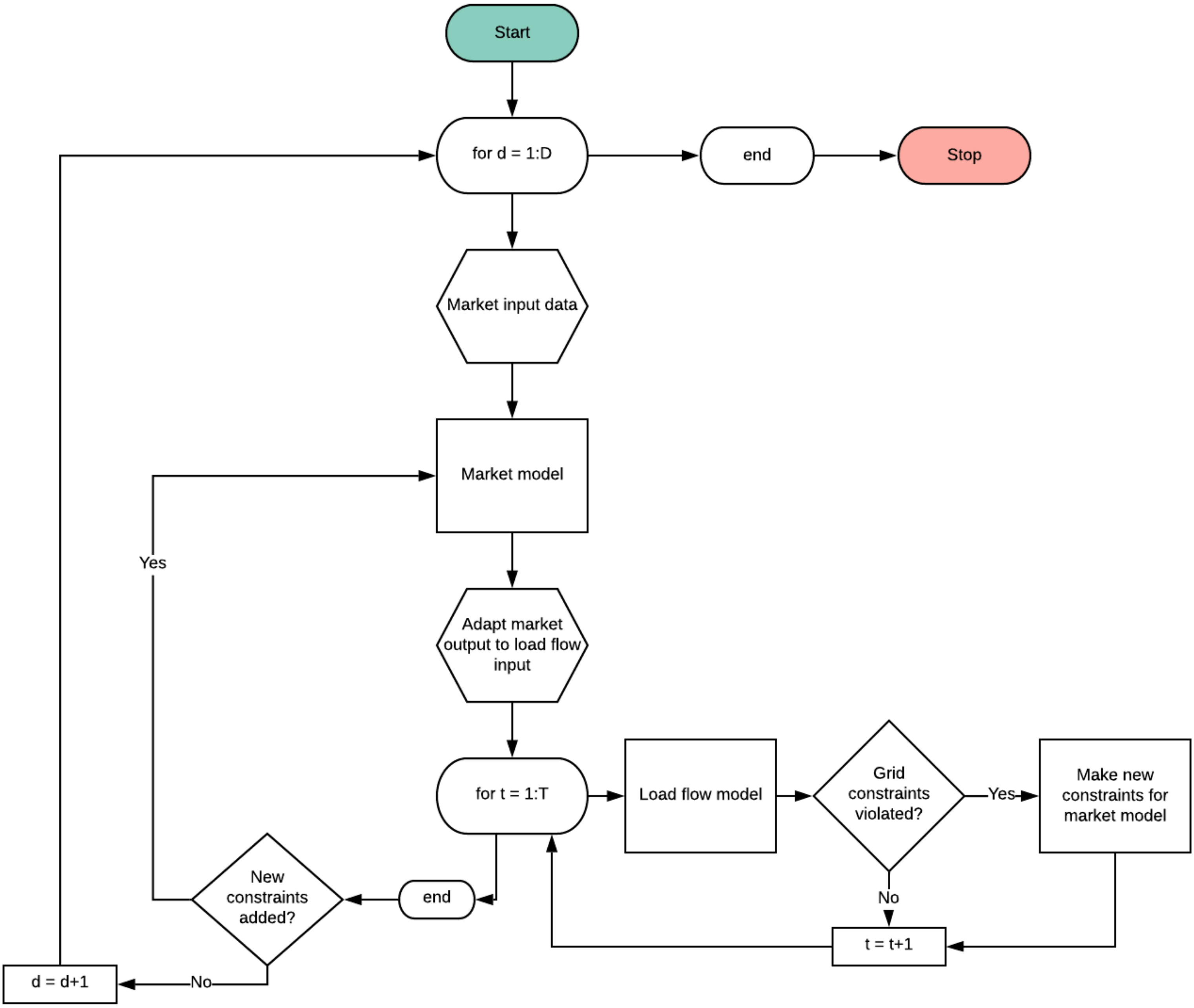


Figure 4.3: Flowchart of extended model with callback to market model.

Chapter 5

Case studies

5.1 Grid Description

The low voltage distribution grid used for all case studies in this thesis is based on data from a real distribution grid located in Mid-Norway. A single-line diagram of the network is depicted in Figure 5.1. The system is connected to the main grid through a 315 kVA distribution transformer, which was modelled as a cable in series connection between the main feeder and the external grid. The external grid was modelled as an infinite PV generator bus and was used as slack bus in the load flow analyses. The voltage magnitude of the slack bus was fixed to 1 p.u. = 230 V.

52 end-users are connected to the distribution grid, through 16 feeder lines. All these nodes, as well as the bus bars connecting the feeder lines with the end-user branches, were modelled as PQ buses. In total, including both PV and PQ, there are 70 nodes in the system.

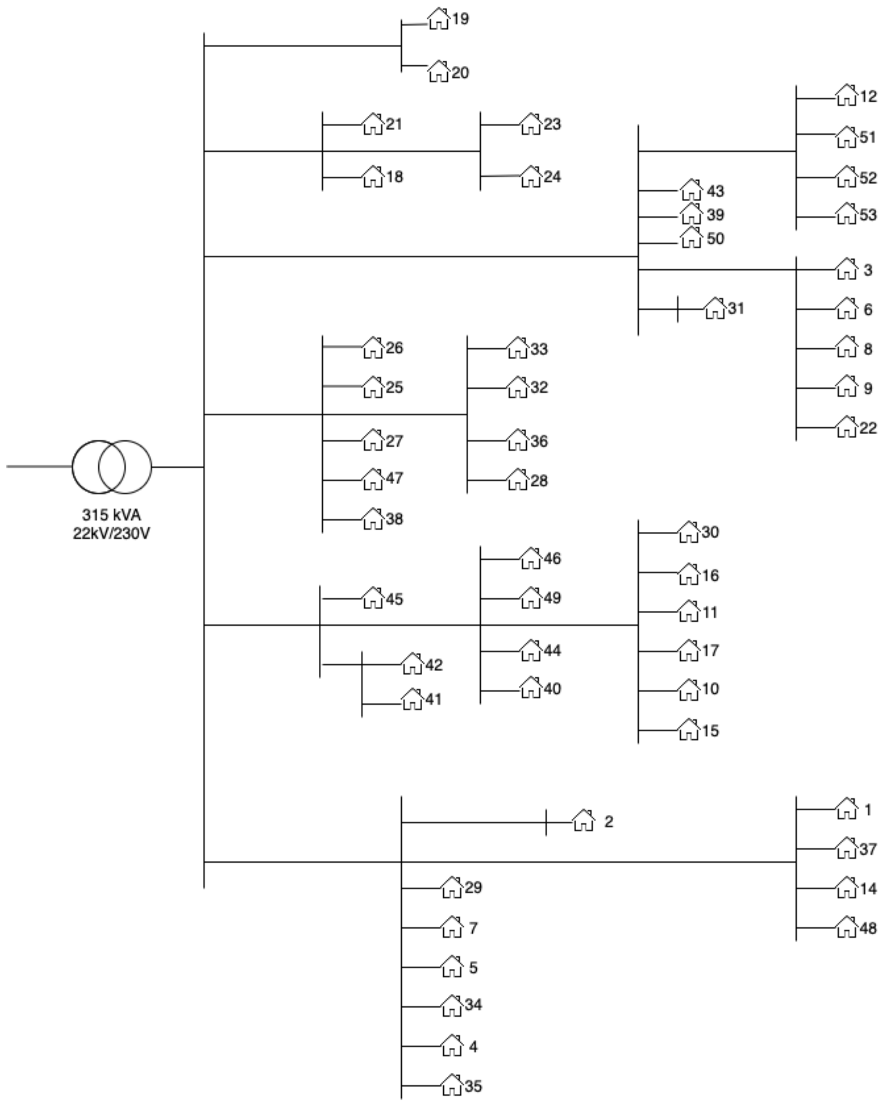


Figure 5.1: Single-line diagram of distribution system used in the case studies.

5.2 Case Descriptions

In this thesis, five different cases have been studied. This involves two different situations of DER instalment, as well as a reference case, and comparison of the impact of establishing a P2P market or not. In the following section, the different case studies will be described.

5.2.1 Reference Case

In order to get a complete understanding of the impacts of both integrating DERs and introducing a local market, a reference case was analysed. Here, there are no PV panels or batteries installed, and everyone buys their electricity from the wholesale market. This reflects the current situation in most Norwegian low-voltage distribution grids. As there are no other possibilities to cover the demand than importing from the global grid, there are no decisions to be made and thus no need for an optimisation model. Hence, the model described in Chapter 4 is reduced to only perform a power flow analysis for each time step.

5.2.2 System A

Now, it is assumed that some of the houses in the neighbourhood have invested in PV panels. The houses that have made the investments and the respective sizes of the installed panels are listed in Table 5.1. The installed capacity for each house is decided by their peak demand, regardless of geographical position in the grid. Two different cases are studied with this system setup. The setup will henceforth be referred to as System A.

Table 5.1: Size of PV installed on each house.

PV size	Houses
4 kW	4, 6, 7, 11, 12, 14, 16, 19, 26, 27, 29, 30, 52, 53
6 kW	9, 10, 18, 22, 23, 32, 34, 36, 38, 42, 45, 46, 48
8 kW	8, 39
10 kW	2, 20, 31, 50

No Local Market

In this case, each house can cover their demand by generation from their own PVs or buy from the grid. Each prosumer can also sell their excess electricity back to the grid, but not directly to any of its neighbours. Like in the reference case, there is no need for optimisation. Therefore, the amount generated by the PV at house h is subtracted from the demand of house h to find the net injection for the power flow model. All surplus is thus assumed to be fed back to the grid.

P2P Market

Now, the neighbourhood peers establish a local P2P market. The amount and location of PVs are the same as in the no market case, but now each peer can trade with each other. The prosumers are still able to sell their additional surplus to the grid. In order to analyse this case, the complete model from Chapter 4 is used, but without the battery constraints.

5.2.3 System B

Some of the peers that invested in PVs in the previous case have now chosen to invest in batteries as well. This mainly includes houses with the highest demand. They all invest in the same battery, which will be further described in subsection 5.3.3. Two different cases are studied with this system setup as well. The setup will be referred to as System B from this point.

Table 5.2: Houses with respective PV size installed. Red text indicates battery installed.

PV size	Houses
4 kW	4, 6, 7, 11, 12, 14, 16, 19, 26, 27, 29, 30, 52, 53
6 kW	9, 10, 18, 22, 23, 32, 34, 36, 38, 42, 45, 46, 48
8 kW	8, 39
10 kW	2, 20, 31, 50

No Local Market

The market strategy is similar to the corresponding case from the previous system setup. However, since some peers now own a battery, operation decisions are required for each time step. Therefore, the market optimisation part of the model is included, but without the P2P trading constraints.

P2P Market

With both PVs and batteries installed in the neighbourhood, the complete model described in Chapter 4 is used.

5.2.4 Loss Reduction Case

As introduced in Section 4.4, based on the results of the previous cases, a regression can be estimated to empirically calculate the losses as a function of grid imports, total system demand, and solar power production. The regression provides a function to calculate the losses within the market model and hence create a penalty or pricing (cost) of losses in the objective function. To be able to derive a statistically significant linear regression, various regression models were tested and analysed. Table 5.4 summarizes the regression model used in the pricing case: $Losses = \alpha \cdot DEMAND + \beta \cdot GRID_{Import} + \gamma \cdot PV_{Gen}$.

As can be seen in Table 5.3, the reported R^2 is quite high and has no significant deviation from the adjusted R^2. Statistically speaking, this provides high confidence in the regression accuracy. The R^2 value could perhaps be improved even further by considering non-linear components in the model or introduce discrete variables (e.g. peak time). However, this would make the optimisation model non-linear or integer. Therefore, it was preferred to have a linear regression model. Appendix A provides other linear regression models, showing that various alternatives were investigated and tested. Also, as noted in Table 5.4, all the regression coefficients report being statistically significant with a P-value lower than 0.001. This confirms that the regression model will provide an almost accurate calculation of losses.

Table 5.3: Regression Statistics

Multiple R	0.964707905
R^2	0.930661343
Adjusted R^2	0.928388534
Standard Error	0.476065793
Observations	504

Table 5.4: Regression Results

	Coefficient	Standard error	t Stat	P-value	Lower 95 %	Upper 95 %
Total Demand, α	-0.006587274	0.000522465	-12.60806486	7.54884E-32	-0.007613767	-0.005560781
Total Grid Import, β	0.021874802	0.000474945	46.05750318	3.3676E-182	0.020941672	0.022807933
Total PV Generation, γ	0.005376288	0.000662814	8.111305865	3.88639E-15	0.00407405	0.006678525

5.3 Input Data

Simulation period d is chosen to span over 24 hours t from noon to noon, similar to the day-ahead market. All input time series presented in the following sections is thus modified to fit this time horizon.

5.3.1 Demand Profiles

Data sets for the entire area were provided by Zaferanlouei et al. [47], including both demand for each house and technical grid specifications. The demand for each node was aggregated to fit a one hour time step to match the availability of solar data. Also, as the thesis intends to illustrate the differences in grid operation with different market structures, only 21 days during summer was extracted and used in the simulation. It is expected that the most significant differences will occur during summer, because of more local trading due to high PV generation. Figure 5.2 depicts the data used in the cases, reflecting the area demand during a 21 day period in the summer of 2012.

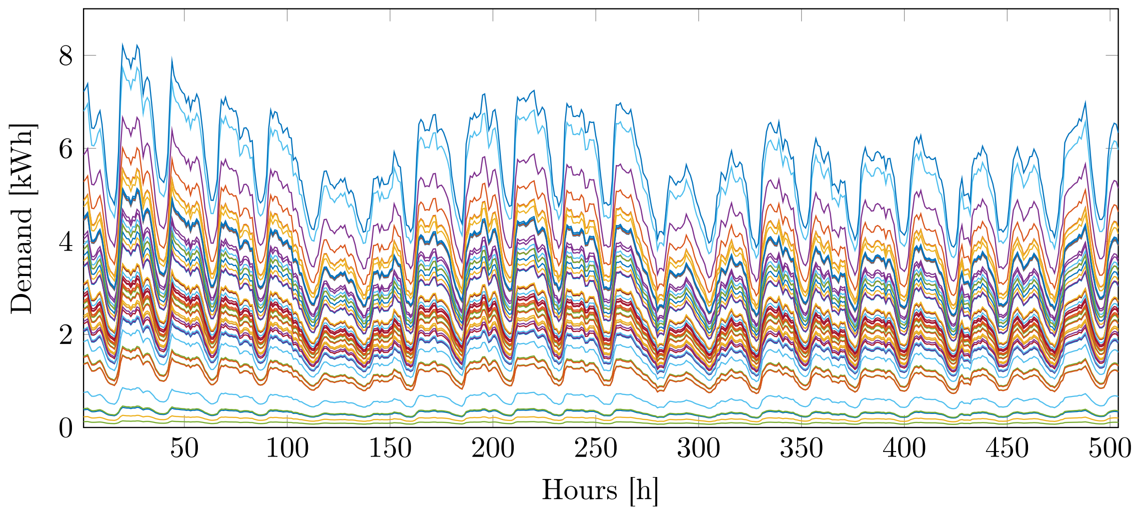


Figure 5.2: Demand profile for all nodes in the system for the 21 day simulation period.

5.3.2 PV Production Time Series

As the distribution grid is located in Mid-Norway, historical PV production time series for this area were obtained from the site renewables.ninja [48]. The site gets, in turn, its data set from the NASA MERRA-2 database which contains meteorological data for the area from 2019 [49]. As the years of the demand data and the PV data did not match, it was chosen to use arbitrary days from June and July in the PV data, to capture the effects of different degrees of irradiation. As recommended for the geographical area, a panel tilt of 45° was used. The complete time series for production from one south faced 1 kW PV panel, with an assumed system loss of 10 %, is shown in Figure 5.3.

As the period of analysis starts at noon the first day, one can observe from Figure 5.3 that the peak production is around noon for all the consecutive days. This corresponds well with the typical irradiation pattern. As this is historically measured data, variations due to weather changes are already taken into account, clearly illustrated by, e.g. the fourth day in the figure. However, to get some additional variations within the neighbourhood, the time series were modified with an exogenously given randomisation model. This model randomly generates numbers based on standard deviation from the historical PV data, and use these to rescale the output time series for arbitrarily chosen houses.

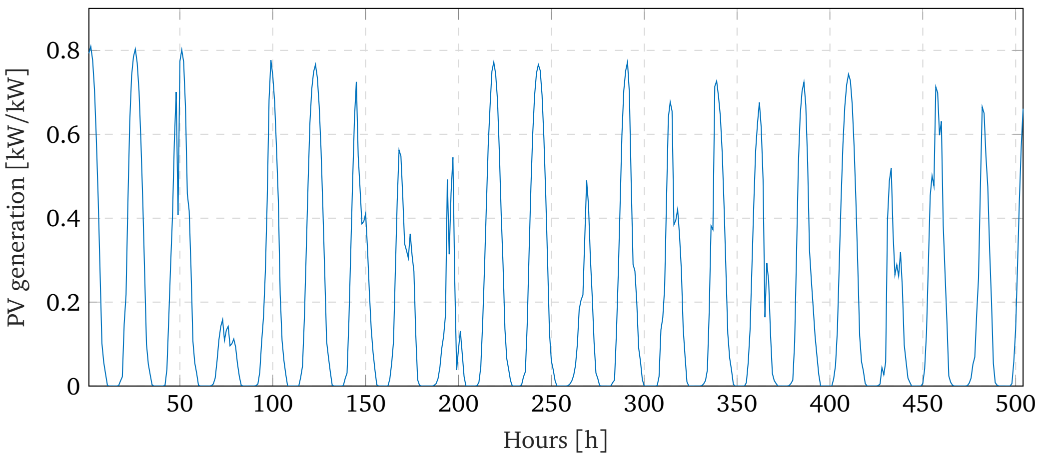


Figure 5.3: PV production time series.

5.3.3 Battery Specifications

All the houses that invest in batteries in the last two cases invest in the same battery; a Tesla Powerwall 2AC [50]. The technical performance specifications needed as input for the model are listed in Table 5.5. Both charging and discharging are constrained by an inverter of 5 kW nominal power, yielding full charge/discharge within 2.7 hours. As this thesis aims to analyse the technical impacts of the grid, technical details of the batteries are of secondary issues. As of this, no degradation processes are considered, and all efficiencies are assumed to be constant.

Table 5.5: Battery performance specifications [50].

$\overline{s}$, Upper SOC	13.5 kWh
$\underline{s}$, Lower SOC	0
α, Max. charge rate	5 kW
β, Max. discharge rate	5 kW
η^C, Charging efficiency	95 %
η^D, Discharging efficiency	95 %

5.3.4 Electricity Prices

The optimisation and following market decisions of the P2P model are highly dependant on the wholesale spot prices. In order to reflect the relevant geographical area, these prices are retrieved for the NordPool pricing area NO5, Trondheim. Historical time series are openly available at NordPool's website, and three weeks corresponding to the demand data, but from 2019, were used. It was decided to use a more recent price time series, as it would better reflect the conditions of today's market. The complete time series are presented in Figure 5.4.

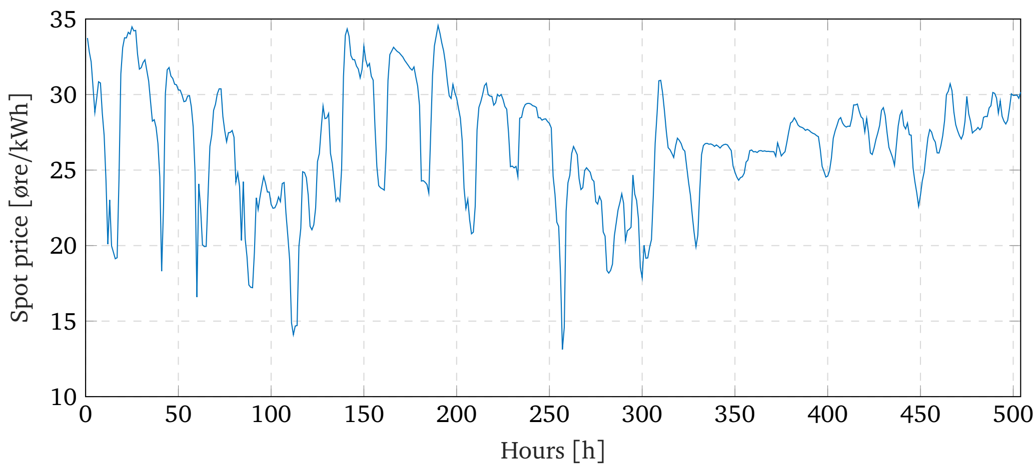


Figure 5.4: Spot price time series.

The grid tariff is determined by the local DSO, which in this case is Tensio AS. As of 2020, the energy term for households are set to 52.61 øre/kWh [51].

Chapter 6

Market Results

To better understand the results for the power flow impact, one must first analyse the market decisions made for the different cases. The results presentation of this thesis is thus divided into two parts; one for market results and one for grid impact results. In this chapter, the results from the market optimisation model will be presented, with a focus on the operation decisions for representative peers in the system. An overview of the economic disparities for the whole community will also be provided.

6.1 Local Trading

Figure 6.1 presents the total capacity traded through the P2P market scheme for the two cases of DER integration for each day of the simulation period. It is clear that with the presence of batteries, the amount traded within the community is almost twice as much in some days than without storage opportunities. For both cases, day six yields the most local trade and is thus chosen as exemplary for the following comparison of results in the thesis.

One can also observe from Figure 6.1a) that there are some days with no local trade in the case of only PV panels installed. This correlates with the PV generation profile presented in Figure 5.3, illustrated by, e.g. day 4 with little solar irradiation. In such situations, self-sufficiency will be a priority for the peers, and there is subsequently no local trading.

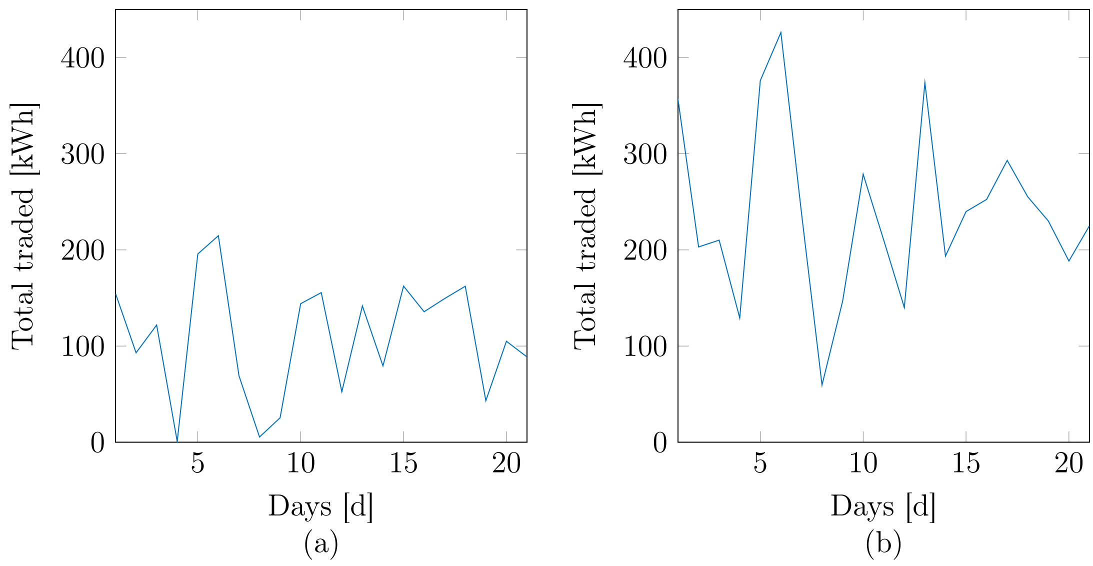


Figure 6.1: Total amount traded by P2P for a) System A and b) System B.

With batteries available, however, electricity is traded within the community every day, as depicted in Figure 6.1b).

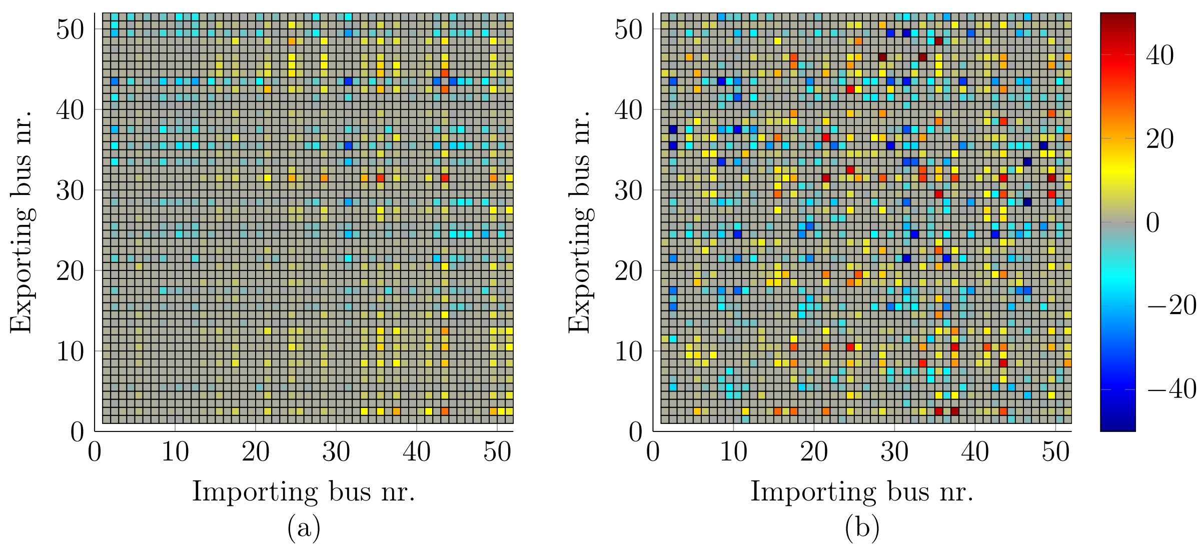


Figure 6.2: Total P2P trade between each node for a) System A and b) System B. Color bar values given in kWh.

Figure 6.2 provides an overview of the total trading between each peer throughout the simulation period. Negative values indicate import, while positive values indicate export. By studying the figure, one can see that more peers are active in the local market when batteries are installed. The batteries allow for price arbitrage and extend the trading period, thus allowing more peers to trade locally.

6.2 Operational Decisions

For the sake of showcasing the different operational decisions of the nodes, one arbitrary node from each peer category is chosen. Node 2 represent peers with both solar and storage, node 48 represents peers with PV only, and node 24 represent the pure consumer peers. The other peers in the same category show similar behaviour, mostly due to the uniform pricing scheme. It is important to note that the operational decisions are made according to the optimal solution at community level, not necessarily the optimum for each peer.

6.2.1 System A

In Figure 6.3, the pure consumers are represented by the house located at node 24. The figure depicts its supply/demand balance for day 6. It is evident that the consumer is able to exploit the lower P2P prices to cover its demand by P2P purchases when possible. With no storage available in the system, local trade is only possible when the PVs are generating electricity, and the consumer has no choice but to import from the grid during night time.

In Figure 6.4, representing the system's prosumers, it is clear that all surplus from PV generation is exported regardless of market structure. Comparing the two market schemes, one can observe that the same capacity is exported from the node, only differing in purpose. When a local market is present, the peer prioritises to sell its excess power within the community. There is, however, some export to the grid between noon and 2 pm, probably due to a saturated local market and lack of storage alternatives.

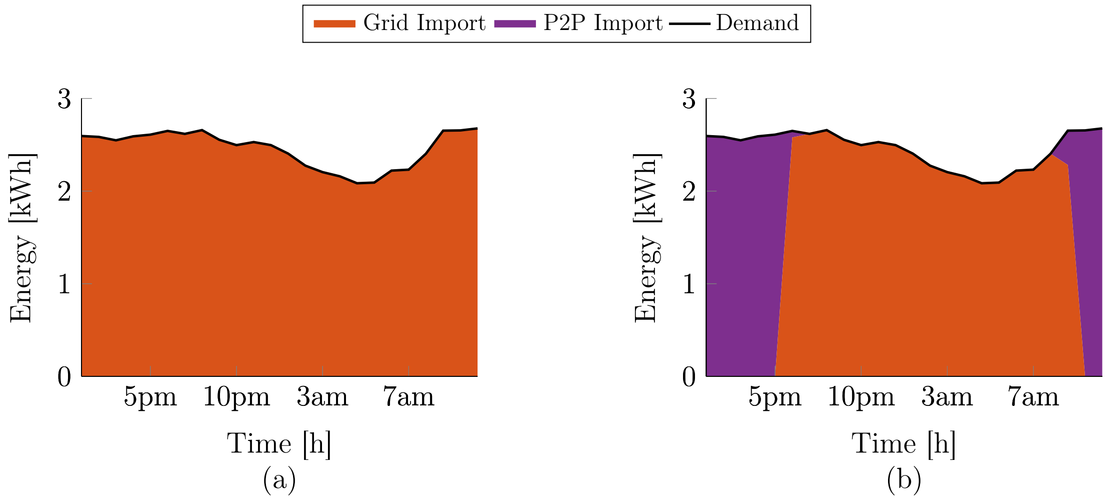


Figure 6.3: Operation of node 24 day 6 for a) No market case b) P2P case, System A.

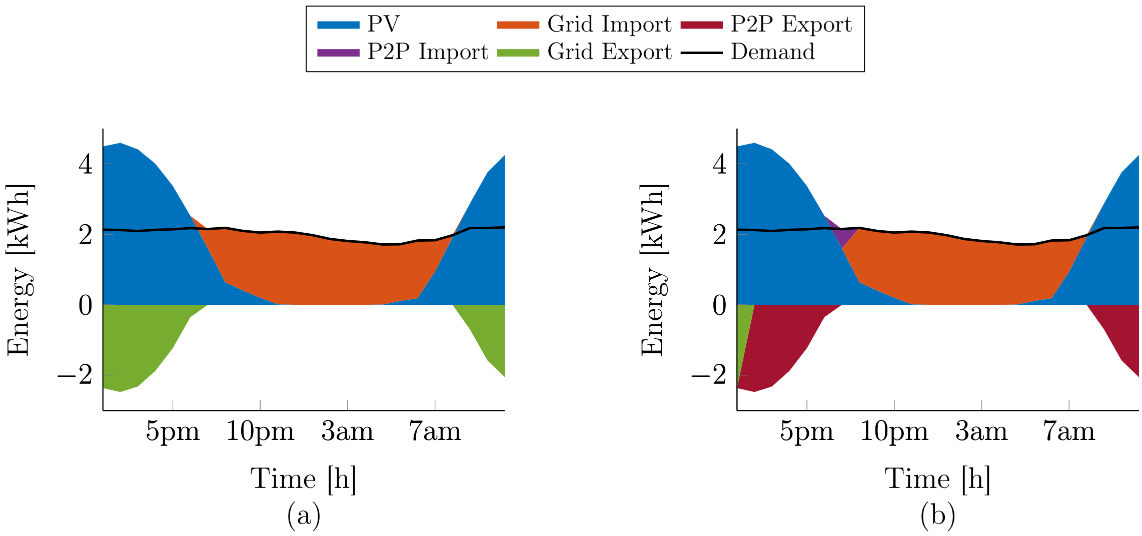


Figure 6.4: Operation of node 48 day 6 for a) No market case b) P2P case, System A.

6.2.2 System B

Some of the peers in the neighbourhood have now invested in batteries. From Figure 6.5, one can observe that even with no generation or flexibility of its own, the pure consumer now participates actively in the local market when given the opportunity. The peer goes from being a passive price-taker relying solely on wholesale grid import, to being able to take more active decisions of the origin of its electricity consumption in order to minimise its electricity bill.

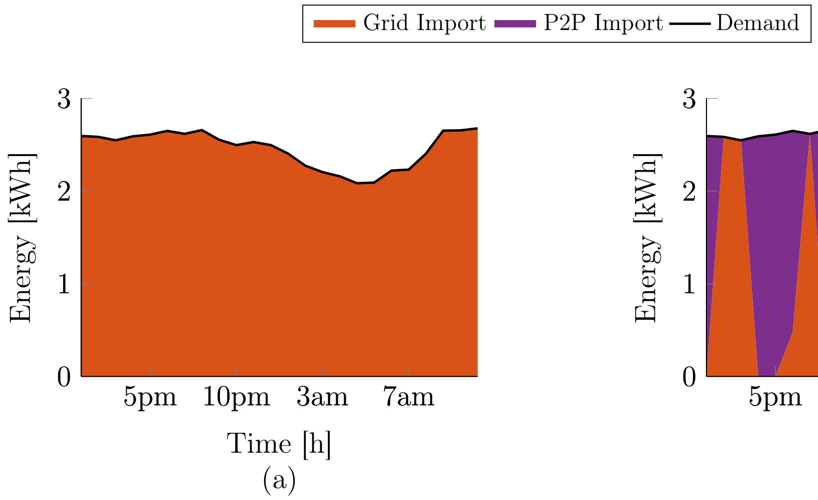


Figure 6.5: Operation of node 24 day 6 for a) No market case b) P2P case, System B.

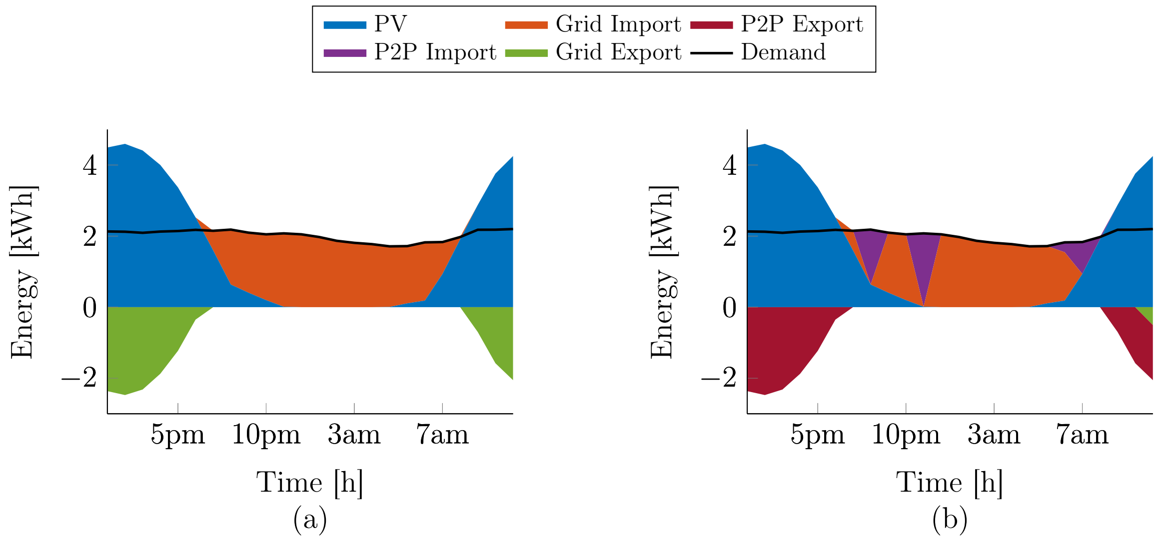


Figure 6.6: Operation of node 48 day 6 for a) No market case b) P2P case, System B.

Figure 6.6 shows the supply/demand balance at node 48 at day 6, representing the nodes with only PV panels installed. The following is observed:

- All surplus is exported in both cases. However, P2P trade is prioritised over grid feed-in in Figure 6.6(b).

- The peer relies on purchasing electricity from other peers during evening and morning when the P2P market is available. Comparing Figure 6.6(b) with Figure 6.7(b), one can assume that it imports electricity from peers with charged batteries.

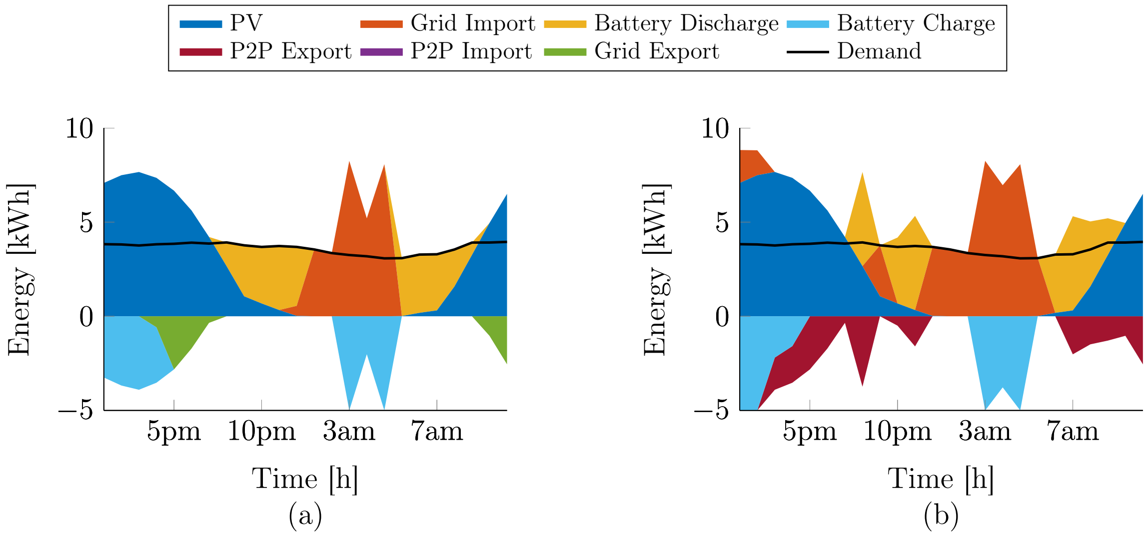


Figure 6.7: Operation of node 2 day 6 for a) No market case b) P2P case, System B.

From Figure 6.7, the following can be observed:

- For both cases, the peer is self-sufficient in times of PV generation and mostly self-sufficient by battery discharge in the evening and morning. During the night, the demand is covered by grid import.
- For both cases, surplus electricity is being exported and no PV generation is curtailed.
- When the peer has the opportunity to trade electricity locally, it prioritises this over grid feed-in.
- In both cases, the battery is charged by surplus PV generation during the day.
- For both cases, the peer imports electricity to charge the battery. With the P2P market, one can observe that the peer prioritises discharging its battery in order to sell locally, instead of using it for self-consumption.
- In the case of P2P, in Figure 6.7(b), the peer chooses to import from the grid despite having an excessive PV generation. One can observe that this imported capacity is used to charge the battery.

- For both cases, there is a maximum charging of 5 kW to the battery for a couple of time steps during the night. Studying Figure 6.8, it is clear that this correlates with the drop in spot price level. This indicates that it is profitable for the peers (community) to procure extra from the grid during this time-slot and save it for later self-consumption or local trade, even with a 10 % loss in the round-trip charge/discharge of the battery.

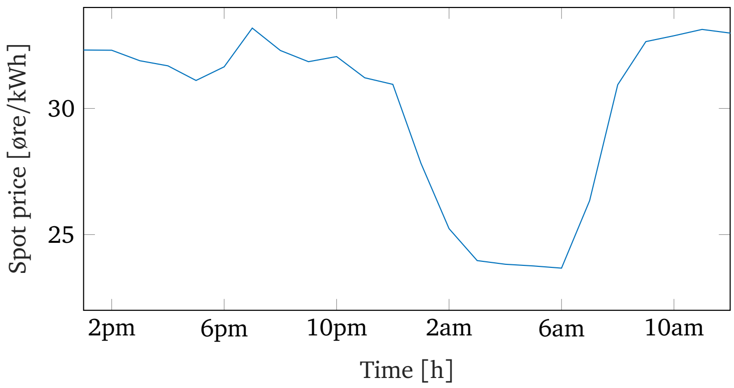


Figure 6.8: Spot prices for day 6 of simulation period.

6.3 Community Costs

To evaluate the effectiveness of the system operation one must look at the objective function value for each case. As the optimisation model aims to minimise the electricity related costs for the whole community, a lower objective function value indicates a more effective usage of local flexibility assets and P2P trade. In Table 6.1 the total community costs for the 21 day simulation period are presented for each case, and compared with the reference case. The share of expense and revenue from grid import/export is also given.

As can be noted from the results in Table 6.1, all cases with integrated DERs lower the total costs with around a third compared to the reference case. This is a natural consequence of the community relying less on centrally generated electricity, due to local production. The savings of establishing a P2P market is, however, of less eminence.

It is also clear that both cases with P2P market yields a lower dependency on grid import, as the community is able to utilise the locally generated electricity in a more efficient man-

Table 6.1: Comparison of total community costs for each case, given in NOK.

	Reference	**System A**		**System B**	
		No Market	P2P	No Market	P2P
Total costs	**51,971**	**36,007** (-30.71 %)	**34,766** (-33.10 %)	**35,219** (-32.23 %)	**34,293** (-34.10 %)
Costs No Market vs. P2P	-	-	-3.45 %	-	-2.63 %
Costs of grid import	51,971	36,695	34,847	35,644	34,303
Revenue of grid export	-	687	82	425	10
Total grid import [kWh]	65,236	46,361	44,061	45,442	43,875
Total grid export [kWh]	-	2,657	356	1,622	41
Total P2P trade [kWh]	-	-	2,300	-	5,026
Demand by grid	100 %	71.07 %	67.54 %	69.63 %	67.23 %
Demand by local DERs	0 %	28.93 %	32.46 %	30.37 %	32.77 %

ner. As the peers prioritise local trade over grid export, as seen in the previous section, the amount exported to the grid in both these cases are significantly lower than their corresponding cases with no local market.

Chapter 7

Grid Impact Results

In this chapter, results from the power flow analyses of the five cases will be presented. It will focus on voltage levels, peak grid consumption and system losses and is thus divided into these three focus areas. Lastly, the results from the case with the loss reduction pricing mechanism will be provided.

7.1 Voltage profiles

Four nodes have been chosen to illustrate the different impacts on voltage levels of the case simulations. They have been selected based on impact degree and location in the distribution network. All four nodes are placed at the end of its radials.

7.1.1 Reference Case

Figure 7.1 shows the voltage levels at the representative nodes for the sixth day of the simulation, when there are no DERs connected to the grid. Since the nodes are placed at the end of their respective radials, the voltages are always lower than 1 p.u. The voltage levels at each of the nodes are relatively stable for all time steps, with a slight increase at night when the load is lower.

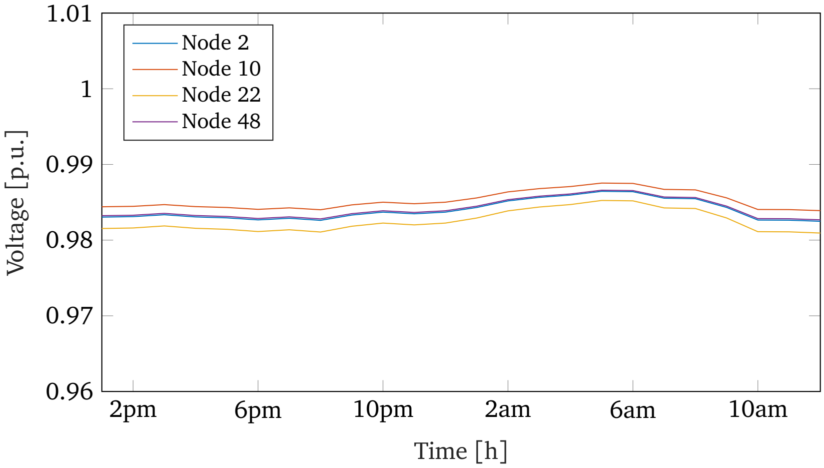


Figure 7.1: Voltage levels at representative nodes for reference case. Day 6 of simulation period.

7.1.2 System A

The voltage levels at the representative nodes when PV panels are installed are presented in Figure 7.2. As can be expected, the voltages rise correspondingly with the PV production at the nodes, reaching a level above 1 p.u. at the peak generation hours. The results are identical for both market cases for the entire simulation period. This is due to the net load being the same at each node for each time step, as the same amount is being imported and exported regardless of market scheme. Hence, only one graph is included here.

7.1.3 System B

No Local Market

Since the batteries are allowed to be charged from power imported from the grid, the load at the corresponding node increases at the time of charging. With the wholesale spot prices being lower at night, this is a natural choice of charging time for battery owners. The effects can be seen in Figure 7.3 with quite significant voltage drops between 3 and 5 a.m.. All charging power is imported from the grid due to no PV generation at this time.

Here, one can also observe the effects on the nodes without private batteries. Node 48, as

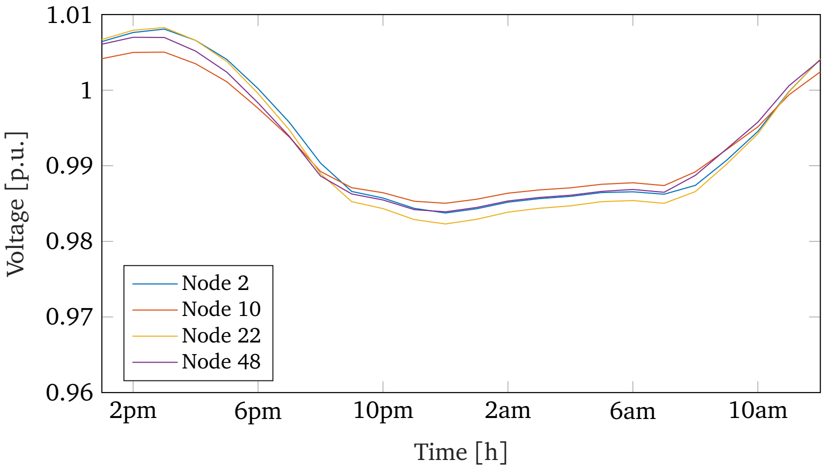


Figure 7.2: Voltage levels at representative nodes for System A cases, day 6 of simulation period.

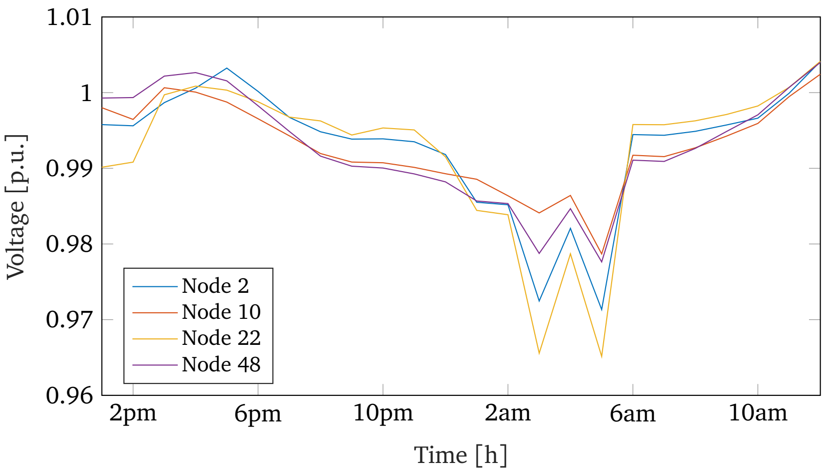


Figure 7.3: Voltage levels at representative nodes for System B case with no local market. Day 6 of simulation period.

illustrated in Section 6.2, and none of the other nodes sharing its closest feeder line owns a battery. Nonetheless, it is clear from Figure 7.3 that its voltage levels are affected by the batteries in the radial charged closer to the transformer, e.g. at node 2.

P2P Market

The voltage profile in Figure 7.4 shows some of the same tendencies as the profile in Figure 7.3, with significant drops between 3 and 5 a.m. However, the voltage at each node tends to fluctuate more when power is traded within the community. This is especially evident between 6 and 10 p.m. when the demand is high and PV generation is low, and power is traded locally by discharging local batteries.

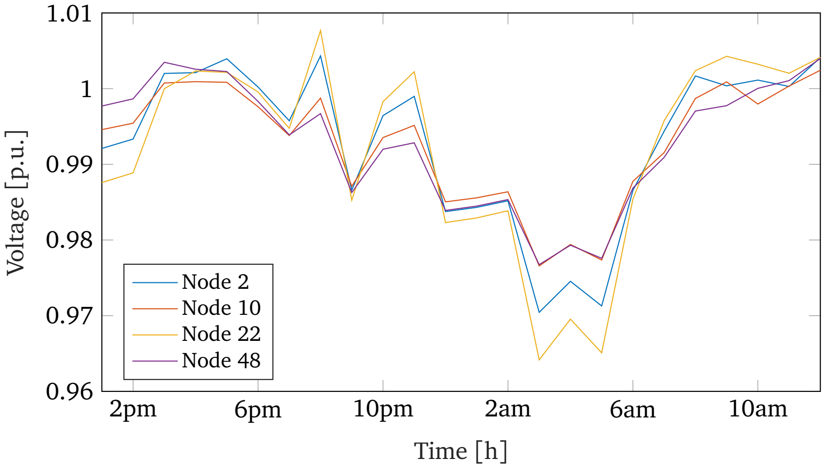


Figure 7.4: Voltage levels at representative nodes for System B case with P2P market. Day 6 of simulation period.

7.2 Peak Grid Consumption

As the distribution network must be dimensioned for peak capacity, this value is of great interest for the local DSO. In Table 7.1, peak demand and total grid consumption are presented for all cases. The values stated for peak demand represents the neighbourhood's maximum total demand for import from the external grid in one time step, via the transformer. It is clear from the table that the installation of roof-top PVs reduces the peak demand for both market strategies. The peak value does, however, increase significantly with the integration of batteries. Now, there is no difference between the market structures. At times with low spot prices, and little PV generation, situations can occur where households consume power both for their regular demand and for battery charging. The consequence can be seen in Table 7.1, with an increase in peak consumption value of 19.19 % compared to the reference case.

In the reference case, the peak consumption hour happens at 2 pm on the second day of the

Table 7.1: Comparison of peak consumption for each case.

	Reference	System A		System B	
		No Market	P2P	No Market	P2P
Peak grid consumption [kWp]	185.95	160.42	160.42	221.64	221.64
Compared to reference	-	−13.73%	−13.73%	+19.19%	+19.19%
Total grid consumption [kWh]	65,236	46,361	44,061	45,442	43,875
Compared to reference	-	−28.93%	−28.93%	−30.34%	−32.74%
Demand by grid	100 %	71.07 %	67.54 %	69.63 %	67.23 %
Demand by local DERs	0 %	28.93 %	32.46 %	30.37 %	32.77 %

simulation period. In Figure 7.5, one can observe how the integration of DERs and storage has shifted the grid consumption profile this day. Here, one can clearly see the differences stated in Table 7.1. The grid consumption of the cases of System A is never higher than the reference case and matches the reference level during the night. The peak grid import of the cases of System B is, however, shifted to the early morning hours and is much higher than the reference case. A similar profile is obtained for all the other days of simulation.

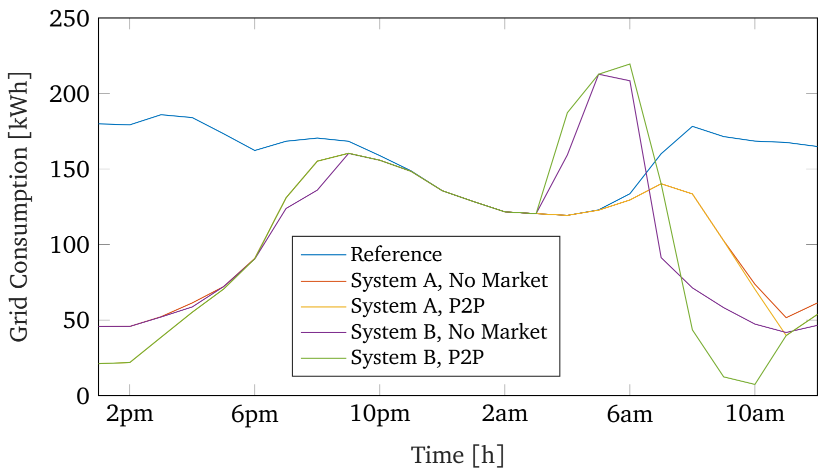


Figure 7.5: Illustration of grid consumption for all five cases for day 2 of simulation period.

Figure 7.6 shows the duration curve for grid import for all five cases. In line with the values in Table 7.1, the peak consumption for the cases of System B are the highest. There are, however, not many hours of the simulation period that requires this high capacity, and both curves descend quite steeply. Now, one can also observe a difference between the trading schemes with System A, as the P2P curve is slightly steeper. For both cases of P2P trading, several hours in the period requires no import from the external grid. This implies that the community can utilise the local assets more efficiently with a local market in place. It is also confirmed by the results in Table 7.1, with the demand covered by DERs given in percentage.

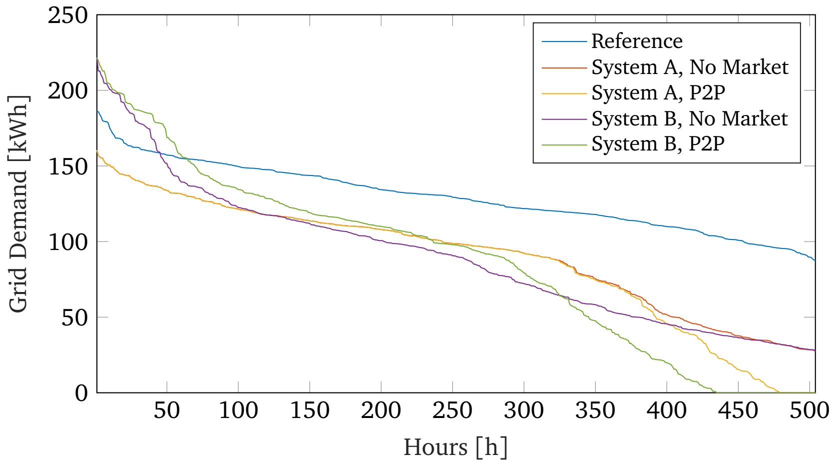


Figure 7.6: Duration curve for all five cases.

7.3 System Losses

An essential motivation for integrating DERs in the distribution network is the prospect of reducing the total system losses. A focus in this project was thus to investigate if establishing a P2P market would further enhance or diminish these positive effects of DERs. Note that the system losses analysed in the following sections refer to the losses within the low-voltage distribution network. The effects on losses in the higher-level grid will be addressed in Chapter 8. Similar to Section 7.1, the sixth day of the simulation period will be in focus.

7.3.1 Reference Case

The total losses for day 6 for the reference case are depicted in Figure 7.7, to illustrate how both integration of DERs and local electricity trading affect the system losses. One can observe that the amount of losses is higher during the day and lower during the night. This correlates with the grid usage, as there is higher total demand during the day and lower at nighttime. All other days within the simulation period show the same tendency.

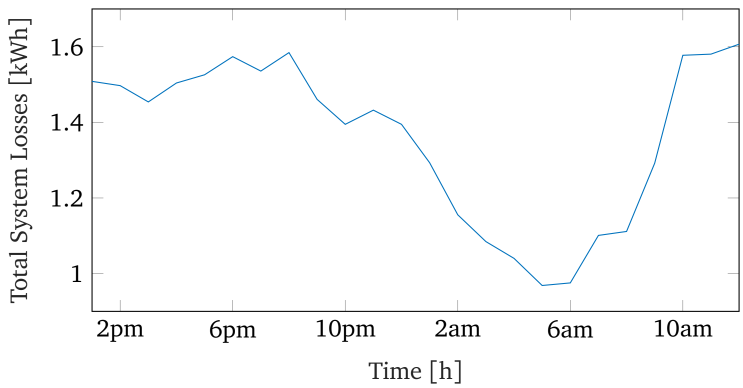


Figure 7.7: Total system losses for reference case, day 6 of simulation period.

7.3.2 System A

As the neighbourhood invests in PV panels, the system behaviour in terms of system losses changes significantly. The total system losses for the sixth simulation day is presented in Figure 7.8. Compared to the reference case, the shape of the curve has an almost opposite tendency, with high system losses during the night and low during the day. This correlates with the PV production profile and confirms that self-consumption from private DERs during production hours is prioritised among the peers in the absence of storage alternatives. With a higher degree of self-sufficiency, there is less need for transfer capacity in the distribution grid and hence fewer losses.

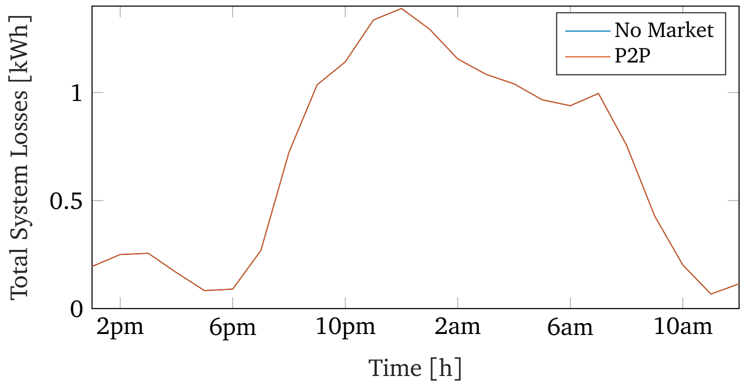


Figure 7.8: Total system losses for System A cases, day 6 of simulation period.

One can also observe that there are no differences between the two market strategies. This is true for the whole simulation period. Without the opportunity to store any excess electricity, the only other option than curtailing is to export. The identical system losses behaviour is a consequence of the power flows in the system being the same regardless of the trading scheme, as the nodal net loads are identical for both cases.

7.3.3 System B

When batteries are installed in the neighbourhood, the effect of the chosen market strategy becomes more evident. As can be observed from Figure 7.9, the curve shares some of the same tendencies as with the System A cases, with a high amount of losses during the night and low during the day. However, compared to Figure 7.8, the period with higher losses in Figure 7.9 is shorter and the quantity is bigger.

Now there is also a distinct difference between the case of P2P trade and the case with no local market. Due to different operation of the batteries, the distribution line usage also varies between the cases. As observed from the individual operational decisions in Section

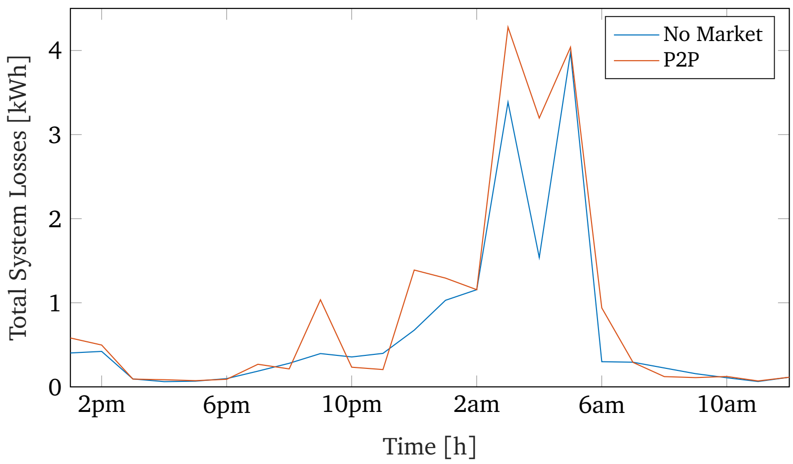


Figure 7.9: Total system losses for System B cases, day 6 of simulation period.

6.2.2, a peer with batteries will often sell stored energy locally rather than using it for self-consumption, and the grid is thus used more. Accordingly, this leads to more losses compared to the case with no local market.

In Table 7.2, a comparison of the total system losses of all five cases are presented. These numbers represent the total losses over the entire simulation period of 21 days. With the high degree of self-sufficiency in all cases involving DERs, it is clear that the losses decrease significantly compared to the reference case. Still, for the cases of System B, a P2P market structure leads to 13.79 % more losses than with no local trading. Note that with a 90 % round-trip efficiency of the batteries, the losses induced by charging/discharging is of quite a significance. These are additional to the total system losses.

Table 7.2: Comparison of total system and battery losses for each case.

	Reference	**System A**		**System B**	
		No Market	P2P	No Market	P2P
Total system losses [kWh]	937.15	517.96	517.96	566.36	644.47
Compared to reference	-	−44.73%	−44.73%	−39.57%	−31.23%
No Market vs. P2P	-	-	0%	-	+13.79%
Battery losses [kWh]	-	-	-	581.69	650.70

7.4 Loss Pricing Case

In this case, the additional constraint and updated objective function presented in Section 4.4 and 5.2.4 is applied to the model. The case simulated with this model is the P2P market with the System B setup. As can be noted from Table 7.3, the actual losses calculated with the power flow model output is reduced with 4.67 % compared to its corresponding case without the price signal. The total losses are still more than in the corresponding case of no market, but the difference between the losses yielded with a P2P market and no market is reduced by 38.51 %.

Table 7.3: Comparison of results for cases of System B, with and without loss pricing.

	System B without pricing		**System B with pricing**
	No Market	P2P	P2P
Power flow model losses [kWh]	566.36	644.47	614.39
Compared to No Market Case	-	+13.79%	+8.48%
Compared to P2P case	-	-	−4.67%
Market model losses [kWh]	-	-	646.12
Battery losses [kWh]	581.69	650.70	615.88
Total grid consumption [kWh]	45,442	43,875	43,890
Total grid export [kWh]	1,622	41	63
Total P2P trade [kWh]	-	5,026	3,794
Total costs [NOK]	35,219	34,293	34,327
Total costs of grid import [NOK]	35,644	34,303	34,343
Costs of losses [NOK]	-	-	502

The total consumption of electricity procured from the grid is almost the same for both P2P cases, as seen in Table 4.4. The total community costs of the pricing case represents the objective function value subtracted the costs of losses, and are almost identical to the original P2P case costs. By percentage, the total costs of losses are small to the total community costs. There is also a significant decrease in the total amount traded locally, along with a decrease in losses induced by the batteries. These results indicate that the community values self-consumption among the peers over P2P trade with this pricing scheme, as well as less price arbitrage with the batteries. There is also a slight increase in grid export, possibly to compensate for the additional costs induced by the losses.

As the total system losses are included as a variable in this version of the model, the losses calculated by the regression constraint can also be analysed. As can be seen in Table 7.3, this value is a about 5 % higher than the losses calculated by the power flow model. The value is about the same as the power flow losses from the P2P case without the pricing scheme.

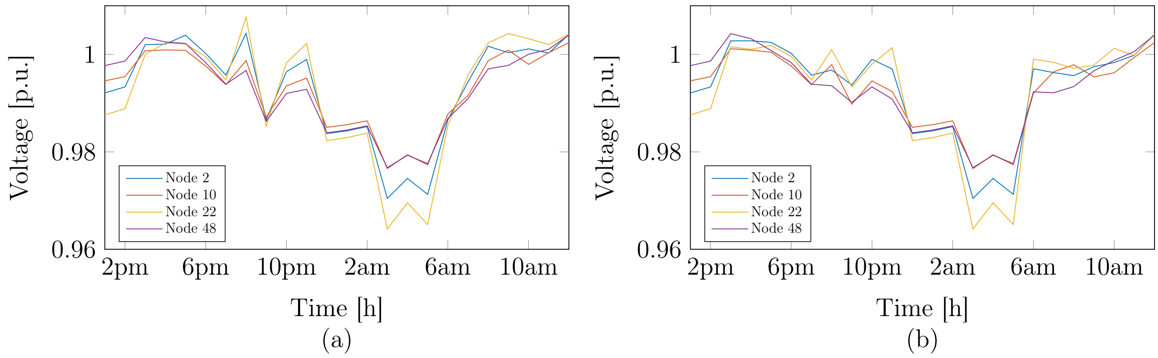


Figure 7.10: Comparison of voltage levels for (a) P2P without pricing and (b) P2P with pricing, day 6.

Figure 7.10 depicts the changes in voltage levels caused by the pricing scheme. As one can observe, some of the most considerable fluctuations that occurred in the original P2P case are slightly dampened. The drop during nighttime is, however, unchanged. This is a consequence of less local trading and an almost unaffected charging behaviour. The peak demand value remains unchanged, at 221.64 kWp.

Chapter 8

Discussion

The purpose of this study was to evaluate the technical and economical impacts of establishing a P2P market within a low-voltage distribution grid. In this chapter, the results of Chapter 6 and 7 will be discussed with this purpose in mind. Validation of the methodology and assumptions used in the study will also be provided.

8.1 Comparison of Case Studies

In this thesis, five different cases were explored. This includes a reference case representing today's situation, and two instances of DER integration with a case of no local market and a case of P2P market for each system setup. Some of the contrasts between the cases were addressed along with the presentation of the results and will be further discussed in this section. Table 8.1 provides a summary of the key results obtained in this study.

8.1.1 Market Behaviour

Community Costs

From the results of Section 6.3, it was evident that all cases of DER and storage implementation, regardless of market structure, lowered the total community costs significantly. The savings of establishing a P2P market was, however, of less eminence, with only 3.45 % and

Table 8.1: Summary of results for each case.

	Reference	**System A**		**System B**	
		No Market	P2P	No Market	P2P
Total costs [NOK]	**51,971**	**36,007**	**34,766**	**35,219**	**34,293**
Compared to reference	-	-30.71 %	-33.10 %	-32.23 %	-34.10 %
Costs No Market vs. P2P	-	-	-3.45 %	-	-2.63 %
Costs of grid import [NOK]	51,971	36,695	34,847	35,644	34,303
Revenue of grid export [NOK]	-	687	82	425	10
Peak demand [kWp]	185.95	160.42	160.42	221.64	221.64
Total grid import [kWh]	65,236	46,361	44,061	45,442	43,875
Total grid export [kWh]	-	2,657	356	1,622	41
Total P2P trade [kWh]	-	-	2,300	-	5,026
Grid losses [kWh]	937.15	517.96	517.96	566.36	644.47
Compared to reference	-	−44.73%	−44.73%	−39.57%	−31.23%
No Market vs. P2P	-	-	0%	-	+13.79%
Battery losses [kWh]	-	-	-	581.69	650.70
Demand by grid	100 %	71.07 %	67.54 %	69.63 %	67.23 %
Demand by local DERs	0 %	28.93 %	32.46 %	30.37 %	32.77 %

2.63 % savings. This is in contrast with the results of Lüth et al. [9], where a pure implementation of local trade yielded savings of 22 % and 16 %, respectively with and without decentralised storage. One of the main reasons for these differences is likely the results' high dependency on the system characteristics and price schemes. For instance, some of the houses in the case studies of Lüth et al. [9] also operate local wind turbines, which often have a complementary production profile to PV panels. Therefore, the agents were self-sufficient for more extensive parts of the day compared to the cases used in this study, even with the presence of storage. The P2P trading timeframe is thus extended, enhancing its benefits compared to the case of no local market. The UK wholesale prices used are also known to be higher and more volatile than the Norwegian prices, thus encouraging more price arbitrage.

As the objective function value of the market optimisation results are perceived as the total community costs, the changes applied to the function in this thesis will naturally lead to different costs compared to the ones in Lüth et al.'s [9] paper. One can, however, argue that the possibility of grid feed-in has had little effect on the objective value based on the values in Table 8.1. The revenue of grid export is shown to be almost negligible in both cases of P2P trading. However, one can also observe that the sum of total amount traded locally by P2P trade and exported by feed-in in these two cases, is equal or larger than the total amount exported in the cases of no market. With the P2P prices assumed to be lower than the grid import price and higher than the grid export price, this result implies a revenue/saving among the peers. These individual costs are not available with the chosen modelling approach and should be explored further.

The reference case used in this thesis, which reflects the current situation in the simulated distribution grid, encompasses no DER or storage facilities. As such, substantial investments have to be made in order to realise any of the four subsequent cases. These costs are not addressed in this study, as it mainly focuses on the operational value of the different market strategies. Besides, the investment costs of DERs, especially batteries and PVs, have decreased exponentially in recent years.

Supply-Demand Decisions

From Chapter 6, it became clear that with the opportunity to export excess electricity back to the grid, nothing was curtailed from the PV generation. With the establishment of a P2P market, the same amount was exported, but local trading was prioritised over grid feed-in. This is in line with the assumption of the P2P prices being lower than the grid import prices, but higher than grid feed-in prices.

With batteries installed at some houses in the neighbourhood, more peers became active in the local market. When there were no storage alternatives within the community, pure consumers could only procure locally produced electricity during daytime, when the PV generation was high. In a typical Norwegian household, the demand is often almost inversely dependent on temperature and solar irradiation, and generally lower midday than morning and afternoon. This limits the value of local trading, as the electricity must be consumed at the same time as being generated with no storage options.

With some PV owners also investing in batteries, the timeframe of possible P2P trading is extended significantly. Consumers can now buy locally generated electricity when their demand is higher, e.g. during the evening or morning, exploiting the lower prices. As the wholesale spot prices generally are higher during these periods, likely also increasing the local prices, prosumers are also benefiting from the shifted trading period.

Price Arbitrage Operations

Differing from the model used by Lüth et al. [9], peers are allowed to perform arbitrage operations by charging their batteries from electricity procured from the wholesale market in this model. This behaviour asserts itself in the case of P2P trading with batteries. As depicted in Section 6.2.2, prosumers procure electricity from the grid despite having an excessive PV generation at the same time step. The imported power is used to charge their batteries, for then to be sold to other peers at favourable prices during peak time. The extent of this behaviour is likely dependent on the historical time series used for the spot price input data.

8.1.2 Grid Impacts

Voltage Levels

The results in Chapter 7 revealed a voltage rise above 1 p.u. parallel with PV generation with the System A setup. However, the maximum values were well beneath the rated limit and thus of no great concern. There were also no differences between the two market schemes with the same system setup. With no flexibility options in terms of load and storage, all nodes import and export the same amount regardless of market design, only differing in origin and purpose, thus not affecting the net injection at each node.

The voltage fluctuations of the cases involving batteries were also within the limits of $\pm10\%$. Due to the extensive battery charging within a few time steps, the represented nodes occasionally experienced lower voltage levels than in the reference case. Furthermore, due to the focus on local trading instead of self-sufficiency, e.g. during the evening, the P2P case experiences more fluctuations than the case with no local market. The moderate voltage drops may indicate that this particular distribution grid is relatively robust, with sufficient impedance levels to handle the additional demand caused by the batteries and power fluctuations from the PVs.

It is important to note that the power flow model assumes that all three phases in the grid are fully balanced. Rooftop PV panels are often connected to the grid with a single-phase inverter to one of the grid phases, due to the structure of the Norwegian distribution grid. This makes the whole system unbalanced and can give more voltage variations than shown in these results. According to Kirkeby et al. [52], the voltage drop/increase is reduced by 50 % in a balanced grid compared to a completely unbalanced grid. This scenario is, however, not possible to show with the chosen modelling technique.

One can also expect the shown effects to increase in magnitude with an increase of DER and storage penetration. The severity of such voltage fluctuations on the power system is hard to determine. The one-hour time step used in the thesis' model does not create a full picture of the more rapid effects of solar irradiance variations. Current voltage control schemes operated by the DSOs, such as on-load-tap-changing transformers may not be able to respond to such rapid changes in voltage levels. These issues are, however, not possible to address with the chosen approach and is an important subject for further work.

Peak Grid Demand and Dependency

None of the cases showed any differences related to market structure in terms of peak grid consumption. The integration of PVs managed to decrease it with 13.73 %, while the integration of batteries led to an increase of 19.19 %. Both are relative to the reference case. These differences only represent whats imported via the transformer to the low voltage distribution grid but are also confirmed by analysing the peak net demand at each node. The proposed utility tariff restructuring to include a peak power term may curb some of the extensive battery charging from grid import, as it will become less profitable. This may, in turn, make procurement of decentralised batteries less attractive.

As of total import from the external grid, both P2P cases yielded the lowest amount of all five cases. This is in line with the results of Lüth et al. [9]. This was the only difference in terms of grid impact between the two cases of System A that could be distinguished in this study. As could be observed from Figure 7.6, both P2P cases even induced multiple hours of no import from the grid at all, respectively 70 and 26 hours with and without batteries. This implies a potential for higher security of supply and resilience within the community by inaugurating local trading.

System Losses

The installment of PVs contributed to an almost 45 % reduction of grid losses, as several peers became self-sufficient in large parts of the day. No difference between the market designs was apparent for this aspect either. Due to the physical laws of the system power flows, the same amount is transported over the same distribution lines when the net power injection at each node is the same. Naturally, this leads to the same amount of system losses.

An interesting result is that the P2P market with batteries yielded the lowest total grid import, but the highest amount of system losses. This is mainly due to the extensive battery charging during the night. As many of the batteries are placed at peers at the end of the network radials, the increased demand leads to an increased amount of power transported over longer distances. This leads to higher losses. Furthermore, from the supply/demand balances presented in Chapter 6, one of the main differences between the two market cases with batteries was the priority of self-consumption. In the case of P2P, the prosumers owning a battery often traded locally instead of consuming from the storage themselves, and more electricity was thus exported from the far-out radials. The results may thus have been different if the different assets were optimally placed.

Impact on Higher Level Grid

A small test was conducted to analyse what effect the different decisions of grid import would have on the grid losses at higher voltage levels. An mpc model was set up with available data for the 22 kV distribution grid, to which the low voltage grid from the cases is connected. Loads of the other low voltage distribution grids connected to the 22 kV grid were aggregated into single, representative nodes. The low voltage grid from the cases was also represented as a single node, with the total grid import decision for each time step of each case used as a load. However, the load of this grid appeared to be quite insignificant compared to the total load of the 22 kV grid, and the different cases revealed no differences in total system losses. Nonetheless, a higher degree of self-sufficiency within the low-voltage distribution grid requires less energy to be transported over long distances and thus, lower system losses.

8.1.3 Loss Pricing Case

The case including a price signal to reduce the total system losses showed that it is possible to adjust the community's behaviour according to grid conditions using pricing mechanisms. This was a very innovative technique in this thesis. While the approach intended to curb some of the grid consumption, the results showed a decrease in local trade instead, thus limiting the market efficiency. A possible reason is that the community values self-consumption among the peers over local trade with this grid import penalty in place. The local DERs only cover 32.77 % of the community demand in the corresponding case without loss pricing. With a higher penetration, the effects of the pricing mechanism may have been more apparent.

In Figure 5.4, one can observe that the periods with low prices is very short each day. The difference between this low price and the following higher prices is, however, of quite a significance. The savings of charging the battery during this limited time slot may thus outweigh the cost penalties of charging later the same day, even with the additional costs of the losses. With more extended or more frequent periods of relatively low prices, the response to the pricing scheme may thus be different.

The losses calculated by the regression constraint was 5 % higher than the actual amount calculated by the power flow model. First of all, this confirms that the regression approach provides high accuracy. However, it also indicates a slight overcharging of the community in terms of compensating for the system losses. The linearity approach and a R^2 value of 0.93

can be the reason. Further regression analyses should be conducted to improve this error in the further development of this method.

8.2 The Grid Owner's Perspective

The future role of the traditional DSOs is already a topic of discussion, with the emergence of smart grids, micrograds and energy communities. With the increasing amount of DERs connected to the low-voltage network, new issues and areas of responsibility will arise for the DSO in any case. As proposed by the International Renewable Energy Agency (IRENA) in Figure 8.1, the future DSO could work as a neutral market facilitator, providing a technical validation for the local market dispatch. In terms of the market methodology presented in this thesis, the DSO would perform the power flow analysis after the local market platform has found the optimal market equilibrium. Accordingly to the model proposed in Section 4.5, the DSO would analyse the technical implications of the local trades, and send return signals back to the market platform if the solution causes any problems.

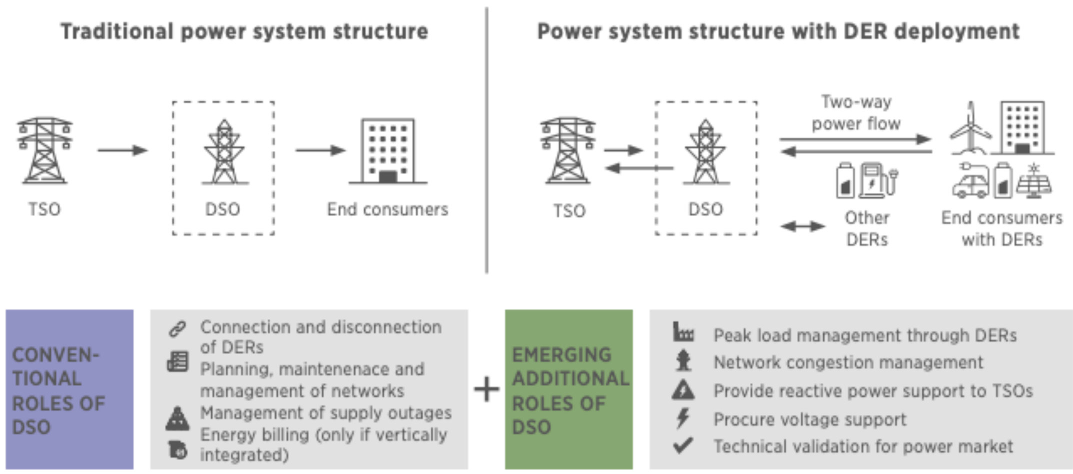


Figure 8.1: Proposal by IRENA of new roles for the DSO [53].

In light of the results obtained in this study, it is clear that the inclusion of the local DSO is essential when establishing a local electricity market. As revealed in Section 7.2, uncontrolled battery charging may increase the peak load in terms of grid import in the neighbourhood. It was also clear that the implementation of a P2P market would not help to reduce the peak value, unless addressed directly in the market model, like in the work of Sæther [54]. As this is an important aspect for the grid owner, this result gives less incentive to the DSO to encourage the establishment of a local market. External storage, like investigated in the work of Lüth et al. [9], may be a valuable alternative in the perspective of the DSO.

By introducing incentives for Demand Response (DR) or other flexibility assets than PVs and batteries, parts of the grid impacts caused by the local market could be mitigated. Although there were no differences in grid impact related to the local market structure when there was no storage available, the presence of a well-established market platform may ease the collaboration between the market participants and the DSO. Blockchain-based information platforms could provide necessary information to all market agents, including the DSO. DSOs could then take an active part in the local market platform, trading flexibility directly with the market participants or through the market operator. It is nevertheless essential to properly articulate to which extent a DSO should be able to interfere in the market decisions, as it may raise issues concerning its requirements of neutrality.

8.3 The End-Users' Perspective

Increased flexibility through DR and DERs has been accentuated as one of the key benefits of organising prosumers and consumers into local markets. Of the assets used in the cases of this thesis, battery storage has been praised with the most potential as it can flatten out demand curves and provide both up- and down-regulation. It was, however, shown in this thesis that an uncontrolled deployment in terms of charging time and geographical location may lead to an opposite effect. Price signals such as the new utility tariff may change this behaviour, but also the employment of more varied flexibility resources may be a solution. As the peers in the market are geographically close, weather dependent DERs like PVs create a uniform pattern, such that the system batteries are charged simultaneously. As such, an interesting direction of further work is to expand the system with other DERs and flexibility assets, as well as introducing DR mechanisms. New assets could, e.g. include small wind turbines, combined heat and power plants, heat pumps or electric vehicles.

The grid impacts of their behaviour may not be of great concern for the average end-user, and their willingness to invest in and provide services with different flexibility assets is difficult to predict. A survey conducted by the DSO Skagerak Energi in 2012 revealed that consumers were willing to shift their load to other parts of the day for a minimum of 1000 NOK per year [55]. Other surveys conducted by SINTEF indicate that three out of four households will delay the usage of their washing machine and dishwasher until later that day. Two out of three can accept remote control of their water heater by a few degrees in order to relieve stress from the grid [56]. This attitude will probably differ depending on the geographical area and consumer composition. In order to adequately facilitate DR and local trading, it is essential to initiate consumer involvement, e.g. through surveys. In that way, DSOs and other market operators know which market schemes are most suitable, and barriers among the end-users such as risks and uncertainties are diminished.

Well-designed consumer-centric local markets promote consumer empowerment, engagement and awareness of their energy consumption. With this mindset adapted among the peers, the threshold for providing DR for other incentives than just financial may also be lowered. The prospect of being self-sufficient, promote renewable energy and being able to control the origin of the electricity consumed may be of high value for some consumers. Also, a high degree of self-sufficiency at community level may increase the attractiveness of the neighbourhood, possibly increasing the estate value and motivate more peers to join. The sense of community affiliation is also a significant motivation.

8.4 Market Structure

The P2P market structure in this thesis was based on the work of Lüth et al. [9], with some adjustments made to fit better the Norwegian conditions and cases in this project. The market is structured with a community-based approach, where the overall objective is to minimise the total community costs. As the market strategy heavily influence each peer's decisions, the grid impact results are probably sensitive to the design as well. Local market setups are a debated topic within the research field, as the systems to be considered are complex and the most suitable market design is highly dependent on the system features.

With a community-based approach, the presence of a community manager is often assumed. As presented in Section 2.2, the manager finds an optimal solution for the whole community based on information from all agents. It can also work as an interface between the local and the wholesale market, as well as communicating with the system operator on behalf of the community. When considering the handling of grid-related issues, it is easier for a community manager to provide relevant services as an aggregator to the DSO than for an individual peer.

In the current model, it is assumed that all peers provide detailed information about their energy profiles to the local market platform. This is a bold assumption, as the privacy concern is likely a barrier for many peers to join such a market. A possible solution is the market design proposed by Moret et al. [57], where all prosumers are in charge of optimising their own assets before the supervisory node finds the community optimum. With this scheme, the different agents are only required to share their net utility function with the community manager, leaving out sensitive information about their demand and production.

A community-based market is reliant on the peers' willingness to collaborate in order to achieve a social optimum. However, Moret et al. [57] argue that such collaborative structures are prone to experience unfair behaviour, as some participants may act strategically. In this case, strategic behaviour involves not providing correct information to the supervisory node in order to gain personal profit or due to privacy concern. In addition to reducing market efficiency, these situations could lead to challenges for the system operator. ”Non-technical” losses, congestions and voltage problems can arise, which the DSO is not able to prepare for through the power flow analysis. The enrollment of smart meters may, however, mitigate some of these risks.

As previously discussed, it is not possible to analyse the economic consequences for each individual peer with the chosen modelling approach. Pricing schemes for P2P markets are as debated as market structures in the research field, and it was chosen not to look further into this in this study. Although a market solution is optimal for the community, it may be suboptimal for the individual peer. If the peer feels that his preferences are overruled by the ”common good”, he may also be reluctant to cooperate further.

8.5 Assumptions and Simplifications

Due to the complexity of both the power system and market design, several assumptions and simplifications have been made when developing the model and constructing the use cases in this thesis. It is important to keep these in mind when analysing the results, as they can be of significant influence. A summary of the key assumptions and simplifications are listed below, as they already have been explained throughout the thesis.

- The one-hour time step only allows for analysis of slow variations in the system. Output transients caused by, e.g. fast-moving clouds are a well-known issue when it comes to PV operation, but cannot be analysed with the chosen methodology.
- Demand, PV generation and wholesale spot prices are all assumed to be known for each time step in the optimisation model, as historical time series are employed. Thus, the more realistic stochastic nature of the optimisation problem is neglected.
- The historical time series are not perfectly correlated in terms of year and date, and may thus not fully account for the dependencies between demand, weather conditions and spot prices.
- The grid capacity for import from the wholesale market is assumed to be unlimited.
- As the thesis has focused on the technical impact of the actual operation of a P2P market, investment costs for the enabling components are not considered.
- Operational and maintenance costs for the PV panels and batteries are also neglected. In reality, these would probably influence the individual P2P prices which are ignored in the model due to the community approach.
- The system is modelled as fully balanced at all times. As the PV panels and batteries normally are connected to one phase, this may not always be true and may diminish some of the effects of PV and battery integration.
- No degradation of the batteries are considered, and all efficiencies for both batteries and

PVs are assumed to be constant. With the short timeframe of the simulations, this assumption has likely little effect on the validity of the results.

- Compared to traditional time horizon simulations, the period chosen was from noon-to-noon. This might have had a small effect on the battery charging decisions.

Chapter 9

Conclusion and Recommendations for Further Work

9.1 Conclusion

In this thesis, the impact on grid operation of establishing local electricity markets has been investigated. The study has been conducted by evaluating five different cases of different DER and storage deployment and different market designs.

The overall results showed that the integration of PV panels within the distribution network helped to mitigate both peak grid consumption and total system losses, with a decrease of respectively 13.73 % and 44.73 %. The establishment of a P2P market showed no differences in these results, due to the physical nature of the system power flows. The total amount of electricity procured from the wholesale market did, however, decrease with almost 5 % with the P2P market. In this case, the neighbourhood was even wholly independent from the external grid for 26 hours. This implicates a more efficient use of local resources and higher resilience of the community.

Accordingly, the same tendency could be observed when introducing local trade to System B, with 70 hours of independent operation. An uncontrolled charging of the private batteries led to voltage drops and an increased peak consumption of 19.19 % compared to the reference case. Now, the discrepancies in the results caused by the market design also became more apparent. The window of possible local trading was extended beyond the PV generation period, thus inducing more voltage fluctuations and a 13.79 % increase of system losses compared to the case of no local market. Economically, the P2P cases yielded the lowest aggregated community costs in total.

A novel approach was introduced to reduce the aggregated system losses. A regression was conducted based on the loss data obtained from P2P case of System B. This resulted in a constraint and an updated objective function, attempting to minimise the system losses as a function of total grid import, demand and PV generation. The overall intention was to reduce the total grid import. The results confirmed that the approach could affect the peers' behaviour according to the grid conditions, and showed a $\sim 5\%$ decrease of system losses. However, the operational decisions mainly affected the local trade instead of grid consumption.

The results in this study are likely highly system dependent, both in terms of market design and system setup. With the market model featuring a centralised approach, it is clear that the community's assets and trade capacity are operated according to the optimal solution for the entire neighbourhood. This market structure is reliant on transparency and willingness to share data, which for many, is a significant barrier for joining the market. The coordination between the market agents and the DSO, however, may easier be facilitated with such a market structure with a local market operator serving as an interface.

P2P market models have gained popularity in academic research and real-life projects over the recent years, and this thesis contributes to a little-explored aspect of the implementation. As the market is connected to a complex power system, it is essential to thoroughly analyse the effects such behaviour will have on the physical operation of the grid. The model has to take into consideration the specifications of the relevant network and location and characteristics of the DERs or storage assets installed. As such, the study does not provide a definite conclusion to the grid impacts of a local market, but creates a novel insight and framework for further analyses on the topic.

9.2 Recommendations for Further Work

Below, a list of topics suggested for further work is presented. The recommendations are based on the assumptions and simplifications of this study, and the discussion in Chapter 8.

- **Further investigate more detailed grid impacts**: In the scope of this study, only steady-state effects on the power flow have been analysed. Thus, only the slow variations of the voltage's effective value could be detected. However, more rapid effects caused by, e.g. changes in solar irradiation, such as harmonics and output transients, flicker phenomenons and voltage spikes, should be further explored to get an overall impression of the grid impacts. Furthermore, the chosen power flow modelling approach assumed a completely balanced system at all times, which may mitigate some of the actual effects. Further analyses considering a possibly unbalanced three-phased system should be conducted.

- **Study interface enabler between local market and DSO**: One of the key enablers to facilitate a well-functioning relationship between the local market and the grid owner is to develop a common platform. In Section 8.2, a blockchain-based information system were suggested as a provider of necessary real-time data for all parts. Blockchain technology has been a popular topic in research as an enabler of P2P transactions, but further studies should focus on how it could include cooperation with the DSO as well.

- **Evaluate other market designs and their impact on grid operation**: The market design was a significant driver of the operational decisions made in the case studies. An interesting approach would be to convert the market design into a decentralised optimisation approach, as discussed in Section 8.4. The structure should consider the individual preferences of the market participants, while also guaranteeing their privacy. This may also lead to a less uniform trade scheme among the peers, and consequently, other impacts on the grid operation.

- **Further elaborate pricing mechanism to reduce grid impacts**: The regression approach proposed in this study aims to reduce the aggregated total system losses. The losses were reduced, but other aspects were affected negatively, e.g. the market efficiency. Furthermore, the costs may be unfair as it is targeting the whole neighbourhood, not just the ones inducing the losses.

- **Develop a forecasting model or include stochasticity in the model**: The input data used in the model is based on historical time series and is thus assumed to be known with full certainty prior to the optimisation. In order to account for more realistic conditions, methods for more accurate forecasting or consideration of stochastic uncertainties should be further explored. Moreover, one could also explore implementing a rolling horizon framework.

- **Expanding the deployment of DERs/storage or include other types of DER**: In all the four main case studies, the local DER generation was able to cover between 30-33 % of the community demand. More ambitious penetration levels should be analysed both in terms of market behaviour and grid impacts. This could also result in a higher impact by the loss pricing scheme. Furthermore, as discussed in Section 8.3, other assets than just PVs and batteries should be implemented in the system. Preferably, these additional assets should have daily or seasonal complementary generation profiles in order to expand the P2P trading opportunities.

- **Implement DR or other flexibility mechanisms**: As discussed in Section 8.2 and 8.3, DR and end-user flexibility could be one method for mitigating some of the grid impacts caused by a local market. This should be further explored as an extension of the model developed in this thesis.

- **Make a proper model for individual P2P prices/design bidding strategy**: With the chosen modelling approach and the scope of the study, individual costs were not analysed. This is, however, an essential aspect in terms of evaluating the peers' willingness to participate in a P2P market. A suitable pricing scheme and bidding strategy should thus be designed and included in the market model.

- **Investigate the effect of the peak power term in the proposed utility tariff**: The significant grid import with the purpose of battery charging leads to an increased peak grid consumption in this study. It would thus be interesting to investigate how the new utility tariff proposed by NVE would affect the market behaviour in combination with decentralised storage.

- **Include all costs and perform a proper long-term cost-benefit analysis**: The results of this study indicate that establishing a P2P market would be economically beneficial for the community. However, investment, operational and maintenance costs are neglected, and the analysis only covers a few weeks with high PV generation. Simulations should thus be done over a longer time-horizon, and include all relevant costs in a cost-benefit analysis.
- **Further develop the model presented in Chapter 4.5**: A complete call-back principle between the power flow and market model was proposed, but not realised, in Chapter 4.5 as it would be unnecessary with the results of this particular study. The framework would nevertheless be useful for systems with more dramatic effects, e.g. weaker grids or higher penetration of volatile DER generation.

Bibliography

[1] C. Martin, *Better Batteries*, `https://www.bloomberg.com/quicktake/batteries`, Last accessed: 9.6.2020, 2019.

[2] IRENA, 'Renewable Power Generation Costs in 2018', 2019.

[3] A. Woyte, V. Van Thong, R. Belmans and J. Nijs, 'Voltage fluctuations on distribution level introduced by photovoltaic systems', *IEEE Transactions on Energy Conversion*, vol. 21, no. 1, pp. 202–209, 2006.

[4] M. Karimi, H. Mokhlis, K. Naidu, S. Uddin and A. Bakar, 'Photovoltaic penetration issues and impacts in distribution network – A review', *Renewable and Sustainable Energy Reviews*, vol. 53, pp. 594–605, 2016, ISSN: 1364-0321. DOI: `https://doi.org/10.1016/j.rser.2015.08.042`.

[5] C. Zhang, J. Wu, C. Long and M. Cheng, 'Review of Existing Peer-to-Peer Energy Trading Projects', *Energy Procedia*, vol. 105, pp. 2563–2568, 2017, 8th International Conference on Applied Energy, ICAE2016, 8-11 October 2016, Beijing, China, ISSN: 1876-6102. DOI: `https://doi.org/10.1016/j.egypro.2017.03.737`.

[6] B. Microgrid, *About Brooklyn Microgrid*, Last accessed: 9.6.2020, 2019. [Online]. Available: `https://www.brooklyn.energy/about`.

[7] C. Eid, L. A. Bollinger, B. Koirala *et al.*, 'Market integration of local energy systems: Is local energy management compatible with European regulation for retail competition?', vol. 114, 2016, pp. 913–922.

[8] T. Sousa, T. Soares, P. Pinson, F. Moret, T. Baroche and E. Sorin, 'Peer-to-peer and community-based markets: A comprehensive review', *Renewable and Sustainable Energy Reviews*, 2019.

[9] A. Lüth, J. Zepter, P. del Granado and R. Egging, 'Local electricity market designs for peer-to-peer trading: The role of battery flexibility', *Applied Energy*, vol. 229, pp. 1233–1243, 2018.

[10] M. Khorasany, Y. Mishra and G. Ledwich, 'Peer-to-peer market clearing framework for DERs using knapsack approximation algorithm', in *2017 IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT-Europe)*, 2017, pp. 1–6.

[11] C. Long, J. Wu, C. Zhang, L. Thomas, M. Cheng and N. Jenkins, 'Peer-to-Peer Energy Trading in a Community Microgrid', Jul. 2017. DOI: `10.1109/PESGM.2017.8274546`.

[12] Energy Facts Norway, *The Power Market*, Last accessed: 18.4.2020. [Online]. Available: `https://energifaktanorge.no/norsk-energiforsyning/kraftmarkedet/`.

[13] NordPool, *The Power Market*, Last accessed: 2.5.2020. [Online]. Available: `https://www.nordpoolgroup.com/the-power-market`.

[14] I. Wangensteen, *Power System Economics - the Nordic Electricity Market*, 2nd ed. Fagbokforlaget, 2012.

[15] NordPool Group, *Price calculation*, Last accessed: 14.4.2020, 2020. [Online]. Available: https://www.nordpoolgroup.com/trading/Day-ahead-trading/Price-calculation/.

[16] NordREG, 'Electricity custmer in the Nordic countries - Status Report Retail Markets 2016', 2017.

[17] NVE, 'RME høringsdokument - Endringer i nettleiestrukturen', vol. 1, 2020.

[18] NVE-RME, *Plusskunder*, Last accessed: 10.4.2020, 2020. [Online]. Available: https://www.nve.no/reguleringsmyndigheten/nettjenester/nettleie/tariffer-for-produksjon/plusskunder/.

[19] Tibber, *Våre avtalevilkår*, Last accessed: 2.5.2020. [Online]. Available: https://tibber.com/no/avtalevilkar.

[20] O. R. Valmot and E. H. Urke, *Slik styrer Tibber oppvarmingen og elbillading, og kjøper strømmen når den er billigst*, Last accessed: 2.5.2020. [Online]. Available: https://www.tu.no/artikler/slik-styrer-tibber-oppvarmingen-og-elbillading-og-kjoper-strommen-nar-den-er-billigst/477490.

[21] O. Wolfgang, M. Askeland, S. Backe *et al.*, 'Prosumer's role in the future energy system', FME CenSES, 2018.

[22] Otovo, *Om oss*, Last accessed: 29.5.2020. [Online]. Available: https://www.otovo.no/about.

[23] M. F. Dynge, 'Local Market Potential between Positive Energy Blocks in Trondheim', Specialization Project, *Unpublished*, Dec. 2019.

[24] P. Pinson, T. Baroche, F. Moret, T. Sousa, E. Sorin and S. You, 'The Emergence of Consumer-centric Electricity Markets',

[25] S. Backe, P. C. del Granado, G. Kara and A. Tomasgard, 'Local Flexibility Markets in Smart Cities Interactions between Positive Energy Blocks', *16th IAEE European Conferance*, 2019.

[26] T. Brudermann and Y. Yamagata, 'Towards an agent-based model of urban electricity sharing', in *2014 International Conference and Utility Exhibition on Green Energy for Sustainable Development (ICUE)*, Mar. 2014, pp. 1–5.

[27] E. Sorin, L. Bobo and P. Pinson, 'Consensus-based Approach to Peer-to-Peer Electricity Markets with Product Differentiation', *IEEE Transactions on Power Systems*, vol. PP, Apr. 2018. DOI: 10.1109/TPWRS.2018.2872880.

[28] D. I. Hidalgo-Rodríguez and J. Myrzik, 'Optimal Operation of Interconnected Home-Microgrids with Flexible Thermal Loads: A Comparison of Decentralized, Centralized, and Hierarchical-Distributed Model Predictive Control', in *2018 Power Systems Computation Conference (PSCC)*, Jun. 2018, pp. 1–7. DOI: 10.23919/PSCC.2018.8442807.

[29] Y. Parag and B. K. Sovacool, 'Electricity market design for the prosumer era', *Nature Energy*, 2016.

[30] S. Bertelsen (Trondheim Kommune), K. Livik (Powel) and M. Myrstad (Trondheim Kommune), 'D2.1 Report on Enabling Regulatory Mechanism to Trial Innovation in Cities', *+CityxChange, Work Package 2, Task 2.1*, 2019.

[31] G. Zizzo, E. Sanseverino, M. Ippolito, M. L. Di Silvestre and P. Gallo, 'A Technical Approach to P2P Energy Transactions in Microgrids', *IEEE Transactions on Industrial Informatics*, vol. PP, pp. 1–1, Feb. 2018. DOI: 10.1109/TII.2018.2806357.

[32] E. Munsing, J. Mather and S. Moura, 'Blockchains for decentralized optimization of energy resources in microgrid networks', Aug. 2017, pp. 2164–2171. DOI: 10.1109/CCTA.2017.8062773.

[33] T. Baroche, P. Pinson, R. Latimier and H. Ben Ahmed, 'Exogenous Approach to Grid Cost Allocation in Peer-to-Peer Electricity Markets', *IEEE Transactions on Power Systems*, vol. PP, Mar. 2018. DOI: 10.1109/TPWRS.2019.2896654.

[34] J. Guerrero, A. C. Chapman and G. Verbič, 'Decentralized P2P Energy Trading Under Network Constraints in a Low-Voltage Network', *IEEE Transactions on Smart Grid*, vol. 10, no. 5, pp. 5163–5173, 2019.

[35] T. Orlandini, T. Soares, T. Sousa and P. Pinson, 'Coordinating Consumer-Centric Market and Grid Operation on Distribution Grid', in *2019 16th International Conference on the European Energy Market (EEM)*, 2019, pp. 1–6.

[36] Energy Facts Norway, *The Electricity Grid*, Last accessed: 10.4.2020, 2019. [Online]. Available: https://energifaktanorge.no/en/norsk-energiforsyning/kraftnett/#description-of-the-norwegian-electricity-grid.

[37] NVE, *The Norwegian power system. Grid connection and licensing.* http://publikasjoner.nve.no/faktaark/2018/faktaark2018_03.pdf, 2018.

[38] P. Murty, 'Chapter 10 - Distribution System', in *Electrical Power Systems*, P. Murty, Ed., Butterworth-Heinemann, 2017, pp. 203–227, ISBN: 978-0-08-101124-9. DOI: https://doi.org/10.1016/B978-0-08-101124-9.00010-3. [Online]. Available: http://www.sciencedirect.com/science/article/pii/B9780081011249000103.

[39] A. Szultka, R. Malkowski, S. Czapp and S. Szultka, 'Impact of R/X ratio of distribution network on selection and control of energy storage units', in *2017 International Conference on Information and Digital Technologies (IDT)*, Jul. 2017, pp. 359–364. DOI: 10.1109/DT.2017.8024323.

[40] H. Kirkeby and H. Seljeseth, 'Utfordrende elektriske apparater', SINTEF, Tech. Rep. TR A7448, 2015.

[41] J. D. Glover, T. J. Overbye and M. S. Sarma, *Power System Analysis and Design*, 6th ed. Cengage Learning, 2016.

[42] K. Balamurugan and D. Srinivasan, 'Review of power flow studies on distribution network with distributed generation', *Proceedings of the International Conference on Power Electronics and Drive Systems*, pp. 411–417, Dec. 2011. DOI: 10.1109/PEDS.2011.6147281.

[43] R. Zimmeramann, C. Murillo-Sánchez and R. Thompson, 'MATPOWER: Steady-State Operations, Planning and Analysis Tools for Power SYstems Research and Education', 1, vol. 26, Feb. 2011, pp. 12–19. DOI: https://doi.org/10.1109/TPWRS.2010.2051168.

[44] R. Zimmermann and C. Murillo-Sácez, *Matpower User's Manual*, https://matpower.org/docs/MATPOWER-manual-7.0.pdf, 2019.

[45] Tensio, *Nettleiepriser privat gjeldende fra 1. januar 2020*, Last accessed: 5.5.2020. [Online]. Available: https://ts.tensio.no/kunde/avtaler/2020-nettleie-privat.

[46] R.D.Zimmermann and C. Murillo-Sancez, *MATPOWER*, version 7.0, 2019. [Online]. Available: https://matpower.org.

[47] S. Zaferanlouei, M. Korpås, H. Farahmand and V. V. Vadlamudi, 'Integration of PEV and PV in Norway using multi-period ACOPF — Case study', in *2017 IEEE Manchester PowerTech*, 2017, pp. 1–6.

[48] S. Pfenninger and I. Staffell, 'Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data', *Energy 114*, pp. 1251–1265, 2016. DOI: https://dx.doi.org/10.1016/j.energy.2016.08.060. [Online]. Available: renewables.ninja.

[49] M. M. Rienecker, M. J. Suarez, R. Gelaro *et al.*, 'MERRA: NASA's Modern-Era Retrospective Analysis for Research and Applications', *Journal of Climate*, vol. 24, no. 14, pp. 3624–3648, Jul. 2011, ISSN: 0894-8755. DOI: 10.1175/JCLI-D-11-00015.1. [Online]. Available: https://doi.org/10.1175/JCLI-D-11-00015.1.

[50] Tesla, Inc., *Tesla Powerwall Technical Specs*, Last accessed: 5.5.2020, 2020. [Online]. Available: https://www.tesla.com/en_GB/powerwall?redirect=no.

[51] Tensio, *Nettleiepriser 2020 - for private husholdninger*, 2020.

[52] B. N. Torsæter and H. Kirkeby, *Simuleringsstudie av spenningskvalitet i lavspenningsnett med plusskunder*, https://www.sintef.no/globalassets/project/nef-tm-2017/rapporter-2017/sesjon-4-2—21—bendik-nybakk-torsater-og-henrik-kirkeby—simuleringsstudie-av-spenningskvalitet-i-lavspenningsnett-med-plusskunder.pdf.

[53] IRENA, 'Innovation landscape brief: Future role of distribution system operators.', *Interanational Renewable Energy Agency*, 2019.

[54] G. Sæther, 'Peer-to-Peer Energy Trading in Combination with Local Flexibility Resources in a Norwegian Industrial Site', Master Thesis, Norwegian University of Science and Technology, 2019.

[55] Nordic Council of Ministers, *Demand side flexibility in the Nordic electricity market - From a Distribution System Operator Perspective*. 2017.

[56] SINTEF, *Flexible resources in the power system (WP5) - Results 2018*, Last accessed: 9.6.2020, 2018. [Online]. Available: https://www.sintef.no/projectweb/cineldi/research/work-packages/flexible-resources-in-the-power-system-wp5/#Results2018.

[57] F. Moret and P. Pinson, 'Energy Collectives: a Community and Fairness based Approach to Future Electricity Markets', English, *IEEE Transactions on Power Systems*, vol. 34, no. 5, pp. 3994–4004, 2019, ISSN: 0885-8950. DOI: 10.1109/TPWRS.2018.2808961.

Appendix A

Regressions

A.1 Regression 1

Model constraint:

$$Losses^{(t)} = Intercept + \alpha \cdot \sum_h dem^{(t,h)} + \beta \cdot \sum_h G^{(t,h)} + \gamma \cdot \sum_h res\_pv^{(t,h)} \qquad \forall t \in T \quad (A.1)$$

Table A.1: Regression Statistics, regression 1.

Multiple R	0.927700705
R Square	0.860628599
Adjusted R Square	0.85979237
Standard Error	0.476180911
Observations	504

Table A.2: Regression Results, regression 1.

	Coefficient	Standard error	t Stat	P-value	Lower 95 %	Upper 95 %
Intercept	-0.129959828	0.149290897	-0.870514085	0.384437264	-0.423274615	0.163354958
Total Demand	-0.005708192	0.00113705	-5.020176767	7.19151E-07	-0.007942177	-0.003474207
Total Grid Import	0.022032256	0.000508329	43.34255439	1.8469E-171	0.021033533	0.023030979
Total PV Generation	0.005372606	0.000662988	8.10362611	4.12513E-15	0.00407002	0.006675191

A.2 Regression 2

Model constraint:

$$Losses^{(t)} = Intercept + \alpha \cdot \sum_{h} G^{(t,h)} \qquad \forall t \in T \tag{A.2}$$

Table A.3: Regression Statistics, regression 2.

Multiple R	0.917228727
R Square	0.841308539
Adjusted R Square	0.84099242
Standard Error	0.507101705
Observations	504

Table A.4: Regression Results, regression 2.

	Coefficient	Standard error	t Stat	P-value	Lower 95 %	Upper 95 %
Intercept	-0.413519997	0.039827425	-10.38279523	5.22255E-23	-0.491768973	-0.335271022
Total Grid Import	0.019438939	0.000376808	51.5884794	8.4659E-203	0.018698625	0.020179254

Appendix B

Paper: Impact of local electricity markets and peer-to-peer trading on low-voltage grid operations

Impact of local electricity markets and peer-to-peer trading on low-voltage grid operations

Marthe Fogstad Dynge[a], Pedro Crespo del Granado[b,c], Naser Hashemipour[b], Magnus Korpås[a]

[a] *Dept. of Electric Power Engineering, Norwegian University of Science and Technology, Trondheim, Norway*
[b] *Dept. of Industrial Economics and Technology Management, Norwegian University of Science and Technology, Trondheim, Norway*
[c] *SINTEF Energy Research, Smart Grids Group, Trondheim, Norway*

Abstract

Local electricity markets and peer-to-peer (P2P) trading schemes applied to low voltage networks have emerged as a new paradigm to further incentivise the adoption and deployment of decentralised energy sources (solar PV, batteries and others). In this paper, we analyse a local market applied to a neighbourhood of households in Norway. The case compromises 52 houses that have the presence of Solar PV and batteries on-site. As prosumer and consumer trade within this community, we analyse the value of P2P trading compared to business as usual, along with the impact of PV and batteries deployment. As these technologies and trading interactions might create challenges to the physical operations of the grid, we analyse the effect on power flows, voltage variations and system losses. The main findings indicate that there are no significant impacts on the grid operation of a P2P market when only PVs are installed in the system. With decentralised batteries available, the P2P trade induced more voltage fluctuations and 13.79 % more losses within the neighbourhood than the case with no local market. However, the local market brings overall savings for the end-user and sets the frame to design pricing schemes (e.g. manage losses) that are tailored to support DSO operations.

Keywords: Peer-to-peer trade, low voltage grid, batteries, Local electricity market, grid operations, decentralized generation

1. Introduction

In light of facing the growing energy demand and necessity of finding low-carbon solutions, more attention has been brought to the development and deployment of renewable energy. With this increased focus, investment costs in Distributed Energy Resources (DER) technology like solar PVs and batteries have been declining exponentially over the recent years [1, 2]. The tendency is thus that small-scale energy technology is starting to get affordable to regular households, creating the transition from consumerism to prosumerism as they simultaneously inhabit the role of consumption and production.

The traditional power system has had a top-down structure, designed to accommodate large, centralised generation units located far from the end-users. The increasing penetration of DERs has thus drastically changed the topology of the system, shifting problems that are faced at transmission-level today down to lower voltage levels. This introduces new challenges and areas of responsibility for the DSO.

With the simultaneous advancement of ICT, enrollment of smart meters, and distributed ledger technology, new frameworks for managing the energy transition are emerging. This allows for closer interaction between end-users, DSOs, and other system agents, and introduces the possibility of a more consumer-centric energy system. As a result, the power market needs to undergo a restructuring, dividing the system into smaller entities.

Local markets and P2P trading has thus gained increased focus within academic research, as well as pilot projects in various countries [3, 4, 5]. The decentralised management and collaborative principles characterising these structures allow for the prosumers' preferences to be better implemented in the market [6]. Studies have found P2P trading to reduce total electricity costs, improve self-consumption, and promote more effective utilisation of local DERs [7, 8, 9]. However, the exchange of electricity is different from other goods' trade, as the agents are connected to a complex power system. Accordingly, how such novel market structures will concur with the hard technical constraints of the grid needs to be addressed.

Despite the growing focus on local market designs and challenges occurring with DER deployment, little attention has been brought to explore how a more active operation by the prosumer, when participating in a local market, can affect these challenges. Zizzo et al. [10] evaluate power loss allocation due to energy exchanges using blockchain technology in a medium voltage network. Others, like Munsing et al. [11] and Baroche et al. [12] have utilised different versions of decentralised optimal power flow and grid utilisation costs strategies. None of these methods, however, explore the actual impacts on the grid, as they mainly focus on the market solutions obtained with the grid constraints integrated into the market optimisation.

Guerrero et al. [13] propose a method based on sensitivity analysis to evaluate the technical impacts caused by the P2P transactions in a low voltage network and to ensure that no network constraints are violated. They utilise sensitivity coefficients for voltage change, system losses, and power distribution factors to predict the network state caused by each transaction made in the P2P market dispatch. The study provides an analysis of the network state after the grid constraints have been implemented.

Orlandini et al. [14] have conducted one of few studies performing a full AC power flow to analyse the grid impacts of P2P trading. An iterative methodology is proposed, which utilises product differentiation and artificial congestion tariffs to motivate market participants to avoid grid congestion. The study focuses on line congestion and how it changes under the proposed tariff scheme.

Differing from the work of Guerrero et al. [13], this study will mainly focus on the technical impacts of a non-interfered P2P market dispatch. An approach similar to the one of Orlandini et al. [14] is applied, but with a different market structure and a broader focus on voltage levels, losses, and peak demand values. The study will also analyse different cases of DER and storage integration and perform parallel simulations of the system without local trading. This approach intends to get a more comprehensive understanding of the impacts of implementing a P2P market. The paper contributes to the research field by exploring the following questions:

- What cost-benefits provide P2P and local markets compared to "business as usual"?
- What is the impact of local markets on voltage variations, grid dependency and losses?
- How does market behaviour vary with different assets available, and how do the following decisions affect the grid operations?

The paper is organised as follows. The next section 2 describes the models and the overall methodology, the mathematical model formulations. After this, Section 3 summarises the neighbourhood grid, houses, and overall data scope, while the results and analysis are given in Section 4. Finally, Section 5 summarises conclusions and perspectives for future work.

2. Modelling local markets and distribution grid operations

2.1. P2P model

The P2P model used in this research is a multi-period linear programming, based on the work of Lüth et al. [7]. With a community-based P2P market structure, the objective function comprises the total electricity costs for the whole neighborhood, subject to supply, demand, trade and storage constraints. Similar to the day-ahead market in the wholesale electricity market, the model finds an optimal solution for the next 24 hours based on predefined demand and supply quantities. The stochastic nature of a household's consumption, wholesale electricity prices or PV panel generation is not considered in this paper and is assumed to be known for each time-step. A nomenclature for the full version of the P2P optimization model is presented in Table 1.

The objective function that is represented in Equation 1 aims to minimize

Table 1: Nomenclature of P2P model

Sets		
$t \in T$	Hours t in time horizon T	hours
$h, p \in H$	Houses h and peers p in community H	-
$d \in D$	Days d in time horizon D	days
Scalars		
ψ	System loss factor	%
$\bar{\mathrm{s}}/\underline{\mathrm{s}}$	Upper/lower bounds of storage levels in battery	kWh
α/β	Maximum charge/discharge rate of battery	kW
η^C/η^D	Battery charging/discharging efficiency	%
c_{en}	Energy term of grid tariff	øre/kWh
Parameters		
$dem^{(t,h)}$	Demand of house h in time step t	kW
$res\_pv^{(t,h)}$	Electricity production from PV of house h in time step t	kW
$c_{spot}^{(t,h)}$	Wholesale spot price for electricity from the grid in time step t	øre/kWh
$S_0^{(d,h)}$	Energy storage level at beginning of optimization period d	kWh
Variables		
$C^{(t,h)}$	Charge of battery at house h in time step t	kW
$D^{(t,h)}$	Discharge of battery at house h in time step t	kW
$S^{(t,h)}$	Energy storage level in battery of house h in time step t	kW
$G^{(t,h)}$	Grid consumption of house h in time step t	kW
$E^{(t,h)}$	Export to grid from house h in time step t	kW
$I_{p,p2p}^{(t,h\leftarrow p)}$	P2P electricity purchase of house h from peer p in time step t	kW
$X_{p,p2p}^{(t,h\rightarrow p)}$	P2P electricity sold by house h to peer p in time step t	kW
$I_{p2p}^{(t,h)}$	P2P electricity purchase of house h in time step t	kW
$X_{p2p}^{(t,h)}$	P2P electricity sold by house h in time step t	kW

the total costs related to the community's electricity consumption.

$$min \quad \sum_h \left(\sum_t (c_{spot}^{(t)} + c_{en}) \cdot G^{(t,h)} - \sum_t c_{spot}^{(t)} \cdot \psi \cdot E^{(t,h)} \right) \tag{1}$$

As all P2P trade is happening within the community, and thus the price someone pays cancel out what someone earns, these costs are not included in the objective function. Compared to the objective function in the model of Lüth et al., grid tariff consideration and the possibility to sell electricity to the grid has been added. Since each house in the community is subject to the fixed-term of the grid tariff regardless of the market strategy, this is excluded from total costs. The energy term is, however, added to the costs of importing electricity from the grid. It must be noted that prosumers are exempted from paying the feed-in tariff when exporting electricity to the grid. They do, however, have to pay for the possible extra losses occurring in the system due to their export. The total earnings of this action are thus set to be the wholesale spot-price multiplied with a system loss factor ψ. This factor is set to reflect the marginal loss rate of 5 % (ψ = 95 %) used by the DSO Tensio in the summer, which will be relevant for the area of the case studies [15].

The P2P trading set up within the community allows for direct trade of electricity among all peers, regardless of an actual physical connection. Therefore, the import of prosumer h from p equals to the export of p to h for each time step, considering the losses based on the marginal loss rate.

$$I_p^{(t,h\leftarrow p)} = X_p^{(t,p\rightarrow h)} \qquad \forall\, p \neq h, \tag{2}$$

The total amount of sold electricity through P2P trade $X_{p2p}^{(t,h)}$ from each house $h \in H$ for each time step $t \in T$ is defined by Equation 3.

$$X_{p2p}^{(t,h)} = \sum_{p\neq h} X_{p,p2p}^{(t,h\rightarrow p)} \qquad \forall t \in T, \forall h \in H \tag{3}$$

The total amount of purchased electricity through P2P trade $I_{p2p}^{(t,h)}$ is defined similarly by Equation 4.

$$I_{p2p}^{(t,h)} = \sum_{p\neq h} I_{p,p2p}^{(t,h\leftarrow p)} \qquad \forall t \in T, \forall h \in H \tag{4}$$

It is assumed that the P2P trade is limited to stay within the community, with the variable $E^{(t,h)}$ defining the potential surplus leaving the community. A constraint to ensure that the sum of sales made by P2P trade equals the sum of purchases is thus defined by Equation 5. Compared to the work of Lüth et al., there is no system loss coefficient included in this constraint. As the actual losses for each trade are found by performing a power flow analysis in this model, it was considered superfluous to have it in the market model as well.

$$\sum_h X_{p2p}^{(t,h)} = \sum_h I_{p2p}^{(t,h)} \qquad \forall t \in T \tag{5}$$

A central constraint in the model is the power balance equation, represented in Equation 6. This constraint ensure that the supply equals the demand at each house h at each time step t.

$$\begin{aligned} &G^{(t,h)} + I_{p2p}^{(t,h)} + D^{(t,h)} + res\_pv^{(t,h)} \\ &\qquad \geq dem^{(t,h)} + X_{p2p}^{(t,h)} + C^{(t,h)} + E^{(t,h)} \qquad \forall t \in T, \forall h \in H \end{aligned} \tag{6}$$

For the cases involving batteries, some additional constraints have to be added to the market model to control their behaviour. For each battery, there is an upper and lower bound in both SOC and charging and discharging rate, represented by Equation 7, 8 and 9.

$$\underline{\mathrm{s}} < S^{(t,h)} < \overline{\mathrm{s}} \qquad \forall t \in T, \forall h \in H \tag{7}$$

$$0 < C^{(t,h)} < \alpha \qquad \forall t \in T, \forall h \in H \tag{8}$$

$$0 < D^{(t,h)} < \beta \qquad \forall t \in T, \forall h \in H \tag{9}$$

The SOC for each battery in each time step is also a function of the SOC of the previous time step and the charge and discharge of this time step. This is one of the main motivations of performing a multi-period optimization as the decisions of time step t will depend on the decisions made in time step $(t-1)$.

$$S^{(t,h)} = S_0^{(d,h)} + \eta^C \cdot C^{(t,h)} - \frac{1}{\eta^D} \cdot D^{(t,h)} \qquad \forall t \in T, \forall h \in H, \forall d \in D \tag{10}$$

Here, d represents the day in the overall time horizon D which are being optimized. At the first day, S_0 is set to be zero for all batteries, while S_0 for all consecutive days are set to be equal to $S^{(t,h)}$ at the last time step t of $(d-1)$. As the market model only finds the optimal solution for each time step d, this battery behaviour creates a more realistic dependency between the periods.

In the original model, the batteries were only assumed to be charged with excess power of the local DERs. In this study, the peers are allowed to perform arbitrage operations and charge their batteries with electricity procured from the wholesale market.

2.2. Power Flow Model

After the P2P model has found the optimal solution for the day d, the main model proceeds to the power flow analysis part. Due to the distribution grid's distinct topology [16], it was decided to use the forward/backward sweep method with power summation.

One of the main ideas behind the proposed method is to combine the market and technical models. The P2P model finds a global optimal solution for the hours t within period d. The power flow is then executed for each hour of the market solution. As an output from the P2P model, we get the seven first matrices described under 'Variables' in Table 1. These must be adapted to fit the input requirements of the power flow, which is the net active and reactive demand at each node. The net active power demand is assumed to be the sum of the capacity imported to the node minus the capacity exported from the node. Hence, for each house h the active power demand for each time step t is calculated by Equation 11. The battery charging and discharging is assumed to happen behind the connection point at each node and is thus not included in the net power injection calculation.

$$P_d^{(t,h)} = G^{(t,h)} + I_{p2p}^{(t,h)} - E^{(t,h)} - X_{p2p}^{(t,h)} \qquad \forall t \in T, \forall h \in H \tag{11}$$

The P2P model only treats the exchange of active power and neglects the changes in reactive power caused by this exchange. However, the reactive power net injection at each node would likely be influenced by the trade as well. The net reactive power demand for each node must thus be calculated for each time step t. For simplicity, it was decided to find an average power factor for each of the nodes, and keep that constant for all time steps. From the given load data, it was obtained that all buses maintained a constant power factor of 0.98. The reactive power demand for each house h for each time step t was thus calculated with Equation 12.

$$Q_d^{(t,h)} = \sqrt{\frac{P_d^{(t,h)^2}}{\cos\phi^2} - P_d^{(t,h)^2}} = \sqrt{\frac{P_d^{(t,h)^2}}{0.98^2} - P_d^{(t,h)^2}} \qquad \forall t \in T, \forall h \in H \tag{12}$$

After calculating the net active and reactive power injections of various houses in day d based on Equations 11 and 12, the main model proceeds to the power flow analysis part. This part of the model is based on the open-source analysis tool MATPOWER [17]. In order to run a power flow analysis with this tool, a case struct is passed in as an input by one of the main functions *runpf*. This case struct must be set up as a specified MATPOWER case struct (mpc), which contains the necessary information for each node for one timestep. As it was decided to use the forward/backward sweep method with power summation, the solver 'PQSUM' was called upon with the options struct.

The load flow problem is then solved by the algorithm described in the following steps.

1. Set all voltages to 1 p.u.

2. The apparent branch power flow at the receiving end (s_t^k) is set to be equal to the total demand at receiving end (s_d^k) and the power drawn by the shunt admittance (y_d^k) connected to bus k. n_b represents the total number of buses in the system.

$$s_t^k = s_d^k + \frac{(y_d^k)^*}{v_k^2}, \qquad k = 1, 2, \ldots, n_b \tag{13}$$

3. *Backward sweep*: The sending end branch flows are calculated as the sum of the receiving end branch flows and branch losses by equation 14. Power summation is performed starting from the branch with the biggest index and heading towards the branch connected to the slack node. Equation 15 adds the receiving power at bus k to the sending power of the corresponding branch.

$$s_f^k = s_t^k + z_s \cdot \left|\frac{s_t^k}{v_k}\right|^2 \qquad k = n_l, n_l - 1, \ldots, 2 \tag{14}$$

$$s_{t,new}^i = s_t^i + s_f^k \qquad k = n_l, n_l - 1, \ldots, 2 \tag{15}$$

4. *Forward sweep*: The receiving end bus voltages are calculated with known sending power, voltage and series impedance.

$$v_k = v_i - z_s^k \cdot \left(\frac{s_f^k}{v_i}\right)^* \qquad k = 2, 3, \ldots, n_l \tag{16}$$

5. Compare voltages derived in iteration ν with the voltages from iteration $\tau - 1$ using equation 17.

$$\max_{i=1,\ldots,n_b} = \left\{ \left| v_i^{\tau} - v_i^{\tau-1} \right| \right\} < \varepsilon \tag{17}$$

If the difference between the voltage magnitudes is greater than the specified error limit ε, more iterations are needed and the process goes back to step 2. In MATPOWER, the default tolerance is set to be 10^{-8}.

After the *runpf* function is executed, the discrepancy between the flows in each direction is used to determine the power losses in the system, by Equation 18. Here, i and k represents the nodes at each end of the branch.

$$P_{loss} = P^{(i\rightarrow k,t)} + P^{(k\rightarrow i,t)} \qquad \forall i,k \in N \quad \forall t \in T \tag{18}$$

3. Implementation on real low-voltage network case

3.1. Grid Description

The low-voltage distribution grid used for all case studies in this paper is based on data from a real distribution grid located in Mid-Norway. The system is connected to the main grid through a 315 kVA distribution transformer. The voltage magnitude of the external grid, which is considered as the slack bus was fixed to 1 p.u. equal to 230 V. Fifty-two end users are connected to the distribution grid, through 16 feeder lines. All these nodes, as well as the bus bars connecting the feeder lines with the end-user branches, were modeled as PQ buses. In total, including both PV and PQ, there are 70 nodes in the system. A single-line diagram of the distribution system is depicted in Figure 1.

3.2. Case Descriptions

In this research, five different cases have been studied. This involves three different situations of DER instalment and a comparison of the impact of establishing a P2P market or not. The different case studies will be described in the following.

3.2.1. Reference Case

In order to get a complete understanding of the impacts of both integrating DERs and introducing a local market, a reference case was analyzed. Here, there are no PV panels or batteries installed, and everyone buys their electricity from the wholesale market. This reflects the current situation in most Norwegian low-voltage distribution grids.

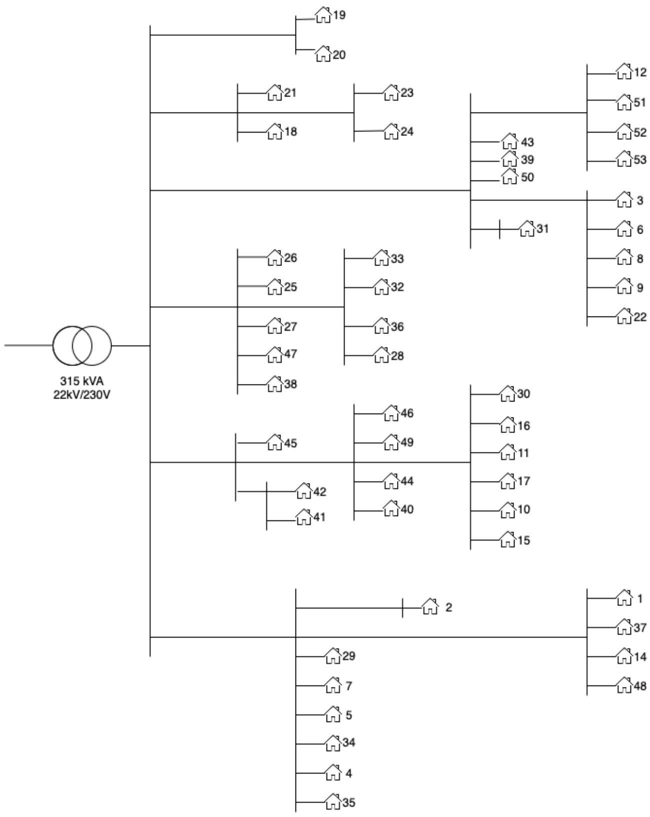


Figure 1: Single-line diagram of distribution system used in the case studies.

3.2.2. System A

Now, it is assumed that some of the houses in the neighborhood have invested in PV panels. The houses that have made the investments and the respective sizes of the installed panels are listed in Table 2. Considering this system setup, two cases named "No Local Market" and "P2P Market" are studied. The setup will henceforth be referred to as System A. In the No Local Market case, each house can cover their demand by generation from their own PVs or buy from the grid. Each prosumer can also sell their excess electricity back to the grid, but not directly to any of its neighbours. While, in the other case related to system A, the neighbourhood peers establish a local P2P market. The amount and location of PVs are the same as in the no market case, but now each peer can trade with each other. The prosumers are still able to sell their additional surplus to the grid.

3.2.3. System B

Some of the peers that invested in PVs in the previous case have now chosen to invest in batteries as well. This mainly includes houses with the highest demand. They all invest in the same battery, which will be further described in subsection 3.3.3. Similar to System A, both a No Local Market model and a P2P Market are studied for this configuration. The setup will be referred to as System B from this point.

Table 2: Houses with respective PV size installed. Blue text indicates battery installed.

PV size	Houses
4 kW	4, 6, 7, 11, 12, 14, 16, 19, 26, 27, 29, 30, 52, 53
6 kW	9, 10, 18, 22, 23, 32, 34, 36, 38, 42, 45, 46, 48
8 kW	8, 39
10 kW	2, 20, 31, 50

3.3. Input Data

3.3.1. Demand Profiles

Data sets for the entire area were provided by Zaferanlouei et al. [18], including both demand for each house and technical grid specifications. The demand for each node was aggregated to fit a one hour time step to match the availability of solar data. It is expected that the most significant differences will occur during summer, because of more local trading due to high PV generation. Hence, a 21 day period in the summer of 2012 were used.

3.3.2. PV Production Time Series

As the distribution grid is located in Mid-Norway, historical PV production time series for this area were obtained from the site renewables.ninja. The site gets, in turn, its data set from the MERRA-2 NASA database which contains meteorological data for the area from 2019. As the years of the demand data and the PV data did not match, it was chosen to use arbitrary days from June and July in the PV data, to capture the effects of different degrees of irradiation. As recommended for the geographical area, a panel tilt of 45° was used.

3.3.3. Battery Specifications

All the houses that invest in batteries in the corresponding cases invest in the same battery; a Tesla Powerwall 2AC. The technical performance specifications needed as input for the model are listed in Table 3. Both charging and discharging are constrained by an inverter of 5 kW nominal power, yielding full charge/discharge within 2.7 hours. As this thesis aims to analyse the technical impacts of the grid, technical details of the batteries are of secondary issues. As of this, no degradation processes are considered, and all efficiencies are assumed to be constant.

Table 3: Battery performance specifications [19].

$\bar{s}$, Upper SOC	13.5 kWh
$\underline{s}$, Lower SOC	0
α, Max. charge rate	5 kW
β, Max. discharge rate	5 kW
η^C, Charging efficiency	95 %
η^D, Discharging efficiency	95 %

3.3.4. Electricity Prices

The optimization and following market decisions of the P2P model are highly dependant on the wholesale spot prices. In order to reflect the relevant geographical area, these prices are retrieved for the NordPool pricing area NO5, Trondheim. Historical time series are openly available at NordPool's website, and three weeks corresponding to the demand data, but from 2019, were used. It was decided to use a more recent price time series, as it would better reflect the conditions of today's market. The grid tariff is determined by the local DSO, which in this case is Tensio AS. As of 2020, the energy term for households is set to 52.61 øre/kWh [20].

4. Results

To better understand the results for the power flow impact, one must first analyse the market decisions made for the different cases. The results presentation of this paper is thus divided into two parts; One for market results and one for grid impact results.

4.1. Market Results

4.1.1. Local Trading

Figure 2 presents the total capacity traded through the P2P market scheme for the two cases of DER integration for each day of the simulation period. It is clear that with the presence of batteries, the amount traded within the community is almost twice as much in some days than without storage opportunities. For both cases, day six yields the most local trade and is thus chosen as exemplary for the following comparison of results in the following. One can also observe from Figure 2(a) that there are some days with no local trade in the case of only PV panels installed. This happens in situations with little solar irradiation which self-sufficiency will be a priority for the peers, and there is subsequently no local trading. With batteries available, however, electricity is traded within the community every day, as can be seen in Figure 2(b).

Figure 3 provides an overview of the total trading between each peer throughout the simulation period. Negative values indicate import, while positive values indicate export. By studying the figure, one can see that more peers are active in the local market when batteries are installed. The batteries allow for price arbitrage and extend the trading period, thus allowing more peers to trade locally.

4.1.2. Operational Decisions

For the sake of showcasing the different operational decisions of the nodes, one arbitrary node from each peer category is chosen. Node 2 represents peers with both solar and storage, node 48 represents peers with PV only, and node 24 represents the pure consumer peers. With no local market operation, the only option for pure consumers like the house located at node 24 is to import from the main grid, as shown in 4(a). Considering the P2P trading opportunity provided by the local market, this house is able to exploit the lower P2P prices to cover its demand by P2P purchases when possible. With no storage available in the system (System A), as can be seen in Figure 4(b), local trade is only possible when the PVs are generating electricity. The consumer has no choice but to import from the grid during night time. However, in System B, as Figure 4(c) illustrates, even with no generation or flexibility of its own, the consumer located in node 24 participates actively in the local market when given the opportunity. The peer goes from being a passive price-taker relying solely on wholesale grid import, to being able to take more active decisions of the origin of its electricity consumption in order to minimise its electricity bill.

The operation of node 48 with only PV installation, for both market schemes, with System A and System B are illustrated in Figure 5. For this house, all surplus from PV generation is exported regardless of market structure. Comparing the presented schemes, one can observe that the same capacity is exported from the node, only differing in purpose. When a local market is present, the peer prioritises to sell its excess power within the community. Figure 5(b) illustrates that some export to the grid between noon and 2 pm, probably due to a saturated local market when there is no storage in the system. However, integrating storages to the grid leads to a change in the behaviour of the participants. The following observations can be figured out about the house connected to node

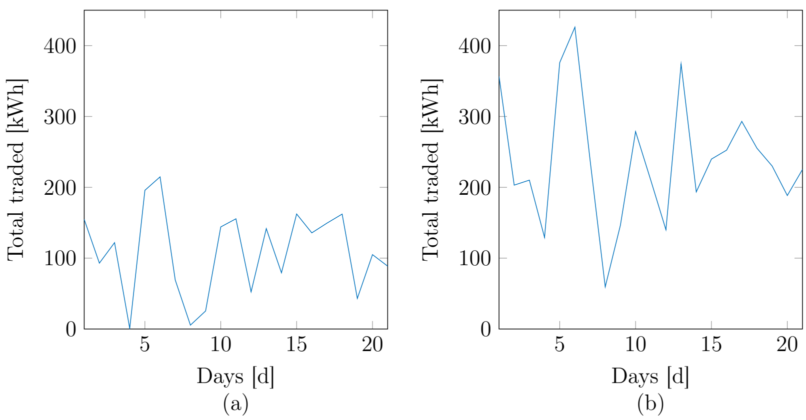


Figure 2: Total amount traded by P2P for a) System A and b) System B.

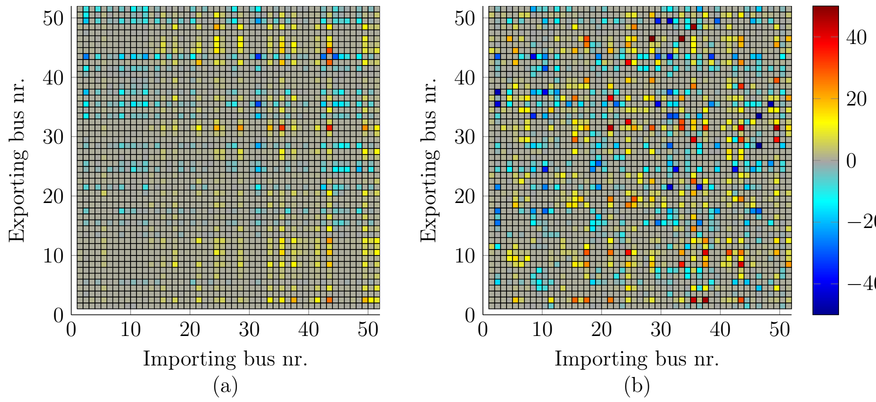


Figure 3: Total P2P trade between each node for a) System A and b) System B. Color bar values given in kWh.

48, comparing Figures 5(a), 5(b), and 5(c):

- All surplus is exported in all cases. However, P2P trade is prioritised over grid feed-in in Figure 5(c).
- The peer relies on purchasing electricity from other peers with charged batteries during the evening and morning when the P2P market is available, as can be seen in Figure 5(c).

From Figure 6, comparing no market and local market structures for node 2, the following can be observed about houses with both PV and storage installations:

- For both cases, the peer is self-sufficient in times of PV generation and mostly self-sufficient by battery discharge in the evening and morning. During the night, the demand is covered by grid import.
- For both cases, surplus electricity is being exported and no PV generation is curtailed.
- In both cases, the battery is charged by surplus PV generation during the

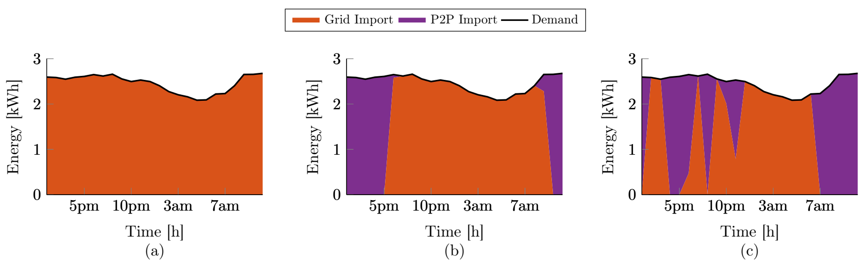


Figure 4: Operation of node 24 day 6 for a) No market case b) P2P case, System A and c) P2P case, System B.

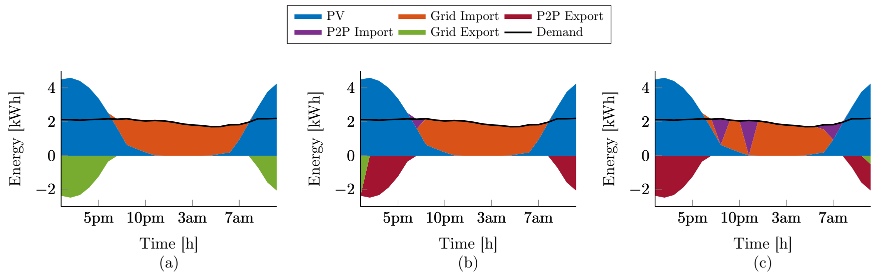


Figure 5: Operation of node 48 day 6 for a) No market case b) P2P case, System A and c) P2P case, System B.

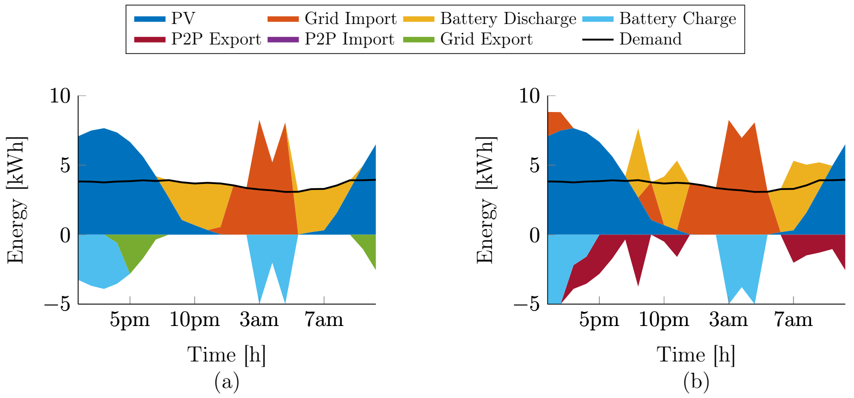


Figure 6: Operation of node 2 day 6 for a) No market case b) P2P case, System B.

day.

- When the peer has the opportunity to trade electricity locally, it prioritises this over grid feed-in.
- For both cases, the peer imports electricity to charge the battery. With the P2P market, one can observe that the peer prioritises discharging its battery in order to sell locally, instead of using it for self-consumption.
- In the case of P2P, in Figure 6(b), the peer chooses to import from the grid despite having an excessive PV generation. One can observe that this imported capacity is used to charge the battery.
- For both cases, there is a maximum charging of 5 kW to the battery for a couple of time steps during the night. This indicates that it is profitable for the peers (community) to procure extra from the grid during the low price time-slots and save it for later self-consumption or local trade, even with a 10 % loss in the round-trip charge/discharge of the battery.

4.1.3. Community Costs

To evaluate the effectiveness of the system operation one must look at the objective function value for each case. As the optimisation model aims to minimise the electricity related costs for the whole community, a lower objective function value indicates a more effective usage of local flexibility assets and P2P trade. In Table 4 the total community costs for the 21 day simulation period are presented for each case, and compared with the reference case. The share of expense and revenue from grid import/export is also given.

Table 4: Comparison of total community costs for each case, given in NOK.

	Reference	System A		System B	
		No Market	P2P	No Market	P2P
Total costs	**51,971**	**36,007** (-30.71 %)	**34,766** (-33.10 %)	**35,219** (-32.23 %)	**34,293** (-34.10 %)
Costs No Market vs. P2P	-	-	-3.45 %	-	-2.63 %
Costs of grid import	51,971	36,695	34,847	35,644	34,303
Revenue of grid export	-	687	82	425	10
Total grid import [kWh]	65,236	46,361	44,061	45,442	43,875
Total grid export [kWh]	-	2,657	356	1,622	41
Total P2P trade [kWh]	-	-	2,300	-	5,026
Demand by grid	100 %	71.07 %	67.54 %	69.63 %	67.23 %
Demand by local DERs	0 %	28.93 %	32.46 %	30.37 %	32.77 %

As can be noted from the results in Table 4, all cases with integrated DERs lower the total costs with around a third compared to the reference case. This is a natural consequence of the community relying less on centrally generated electricity, due to local production. The savings of establishing a P2P market is, however, of less eminence. It is also clear that both cases with P2P market yields a lower dependency on grid import, as the community is able to utilise the locally generated electricity in a more efficient manner. As the peers prioritise local trade over grid export, as seen in the previous section, the amount exported to the grid in both these cases are significantly lower than their corresponding cases with no local market.

4.2. Grid Impact Results

4.2.1. Voltage profiles without local market

Four nodes has been chosen to illustrate the different impacts on voltage levels of the case simulations. All four nodes are placed at the end of its radials.

Figure 7 shows the voltage levels at the representative nodes for the sixth day of the simulation with no local market present. Figure 7(a) shows the voltage levels, when there are no DERs connected to the grid. Since the nodes are placed at the end of their respective radials, the voltages are always lower than 1 p.u. The voltage levels at each of the nodes are relatively stable for all time steps, with a slight increase at night when the load is lower. The voltage levels at the representative nodes when PV panels are installed are presented in Figure 7(b). As can be expected, the voltages rise correspondingly with the PV production at the nodes, reaching a level above 1 p.u. at the peak generation hours. With the System B setting, since the batteries are allowed to be charged from power imported from the grid, the load at the corresponding node increases at the time of charging. With the wholesale spot prices being lower at night, this is a natural choice of charging time for battery owners. The effects can be seen in Figure 7(c) with quite significant voltage drops between 3 and 5 a.m. All charging power is imported from the grid due to no PV generation at this time.

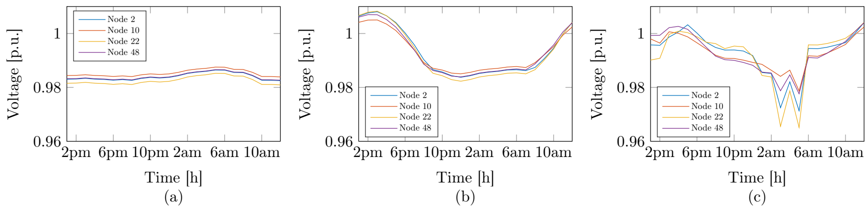


Figure 7: Voltage levels at representative nodes for Day 6 of simulation period with no market situation a) reference case b) system A and c) system B.

4.2.2. Voltage profiles with local market

Since all PV surplus is injected to the grid, regardless of the market structure, the voltage levels in system A remains unchanged. But, in System B, battery charging and discharging along with opportunity to trade within the community changes the voltage levels. This can be seen in Figure 8. It shows some of the same tendencies as the profile in Figure 7(c), with significant drops between 3 and 5 a.m. However, the voltage at each node tends to fluctuate more in the case of P2P trading. This is especially evident between 6 and 10 p.m., when the demand is high and PV generation is low.

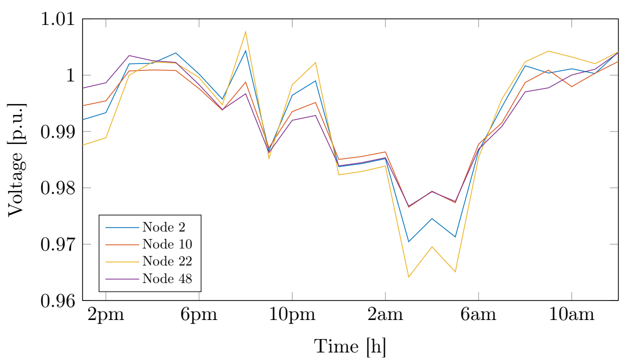


Figure 8: Voltage levels at representative nodes for System B case with P2P market. Day 6 of simulation period.

4.2.3. Peak Grid Consumption

As the distribution network must be dimensioned for peak capacity, this value is of great interest for the local DSO. In Table 5, peak demand and total grid consumption is presented for all cases. The values stated for peak demand represents the neighbourhood's maximum total demand for import from the external grid in one time step, via the transformer. It is clear from the table that the installation of roof-top PVs reduces the peak demand for both market strategies. The peak value does, however, increase significantly with the integration of batteries regardless of market structure. In this model, the battery owners are allowed to charge their batteries with procured electricity from the grid, not just their own solar panels. Consequently, at times with low spot prices, and little PV generation, situations can occur where households consume power both for their regular demand and for battery charging.

Table 5: Comparison of peak consumption for each case.

	Reference	**System A**		**System B**	
		No Market	P2P	No Market	P2P
Peak grid consumption [kWp]	185.95	160.42	160.42	221.64	221.64
Compared to reference	-	−13.73%	−13.73%	+19.19%	+19.19%
Total grid consumption [kWh]	65,236	46,361	44,061	45,442	43,875
Compared to reference	-	−28.93%	−28.93%	−30.34%	−32.74%
Demand by grid	100 %	71.07 %	67.54 %	69.63 %	67.23 %
Demand by local DERs	0 %	28.93 %	32.46 %	30.37 %	32.77 %

In the reference case, the peak consumption hour happens at 2 pm at the second day of the simulation period. In Figure 9, one can observe how the integration of DERs and storage has shifted the grid consumption profile this day. Here, one can clearly see the differences stated in Table 5. The grid consumption of the cases of System A is never higher than the reference case, and matches the reference level during the night. The peak grid import of the cases of System B is, however, shifted to the early morning hours and is much higher than the reference case. A similar profile is obtained for all the other days of simulation.

Figure 10 shows the duration curve for grid import for all five cases. In line with the values in Table 5, the peak consumption for the cases of System B are the highest. There is, however, not many hours of the simulation period that requires this high capacity, and both curves descend quite steeply. Now, one can also observe a difference between the trading schemes with System A, as the P2P curve is slightly steeper. For both cases of P2P trading, several hours in the period requires no import from the external grid. This implies that the community can utilise the local assets more efficiently with a local market in place. This is also confirmed by the results in Table 5, with the demand covered by DERs in percentage.

4.2.4. System Losses

An essential motivation for integrating DERs in the distribution network is the prospect of reducing the total system losses. A focus in this project

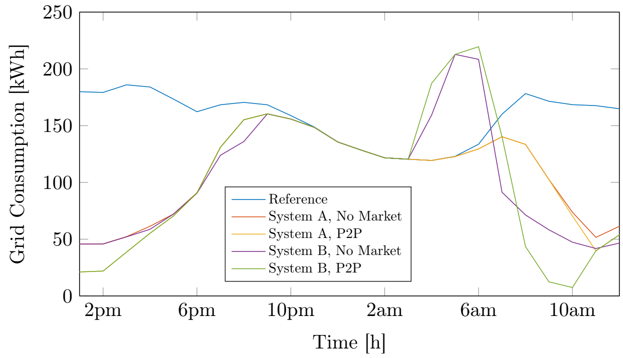


Figure 9: Illustration of grid consumption for all five cases for day 2 of simulation period.

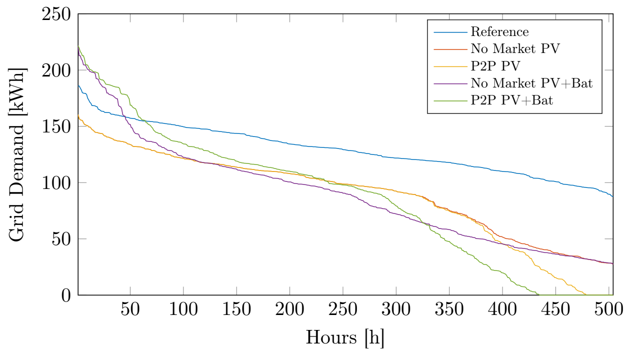


Figure 10: Duration curve for all five cases.

was thus to investigate if establishing a P2P market would further enhance or diminish these positive effects of DERs. Note that the system losses analysed in the following sections refer to the losses within the low-voltage distribution network.

The total losses for day 6 for the reference case are depicted in Figure 11(a), to illustrate how both integration of DERs and local electricity trading affect the system losses. One can observe that the amount of losses is higher during the day and lower during the night. This correlates with the grid usage, as there is higher total demand during the day and lower at nighttime. All other days within the simulation period show the same tendency.

As the neighbourhood invests in PV panels, the system behaviour in terms of system losses changes significantly. The total system losses for the sixth simulation day is presented in Figure 11(b). Compared to the reference case, the shape of the curve has an almost opposite tendency, with high system losses during the night and low during the day. This correlates with the PV production profile and confirms that self-consumption from private DERs during production hours is prioritised among the peers in the absence of storage alternatives. With a higher degree of self-sufficiency, there is less need for transfer capacity in the distribution grid and hence fewer losses. One can also observe that there are no differences between the two market strategies. This is true for the whole simulation period. Without the opportunity to store any excess electricity, the only other option than curtailing is to export. The identical system losses behaviour is a consequence of the power flows in the system being the same regardless of the trading scheme. The net load for each house at each time step is the same for both cases, whether the power flow is due to local or wholesale trading.

When batteries are installed in the neighbourhood, the effect of the chosen market strategy becomes more evident. As can be observed from Figure 11(c), the curve shares some of the same tendencies as with the System A cases, with a high amount of losses during the night and low during the day. However, compared to Figure 11(b), the period with higher losses in Figure 11(c) is shorter and the quantity is bigger. Now there is also a distinct difference between the case of P2P trade and the case with no local market. Due to different operation of the batteries, the distribution line usage also varies between the cases. As mentioned before, a peer with batteries will often sell stored energy locally rather than using it for self-sufficiency, and the grid is thus used more. Accordingly, this leads to more losses compared to the case with no local market.

In Table 6, a comparison of the total system losses of all five cases are presented. These numbers represent the total losses over the entire simulation period of 21 days. With the high degree of self-sufficiency in all cases involving DERs, it is clear that the losses decrease significantly compared to the reference case. Still, for the cases of System B, a P2P market structure leads to 13.79 % more losses than with no local trading. Note that with a 90 % round-trip efficiency of the batteries, the losses induced by charging/discharging is of quite a significance. These are additional to the total system losses.

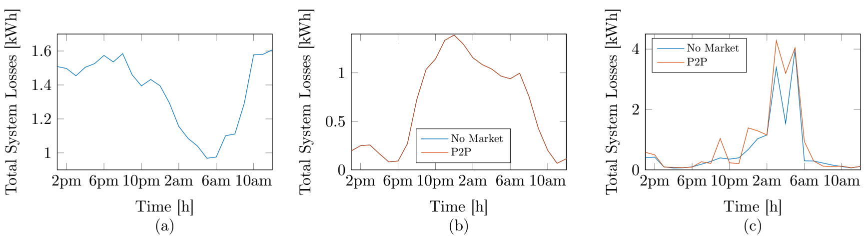


Figure 11: Total system losses, day 6 of simulation period for a) reference case, b) system A, and c) system B.

Table 6: Comparison of total system and battery losses for each case.

	Reference	System A		System B	
		No Market	P2P	No Market	P2P
Total System Losses [kWh]	937.15	517.96	517.96	566.36	644.47
Compared to reference	-	−44.73%	−44.73%	−39.57%	−31.23%
No Market vs. P2P	-	-	0%	-	+13.79%
Battery Losses [kWh]	-	-	-	581.69	650.70

5. Conclusions

The overall results showed that the integration of PV panels within the distribution network helped to mitigate both peak grid consumption and total system losses, with a decrease of respectively 13.73 % and 44.73 %. The establishment of a P2P market showed no differences in these results, due to the physical nature of the system power flows. The total amount of electricity procured from the wholesale market did, however, decrease with almost 5 % with the P2P market. In this case, the neighbourhood was even wholly independent from the external grid for 26 hours. This implicates a more efficient use of local resources and higher resilience of the community.

Accordingly, the same tendency could be observed when introducing local trade to System B, with 70 hours of independent operation. An uncontrolled charging of the private batteries led to voltage drops and an increased peak consumption of 19.19 % compared to the reference case. Now, the discrepancies in the results caused by the market design also became more apparent. The window of possible local trading was extended beyond the PV generation period, thus inducing more voltage fluctuations and a 13.79 % increase of system losses compared to the case of no local market. Economically, the P2P cases yielded the lowest aggregated community costs in total.

The results in this study are likely highly system dependent, both in terms of market design and system setup. With the market model featuring a centralised approach, it is clear that the community's assets and trade capacity are operated according to the optimal solution for the entire neighbourhood. This market structure is reliant on transparency and willingness to share data, which for many, is a significant barrier for joining the market. The coordination between the market agents and the DSO, however, may easier be facilitated with such a market structure with a local market operator serving as an interface.

P2P market models have gained popularity in academic research and real-life projects over the recent years, and this paper contributes to a little-explored aspect of the implementation. As the market is connected to a complex power system, it is essential to thoroughly analyse the effects such behaviour will have on the physical operation of the grid. The model has to take into consideration the specifications of the relevant grid and location and characteristics of the DERs or storage assets installed. As such, the study does not provide a definite conclusion to the grid impacts of a local market, but creates a novel insight and framework for further analyses on the topic.

To compliment and extend the results presented in this paper, further research should consider the following:

- Designing pricing schemes to adjust the market behaviour to align with the grid conditions.
- The one-hour time step and chosen methodology only capture the slow and steady-state effects on the grid. Further analyses should be conducted exploring more rapid effects such as output transients caused by, e.g. variations in solar irradiation. It should also consider analysing a possibly unbalanced three-phased system.
- The results in this paper is likely dependent on the market structure. As such, one should further evaluate other market designs and their impacts on grid operations.
- In all the four main case studies of this paper, the local DER generation was able to cover between 30-33 % of the community demand. More ambitious penetration levels should be analysed, or the system could be extended with other DERs with complementary generation profiles to extend the P2P trading opportunities. Demand response mechanisms is also an interesting aspect to be included in the presented model.

Acknowledgments

We are grateful to the the +CityxChange project (2018–2023), which has received funding from the Horizon 2020 research and innovation program under Grant Agreement No. 824260. We also acknowledge the support of the BEYOND project funded by the framework of the joint programming initiative ERA-Net Smart Energy Systems co-funded by H2020 under grant agreement No 775970.

References

[1] C. Martin, "Better Batteries." https://www.bloomberg.com/quicktake/batteries, 2019. Last accessed: 9.6.2020.

[2] IRENA, "Renewable Power Generation Costs in 2018," 2019.

[3] C. Zhang, J. Wu, C. Long, and M. Cheng, "Review of Existing Peer-to-Peer Energy Trading Projects," *Energy Procedia*, vol. 105, pp. 2563 – 2568, 2017. 8th International Conference on Applied Energy, ICAE2016, 8-11 October 2016, Beijing, China.

[4] Brooklyn Microgrid, "About Brooklyn Microgrid," 2019. Last accessed: 9.6.2020.

[5] C. Eid, L. A. Bollinger, B. Koirala, D. Scholten, E. Facchinetti, J. Lilliestam, and R. Hakvoort, "Market integration of local energy systems: Is local energy management compatible with European regulation for retail competition?," vol. 114, pp. 913–922, 2016.

[6] T. Sousa, T. Soares, P. Pinson, F. Moret, T. Baroche, and E. Sorin, "Peer-to-peer and community-based markets: A comprehensive review," *Renewable and Sustainable Energy Reviews*, vol. 104, pp. 367 – 378, 2019.

[7] A. Lüth, J. M. Zepter, P. C. del Granado, and R. Egging, "Local electricity market designs for peer-to-peer trading: The role of battery flexibility," *Applied Energy*, vol. 229, pp. 1233 – 1243, 2018.

[8] M. Khorasany, Y. Mishra, and G. Ledwich, "Peer-to-peer market clearing framework for ders using knapsack approximation algorithm," in *2017 IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT-Europe)*, pp. 1–6, Sept 2017.

[9] C. Zhang, J. Wu, Y. Zhou, M. Cheng, and C. Long, "Peer-to-peer energy trading in a microgrid," *Applied Energy*, vol. 220, pp. 1–12, 2018.

[10] G. Zizzo, E. Sanseverino, M. Ippolito, M. L. Di Silvestre, and P. Gallo, "A Technical Approach to P2P Energy Transactions in Microgrids," *IEEE Transactions on Industrial Informatics*, vol. PP, pp. 1–1, 02 2018.

[11] E. Munsing, J. Mather, and S. Moura, "Blockchains for decentralized optimization of energy resources in microgrid networks," pp. 2164–2171, 08 2017.

[12] T. Baroche, P. Pinson, R. L. G. Latimier, and H. B. Ahmed, "Exogenous approach to grid cost allocation in peer-to-peer electricity markets," *CoRR*, vol. abs/1803.02159, 2018.

[13] J. Guerrero, A. C. Chapman, and G. Verbič, "Decentralized P2P Energy Trading Under Network Constraints in a Low-Voltage Network," *IEEE Transactions on Smart Grid*, vol. 10, no. 5, pp. 5163–5173, 2019.

[14] T. Orlandini, T. Soares, T. Sousa, and P. Pinson, "Coordinating Consumer-Centric Market and Grid Operation on Distribution Grid," in *2019 16th International Conference on the European Energy Market (EEM)*, pp. 1–6, 2019.

[15] Tensio, "Nettleiepriser privat gjeldende fra 1. januar 2020." Last accessed: 5.5.2020.

[16] K. Balamurugan and D. Srinivasan, "Review of power flow studies on distribution network with distributed generation," *Proceedings of the International Conference on Power Electronics and Drive Systems*, pp. 411–417, 12 2011.

[17] R. Zimmeramann, C. Murillo-Sánchez, and R. Thompson, "MATPOWER: Steady-State Operations, Planning and Analysis Tools for Power SYstems Research and Education," vol. 26, pp. 12–19, February 2011.

[18] S. Zaferanlouei, M. Korpås, H. Farahmand, and V. V. Vadlamudi, "Integration of PEV and PV in Norway using multi-period ACOPF — Case study," in *2017 IEEE Manchester PowerTech*, pp. 1–6, 2017.

[19] Tesla, Inc., "Tesla Powerwall Technical Specs," 2020. Last accessed: 5.5.2020.

[20] Tensio, "Nettleiepriser 2020 - for private husholdninger," 2020.