Tampere University

Mehdi Attar

DISTRIBUTION SYSTEM CONGESTION MANAGEMENT THROUGH MARKET MECHANISM

ABSTRACT

Mehdi Attar: Distribution System Congestion Management Through Market Mechanism
Master of Science Thesis
Tampere University
Degree Program in Electrical Engineering, MSc (Tech)
November 2019

Nowadays, the electricity industry has experienced essential changes compared to the past. The idea of distributed generations (DGs) in distribution networks replacing the bulk power plants traditionally connected to the high voltage levels is one of those changes. Irrespective of the positive aspects of the mentioned change, congestion is the problem that is increasingly occurring in distribution systems due to an upward trend in DGs' penetration in distribution networks. Methods to solve the congestion in distribution networks has received the attention of researchers and those who are working in the distribution network domain recently.

The idea of the thesis is to solve the congestion in distribution networks through market mechanisms. To do so, a simulation environment is designed and implemented in order to enable us to analyze and understand the features of various scenarios associated with congestion management with or without using market mechanisms. By using the simulation environment, five different scenarios are investigated, and the results show the congestion relief of the distribution network by linking the flexibility buyers (distribution system operators (DSOs)) to flexibility providers (aggregators) through the local flexibility market (LFM) platform. Timing and frequency of operation are proposed for LFM in the thesis. Besides, the benefits of LFM for DSOs are investigated, and the impact of inaccuracy in predictive optimal power flow (OPF) on the real-time operation of the distribution system is studied as well.

Keywords: DG, congestion management, distribution network, simulation environment, LFM, aggregator, flexibility provider, OPF

PREFACE

I opened a new chapter in my life when I started my master's studies in Tampere University, Tampere, Finland. Finding myself in a new place with multiple unknown things was a new challenge. As time passed, I found that Finland is a place where I can grow, and I decided to do my best in my studies. November 2017 was the time when I proudly started collaborating with Prof. Sami Repo about a paper related to distribution system voltage control. The collaboration continued until May 2018 when I became his full-time research assistant. From that time, the speed of learning new things in the area of distribution network voltage control, electricity markets, distribution system automation, and information technology was accelerated, which I am very cheerful about that.

I wish to express my gratitude to my parents, who have supported me for the last 30 years of my life, my brothers, and also my friends across the world. Finally, I sincerely thank my beloved wife Kiana who tolerated the difficulties and gave me positive energy along the way.

Tampere, 1 November 2019

Mehdi Attar

CONTENTS

LIST OF SYMBOLS AND ABBREVIATIONS

aFRR	automatic Frequency Restoration reserve
AM	Ahead Market
AVR	Automatic Voltage Regulator
BRP	Balance Responsible Party
CB	Circuit Breaker
CM	Congestion Management
CRP	Conditional Reprofiling
CVC	Coordinated Voltage Control
DA	Day-ahead Market
DER	Distributed Energy Resource
DG	Distributed generation
DMS	Distribution Management System
DSO	Distribution System Operator
EHV	Extra High Voltage
EPS	Electric Power System
EU	European Union
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
EV	Electric Vehicle
FCR-D	Frequency Containment Reserve- Disturbance
FCR-N	Frequency Containment Reserve- Normal
GDPR	Genaral Data Protection Regulation
HC	Hosting Capacity
HDI	Human Development Index
HV	High Voltage
ID	Intra-day Market
IoT	Internet of Things
IT	Information Technology
LFM	Local Flexibility Market
LV	Low Voltage
mFRR	manual Frequency Restoration reserve
MOL	Merit Order List
MV	Medium Voltage
NOS	Normally Open Switch
OBJ	Objective function
OLTC	On Load Tap Changer
OPF	Optimal Power Flow
PCC	Point of Common Coupling
RR	Restoration Reserve
RVC	Rapid Voltage Change
RES	Renewable Energy Source
SAIFI	System Average Interruption Frequency Index
SCR	Short Circuit Ratio
SO	System Operator
SOGL	System Operation Guideline
SRP	Scheduled Reprofiling
TLC	Traffic Light Concept
TSO	Transmission System Operator
UML	Unified Modeling Language
VM	Virtual Machine

α	Subscription charge

β	Volumetric charge
D^i	Duration of the ith solution candidate
E^i	Energy price for during the activation of the ith solution candidate
GT	Grid tariff
$I_{branch}^{i,m}$	Current of mth branch as a result of activating the ith solution candidate
$I_{branch,max}^m$	Maximum allowed current of the mth branch
OBJ^i	Objective function of the ith solution candidate
P	Active power
P_g	Active power generation of DG
P_{ohmic}	Ohmic power losses
P_{sun}	Power received from sun
$P_{f.convection}$	Forced convection cooling power
$P_{radiation}$	Thermal radiation power
P_{lossB}^i	Power losses of the network if i^{th} solution candidate is activated
P_{lossA}	Power losses of the network currently
Q	Reactive power
R	Resistance
SC^i	Associated costs of ith solution candidate activation
V	Voltage
ΔV	Voltage difference
V_{min}	Minimum permissible voltage
V_{max}	Maximum permissible voltage
$V_{bus}^{i,n}$	Voltage of nth bus as a result of activating the ith solution candidate
X	Reactance
γ	Capacity charge

1. INTRODUCTION

It is an undeniable fact that energy, as a motive force of humankind, plays a vital role in the development of any society. Besides global population growth, the rising of living standards, and the upward trend of automation systems have been rocketing the energy consumption worldwide. Among various types of energy (e.g., mechanical, chemical, thermal, mechanical, etc.), electrical energy is one of the most popular kinds because it is weightless, relatively easier to transport and distribute, and high efficient in consumption. Hence, it is not a surprise to have a rising tendency in electricity consumption nowadays. Not only the demand sector but also electricity generation has been experiencing significant changes, mainly due to the integration of renewable energy sources (RESs) in electricity production. However, RESs' integration in electricity production phases out the bulk fossil fuel power plants that are desirable from environmental aspects, RES's intermittency in power production is their drawback. Another difficulty is that RESs are usually small in size, and tens/hundreds of them scattering in the whole power system should replace a bulk fossil fuel power plant, which means stress from transmission system is gradually shifting to distribution networks where RESs are often connected. Also, a robust control system is required in order not to compromise controllability when a large number of RESs replace a huge power plant. One of the problems created by the above changes in the electricity industry is congestion, which will be discussed in the following. In power engineering world, it is an indisputable fact that production and consumption should have a perfect balance otherwise; in effect, frequency fluctuation is unavoidable. Even if the production and consumption meet each other perfectly in the system level, in a localized view, area electric power system (EPS) needs to have a balance between consumption and production, if not, excessive power flows through lines that may violate the network constraints and congestion (bottleneck) occurs at the local level of power system. However, congestion may cause stability problems in the system level if not treated well; it is often understood as a localized problem, especially in distribution networks.

Congestion can be managed by either taking some technical courses of action by a grid operator itself or procuring some flexibility services from available markets. Flexibility is defined as "the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) to provide a service within the energy

system" [1]. About the congestion problem in distribution networks, it should be stated that it is caused by either too high demand or too high production in an area EPS. Almost without any impact on the system frequency, demand-supply imbalance in the local level of EPS contributes to a power flow from stronger areas to the weaker areas of the network. This amount of power flow may violate the network limitations causing congestion. Furthermore, network contingencies (e.g., faults, force majeure conditions, etc.) can be counted as a reason for congestion because they can lead to an outage of components resulting in overloading or voltage problems of adjacent devices. Maintenance work may cause congestion as well, which can be avoided if it is scheduled along with taking some actions to support the system during maintenance time.

The congestion problem dealing with in this thesis occurs in distribution networks, however, due to the existence of the similar problem in transmission level, it is beneficial to shortly discuss the ongoing alternatives of congestion problem in transmission level through the market mechanism in the following.

Nord Pool [2] is a leading power market in Europe that operates ahead markets (day-ahead (DA) and intraday(ID)). It works in Finland, Norway, Denmark, Sweden, Estonia, Latvia, Lithuania, Germany, and the UK. However, the detailed information of the markets will be presented in the next chapter; a brief explanation about congestion management (CM) through the DA market in transmission system operator (TSO) level is provided here. Three distinct approaches can be taken into account for DA market clearance. The first methodology is based on a nodal pricing model where the best answer to a welfare maximization problem subject to generation restrictions, transmission constraints, and energy balance limitations should be found [3]. Due to having a huge number of prices, price formation is cumbersome and time-consuming, which is not desirable for market operators and participants [4]. Therefore, a simplified version of the nodal pricing model known as "zonal pricing" with predetermined zones became the choice of Nord Pool. The market is cleared based on pan-European hybrid electricity market integration algorithm (EUPHEMIA) [5]. The extreme form of the zonal pricing model is the uniform pricing system, where all the nodes share a common energy price [4]. It is highly likely to hit transmission restrictions by using the uniform model, which is why ex-post adjustment of market outcomes known as redispatch is necessary for the uniform model. It should be noted that both uniform and zonal pricing models utilize redipatch to avoid congestion.

Once the DA market in Nordpool is cleared based on the uniform pricing system, the system price will be announced to market participants meaning that the electricity price per MW becomes identical for all market players irrespective of their geographical location. In the condition of congestion, to meet the transmission constraints between two

nearby zones, the zonal pricing system is deployed, meaning that by up and downregulation of bids (redispatch), the electricity price gets higher in the zone with production shortage and lower in the area with production surplus. In this way, redispatch contributes not to violate transmission capacities resulting in congestion elimination. By using redispatch (counter-trading), the generated price signals induce both producers and consumers to consider the physical reality of the system in their portfolio management. Also, a price difference between nearby price zones is a sign of transmission scarcity, which is used as an input for decision making of investment in transmission and generation sector. Moreover, the price difference between two zones yields congestion income[1] which is used for maintenance and transmission extension measures [4].

The discussed practice in the DA market is a successful example of market mechanism utilization on CM in the transmission level. Similar to the redispatch approach in the DA market, it is suggested that DSOs can overcome the ascending trend of congestion in distribution networks by procuring flexibility. Therefore, a need was felt to have a piece of work discussing the congestion problem in distribution networks and covering almost all the relevant aspects.

1.1 Objectives and research questions

The following objectives are pursued in the thesis: Enabling a DSO to access the flexibilities through market mechanism is the first objective of the thesis followed by finding various ways for CM in distribution systems including a combination of market and non-market based solutions. In addition it is aimed to build a simulation environment where different scenarios can be compared and analyzed. Also understanding the requirements of data exchange, protocols, data formats for efficient communication in the simulation environment is another objective of the thesis.

To be more specific, the following research questions are aimed to answer in the thesis. Firstly, having an idea about the frequency and operation time of LFM. Secondly, understanding whether LFM brings benefits to DSOs.Thirdly, the impact of accuracy of predictive OPF on CM will be investigated.

---

[1] Congestion rent, transmission surplus and merchandising surplus are equivalent terms for congestion income [4].

1.2 Scope

Solving the congestion problem of a distribution system through LFM which is represented by the designed simulation environment is the scope of the thesis as shown in Figure 1. In other words, three computers forming the simulation environment act as a tool to clarify how CM can be realized in practice by examining different scenarios. Extendibility and flexibility of the simulation environment have been taken into account in its design stage because the aim is to analyze various situations whether for the sake of the thesis or future studies. It is worth mentioning that technical aspects of distribution networks related to CM have been focused, and economic studies are not taken into account in the present work. Therefore, the monetary evaluation of various scenarios is out of the scope of the thesis.
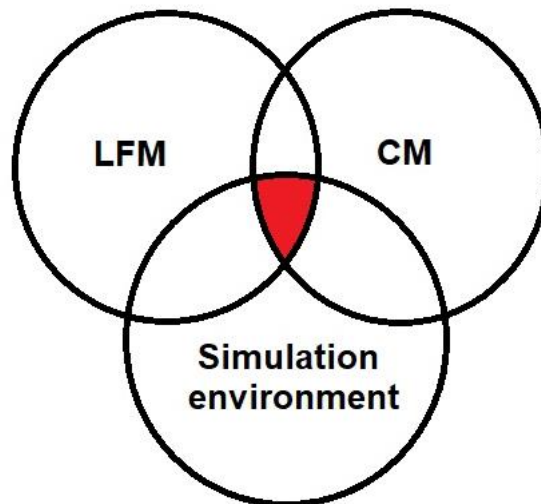
Figure 1.Scope of the thesis

1.3 Tasks

The following tasks should be accomplished in order to enable us to achieve the objectives and answering the mentioned research questions:

- Providing a broad perspective about flexibility, energy, and power markets.
- Defining the congestion and surveying DSO's non-market based solutions for congestion relief.
- Understanding how CM through a market mechanism realizes in distribution networks.

- Discovering the positive impact of the market on CM by numerical studies implementation.
- Building a simulation environment by using a simulated case study.
- Modeling the simplified implementation of the LFM and distribution management system (DMS) to the simulation environment.
- Adapting the existing functionality of CM to the simulation environment.
- Proposing the required information needed to be exchanged between systems in the simulation environment.

1.4 Structure of the thesis

Non-market based methods of congestion relief are presented in chapter 2. Chapter 3 contains an explanation concerning electricity markets, including LFM. Numerical studies and simulations are conducted in chapter 5, and chapter 6 is devoted to the discussion. Chapter 7 will present a conclusion.

2. NON-MARKET BASED CONGESTION MAN-AGEMENT OF DISTRIBUTION SYSTEM

Non-market based methods of congestion management will be presented in this chapter. However, before relieving congestion, it seems vital to know the underlying reasons behind the congestion and its definition. As congestion in the distribution network is intended to be investigated in this thesis, once the congestion problem itself is discussed, congestion solutions suiting distribution system characteristics will be provided.

The Commission Regulation (EU) 2015/1222 [6] defines physical congestion in transmission level as "any network situation where forecasted or realized power flows violate the thermal limits of the elements of the grid and voltage stability, or the angle stability limits of the power system." In distribution networks, since voltage and angle stability are not an issue, voltage (over-voltage, under-voltage, harmonic content), current and thermal violations will be discussed.

- **Voltage violation**

EN 50160 [7] is the European standard ensuring the minimum requirement of power quality for MV and LV customers. Different requirements such as power frequency, voltage magnitude, rapid voltage change, harmonic voltage, etc have been introduced in the standard. Among them, steady-state voltage magnitude of LV and MV should stay between +-10% of nominal voltage for 95% of a week [7]. Among the mentioned voltage quality problems causing congestion, over-voltage is an increasing problem of distribution networks, and proof of voltage rise due to active power injection will be shortly explained in the following. Therefore, a grid operator should assure that the power generation of a distributed generator (DG) does not hit the maximum permissible limit of voltage.

Figure 2 shows the single-line diagram of a 2-bus distribution system useful for voltage rise analysis.
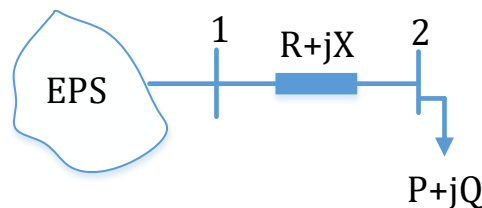

Figure 2*.Single-line diagram of a 2-bus system*

$$\overrightarrow{V_2} = \overrightarrow{V_1} - (R + jX)\frac{P - jQ}{\overrightarrow{V_2^*}} \tag{1}$$

$$\overrightarrow{\Delta V} = \frac{RP + XQ}{\overrightarrow{V_2}} + j\frac{XP - RQ}{\overrightarrow{V_2}} \tag{2}$$

$$\overrightarrow{\Delta V} = \frac{RP + XQ}{\overrightarrow{V_2}} \tag{3}$$

The deduction of the voltage drop of the line from the voltage of bus 1 denoted by V_1 gives the voltage at bus 2 indicated by V_2 According to (1). In the equation, R and X represent line resistance and reactance respectively, and active and reactive power consumption have been signified by P and Q, respectively. After some algebra, equation (2) is derived. Since the imaginary term of (2) is negligible, equation (3) can be assumed to be equal to the equation (2). By looking at (3), it is clear that either active or reactive power consumption causes a voltage drop at bus 2. Figure 3 shows the same network after adding a distributed generator (DG) on bus 2. DG's impact on the voltage change can be seen in equation (4) when DG produces active power only. The voltage at bus 2 is dependant on the magnitude of DG's power output. If DG's power generation is more than the load at bus 2, then voltage rise starts to happen, that is the reason for the voltage rise behind active power injection.
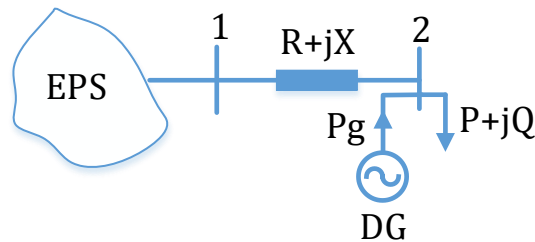

Figure 3.Single-line diagram of a 2-bus system with DG

$$\overrightarrow{\Delta V} = \frac{R(P - Pg) + XQ}{\overrightarrow{V_2}} \tag{4}$$

- **Current violation**

Except for the condition that power production and consumption are located on the same bus, power needs to travel the physical distance between production and consumption points. If the amount of current flow between production and consumption points is more than the ampacity of underground cables, overhead lines, transformers, circuit breakers (CBs), etc., congestion occurs. Conductor resizing, construction of new lines, distributing the loads between adjacent feeders based on their current rating, etc can be used as a remedy for congestion caused by overloading.

- **Thermal violation**

Thermal equilibrium available in (5) [8] guarantees the steady temperature of a conductor; otherwise, the temperature change is expected.

$$P_{ohmic} + P_{sun} = P_{f.convection} + P_{radiation} \tag{5}$$

Conductor resistance gives rise to ohmic losses P_{ohmic} Because of the current flow. The power received from sunlight termed P_{sun} and $P_{f.convection}$ stands for forced-convection cooling power leading to heat dissipation. A part of generated heat dissipates through thermal radiation termed $P_{radiation}$.

With constant current magnitude, the ohmic loss is proportional to the conductor's resistance. P_{sun} is influenced by net solar irradiance, conductor material, color, etc. Therefore, cloudy days favor transmission lines, pole-mounted transformers, etc being operated with lower temperatures. For underground cables, P_{sun} is zero. Wind speed and ambient temperature are highly influential factors in $P_{f.convection}$ Allowing grid operators to deploy the system under overloading conditions. For instance, during wintertime in Finland, minus temperatures increase the ampacity of overhead lines and pole-mounted transformers.

In a condition that a high amount of energy is produced at a node or in an area, except the energy consumed by local loads, the remaining generated energy travels to nearby loads giving rise to a violation of the thermal limit of components. Therefore, the thermal limit is a confining factor for the operation of the power system that may create congestion.

It should be stressed that the underlying reason for congestion, even for a single network is not similar over time. For instance, during wintertime, congestion of a distribution feeder could be due to over-loading of secondary substation's transformer while congestion of the same feeder in the summertime can be caused by excess power injection of rooftop solar panels leading to an over-voltage problem. Therefore, DSOs should monitor the network's constraints, knowing that they can predict the type of probable congestion based on the strengths and weaknesses of their grid.

The non-market based solutions of CM in distribution networks will be covered in the rest of this chapter.

2.1 Network reinforcement

Reduction of the network's impedance between production and consumption by conductor resizing, constructing a new line with lower impedance, etc. is termed network reinforcement. However, network reinforcement is cost-intensive; it is almost the first solution

of many DSOs dealing with congestion problem because DSOs have done this practice several times, and they are technically capable of that besides that reinforcement is a very reliable solution. During the construction time of grid reinforcement, other measures such as real power curtailment could be used. This measure is more applicable during the construction time if feed-in peaks are rarely happening [9]. However, network reinforcement is the most obvious solution for the congestion problem; it cannot always be used mainly because of two reasons. Firstly it is expensive and time-consuming. Secondly, due to a long length of planning horizon (i.e., 20 years), the uncertainty of influential parameters in planning such as electricity generation and consumption, municipal planning, etc intensifies, and the decision making becomes riskier. For instance, prosumers are increasingly persuaded to inject power (especially renewable kind which is intermittent) to the grid due to feed-in-tariffs; meanwhile, the emergence of new technologies, namely electric vehicles (EVs) makes the load forecasting harder due to changing the consumption pattern. Therefore it sounds rational to reduce the frequency and size of network reinforcement. To do so, as network reinforcement is a long-term solution, in strategic planning of network, reinforcement should be assisted by some complementary alternatives such as coordinated voltage control (CVC) [10], market-based solutions, etc.

2.2 Active power curtailment

Curtailing the active power of generators operating in a distribution system is a mean of CM [11]. However, this method solves the congestion in a short time; in the long-run, it is not often financially viable because compensation payments for feed-in curtailment become expensive. The required amount of curtailment duration in a fixed period (i.e., annually), congestion cost for a DSO, age of the existing network and financial strength of a DSO, etc define whether to consider active power curtailment as long, medium or short-term solution. A DSO is not entitled to active power curtailment of production units instead depending on the HC of the distribution network and required capability of a generator; the DSO usually provides various connection capacity schemes such as firm and non-firm kinds. The non-firm connection allows DSO to curtail according to an agreed amount of curtailment hours, which instead makes the connection cost cheaper for the electricity producer compared to a situation that a generator with firm connection capacity does not provide any active power flexibility to its connected DSO. Financially speaking, a cheaper connection cost is counterbalanced by active power curtailment. Due to a cheap operation cost and expensive investment cost of RESs in electricity production, the maximum energy desired to be extracted from RERs opposes the idea of

active power curtailment. Therefore active power curtailment is not a very welcome congestion solution neither for RESs' owners nor for climate-concerned parties. If the frequency and duration of feed-in peaks are limited to a few hours per month, real power curtailment can be seen as a workable solution.

2.3 Network reconfiguration

With respect to numerous switches available in a distribution network, changing the status of switches is a real-world solution for DSOs to mitigate congestion [12]. Figure 4 (a) depicts a primary substation feeding two feeders. The normally open switch (NOS) guarantees the radial operation of the two feeders emphasizing the fact that the protection of meshed networks is more complicated than radial networks, which is why that switch is on normally-open mode. Now, as shown in Figure 4 (b), it is assumed that a DG is connected to bus 3, creating over-voltage at that bus and its nearby buses due to power production more than HC of the feeder 1 and sending power back to the primary substation. The DSO's solution to eliminate congestion can be an increase in the loading of feeder 1 by adding a medium voltage load to feeder 1, as shown in Figure 4 (c), such a way that power produced by the DG is consumed locally preventing reverse power flow and overvoltage. To avoid overloading the feeder 1 when DG is shutdown, the state of the network should return to the initial state as shown in Figure 4 (a). It means that a robust automation system should be responsible for the coordinated actions of all involved switches. Indeed, it should be stressed that the mentioned solution is applicable only if both NOSs are fully automated coordinating with DG automation system. Changing the status of switches are used as a mid-term alternative for congestion relief.
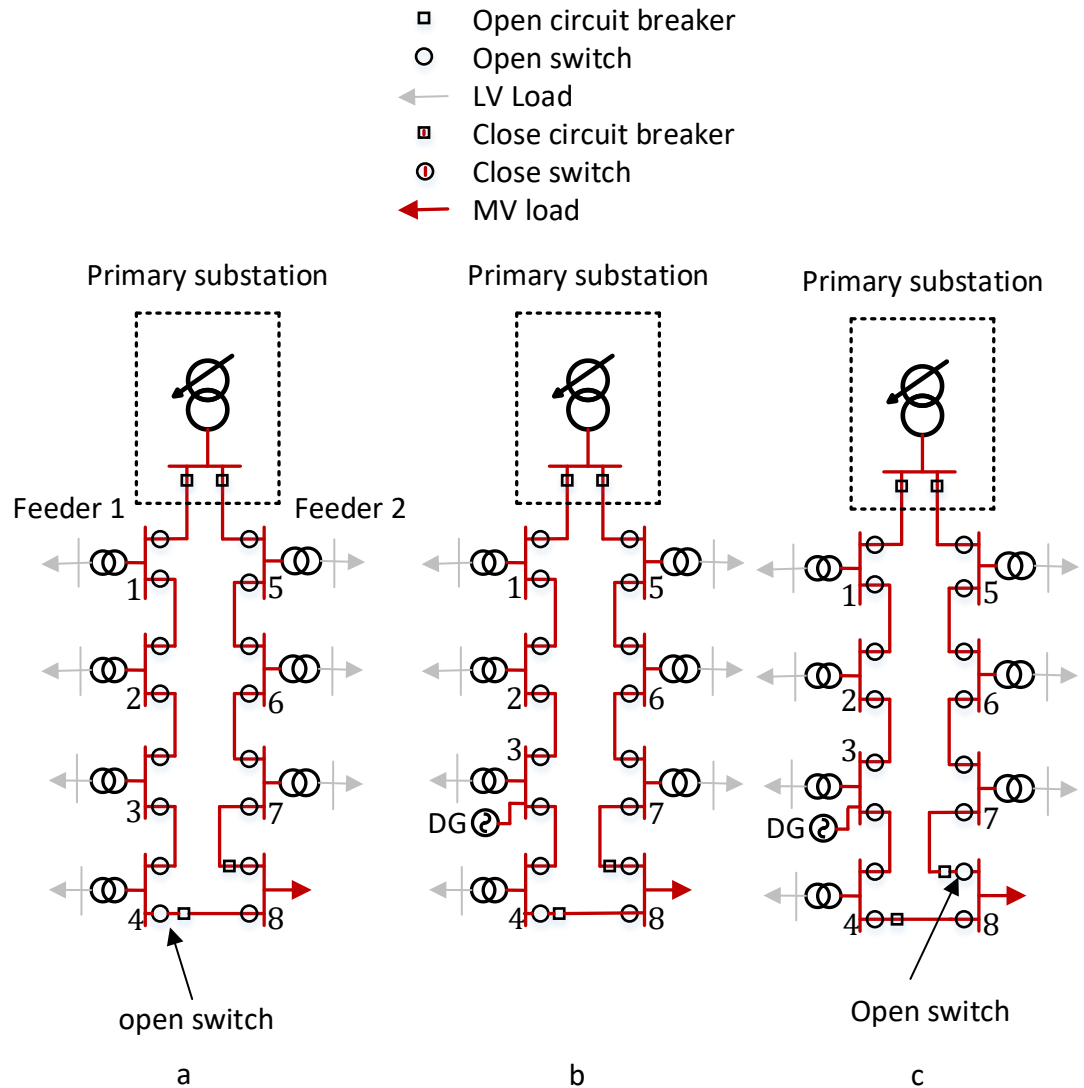
Figure 4.Sample one-line diagram of MV and LV network. a) Network before DG interconnection b) Network after DG interconnection c) Network after recon-figuration

2.4 Grid code

Grid code is a set of requirements that power generation units should satisfy to receive grid connection permission. The higher the rating of the production unit, the stricter the grid code because the impact of larger generators on the grid is substantial, and grid code is defined to unify the power plant's behavior in steady and transient states. Grid codes are different depending on the country and the state of the power system that they have been designed for. For instance, the grid code released by ENTSO-E on 8th March 2013 [13] consists requirements for grid connection applicable to all generators which is more flexible than its kind in America (IEEE-1547) [14] because ENTSO-E cannot regard the specific features of national power systems of each country in Europe under one

standard. Grid codes mainly contain frequency and voltage quality requirements for generators in steady and transient states. Voltage requirements can be designated such that it favors CM. As an example, grid code may require the Volt/Var control system to every generator aiming to interconnect to the grid in order to support the voltage. By supporting the grid's voltage, congestion probability stemming from either over or under-voltage is reduced. As a result, grid code can be a mean of CM if well established. As a real-world case, in Finland, since grid code does not oblige DERs to be on Volt/Var mode, DSOs are willing to procure reactive power.

2.5 Grid tariff

A grid tariff affects customers' consumption pattern slowly; nevertheless, it can be seen as a powerful mean to satisfy different objectives such as energy efficiency, bill savings, loss reductions or long-term investment cuts on the grid [14]. The reason why the grid tariff is mentioned here is that it can slowly change the customer's behavior in favor of CM if a capacity charge is added to the current grid tariffs.

The present grid tariff of some DSOs include two parts are as follows:

$$GT\left(^{\epsilon}/_{kWh}\right) = \alpha + \beta(energy) \tag{6}$$

where GT represents grid tariff payable by customers. α stands for subscription charge ($^{\epsilon}/_{period}$), which contains monthly or periodic fees covering metering and customer services. Besides, customers pay for factor β representing volumetric charge ($^{\epsilon}/_{kWh}$). The mentioned grid tariff is not cost-reflective enough because capacity adequacy of the network might be endangered if the grid tariff does not hamper power peaks, and a DSO needs to make infrastructure investment. Therefore it is recommended that γ be added to the current grid tariff as shown in (7) in a similar way that some DSOs in Finland already did this practice [15] because a DSO is obliged to maintain enough capacity for continuity of the service and if a customer causes peaks, the capacity charge income will be devoted to distribution network reinforcement in future.

$$GT\left(^{\epsilon}/_{kW}, ^{\epsilon}/_{kWh}\right) = \alpha + \beta(energy) + \gamma(power) \tag{7}$$

Where γ is representative of capacity charge ($^{\epsilon}/_{kW}$) depending on the maximum capacity of the connection point or used power ($^{\epsilon}/_{kW_{max}}$). Once the capacity charge is added to the grid tariffs, as it is not intended to increase the grid tariff and restructuring is the target, the weight of fixed and volumetric charges should be reduced intelligently to provide space for capacity charge involvement.

2.6 Reactive power compensation

Reactive power compensation is a mean of CM [16]. Equation (8) is the extended version of (4) suitable for analysis of reactive power compensation of a DG on voltage changes of the network. As shown in figure 5, if it can be assumed that the DG is a synchronous generator, by changing the excitation current of the DG's field coil, either absorption or generation of the reactive power at terminals of the DG can be realized. Therefore, concerning (8), the numerator of the voltage change equation is a function of not only active power generation but also reactive power compensation of the DG. In fact; by altering the amplitude and sign of Qg in the numerator, a degree of freedom to active power production is awarded, resulting in congestion prevention. To avoid a voltage rise problem, the DG can consume a limited amount of reactive power to dampen voltage rise. In contrast, to prevent under-voltage situations, reactive power injection is possible. It is recommended that the DGs with reactive power compensation capability (e.g., synchronous generators) should be equipped with a control system (e.g., volt/var) to compensate reactive power where steady-state voltage violation is about to happen. However, it is arguable that volt/var control of DGs interferes with the operation of other voltage regulation devices such as on-load tap changer (OLTCs), by proper coordination of all voltage control equipment the maximum benefit for DSO can be harvested.

$$\overrightarrow{\Delta V} = \frac{R(P - P_g) + X(Q \pm Q_g)}{\overrightarrow{V_2}} \tag{8}$$
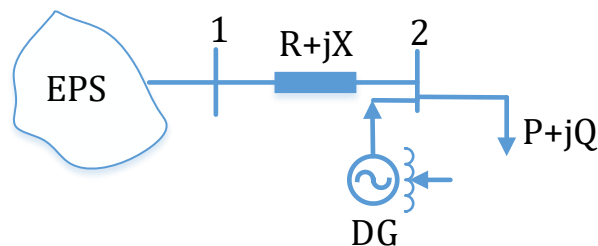

Figure 5.*Single line diagram of a 2-bus system with DG on reactive power compensation mode*

If congestion is caused by overloading of components, reactive power compensation with the aim of power factor improvement can also be used. In this condition, DG's reactive power compensation becomes a function of flowing apparent power of the network at a point of common coupling (PCC).

Due to reliability concerns, it is a common practice in Finland to replace overhead lines with underground cables, especially for feeders crossing in the middle of woods, and as a consequence, over-voltage becomes an issue during light loading levels. Therefore, unlike in the past years, reactive power absorption methods receive more attention than reactive power production methods in distribution systems these days.

2.7 Load shedding

When the state of a network is in the amber phase [17], market-based solutions of CM are the first alternative. If the amber phase transits to the red phase, then emergency measures such as load shedding should be taken into account [18]. Load shedding of certain customers should be based on a special contract between the DSO and the customer allowing a DSO to shed the loads for a few hours (i.e., yearly, monthly, etc.). Load shedding is one of the short-term solutions of DSOs for the congestion resulting from the overloading of grid components. Load shedding can be an option when it comes to having the possibility of blackout or damage to network assets. Therefore, in some cases, load shedding is recommended because it disconnects some devices of a few selected customers (based on a prior plan) whereas not adopting load shedding can cause a major blackout of a part of distribution system leading to a power outage of many customers with different supply priorities (households, hospitals, data centers, etc). It is worth mentioning that load shedding remains an alternative for CM especially if loads with low feeding priority such as cooling and heating exist.

2.8 Coordinated voltage control (CVC)

CVC empowers the notion of the smart distribution system. If we look at the distributed hierarchical control architecture in distribution systems, decision-making is realized by stand-alone controllers, secondary controllers (secondary substation automation systems) and then tertiary control (distributed management level (DMS) level) respectively. It should be mentioned that the mentioned distributed hierarchical control system is one possible way to implement controllability across the distribution system, considering the fact that there are several other control structures. The CVC [10] is applicable in the secondary control level to control LV network; likewise, it is also used in DMS to control MV network where tens of options are available to choose from. The idea of CVC relates to finding the optimal solution for the operation of the distribution system concerning both the multi-objective function of OPF and constraints [10]. Minimization of power losses, active power curtailment, tap changing operation of OLTCs, etc can be terms of a multi-objective function. A solution candidate with the best value of the objective function (OBJ) while satisfying all the network's constraints (voltage, current) is known as the OPF's final answer, which is why CVC is regarded as a method for CM.

3. ELECTRICITY MARKETS

In the 1980s and 1990s criticism of the performance of state-owned entities, combined with criticism of the effectiveness of monopoly price regulation and renewed interest in reliance on competition, led to a wave of regulatory reforms that had far-reaching consequences for the organization and operation of the traditional 'public utility' sectors, such as electricity, gas and telecommunications. These reforms had slightly different emphases in different sectors and different countries. However, there was a clear central set of ideas that were applied across many various industries [19].

Reforms to the electricity industry typically have focused on the use of competition to achieve efficient use of, and investment in, generation resources [19]. Nowadays, these competitions have been realized in different electricity market places that will be discussed in the following. It is worth mentioning that market design varies country by country. For instance, the market design of Nord Pool is different from Australian National Electricity Market.

The focus of the thesis is on the congestion management through LFM; however, the existing markets other than the LFM including day ahead (DA) market, intraday (ID) market, balancing energy market and frequency contained reserve market will also be discussed in the current chapter due to their impact on LFM. The effect of those markets on LFM is initiated from that production, and demand-side flexibility can participate in almost all of those markets (regardless of product's technical requirement), and it might be so that no flexibility remains to participate in LFM. Therefore, a better understanding of the structure and operational principals of the existing markets is required.

3.1 Day-ahead (DA) market

Except for Elspot that is operated by Nord Pool, EPEX, GME, APX NL, Belpex, and Mibel are examples of the most important European DA markets [20]. The DA market usually closes in the afternoon before the day of actual dispatch. The market participants must submit their bids and offers to the DA market before the gate closure time (i.e., 12:00 CET in Elspot [21]). After that, the market operator arranges sell and purchase bids in merit-order based to obtain supply and demand curves. The intersection of both curves for each hour determines the traded volume and clearing price of the market [20]. The market operates over a period of, say, 24 h into the future. Market participants are then obliged to the market-clearing price and their dispatched volume.

In the presence of system constraints, the dispatch of generation and load resources must be coordinated with the physical limits on the transmission and distribution networks. Many liberalized electricity markets including Elspot carry out this coordination by integrating the physical network limits into the computation of the efficient use of generation and load resources [19]. However, many other markets take into account physical network limits in an ad hoc manner. For example, the wholesale price may be computed ignoring network limits; where network constraints arise, *the network operator* may adjust generators and loads up and down (redispatch) to the extent necessary to relieve constraints. The Nord Pool practice to satisfy network constraints is similar to ad hoc manner but entirely through the market mechanism, meaning that at first network constraints are ignored to achieve a price called "system price" defining an identical electricity price for all market participants throughout the covered areas of Nord Pool. Afterward, if constraints are violated, then the zonal pricing system will ramp up and down the generation and consumption of zones in order to meet the network constraints. The difference here (Elspot) with ad hoc manner is that the congestion is removed through the market mechanism by using the zonal pricing system instead of leaving the responsibility of congestion relief to the *network operators*.

Transmission system capacity calculation and allocation to day-ahead and intraday market are fundamental issues from market efficiency and socio-economy point of view. Nordic TSOs strive to allocate the maximum cross-border capacity to the markets without facing cross-border and internal congestions. Since there is usually a correlation between cross-border capacity and internal congestions (especially in simple systems like northern Europe power system), reduction of cross-border capacity to avoid internal congestion is a common practice of TSOs. It has been noticed that TSOs underestimate their cross-zonal transmission capacities in order to prevent internal congestions [22]; that is why in 2010 the Swedish network operator subdivided into four price zones because of the European Commission pressure [23]. In Finland, the cross-border capacity of FI-SW1 is reduced by Fingrid in order to relieve P1-cut congestion [22]. Redispatch is another alternative for internal congestion management used by Fingrid. Nowadays, a combination of cross-border capacity reduction and redispatch is utilized by Fingrid to avoid internal congestions and minimize congestion costs. If cross-border capacity reduction and redispatch are done optimally, the flexibility is being used in the ahead markets (AMs) efficiently, and consequently, flexibility can flow to the other markets including LFM.

It is worth emphasizing that markets as a platform along with balance responsible parties (BRPs) are financially responsible to maintain the system balance due to stability considerations of the power system. For instance, after the operation time of the system,

penalization as a market alternative is imposed on parties causing imbalances. Meanwhile, transmission system operators are technically responsible for the system balance. In the system level, transmission system operators and markets are required to cooperate hand-in-hand for optimal operation of the system and markets. Besides penalization mechanism useful in imbalance settlement, there are some other market-based methods to facilitate the operation of the system for system operators for instance in conditions that production is far more than consumption, in order to encourage a customer to consume more and maintain the system balance, the negative price is possible in Elspot market. However, It should be mentioned that markets such as Mible (Spain and Portugal) and GME (Italy) do not allow negative pricing [20].

3.2 Intra-day (ID) market

The intra-day market operated by Nord Pool is ELBAS and EPEX, APX/Belpex are other examples of the ID market in Europe [17]. ID market supplements the DA market in which a secure balance between supply and demand is the aim bearing in the mind that the majority of the energy volume is traded on the DA and derivatives markets (e.g., Nasdaq OMX). The ID use cases can be initiated by incidents that may take place in the time interval between the DA market closure and delivery time. For instance, a nuclear power plant may stop operating due to a persisting fault, or strong winds may produce an unexpected amount of power. At the ID market, buyers and sellers can trade volumes close to real-time to minimize their imbalances and also bring the market back in balance [24]. ID market provides a chance to the market participants to optimize their portfolio based on more accurate information (i.e., updated weather forecast). Therefore, ID market has a positive impact on the value of intermittent renewable energy resources because corrective measures happening in ID market enhance the accuracy of power generation predictions. In fact, ID market reduces the imbalance costs of market players in the balancing energy markets. In addition, ID market opens a platform for not accepted bids in DA market to be presented in ID market which is beneficial to market players.

3.3 Balancing energy markets (mFRR, aFRR) and Frequency containment reserve markets (FCR-N, FCR-D)

Keeping the balance between production and consumption is one of the main duties of a TSO from power system stability point of view. AMs have been designed to provide a platform to ease trade between electricity producers and consumers as well as regarding the constraints of grid operators only in transmission level. The ID market is supposed

to enhance the precision of bids by taking corrective actions after the closure of DA market; nevertheless, actual and predicted volumes of power do not necessarily match perfectly in real-time. Therefore, balancing energy market that is managed by the TSO is a market mechanism that assures the real-time balance between production and consumption.

It is a fact that electricity production and consumption must be equal at all times and frequency is an indication of a balance between production and consumption. However, the market participants plan and balance their production and consumption in advance (with certain resolution defined by markets), frequency deviations from nominal value (50/60 Hz) is inevitable within each hour. In order to balance these deviations, a TSO procures different kinds of reserves from reserve markets. Reserves can be power plants and consumption, which either increase or decrease their electric power according to the power system needs [25]. Figure 6 demonstrates how reserves are used in Nordic countries.

Frequency containment reserve (FCR) is known as primary frequency control dealing with frequency deviation instantaneously. It is dimensioned within a synchronous area (i.e., the joint Nordic system), which strives for the frequency stabilization of the power system [26]. FCR is activated nonselective in a synchronous area to stabilize the frequency within seconds. After a short time (some minutes), FCR is replaced by secondary control called automatic frequency restoration reserve (aFRR), which is located in load frequency area (LFC-area), causing the imbalance. For instance, if a disturbance in Finland cause frequency deviation for the Nordic synchronous area, aFRR procured by Finnish TSO (Fingrid) must be activated after FCR and other TSO's (e.g., Norwegian TSO Statnett) within the synchronous area do not take any actions for replacement of FCR by aFRR [26]. Later when FCR is replaced by aFRR, the TSO usually substitutes or complements the aFRR by tertiary control known as manual frequency restoration reserve (mFRR) and restoration reserve (RR).
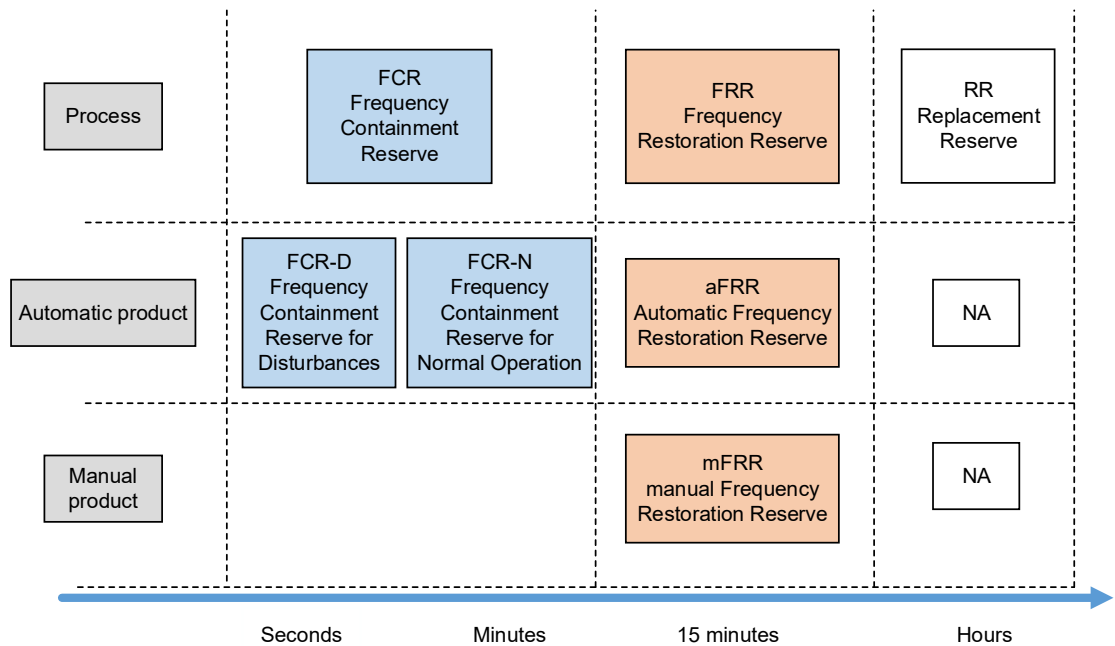
Figure 6*.Reserve products* [26]

3.4 Local flexibility market (LFM)

The reduction of carbon emission to the degree of 80% compared to its level in 1990 is the ambitious goal of the European Union by the year 2050 [27]. For that reason, feed-in tariffs for renewable energies have been defined in some countries to make customers (usually large customers) active in electricity production. It should be noted that feed-in-tariffs are not the only support system for renewables; for example, Premium system and green certificate system are used in Finland and Sweden respectively. However, regardless of the type of the incentive system, at first glance, the trend means that customers' dependency on the grid's electricity becomes less that is realized by the customer's self-generation, but in case of prosumers, it should be noted that distribution systems have not been designed based on bidirectional power flow resulting from prosumers' contribution to power injection to the grid. In fact; with the advent of distributed energy resources (DERs) such as rooftop solar panels and small-scale wind generations, the distribution system with unidirectional design principles is challenged significantly. Figure 7 shows the installed capacity of DERs to different voltage levels of the power system in Germany [28], causing congestion in distribution system because the installed DERs are mainly connected to MV feeders, then LV and HV lines.
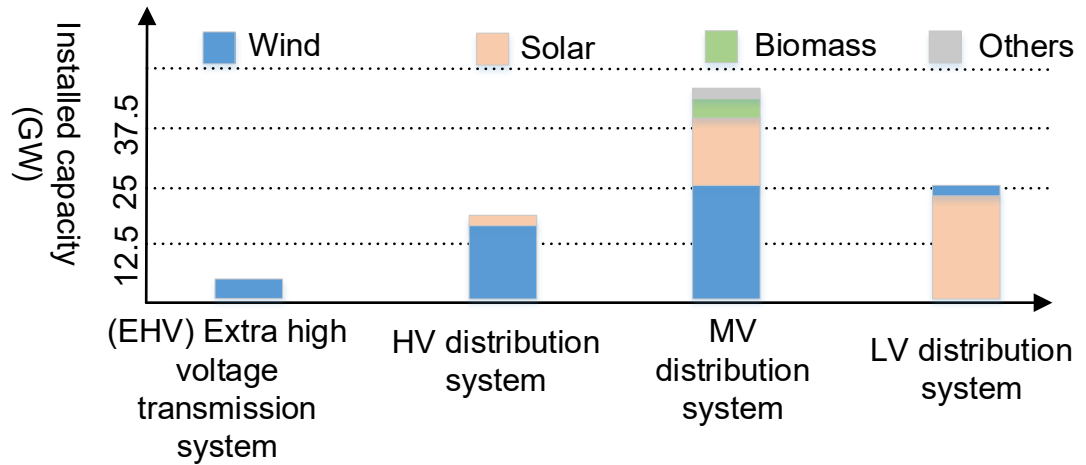
Figure 7.*Installed capacity of DERs in Germany at the end of 2015* [28]

From a consumption standpoint, nowadays, electric vehicles being supplied from a low voltage network replace fossil fuel vehicles. Besides, in countries like Finland where heat pump technology is prevalent, electricity is more in demand compared to the places where various types of residential heating systems based on fossil fuels are available. Furthermore, it is an undeniable fact that the human development index (HDI) reflecting the standard of living is proportional to electricity demand. As living standards are getting better, especially in developing countries, a noticeable boost in electricity consumption is anticipated in the future. However, resultant of all the recent changes in consumption sector means more electricity demand; the good news is that the inherent flexibility existing in the nature of the mentioned loads (e.g., electric vehicles, heat pumps, etc.) can be smartly utilized to counterbalance the generated stress of those changes on distribution systems. For instance, due to the requirement of building code in Finland [29], those houses compliant with the law have enough thermal inertia to consider their heat pump as an example of flexibility (demand response). Extraction of available flexibilities is one of the DSO's alternatives to deal with the all-aforementioned changes in both production and consumption causing problems in distribution systems such as congestion.

As a market-based CM method, the LFM introduces a regulated platform to facilitate the procurement of flexibility for a DSO.

However, as mentioned before, grid reinforcement and active power curtailment are the simplest ways to address congestion; they are costly alternatives that are categorized as old solutions not dynamic enough to pursue fast-paced changes of distribution systems. Therefore flexibility procurement from LFM combined with non-market based solutions discussed in the previous chapter for distribution system congestion management can create a maximum socio-economic benefit in general view. As CM through market mechanism, specially LFM is the topic of the thesis, the rest of the chapter will discuss with more details some considerations required for LFM market success.

An aggregator, as the actor of the virtual power plant's concept, accumulates the flexibility of customers and represents them in different markets to maximize its benefit. Therefore, LFM, which is mainly designed for DSO's desires, should be able to compete with the existing markets such as AMs and balancing energy markets, etc mostly built for the benefits of electricity producers, consumers, and TSOs. The aggregator's financial benefit from participation in LFM should be close to the potential gain coming from participation in other markets because a resource can only be traded once at a time. On the other hand, aggregator's participation in LFM can increase aggregator's flexibility utilization because of opening up more trading possibilities. Therefore the combination of the mentioned factors should be beneficial enough to encourage an aggregator to participate In LFM. Figure 8 shows the minimum revenue expected form participation in LFM. If the aggregator's revenue is less than that, then probably the LFM is not an attractive market place for an aggregator. The second column of Figure 8 may be taller or shorter than the first column depending on the portfolio management of an aggregator; however, the intention of plotting the figure is to show what aggregators expect from LFM. The point is that the benefits resulting from LFM participation by an aggregator should outweigh the benefits of the involvement in the markets other than LFM otherwise LFM is not an attractive market place.
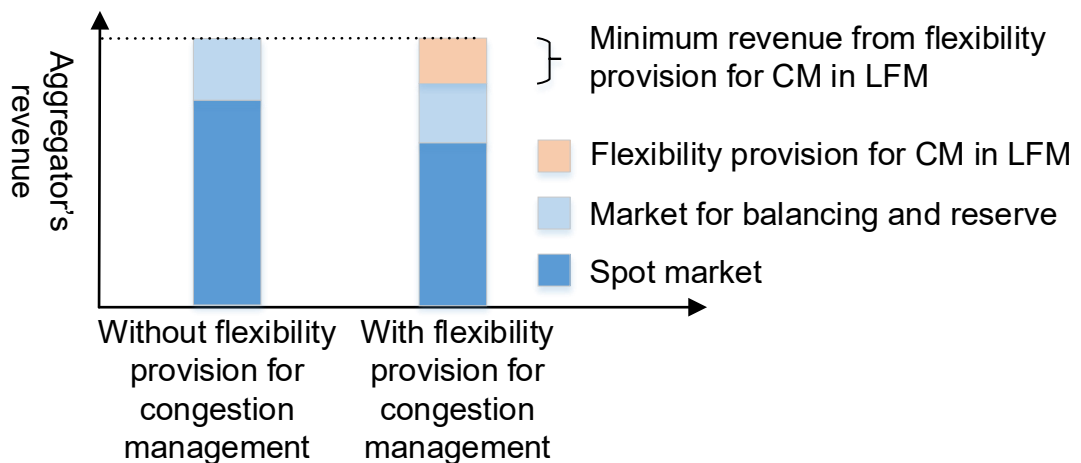

Figure 8.*Aggregator's revenue from the marketing of flexibility* [28]

Since LFM is supposed to compete with existing markets, factors such as timing, product design, prequalification process, market-clearing methodology, frequency of market operation, settlement process, TSO/DSO coordination, and transparent and fair flow of information among market participants are crucial issues for the success of the LFM.

Like every market, to have a success LFM, some needs and requirements should be taken into account in the design and operation of LFM, such as coordination between stakeholders, data exchange, data privacy, cybersecurity, interoperability, and liquidity.

In [30], the needs and requirements have been explained thoroughly; however, they are briefly discussed in the following.

Making sure that the flexibility trade does not disturb involved stakeholders is one important aspect of LFM design which is doable by proper coordination. For instance, Markets for flexibility should be changed/designed such that the flexibility trade between parties does not impose a cost on other stakeholders. For example, flexibility procurement of a TSOs should not cause a problem for involved DSOs because the needed volumes to solve a problem in transmission level may need to involve several DSOs and could create congestions. The other way around is also right: An increasing volume of flexibility connected to the distribution grid will be required to fulfill balancing needs of TSOs, and therefore should not be locked in at local level for DSOs' needs. As another example, independent aggregators sometimes have conflicting interests with retailers when it comes to a situation that the sold flexibility of an aggregator causes imbalance to retailers' BRPs. In contrast, the flexibility trade of an aggregator may reduce retailers' imbalances, which opens an opportunity for coordination and internal agreements between them. In this case, independent aggregators' model should consider all stakeholders' concerns [30].

TSOs and DSOs have to coordinate with all market actors to operate the electricity system in the most cost-efficient way and fulfill the targets set by the existing and upcoming regulation like a European Clean Energy Package. Regarding the transparency in data exchange, it is considered a necessity and has been addressed in respective EU regulations (i.e., Regulation No 1227/2011 on wholesale energy market integrity and transparency, Regulation No 543/2013 on submission and publication of data in electricity markets, etc.). The minimal requirements for data exchange are addressed in EU Network Codes (e.g., system operation guidelines (SOGL), etc.). The following point should be taken into account in the design and operation of a market:

- Timely and transparent availability of market data is necessary for a well-functioning electricity market, and market actors need access to market data for operating more effectively, by also developing appropriate plans and business strategies.

Following GDPR 2016/679 of the European Parliament and the Council implemented on 25 May 2018 [31], consumer data is only shared with the explicit agreement given by the consumer. On principle, every effort will be made to preserve the privacy of the participants, which means that in general, the participant's identity will be kept confidential by default unless they wish to be identified and their involvement to be published. The participant (consumer/prosumer) agrees to share data with a specific energy service. Data only move if there is a valid agreement for sharing. Regarding anonymous data, it may

need to be considered as private data if it is linked with other data like a location in the grid. In that case, it is possible to identify the customer, even if data is originally anonymous. Therefore, GDPR can be applied to anonymous data as well.

High-level objectives defined by "Cyber Security in the Energy Sector [32]" are:

- To secure energy systems that are providing essential services to European society.

- To protect the data in the energy systems and the privacy of the European citizen.

The energy and power ecosystem features a communication network involving interconnected smart devices, smart meters, internet of things (IoT) components, control units and other software platforms from heterogeneous environments. Since it is impossible to ensure that every part, device, and node in the energy sector is invulnerable to attacks, a large scale information technology (IT) security mechanism is needed for identifying and taking countermeasures to abnormal incidents. These mechanisms should be robust and rigorous, to monitor and conduct analyses of huge levels of traces and accurate for providing the cybersecurity assessment (and attack detections).

Interoperability is an important aspect influencing the participation of flexibility into markets, including LFM. Interoperable platforms facilitate market participation and speed up the communication process by using similar and standard data models, protocols, and communication technologies for information exchange. Interoperability will become more critical where stakeholders and market platforms need to exchange a massive amount of data because multiple market platforms, data hubs, DSOs, TSOs, flexibility providers, etc. need to talk together continuously. Besides, the need to have interoperable interfaces will increasingly rise because the dynamics of the power system and liberalized markets will be higher shortly soon, and therefore, a real-time (minute resolution or shorter) data exchange is required if a party tends to gain benefit in a competitive market environment. Furthermore, when it comes to either update or repair a part of an IT system, the cascading need for a change in other involved interoperable platforms is minimum.

In [33], liquidity is defined by "the speed with which a substantial amount of a particular asset is purchased or sold (immediacy), having small transactional costs, without causing substantial movements in the price of the asset (resilience)." In the context of this thesis, flexibility is the asset requiring liquidity. Regulations, market membership and cancellation fees, trading and exchange costs, the technical requirement for flexibility participation, etc are some examples of influential factors on market liquidity.

Non-market and market-based solutions for CM have been presented so far. In the next chapter, it is aimed to build a simulation environment in which a DSO is empowered to procure flexibility from LFM while taking some non-market based solutions for CM.

4. SIMULATIONS

The objectives and research questions mentioned in the introduction chapter needs to be addressed. Therefore in this chapter, the aim is to build a simulation environment that enables us to answer the research questions and study five scenarios to increase our understanding regarding CM through the market mechanism.

As illustrated by figure 9, actors, systems, use cases (functionalities), and relationships have been utilized according to the Unified modeling language (UML) to visualize the simulation environment's design. An actor is defined as "an entity that communicates and interacts such as people, software, databases, etc."[34]. Primary and secondary are two types of actors that are distinguished based on their initiation sequence, and they are located on the left and right side of a use case diagram, respectively. A primary actor initiates the use of a system, whereas a secondary actor is reactionary. As shown, DSO is a primary actor, whereas OpenDSS, market operator and flexibility provider are secondary kinds. Typical industry management of components, serving a set of use cases are termed "system" [34]. DMS computer, OpenDSS and LFM market virtual machines (VMs) are three systems of the designed simulation environment. The oval-shaped blocks represent use cases in figure 9. A use case describes the functionalities of a system. Lastly, the arrows linking actors to the use cases are association sort of relationship signifying communication and interaction between an actor and use case.

The three systems are designed to exchange data and information with each other. However, in the thesis, the communication channel between DMS computer and OpenDSS machine is not complete yet, which means, for the time being, the functionality of the OpenDSS machine is done in DMS computer. In the following, the functionality and a lower level use case diagram of all the mentioned systems will be provided.
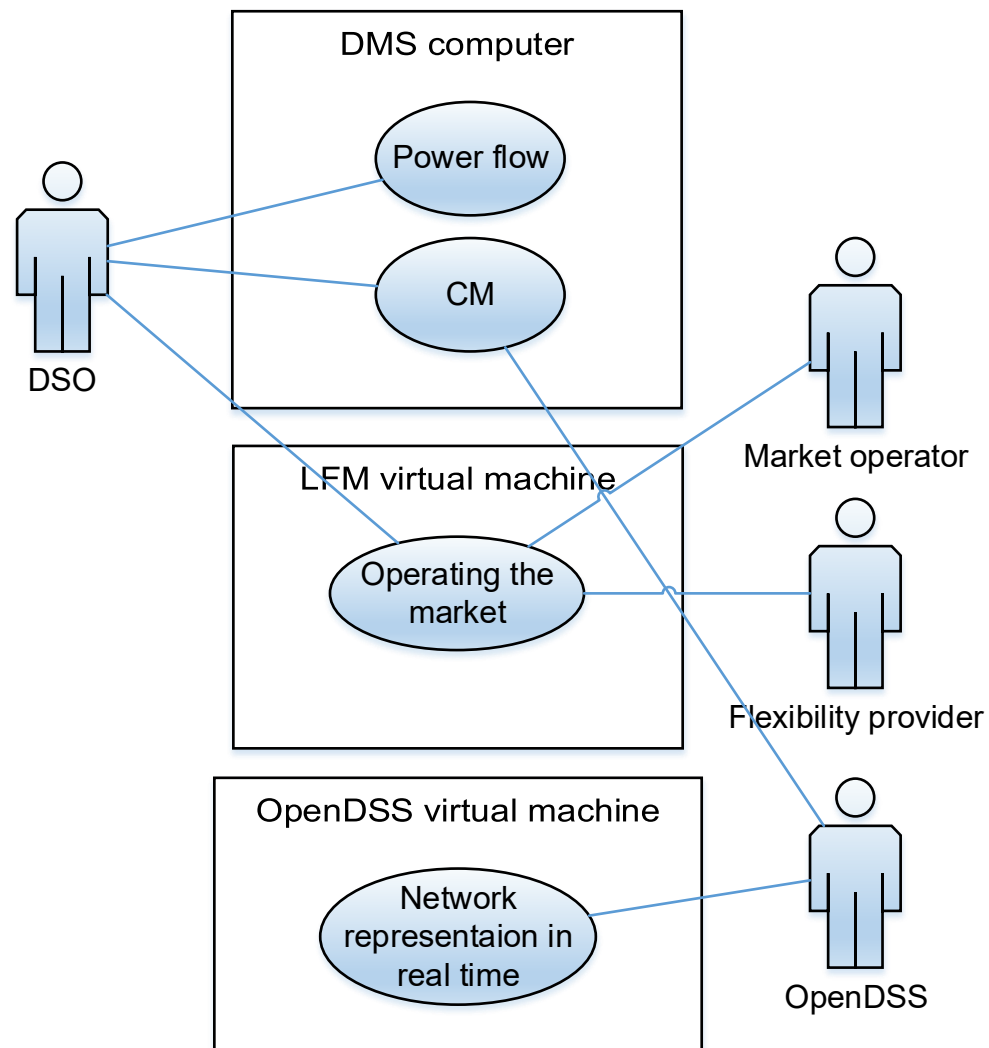
Figure 9*.The high-level use-case diagram of the simulation environment*

4.1 DMS computer

Various application systems are permanently running in the DMS computer performing different functionalities such as work-force management, fault, and restoration management, forecasting, asset management, CM, etc. Among all of the application systems, the OPF that is running inside the CM is intended to be focused on this thesis because it can discover the best solution for CM.

Figure 10 [35] illustrates various network states, which three of them including non-acceptable, non-optimal, and optimal is explained here considering that the details about the restorative, disturbed and faulted state can be found in [35]. An operation made by the operator is shown with a black arrow while the grey arrow shows an operation caused by an external factor (e.g., load change). The white arrow indicates an operation accomplished by the automation system. The non-acceptable state occurs when one of the

network constraints violates, for instance, overvoltage condition. When all network con-straints are satisfied, the state of the network is non-optimal. A network without constraint violation operating with a minimum operational cost is on the optimal state. The OPF tries to transit the state of the network either from non-optimal or non-acceptable to the optimal state. To do so, once the state of the network is acquired from the open-DSS server to understand the current state of the network in real-time, an OPF evaluating an objective function (OBJ) is run in order to pick the best alternative up from the available solution candidates for the operation of the network. The evaluation of each solution candidate is according to the value of OBJ and also the satisfaction of all network con-straints. It should be mentioned that in the designed simulation environment, there are two different OPFs. Both of them function in the DMS machine. The first one which is run a day before the network's operation time that is called predictive OPF in order to enable a DSO to foresee any probable congestion within the day ahead (next 24 hours) and find a solution (either market based or non-market based solution) for that while the second OPF is performed in real-time in DMS machine in order to move that state of the network form non-acceptable or non-optimal to optimal state. The OBJ is determined as follows:
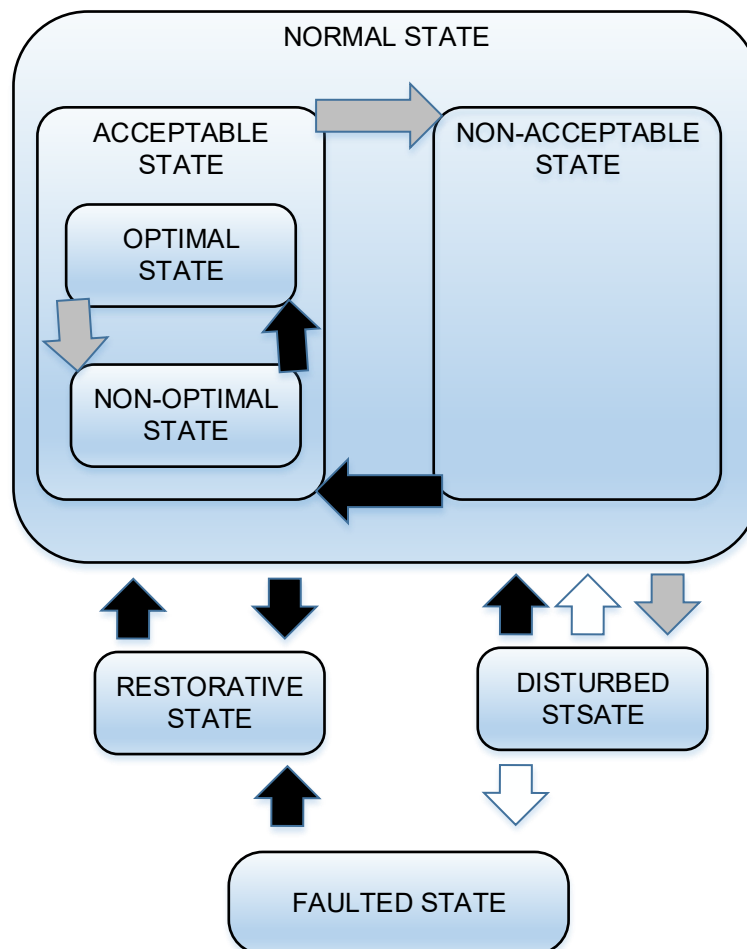

Figure 10.State transition of distribution network

$$OBJ^i = E^i * D^i * \left(P_{lossB}^i - P_{lossA}\right) + SC^i \tag{9}$$

where OBJ^i stands for the objective function value of the ith solution candidate in €, E^i symbolizes rate benefit for loss reduction in terms of $\frac{€}{kWh}$ and duration of ith solution candidate per hour is denoted by D^i. P_{lossB}^i is the power losses of the network in terms of kW if the ith solution is activated while P_{lossA} represents the current power losses of the network. SC^i represents all involved costs of purchase and enabling the ith solution candidate in € (i.e., price of purchasing flexibility from LFM). It should be noted that the defined CM problem is a minimization kind meaning that the optimum solution should possess the minimum objective function value while satisfying the network's constraints represented below:

$$V_{min} < V_{bus}^{i,n} < V_{max} \tag{10}$$

$$I_{branch}^{i,m} < I_{branch,max}^m \tag{11}$$

where EN 50160 [7] determines the minimum and maximum permissible voltages in distribution networks notified by V_{min} and V_{max} respectively. The voltage of nth bus and the current of the mth branch is represented by $V_{bus}^{i,n}$ and $I_{branch}^{i,m}$ respectively as a result of applying the ith solution. The physical characteristics (e.g., cross-section, material, cooling system, etc.) of the network's assets such as cables, overhead lines, transformers, etc define the value of maximum allowed current of the mth branch denoted by $I_{branch,max}^m$.

4.2 Open-DSS virtual machine

The OpenDSS virtual machine emulates the behavior of the real distribution network in the simulation environment when OPF tries to transits the state of the network to optimum in real-time. The advantage of using the OpenDSS software in a dedicated VM is that it enables the simulation environment to be used in the real-world when necessary with minor changes (i.e., protocols, data format, etc) depending on the situation of the real network. In fact, if the built simulation environment of the thesis required to be applied on a real network, the real network will replace the OpenDSS VM, and the rest of the simulation environment will remain intact. A power flow is periodically (or event-based) running in the OpenDSS server in order to reflect the reality of the distribution network. However, all node voltages and branch currents are known in OpenDSS server as a consequence of running the power flow, to be realistic, the values of the network where measuring devices exist can only be transferred to the DMS computer.

4.3 LFM virtual machine

As mention in chapter three, section four, LFM is a platform where flexibility is offered by flexibility providers for the use of DSO to manage congestion. In the designed simulation environment, LFM and DMS virtual machines interact with each other for probable procurement of flexibility. Figure 11 depicts a detailed look at LFM's virtual machine structure and its functionalities.

The application of LFM for CM is when congestion occurs in a part of the distribution network that the state is known as the amber phase [17]. According to the traffic light concept (TLC) [17], the status of a network is green when network constraints are not violated meaning that market players can freely operate in different markets. If there is a prediction of probable violation in the future (i.e., for the day ahead say 2 pm) or in the condition that a constraint has been already violated, the network status turns to the amber phase meaning that the DSO announce that there is a willingness in DSO side to procure flexibility from LFM. Besides, the DSO informs the market platform about the congestion area and the required flexibility products (e.g., activation time, duration of flexibility, technology, rebound condition, etc.). In fact; The application of the LFM starts here in which its functionalities are shown in figure 11. Offering flexibilities to the LFM is started once the DSO initiates the call for bids for a specific network area. Based on the available information which should be accessible for all market players, flexibility providers make their offers. After the closure of the market gate, a merit-order list (MOL) is created by the market operator to be used by the DSO. The DSO (predictive OPF) should pick the most cost-effective solution out from the available solution candidates either by the procurement of flexibility from LFM or taking some non-market based measures (discussed in chapter 2). For instance, It might be so that the DSO decides not to take any bid from the LFM or a mix of market and non-market solutions may bring the most benefit.

Figure 12 illustrates the chronological order of LFM operation, which starts from a day ahead until the operation day of the distribution network. As shown, based on the results of DA market clearance, maintenance schedule, weather forecast, estimated load and production profiles, etc the predictive OPF foresees the network's state for each period of the next day (i.e., with 15 min time resolution). If flexibility procurement is needed, then the DMS requests the LFM market operator to open the LFM market. In this condition, DMS should define the required flexibility, congestion area, direction (upward, downward), technology, etc (more criteria of flexibility need can be found in [1]). The LFM gate is open for flexibility providers between 3 pm to 5 pm to submit their bids to the market platform. At 5 pm the LFM market is closed, and LFM forwards a MOL to DMS. The

predictive OPF selects the Bids that can bring the most benefit for the DSO and inform the LFM about the accepted bids. At 6 pm LFM publishes the accepted bids to flexibility providers so that they become ready to activate their promised flexibility if needed in real-time operation. During the operation day, the OPF decides whether the procured flexibility is necessary and its required amount. Due to inaccuracy of the predictive OPF which is inherently inevitable, predicted congestion might not realize in real-time, which means the procured flexibility remains unused in this case. This is the reason why in the next chapter (scenarios 4 and 5), it aims to show what happens in real-time if predictions have a certain amount of inaccuracy.

It should be mentioned that essential issues such as product design and prequalification, grid prequalification, settlement process, monitoring and activation of flexibilities, coordination, etc should be taken into account in LFM design and operation, nevertheless, these topics are out of scope of the thesis and they worth to be studied in a dedicated research work.
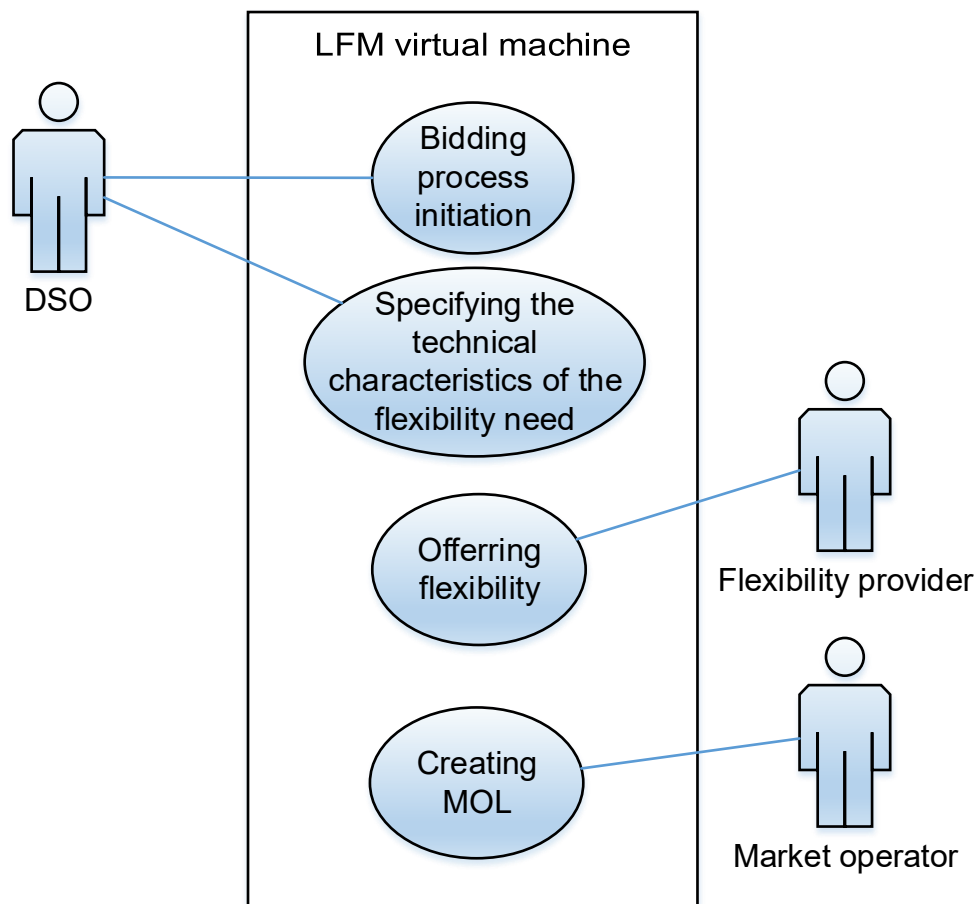

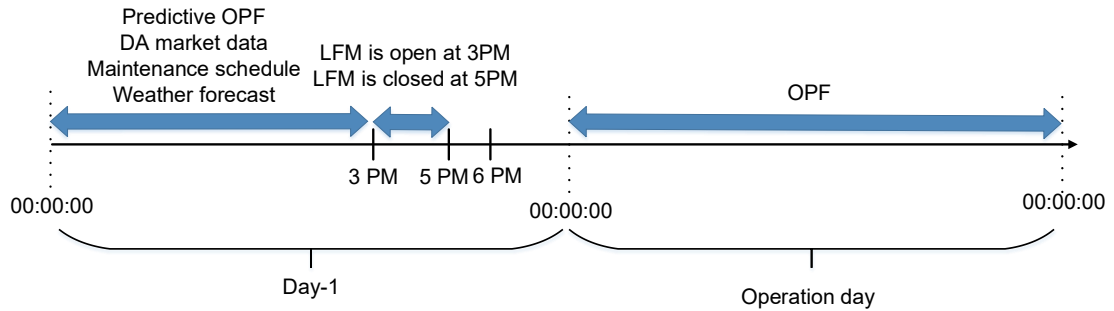*Figure 11*.The use-case diagram of LFM's VM

Figure 12.LFM's operational scheme

4.4 CM through the simulation environment

Up to now, the functionalities of the DMS computer and VMs were discussed. The following part offers a broad picture of the entire simulation environment for CM, which is illustrated by the flow chart available in figure 13. The target is to understand how CM in realized by predictive OPF using the LFM in the simulation environment. The flowchart possesses 18 blocks. Table 1 has been used to clarify and explain the functionality of each block. The comment column in the table provides some supportive information associated with each block.

The flow chart starts with block 1 when the network's state in the first quarter-hour is going to be assessed. Block 2 acquires the state of the network by running a power flow in DMS followed by block 3 where it is decided whether congestion has happened or not based on the power flow results. If the network state is in permissible ranges, then the next quarter-hour is examined. If the answer to network violation existence is yes, then block 6 represents that the DMS will communicate with LFM and receives a merit-order list (MOL) from it. The number of bids available in the MOL is called m represented by block 7. Blocks 8 to 12 calculate the network's status while activating each bid available in MOL. Blocks 13 to 15 select the best bid (with a minimum objective function value). Block 16 assures that all of the quarter-hours a day (96 in this case) has been assessed.
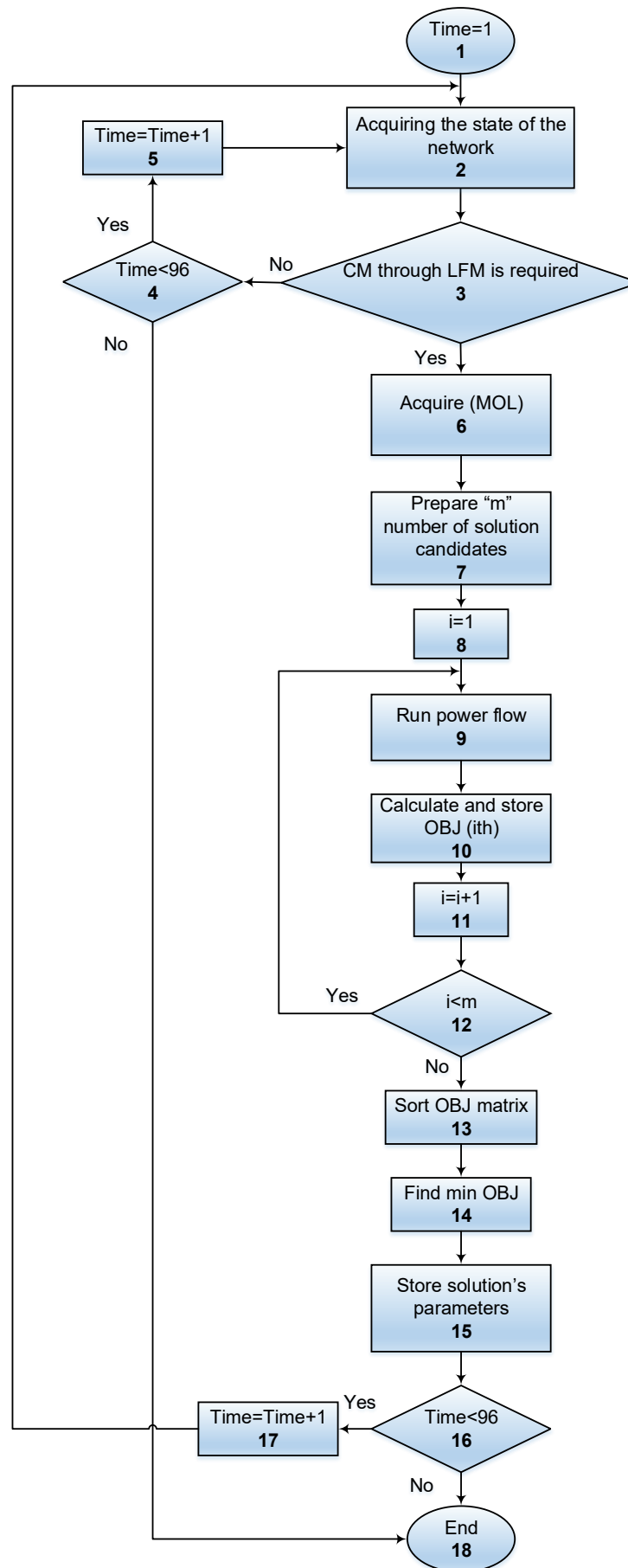
Figure 13*.Congestion management flow chart through LFM*

Table 1.CM through LFM

Block	Functionality	comment
1	Sets the "Time" as 1	One day consists of 24 hours. Since the time resolution of the simulation environment is 15 min, then the maximum number for "Time" is 96.
2	The state of the network (voltages, currents) is achieved	Newton-Raphson (N-R) power flow exists in the DMS computer. Therefore, based on the predicted load and generation profiles, the state of the network can be predicted for each flow state of the network.
3	Decides whether CM is required	CM is required if any of the voltage and current values across the network violate.
4	Decides whether "Time" is larger than 96	
5	Jump to the next time slot	
6	MOL is received from LFM	This block is used when CM is required, and a market-based solution is explored.
7	DMS prepares "m" number of solution candidates for CM	The number of solution candidates "m" comes from the number of bids. For example, if there are 5 bids available, the MOL of them will consist of 5 candidates.
8	Defines "i" as 1	"i" is a counter
9	Runs N-R power flow	
10	OBJ of each solution candidate (bid) is calculated and stored in DMS	Once N-R power flow provides the network states, including voltages, currents, losses, etc, then OBJ (13) is calculated.
11	Counter "i" counts	
12	Decides whether all number of solution candidates "m" has been evaluated	
13	Sort OBJ matrix according to their OBJ's value	
14	Solution candidate with minimum OBJ is selected	The optimization problem of the thesis is minimization kind. Therefore, a solution candidate with minimum OBJ's value is the optimum answer of the CM.
15	Solution's parameters are stored	Since we are on the predictive part, parameters related to the bought flexibility are just stored. The next day (in real-time), if congestion occurs, then the procured flexibility might be activated.
16	Decides whether "Time" is larger than 96	

17	Similar to block 5	
18	end	When all 96 quarter hours are investigated, then predictive OPF has accomplished its task.

4.5 DMS - OpenDSS information exchange

The communication purpose between DMS computer and OpenDSS VM is done for CM in real-time operation of the network. Figure 14 shows the sequence diagram of DMS-OpenDSS communication. It is initiated by an inquiry regarding the status of the controllable elements followed by requesting real-time measurements (i.e., voltages and currents) and finally asking total power losses of the network. The OpenDSS sends the losses to DMS because, at the moment, there is no state estimation running in DMS to calculate the losses from real-time measurements. But later, state estimation needs to be added to DMS.

Table 2 provides detailed information about DMS- OpenDSS communication. It should be noted that the exchanged data between two machines has been designed to be in JSON[1] data format because it is easily parsable in the Matlab environment; nevertheless, data formats such as XML[2] could be used.

The sequence diagram shown in Figure 14 is repeated within 15 min in the real-time operation of the distribution system. In fact, DMS acquires necessary information regarding the status of the network every 15 min which is plausible because, in the designed control architecture of the thesis, DMS acts as a secondary control and primary controllers (stand-alone controllers such as OLTC) act first. In case of any violation in voltage or current, once the DMS receives the data, OPF running in the DMS attempts to remove the congestion through some corrective actions. The corrective actions are dependant on the accuracy of the predictive OPF. For instance, if the predictive OPF has anticipated the congestion in advance and procurement of flexibility from LFM has been done already, then OPF needs to take the previously settled flexibility into account and send the activation signal to the relevant device to remove congestion. Therefore, predictive OPF plays a significant role in success of OPF (for CM) in real-time operation of the network.

---

[1] JavaScript Object Notation (JSON), https://en.wikipedia.org/wiki/JSON
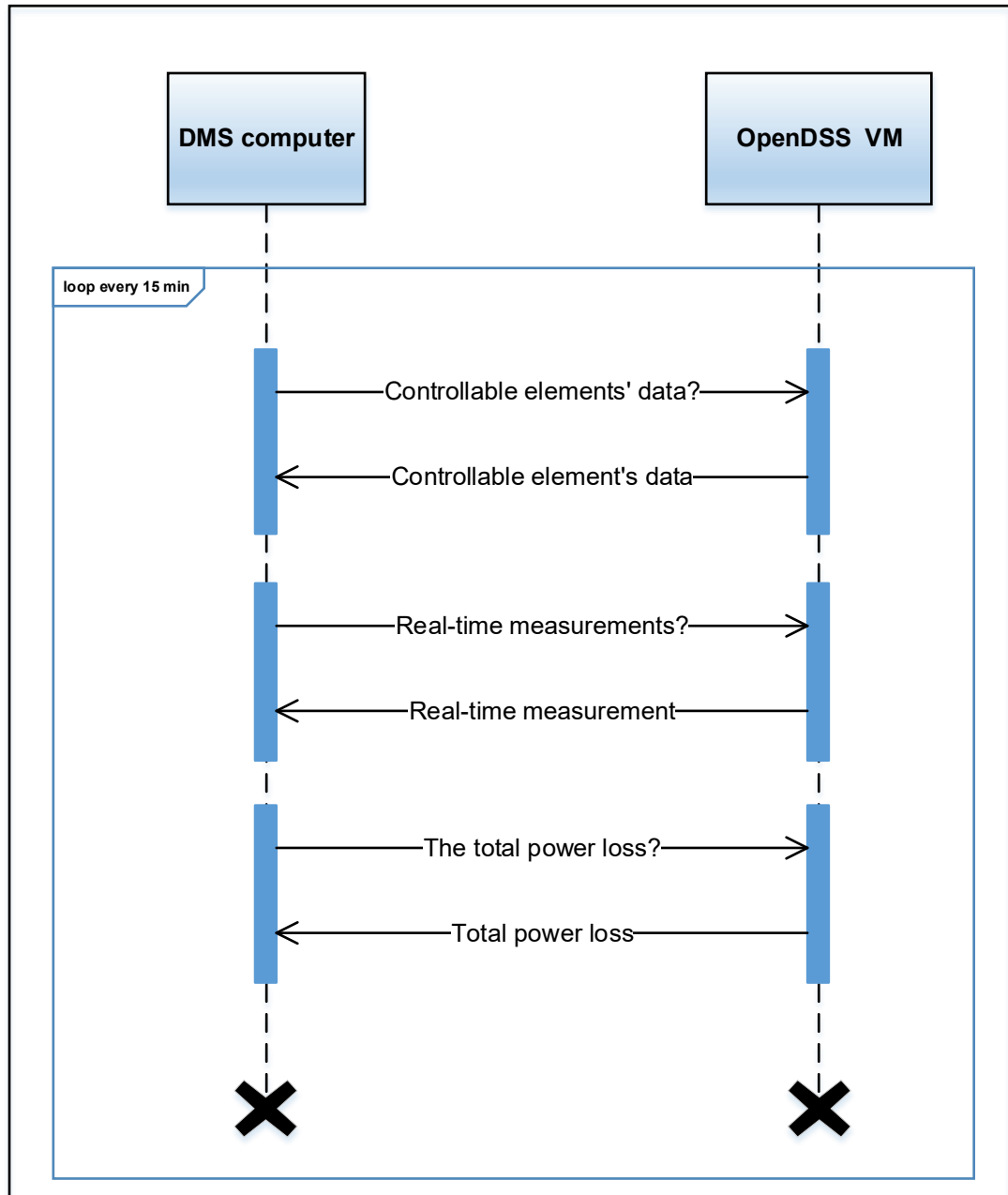[2] Extensible Markup Language (XML), https://fi.wikipedia.org/wiki/XML

***Figure 14**.Sequence diagram between DMS computer and OpenDSS VM in real-time*

Table 2.CM through LFM in real-time

Number	Inquiry sent to OpenDSS	Element	Data sent to DMS
1	Controlable element's data	OLTC	{"Total number of trans": "integer", "trans details": [{"name": "string", , "from bus": "string", "to bus": "string", "tap status": "offline/online", "tap position": "integer", "tap step": "float", "reference value":"float (p.u.)", "deadband":"float (p.u.)","connection group":"string"}]}
		Volt/Var mode of generator	{"Total number of production units": "integer", "unit details": [{"connected to bus": "string", "power factor": "float", "power output": "float (p.u.)", "generator base": "float (MW)"}]}
		switch	{"Total number of switches": "integer", "switch details":[{"switch name": "string", "from bus": "integer", "to bus": "integer", "switch status": "binary"}]}
2	Real-time measurement	voltage	{"Total number of measurements": "integer", "measurement details": [{"bus": "string", "value": "float (V)"}]}
		current	{"Total number of measurements": "integer", "measurement details":[{"name": "string", "from bus": "string", "to bus": "string", "value": "float (A)"}]}
3	Total power loss	power loss	{"Total series power losses": "float (W)", "Total parallel power losses": "float (W)"}

4.6 DMS – LFM VM information exchange

The LFM functions as a bridge between flexibility providers and DSOs. When the predictive OPF foresees network congestion during the day ahead, the network state for that specific time turns to the amber phase, and DMS Informs the LFM about the existing need for flexibility and initiates the bidding process at 3 PM as shown in Figure 15. The figure presents the communication between the DMS computer and LFM VM once congestion predicted in the network. After initiation of the bidding process by the DMS computer, the LFM VM acquires some data regarding congestion type (over-voltage, under-voltage, overloading), congestion area, required flexibility volume and direction (up-regulation, down-regulation), flexibility duration, etc from the DMS computer. Afterward, the general data protection regulation (GDPR) compliant information is published to the market platform, which makes the information accessible for all market players to enjoy a level playing field. After closing the market gate at 5 PM, as shown in Figure 15, a MOL

is forwarded to DMS computer to be evaluated in predictive OPF. After that, DMS transmits the accepted bids at 6 PM to the LFM in order to inform all market players about the market clearance results which is based on pay as bids method [36]. The bottom part of figure 15 shows the situation when LFM is not ready for initiation of the bidding process (due to any reason), which means DMS should explore non-market based solutions. It should be noted that opening the LFM by a DSO does not oblige the DSO to procure flexibility; instead, it brings more freedom for decision making of the DSO to choose the most cost-effective solution for CM.

In order to increase the transparency of market operation, some critical data such as required flexibility volume needs to be accessible for all market participants. According to the value of flexibility need, flexibility providers can adjust their bidding and enhance their chance of selling offers. Specifying the flexibility need for voltage and current violations are different, which will be explained in the next paragraph.

For overloading type of congestion, since the network is assumed to be operated radially, the exact amount of overloading in the form of up-regulation bids located in the downstream of the congestion point can solve the congestion. However, if congestion stems from over or under voltage problems, then specifying the required flexibility in the congestion area is not as simple as an overloading case. Based on the methodology presented in [37], an approximation has been used to find the congestion matrix for each flow state of the network. For instance, if over-voltage congestion occurs in an area of the network, the needed flexibility to solve the congestion is location-dependant, which is visible in congestion matrix. The closer the flexibility (electrical distance) to the bus where the congestion is created, the smaller the volume of flexibility is needed for CM.
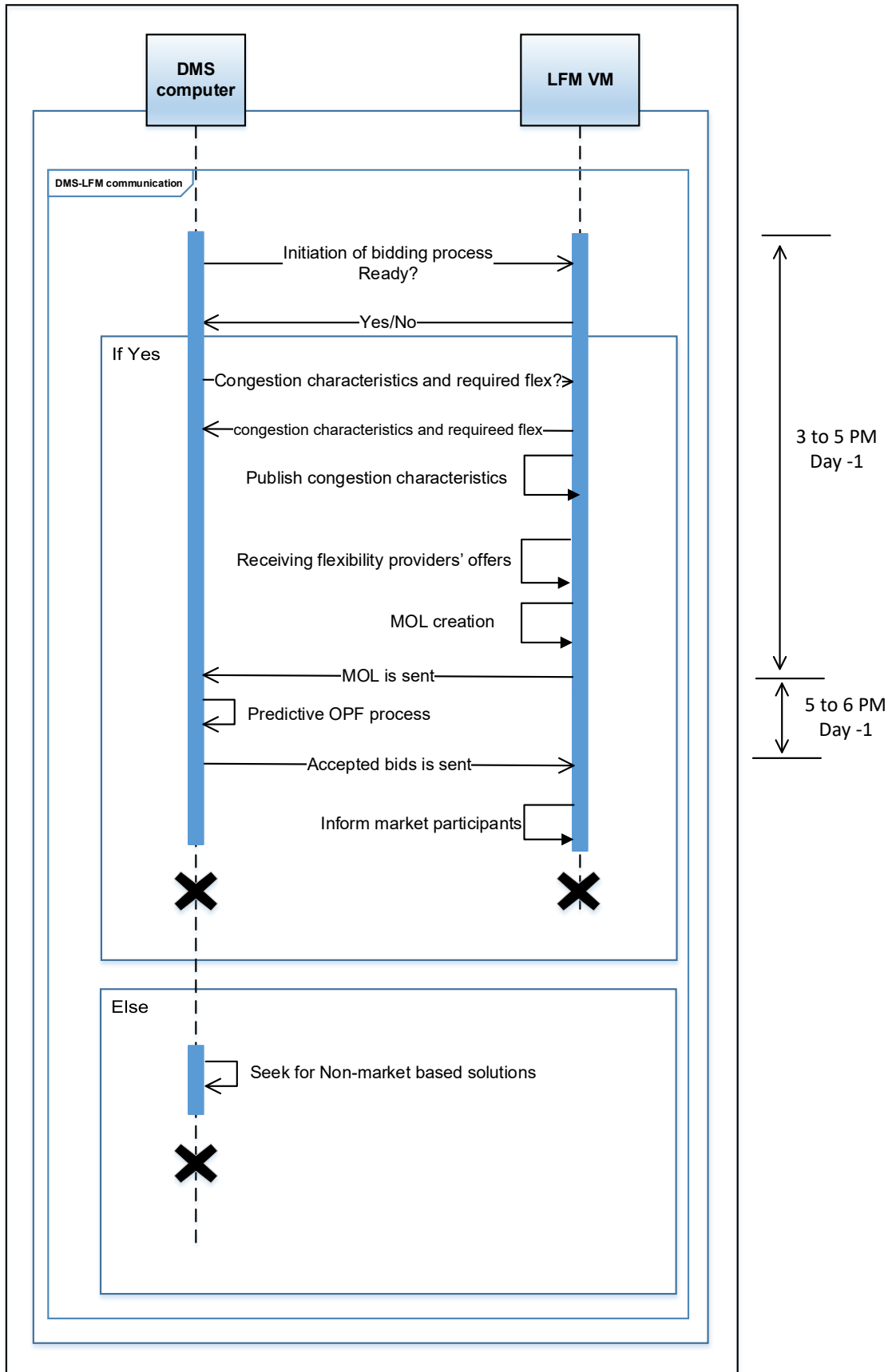
Figure 15*.Sequence diagram between DMS computer and LFM VM*

5. SIMULATION RESULTS

In this chapter, five different scenarios are compared to illustrate the impact of various alternatives for CM. The operation of the network without using any controllability is shown through scenario 1 in order to understand what is the situation of the network if no controllability is available. Then the target is to increase the controllability in each scenario to be able to observe the changes in the network's operation. Therefore in scenario 2, the primary substation's online tap changer (OLTC) is activated followed by scenario 3 where reactive power control of the DG is also activated. In scenario 4, in addition to all activated controllabilities (OLTC and DG's reactive power control), LFM as a CM solution is also utilized to see its impact. In other words, scenario 4 attempts to show the results of a mixture of deploying market and non-market based solutions for CM. Since predictive OPF always contains some inaccuracy, the effects of error in the predictive OPF process is investigated in scenario 5.

The under-study distribution system of the thesis is a simple 6-bus network as shown in figure 16. It includes two voltage levels of 110kV and 20kV. The transformer is equipped with OLTC regulating the voltage of bus 3 within a predefined dead band. Figure 17 illustrates the up set point (UP), down set point (DP), and the reference value of dead band which are set 1.01, 1 and 1.005 p.u.. The tap changer posses 32 tap steps with 0.00625 p.u. tap ratio. The distributed generator (DG) is a photovoltaic kind that is connected to the grid through an inverter. If the volt-var mode of the DG is activated, the DG's reactive power compensation will be based on figure 18. V_1, V_2, dead band and V_{ref} are set 0.96, 1.04, 0.04 and 1 p.u.. Line impedances of the distribution system are shown in Table 3. The 20kV lines are assumed to have the maximum ampacity of 130 A. For the sake of simplicity, the transformer's parallel impedance has been neglected in the calculations (N-R power flow). Loadings at buses 4, 5, and 6, in addition to the power generation of the DG, is shown in figure 19. Since the predictive simulations in DMS are done for the next day (next 24 hours), considering that the time resolution of data is 15 min; therefore, 96 flow states representing a day ahead will be studied here.
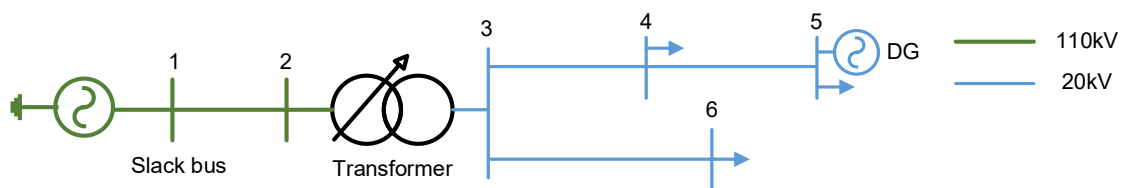
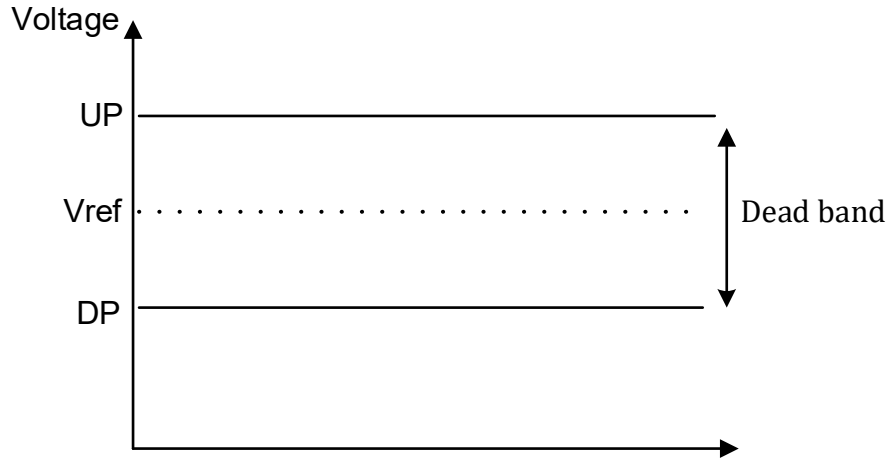

Figure 16.Under-study distribution system

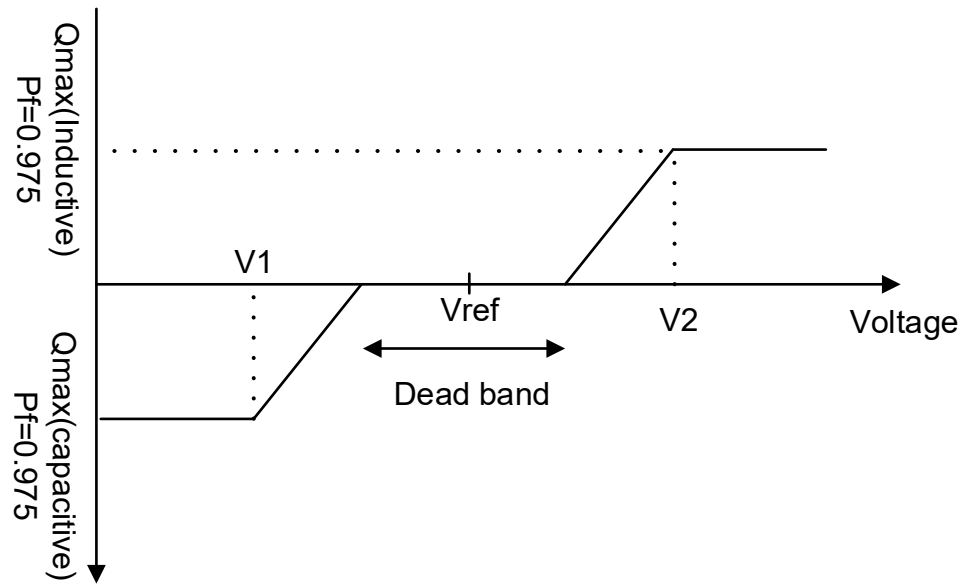***Figure 17****.Control system of primary substation's OLTC*

Figure 18*.Volt-Var mode of the DG*

Table 3*.Network's impedances*

From bus	To bus	Impedance (ohm)
1	2	4.9912+14.0058 j
2	3	4.2350+86.2125 j
3	4	4.1393+2.1263 j
3	6	6+3.12 j
4	5	4.1393+2.1263 j
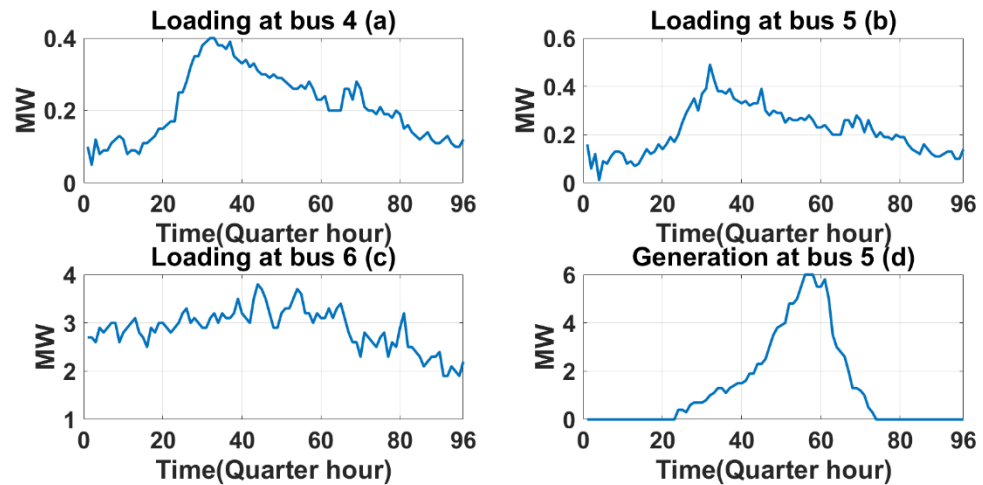
Figure 19.*Demand and generation profiles*

Having said the detailed information of the under-study distribution network, studying various scenarios of the next section will be possible.

5.1 Scenario 1

In this scenario, the distribution system without any controllability is assumed which can be considered the worst-case scenario from a controllability point of view. In practice, it means that the primary substation's transformer has a fixed tap position (tap step 12), and the reactive power compensation mode of the DG is off. Due to that DG's active power generation reaches its peak around midday, bus number 5, and its nearby bus (bus 4) experience overvoltage problem around noon, as shown in figure 20. Figure 21 illustrates the total active and reactive power losses of the network, DG's active and reactive power output, and loading of the lines between busses 3 to 6 and 4 to 5. The red dots in section (f) of figure 21 show a current violation in the line between buses 4 and 5 which is resultant of reverse power flow from bus 5 toward the primary substation. The voltage of buses 3, 5 and 6 along with tap movement of the OLTC is shown in figure 22. Section (a) of figure 22 illustrates the voltage violation during the mid-day when the DG's output is close to its maximum. Similar graphs have been plotted for the following scenarios to enable us to compare the changes after applying different controllabilities. Concerning figure 20 and its similar kinds in the next scenarios (figures 23, 26, 29, 32, 35), it should be mentioned that color intensity shown in each figure's legend is different, and therefore figure analyses just by color comparison is not recommended.
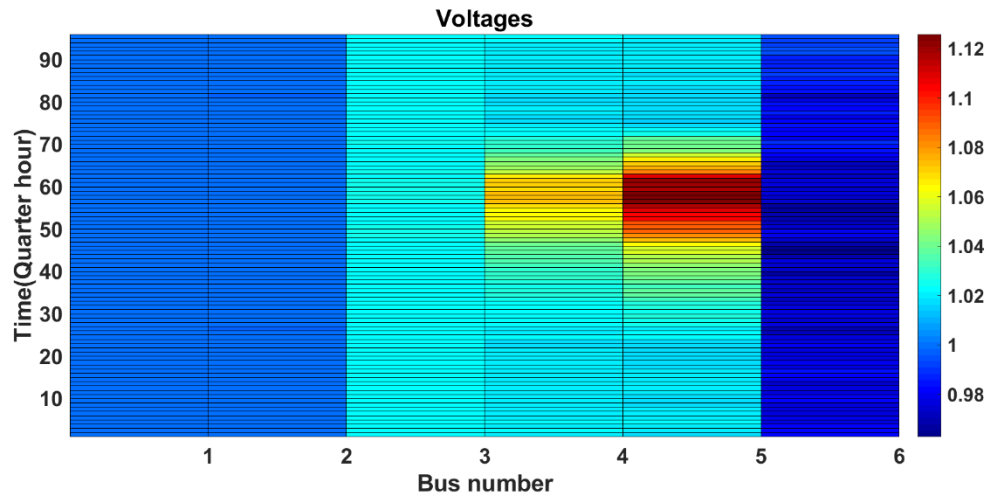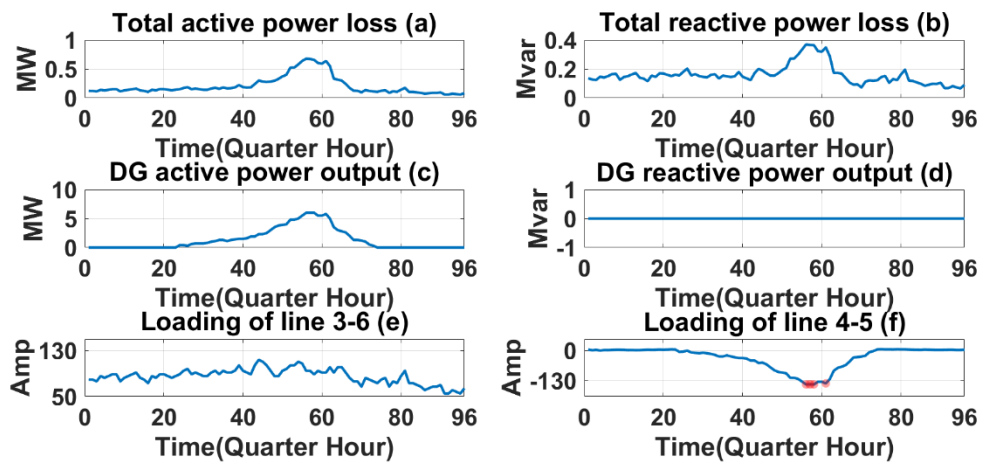
Figure 20.Voltage profile- scenario 1

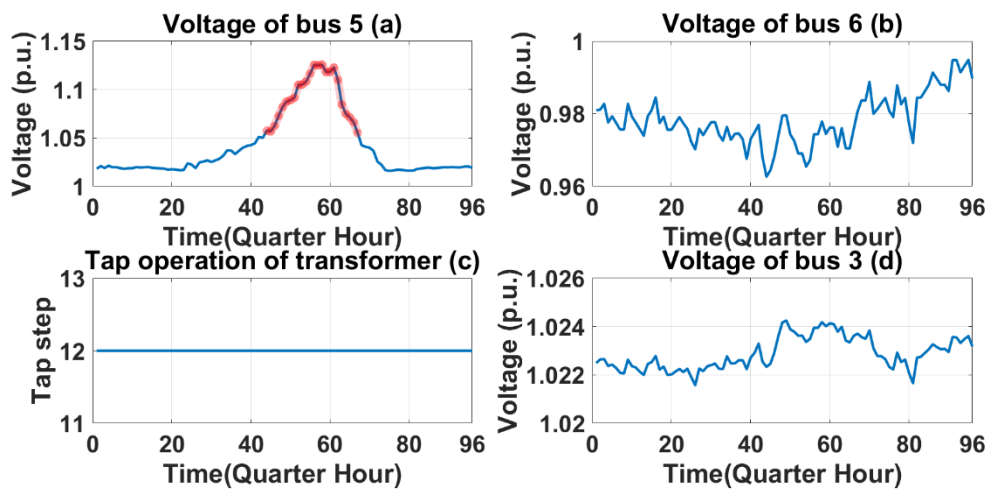*Figure 21*.Distribution network's losses (a,b), loading (e,f) and DG's output (c,d)- scenario 1

Figure 22.Bus voltages (a,b,d) and OLTC's tap operation (c)- scenario 1

5.2 Scenario 2

The primary substation's OLTC has been activated in this scenario. The transformer's automatic voltage regulator (AVR) tries to maintain the voltage at bus 3 within the defined dead band (between 1 to 1.01 p.u.). Based on the results shown by figure 23 and 24, the intensity of the overvoltage problem at bus 5 where the DG exists there has been reduced. However, section (f) of figure 24 depicts that the overloading problem still exists. Figure 25 section (c) describes 7 movements of the primary substation's tap changer as a result of voltage fluctuation of bus 3 during the day. Section (b) of the figure also indicates that voltage at bus 6 drops below the minimum permissible limit (0.95 p.u.) at some points around noon because the OLTC tries to reduce the voltage rise resulting from DG active power injection in mid-day. It means that DG connected to bus 5 can slightly increase the primary substation's voltage and make the tap changer to reduce the voltage of bus 3. The reduction of the voltage at bus 3 by OLTC leads to under-voltage problem in bus 6.
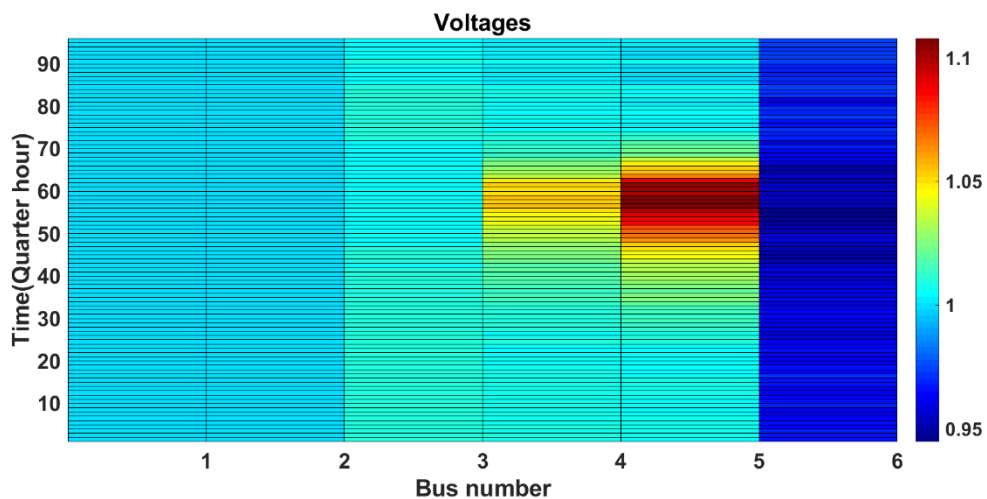

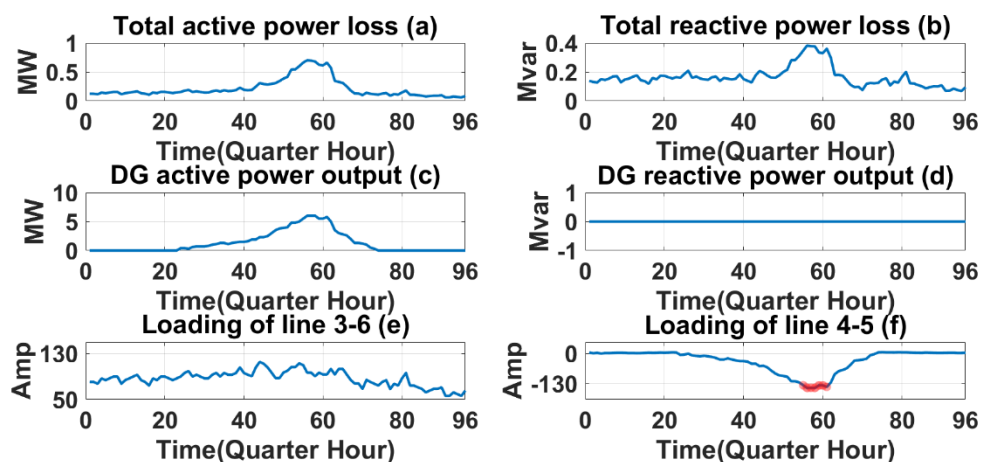**Figure 23**.Voltage profile- scenario 2

Figure 24.Distribution network's losses (a,b), loading (e,f) and DG's output (c,d)- scenario 2
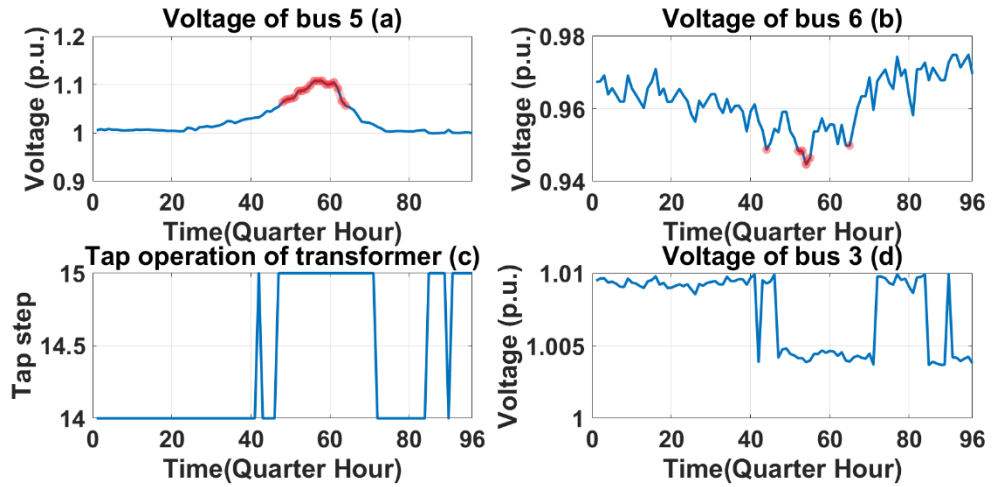

Figure 25.Bus voltages (a,b,d) and OLTC's tap operation (c)- scenario 2

5.3 Scenario 3

In addition to the primary substation's OLTC, the volt/var mode of the DG connected to bus 5 has been activated in this scenario. As figures 26, 27 and 28 illustrate, the intensity of voltage rise at bus 5 has been further reduced considering that the DG's reactive power compensation has led to a rise in active and reactive power losses of the network. Overloading of the line between buses 4 and 5 still exists (figure 27 section (f)) in this scenario due to the active power injection of the DG. It should be mentioned that whenever overvoltage at a bus coincides with the overloading of the nearby lines, reactive power compensation is not a good practice to relieve the overvoltage problem because it aggravates the overloading problem. Section a and b of figure 5 illustrate over voltage and under voltage at buses 5 and 6 respectively. Therefore, scenario 3 is not the solution of the congestion problem for the under-study distribution network.
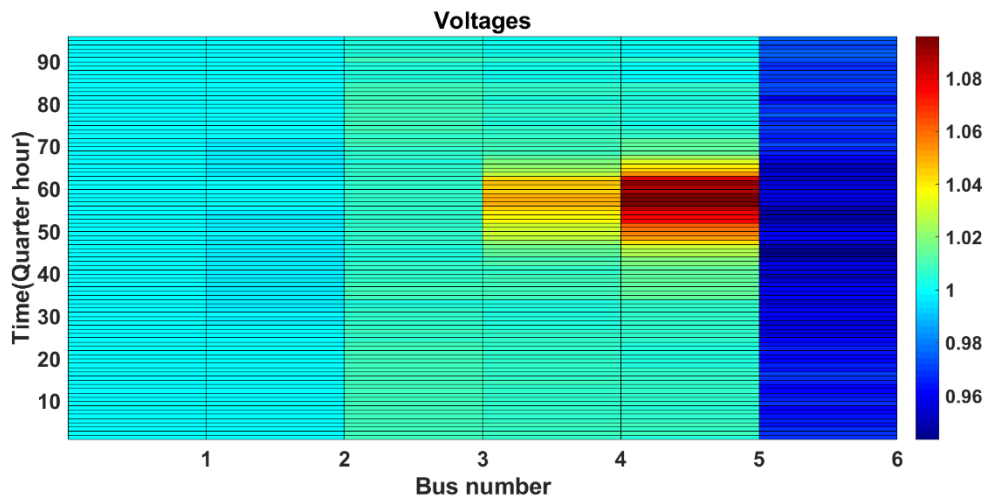

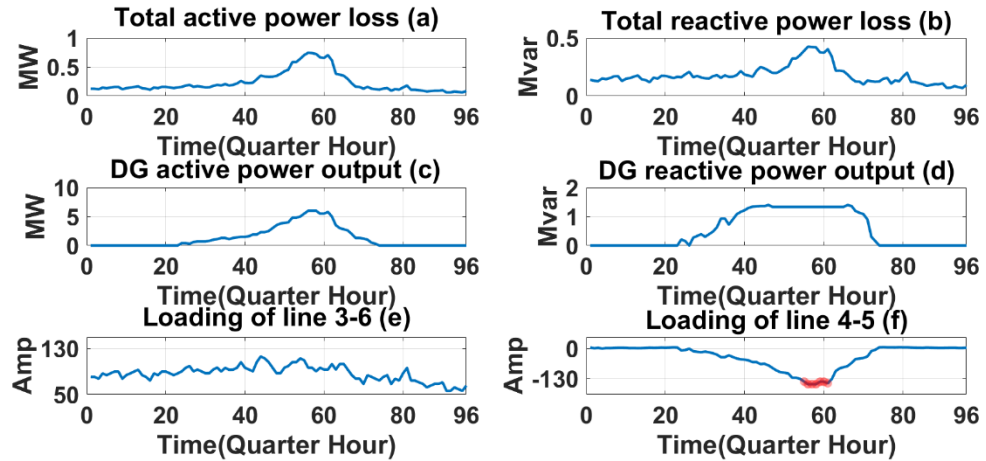*Figure 26.Voltage profile- scenario 3*

***Figure 27**.Distribution network's losses (a,b), loading (e,f) and DG's output (c,d)- scenario 3*
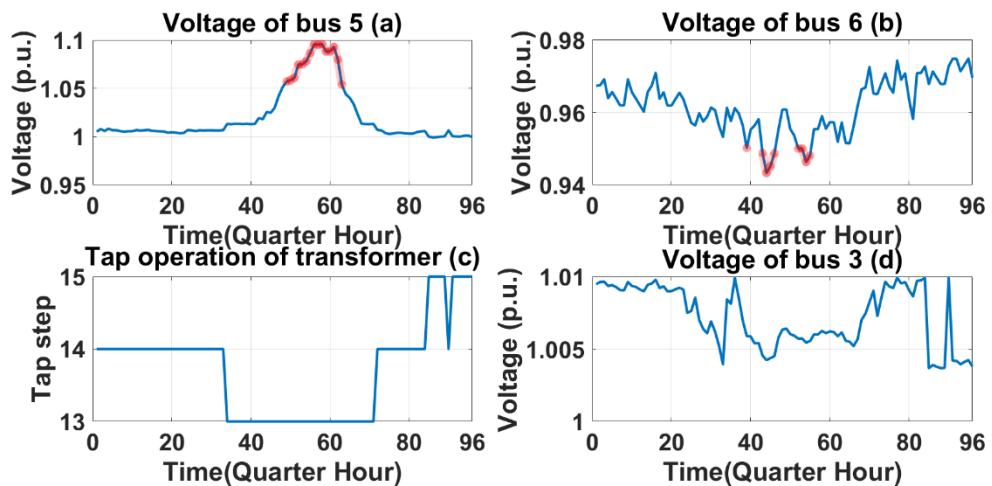

***Figure 28**.Bus voltages (a,b,d) and OLTC's tap operation (c)- scenario 3*

5.4 Scenario 4

In this scenario, the target is to combine non-market based solutions (primary substation's transformer and DG's volt/var control) with the market-based solution (LFM) and observe how the network's operation changes. The sequence of CM in this scenario starts with using non-market solutions followed by using LFM if it is needed. In other words, after taking non-market based solutions if the congestion persists, LFM is utilized in order to unlock some flexibility for the use of DSO. When flexibility for the congested quarter hours is procured, it has been designed that the predictive OPF uses the flexibilities for CM firstly, and secondly it utilizes non-market based solutions; however, the mentioned sequence of using market and non-market solutions is not the only way for CM which can vary based on different parameters and considerations (i.e. flexibility product design). In the proposed method of the thesis, the non-market based solutions act as a support for the procured flexibilities in the real-time operation of the network. Table 4 provides data about flexibility procurement, congested bus, and the flexibility direction. Figures 29, 30 and 31 confirm that the procured flexibility of table 4 has been effective

on congestion because neither voltage nor current violation is visible, so it can be claimed that the network status is in an acceptable state by combining market and non-market based alternatives for CM of the under-study distribution network.
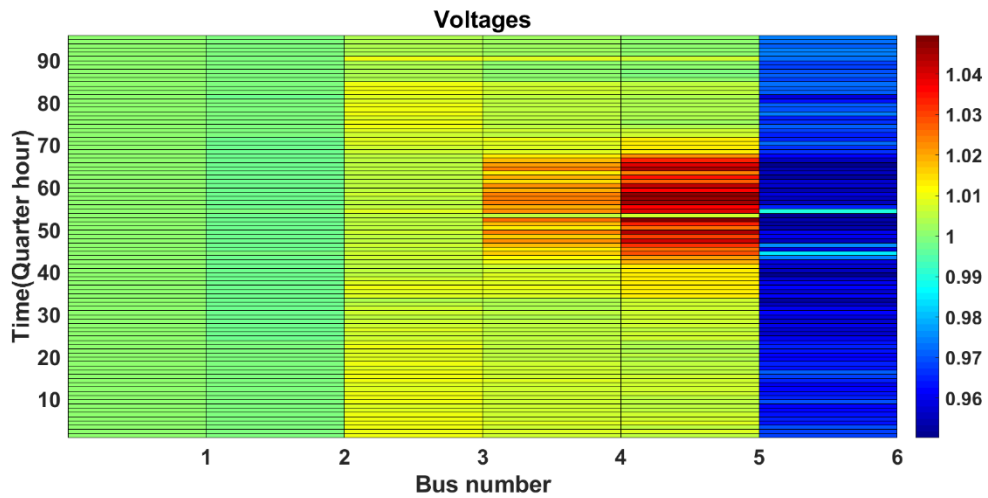

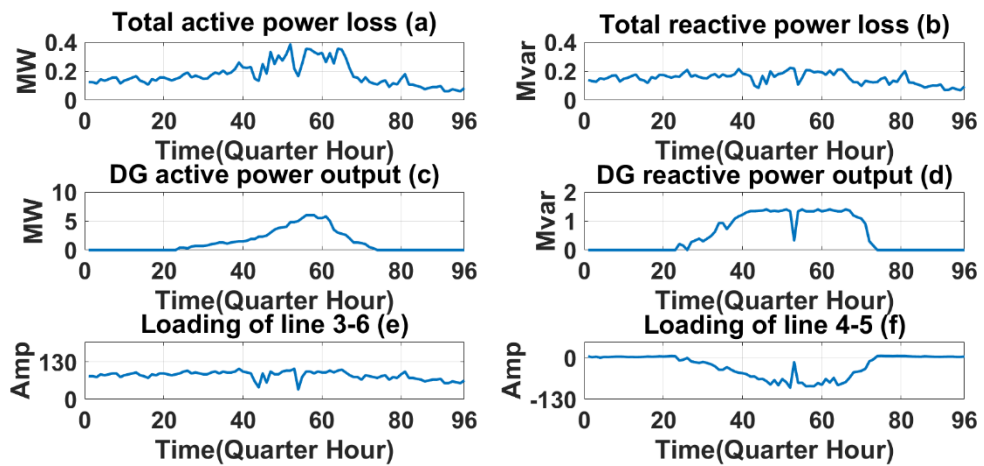
Figure 29.Voltage profile- scenario 4

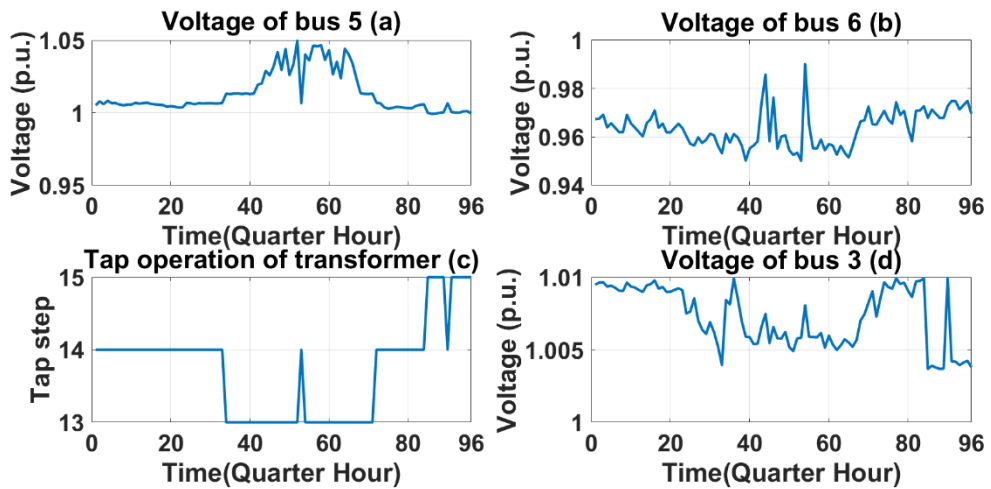*Figure 30*.Distribution network's losses (a,b), loading (e,f) and DG's output (c,d)- scenario 4

Figure 31.Bus voltages (a,b,d) and OLTC's tap operation (c)- scenario 4

Table 4.Flexibility procurement

Procured flexibility (MW)	Congested bus	Time (quarter-hour)	Direction
1.40	6	43	Upregulation
2.38	6	44	Upregulation
0.70	6	45	Upregulation
1.54	6	46	Upregulation
1.12	5	48	downregulation
0.70	5	49	Downregulation
1.68	5	50	Downregulation
1.40	5	51	Downregulation
1.40	5	52	Downregulation
4.20	5	53	Downregulation
2.24	5	54	Downregulation
2.52	6	54	Upregulation
2.80	5	55	Downregulation
0.98	6	55	Upregulation
2.80	5	56	Downregulation
2.80	5	57	Downregulation
2.80	5	58	Downregulation
2.80	5	59	Downregulation
2.52	5	60	Downregulation
3.64	5	61	Downregulation
2.38	5	62	Downregulation
1.54	5	63	Downregulation

5.5 Scenario 5

In order to recap what has been done for CM, it should be stated that the predictive OPF, if needed, procures flexibility from LFM, and later in real-time operation, the OPF takes the previously settled flexibilities into account in the network operation. In fact, it can be said that the predictive OPF feeds the OPF. Consequently, any error in the predictive OPF's process potentially impacts the real-time optimization of OPF, which is why in this scenario it is aimed to understand how much inaccuracy of predictive OPF is tolerable in real-time OPF.

5.5.1 3% inaccuracy in load and generation profiles

Once the required flexibility is procured from LFM within the process of the predictive OPF, in order to simulate 3 percent estimation error of load and production data, load and production profiles with +-3% change have been applied in real-time operation of the network. In this way, the predictive profiles (loads and production) contain +-3% dif-ference from the profiles which is occurring in real-time operation of the network. Figure 32 shows that the voltage of all buses is within acceptable limits; however, the voltage at bus 5 has some red areas, but they are in the permissible zone. Figure 33 does not

report any overloading of the lines and figure 34 approves that no voltage violation happens if the predictive optimization contains +-3% error. In other words, +-3% error in predictive OPF is tolerable for real-time OPF.
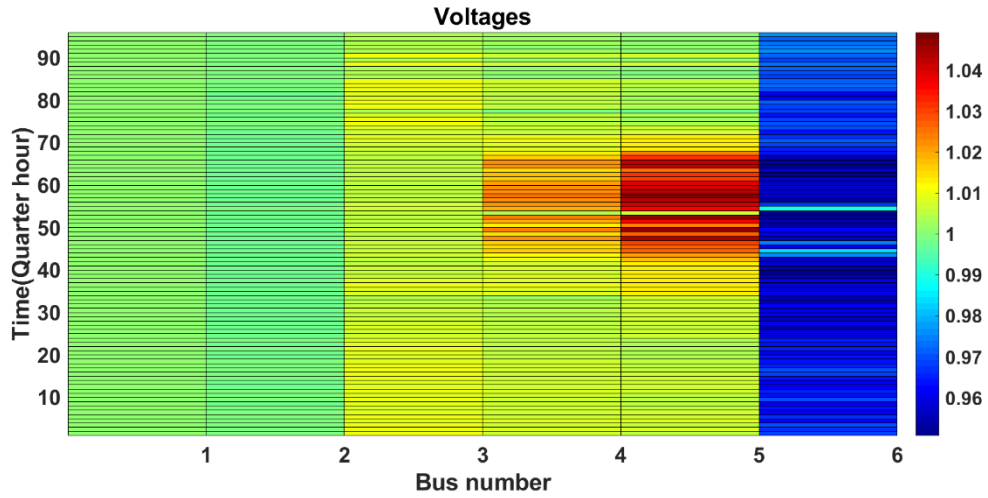

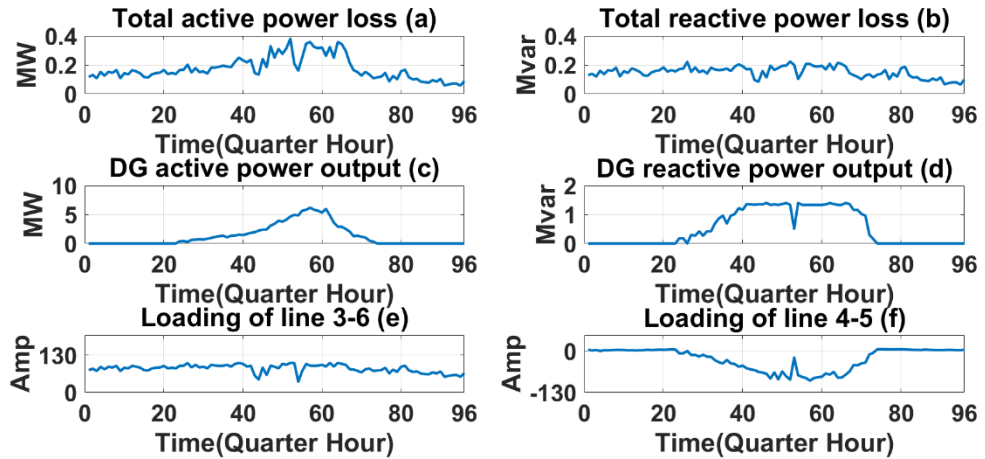*Figure 32.Voltage profile- scenario 5 (3% error)*

Figure 33.Distribution network's losses (a,b), loading (e,f) and DG's output (c,d)- scenario 5 (3% error)
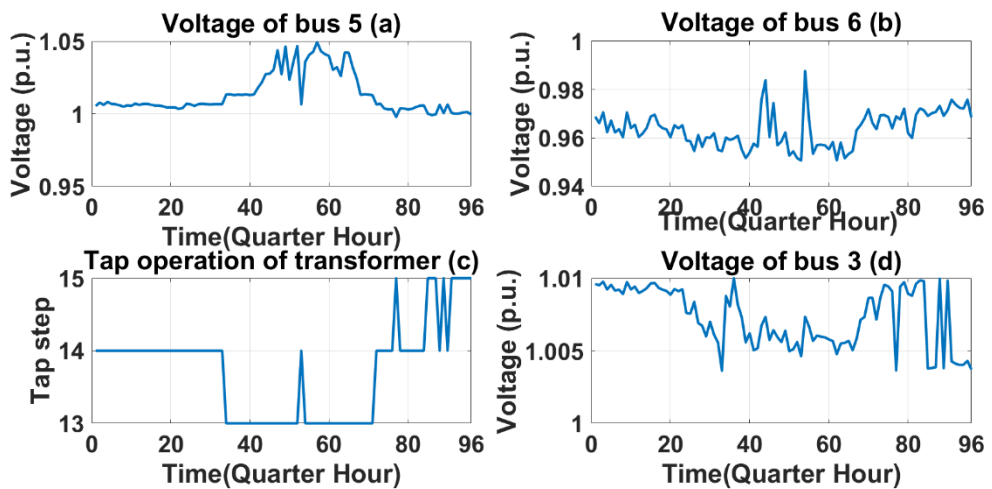

Figure 34.Bus voltages (a,b,d) and OLTC's tap operation (c) -scenario 5 (3% error)

5.5.2   10% inaccuracy in load and generation profiles

In section 5.5.1, the OPF could tolerate up to +-3% prediction error. In this scenario, it is aimed to increase the prediction error to +-10% and observe the network's state. Figure 35 implicitly shows a slight overvoltage problem on bus 5. Overloading violation does not happen in the network, as depicted in figure 36 section (e,f). In figure 37, two-quarter hours of over-voltage at bus 5 and five-quarter hours of under-voltage at bus 6 have been highlighted with red dots in sections a and b respectively. Therefore, it can be said that +-10% prediction error has caused slight violations in the real-time operation of the network. The reason behind fluctuations in some graphs (e.g., figure 37 sections (b, d)) is that the load and production profiles contain +-10 percent variation every other quarter-hour.
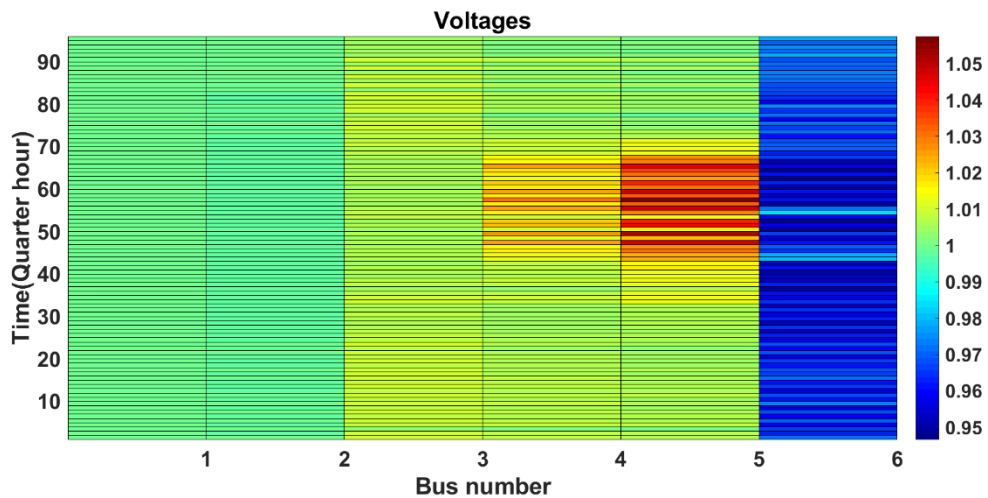

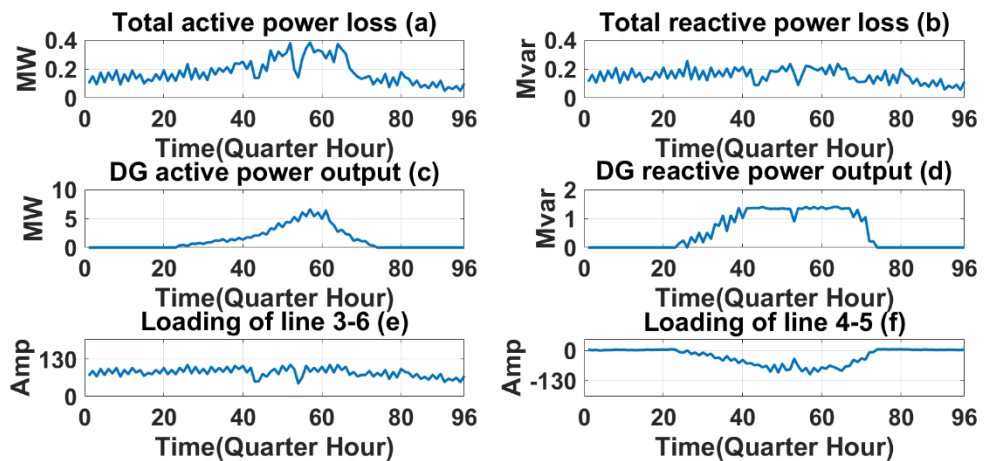***Figure 35**.Voltage profile- scenario 5 (10% error)*

***Figure 36**.Distribution network's losses (a,b), loading (e,f) and DG's output (c,d)- scenario 5 (10% error)*
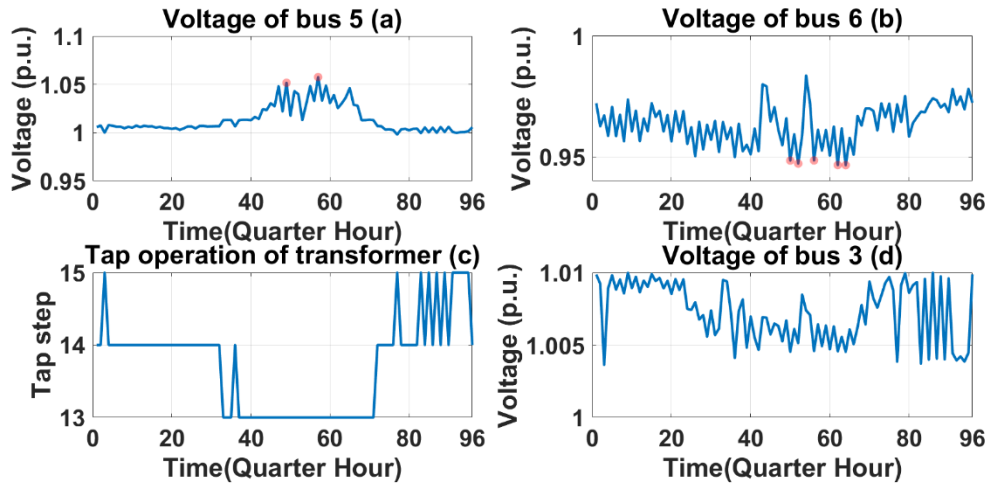
Figure 37*.Bus voltages (a,b,d) and OLTC's tap operation (c)- scenario 5 (10% error)*

5.6 Results comparison and analysis

Table 5 provides a holistic view of the studied scenarios. The number of violated quarter hours, total reactive power losses, total active energy losses and tap changer movements of the primary substation's OLTC are the criteria that seem important to be compared between the studied scenarios.

By comparing the results, firstly, it is noticed that the number of violated quarter hours has been reduced step by step with respect to the added controllability to the system. The number of violated quarter hours is 42 when no controllability is used in scenario 1 whereas it reaches 0 in scenario 4 where a combination of market base and non-market based solutions have been considered. The amount of violations is related to the accuracy of the predicted OPF data, which this claim can be approved by observing the violated quarter hours in scenario 5. The predictive OPF with 3% error has no violation, whereas 10% prediction error leads to 7 quarter-hours of violation.

Secondly, the total reactive power losses of scenario 3 is the maximum, which is understandable due to the activation of DG's reactive power compensation mode. Like reactive power losses, the total active energy losses have experienced its maximum in scenario 3. A boost in the network losses due to using reactive power control is one of the downsides of volt/var control used in scenario 3, especially for strong networks. The stronger the network, the more reactive power is needed to maintain the voltage in acceptable limits leading to excessive reactive power flow through distribution network lines, which may even hit the maximum allowable current limits of lines considering the fact that DGs usually have some restriction in terms of reactive power generation unless capacitor or reactor are used.

Thirdly, in general, the number of tap movements of the OLTC is acceptable (less than 30 per day is acceptable [38]) is all scenarios meaning that regardless of the used method for the congestion management in the thesis, limitation in tap movements has not created any restriction in our simulations. It should be stressed that tap movements are dependant on many factors such as AVR's dead band and reference value, volatility

in load and generation profiles, the strength of the network, etc and making a comprehensive conclusion about tap movements needs further studies.

Table 5.*Comparison of the studied scenarios*

Scenario	Used controllability	Number of violated quarter hours	Total reactive power losses (MVarh)	Total active energy losses (MWh)	Number of tap changer movements
1	None	42	3.8336	4.9901	0
2	OLTC	33	3.9530	5.1558	7
3	OLTC+ reactive power compensation	22	4.3011	5.5086	6
4	OLTC+ reactive power compensation+ LFM (prediction error:0%)	0	3.6153	4.2020	8
5	OLTC+ reactive power compensation+ LFM (prediction error:3%)	0	3.6086	4.1963	12
5	OLTC+reactive power compensation+LFM (prediction error:10%)	7	3.6535	4.2344	17

6. DISCUSSION

The CM through the market mechanism on a broader view than what was discussed so far in the thesis is intended to be presented here. Topics related to LFM product design and economic aspects of CM, unsolved issues and future developments of the simulation environment, and simulation environment benefits are the topics worth discussing In this chapter.

6.1 Product design and economical aspects of CM

Several issues need to be taken into account when flexibility as a product is in the design phase to be used by a DSO. In fact, the final decision on how the product is designed should result from a synergy between DSOs, TSO and flexibility providers. In product design, two types of flexibility can be thought of including conditional re-profiling (CRP) and scheduled re-profiling (SRP) [39] [40]. CRP is a product similar to reserve services in transmission level, which is activated upon the buyer's request (DSO). Consequently, the payment from a DSO to the flexibility provider is made in two stages, one for procuring capacity and one in case of activation of it. On the other hand, in SRP, up or down-regulation of a settled volume at a certain time must be provided by the flexibility providers. In the designed LFM of the thesis, CRP might be used when the DSO is not completely sure about congestion for the upcoming day. In contrast, if the DSO is certain about the future congestion in the network (i.e. due to scheduled maintenance), then SRP sounds more secure for a DSO from operational perspectives, and also it might be cheaper than CRP.

Another important aspect of product design is bid splitting. In a flexibility market with pay as bid market-clearing method, if a DSO is free to split the bids to its required amount, then the DSO may pay less cost for its CM. Another positive aspect of splitting is that flexibility is used more efficiently. The difficulty is mostly on the flexibility providers' side because when their bids are split, then portfolio management becomes harder for them keeping in mind that an offered bid in the market might be the mix of several individual flexibilities and splitting them is not possible for a flexibility provider. One solution might be so that the flexibility provider defines whether its bid is splittable or not. Also, the splitting point of the bids can be added to the bid description in the market platform.

Economic aspects of CM are one of the most important areas since every technical aspect of the electricity system eventually can be translated to monetary values. The truth is that CM through a market mechanism is not the only mean of DSO for CM. Market-based CM is cost-effective when other alternatives such as grid reinforcement, grid re-configuration, etc are too costly, time-consuming, or not possible (i.e. difficulty at receiving a loan from bank). For instance, it might be so that the DSO is not financially capable to reinforce the grid, and it is seeking an immediate solution to deffer the reinforcement. Along with all conventional solutions of CM, the LFM as a new alternative may temporarily solve the congestion, or at least it can widen a DSO's solutions for CM.

As LFM is expected to have limited liquidity and resources compared to the existing markets, in product design, the market power considerations require more attention. There are various ways addressing market power for instance price cap method. In this method, the maximum value of flexibility is defined by the regulator so that an aggregator can not abuse the market power. Besides, whenever the security of the network is endangered by congestion (red phase network state), and there is no bid available in the market, then mandatory bidding is another approach that can be put in place by the regulator. The mentioned considerations limit the market power abuse and assure the market participants that their companies' benefits merely lie in their level of cooperation.

Opening and closing time of the LFM play an important role in liquidity and congestion management costs of a DSO. If the time when LFM is open happens after the closure of existing flexibility markets (e.g., aFRR), then probably most of the flexibilities flow toward the existing markets considering that existing markets are less risky for flexibility providers to participate because they already have learned the markets compared to a new market like LFM. In fact; flexibility availability and flexibility price become highly dependant on the existing markets. If LFM operates when existing markets are still open, then the dependency of the LFM market on the existing markets become less; however, it becomes more complex for flexibility providers from bidding optimization point of view. If the LFM opens prior to the existing markets, since the liquidity of LFM is negligible compared to existing markets, then flexibility providers probably do not tend to participate in LFM. Another idea is to make the LFM time-independent, meaning that the LFM operates when it is requested by a DSO. The implementation of this idea requires the flexibility providers to bid at any time of a day, which is demanding from bid optimization and data communication (i.e., robust, quick, etc.) point of view. The mentioned discussion about the timing of LFM opens up the importance when LFM needs to be operated, emphasizing the fact that each of the beforesaid options has its pros and cons.

6.2 Unsolved issues and future development of the simulation environment

In the simulation environment, the bids available in LFM were hardcoded meaning that a certain amount of flexibilities assumed to be the same in the studied scenarios because the behavior of the market players has not been emulated here. Emulating the flexibility providers' behaviors in the market is very complex; however, it can enlighten us about the pros and cons of different scenarios. For instance, if the price in the balancing market is too high (due to any reason), then flexibility providers either do not participate in LFM or increase their asking price leading to a low liquid LFM. In addition, we know that flexibility providers usually are not the owners of the physical devices and they have contract with customers. The clauses of that contract can impact the bidding of the flexibility providers in markets. The algorithms used by flexibility providers to stack their flexibility and present them into the most profitable markets play an essential role as well. Therefore, flexibility providers' behavior is dependant on several factors and its emulation requires a lot of work and consideration. This could be one area worth developing in the simulation environment in the future.

Issues associated with TSO/DSO coordination is another missing aspect in the current version of the simulation environment. Furthermore, the forecasting part which is a necessity of the predictive OPF needs to be implemented in the future. Also from IT perspective, standardizing the used protocols, cyber-security considerations, etc are essential steps toward the practicality of the simulation environment in order to make it a more realistic tool. Emulation of households to see the true behavior of customers concerning their flexibility is another open area for development. Finally, since the under-study network of the thesis for the sake of simplicity is small, it is aimed to update the under-study distribution network of the thesis to a larger and real-world network in order to increase the validity of our analyses.

6.3 Simulation environment benefits

Having more realistic simulations, the ability to study the conflicts of interests (or synergies) of different stakeholders while being scalable, modular and extendable are significant benefits of the simulation environment. The modularity allows not to necessarily model everything in one system but connecting different systems that are best for each usage. Users of each system do not need to fully understand every part of other systems provided that proper documentation is done. The mentioned virtues of the simulation environment enable us to examine and comprehend various potential scenarios. Since LFM is in development phase nowadays, there is no unique understanding of how it can be implemented in practice, therefore, a tool such as the simulation environment of this thesis is highly required to study and compare different scenarios.

7. CONCLUSION

Distribution system congestion management through LFM was investigated in the thesis. Not only to solve congestion through LFM but the aim was to build such a simulation environment in order to study different scenarios regarding the distribution system congestion management. Congestion management alternatives including non-market base solutions, market-based solutions, and a mix of them have been studied in chapter 5 (simulation results). In the following, the findings have been proposed.

Regarding the timing and frequency of the LFM operation, a clear proposal in the thesis was investigated. Since the process of CM was divided into two sections, including predictive and real-time, it is proposed that LFM can be operated a day ahead of the operation time of the network. It means that the LFM is performed once a day dependant on the DSO's prediction concerning the state of its network for the upcoming day. If CM through LFM is needed, then at 3 pm the LFM is opened, and 6 pm is the proposed time for publishing the market-clearing results to market participants.

Based on the achieved results of chapter 5, it is concluded that LFM can bring benefits to DSOs because there are some times when non-market based alternatives such as CVC are not enough to relieve congestion, and a DSO should be assisted through a market mechanism (LFM) to manage congestion.

With respect to the impacts of predictive OPF errors on the real-time operation of the network, it seems that a slight amount of prediction errors (few percents, e.g., 3 percent in the under-study case of the thesis) is tolerable for real-time operation of the network and rise of prediction inaccuracy potentially increase the violations of the network.

REFERENCES

[1]   N. S. Barnes, P. A. Brinster, and P. Fahey, "An Integrated Approach to Active System Management," vol. 28, no. 1, pp. 24–29, 2019.

[2]   "Nord Pool website." [Online]. Available: https://www.nordpoolgroup.com/.

[3]   R. E. Bohn, "Optimal Pricing in Electrical Networks over Space and Time Author (s): Roger E . Bohn , Michael C . Caramanis and Fred C . Schweppe Published by : Wiley on behalf of RAND Corporation Stable URL : http://www.jstor.org/stable/2555444 Optimal pricing in el," vol. 15, no. 3, pp. 360–376, 2016.

[4]   M. Weibelzahl, "Nodal, zonal, or uniform electricity pricing: how to deal with network congestion," *Front. Energy*, vol. 11, no. 2, pp. 210–232, 2017.

[5]   "EUPHEMIA." [Online]. Available: https://www.n-side.com/pcr-euphemia-algorithm-european-power-exchanges-price-coupling-electricity-market/.

[6]   European Commission, "COMMISSION REGULATION (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management," *Off. J. Eur. Union*, no. July, pp. 24–72, 2015.

[7]   C. TC, "Voltage Disturbances Standard EN 50160 Voltage Characteristics in Public Distribution Systems," *Power Qual. Appl. Guid.*, vol. 5.4.2, pp. 4–11, 2004.

[8]   J. Rodriguez and C. M. Franck, "Dynamic Line Rating of overhead transmission lines under natural convective cooling," *2015 IEEE Eindhoven PowerTech, PowerTech 2015*, pp. 1–5, 2015.

[9]   K. Geschermann and A. Moser, "Evaluation of market-based flexibility provision for congestion management in distribution grids," *IEEE Power Energy Soc. Gen. Meet.*, vol. 2018–Janua, pp. 1–5, 2018.

[10]   A. Kulmala, S. Repo, and P. Järventausta, *Active Voltage Control in Distribution Networks Including Distributed Energy Resources*, vol. 5, no. 4. 2014.

[11]   A. N. M. M. Haque, M. T. Rahman, P. H. Nguyen, and F. W. Bliek, "Smart curtailment for congestion management in LV distribution network," *IEEE Power Energy Soc. Gen. Meet.*, vol. 2016–Novem, 2016.

[12]   S. Pal, S. Sen, and S. Sengupta, "Power network reconfiguration for congestion management and loss minimization using Genetic Algorithm," *IET Conf. Publ.*, vol. 2015, no. CP683, pp. 291–296, 2015.

[13]   ENTSO-E, "Network Code for Requirements for Grid Connection Applicable to all Generators," no. June, p. 81, 2012.

[14]   Institute of Electrical and Electronics Engineers, *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*. 2018.

[15]   K. Lummi, "25 th International Conference on Electricity Distribution Paper n ° 1680 UPCOMING CHANGES IN DISTRIBUTION NETWORK TARIFFS – POTENTIAL HARMONIZATION NEEDS FOR DEMAND CHARGES 25 th International Conference on Electricity Distribution Commonly emphasized pr," no. June, pp. 3–6, 2019.

[16]   S. Chanana and A. Kumar, "Power flow contribution factors based congestion management with real and reactive power bids in competitive electricity markets," *2007 IEEE Power Eng. Soc. Gen. Meet. PES*, 2007.

[17]   BDEW German Association of Energy and Water Industries, "Smart Grid Traffic Light Concept - Design of the amber phase," no. March, 2015.

[18]   S. S. Reddy, "Multi-Objective Based Congestion Management Using Generation Rescheduling and Load Shedding," *IEEE Trans. Power Syst.*, vol. 32, no. 2, pp. 852–863, 2017.

[19]   D. R. Biggar and M. reza Hesamzadeh, *The Economics of ELECTRICITY*

MARKET, First. John wiley, 2014.

[20] N. Mazzi, A. Lorenzoni, S. Rech, and A. Lazzaretto, "Electricity auctions: A European view on markets and practices," *Int. Conf. Eur. Energy Mark. EEM*, vol. 2015–Augus, pp. 1–5, 2015.

[21] Nordpool, "Day ahead market," 2019. [Online]. Available: https://www.nordpoolgroup.com/the-power-market/Day-ahead-market/.

[22] S. T. Examiner and S. R. Examiner, "NIKO KORHONEN AVOIDING UNDUE DISCRIMINATION IN TRANSMISSION CA- PACITY CALCULATION AND ALLOCATION Master of Science Thesis NIKO KORHONEN : Avoiding undue discrimination in transmission capacity cal- Major : Power systems and market Examiner : Professor Sa," no. March, 2018.

[23] J. Dijk and B. Willems, "The effect of counter-trading on competition in electricity markets," *Energy Policy*, vol. 39, no. 3, pp. 1764–1773, 2011.

[24] NORDPOOL, "Intraday market," 2019. [Online]. Available: https://www.nordpoolgroup.com/the-power-market/Intraday-market/.

[25] Fingrid Oyj, "Reserve and balancing power," 2019. [Online]. Available: https://www.fingrid.fi/en/electricity-market/reserves_and_balancing/#reserve-products.

[26] Fingrid, "Reserve products and reserve market places," 2018.

[27] EU commission, "EU climate action," 2019. [Online]. Available: https://ec.europa.eu/clima/citizens/eu_en.

[28] K. Geschermann and A. Moser, "Evaluation of market-based flexibility provision for congestion management in distribution grids," *IEEE Power Energy Soc. Gen. Meet.*, vol. 2018–Janua, pp. 1–5, 2018.

[29] Ministry of the envirionment, "The national building code of Finland," 2019. [Online]. Available: https://www.ym.fi/en-US/Land_use_and_building/Legislation_and_instructions/The_National_Building_Code_of_Finland.

[30] INTERRFACE, "State of the arts of markets for flexibility," 2019. [Online]. Available: http://www.interrface.eu/.

[31] European Union, "Regulation 2016/679," *Off. J. Eur. Communities*, vol. 2014, no. March 2014, pp. 1–88, 2016.

[32] E. S. Framework and P. Future, "Cyber Security and in the Energy and Sector," no. February, 2017.

[33] L. M. Freire, E. M. A. Neves, L. I. Tsunechiro, R. Cabral, and Z. Souza, "Liquidity in the Brazilian electricity market," *9th Int. Conf. Eur. Energy Mark. EEM 12*, pp. 1–8, 2012.

[34] "Deliverable 3.1: Distribution Automation Concept," 2014. [Online]. Available: https://ide4l.eu/results/.

[35] P. Verho, "Configuration Management of Medium Voltage Electricity Distribution Network," Tampere University of Technology, Tampere, 1996.

[36] N. Mazzi, J. Kazempour, and P. Pinson, "Price-Taker Offering Strategy in Electricity Pay-as-Bid Markets," *IEEE Trans. Power Syst.*, vol. 33, no. 2, pp. 2175–2183, 2018.

[37] Q. Tao, D. Wang, B. Yang, H. Liu, and S. Yan, "Voltage control of distribution network with distributed generation based on voltage sensitivity matrix," *Proc. - 2nd IEEE Int. Conf. Energy Internet, ICEI 2018*, pp. 298–302, 2018.

[38] T. Niknam, "A new HBMO algorithm for multiobjective daily Volt/Var control in distribution systems considering Distributed Generators," *Appl. Energy*, vol. 88, no. 3, pp. 778–788, 2011.

[39] M. Á. Moreno and J. Usaola, "Technical constraints and flexibility management in smart grids," *Int. Conf. Eur. Energy Mark. EEM*, vol. 2015–Augus, pp. 0–4, 2015.

[40] I. Grid, "Deliverable 3.1: Distribution Automation Concept (Idea grid for all, Project no: 608860)," 2016.