Digital Twin Application for Congestion Management in Distribution Network

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by

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This thesis is confidential and cannot be made public until August 29, 2020.

Preface

High penetration of rooftop PV generation in the distribution network increases the variability of power flows and the frequency of network and hence congestions occurs at various network locations of the network. Congestions have various defects such as it deteriorates network performance, power quality and therefore can lead to a shutdown by the automatic safety systems installed to prevent a total system collapse. Therefore, it is important to study and control the congestion management issues during the high impact of DER's in a distribution network. In this project is based on practical insight from real world VPP application in the CityZen project (EU FP7). Community Battery Energy Storage along with the Digital Twin will be used to alleviate congestion in LV distribution network.

Kamdin Shafiepour
Delft, August 2019

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List of Acronyms

NAZ National Action Plan on Solar Power

DSO Distribution System Operator

VPP Virtual Power Plant

OLTC On Load Tap Changer

PV Photovoltaic

DER Distributed Energy Resource

TSO Transmission System Operator

CBESS Community Battery Energy Storage System

BESS Battery Energy Storage System

TVPP Technical Virtual Power Plant

CVPP Commercial Virtual Power Plant

DG Distributed Generations

RES Renewable Energy Sources

DS Distributed Substation

DoE Department of Energy

DMS Distribution Management System

ENTSO-E European Network of Transmission System Operators for Electricity

PLM Product Lifecycle Management

DDM Dynamic Digital Mirroring

RTU Remote Terminal Units

PMU Phasor measurement Units

CPES Cyber-Physical Energy System

TCI Total Congestion Index

CI Congestion Index

1 Introduction

1.1. Research Theme

The share of renewables in meeting global energy demand is expected to grow at an accelerated pace. From around 25% today to approximately 50% by 2035 and further close to 75% globally by mid-century [5]. As solar and wind generation combine to reach a 30-50% total generation, the power system presents significant challenges to electricity grid management.

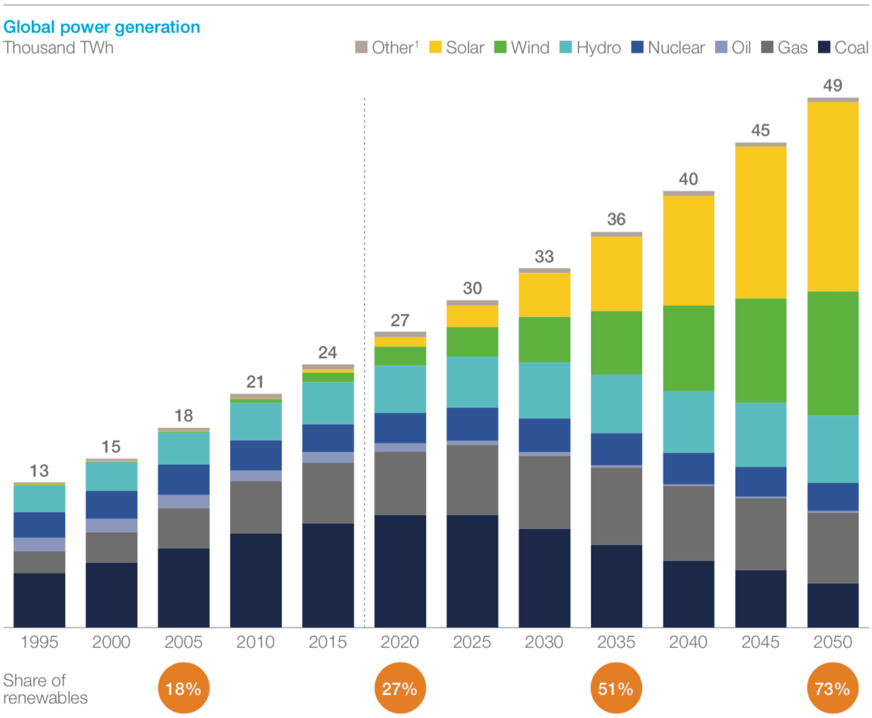

Figure 1.1: Other includes biomass, geothermal, and marine
Source: McKinsey Energy Insight'Global Energy Prospective, January 2019 [5]

As of December 2018, Europe's new target for 2030 is to increase renewable energy by 32% and the energy efficiency by 32.5%, alongside the existing 40% greenhouse gas emission target [10]. The Paris agreement and the Commission's 2050 long-term plan aims to make the power system close to be full decarbonised. European Network of Transmission System Operators for Electricity (ENTSO-E) highlighted in 2040 "NO Grid" scenario that a lack of investment in transmission grid would lead to increase of marginal electricity prices by 3-29%, curtailment of renewable energy and damage to the security of supply [10].

One type of dispersed generators in distribution grid which has shown a large increase in the past decade is Photovoltaic (PV). Looking at the global market outlook for solar power in figure 1.2 countries such as Netherlands and Belgium have been focusing on rooftop solar [11]. According to the National Action Plan on Solar Power (NAZ), the current rooftop potential for the generation of solar power in residential buildings in The Netherlands is approximately 70 GW . The Netherlands contributes to roughly 1,5 GW solar PV capacity. Domestic PV systems are increasingly popular. Hence, this number is estimated to increase up to 10 GW with a high growth rate close to 2.5 million Dutch households in 2023 [9].

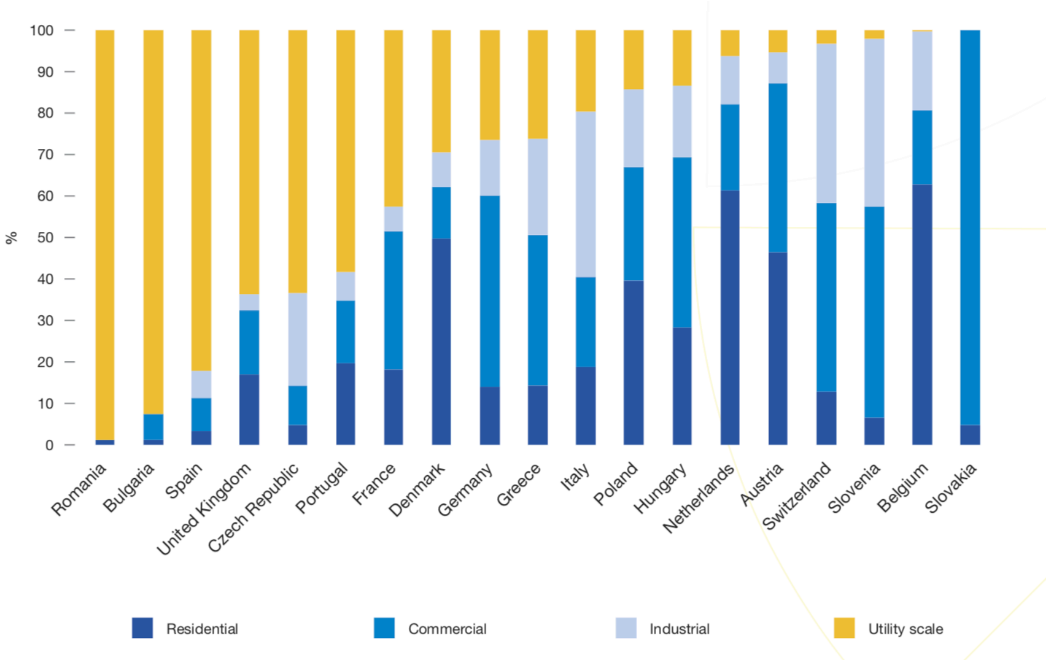

Figure 1.2: European solar PV total capacity 2017/2018 [11]

Another aggressively growing energy technology is energy storage which is indicated to be the major link to renewable energy and can serve other purposes such as supplying ancillary services, transmission and distribution infrastructure. Aggregation of Distributed Energy Resource (DER) such as PV and storage set a base concept for Virtual Power Plant (VPP). A VPP is an aggregation of small generated units and controllable loads aiming to make contracts in the wholesale market and also to provide services to the system operator [25]. More definitions on VPP and also the types of VPP will be further described in section 1.7. Studies conducted to evaluate the performance of such a VPP are limited. Congestion management is one of the problems in the distribution grid addressed by using VPP. Currently, the large part of electricity has a 'top-down' structure which flows from large scale centralized power plants through the transmission grid and there after to the distribution grid where it is consumed by the end users. In general, transmission grid with higher supervision and control possibilities is more active and the Transmission System Operator (TSO) perform different control methods to keep the system stable. On the other side, distribution system with little or no communication possibilities and limited local control and monitoring system has been very passive in nature. The massive increase of the intermittent dispersed generation in distribution networks has led to a bidirectional power flow that if the capacity of the network is inadequate, congestion/ bottlenecks will occur. Moreover, assets are overloaded and voltage deviations may occur and cause failures. Therefore there is an urgent need for new monitoring, operational and control strategies by system operator to face challenges in terms of instability, power quality and feeder capacity problem. To avoid any congestion occurrence in a smart grid with large number of DERs, additional investment in distribution network

is required. It can happen that the transmission capacity may be inadequate and it is not economical to plan a network with overestimate capacity. It is necessary to study the impact of increasing the number of DERs in the distribution system. The customers involved do not just consume but can also behave as an energy supplier. Among different solutions, congestion management is one of the most promising strategies to deal with the problems occurring in the network. Congestion management has been traditionally used in the transmission network, however with significant increase in number of DERs this strategy has to be applied in the distribution network as well. Due to the power injection by DERs in distribution network, voltage variation occurs. Distribution System Operator (DSO) have been facing troubles to control the voltage variations at the point of couplings in low voltage distribution network. In most of the countries, monitoring is not available at the distribution level and distributed generators are not used as ancillary service to support the grid. This increases the probability of the failure, increases the risk and threats the security of the system.
There are many examples to demonstrate the risk of congestion in the distribution network due to injected power by large number of DERs. In Galicia, Spain, the total amount of 2203 MW connected to the distribution network represents 120% of the total peak demand (1842MW). In 2011, Italy had the highest worldwide installation of solar PV in Enel distribution grid (Enel Distribuzione) connecting 10 GW of solar power. In Northwest Ireland 307.75 MW of wind power generation connected to the distribution network with a high peak demand of 160 MW, and many other countries pushing towards the Paris agreement and the Commission's 2050 long-term plan are the few examples showing the need for monitoring, control and congestion management in the distribution level.
In a dynamic power system where the behavior of the system is not predictable and the forecasting information may contain errors and a short period of disruption may lead to financial damages to the customers and service providers, it is essential to implement intelligent algorithms to minimize unpredictive service disruptions due to unavoidable contingencies. The control centers technology are developing rather slowly while the number of DERs and decommissioned conventional power plants are increasing which leads to a higher rate of failure and increase the probability of contingencies occurring in the network. The time to deal and react with the failures also reduces. For that a new precise and flexible monitoring tool to control the operational issues will be needed [18].
In a smart power system, smart measurement infrastructure brings so many advantages in monitoring and control of the power system. It makes it possible to effectively gather and analyze real-time and synchronized data, run fast intelligent algorithms and send the control signal to controllers. In this work a close to real time congestion monitoring and management for power systems using Digital Twin is proposed along with a Community Battery Energy Storage System (CBESS) for congestion management in distribution network. Using CBESS allows to store the excessive power injected by DER to the distribution grid and therefore avoid shutting down of these generating units. The impact of CBESS is further explained in section 2.5.
Moreover, this CBESS is controlled by digital twin. Digital twin is defined as a Digital replica of a system or an asset that changes its properties and behavior by means of models and data [18]. The close to real time congestion management mechanism by Digital Twin is used to support the DSO with smart operation of distribution network and help VPP to continuously operate and reduce the active power curtailment by the DERs. In this work Digital twin is used to first detect the congestion occurs when the VPP is operating and second to control the CBESS to deal with the congestion scenarios.

1.2. State-of the art & Scientific Gap

Different approaches have been proposed for congestion management in a distribution network. One approach is by using indirect control methods. These methods consist of market mechanism to control congestion problem in the system. Market methods are mainly based on congestion price setting or a regional electricity price mechanism. These methods include system rescheduling by decreasing trading contracts and transmission schedules, increasing and decreasing generator output, load shedding and implementing load rights [20]. Indirect

control methods are not the focus of this work.
Another approach in congestion management method is by using direct control methods. There are various methods developed in literature for congestion management using direct control methods. One method constitutes the re-configuration of the network and upgrade network feeders [29], this method mainly focuses on improving the infrastructure. However, the problem with this method is that it is economically costly for distribution system operator.
Other approaches have been suggested in the literature, such as changing the distribution transformer output voltage by On Load Tap Changer (OLTC) [33]. However, in this method there is no reliability guarantied in case of reverse power flow, as it would increase the tap changer operation frequency and therefore causes some customers to experience difficulties in power supply.
An alternative method is active power curtailment with equal beneficial level for both producers and customers as discussed in [31]. As this method is associated with the cost or discomfort to the customers, it is considered to be the last option for congestion control.
Another method is to absorb reactive power to decrease the voltage at the point of coupling [41]. Previously in development of VPP in City-Zen project, the power factor of 1 was considered for prosumers [39]. Also, due to higher resistivity of the lines in the low voltage distribution network active power control has more effect comparing to reactive power control methods.
Another literature suggests utilization of storage for self-supply as discussed in [23] but it is not ideal if the DSO cannot control the storage. Also in cases where the local storage is used to trade in the market within a virtual power plant the situation can get worse and most importantly in this work we are considering the cases when the local energy storage units are already full charged.
One of the recent methods to solve congestion in the distribution network is by installing CBESS at a location along the feeder which improves the efficiency of the grid operation and postpone or remove the need for large expenditure to improve the infrastructure of the grid, and more importantly it allows more renewables penetration in the network [19]. Most of the literature sources are discussing the planning phase of community battery and less about the operation of such battery. In this work, digital twin of the power system will decide on the operational point of view or in other words the control action of the CBESS for congestion relief purposes.
Digital twin is based on advanced digitalization. Modern energy system will have access to plenty of data gathered from sensors. A Cyber-Physical Energy System (CPES) uses the available digital data of the actual physical system and its environment. Due to the increasing amount of distributed generators in distribution networks, household end-consumers can be the prosumer of energy. Due to this energy transition, the capacity of the distribution grid soon will be inadequate at many places. Also voltage problems may occur frequently by connecting the new source of generation to the grid. Accordingly, DSO which has to to deal with these issues could avoid or postpone costs related to grid infrastructure improvements by playing an active role in energy management. During the operation of such distribution network, Cyber-Physical Energy System (CPES) creates many digital data. It is very difficult for a human to check for abnormal behavior of the system manually. For this, the application of digital twin is studied in monitoring and control to deal with abnormal conditions in the system. For power system digital twin has been used in design, commissioning and maintenance [8, 21, 44, 45, 47]. Digital twins are not yet used for power system monitoring and control. However there are literature focusing on mitigation of fault event in power system in [13, 14].
The advantage of Digital twin in this work is the fast detection of the congestion by introducing a metric called congestion index which represent the status of the network in terms of loading of cables and voltage at the bus bars. Moreover, it provides the operator different control options to choose to deal with the congestions. Each control options has a certain effect on grid operation. As the digital twin of the system gets updated with close to real time data, it makes it possible to perform the congestion management close to real-time as well.

1.3. Scope of the Project & Research Questions

Based on the introduction where problem definition was defined, the state-of the-art on the topic of congestion management in distribution network, as well as on the identified gaps in the available literature, the scope of the work has been defined, which is explored through the study of main research questions. The main goal of this project constitutes the study of *How the digital twin along with the CBESS unit can be used to assist congestion management in distribution network*. The focus is placed on overloading of the cables and bus voltage issues where the distributed generator is connected. This constitutes an important challenge that DSO will face in the power grid, where increased number of DER makes the behavior of the power grid unpredictive.
Research questions have been formulated to address the main objective:

1. How the increased number of DERs affect lines loading and voltage magnitude of buses in distribution network?

2. How Digital Twin can be used for congestion management in distribution network?

    - How digital twin and the community battery energy storage can reduce/solve the congestion in the distribution network?
    - How digital twin can detect the congestion in distribution network?
    - How digital twin can provide the system operator different control options to solve the congestions?
    - How digital twin can be used in the planning phase to recommend battery capacity and the times to discharge/charge power?
    - How can digital twin and Community Battery Energy Storage improve the operation of VPP in cityZen project?

1.4. Research Approach & Project Description

The VPP developed in CityZen project contains distributed households in which each houshold is equipped with PV solar panels and local battery energy storage. In the VPP model the local battery of each household is operating in three different modes: Self-consumption mode when the intention is to use the generated power only for local consumption , trading mode when the aim is to participate in the Energy Imbalance Market (EIM) and self-consumption and trading mode which is a combination of previous two modes . In this project we are only focusing on reducing/solving the congestions when the battery is operating in the self-consumption mode.

Moreover, a CBESS is used for the purpose of congestion relief due to injected power by DERs in the network when the VPP operates in self-consumption mode. In addition, the digital twin is developed to control the CBESS close to real-time. To implement the digital twin, PowerFactory and python are used. With PowerFactory's load flow analysis the amount and the location of the congestion in the network can be calculated and shown. Furthermore, two algorithms were developed in python namely detection and decision algorithms. The detection algorithm evaluates the system operational status by performing load flow analysis considering the constraints on line over-loading and voltage under/over voltages. The detection algorithm detects the congested lines and over/under voltage buses. Once the detection algorithm identifies the congestions in the network, in the next step decision algorithm is executed. The aim of decision algorithm is to find the best control action to solve the congestion in the distribution network. Here the control actions are the amount of charging power by the CBESS to solve/reduce congestions. In addition, offline studies are performed to determine the battery operational interval or in other words the number of twins. Number of twins are the number control actions by the battery which is determined by the system operator. In offline studies also recommendations are given for size of the CBESS and also to the times for the battery to discharge the power during the day.

1.5. Project Contribution & Boundaries

1.5.1. Project Contribution

The most important contributions of this project compared to the available literature, and based on the scientific gap are summarized as follows:
This project showed that noticeable integration of DERs in a distribution network results in bidirectional power flows, with the possibility of constraints such as branch congestion and voltage unbalances among downstream feeders. Such congestions have impact on the operation of the VPP and in longer term cause failure of the assets in the network and moreover it avoids penetration of more RES. In this project, a CBESS is used to deal with the congestions. In addition, Digital Twin methodology is introduced as a close to real-time congestion management tool. The Digital Twin is able to detect the congestions including overloading of the cables and over/voltage at the buses. It analyzes the post-congestion behavior of the system and assists the operator to make faster and efficient decisions.

1.5.2. Project Boundaries

The boundaries of the projects have been set associated with the time frame. In this project:

- Congestions refer to overloading of the lines and over/under voltage at the buses. The other assets in the network are not considered for this study.
- The congestions are happening due to injected powers by DERs in the distribution network when the VPP is operating in self-consumption mode.
- The location of the CBESS is fixed. Also the state of energy of the battery is not the focus of this study. Hence, we are only dealing with active power control (Charging power) of the CBESS.
- The communication means are not part of this study. We are assuming that we have received the real time measurements such as voltage magnitude at buses and lines loading from real system.
- The three phases connection at the load side is balanced.
- We are using a test network where the data regarding the assets are known.
- The overloading limit of the cables is assumed to be 90%.

1.6. Master Thesis Outline

- **Chapter 1:** Definition of Virtual Power Plant (VPP) and its operation in CityZen project will be discussed in this chapter. Also the collaboration between VPP and DSO for congestion management will be explained.
- **Chapter 2**: This chapter deals with theoretical background regarding congestion such as capacity limitation and voltage rise by increasing number of DER in the distribution network. Moreover, an overview of congestion management method including direct and indirect methods in distribution network will be discussed. In addition, the impact of CBESS in distribution network and its effect on congestion will be explained. Finally, the model of battery storage used in PowerFactory and its specification will be discussed.
- **Chapter 3**: In this chapter the digital twin concept is introduced. Moreover, the application of digital twin focusing on congestion management in distribution network will be elaborated. The methodology used in this work to detect and solve the congestion using digital twin and the CBESS will be discussed.
- **Chapter 4**: The case study used for studying the application of digital twin will be shown in this chapter. The results showing the effect of detection and decision algorithm of digital twin to control the CBESS and solve the congestion will be explained.

1.7. Virtual Power Plant

A virtual power plant is a decentralized energy management system. It is an aggregation of small generation units and controllable loads. A VPP is a representation of a portfolio of DER that can be used to make contracts in wholesale markets and to offer services to the system operators. The many small units are combined together in a platform (software) that can be controlled virtually as an entity (power plant) as shown in figure 1.3.

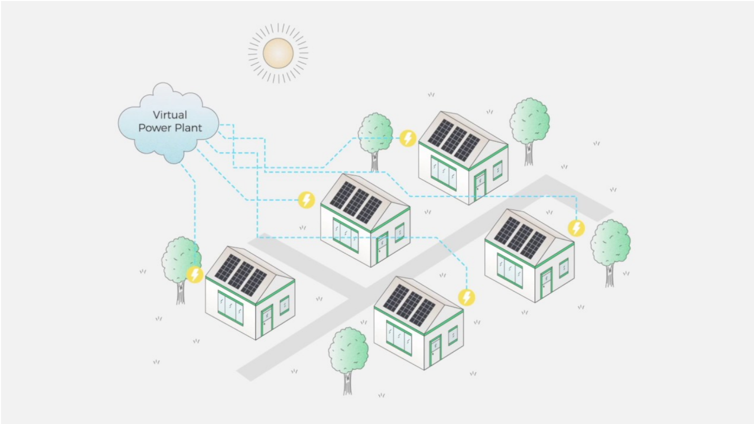

Figure 1.3: Virtual Power Plant [4]

The VPP aggregates the capacity of many diverse DERs and then creates a single operation profile of the DERs in a specific zone or operational area. This profile contains the parameters characterizing each DER state in its operation region. Therefore from the grid operators prospective the VPP behaves as a single unit [38].
In the other way around a VPP can help system operator to visualise distributed resources in the system. The VPP translates the grid operators requests into commands for the individual participants. It facilitates the interaction between all actors and it can give switching commands to the individual units to trigger more consumption or turn off some renewable units. It is also possible to enable grid operators to have control over instantenous DER power. Therefore the VPP is an intermediate level between the grid operators and DER units.
A VPP based on the functionality can be divided in to two configurations: Technical VPP (Technical Virtual Power Plant (TVPP)) and commercial VPP (Commercial Virtual Power Plant (CVPP)). CVPP is a financial instrument and it enables VPP to participate in the energy market. A TVPP can perform CVPP function and also it is optimized to deliver technical services to the grid such as congestion management or frequency control [17]. The energy management system (EMS) as the main part of the VPP collects data from generating units, controllable loads and storage within the operational region of the VPP.

1.8. Operation of Virtual Power Plant in CityZen project

The virtual power plant developed in CityZen project [39] is an aggregation of households owning rooftop PV solar panels and an energy storage located in one of the district in Dutch capital - Amsterdam. Depending on the local energy storage system the VPP is operating in three different operational mode:

- **Battery operating in self-consumption driven scheme**
  The aim of the self-consumption mode of the battery is to cover all the local demand from the PV or battery system. In this scheme, if the power from the PV is not directly consumed by the load then battery will start charging.

- **Battery operating in trading scheme**
  The aim of trading mode of the battery is to maximize the amount of power to be traded at energy imbalance market. The battery in this mode can be charged due to over

production of the PV just as self-consumption mode or when the CVPP decided to get in to short position in the energy market. In this scheme, even though the aim is not to use the battery for self-consumption, some portion of it will be covered from the battery when CVPP decided to get into a long position in the energy market.

- **Battery operating in self-consumption and trading scheme**
  This scheme is a combination of above mentioned modes. In this scheme the battery is charged in the same way as in the trading scheme. The priority in this mode is with the CVPP signal in a way that if a trading signal is sent by CVPP it will carry the action by CVPP and if there is no signal the battery behavior is the same as in self-consumption mode.

One of the important requirements to participate in the energy market is the bid size. When a VPP consist of large amount of distributed generators then it will be easier to participate in the energy market as the size of the bid increases. In this case the large volume of injected power by the participants brigs up new challenges for the system operator in the grid.
Based on the physical impact analysis during the operation of VPP in the CityZen grid, congestions in the network were observed in different battery modes. In this work we are focusing on the operation of the VPP in self-consumption mode. The congestions in this mode happened mainly in the summer time due to injected power by the prosumers in distribution network. The power generation by the local household were high enough to fully charge the local batteries and the rest of the power was injected into the grid. Due to thr large number of households within a feeder and the accumulated injected power from prosumers, reverse power flow occurred and it caused the capacity of the lines closer to the transformer to be overloaded. Also, voltage issues at bus bars were observed specially at the end of the feeder far from the transformer.
In opposite to conventional congestion issues which were mainly consumption-driven, the current issue causes a supply-driven congestion. As still in most of the electrical grids there is no congestion based market, the prosumers are often forced to decrease the production level without any compensation and if the prosumers do not agree with the shut down orders, they don't get any grid connection [17].
As the number of DERs are significantly increasing in distribution network, the voltage and loading issues will be more critical and difficult to handle by the network operator. Therefore there is a need of automatic regulation in low voltage network to deal with congestion issues. If no actions are taken, the above mentioned issues will be more critical to handle and operational problems regarding voltage variations, power quality, system stability and protection will be more intense. The law in the Netherlands states that the priority of using and connecting renewable energy sources in the grid is higher than the conventional energy. Thus the operator has to manage the power flow and ensure that the generation and the demand is balanced in future networks [28].

Collaboration between DSO and VPP for congestion management

Normally, most of the DGs in distribution network is connected without any control option and the grid operator needs to observe if the capacity is enough to transport the generated power. When the difference between the amount of generation and consumption is higher than the rated line capacity for certain amount of time, the protection device will trip. To avoid such an issue grid operators do not permit more DER to be connected to that area. If the grid capacity is not enough to host the power from DER only for a few hours during a year, it prevents larger share of renewables in the grid. The grid operators to handle the demand requesting installing more renewable sources, they install a telecontrol to shut down the DER in case of congestion [17].
By increasing large scale integration of Renewable Energy Sources (RES) in the distribution network, better operational strategies are needed to be employed in order to prevent congestion.

In [30] a coordinative congestion management method is proposed for flexible DERs which be controlled by VPP. In this coordination approach scheduling of the resources within a VPP can be organized according to the information shared by the DSO. DSO identifies congestions on the distribution network and VPP adjusts the schedules accordingly as illustrated in figure 1.4. This coordination requires a bilateral agreement between the two actors.

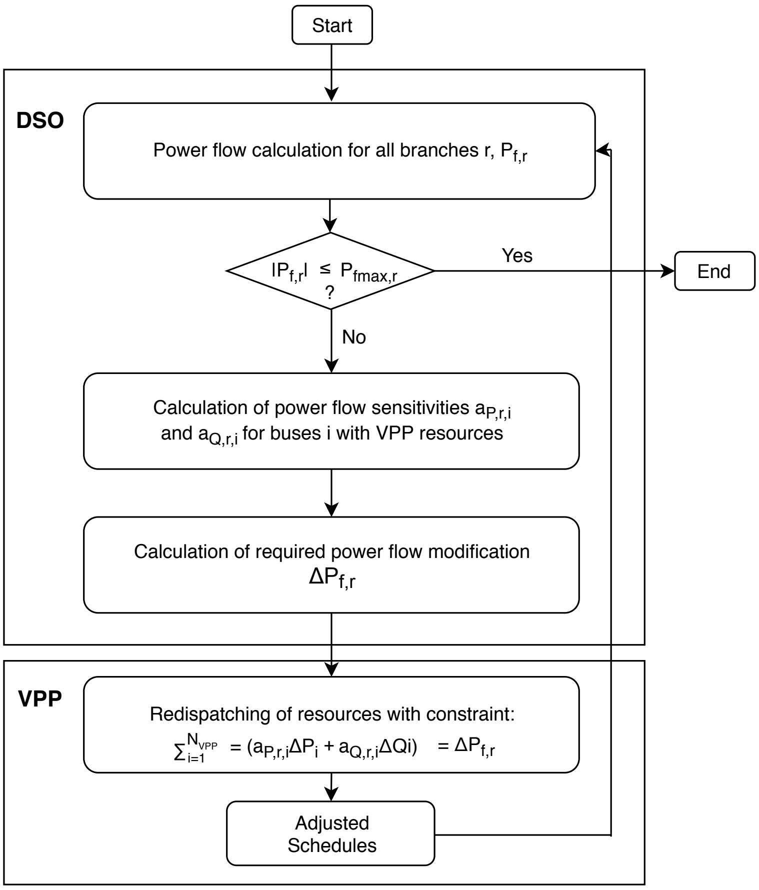

Figure 1.4: Flowchart for coordinative congestion management [30]

First part of the flow chart is associated with the DSO. In this part DSO receives the intraday schedules of the resources within VPP hours before the real time operation. Afterwards DSO runs the power flow calculation in all branches (r) to check whether the system is operation withing the operational limits or not. If the power flow exceeds the constraints of the maximum active power that can pass through that branch $P_{fmax,r}$then DSO informs the VPP regarding the rejection of the schedules which takes place at the termination point of the flow chart and VPP can perform another scheduling. DSO performs sensitivity analysis from AC power flow calculations which indicates the change of active power on branch r. For each node (i) there are active power $a_{P,r,i}$ and reactive power $a_{Q,r,i}$ injections from the resources of the VPP. In the next step DSO determines the required power flow modification $\Delta P_{f,r}$. This power flow modification is the amount which VPP has to take into account to modify the power flow on branch (r) to get the value of power flow back to $P_{fmax,r}$. All the sensitivities ($a_{P,r,i}$ and $a_{Q,r,i}$) for all nodes (i) along with the amount of power flow modification ($\Delta P_{f,r}$) sent to VPP. In the second part of the flow chart VPP receives there information from DSO and starts to schedule or adjust the resources. This adjustment by the VPP is formed based on the following constraint:

$$\sum_{i=1}^{N_{VPP}} (a_{P,r,i}\Delta P_i + a_{Q,r,i}\Delta Q_i) = \Delta P_{f,r} \tag{1.1}$$

According to this equation the sum of the injected active and reactive power at node (i) weighted by the sensitivities must be equal to the $\Delta P_{f,r}$.

2

Congestion in distribution network

2.1. Introduction

This chapter is structured as follows: First the impact of increasing number of DERs in distribution network on bus voltage and lines loading will be discussed. Second congestion management methods in distribution network will be discussed. Following that the impact of Community Battery Energy Storage and its role for congestion management in distribution network will be explained. Finally the CBESS modeled in PowerFactory and used in this work will be shown.

2.2. Analysis of Voltage Rise Effect on Distribution Network with Distributed Generation

Distribution systems are designed as a passive circuit to receive power from transmission network and further distributed along the feeders to the end customers. The flow of both active and reactive power in such a case is from higher voltage to lower voltage level. However, the reverse power flow may occur due to penetration of distributed generation where the generation becomes higher than the local demand. The distribution network in this case is no more passive but an active system where the voltage levels are determined by the amount of generation and the demand. Therefore, the distribution system is more dynamic as nature.

Among the renewable energy sources, the installation of solar PV is significantly increasing in the distribution network. The dispersed PV connected sources cause challenges such as: 1) The mismatch between the production and the demand due to stochastic behavior of PV generation enables bidirectional power flow which has impact on the loading of the network and the operating protection systems. 2) The voltage rise issues at the point of coupling due to small X/R ratios at low voltage feeders and potential overloading the network assets. Among these the voltage rise is one of the major problems in the distribution network due to high penetration of PV power. The voltage rise occur due to active power injection and low X/R ratio limits the amount of capacity of power to be installed in households within low voltage feeder. Consequently, the customers which are located at the end of the feeder face over-voltages issues and it causes the inverters to stop working due to operational constraints of the grid which leads to economical damages. Therefore, DSO would require more services to increase the penetration level of PV in a low voltage distribution network[34]. In general, DSO uses Automatic Voltage Controller (AVC), OLTC and shunt compensators in order to keep the voltage within a specified limit.

The following sections will discuss the effect of voltage rise in distribution network due to high penetration of distributed generation under different circumstances. Further, voltage rise mitigation methods are discussed.

2.2.1. Voltage Profile of Conventional Distribution Network

As mentioned in 3.1 distribution networks are modeled as passive networks with radial configuration where the flow of active power (P) and reactive power (Q) are from higher voltage to lower voltage levels. In transmission networks the ratio $(\frac{R}{X}) \geq 10$ and this ratio ≤ 0.5 in distribution networks. This represents that the resistance is comparatively higher than the reactance in distribution network [32]. This will cause voltage drop along the feeder from the primary substation towards the end customer. The amount of voltage drop along the line is calculated based on the simple two bus system as shown in figure 2.1

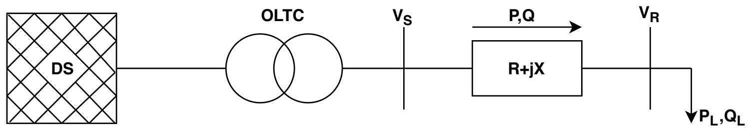

Figure 2.1: Two bus system in distribution network [32]

In this figure Distributed Substation (DS) and OLTC stand for distribution substation and on-load tap-changer respectively. V_S is the sending voltage and V_R is the receiving voltage at the end of the line. P and Q are the active and reactive power coming from distributed substation and flowing through the line towards the load. P_L and Q_L are the active and reactive power of the loads respectively. The voltage at the sending side can be formulated as:

$$\widehat{V_S} = V_R + \hat{I}(R + jX) \tag{2.1}$$

where $\hat{I}(I = |\hat{I}|)$ is the phasor representation of the current which flowing through the line. The Power supplied from distributed substation can be written as:

$$P + jQ = \widehat{V_S}\widehat{\mathbf{I}}^* \tag{2.2}$$

Further, the current flowing in the line can be written as:

$$\hat{I} = \frac{P - jQ}{\widehat{V_S}} \tag{2.3}$$

The equation 2.1 can be rephrased by substituting the value of $\hat{I}$ and can be written as:

$$\widehat{V_S} = \widehat{V_R} + \frac{P - jQ}{\widehat{V_S}}(R + jX) = \widehat{V_R} + \frac{RP + XQ}{V_S} + j\frac{XP - RQ}{\widehat{V_S}} \tag{2.4}$$

The voltage drop between the sending and receiving voltage can be written as:

$$\Delta\widehat{V} = \widehat{V_S} - \widehat{V_R} = \frac{RP + XQ}{\widehat{V_S}} + j\frac{XP - RQ}{\widehat{V_S}} \tag{2.5}$$

Since the angle between the sending and the receiving voltage is very small, the reactive power part of the equation 2.5 can be neglected and the voltage drop will be approximately equal to the active power part of the equation. If the sending bus is considered to be the reference bus, the angle of this bus is zero and $\widehat{V_S} = |V_S| = V_S$. Thus, the equation above can be written as:

$$\Delta V \approx \frac{RP + XQ}{V_S} \tag{2.6}$$

The equation 2.6 can be more simplified by assuming the voltage at the sending bus to be the base voltage. In that case V_S is considered as 1 and the above equation changes as:

$$\Delta V \approx RP + XQ \tag{2.7}$$

The voltage level at the point of coupling of the load to the grid is an important factor for the quality of supply. If the lines are longer or loads are greater, the voltage drop will be higher at the far end node where the last load is connected as shown in figure 2.2.

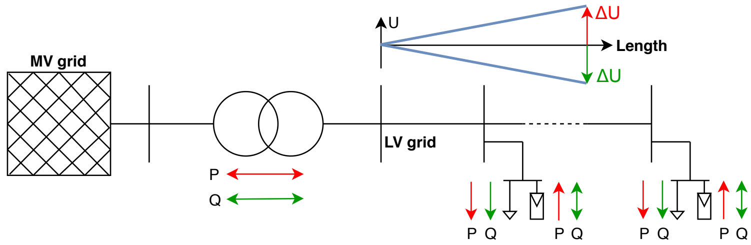

Figure 2.2: Bidirectional power flow and voltage fluctuations in LV networks with PV integration [35]

2.2.2. Voltage Rise on Distribution Network With Distributed Generation

The voltage profile in the previous section where the power is flowing from the distributed substation to the loads is more stable. Connecting distributed generators to the distribution network changes the direction of power flow and this effects the voltage profiles. This is where the system is no more passive but active. When the prosumer is injecting power, the voltage increases at the bus where the distributed generator is connected compared to the previous case when the power was supplied to a load [32]. In this case as the direction of power flow is reversed the receiving end voltage (V_R) can be written as:

$$V_R \approx V_S + RP + XQ \tag{2.8}$$

Therefore, the voltage at the bus bar where the generator is connected becomes higher compare to the sending end voltage. This is also shown in figure 2.3:

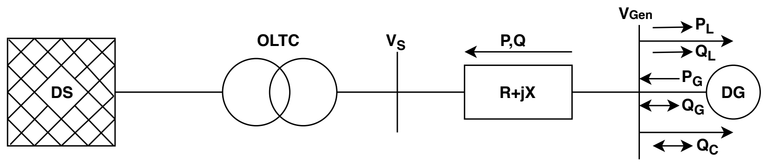

Figure 2.3: Two bus system in distribution network with DG

In figure 2.3, DG is connected to the bus at the end of the line. The voltage at the bus where the DG is connected to is indicated as V_{Gen}. Active power and reactive power of the generator are P_G and Q_G, and P_L and P_Q are the active and reactive power of the load respectively. Q_C is the reactive power of the shut compensator. The DG along with the shunt compensator is connected to the distribution substation with the line and OLTC in the middle. The voltage rise in the distribution network caused by connetion of DG can be written as:

$$\Delta V = V_{GEN} - V_S \approx \frac{RP + XQ}{V_{GEN}} \tag{2.9}$$

Where $P = (P_G - P_L)$ and $Q = (\pm Q_C - Q_L \pm Q_G)$. In case V_{GEN} is in terms of per unit, then the equation 2.9 can be written as follow:

$$\Delta V = V_{GEN} - V_S \approx R(P_G - P_L) + X(\pm Q_C - Q_L \pm Q_G) \tag{2.10}$$

The distributed generator is exporting active power ($+P_G$) and also may export or import reactive power ($\pm Q_G$) as well. The load consumes both active ($-P_L$) and reactive power ($-Q_L$) and the shunt compensator may import or export reactive power ($\pm Q_C$).

2.2.3. Distributed Network With Worst Case Scenario

The number of distributed generators are increasing in the distribution network. As mentioned in the introduction chapters the number of rooftop solar panels are significantly increasing in the local districts. The level of generation that can be connected to the distribution system can be briefed in the following equation [32]:

$$P_G \approx \frac{V_{GEN} - V_S + RP_L - X(\pm Q_C - Q_L \pm Q_G)}{R} \tag{2.11}$$

The level of generation connected to the distribution system is further limited by the following factors:

- Voltage at the primary substation.
- Voltage level at the end of the line or receiving end.
- Size of the conductors and the rating current of the cables.
- The distance from the distribution substation.
- Total consumption or on the system.
- Other connected generators to the system.

DSO should consider the worst case operation scenarios to analyze the effect of distribution generators on voltage profile of the network. DSO has to ensure that the network is operating within the operational constraints and it doesn't have a negative impact on the customer. The worst case scenarios can be listed as:

- Minimum consumption and maximum generation.
- Maximum consumption and minimum generation.
- Maximum consumption and maximum generation.

The voltage rise effect can be described easily by the worst cases listed above. By considering the worst case scenario with the minimum consumption and the maximum generation and the equation written in 2.10 we can state [32]:

$$P_L = 0, \quad Q_L = 0, \quad and \quad P_G = P_{G_{max}} \tag{2.12}$$

If the system is operating at $PF = 1$ (unity power factor), then reactive powers $\pm Q_C = 0$ and $\pm Q_L = 0$ and the equation 2.10 for this worst condition can be written as:

$$\Delta V_{worst} = V_{GENmax} - V_S \approx RP_{Gmax} \tag{2.13}$$

Equation 2.13, shows that the increase in voltage is related to the resistance of the distribution lines as well as the power supplied by the distribution generator. In case the resistance of the distribution network is constant then the following relation can be written:

$$\Delta V_{worst} \propto P_{G_{max}} \tag{2.14}$$

Thus, the voltage in a distribution network is directly proportional to the amount of active power injected by the distribution generators. Since there is a linear relation between the increase in voltage and the amount of injected active power, the highest voltage rise can be expected when the there is no consumption in the network and all the power generated by the distributed generators is fed back to the distribution substation. The amount of distribution generation connected to the grid is limited by voltage constraints and can be shown in equation 2.13. From equation 2.11, the following can be written:

$$P_{G_{max}} \approx \frac{V_{GEN_{max}} - V_S}{R} \tag{2.15}$$

The amount of generation in the system is limited by the maximum voltage constraint at the bus bar where the distributed generator is connected to and can be written as:

$$P_{Gmax} \leq \frac{V_{GEN_{max}} - V_S}{R} \tag{2.16}$$

Based on the worst case scenario study it is clear that the resistance of the lines in distribution network and also voltage rise are the factors that are directly proportional to the amount of distributed generators that can be connected in to the system.

Voltage level and the connection cost

It is interesting to mention a few words regarding the policy of connecting distributed generators as they have major impact on the voltage profile in the distribution network.
The overall connection cost is primarily based on the voltage level in which the distributed generator is connected to. In general, the higher the voltage level the higher the connection cost. Therefore, the distributed generator owners prefers to connect to the lowest possible voltage level.
In DSO's operation point of view, it would be better to connect the distributed generators to higher voltage level in order to reduce the impact on the grid in terms of steady state voltage level and power quality. Therefore, there should be a balance between these two conflicting prospective and for that there is a need of economical and technical impact analysis. Different study cases including different connection designs and also the ability to manage the system operation and stability has to be assessed. If the generator is connected to a weak network the voltage rise effect will be critical and there is more probability for the system to go beyond the pre-defined voltage level [32].

Mitigation of voltage rise

The increasing amount of DG causes an increase in voltage in distribution network. Traditionally, over voltage protection relays in the distribution system had the role to protect the system against over voltage issues. When the over voltage occurs the relay disconnects the distribution generator or it may disconnect the distribution grid from transmission grid. This causes highly economical disadvantages for both the DG owner and the DSO [32]. The voltage rise mitigation can be performed through the following methods:

- Resistance reduction method
- Reactive power compensation
- Coordinated voltage control
- Power curtailment

Resistance reduction method

Referring to equation 2.15 if $P_{G_{max}}$ is constant or in other words if the amount of generation is constant then we can write:

$$\Delta V_{worst} \propto R \tag{2.17}$$

By looking at equation 2.17, one can note that the worst case voltage increase in distribution network is directly proportional to the resistance of the lines. In order for the voltage rise to decrease, the resistance of the line needs to be reduced as well. This can be done by increasing the conductor size of the lines. However, since this is a difficult approach for the DSO to increase all the line conductor sizes of an existing grid, therefore this should be done before implementing a new distribution network and it should be taken in to account in the planning phase to make provisions for large DG.

Reactive power compensation

Referring to equation 2.10 we can write:

$$\Delta V = V_{GEN} - V_S \approx R(P_G - P_L) + XQ_{import} \tag{2.18}$$

Here $Q_{import} = \pm Q_C - Q_L \pm Q_G$. By considering the worst case scenario and the condition that the distributed generator is not operating at with the unity power factor from equation 2.18 we can write:

$$\Delta V_{worst} \approx RP_{G_{max}} + XQ_{import} \tag{2.19}$$

The equation above indicates the fact that if XQ_{import} has higher negative value or in other words the amount of imported reactive power increases in the network the voltage rise will

be reduced in the system. In general, the amount of reactive power than can be imported depends on the generators. For example, synchronous generators can import power at 0.95 power factor or wind turbine with uncompensated induction generator at approximately 0.9 power factor [32].
It is very important to note that absorbing reactive power might increase in loading of the lines as well as losses. Also it can happen that transient voltage rise occur occur in case a generator trips and this would take some seconds for the transformer tab-changer to act and adjust the voltage level. Therefore, DSO need to use other means of power compensation to restore the voltage in the network.

Coordinated voltage control approach

Traditionally, in conventional passive distribution network, it is usual process for DSO to maintain the voltage at the distribution substation more than the nominal voltage to guaranty that the voltage profile is within the pre-defined limits as the voltage drops along the line.
By regulating the sending end voltage as shown in equation 2.20 the voltage drop can be changed. This is possible by using the OLTC connecting to a short distance distribution grid. However, in case of long distance and complex distribution networks with several distribution transformers, using OLTC may be impractical as the value of the voltage as well as the tab position needs to optimized [32].

$$\Delta V_{worst} = V_{GEN_{max}} - V_S \tag{2.20}$$

Power Curtailment

Power curtailment method is related to an extreme case when the demand in the network is minimum and the amount of generation is at its maximum level. In this method, when the voltage at the bus bars exceeds beyond the specific limit then the power from the DG will be curtailed [32]. The impact of power curtailment on the hosted capacity which can be connected to the network can be formulated as follow:

$$P_{G_{max}} \approx P_{G_{curtailed}} + \frac{V_{GEN_{max}} - V_S}{R} \tag{2.21}$$

$$\Delta V_{worst} \approx RP_{G_{max}} - RP_{G_{curtailed}} \tag{2.22}$$

Equation 2.22 shows that the voltage rise can be mitigated through power curtailment from generators.

2.3. Lines loading and Energy loss

The loading of the cable refers to the percentage of remaining capacity that is being used by the maximum load. The line loading is calculated by dividing the maximum load at a certain time step, by the capacity at that time step. The factors have been taken into consideration by Enexis to find the capacity of a cable [36]:

- Cable type such as Paper Insulated Lead Covered (PILC), Cross-Linked Polyethylene (CLPE), Aluminium and Copper and cross section of the cable.
- Thermal effect of parallel cables near to each other.
- Heat expansion of inequivalent loaded cables.
- Ground temperature based on deepness of the cable.
- Thermal resistance of the ground.
- Load profile

The effect of the above mentioned factors have been applied in the following formulas:

$$I_{max\_equal\_loaded} = I_{nom}.P.T.D \tag{2.23}$$

$$V = \sqrt{\frac{\sum I^2_{max\_equal\_loaded}}{\sum I^2_{load}}} \tag{2.24}$$

$$I_{max\_unequal\_loaded} = I_{load}.V \tag{2.25}$$

Where:
$I_{max\_equal\_loaded}$: Maximum load of cables with an equal load division at parallel cables.
$I_{max\_unequal\_loaded}$: Maximum load of cables with an unequal load division at parallel cables.
I_{load}: Measured maximum load of cables.
I_{nom}: Cable loads according to table B.1
P: Correction for thermal resistance of the ground and thermal effect of parallel cables according to table B.2.
T: Correction for the ground temperature according to table B.3.
D: Correction for the load profile according to table B.4.
V: Correction for the parallel cables with various loading (more information in section B).
As some of the factors listed above are season dependant, it causes the formulas to have different results during summer(jul, aug, sep) and winter time(dec, jan, feb, march) and for rest of the months it is linear between these two seasons [36].

By considering the worst case scenario with minimum consumption and maximum generation the injected power by DER causes reverse power flowing in to distribution network. The power flows from the distributed generation source towards the distribution substation. This causes the lines that are closer to the transformer located in distributed substation have higher loading compare to the lines at the end of the feeder at the end prosumers.

Energy losses estimation

Energy losses in the network depends on the structure of the network, the type of equipment and the amount of load in the network. By transporting energy from the generation point to the consumer within the network losses occur. In low voltage network the resistivity of the lines are higher and therefore network losses are higher. In general losses are divided in to two categories [36]:

1. Technical losses due to current flowing through resistances (I^2R), hysteresis, eddy current and dielectric losses.

2. Non-technical losses such as metering errors.

Moreover, technical losses are grouped into load dependent or copper losses and not load dependent or iron losses. Load dependent losses are the ones corresponding to current and resistance and not loaded dependent corresponds with voltage and frequency. The no load losses are constant if the voltage is almost constant and if the frequency remains the same. But load dependent losses differ by loading of the equipment. There are losses in the cable such as loss in insulation, loss due to corona discharge and copper loss. The copper loss is the main reason for increasing temperature in the cables and it is competitively higher than two other losses. The copper losses are equivalent to I^2R where the resistance is related to the surface area and type of the conductor. The network losses can be determined at different time steps with a network simulation program such as PowerFactory.

2.4. Review of Congestion Management in Distribution Network

In general, congestion occurs if the transmission constraints of the system exceeds their limits. Congestion in distribution network might occur due increased number of DER, such as PV, wind power systems, electric vehicle and heat pump. Congestion problem in a distribution network contain voltage problems (bus voltage is close to or exceeding the limit, typically +/- 10%) and overloading (loading is close to or exceeding the thermal limit of the power components).
The goal of congestion management is to make sure that the system operates within the thermal limits and also to minimize the impacts on the customers. Transmission lines are not

equally affected by system disturbances. There are transmission lines which are more likely to congestion than others. The goal of the distribution network is to efficiently deliver the active power to the customers as required with high reliability. The customers can absorb some reactive power in the allowed range (according to the grid code). Delivering active and reactive power through a feeder will lead to voltage drop problems. Similarly, high penetration of RES can lead to over-voltage problems. In both cases, if the power flow exceeds the thermal limits of power components, it will lead to overloading problems. To deal with the under-voltage or over-voltage issues, DSO can improve the infrastructure of the grid (i.e. use cables with higher current carrying capability and smaller impedance). However, in most of time the feeder transmission capacity may be adequate and it is not economical to plan a network with overestimate capacity. Congestion occurrence in distribution network forces DSO to mitigate customers' energy. For that it will use communication infrastructure to send signals in order to make a deviation from the customer's desired amount of energy through market methods. The DSO can also influence the active and reactive power by installing local new distributed generators and FACTS devices such as static VAR compensator (SVC), or by directly controlling the active/reactive power under pre-agreement with the customers.

In general, congestion management for distribution networks can be divided in to two groups namely market methods and direct control methods. The market methods consist of dynamic tariff, distribution capacity market, shadow price and flexible service market. The direct control methods are comprised of network reconfiguration, reactive power control and active power control.

2.4.1. Indirect control methods

Market methods or indirect control methods for congestion management use price signals to effect the behaviour of the flexible demands. The methods in the recent literature are divided into four groups based on the market types and the commodity being traded on the market and are described briefly here [27]:

- **Day-ahead dynamic tariff**: In this method, the DSO finds the lowest Dynamic Tariff (DT) to encourage both flexible and non-flexible demands to prevent loading of the grid.

- **Distribution capacity market**: Here, the total capacity of distribution grids is allocated to the aggregators with an optimized price. With the allocated maximum distribution grid capacity, the aggregators can send their bids to the spot market. This puts a cap on the maximum amount of energy being traded over a line, thereby creating an inter-connection between the grid layout and the energy market system. The price of the energy to be traded depends on the remaining capacity available in the distribution line.

- **Intra-day shadow price**: This method considers a scenario when aggregators (or Balance Responsible Parties, BRP) have already placed bids on the spot market but the actual demand varies with the bid submitted to the spot market in real time. If the aggregators do not stick to the plan, then a balance price will be charged. Aggregators could use the flexible demands to come up with a new optimal schedule of the next few hours with a reasonable price (shadow price) in order to reduce the balance cost being charged.

- **Flexibility service market**:Here, the aggregators can make their own demand plan without considering the distribution grid capacity. To prevent congestion, DSOs would have to buy flexibility services from alternate sources. Further studies are required in order to choose a market method for congestion management for the test system.

2.4.2. Direct control methods

Market based methods are effective ways to solve congestion. However, It may happen that congestion through market method fails due to market failure of forecasting errors. In that case, direct control methods can be used against system interruption due to over loading or over/under voltage. The direct control methods in distribution network due to increase number of DERs consist of active, reactive power control and network reconfiguration [27].

Reconfiguration

Reconfiguration in distribution grid refers to changing the infrastructure by changing the status of open/close switches to keep same radial structure of the network but in a more efficient way to deliver power to the end customers.
The optimization problem:

$$\begin{aligned} & min_y o(f) \\ s.t. \quad & h(f,v) = 0 \\ & g(f,v,y) \leq 0 \end{aligned} \tag{2.26}$$

Where:
f: Line loading
v: Bus voltages
y: Status of the switches, integer variable)
o: Objective function (e.g. line losses)
h: Load flow equations
g: Voltage limit, line loading limits, radial structure assurance inequalities

Problem 2.26 is a non linear integer optimization problem. There are number of methods in the literature to solve such optimization problem:

- MILP or Mixed integer linear program [26] where conventional MILP solvers are used to solve the optimization problem.
- LP or NLP methods. In [16] a method so called 'branch exchange method' was developed. This method aims to reduce the cost function among all neighbours by going through the feasible points (with respect to y) and finds a local minimum point. In [12] authors used 'modified simplex method'. This method was modified ensures that in each step of exchanging variables will maintain a radial structure.
- Heuristic methods such as generic algorithm(GA) [22], [48] which generally solve the non linear integer problems aiming to reach the global minimum. However, the disadvantage of above mentioned methods is that the global minimum methods might not be found due to the non-deterministic nature of these methods.

Reactive power control

Flexible AC transmission system (FACTS) devices such as Static VAR compensator (SVC) can be used as reactive power support in weak networks where under/over voltage problems occur. The optimization problem for reactive power control can be formed as:

$$\begin{aligned} & min_Q o(f) \\ s.t. \quad & h(f,v,Q_d) = 0 \\ & g(f,v,Q_d) \leq 0 \end{aligned} \tag{2.27}$$

Q_d is the adjustable reactive power from the support devices. The value of Q_d can be positive which is the indication to prevent voltage rise or it can be negative to prevent voltage drop. In addition, literature [49] suggests to employ on-load tap changer together with the reactive power control in order to deal with the congestion more efficiently.

Active power control

Active power control method is related to the cost or discomfort of the customers. In this case, it is assumed that the congestion is caused by the flexible demand and therefore the active power control can be implemented so solve the congestion efficiently. The optimization problem for active power control can be formed as:

$$\begin{aligned} & min_{\Delta Q_d} o(f, \Delta P_d) \\ s.t. \quad & h(f, v, \Delta P_d) = 0 \\ & g(f, v, \Delta P_d) \leq 0 \end{aligned} \tag{2.28}$$

In the above equations ΔQ_d refers to the adjustment of active power. There are different literratures regarding the selection of objective function. In [42], addition of adjustment and the line losses are used as the objective function. In [43] particular weights are assigned to all customers and it is used for addition of adjustments which makes it more suitable for active power control. However how to decide the weights for different customers is not discussed. In [46] regulation prices in the electricity market are used as weights of the up and down adjustment in the objective function and line losses are not considered. DSO should choose the objective function based on the current situation, market conditions and cost of generation.

Summary of methods

Distribution system operator (DSO), market parties and aggregators have to collaborate together in order to solve the congestion problem. Table 2.1 shows the summery of the above mentioned methods and the responsible parties for each method.

Method	**Responsible parties**	**Relation to the conventional market/time frame**	**Objective**
DT	only DSO	Before spot market	Lowest DT, could prevent congestion
Distribution capacity market	DSO and aggregators	Before spot market	Lowest tariff, that could prevent congestion
Intra-day shadow price	DSO and aggregators, but DSO has no profit	After spot market, tens of minutes before operation	Lowest imbalance
Flexibility service market	DSO and aggregators, but aggregators are not obliged	Parallel to the conventional market	Not mentioned
Reconfiguration	Only DSO	It can be either a day-ahead planning or a real-time operation	Minimize line losses, balance line loading, etc.
Reactive power control	Only DSO	It can be either a day-ahead planning or a real-time operation	Minimize line losses, maximize loadability, etc.
Active power control	Only DSO	It can be either a day-ahead planning or a real-time operation	Minimize the adjustments, minimize the cost of adjustments , etc.

Table 2.1: Summary of the congestion management methods [27]

2.5. Community Battery energy storage system and its impact in distribution network

The integration of Battery Energy Storage System (BESS) is increasing in distribution network. The U.S. Department of Energy (DoE) has reported several hundreds battery energy storage based projects in distribution network globally ranging from 2 kW to 6 MW, and 800 Wh to 28 MWh. There are several benefits with integrating BESS in distribution network: it improves operational efficiency, delays or removes the need to improve the network infrastructure, creates opportunity for integration of more renewables and if allowed also creates service.
According to the Paris agreement, as countries are moving towards the energy transition, more renewable energy sources are being installed. Most of these renewable sources are wind and solar. These energy sources are not predictable by nature and they create challenges and problems in the network such as stability, operation and control, power quality issues. Moreover, the inertia in the network is decreasing cause of no-rotating synchronized generation, the network is getting weaker and systems are becoming more automated. One of the clean solutions to solve all the issues mention above is using BESS in the network. Batteries count as a proven technology for a long time, but their application in the grid and/or ancillary services are new. BESS can be connected to the AC grid via power conversion equipment with very fast response and can provide both active and reactive power support to the network [19].

BESS operational consideration

Energy storage systems can have many applications in the distribution network and offer benefits in technical and economical point of view. BESS comprises of a fast dynamic response around 20 ms compare to other energy storage systems, thus there are useful for variety of applications from short-term power quality support to long-term energy management.
BESS connected to the distribution system has many advantages in both distribution and transmission levels. Depending on the operation of distribution and transmission as well as the market framework these advantages can be listed as follow [19]:

- Primary frequency control in MV/LV microgrids
  One of the benefits of BESS is in the operation of microgrids. A microgrid is a small scale power system containing microgeneration such as photovoltaic and wind generation along with the storage systems and loads. Microgrids are designed to operate in two different modes: grid-connected and islanded modes. When the microgrid is operating in the islanded mode the frequency is not supported by the main grid anymore. With Unbalance between the load and generation the frequency changes quickly as low inertia exist in the grid. Primary frequency control in the islanded mode can be mode readily realized by BESS.

- Increasing and balancing RES
  RES are intermittent by nature and this behavior arises issues such as voltage and frequency variations in the network. The integration of large amount of generation by RES introduces new challenges in the operation point of view. The main problem for increasing amount of RES and replace it with fossil fuels is balancing the generation and the demand. Depending on the time scale benefits can vary:

  - Short term balancing
  - Multi-hour storage

- Load leveling and peak shaving
  BESS can be used to store the surplus of generated power and use it when the demand is high. It can be used to reduce the feeder loading. As an example if the loads in the distribution network are equipped with solar panels the over production of power generated by PVs can be charged during the day and use it at night when the consumption or demand is higher.

- Infrastructure investment deferral
  BESS can be used to delay the improvement in infrastructure in distribution network. It can store the excess amount of power by DERs and discharge the power when there is sufficient capacity in the network. Improvements in distribution network such as upgrading cables or transformer is quiet costly and by using BESS such extra costs can be avoided. In addition, to get the permission to improve or install a new infrastructure is a time consuming procedure and BESS for distribution upgrade can avoid that.

- Ancillary services
  BESS can be used to provide ancillary services such as:
  - Voltage regulation through reactive power control.
  - Frequency regulation through real power control.
  - Oscillation damping in synchronous generator excitation systems by controlling active and reactive power.
  - Improving power quality (voltage distortion and reducing harmonics)
  - Spinning reserve

- Energy arbitrage
  This is relevant to the market conditions in which with BESS the electricity can be bought with lower cost and sell later at higher cost. This also depends on different timescales:
  - Medium term or less than an hour.
  - Long term or several hours a day.

- Resiliency
  The BESS can be used during the black out periods when the supply from power system fails, it can:
  - Provide back up power specially to critical loads.
  - Assist the microgrids operation while changing from grid connected to islanded mode.
  - Enabling islanded operation.

Technology type and installation size

Around 70% of the BESS used in medium/low voltage distribution network is from Lithium-ion batteries 20% are from flow batteries and mainly zinc based. Moreover, around 20% of the installed BESS are from total capacity of roughly 10 kW, 50% installation are from medium capacity between 12 kW-2 MW and 30% are higher capacity between 2-6 MW. The energy capacity for 0.4 GW of storage in medium/low voltage is about 0.9 GWh [19].

Use cases

Based on 29 use cases in DoE database, the most BESS use cases is in Energy arbitrage at around 180 MW in distribution network. BESS primary uses after energy arbitrage are in ancillary services and balancing renewable energy and shifting the demand. Among these use cases third party owners of BESS are focusing more on energy arbitrage where as utility-owned storage is focusing more on lead balancing and peak demand [19].

Siting and sizing, selection of storage technology

Before installing the BESS in distribution network, proper optimization which include aspects such as functionality, costs, revenues, and all the limitations for installing as well as operational constraints has to be taken in to account. The output of the optimization module should provide the proper siting and sizing of the BESS in order to make the maximum profit.

The benefit of BESS can significantly increase with a Distribution Management System (DMS) at DSO control center to effectively control the active and reactive power in a distribution network. Based on the data collected from local units in the network, the DMS sends the control action to the BESS local controllers to charge/discharge power accordingly. The DMS control takes into account the forecasts load/generation profiles, operating constraints of the network, security limits etc and use it to control the operation of the grid and the assets under its control.

Energy storage contribution to distribution network is becoming more recognized around the world as it provides flexibility and enables integration of more renewable energy in distribution network. It can balance both top-down conventional or distributed electricity generation. Development of BESS has been improving and the cost of these assets are reducing. It is also predicted that there will be a further price reduction in the coming years [19].

PowerFactory model of the BESS

The storage device used for this work is a static generator *ElmGenstat* which represents any non-rotating kind of generators. Generally, these kind of generators are connected to the grid using a static converter. The application of static generators consist of [6]:

- Photovoltaic generators
- Fuel cells
- Storage devices
- HVDC terminals
- Reactive power compensation

In the basic Data/General tab of the model the phase technology can be selected. The variety of connection such as 3PH, 3Ph-E, 1 Ph Ph-E, 1Ph Ph-N can be chosen. The number of parallel units within the same tab represents the parallel machines for the model. Accordingly, the nominal apparent power rating of a single generator as well as the power factor can be specified. After specifying the mentioned values, the total power output from the a single generator will be multiplied by the number of parallel units.

Load Flow Analysis

The dispatch from static generator is controlled via the local controller. The dispatch can be specifically in the form of active power and reactive power or the combination of both P, Q, S or cos(phi). The local controller can be adjusted to different modes. These modes are [6]:

- Const.V
- Voltage Q-Droop
- Constant.Q
- Voltage iq-droop
- Q(P) - Characteristic
- Q(V) - Characteristic
- cosphi(P) - Characteristic

The above mentioned local controller modes by the static generator are described briefly in the following subsections.

Const.V

In this mode the adjustment of voltage is done by controlling the reactive power of the static generator in order to achieve a specific voltage at the terminal where it is connecting to. Here, the active power dispatch is constant. This controller corresponds to a PV bus type and the block diagram is shown in figure 2.4 where second control option (P, U) represents the local controller in const.V mode. The reactive power will increase or decrease until reaching the specified voltage level at the terminal. Also, limits can be set for maximum or minimum reactive power levels in load flow/operational limits tab of the static generator.

Voltage Q-Droop control

The voltage Q-droop control corresponds to controlling the reactive power proportional to the deviation of voltage set-point as shown in figure2.4 as the third control option (U, droop). The droop control can be be used if the voltage for many machines that are located close to each other has to be controlled.

Constant Q

Constant Q controller mode of the static generator corresponds to a PQ bus. This is the first control option (P, cos(ϕ)) in figure 2.4.
With this type of controller, the active and reactive power can be specified by the user. The specified values will be the output of the static generator. These values can be specified in different forms depending on the input mode chosen for the dispatch.

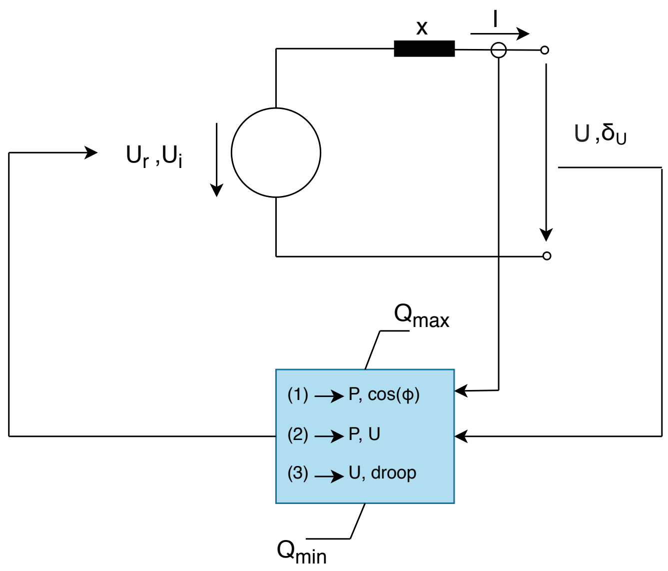

Figure 2.4: Different modes in local controller [6]

Voltage iq-Droop

In voltage iq-droop mode, the control is based on the reactive current controller. This current is calculated in proportion to the deviation from voltage set point.

Q(P)-Characteristic

The Q(P) characteristic mode is controlling reactive power in such a way that this control is adjusted according to the active power output of the generator.

Q(V)-Characteristic

Similarly to Q(P)-characteristic mode, Q(V) characteristic also aims to control the reactive power with a variable set point. In this control method a reference voltage within a deadband is defined. If the reference voltage exits this deadband, the reactive power set point change according to the droop specified by the user and the voltage deviation from the corresponding end of the deadband.

cosphi(P)-Characteristic

This controller corresponds to power factor control which follows a certain characteristic. Here, the user specified two limits for characteristic for the input active power flow. These limits are overexcited and under-excited limits.

2.6. Discussion

The voltage rise effect on distribution network with distributed generation connected was discussed in this chapter. The worst case scenario with minimum consumption and maximum

generation showed that the voltage in a distribution network is directly proportional to the amount of active power injected by the distributed generators and the resistance of the lines. Moreover based on worst case scenario the resistance of the line in distribution network and voltage rise are the factors that are directly proportional to the amount of distributed generator that can be connected in to the system.
In addition, in the worst case scenario the lines that are located closer to the distribution substation are more prone to congestion. In opposite to the conventional power network where the direction of power was from transmission to distribution level, in this case the reverse power flowing towards the distribution substation and causes the surrounding lines to be loaded.
This section also gave an overview on congestion management methods in distribution network using indirect control methods(market methods) and also direct control methods by reconfiguration, active and reactive power control methods. Moreover a recent method using Community Battery Energy Storage System was introduced in distribution network. Installing BESS enables congestion management in distribution network to store the surplus of generated power and use it when the demand is low.

3 Digital Twin

3.1. Introduction

In this chapter first the Digital Twin concept is introduced and its application and use cases will be discussed. Second this chapter focuses more on the application of digital twin in congestion management in distribution network. The methodology used in this work to deal with the congestions in the network using digital twin and community battery energy storage will be discussed in details.

3.2. Digital Twin Concept and its application

Digital twin refers to a virtual prototype, a dynamic digital representation of a physical system. It is one of the most promising digital technologies of the future. Digital Twin was first introduced by Michael Grieves in 2002 at the University of Michigan. At that time this concept was called ”Conceptual Ideal for Product Lifecycle Management (PLM)”. Afterwards the name changed by Grieves in 2006 to ”Information Mirroring Model” and finally to ”Digital Twin” in 2010. This concept derived from a simple PLM tool and has become a powerful tool to assist business decisions(GE Digital 2016;(Tao, Cheng, Qi, Zhang, Zhang and Sui, 2017)[40].
It is necessary to understand two main features from PLM roots of the Digital Twin: 1) It is the tool that illustrates the life cycle of an asset through its entire operation 2) It is centrally operated with the updated dynamic behavior of an asset using machine learning processes (Tao, Cheng, Qi, Zhang, Zhang and Sui, 2017)[40].

In [18] Digital Twin is defined as the digital representation of an asset that changes its properties and behavior by means of models and data. It is the software-based representation of the asset in the physical system in which its properties continuously gets updated via a communication link. A mirror of a physical system can be presented by the digital twin in order to illustrate the physical condition of the system in real time. This digital replica of the system makes it possible to perform advanced analytics for the system and link the physical and real world together. Digital twin also makes it possible to identify problems in the system before they occur. This is currently intensively under development by the manufacturig industry.
Currently, there are many applications of digital twin in the PLM such as: in power industry for planning phase in power plant, engineering, commissioning and maintenance. Digital twins are not yet developed in power system monitoring and control, however the concept of Dynamic Digital Mirroring (DDM) is already being discussed[18].

Mirroring the system state by dynamic simulation

A DDM represents the dynamic model of the system. This dynamic model reflects the system condition and dynamic behavior in real-time. Based on the application of the digital twin such as power network, a DDM is made from the data pool of the asset operator which contains the grid model and the data regarding the operational status of the grid. A DDM

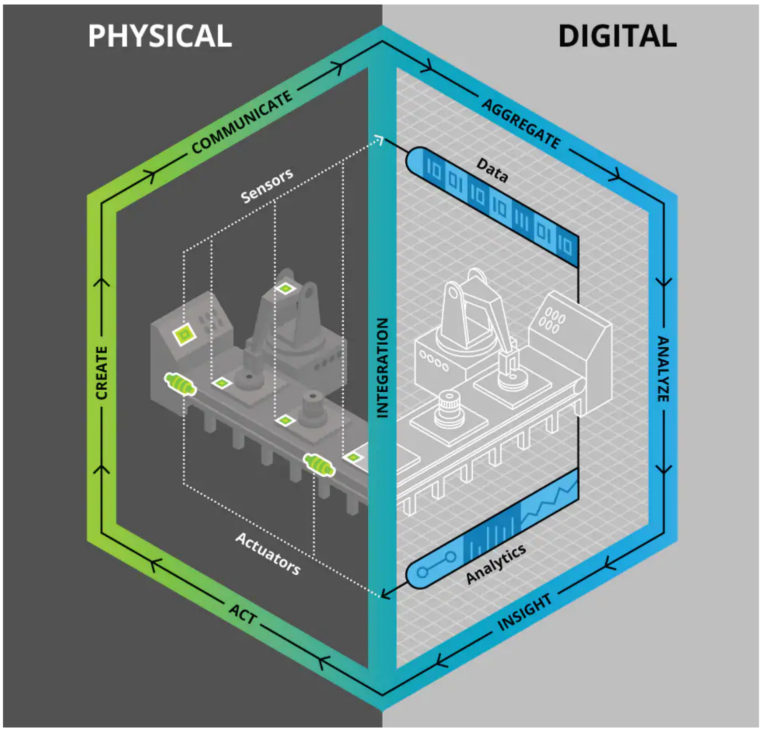

Figure 3.1: Manufacturing process digital twin model
source: Deloitte University Press [15]

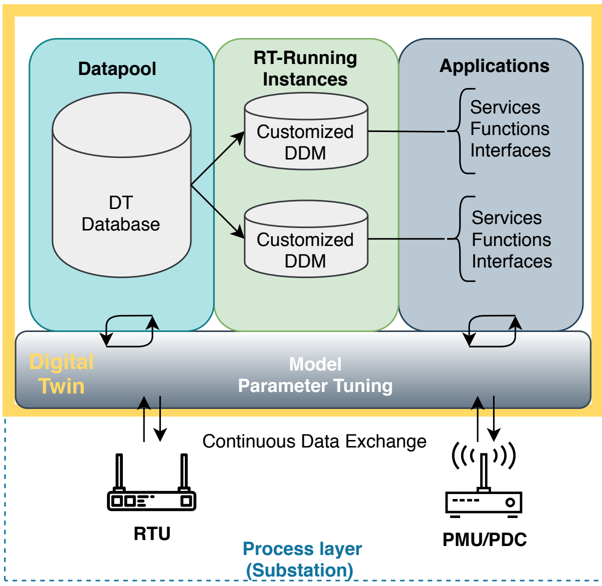

Figure 3.2: The Digital Twin Concept for power System Control Centers [18]

can be considered as a modelling engine which is running constantly and provides the asset operating status in real-time. As it can be seen in figure 3.2, DDM can represent either the whole system model or only the customized part of it. In real-time simulations, the data from Remote Terminal Units (RTU) and Phasor measurement Units (PMU) are fed into the digital twin database and it further used in DDM to create a digital image of the system for fast system analysis and decision on control action. The advantage of using dynamic simulation in power system monitoring is that if the communication is lost with the real system or measurements failures, the access to the latest system data and operating status is still possible [18].

Utilizing Digital Twins in Control Centers

Digitalization is becoming increasingly important to a wide variety of energy sectors. Modern energy system will have access to plenty of data gathered from sensors. More consideration will be needed to completely benefit from monitoring and control systems. A CPES uses the available digital data of the actual physical system and its environment.
Due to the increasing amount of distributed generators in distribution networks, household end-consumers can be the prosumer of energy. Due to this energy transition, the capacity of the distribution grid soon will be inadequate at many places. Also voltage problems may occur frequently by connecting the new source of generation to the grid. Accordingly, DSO which has to to deal with these issues could avoid or postpone costs related to grid infrastructure improvements by playing an active role in energy management. During the operation of such distribution network, CPES creates many digital data. It is very difficult for a human to check for abnormal behavior of the system manually. For this, the application of digital twin is studied in monitoring and control to deal with abnormal conditions in the system. A digital equivalent of a process as a base for optimization is adaptable for many systems or objects which are expressed as cyber-physical system.
Adaption of digital twin will eventually lead to next step in power system control technology. Table 3.1 shows the comparison and development in simulation and control center technology.

	Simulation Technology	**Control Center Technology**
1st Generation	Individual Application: Simulation limited to only specific topics	Hard Wired, Fully Analog Communication
2nd Generation	Simulation Tool: Simulation is a standard tool for engineers	IP/TCP based Communication
3rd Generation	Simulation-based System Design	Dynamic Assessment Tools
4th Generation	Digital Twin: Simulation is the Core Functionality of Systems	Digital Twin Centric Control Center Architecture

Table 3.1: Evolution of Simulation and Control Center Technology [18]

The application of digital twin for this manner consist of: (1) anomaly detection to identify abnormal behavior and root cause analysis for identification of the elements (root causes) of identified problems in CPES. The report of identified abnormal behaviors is in a form so that is it is suitable for human operator. Such report is in form of graphical to illustrate the detection and root cause of abnormal behaviors. (2) Decide on the suitable control action for the system operator to solve or reduce abnormal behavior in the system.
The application of digital twin is studied in this work to help operator to deal with abnormal conditions in the distribution network. In our approach, the digital twin is considered to be synchronized in a (close enough to) real-time with the physical system using sensor and context data to complete the simulation model. In the operation of digital twin the abnormal behaviors are detected using a key metric instead of set of measurements for parameters that are not able to inform the operator on anomalies. In addition the digital twin can support decisions in the physical twin, give insight to the operator on all possible control actions to deal with detected abnormal behaviors [18].

Obstacles for Digital Twin Development

To fully benefit the value of digital twin, a comprehensive approach is needed to manage the digital twin data. This approach involves storing, examination and validation of the data. Moreover, modelling of dynamic power system is not an easy task, therefore it is difficult to determine the precision of the modeled system. This will depend on how detailed the models are. Accordingly, as a simple model does not reflect the precision of the physical system, to create a very detailed and accurate model is a complex task taking into consideration the data sheets of the equipment, measurement tools and abounding amount of signals to represent the digital model of the physical system [18].

Example of a Digital Twin Usecases

One of the use cases in application of digital twin is in power plant operation. Digital twin implementation assists the plant operator to make a better decision on the control actions and test the ”what if” scenarios. It helps the plant operator to have the bigger picture and overview the important factors to take into account to make an informed decision.In addition, it gives more visibility on those factors which had the minimal visibility previously.
A digital twin for power system operation and control optimizes the operation performance of the power system which results in saving initial investment and reduces the emissions. There are various business applications where digital twin can provide opportunities to create additional revenue and find the possibilities to reduce cost. These applications can be divided in to the following categories [8]:

- Asset Performance Management(APM): By creating a single source of data for all power generation and renewable sources, exploiting the predictive methods to identify the operational problems before it happens, the lifetime of the asset will be extended while keeping the maintenance cost balanced and shortening the downtime of of the asset.
- Operations optimization: By improving the visibility of the data across the power plant and providing the bigger picture to understand the operational decisions and accordingly to take actions that can reduce the production costs. Enhance productivity with defined KPIs and business objectives.
- Business Optimization: By lowering the financial risk and increase profitability with forecasting and more effective business decisions.
- Advance Controls/Edge Computing: Increasing the revenue, decreasing the costs by controlling the power plant operation with high level technology and analytic based solutions.
- Cyber: To protect critical infrastructure with cyber security regulation and implementing a defence system to ensure security to assess system gaps.
- Digital Twin Application Suite: A set of applications together with digital twin models that are interfacing with asset management performance, operations optimizations, business optimization and advanced controls for better visualization of the plant and influence the decisions and accordingly improve the business profit.

Digital Twin for Power System Control Centers

The digital twin of power systems is not yet available for control center applications, but all the requirements to establish the digital twin exist. For digital twin to become the next generation and the main element in control system, attention has to be given to interconnection and communication between several digital twins of different system operators. With the benefit of digital mirroring of the power system the comparison between the physical grid and the simulated grid operation can be studied and pattern recognition can found to further assist in fast detection, create automated feedback and make efficient decisions, prevent blackouts, offline control room practice training for the operators, asset optimization and investment reduction.

3.3. Digital Twin Methodology for Congestion Management

In the proposed concept for utilization of Digital Twins in power system monitoring and control , the application of Digital Twin for congestion management in distribution network is discussed. The congestions happen due to operation of VPP in self-consumption mode. The congestions in this context are equivalent to loading of the lines and voltage magnitudes at the bus bars in the network. Congestion relief is done using a community battery energy storage System. The role of digital twin is to detect the congestion and further to give the control action to the community battery to deal with the congestion scenarios.

Before explaining the Digital twin methodology used in this work, it is important to mention that there were offline studies performed to recommend a capacity of the community battery energy storage to be installed in the network. Moreover since we are studying the congestion due to over production of DER, suggested times were proposed for the community battery to discharge. These offline studies are based on forecast information of how much active power is being injected to the distribution grid by each DER. The same methodology which will be explained in this section is used to develop the digital twin for a longer period of time (24 hours and a month) to perform these offline studies. This shows that the same methodology used in the work can be extended to not only the operational point of view but also in the planning phase as well. The offline studies will be discussed in section 4.4. Digital Twin architecture for congestion management is shown in figure 3.3. PowerFactory and python are used to develop the digital twin for congestion management. PowerFactory helps to accurately illustrate the congestion scenarios and fast simulations helps to take the control actions fast enough to prevent congestions in the network. In general two scripting languages exist to support PowerFactory. One is the DIgSILENT programming Language (DPL) which is developed by DIgSilent to use PowerFactory. The syntax of DPL is similar to C language. Another scripting language used for PowerFactory is Python. A python wrapper for API is provided for the PowerFactory. Python script can be used to run the PowerFactory application in engine mode by an external python script. Comparing to DPL, Python has more cleaner syntax and less number of lines of codes are needed to perform the same functionality of the DPL script. In addition, python scripts are easier to write, read, debug in comparison to DPL coding [24].

The master algorithms developed in python are divided into three parts: The first part corresponds to the real power system with real-time simulation where measurement data in real time are collected and given to the control room. The real-time simulation contains the distribution network model and it provides the necessary data such as voltage at the bus bars and loading of the cables. In this work we assume that the data is already collected from the real system and fed to the digital twin. The second and third part of the master algorithm are detection and decision algorithms respectively. The aim of detection algorithm is to detect and identify the congestions (overloading and over/under voltage issues) in the network and the aim of decision algorithm is to act on the congestions found by the detection algorithm and to evaluate the post-congestion behavior of the network. It is important to note that before starting the process for congestion management using digital twin and the CBESS, the number of twins or in other words the battery operating interval in decision algorithm has to be determined by the system operator. In this work the number of twins are determined based on data identifying the worst case scenario. Worst case scenario is equivalent to maximum injected power by DER into the distribution network and it is identified by studying the forecast information. More information regarding determining the worst case scenario and the number of twins will be given in section 4.4. In the following sections the process by detection and decision algorithm will be discussed in details.

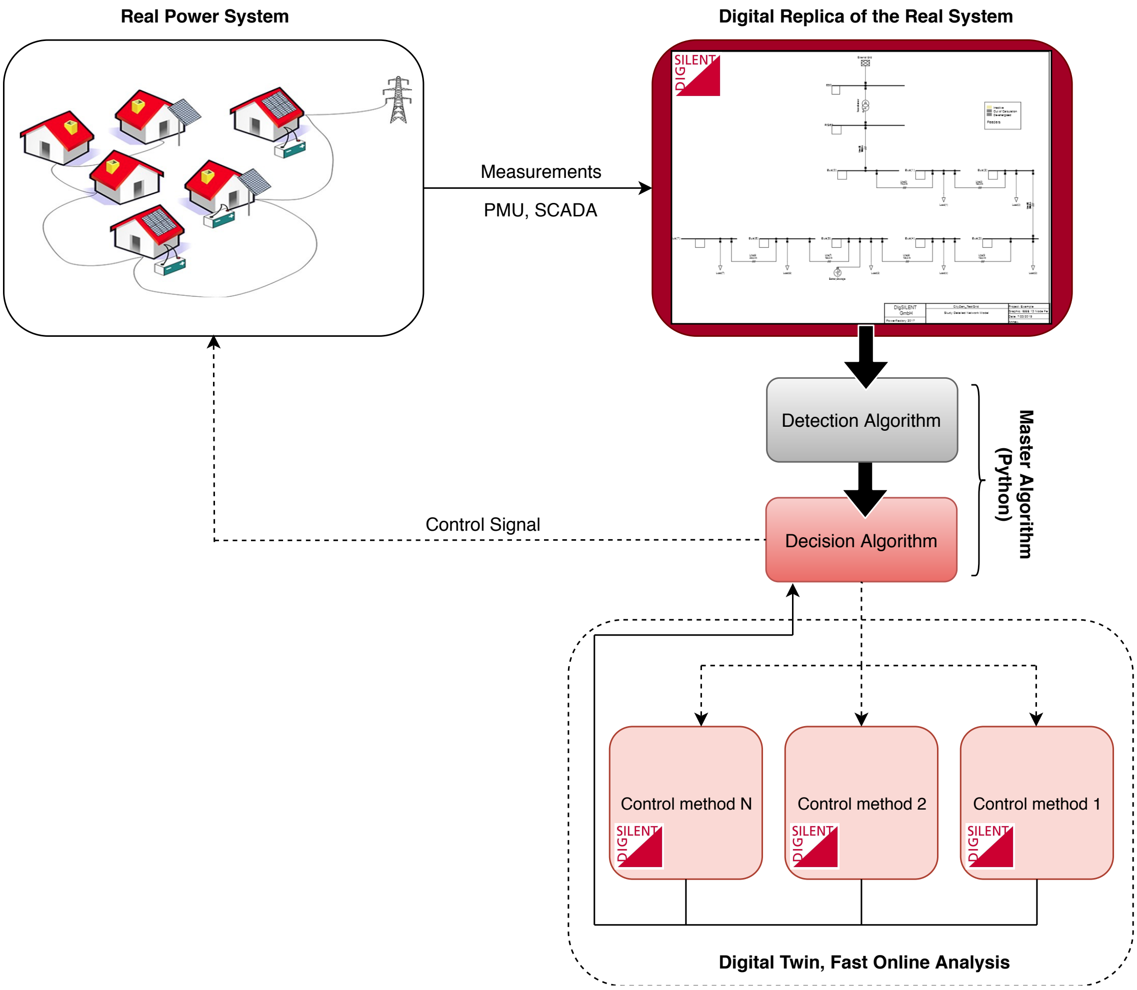

Figure 3.3: Digital Twin Architecture

3.3.1. Detection algorithm

As it was mentioned above the aim of detection algorithm is to detect and identify the congestions in the network. The key feature of detection algorithm is the fast calculation of Congestion Index (CI). The congestion index is used as a metric to identify and quantify the amount of congestion in the network. In addition, this metric will be used to as a base to identify different control actions by decision algorithm. In detection algorithm, there are constraints defined for both loading of the cables and voltage thresholds at the bus bars in the network. According to the European standard EN 50160 [7] – Voltage characteristics of electricity supplied by public electricity networks, voltage limitations are made in the distribution grid:
Under-voltage/Over-voltage:„Under normal operating conditions excluding the periods with interruptions, supply voltage variations should not exceed ± 10 % of the nominal voltage." Another constraint that has been taken into account is the over-loading of the cable which is considered to be limited by 90 % under normal operating condition. It is important to note that cables can withstand overloading for a specific time depending on the thermal limit defined of the cables. This physical property of the cables are not defined here. According to the above mentioned constraints the Congestion Index can be formulated as following:

$$CI_{Total} = \sum CI_{Loading} + \sum CI_{Voltage} \tag{3.1}$$

where:

- CI_{Total}: Total Congestion index.
- $CI_{Loading}$: Number of overloaded lines.
- $CI_{Voltage}$: Number of over-voltage and under-voltage buses.

The flow chart for the detection algorithm is shown in figure 3.4.

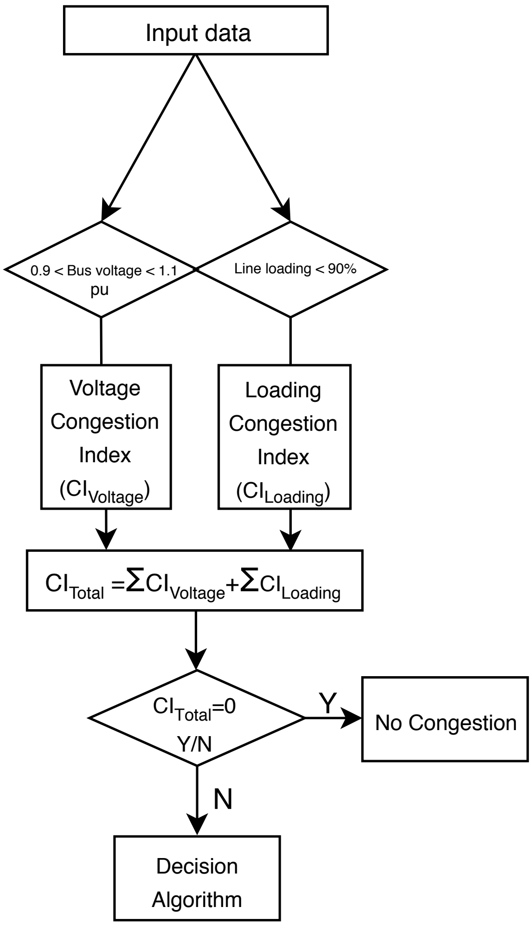

Figure 3.4: Detection Algorithm Flow Chart

The measurement data from the real system containing the voltage at buses and lines loading are fed to the python master algorithm. In this work the measurement data are the injected active power profiles by DER in the distribution network. These profiles are stored in a csv file and will be imported to PowerFactory using python. Then the load flow calculation will be performed to evaluate the status of the system in terms of lines loading and voltage magnitude at the bus bars. The load flow calculation allows to understand the behavior of the system in steady state. By load flow calculations, information such as voltage magnitudes, current and power flow in the network can be collected. The load flow calculation need certain input to generate desired output results. These inputs and outputs are shown in figure 3.5. The inputs for load flow calculation includes network topology and the information regarding elements and the nodes. A node can be electrically described by the following parameters:

- The voltage magnitude: $|V|$
- The voltage angel: δ
- The injected active power: P
- The injected reactive power: Q

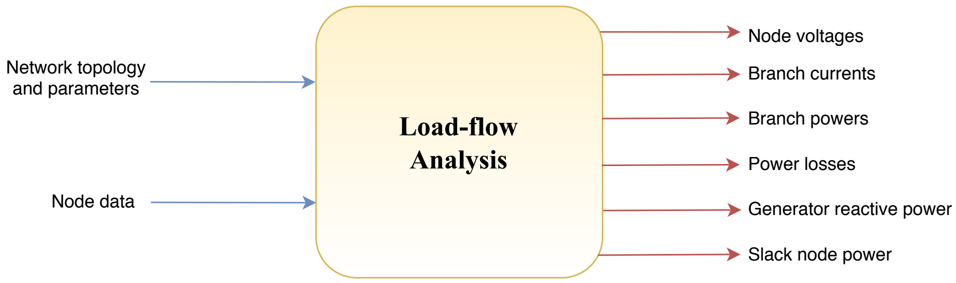

Figure 3.5: Load flow computation [36]

Depending on type of the node in the network, two parameters from above mentioned parameters need to be known to generate the other two unknown parameters. The unknown parameters will be found after the load flow calculation using a method for visual network analysis namely Newton-Raphson method. The approach to Newton-Raphson load flow is similar to that of solving a system of nonlinear equations using the Newton-Raphson method. In general, non-linear equations have more than one solution, but the Newton-Raphson starts with an initial estimate for the unknown parameter and the output is one solution which is close to the starting point. The process time to perform load flow calculation increases by expanding the network size and it is specially useful for applications of large networks that needs precise solutions. With low flow analysis the following major parameters can be retrieved [36]:

- Voltage magnitude at buses/nodes.
- Amount of losses in the network.
- Loading of assets in the network.

More details regarding load flow calculation using Newton-Paphson can be found in [1–3]. The version of PowerFactory 2017 was used in this work and for that an interpreter for python 3.5 may be used. In PowerFactory, all the elements have a specific object that can be accessed through python. The object name for general loads is called ”*E*lmLod”. In case of balanced load flow the active power parameter name is called ”*plini*”. The Load object and the active power parameter is shown in figure 3.6. It is important to note that the active power has to be assigned and imported with a negative sign. The negative sign of active power for the load indicates the injecting active power and positive sign refers if the load is consuming. The negative active power can be directly imported with a negative sign or by ”Scaling Factor” of the load defined in the load flow section in 3.6. In that case the scaling factor has to be set as -1. This can be done via python by accessing the scaling factor parameter ”*scale0*”. Similarly, the active power ”*pgini*” has been set for the battery with object name of ”*ElmGenstat*” in PowerFactory. Moreover, the local controller mode of the battery can be accessed with parameter *av_mode*. Since the active power of the battery is controlled the ”Const.Q” mode is accessed via ”*constq*” parameter. The load flow object ”*ComLdf* is retrieved from PowerFactory and the mode which is the *balanced* mode is selected using python to perform balanced load flow calculation. In PowerFactory, the line’s object is defined as ”*ElmLne*”. The parameter ”*loc_name*” holds the name of an elements in the grid and the parameter which defines loading of the line is ”*c:loading*”. The python access the lines through the objects and each line can be selected via its name and then through the parameter *c:loading* the loading of the line can be retrieved. Also the line losses parameter is defined as ”*m:Ploss:bus1*” in PowerFactory. This parameter refers to the active power losses in the network. Due to the higher resistivity of the lines in the network, the reactive power losses are neglected. Similar to lines, python access the bus bars in the network through the object ”*ElmTerm*” and each bus is accessed via the local name ”*loc_name*”. The parameter defined to retrieve a bus voltage magnitude is ”*m:u*” in this case. The parameters and the object used in PowerFactory are illustrated in figure 3.7.

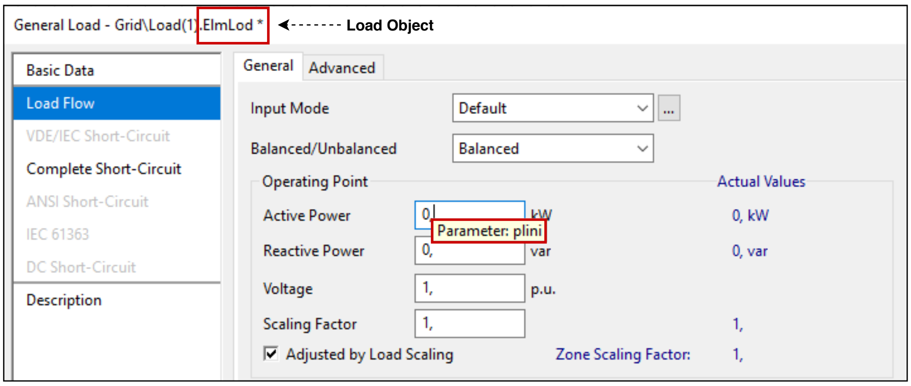

Figure 3.6: Identifying Line Object "*ElmLod*" and Active Power Parameter in the load "*plini*" in PowerFactory

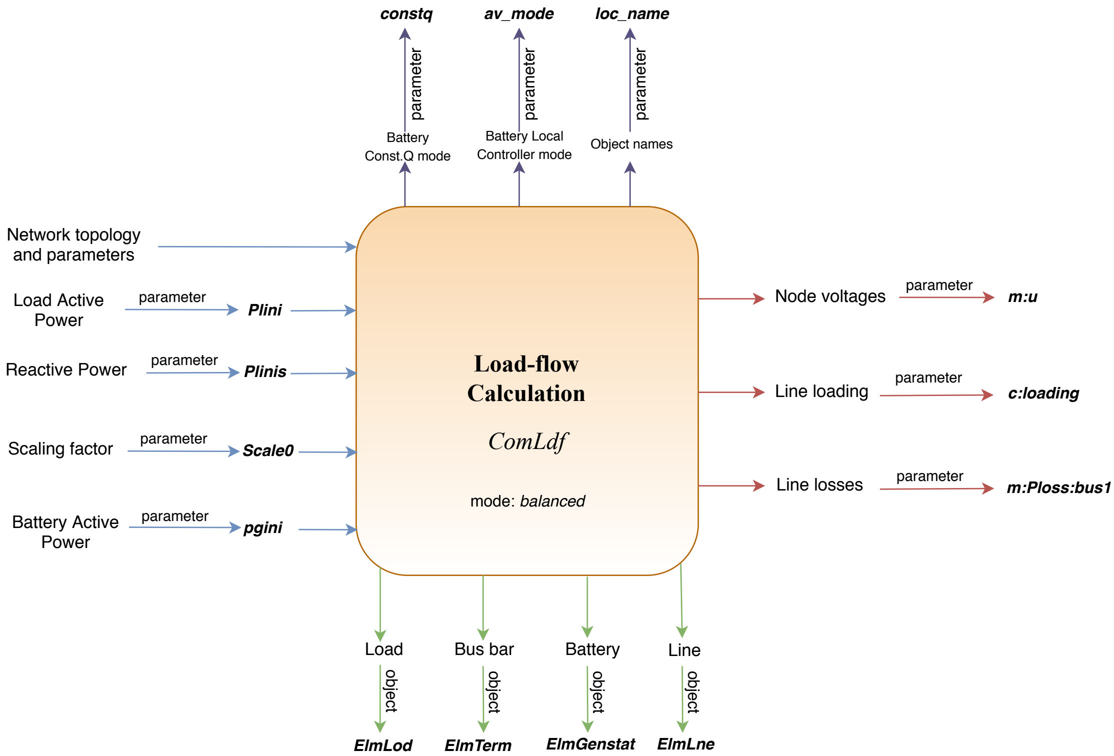

Figure 3.7: Parameters and objects accessed from PowerFactory

After performing the load flow calculation, in the next step, detection algorithm finds exactly which element (cable/bus) is not within the operational limits using the local names of the element and it counts the number of elements independently for both overloaded lines and under/over-voltage buses. It further indicates these independent counters as loading congestion index and voltage congestion index respectively.
Finally, the detection algorithm adds up the loading and voltage congestion index to represent the total status of the network. Summation of these two indices is called Total Congestion Index (TCI). If there is no congestion in the system this value will be equal to zero and therefore there is no need for the decision algorithm to act as there are no voltage nor loading issues in the network. However, If there is any congestion detected, the decision algorithm will start running in the next step. In the following section the operation of decision algorithm will be discussed.

3.3.2. Decision algorithm

The role of decision algorithm is to control the community battery storage by giving input control signal to the battery. Since in this work we are only dealing with the cases when the congestion occur due to over-production of distributed generations, accordingly this control input will be the amount of active power that the battery has to store in order to solve the congestion. However, it should be mentioned that this battery can also be used during the times when the demand is higher than generation which in that case the battery can supply power accordingly. Later in the offline studies we will discuss the times that the community battery can discharge the power during the day.

Once the congestion is identified by the detection algorithm the battery starts acting as the first step by decision algorithm. As mentioned earlier the number of twins or the community battery operation interval has to be determined by the system operator in advance. The number of twins depends on two parameters: 1)The maximum operational set point of the battery, 2)The step size for battery operation. The maximum operational set point of the battery is based on worst case scenario, at a time step when the total amount of injected power by DER are at its highest level during a month. This step size is equivalent to the length of steps in battery operational interval. If we call the beginning of the battery operational P_{init} and the end of the interval P_{end} and the step size P_N then the control input of the battery is set linearly from P_{init} to P_{end} (figure 3.4) with increment of P_N. In this work the starting point when the battery acts on the congestion and the step size is equal to 1 kW. P_{end} is the last input to the battery and it corresponds to the maximum operational point of the battery or the number of digital twins. P_{end} can also be set to the maximum amount of active power that the battery can store, however to reduce the number of twins and number of load flow calculations and therefore make the simulation faster this value has been set according to the total amount of injected power by DER at the worst case scenario. A total number of load flows equal to P_{end} will be executed and in each iteration the total congestion index (CI_{Total}) or TCI will be calculated. The process of decision algorithm is illustrated in figure 3.9. One should note that if there is no congestion identified by the detection algorithm there would be no need of decision algorithm to be executed. Therefore, the battery input power is considered will be zero in this case.

In this work python API is used for PowerFactory software. Running PowerFactory in engine mode enables fast impact analysis of the system which leads to find the charging power of the battery to relief congestion. After the iterative load flow calculation in interval between P_{init} to P_{end} is performed and the lines loading and bus voltages magnitudes at each load flow iteration are determined, values with TCI equal to zero will be selected. Those values are shown in Figure 3.8 in green zone and the red zones are the ones where there is congestion detected in the system. P_{min} is the minimum and P_{max} is the maximum amount of power that the battery must store in order to solve the congestion respectively. Moreover, decision algorithm will look more precisely in to the green area (between P_{min} and P_{max}) and it will choose higher level control action based on the operator's priority.

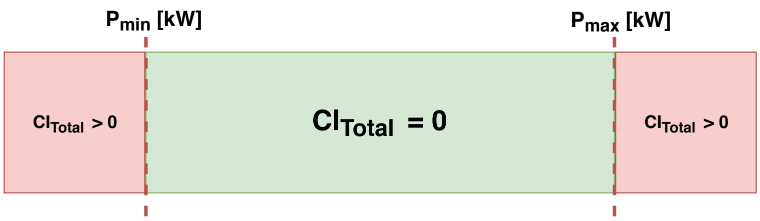

Figure 3.8: Battery input power thresholds to solve congestion

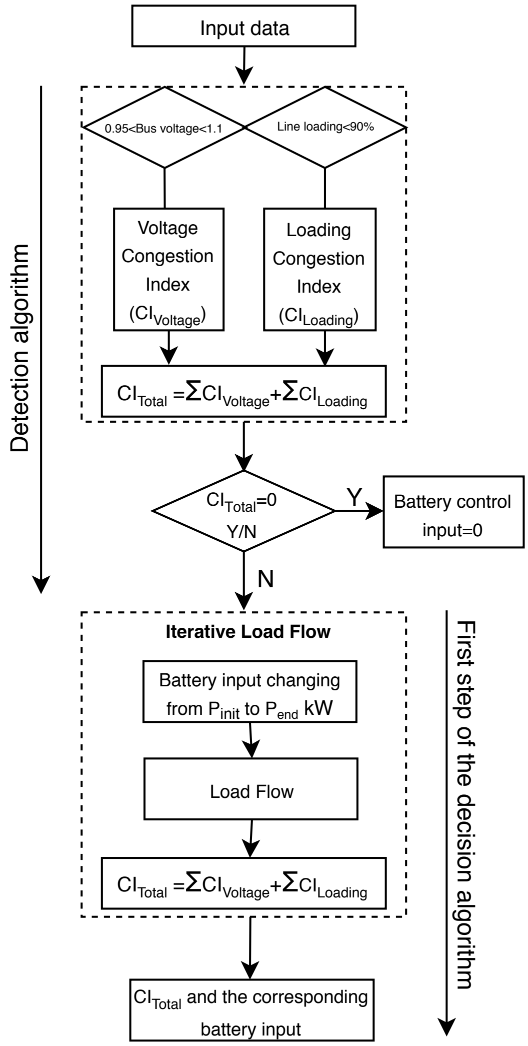

Figure 3.9: Decision Algorithm Flow Chart

Depending on the operation point of view decision algorithm is divided into four methods as shown in figure 3.11. Minimum power, minimum losses, min of max loaded lines and minimum voltage difference are the methods by decision algorithms and are described below.

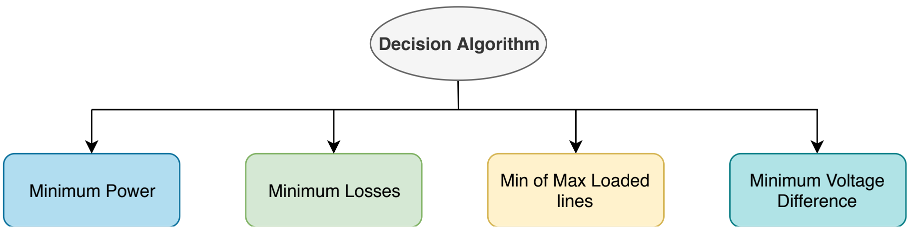

Figure 3.10: Second step of Decision Algorithm methods

- **Minimum Power**
  First method by decision algorithm is called "minimum power" and it refers to the minimum amount of power that needs to be charged by the battery to solve both loading and voltage issues in the network.
  After the set of TCI equal to zero and their corresponding battery charged power are selected by the decision algorithm, the minimum value of charging power within the

	P_{bat} = A [kW]	P_{bat} = B [kW]
Line 1	80	75
Line 2	5	75
Line 3	5	75

Table 3.2: Lines loading when the battery charging power is A or B kW
Example to demonstrate the deference between minimum loss and min of max loaded lines

green zone indicates the minimum amount of power that battery has to store to solve the congestion. This value is indicated as P_{min} in figure 3.8.

- **Minimum Losses**
  Minimum losses is the second method by decision algorithm. In this method at each load flow iteration, the amount of losses in the lines will be extracted. In the next step, summation of all the lines losses (real losses) will be calculated in every iteration. The decision algorithm for this method shows the total amount of lines losses in the network and its corresponding charging power of the battery. Finally, the output of the decision algorithm will be the minimum amount losses found in the network with the corresponding battery charging power and will communicate this value as the control signal to the real network.

- **Min of Max Loaded Lines**
  The third and fourth methods by decision algorithm deals with cases when the operator sets priority between loading or voltage issues. Operator can prioritize the system behavior to either minimize the lines loading or to minimize voltage at the bus bars and choose the best control action accordingly. Increasing the battery power will consequently alleviate congestion in part of the grid however it might introduce congestion another part of the network, therefore it is necessary for the operator to look where the highest loading or voltages or even losses occur in the network. The method to choose the best control action to minimize lines loading starts with the decision algorithm iterating through the set of battery charged powers for which the TCI is equal to zero. During every load flow iteration at each battery power input the maximum loaded line in the network will be specified an extracted. At the end, all the values indicating maximum loaded lines for each battery charging power will be compared and the minimum value will be selected as the output of the decision algorithm.
  A simple example to better understand the difference between minimum losses and min of max loaded lines methods is demonstrated based on table 3.2. Two columns in this tables specify two cases when the battery storing 'A' kW and second 'B' kW respectively. If the decision algorithms choose the control action based on the minimum loss method, then first case will be chosen as summation of lines losses will be lower as the loading of line 2 and line 3 are comparatively lower in case 'A'. In opposite, if the decision algorithm decides to select the best control action based on min of max loaded lines then the second case when the battery storing 'B' kW of power will be chosen. This method looks at a single value which is the maximum loaded line in the network. In this table the maximum loaded line is 80% in case 'A' and 75% in case 'B' and then then minimum of these values which is 75% will be selected by the "min of max loaded line" method of decision algorithm.
  The aim of min of max loaded line method is to minimize the maximum loaded line in the network. Due to the power surplus from distributed generators, reverse power flow occur in the network. The power from distribution grid will flow towards the distribution substation. The accumulation of power from distributed generators causes the lines closer to the transformer to be more prone to overloading problem. The min of max loaded line method by decision algorithm minimize the loading in such a line in order to reduce the probability of overloading.

- **Minimum Voltage Difference**
  The last method by decision algorithm tries to minimize the voltage difference in the network. Similar to the third method, decision algorithm will focus on the on battery input powers where the TCI is equal to zero. In this method at each load flow iteration iteration, the maximum voltage and minimum voltage magnitude among all buses are found and extracted . Then, the difference between the maximum and the minimum voltage of the buses in the network will be calculated. The minimum difference with the corresponding battery input power will be the output of the decision algorithm in this case. It is important to note that finding the best control action to solve the voltage issue doesn't introduce an overloading issue in the system or the other way around finding the best solution to minimize the lines loading doesn't introduce an over/under voltage problem. Here the decision algorithm is iterating through the battery charged powers where the TCI is equal to zero which means there is no congestion in the system.

3.3.3. Discussion

The application of Digital Twin for congestion management in distribution grid was discussed in this chapter. The digital twin developed in this work consists of detection and decision algorithm. The role of detection algorithm is to detect anomalies such as lines loading or bus over/under voltage and identify the congested elements. The aim of decision algorithm is to act on the detected congestion based on the control action selected by the system operator to reduce/relief congestions.
The main advantage of digital twin is the fast detection and fast analysis of post-congestion behavior effected by different control actions. The system operator has numerical and graphical overview of what is happening to network and therefore make better decisions on the operational point of view. The decision algorithm sends the control action to the CBESS to act on the congestion. As the Digital twin is updated with the close to real-time measurement data it makes it possible to perform close to real-time congestion management. The combination of Digital twin and the CBESS for congestion management improves the operation of VPP in power demand mode. With the advantage of close to real-time congestion management, it is not necessary for the VPP to send the generation/injected power schedules by DER every time to the DSO to check for congestions. The digital twin can control the CBESS in close to real-time and avoid possible congestions in the network. However, for the safety of operation it is still recommended for the VPP to send the schedule prior to real time for two reasons. One reason is in extreme case when the battery installed doesn't have enough capacity to store the injected powers by DER. Therefore, proper offline studies are needed to choose an adequate capacity of the battery. Another reason is because the control method in decision algorithm can be selected by the system operator prior to real time operation.
with the advantage of BESS the active power curtailment by prosumers are avoided. In the normal operation when the VPP sends the generation schedule to the DSO, if there is any congestion observed, DSO sends the command to VPP to curtail power from certain nodes. By installing the CBESS, active power curtailment are avoided. Also if there is any errors with the sending schedule of the VPP, the real time congestion management can act and make sure the stability of the system. It is important to note that in an extreme condition when the battery capacity is not enough active power curtailment should be applied to avoid congestion in distribution network.

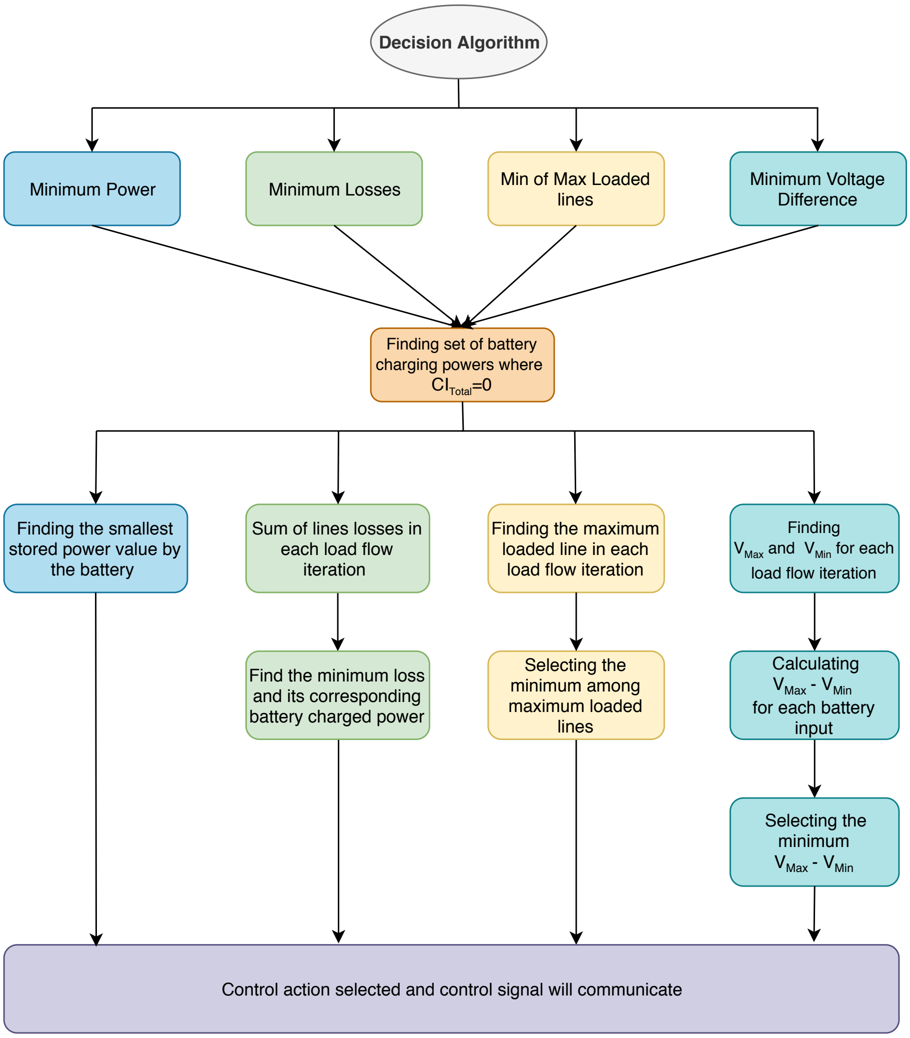

Figure 3.11: Decision Algorithm method

4

Case Study & Results

4.1. Introduction

In this chapter the digital twin methodology explained in the previous chapter will be applied on a test network to detect and identify the congestions in the network. Furthermore, the decision algorithm will control the community battery energy storage unit and provide different control options to the system operator to deal with the congestions in the network. Moreover, towards the end of this chapter offline studies are performed to determine the number of twins for the community battery energy storage operation. Moreover in offline studies the community battery energy storage capacity to be installed is recommended and also there are times suggested for this battery to discharge the power during the day. Finally, the process time of digital twin to detect and relief the congestion are measured and shown.

4.2. Network Configuration

The case study was inspired by the operation of the virtual power plant in CityZen project. A test system in a smaller scale representing the radial structure of the distribution network used in the CityZen project is designed in PowerFactory and shown in figure 4.1. This distribution network is connected to the transmission grid from HV side and the LV side of the network consist of a feeder with 7 loads representing the households. These loads are general 3 phase load model defined in PowerFactory. Moreover, this network consist of a two winding 10.5/0.42 KV 160 kVA transformer connected to the external grid from the high voltage side. Bus 650 as the reference bus is located at the high voltage side of the transformer and 9 other buses are located along feeder in the low voltage side.
The lines in this distribution network comprised of three types and the data such as resistance, impedance, rated current and length of the cables are provided in table 4.1. One can notice the higher R/X ratio in these lines which is the specification of lines in distribution network.
The community battery energy storage system is a static generator model in PowerFactory (Section 2.5) is installed at bus 5 in the distribution network. As determined in the project boundaries in 1.5.2 the placement of the battery has considered to be fixed and in this work we are dealing with the operational point of the battery.

In the following sections, first a profile of the injected power by DERs to the distribution network during a month is shown and then the network status on the worst case scenario will be evaluated. The worst case scenario is identified based on an offline studies in section 4.4.1. It will be shown that the highest number of congestion occurs during a time step (July 29th at 12:45 pm) where the injected power by DERs is highest during the month. Afterwards, the digital twin methodology is applied on the worst case scenario. At the end a brief discussion as a recommendation based on an offline study is given regarding the capacity of the battery to be installed so that it can compensate for the amount of congestion occur due to overproduction of power by the PVs in distribution network. Moreover, there will be another recommendation on the times when the battery should discharge the power.

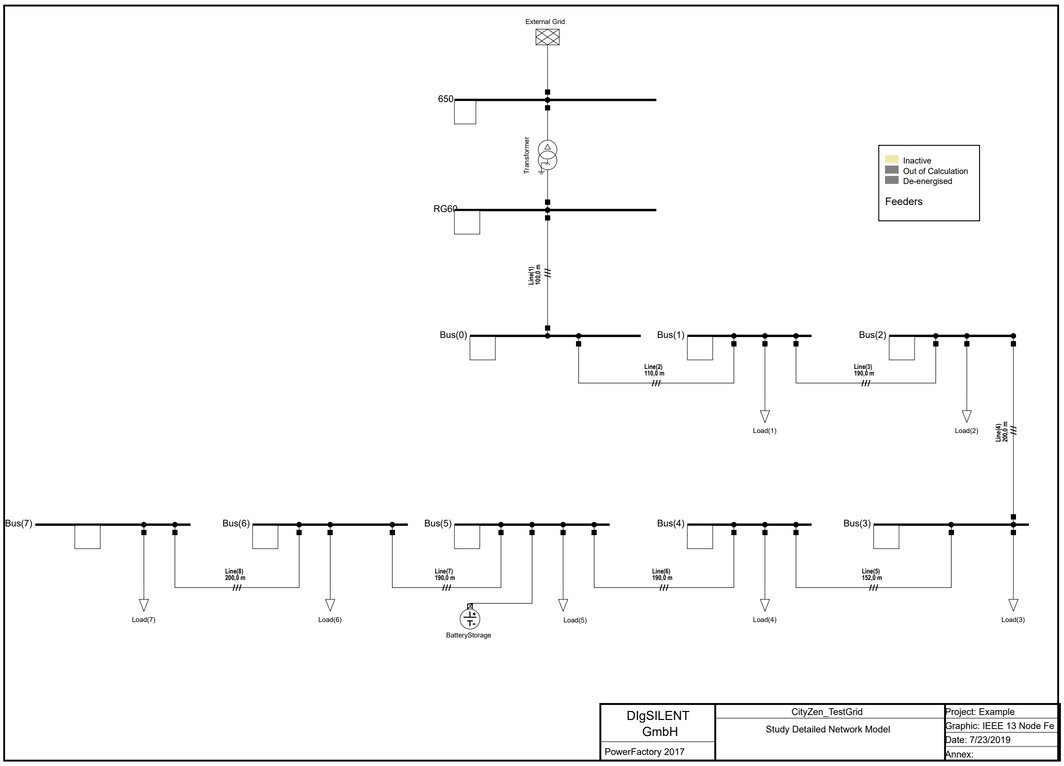

Figure 4.1: CityZen test grid

	Length [m]	Rated Current [kA]	R[ohm/kM]	X[ohm/km]
Line(1)	100	0.235	0.206	0.079
Line(2)	110	0.16	0.387	0.072
Line(3)	190	1.16	0.387	0.072
Line(4)	200	0.24	0.195	0.069
Line(5)	152	0.24	0.195	0.069
Line(6)	190	0.24	0.195	0.069
Line(7)	190	0.24	0.195	0.069
Line(8)	200	0.24	0.195	0.069

Table 4.1: Cables Data

The injected power profile for a month in July is shown in figure 4.2. This profile was used in CityZen project as a generation profile of DERs and it is generated from Royal Netherlands Meteorological Institute (KNMI). In this work this profile represents the amount of injected active power by each prosumer to the distribution network within 15 minutes time step. The reactive power of the prosumers is considered to be zero as discussed in project boundaries. The profiles are imported to PowerFactory via Python using the objects and the parameters explained in section 3.3.1. After importing the profiles to PowerFactory, the next step is to evaluate the system operational status in terms of lines loading and voltage level at the bus bars.

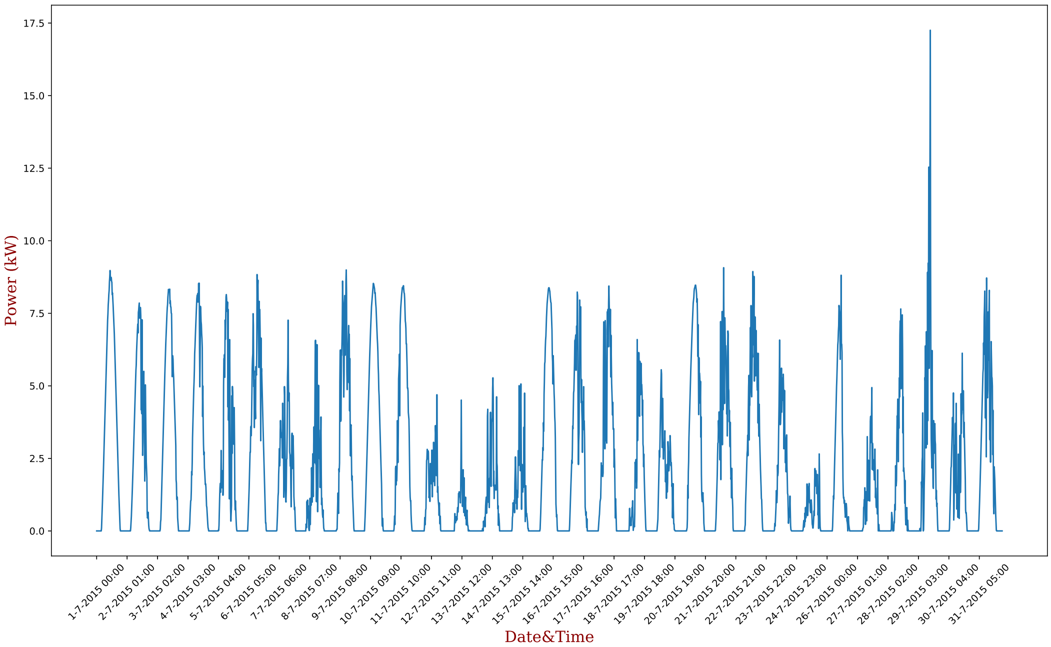

Figure 4.2: Injecting active power profile by prosumers in July

4.3. Network status at worst case scenario

To evaluate the network operational condition, load flow calculation at worst case scenario is performed. The snap shot of the distribution network illustrating the loading status of the system is shown as a heat map in figure 4.4. As shown in the legend, the red color in this figure indicates the loading above 90% that has been set as a constraint in the network. These values are listed in table 4.2. By comparing the loading values of each line, one can notice that the lines closer to the transformer have higher loading. This is due to the reverse power flowing from end of the feeder towards the transformer. The line at the end of the feeder (line 8) has the lowest loading of 8.7% and this value is gradually increasing by injecting active power by the prosumers until the capacity of the line 2 has exceeded its limit. Line 1 which is the closest to the transformer has less loading compare to line 2 or 3. The reason is that line 1 has higher rated current of 0.235 kA compare to line 2 and 3 where this value is 0.16 kA for both of the cables.

Lines	Loading[%]
Line(1)	64.1
Line(2)	94.2
Line(3)	80
Line(4)	44.2
Line(5)	35.2
Line(6)	26.3
Line(7)	17.5
Line(8)	8.7

Table 4.2: Lines loading in worst case scenario

Buses	Voltage[pu]
650	1.0
RG60	1.056
Bus(0)	1.069
Bus(1)	1.097
Bus(2)	1.137
Bus(3)	1.157
Bus(4)	1.165
Bus(5)	1.176
Bus(6)	1.183
Bus(7)	1.186

Table 4.3: Bus Voltages in worst case scenario

The snapshot of the system to illustrate the voltage at the bus bars in the distribution network is shown in figure 4.3. The red color indicates the buses that are above the operational limit of 1.1 pu or in other words the buses that have over voltage issue. The exact values of voltage magnitudes are listed in table 4.3. Since all the loads are injecting power in to the network and because of the reverse power flow, the highers voltage occurs at the end of the of feeder at bus 7 with 1.186 pu voltage magnitude and by moving towards the transformer the voltage drops due to higher resistivity of the lines as explained in section 2.2.1. The over-voltage problems here are more intense than the loading issues as we have 7 buses that has passed 10% over-voltage limits.

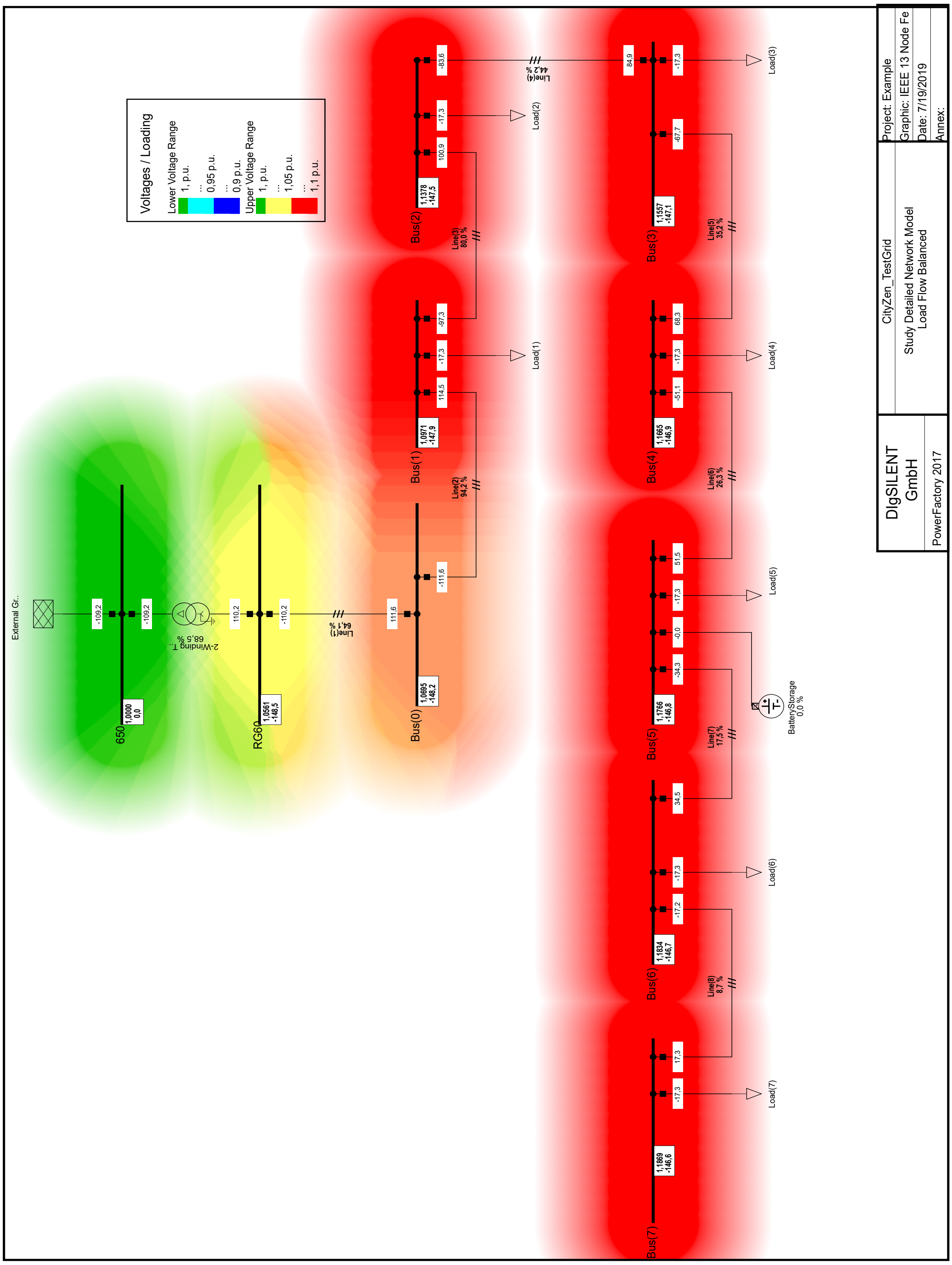

Figure 4.3: Heat Map: Bus voltage in the network at worst case scenario

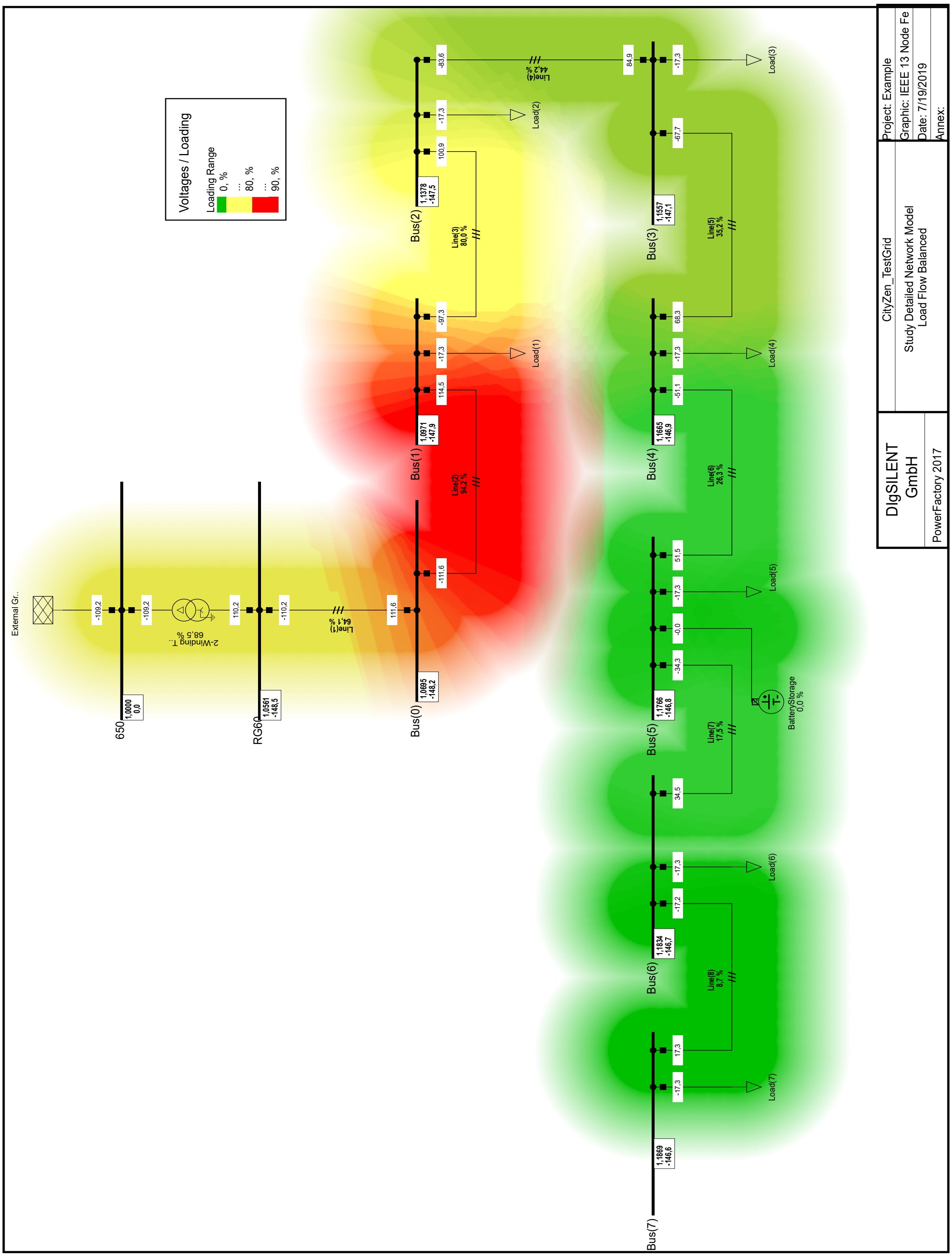

Figure 4.4: Heat Map: Lines loading in the network at worst case scenario

4.3.1. Detection algorithm

As mentioned in section 3.3.1, the aim of the detection algorithm is to check if there is any congestion due to overloading of the lines and if the voltage levels at buses are within the specified thresholds.
Once the load flow calculation is performed at each time step and the corresponding loading and voltage values are determined in the network, the values will be compared against the system operational constraints that has been introduced in 3.3.1. The detection algorithm counts the number of lines or buses that are out of the operational boundaries. For that it creates congestion index for both overloaded cables and over/under voltage buses respectively. It further calculates the total congestion Index (TCI) as an indicator to represent the status of the system.
The detection algorithm further informs the network operator regarding which lines and which buses are out of the limit. It also gives a graphical overview to illustrate the behavior of the system as shown in figure 4.5 and 4.6. From the data in table 4.2 and graph 4.5 we can conclude that the loading congestion index ($\sum CI_{Loading}$) is equal to 1 as line 2 is above the operational limit with +4.2%.
Similarly, based on information in table 4.3, and the figure 4.6, there are 6 buses (bus 2-7) that are congested due to over-voltage issue. Therefore the voltage congestion index ($\sum CI_{Voltage}$) in this case is equal to 6.
By adding voltage and loading congestion index, the TCI equal to 7 is obtained. Since there are clearly congestions happening in the network, in the next step decision algorithm is activated to act on the detected congestions and provide control actions to reduce/relief congestion in the network.

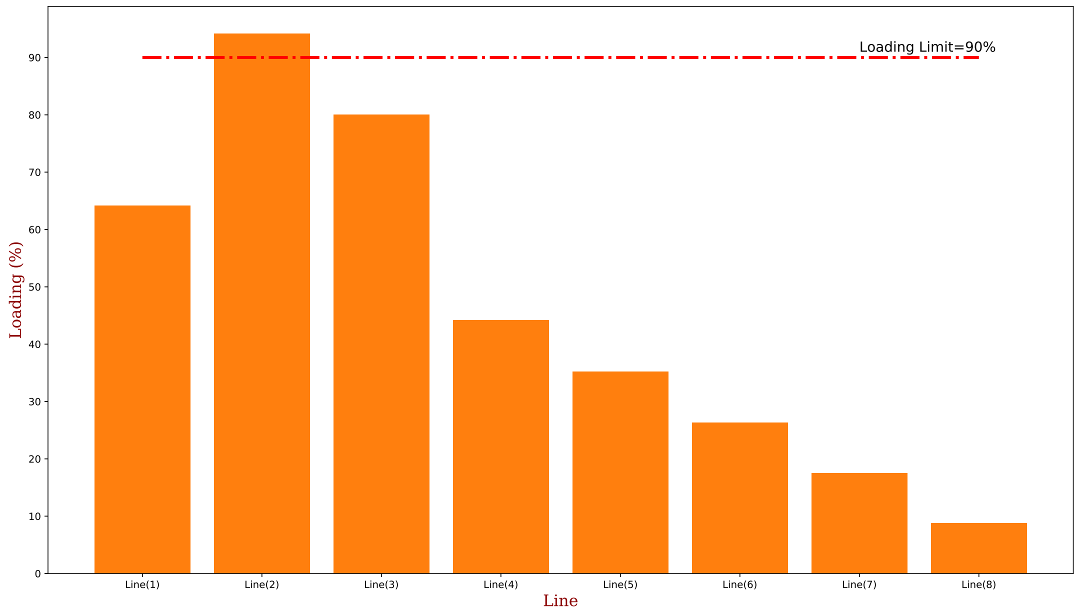

Figure 4.5: System Status:Lines loading at worst case scenario

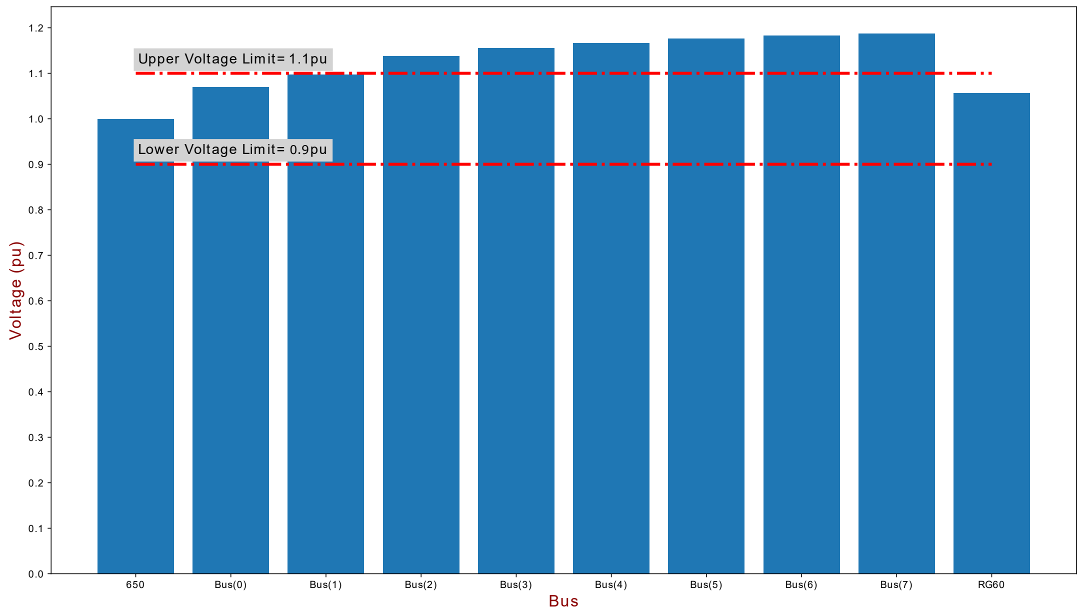

Figure 4.6: System Status: Voltage magnitude at the buses at worst case scenario

4.3.2. Decision algorithm

Once the congestion is detected by detection algorithm, decision algorithm performs iterative load flow calculations in interval between P_{init} to P_{end} with step size of 1 kW. Each value within this interval is the amount of charging power by the battery. P_{init} as the starting point of this interval has been set to 1 kW. As we discussed in section 3.3.1, P_{end} was considered to be the total amount of injected power by DER at worst case scenario in distribution network, this values is approximately equal to 120 kW. However, to show the effect of increasing battery charging power we have increased this value to be 200 kW. This means that with step size of 1 kW the total number of twins is equal to 200.

The variation of lines loading with respect to battery charged power is shown in figure 4.7. The dashed black line indicates the loading limit of 90%. This figure shows that in the beginning when the battery is not yet acting on the congestion and the input power to the battery is zero, line 2 is overloaded as it was observed in figure 4.5. Moreover, as the power charged by the battery is increasing, lines loading has decreases up to a point in lines 1 to 6. As the power charged by the battery keep increasing, the battery act as a big load, this causes an increase in lines loading again and if the charged power by the battery reaches a value close to 200 kW, lines 2,3,5,6 are overloaded.

When the charged power by the battery is between 7 kW and 183 kW there is no congestion due to loading of the lines. This figure also shows that the lines closer to the battery are reaching their minimum loading sooner and as we move towards the transformer, lines are reaching the minimum loading with more power charged by the battery. This is because of the location of the battery installed in the grid and also the direction of power flow. As an example in this figure, line (6) reaches the minimum loading soonest. Due to the reverse power flow and the connection of the battery at bus (5), battery stores power injected from prosumers 7, 6 and 5. Each prosumer is injecting around 17.2 kW in to the grid, therefore the total power of 51.7 kW are injected in total by the three loads. When the battery charged power reaches 51.7 kW of power, the loading of line (6) reaches its minimum value. This values increases once the charged power by the battery gets higher than 51.7 kW. In this case line (6) will start carrying power from prosumer (5) and as the injected power of the

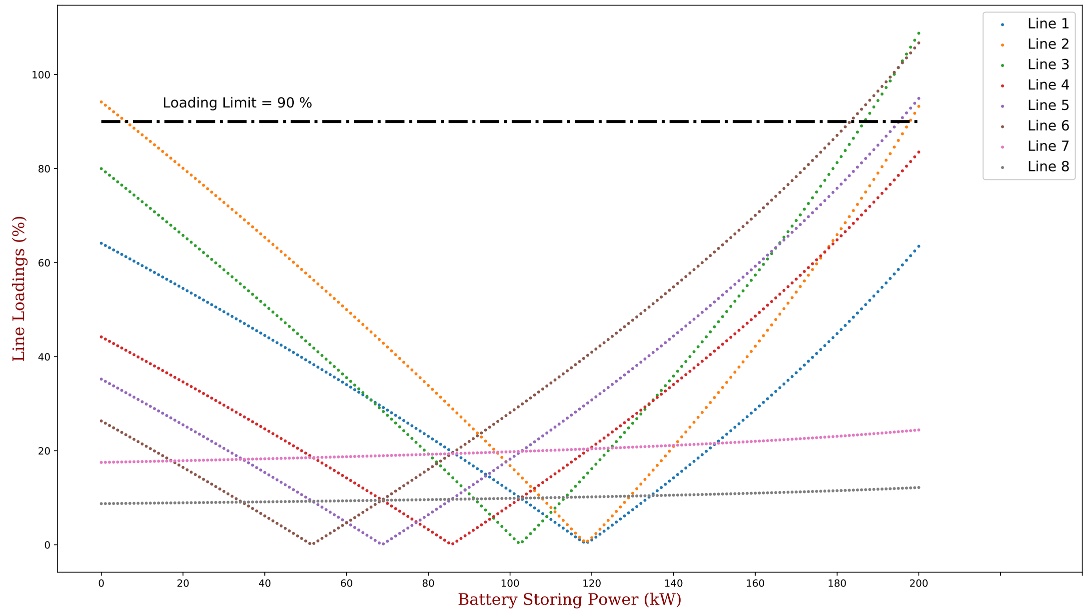

Figure 4.7: Lines loading in worst case scenario with different battery charging power

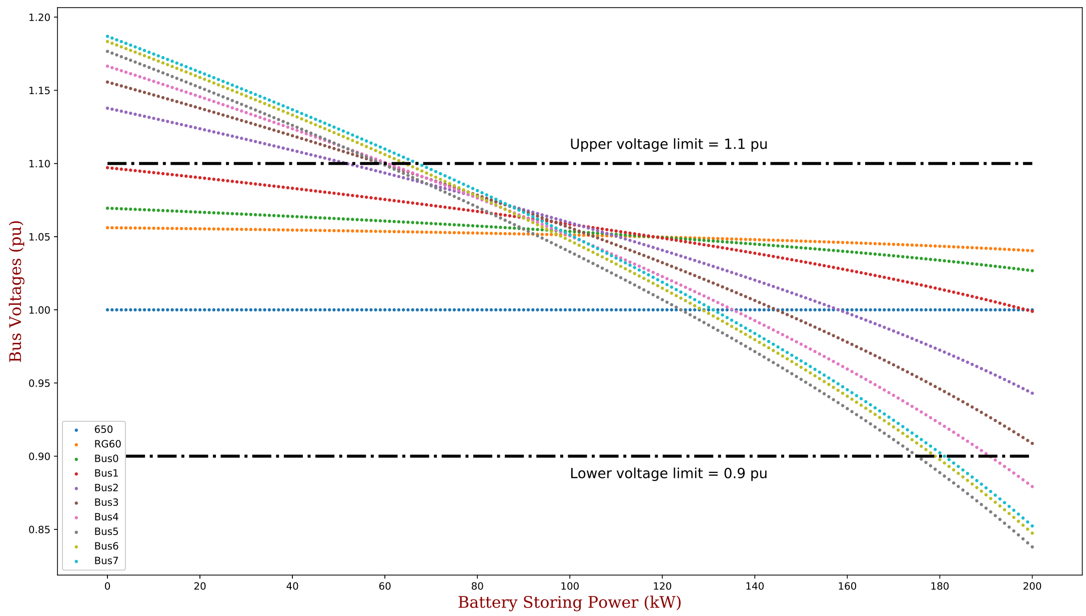

Figure 4.8: Voltage magnitude at buses in worst case scenario with different battery charged power

prosumers increases the line (6) loading will increases accordingly.
Lines 7 and 8 are however do not follow the ”V” shape as other lines in the network. This is due to their location in the network. Lines 7 and 8 are the last two lines along the feeder.

They are located after bus 5 where the battery is installed. In any cases the injected power from load 6 and 7 has to flow in lines (7) and (8), therefore the changes in these two lines remains almost constant.
Referring to figure 4.6 in voltage status at worst case scenario, there were 7 buses that were congested due to over voltage issues. These buses can also be spotted in figure 4.8 where the input power to the battery is equal to zero.
The dashed black line indicates the loading limits of 90% in case of lines loading and 0.9 pu and 1.1 pu are indicated as under and over voltage limits respectively.
In this figure at worst case scenario when the battery is not activated yet, bus (7) located at the end of the feeder has the highest voltage as all the DERs are injecting power in to the grid and the voltage drops along the line towards the transformer due to higher R/X ratio. As the power charged by the battery keep increasing the voltage magnitude at buses decreases. The congestion due to voltage issues is solved when the charged power by the battery is between 68-175 kW of power.
In the following sections the methods by decision algorithm will be applied at worst case scenario to find the proper control actions to deal with the congestions in the system.

4.3.3. Minimum power

Depending on the operation point of view, decision algorithm was divided in to three parts as explained in section 3.3.2. In the first method, the operator's interest is to find out the minimum amount of power that has to be charged by the battery to solve both loading and voltage issues in the network.
The stack bar graph 4.9 shows the congestion index for both voltage and loading with blue and orange respectively. This figure shows the total congestion index at top of the bar as summation of both loading and voltage congestion index. The zero charged power by the battery in this graph corresponds to the worst case scenario described above when the battery is not yet acting on congestion issues. In this case, as we observed previously, the loading congestion index is equal to 1 and it is shown with orange color in this figure. Similarly the voltage index is ranging from 1 till 7 which is equivalent to 6. Therefore the total congestion index is equal to 7 in this case.
In the minimum power method, at first the decision algorithm aims to find an interval where the TCI is equal to zero. Zero TCI means that there is no congestion due to line loading or bus voltage magnitude in the system. For that it looks for a common interval of battery inputs where the loading and voltage issues are solved. This interval is the green zone from P_{init} to P_{end} as defined in figure 3.8. In network status section, it was found that the loading issue is solved when the charged power by the battery is between 7 kW and 183 kW thresholds and the voltage issue is solved when the battery stores power between 68-175 kW thresholds. The decision algorithm find the common interval between these two thresholds which is 68-175 kW of power. This interval is where the TCI is equal to zero as there is no congestion in the system and it is shown also in figure 4.9. In the next step the minimum power method selects the minimum value within this interval. This value is equal to 68 kW and it is shown with a dashed line. This value is the result of first control action by decision algorithm and it corresponds to the minimum amount of power that battery has to store in order to solve the congestions. The lines loading value when the battery is storing 68 kW is listed in table 4.4 and it is visualized in figure 4.10. Similarly, the results of bus voltage after load flow calculation at input power of the battery equal to 68 kW is listed in 4.5 and graphed in figure 4.11. As it can be observed in these graphs all the values for lines loading and voltage magnitudes at buses are within the operational limits and the operator is able to get the picture of the system status and the corresponding results for the minimum power required to solve the congestion in the distribution network.

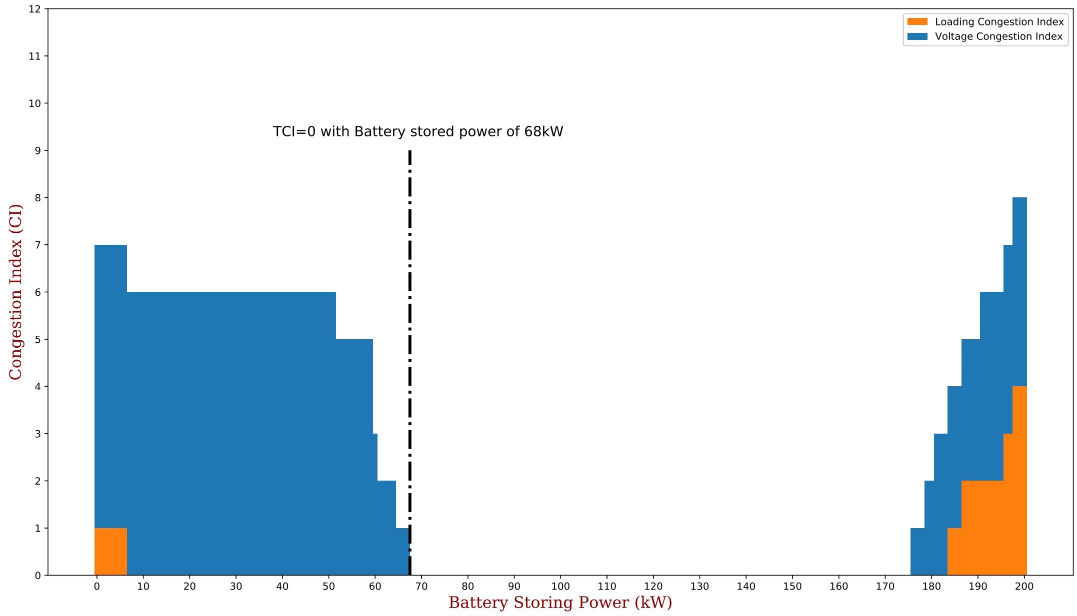

Figure 4.9: Stack bar graph indicating the loading, voltage and the total congestion indices

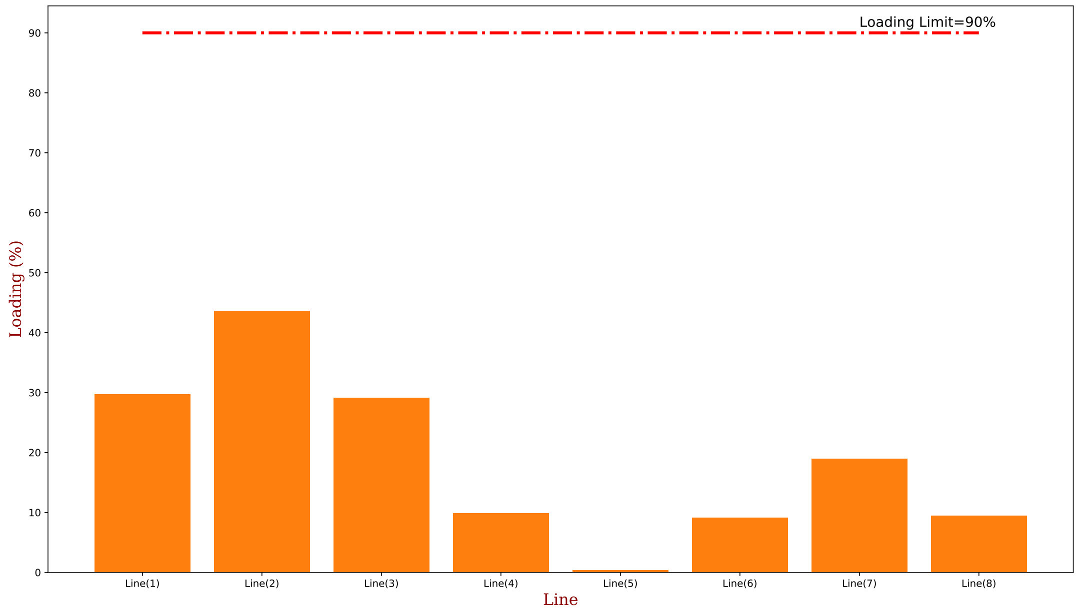

Figure 4.10: Lines loading values when the battery charged power = 68 kW

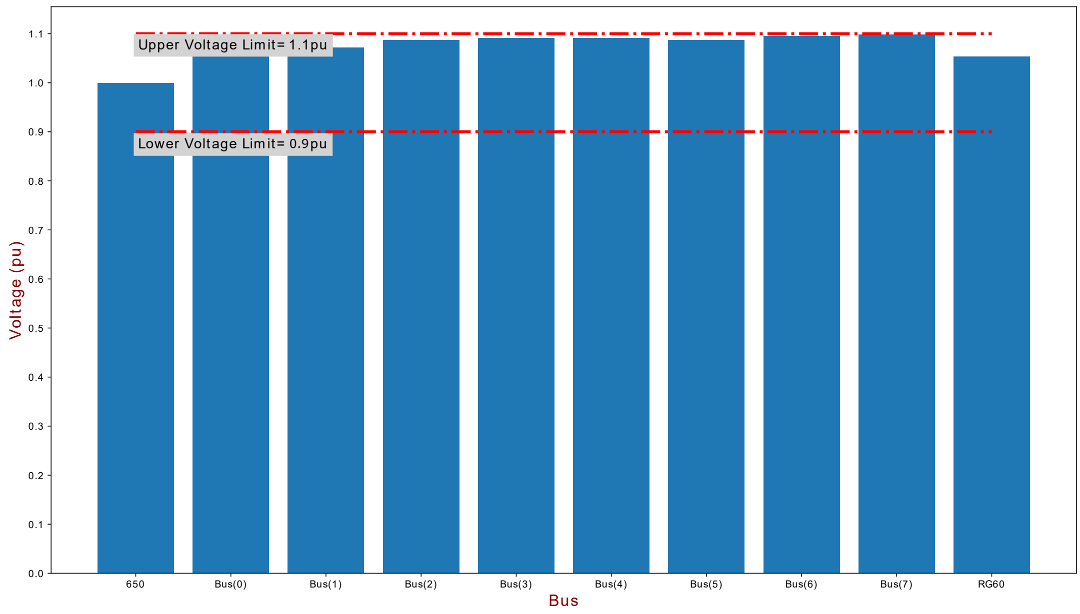

Figure 4.11: Voltage magnitude at buses when the battery charged power = 68 kW

Lines	Loading[%]
Line(1)	29.7
Line(2)	43.6
Line(3)	29.1
Line(4)	9.8
Line(5)	0.3
Line(6)	9.1
Line(7)	18.9
Line(8)	9.4

Table 4.4: Lines loading when the charged power by the battery is 68 kW

Buses	Voltage[pu]
650	1.0
RG60	1.053
Bus(0)	1.059
Bus(1)	1.072
Bus(2)	1.087
Bus(3)	1.091
Bus(4)	1.0911
Bus(5)	1.087
Bus(6)	1.094
Bus(7)	1.098

Table 4.5: Voltage at the Bus bars when the charged power by the battery is 68 kW

4.3.4. Minimum loss

Another method by decision algorithm is based on the losses in the system. In this method first the interval where the TCI is equal to zero is selected by the decision algorithm. In the next step the decision algorithm looks more in details within this interval and at each battery charging power the line losses will be retrieved after the load flow calculation. After a load flow calculation at each battery charging power, the lines losses (active power losses) are added together. Figure 4.12 shows this total real power losses versus the battery power charged in each 1kW incremental step. This method gives the operator the opportunity to have the overview on losses in the system at each battery charged power value. As it can be seen the minimum amount of losses occurred when the battery stores 92 kW of power. The total losses with 92 kW of power is 1.074 kW. Decision algorithm will select this value as output and send it as a control signal to the real system. The individual line losses when the battery input power is equal to 92 kW are listed in table .

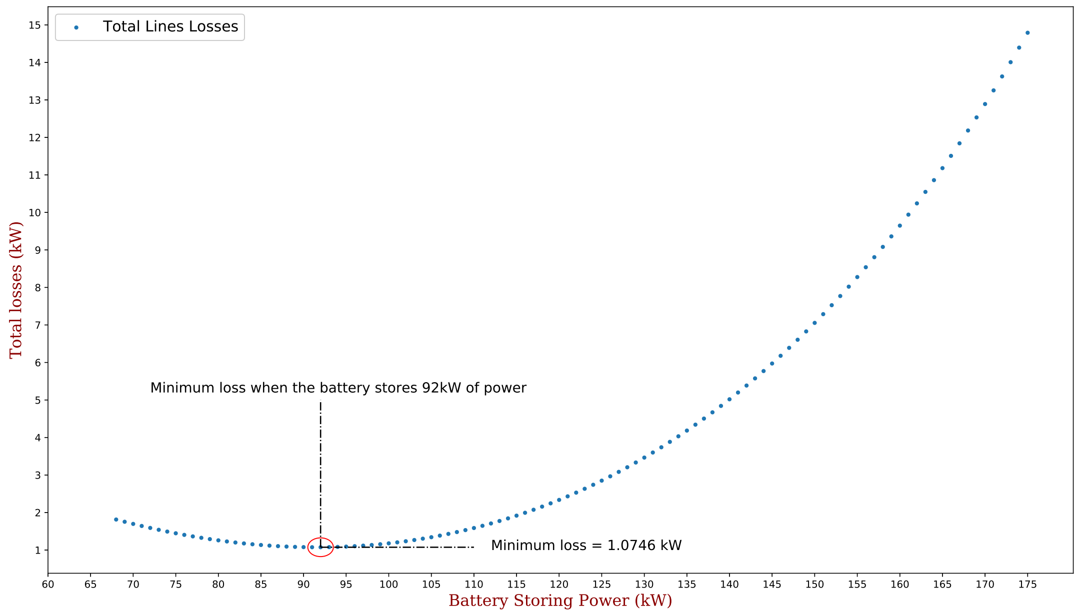

Figure 4.12: Total real power loss in the network at each battery charged power

Lines	Losses[kW]
Line(1)	0.0893
Line(2)	0.1874
Line(3)	0.0496
Line(4)	0.009
Line(5)	0.0919
Line(6)	0.3438
Line(7)	0.2446
Line(8)	0.0641

Table 4.6: Lines losses when battery charged power=92 kW

4.3.5. Min of Max loaded lines

Another decision algorithm method is aiming to minimize the loading in the network. After the interval when the TCI equal to zero is determined by the decision algorithm it will select the maximum loaded line at each load flow iteration. This is shown in figure 4.13 where the minimum point was spotted when the battery charged power is equal to 92 kW. This minimum point refers to the maximum loaded line at 92 kW charging power of the battery and its is equal to almost 24%. This means that rest of the lines loading will be lower than this value in the network at 92 kW charged power by the battery. The loading values at this point is shown in table 4.7. The min of max loaded line method assists the operator to have an overview on loading status of the lines and check what is the maximum loaded line at each battery charged power.
Moreover this figure shows that until 92 kW of charged power by the battery the maximum loaded line is line (2) which is the second line closest to the transformer as all the injection by DERs are flowing towards the distribution substation. The maximum loaded line could be line (1) but due to higher rated current of line (1) compare to line (2), this line is less loaded. After reaching the minimum point at 92 kW charged power by the battery, the maximum loading belong to line (6) as the charged power by the battery increases. The charged power

keep increasing by the battery and the power flow will be directed towards the battery. This causes more stress on the cables surrounding it and therefore line (6) becomes the most loaded cable in the network.
It is interesting to note that the value of 92 kW battery charged power is equal to the output of minimum loss method by decision algorithm. It is obvious that by minimizing the loading on the cables, the losses in the network decreases accordingly. However, this is not the case all the time. With scenarios such as the example demonstrated in section 3.3.2 the outputs of these two methods will be different.

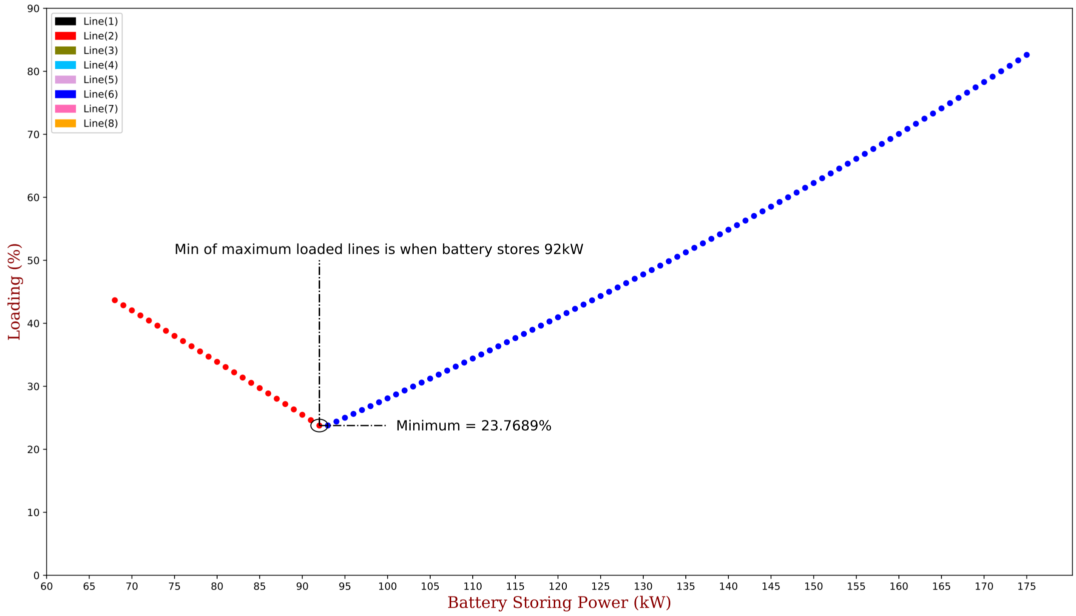

Figure 4.13: Maximum loaded lines at each battery charged power

Lines	Loading[%]
Line(1)	16.1
Line(2)	23.7
Line(3)	9.1
Line(4)	3.6
Line(5)	13.3
Line(6)	23.1
Line(7)	19.5
Line(8)	9.7

Table 4.7: Lines loading when battery charged power= 92 kW

4.3.6. Minimum Voltage Difference

The last method by decision algorithm is based on the difference between the maximum and minimum voltage of buses with battery charged power changing from 68 to 175 kW or in other words when the total TCI is equal to zero. The aim of the operator in this method is to minimize the voltage level in the network. As shown in figure 4.14, the minimum voltage difference is observed when the battery is storing power of 124 kW. This voltage difference is equal to 0.049 pu. The Voltage magnitudes when the charged power by the battery is 124 kW is listed in table 4.8. It is important to note that if the number of twins has been set to 120, then the minimum voltage difference would be at 120 kW accordingly.

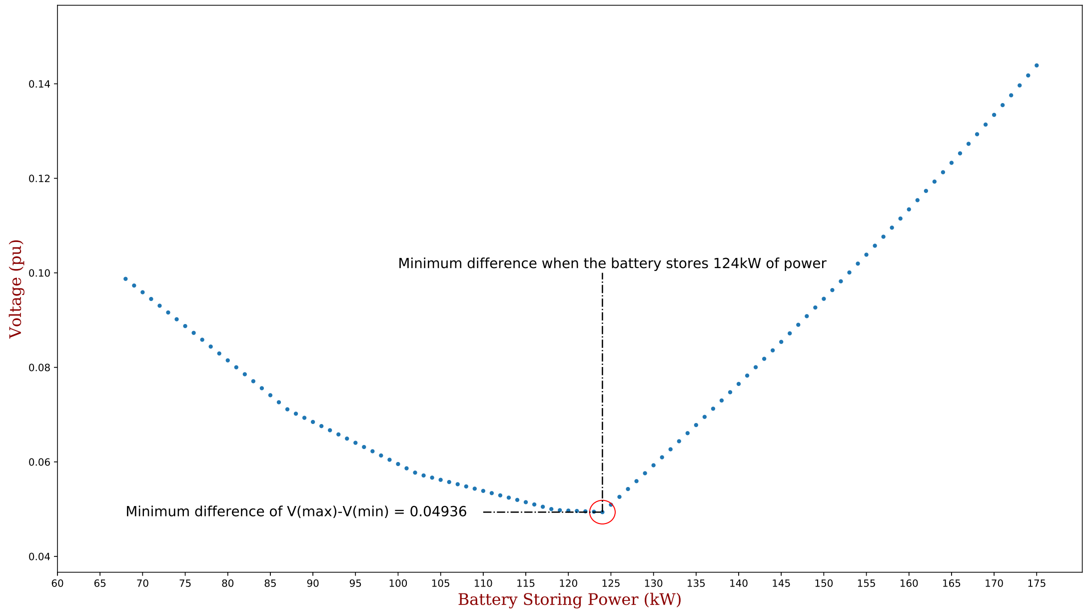

Figure 4.14: Voltage difference difference for time step 12:30 with different battery charged power

Buses	Voltage[pu]
650	1.0
RG60	1.04936
Bus(0)	1.04858
Bus(1)	1.04703
Bus(2)	1.03677
Bus(3)	1.02725
Bus(4)	1.0169
Bus(5)	1.00076
Bus(6)	1.00798
Bus(7)	1.01213

Table 4.8: Bus Voltages when battery charged power =124 kW

4.3.7. Execution process time

The digital twin execution process time is shown in figure 4.15. The execution time from importing profiles to PowerFactory, detecting congestion and decision making depends on type of the simulation. In case of parallel computing where the twins indicating control actions are running in parallel the simulation time is within milliseconds and shown with red colour in figure 4.15. This time is obtained based on simulating one control action in each method. However, the parallel computation is not yet possible due to the license issue of PowerFactory.
If the simulation is performed on a single run then the simulation is executed within seconds by decision algorithm. The process time in this case is shown with blue colour.

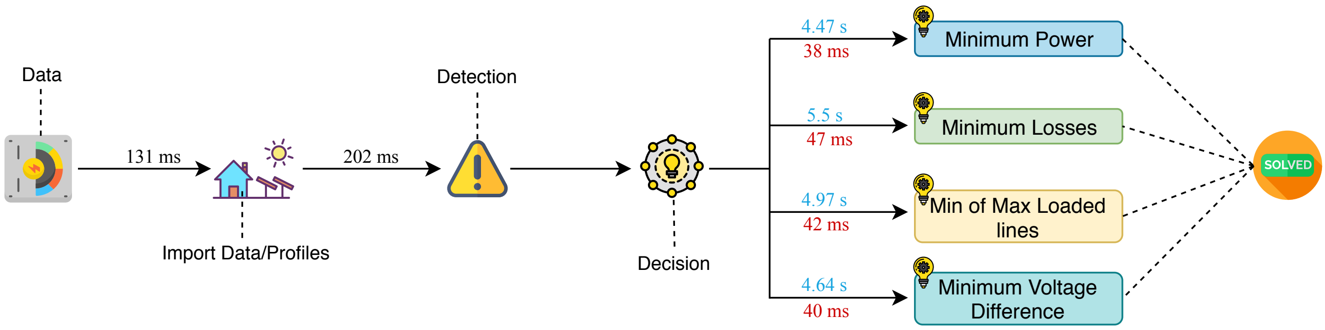

Figure 4.15: Digital twin process execution time on a single run/parallel computation

4.4. Offline studies

4.4.1. Determining the number of twins

Now that it is clear how the detection and decision algorithm works for a single time step, we extend the simulation to one month operation. The goal here is to determine the number of twins for application of digital twin in congestion management. For that, first the time step at which the most number of congestion occurred has to be identified. The total congestion index at every 15 minutes time step is shown in figure 4.16 during the month. The same for the day when the worst case scenario occurred is shown in figure 4.17. From this figure, we can see that more amount of congestion happened on 29th of July at 12:45 pm. Moreover, figure 4.18 informs more information regarding this point. At this time step, the total congestion index is equal to 7 in which one of the lines are overloaded and voltage magnitudes at 6 buses are out of the specified operational limit. Based on this approach the number of twins can be set as sum of the active power injection by DERs in distribution network at that time step. This means that the operation set points of the battery is until it can store all the injected powers by DERs in the network at the worst case scenario. The number of twins are determined by the system operator and more number of twins corresponds to longer simulation times.

4.4.2. Recommendation on battery capacity

The aim of this section is to suggest a battery capacity to be installed and moreover to suggest a time period when the battery discharge the charged power. This study is performed during the month of July where the frequency of congestion was shown in figure 4.16.
The same methodology used for single time step is extended for a month operation. The total number of congestions occur during a day is shown in figure 4.19. This figure indicates that more number of congestion is happening during 1st of July. The frequency of congestion is 29 times on this day.

Next step is to determine what are the minimum power required to solve the detected congestions during the month. The minimum power required to solve the congestion at each 15 minutes time step during the month is shown in figure 4.20. The minimum power at each time step is summed up for a day and the results is shown in figure 4.21.

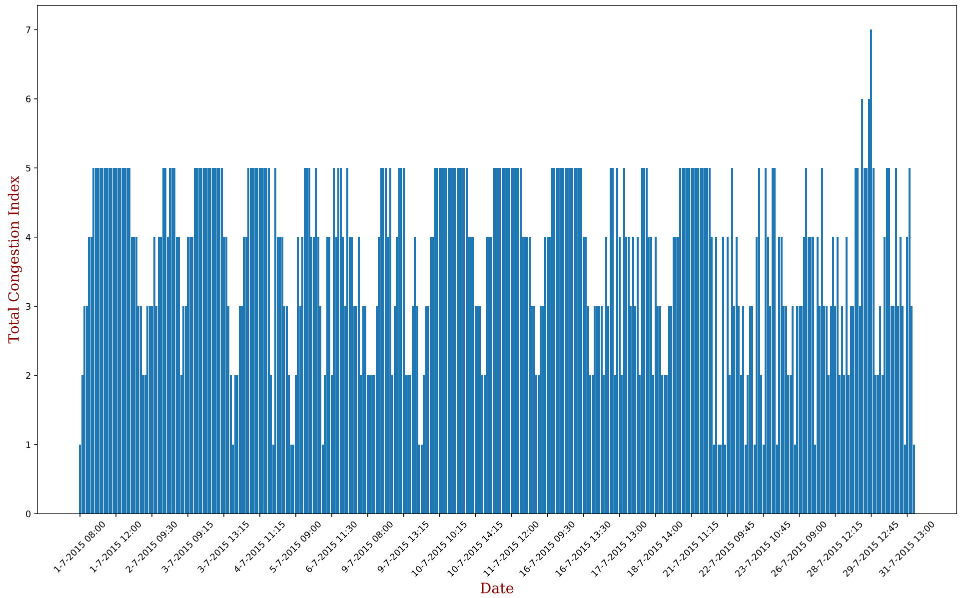

Figure 4.16: Total congestion index in July

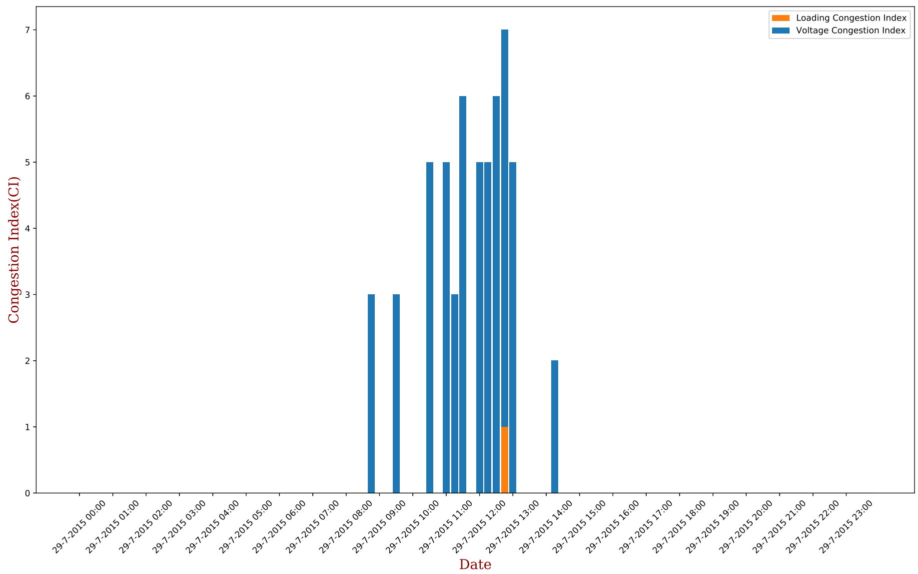

Figure 4.17: Congestion index on July 29th - 24 hours

Based on the gathered data on the amount of congestion at each time step and during the days, it can be observed that on 1st of July when the frequency of congestion had its highest point, the amount of power needed to deal with the congestions is higher accordingly.
The minimum amount of power that is required for the battery to store at each 15 minutes time step is multiplied by 0.25 hour to see how much energy capacity is needed to deal with the congestions. These minimum energy are summed up for each day and are shown in figure 4.22. Based on this graph we can assume if a battery capacity of 85kWh is installed, then this capacity will be high enough to deal with the congestion for other days (24 hours) where the frequency of congestion is lower and also less power required to compensate for

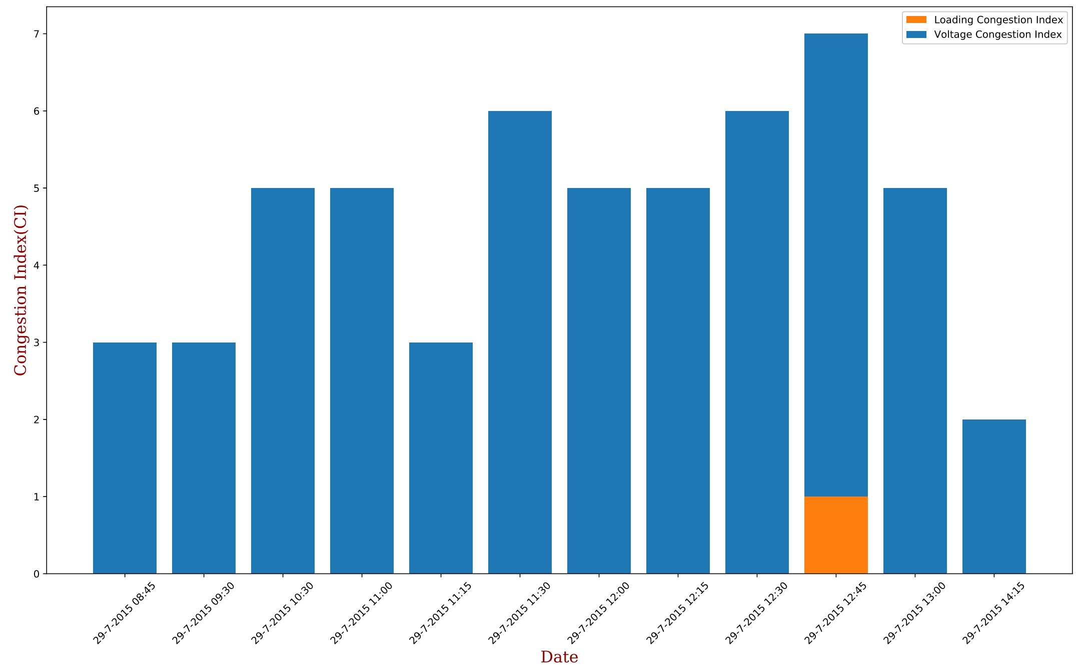

Figure 4.18: Congestion index more than zero on July 29th

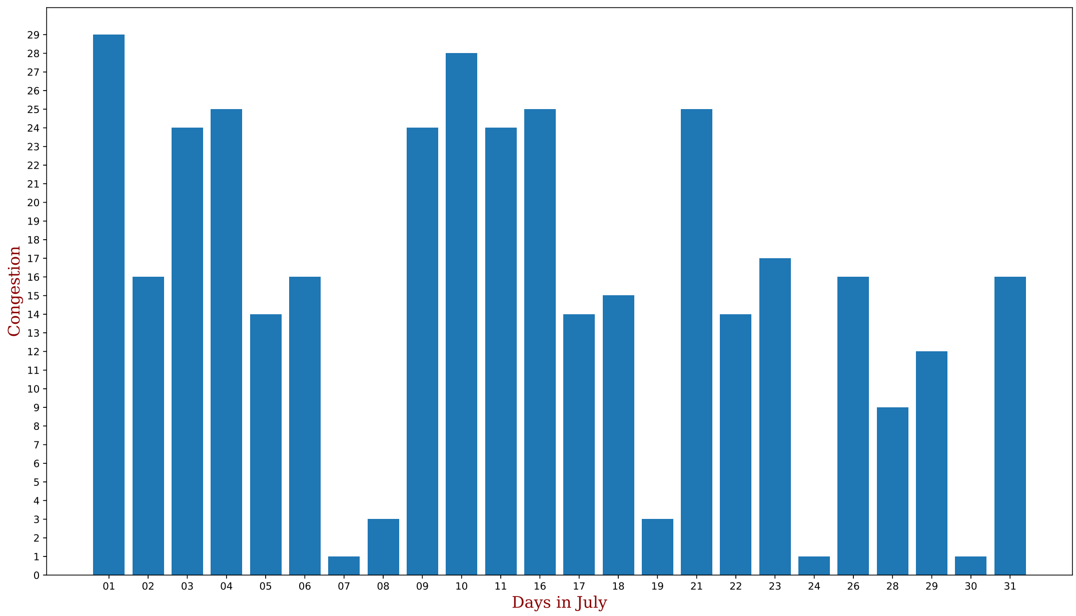

Figure 4.19: Total amount of congestion (congestion frequency) during days in July

the congestion issues in the network.
It is important to note that this value (85kWh) is based on the ”minimum power” by decision algorithm which is considered to be the least power required to solve the congestion. If

the operator choose another method by decision algorithm i.e to reduce the voltage levels, minimize loading or to reduce losses then higher battery capacity is needed to be installed in the network.
It is also important to mention that the value of 85 kWh is chosen assuming that the battery is not discharging until the last congestion happens during July 1st. As it can be seen in figure 4.23, the last congestion happens at 15:00 o'clock. The value 340 kW is the summation of all active power required from 8:00 am till 15:00 pm.

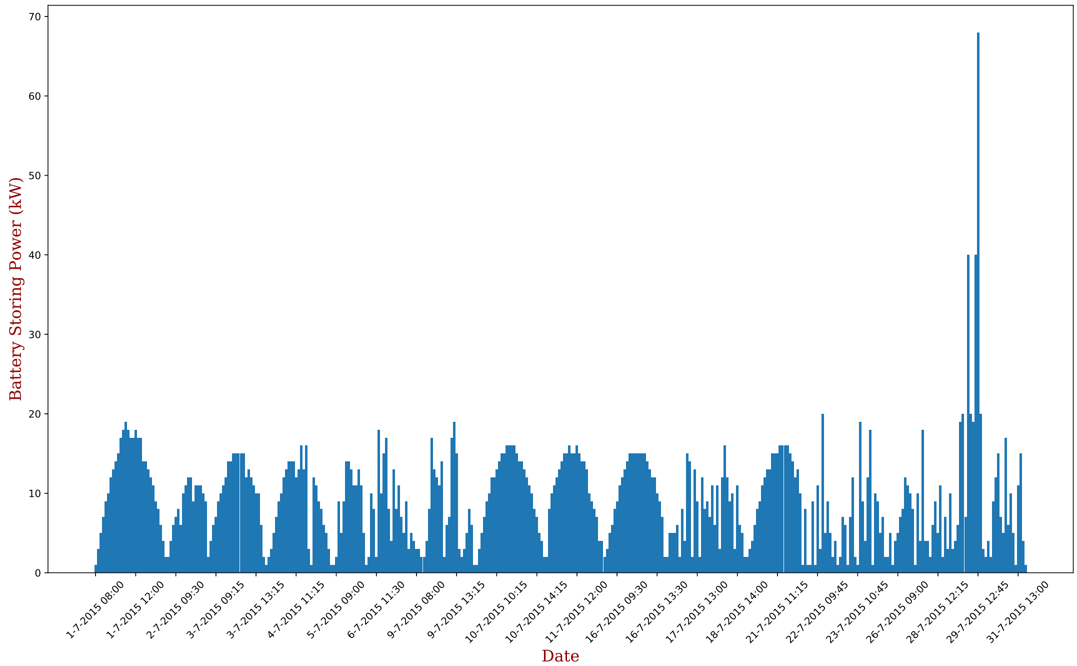

Figure 4.20: Min charged power by the battery to solve the congestions during a month at each 15 minutes time step

Now that the battery capacity to be installed is recommended the next step is to suggest the times to discharge the charged power during a day. The discharge of power has to occur at the times when the TCI in the system is equal to zero. Since the detection algorithm is able to calculate the TCI at each time step and provide control action to battery to store the power, in the same way the same control action can be given to discharge the power taking into consideration the operational constraints of the network. Most of the charged power by the battery can be discharged during late afternoon or evening period when there is no more power injection by DERs in distribution network. This period is shown as a green area on a sample 48 hours injected power profiles shown in graph .
Moreover, the power discharged by battery can be used to charge the local batteries during the times when demand is high and also this power can be transported to another distribution network in the neighbourhood if needed. But its is important to ensure that the battery is discharged at the end of the day so that it has enough capacity to deal with the congestions in the next day. Discharging the battery at the end of the day would be a better option since frequent charging and discharging during the day increase the degradation of the batter. For this the an adequate battery capacity has to be installed to store all the injected powers that has caused congestion during the day.

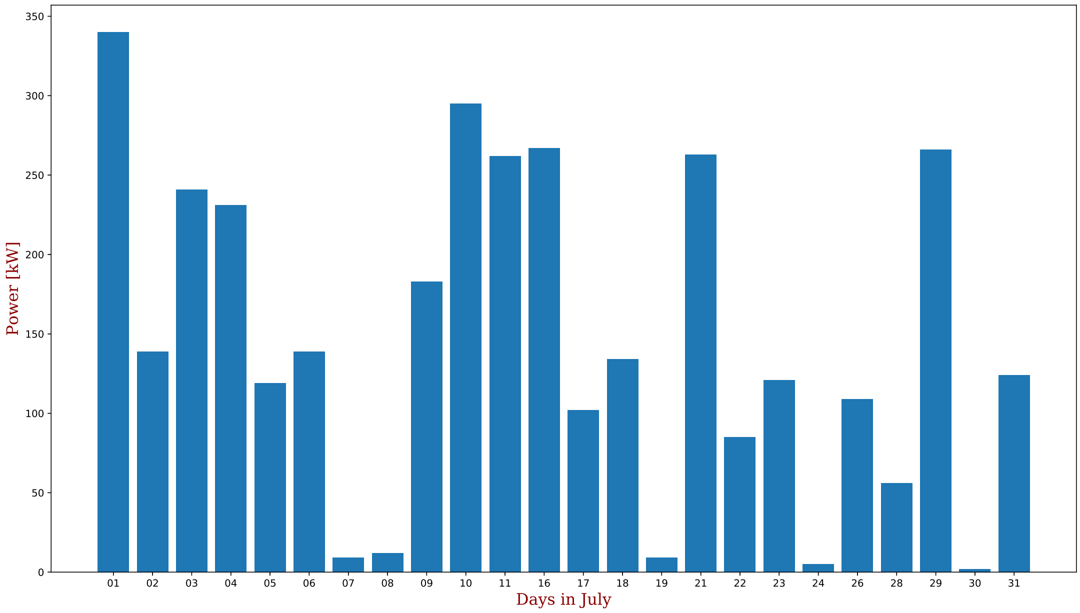

Figure 4.21: Summation of minimum power required to solve the congestion in each day during July

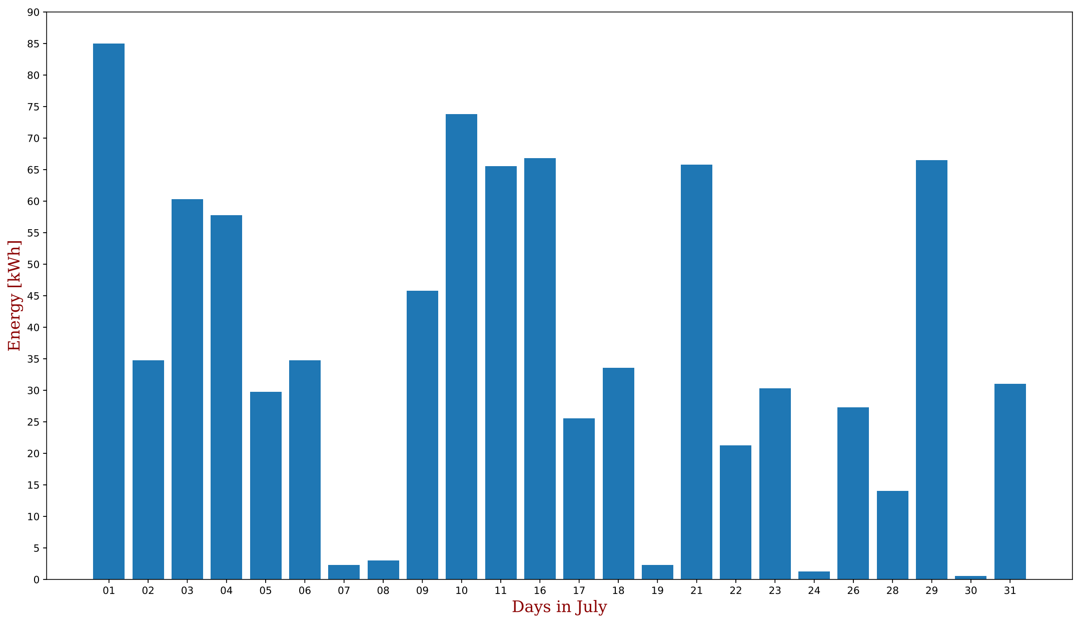

Figure 4.22: Summation of minimum Energy required to solve the congestion in each day during July

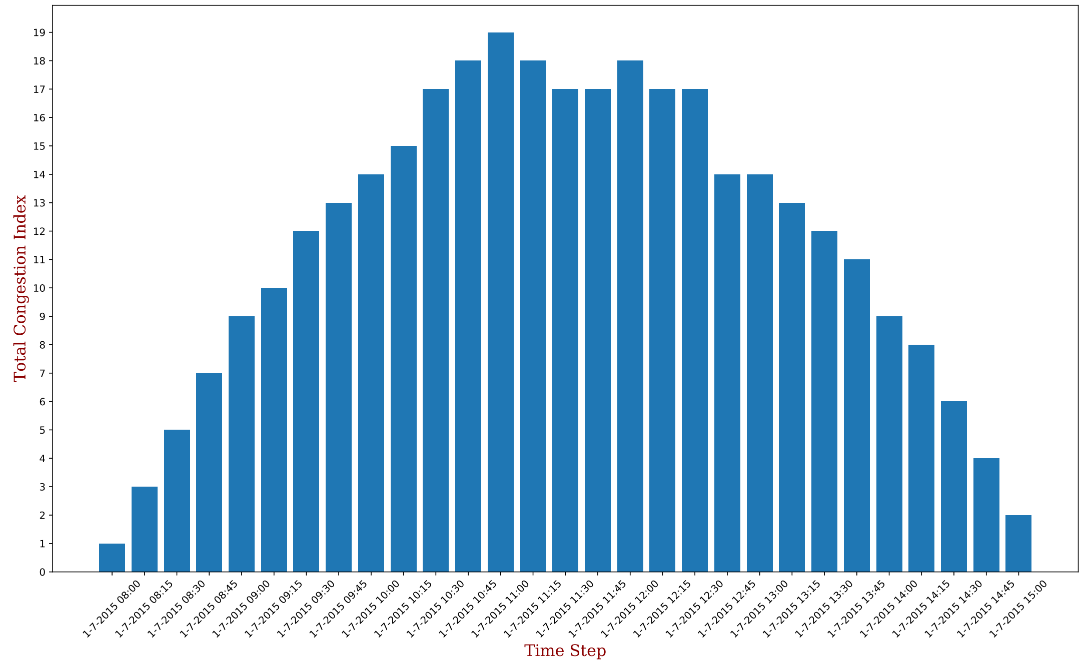

Figure 4.23: Total congestion index on 1st of July

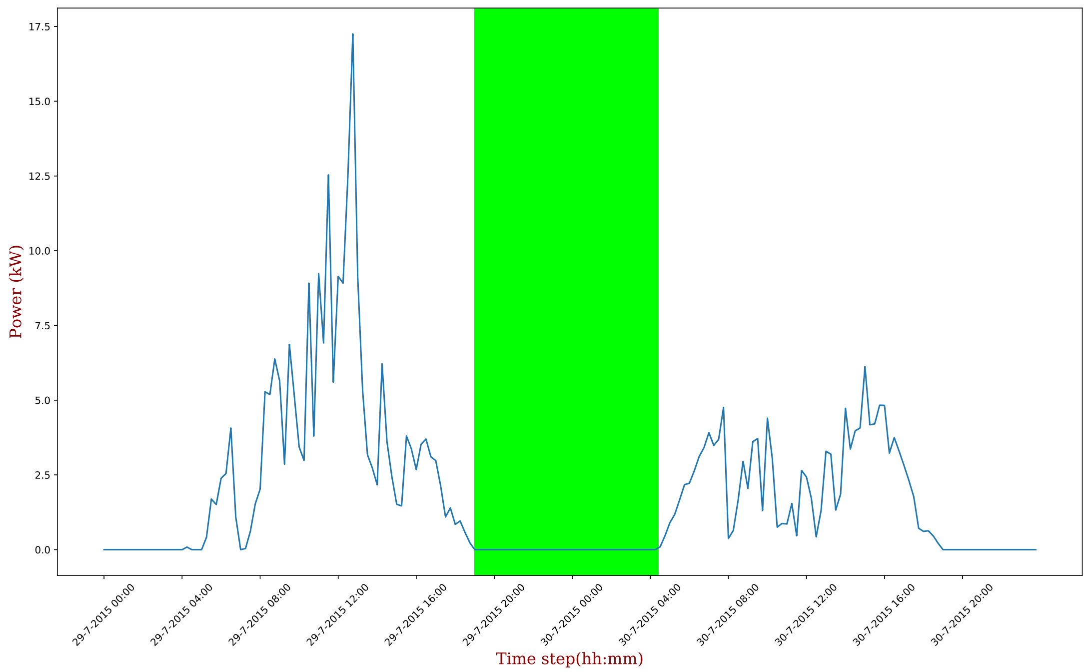

Figure 4.24: Injected power profile on 29th and 30th of July
Greenarea: The time interval for the battery to fully discharge

4.5. Discussion

In this work the network status at worst case scenario when the injected power by DERs were at their maximum level was studied. The results showed that as all the DERs are injecting power in to the grid, over-voltage occurred at the end of the feeder and overloading issues happened at the lines closer to the transformer.
The digital twin and the community battery energy storage were proposed to deal with the congestion in distribution network. The community battery energy storage can store the injected power by DERs which consequently avoids power curtailment. Moreover, the digital twin by controlling the operation of community battery energy storage will make it possible for VPP to operate in close to real-time.

The digital twin proposed in this work consists of detection and decision algorithms. The detection algorithm checks whether there is any congestion in the network and identify the congested element using a metric called congestion index. The decision algorithm controls the operation of community battery energy storage in case there is any congested detected by detection algorithm. Moreover, it gives the operator the opportunity to select between different control actions. Each control action has different outcome and effect on the network.

The network status at worst case scenario with low demand and maximum generation were analyzed in this chapter. Based on the results obtained from detection algorithm since all the prosumers in distribution network are injecting power, the voltage starts to rise at the bus where the DER are connected to. Accordingly the highest voltage occurs at the end of the feeder far from the transformer.
In addition, the results show that in worst case scenario the lines closer to the transformer have higher loading compare to the ones at the end of the feeder due to the reverse power flow.

In the next step, decision algorithm was applied to act on the congestions detected by decision algorithm. Four different control actions are the provided by decision algorithm and their effects on the network were shown.

The process time by digital twin was measured. It was shown that in case of parallel computation of twins the execution time would be in terms of milliseconds and if the process is executed in single run then execution time is in terms of seconds. However, parallel computation is not possible at this point as PowerFactory requires licence.

There were also offline studies performed in this work to recommend a battery capacity and also recommend the times to discharge the power from community energy battery storage. To determine the battery capacity the ”minimum power” method by decision algorithm was performed during the one month period.
It was observed that the stored power by the battery can be discharge during the times when the total congestion index (TCI) is equal to zero. This happens mostly during the evenings when there injected power by DERs are low. It was noted that the battery should fully discharge the power during this time so that it will be ready to operate for the next day and deal with the congestion due to injected powers by DERs.

The digital twin designed in this work can further be developed by:

- Adding more methods to decision algorithm so that the operator has wide range of options to decide on proper control action. The methods can be developed by taking into consideration the economical and technical aspects of the VPP and distributed generator.
- More detailed modeling of community battery energy storage can be developed such as implementing the state of charge (SoC), rate of degradiation of the battery.
- The operational condition of other asset in the network can be added to the digital twin model.
- Developing KPI and machine learning algorithms to suggest the control action faster and also predict the possible congestion in the network.

Appendices

A

Congestion management monitoring/On-line power system analysis

A.0.1. Architecture for online power system analysis

The current near to real-time of online dynamic security assessment (DSA) is used in dispatching control centers for over a decade. The steps for the current online DSA is shown in figure A.1 starting with power grid redundant telemetry (RTU) measurement data are processed by supervisory control and data acquisition (SCADA) and following that by state estimation (SE) to evaluate the state of the grid and perform a power flow study prior to DSA analysis. The full DSA assessment may take up to minutes depending on the complexity of the network [37].

Figure A.1: The current online analysis system architecture where min-order is response time in order of minutes, and sec-order is response time in the order of seconds [37].

With increased penetration of distribution generation, installation of Power electronic devices such as HVDC and FACTS, we expect that the segments of the grid to become more dynamic with less inertia to keep the synchronization. To improve the security and stability of the system more focus should be kept on computational speed of the real-time system control. A new and fast real-time online DSA system can assist the system operator to analyse the system and make effective decisions while the system dynamic is running and not relying on after-the-problem analysis.

For this purpose, first online analysis system architecture will be investigated in the following steps:

A.0.2. Research on Online Analysis

Security of the power system is defined as the ability of the system to withstand sudden disturbances and remain within its operating points. Violation of any security related inequality constraints pushes the system to emergency or insecure state, thereby initiating corrective actions to be taken to bring the system back to secure state. To make sure that the power system is operating within the operational limits the design of the system has to be sufficiently secure and operation of the system has to be constantly monitored to ensure the reliability of the system. As mentioned earlier the predictability of the power system's operation is reducing with more integration of renewable sources as well as the installing more power electronics devices in the grid, accordingly the system robustness will be reduced by the time. The following section discuss about the current research in online analysis [37]:

A. Dynamic Security Assessment
The control center of the power system has crucial part to monitor and control the behavior of the system, ensures security and performs adjustment in order for the system to operate within operational limits. Traditionally, security was performed through offline monitoring methods through forecatsted data. However, these methods has proven to be not reliable enough to maintain the security of the system. Online DSA is a more practical method comparable to offline methods as it needs less prediction of system behavior. With an online DSA a snapshot of the system is taken which represents the current condition of the system and therefore security can be assessed.

B. Online Analysis
As mentioned earlier online analysis is performed through assessing the current snapshot of the system in order to evaluate the security of the system. There has been many challenges in order to improve the online analysis by different methods such as grid model reduction, distributed/parallel computing and different computational methods. The complete entire analysis from taking the snapshot till the results are made for tor the grid operator would take between 5 to 60 minutes.

C.Complex Event Processing(CEP)
Event processing is a method to evaluate information based on a digital event occur in the physical system in order to drive some conclusions. Complex event processing is an event processing methods that gather data from different sources over a period of time to figure out events and patterns of much more complex cases. The purpose of the CEP is to track information and events to find possible treats and respond to these treats in real time. Identifying and analyzing certain pattern by CEP is important as it can prevent or limit the major failures before they happen. These patterns are based on historical information or, human experience that can lead to a failure. Usually CEP based monitoring system contains two main parts: 1) a real-time physical system model 2) a rule engine. A power system model should support the real-time updates to provide information regarding its status so that the monitoring rules applies for fast assessment.

Most of the focus on online monitoring has been kept on improving the subsystems of online analysis system and less on online analysis response speed issue, therefore in the following section the architecture of the online analysis system will be studied.

A.0.3. Architecture patterns

Software system architecture refers to the fundamental structure of the software system which converts software characteristics such as flexibility, scability, feasibility, reusability and security into a structured solution in a way to meet the technical and business expectatins [37].

A.Power Grid model
There are two types of power grid modeling: 1)node/breaker physical device model, The data regarding these models are stored in the in-memory database 2)bus/branch logical analysis model which are the input information to power system online analysis program. Both models have important role for the online analysis to illustrate the state of the system.
(remove this line just read it) The primary goal of the proposed new online architecture presented in this paper is to make the new bus/brancg logiical analysis model real-time or with responce in order of seconds.

B. In-memory Database (IMDB)
(which the node/breaker model type)

An in-memory database (IMDB) is a database management system relies on main memory (RAM) for computer data storage (wiki). IMDB is mainly used for the big data analytic applications where response time is critical.

c. In-memory Data Grid (IMDG)

IMDG is a data structure that completely relies on RAM distributed between different computer nodes. IMDGs are able to process big data and support hundreds of thousands in-memory data updates per second. They can accumulate and scale up in a way to support large quantities of data.

D. In-memory Computing (IMC)

In-memory data computing is when IMC permits for data storage in RAM along group of computer nodes. Each nodes stores a part of the overall data or in other words the data is partitioned. This allows for parallel distributed processing of data and achieve high efficiency. The following discuss about different IMC technology in power system analysis.

E. Pattern1: Distributed Active/Passive Data Storage

Figure A.2 shows the distributed active/passive data storage architecture. It consist of primary/active and secondary/passive in-memory database. These two in-memory databases are independent and the are connected with the same bus for data change. This pattern does not guaranty consistency of the data stored in these two databases and therefore this pattern is not suitable to store power grid online node/breaker physical device model data.

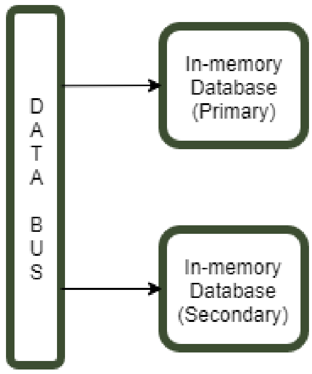

Figure A.2: Pattern1:distributed Active/Passive data storage [37]

F. Pattern2: Distributed Master/Slave Data storage

Figure A.3 shows the master/slave data storage architecture pattern. IMDG software feature is keeping the data synchronized between master/slave nodes. The automatic data change mechanism by IMDG is done through internal communication between master and slave modes and therefore it guaranties (eventual) consistency of the stored data. (maybe add eventual consistency)

G. Pattern 3: Relational Structure Based Data Processing

In this pattern the data storage system and the computation system are hosted on different computer nodes as shown in figure A.4. In this pattern, the data node and the computation node are located on different computer nodes. The measurements from power grid which are collected by the RTU is stored in an EMS in-memory relational database. Once the computation process begins the simulation program on the computation node receive the data from in-memory data base which is on the data node. This data has a relational data structure (so called OR mapping) and it works in such a way that it maps the data to an object relationship.

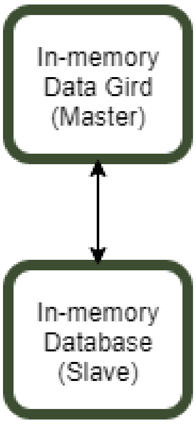

Figure A.3: Pattern2: Distributed Master/Slave Data Storage

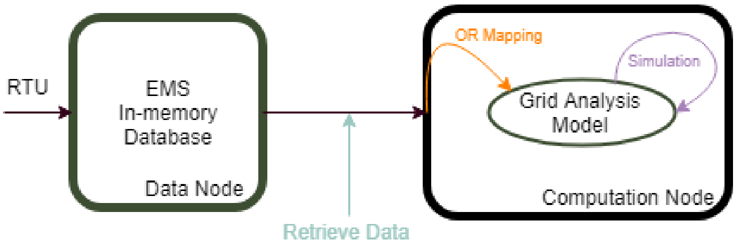

Figure A.4: Pattern3: Relational structure based data processing [37]

H. Pattern 4: Data Grid Based In-memory Computing

In this pattern, computer node contains both storage and computation systems. The information from the RTU is fed in to the grid analysis model in real-time. In this pattern, the information from the grid is not working with relational data structure as in previous case. Once the computation starts, simulation algorithm is applied to the to the grid model analysis via in-memory access. The structure of data grid based in-memory computing is shown in figure A.5.

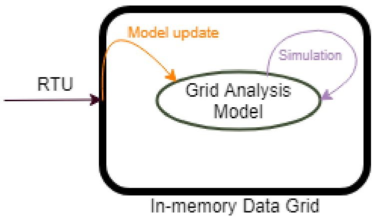

Figure A.5: Pattern 4: Data Grid Based In-memory Computing [37]

In the next section, we discuss about the data processing and computation performance related to the above mentioned patterns to differentiate the current online analysis architecture with the one in Digital Twin.

A.0.4. Current online analysis VS Digital Twin architecture

Current online analysis model is motsly based on distributed active/passive data storage andthe relational data structure patterns as shown in figure A.6. An in-memory database is located behind the SCADA and SE to support them. The measurement information from RTU is fed into a data bus. As it can be seen in figure A.6 the flow of data is in sequence starting from node/breaker physical device model towards the grid bus/branch logical analysis model.. The response speed in the current online analysis model is in the order of minutes. The grid node/breaker physical device model updates the grid analysis model periodically.

The new online architecture is introduced parallel with the current online analysis model in figure A.6. The new path added to the current model is based on distributed master/slave data storage pattern and IMDG based allows the in-memory computing pattern which enables the grid node/breaker physical device model and grid bus/branch logical analysis model to run in parallel. In this architecture, an event-driven real time data processing is used. Grid analysis model is updated in real time by SCADA in case of changes in the power grid behavior (even-driven mechanism). It is also periodically synchronized with the SE. The order of processing in the new architecture is in the order of seconds [37].

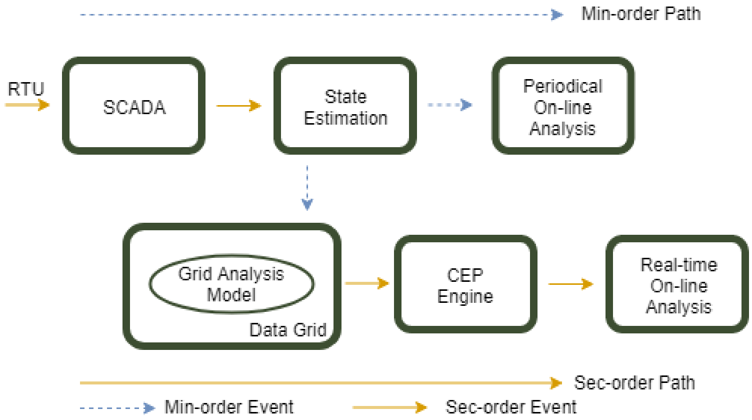

Figure A.6: New online analysis system architecture

B

Cable loading: Correction factors

$I_{nominal}$
The nominal current of single core XLPE cable depends on the earthing strategy, position configuration and cross bounding if used. The values for the factors in this appendix corresponds for the single-core XPLE cable.

Cross Section mm^2	Cross bounding or single earthing?	Positioning			
		Triangle		Flat	
		Al	Cu	Al	Cu
150	Yes	290	370	315	410
240	Yes	375	490	420	540
400	Yes	485	615	520	670
630	Yes	620	775	675	850
800	Yes	700	850	765	950
150	No	285	365	300	375
240	No	370	475	385	480
400	No	475	590	455	540
630	No	605	735	560	650
800	No	675	805	610	695

Table B.1: Nominal current of XLPE cables [36]

P (correction factor for parallel circuits and deviating thermal resistance)
The correction factor P consists of thermal background and it depends on:

- Number of parallel cables.
- Distance between the parallel cables
- Thermal resistance of the ground

Thermal resistance of the ground	Inter-space	Number of parallel cables operational								
		Single-core (triangle)						Single-core (flat)		
[Km/W]	[mm]	1	2	3	4	5	6	1	2	3
Peat:	-	0,81	-	-	-	-	-	0,81	-	-
	70	-	0,63	0,54	0,46	0,40	0,35	-	0,64	0,57
2,0	250	-	0,67	0,60	0,54	0,59	0,45	-	-	-
Other raw	-	1,00	-	-	-	-	-	1,0	-	-
materials:	70	-	0,78	0,68	0,59	0,52	0,47	-	0,80	0,71
0,75	250	-	0,84	0,74	0,67	0,62	0,58	-	-	-

Table B.2: Correction factors for parallel circuits and deviating thermal resistance [36]

T (correction factor for deviating ground temperature)
This factor is defined by the ground temperature and depends on depth and position of the cables. The ground temperatures and the corresponding correction factors are shown in table B.3.

Period of the year	Maximum ground temperature	Correction factor XLPE
dec, jan, feb, mrt,	10°C	1,07
jul, aug, sep	20°C	0,92

Table B.3: Correction factors for deviating ground temperature [36]

D (correction factor for changing load pattern)
The data of the nominal cable load given in the above tables are only valid if the cable is continuously loaded. In normal case the load is not continuous all the time and changes during the day. When the load changes during the day it is allowed to have higher load for a certain time only if the cable has enough time to cools down again.

Load Type	Number of parallel cables		
	1	2	≥3
Domestic	1,50	1,40	1,30
Industrial or mixed	1,45	1,30	1,25
Individual customer	1,10	1,10	1,10
Individual customer with DG	1,00	1,00	1,00

Table B.4: Correction factors for changing load pattern [36]

V (correction factor for unequal parallel cables)
For $I_{max\_equal\_loaded}$ the correction factor P is considered for equally loaded parallel lines. However, the lines might have unequal loads which causes one cable to reach its limit earlier than the other cables. In these cases the heat development of the cables is lower compare to when the cables reach their limits at the same time. The correction factor V is used to discount this temperature difference.

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