Hierarchical Distributed Control of Active Electric Power Distribution Grids

Nainar, Karthikeyan

Publication date:
2019

Document Version
Publisher's PDF, also known as Version of record

Citation for published version (APA):
Nainar, K. (2019). *Hierarchical Distributed Control of Active Electric Power Distribution Grids*.

HIERARCHICAL DISTRIBUTED CONTROL OF ACTIVE ELECTRIC POWER DISTRIBUTION GRIDS

BY
KARTHIKEYAN NAINAR

Publication based on dissertation, 2019

AALBORG UNIVERSITY
DENMARK

Hierarchical Distributed Control of Active Electric Power Distribution Grids

Ph.D. Dissertation

Karthikeyan Nainar

Publication based on dissertation

This publication is based on the dissertation

Abstract

In Denmark, the electric power system is undergoing a major change with the integration of renewable energy sources such as wind and solar to meet the target of 100% renewables based energy system. Due to electrification of the heating and transport sectors, heat pumps and electric vehicles will be present in huge numbers in future power distribution systems. The future distribution grid operation scenarios may include highly fluctuating wind and solar generation, simultaneous charging of huge number of electric vehicles and long duration operation of many heat pumps during periods of high heating requirements. In case of lack of coordination among the abovementioned distributed energy resources (DERs), network congestion may occur in the form of overloading of network assets and violations of limits of voltages and currents.

This thesis attempts to address the challenges of distribution system operator (DSOs) in the operation of future distribution grids such as network congestion and optimum utilization of flexibility from DERs. The problems due to high penetration of solar PV on a low-voltage distribution network operation are studied. This thesis explores solutions that consider DSOs interactions with expected future market mechanisms and improved coordination with the transmission system operator (TSO) for exchange of ancillary services. Influence of the network topology and variations in power generation from DGs on the network power losses are assessed. Impact of connection of DGs on the short circuit level and changes in fault current contribution are analyzed and their effects on the functioning of the protection system are studied.

In this thesis, a hierarchical distributed control framework is proposed for aggregated power control of medium and low-voltage distribution networks. The proposed hierarchical control consists of medium and low voltage aggregated controllers at top and middle levels respectively and controllers of DERs at the bottom level of the hierarchy. Day-ahead and intraday markets are interfaced with the proposed hierarchical control. Predictive control algo-

rithms in a centralized and distributed fashion are proposed for controlling low-voltage DERs. A novel linear power flow method is proposed which is shown to be more accurate in estimation of network voltages compared to the state of art. The proposed predictive control solves a constrained linear optimization problem that includes proposed linear model of the power network and linear state-space models of DERs.

For utilizing flexibility from DERs, various methods including volt/var control and demand response control are proposed in this thesis. These methods are used for applications such as autonomous voltage regulation, peak shaving, maximum accommodation of PV power, minimization of network power losses and network congestion management. A novel network reconfiguration scheme is proposed in this thesis that extends the linear programming developed for hierarchical control into a mixed-integer linear programming. A simple adaptive protection scheme is proposed to prevent protection blinding and false-tripping issues due to connection of DGs in a medium-voltage network. An improved interface among DSOs and the TSO is proposed which includes pre-qualification check by the DSO regarding utilization of DGs at distribution networks by the TSO for secondary frequency regulation.

Simulation studies are conducted using models of Cigre benchmark networks and modified versions of Danish distribution networks in DigSilent Power factory and Matlab/Simulink software to numerically validate the above-proposed methods. Simulation studies are done in a real-time digital simulator for analyzing the impact of connection of DG on a small-scale medium-voltage distribution network for various fault scenarios.

Resumé

I Danmark gennemgår det elektriske energisystem en større ændring med integrationen af vedvarende energikilder som vind og sol for at nå målet om et 100% vedvarende energisystem. På grund af elektrificering af varme- og transportsektorerne, vil varmepumper og elektriske køretøjer være til stede i stort antal i fremtidens elnet. De fremtidige scenarier for drift af distributionsnettet kan omfatte stærkt svingende vind og solproduktion samtidig med opladning af et stort antal elektriske køretøjer og langvarig drift af mange varmepumper i perioder med stort behov for opvarmning. I tilfælde af mangel på koordinering blandt de ovennævnte distribuerede energiressourcer (DER), kan elnettet bryde sammen pga. overbelastning af komponenterne i nettet eller via overskridelse af grænser for spændinger og strømme.

Denne afhandling forsøger at tackle udfordringerne hos distributions netselskaberne (DSO) i forhold til driften af det fremtidige distributionsnet, såsom nedbrud af elnettet, optimal udnyttelse af fleksibilitet fra DER, optimal netkonfiguration og adaptiv relæbeskyttelse. Problemer under driften af lavspændingsnettet på grund af høj anvendelse af solceller undersøges. Denne afhandling finder løsninger, der anvender DSO interaktion med forventede fremtidige markedsmekanismer og forbedret koordinering med de system ansvarlige (TSO) for udveksling af serviceydelser. Indflydelse af nettopologi og variationer i produktion fra DER i forhold til tab i nettet vurderes. Påvirkning ved tilslutning af DER på kortslutningsniveauet og fejlstrøm analyseres, og deres virkninger på beskyttelsessystemets funktion undersøges.

I denne afhandling opsættes et hierarkisk distribueret kontrolsystem til styring af den aggregerede effekt i mellem- og lavspændingsnet. Det foreslåede hierarkiske kontrolsystem består af aggregerede styringer for mellem- og lavspænding på henholdsvis øverste og mellemliggende niveau og styringer til DER på nederste niveau af hierarkiet. Spot- og balancemarked giver input til det foreslåede hierarkiske kontrolsystem. Centraliserede og distribuerede forudsigelsesalgoritmer er opsat til styring af lavspændings

DER. Der er opstillet en ny lineær metode til analyse af effektoverførslen, som viser sig at være mere nøjagtig ved estimering af netspændinger sammenlignet med den kendte teknik. Den foreslåede prædikative kontrol løser et afgrænset lineært optimeringsproblem, der inkluderer den foreslåede lineære model af elsystemet og lineære tilstandsmodeller af DER.

For at udnytte fleksibilitet fra DER foreslås forskellige metoder inklusive spænding/reaktiv effekt styring og belastningsstyring i denne afhandling. Disse metoder bruges til applikationer såsom autonom spændingsregulering, udglatning af spidslaster, maksimal tilslutning af solceller, minimering af nettab og modvirkning af netsammenbrud. En ny metode til netkonfiguration foreslås i denne afhandling, der udvider den lineære programmering, der er udviklet til det hierarkiske kontrolsystem, til en mixed-integer lineær programmering. En simpel adaptiv relæbeskyttelsesmetode foreslås for at forhindre at relæerne ikke kobler forkert, enten ved at de kobler hvor de ikke skal, eller ikke kobler når de skal, når der tilsluttes DER i mellemspændingsnettet. Der foreslås input til en forbedret grænseflade imellem DSO og TSO, som inkluderer prækvalifikationstjek fra DSO ved anvendelse af DER på distributionsnettet til sekundær frekvensregulering af TSO.

Simuleringer udføres ved hjælp af modeller som Cigre benchmark-nettet og modificerede versioner af danske distributionsnet i DigSilent Power Factory programmet og Matlab/Simulink-software til numerisk validering af de ovenfor foreslåede metoder. Simuleringer udføres endvidere i en realtids digital simulator til analyse af påvirkningen af tilslutning af DER på et lille mellemspændingsnet under forskellige fejlscenarier.

Acknowledgments

I am very thankful to ForskEL who provided financial support for this research project "Determination of Automation Demands for Improved Controllability and Observability in Distribution Networks (DECODE)".

I would like to express my gratitude and appreciation to my supervisors, Assoc. Prof. Jayakrishnan R. Pillai (main supervisor) and Prof. Birgitte Bak-Jensen (co-supervisor) for their valuable feedbacks, support and guidance throughout the PhD duration. *Tusind tak* to Birgitte for her critical feedback and suggestions for improvement of my work during project and group meetings. I also thank her for approving generous travel grants to attend international conferences, which enhanced my knowledge on the present power system research topics. I thank Jay for giving me freedom to explore different ideas, for his friendly advice and suggestions to plan and execute my PhD tasks. I also thank Jay for providing me the opportunity to co-supervise two Master theses with him.

I would like to thank Asst. Prof. John W. Simpson-Porco for accepting me as a visiting graduate student in his research group at the University of Waterloo, Canada. Many thanks to John for mentoring me on my research topics with great care. John provided me good insights on convex optimization and model predictive control. He was my greatest admiration and inspiration. I thank John very much for co-authoring a paper and his guidance for mathematical formulation of optimization problems.

I would also like to express my sincere thanks to my colleague Basanta Raj Pokhrel for all the collaborative work and our project partners Allan Jensen from Eniig A/S, Jacob Andreasen from Syd Energi A/S, Jacob Kledal from ABB A/S, Thomas Helth and Kenn H. B. Frederiksen from Kenergy A/S for their help with required data and discussions during the course of this work.

Above all, I would like to deeply thank my beloved wife Punitha, my lovely sons Ashwin and Kathirvel, my parents Nainar and Saratha Devi, my brother Vigneswaran and rest of my family members for their unconditional love, patience, understanding, and support throughout my PhD.

Contents

Thesis Details

Thesis Title:	Hierarchical Distributed Control of Active Electric Power Distribution Grids
Ph.D. Student:	Karthikeyan Nainar
Supervisors:	Assoc. Prof. Jayakrishnan R. Pillai, Aalborg University and Prof. Birgitte Bak-Jensen, Aalborg University

The main body of this thesis consists of the following papers.

[J1] **N. Karthikeyan**, J. R. Pillai, B. Bak-Jensen, and J. W. Simpson-Porco, "Predictive control of flexible resources for demand response in active distribution networks", *IEEE Transactions on Power Systems*, vol. 34, no. 4, pp. 2957-2969, 2019 . DOI: 10.1109/TPWRS.2019.2898425.

[J2] **N. Karthikeyan**, J. R. Pillai, B. Bak-Jensen, and J. W. Simpson-Porco, "Hierarchical distributed predictive control for demand response in active distribution networks", *IEEE Transactions on Power Systems* [To be submitted].

[C1] **N. Karthikeyan**, B. R. Pokhrel, J. R. Pillai, and B. Bak-Jensen, "Multi-level control framework for enhanced flexibility of active distribution network," *IEEE PES Innovative Smart Grid Technologies North America 2017*, Washington DC, USA, 2017. DOI: 10.1109/ISGT.2017.8085963.

[C2] **N. Karthikeyan**, B. R. Pokhrel, J. R. Pillai, and B. Bak-Jensen, "Coordinated voltage control of distributed PV inverters for voltage regulation in low-voltage distribution networks," *IEEE PES Innovative Smart Grid Technologies Europe 2017*, Turin, Italy, 2017. DOI: 10.1109/ISGTEurope.2017.8260279.

[C3] **N. Karthikeyan**, B. R. Pokhrel, J. R. Pillai, B. Bak-Jensen, and K. H. B. Frederiksen, "Demand response in low-voltage distribution networks with high PV penetration," *Universities Power Engineering Conf. 2017*, Crete, Greece, 2017. DOI: 10.1109/UPEC.2017.8232014.

[C4] **N. Karthikeyan**, B. R. Pokhrel, J. R. Pillai, and B. Bak-Jensen, "Utilization of battery storage for flexible power management in active distribution networks," *IEEE PES General Meeting, 2018*, Portland, OR, USA, 2018. DOI: 10.1109/PESGM.2018.8586215.

[C5] **N. Karthikeyan**, B. R. Pokhrel, J. R. Pillai, B. Bak-Jensen, A. Jensen, T. Helth, J. Andreasen, and K. H. B. Frederiksen, "Coordinated control with improved observability for network congestion management in medium-voltage distribution grid," *Cigre session 2018*, Paris, France, 2018.

[C6] **N. Karthikeyan**, B. R. Pokhrel, J. R. Pillai, B. Bak-Jensen, A. Jensen, T. Helth, J. Andreasen, and K. H. B. Frederiksen, "Advanced TSO-DSO interface for provision of ancillary services by DER in distribution networks," *Cigre symposium 2019*, Aalborg, Denmark, 2019.

This thesis has been submitted for assessment in partial fulfillment of the PhD degree. This thesis is based on the scientific papers listed above. Parts of the papers are used directly or indirectly in the extended summary of this thesis. As part of the assessment, co-author statements have been made available to the assessment committee and are also available at the Faculty. Paper [J2] is under preparation and due to this reason, its draft is not attached in Part II of this thesis. The basic concepts of Paper [J2] can be found in Section 2.6 of Chapter 2 wherein a generic distributed predictive control algorithm and its formulation for the control of DERs are provided, and in Section 3.1 of Chapter 3, where a small illustrative case study for distributed predictive control of BESS is provided.

In addition to the above main papers, the following co-authored publications have also been made during the PhD study period. The below papers are not part of this thesis.

[D1] B. R. Pokhrel, **N. Karthikeyan**, B. Bak-Jensen, J. R. Pillai, A. Jensen, T. Helth, J. Andreasen, and K. H. B. Frederiksen, "Improved TSO-DSO interoperability and their cooperation in smart grid," *Cigre symposium 2019*, Aalborg, Denmark, 2019.

[D2] B. R. Pokhrel, **N. Karthikeyan**, B. Bak-Jensen, and J. R. Pillai, "An intelligent approach to observability of distribution networks," *IEEE PES General Meeting, 2018*, Portland, OR, USA, 2018. DOI: 10.1109/PESGM.2018.8585752.

[D3] B. R. Pokhrel, **N. Karthikeyan**, B. Bak-Jensen, and J. R. Pillai, "Effect of smart meter measurements data on distribution state estimation", *19th*

IEEE International Conf. on Industrial Tech. 2018, Lyon, France, 2018. DOI: 10.1109/ICIT.2018.8352350.

[D4] B. R. Pokhrel, **N. Karthikeyan**, B. Bak-Jensen, and J. R. Pillai, "Intelligent architecture for enhanced observability for active distribution system", *IEEE PES Innovative Smart Grid Technologies Europe 2017*, Turin, Italy, 2017. DOI: 10.1109/ISGTEurope.2017.8260186.

[D5] B. R. Pokhrel, **N. Karthikeyan**, B. Bak-Jensen, and J. R. Pillai, "Loss optimization in distribution networks with distributed generation", *Universities Power Engineering Conf. 2017*, Crete, Greece, 2017. DOI: 10.1109/UPEC.2017.8232015.

[D6] B. R. Pokhrel, **N. Karthikeyan**, R. Sinha, B. Bak-Jensen, and J. R. Pillai, "Architecture of integrated energy systems," Book chapter on *Reliable and Sustainable Electric Power and Energy Systems Management.*, Springer [Under review].

Preface

This PhD dissertation is part of the *Determination of Automation Demands for Improved Controllability and Observability in Distribution Networks ("DE-CODE")* project. The DECODE project was supported by the PSO-ForskEL programme funded by the Danish TSO Energinet. The principal investigator was Prof. Birgitte Bak-Jensen from the Department of Energy Technology, Aalborg University. Other project partners, besides Aalborg University were Eniig A/S, Syd Energi A/S, ABB A/S and Kenergy A/S. The main objective of the DECODE project was to develop novel, reliable and cost-effective solutions to improve the observability, controllability, system protection and the interface among grid stakeholders of active distribution grids. The contents of this thesis are part of the work-packages 1, 2, 4, 5, 6 and 7. The work-package 2, regarding development of hierarchical control framework and the work-package 4, regarding development of adaptive protection and reconfiguration schemes, were executed by me and the tasks related all other work-packages were done by me along with my co-PhD student. During my PhD study abroad program, I stayed at the University of Waterloo, Canada for about four months. The work related to predictive algorithm for demand response of flexible resources at distribution networks was done under the supervision of Asst. Prof. John W. Simpson-Porco at the University of Waterloo. The data of Danish distribution grids used for numerical validation of the developed methods were provided by the Danish DSOs, Eniig A/S and Syd Energi A/S. An adaptive protection scheme developed in this project is tested, simulated and validated in DigSilent Power factory software and a real-time digital simulator.

Karthikeyan Nainar

Aalborg University, October 15, 2019

Part I

Summary

Chapter 1

Introduction

1.1 Background and Motivation

The Danish government has setup an ambition plan on February 2011 to cover all the energy needs of the country including electricity, heat, industry and transport through 100% renewable energy by 2050 to secure future energy supply and combat climate change [1]. Milestones planned for this energy policy are provided in Fig. 1.1. To meet this target, the Danish electric power system is undergoing a phenomenal change over the past few decades with the addition of renewable power technologies of distributed nature such as wind, solar, bio-gas and bio-mass based power generation [2]. Among these renewable power sources (RES), the wind power generation alone has met 43.4% of Denmark's annual electricity consumption in 2017 [3]. The RES are decentralized in nature and are mostly connected to medium-voltage (MV) and low-voltage (LV) distribution networks. Due to electrification of the heating and transport sectors, new types of active loads such as heat pumps and electric vehicles (EVs) with chargeable battery energy storage systems (BESS) are increasingly connected to LV networks. The current initiatives in Denmark that will enable to reach the goal of a fully RES based energy system can be found in [4].

In this thesis, the terms *network* and *grid* are used interchangeably to denote a system intended to dispatch electric power. Unless otherwise explicitly mentioned, the term grid or network represents an *electric power distribution system*. The term *distributed energy resource* (DER) is used to collectively represent small-scale renewable sources such as micro-CHP and roof-top solar with battery storage, and active loads such as electric vehicles (EVs) and heat

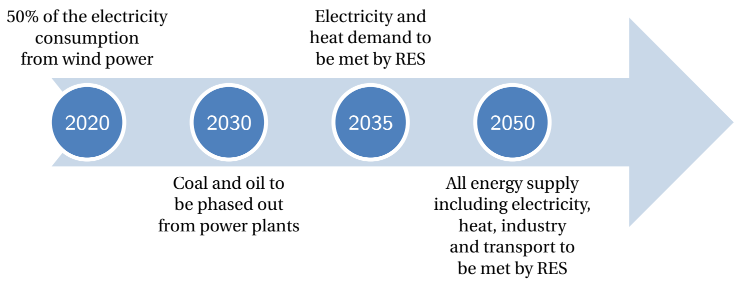


Fig. 1.1: Planned milestones of the Danish government's energy policy [1].

pumps (HP) which have the capability to offer flexibility to the electricity grid [5]. The term *distributed generation* (DG) is used to represent DERs such as wind and CHP plants that are connected to medium-voltage networks.

In order to utilize the flexibility from DERs for harnessing the time-varying power generation from RES especially wind power, the Danish ministry of climate, energy and building has proposed a strategy for smart energy system and smart electricity grid on February 2013 [6]. The main idea of the smart grid strategy described in [6] is to manage the flexible electrical loads for providing flexible power consumption through remotely read smart meters on hourly basis, variable electricity tariff, and wholesale and retail electricity markets. In this context, it is important to look at the present status and the future directions related to the operation of Danish distribution grids, which are described as follows.

1.1.1 Present Status of Distribution Grid Management

In this section, the present status of distribution grid management from the perspective of Denmark is provided.

Electricity Network of Denmark

The electricity network of Denmark consists of two asynchronously operated areas namely, Jutland-Funen (DK1), and Zealand and Bornholm (DK2), which are connected together, and to neighboring countries through long distance high-voltage ac or dc transmission lines. DK1 is the western part of Denmark connected synchronously to continental Europe, while DK2 is eastern part of Denmark connected with Nordic countries: Sweden, Norway and Finland [7]. The transmission system of both areas are operated by the Danish TSO Energinet. In DK1, Syd Energi A/S and Eniig A/S are the main DSOs operating the distribution systems from voltage levels 60 kV to 0.4 kV.

Syd Energi operates the distribution networks at southern part of Denmark and Eniig is responsible for central and north Jutland areas.

Monitoring and Control of Distribution Grids

At present, the DSOs of Denmark are not actively monitoring the LV and MV grids. Though the smart meters present at customer locations of LV networks are capable of measuring all the network variables, only energy consumption details are measured on hourly basis and are used for billing purpose only. At MV networks, measurements are available only at 60/15 kV or 60/10 kV substations. Few measurements available at critical MV nodes are used for analysis/diagnostics purposes and not for real-time control of the distribution network.

In addition, the DSOs have limited/no automation at distribution networks. Transformers at MV/LV substations do not have online tap changers and the taps are changed manually, while those at 60/10 kV or 60/20 KV substations are remote controlled. DERs at MV and LV networks are not utilized for flexibility by the DSOs though there may be a need in near future. The current regulations are preventing the DSOs to provide incentives to the customers for time shifting their loads, although some work is in progress to bring new market mechanisms for flexibility trading [8]. As of today, the flexibility from DERs are not used for addressing the operational challenges of the DSOs.

Due to presence of large amount of wind, solar and CHP plants, reverse power flows are experienced at distribution networks of DK1 managed by Syd Energi and Eniig. Reverse power flows may interfere with the protection system and lead to false tripping, if there are no preventive measures taken [9]. An excess reverse power flow may cause over-voltages at some nodes. As per the current regulations, PV inverters are required to disconnect from the grid, if the voltages at the nodes to which they are connected are more than a specified limit, to alleviate the overvoltage problem. Another aspect is the network reconfiguration, which is at present can be made only by manual intervention.

Interactions among the DSOs and the TSO

At present, the interactions among the DSOs and the TSO are limited. The TSO is solely responsible for balancing the power generation and demand at each time instant and the DSOs play no role. However, in future, the DSOs could potentially contribute to power balancing, in coordination with the TSO, by utilizing flexibility from millions of small-scale DERs in the distribution networks. The TSO is utilizing ancillary services for frequency regulation from large-scale DERs only at MV networks as of today, and DSOs can also be involved in this activity in future for better network asset utilization.

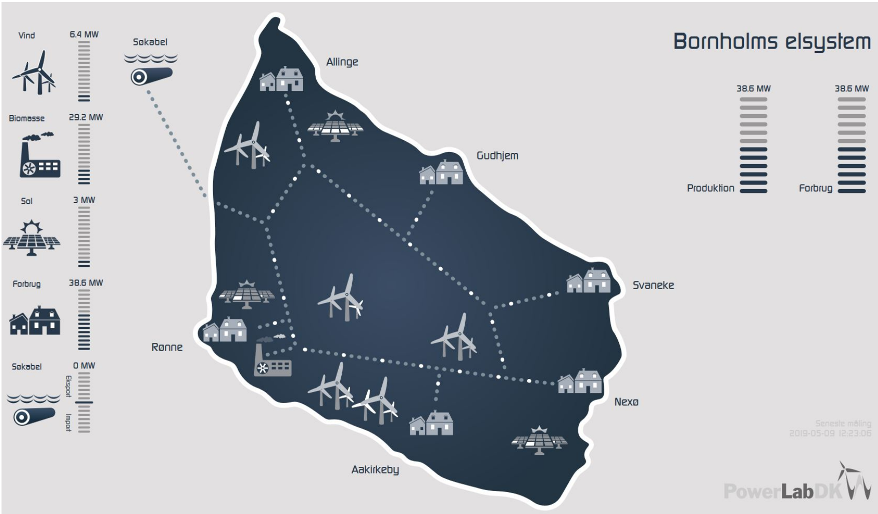


Fig. 1.2: Practical use of flexibility from EVs to balance power from wind generators in Bornholm [11]

A case study in Denmark to utilize flexibility

In Denmark, few large-scale experimental studies are being performed to demonstrate the smart grid concept of using flexibility for maximizing the renewable power absorption by the grid. Let us consider one such case study done on Bornholm island, Denmark and reported in [10] as follows. Bornholm is connected to Sweden by a sea-cable, which normally provides the balancing power to manage the fluctuating renewable power generation in the island. In case of failure of this connection, Bornholm power system has to be operated in islanded mode mostly with renewable energy sources. During such a cable disconnection due to maintenance work, EVs in Bornholm with smart charging capabilities were utilized as micro-power sources to balance the power generation from wind plants. A snapshot of power flows in Bornholm during islanded mode is shown in Fig. 1.2. Flexibility from EVs were used for primary frequency regulation while the biomass plants, whose startup time is about 15 min, provided secondary frequency regulation. This example shows the interests of the grid stakeholders in Denmark to utilize the flexibility from DERs for managing the grid with high penetration of renewable energy sources.

The future directions in management of active distribution grids are explained as follows.

1.1.2 Future Perspectives in Distribution Grid Management

In order to be prepared to operate a 100% RES based power system, from the perspective of the Danish grid operators (the TSO and the DSOs), the following aspects are to be considered [4].

- Upgrade of electricity grid infrastructure

  Due to increasing penetration of the RES, network congestion may occur, for example, during high wind and sunny periods. Overloading of transformers and under-voltages may occur if power intensive loads such as EVs are charged at large numbers in the same time period. The corresponding network may be reinforced with additional cabling and/or transformers. Upgrade of the network is generally very expensive which may be avoided or postponed by other means such as demand response control [12], volt/var control [13], network reconfiguration [14] and power curtailment of the RES [15]. However, such methods may require a two-way communication platform, local measurements, wide area monitoring system, remote-controlled switches/circuit breakers, on-load tap changers and an advanced distribution management systems (ADMS) [16].

- Supportive market mechanisms

  High penetration of RES brings new challenges in the electricity markets which are interlinked with the power system operation in a deregulated environment. In Denmark, the prevailing electricity market framework supports integration of high capacity RES whose owners can bid in the day-ahead market called Elspot, intraday market called Elbas, both managed by NordPool [17] and in the regulating power market operated by the TSO for ancillary services. The existing market structure described above is not compatible to activate flexibility from customers who owns DERs as the electricity price is fixed and there is no mechanism for them to sell their flexible power consumption. A new market may be introduced for trading of flexibility, which should be coordinated with the existing markets. The Danish energy association recommends three stages of development of such a market in which, stage 1 involves only bilateral contracts between the grid operators and the DER owners, stage 2 being a simple market place wherein, the grid operators and the DER owners can buy/sell their flexibility products and stage 3 involves definition of a formal market for establishment of uniform flexibility services [5].

- Synergies among multi-energy systems

  The concept of *smart energy system* not only include electricity networks, but also its integrated operation with other energy sectors such as heating, cooling, and transportation and energy storage systems. A smart energy system enables identification of synergies among the many energy systems to achieve an optimal solution for each individual energy sector and for the overall energy system [18]. The electricity network can be hugely benefited from a smart energy system to handle the variable power generation from RES by means of technologies such as power to gas (P2G), power to heat (P2H) and power to transport (P2T) [19]. The above-mentioned technologies can be employed to balance the electric power generation from RES and demand in the electricity grid utilizing the energy storage facilities and inherent flexibility in the operation of other energy sectors [20].

In line with Denmark's ambition for a smooth green energy transition with less investment in the electricity grid infrastructure, this thesis work proposes novel control strategies for achieving a *flexible* electricity distribution grid. The proposed strategies also addresses the challenges regarding collection and processing of data from DERs, expected future market mechanisms and integrated energy systems. It will be shown in the subsequent Sections and Chapter 3 that usage of the proposed control algorithms indeed avoid or postpone reinforcement of distribution grids. It will be also shown that the works reported in this thesis pave the way to reach the ultimate goal of achieving a smooth and cost-effective operation of the Danish power system with high amounts of RES.

Let us first consider a typical layout of the modern power system shown in Fig. 1.3. It consists of active power generators and loads at various voltage levels not only at transmission networks but also located at trans-regional, regional and local distribution networks. A research question that naturally arises here is how to manipulate these active resources at different voltage levels for optimal power flows in the distribution networks.

Let us look at the power generation and consumption details of Denmark collected from [21] on a typical winter week (Jan 14-18, 2019) shown in Fig. 1.4. As seen in Fig. 1.4, power generation from wind is high on some days to cover the entire power demand of Denmark causing negative spot prices. Due to strong interconnections with neighboring countries, Denmark is able to manage high penetration of RES by exporting/importing power. However, in future, power from RES including wind is required to be utilized for electrification of transport and heating systems at distribution levels. Utilization of fluctuating power from RES for a green transition will be a challenge for the DSOs.

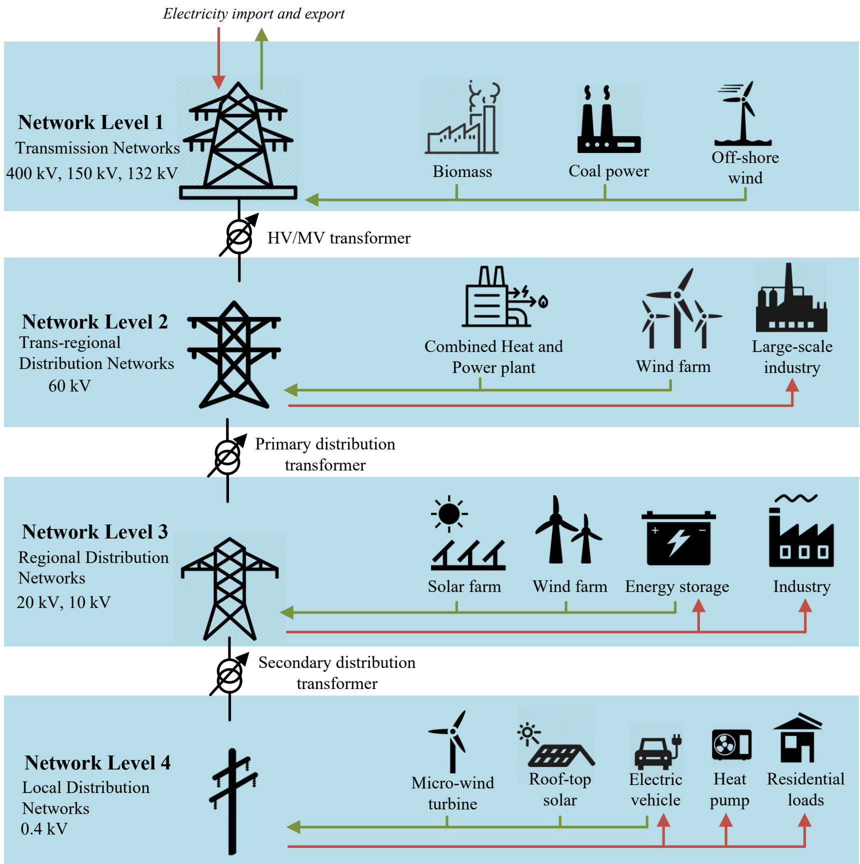


Fig. 1.3: Layout of modern power system with active elements across different voltage levels.

1.1.3 Motivations

Keeping in mind of the above described background, the main motivations of this thesis are

- To invent control technologies that can help the DSOs to maximize the utilization of power generated by RES for electrification of transport and heating systems.
- To achieve a coordination between the TSO and electricity markets for overall benefits as well as optimized operation of the power system.
- To maximize the grid assets utilization and prevention or delay of costly grid reinforcements.

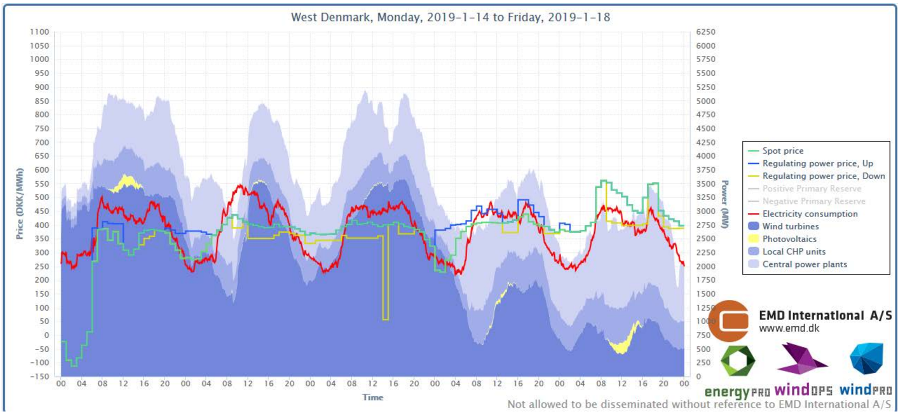


Fig. 1.4: Power generation and consumption profile in DK1 (West Denmark) [21].

This chapter is organized as follows. The main three operational challenges faced by the DSOs in an active distribution network management are explained in the next section. In Section 1.3, the state of the art of the distribution system control is presented followed by three hypotheses made in Section 1.4 to overcome the major challenges of the DSOs. Objectives of this thesis work are defined in Section 1.5 followed by assumptions and limitations in the next sections. This Chapter concludes with an overview of the contributions made in this thesis.

1.2 Challenges of the DSOs

In this section, the three major challenges in MV and LV networks with high amount of RES and active loads are explained. The key challenge is to utilize the flexibility from DERs as and when required by the grid operators with minimum automation and at less cost.

Challenge 1. *Grid Congestion Management*

Network congestion in the form of over-voltages at some nodes, over-currents in some branches and overloading of network assets such as transformers may occur due to the following.

- High penetration of DERs.
- Lack of proper coordination between the TSO and the DSOs while the TSO utilizes ancillary services from DERs at distribution networks.

The details of the above two reasons are presented as follows.

Network congestion due to high penetration of DERs

Renewable energy sources (RES) such as wind and solar produce electric power based on the weather conditions (wind speed and solar irradiation respectively). If the penetration of RES is high, network congestion in the form of over-voltages may occur during their peak power generation. There are certain class of loads such as heat pumps and electric vehicles whose power consumption is high at certain time period. For example, electric vehicles may be charged during evenings creating a peak demand. Due to increase in the penetration of the above-mentioned loads, the grid could experience congestion in the form of under-voltages at some nodes and over-currents at some branches. It is to be noted that the above-mentioned loads have flexibility in power consumption subjected to their availability and satisfactory quality of service to the owners.

Dansk Energi, which is an interest group for energy companies in Denmark, conducted a detailed survey about the impact of small-scale residential PV generation on the voltages of LV networks. Results of that survey reported in [22] show that feeders will experience over-voltages if PV capacity is more than 0.7 kW per user in all feeders. As there are plans to integrate more PVs in LV networks, it is important for the DSOs to ensure proper control measures to avoid voltage violations. At present, the PV inverters are instructed to cut-off from the grid if the measured voltage is above some threshold. Though this simple technique could avoid over-voltages, renewable power from PV is lost and it impedes the addition of more PVs in the same area.

At present, the DSOs have no monitoring devices at the LV networks and monitoring is done at few locations on the MV networks such as the primary distribution substation (60/20 kV and 60/10 kV) and few secondary distribution substations (20/0.4 kV and 10/0.4 kV). Hence the challenges are to monitor the network congestion as well as adopting proper control measures to mitigate them.

Network congestion due to lack of proper TSO-DSO interface

In Denmark, the TSO owns and operate the ancillary services market in which DERs (wind power plants) connected to distribution grids bid to provide primary and secondary frequency regulation services. Once the bids of DERs are approved by the TSO for providing ancillary services, it is the responsibility of the DERs to maintain the required capacity available to provide frequency up/down regulation at any time. The primary frequency regulation by DERs is automatic based on the measured frequency and is not discussed in this thesis. DERs provide secondary frequency regulation based on the active power setpoints dispatched by the TSO. The present TSO-DSO interface does not allow the DSOs to cross-check and take preventive actions if the response of DERs causes congestion in distribution networks. This is an important challenge too and it requires modification in the way the TSO and the DSOs interact today and introduction of mechanisms for the DSOs to be proactive.

Apart from preventing or relieving network congestion, a systematic way of managing power consumption is also required to accelerate RES penetration, which is addressed in the challenge below.

Challenge 2. *Optimized Operation of Distribution Grids*

The term *optimized operation* here means the ability of the distribution management system (DMS) to deliver power to the customers within the network operational constraints at minimum operating costs by controlling the power outputs of DERs located at various nodes.

The above statements should be understood in the context of an *optimal power flow problem* with the below formulation. An objective function can be formulated to minimize the costs incurred in network power losses, costs for buying flexible power consumption from DERs etc. The above objective function will be subjected to the operating constraints of the network which is modeled by steady-state power flow equations. In addition, the constraints of DERs will also be taken into account, which are represented by dynamic models including their state, input and output constraints. The challenge here is to solve such an optimal power flow (OPF) problem by an advanced distribution management system (ADMS) at every time-step for computing the power setpoints of the DERs that minimizes the total costs of network operation.

The prerequisite for optimized grid operation is to have required monitoring of the grids. The DSOs need to install remote terminal units (RTU) or phasor measurement units (PMU) [23] for monitoring of MV distribution grids. At LV grids, the DSOs can utilize the smart meter measurements obtained from customers' locations for monitoring and diagnostics. The challenge of ensuring good monitoring of the grids based on the critical measurements is not addressed in this thesis. It is assumed in this thesis that the network states (node voltage phasors), load and generation forecasting with reasonable accuracy are readily available for the control modules to manipulate the power outputs of the DERs.

As mentioned in Section 1.1, flexibility in power consumption will be the most important factor for active management of the future power system. The challenge here is to design a suitable control framework that can utilize the feedback of the network states and predicted information of the network power generation and load for issuing proper commands to the controllable resources.

However, the power demand from inflexible loads has to be met at each time instant and power from RES is uncertain based on weather conditions, the DSOs have the opportunity to control the power outputs of the DERs depending on the available flexibility.

Challenge 3. *Resilient Operation of Grids*

Due to dynamic nature of the DG and active loads, the DSOs face the challenge of making the grid *resilient*, by which it is meant that the DSOs can overcome the adverse effects of the power variations from active elements during the network operation.

Intermittent power generation from DG such as wind and solar may cause significant changes in network branch power flows. The total power losses of the network may increase if the network is operated with a fixed configuration. In such networks, automatic network reconfiguration is a valuable and cheap tool to minimize the network power losses [24]. Network reconfiguration can also be applied for other applications such as load balancing [14], network congestion management and improving the hosting capacity of the networks with high amount of RES [25]. Challenge of the DSOs is to study, analyze and adopt a suitable reconfiguration scheme, which will be cost-beneficial.

Connection of DG may change the fault current levels significantly in the distribution grids. If the protection settings of the relays are fixed, the relays may malfunction and cause security concerns [9]. Challenge of the DSOs, in this context, is to implement an adaptive protection scheme [26] by which a group of relay settings may be calculated offline for various expected fault conditions and DG power generation scenarios and the relevant settings can be communicated to the relays based on the present network conditions.

1.3 State of the Art

In this section, only the key articles available in the literature related to the above three challenges are explained. In Chapter 3, a comprehensive state of the art for each contribution of this thesis is provided.

A survey was conducted in [27] involving 36 distribution system operators (DSOs) across geographical regions of North and South America, and east and west Europe including Denmark. The results of the survey show that most of the MV and LV distribution grids are poorly observable and controllable, due to lack of monitoring and automation facilities. The above results are consistent with the practices of the DSOs in DK1. An overview of integration issues of RES in distribution networks is provided in [28]. In [29], a three-level hierarchical control is proposed for network congestion management in distribution networks by controlling the on-load tap changing transformer at HV/MV substation and the RES at the LV networks. However, to accommodate more renewable energy and more DERs without under/over-voltages and overloading of lines, it is important to utilize the flexibility in power consumption. Demand response control proposed in [30], utilizes only EVs for energy management. Short-term flexibility can be obtained from heat pumps as discussed in [31, 32]. BESS, which are installed for storing energy from PV systems, can be utilized for grid voltage support, peak shaving and energy management [33]. Congestion in distribution grids are preventable by day-ahead scheduling of the generators and the loads using the forecasts information [34]. During real-time operation, the grid congestion can be relieved by re-configuring the grid topology and by utilizing the flexibility in the power generation and active loads [25].

The DSOs can optimize the operation of distribution grids by using a predictive control algorithm [32], [35], [36], [37], [38] by utilizing DERs as control assets. A multi-objective optimization problem can be formulated and solved to meet the objectives of both the DSOs as well as the DER owners resulting in a cost-effective operation of the distribution grids [39], [40], [41].

A survey is reported in [42] about the coordination between the DSOs and the transmission system operators (TSOs) in many European countries including Denmark. It shows that the information exchange among the DSOs and the TSOs is not automated and based on the operational requirements. Guidelines for the operation of future active distribution networks with advanced TSO-DSO interactions are provided in [43], [42], [44]. Involvement of DSOs in the provision of ancillary services is emphasized in [45]. The roles of electricity markets for obtaining flexibility from RES are illustrated in [46]. The involvement of markets in demand response control by price signals instead of direct load control is explained in [47]. A real-time market architecture for activating flexibility in a time-frame of 5 minutes through electricity prices is developed in [48].

Adaptive protection schemes, which update the relay settings based on the operating conditions of a distribution network with DG, are proposed in [49], [26], [50], [51]. All these methods involve offline calculation of relay settings for various operating scenarios and the most relevant settings are communicated to the relays from the control center as and when required. Network reconfiguration based on a simple analytical approach is developed in [14]. Convex optimization based reconfiguration methods and their comparisons are done in [52].

As seen from the above discussions, the literature is vast in the area of control and optimization of distribution grids. The objective of this work is to develop a hierarchical distributed control framework that employs algorithms, which have less computational burden but at the same time cost-effective, minimum communication requirements, accurate and robust enough to provide feasible solutions even under uncertain operation of distribution grids.

1.4 Hypotheses

In this thesis, the following three hypothesis are formulated in such a way to address the above-mentioned three challenges of the DSOs.

Hypothesis 1. *A hierarchical control framework can enable the DSOs for active management of the distribution grids with reduced operating costs by optimal utilization of flexibility from the DERs.*

Hierarchical control structure is already being successfully used in the control of power transmission networks for many years. For example, the TSOs performs frequency regulation using three levels of hierarchy on a temporal basis namely primary, secondary and tertiary frequency regulations. Similar to that approach, in this work, a hierarchical control framework with three control levels is proposed for active distribution system management. In active distribution network management, a three-level hierarchical control, the top level being the aggregated MV network control on hourly basis, the middle level for aggregated LV network in a time frame of 10 min and the bottom level to address control of each flexible device in real-time can be envisioned to address most of the operational challenges. This hypothesis states that a hierarchical control framework can be formulated to enable the DSOs to address the three challenges mentioned in the previous sections.

Hypothesis 2. *By adapting the grid topology and the relay settings to the varying power generation from the DG, both the network power losses and the risk of maloperation of the protection system of a MV network can be minimized.*

This hypothesis states that by introducing new schemes such as network reconfiguration and adaptive protection, MV networks can be made resilient to varying power generation from DG such as wind and power. The total active power losses of a MV distribution grid depends on the impedance and power flows in its branches. Power generation from DG could cause large variations in branch power flows which in-turn may result in network congestion and/or increase in total active power losses. By rerouting the power flows, both of the above-mentioned problems can be addressed.

The presence of DG and its varying power generation may cause big changes in the fault current levels of the MV networks. In this case, a fixed protective relay settings may not work as intended for different scenarios such as connection/disconnection of DG and varying power generation. Hence, it is hypothesized that an adaptive protective scheme can fix this problem, wherein the relay settings are updated according to the operating conditions of the DG.

Hypothesis 3. *Improved interface of the DSOs with the TSO and the market players along with proper monitoring and control measures are required to foresee the grid congestion and alleviate them.*

In this hypothesis, the need and benefits of the interactions of the ADMS with its external partners such as the TSO and the electricity market are stated. The existing and the expected future market mechanisms can enable the DSOs to purchase flexibility at a competitive price. Advanced interface to the TSO with bidirectional communications and information exchange can benefit the DSOs to take preventive measures while ancillary services are provided to the TSO by the DERs at the distribution networks.

1.5 Objectives

From the state of the art, it is clear that from Denmark's perspective, the DSOs are required to improve the monitoring and control of the distribution grids during day-ahead planning and real-time operation. Following are the major objectives of this thesis

- To find control solutions that address the operational challenges of the DSOs in active distribution network management.
- To develop innovative methods for utilizing flexibility from DERs through demand response.
- To develop a novel grid control architecture for active interactions with the TSO and participation in the electricity markets for economic operation of the distribution grids.

The desired control functions to be developed to achieve the above objectives are listed in top-down fashion in Fig. 1.5. As seen in Fig. 1.5, hosting capacity improvement and reliable power delivery are the most important objectives to reach the overall objective of flexible power distribution. Demand side management, which includes BESS control and flexible load control, are the required control functions to be developed for active power

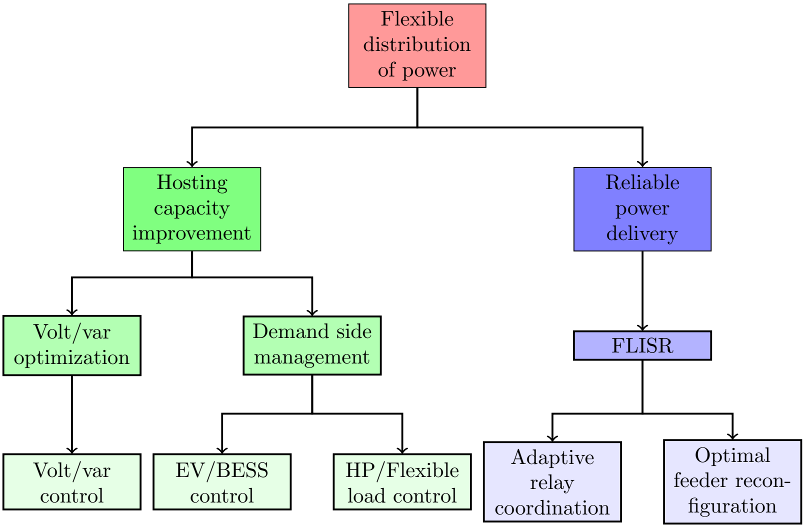


Fig. 1.5: Desired functions of an advanced distribution management system in an active distribution network [C1].

management. Volt/var control is to be developed for reactive power management. Both active and reactive power management are required for hosting capacity improvement. Adaptive protection functions and automatic network reconfiguration schemes are to be developed for fault location identification and system restoration (FLISR) which enables reliable power delivery to end customers.

1.6 Methodology

The following methodologies are applied to meet the above objectives in this thesis.

1. Predictive control algorithm for control of DERs that uses power generation and load forecasts and estimated states to compute the control inputs to the devices for the current time-step and for a future prediction horizon.

2. Alternating direction method of multipliers (ADMM) algorithm for solving a centralized convex optimization problem in a distributed manner.

3. Convex optimization algorithms such as linear programming, quadratic

programming, second-order cone programming and semidefinite programming for solving the optimal power flow problem.

4. Voltage sensitivity analysis to compute the droop settings of volt/var control of the PV inverters in a LV network.

5. A simple adaptive protection algorithm and its validation in a real-time digital simulator.

1.7 Assumptions

Following are the major technical assumptions in this work.

A1) Availability of distribution state-estimation and forecasting algorithms.

It is assumed that distribution state-estimation (DSE) and generation/load forecasting algorithms provide inputs (node voltage magnitudes and hourly forecasted values) with reasonable accuracy (less than 1% for DSE and 2% for forecasting algorithm) to the proposed hierarchical control algorithm.

A2) Availability of automation and communication infrastructure.

It is assumed that automation infrastructure such as remote controlled circuit breakers/switches, RTUs, SCADA, smart EV chargers, smart heat pump controllers etc., will be present in future distribution networks.

A3) Existence of electricity markets and possibility of having an interface with the TSO in future.

It is assumed that relevant market mechanisms, commercial aggregators etc., and implementing an advanced interface with the TSO will be a reality in future distribution networks.

1.8 Limitations

The overall limitations of the work reported in this thesis are provided below. Limitations which are specific to each contribution are described in the individual sections in Chapter 3.

- Impact of the communication delays and failures, cyber-attacks, malfunctioning of network controllers, erratic behavior of DER controllers etc., are not addressed.

- Only linear models of DERs and continuous range of power levels in their operation are considered.
- This thesis deals only with balanced three-phase ac distribution networks of radial topology.
- Power quality aspects of the distribution system operation such as voltage flicker, voltage dips, current harmonics etc., are not considered.
- Interactions of other energy systems such as gas and heating systems with the electricity network are not considered.
- Online tap changing function of distribution transformer is not considered in voltage regulation, though it may be easily modeled in the proposed optimization framework.

1.9 Overview of the Contributions

In the following, an overview of the main contributions of this thesis is provided. The contributions are divided into four main categories. The first category *Hierarchical control framework for ADMS* consists of three papers (Papers C1, J1 and J2) in relation to Hypothesis 1. The second category *Utilization of DERs for flexibility* consists of three papers (Papers C2, C3 and C4) that addresses Hypothesis 1 and Paper C5 that addresses Hypothesis 3. The third category *Grid reconfiguration and adaptive protection* attempts to prove Hypothesis 2. It is to be noted that there are no publications made for this contribution and the details of this contribution can be found in Section 3.3 of Chapter 3. Finally, the fourth category is *Advanced interface between the TSO and DSOs* consists of one paper (Paper C6) and validates Hypothesis 3.

Each paper is associated with a small introduction to give an overview of the contributions of this work. A much more detailed summary of the actual content of the contributions is presented in Chapter 3. Finally, the actual papers associated with the four categories are presented in full in the Part II of the thesis.

Paper C1

Title	:	Multi-level control framework for enhanced flexibility of active distribution network
Authors	:	N. Karthikeyan, B. R. Pokhrel, J. R. Pillai, and B. Bak-Jensen
Published in	:	Proceedings of the IEEE PES Innovative Smart Grid Technologies North America 2017, Washington DC, USA, 2017.

Paper C1 presents a three-level control framework for management of active distribution networks. The work reported in this paper is a precursor for development of a hierarchical control framework as per Hypothesis 1. This paper provides a state-of-the-art overview of control challenges of the DSOs and a hierarchical control framework to overcome those challenges.

Paper J1

Title	:	Predictive control of flexible resources for demand response in active distribution networks
Authors	:	N. Karthikeyan, J. R. Pillai, B. Bak-Jensen, and J. W. Simpson-Porco
Published in	:	IEEE Transactions on Power Systems, vol. 34, no. 4, pp. 2957-2969, 2019.

Paper J1 presents a centralized predictive control for aggregated LV network control which is part of a three-level hierarchical control framework mentioned in Hypothesis 1.

Paper J2

Title	:	Hierarchical predictive control for demand response of DERs in distribution grids
Authors	:	N. Karthikeyan, J. R. Pillai, B. Bak-Jensen, and J. W. Simpson-Porco
To be submitted to	:	IEEE Transactions on Power Systems.

Paper [J2] is under preparation and its draft is not attached in Part II of this thesis. The basic ideas and expected outcomes of Paper [J2] are provided in Section 2.6 of Chapter 2 wherein a generic distributed predictive control algorithm and its formulation for the control of DERs are provided, and in Section 3.1 of Chapter 3, where a case study regarding distributed predictive control of BESS is provided.

Paper C2

Title	:	Coordinated voltage control of distributed PV inverters for voltage regulation in low-voltage distribution networks
Authors	:	N. Karthikeyan, B. R. Pokhrel, J. R. Pillai, and B. Bak-Jensen
Published in	:	Proceedings of the IEEE PES Innovative Smart Grid Technologies Europe 2017, Turin, Italy, 2017.

Paper C2 presents a fully decentralized method for volt/var control by PV inverters at different nodes in a LV network. This paper addresses the Challenge 1 by an autonomous response from PV inverters for reactive power provision and active power curtailment based on the measured node voltages.

Paper C3

Title	:	Demand response in low-voltage distribution networks with high PV penetration
Authors	:	N. Karthikeyan, B. R. Pokhrel, J. R. Pillai, B. Bak-Jensen, and K. H. B. Frederiksen
Published in	:	Proceedings of the Universities Power Engineering Conf. 2017, Crete, Greece, 2017.

Paper C3 presents a method for planning the hourly flexibility required on the following day to prevent network congestion, specifically over-voltages in a LV network with high PV penetration. In this paper, the day-ahead market price signals of Nord Pool [17] are used as weighting factors for deciding the optimal demand response. This paper treats the effect of market price signals as per Hypothesis 3 on the utilization of flexibility.

Paper C4

Title	:	Utilization of battery storage for flexible power management in active distribution networks
Authors	:	N. Karthikeyan, B. R. Pokhrel, J. R. Pillai, and B. Bak-Jensen
Published in	:	Proceedings of the IEEE PES General Meeting, 2018, Portland, OR, USA, 2018.

Paper C4 presents a method based on model predictive control technique to utilize BESS for maximum self-absorption of the PV power addressing Hypothesis 1.

Paper C5

Title	:	Coordinated control with improved observability for network congestion management in medium-voltage distribution grid
Authors	:	N. Karthikeyan, B. R. Pokhrel, J. R. Pillai, B. Bak-Jensen, A. Jensen, T. Helth, J. Andreasen, and K. H. B. Frederiksen
Published in	:	Proceedings of the Cigre session 2018, Paris, France, 2018.

Paper C5 presents the idea of coordinated control aided by information from state estimation and forecasting algorithms and price signals from day-ahead and intraday markets as claimed by Hypothesis 1.

Paper C6

Title	:	Advanced TSO-DSO interface for provision of ancillary services by DER in distribution networks
Authors	:	N. Karthikeyan, B. R. Pokhrel, J. R. Pillai, B. Bak-Jensen, A. Jensen, T. Helth, J. Andreasen, and K. H. B. Frederiksen
Published in	:	Proceedings of the Cigre symposium 2019, Aalborg, Denmark, 2019.

Paper C6 presents the advancements to be made in the interface between the TSO and the DSOs to prevent network congestion which may arise due to ancillary services by DERs connected to distribution networks. The analysis and results reported this paper proves the Hypothesis 3.

In Chapter 2, a mathematical model of the grid, derivation of linear power flow equations, formulation of optimization problems for centralized predictive control, distributed predictive control and network reconfiguration are presented. Chapter 3 summarizes the four categories of contributions of this thesis.

Chapter 2

Mathematical Modeling

This chapter presents the details of mathematical modeling and optimization methods which are required for solving many of the challenges discussed in Chapter 1 and Chapter 3. Objectives of the mathematical modeling in the next section followed by derivation of linear power flow model and formulation of optimization algorithms in the subsequent sections.

2.1 Objectives of Mathematical Modeling

In the mathematical modeling, our main objective is to derive linear power flow equations for balanced three-phase ac distribution networks of radial topology. The linear power flow equations are used to calculate network voltage magnitudes and to estimate branch power losses and power flows from node active and reactive power injections. Aim is to derive a linear power flow method, whose co-efficient matrices can be updated at each time-step with the latest network voltage measurements/estimations. It is proposed to have the following characteristics in the linear power flow equations.

- Proposed method needs only measured/estimated voltage magnitudes and not the voltage phase-angles to update the coefficient matrices at each time-step. It is to be noted that, accurate estimation of node voltage magnitudes are relatively easy than estimating voltage phasors. By eliminating the need for estimating the voltage phase-angles, the accuracy of linear coefficient matrices could be improved and their values may hold good for an extended range of network operating point.

- Errors in branch active and reactive flows can be brought within a specified tolerance. This can be achieved by piece-wise linear approximation of quadratic branch power losses. By increasing the number of partitions involved in approximating branch power losses, more accuracy in the estimation of power flows can be achieved.

By formulating a linear power flow method with the above-desired characteristics, the following can be achieved. Proposed linear power flow equations can be used for many applications. In this thesis, it is utilized in three algorithms namely, centralized predictive control, distributed predictive control, and network reconfiguration. In all the three algorithms, the proposed linear power flow equations represents the model of distribution network in linear form. Both centralized and distributed predictive control of DERs solve a multi-period optimal power flow problem while the network reconfiguration algorithm solves an optimal power flow problem for just one time-step.

The objective is to formulate linear programming (LP) based optimization problems for centralized and distributed predictive control, and network reconfiguration algorithms because of the following merits.

- In general, LP has good algorithmic maturity and has less computational cost compared to other optimization techniques such as second-order cone programming (SOCP) and semidefinite programming (SDP) [53], [54].
- LP with integer variables called mixed-integer linear programming (MILP) is very much attractive for network reconfiguration problem. Though MILP is a NP-hard problem, it can be solved much effectively as of toady, compared to MISOCP and MISDP algorithms [52], [53].
- Decomposition of LP is possible with techniques such as alternating-direction method of multipliers (ADMM). The convergence of a distributed optimization problem based on ADMM can be improved by properly choosing the tuning parameter (ρ) [55], [56], [57]. This characteristic is very useful for distributed predictive control of DERs and is also an important reason to use LP in this thesis.

2.2 Notation

The following notations are used in the mathematical models developed in this thesis.

Matrices and vectors are represented using bold font; $(\cdot)^{\mathrm{T}}$ denotes matrix/vector transpose; $|\cdot|$ denotes the magnitude of a variable, or absolute value of each element of a vector; $(\bar{\cdot})$ denotes a complex phasor; $\mathrm{Re}(\cdot)$ and

$\mathrm{Im}(\cdot)$ denote the real and imaginary parts of a complex number respectively; $\mathbf{j} := \sqrt{-1}$ denotes the unit imaginary number; $(\cdot)^*$ denotes complex conjugate and $\arg(\cdot)$ denotes the phase of a complex number or the argument of a function. The vectors $\mathbf{1}$ and $\mathbf{0}$ denote a column vector of all ones and zeros respectively and their length is dependent on the context it is used.

2.3 Modeling of Distribution Network

The distribution network modeling presented here is based on [J1]. Only balanced three-phase networks of radial topology are considered in this thesis. Such a network can be represented as an oriented acyclic graph: $\mathcal{G} := (\mathcal{N}_0, \mathcal{L})$. The vertices of the tree, denoted by the set $\mathcal{N}_0 := \{0\} \cup \mathcal{N}$, represents $N+1$ network buses which consist of a set of N buses denoted as $\mathcal{N} := \{1, \ldots, N\}$ and the slack bus, which represents the secondary side of the LV distribution transformer, is denoted as 0. The edges of the tree represented by the set $\mathcal{L} \subset \mathcal{N}_0 \times \mathcal{N}_0$ denotes the network branches with arbitrary numbering and are oriented outwards from the slack bus [58].

It is to be noted that unlike transmission lines, the resistances in distribution networks are not negligible [59]. The impedance of each network branch $(i, j) \in \mathcal{L}$ is denoted as $z_{ij} = r_{ij} + \mathbf{j}x_{ij}$, where r_{ij} and x_{ij} are the branch resistance and reactance respectively in pu. The branch admittance is calculated from its reciprocal given by $y_{ij} = 1/z_{ij}$. The shunt admittances at each node are neglected. Let $\mathbf{R}_{db} = \mathrm{diag}(r_{ij})_{(i,j)\in\mathcal{L}}$ and $\mathbf{X}_{db} = \mathrm{diag}(x_{ij})_{(i,j)\in\mathcal{L}}$ be the diagonal matrices with branch resistance and reactance values respectively. Let us define the bus admittance matrix of the above network of size $\mathbb{C}^{(N+1)\times(N+1)}$ as

$$\mathbf{Y}_{ij} = \begin{cases} \sum_{k\in\mathcal{N}_0} y_{ik} & \forall i = j \\ -y_{ij} & \forall i \neq j \end{cases} \tag{2.1}$$

Let $\bar{v}_n, \bar{i}_n \in \mathbb{C}$ denote the phasors for the bus-to-ground voltage and current injected at each bus $n \in \mathcal{N}_0$ whose magnitudes $(|\bar{v}_n|, |\bar{i}_n|)$ are denoted as v_n and i_n respectively. The slack bus voltage is taken as reference, due to which, $\arg(\bar{v}_0) = 0$ and $\bar{v}_0 = v_0$. The complex bus-to-ground voltages and currents injected at the N non-slack buses are $\bar{\mathbf{v}} := [\bar{v}_1, \cdots, \bar{v}_N]^{\mathrm{T}} \in \mathbb{C}^N$ and $\bar{\mathbf{i}} := [\bar{i}_1, \cdots, \bar{i}_N]^{\mathrm{T}} \in \mathbb{C}^N$. Let the vectors $\mathbf{p} \in \mathbb{R}^N$ and $\mathbf{q} \in \mathbb{R}^N$ contain the values of net active power and reactive power demand (load minus generation) at each bus $n \in \mathcal{N}$. Let us define a vector $\mathbf{v}_s := [v_0, \cdots, v_0]^{\mathrm{T}} \in \mathbb{R}^N$ and a diagonal matrix $\bar{\mathbf{V}}_d = \mathrm{diag}(\bar{\mathbf{v}})$.

2.4 Modeling of Network Power Flows

The exact nonlinear ac power flow equations are presented first, followed by the derivation of a linear form of ac power flow equations.

AC Power Flow Equations [60]

Apparent power at node j is given by

$$\bar{s}_j = \bar{v}_j \bar{i}_j^* \tag{2.2}$$

The current at each node j according to Kirchoff's current law and using the definition of bus admittance matrix can be written as

$$\bar{i}_j = \sum_{k \in \mathcal{N}_0} \bar{v}_k \mathbf{Y}_{jk} \tag{2.3}$$

The ac power flow equations which represent nodal power injections can be written from (2.2) and (2.3) as [60]

$$p_j = \sum_{k \in \mathcal{N}_0} |\bar{v}_j||\bar{v}_k||\mathbf{Y}_{jk}| \cos\left(\delta_j - \delta_k - \theta_{jk}\right) \quad j \in \mathcal{N}_0 \tag{2.4a}$$

$$q_j = \sum_{k \in \mathcal{N}_0} |\bar{v}_j||\bar{v}_k||\mathbf{Y}_{jk}| \sin\left(\delta_j - \delta_k - \theta_{jk}\right) \quad j \in \mathcal{N}_0 \tag{2.4b}$$

where, $\theta_{jk} = \arg(\mathbf{Y}_{jk})$ and $\delta_j = \arg(\bar{v}_j)$. The above $2(N+1)$ ac power flow equations are nonlinear. If we assume the power injections at all nodes $n \in \mathcal{N}$ are known, and considering the transformer secondary side to be the slack bus ($\bar{v}_0 = 1\angle 0$), then the problem is to find the voltage phasors $\bar{\mathbf{v}}$ by taking partial derivatives and rearranging (2.4). Numerical methods such as Gauss-Seidel or Newton-Raphson method may be employed to solve the resulting nonlinear system of equations [60].

Linear Power Flow Equations

As the purpose of this thesis is to develop a predictive control algorithm based on linear programming, deriving a linear model of ac power flow equations is necessary.

In radial LV distribution networks, the R/X ratio is typically around 2.0 and the following assumptions may be valid [59].

A1) The angle of bus voltage phasors are negligible.

A2) The linear version of power flow equations holds good for each time-step.

Linear Approximation of Bus Voltages [J1]

The branch currents $\bar{\mathbf{i}}_b \in \mathbb{C}^{N\times 1}$ can be computed from the node currents $\bar{\mathbf{i}}$ (with the convention of negative current injection) as follows

$$\bar{\mathbf{i}}_b = \mathbf{M}_r \bar{\mathbf{i}} \tag{2.5}$$

where, $\mathbf{M}_r \in \mathbb{R}^{N\times N}$ is the bus injection to branch current matrix with binary values in which the column belongs to the slack bus current is removed [61]. The above matrix is the inverse of the reduced bus incidence matrix as the bus current injections are considered negative. The branch voltage drops can be computed using Ohm's law from the bus current injections as $\bar{\mathbf{v}}_b = (\mathbf{R}_{db} + \mathbf{j}\mathbf{X}_{db})\bar{\mathbf{i}}_b$. The bus voltage phasors $\bar{\mathbf{v}} = \mathbf{v}_s - \mathbf{M}_r^{\mathrm{T}}\bar{\mathbf{v}}_b$ can be expressed in terms of branch currents as

$$\mathbf{v}_s = \bar{\mathbf{v}} + \mathbf{M}_r^{\mathrm{T}}(\mathbf{R}_{db} + \mathbf{j}\mathbf{X}_{db})\bar{\mathbf{i}}_{\mathbf{b}} \tag{2.6}$$

From the branch currents and impedance, the complex power losses of the branches are

$$\bar{\mathbf{s}}_l = (\mathbf{R}_{db} + \mathbf{j}\mathbf{X}_{db})\left(\mathrm{diag}(\bar{\mathbf{i}}_b)\bar{\mathbf{i}}_b^*\right) \tag{2.7}$$

Let us assume that voltage magnitudes of the N buses are measured at each sample time, denoted as $\mathbf{v}_m = [v_{m1}, \cdots, v_{mN}]^{\mathrm{T}}$ and collected in the diagonal matrix $\mathbf{V}_{dm} = \mathrm{diag}(\mathbf{v}_m)$. Equation (2.5) can be expressed in terms of the bus active and reactive powers with the following approximation.

$$\bar{\mathbf{i}}_b \approx \mathbf{M}_r \mathbf{V}_{dm}^{-1}(\mathbf{p} + \mathbf{j}\mathbf{q})^* \tag{2.8}$$

where, the bus current injections are calculated as $\bar{\mathbf{i}} \approx \mathbf{V}_{dm}^{-1}(\mathbf{p} + \mathbf{j}\mathbf{q})^*$. The real part of the expression in (2.6) is

$$\mathrm{Re}(\Delta\bar{\mathbf{v}}) = \begin{bmatrix} -\mathbf{M}_r^{\mathrm{T}}\mathbf{R}_{db} & \mathbf{M}_r^{\mathrm{T}}\mathbf{X}_{db} \end{bmatrix} \begin{bmatrix} \mathrm{Re}(\bar{\mathbf{i}}_b) \\ \mathrm{Im}(\bar{\mathbf{i}}_b) \end{bmatrix} \tag{2.9}$$

where, $\Delta\bar{\mathbf{v}} = \bar{\mathbf{v}} - \bar{\mathbf{v}}_s$. Using (2.8), the above expression can be approximated in terms of bus active and reactive powers as below.

$$\mathrm{Re}(\Delta\bar{\mathbf{v}}) \approx -\mathbf{M}_r^{\mathrm{T}}\mathbf{R}_{db}\mathbf{M}_r\mathbf{V}_{dm}^{-1}\mathbf{p} - \mathbf{M}_r^{\mathrm{T}}\mathbf{X}_{db}\mathbf{M}_r\mathbf{V}_{dm}^{-1}\mathbf{q} \tag{2.10}$$

After applying the first approximation ($\mathrm{Re}\{\bar{\mathbf{v}}\} \approx \mathbf{v}$), (2.10) becomes

$$\mathbf{v} \approx -\mathbf{M}_r^{\mathrm{T}}\mathbf{R}_{db}\mathbf{M}_r\mathbf{V}_{dm}^{-1}\mathbf{p} - \mathbf{M}_r^{\mathrm{T}}\mathbf{X}_{db}\mathbf{M}_r\mathbf{V}_{dm}^{-1}\mathbf{q} + \mathbf{v}_s \tag{2.11}$$

The above expression for bus voltage magnitudes is linear (as the matrices $\mathbf{B}_{vp}$ and $\mathbf{B}_{vq}$ are constants at each sample time) with respect to the bus active and reactive powers.

Piece-wise Linear Approximation of Branch Power Losses [J1]

Substituting the approximated expression of branch currents (2.8) in that of branch power losses (2.7) and expanding the terms, we obtain

$$\mathbf{p}_l \approx \underbrace{\mathbf{R}_{db}\mathrm{diag}(\mathbf{M}_{rv}\mathbf{p})\mathbf{M}_{rv}\mathbf{p}}_{\mathbf{p}_{lp}} + \underbrace{\mathbf{R}_{db}\mathrm{diag}(\mathbf{M}_{rv}\mathbf{q})\mathbf{M}_{rv}\mathbf{q}}_{\mathbf{p}_{lq}} \tag{2.12}$$

$$\mathbf{q}_l \approx \underbrace{\mathbf{X}_{db}\mathrm{diag}(\mathbf{M}_{rv}\mathbf{p})\mathbf{M}_{rv}\mathbf{p}}_{\mathbf{q}_{lp}} + \underbrace{\mathbf{X}_{db}\mathrm{diag}(\mathbf{M}_{rv}\mathbf{q})\mathbf{M}_{rv}\mathbf{q}}_{\mathbf{q}_{lq}} \tag{2.13}$$

where, $\mathbf{M}_{rv} = \mathbf{M}_r\mathbf{V}_{dm}^{-1}$. In (2.12), the active power losses $\mathbf{p}_l \in \mathbb{R}_+^{N\times 1}$ are separated into two parts ($\mathbf{p}_{lp}$ and $\mathbf{p}_{lq}$) such that $\mathbf{p}_l = \mathbf{p}_{lp} + \mathbf{p}_{lq}$. Similarly, the branch reactive power losses are also expressed as $\mathbf{q}_l = \mathbf{q}_{lp} + \mathbf{q}_{lq}$.

It is to be noted that the individual branch power loss approximations in (2.12) and (2.13) are quadratic with respect to either $\mathbf{p}$ or $\mathbf{q}$. In order to linearize these expressions, piece-wise linear functions can be constructed for a short range of branch current magnitude i_b such that the approximated power losses bound the true losses from above by a small amount [62]. Let us consider the following approximation $\mathbf{p}_{lp1} \approx \mathbf{B}_{p1}\mathbf{p} + \mathbf{d}_{p1}$ for the range $i_b \in [0, I_{b1}]$ and $\mathbf{p}_{lp1} \approx -\mathbf{B}_{p1}\mathbf{p} + \mathbf{d}_{p1}$ for the range $i_b \in [-I_{b1}, 0]$ where, $\mathbf{B}_{p1} \in \mathbb{R}^{N\times N}$ and $\mathbf{d}_{p1} \in \mathbb{R}^N$ are constants at each sample time, such that $\mathbf{p}_{lp1} \in \mathbb{R}_+^{N\times 1}$ is linear with respect to $\mathbf{p}$. Similar terms can be derived for the whole range of i_b as follows. Let the set $\mathcal{K}_0 := \mathcal{K} \cup \{0\}$ where $\mathcal{K} := \{1, \cdots, K\}$ contains the K partitions of the branch current as $I_{\mathcal{K}_0} = \{I_{b0}, \cdots, I_{bK}\} \in \mathbb{R}_+$, which are calculated as follows

$$I_{bk} = \frac{k}{K} I_{b\,\max} \qquad k \in \mathcal{K}_0\,, \tag{2.14}$$

where, $I_{b\,\max}$ is the maximum branch current magnitude. Let us define the following K diagonal matrices with branch resistances ($\mathbf{B}_{pk,k\in\mathcal{K}}$) and reactances ($\mathbf{B}_{qk,k\in\mathcal{K}}$) as follows.

$$\mathbf{B}_{pk} = \left(I_{b(k-1)} + I_{bk}\right)\mathbf{R}_{db}\mathbf{M}_r\mathbf{V}_{dm}^{-1} \quad k \in \mathcal{K} \tag{2.15a}$$

$$\mathbf{B}_{qk} = \left(I_{b(k-1)} + I_{bk}\right)\mathbf{X}_{db}\mathbf{M}_r\mathbf{V}_{dm}^{-1} \quad k \in \mathcal{K} \tag{2.15b}$$

Let us also define the column vectors given below.

$$\mathbf{d}_{pk} = -\mathbf{R}_{db}\mathbf{1}I_{b(k-1)}I_{bk} \quad k \in \mathcal{K} \tag{2.16a}$$

$$\mathbf{d}_{qk} = -\mathbf{X}_{db}\mathbf{1}I_{b(k-1)}I_{bk} \quad k \in \mathcal{K} \tag{2.16b}$$

From the above diagonal matrices and column vectors, let us define a linear function $\mathbf{f}_{pk}(\mathbf{x}) = \mathbf{B}_{pk}\mathbf{x} + \mathbf{d}_{pk}$. Using the above function, the approximate branch active power losses due to bus active power ($\mathbf{p}_{lp}$) can be calculated from the below expression.

$$p_{lpi} \approx \max\big(\max_{k\in\mathcal{K}}(\mathbf{e}_i^{\mathrm{T}}\mathbf{f}_{pk}(-\mathbf{p})), \max_{k\in\mathcal{K}}(\mathbf{e}_i^{\mathrm{T}}\mathbf{f}_{pk}(\mathbf{p}))\big) \tag{2.17a}$$

where, $i \in \mathcal{N}$ and $\mathbf{e}_i$ denotes a unit vector in $\mathbb{R}^N$ whose i^{th} element is 1 and rest are 0. The approximate branch active power losses due to bus reactive powers ($\mathbf{p}_{lq}$) are given by

$$p_{lqi} \approx \max(\max_{k\in\mathcal{K}}(\mathbf{e}_i^{\mathrm{T}}\mathbf{f}_{pk}(-\mathbf{q})), \max_{k\in\mathcal{K}}(\mathbf{e}_i^{\mathrm{T}}\mathbf{f}_{pk}(\mathbf{q}))) \tag{2.17b}$$

Similar expressions can be written for the branch reactive power losses using the piece-wise linear function $\mathbf{f}_{qk}(\mathbf{x}) = \mathbf{B}_{qk}\mathbf{x} + \mathbf{d}_{qk}$ as given below.

$$q_{lpi} \approx \max(\max_{k\in\mathcal{K}}(\mathbf{e}_i^{\mathrm{T}}\mathbf{f}_{qk}(-\mathbf{p})), \max_{k\in\mathcal{K}}(\mathbf{e}_i^{\mathrm{T}}\mathbf{f}_{qk}(\mathbf{p}))) \tag{2.18a}$$

$$q_{lqi} \approx \max(\max_{k\in\mathcal{K}}(\mathbf{e}_i^{\mathrm{T}}\mathbf{f}_{qk}(-\mathbf{q})), \max_{k\in\mathcal{K}}(\mathbf{e}_i^{\mathrm{T}}\mathbf{f}_{qk}(\mathbf{q}))) \tag{2.18b}$$

The above piece-wise linear approximations of branch power losses can be expressed as inequalities in a linear programming problem and the expressions can be seen in equations from (2.19d) to (2.19g) in the next section.

2.5 Centralized Predictive Control of DERs

In this section, formulation of a linear centralized model predictive control method for LV DERs is presented. Detailed description can be found in [J1]. Let $\mathbf{C}_f \in \mathbb{R}^{N\times F}$ be a binary matrix which maps the DERs to the LV bus to which they are connected. Let us define a variable $\kappa = \{1, \cdots, N_p\}$ where, N_p is the prediction horizon. In this work, the control horizon (N_c) is considered to be equal to the prediction horizon, i.e., $N_c = N_p$. Assuming a 10 min time-step, and a prediction horizon of 4 hours, the value of $N_p = 24$. The power setpoints of the DERs are obtained by solving an optimization problem [J1] provided in (2.19). The objective function in (2.19a) consists of three parts namely, minimizing the costs of deviations of aggregated LV network power from its reference, minimizing the costs of active and reactive power losses and minimizing the cost of power consumption by DERs.

$$\begin{aligned}\min_{\mathbf{u}} J = \sum_{\kappa=1}^{N_c} c_{ps}^{\kappa}\left|p_{sref}^{\kappa} - p_s^{\kappa}\right| + c_{pl}^{\kappa}\mathbf{1}^{\mathsf{T}}(\mathbf{p}_{lp}^{\kappa} + \mathbf{p}_{lq}^{\kappa}) \\ + c_{ql}^{\kappa}\mathbf{1}^{\mathsf{T}}(\mathbf{q}_{lp}^{\kappa} + \mathbf{q}_{lq}^{\kappa}) + \mathbf{c}_{pf}^{\kappa\mathsf{T}}\left|\mathbf{p}_f^{\kappa}\right| + \mathbf{c}_{qf}^{\kappa\mathsf{T}}\left|\mathbf{q}_f^{\kappa}\right|\end{aligned} \tag{2.19a}$$

subject to
Power balance equation:

$$p_s^\kappa + \mathbf{1}^\mathsf{T}(\mathbf{C}_f \mathbf{p}_f^\kappa - \mathbf{p}_d^\kappa) - \mathbf{1}^\mathsf{T}(\mathbf{p}_{lp}^\kappa + \mathbf{p}_{lq}^\kappa) = 0 \tag{2.19b}$$

Linear expression for node voltages as functions of nodal power expressions from (2.11) is written as

$$\mathbf{v}^\kappa = \mathbf{v}_s^\kappa + \mathbf{B}_{vp}(\mathbf{C}_f \mathbf{p}_f^\kappa - \mathbf{p}_d^\kappa) + \mathbf{B}_{vq}(\mathbf{C}_f \mathbf{q}_f^\kappa - \mathbf{q}_d^\kappa) \tag{2.19c}$$

The relation between branch power losses and nodal power injections are expressed as inequalities based on (2.17) and (2.18) as follows.

$$\mathbf{B}_{pk}(\mathbf{C}_f \mathbf{p}_f^\kappa - \mathbf{p}_d^\kappa) - \mathbf{d}_{pk} \leq \mathbf{p}_{lp}^\kappa \quad k \in \mathcal{K} \tag{2.19d}$$

$$\mathbf{B}_{pk}(\mathbf{C}_f \mathbf{q}_f^\kappa - \mathbf{q}_d^\kappa) - \mathbf{d}_{pk} \leq \mathbf{p}_{lq}^\kappa \quad k \in \mathcal{K} \tag{2.19e}$$

$$\mathbf{B}_{qk}(\mathbf{C}_f \mathbf{p}_f - \mathbf{p}_d^\kappa) - \mathbf{d}_{qk} \leq \mathbf{q}_{lp}^\kappa \quad k \in \mathcal{K} \tag{2.19f}$$

$$\mathbf{B}_{qk}(\mathbf{C}_f \mathbf{q}_f^\kappa - \mathbf{q}_d^\kappa) - \mathbf{d}_{qk} \leq \mathbf{q}_{lq}^\kappa \quad k \in \mathcal{K} \tag{2.19g}$$

States of DERs:

$$\mathbf{x}_f^{\kappa+1} = \mathbf{\Phi}_f \mathbf{x}_f^\kappa + \mathbf{\Gamma}_f \mathbf{p}_f^\kappa \quad f \in \mathcal{F} \tag{2.19h}$$

Bounds of states of DERs:

$$\mathbf{x}_{f\,\min} \leq \mathbf{x}_f \leq \mathbf{x}_{f\,\max} \tag{2.19i}$$

Bounds of branch currents:

$$-\mathbf{i}_{b,\max} \leq \mathbf{B}_m \mathbf{p}^\kappa \leq \mathbf{i}_{b,\max} \tag{2.19j}$$

Bounds of node voltages:

$$\mathbf{v}_{\min} \leq \mathbf{v}^\kappa \leq \mathbf{v}_{\max} \tag{2.19k}$$

where, the decision variables are represented by the vector $\mathbf{u} = \begin{bmatrix}\mathbf{v} & p_s & \mathbf{p}_{lp} & \mathbf{p}_{lq} & \mathbf{q}_{lp} & \mathbf{q}_{lq} & \mathbf{p}_f & \mathbf{q}_f\end{bmatrix}^\mathsf{T}$. The states of DERs are bounded using the constraint (2.19i) to ensure the quality of service to the DER owners. The network voltage limits are specified in the constraint (2.19k) to ensure the voltage quality of supply. The branch current limits are specified by the box constraints in (2.19j) where, $\mathbf{B}_m = k_m \mathbf{M}_r \mathbf{V}_{dm}^{-1}$ and k_m is a scaling factor based on the static or dynamic ratings of the feeder.

The costs of each term in the objective function (2.19) may vary at each step-time depending on the market decisions. The variable c_{ps} is the penalty cost for deviating the aggregated power setpoint; c_{pl} and c_{ql} are the costs of active and reactive power losses of LV network; the vector $\mathbf{c}_{qf}$ contains the cost of reactive power provision from each DER. The cost c_{ps} is the price for regulating power imbalances [63], the cost c_{pl} is the hourly electricity price signals [64]. The cost, c_{qf} can be calculated from electricity price and power loss of the BESS [65].

2.6 Distributed Predictive Control of DERs

The centralized predictive control algorithm formulated in (2.19) has the following disadvantages.

- If the optimization algorithm (2.19) has to be applied for larger distribution systems with high number of DERs, the computational effort will be high, as the size of the optimization variables will be huge [41], [66].
- States of all DERs have to be communicated to the central predictive control which will increase the communication overhead. It may cause concerns regarding protecting the data privacy of the DER owners.

Distributed optimization techniques such as alternating-direction method of multipliers (ADMM) [67] can be used to decompose the above centralized optimization problem as follows. The approach to decompose the optimization algorithm (2.19) in this thesis is similar to the ones available in [68], [69] and [66]. The problem in (2.19) is proposed to be solved in a distributed manner by the network controllers (MVNC and LVNC) and the DER controllers and the role of a coordinator is done by the network controller. The next sections describe the proposed optimization problems to be solved by the above mentioned entities.

2.6.1 Optimization Problem of the Network Controllers

The changes that are made in the centralized optimization algorithm (2.19) are introducing auxiliary variables in the vectors ($\tilde{\mathbf{p}}_f$ and $\tilde{\mathbf{q}}_f$) of each size $\mathbb{R}^{F\times N_c}$ and removal of constraints related to states and outputs of DERs. The states of DERs are not known to network controllers in distributed predictive control and hence they are not enforced. The variables $\tilde{\mathbf{p}}_f$ and $\tilde{\mathbf{q}}_f$ are the expected power consumption calculated by the network controller from each DER on the present and future time-steps.

$$\begin{aligned}\min_{\tilde{\mathbf{p}}_f^\kappa,\tilde{\mathbf{q}}_f^\kappa} J_u = \sum_{\kappa\in\mathcal{N}_c} & c_{ps}^\kappa p_{se}^\kappa + c_{pl}^\kappa \mathbf{1}_N^\mathsf{T}(\mathbf{p}_{lp}^\kappa + \mathbf{p}_{lq}^\kappa) \\ & + c_{ql}^\kappa \mathbf{1}_N^\mathsf{T}(\mathbf{q}_{lp}^\kappa + \mathbf{q}_{lq}^\kappa)\end{aligned} \tag{2.20a}$$

subject to the following constraints in which $\kappa \in \mathcal{N}_c$.

$$\pm\, p_{se}^\kappa \leq p_{sref}^\kappa - p_s^\kappa \tag{2.20b}$$

$$p_s^\kappa + \mathbf{1}^\mathsf{T}(\mathbf{C}_f\tilde{\mathbf{p}}_f^\kappa - \mathbf{p}_d^\kappa) - \mathbf{1}^\mathsf{T}(\mathbf{p}_{lp}^\kappa + \mathbf{p}_{lq}^\kappa) = 0 \tag{2.20c}$$

$$\mathbf{v}^\kappa = \mathbf{v}_s^\kappa + \mathbf{B}_{vp}(\mathbf{C}_f\tilde{\mathbf{p}}_f^\kappa - \mathbf{p}_d^\kappa) + \mathbf{B}_{vq}(\mathbf{C}_f\mathbf{q}_f^\kappa - \mathbf{q}_d^\kappa) \tag{2.20d}$$

$$\mathbf{B}_{pk}(\mathbf{C}_f\tilde{\mathbf{p}}_f^\kappa - \mathbf{p}_d^\kappa) - \mathbf{d}_{pk} \leq \mathbf{p}_{lp}^\kappa \quad k \in \mathcal{K} \tag{2.20e}$$

$$\mathbf{B}_{pk}(\mathbf{C}_f\tilde{\mathbf{q}}_f^\kappa - \mathbf{q}_d^\kappa) - \mathbf{d}_{pk} \leq \mathbf{p}_{lq}^\kappa \quad k \in \mathcal{K} \tag{2.20f}$$

$$\mathbf{B}_{qk}(\mathbf{C}_f\tilde{\mathbf{p}}_f - \mathbf{p}_d^\kappa) - \mathbf{d}_{qk} \leq \mathbf{q}_{lp}^\kappa \quad k \in \mathcal{K} \tag{2.20g}$$

$$\mathbf{B}_{qk}(\mathbf{C}_f\tilde{\mathbf{q}}_f^\kappa - \mathbf{q}_d^\kappa) - \mathbf{d}_{qk} \leq \mathbf{q}_{lq}^\kappa \quad k \in \mathcal{K} \tag{2.20h}$$

$$-\mathbf{i}_{b,\max} \leq \mathbf{B}_m\mathbf{p}^\kappa \leq \mathbf{i}_{b,\max} \tag{2.20i}$$

$$\mathbf{v}_{\min} \leq \mathbf{v}^\kappa \leq \mathbf{v}_{\max} \tag{2.20j}$$

$$\tilde{\mathbf{p}}_{f\,\min} \leq \tilde{\mathbf{p}}_f^\kappa \leq \tilde{\mathbf{p}}_{f\,\max} \tag{2.20k}$$

$$-\tilde{\mathbf{q}}_{f,\max} \leq \tilde{\mathbf{q}}_f^\kappa \leq \tilde{\mathbf{q}}_{f,\max} \tag{2.20l}$$

2.6.2 Optimization Problem of DERs

The models of DERs such as BESS and heat pumps can be found in [J1] and they are not presented in this thesis. It is proposed that the DERs solve the below optimization problem to find their individual power consumption at the present and future time instants, i.e., over the prediction horizon N_p (Note: $N_p = N_c$ in this formulation).

Each DER $k \in \mathcal{F}$ solves the below optimization problem to compute $\mathbf{p}_{fk}$ and $\mathbf{q}_{fk}$ of each size N_c.

$$\min_{\mathbf{p}_{fk},\mathbf{q}_{fk}} J_f = \sum_{\kappa\in\mathcal{N}_c} c_{pfk}^\kappa p_{fk}^\kappa + c_{qfk}^\kappa q_{fka}^\kappa \tag{2.21a}$$

subject to the following constraints

$$\mathbf{x}_{fk}^{\kappa+1} = \mathbf{\Phi}_{fk}\mathbf{x}_{fk}^\kappa + \mathbf{\Gamma}_f p_{fk}^\kappa \quad \kappa \in \mathcal{N}_c \tag{2.21b}$$

$$y_{fk}^\kappa = \mathbf{C}_{fk}\mathbf{x}_{fk}^\kappa \quad \kappa \in \mathcal{N}_c \tag{2.21c}$$

$$\mathbf{x}_{fk\,\min} \leq \mathbf{x}_{fk}^\kappa \leq \mathbf{x}_{fk\,\max} \quad \kappa \in \mathcal{N}_c \tag{2.21d}$$

$$p_{fk\,\min} \leq p_{fk}^\kappa \leq p_{fk\,\max} \quad \kappa \in \mathcal{N}_c \tag{2.21e}$$

$$-q_{fk,\max} \leq q_{fk}^\kappa \leq q_{fk,\max} \quad \kappa \in \mathcal{N}_c \tag{2.21f}$$

$$\pm q_{fk}^\kappa \leq q_{fka}^\kappa \quad \kappa \in \mathcal{N}_c \tag{2.21g}$$

The network controller receives $\mathbf{p}_{fk}$ and $\mathbf{q}_{fk}$ from all DERs ($k \in \mathcal{F}$), and it can be stacked into vectors $\mathbf{p}_f$ and $\mathbf{q}_f$ of each size $F \times N_c$.

In the next subsection, the procedure for solving the optimization problem in a distributed manner is explained.

2.6.3 ADMM based Decomposition

Let $\mathbf{x} = \begin{bmatrix}\tilde{\mathbf{p}}_f & \tilde{\mathbf{q}}_f\end{bmatrix}^\mathsf{T}$ from the results of network controller's optimization problem and $\mathbf{z} = \begin{bmatrix}\mathbf{p}_f & \mathbf{q}_f\end{bmatrix}^\mathsf{T}$ from the results of DER controller's optimization problem and they are of size $2F \times N_c$.
The distributed optimization problem is written as [67]

$$\min_{\mathbf{x}\in\mathcal{X},\mathbf{z}\in\mathcal{Z}} J_u(\mathbf{x}) + J_f(\mathbf{z}) \tag{2.22a}$$

subject to

$$\mathbf{x} - \mathbf{z} = \mathbf{0} \tag{2.22b}$$

where, $\mathcal{X}$ and $\mathcal{Z}$ are the feasible sets for the vectors $\mathbf{x}$ and $\mathbf{z}$ respectively. The augmented Lagrangian for the above optimization problem can be written as

$$L_\rho := J_u(\mathbf{x}) + J_f(\mathbf{z}) + \mathbf{y}^\mathrm{T}(\mathbf{x}-\mathbf{z}) + \frac{\rho}{2}\left\|\mathbf{x}-\mathbf{z}\right\|_2^2 \tag{2.23}$$

where, the vector $\mathbf{y}$ contains the Lagrange multipliers and the variable ρ is the tuning parameter of ADMM. The tuning parameter (ρ) has a big impact on the convergence rate of the ADMM algorithm and the procedure for choosing it can be found in the references given in [55]. The ADMM algorithm iteratively minimizes L_ρ as follows

$$\mathbf{x}^{k+1} := \underset{\mathbf{x}}{\operatorname{argmin}}\, L_\rho(\mathbf{x}, \mathbf{z}^k, \mathbf{y}^k) \tag{2.24a}$$

$$\mathbf{z}^{k+1} := \underset{\mathbf{z}}{\operatorname{argmin}}\, L_\rho(\mathbf{x}^{k+1}, \mathbf{z}, \mathbf{y}^k) \tag{2.24b}$$

$$\mathbf{y}^{k+1} := \mathbf{y}^k + \rho(\mathbf{x}^{k+1} - \mathbf{z}^{k+1}) \tag{2.24c}$$

It is to be noted that the function L_ρ is decomposable because the variables $\mathbf{x}$ and $\mathbf{z}$ are independent. The variables $\mathbf{x}^{k+1}$ and $\mathbf{z}^{k+1}$ can be independently computed by the network controllers and DERs. The previous iteration values of $\mathbf{z}$ and $\mathbf{y}$ are used by the network controllers to compute $\mathbf{x}^{k+1}$. The latest value of $\mathbf{x}^k$ i.e., $\mathbf{x}^{k+1}$ and the old value of $\mathbf{y}$ i.e., $\mathbf{y}^k$ are used by the DERs to compute $\mathbf{z}^{k+1}$. It is to be noted that each DER f solves its own optimization independently of other DERs using the corresponding values ($\tilde{p}_f^{k+1}$ and $\tilde{q}_f^{k+1}$) from the vector $\mathbf{x}^{k+1}$ and the corresponding Lagrange multipliers from $\mathbf{y}^k$ and it computes and sends its optimal values (p_f^{k+1} and q_f^{k+1}) to the network controller. As network controller acts as the coordinator, it receives $\mathbf{x}^{k+1}$ and $\mathbf{z}^{k+1}$, computes $\mathbf{y}^{k+1}$ and communicates it to all DERs so that those values can be used in the next iteration. The iterations mentioned in (2.24) are continued until the results converge within a specified tolerance.

2.7 MILP based Network Reconfiguration

The proposed network reconfiguration scheme is based on an extended version of linear optimization method described in Section 2.5 and [70]. Here, the status of switches are represented as binary variables resulting in a mixed-integer linear program (MILP). The proposed MILP optimization problem solves the network reconfiguration problem based on the inputs from state-estimation block (node voltage magnitudes, node active and reactive powers) to determine the status of switches that will result in minimum power loss without any network congestion.

Compared to the linear predictive control algorithm formulated in (2.19), the MILP is solved to find the status of switches for the next time-step only ($N_p = 1$). Unlike in (2.19), the matrix M_r is not a constant binary matrix but it is composed of binary variables to represent switch status. Let us consider M number of additional branches in the network that have switches to enable alternate network configurations. Then the size of $\mathbf{M}_r$ will be $(N+M) \times N$. Let the diagonal matrices $\mathbf{R}_{dbs}$ and $\mathbf{X}_{dbs}$ of size $(N+M) \times (N+M)$ contain the resistance and reactance of all the branches of the network (including the ones which are in open position). A binary matrix $\mathbf{M}_{r0}$ of size $(N+M) \times N$ is defined to find the voltage drops in the normal as well as the additional branches that are in open position due to their switch status in off condition. By modifying (2.10), we can calculate $\Delta\mathbf{v}$ as follows.

$$\Delta\mathbf{v} = \begin{bmatrix}\mathbf{R}_{dbs}\mathbf{M}_{r0}\mathbf{V}_{dm}^{-1} & \mathbf{X}_{dbs}\mathbf{M}_{r0}\mathbf{V}_{dm}^{-1}\end{bmatrix}\begin{bmatrix}\mathbf{p}\\ \mathbf{q}\end{bmatrix} \tag{2.25}$$

Explanation about defining the above matrices are provided in the simple 5 bus MV network example below.

The objective of the proposed MILP is to minimize the active power losses of the network as provided below. The inputs (known values) to this optimization problem are the estimated voltages ($\mathbf{v}_m$) and node active and reactive powers (vectors $\mathbf{p}$ and $\mathbf{q}$) from state-estimation algorithm.

$$\min_{\mathbf{s}} J = \sum(\mathbf{1}^\mathsf{T}\mathbf{p}_{lp} + \mathbf{1}^\mathsf{T}\mathbf{p}_{lq}) \tag{2.26a}$$

where, the decision variable $\mathbf{s}$ is a binary vector containing the status of all switches. The constraints of the above optimization problem are provided below.
The power balance equations in the MV network, which states that summation of all power generation and loads equals the summation of all power losses in the network are written as follows.

$$\mathbf{1}^\mathsf{T}\mathbf{p}_l = p_s - \mathbf{1}^\mathsf{T}\mathbf{p} \tag{2.26b}$$

$$\mathbf{1}^{\mathsf{T}}\mathbf{q}_l = q_s - \mathbf{1}^{\mathsf{T}}\mathbf{q} \tag{2.26c}$$

The expression for voltage approximation which is linear with respect to nodal power injections is provided below.

$$\mathbf{v} = \mathbf{v}_s - \mathbf{M}_r^{\mathsf{T}}\Delta\mathbf{v} \tag{2.26d}$$

In the above equation, the unknown variables are $\mathbf{v}$ and the binary variables in $\mathbf{M}_r$. The active and reactive power losses in the lines are calculated from the nodal power injections as shown below.

$$\mathbf{p}_{lp} \geq \mathbf{B}_{pk}\mathbf{p} - \mathbf{d}_{pk} \tag{2.26e}$$

$$\mathbf{p}_{lq} \geq \mathbf{B}_{pk}\mathbf{q} - \mathbf{d}_{pk} \tag{2.26f}$$

$$\mathbf{q}_{lp} \geq \mathbf{B}_{qk}\mathbf{p} - \mathbf{d}_{qk} \tag{2.26g}$$

$$\mathbf{q}_{lq} \geq \mathbf{B}_{qk}\mathbf{q} - \mathbf{d}_{qk} \tag{2.26h}$$

where, $\mathbf{B}_{pk}$, $\mathbf{B}_{qk}$ are calculated using the matrix $\mathbf{M}_r$ and the values of $\mathbf{v}_m$ and $\mathbf{d}_{pk}$, $\mathbf{d}_{qk}$ are constant vectors. The limits of the branch currents are specified in the below box constraints.

$$-\mathbf{i}_{b,\max} \leq \mathbf{B}_m\mathbf{p} \leq \mathbf{i}_{b,\max} \tag{2.26i}$$

The limits of the voltages are specified by the following box constraints.

$$\mathbf{v}_{\min} \leq \mathbf{v} \leq \mathbf{v}_{\max} \tag{2.26j}$$

The next section shows a small example to illustrate the formulation of the matrices $\mathbf{M}_r$ and $\mathbf{M}_{r0}$ in the proposed MILP.

An Example of MILP Formulation

Let us consider a 5-bus MV network shown in Fig. 2.1. There are two switches in the branches M_{12} and M_{34} which are normally closed and two switches in the branches M_{02} and M_{04} which are normally open. The reconfiguration problem is to find status of all the four switches such that the total branch active power losses are minimized and the branch voltages and currents are within limits.

Let us first write the relationship between branch currents and node currents (currents leaving the node are positive) for all the branches as follows.

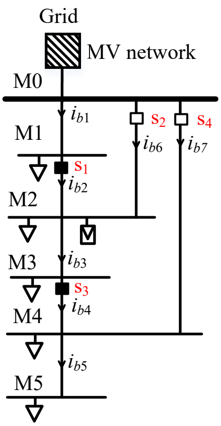


Fig. 2.1: A small MV network to illustrate formulation of MILP based reconfiguration.

$$\begin{bmatrix} i_{b1} \\ i_{b2} \\ i_{b3} \\ i_{b4} \\ i_{b5} \\ i_{b6} \\ i_{b7} \end{bmatrix} = \begin{bmatrix} 1 & s_1 & s_1 & s_1s_3 & s_1s_3 \\ 0 & s_1 & s_1 & s_1s_3 & s_1s_3 \\ 0 & 0 & 1 & s_3 & s_3 \\ 0 & 0 & 0 & s_3 & s_3 \\ 0 & 0 & 0 & 0 & 1 \\ 0 & s_2 & s_2 & s_2s_3 & s_2s_3 \\ 0 & 0 & 0 & s_4 & s_4 \end{bmatrix} \begin{bmatrix} i_1 \\ i_2 \\ i_3 \\ i_4 \\ i_5 \end{bmatrix} \tag{2.27}$$

As the above relationship between the branch current vector $\mathbf{i}_b$ and the node current vector $\mathbf{i}$ (with the convention of negative current injection) is nonlinear, it is represented in linear relationship by introducing new variables as follows.

$$\mathbf{M}_r = \begin{bmatrix} 1 & s_1 & s_1 & s_{13} & s_{13} \\ 0 & s_1 & s_1 & s_{13} & s_{13} \\ 0 & 0 & 1 & s_3 & s_3 \\ 0 & 0 & 0 & s_3 & s_3 \\ 0 & 0 & 0 & 0 & 1 \\ 0 & s_2 & s_2 & s_{23} & s_{23} \\ 0 & 0 & 0 & s_4 & s_4 \end{bmatrix} \tag{2.28}$$

The auxiliary variables (s_{13} and s_{23}) in $\mathbf{M}_r$ which represent the multiplication of two binary variables (say, s_i and s_j) can be written by imposing the below inequalities.

$$s_{ij} \leq s_i \tag{2.29a}$$

$$s_{ij} \leq s_j \tag{2.29b}$$

$$s_{ij} \geq s_i + s_j - 1 \tag{2.29c}$$

It is to be noted from the above expressions that $s_{ij} = 1$ if and only if $s_i = 1$ and $s_j = 1$, and it is 0 otherwise. In the above example, the decision variables are $\mathbf{s} = \begin{bmatrix} s_1 & s_2 & s_3 & s_4 \end{bmatrix}^\mathsf{T}$, value of $M = 2$ and size of $\mathbf{M}_r$ is 7×5. The matrix $\mathbf{M}_{r0}$ is obtained from $\mathbf{M}_r$ and setting the relevant switches to be 1, so that this matrix can be used to calculate the expected currents in all the $(N + M)$ branches and the corresponding expected voltage drops using (2.25).

$$\mathbf{M}_{r0} = \begin{bmatrix} 1 & 1 & 1 & 1 & 1 \\ 0 & 1 & 1 & 1 & 1 \\ 0 & 0 & 1 & 1 & 1 \\ 0 & 0 & 0 & 1 & 1 \\ 0 & 0 & 0 & 0 & 1 \\ 0 & 1 & 1 & 1 & 1 \\ 0 & 0 & 0 & 1 & 1 \end{bmatrix} \tag{2.30}$$

Remark 2.7.1:
The expression for $\mathbf{M}_{r0}$ is found easily and it correctly expresses the expected branch currents in all branches for this small network, but for large networks with many switches in series/parallel combinations, finding the matrix $\mathbf{M}_{r0}$ will not be straightforward. However, large networks with complex connection of switches are not considered in this work and it is part of our future work.

2.8 Conclusion

In this chapter, mathematical modeling of radial distribution networks and their power flow equations are derived both in exact form and its linear version. The linear power flow equations hold good for small changes in the network power flows and their coefficient matrices have to be updated at each time-step based on the new operating point of the network. A centralized predictive control method using linear programming that uses the linear power equations and linear models of DERs is formulated. The same formulation is also used for distributed predicted control method and its modified version with binary variables for switches are used for network reconfiguration problem.

Chapter 3

Summary of Contributions

In this chapter, a summary of the contributions of this thesis in four different categories are provided. Category 1 regarding hierarchical control framework for active distribution management system (ADMS) is provided in Section 3.1, category 2 about utilization of DERs for flexibility is provided in Section 3.2, category 3 which explains about grid reconfiguration and adaptive protection is given in Section 3.3 and finally the fourth category concerning advanced interface between the TSO and the DSOs is provided in Section 3.4.

3.1 Hierarchical Control Framework for ADMS

A power distribution typically consists of hundreds of nodes with thousands of flexible, inflexible loads, and renewable energy sources such as solar, wind and CHP plants. The primary objective of a DSO with respect to distribution grid control is to ensure supply voltages within an allowable range in all the nodes. Secondary objectives may include minimization of feeder power losses and maximum utilization of network assets including transformers with on-load tap changers (OLTC). Automated solutions are preferable to manage the grid for fast and reliable control. Three types of control architecture namely central, distributed and decentralized control are applicable for controlling the grid. Comparison of these three types are provided below.

- Centralized control is complex and cannot effectively handle a complex and ever expanding system with many DERs and an advanced interface to the TSO. Dispersed location of DERs across the distribution grids at different voltage levels (medium and low-voltage networks) makes it difficult for the DSOs to implement a centralized control solution.

The required communication protocols, speed and accuracy may not be affordable by the DSO. The supporting automation infrastructure required are high and needs huge investment in the infrastructure [71], [72].

- Decentralized control may not provide an overall optimum solution. The cross couplings and interactions among the isolated control loops may be difficult to avoid and pose a threat to the stable operation of the grid [73], [74].
- Distributed control of an active distribution system can make the coordination easier and reliable. The requirements to the automation and communication systems can be minimized and the existing infrastructure can be used for efficient operation of the grid [29], [75], [76], [77].

Application of a hierarchical control concept to power distribution systems is addressed in the literature see e.g., [29], [75], [76] and [69]. As discussed in [75], a hierarchical control structure will enable the DSOs to pursue multiple objectives in the grid management by utilizing the network assets effectively. In [29], a hierarchical control method with three control levels is proposed to manage the network congestion caused by high amount of renewables. However in [29], the main objective is only the network congestion management and other control objectives are not addressed. In [76], three levels of control based on multi-agent technique is proposed for small-scale power networks with DERs working as grid connected microgrids. But the market mechanisms to purchase flexibility services and involvement of other actors in network operation are not considered in [76].

The electricity grid is rapidly changing with new types of active loads and more renewables (solar PV and wind power). To cope with the changing generation and consumption patterns, the DSO has to face unprecedented challenges such as over-voltages, increase in peak load due to power-intensive, and short-duration loads such as EVs etc.

Flexibility services are required by the DSOs in future to manage the network from controllable (dispatchable) generation, adjustable power consumption and reactive power provision [29], [78], [79]. The flexible resources that can provide the above mentioned flexibility are small-scale industrial/commercial customers and residential customers with DERs [78], [80], [81].

Proposed Hierarchical Control of Active Distribution Network

In this thesis, a three-level hierarchical control framework is proposed to address the challenges of active network management described in Chapter 1. In the proposed multi-level control framework, the DSO plays the role of a central authority as well as a coordinator/aggregator of DERs at MV and LV networks and activates their flexibility for optimizing the network operation. The proposed control framework can be integrated to existing electricity markets including day-ahead and intraday markets. Functioning of the proposed multi-level control depends on the information from state-estimation and forecasting algorithms.

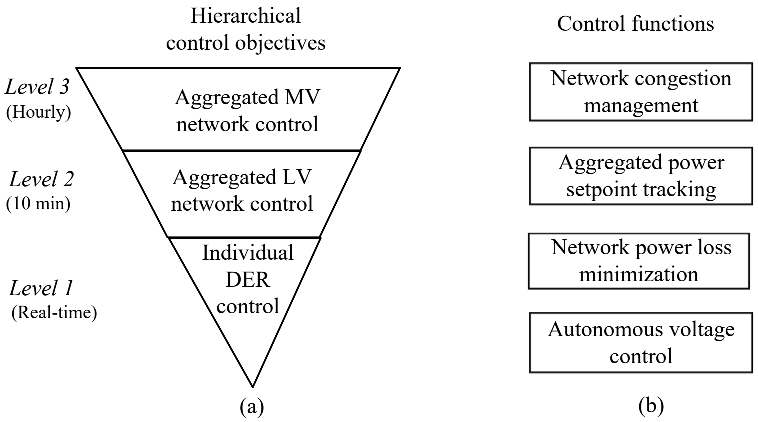


Fig. 3.1: Proposed hierarchical control (a) objectives and (b) control functions.

While defining the objectives of the proposed control, the interests of Danish DSOs and their relevant practices are taken into account by considering study scenarios related to Denmark, and using Danish power distribution systems for simulation studies. Objectives of employing hierarchical control to active distribution system management include the following.

- Minimization of the costs of automation and communication infrastructure by novel control methods and effective utilization of existing network assets.
- Improved control of the LV and MV distribution networks by integrating advanced monitoring techniques such as dynamic state estimation and generation and load forecasting algorithms.

The hierarchical control objectives and the available control functions to the DSOs are shown in Fig. 3.1.

The functions of each control level are provided in Table 3.1.

Table 3.1: Control levels and their functions

Control level	Controller	Functions
Level 3 control	MVNC	Day-ahead scheduling of flexible consumption and communication of the same to MV DERs and LVNCs based on day-ahead market. Activation of additional flexibility on the operational day on hourly basis through intraday market, if required.
Level 2 control	LVNC	For demand response control of LV DERs either by a centralized or a distributed predictive control method.
Level 1 control	LV DERs	Receive setpoints from level 2 control every 10 min for control of each DER. If under/overvoltages are experienced during operation, the setpoints from level 2 control are disregarded and the power consumption of DERs are modified autonomously to bring the voltages within limits.
	MV DERs	Receive hourly power consumption schedule from MVNC and operate each MV DER to follow the power schedule.

The schematic diagram of the proposed hierarchical control is shown in Fig. 3.2. In order to have a coherent control mechanism, the controls at the different levels should work in coordination [75]. The level 1 control is the fastest and can react to local network voltage violations in a fraction of a second. The level 2 control works for aggregated control of LV networks on 10 min basis. The level 3 control is involved in the aggregated control of MV networks and works on hourly basis. The algorithms of day-ahead planning, aggregated MV network control (level 3 control) and aggregated LV network control (level 2 control) are provided below.

3.1.1 Level 3 Control

The below algorithm is executed at 12:00 of every day for day-ahead scheduling of flexibility. The term *flex-offer* [82] is the flexibility offer submitted by LV and MV DERs and LVNCs (aggregated flex-offers from individual flex-offers of LV DERs) which contain information about their nominal hourly power consumption p_f and the range $[p_{f\,\mathrm{min}}\ \ p_{f\,\mathrm{max}}]$ at which it can be manipulated. A simple example would be an EV with a charging plan (using a 10 kW three-phase charger) at 6 pm of a day may provide its flex-offer as 10 kWh

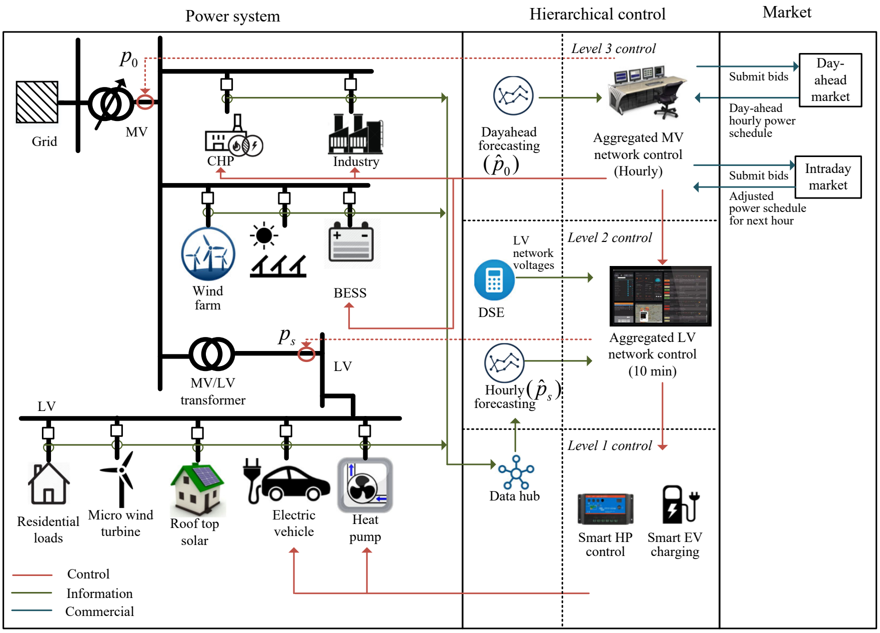


Fig. 3.2: Schematic diagram of proposed hierarchical control of an active distribution network [C1] (The dotted red lines show the aggregated powers (p_s and p_0) being managed by level 2 and 3 controllers respectively).

and its flexibility range as 0 to 10 kWh, if it wishes to fully charge and is also willing to partially charge or completely avoid charging in that hour based on LVNC's request.

Remark 3.1.1:
The distributed optimization algorithm formulated in (2.20) is used by both level 3 and level 2 controllers. In level 2 control, optimization problem of LV DERs includes their dynamic state-space equations. However, in level 3 control, the distributed optimization problem of MV DERs and LVNCs does not include the equations (2.21b) and (2.21c). Thus, the iterations done to find flexibility by level 3 control is more straightforward than level 2 control. Hence, in this thesis, the simulation results for distributed optimization are provided only for level 2 control. Simulation of the all three levels of control together for a typical day operation of distribution network is left as a future activity.

Algorithm 1 Day-ahead Scheduling of Flexibility

1: LV DERs submit flex offers for the next day to respective LVNCs. LVNCs aggregate the flex offers from LV DERs.
2: MV DERs prepare their flex offers for the next day.
3: MV DERs and LVNCs submit their flex offers to MVNC.
4: MVNC aggregates flex offers from MV DERs and LVNCs.
5: MVNC estimates aggregated MV load profile for the next day.
6: MVNC bids in the day-ahead market with hourly consumption profile for the next day.
7: In the day-ahead market, the bids are approved.
8: MVNC gets the values of aggregated power (p^s_{0ref}) for each hour to be tracked on the next day.

The below algorithm is executed by MVNC every hour during operation.

Algorithm 2 Aggregated MV Network Control (Level 3 Control)

1: MVNC receives the updated power schedule for the next hour from intraday market ($p_{0ref} = p^s_{0ref} + p^a_{0ref}$). If there is no adjustment in the scheduled power i.e., $p^a_{0ref} = 0$, then the aggregated power reference planned during day-ahead scheduling is tracked.
2: MVNC solves a distributed optimization problem formulated in (2.20) with MV DERs and LVNCs to find the power consumption of each MV DER and LVNC such that its total operating cost in (2.20a) is minimized.
3: Each MV DER controller receives hourly power setpoint to follow and it should provide the requested flexibility.
4: Each LVNC should manage its own LV DERs to track the received power setpoints .

The proposed objectives of level 3 and level 2 control are minimization of costs of the errors in tracking the aggregated power reference, and minimization of the costs of branch active and reactive power losses.

3.1.2 Level 2 Control

The below algorithm is executed by LVNC every 10 min during operation.

The logic behind having a smaller time-step (10 min) for LVNC is as follows. Unlike a medium-voltage network, the power variations in a low-voltage network may be higher due to high concentration of flexible resources, inflexible loads and residential solar PV. The forecasts of LV aggregated power (p_s) may

Algorithm 3 Aggregated LV Network Control (Level 2 Control)

1: Each LVNC tries to provide the hourly flexibility committed to MVNC by activating flexibility from LV DERs in a time frame of 10 min.
2: Each LVNC solves either a centralized optimization problem formulated in (2.19) or a distributed optimization problem formulated in (2.20) to find how much flexibility is required from each LV DER every 10 min so that its operating costs in (2.20a) are minimized.
3: Each LV DER is operated by its own controller and it should provide the requested flexibility.

not be as accurate as the MV aggregated power (p_0). It may be difficult to avoid network congestion (for example under/over voltages) in a LV network if the flexibility of LV DERs is scheduled and activated for 1 hour instead of a shorter time frame.

There is lot of uncertainty in the LV network operation as seen in the above statements, hence it is proposed to operate the LVNC once in 10 min, so that feedback about the network is obtained at each time step from state-estimation algorithm (states of DERs are also obtained in case of centralized predictive control) to find new power setpoints for the LV DERs.

3.1.3 Level 1 Control

In this thesis, the level 1 controllers, which are the individual controllers of MV and LV DERs including CHP plants, EVs, heat pumps and BESS, are assumed to be smart, capable of communicating with level 2 control (LVNC), and are able to operate the respective equipment in an ideal manner.

In a centralized predictive control setup, level 1 controllers receive power setpoints from LVNC every 10 min interval and operate the device to follow those power setpoints as well as ensuring the quality of service and device operational constraints. In a distributed predictive control setup, each level 1 controller solve the optimization problem in (2.21).

Level 1 control can work autonomously to alleviate network congestion such as under and over voltages which may occur due to unexpected power variations within the 10 min time frame of LVNC [30]. In such conditions, power setpoints communicated from the LVNC will be neglected and the level 1 control directly controls the active and reactive power consumption from the respective DER to help remove the congestion.

The next section discusses the centralized predictive control of LV DERs by LVNC followed by its distributed version.

3.1.4 Centralized Predictive Control of LV DERs

In this section, a multi-objective predictive control method is discussed for utilizing the aggregated flexibility from DERs at LV distribution networks. The motivation for employing a predictive control method is to make use of network states provided by state estimation and predictions of the future network power flows provided by forecasting algorithm and perform direct control of LV DERs at every time-step.

The schematic diagram of the proposed predictive control of LV DERs is shown in Fig. 3.3. It consists of four layers and their detailed description can be found in [J1]. As seen in Fig. 3.3, the proposed centralized predictive control needs the states of LV DERs and network voltage magnitudes to compute the power setpoints for each LV DER. It requires lot of communication overhead to communicate states of all DERs to a centralized controller. It also involves privacy issues of the DER owners. A distributed predictive control is an alternative control method, which does not need states of LV DERs to control them.

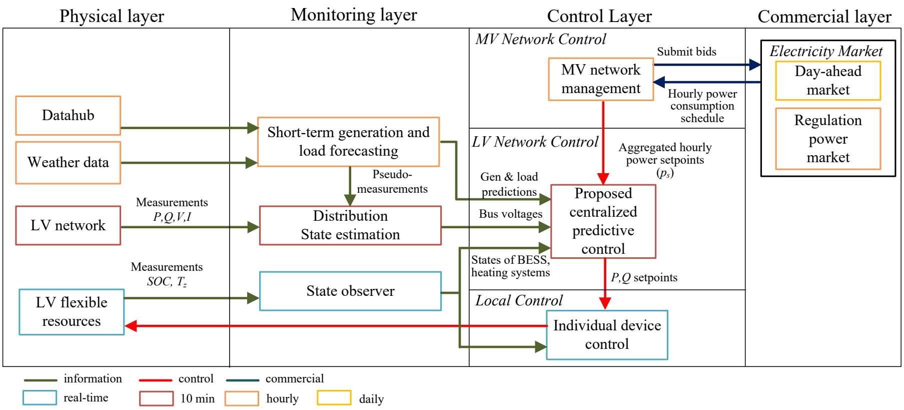


Fig. 3.3: Layout of the model predictive control method of DERs at LV networks [J1].

Comparison of Proposed Linear Power Flow with State of the Art [J1]

Let us consider the 4-bus LV network shown in Fig. 3.4. Let the impedance of first branch which represents the transformer impedance be $Z_{12} = 0.0117 + \mathrm{j}0.0327$ pu and other branch impedances be $0.0102 + \mathrm{j}0.0085$ pu . Assuming the power injections at nodes 1 to 4 be $-0.215 - \mathrm{j}0.09$ pu. The error in substation reactive power (Q_s) is 16.2% in methods proposed in [83] and [38], while in the proposed method it is less than 0.5%. The error in substation

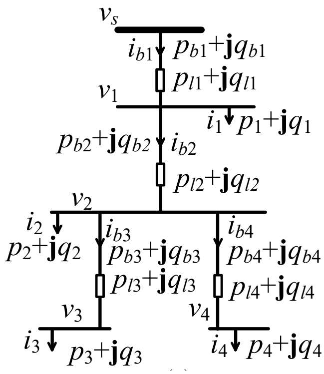


Fig. 3.4: Small LV network for illustration [J1].

Table 3.2: Summary of Comparison of Linear Power Flow Methods [J1]

Method	V_4 [pu]	P_s [pu]	Q_s [pu]
Newton-Raphson	0.909	0.9108	0.4295
LinDistFlow [83]	0.9182	0.86	0.36
LPF [38]	0.9108	0.9128	0.36
Proposed LPF	0.9108	0.9128	0.4314

active power is about 5% in [83], while in [38] and the proposed method it is less than 0.1%. From the above results, it can be seen that the proposed LPF is more accurate in the estimation of network power flows.

Proposed Centralized Predictive Control of LV DERs [J1]

The procedure to solve the proposed centralized predictive control method is stated below.

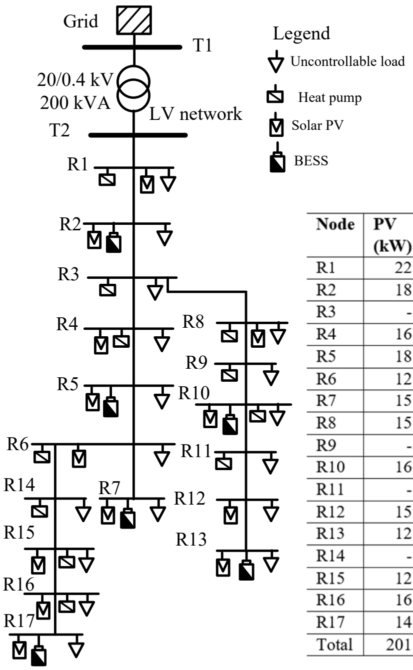
Algorithm 4 Proposed centralized predictive control algorithm [J1]

1: Get the state vectors $\mathbf{v}_m$ and $\mathbf{x}_{f0}$ from the observer blocks.
2: Calculate the linear coefficient matrices and vectors $\mathbf{B}_{vp}$, $\mathbf{B}_{vq}$, $\mathbf{B}_{pk,k\in\mathcal{K}}$, $\mathbf{B}_{qk,k\in\mathcal{K}}$ used in (2.19) with the new measurements $\mathbf{v}_m$.
3: Solve the optimization problem defined in (2.19) for the prediction horizon N_p.
4: From the optimal solution $\mathbf{u}$, send only the power setpoints $\mathbf{p}_f^\star$ and $\mathbf{q}_f^\star$ for the next time-step to the local controllers of the DERs. Go to step 1.

In the following subsection, few simulation cases done for numerical validation of the proposed predictive control of two types of DERs namely BESS and heating systems at LV networks are presented.

Simulation Studies [J1]

In this simulation studies, a modified form of LV radial network at Askov, Denmark with residential customers is used and its schematic diagram is shown in Fig. 3.5(a). The ratings of the solar PV, BESS and heat pumps at each bus are provided in Fig. 3.5(b). Fig. 3.6 shows the plot of solar



(a)

Node	PV (kW)	BESS (kVA)	HP (kW)
R1	22	-	10
R2	18	15	-
R3	-	-	8
R4	16	-	5
R5	18	15	-
R6	12	-	7
R7	15	15	-
R8	15	-	8
R9	-	-	6
R10	16	15	7
R11	-	-	8
R12	15	-	-
R13	12	10	-
R14	-	-	8
R15	12	-	-
R16	16	-	10
R17	14	10	-
Total	201	80	77

(b)

Fig. 3.5: LV distribution network considered for the simulation studies: (a) schematic diagram, (b) ratings of the PV, BESS and HP [J1].

irradiance on a typical sunny day of summer and winter in Denmark and a residential load profile with very less demand during peak PV power (worst-case scenario).

Two simulation cases are presented in this section, which were done to validate the efficacy of the proposed predictive control on the conditions of a typical summer day in Denmark. These simulations were done with a time-

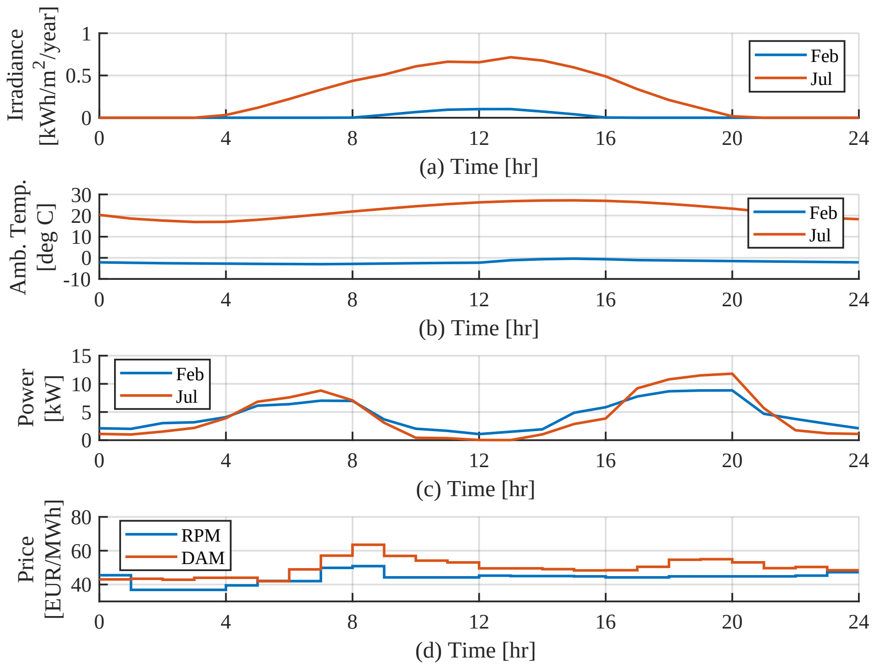


Fig. 3.6: Plot of profiles during winter and summer: (a) solar irradiance measured on a clear sky day, (b) typical ambient temperature (c) hourly load profile of a residential house and (d) typical hourly price signals of regulating power market (RPM) for down regulation and day-ahead market (DAM) [J1].

step of 10 minutes, a prediction and control horizon of 4 hours and for a period of 24 hours.

Case 1: Without Proposed Predictive Control of BESS on a Summer Day

This simulation case is done to study the BESS operation without the proposed control method and the BESS charging starts as soon as sun shines. The plot showing the state of charge of the BESS, bus voltages and transformer active power (p_s) are shown in Fig. 3.7. The bus voltages at the end nodes are above the limit of 1.1 pu and the peak transformer loading is close to 100% during peak PV power.

Case 2: With Proposed Predictive Control of BESS on a Summer Day

In this case, the proposed control method is used. Compared to Case 1, all the bus voltages are maintained within the limit of 1.1 pu as seen in Fig. 3.8.

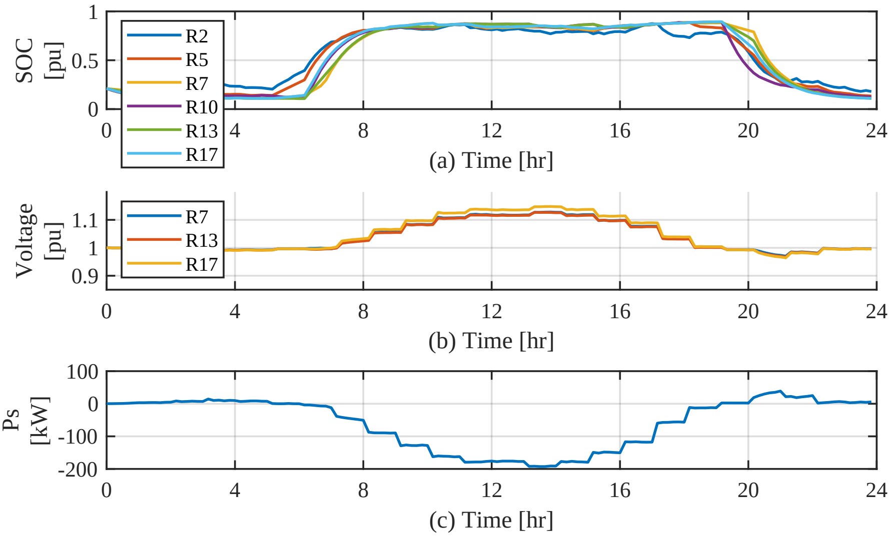


Fig. 3.7: Plot of case 1: Without proposed predicted control on a typical summer day: (a) State of charge of the BESS, (b) bus voltages at the far end nodes of the network, and (c) aggregated power flow at the MV/LV transformer [J1].

Additional simulation cases which are done with BESS and HP for a typical winter day can be found in [J1]. To summarize, the predictive control method proposed for the aggregated low-voltage network control can effectively utilize the DERs such as BESS and HP for economic operation of the network based on the electricity prices, forecasts of generation and load and system states.

In the next subsection, a distributed control method to solve the above optimization problem with minimum exchange of system information among the controllers is discussed.

3.1.5 Distributed Predictive Control of LV DERs

In this section, a simple example to illustrate distributed predictive control of LV DERs, and its comparison with the centralized method are discussed. Let us consider a 7-bus LV network with typical impedance values, load and generation profiles taken from the network shown in Fig. 3.5. In this network, 4 battery storage systems of identical rating are considered to be connected to nodes 2, 4, 5 and 7. The basic linear model of BESS given in (3.4) is used in this study. A hypothetical power reference signal for aggregated LV network power reference is assumed to maximize the PV power absorption by the

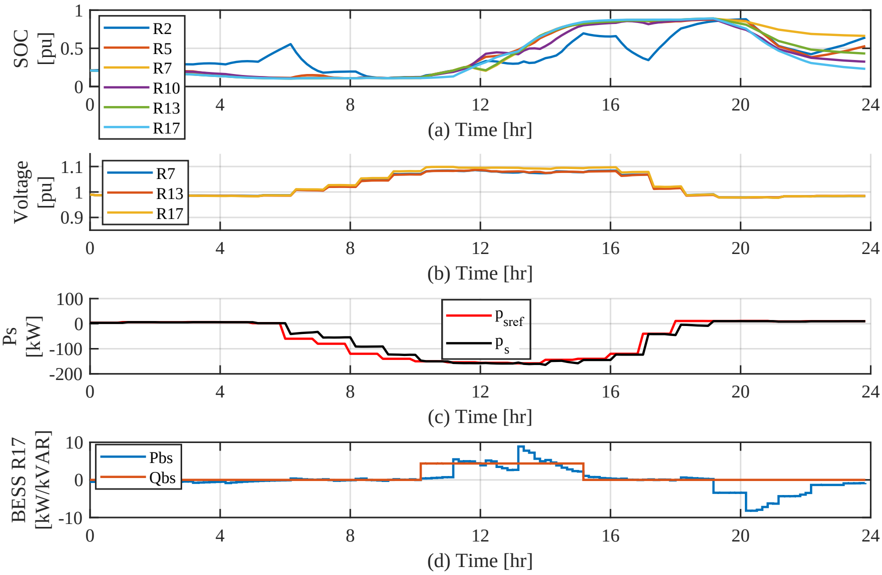


Fig. 3.8: Plot of case 2: With proposed predicted control on a typical summer day: (a) State of charge of the BESS, (b) bus voltages at the far end nodes of the network, (c) tracking of aggregated power power flow at the MV/LV transformer, and (d) active and reactive power setpoints computed by the proposed control for BESS at the node R17 [J1].

grid. The centralized predictive control problem formulated in (2.19) and its distributed version provided in (2.20) were done with a prediction horizon of 4 hours, and the results are plotted in Fig. 3.9. From the Fig. 3.9, it is seen that the node voltage profile and tracking of aggregated reference power are almost identical in both the simulations.

Remark 3.1.2:
The hierarchical control discussed in this section enables coordination across low and medium voltage networks, uses the data from state estimation, forecasting algorithms and provide interface to the electricity markets.

3.2 Utilization of DERs for Flexibility

Flexibility from DERs are required for multiple purposes such as network congestion management and minimization of power losses of the network. In this section, four different categories of utilization of flexibility are provided as follows.

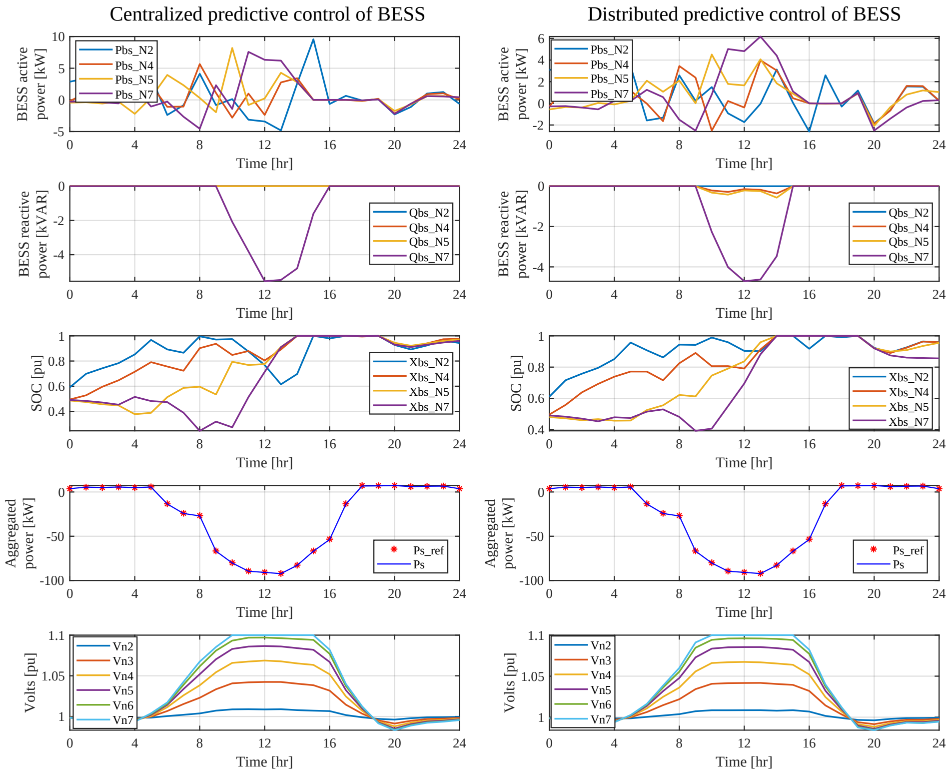


Fig. 3.9: Comparison of centralized and distributed predictive control of BESS.

3.2.1 Real-time Flexibility using Volt/var Control

The aggregated medium-voltage and low-voltage controllers described in Section 3.1 operate in a time frame of 1 hour and 10 min respectively. However, power consumption from loads and generation from RES may vary largely within seconds which may cause network voltage violations. To mitigate network under/over voltages, it is essential to have some local control which senses the voltages locally and adjusts either the reactive power or the active power generation/consumption based on predetermined droop settings [40], [84]. The local control works autonomously and does not need any inputs from upper-level controllers [85], [86]. In case of failure of operation of MVNC and/or LVNC, these local controllers can take over the network operation automatically and control the network states without violations.

In this section, a droop control method, which utilizes PV inverters to provide real-time flexibility for over-voltage mitigation, is presented. The same method can be applied for DERs such as EVs, heat pumps and BESS with suitable modifications. The plot of droop in reactive power with respect to node voltage magnitude is presented in Fig. 3.10 (a) and the droop for curtailment of active power generation from PV inverters with respect to node voltage magnitude is presented in Fig. 3.10 (b). From (2.4), the following ex-

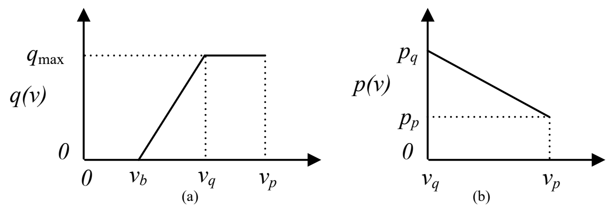


Fig. 3.10: (a) volt/var droop control - $q(v)$, (b) active power curtailment droop control - $p(v)$ [C2].

pression to calculate changes in voltage angles and magnitudes with respect to nodal active and reactive power injections can be written.

$$\begin{bmatrix} \Delta\delta \\ \Delta\mathbf{v} \end{bmatrix} = \underbrace{\begin{bmatrix} \frac{\partial\delta}{\partial\mathbf{p}} & \frac{\partial\delta}{\partial\mathbf{q}} \\ \frac{\partial\mathbf{v}}{\partial\mathbf{p}} & \frac{\partial\mathbf{v}}{\partial\mathbf{q}} \end{bmatrix}}_{\mathbf{S}} \begin{bmatrix} \Delta\mathbf{p} \\ \Delta\mathbf{q} \end{bmatrix} \tag{3.1}$$

The co-efficients of the sensitivity matrix $\mathbf{S} \in \mathbb{R}^{2N\times 2N}$ in (3.1) determine the effect of modifying node power injections on the node voltages [87]. Assuming PV inverters are present at all nodes $n \in \mathcal{N}$, the procedure to calculate the voltage bands v_{bj}, v_{qj} and v_{pj} at each node $j \in \mathcal{N}$ is given in [C2] from which the following droop settings $m_{qj} = q_{j\max}/(v_{qj} - v_{bj})$ and $m_{pj} = (p_{qj} - p_{pj})/(v_{pj} - v_{qj})$ can be calculated. It is to be noted that $q_{j\max}$ is the maximum/rated reactive power of the PV inverter at node j and p_{qj} is the available active power before curtailment. In the proposed method, the reactive power output from each PV inverter is calculated from the expression below. Note that generator convention is followed here, which means a positive value indicates reactive power being absorbed by the PV inverter.

$$q_j = \begin{cases} 0 & v_j < v_{bj} \\ m_{qj}(v_j - v_{bj}) & v_{bj} \leq v_j \leq v_{qj} \\ q_{j\max} & v_j > v_{pj} \end{cases} \tag{3.2}$$

The active power output from each PV inverter $j \in \mathcal{N}$ is calculated from

$$p_j = \begin{cases} p_{qj} & v_j < v_{qj} \\ p_{qj} - m_{pj}(v_j - v_{qj}) & v_{qj} \leq v_j \leq v_{pj} \\ p_{pj} & v_j > v_{pj} \end{cases} \tag{3.3}$$

The conventional volt/var droop control [86] uses the same voltage bands for all the PV inverters (v_b, v_q and v_p have the same values for all the nodes) resulting in differences in active/reactive power contribution to the voltage regulation. The PV inverters at the far end node will have to provide more reactive power than the ones close to the substation. This is demonstrated through simulation studies done in [C2] on a modified Cigre LV benchmark network and is shown in Fig. 3.11a. With the proposed method, there is a fair sharing of reactive power provision as seen in Fig. 3.11b.

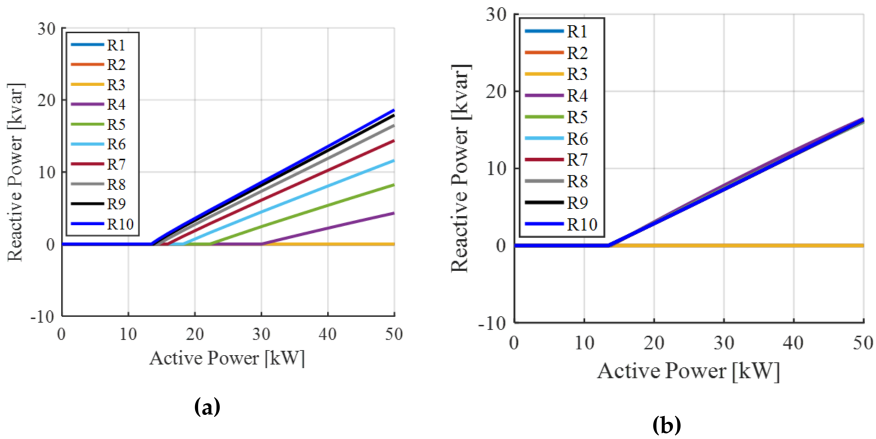


Fig. 3.11: Plot of reactive power provision from PV inverter (a) conventional method (b) proposed method [C2].

Remark 3.2.1:
It is assumed in the simulation studies shown in Fig. 3.11 that the PV ratings are identical in all the nodes and the PV output powers from all PV inverters are same. In reality, this is not true and in case of different PV ratings, the power factor of each PV inverter during operation will be identical. In such a condition, though the amount of reactive powers contributed by PV inverters will not be same, fair sharing of contribution from PV inverters to voltage regulation is ensured.

3.2.2 Computation of Optimum Flexibility

In Paper [C3], an algorithm to compute optimum flexibility in a low-voltage network to accommodate maximum PV power is proposed. The flowchart of the proposed algorithm is provided in Fig. 3.12.

Four cases were simulated on the model of a modified 25 bus LV network of Lind, Denmark. Please refer to Paper [C3] for the details of the simulated

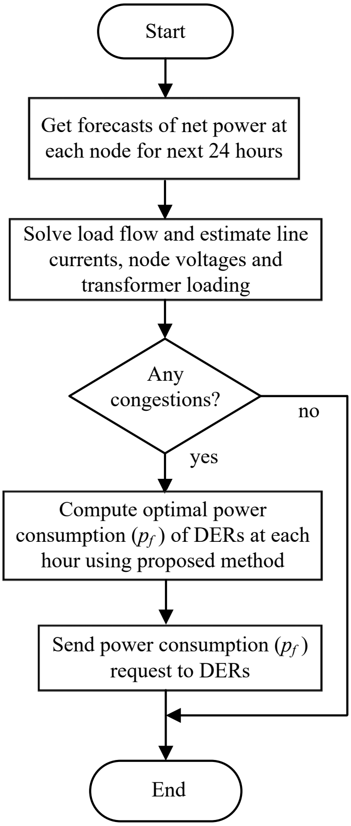


Fig. 3.12: Flowchart to manage network congestion in a LV network by optimum flexibility [C3].

network. A comparison plot of all the four cases with respect to the PV power absorption by the grid is shown in Fig. 3.13. Here, the variable α indicates a weighting factor in the objective function of the proposed optimization problem in Paper [C3], that decides how much weightage is given to demand response (DR) than the power curtailment from PV. From Fig. 3.13, it can be seen that maximum PV power is absorbed by the grid in the Case 3 (DR with $\alpha = 1$). The purpose of including the market price through the weighting factor α is to motivate demand response from customers and to accommodate more renewable power generation. The numerical results of the above cases are summarized in Table 3.3.

Remark 3.2.2:
From the results in Table 3.3, it is observed that demand response is helpful to accommodate more PV power in a low-voltage network. The energy savings

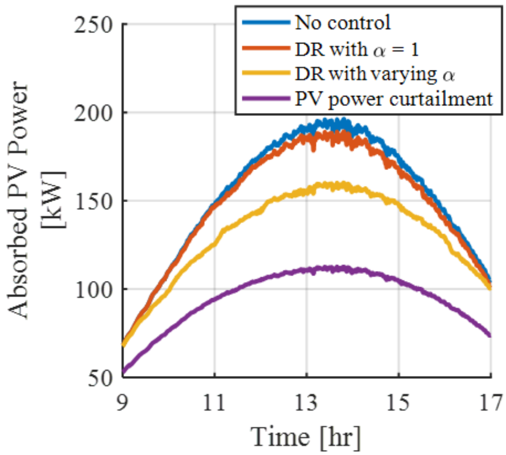


Fig. 3.13: Plot of comparison of absorbed PV power in all simulation cases [C3].

Table 3.3: Summary of Simulations on Optimum Demand Response [C3]

Case	Peak volt [pu]	PV power peak [kW]	DR power peak [kW]	PV energy absorbed [kWh]
Case 1: No control	1.14	195	0	1226.5
Case 2: PV power curtailment	1.08	112	0	761.5
Case 3: DR with $\alpha = 1$	1.08	185	100	1195.8
Case 4: DR with varying α	1.08	162	50	1050.9

obtained by activating demand response can be used to make payments to the customers who participated in demand response.

3.2.3 Flexibility from BESS for Peak-shaving

In [C4], utilization of a BESS located at far end node of the network for peak power shaving [36] of a low-voltage distribution network is studied in which the battery is charged during high PV power in-feed, and discharged at peak demand period and help to maintain the node voltages within limits. Fig. 3.14 shows the schematic diagram of the proposed battery storage control. The inputs to the proposed BESS control are explained as follows. The costs c_{p1} and c_{p2} are the cost weighting factors on the power regulation and power loss respectively, c_{b1}, c_{b2} and c_{b3} are the cost factors of the bat-

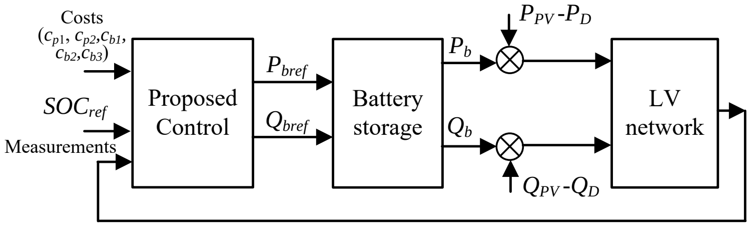


Fig. 3.14: Schematic diagram of the proposed battery storage control [C4].

tery [88], [89]. The variable SOC_{ref} is the desired state of charge of the BESS which is fixed over time [88] and measurements provided from LV network are the node voltages.

A basic linear battery model [35] is used and its discrete version is given below.

$$SOC(\kappa+1) = SOC(\kappa) - \frac{\eta_{bs} T_s}{E_{bs}} p_{bs}(\kappa) \tag{3.4}$$

where, SOC is the state of charge of the battery, η_{bs} is the battery efficiency for both charging and discharging, p_{bs} is the battery output power, whose positive value indicates battery discharging and negative value indicates charging, T_s is the step time, κ is the discrete time instant, E_{bs} is the rated capacity of the battery.

The proposed control solves a quadratic programming problem explained in [C4] to compute the active and reactive power setpoints of the BESS at each time-step (10 min). Plots of the simulation studies done on a Danish distribution network at Askov, Denmark are shown in Fig. 3.15.

Summary of the simulation studies is provided in Table 3.4. As seen from Table 3.4, in the Cases 2 and 3, the node voltages are maintained within limits (1.1 pu). Though the peak power reduction is lesser in Case 3 compared to

Table 3.4: Summary of Simulation Results of Proposed BESS Control [C4]

Case	Maximum voltage [pu]	Peak power reduction [%]	Net energy loss [kWh]
Case 1: Without BESS and no control	1.107	0	85.54 (6.30%)
Case 2: Peak shaving and minimum loss	1.086	20	78.52 (5.98%)
Case 3: Peak shaving, minimum loss and minimum variation in SOC	1.092	15	81.49 (6.08%)

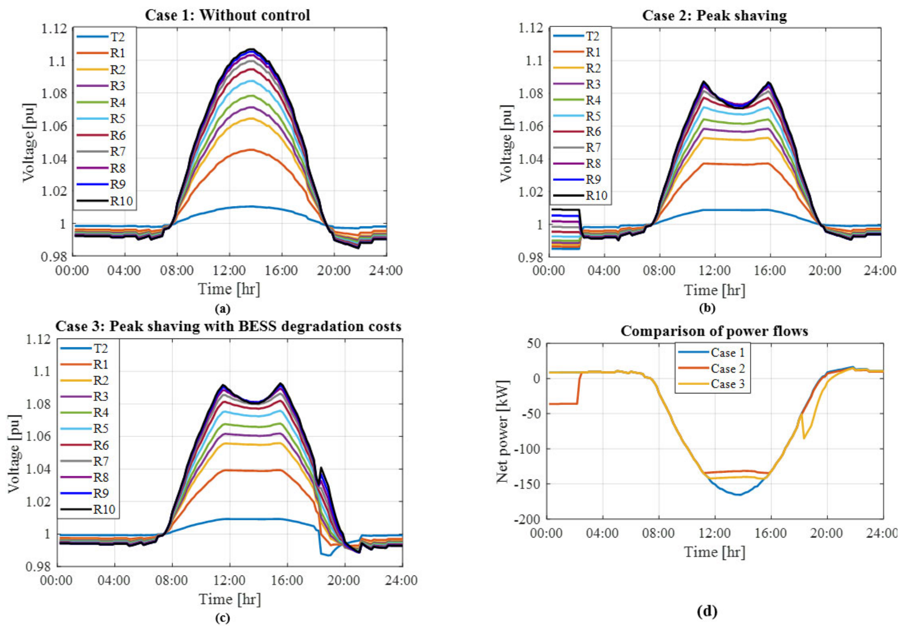


Fig. 3.15: Plot of siumlation results (a) without BESS and no control, (b) with proposed BESS control for peak shaving and minimum network power loss but without considering battery degradation, (c) with proposed BESS control for peak shaving, minimum network power loss and minimum battery degradation, and (d) aggregated net power flow at the secondary side of LV transformer in cases 1, 2 and 3 [C4].

Case 2, the variation in SOC is less which may lead to less battery degradation.

Remark 3.2.3:
From the above simulation studies with BESS, it is understood that by having a BESS in the distribution network, the network controllability is improved and its benefits being peak shaving, prevention of node voltage violations and minimization of network power losses.

3.2.4 Flexibility for Network Congestion Management

In Paper [C5], two algorithms for distribution network congestion management namely congestion management - planning (CMP) and congestion management - operation (CMO) are proposed for day-ahead planning and real-time network operation respectively. Both the algorithms work based on a predictive control algorithm using second-order cone programming (SOCP) based relaxation of the original nonlinear ac power flow. The proposed algorithms are interfaced with the monitoring modules (distribution state estimation and forecasting algorithms) and electricity markets (day-ahead and intraday markets) and they calculate the optimum demand response from DERs. The proposed algorithms for congestion management are tested in a simulation model of a modified Danish 10 kV MV distribution grid of Lind, Denmark which is a 25 bus MV network, with a 6 bus LV network connected to MV bus number 22. Please refer to Paper [C5] for the detailed explanation and their summary are provided below.

Congestion Management - Planning

This algorithm works on a day-ahead basis and calculates the optimum flexibility to be procured by the DSO from the day-ahead market. At beginning of each day, the DSO receives day-ahead forecasts of aggregated generation and loads at each MV bus. DSO runs the proposed SOCP based optimization algorithm to check for network congestion during each hour of next day. If network congestion are expected, the required flexibility is computed during the above analysis, and the DSO approves the required bids submitted by DERs. The final consumption schedule is communicated to all the individual DERs by the market. An example simulation study is shown in Fig. 3.16 in which it can be seen that the overloading of branches which could occur based on the forecasted information is prevented by procuring the required flexibility from DERs.

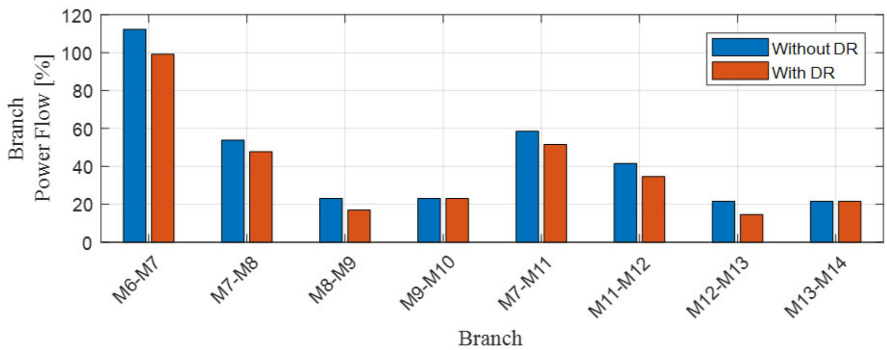


Fig. 3.16: Plot of branch loading without and with procured flexibility from the day-ahead market to be activated by demand response (DR) [C5].

Congestion Management - Operation

This algorithm works close to real-time with a time-step of 10 min. This algorithm along with a distribution state estimation algorithm, detects network congestion and calculates aggregated setpoints for DERs at each MV bus, and are communicated to the respective DER controllers. For LV networks connected to MV buses, it is assumed that there is an aggregated controller at those MV buses which is responsible for calculation of individual power setpoints to each DER in that LV network. In Fig. 3.17, a simulation result is shown in which activation of flexibility in real-time mitigated the under-voltage phenomenon as the proposed CMO algorithm is active.

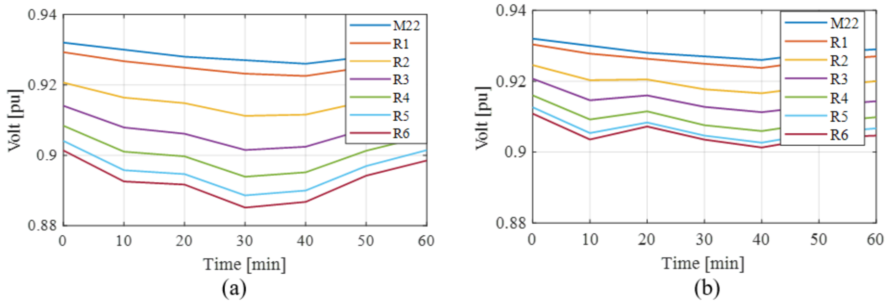


Fig. 3.17: Plot of node voltages of LV network at MV bus M22 (a) without flexibility (b) with flexibility [C5].

Remark 3.2.4:
From the above discussions regarding utilization of flexibility, it is evident that a hierarchical control framework proposed in Section 3.1 is helpful for coodination among DERs located at different voltage levels and the time frame at which they operate.

3.3 Network Reconfiguration and Adaptive Protection

In this section, a network reconfiguration scheme is proposed for network loss minimization, followed by an adaptive protection scheme for preventing malfunction of the protective relays due to connection/disconnection of DG for a medium-voltage distribution network.

3.3.1 Reconfiguration Scheme for MV Networks

A reliable and economical delivery of power in an ADN can be improved if a suitable reconfiguration scheme is employed. The reconfiguration of a network involves closing and opening of sectionalizing switches such that the objective of optimum network operation is achieved without compromising on the quality and reliability of power delivery. The objectives of network reconfiguration could be network power loss minimization, load balancing or a combination of both. As the renewable power sources in an ADN produce power based on weather conditions, reconfiguring a network may be necessary to manage the network congestions along with other economic objectives. The need for network reconfiguration schemes [14], [24], [25] in an ADN are

- Network power loss reduction – Due to time-varying generation profile of DER, a fixed configuration of network may cause more network power loss. Reconfiguring the network can potentially reduce the branch power losses.
- Load balancing – Based on the location and power generation of the DER, the line power flows at some branches may be congested and exceed the thermal limits. By rerouting the power flows, the loading of each branch may be leveled.

In this work, the discussions of network reconfiguration are limited to normal operation though the proposed methods can be applied for contingency and emergency situation of the network.

Proposed Network Reconfiguration Scheme

The proposed network reconfiguration scheme is based on the mixed-integer linear programming problem defined in (2.26).

Simulation Studies

In this work, the original 53-bus 60/10 kV MV Lind network is modified to a 25-bus network as shown in Fig. 3.18 and it is used for simulation studies. This network has five switches and DERs such as solar and wind power plants are also present in the network. At first the proposed optimization problem for network reconfiguration (2.26) is compared with load flow in DigSilent Power factory based on Newton-Raphson method for a fixed configuration of the network.

Errors in Linear Approximation of Power Flows

Let us consider the following network configuration shown in Table 3.5. In this configuration, a peak load condition is considered which could cause

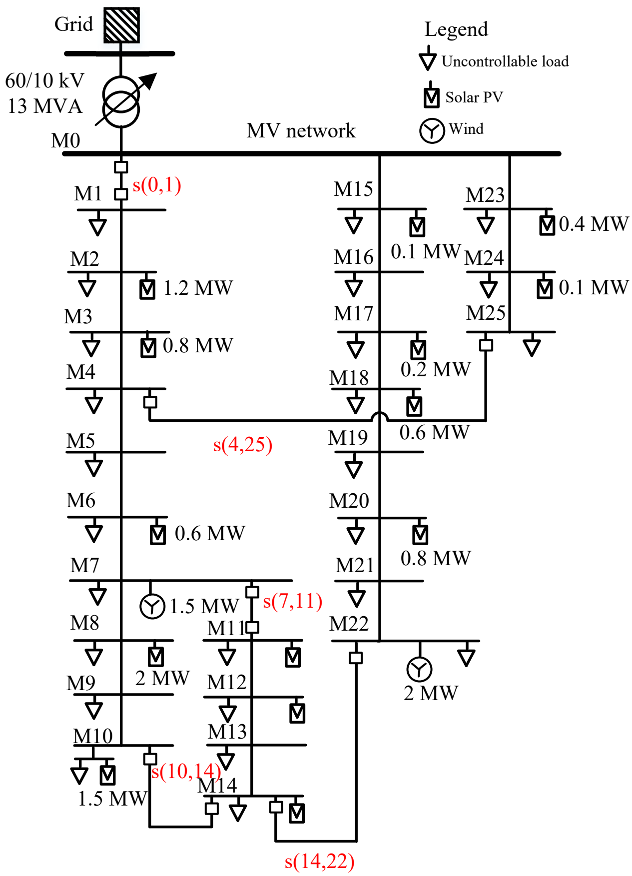


Fig. 3.18: Schematic of simplified MV distribution network of Lind, Denmark.

under-voltages in some nodes of the feeder. It is to be noted that this type of load condition is fictitious and does not occur in the real network but it is considered here to study the performance of the reconfiguration algorithm. The loads are increased arbitrarily until the network voltages fall below 0.9 pu. A simulation is conducted with the base configuration of the network provided in Table 3.6 to calculate the active and reactive power losses and node voltage magnitudes using the proposed liner power flow equations in Section 2.4. The estimated values are shown in Table 3.6. The results show that the network voltages are less than the allowed limit of 0.9 pu in some nodes. These values are compared with that of the results from Newton-Raphson (NR) method using DigSilent Power factory and the comparison results are shown in Table 3.7.

Table 3.5: Base network configuration

Switch	Status	Switch	Status
$S(0,1)$	1	$S(7,11)$	1
$S(4,25)$	0	$S(14,22)$	0
$S(10,14)$	0		

Table 3.6: Estimated values using linear power equations

Total active power losses [kW]	Total reactive power loss [kVAR]	Voltages within limits?
849.9	838.19	No V_{n7} to V_{n14} are less than 0.9 pu.

The errors in the estimation of substation powers are less than 1% and the maximum voltage error at node 16 is less than 0.1%, compared to the NR method which gives the true values.

Table 3.7: Comparison of results of linear power equations with NR method

Error in calculation of MV substation active power (P_s) [%]	Error in calculation of MV substation reactive power (Q_s) [%]	Error in calculation of voltage at node 14 (V_{n14}) [%]
0.85	0.35	0.054

MILP based Network Reconfiguration

As shown in the simulation results above, the network voltages are below the limits. The best configuration of the network is found using the proposed MILP formulated in (2.26) and the results are given in the Table 3.8. It was also observed that all the node voltages after reconfiguration were within limits.

Table 3.8: Network configuration found by MILP

Switch	Status	Switch	Status
$S(0,1)$	1	$S(7,11)$	0
$S(4,25)$	0	$S(14,22)$	1
$S(10,14)$	0		

Comparison of network power losses before and after reconfiguration using

MILP is presented in Table 3.9. As seen in Table 3.9, power losses in the

Table 3.9: Summary of Simulation Results

Case	Active power at MV substation (P_s) [MW]	Reactive power at MV substation (Q_s) [MVAR]	Total active power losses (P_l) [kW]
Base case before reconfiguration	12.55	6.12	847.25
After reconfiguration using MILP	12.42	6.02	706.18

network is reduced from 6.75% to 5.68%. As observed from the above simulation results, the proposed MILP method can estimate the network power flows and switch status with reasonable accuracy.

Remark 3.3.1:
From the above study, it is learned that, network power losses can be minimize and network congestion can be managed by employing network reconfiguration schemes.

3.3.2 Adaptive Settings for Over-current Relays

In MV distribution networks, the amount of distributed generation (DG) from wind, solar and CHP power plants being integrated is expected to increase steadily. Protection systems with static settings may malfunction due to connection/disconnection of DG or if there is a change in the network topology [28]. The traditional overcurrent relay based protection system with fixed settings is not adequate to address the above problem. A solution is to make the protection system adaptive taking into account the changes in network topology and connection/disconnection of DG.

In this thesis, a simple adaptive protection algorithm is proposed to cope with the above-mentioned changes in the distribution network. The protection challenges in an islanded network is not addressed in this work. Only radial MV networks are considered as in Denmark, the distribution system are often operated in radial topology although it could be operated in ring configurations [9]. The characteristics of DGs are plays a key role in the design of an adaptive protection algorithm as discussed below.

Characteristics of DGs

The short circuit current contribution of DGs differs from the conventional centralized large generation resources in the following ways [9].

- The short circuit contributions from DGs may originate from different directions as they are present at various parts of the network.
- The DGs may be synchronous or asynchronous machines, and power electronic converters based DGs are common nowadays. The magnitude of the short circuit current of inverter based DGs is usually limited to values slightly higher than its nominal current. The short circuit capacity of grids is dependent on the type of DGs present in the network.
- Rotating machine based DGs behave like a voltage source under short circuit conditions. However, the time characteristic of the short circuit current is dependent on the control scheme of the inverters.

In this work, only rotating machine based DGs are considered, as they are more problematic compared to inverter based DGs in terms of blinding of the protection and false tripping of the network [28].

Blinding of Protection

Let us consider a bolted three-phase fault occurring at the bus 2 of a three-bus network as shown in Fig. 3.19 and analyze the fault current without and with DG connection. Let us assume the network is balanced, and bus voltages are at rated values (1.0 pu) under normal load condition of the network. Due to symmetrical fault at bus 2, the network fault currents can be analyzed on per-phase basis [60]. Both the grid and the DG contribute to the fault current flowing from bus 1 ($I_{1f} = I_{gf} + I_{sf}$). The fault current contribution from the grid depends on the grid, DG, and line impedances and the following reasoning is valid [51].

- The more the size of DG, lesser will be the fault current contribution from the grid.
- For fault locations closer to the bus 2, lesser will be the fault current contribution from the grid.

The above described scenarios may lead to poor fault current detection by the relay R1. It is even possible that the short-circuit stays undetected because the grid contribution to the short-circuit current never reaches the pickup current of the feeder protection relay R1. This mechanism is called blinding of protection and is also known as protection under-reach. Integrating a small size DG into a comparatively “strong” distribution grid composed of

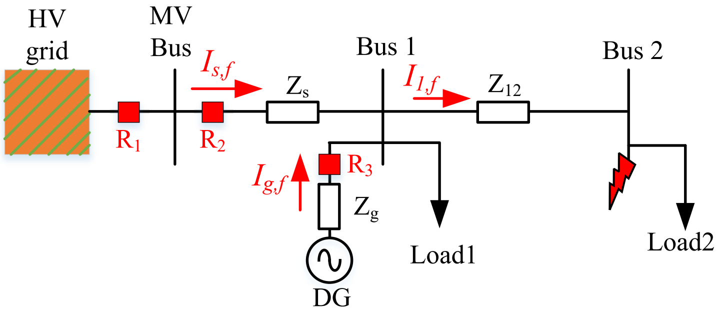


Fig. 3.19: Schematic of MV network to explain protection blinding.

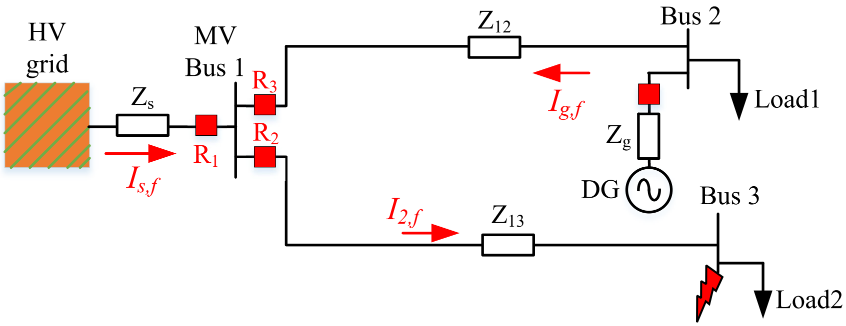


Fig. 3.20: Schematic of MV grid to illustrate false tripping.

cable feeders of a moderate length does not normally lead to blinding of protection. A simple solution to prevent protection blinding is to reduce the pickup current setting of R1 when DG is connected to Bus 1 so that R1 will detect the fault and trips the faulty section of the feeder.

False Tripping

False tripping, also known as sympathetic tripping, may occur when a DG contributes to faults in an adjacent feeder connected to the same substation. The DG contribution to the fault current may exceed the pickup level of the overcurrent protection in its feeder and the time coordination between relays in the two feeders may be incorrect. Due to the above reasons, the relay in the healthy feeder may trip before the fault is cleared by relays in the faulty feeder [9], [50].

False tripping can be illustrated in a faulted three-bus MV network shown in Fig. 3.20. Let us assume a three-phase fault at bus 3. The DG at bus 2 also contributes to the fault current along with the grid ($I_{2f} = I_{gf} + I_{sf}$). In case I_{gf} exceeds the pickup current setting of relay R3 and the time dial setting of R3 is less than the relay R2, then R3 will trip before R2, causing a false trip at the healthy feeder. By implementing directional overcurrent relays, false tripping can be avoided, but it may be more expensive for DSOs. A simple solution would be to change the relay settings for proper coordination among relays in adjacent feeders [49].

Adaptive Protection

In this work, a communication assisted centralized protection scheme is assumed for online update of relays. A centralized controller in the control centre of the DSO can update the relay settings during major changes in grid topologies such as network reconfiguration or connection/disconnection of DGs. Each overcurrent relay has two types of settings namely the primary and backup protection setting. The calculation of these settings are described below.

Settings of Primary Protection

The primary protection is the protection offered by each relay to a particular zone of the distribution network before other relays in the vicinity respond to faults occurring in that zone. In order to have a proper coordination among the relays, the setting must be larger than the fault current ($I_{f|l=l_p}$) occurring at the end of its primary protection zone (at the distance l_p). As we know that a three-phase fault produces the maximum fault current, the relay setting is selected as given below.

$$\begin{aligned} I_p &= K_p I_{f|l=l_p} \\ t_p &= 0 \end{aligned} \tag{3.5}$$

where, $K_p > 1$ is the reliability coefficient. It is to be noted that the operating time in (3.5) is set to zero, so that the relay trips instantaneously once the fault current is detected within its primary protection zone.

Settings of Backup Protection

To provide backup protection for a selected zone, the backup protection setting of the relay must be lesser than the phase-phase fault current occurring at the end of the line as given below.

$$I_b = \frac{I_{f|l=l_b}}{K_b} \tag{3.6}$$

The time-delay of the backup protection setting can be calculated based on the time-overcurrent characteristics of the relay as explained below.

Time-overcurrent Characteristics of Relay

The inverse-time characteristic curves of overcurrent relays can be selected conforming to IEC/IEEE Standards [90] as below

$$t_{i,f} = TD_i \left(\frac{A}{\left(\frac{I_{f,i}}{I_{p,i}}\right)^B - 1} + C \right) \tag{3.7}$$

where, A, B, C are constants depending on the relay characteristics (for example, standard inverse), TD_i and $I_{pu,i}$ are the time-dial and pickup current settings and $I_{f,i}$ is the fault current in secondary amperes measured by the i^{th} overcurrent relay.

Calculation of Pickup Current

Let us assume that the load current (I_l) is known at the point where the relay is connected. If DGs are present in the network, it is important to consider only the stabilized load current value. Then the value of pickup current (I_p) is given by [50]

$$I_p = K_p I_l \tag{3.8}$$

where, the constant K_p is the plug multiplier which is normally set to 1.5 and can be changed depending on the network operating conditions. If there is change in the network configuration which results in a different load current, equation (3.8) can be used to calculate the new pickup current settings, thereby making the protection adaptive.

Calculation of Time-dial Setting

Due to change in network configuration or connection/disconnection of DGs, the time-dial setting can be updated as [50]

$$TD_{\text{new}} = TD \frac{(A + C(M^B - 1))(M^B_{\text{new}} - 1)}{(A + C(M^B_{\text{new}} - 1))(M^B - 1)} \tag{3.9}$$

where, $M = \frac{I_f}{I_p}$ is the ratio between fault and pickup currents. The changes in network configuration can result in a new load current magnitude which can be used to update the pickup current as per equation (3.8) and the new time-dial setting can be calculated as per equation (3.9).

Simulation Studies of Adaptive Protection

In this work, the simulation studies are conducted using DigSilent Power factory software on a simplified 60/10 kV MV network of Lind area, Denmark. The network is shown in Fig. 3.21. At the bus M4, a set of asynchronous generator of 3 units of 2 MVA belonging to wind turbine generator is connected. The line parameters are provided in Table 3.10.

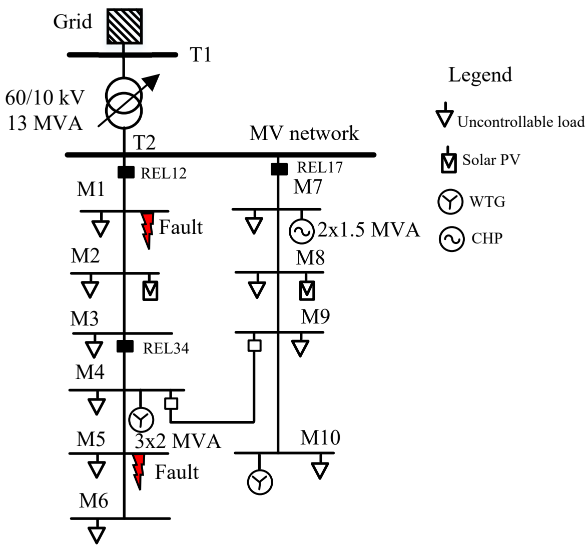


Fig. 3.21: Schematic of simplified 60/10 kV MV network, Lind.

Case 1: Illustration of Protection Blinding

To illustrate the protection blinding phenomenon, let us consider the MV network shown in Fig. 3.21. Let us apply a balanced three-phase fault on the bus M6.

Fault Detection Without DG

This simulation is done without the connection of DG at bus M4. The pickup current setting of relay REL34 is 2.9 sec.A, and the fault at bus M5 is detected

Table 3.10: (a) Line Parameters and (b) Parameters of DG

Line	Resistance (Ω)	Reactance (Ω)
VKH-M1	0.570	0.397
M1_2	0.018	0.012
M2_3	0.274	0.093
M3_4	0.021	0.007
M4_5	0.191	0.065
M5_6	0.029	0.010
VKH-M7	0.446	0.152
M7_8	0.334	0.114
M8_9	0.172	0.058
M9_10	0.108	0.037

(a)

Parameters	CHP	WTG
Generator type	Synchronous	Asynchronous
Rated Power	1.5 MW	2 MW
Number of units	2	3
Rated voltage	10 kV	10 kV
Stator resistance	0.0132 p.u.	0.018 p.u.
Stator reactance	0.04 p.u.	0.015 p.u.
d-axis synchronous reactance	2.78 p.u.	-
d-axis transient reactance	0.24 p.u.	-
d-axis sub-transient reactance	0.17 p.u.	-
q-axis synchronous reactance	2.05 p.u.	-
q-axis sub-transient reactance	0.21 p.u.	-
d-axis transient time constant	0.29 s	-
d-axis sub-transient time constant	0.03 s	-
q-axis sub-transient time constant	0.03 sec	-
Inertia time constant	0.54 sec	0.38 sec
Magnetizing reactance	-	4.42 p.u.
Rotor resistance	-	0.0108 p.u.
Rotor reactance	-	0.128 p.u.

(b)

by the relay REL34 as shown in Fig. 3.22.

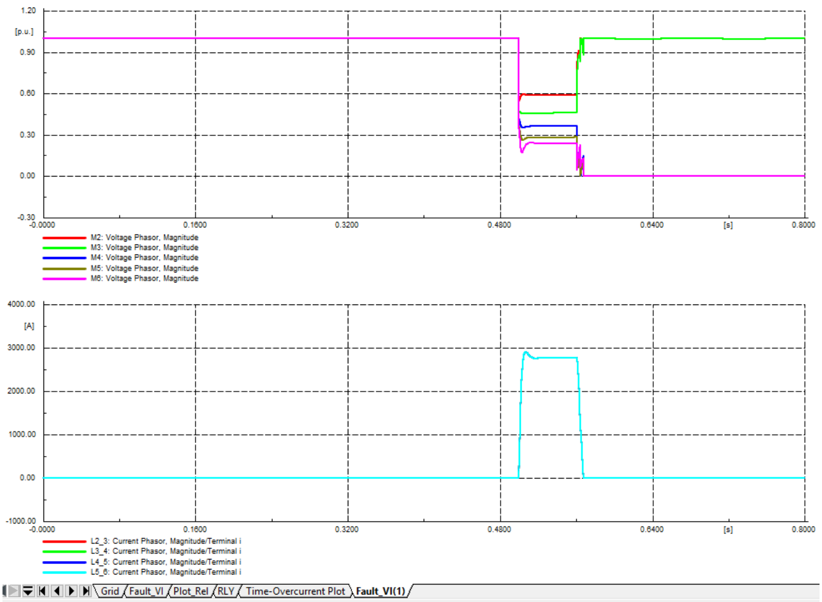


Fig. 3.22: Detection of fault without DG

Protection Blinding With DG

The same simulation is repeated with DG connected at bus M4. As the relay setting is same, the fault is not detected as shown in Fig. 3.23. The reason is that the fault current seen by REL34 is now reduced as seen in Fig. 3.23 due to fault current contribution from the DG. As a result, for the fault at M5, the REL34 is blinded. The solution to this problem is to adaptively change the settings of REL34 based on (3.8) and (3.9). Summary of the adaptive relay settings without and with DG is provided in Table 3.11. The close-in fault currents (CI) and far-bus fault currents (FB) for faults at bus M4 seen by the relay REL34 are calculated from simulations.

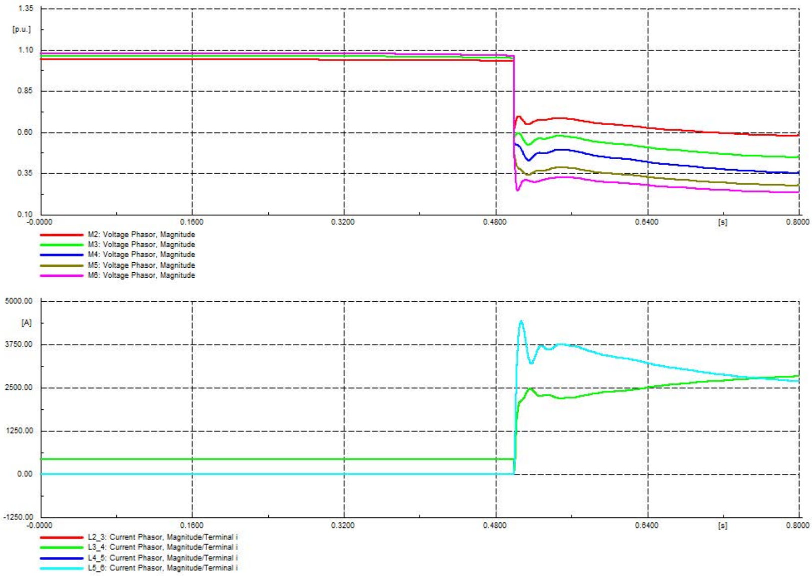


Fig. 3.23: Protection blinding of REL34 with DG

Table 3.11: Summary of Relay Settings

Case	Fault current CI L45 [kA]	Fault current FB L34 [kA]	I_p [sec.A]	TDS [pu]
Without DG	3.1	2.85	2.9	0.21
With DG	4.1	2.5	2.6	0.2

Fault Detection With DG

A set of asynchronous generator of 3 units of 2 MVA belonging to wind turbine generator is connected at the bus M4 for this simulation case. The settings of REL34 is changed to 2.9 sec.A from 2.6 sec.A, and with the new setting, the fault at M5 is detected properly as shown in Fig. 3.24.

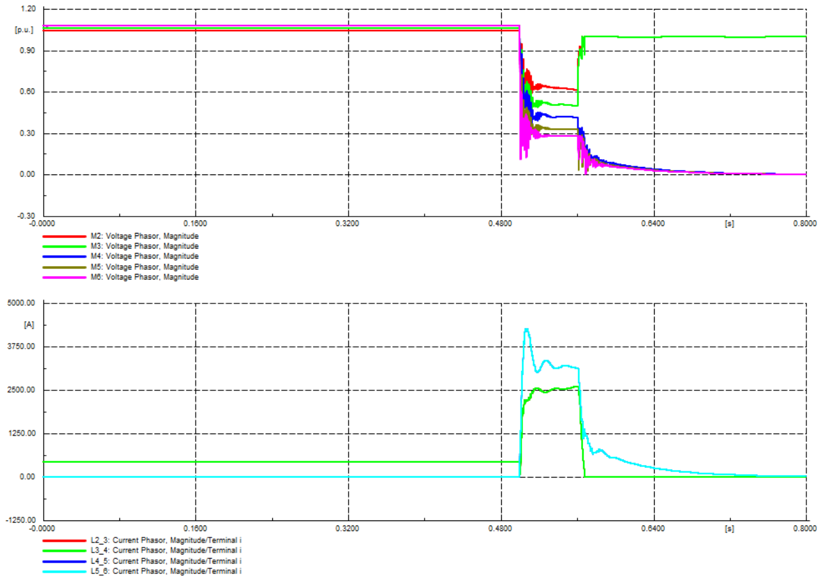


Fig. 3.24: Fault detection with DG due to change in setting

Case 2: Illustration of False Tripping

Let us consider the MV network shown in Fig. 3.21. Let us apply a three-phase balanced fault at bus M1. The following two simulation cases are done without and with adaptive protection settings.

Simulation Without Adaptive Relay Settings

The relay settings of REL12 and REL17 are set such that they detect faults instantaneously at their vicinity according to equation (3.8). These values are calculated without considering the presence of DG at Bus 7 and the pickup currents are set to 1.2 sec.A in both the relays. Due to this fact, for faults at feeder T2-M1, the relay REL17 may also pickup causing tripping of line L17 falsely. This is illustrated through the simulation plot in Fig. 3.25, where it can be seen that the relay REL17 in healthy feeder got tripped instead of the relay REL12.

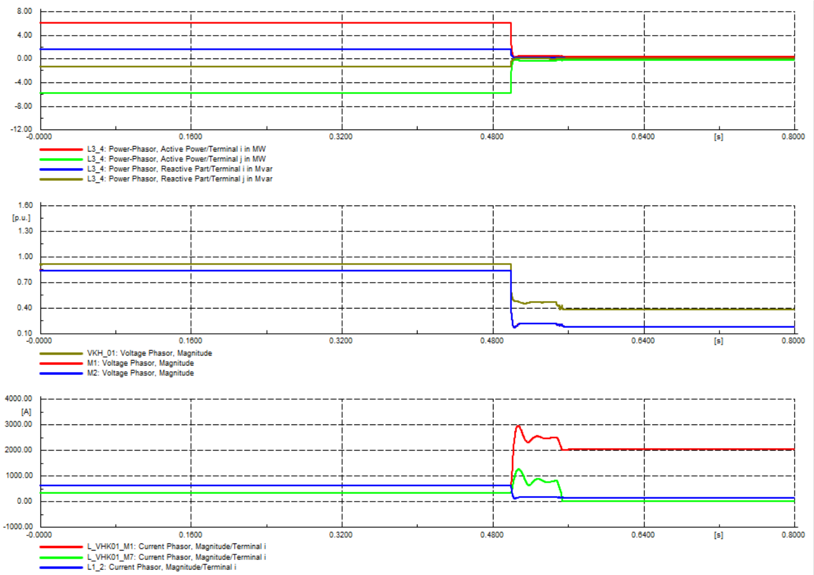


Fig. 3.25: Plot of false tripping of REL17.

Simulation with Updated Settings of Relays

In this simulation case, the relay settings are calculated considering the presence of DG at bus M7 and the relay settings are updated as per (3.8) and (3.9) for proper distinguishable of fault at bus M1 and the pickup current settings are increased for REL12 and REL17 from 1.2 to 1.5 sec.A. In this case, for faults at feeder T2-M1, only REL12 will trip. The simulation is repeated and now the false tripping is avoided as seen in the plots in Fig. 3.26, where it is shown that the relay REL12 in the faulty feeder got tripped.

Remark 3.3.2:
The above simulation studies show that adaptive protection settings of the relays will help in proper detection of faults when there is significant change in power flows and short circuit levels in the network due to change in DG power production. In this work, the adaptive settings are demonstrated for protection blinding and false tripping problems in the network.

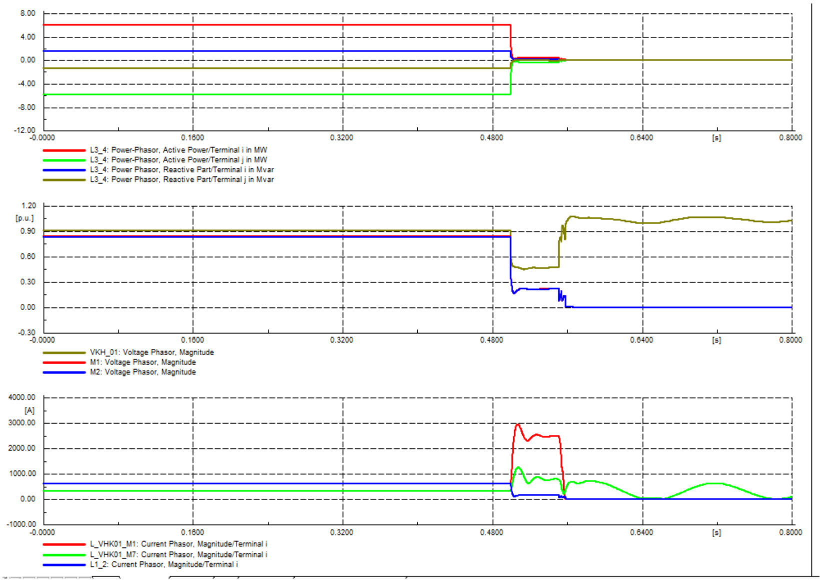


Fig. 3.26: Elimination of false-tripping due to corrected relay settings

Validation of Adaptive Protection in RTDS Simulator

The adaptive protection algorithm discussed above is further validated in a real-time digital simulator (RTDS®) from RTDS technologies. The same 10-bus distribution network modeled in Power factory simulations shown in Fig. 3.21 is modelled in RSCAD, a proprietary software from RTDS technologies. The relays, DG and their control are modeled using relevant modules in the RSCAD software and it is shown in left side of Fig. 3.27. The right side of this figure shows the different settings and fault control which can be manipulated during run-time.

For brevity, only the simulation result of validating the solution of protection blinding is shown in Fig. 3.28 which was performed with similar conditions of the simulations done in Power factory. From Fig. 3.28, it can be seen that the fault current magnitudes (2.6 kA), tripping time (0.1 s) and voltage profile are closely matching with the Power factory simulations of the same case shown in Fig. 3.24.

The RSCAD models developed in this work will be useful to conduct hardware-in-loop simulations in near future, by using an ABB relay of model REF615 instead of a software relay.

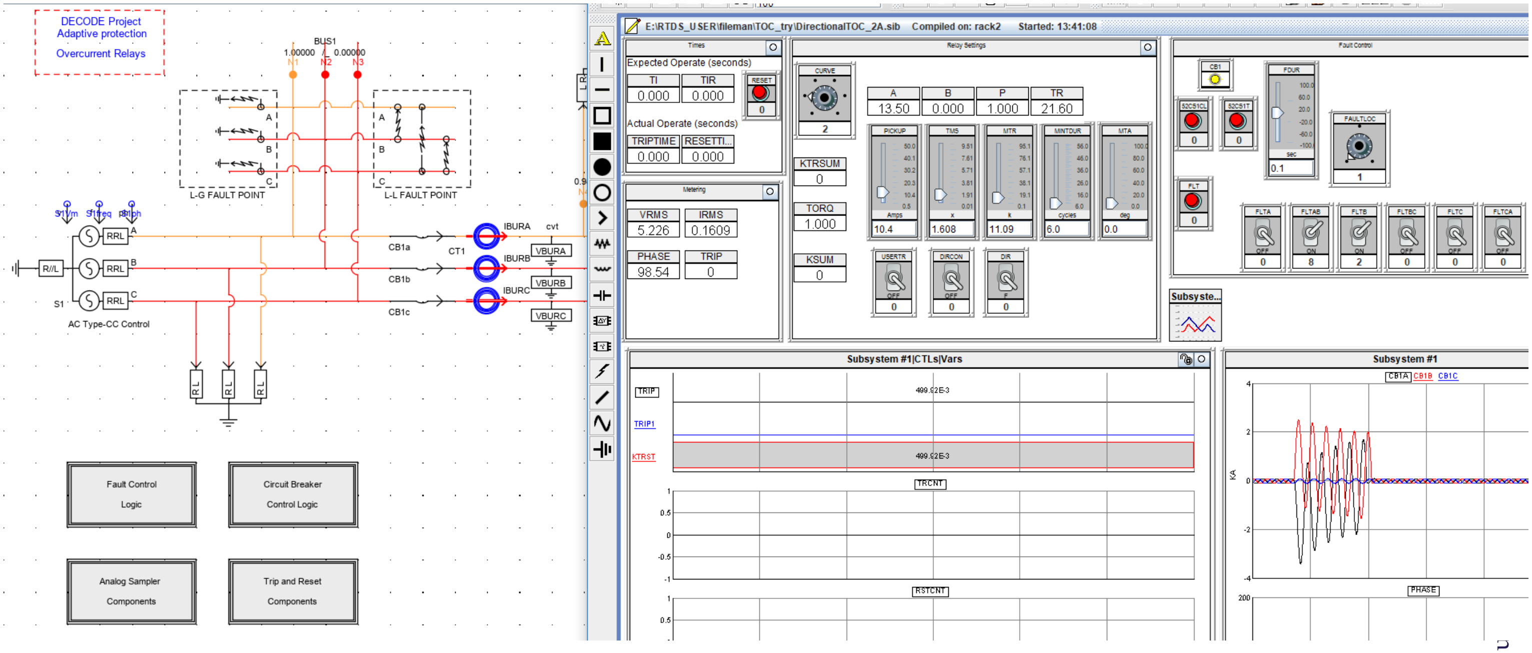


Fig. 3.27: Layout of simulation tests in RTDS simulator.

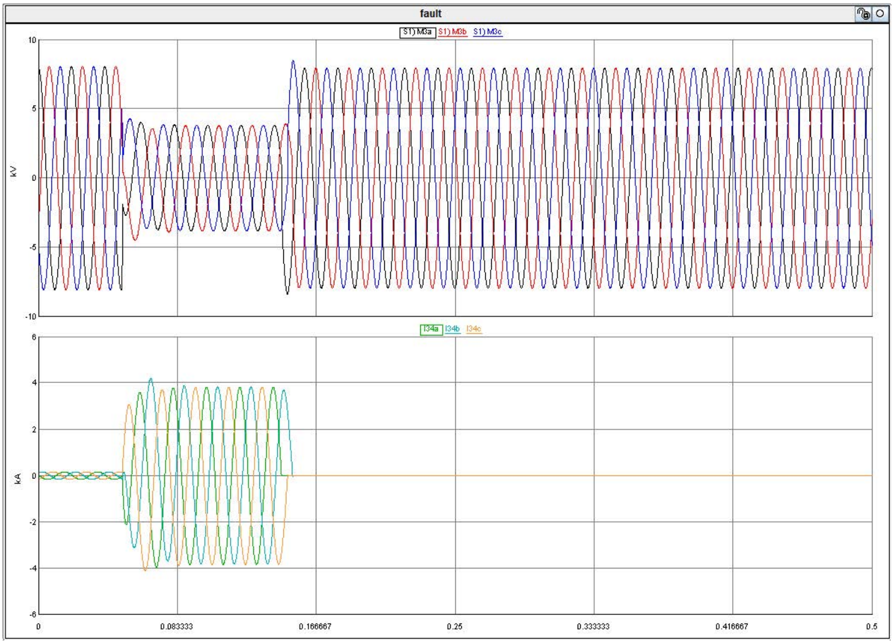


Fig. 3.28: Plot of prevention of protection blinding due to updated relay settings.

3.4 Advanced TSO-DSO Interface

In this section, an advanced TSO-DSO Interface (ATDi) proposed in the Paper [C6] is summarized as follows.

3.4.1 Role of DSOs in Ancillary Services Provision by DGs

DGs connected at distribution networks can provide ancillary services including frequency and voltage regulation to the TSOs [91]. The roles and responsibilities of the grid operators and DGs regarding ancillary services from European perspective are described in [42]. At present, DSOs are only responsible for distribution network congestion management and voltage regulation [44]. In Denmark, as stated in Chapter 1, DSOs and the TSO do not interact unless there is a requirement, although the TSO is able to utilize ancillary services by DGs at distribution networks. Proper interface between the TSO and DSOs is required to prevent undesired network congestion, which may occur due to provision of ancillary services by DGs. In [27], a survey done across different geographical regions including Europe also stresses the importance of interactions among TSOs and DSOs. A study presented in [43] by CIGRE C6.25/B5 Joint Working Group (WG) provides guidelines about the roles of TSOs in utilizing ancillary services from DGs. The present day TSO-DSO interface can be improved by improving automation and communication infrastructure [45].

In this work, an advanced TSO-DSO interface is proposed which involves the DSO for pre-qualifying the power dispatch from the TSO for secondary frequency regulation. For pre-qualification check, an optimal power flow method (called OPF_Q) [45], which is based on semidefinite programming (SDP) [92] is proposed in this work. The proposed OPF_Q calculates the reactive power setpoints of DGs to prevent network congestion, if it could occur according to the original power dispatch plan from the TSO. If the OPF_Q problem is feasible, which means reactive power dispatch to DGS can prevent network congestion, if any, then the ancillary service request of the TSO is approved. If it is not the case, then a request to revise the active power dispatch is sent to the TSO. In this work, SDP method is chosen as this relaxation provides a global optimum solution [92].

From Denmark's Perspective

Secondary frequency regulation is one of the ancillary services required by the Danish TSO in DK1 and DK2 [93]. The secondary frequency regulation is activated by the TSO during major system disturbances if primary frequency regulation is not sufficient and its activation time is 15 min in DK1 and 5 min in DK2 [93]. It is to be noted that a ramp of the requested power is allowed and it is to be achieved in full within the time mentioned above. In this work, DGs of category C as per the regulations [94] and [95], which are in the range 1.5 MW to 25 MW are considered for providing secondary frequency regulation.

Advanced TSO-DSO Interface

As discussed above, a strong interaction between TSO-DSO at different periods is necessary for sustainable and optimal utilization of the grid assets. Present and proposed configurations of the TSO-DSO interface concerning the utilization of ancillary services are shown in Figure 3.29.

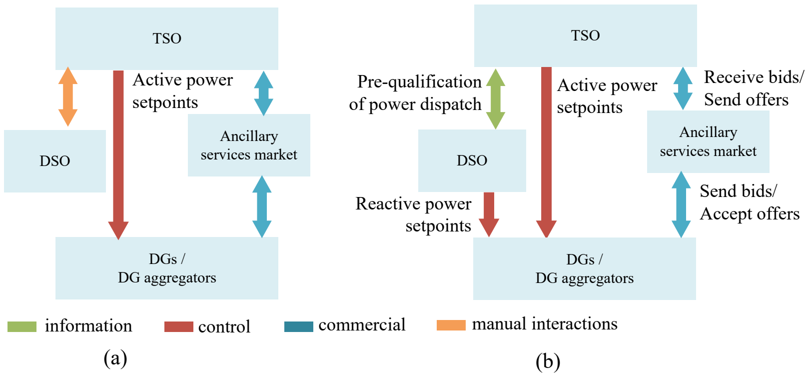


Fig. 3.29: Interaction of the TSO and DSO for secondary frequency regulation in (a) present scenario, and (b) proposed ATDi [C6].

The signal flow in the proposed ATDi is shown in Figure 3.29 (b), and it can be seen that the DSO is involved in the utilization of ancillary services from DGs.

In Table 3.12, a summary of the roles of each player is provided.

Table 3.12: Summary of the roles in the proposed ATDi [C6]

Player	Roles in the proposed ATDi
Market	A common market is proposed for ancillary services called ancillary services market, operated by the TSO, for resources connected at both transmission and distribution levels.
TSO	Responsible for the operation of transmission network and procurement of ancillary services. The constraints of the distribution network are not taken into account. The TSO is not aware whether activation of ancillary services cause network congestion in the distribution networks.
DSO	Not involved in the procurement and activation process of ancillary services by the TSO. However, the DSO runs OPF_Q to check whether the utilization of DG for ancillary services by the TSO causes network congestion. If yes, OPF_Q tries to solve it by calculating reactive power dispatch of DG or else feedback is given to the TSO to modify the power dispatch of the DG.
DGs	Participate in the ancillary service market either individually depending on the power rating or as a group coordinated by an aggregator to provide secondary frequency regulation to the TSO. Receive active power dispatch from the TSO and reactive power setpoints from the DSO.

Utilization of Ancillary Services from DGs by the TSO

Based on the discussions about the proposed ATDi above, its schematic diagram is provided in Figure 3.30. As shown in Figure 3.30, the DSO computes reactive power regulation signal using the proposed OPF_Q and send it to the DGs. The formulation of the proposed OPF_Q is shortly explained below and its details can be found in [C6].

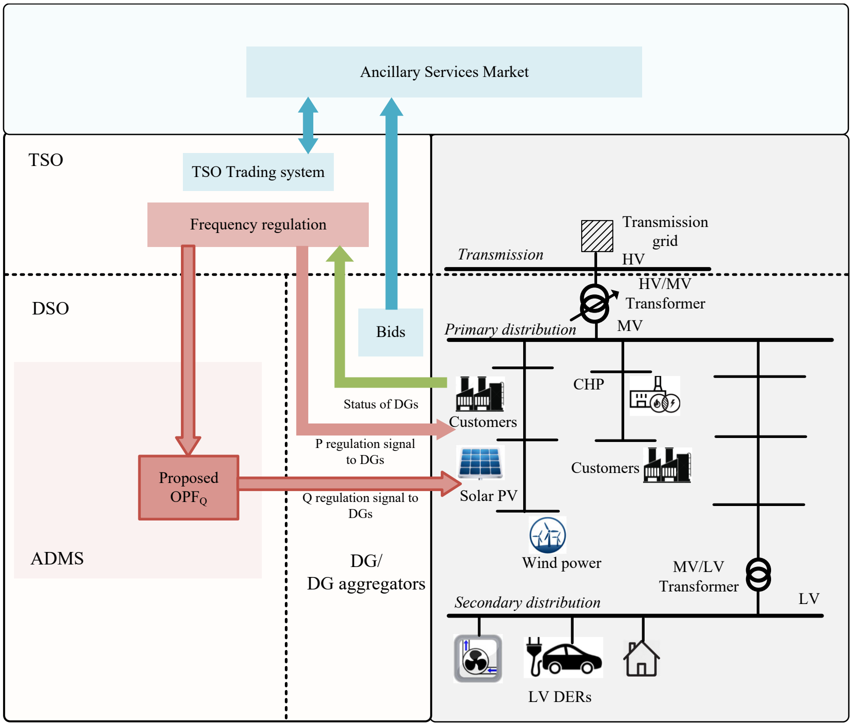


Fig. 3.30: Schematic diagram of the proposed ATDi from the context of DK1 region, Denmark (the lines and a box with thick red color are the proposed additions) [C6].

Semidefinite Programming based OPF [C6]

The OPF_Q based on SDP finds the minimum absolute value of reactive power required from DGs to maintain the network voltages within limits and its details can be found in [C6]. The SDP expresses the network variables (node voltages and node active and reactive powers) as vectors/matrices. The SDP formulation uses matrix properties such as positive semi-definite for convex relaxations of the ac nonlinear power equations [92]. DSO can solve the proposed OPF_Q to compute reactive power setpoints of DGs to maintain the network voltages within limits. The flowchart shown in Figure 3.31 explains the above-described process.

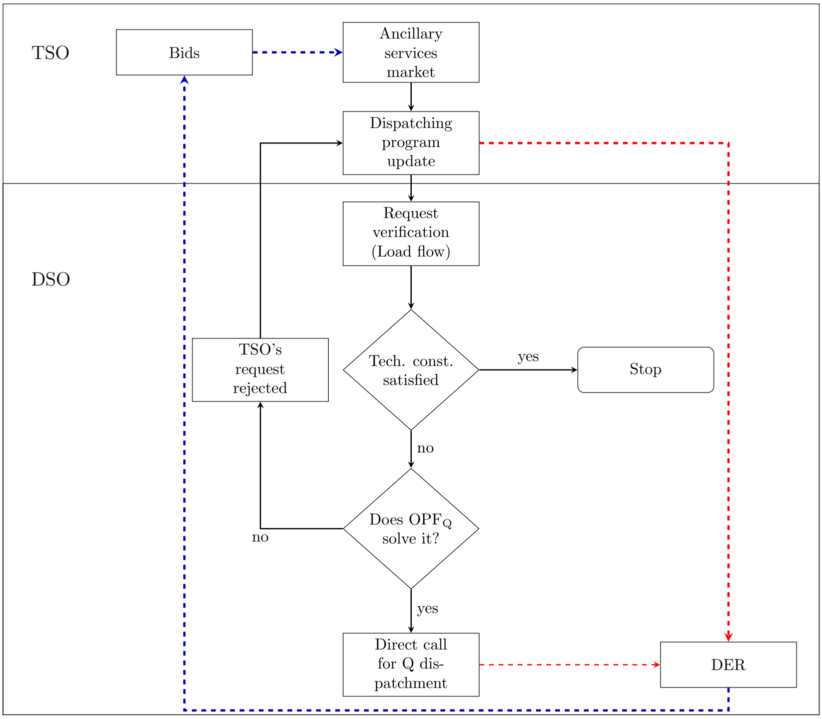


Fig. 3.31: Flowchart for involvement of the DSO for ancillary services provision (aFFR) by DGs [45], [C6].

3.4.2 Simulation Studies

In this work, the modified 60/20 kV MV distribution network of Støvring area described in [91] and [96] is used for simulation studies. Figure 3.32 shows the modified MV network with wind, solar and CHP plants and its parameters can be found in [96]. The power profile of CHP plant with a time-step of 15 min is obtained based on data from Skagen district heating website Energy Web. Wind power profile is obtained from [97], and that of PV is obtained on a clear sky day in Denmark, both with a time-step of 15 min. The OPF$_Q$ problem is solved using Matlab based toolbox YALMIP with the solver MOSEK.

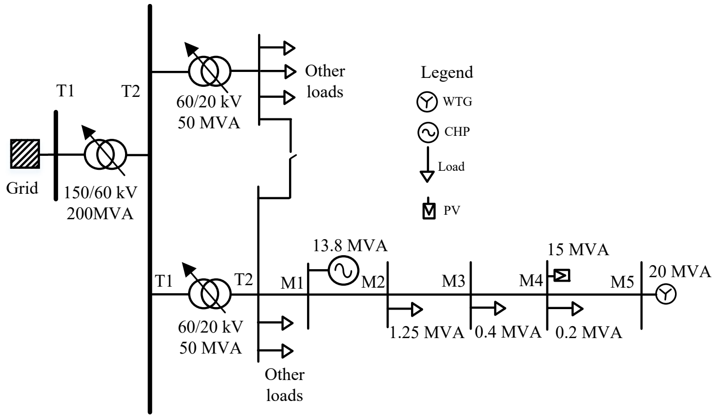


Fig. 3.32: Modified MV network of Støvring in North Jutland, Denmark [91], [C6].

Case 1: Without Proposed TSO-DSO Interface

In this simulation case, a hypothetical power response from DGs (CHP, solar and wind power plants) as shown in Figure 3.33(a) with respect to ancillary service request from the TSO is considered. The DGs are assumed to be operating at unity power factor. The 60/20 kV transformer tap setting is assumed to be 0.935 pu at the secondary side. The voltage which would be experienced during ancillary services from DGs, are depicted at Figure 3.33(b). As the DSO is not aware of the ancillary services by DGs, the node voltages are above the limit of 1.1 pu.

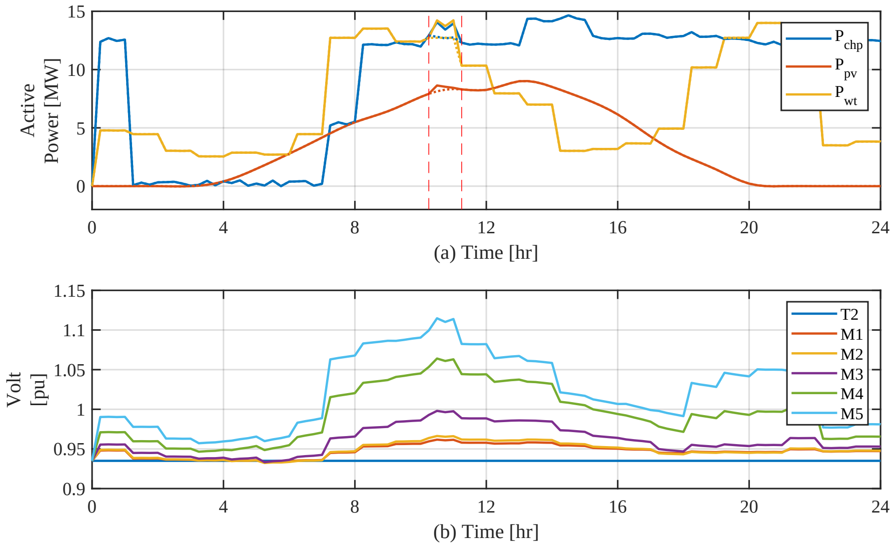


Fig. 3.33: Case 1: Without proposed TSO-DSO interface: (a) active powers of CHP, solar and wind power plants in response to an hypothetical TSO's request for freqeuncy up-regulation within the time period marked in vertical red color lines (solid and dashed lines show the power profile with and without ancillary services), and (b) voltages at MV nodes [C6].

Case 2: With Proposed TSO-DSO Interface

In this simulation case, it is assumed that the TSO communicates the expected active power response from DGs for ancillary services to the DSO. The DSO executes the proposed OPF_Q to find the reactive power setpoints of the DGs as shown in Figure 3.34(b) that could prevent network congestion. When the DGs are operated with updated reactive power setpoints from the DSO, the node voltages are maintained within the limit of 1.1 pu as seen in Figure 3.34(a).

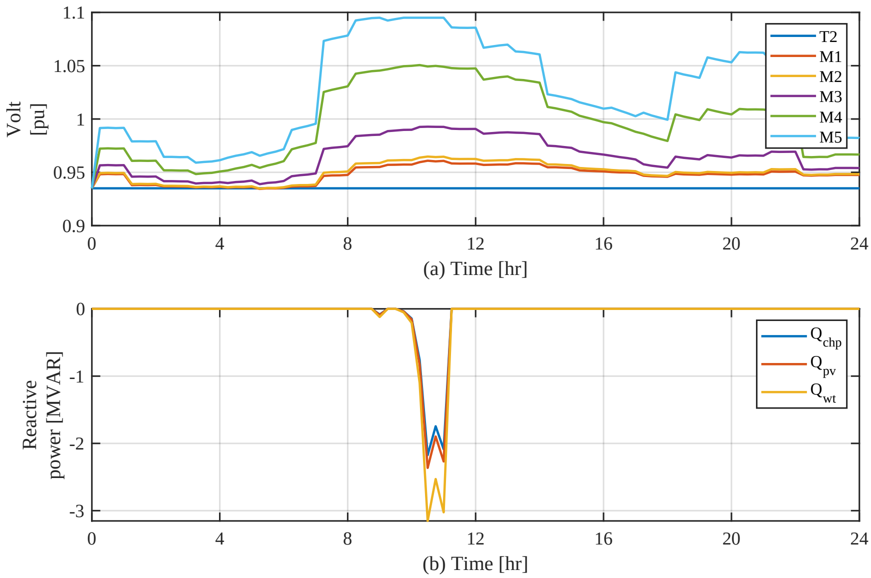


Fig. 3.34: Case 2: With proposed TSO-DSO interface: (a) voltages at MV nodes (b) reactive powers dispatched by the DSO to CHP, solar and wind power plants [C6].

Remark 3.4.1:
From the above simulation results, it is clear that, DSOs should be aware of the ancillary services provided by DGs at distribution networks and if they are involved in the pre-qualification process during the power dispatch from the TSO to the DGs, network congestion may be prevented.

3.5 Conclusions

In this chapter, a summary of the four contributions of this thesis is provided. The category 1 regarding hierarchical control dealt with the network controllers (level 3 and 2 controllers) and DER controller (level 1 control). The predictive algorithm based on linear programming proposed in centralized or distributed manner can be employed for both network controllers. An extension of the above linear programming to an MILP algorithm can be used for network reconfiguration problem. Utilization of flexibility from DERs in real-time from PVs, in day-ahead planning and operation phases for network congestion management are discussed with simulation results. A simple protection algorithm to calculate relay settings was presented. Finally, an advanced TSO-DSO interface for ancillary services by DERs and prevention of network congestion is also discussed in this chapter.

Chapter 4

Conclusion

To conclude, a hierarchical distributed control framework for management of an active distribution network is proposed in this thesis. The top and middle level controllers of the proposed control hierarchy are part of an advanced distribution management system (ADMS) of the distribution system operator to manage medium and low-voltage networks respectively. The bottom level controllers are individual controllers of DERs owned by customers. Simulation studies on models of Danish distribution networks prove that the proposed framework can manage the network congestion and make the network operation cost-effective. A network reconfiguration algorithm proposed in this thesis based on mixed-integer linear programming can find a suitable topology of the network that minimizes the network power losses and ensures that the nodes voltages and branch current are within limits. A simple adaptive protection algorithm that changes the settings of over-current relays is developed to address the protection blinding and false tripping problems in a medium-voltage distribution network due to connection of DGs.

In the following sections, a conclusion on the proposed hypotheses is provided followed by an overall conclusion, perspectives and future research directions of this work.

4.1 Conclusion on the Proposed Hypotheses

Regarding Hypothesis 1, which stated that a hierarchical control could reduce operating costs of a distribution network, the following conclusions can be drawn. At first, the conclusions with respect to the category of *Hierarchical control framework for ADMS* are discussed as follows. From Paper [C1], which is based on a state of the art review of control methods of future active distribution networks, it can be concluded that a hierarchical control framework is useful to (i) increase the penetration of DERs, (ii) maximize the utilization of network assets, and (iii) enhance the operational resilience of the network by means of automatic network reconfiguration and adaptive protection. In Paper [J1], it is shown through simulation studies that an aggregated low-voltage network control (LVNC) can manage the network in a cost effective way by direct control of DERs. It is proven that the proposed LVNC, which is the middle level control of the proposed control hierarchy, can dispatch active and reactive setpoints to heat pumps and BESS once in 10 min by solving a predictive control algorithm based on linear programming. A linear power flow method developed in Paper [J1] which is used to represent the model of the distribution network in the proposed control algorithm is shown to be more accurate than few methods available in the literature. The Section 3.1 has treated the hierarchical control framework envisioned in Hypothesis 1 in-depth and discusses the operation of all the three control levels. In Section 3.1, it is also shown by comparison that a distributed predictive algorithm can solve the predictive control algorithm developed in Paper [J1] for control of BESS in low-voltage network by employing a decomposition technique based on alternating-direction method of multipliers method.

From the second category of contribution *Utilization of DERs for flexibility*, in relation to Hypothesis 1, the following concluding remarks can be made. In Paper [C2], the simulation results show that flexibility from PV inverters in the form of reactive power provision by volt/var droop control can provide better voltage regulation in a fair manner. The results reported in Paper [C3] show that operating costs of the network can be reduced by calculating the optimal demand response required for the next day. From the results presented in Paper [C4], it can be concluded that by utilizing flexibility from BESS, power losses of the network can be reduced which results in cost savings taking into account of the battery degradation.

In connection to Hypothesis 2 which talked about adaptive grid topology and adaptive relay settings as solutions for network loss minimization and prevention of protection system mal-operation respectively, the following conclusions are made. Two contributions namely network reconfiguration and adaptive protection are reported in this thesis. From the studies on network reconfiguration on a modified medium-voltage network of Lind, Denmark, it is shown that the total network power loss can be decreased from 6.75% to 5.68%. Apart from reducing the network power losses, the network reconfiguration algorithm is also able to find the right configuration of the network in which the network voltages and branch currents are within the limits. A simple adaptive protection algorithm developed in this thesis is able to prevent two potential problems namely protection blinding and false tripping with regard to the connection of DG in a medium-voltage grid. Simulation studies done on a real-time digital simulator and the testing and validation of the proposed adaptive protection algorithm done in DigSilent Power factory supports the above mentioned statement.

Hypothesis 3 claimed that network congestion can be managed by improved interface among the grid stakeholders and improved network observability and controllability. Papers [C5] and [C6] are made on the basis of Hypothesis 3, from which the following conclusions are derived. It is to be noted that Paper [C5] deals with the need for proper monitoring and control measures in coordination with electricity markets to foresee and prevent grid congestion and Paper [C6] illustrates the importance of improved TSO-DSO interface aspects of Hypothesis 3. Paper [C5] concludes that network congestion can be managed in two stages as follows. The first stage is a day-ahead planning stage, in which flexibility can be procured in advance for the next day from the day-ahead market and the second stage being the operation phase, in which additional flexibility can be procured from intraday market if required to remove network congestion. Simulation studies reported in Paper [C5] show that overloading of branch currents of a MV network can be prevented in the planning stage itself and unexpected over-voltages in a LV network can be alleviated by the network control in the operating stage based on the information from the network monitoring algorithm. In Paper [C6], the simulation studies on a simple MV network of Støvring, Denmark demonstrate that, involving DSOs in the secondary frequency regulation can prevent voltage violations in the distribution network. It is shown that, if the TSO shares with the DSO about the active power dispatch to the DERs, then the DSO can perform a pre-qualification check and take appropriate action to prevent network congestion, if any, during utilization of DERs for secondary frequency regulation.

4.2 Overall Conclusion

In this section, the overall conclusion of this thesis is provided. It is evident from the analysis reported in this thesis that network congestion will be prevalent in future Danish distribution networks with high penetration of DERs. It is discussed that without proper coordination between the TSO and DSOs, network congestion may occur in distribution networks while DERs are utilized by the TSO for ancillary services. It is shown that without proper control measures that optimizes the utilization of network assets, DSOs may not be able to maintain the quality of service to the customers and they may have to opt for costly network upgrades. It is illustrated that operating the network with a fixed topology may result in more power losses and voltage violations at some nodes depending on the location and power outputs from DERs. The analysis regarding connection and disconnection of DGs in medium-voltage grids shows that short-circuit capacity and fault current levels may be significantly different. As a result, fixed protective relay settings may cause mal-operation of the protection system.

Keeping in mind of the above analysis, this thesis concludes that in future, improving the monitoring and control of distribution networks is of utmost importance for DSOs. Observability of the distribution networks may be enhanced by identifying and setting-up data collection from critical network nodes. Controllability of the network may be improved by automating the tap changing of low-voltage distribution transformers and switching of circuit breakers, and implementing demand response. Once the network observability and controllability are ensured to the required level, managing network congestion may be feasible by means of cost-effective solutions. The recommended solutions for network congestion management in order of preference are volt/var control, network reconfiguration and demand response. Assuming market mechanisms are revised suitably in future, participation of DSOs in electricity markets to buy flexibility is recommended to increase competition and mutual cost benefits for DSOs and customers. A hierarchical control architecture is preferable for aggregated control of flexible resources at different voltage levels and geographical locations. Distributed predictive control is the recommended for large-scale implementation of demand response of DERs as it is promising in terms of scalability, minimizes the communication burden and respects the data privacy of the customers. An assessment of the impact of DGs on protection system is essential for adaptive configuration of relay settings than can prevent its malfunctioning. Increased coordination among DSOs and the TSO is recommended which may pave the way for exchanging ancillary services without creating operational problems in networks.

4.3 Perspectives

In this section, few perspectives about the research carried out in this thesis are discussed. For practical success of hierarchical distributed control of distribution grids, the following conditions are important. Communication and automation infrastructure should be present connecting utility with customers. The necessity and commercial value of flexibility are important for the grid stakeholders to implement the proposed method. The customers should be motivated and empowered to participate in demand response program, thereby they can achieve economic gains and contribute to green energy transition. At present, small-scale DERs are not allowed to participate in electricity markets to sell their flexibility. However, in future, new electricity markets such as integrated flexibility market may be introduced in Denmark, in which DSOs, the TSO and DERs (either individually or through a commercial aggregator) can participate to buy and sell flexibility services. Market availability of suitable control technologies are also important so that the DSOs can purchase and implement them as turn-key solutions for a stable and optimal operation of distribution grids. As of today, PV inverters in Denmark are operated at unity power factor. By appropriate revisions of Danish grid codes, PV inverters could be obliged to provide reactive power support using volt/var control proposed in this thesis. It is possible to implement network reconfiguration in Danish distribution grids for power loss minimization by automating the control of switches. False tripping is not a concern in Danish medium-voltage grids due to the design of protection system, however, protection blinding could happen if large DGs are connected to MV nodes. Study of the impact of connection of DGs and the need for adaptive relay settings have to be assessed on case by case basis.

4.4 Future Research Directions

In this section, some of the future research directions that may extend or improve the work presented in this thesis are provided. At first, possible future extensions of this thesis work are listed below.

- An incentive based demand response scheme may be developed wherein; the distribution system operator calculates a global incentive price signal and broadcasts it to the customers to actualize flexibility.
- Methods to utilize flexibility from DERs and active loads that have discrete or binary levels of output power may be explored. In addition, utilization of the on-load tap-changing operation of the transformers in distribution network voltage control may be considered.
- Comparison of the proposed reconfiguration scheme with state of the art methods for large-scale distribution networks with many controllable switches for reconfiguration may be performed to study the merits/demerits of the proposed scheme.
- Hardware-in-loop simulations may be carried out with a suitable protective relay such as REF615 of ABB make to validate the proposed adaptive protection scheme in a real-time digital simulator.
- Advanced TSO-DSO interface proposed in this thesis for secondary frequency regulation may be extended for other ancillary services such as voltage regulation.

In the following, future research directions either to improve or to solve from different perspectives are discussed. Models of the distribution network, DERs and their parameters are assumed to be deterministic. This assumption enables us to apply a deterministic optimization technique to solve the optimal power flow problem formulated in this thesis. However, there are lot of uncertainty in the above mentioned models and parameters as well as in the behavior of customers, electricity prices, and the power outputs from wind and solar plants are stochastic.

- A future research activity could be employing a stochastic optimization or a distributed robust optimization technique to solve the optimal power flow problem.
- Game theory and mean field control methods can be explored as an alternative to the distributed predictive control technique proposed in this thesis.
- McCormick envelopes based quadratic programming algorithm may be studied and applied for finding the settings of relays considering various fault scenarios, short-circuit levels, network configurations and connection status of DGs.

References

[1] The Danish Government, "Our future energy," Tech. Rep. November, 2011. [Online]. Available: http://www.ens.dk/en/policy/danish-climate-energy-policy

[2] "Energinet - The Danish national transmission system operator for electricity and natural gas." [Online]. Available: http://www.energinet.dk

[3] "Wind amount | Wind Denmark International." [Online]. Available: https://en.winddenmark.dk/wind-in-denmark/statistics/wind-amount

[4] P. Pinson *et al.*, "Towards fully renewable energy systems: Experience and trends in Denmark," *CSEE J. Power Energy Syst.*, vol. 3, no. 1, pp. 26–35, 2017.

[5] Danish Energy Association, "Smart grid in Denmark 2.0," Tech. Rep. [Online]. Available: https://www.usef.energy/app/uploads/2016/12/Smart-Grid-in-Denmark-2.0-2.pdf

[6] M. Lidegaard, "Smart grid strategy - The intelligent energy system of the future," 2013. [Online]. Available: http://www.kemin.dk

[7] E. Rivero, J. Barquín, and L. Rouco, "European balancing markets," *2011 8th Int. Conf. Eur. Energy Mark.*, no. May, pp. 333–338, 2011.

[8] Energinet, "Market model 2.0," 2015. [Online]. Available: https://en.energinet.dk/About-our-reports/Reports/Market-Model-2-0

[9] B. Bak-Jensen, M. Browne, R. Calone, R. C. Gonzalez, A. Craib, and G. Donnart, "Protection of Distribution Systems with Distributed Energy Resources," *Jt. Work. Gr. B5/C6.26/CIRED, CIGRE*, no. March, 2015.

[10] "Disconnected power cable to Bornholm offers unique test option - DTU." [Online]. Available: https://www.dtu.dk/english/news/2019/05/disconnected-power-cable-to-bornholm-offers-unique-test-option?id=b5de3f2e-986d-4a13-b2d1-b61dd801c853

[11] "Bornholm Visualizer." [Online]. Available: http://bornholm.powerlab.dk/

[12] P. Palensky and D. Dietrich, "Demand side management: Demand response, intelligent energy systems, and smart loads," *IEEE Trans. Ind. Informatics*, vol. 7, no. 3, pp. 381–388, 2011.

[13] E. Demirok, P. C. González, K. H. B. Frederiksen, D. Sera, P. Rodriguez, and R. Teodorescu, "Local reactive power control methods for overvoltage prevention of distributed solar inverters in low-voltage grids," *IEEE J. Photovoltaics*, vol. 1, no. 2, pp. 174–182, 2011.

[14] M. E. Baran and F. F. Wu, "Network reconfiguration in distribution systems for loss reduction and load balancing," *Power Deliv. IEEE Trans.*, vol. 4, no. 2, pp. 1401–1407, 1989.

[15] R. Tonkoski, L. A. C. Lopes, and T. H. M. El-Fouly, "Coordinated active power curtailment of grid connected PV inverters for overvoltage prevention," *IEEE Trans. Sustain. Energy*, vol. 2, no. 2, pp. 139–147, 2011.

[16] A. P. Sakis Meliopoulos, E. Polymeneas, Z. Tan, R. Huang, and D. Zhao, "Advanced distribution management system," *IEEE Trans. Smart Grid*, vol. 4, no. 4, pp. 2109–2117, 2013.

[17] "The Nord Pool spot market." [Online]. Available: http://www.nordpoolspot.com/

[18] H. Lund, P. A. Østergaard, D. Connolly, and B. V. Mathiesen, "Smart energy and smart energy systems," *Energy*, vol. 137, pp. 556–565, 2017.

[19] J. Mortensen, J. Flackeberg, A. Goul, and M. Johansen, "The Smart Energy System," Tech. Rep., 2015. [Online]. Available: https://www.cleancluster.dk/

[20] E. Dall'Anese, P. Mancarella, and A. Monti, "Unlocking flexibility: Integrated optimization and control of multienergy Systems," *IEEE Power Energy Mag.*, no. Feb, pp. 43–52, 2017.

[21] EMD International A/S, "Elpriser og estimeret elproduktion og forbrug i vest-Danmark (Jylland/Fyn)." 2019. [Online]. Available: http://www.emd.dk/el/

[22] Dansk Energi, "DEFU rapport RA 579 - Solceller og spændingsvariationer i 0,4 kV net," *[online] www.danskenergi.dk*, 2012.

[23] J. Sexauer, P. Javanbakht, and S. Mohagheghi, "Phasor measurement units for the distribution grid: Necessity and benefits," *2013 IEEE PES Innov. Smart Grid Technol. Conf. ISGT 2013*, pp. 1–6, 2013.

[24] M. R. Dorostkar-Ghamsari, M. Fotuhi-Firuzabad, M. Lehtonen, and A. Safdarian, "Value of Distribution Network Reconfiguration in Presence of Renewable Energy Resources," *IEEE Trans. Power Syst.*, vol. 31, no. 3, pp. 1879–1888, 2016.

[25] F. Capitanescu, L. F. Ochoa, H. Margossian, and N. D. Hatziargyriou, "Assessing the potential of network reconfiguration to improve dis-

tributed generation hosting capacity in active distribution systems," *IEEE Trans. Power Syst.*, vol. 30, no. 1, pp. 346–356, 2015.

[26] S. Shen *et al.*, "An Adaptive Protection Scheme for Distribution Systems with DGs Based on Optimized Thevenin Equivalent Parameters Estimation," *IEEE Trans. Power Deliv.*, vol. 32, no. 1, pp. 411–419, 2017.

[27] F. Pilo *et al.*, "Control and Automation Systems at the TSO-DSO interface: A survey on the actual functionalities and DSO requirements," in *Cigre WG C6.25, Dublin*, 2017, pp. 1–10.

[28] E. J. Coster, J. M. A. Myrzik, B. Kruimer, and W. L. Kling, "Integration Issues of Distributed Generation in Distribution Grids," *Proc. IEEE*, vol. 99, no. 1, pp. 28–39, 2011.

[29] A. Kulmala *et al.*, "Hierarchical and distributed control concept for distribution network congestion management," *IET Gener. Transm. Distrib.*, vol. 11, no. 3, pp. 665–675, 2017.

[30] B. P. Bhattarai *et al.*, "Design and co-simulation of hierarchical architecture for demand response control and coordination," *IEEE Trans. Ind. Informatics*, vol. 13, no. 4, pp. 1806–1816, 2017.

[31] F. M. Andersen *et al.*, "Analyses of demand response in Denmark," Tech. Rep. October, 2006.

[32] R. Halvgaard, N. K. Poulsen, H. Madsen, and J. B. Jorgensen, "Economic model predictive control for building climate control in a smart grid," in *IEEE PES Innov. Smart Grid Technol.*, Washington DC, 2012.

[33] F. Marra, G. Yang, C. Træholt, J. Østergaard, and E. Larsen, "A decentralized storage strategy for residential feeders with photovoltaics," *IEEE Trans. Smart Grid*, vol. 5, no. 2, pp. 974–981, 2014.

[34] A. Haque, P. Nguyen, W. Kling, and F. Bliek, "Congestion management in smart distribution network," *Proc. Univ. Power Eng. Conf.*, no. Mv, 2014.

[35] P. Fortenbacher, J. L. Mathieu, and G. Andersson, "Modeling and Optimal Operation of Distributed Battery Storage in Low Voltage Grids," *IEEE Trans. Power Syst.*, vol. 32, no. 6, pp. 4340–4350, 2017.

[36] A. Di Giorgio, F. Liberati, A. Lanna, A. Pietrabissa, and F. D. Priscoli, "Model Predictive Control of Energy Storage Systems for Power Tracking and Shaving in Distribution Grids," *IEEE Trans. Sustain. Energy*, vol. 8, no. 2, pp. 496–504, 2017.

[37] M. Kramer, A. Jambagi, and V. Cheng, "A model predictive control approach for demand side management of residential power to heat technologies," *2016 IEEE Int. Energy Conf.*, pp. 1–6, 2016.

[38] P. Fortenbacher, A. Ulbig, and G. Andersson, "Optimal Placement and Sizing of Distributed Battery Storage in Low Voltage Grids using Receding Horizon Control Strategies," *IEEE Trans. Power Syst.*, vol. 33, no. 3, pp. 2383–2394, 2018.

[39] W. Zhong, C. Yang, K. Xie, S. Xie, and Y. Zhang, "ADMM-Based Distributed Auction Mechanism for Energy Hub Scheduling in Smart Buildings," *IEEE Access*, vol. 6, pp. 45 635–45 645, 2018.

[40] D. H. Nguyen, T. Narikiyo, and M. Kawanishi, "Optimal Demand Response and Real-Time Pricing by a Sequential Distributed Consensus-Based ADMM Approach," *IEEE Trans. Smart Grid*, vol. 9, no. 5, pp. 4964–4974, 2018.

[41] X. Zhou, E. Dallanese, L. Chen, and A. Simonetto, "An incentive-based online optimization framework for distribution grids," *IEEE Trans. Automat. Contr.*, vol. 63, no. 7, pp. 2019–2031, 2018.

[42] H. Gerard, V. Energyville, E. Rivero, V. Energyville, D. Six, and V. Energyville, "Basic schemes for TSO-DSO coordination and ancillary services provision," SmartNet, Tech. Rep., 2016.

[43] F. Pilo, G. Mauri, B. Bak-Jensen, E. Kämpf, J. Taylor, and F. Silvestro, "Control and automation functions at the TSO and DSO interface – impact on network planning," *CIRED - Open Access Proc. J.*, vol. 2017, no. 1, pp. 2188–2191, 2017.

[44] P. Michael, R. Carsten, N. Christer, D. Ellen, and P. Seamus, "System operation emphasizing DSO -TSO interaction and coordination," in *Cigre Jt. Work. Gr.*, no. August, 2018.

[45] G. Mauri, P. Fabrizio, T. Jason, and B. Gianluca, "Control and automation systems for electricity distribution networks of the future," in *Cigre WG C6.25/B5*, no. Jun, 2017.

[46] T. Soares, "Renewable energy sources offering flexibility through electricity markets," p. 198, 2017.

[47] E. M. Larsen, "Demand response in a market environment," 2015.

[48] Y. Ding, S. Pineda, P. Nyeng, J. Østergaard, E. M. Larsen, and Q. Wu, "Real-time market concept architecture for EcoGrid EU - A prototype for European smart grids," *IEEE Trans. Smart Grid*, vol. 4, no. 4, pp. 2006–2016, 2013.

[49] P. Mahat, Z. Chen, B. Bak-Jensen, and C. L. Bak, "A simple adaptive overcurrent protection of distribution systems with distributed generation," *IEEE Trans. Smart Grid*, vol. 2, no. 3, pp. 428–437, 2011.

[50] B. C. Sung, S. H. Lee, J. W. Park, and A. P. Meliopoulos, "Adaptive protection algorithm for overcurrent relay in distribution system with DG," *J. Electr. Eng. Technol.*, vol. 8, no. 5, pp. 1002–1011, 2013.

[51] V. A. Papaspiliotopoulos, G. N. Korres, V. A. Kleftakis, and N. D. Hatziargyriou, "Hardware-In-the-Loop Design and Optimal Setting of Adaptive Protection Schemes for Distribution Systems with Distributed Generation," *IEEE Trans. Power Deliv.*, vol. 32, no. 1, pp. 393–400, 2017.

[52] J. A. Taylor and F. S. Hover, "Convex models of distribution system reconfiguration," *IEEE Trans. Power Syst.*, vol. 27, no. 3, pp. 1407–1413, 2012.

[53] J. A. Taylor, *Convex optimization of power systems optimization*. Cambridge University Press, 2015.

[54] S. Boyd and L. Vandenberghe, *Convex Optimization*. Cambridge University Press, 2009.

[55] D. K. Molzahn *et al.*, "A survey of distributed optimization and control algorithms for electric power systems," *IEEE Trans. Smart Grid*, vol. 8, no. 6, pp. 2941–2962, 2017.

[56] D. P. Palomar and M. Chiang, "A tutorial on decomposition methods for network utility maximization," *IEEE J. Sel. Areas Commun.*, vol. 24, no. 8, pp. 1439–1451, 2006.

[57] A. J. Conejo, E. Castillo, R. Minguez, and R. Garcia-Bertrand, *Decomposition techniques in mathematical programming*. Springer, 2006.

[58] F. Dorfler, J. W. Simpson-Porco, and F. Bullo, "Electrical networks and algebraic graph theory: Models, properties and applications," *Proc. IEEE*, vol. 106, no. 5, pp. 977–1005, 2018.

[59] W. H. Kersting, *Distribution System Modeling and Analysis*. CRC press, 2012.

[60] H. Saadat, *Power system analysis*. WCB/McGraw-Hill, Singapore, 1999.

[61] J. H. Teng, "A direct approach for distribution system load flow solutions," *IEEE Trans. Power Deliv.*, vol. 18, no. 3, pp. 882–887, 2003.

[62] C. Coffrin and P. V. Hentenryck, "A linear programming approximation of ac power flows," *INFORMS J. Comput.*, vol. 26, no. 4, pp. 718–734, 2014.

[63] I. D. De Cerio Mendaza, I. G. Szczesny, J. R. Pillai, and B. Bak-Jensen, "Demand Response Control in Low Voltage Grids for Technical and Commercial Aggregation Services," *IEEE Trans. Smart Grid*, vol. 7, no. 6, pp. 2771–2780, 2016.

[64] C. Bang, F. Fock, and M. Togeby, "The existing Nordic regulating power market," Tech. Rep., 2012.

[65] O. Gandhi, W. Zhang, C. D. Rodriguez-Gallegos, M. Bieri, T. Reindl, and D. Srinivasan, "Analytical approach to reactive power dispatch and energy arbitrage in distribution systems with DERs," *IEEE Trans. Power Syst.*, vol. 33, no. 6, pp. 6522–6533, 2018.

[66] R. Halvgaard, L. Vandenberghe, N. K. Poulsen, H. Madsen, and J. B. Jørgensen, "Distributed Model Predictive Control for Smart Energy Systems," *IEEE Trans. Smart Grid*, vol. 7, no. 3, pp. 1675–1682, 2016.

[67] S. Boyd, N. Parikh, E. Chu, B. Peleato, and J. Eckstein, "Distributed Optimization and Statistical Learning via the Alternating Direction Method of Multipliers," *Found. trends Mach. Learn.*, vol. 3, no. 1, pp. 1–122, 2011.

[68] S. S. Guggilam, E. Dall'Anese, Y. C. Chen, S. V. Dhople, and G. B. Giannakis, "Scalable optimization methods for distribution networks with high PV integration," *IEEE Trans. Smart Grid*, vol. 7, no. 4, pp. 2061–2070, 2016.

[69] P. Braun, T. Faulwasser, L. Grüne, C. M. Kellett, S. R. Weller, and K. Worthmann, "Hierarchical distributed ADMM for predictive control with applications in power networks," *IFAC J. Syst. Control*, vol. 3, pp. 10–22, 2018.

[70] K. Nainar, J. R. Pillai, B. Bak-Jensen, and J. W. Simpson-Porco, "Predictive control of flexible resources for demand response in active distribution networks," *IEEE Trans. Power Syst.*, vol. 34, no. 4, pp. 2957–2969, 2019.

[71] H. L. Storey, "Implementing an integrated centralized model-based distribution management system," *IEEE Power Energy Soc. Gen. Meet.*, pp. 1–2, 2011.

[72] O. Samuelsson, S. Repo, R. Jessler, J. Aho, M. Karenlampi, and A. Malmquist, "Active distribution network — Demonstration project ADINE," *2010 IEEE PES Innov. Smart Grid Technol. Conf. Eur. ISGT Eur.*, pp. 1–8, 2010.

[73] C. H. Lo and N. Ansari, "Decentralized controls and communications for autonomous distribution networks in smart grid," *IEEE Trans. Smart Grid*, vol. 4, no. 1, pp. 66–77, 2013.

[74] A. Rita, D. Fazio, G. Fusco, and M. Russo, "Decentralized voltage control of distributed generation using a distribution system structural MIMO model," *Control Eng. Pract.*, vol. 47, pp. 81–90, 2016.

[75] S. A. Arafeh, "Hierarchical control of power distribution systems," *IEEE Trans. Automat. Contr.*, vol. AC-23, no. 2, pp. 333–343, 1978.

[76] A. Bidram, F. L. Lewis, and A. Davoudi, "Distributed Control Systems for Small-Scale Power Networks: Using Multiagent Cooperative Control Theory," *IEEE Control Syst. Mag.*, vol. 34, no. 6, pp. 56–77, 2014.

[77] M. Brenna *et al.*, "Automatic distributed voltage control algorithm in smart grids applications," *IEEE Trans. Smart Grid*, vol. 4, no. 2, pp. 877–885, 2013.

[78] EDSO, "Flexibility: The role of DSOs in tomorrow's electricity market," *Tech. Rep.*, 2014. [Online]. Available: https://www.edsoforsmartgrids.eu/wp-content/uploads/public/EDSO-views-on-Flexibility-FINAL-May-5th-2014.pdf

[79] Z. Hu and F. Li, "Cost-benefit analyses of active distribution network management, part I: Annual benefit analysis," *IEEE Trans. Smart Grid*, vol. 3, no. 3, pp. 1075–1081, 2012.

[80] L. Gkatzikis, I. Koutsopoulos, and T. Salonidis, "The role of aggregators in smart grid demand response markets," *IEEE J. Sel. Areas Commun.*, vol. 31, no. 7, pp. 1247–1257, 2013.

[81] G. K. H. Larsen, N. D. van Foreest, and J. M. A. Scherpen, "Power supply-demand balance in a Smart Grid: An information sharing model for a market mechanism," *Appl. Math. Model.*, vol. 38, no. 13, pp. 3350–3360, 2014.

[82] E. Valsomatzis, K. Hose, and T. B. Pedersen, "Balancing energy flexibilities through aggregation," in *Data Anal. Renew. Energy Integr. - Lect. Notes Comput. Sci.*, W. W., A. Z., and M. S., Eds. Springer, 2014, vol. 8817, pp. 17–37.

[83] K. Turitsyn, P. Sulc, S. Backhaus, and M. Chertkov, "Local control of reactive power by distributed photovoltaic generators," in *IEEE Int. Conf. Smart Grid Commun.*, Gaithersburg, MD, 2010, pp. 79–84.

[84] S. Alyami, Y. Wang, C. Wang, J. Zhao, and B. Zhao, "Adaptive real power capping method for fair overvoltage regulation of distribution networks with high penetration of PV systems," *IEEE Trans. Smart Grid*, vol. 5, no. 6, pp. 2729–2738, 2014.

[85] C. Heinrich, P. Fortenbacher, A. Fuchs, and G. Andersson, “PV-integration strategies for low voltage networks,” *2016 IEEE Int. Energy Conf. ENERGYCON 2016*, vol. 2, no. 1, 2016.

[86] B. Smith, J.W., Sunderman, W., Dugan, R., Seal, “Smart inverter volt/var control functions for high penetration of PV on distribution systems,” in *2011 IEEE/PES Power Syst. Conf. Expo.*, Phoenix, AZ, 2011, pp. 1–6.

[87] B. Bletterie, S. Kadam, R. Bolgaryn, and A. Zegers, “Voltage control with PV inverters in low voltage networks – In depth analysis of different concepts and parameterization criteria,” *IEEE Trans. Power Syst.*, vol. 32, no. 1, pp. 1–1, 2016.

[88] P. Fortenbacher, J. L. Mathieu, and G. Andersson, “Modeling, identification, and optimal control of batteries for power system applications,” *2014 Power Syst. Comput. Conf.*, pp. 1–7, 2014.

[89] P. Fortenbacher, G. Andersson, and J. L. Mathieu, “Optimal real-time control of multiple battery sets for power system applications,” *2015 IEEE Eindhoven PowerTech, PowerTech 2015*, 2015.

[90] IEEE, “IEEE Standard Inverse-Time Characteristic Equations for Overcurrent Relays,” in *IEEE Std C37.112-1996*, 1996.

[91] M. Altin, X. Han, A. D. Hansen, R. Løvenstein Olsen, N. A. Cutululis, and F. Iov, “Technical Feasibility of Ancillary Services provided by ReGen Plants,” DTU Wind Energy, Tech. Rep., 2018.

[92] J. Lavaei and S. H. Low, “Zero duality gap in optimal power flow problem,” *IEEE Trans. Power Syst.*, vol. 27, no. 1, pp. 92–107, 2012.

[93] Energinet.dk, “Ancillary services to be delivered in Denmark - Tender conditions,” Tech. Rep. 13/80940-91, 2017.

[94] Energinet.dk, “Technical regulation 3.2.2 for PV power plants with a power output above 11 kW,” Tech. Rep., 2015.

[95] Energinet.dk, “Technical regulation 3.2.5 for wind power plants with a power output above 11 kW,” Tech. Rep., 2015.

[96] S. Christoffer, R. Pedersen, N. Silva, S. Bessler, and A. Carrapatoso, “Control Framework and Models,” SmartCeNet Deliverable D4.1, Tech. Rep., 2014.

[97] A. Saint-Pierre and P. Mancarella, “Active Distribution System Management: A Dual-Horizon Scheduling Framework for DSO/TSO Interface under Uncertainty,” *IEEE Trans. Smart Grid*, vol. 8, no. 5, pp. 2186–2197, 2017.