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A Distributed Control and Coordination Strategy Based on Voltage Sensitivity for Network Management

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Abstract

Advances in technology and incentives from governments are enabling growing deployment of distributed energy resources (DER) and this raises challenges over how distribution network operators (DNOs) should host these resources other than through traditional grid reinforcement. The alternative is active network management (ANM) which can control non-firm connections of DERs to ensure the network is compliant with voltage and thermal operating limits while increasing the capacity of the network to host DER. Furthermore, with changes expected in the regulatory paradigm to create ancillary service markets to promote other benefits of DERs, new streams of revenue for DER owners are anticipated. ANM schemes should manage growing volume of DERs while minimising costs of ancillary services. In this context, it is proposed and evaluated a distributed form of ANM for radial networks that manages voltage and thermal constraints and does this cost-effectively by including the costs of ancillary services in its objective function. To distribute the ANM, a mathematical formulation for local calculation of voltage sensitivities is derived that enables each local controller (LC) to take decisions over power injections to solve constraints. These estimates are combined in a message passing process that results in a coordinated set of decisions that solve local and non-local network constraint. The proposed ANM, based on estimated sensitivities and local message passing, is compared with a centralised ANM based on optimal power flow (OPF). Case-studies examined through time-domain simulations showed that the proposed ANM successfully identified the most appropriate DER to act and produced near identical control actions to the OPF. The approach is evaluated across multiple randomly generated scenarios, providing good confidence that the method is widely applicable and accurate. Mismatches of the order of 10^{-2} p.u were observed when compared to centralised algorithm and considerable decrease in computational time and data transmission was achieved.

Declaration of Originality

I, Thiago Mendonca, confirm that all work presented in this thesis is my own and all work undertaken by other authors is appropriately referenced within the text. All of my work is original and has not been published before by a different author. All work that has been published by myself is clearly indicated within the introduction of the relevant chapter.

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List of Acronyms

AC	Alternating Current
ADN	Active Distribution Network
ANM	Active Network Management
AVR	Automatic Voltage Regulator
BES	Battery Energy System
CB	Circuit Breaker
CC	Central Coordinator
CHP	Combined Heat and Power
DC	Direct Current
DER	Distributed Energy Resources
DERMS	Distributed Energy Resources Management System

DG	D istributed G enerator
DN	D istribution N etwork
DNO	D istribution N etwork O perator
DSO	D istribution S ystem O perator
DSR	D emand S ide R esponse
EHV	E xtra H igh V oltage
EV	E lectric V ehicle
GHG	G reenhouse G as
HV	H igh V oltage
LC	L ocal C ontroller
LIFO	L ast I n F irst O ut
LV	L ow V oltage
MV	M edian V oltage
NOP	N ormally O pen P oint
OLTC	O n L ine T ap C hanger
OPF	O ptimal P ower F low
POA	P inciples O f A ccess
PV	P hotovoltaic P anel

RES	R enewable E nergy S ources
SCADA	S upervisory C ontrol and D ata A cquisition
SOP	S oft O pen P oint
TN	T ransmission N etwork
TSO	T ransmission S ystem O perator
VSB	V oltage S ensitivity B ased
ZC	Z one C ordinators

List of Symbols

P_i	Active power injected at node i
Q_i	Reactive power injecting at node i
P_i^{bus}	Active power flowing to node i through its upstream branch
Q_i^{bus}	Reactive power flowing to node i through its upstream branch
$\frac{\partial V_i}{\partial P_j}$	Voltage sensitivity at node i due to active power injection at node j
$\frac{\partial V_i}{\partial Q_j}$	Voltage sensitivity at node i due to reactive power injection at node j
$\frac{\partial V_i}{\partial P_j^{up}}$	Voltage sensitivity at node i due to active power flowing to node j through its upstream branch
$\frac{\partial V_i}{\partial Q_j^{up}}$	Voltage sensitivity at node i due to reactive power flowing to node j through its upstream branch
$\frac{\partial V_i}{\partial P_j} \Big _k$	Voltage sensitivity at node i due to active power injection at node j , calculated by node k
$\frac{\partial V_i}{\partial Q_j} \Big _k$	Voltage sensitivity at node i due to reactive power injection at node j , calculated by node k
R_i	Resistance of the line connecting node i to its upstream node
X_i	Reactance of the line connecting node i to its upstream node

V_i	Voltage at node i
$ V_i $	Voltage magnitude at node i
θ_i	Voltage angle at node i
J	Jacobian Matrix
V_i^{LD}	Voltage line drop between node i and its upstream node
L_i	Load demand connected at node i
G_i	Generator connected at node i
V_i^{new}	Estimated voltage outcome due to change in power flow
V_i^{old}	Voltage measured before power flow alteration
$V_{nominal}$	Nominal voltage
P_i^G	Active power generated at node i
Q_i^G	Reactive power generated at node i
P_i^D	Active power demanded at node i
Q_i^D	Reactive power demanded at node i
P_i^C	Contracted (or agreed) generation capacity of active power at node i
Q_i^C	Contracted (or agreed) generation capacity of reactive power at node i
C^A	Total cost for procuring ancillary services
A_i^P	Cost per unit of power adjusted away from agreed set point for procuring ancillary service of active power adjustment from node i

A_i^Q	Cost per unit of power adjusted away from agreed set point for procuring ancillary service of reactive power adjustment from node i
C_i^{A-}	Total cost for procuring ancillary services for operating DER at node i below contracted capacity
C_i^{A+}	Total cost for procuring ancillary services for operating DER at node i above contracted capacity
A_i^{P-}	Cost per unit Wh that DER at node i agrees to have its active power adjusted below agreed set point
A_i^{P+}	Cost per unit of Wh that DER at node i agrees to have its active power adjusted above agreed set point
A_i^{Q-}	Cost per unit of VARh that DER at node i agrees to have its active power adjusted below agreed set point
A_i^{Q+}	Cost per unit of VARh that DER at node i agrees to have its active power adjusted above agreed set point
$\frac{\partial V_i}{\partial Cost P_j}$	Voltage sensitivity at node i in respect to costs of procuring active power ancillary services from node j
$\frac{\partial V_i}{\partial Cost Q_j}$	Voltage sensitivity at node i in respect to costs of procuring reactive power ancillary services from node j
$\bar{V}_i$	Upper threshold for voltage
$\underline{V}_i$	Lower threshold for voltage
ΔV_i^U	Voltage change that causes voltage at node i to reach the upper voltage threshold
ΔV_i^L	Voltage change that causes voltage at node i to reach the lower voltage threshold
$\bar{S}_i$	Thermal rating, or power flow limit in the line connecting nodes i and its upstream

ΔS_i^{max}	Apparent power flow change that constrains the line thermal capacity
S_i	Apparent power flowing to node i from its upstream node
$\Delta V_i^{Ucritical}$	Voltage change at node i that will cause voltage to reach the upper limit at a given node of the network
$\Delta V_i^{Lcritical}$	Voltage change at node i that will cause voltage to reach the lower limit at a given node of the network
$\Delta S_i^{critical}$	Apparent power change at node i that will reach the thermal limit of a given line in the network
$\overline{\Delta P_i}$	Active power injection change in node i that will cause voltage at a given node of the network to reach its upper limit
$\underline{\Delta P_i}$	Active power injection change in node i that will cause voltage at a given node of the network to reach its lower limit
$\overline{\Delta Q_i}$	Reactive power injection change in node i that will cause voltage at a given node of the network to reach its upper limit
$\underline{\Delta Q_i}$	Reactive power injection change in node i that will cause voltage at a given node of the network to reach its lower limit

Chapter 1

Introduction

The origin of the electricity supply industry and of power system engineering was toward the end of the 19th century, when local direct current (DC) generators were deployed close to demand and without the need to transmit energy over long distances. Networks were not interconnected and each local system could be operated with small generators supplying local demand. The drive to operate electricity systems efficiently saw economies of scale exploited and over time larger power plants were constructed closer to where fuel, mostly coal, or hydro resource was readily available and where land was cheap and accessible [1]. This in turn required energy to be transmitted over longer distances to reach consumers, mostly relatively wealthy people in towns and cities.

To supply electricity to distant locations with the technology available at the time, the DC system changed to alternating current (AC) and a transmission network was designed, using transformers to elevate voltage and consequently reduce conduction losses [2]. Local systems started to be joined together to make better use of available generation and to provide reserve more efficiently, resulting in a more interconnected electricity network, based on larger power plants. By the beginning of the 20th century, power systems all around the world followed the same pattern of large central AC generators with power transmitted over long distances through a transmission network (TN) utilising very high voltages to substations and onward through a distribution network (DN) operated with lower voltages to consumers.

Although the design of power systems in this format has enabled electrification of large numbers of consumers in a cost-effective and reliable way, and served the economies of many countries of the world well for a hundred years, it has now come to a point where this paradigm is challenged by changed circumstance, notably the growing attention to environmental concerns.

Many countries have now adopted policies for management of their economy and its growth that incorporate environmental goals. For instance, the United Kingdom has defined a strategy for clean growth, *i.e.* economic growth through promoting the technologies that deliver reduction of greenhouse gas (GHC) emissions while also defining an ambitious plan of decarbonising economy thorough a set of “carbon budgets” that presently extend to 2032 [3,4]. Additionally, in the climate change act of 2008 [5], the UK committed to reduce emissions by 80% by 2050 (when compared with 1990 level).

The incentives to build renewable energy has led to an increase in the number of small scale generation connected to the high voltage distribution network rather than the extra high voltage transmission network. This has become known as distributed generation (DG), which often includes on-shore wind farms of modest size, solar farms or roof-top solar installations and can also include combined heat and power (CHP). The deployment of these low carbon technologies, specially renewable energy resources (RES) in DG form, was initially driven by various subsidies by governments. However, as RES technologies have improved they are at or near the point of being competitive with gas-fuelled generation without a subsidy. Thus, the dominance of the centralised paradigm of power systems development is challenged [6]. The authors in [7] categorised the main drivers for integration of DG as environmental, commercial and regulatory, as summarised in the following list.

1. Construction of transmission circuits and large generating units are always accompanied by environmental impact;
2. Large-scale plant and equipment, with large capital investment take longer to complete and become operational;
3. Uncertainties over long term electricity market environment favour small-scale generation investments because the financial risk is smaller;

4. Each distributed generation supplies enough energy for small groups of customers, and therefore failure of one unit has only a small impact on the whole system. Only failure of multiple units at the same time, which is less likely to happen, will lead to interruption of customer supplies;
5. With DG requiring smaller individual investments and being quicker to deploy, a more diverse energy mix is possible;

It is not only small-scale generators in DN that are being incentivised by new policies but also battery energy storage (BES), electric vehicle (EV), controllable loads participating in demand side response (DSR), which are collectively defined as distributed energy resources (DER) [8,9]. The term “Distributed Energy Resources” has been coined to cover all of these technologies but definitions across academia and industry vary. In this thesis, its definition aligns with the broad consensus definition from [8–13].

***Distributed Energy Resource (DER)** is any resource connected to the distribution network that is capable to produce electricity and/or change the demand profile. Examples of such devices include traditional fossil fuelled distributed generator, battery energy storage, responsive loads participating in demand side response, controllable capacitor banks, electric vehicles and respective charging stations, intermittent RES such as wind and solar.*

Note that the production of electricity as mentioned in this definition refers not only to the capability of generating electrical energy, but also the ability to modulate or shift demand profiles by reducing consumption, as in the case of responsive loads. From a system operator’s perspective, it is the same whether electricity is generated or demand is reduced, since the effect on the node in the network is indistinguishable because the change in power flow and the effect on the balance between supply and demand is the same.

Although integration of DERs have benefits to attain environmental and government targets, the high number of connections made in a short period of time has led to many operational challenges since it can lead to increased demand, for charging EVs for instance, and less predictable behaviour of net demand because of variation of RES [7,14]. The large volume of DER

penetration can cause violation of statutory voltage limits or violation of thermal constraints of cables and transformers [15]. There are also times when power flow may reverse in the once unidirectional radial lines, for instance during high generation periods from DGs and low demand from consumers, which causes voltage rise and possibly invalidates some assumptions underlying protection system design [16].

To enable a distribution network to be run reliably and remain within the operational limits while servicing a large set of consumer requirements would traditionally need high investment in network reinforcement. That reinforcement would traditionally be through greater capacity substations and cables/line [17, 18]. Although network reinforcement represents an effective solution, it comes at a great cost and with lengthy periods needed for planning and implementations before it becomes operational, to the extent that the resources of Distribution Network Operator (DNO) may not be sufficient to cope and the costs passed on to customers may not be acceptable.

As a lower-cost alternative to traditional reinforcement, it has been proposed that connections be managed in a more “intelligent” way, known in literature as Active Network Management (ANM) [19]. The aim is to make more efficient and effective use of the existing infrastructure and thereby expand the volume of new customer use, consumption or production, that can be accommodated [20, 21]. In contrast to the problems that can arise from simply connecting DERs, if planning and operation is optimised with DER in mind then it can play a beneficial role in the future distribution grid, improving energy efficiency, decreasing energy costs and increasing security of supply [22].

In order for DERs to play a full role in actively managed distribution networks, a new regulatory paradigm will be required, one that introduces ancillary services, offering increased consumer participation, with a range of new business streams, *e.g.*, DER owners connecting as flexible demand or dispatchable resources offering the capability to adjust its output to aid in network operation. This ancillary service market creates new streams of revenue for DER owners and improves means by which the network is operated. Such arrangements are being trialed in the UK [23].

This gradual shift in distribution network operation, introducing ancillary services with greater customers participation, requires changes in current business model and roles of distribution network operators. Key limitation from traditional DNO role is that it have no interest or rights to influence demand and generation and only does so to meet regulatory requirements to avoid service interruptions or operation failures. To improve capabilities of DNO for an actively managed distribution networks, they are now shifting to distribution system operator (DSO), which have broader portfolio of services involving demand response, energy storage and dispatchable generators that can be contracted and managed for operating distribution networks and also to interact with the wider system operator [24]. In summary, actively managed distribution networks requires new services and interactions with the wider network, and so DNO business model is changing to encompass them, known as the DNO to DSO transformation. The ANM schemes themselves will need to be enhanced so that they can identify and dispatch the most cost-effective combinations of services procured from ancillary services market that solve network constraints wherever and whenever they occur.

Improving active management of connections is one of the key objectives of the research presented in this thesis and therefore this concept is explored further in the following section.

1.1 Motivation and Objectives

Transmission networks are routinely provided with communication devices between power plants and a centralised management system so that real-time management can dispatch the power plants to meet demand and provide a secure and stable network [25]. Algorithms for ANM in transmission have been developed over decades and optimised for convergence time and precision considering specific characteristics of transmission networks. Now that ANM for distribution is required, some attempts have been made to rearrange and re-optimize algorithms for load-flow and other calculations for the characteristics of distribution networks, as discussed in [26,27] for example. However, it is often the case that the problem is still posed in terms of a centralised data acquisition and control scheme. Such centralised control is highly

dependent on data exchange and susceptible to single-point failure in the communication or control (unless redundancy is provided) leaving it questionable whether it is practical, at scale, for a distribution network [28, 29]. Moreover, acquiring the data needed for system-wide optimisation algorithms becomes unrealistic when considering continuously changing outputs from loads and generation in a large network [30, 31]. These difficulties hinder centralised energy management in distribution networks and so efforts have been directed to decentralising the control and coordination of DER, as discussed by many authors [32–36]. Finally, the ANMs should be able to cope with new regulatory conditions, identifying and procuring the most cost-effective combinations of ancillary services offered by participating DERs.

In this thesis a series of questions will be addressed concerning transition to a more active operation of distribution networks, one that is able to efficiently host larger numbers of DERs and that considers different means of consumer participation, all of this without compromising network equity, security of supply and sustainability. As part of addressing these questions, a distributed design of active network management will be created that seeks to control and coordinate large numbers of DERs, participating in possible ancillary service market, without incurring an unreasonable computational and communication burden. The questions and issues addressed in this thesis are as follows.

- What frameworks or approaches might be used to engage DER in managing network constraints?
- Is decentralisation of active network management suitable for distribution networks, especially in efficient integration of DER, and what drawbacks of decentralisation are observed?
- How might the drawbacks of decentralised algorithms for ANM be overcome?
- How closely can a distributed ANM scheme match the solutions obtained by centralised algorithms?

1.2 Contributions

The contributions of this thesis will be gathered and discussed in the final chapter. To give a foretaste of that so that the purpose of the thesis is clear, the main contributions will be summarised here. The overall contribution is to propose and evaluate a distributed form of active network management that can control and coordinate growing number of DERs participating on possible ancillary service schemes without incurring in burdensome computational nor communication requirements. The distributed design is based on a mathematical formulation for calculation of voltage sensitivities based on local measurements and message passing. This distributed form of ANM that has been developed seeks the most effective adjustments of DER set-points away from their intended consumption/supply (as perhaps agreed in a forward energy market, and subject to their own physical limits) and therefore seeks the smallest possible interventions. Through these adjustments, the DSO ensures that its network is safely operated but, further, through minimising its interventions the DSO reduces the costs of procuring ancillary services (recognising that costs are subsequently passed on to customers as use-of-system charges) while ensuring that DER are free to operate in their own best interests to the greatest extent possible.

This approach does envisage that a rich set of actions (ancillary services), covering real and reactive power, are available from controllable loads, generators and storage across the network. The proposed form of ANM can therefore aid in the process of unlocking full benefits of DER participating in a future ancillary services market. All results are compared with a benchmark centralised optimal power flow (OPF) solver to validate that decisions from proposed method are at least reasonable and at best are close approximations to the global optimum.

The outcome of this research is an ANM which (i) is distributed, and therefore appropriate for large distribution networks without incurring an unreasonable computational and communication burden, (ii) minimises the cost of procuring the required ancillary services and (iii) allows unhindered DER operation to the greatest extent possible. The output of original work presented along this thesis is listed and summarised.

1. Mathematical formulation for calculation of voltage sensitivities to power flow adjustments based on local measurements;
2. Review of DER participation in ancillary services for supporting network operation;
3. Improvement of curtailment schemes traditionally based on Last-In First-Out (LIFO) or Pro-Rata that doesn't consider minimisation of curtailment to a scheme based on voltage sensitivity approximations proposed here;
4. Design a scheme for control and coordination of distributed energy resources participating in active network management, adjusting power flow injections based on voltage sensitivity and offered costs of ancillary services for regulating voltage and line capacity to be within statutory limits;
5. Testing and validation of the control and coordination strategy of devices participating in ANM, comparing with centralised approach, minimising adjustments of DERs' output away from their intended/contracted positions. Also, it is considered minimisation of costs for procuring ancillary services, enabling ANMs to dispatch DERs not only based on their voltage sensitivity, but to also to consider their offered costs of services.

1.3 Publications

The work developed throughout the PhD resulted in the following publications [37–40].

- **T. Mendonca, M. Collins, M. Pinto, and T. Green, “Decentralisation of power flow solution for facilitating active network management,” in *CIREN - Open Access Proceedings Journal*, 2017.** → This paper presents a mathematical formulation which enables distributed calculation of voltage sensitivity at node i due to power flow in the same node i , *i.e.*, $\frac{\partial V_i}{\partial P_i}, \frac{\partial V_i}{\partial Q_i}$. The content of this paper forms part of chapter 3 of this thesis.

- **T. Mendonca, N. Bottrell, and T. Green, “Simplified Voltage Sensitivity Based Curtailment Arrangement for Active Network Management,” in IEEE PES Powertech - Milano, Italy, 2019.** → This paper reports the proposed voltage sensitivity based (VSB) connection agreements that is described in Chapter 3. The proposed VSB is compared to traditional agreement based on chronological order of connection (as described in Chapter 2 of this thesis) and is shown to reduce unnecessary curtailments.
- **T. Mendonca, N. Bottrell, and T. Green, “Incorporating Ancillary Service Costs in Distributed Energy Resources Management Systems,” in IEEE PES Innovative Smart Grid Technologies Conference Europe, ISGT Europe, 2019.** → This paper reports the voltage sensitivity based connection agreement considering also the inclusion of ancillary service costs of possible market frameworks for DER owners. The results presented in the paper are for a scenario in which a central coordinator reduces computational burden by requesting distributed calculation of ancillary costs for voltage change from each participating DER and then takes a decision to solve constraints while minimising the costs of procuring services. These results form part of Chapter 4.
- **T. Mendonca and T. Green, “Distributed Active Network Management Based on Locally Estimated Voltage Sensitivity,” IEEE Access, 2019.** → This paper reports the complete ANM strategy that emerged from the research reported in the thesis and which is based on distributed calculations of voltage sensitivity to control and coordinate DERs. It is discussed more fully in Chapter 4.

1.4 Thesis Overview

Chapter 2: Provides background about state of operation of distribution networks, discussing drivers and needs for redesigning it for comportsing new trends of the electricity sector. It is presented how networks are traditionally managed and how it can be improved to maintain safe operation while increasing hosting capacity of new DER connections. Active Network Management is formally defined as well as subdivided into three categories based on the control and coordination structure, namely, centralised, decentralised and distributed. Related works are discussed for each topology, explaining its benefits and drawbacks.

Finally, the envisioned network considering the control and coordination design proposed in this thesis is described, highlighting the main benefits that motivated the work.

Chapter 3: The main difficulty in designing decentralised and distributed ANM is that controllers are unaware of other controllers' situation (constraint violation and efficiency in solving them). One way to improve system observability seen by each controller is to estimate non-local conditions and for this, it is required calculations based on local measurements of network states. This chapter describes our approach to decentralise power flow solutions to allow controllers to make reliable approximations about local and non-local constraints. First it is described how local voltage changes due to local power flows, defined as local voltage sensitivity, which is later expanded to estimate how non local voltage changes due to non local power flows, defined as non-local voltage sensitivity. With these approximations, the full voltage magnitude sensitivity matrix can be estimated by every controller, based only on local measurements and limited message exchange with neighbouring controllers. These calculations provides the foundation for designing the proposed control and coordination strategy.

Chapter 4: This chapter describes how to integrate the estimation of the full voltage magnitude sensitivity, based on local measurements presented in the previous chapter in order to improve observability of each DER controller. It formulates how the proposed distributed control and coordination strategy works and presents the concept of multiple controllers cooperating, defining the types of controllers required to run the proposed strategy. In this chapter all the details regarding message exchange and coordination between local controllers composing the management system are presented. It also presents how the ancillary service costs is modelled and used by the ANM, together with voltage sensitivities calculations in order to obtain most cost effective dispatch of DER injections.

Chapter 5: This chapter presents all the methodology for simulating the distributed ANM and presents the results. It is subdivided in several test case scenarios exploring different capabilities of the proposed approach as well as validating its performance.

Chapter 6: Chapter summarising the outcomes of the thesis and presenting conclusions.

Chapter 2

Background

For the reasons laid out in Chapter 1, DNOs are witnessing a growth in DER in their networks and regulatory pressure to accommodate this growth in fulfilment of government policies. The power system as a whole, and distribution networks in particular, are now expected to accommodate not only a wide variety of variable sources throughout the system, but also new types of demand, such as electric vehicles and customers offering demand-response services. These DERs if unobserved and un-managed will hinder operation of the system. Simple connection of DER needs to be replaced by integration of DER through careful planning and revised operational systems in order to maintain network operation within statutory limits while still exploiting the full range of benefits offered by DERs.

This chapter provides the background to traditional and transitioning state of operation of distribution networks. It presents the drivers for redesigning operation so as to accommodate the changes happening in the electricity sector. Section 2.1 describes the transformation of distribution networks, moving from a traditional operation and planning, where limited DER existed and a simple passive approach was sufficient, to a more actively managed network designed to accommodate new connections. In Section 2.2, it is discussed the different design of active network management schemes, highlighting key features to be considered for future implementations. The last section describes the motivations for avoiding centralised implementations of ANM for distribution networks and outlines the distributed scheme proposed.

2.1 Transforming the Electricity Distribution Network

This section describes how traditional distribution networks are changing and what the drivers are for that change.

2.1.1 The Traditional Distribution Network

Distribution networks are, traditionally, designed to supply customers who have demand for electrical energy by distributing the energy taken from a higher-level transmission network and passing it through substations [41]. Distribution networks differ from transmission networks not only in voltage level but also in topology and the characteristics of their lines. The main features of distribution networks that distinguish them from transmission networks are:

- Lower voltage levels. Typically below 132 kV, stepped-down in substations, usually equipped with on-load tap-changing (OLTC) transformers for regulating voltage along the subsequent feeders. The voltage level can be further stepped-down depending on design, to the various nominal voltages used in each country, e.g. 11 kV/ 400 V in UK or 4.16 kV/ 220 in USA [2];
- The topology of the feeders leaving the substation is usually radial with some additional normally-open points (NOP) for network reconfiguration when necessary [42]. In radial networks, nodes are never connected to more than one upstream branch, but can have multiple downstream connections;
- Resistance to reactance ratio (R/X) of lines is lower, and close to 1 [43].

A note is needed here on terminology. In this thesis voltages below 1 kV are termed low voltage (LV), of circa 10 kV are termed medium voltage (MV), circa 30 kV as high voltage (HV) and above that is extra high voltage (EHV). However, in UK DNOs the practice is to refer to 11 kV as HV and 33kV and above as EHV. Voltages below 1 kV are LV.

Still on the subject of terminology, a feeder is composed of a main feeder (which leaves the substation), and laterals (or branches) which connects to the main feeder along the circuit. Upstream nodes are to refer for connections in the direction of the main substation, while downstream nodes are used to refer for connections in the direction to the end of feeder.

In many countries, like in the UK, and elsewhere in Europe too, distribution networks are owned and operated by companies licensed by an energy regulator to fulfil that role and meet various licence conditions. These companies are the Distribution Network Operators (DNO) and their roles include maintenance, construction and operation of distribution networks in order to provide a safe, secure, reliable and efficient connection to consumers. Their licence terms also exclude them from certain activities, notably owning generation assets. DNOs also have the obligations to connect and manage connections of DG owned by third parties.

The regulator will evaluate the service quality provided by licensed DNOs and also perform price control to ensure fair (cost-reflective) electricity price for consumers. In UK, the regulatory duty is performed by the Office of the Gas and Electricity Markets, Ofgem, a non-ministerial government department and an independent national regulatory authority recognised by EU Directives [44]. Regulators also operate with incentive mechanisms to encourage improvement of operational efficiency and promoting innovation projects involving distribution networks.

A simple representation of a traditional distribution system is given in Figure 2.1, where medium voltage feeders fan out from a primary substation, passing through circuit breakers (CB), which are capable of interrupting fault currents for protection. The MV feeders might service some customers directly but also connect to secondary substations from which low voltage feeders fan out to service further customers. Historically, DNs contained loads that simply consumed power and little monitoring was needed at LV or even MV because these layers of the network were run passively. Passive here means that networks were designed and built on the basis that even with load growth and under worst-case operating conditions, equipment ratings would not be exceeded. The only controlled elements were tap-change transformers and switches. In particular, DNOs did not and still do not purchase services from either demand or generation customers to help manage the distribution network.

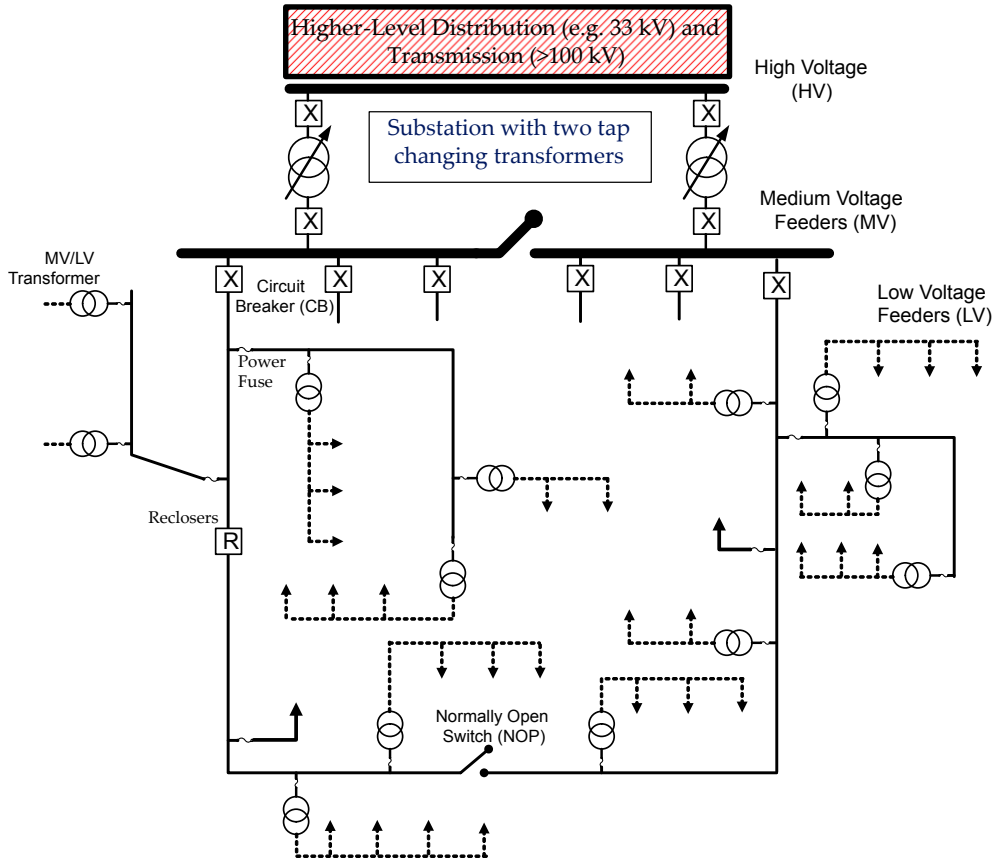


Figure 2.1: Example of a MV traditional distribution network.

The primary substation that converts from high voltage to medium voltage levels are usually equipped with OLTC, which can perform voltage regulation by adjusting voltage at the beginning of the feeder. In some cases (at HV or EHV) voltage regulation can be achieved with FACTS devices for reactive compensation. More details can be found in [2, 42, 45]. The branches, or laterals are usually connected to the main feeder via protection devices such as circuit breakers and fuses that can isolate a faulty portion of network without disconnecting customers not directly affected by a faulted line or cable [41]. Circuit breakers also protect against faults such as insulation failures, items coming into contact with live conductors or third-party damage. Some faults are transitory, particularly on overhead lines and so re-closers can be set to attempt to re-close on the circuit a small number of times and then stay open (lock out) if the fault is found to be persistent.

For improved reliability, radial MV circuits in DN are often provided with normally-open points. At these points switches are provided that can be closed to reconfigure the network. It is common practice that the circuits are kept as radial after the switching operations (additional

switches must open if others are closed), meaning loops or more complex meshed interconnections are not formed. If a fault occurs on one of the circuits, it is possible to quickly restore a portion of the faulted circuit through the use of NOPs. Traditionally, these switches may once have been manually operated but in some countries, like the UK, most switches are now teleoperated and/or automated so that restoration times are shorter.

It is now widely recognised that the passive approach to DN management is a difficult and costly way to accommodate the new uses to which networks are being put [35]. The following subsections describe the changes happening and what impacts they will have on the operation and design of distribution systems.

2.1.2 Distribution Networks in Transition

A combination of advancing technology and governmental incentives is bringing about increased deployment of distributed energy resources. The nature of these DERs is such that the magnitudes of the flows in lines, and even their directions, are much more variable hour to hour, day to day and season to season. As a result, DNOs are observing greater variations of voltage profile, as discussed in [15, 46, 47], and seeing the emergence of difficulties ensuring protection coordination (i.e. difficulties ensuring the correct protection devices open to isolate the smallest network section containing the fault) [16].

Figure 2.2 shows the traditional network of Figure 2.1 with the addition of various DER (both in the low and medium voltage sections) and this represents a distribution network in transition. Note that this figure does not include any additional network control or the monitoring and communication infrastructure and so is broadly similar to the situation in many networks today as discussed in [28, 35]. In a network with larger numbers of DER connected, there can be periods of low load and high generation leading to voltages approaching their upper limits and periods of low generation and excess load leading to voltage decreasing toward their lower limits. The voltage limits might be set by industry standards, license conditions or self-imposed operational limits but ultimately track back to the safe operating range of both network and customer equipment.

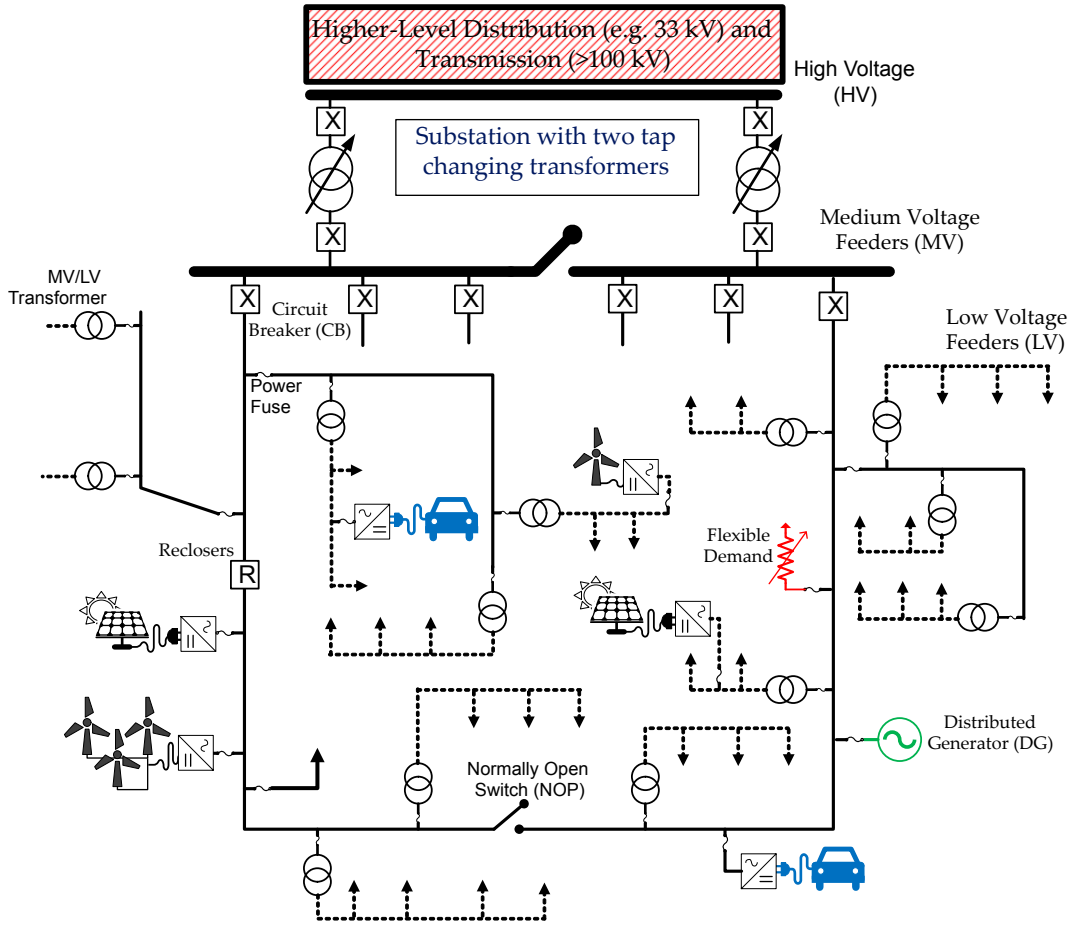


Figure 2.2: Example of distribution network in transition with growing DER connections.

Regulation of voltage traditionally means adjusting the online tap-changer of a transformer and using reactive power compensation but this may not be sufficient with much wider ranges of variation in power flow. There is a particular problem with tap-changers since their action affects the voltage on all feeders at the substation in the same way whereas some may need to be adjusted down and other adjusted up. In order to ensure that the network is never operated outside of its voltage limits, DNOs have limited the volume of connections according to an assessment of the worst case conditions. This is a traditional passive approach for connecting new customers and is also known as “fit and forget” [19]. To accommodate new customers beyond this limit requires network reinforcement. In some cases, DNOs can charge for upgrading (reinforcing) the network for enabling new connections. If consumer wants to connect extra capacity, it must pay some fraction of the reinforcement costs as defined by the regulations (e.g., [48]) and this extra cost might make the planned investment unfeasible. This might be seen as the connection charging regime hindering advancement of low-carbon technologies and governments and regulators would need to act to change the regime.

To maintain the pace of adoption of low-carbon technologies, regulatory bodies usually place strong incentives on DNOs to provide timely and efficient connections for customers. In U.K for instance, it is one of the principle outcomes measured [48]. Various forms of new connection agreement have been created in response to this incentive so that customers can avoid high costs and reduce delays to connection. Customers can apply for a flexible connection, in which no reinforcement costs is required on the understanding that the connection will be managed to regulate operational parameters and ensure safe operation. The rules and agreements between network operators and customers to allow access to the grid stem from some underlying principles of access (PoA) for the network. Defining PoAs that are realisable in practice and satisfy both DNO and customer interests requires several factors to be considered.

- The PoA should maximise the number of connections of distributed devices without compromising safe operation of the network;
- It should provide certainty when connecting customers and provide the level of curtailment to enable the development of accurate business cases for investors;
- It should be simple in design because automation in the distribution network is not as advanced as automation in the transmission network [28].

Above all, PoA should be fair for all the participants and have predefined rules for curtailment. These rules may depend on the type or location of the DG to be connected. Pro-rata and Last-In First-Out (LIFO) are two PoAs that satisfy the above criteria and are commonly used in the UK. They are discussed and reviewed in [49, 50] and will be summarised here based on the information in those references.

Pro-Rata

In a Pro-Rata arrangement, network constraints are managed by adjusting the power output of all DGs participating in the flexible connection scheme in proportion to their size and in that sense all contribute pro-rata to maintain operation within statutory limits. As an example of connections based on a pro-rata agreement, consider the following example. Four DGs (DG_1 , DG_2 , DG_3 and DG_4) with contracted capacities of 3 MW, 6 MW, 2 MW and 4 MW

respectively are connected in a region of DN that can safely accommodate 12MW. Suppose that in a particular period, all DGs start exporting their full capacity, totalling 15 MW. The contribution of each DG towards the total generation can be calculated simply by the ratio of its generation and the total. Therefore, in the given example, DG_1 represents 20% of total generation (result of 3MW/15MW), DG_2 with 40% (result of 6MW/15MW), DG_3 with 13% (result of 2MW/15MW) and DG_4 with 27% (result of 4MW/15MW). In this example, the DGs are exporting 3MW above the network's capacity of 12MW, which will need to be curtailed, following their same contribution towards the total DG generation. DG_1 will be curtailed 0.6MW (which is 20% of 3MW), following same logic, DG_2 , DG_3 and DG_4 will be curtailed 1.2MW, 0.39MW and 0.81MW respectively. To provide a long term certainty for generators, a maximum curtailment level can be pre-specified in the agreement and financial compensation defined if the DNO finds it has to curtail more than that agreed maximum.

Fig. 2.3 depicts the situation described, considering a guaranteed minimum capacity of 50% for all customers as indicated by the blue bars, and showing in red bars the generators output during normal operation, (when no curtailment is needed) and as green bars, the generators output during constrained operation (when curtailment is required to solve network constraints). Note that no generator have been curtailed more than agreed, as seen by the green bars always above blue bars. Also note that all generators participating in this scheme have been instructed to curtail, as can be observed by all green bars below red bars of each respective generator. All generator contributed pro-rata towards solving the network constraint

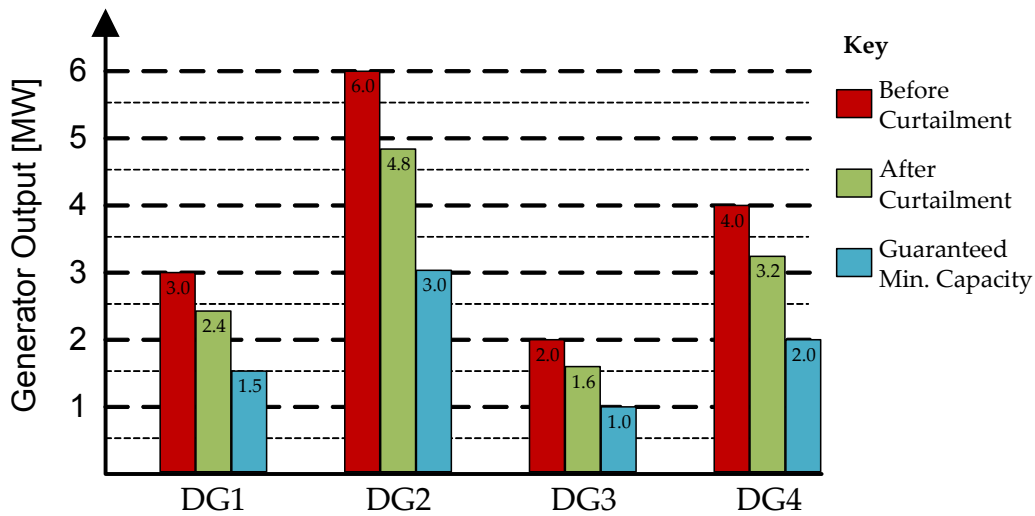


Figure 2.3: Curtailment under Pro-Rata arrangement.

Last-In-First-Out (LIFO)

The last-in, first-out PoA curtails generators in reverse chronological order of connection such that the first generator to connect is the least likely to be curtailed. The maximum curtailment (or guaranteed minimum capacity) is agreed upon when a connection agreement is struck. Consider the example where four DGs, DG_1 , DG_2 , DG_3 and DG_4 , with contracted capacities of 3 MW, 6 MW, 2 MW and 4 MW respectively, are connected to a DN that can safely accommodate 12 MW of DG capacity. To host the 15MW without network reinforcement, the DGs are connected under LIFO arrangement and will be curtailed when necessary according to their inverse order of connection. Assuming that DG_1 connected first, followed by DG_2 , DG_3 and DG_4 in this order, than in case of network constraint violation, the first to be curtailed is DG_4 , followed by DG_3 , DG_2 and lastly DG_1 . The guaranteed minimum is of 60% of connection capacity.

Fig. 2.4 depicts the described situation. The last two generators to connect (DG_4 and DG_3) were curtailed to the maximum agreed, as seen by the green bars with same height as blue bars. The second to connect has also been instructed to curtail, as seen by the green bar below the red bar, but still above the blue bar. The first DG to connect (DG_1) was not required to curtail and could maintain its regular operation, as seen by the red and green bars with the same height.

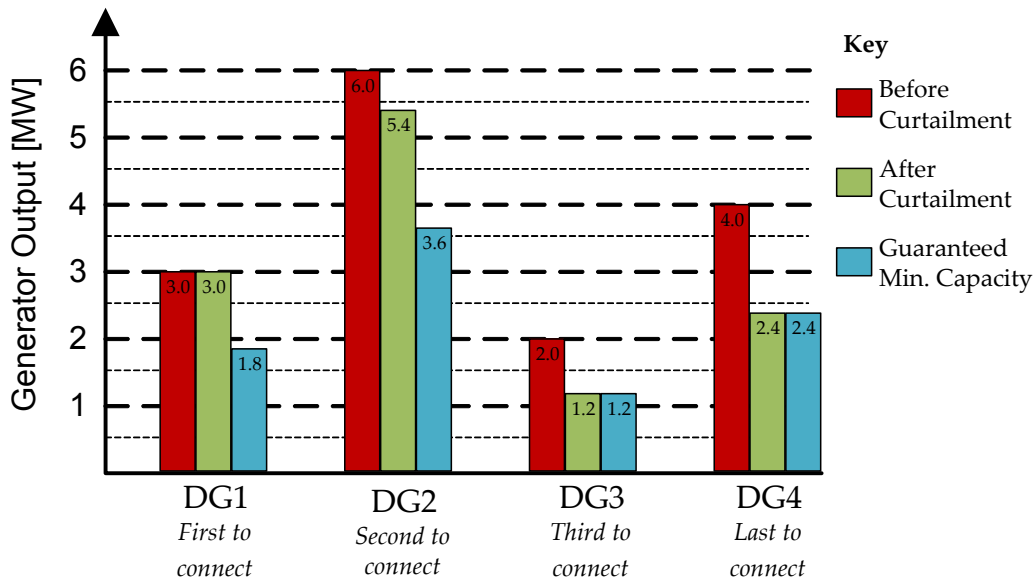


Figure 2.4: Curtailment under Last In, First Out arrangement.

Both of the aforementioned arrangements for curtailment, Pro-Rata and LIFO, are simple in their implementation, are fair to customers and provide certainty for longer term investment planning. This suggest they satisfy all the design requirements for a PoA. However, they do not consider curtailment efficiency in their design, being prone to unnecessary adjustments to DERs' output for sake of simplicity.

As reviewed in [49], other approaches are also proposed in literature, such as a market based, renewable prioritisation or technical best PoA. In a market based PoA, DGs specify the price in which they accept to be curtailed and a management system would alter their output in the order of the least expensive to most expensive until the constraint is solved. Arrangements that prioritise renewable integration simply leave renewable energy sources to be curtailed last. A technical best solution requires to solve an optimisation function to identify the minimal curtailment of DG to solve the constraint.

Although there are many alternatives to pro-rata and LIFO, they each lack at least one of the core objectives entailing PoA implementation, *e.g.* simplicity of implementation, fairness of curtailment and long term certainty for customers, being the main reason for adoption of LIFO and pro-rata in real world implementation as reported in [51, 52].

To control and coordinate these flexible connections while ensuring network is safely operated and PoAs are satisfied, platforms of active network management are employed, as detailed in the next section.

2.2 Active Network Management

As mentioned, in response to regulators, DNOs are offering customers the opportunity to participate in flexible connection schemes, controlled and managed by an active network management platform, which can make more efficient use of existing infrastructure [20, 53]. These customers are offered a non-firm connection managed by an ANM system, which are cheaper and quicker to become operational, but are subject to curtailment. Flexible connections are already offered by some DNOs in U.K, as reported in [52] and [51].

The traditional passive DN utilisation efficiency is very low as it is designed for standing the peak load predicted, which lasts for a few hours of the day, running over-rated during the rest of the day. Active network management platforms deployed in DNs enable a more active operation which can improve utilisation of available infrastructure and ultimately reduce and/or delay network reinforcement costs. A concise definition of active distribution network (ADN) equipped with ANM technologies, is given by the CIGRE working group, detailed in reference [10] and quoted in this thesis.

“Active distribution networks (ADNs) have systems in place to control a combination of distributed energy resources (DERs), defined as generators, loads and storage. Distribution system operators (DSOs) have the possibility of managing the electricity flows using a flexible network topology. DERs take some degree of responsibility for system support, which will depend on a suitable regulatory environment and connection agreement”

ANM strategies are designed to control and coordinate DERs that have agreed to flexible connection terms. In an active distribution network, parameters are constantly being monitored and in case of constraint violation detection, a decision-making algorithm adjusts the output from participating DERs to maintain constraints within limits. The ANM can adjust active or reactive power injection from DERs, can alter tap from OLTCs, can curtail demand/generation in demand response and so on. These control variables are specified to reach optimisation criteria that can vary between voltage regulation, maximising renewable penetration, reducing losses among others [6].

The subsections that follow present a literature review of ANM which control devices in order to achieve an optimal power flow in the distribution system. The review is organised under headings of centralised, distributed and decentralised as the three forms of control and coordination as categorised in [11]. The first relies on a central coordinator (CC) that obtains information from all devices, process it and provides the optimal operating set-points. The second considers neighbouring information sharing for collaboratively defining operating set-points. The last divides the network into centrally coordinated zones.

In outline, centralised approaches are expected to achieve the most efficient DER dispatch, but at the cost of high communication and computational burden. By dividing the networks into zones and solving dispatch algorithms separately, decentralised approaches reduce the computational and communication burden at the expense of accuracy in their solution. In distributed approaches, local controller (LC) are deployed in each node, taking local measurements and exchanging relevant information with neighbouring controllers to reach solutions, obtaining less accurate solutions but calling for even less computational and communication infrastructure. There has been much research directed to improving the balance between solution accuracy and complexity of communications and computation, as will now be discussed.

2.2.1 Centralised ANM

The centralised control and coordination of DERs requires every participating DER to be equipped with monitoring and communication devices to obtain local parameters and send it to a central coordinator, as illustrated in Figure 2.5. The CC must have sufficient computational infrastructure to solve optimal power flow algorithms and obtain the ideal operating set-points of all flexible DERs that satisfies the ruling PoA and ensures network operational parameters to be within statutory limits. The successful implementation of this scheme is highly dependent on a communication framework capable to transmit all the data between all DERs and the CC.

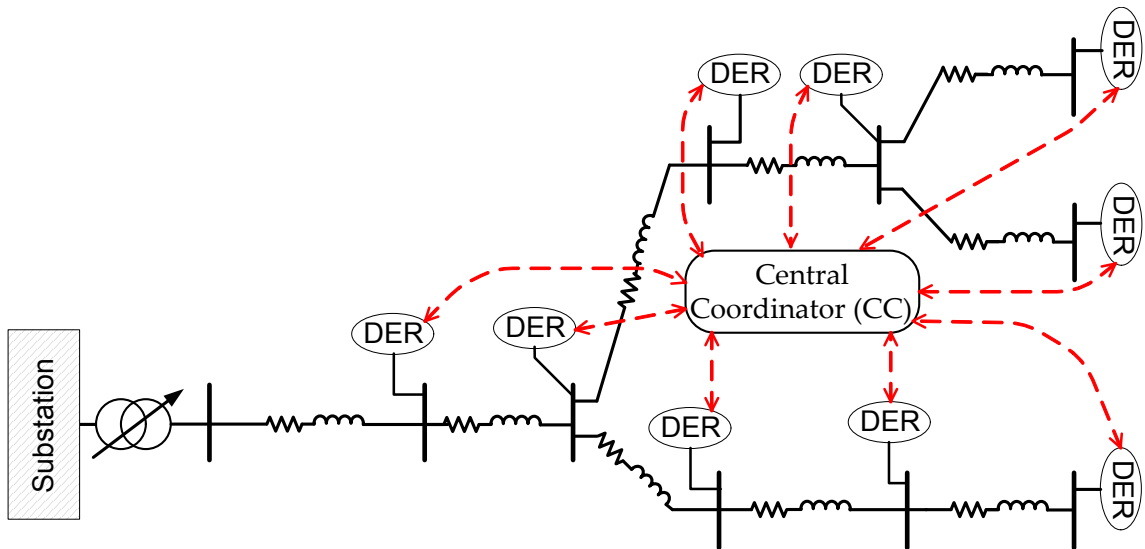


Figure 2.5: Example of network centrally coordinated.

A well-known real world implementation of a centralised active network management scheme, being one of the first to be implemented is the one adopted in the Orkney islands, off the north coast of the UK [54]. It is leading example internationally of smart grid solutions to alleviate power network congestion. The design measures power flows at several locations of the network and enable control of multiple generators connected. The central controller's algorithms detects when power flows are approaching constraints and instructs generators to adjust its output. By 2012, almost 20MW of new renewable generation could be connected under ANM agreement, avoiding expensive network reinforcement [55], which, according to estimations made, would have cost around £30 million (not to mention the time requirement to enable safe connections of additional renewable generators). It is reported that the total cost of developing and delivering the Orkney Smart Grid has been around £500,000.

The authors in [56] proposes an ANM capable to perform curtailment of DG to solve voltage constraints in distribution networks. The approach they propose is based on centralised data acquisition to compute voltage sensitivities and centralised control to avoid unnecessary curtailment. Although the authors showed that their voltage sensitivity based ANM could reduce curtailment to solve voltage constraint, it is not discussed how to deal with conductors thermal constraint, nor did they discuss the increased complexity of centralised implementations with increase of the number of controllable devices. More detail is given in chapter 3 regarding computation of voltage sensitivity terms to be used in distribution networks, as the ANM proposed in this thesis also relies on them to define the necessary changes in power injection from DERs, however avoiding centralised data acquisition.

To deal with voltage and thermal constraints and additionally include switching capability of distribution networks to reduce necessary volume of curtailment by re-configuring the network instead, the authors in [57] designed a mixed integer nonlinear programming based on an alternative power flow approach proposed for radial networks. The work showed that it is possible to reduce curtailment by applying network reconfiguration relying on remotely controlled switches, however it recognises that the computational complexity for evaluating large combinatorial space stemming from growing number of binary control options from the switches might not be realistic for real time implementation.

According to [27], there are many designs of ANM for distribution networks based on centralised control and coordination scheme (around three-quarters of the works reviewed by authors in [27]). This approach is becoming more computational demanding as more controllable devices are connected [35]. Additionally, centralised methods require full network observability to run the optimisation algorithm and thus rely on communication infrastructure, which in traditional distribution networks is often inadequate for this purpose and causes decentralised or distributed approaches to be considered instead [11]. However, in cases where savings or revenue obtained on quicker connections are readily concluded, this method proves valuable as demonstrated by the real-world implementation noted in [54].

2.2.2 Decentralised ANM

The decentralised control and coordination is classified in [27] as a partial step away from a fully centralised system. In this approach, the network and its controllable assets are subdivided into zones and each zone fully observable by a zone coordinator (ZC), which acts as the central coordinator in its respective zone in the sense that it collects all relevant data from participating DERs, run decentralised optimal power flow algorithms to obtain the ideal operating point and sends them back to participating DERs. This design is illustrated in Figure 2.6, where a 10 node network with 9 dispatchable DERs is managed under decentralised control scheme.

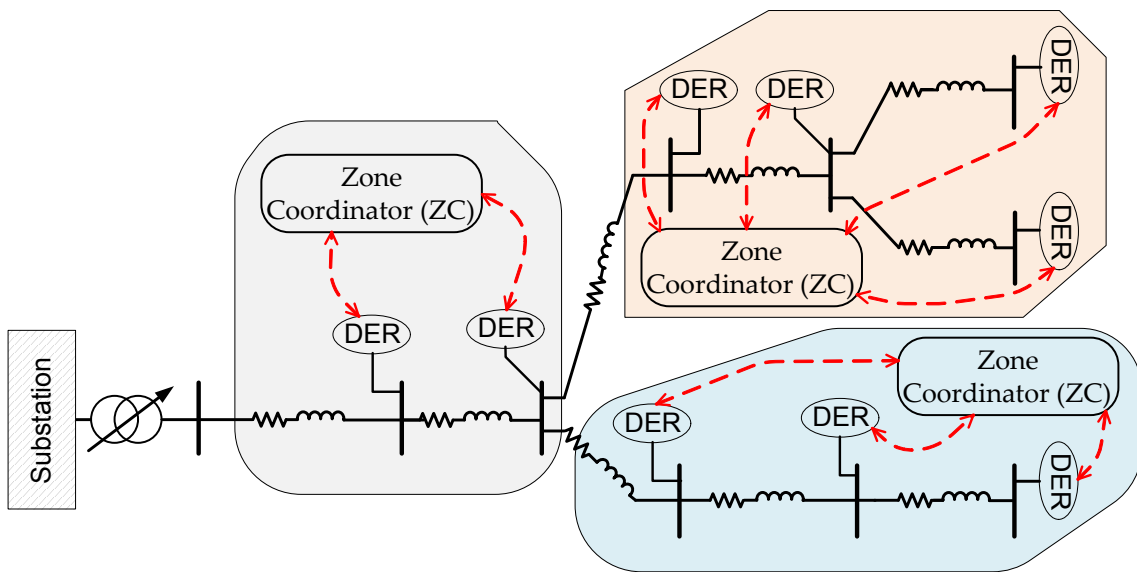


Figure 2.6: Example of network with decentralised control and coordination.

The main benefit is that computational complexity as well as communication burdens are reduced since less data must be handled by each region, as discussed in the review papers [6,27]. The drawback is that the operating set points in which OPF algorithms are run, are based on the limited observability of each ZC, not necessarily resulting in the global optimal. Some examples of the decentralised approach will now be discussed.

In [58], a non-linear programming problem is solved in a decentralised fashion with off-line coordination to optimise voltage profile based on the adjustment of DG reactive power output. The regions are defined in such a way to have only one controllable DG in each zone, where the algorithm will optimise voltage profile. The off-line coordination ensures that multiple DGs do not interact with each other in order to avoid cumulative actions to solve the same problem, also known as “hunting effect” [32]. The main drawback from this approach is when considering high penetration of DG closely connected to one another, in which case it is not possible to define different regions and only specify one controllable DG to regulate voltage. The approach is suitable only for networks with sparsely connected DGs.

Author in [59] presents a decentralised approach of ANM in which the network is subdivided into weakly coupled regions by applying ϵ -decomposition of the sensitivity matrix obtained from the inverse of Jacobian. Later, a linear programming problem to obtain ideal dispatch of DG that minimises losses in each region is applied. However, the process in obtaining the Jacobian, as one of the steps in the Newton-Raphson algorithm, involves centralised data gathering, which might be challenging for applications that requires decision-making closer to real time.

The work proposed in [31] represent an ANM based on a decentralised scheme that controls active and reactive power of inverter-interfaced DGs with the objective function to minimise power loss and voltage profile deviation. The design of control framework uses linear approximations of the ac power flow equations presented in [60]. This approach requires voltage measurements to be transmitted to ZC in order for completion of the algorithm, requiring a communication infrastructure able to do so for real-time applications, which is a challenge in realistic DN. Furthermore, it is not shown nor discussed how nodes without DG connection can have its voltage regulated by another node capable of controlling DG output.

2.2.3 Distributed ANM

This approach represents a further step away from centralisation of control and coordination. In designing a distributed ANM, it is usually assumed (for instance [11]) that the managed network is equipped with local controllers (LC) that monitor local parameters and communicate with neighbouring LCs to achieve a common goal (minimise loss, maximise RES penetration, regulate voltage and so on), as can be depicted in Figure 2.7.

As reviewed in [11], the distributed and decentralised strategies coded into the ANM has been the topic of many researches, differing among them mainly in how LCs exchange information and permissions within the management system to achieve their goals and how all LCs coordinate their control actions in order to avoid multiple adjustments to solve the same problem.

In outline, the decentralised and distributed design of ANM is of interest for implementation in distribution networks due to the fact that higher investment costs for computational and communication infrastructures can be reduced. For this reason, the ANM proposed in this thesis is based on a distributed design. Because it is the scheme used by the proposed ANM, the literature review is more extensive and is given later in chapter 4 during section 4.1, when the strategy of the ANM is presented.

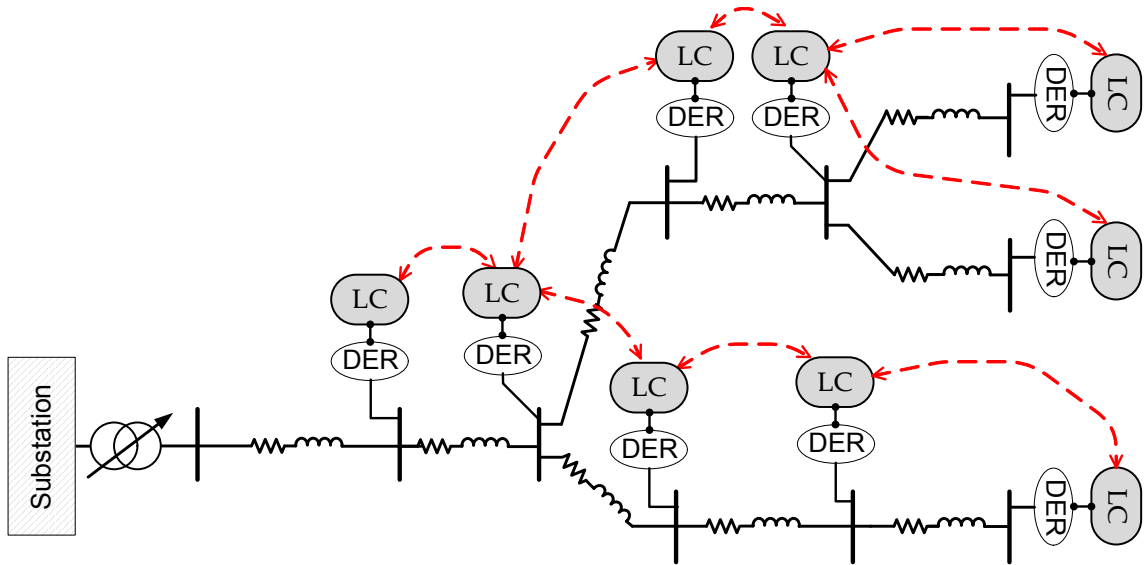


Figure 2.7: Example of network with distributed control and coordination.

2.2.4 DER Participation in Ancillary Service Market

The future of ANM is expected to have active participation of most or all DER within a network, rather than just a few connections, with DER owners offering services rather than being instructed. For this to happen, the regulatory paradigm and DNO roles will need to change to incorporate a range of services and benefits of DERs into an ancillary service market that can be contracted and managed, similar to the services markets already run by transmission system operators (TSO). This change, as defined in chapter 1, is described as the transformation of distribution network operators into distribution system operators (DNO to DSO transformation) and together with it, new streams of revenue for DER owners and new portfolios of services for network management are anticipated.

To fully explore benefits from distributed energy resources and to motivate customers to provide services to aid network operation and management, it is necessary to design commercial frameworks and market schemes to trade new ancillary services from DERs. Participating DERs can be managed to support technical optimisation of dispatch for an agreed cost borne by the distribution system operator. For reducing costs of procuring these services, the management platforms should be improved to consider in its objective function the costs associated with adjusting power injection of participating DERs together with nodal efficiency to resolving constraints.

In the trial project [23], which explores use of DERs to provide dynamic voltage support and constraint management services to the DSO, owners of DERs are compensated for each MWh they are moved away from their original agreed set-point. It is yet not clear how agreement between network operator (or system operator) and DER owner will be reached regarding price (could be a bidding process, or maybe a fixed price per MWh), but one thing is certain, future implementation of management systems must consider costs of procuring ancillary services in their decision making process while maintaining reliable and secure operation. DERs that can cause higher impacts on voltage with lowest cost of ancillary services are the most cost effective device to aid in network management and must be taken into account.

2.3 The Envisioned Distribution Network and ANM

From the preceding discussion, it is clear that moving away from centralised implementations of ANM has some advantages in avoiding unrealistic communication burden and facilitating deployment in real-time. Furthermore, ANM strategies must start to consider minimisation of costs from procuring ancillary services. The research to be described in the following chapters set out to explore and test these concepts by attempting to design a distributed ANM based on an ancillary services market sitting alongside a conventional energy-only market which is a possible route forward for the existing UK regulatory set-up.

As discussed in section 2.2.3, the ANM proposed in this thesis follows a distributed design, in which the LCs can exchange relevant data to manage the DERs to achieve a common goal, which might be minimising system losses, maximising renewable penetration, or regulating voltage, as defined by the algorithm coded in the controllers. An example of the envisioned network that applies distributed ANM is illustrated in Figure 2.8.

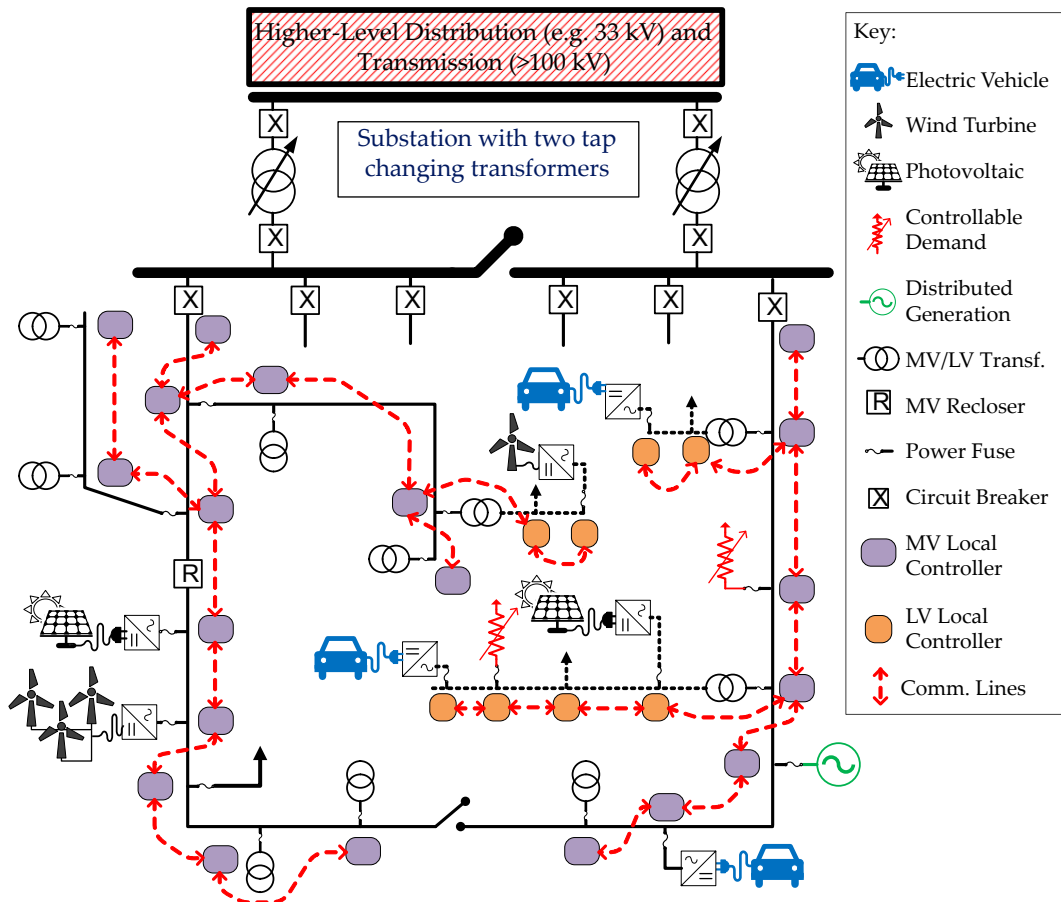


Figure 2.8: Envisioned distribution network with distributed coordination of DER connections.

LCs can be programmed to manage DERs in any voltage level with the possibility to cooperate to solve different constraints. The main idea is that each LC procures ancillary services from DERs, adjusting their output so that the network parameters remain within safe margins while minimising the total costs of procuring these services.

There are many challenges for realising the envisioned DN and its ANM. The first challenge arises from the fact that LCs operate with local measurements and even though an action may seem suitable based on these observations, it might inadvertently cause another node to violate a constraint and so it is essential that there is some form of coordination between LCs. That coordination must also address synchronisation of actions. Multiple actions to solve the same network problem might occur when LCs observe the same constraints and for which they can provide a solution. Since they may be unaware of possible interactions ahead of time, they may all end up making adjustments leading to a hunting effect. That is why it is critical to share some data in order to reveal options and reach a consensus about which LC should act and when responsibility for action should pass from one LC to another. Another challenge, not directly technical, is the possible market framework in which LCs are obliged to find the lowest procurement cost. In order to set its objective and develop algorithms, it must be clear upon which market framework the ANM and the LCs will operate.

With the aim of overcoming the aforementioned challenges, a distributed ANM will be proposed, designed, implemented and tested in the following chapters. In order to demonstrate that the proposed approach is suitable for operation with a possible ancillary service market for DER customers, a framework based on the literature will be considered for programming the LCs. The market framework will also be discussed. It is noteworthy that the ANM is not limited to operate in one specific arrangement, but one must be defined for evaluating performance and convergence accuracy.

Chapter 3

Distributed Calculation of Voltage Sensitivities

The relationships between changes in power flow at nodes and nodal voltages in a network are not straightforward to calculate due to the non-linear nature of loads at some nodes and inter-dependency between nodes [61,62]. However, any distributed form of network control will need to be able to accurately determine this relationship and for that reason approximations that allow local evaluations to be made were examined in detail.

A common approach of decomposition in power flow analysis is to linearise the power flow problem by evaluating the voltage sensitivities terms, which indicates how nodal voltage changes with power flow changes, as discussed and reviewed in [30,62]. Traditionally, these voltage sensitivities with respect to active and reactive power can be obtained by inverting the Jacobian Matrix, J , as part of a Newton-Raphson solution [59], as shown in (3.1), where the inverse of the Jacobian Matrix is indicated by J^{-1} , the vectors of bus voltage angles and magnitudes are indicated by $\boldsymbol{\theta}$ and $\mathbf{V}$ respectively and real and reactive powers injected in the buses are shown as $\mathbf{P}$ and $\mathbf{Q}$. For distribution network applications, the voltage magnitude is of greater interest, reason why sole focus is given to $\frac{\partial \mathbf{V}}{\partial \mathbf{P}}$ and $\frac{\partial \mathbf{V}}{\partial \mathbf{Q}}$.

$$\begin{bmatrix} \Delta \theta \\ \Delta \mathbf{V} \end{bmatrix} = \underbrace{\begin{bmatrix} \frac{\partial \theta}{\partial \mathbf{P}} & \frac{\partial \theta}{\partial \mathbf{Q}} \\ \frac{\partial \mathbf{V}}{\partial \mathbf{P}} & \frac{\partial \mathbf{V}}{\partial \mathbf{Q}} \end{bmatrix}}_{J^{-1}} \cdot \begin{bmatrix} \Delta \mathbf{P} \\ \Delta \mathbf{Q} \end{bmatrix} \quad (3.1)$$

Obtaining $\frac{\partial V}{\partial P}$, $\frac{\partial V}{\partial Q}$ based on Jacobian Matrix inversion is accurate, but in a real-time control process requiring repeated re-computations, the process of updating entries and inverting J , becomes burdensome, as analysed in [34], and may preclude implementation on relatively simple hardware at each LC. Relying on a constant Jacobian matrix for obtaining sensitivity factors may be inaccurate [63]. In addition to the challenge of computational complexity, calculating a full sensitivity matrix requires full system knowledge [30, 31] and therefore is discounted as viable option for control and coordination in distribution networks, where communication infrastructure is, in most cases, inadequate for this purpose [27, 28].

In the approach proposed in this chapter, approximations to the voltage sensitivity terms for radial networks are considered that simplify the calculation. The intention is that they can be used by ANMs to define technically efficient power flow adjustments for constraint management. Basing the approximation on an assumption of a radial network is clearly a limitation but practice in many countries, including the U.K. is that LV and MV networks are radial with simple branches but not closed loops or meshes [2, 41]. Reminding that in a radial network each node may connect to only one node upstream (in the direction of the substation) and may connect to multiple downstream nodes (in the direction of the end of the feeder).

It is shown in this chapter how local voltage changes due to local power flows, defined as local voltage sensitivity, which is later expanded to estimate how non local voltage changes due to non local power flows, defined as non-local voltage sensitivity. This allows coordination of actions to be made by ranking the effectiveness of DER adjustments as will be explored in Chapter 4. In outline, the intention is that an LC will be able to request correcting adjustments from an LC in another location if that controller is identified through sensitivity calculation as the most effective node, *i.e.*, where power alterations have the greatest impact on voltage.

The chapter is organized as follow. Section 3.1 formulates the problem of obtaining voltage sensitivities as well as presents and discuss necessary approximations required to enable local estimations of non local conditions. In section 3.2, the approximations are considered and the equations to perform local estimations of local voltage sensitivities. The formulation is extrapolated in section 3.3 to consider estimations of non local voltage sensitivities as well, improving controllers observability of the network without increasing communication requirements. The complete sensitivity matrix obtained with proposed estimations is presented in section 3.4. the partial results are presented in each section, discussing error sources and how it impacts the proposed control and coordination.

3.1 Problem Formulation

To derive the mathematical formulation of voltage calculation for a radial distribution feeder, it is considered a simple n bus circuit with loads (L_i) and generation (G_i) connected in each node and line impedances ($R_i + jX_i$) between nodes i and its upstream $i - 1$, as shown in Figure 3.1. The voltage line drop between two consecutive nodes $i - 1$ and i is defined as V_i^{LD} . Generators injects S_i^G and loads sinks S_i^D , as indicated in the dark blue arrows. The net injection at node i is defined as $S_i = S_i^G - S_i^D$. The power flowing to node i through its upstream branch is defined as S_i^{up} .

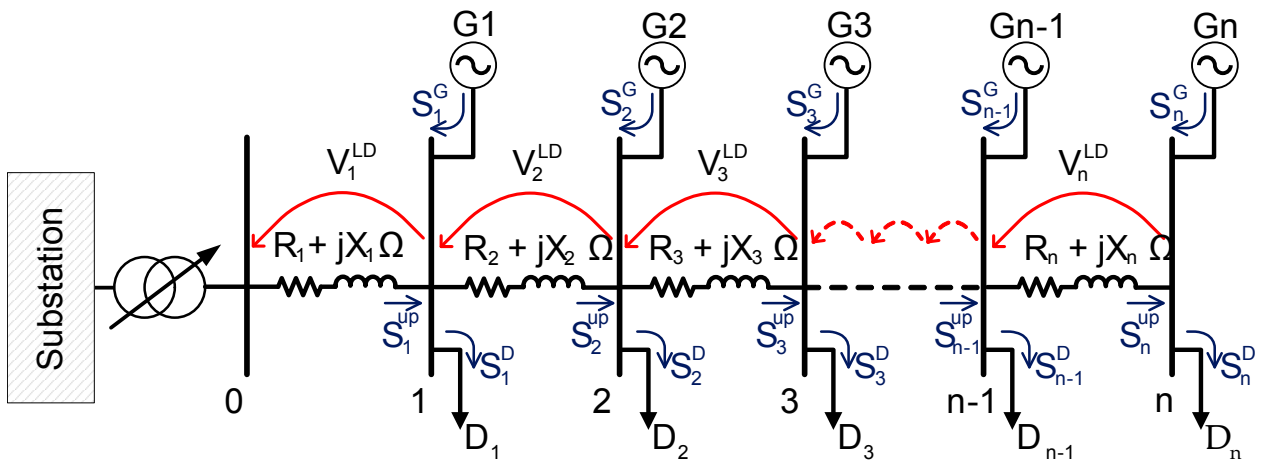


Figure 3.1: Distribution feeder used for problem formulation.

The voltage at a particular node i can be calculated by subtracting all voltage line drops from a known nodal voltage which would normally be the node at the beginning of the feeder (V_0), which is assumed to be a “stiff” voltage source provided by a very low impedance connection to a large grid. This subtraction is shown in equation (3.2).

$$V_i = V_0 - \sum_{k=1}^i V_k^{LD} \quad (3.2)$$

The voltage at node i can also be estimated based on the immediate upstream node $i - 1$ by subtracting it from the the voltage line drop between nodes i and $i - 1$, as shown.

$$V_i = V_{i-1} - V_i^{LD} \quad (3.3)$$

The voltage drop (V_i^{LD}) between a node and its upstream can be calculated as the line impedance between nodes i and its upstream (Z_i) multiplied by the current flowing to node i through its upstream branch (I_i^{up}), where the current is the quotient between the complex conjugate of the apparent power, also flowing to node i from its upstream $i - 1$ ($P_i^{up} - jQ_i^{up}$) and the complex conjugate of voltage (V_i^*). The voltage line drop is derived in equations (3.5) to (3.6). Note that the concept of power injection used in equation (3.1) is different than the power flowing to the node through its upstream (P_i^{up} and Q_i^{up}). But the magnitude of how they change with respect to changes from injected powers from DERs are the same in radial networks, so the voltage sensitivities can be obtained using either of the terms. Since that for our formulation it is required to calculate the voltage drops, P_i^{up} and Q_i^{up} are preferred.

$$V_i^{LD} = \overbrace{(R_i + jX_i)}^{Z_i} \cdot \overbrace{\left(\frac{P_i^{up} - jQ_i^{up}}{V_i^*} \right)}^{I_i^{up}} \quad (3.4)$$

$$V_i^{LD} = \frac{R_i P_i^{up} - jR_i Q_i^{up} + jX_i P_i^{up} + X_i Q_i^{up}}{V_i^*} \quad (3.5)$$

$$V_i^{LD} = \frac{R_i P_i^{up} + X_i Q_i^{up}}{V_i^*} + j \frac{X_i P_i^{up} - R_i Q_i^{up}}{V_i^*} \quad (3.6)$$

For typical conditions of distribution networks, the imaginary part of (3.6) makes little difference to the magnitude of the voltage and can be neglected [2, 42]. Therefore, voltage line drop equation can be approximated as shown in equation (3.7).

$$|V_i^{LD}| \approx \frac{R_i P_i^{up} + X_i Q_i^{up}}{|V_i|} \quad (3.7)$$

Substituting equation (3.7) in (3.3) results in the approximated equation of voltage at node i due to voltage line drop between nodes i and its upstream $i-1$, shown in (3.8).

$$|V_i| \approx |V_{i-1}| - \frac{R_i P_i^{up} + X_i Q_i^{up}}{|V_i|} \quad (3.8)$$

Rewriting (3.8) as a function of upstream voltage and power flowing to node i from its upstream, a second order equation is obtained, shown in equation (3.9).

$$|V_i|^2 - |V_i| |V_{i-1}| + R_i P_i^{up} + X_i Q_i^{up} = 0 \quad (3.9)$$

Whose solution is obtained as result of (3.10).

$$|V_i| \approx \frac{|V_{i-1}| + \sqrt{|V_{i-1}|^2 - 4(R_i P_i^{up} + X_i Q_i^{up})}}{2} \quad (3.10)$$

From (3.10) it is clear that the voltage at node i is a function of the voltage in the immediate upstream node (which in turn is dependent of all its upstream voltages as well) and the power flowing into the node from its upstream (P_i^{up} and Q_i^{up}). Therefore, to estimate nodal voltages requires observation of all power flowing to the nodes from their respective upstream, and this is why a load flow solution is said to be a centralised problem. Solving this system of equations for all nodes in a real-time application is considered impractical due to the frequent changes in

loads and generation across the distribution system, especially with the increasing volume of DERs. However, in a closed loop control system that iterates toward a satisfactory or optimal set of node voltages, it may not be necessary to estimate the exact value of all nodal voltages for every power flow change, it may be sufficient to estimate the gradient of the voltage with respect to power injections. In other words, the sensitivity to voltage to power injection is required and this could be a simple linear approximation to obtain nodal voltages for different power flows.

To linearise load flow calculations, the rate of change of voltage due to active and reactive changes is calculated, defined as voltage sensitivities to active and reactive power injected at node i $\left(\frac{\partial V_i}{\partial P_i}\right)$ and $\left(\frac{\partial V_i}{\partial Q_i}\right)$. These terms enable a control system to estimate how the voltage at a node would change given a change in power flow injections, as shown in equation (3.11).

$$|V_i^{new}| \approx |V_i^{old}| + \frac{\partial V_i}{\partial P_i} \Delta P_i + \frac{\partial V_i}{\partial Q_i} \Delta Q_i \quad (3.11)$$

The introductory section of [64] reviews some of the techniques available for obtaining these sensitivity terms either from a centralised or a decentralised scheme. Essentially, the centralised approach is computationally demanding, based on inversion of Jacobian matrix and relies on system-wide information but can achieve good results whereas the decentralised approach based on local measurements can calculate only sensitivities to local perturbations. The local estimations reviewed are suitable for obtaining local voltage sensitivities due to local power flow changes, sometimes forcing a perturbation signal to detect the changed voltage. However it is not discussed how a controller attached to a flexible DER could estimate how its power change can affect voltage at another node, either to support network operation in maintaining voltage within limits or in case DER needs to limit its output to prevent non local network parameters violating constraints.

In this thesis, it is proposed different approximations for estimation of voltages sensitivities for any node based on local measurements of voltage and power flow. The approximations take advantage of some peculiarities of distribution feeders and their radial topology.

3.2 Local Voltage Sensitivity Calculation

The first step in designing the algorithm for distributed ANM is to understand how the centralised problem of load flow can be simplified to work with limited observability. By examining the proposed approximations, it becomes clear what local information is required and for what type of network configuration the approximations are valid.

As stated before in section 3.1, by calculating the partial derivatives of V_i with respect to injected powers P_i and Q_i , the nodal voltage sensitivities for each node are obtained and used to estimate voltage outcomes due to power injection changes, as shown in equation (3.11). It is important to highlight here that changes in injected power from DER at node i will cause an opposite change (with same magnitude) in the power flowing to the node i through its upstream branch. Therefore, $\frac{\partial |V_i|}{\partial P_i} = -\frac{\partial |V_i|}{\partial P_i^{up}}$. Taking the partial derivatives of equation (3.10) with respect to P_i^{up} and Q_i^{up} , equations (3.12) and (3.13) can be obtained.

$$-\frac{\partial |V_i|}{\partial P_i} = \frac{\partial |V_i|}{\partial P_i^{up}} = \frac{1}{2} \left[\frac{\partial |V_{i-1}|}{\partial P_i^{up}} + \frac{\partial \sqrt{|V_{i-1}|^2 - 4(R_i P_i^{up} + X_i Q_i^{up})}}{\partial P_i^{up}} \right] \quad (3.12)$$

$$-\frac{\partial |V_i|}{\partial Q_i} = \frac{\partial |V_i|}{\partial Q_i^{up}} = \frac{1}{2} \left[\frac{\partial |V_{i-1}|}{\partial Q_i^{up}} + \frac{\partial \sqrt{|V_{i-1}|^2 - 4(R_i P_i^{up} + X_i Q_i^{up})}}{\partial Q_i^{up}} \right] \quad (3.13)$$

Upstream voltage is related to sum of upstream voltage line drops, as can be seen by replacing i with $i-1$ in equation (3.2), reason why the derivative of the voltage of the immediate upstream node with respect to change in local power flow require computation of how various upstream branch power flows change with respect to power at the node in question, as expressed in (3.14) and (3.15). These equations therefore require information not immediately known to a particular node in a decentralised approach. A set of approximations will be needed to make further progress with this approach.

$$\frac{\partial |V_{i-1}|}{\partial P_i^{up}} \approx \frac{\partial |V_0|}{\partial P_i^{up}} - \sum_{k=1}^{i-1} \frac{\partial}{\partial P_i^{up}} \left(\frac{R_k P_k^{up} + X_k Q_k^{up}}{|V_k|} \right) \quad (3.14)$$

$$\frac{\partial |V_{i-1}|}{\partial Q_i^{up}} \approx \frac{\partial |V_0|}{\partial Q_i^{up}} - \sum_{k=1}^{i-1} \frac{\partial}{\partial Q_i^{up}} \left(\frac{R_k P_k^{up} + X_k Q_k^{up}}{|V_k|} \right) \quad (3.15)$$

Since in a radial feeder a node connects to a maximum of one node in its upstream direction and may have multiple downstream connections, it is safe to assume that a change in power flow downstream goes on to make a similar change in power upstream, *i.e.*, $\frac{\partial P_{i-1}^{up}}{\partial P_i^{up}} \approx 1$ and $\frac{\partial Q_{i-1}^{up}}{\partial Q_i^{up}} \approx 1$. This implies that the changes in real and reactive losses in the branch impedances are small with respect to incremental changes in power injections in each respective node. In other words, the change in power loss due to a change in power injection is very small and can be neglected.

A second major assumption that will be introduced to simplify calculation is that voltage at the substation is stiff with respect to power flow changes, *i.e.*, $\frac{\partial V_0}{\partial P_i^{up}} \approx 0$. Generally, the source impedance at higher levels of the network above the substation is low when observed from the low voltage side of the substation transformer. Clearly, this assumption could be relaxed if data was available for the impedances in the higher level network.

It is noteworthy that although interconnected feeders exist in urban areas, the open points ensure only a single path to the substation is formed at any time, leaving other paths available for reconfiguration after an outage or constraint condition [42]. Therefore, it is justifiable to assume in the proposed methodology that feeders are radial. Applying the approximations discussed here to (3.14) and (3.15) results in equations (3.16) and (3.17).

$$\frac{\partial |V_{i-1}|}{\partial P_i^{up}} \approx - \sum_{k=1}^{i-1} \left(\frac{R_k}{|V_k|} \right) \quad (3.16)$$

$$\frac{\partial |V_{i-1}|}{\partial Q_i^{up}} \approx - \sum_{k=1}^{i-1} \left(\frac{X_k}{|V_k|} \right) \quad (3.17)$$

Substituting equations (3.16) and (3.17) into equations (3.12) and (3.13), and reminding that

$\frac{\partial |V_i|}{\partial P_i} = -\frac{\partial |V_i|}{\partial P_i^{up}}$, it is obtained the following:

$$\frac{\partial V_i}{\partial P_i} \approx \frac{1}{2} \sum_{k=1}^{i-1} \left(\frac{R_k}{|V_k|} \right) - \frac{1}{2} \frac{\left(|V_i| + \frac{R_i P_i^{up} + X_i Q_i^{up}}{|V_i|} \right) \left[-\sum_{k=1}^{i-1} \left(\frac{R_k}{|V_k|} \right) \right] - 2R_i}{\sqrt{\left(|V_i| + \frac{R_i P_i^{up} + X_i P_i^{up}}{|V_i|} \right)^2 - 4(R_i P_i^{up} + X_i Q_i^{up})}} \quad (3.18)$$

$$\frac{\partial V_i}{\partial Q_i} \approx \frac{1}{2} \sum_{k=1}^{i-1} \left(\frac{X_k}{|V_k|} \right) - \frac{1}{2} \frac{\left(|V_i| + \frac{R_i P_i^{up} + X_i Q_i^{up}}{|V_i|} \right) \left[-\sum_{k=1}^{i-1} \left(\frac{X_k}{|V_k|} \right) \right] - 2X_i}{\sqrt{\left(|V_i| + \frac{R_i P_i^{up} + X_i P_i^{up}}{|V_i|} \right)^2 - 4(R_i P_i^{up} + X_i Q_i^{up})}} \quad (3.19)$$

It can be seen from equations (3.18) and (3.19) that a local controller using this method to find node voltage changes will need to know not only local parameters (V_i , P_i^{up} and Q_i^{up}), but also the sum, up to its source node, of the quotient between branch impedances and their nodal voltages $\left(\sum_{k=1}^{i-1} \frac{R_k}{|V_k|}, \sum_{k=1}^{i-1} \frac{X_k}{|V_k|} \right)$.

The impedances can be considered constants for each network configuration without significant loss of precision. They could be measured in a centralised fashion and communicated occasionally or pre-programmed in the controllable devices during its deployment. Values of nodal voltages are expected to change during normal operation. In a distributed approach each node controller would measure its own local node voltage but not those up and down the feeder. However, one could assume that when the ANM is running, all node voltages are regulated and expected to be close to their nominal value and therefore could be approximated by that nominal value. There will be an error in computation of voltage sensitivities under this assumption but its impact on the convergence of a controller that iterates toward a solution may be small enough to be tolerated. This will need to be verified for a typical network. The final expression for sensitivities is then obtained by replacing the V_k terms of (3.18) and (3.19) by $V_{nominal}$, as shown in equations (3.20) and (3.21).

$$\frac{\partial V_i}{\partial P_i} \approx \frac{1}{2} \sum_{k=1}^{i-1} \left(\frac{R_k}{|V_{nominal}|} \right) - \frac{1}{2} \frac{\left(|V_i| + \frac{R_i P_i^{up} + X_i Q_i^{up}}{|V_i|} \right) \left[-\sum_{k=1}^{i-1} \left(\frac{R_k}{|V_{nominal}|} \right) \right] - 2R_i}{\sqrt{\left(|V_i| + \frac{R_i P_i^{up} + X_i P_i^{up}}{|V_i|} \right)^2 - 4(R_i P_i^{up} + X_i Q_i^{up})}} \quad (3.20)$$

$$\frac{\partial V_i}{\partial Q_i} \approx \frac{1}{2} \sum_{k=1}^{i-1} \left(\frac{X_k}{|V_{nominal}|} \right) - \frac{1}{2} \frac{\left(|V_i| + \frac{R_i P_i^{up} + X_i Q_i^{up}}{|V_i|} \right) \left[-\sum_{k=1}^{i-1} \left(\frac{X_k}{|V_{nominal}|} \right) \right] - 2X_i}{\sqrt{\left(|V_i| + \frac{R_i P_i^{up} + X_i P_i^{up}}{|V_i|} \right)^2 - 4(R_i P_i^{up} + X_i Q_i^{up})}} \quad (3.21)$$

It is noteworthy that the presented equation is a distributed approach for obtaining voltage sensitivities, considering that only local information is available to each controller. However, in case the communication infrastructure is such that it is possible to obtain information from closest neighbours as well, than the Jacobian can be calculated by taking the derivative of power injection equation with respect to voltage. In (3.22) it is shown the injected power equation and in (3.23) its derivative with respect to nodal voltage, where the admittance matrix $Y_{bus} = G + jB$ and $V_i = |V_i| \angle \theta_i$. Same is done for reactive power.

$$P_i = \sum_{k=1}^N |V_i| |V_k| (G_{ik} \sin \theta_{ik} - B_{ik} \cos \theta_{ik}) \quad (3.22)$$

$$\frac{\partial P_i}{\partial V_i} = \sum_{k=1, k \neq i}^N |V_k| (G_{ik} \cos \theta_{ik} + B_{ik} \sin \theta_{ik}) + \underbrace{2|V_i| G_{ik}}_{\text{if } k=i} \quad (3.23)$$

From equation (3.23) and knowledge of construction of Y matrix, it is possible to perceive that the only elements with a non zero value in matrices G and B will be those regarding neighbouring connections. Therefore, a controller is only required to know these elements' nodal voltages. In the proposed algorithm, the voltages from neighbouring controllers could also be shared and used to compute voltage sensitivity via inversion of (3.23). The next subsection validates accuracy of the proposed approximations and also from inversion of the Jacobian element described in (3.23).

3.2.1 Assessment of Errors in Local Voltage Sensitivity Estimation

To verify that the local voltage sensitivity estimation proposed in this work is sufficiently accurate, it was tested on the IEEE 33 bus network shown in Figure 3.2. One node at a time was subjected to varying power injection with all other power demands held constant at the original values presented in [65], repeated here in Table 3.1 (more details in Appendix A). The voltage sensitivities were calculated locally at the node with varying power injection using equations 3.20 and 3.21. Three other methods were implemented and the results were compared.

Table 3.1: Active and reactive demand connected to each node of IEEE 33 bus system

Node	P (MW)	Q (MVar)	Node	P (MW)	Q (MVar)
2	0.100	0.060	18	0.090	0.040
3	0.090	0.040	19	0.090	0.040
4	0.120	0.080	20	0.090	0.040
5	0.060	0.030	21	0.090	0.040
6	0.060	0.020	22	0.090	0.040
7	0.200	0.100	23	0.090	0.050
8	0.200	0.100	24	0.420	0.200
9	0.060	0.020	25	0.420	0.200
10	0.060	0.020	26	0.060	0.025
11	0.045	0.030	27	0.060	0.025
12	0.060	0.035	28	0.060	0.020
13	0.060	0.035	29	0.120	0.070
14	0.120	0.080	30	0.200	0.600
15	0.060	0.010	31	0.150	0.070
16	0.060	0.020	32	0.210	0.100
17	0.060	0.020	33	0.060	0.040

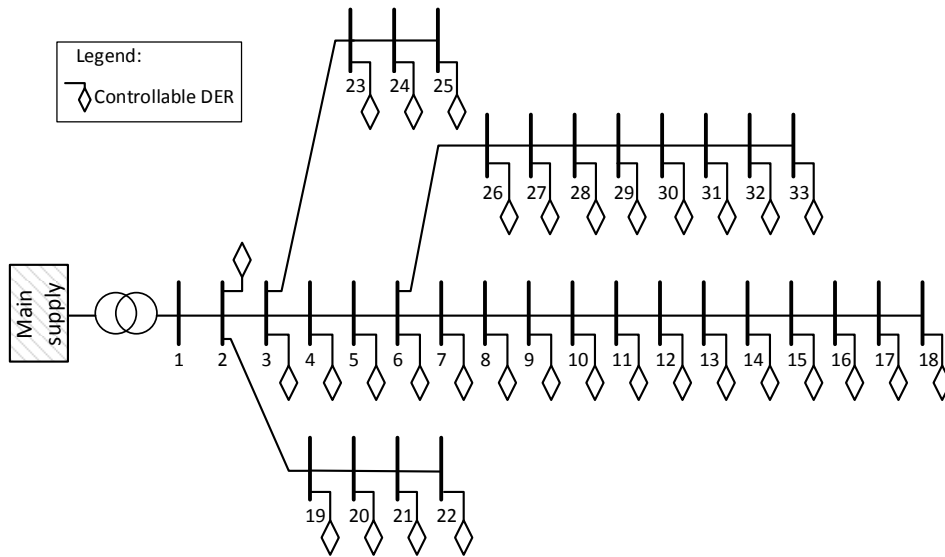


Figure 3.2: IEEE 33 bus network for validating local estimation of voltage sensitivity.

First method is the centralised approach, *i.e.*, inversion of the Jacobian matrix, which can be considered as the authentic result but relies on central data gathering and computation that as discussed, it not practical for distribution networks. Second is the perturb and observe (P&O) method [62], which intentionally causes a power flow change to perturb the voltage and by observing ΔV due to perturbation, voltage sensitivity is estimated. The third method relies on neighbouring voltage information sharing between controllers so that equation (3.23) can be computed. P&O can be difficult to implement because observed ΔV are not exclusively due to power perturbation, since other variations occur in a live network. Direct calculation of (3.23) might have higher errors in case voltage changes abruptly, in such case that the shared voltage information might be too different when received by the other controller. For this test however, all conditions are considered static except for the studied node, which varies linearly. Therefore, results from the P&O and neighbouring voltage sharing are also reliable.

Figure 3.3 shows the results when node 18 is selected for the test and its nodal power is varied from -1.3 MW (negative meaning injected active power) to 0.3 MW (positive meaning consumed active power). The range of power adjustments was selected to cause significant voltage variation relative to the assumed network limits of 5%. The top plot shows the voltage versus power injected at node 18 and the middle plot shows the estimation results from the four methods regarding $\frac{\partial V_{18}}{\partial P_{18}}$ (defined in this thesis as the self voltage sensitivity). The bottom plot presents the error between sensitives from P&O, neighbouring voltage sharing and proposed method compared to those from centralised inversion of Jacobian. Note that P&O and neighbouring voltage sharing have similar results, which is consistent because they both rely on delayed voltage information. Their error are low because voltage is changing linearly. Higher error should happen in case higher voltage changes occurred.

The proposed method produces accurate sensitivity estimate (*i.e.*, in agreement with the inverted Jacobian) in the region where node voltage is close to its nominal value. An assumption that node voltages could be approximated as 1.0 pu in intermediate stages of the sensitivity estimation was a key approximation for decentralising calculation, as discussed in this chapter and published in [37]. Following the same process, but for reactive power, it is possible to evaluate estimation of self voltage sensitivity due to reactive power, shown in Figure 3.4.

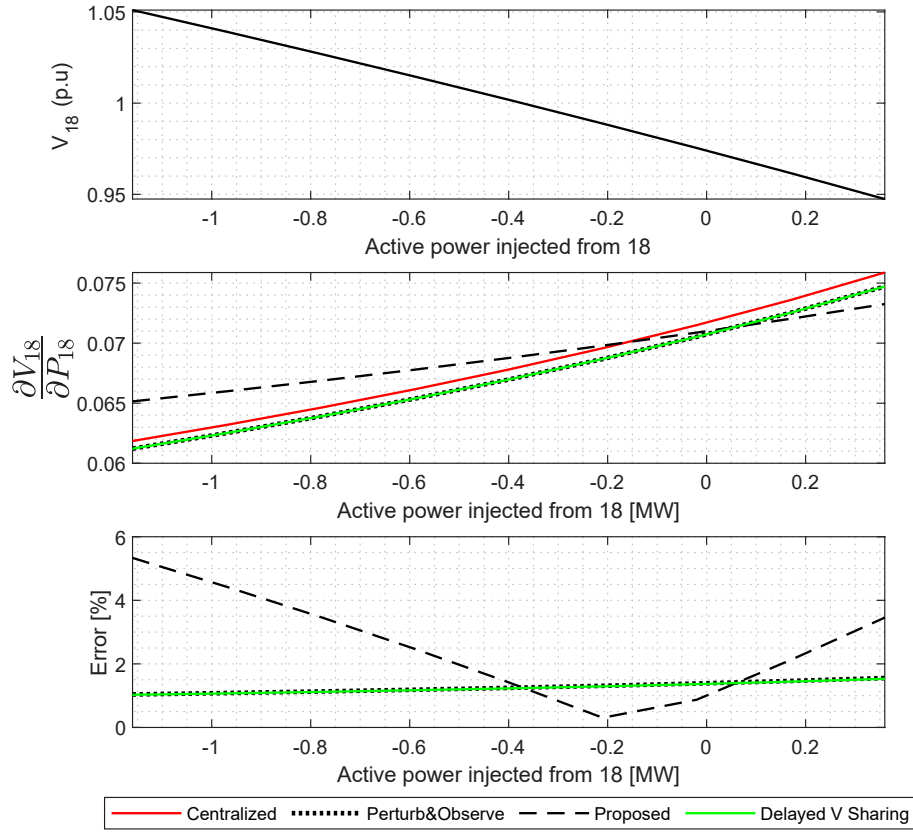


Figure 3.3: Estimation error comparison for local estimation of self $\frac{\partial V_{18}}{\partial P_{18}}$.

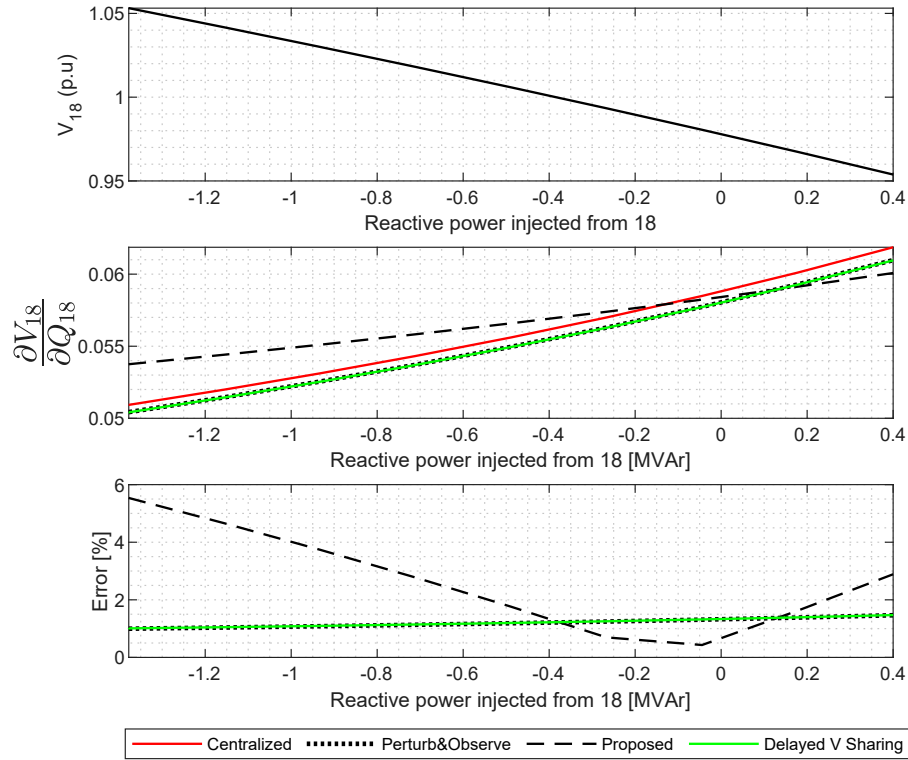


Figure 3.4: Estimation error comparison for local estimation of self $\frac{\partial V_{18}}{\partial Q_{18}}$.

It is not problematic for the ANM even when the estimate sensitivities are in error by circa 5% because of the ANM iterative process, where power adjustment magnitudes that are, in turn, in error will be refined in a subsequent iteration. Also, relatively large errors from large voltage deviations will reduce as voltages are brought within normal range (since one of the main source of error is the assumption of voltages close to nominal operating range). The same test described is also performed for power variations at all other nodes of the test network of Figure 3.2. Results show similar errors in the range of 4-6% during highest voltage deviation.

3.3 Non-Local Voltage Sensitivities Estimation

Previous sub-section presented the necessary approximations that allows calculation of local voltage sensitivity estimation $\left(\frac{\partial V_i}{\partial P_i}, \frac{\partial V_i}{\partial Q_i}\right)$. With this estimation, each participating DER can know how much its own voltage will change with a change in power injection, also in its own node. However, it cannot be used to estimate anything about other participating devices and their respective voltage sensitivities.

A relevant information for proper coordination between DERs operating under an ANM scheme is to know which node is more efficient to alter nodal voltage with power injection change. In this way, only one DER is requested to adjust power at a given time, avoiding hunting effect (multiple actions to solve the same constraint that may end up having a cumulative result). To know which node is more efficient to solve voltage constraints with changes in power injections, it is necessary to know how voltage at some other node j is changed due to power injection changed at the same other node j , defined as non-local voltage sensitivity.

Since the purpose of non-local voltage sensitivities is for coordination and not to quantify the necessary change of power flow adjustment to cause a requested voltage change, the error can be higher. The outcome of errors resulting from non-local voltage sensitivity is that devices participating in the ANM may select incorrect devices to solve constraint. However, local nodes can have a very good estimate of its own efficiency to regulate voltage with changes in power flow and will know with better precision whether to act or not, even though other participating

devices estimated it to be the ideal. Therefore, the local device “fine tunes” the selection of ideal to solve constraint made by incorrect estimations. In summary, the estimation of non-local voltage sensitivities made by DERs are used to show if local actions are preferred to solve local constraint or if another node is more fit to solve it.

For estimating non-local sensitivities of voltage in respect to power changes, equations (3.18) and (3.19) must use measurements from node j , which are unknown by node i and therefore, unrealistic in a distributed approach. However, they can be approximated as local measurements, only as means to compare local and non local sensitivities. For non-local calculation made by controller at node i , equations (3.18) and (3.19) becomes equations (3.24) and (3.25), where the $|_i$ indicate “as seing” by node i , since it relies on power flow measurements in i .

$$\frac{\partial V_j}{\partial P_j}|_i \approx \frac{1}{2} \sum_{k=1}^{j-1} \left(\frac{R_k}{|V_{nominal}|} \right) - \frac{1}{2} \frac{|V_{nominal}| \left[-\sum_{k=1}^{j-1} \left(\frac{R_k}{|V_{nominal}|} \right) \right] - 2R_j}{\sqrt{|V_{nominal}|^2 - 4(R_j P_i^{up} + X_j Q_i^{up})}} \quad (3.24)$$

$$\frac{\partial V_j}{\partial Q_j}|_i \approx \frac{1}{2} \sum_{k=1}^{j-1} \left(\frac{X_k}{|V_{nominal}|} \right) - \frac{1}{2} \frac{|V_{nominal}| \left[-\sum_{k=1}^{j-1} \left(\frac{X_k}{|V_{nominal}|} \right) \right] - 2X_j}{\sqrt{|V_{nominal}|^2 - 4(R_j P_i^{up} + X_j Q_i^{up})}} \quad (3.25)$$

3.3.1 Assessment of Errors in Non-Local Voltage Sensitivity

This subsection aims to evaluate accuracy of the proposed non local voltage sensitivity calculation. For validation, the same network of Figure 3.2 is used. It have been demonstrated in this section how to estimate the local and non-local voltage sensitivities based on local parameters. The local sensitivity estimation allows the participating DERs to quantify the amount of active or reactive power change to cause a determined nodal voltage variation. The non-local sensitivities allows the participating DERs to evaluate how effective each node is to cause voltage variation at a given node. The first relies on equations (3.18) and (3.19), while the latter relies on equations (3.24) and (3.25). It is noteworthy that the other two methods (P&O and neighbouring voltage sharing) are no longer valid for calculating non-local voltage sensitivities. So the proposed algorithm is compared against only the centralised approach.

To clarify these concepts, it is summarised in Figure 3.5 all the nodal voltage sensitivities due to active power injection change, estimated by each node. Each row i contains the estimation of the node i regarding the voltage sensitivity at node j due to power flow adjustment at node j itself (represented in each column). The main diagonal, highlighted in blue, are the calculations made by the same nodal and therefore are estimated with lower errors, around 6% as presented in the previous sub-section. Now the error of other elements are accessed, *i.e.*, how each node estimate voltage sensitivity of other nodes. It is noteworthy that the voltage sensitivity due to reactive power follows the same principle described to construct Figure 3.5.

$$\begin{bmatrix} \frac{\partial V_1}{\partial P_1} \big|_1 & \frac{\partial V_2}{\partial P_2} \big|_1 & \frac{\partial V_3}{\partial P_3} \big|_1 & \dots & \frac{\partial V_N}{\partial P_N} \big|_1 \\ \frac{\partial V_1}{\partial P_1} \big|_2 & \frac{\partial V_2}{\partial P_2} \big|_2 & \frac{\partial V_3}{\partial P_3} \big|_2 & \dots & \frac{\partial V_N}{\partial P_N} \big|_2 \\ \frac{\partial V_1}{\partial P_1} \big|_3 & \frac{\partial V_2}{\partial P_2} \big|_3 & \frac{\partial V_3}{\partial P_3} \big|_3 & \dots & \frac{\partial V_N}{\partial P_N} \big|_3 \\ \vdots & \vdots & \vdots & \ddots & \vdots \\ \frac{\partial V_1}{\partial P_1} \big|_N & \frac{\partial V_2}{\partial P_2} \big|_N & \frac{\partial V_3}{\partial P_3} \big|_N & \dots & \frac{\partial V_N}{\partial P_N} \big|_N \end{bmatrix}$$

Figure 3.5: Local and non-local voltage sensitivities to power flow estimated by each node.

Same test case network from Figure 3.2 is used. Node 17 is selected to vary demand while the other nodes remain fixed. Demand is varied from -1.6MW (negative meaning injecting power) to 0.6MW (positive meaning consuming power). This range causes voltage at node 17 to vary from 1.05 p.u to 0.95 p.u, which is a common operating range in distribution networks and therefore, includes the worst case scenario for the analysis. As the injected power from DER at node 17 is varied, the voltage sensitivity of node 17 due to power change at node 17 is locally estimated by all nodes using equation 3.24. Error analysis is carried out only for active power, and for this reason reactive power in all nodes is kept constant. Results of the estimations from

node 17, nodes 16 and 18 (two closest neighbours from node 17) and estimation from node 33 (furthest node from node 17) are shown in Figure 3.6. The two closest neighbour is chosen to show how error of estimation is similar to node 17 itself, as power flow is indeed more likely to be similar and the approximation considered has lower impact. In addition, node 33, which is located at the end of feeder in another branch of node 17 is also evaluated to show the higher estimation error (higher than 10% during worst case scenario).

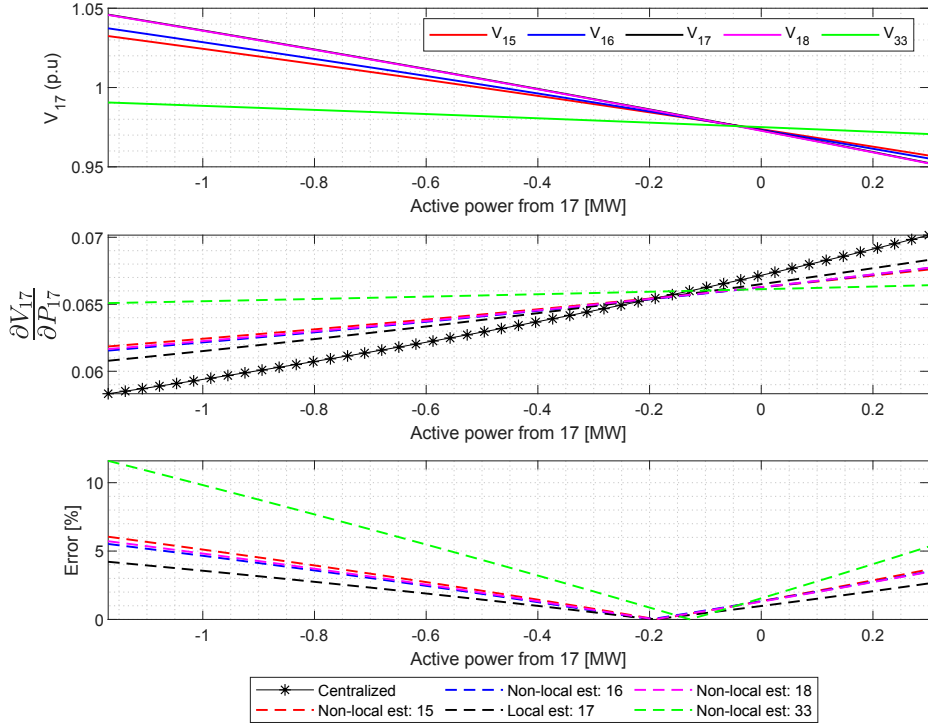


Figure 3.6: Error comparison of Local and non-local voltage sensitivities to active power flow estimated by nodes 15, 16, 17, 18 and 33.

The same logic applies for obtaining voltage sensitivities to reactive power. To obtain the error comparison of local and non-local voltage sensitivities to reactive power, it is considered that demand connected to all nodes are constant except for node 17, which has only its reactive power changed. Figure 3.7 shows the estimation results obtained from nodes 16, 17, 18 and 33 ($\frac{\partial V_{17}}{\partial Q_{17}}|_{16}$, $\frac{\partial V_{17}}{\partial Q_{17}}|_{17}$, $\frac{\partial V_{17}}{\partial Q_{17}}|_{18}$ and $\frac{\partial V_{17}}{\partial Q_{17}}|_{33}$). It is important to highlight that the error in estimating self sensitivity (how voltage at a given node changes due to changes in power injections in the same given node) from non-local nodes are not as critical as errors from estimation of self sensitivity of local node because it is not used to define how much power must be changed in order to cause a requested voltage change, as will be explained in the next subsection.

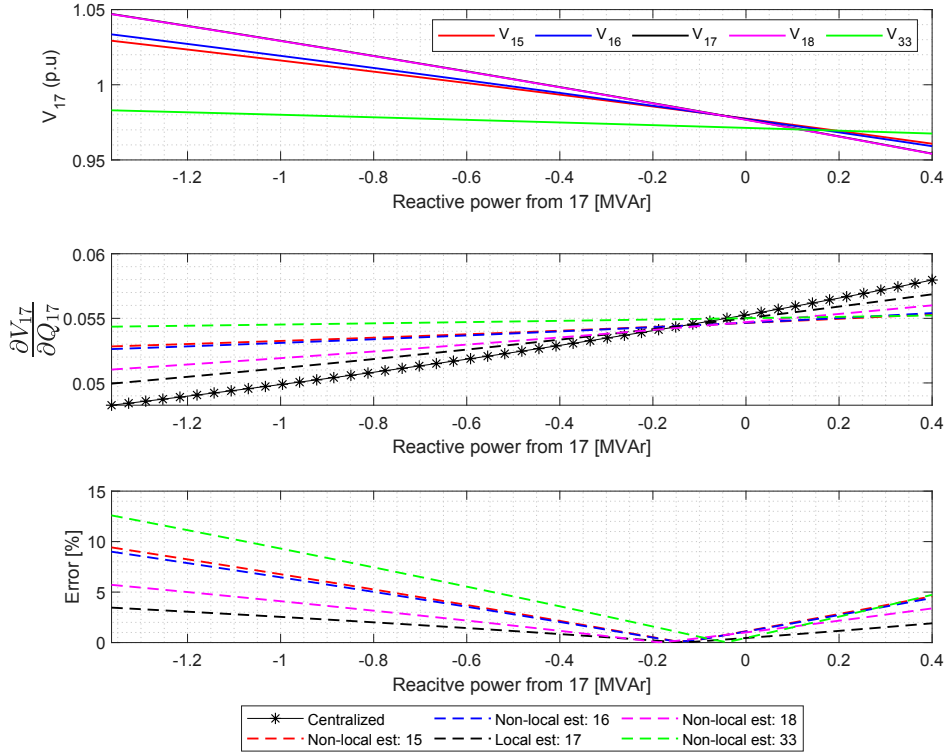


Figure 3.7: Error comparison of Local and non-local voltage sensitivities to reactive power injections estimated by nodes 15, 16, 17, 18 and 33.

3.4 Proposed Voltage Sensitivity Matrix Estimation

It has been presented how a particular node is able to estimate how its own voltage changes due to power injection changes in its own node, defined as local self voltage sensitivity ($\frac{\partial V_i}{\partial P_i}|_i$). It has also been presented how a particular node is able to estimate how other node's voltage changes due to power injection change at the same evaluated node, defined as the non-local self voltage sensitivity ($\frac{\partial V_i}{\partial P_i}|_j$). In the current sub-section, it is presented how to enable each LC to estimate how its local voltage changes due to non local power changes ($\frac{\partial V_i}{\partial P_j}|_i$), completing the full voltage sensitivity matrix. It is important to highlight that the voltage sensitivity matrix is obtained via inversion of the Jacobian matrix in centralised methods. The proposed method avoid matrix inversion and centralised data gathering in the estimation process.

In order to coordinate power adjustments in a distributed fashion, LCs need to be able to estimate the extent to which actions at other nodes of the network can affect its local voltage and its upstream branch power flow. In this way, LCs can decide where in the network, power

flow adjustments are more effective in solving local voltage constraints. In a radial network, changes of power flowing to downstream of a node directly affect power flowing in the upstream of the node in question and therefore, a LC can consider that changes in power at all downstream nodes are nearly equally effective in creating power flow adjustments to solve voltage or thermal constraints at its own node.

In contrast, upstream adjustments of power flow do not directly affect power flow downstream and are therefore ineffective in solving downstream thermal constraints. However, they do change their nodal voltage and since each nodal voltage is dependent on the voltage of the node immediately upstream, an upstream voltage change propagates down the feeder. In the case of branched network, the voltage sensitivity of different branches (or laterals) can be estimated considering the indirect effect that the other branch has on the root (or parent) node of the branch (node that have two or more downstream neighbours, defined in this thesis as node T). Algorithm 1 lays-out the steps used to construct the proposed simplified voltage sensitivity matrix. These estimations, made by each LC with respect to every other LC, is used to infer how non-local power change affects local voltage.

Algorithm 1: steps to construct simplified voltage sensitivity matrix

Start;

Each LC estimates local $\frac{\partial V_i}{\partial P_i}$ and $\frac{\partial V_i}{\partial Q_i}$;

Each LC estimates non-local $\frac{\partial V_k}{\partial P_k}$ and $\frac{\partial V_k}{\partial Q_k}$;

for each LC k Seen by i **do**

if k located downstream of i **then**

$$\quad \left| \frac{\partial V_i}{\partial P_k} = \text{estimated} \frac{\partial V_i}{\partial P_i} \text{ and } \frac{\partial V_i}{\partial Q_k} = \text{estimated} \frac{\partial V_i}{\partial Q_i} \right.$$

else if k located upstream of i **then**

$$\quad \left| \frac{\partial V_i}{\partial P_k} = \text{estimated} \frac{\partial V_k}{\partial P_k} \text{ and } \frac{\partial V_i}{\partial Q_k} = \text{estimated} \frac{\partial V_k}{\partial Q_k} \right.$$

else if k located in other branch, connected to T **then**

$$\quad \left| \frac{\partial V_i}{\partial P_k} = \text{estimated} \frac{\partial V_T}{\partial P_T} \text{ and } \frac{\partial V_i}{\partial Q_k} = \text{estimated} \frac{\partial V_T}{\partial Q_T} \right.$$

end

end

Note that these assumptions of downstream power changes equally affecting upstream nodes and upstream power changes negligibly affecting downstream nodes are only valid for radial topology. However, as will be discussed later in the thesis, new power electronics equipment, called soft open points, or SOP for short, are capable of controlling the power flow between terminals and can therefore control the power sharing between different branches of the circuit, without having a meshed topology [66, 67]. By having different branches interconnected via SOP, all the assumptions for the proposed algorithm are still applicable because the power exchange between the SOP terminals are controlled and can be modelled as a controllable load or generator. The interconnection of different branches or feeders via SOP is defined as “soft mesh” [68] and it represents a way to deploy the proposed approach in broader range of networks, ensuring that the radial topology assumptions also holds for soft meshed networks.

It is noteworthy that the precise value of local voltage sensitivity due to a non-local power injection alteration $\left(\frac{\partial V_i}{\partial P_k}, \frac{\partial V_i}{\partial Q_k} \forall i \neq k\right)$ are not critical in this context since they indicate only whether it is more or less effective to solve a local constraint with a non-local power adjustment rather than being used to quantify precisely how effective that action is. In the case that action at a neighbouring node is seen by the LC to have a larger sensitivity (to be more effective), a message is sent to the upstream or downstream controller stating the local changes in voltage and power flows that can still be supported. The local controller that receives these messages deals with them locally and will have a more accurate sensitivity estimate.

To illustrate the process of estimating the full matrix of voltage sensitivities, consider the simple branched radial network with 6 nodes shown in Figure 3.8. Nodes 3 and 4, and nodes 5 and 6 lie on branches that have node 2 as a root (or parent). Consider that each node has a DER equipped with a LC capable of exchanging messages with neighbours. Each LC needs to estimate how effectively other LC can solve its local constraints.

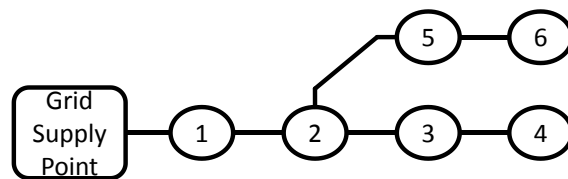


Figure 3.8: Example network to evaluate the simplification process of voltage sensitivity matrix.

The approximations in the estimation of the sensitivity matrix is summarized in Figure 3.9. Some of the original terms (only otherwise obtainable via centralised computation) are replaced with near-equivalents so as to enable its computation in a distributed and approximate fashion. The main diagonal terms in blue are estimated with good accuracy from (3.18-3.19) in case of local node estimation or from (3.24-3.25) in case of non-local estimation. The terms highlighted in green are approximations of voltage sensitivity to downstream power changes achieved by equating the downstream power change to have a same change at the node in question as argued above, for instance, $\frac{\partial V_1}{\partial P_4}$ is replaced by $\frac{\partial V_1}{\partial P_1}$ because a change in power at node 4 will cause almost the same voltage change at node 1 as a change in power at node 1 would cause. Terms highlighted in red are sensitivities of voltage to changes in upstream which can be approximated by the voltage change that happens in the upstream node to the power changed in the same node, on the basis that the voltage of the whole feeder downstream of that point rises or falls as a consequence. Terms in purple are sensitivities to power change in another branch that has a common root node approximated by the voltage change that occurs at the root node.

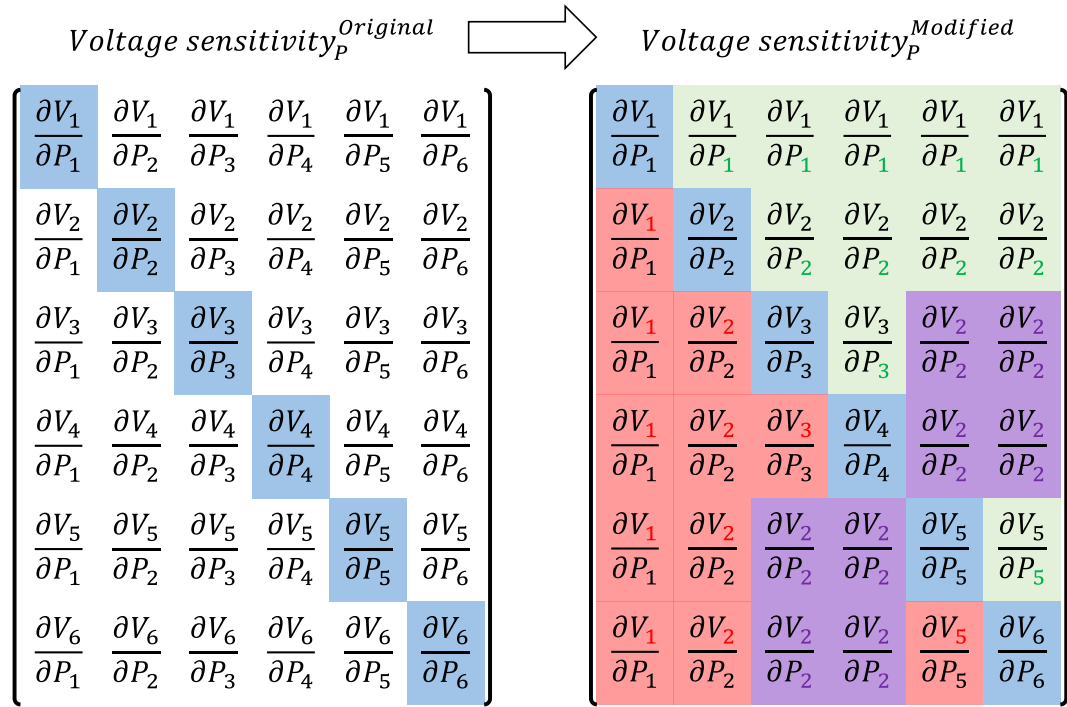


Figure 3.9: Simplification process of how each local controller perceives others' efficiency for adjusting power flow to solve voltage constraint.

In comparison to estimating voltage sensitivities to address voltage constraints, it is straightforward to estimate how effective remote actions are in addressing thermal (power flow) constraints. As noted earlier, for a radial network, downstream power changes directly affect upstream power flow with almost the same change in power and whereas upstream changes have close to zero affect downstream. With this approach, each LC can estimate how effective it is to regulate voltage or thermal constraint by requesting actions from DERs at other nodes.

3.4.1 Partial Results: Voltage sensitivity based adjustment

With new and anticipated changes, more efficient methods of curtailment are required without compromising reliable operation of the network. The complexity of more efficient methods prevents investors from estimating, with sufficient confidence, their future income from the DG. Efficient curtailment involves solving OPF algorithms which evaluate the type and location of constraint to minimise the curtailment of DG.

However, building an ANM that supports solving OPF or computing voltage sensitivities to control and coordinate distributed devices close to real-time has many challenges, not least because the communication infrastructure or automation capabilities in distribution networks are not as developed as in transmission systems. Therefore, simplifications to OPF algorithms or voltage sensitivity calculations are required to enable a realistic implementation of a more efficient PoA. It has been presented a simplification process to obtain voltage sensitivities in distributed fashion that enables each participating DER to obtain its estimates to find ideal adjustments to power flow. In this subsection it is explored how a voltage sensitivity based (VSB) adjustment is more effective than traditional principles of access (such as LIFO and Pro-Rata discussed in Chapter 2).

To validate that the proposed PoA improves the curtailment efficiency when compared with a traditional LIFO PoA, the constraint management decisions of the two PoAs are compared using the test network shown in Fig. 3.10. The test network is a radial network of 10 nodes with two laterals, one stemming from node 3 and the other from node 8. The controllable DGs are connected to nodes 2, 4, 6, 9 and 10 and are shown by the red bus bars. The base voltage and power are defined as $V_{base} = 11kV$ and $S_{base} = 1MVA$. The voltage limits are $\pm 2\%$.

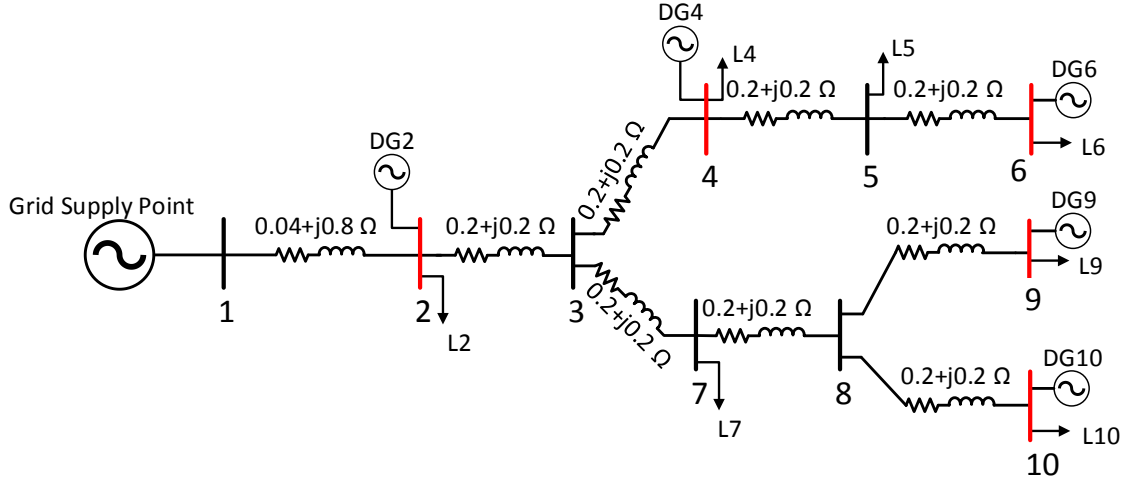


Figure 3.10: Test case network for comparing curtailment agreements. Red bus bars represents controllable DGs participating in the ANM scheme.

Similar to traditional approaches, the proposed PoA also agrees on the generation capacity from each DG and agree on the maximum curtailment (or guaranteed minimum capacity). The agreed contractual details considered for the proposed test case scenario are presented in Table 3.2.

Table 3.2: Connection Agreement Details.

DG	2	4	6	9	10
Max Curtailment (p.u)	0.2	0.2	0.2	0.2	0.2
Generation capacity (p.u)	2.4	2.3	2.2	0.2	2.1

The LIFO PoA curtails the DGs in the reserve order of connection. In the proposed test case of Figure 3.10, the order of connection is DG 6, followed by DGs 10, 9, 4 and 2. Therefore, the LIFO PoA first curtails DG 2, followed by 4, 9, 10 and 6. Constructing the curtailment list for the proposed PoA is more complex because it must consider the location of the node in the network. One curtailment list is created for each bifurcation. In the proposed test case it is possible to see three branches, namely 1) 1,2,3,4,5,6; 2) 1,2,3,7,8,9 and 3) 1,2,3,7,8,10. Each curtailment list is constructed prioritizing the curtailment of the DG connected to the node with the highest voltage sensitivity. The DG selected by the proposed PoA to be curtailed is dependent on the location of the constraint, but nonetheless customers can know beforehand where in the list for each branch their DG is placed (higher voltage sensitivity means that DGs are more likely to be curtailed to solve network's voltage constraints).

Results of load flow calculation for the unconstrained situation are shown in Table 3.3 for each node. Node voltages, the power flow through each node, the load and curtailment are all shown. It is noted that during the unconstrained situation, all DGs are operating at their agreed output, as shown in Table 3.2, without violating voltage limits at any of the nodes.

In a low demand scenario, the network becomes constrained by voltage limits and curtailment needs to be performed. Table 3.4 shows the curtailment from the ANM when following the LIFO arrangement in a scenario with 30% demand decrease. This PoA curtails the DGs in the reverse order that they were connected. As mentioned, for this test case the first to curtail is node 2, followed by 4, 9, 10 and 6.

Table 3.3: Conditions for unconstrained operation. Full hosting of DG and safe operation.

Nodes	Curtailment (p.u)	Voltage (p.u)	Power flow to node (p.u)	Load (p.u)
2	0	0.99785	4.5352	3.814
3	-	0.99115	3.1005	0
4	0	0.98851	1.2275	3.0512
5	-	0.98748	0.47582	1.2079
6	0	0.98905	-0.73325	1.4667
7	-	0.98712	1.8622	0.86279
8	-	0.98495	0.9972	3.4512
9	0	0.98798	-1.4098	0.69023
10	0	0.98721	-1.0509	0.94907

Table 3.4: Constrained operation following LIFO curtailment arrangement.

Nodes	Curtailment (p.u)	Voltage (p.u)	Power flow to node (p.u)	Load (p.u)
2	0.2	1.0006	-4.8918	1.2023
3	-	1.0087	-3.9262	0
4	0.2	1.0134	-2.2747	0.96182
5	-	1.0158	-1.1392	0.47664
6	0	1.0192	-1.6212	0.57878
7	-	1.0122	-1.6679	0.34046
8	-	1.0163	-2.0167	1.3618
9	0.062844	1.02	-1.7648	0.27236
10	0	1.0197	-1.6255	0.3745

Table 3.5 presents the results obtained from the ANM based on the proposed VSB arrangement. Curtailment is improved by selecting DG which are connected to nodes with a greater voltage sensitivity and thus the voltage constraint is solved with the least power flow adjustments.

Table 3.5: Constrained operation following proposed Voltage sensitivity based adjustment.

Nodes	Curtailment (p.u)	Voltage (p.u)	Power flow to node (p.u)	Load (p.u)
2	0	1.0006	-5.2365	1.2023
3	-	1.009	-4.0734	0
4	0	1.0142	-2.4747	0.96182
5	-	1.0165	-1.1392	0.47664
6	0	1.0199	-1.6212	0.57878
7	-	1.0124	-1.6167	0.34046
8	-	1.0164	-1.9651	1.3618
9	0.11484	1.02	-1.7128	0.27236
10	0	1.0198	-1.6255	0.3745

Decisions on which DG to curtail as calculated by the OPF algorithm from Matpower [69] have matched the decisions made in the proposed strategy for the same test case scenario. Thus, validating that the proposed simplification of voltage sensitivity based curtailment is reliable. Fig. 3.11 summarises the results presented in Tables 3.4 and 3.5 by presenting the curtailment levels of the DGs as decided by the two PoAs.

It is noted that with the proposed PoA, node 9 was curtailed more than with LIFO. All other DGs were curtailed less resulting in less total curtailment. For all three cases (LIFO, the proposed approach and the centralised OPF approach with Matpower), the voltage level was kept below the maximum statutory limit of 1.02 p.u. The proposed voltage sensitivity based curtailment approach performed more efficient curtailment without increasing the complexity of implementation.

For the management of reactive power by the ANM, the same principles can be applied, i.e. equation (3.19) can be used to find the voltage sensitivities due to reactive power changes and the ANM can adjust the DG at the node where the voltage is most sensitive to reactive power to achieve voltage regulation.

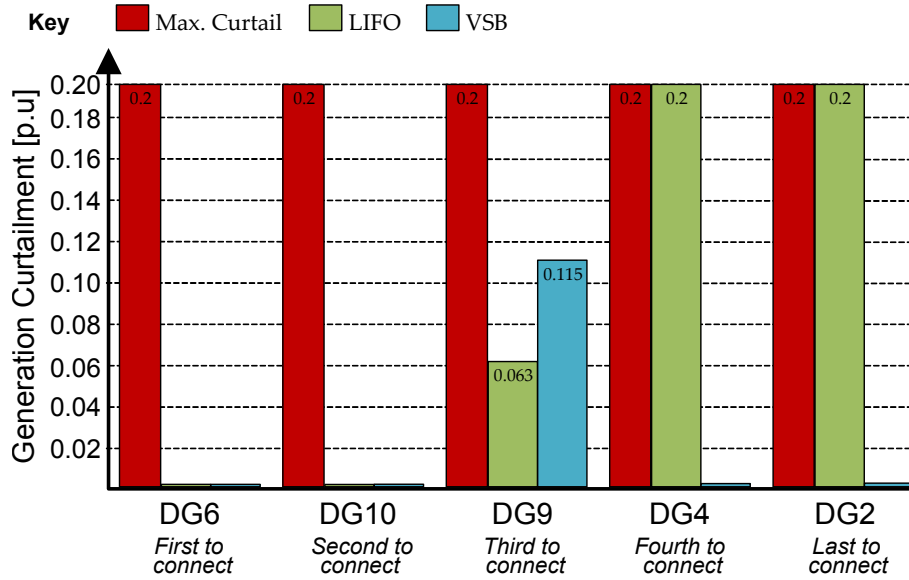


Figure 3.11: Comparison between curtailment levels in two different PoA.

Simulation results show that when considering the traditional LIFO arrangement, the DG located at node 2 has its power injection adjusted first, simply because it was the last to connect. However, the voltage sensitivity to power flow adjustment from node 2 is very low, indicating that its contribution towards solution of constraint is also very low and therefore, higher amount of curtailment is required. It is seen that ANM under LIFO curtailed nodes 2 and 4 up to the maximum allowed before curtailing DG at node 9 and finally solving the voltage constraint. If instead of LIFO, a voltage sensitivity analysis is computed by the ANM to select a DG which is more effective at managing the voltage constraint. Then the DG connected to node 9 is selected and 0.115 MVAR is requested to solve the voltage constraint and regulate the voltage at node 9. For this test case, LIFO required almost 43% more adjustment in power flow because of an inefficient DG selection.

The proposed distributed estimation of voltage sensitivity enables each DER participating in flexible connection agreement to evaluate constraints and adjust its ΔP or ΔQ to meet a voltage target. Additionally, by exchanging relevant information with neighbouring DERs, they can collaborate to resolve systems constraints, as will be discussed next. In the next chapter, a strategy is discussed for operating the network in real-time when constraints arise.

Chapter 4

Algorithm for Control and Coordination of DER

This chapter will set out an ANM algorithm for control and coordination of DER that are operating in ancillary service framework. The objective is to find in a distributed fashion the minimum volume or cost of adjustments of the real and reactive power injections of DER, procured by the ANM, that ensure the network is operated in compliance with its voltage and thermal constraints subject to the physical capacity limits of the DER. It is assumed that the DER have contracted in a forward energy market to operate at particular contracted positions. DER owners may then make offers to make adjustments away from contracted positions as ancillary services. The ANM algorithm will then decide, in real-time, what volume of which ancillary services offers to accept in order to meet its objective.

To deal with line thermal rating constraints (power flow limit between nodes), a straight forward approach is possible due to the direct relationship between downstream and upstream power flow adjustments. When faced with a breach of a thermal constraint, the ANM should request the downstream DER with cheapest cost to provide a real power adjustment, as an ancillary service, in the direction that reduces power flow in the line that has breached its constraint. To satisfy voltage constraints, the ANM needs a more elaborate strategy. The proposal is that each LC within the distributed ANM should estimate voltage sensitivities to power injections at

various other nodes using the voltage sensitivities estimation presented in the previous chapter. Each LC can form an approximation to the inverted Jacobian and can identify whether actions at its own node or actions at a remote node are better choices for satisfying the constraint. The choice of which action is best can be in terms of either the cost or volume of ancillary service that would be procured. To support this distributed decision making, a set of messages will be defined that are to be passed in a peer-to-peer fashion between LCs.

This chapter is organised as follow. First, the literature covering distributed control and coordination of DERs to solve network constraints is introduced in section 4.1. Then, in Section 4.2, the structure of the proposed ANM is described in terms of the roles of local controllers at the head, middle and end of feeders. In Section 4.3, a description is given of the way costs for procuring ancillary services are represented. These cost are then included in the algorithm of local controllers of the proposed ANM and in the formulation of the optimal power flow solver that serves as the comparison case for the ANM. The next element of the algorithm, described in section 4.4, is the use of voltage sensitivities to coordinate the decision making process of the ANM. The important algorithmic feature is to enable multiple controllers to be managed simultaneously while avoiding hunting effect. The mechanism by which LCs exchange information to improve their perception of the managed network is explained in section 4.5. In section 4.6, analysis of the communication burden of various approaches of ANM design is presented. The last section summarises the proposed ANM scheme. Testing of the algorithm is the subject of the following chapter.

4.1 Related Works

Authors in [70] presents a coordination strategy for distributed control that relies on a “token-transversal” in which a token containing the relevant system observations and permissions is passed between controllers, “teaching” them when and through which device they can make adjustments. Although the token-traversal scheme ensures proper coordination and avoids the hunting effect, it does not scale up well for large fleet of controllable devices, since the time taken for the token to complete a trip becomes problematic.

Another approach, [33], uses local estimation of voltage sensitivity based on a perturb-and-observe method and then use this value of sensitivity for adjustment of power to regulate the voltage. However, there is no discussion of how many local controllers using local sensitivity would coordinate their adjustments to achieve a good solution across the network without hunting effect. Additionally, as discussed in Chapter 3, the perturb and observe method is not robust in distribution networks that contains dynamic demand and generation profile along the day, which might cause errors in the method since the observed measurement is not necessarily due to the perturbed signal.

The approach presented in [33] was later refined in [34] by applying surface fitting techniques based on historical data of network operation to define sensitivities and then the multiple DERs were coordinated through applying pre-defined time delays before each DER took its actions. The staggered delays ensured that only one DER acted at a time and thereby hunting between DERs was avoided. The delays were defined in such a way as to respect agreements made previously between a DER owner and the DNO and the access priority implied by those agreements. How the staggered delays technique can be modified to include more sophisticated principles of access for DERs that copes with future designs of ancillary services framework is not discussed.

The work in [71] proposed a consensus control algorithm for improving the voltage profile of a network through coordinated adjustments of DERs. Multiple participating DERs adjust their injections simultaneously, at an agreed pace, which avoids the hunting effect. However the consensus method does not guarantee that action is taken at the node where power adjustment is most effective because no such evaluation is made.

In [72], a linear approximation of a power-flow solution is incorporated into a model predictive control framework to perform dynamic optimal power dispatch of DERs. The results given confirmed that voltage and thermal limits are never violated but also show that greater than necessary curtailment occurs.

The work presented in [73] demonstrates an ANM composed of multiple controllers that exchange messages that express their own constraints and their capabilities to solve constraints

and through this exchange they can identify a common decision. The controllers operate in a bidding system where their prices for adjusting power flows are shared and the cheapest is selected as the best choice for solving the observed constraints. A notional cost is assigned to voltage deviations to penalise decisions that causes voltage outside of the operating limits. The bidding scheme in which the DERs exchange price signals reflecting their intention and ability to adjust their outputs to solve voltage constraint, requires multiple message sharing steps between neighbouring controllers until convergence to a decision is achieved. This seems unfit for real-time operation.

Reflecting on the strengths and weakness of the literature in this area of distributed control and coordination of DERs, the approach to be developed in this chapter should have the following features. The LCs should be able to estimate voltage sensitivities not only to define power flow adjustment for constraint management as in [33] but use these estimations to also coordinate their actions to solve voltage constraints which is in contrast to the works that rely on predefined time-delays as in [34] or consensus as in [71] or token-traversal as in [70].

The approach should also seek to minimise curtailment of power, a feature present in only a few of the works in the literature reviewed in this chapter and in Chapter 2, good examples being in [11, 27]. Without this consideration, undue curtailment can occur making some potential connections less viable and acting contrary to regulatory objectives to facilitate DER. Finally, the approach should be able to cope with new forms of ancillary service market and be able to procure the lowest cost services offered by DER owners to solve network constraints, without high requirements of computational and communication infrastructures. Addressing this shortcoming is the focus of the proposed distributed active network management scheme.

The proposed ANM described in this chapter avoids central computation of optimal actions by relying on the distributed estimations presented in chapter 3. It is based on a two-layer market in which DER have contractual positions for energy provision and on top of that, the ANM can seek adjustments to operating points of DERs, offered as ancillary services, for constraint satisfaction but does so to the smallest extent possible by seeking the DER best placed to deal with each constraint.

4.2 Types of Local Controllers

The proposed algorithm will use different types of local controllers to reflect the fact that the scope for action and measurements available depend on location within a feeder. The three types of LC are explained in the following list and are shown deployed in the envisioned network discussed in chapter 2 at Figure 2.8.

1. **Beginning of Feeder LC:** is deployed at the substation busbar where the a traditional feeder is fed with power from higher levels of the network. Its voltage is more stiff than at downstream nodes and its voltage is considered to be slack bus voltage by the other controllers. The Beginning of Feeder LC can exchange information between voltage levels of the network.
2. **DER Controller:** Deployed on nodes with controllable DERs, monitoring and controlling output to maintain operational parameters within safe constraints. Must respect existing agreements between network operators and DER owners to change operating set-point. These controllers also exchange information with neighbouring controllers and controllable DER.
3. **End of Feeder Controller:** Deployed at end of feeders and as such only require communicating with one neighbour at upstream location. The voltage sensitivity at end of feeders tend to be higher and consequently, DERs connected at end of feeder have voltage that can be more easily adjusted.

It is possible to observe in Figure 2.8 that some LC require communicating with more than two neighbours, e.g. LCs in the medium voltage feeder, which communicates with its upstream and two downstream nodes (one in the same voltage level and another in the lower voltage level). This situation can occur as well in branched networks, where the LC will have multiple downstream controllers to communicate with. Other controllers only communicate with one other controller, as in the case of the end of feeder controllers.

All restrictions obtained from neighbours, will be evaluated the same way and passed along in such a way that the controllers will becoming aware of network's constraint as iteration passes. This process of information handling and propagation to improve internal representation of the network is explained later in this Chapter during Section 4.5.

4.3 Cost & Unit Cost of Ancillary Services

Before describing the ANM strategy, it is relevant to discuss the ancillary service market for participating DERs that will be used during the ANM decision making. Each DER owner participating in ancillary services, connected at node i , specifies a price per unit of energy (referred to here as a unit cost of ancillary service) in which it agrees to have its power output shifted by the ANM in order to solve constraints, defined in this thesis as A_i^P for adjusting active power or A_i^Q for adjusting reactive power. In case of no network constraint is detected, no adjustment is requested and the DERs are dispatched with zero cost of ancillary service procurement, meaning that they are free to operate in their agreed operating limits. In case a network constraint is detected, the ANM platform is expected to solve it in the most cost effective way possible. Figure 4.1 exemplify a simplistic ancillary service cost procurement curve for adjusting active power from DERs participating in ancillary services, inspired by the trial project [23]. The same principle applies for reactive power ancillary services.

Costs from ancillary service procurement is subsequently passed on as use-of-system charges and must be kept at minimum to maintain safe operation while creating additional capacity for integrating more DERs. To minimise the total cost of ancillary services, C^A , the objective function is defined as equation (4.1), where the control variables are the active and reactive power output from DERs at every node i , P_i^G and Q_i^G respectively. The contracted capacity of active and reactive power for each participating DER i are defined as P_i^C and Q_i^C .

$$\min_{P_i^G, Q_i^G} C^A = \min_{P_i^G, Q_i^G} \sum_{i=1}^{N_g} \left(P_i^C - P_i^G \right)^2 \cdot A_i^P + \left(Q_i^C - Q_i^G \right)^2 \cdot A_i^Q \quad (4.1)$$

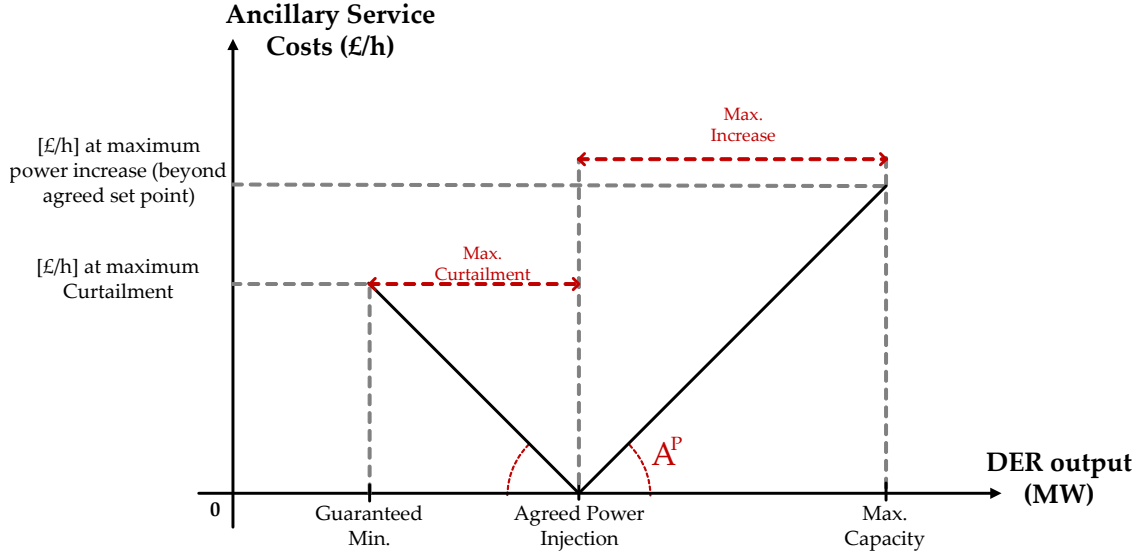


Figure 4.1: Cost curve of procuring ancillary service.

It is possible to evaluate the costs for curtailing and for increasing above the agreed set point separately by splitting into two “virtual” DERs, DER^- and DER^+ as shown in Figure 4.2, being one capable to decrease and the other capable to increase from the agreed (or contracted) set point. By evaluating both curves separately, the quadratic term from equation 4.1 is avoided. The sum of the output from both DERs (DER^- and DER^+) must result in the output from the original DER and for this reason the function of DER^+ is shifted towards the origin so that it is not injecting power unless more power output is required beyond the agreed set point. In case no constraint is met, DER^- injects the agreed amount while DER^+ injects nothing. In case of constraint violation is detected and more injection is required to solve it (under-voltage or over-loading conditions), then the DER^- injects the agreed amount while the DER^+ injects the excess required to solve constraint. Finally, in case of constraint violation is detected in which curtailment is required (over-voltage or under-loading conditions), then DER^- is curtailed below the agreed set-point while the DER^+ remains injecting nothing. Equations (4.2) and (4.3) shows the relation between the output from the original DER, used in equation (4.1), and the pair DER^- and DER^+ .

$$P_i^G = P_i^{G+} + P_i^{G-} \quad (4.2)$$

$$Q_i^G = Q_i^{G+} + Q_i^{G-} \quad (4.3)$$

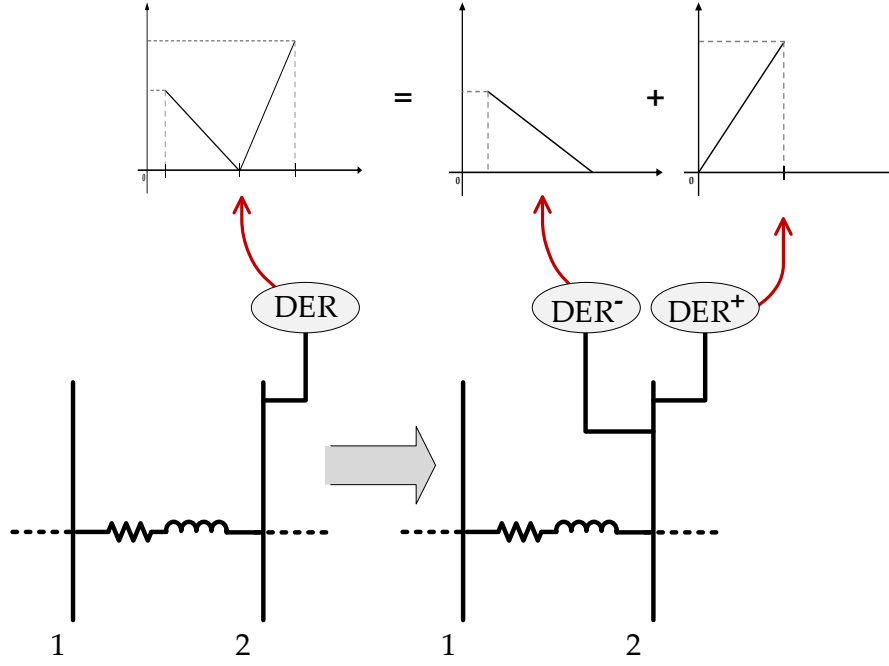


Figure 4.2: Simplification of DER ancillary service costs by splitting costs into decreasing and increasing functions.

The curve for DER^- , represents the cost for procuring ancillary services for operating the DER below the agreed set-point (curtailment), as shown in the left side of Figure 4.3. In the OPF solver, this DER is defined with maximum capacity equal to the agreed set point, when zero cost of ancillary service is required. The minimum capacity that the OPF solver considers possible to dispatch this DER is defined as the guaranteed minimum capacity that the DER agreed to operate. To define the second DER, DER^+ , with increasing cost for increasing power injections away from agreed set point, the maximum capacity coded into the OPF solver is defined as the difference between the original maximum capacity and the agreed power injection (as indicated in Figure 4.1). The minimum capacity of DER^+ is zero, as shown in right side of Fig. 4.3. It is noteworthy that the same principles applies for reactive power case.

The equations that describe the total ancillary service costs for DER^- and DER^+ are shown in equations (4.4) and (4.5) respectively, where A^- and A^+ extends the terms A^P and A^Q used in equation (4.1) for the case that it is desired to consider different costs for moving the power output of DER below or above the agreed set point. The terms P^C and Q^C has the same meaning as in equation (4.1) and the terms P^{G+}, Q^{G+}, P^{G-} and Q^{G-} indicate the active and reactive output of the DER^+ and DER^- .

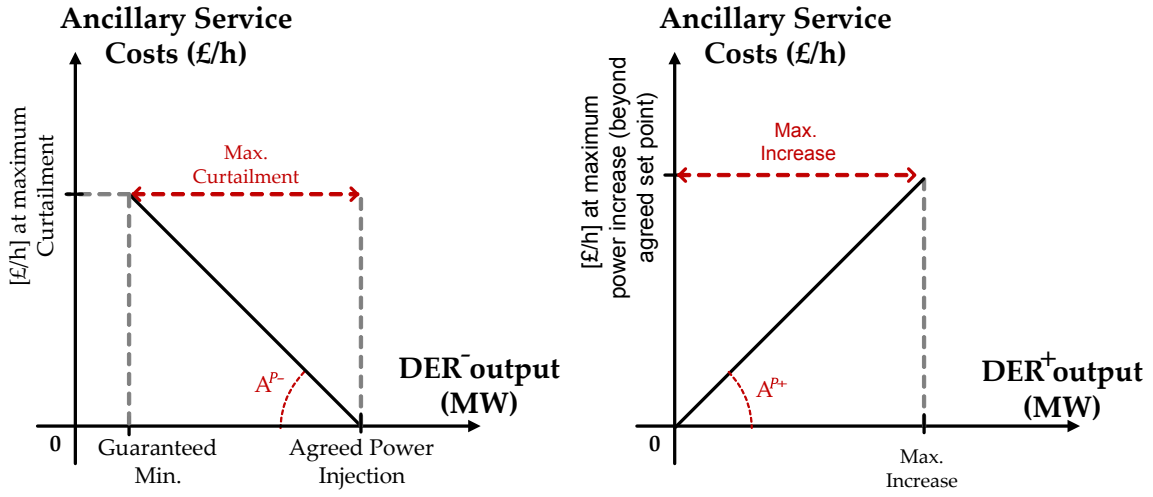


Figure 4.3: Curves for ancillary services for the two virtual generators.

$$C^{A-} = A^{P-} \cdot (P^C - P^{G-}) + A^{Q-} \cdot (Q^C - Q^{G-}) \quad (4.4)$$

$$C^{A+} = A^{P+} \cdot P^{G+} + A^{Q+} \cdot Q^{G+} \quad (4.5)$$

4.3.1 Minimising Costs of Adjustments

The objective of the proposed management system is that it should choose the most cost effective DER to adjust power injections to solve voltage and thermal constraints. It differs from a technical best solution in the sense that more adjustment might be selected in case the procuring DER is participating with lowest cost of actions in the ancillary service market. Whereas in a technical best the most effective node is chosen, without caring for how much it costs to adjust its set point.

This considers that DER owners that are participating in ancillary service markets are offering their ability to adjust power flow and the ANM should procure actions from the most cost-effective participant. By minimising the total costs from procuring ancillary services, the overall costs passed on as use-of-system charges are reduced. It is now discussed how the objective function that minimises cost of ancillary services can be simplified from its original quadratic form, presented in (4.1) utilising the two complementary cost curves presented.

Mathematical Formulation

The mathematical formulation of the optimisation problem are presented in equations (4.6)-(4.14). It considers a radial network composed by a set N that contains all the nodes and a set E that contains all the edges, or lines connecting nodes (i,j) . The active and reactive power output from DER^+ are defined as P_i^{G+} and Q_i^{G+} respectively while the active and reactive power output from DER^- are defined as P_i^{G-} and Q_i^{G-} respectively. They act as the control variables of the optimisation problem, being subject to physical or contractual capacities. Reminding that, from equations (4.2) and (4.3), the complex power generated by DER i , S_i^G , can be written as function of these control variables. The physical or contractual limits for active or reactive powers for DER^+ are defined within the range of $\underline{P}_i^{G+}$ and $\overline{P}_i^{G+}$ for active power, and in the range of $\underline{Q}_i^{G+}$ and $\overline{Q}_i^{G+}$ for reactive power. As for the physical or contractual limits for DER^- , the limits are defined within the range of $\underline{P}_i^{G-}$ and $\overline{P}_i^{G-}$ for active power, and in the range of $\underline{Q}_i^{G-}$ and $\overline{Q}_i^{G-}$ for reactive power. A_i^{P+} and A_i^{Q+} are the costs per unit of energy (or unit cost of ancillary service) for procuring ancillary services from DER^+ . A_i^{P-} and A_i^{Q-} are the costs per unit of energy for procuring ancillary services from DER^- . $|S_{i,j}|$ is the magnitude of the apparent power flowing from node i to node j . $|\overline{S}_{i,j}|$ is the maximum supported magnitude of apparent power flowing from node i to node j , also defined as the thermal limit in the line connecting nodes i,j . The lower and upper limits of nodal voltages are defined as $|\underline{V}_i|$ and $|\overline{V}_i|$ respectively, and the actual nodal voltage at i is defined as $|V_i|$. As mentioned, voltage angles are neglected.

Equation (4.7) represents the objective function of minimising the costs per hour (and ultimately minimising the total cost during the operation period) for procuring ancillary services from DERs. Equation (4.8) represents the known AC nodal power balance equations in its complex and compact form, where S_i^G is the generated power injected in bus i by the connecting DER, S_i^D represents the power demanded by the load connected at the same node i and Y represent the admittance bus of the given network. The inequality constraints representing the operating limits from the network (voltage and thermal limits) and DERs (maximum and minimum capacities) are shown from (4.9) to (4.14).

$$\min_{P_i^{G-}, P_i^{G+}, Q_i^{G-}, Q_i^{G+}} (C^{A-} + C^{A+}) = \min_{P_i^{G-}, P_i^{G+}, Q_i^{G-}, Q_i^{G+}} \left(\sum_{i=1}^N C_i^{A-} + \sum_{i=1}^N C_i^{A+} \right) \quad (4.6)$$

substituting (4.4) and (4.5)

$$\begin{aligned} & \min_{P_i^{G-}, P_i^{G+}, Q_i^{G-}, Q_i^{G+}} \sum_{i=1}^N \left[A_i^{P-} \cdot (P_i^C - P_i^{G-}) + A_i^{Q-} \cdot (Q_i^C - Q_i^{G-}) \right] \\ & + \sum_{i=1}^N \left[A_i^{P+} \cdot P_i^{G+} + A_i^{Q+} \cdot Q_i^{G+} \right] \end{aligned} \quad (4.7)$$

Subject to:

$$S_i^G - S_i^D = \sum_{(i,j) \in E} (Y_{i,j}^* V_i V_j^* - Y_{i,j}^* V_i V_j^*), \forall i \in N \quad (4.8)$$

$$\underline{P}_i^{G+} \leq P_i^{G+} \leq \overline{P}_i^{G+}, \forall i \in N \quad (4.9)$$

$$\underline{Q}_i^{G+} \leq Q_i^{G+} \leq \overline{Q}_i^{G+}, \forall i \in N \quad (4.10)$$

$$\underline{P}_i^{G-} \leq P_i^{G-} \leq \overline{P}_i^{G-}, \forall i \in N \quad (4.11)$$

$$\underline{Q}_i^{G-} \leq Q_i^{G-} \leq \overline{Q}_i^{G-}, \forall i \in N \quad (4.12)$$

$$|S_{i,j}| \leq |\overline{S}_{i,j}|, \forall (i,j) \in E \quad (4.13)$$

$$|\underline{V}_i| \leq |V_i| \leq |\overline{V}_i|, \forall i \in N \quad (4.14)$$

4.4 Coordination Strategy Based on Voltage Sensitivity

In this section it is explained how the voltage sensitivities can be used to coordinate adjustment between multiple controllable devices in order to avoid unwanted interactions from multiple adjustments happening at the same time, *e.g.* causing hunting effect [32, 58, 73]. It has been shown in Chapter 3 that every controller is able to estimate how its local voltage changes with local power change as well as how its local voltage change due to non-local power change, as shown in the complete sensitivity matrix estimation in Section 3.4. With this information, the controllers can evaluate where a power flow adjustment is more effective in alleviating observed local voltage constraint by finding the node with higher sensitivity magnitude.

In case a voltage violation is detected by LC at node i , it checks its estimations of sensitivities and in case a local power flow change causes the higher change in local voltage, it will not send its constraint violation information to other neighbouring controllers and will adjust its own injections to solve constraint. Other controllers are not aware of violations from node i because no message was sent requesting adjustments. Only node i made adjustment, in a coordinated manner. In case node i observed another node to be more effective in changing local voltage, V_i , then a message is sent in the direction that this LC is located (either downstream or upstream).

As the messages propagates along the network, all the receiving controllers perform the same analysis until a LC that estimates itself to be more effective obtains the message and adjusts its power injections to solve it. This process of message passing is explained in more details during Section 4.5. For this section it is only intended to describe that with voltage sensitivity information, the controllers can evaluate if local adjustments are more effective than non-local adjustments to solve local voltage constraint.

It is important to highlight that to solve thermal constraints (power flow limits from line cables) it is adopted a more straight forward strategy. The relationship of how power flow is changed in a radial network due to change in power injections is described as a direct relationship, as discussed in Chapter 3. In case LC i detects a power flowing to its node higher than the thermal limits of its cable specifications, than it knows that any downstream node will have similar effectiveness in solving the constraint while upstream controllers' support is negligible.

4.4.1 Distributed Calculation of Cost-Effective DER

Only evaluating how voltage varies with power flow does not account for ancillary services costs in the selection of participating device to adjust power output. To obtain the most cost effective among the participating DERs to solve voltage constraint it is necessary to include how costly it is to adjust power flow in each node. The management system may opt for a DER located in a lower voltage sensitivity node (i.e. requires more power flow adjustment to change nodal voltage) but that has offered cheaper ancillary service.

In a possible ancillary market for DERs participating in flexible connection arrangement, power flow injection can be adjusted during operation periods for an agreed price per unit of energy adjusted in this period. To indicate how power flow (active or reactive) varies for each unit of cost per hour, it is defined the term cost sensitivity to active and reactive powers, $\frac{\partial P_i}{\partial \text{Cost} P_i}$ and $\frac{\partial Q_i}{\partial \text{Cost} Q_i}$. Higher values means that the corresponding DER agrees to have more power adjusted for smaller costs to the ANM. Lower values means that the corresponding DER is more costly to procure ancillary services to adjust power flow. The management system must prioritise higher cost sensitivities, but must also take into account how power flow actually influence on nodal voltage, *i.e.* how effective it is to solve voltage constraint by adjusting power in a given node. Equations (4.15) and (4.16) presents an expression to evaluate cost-effectiveness of voltage regulation of node i , considering both its unit cost for offered ancillary services and voltage sensitivity of point of connection, for active and reactive power adjustment respectively.

$$\frac{\partial V_i}{\partial \text{Cost} P_i} = \frac{\partial V_i}{\partial P_i} \cdot \frac{\partial P_i}{\partial \text{Cost} P_i} \quad (4.15)$$

$$\frac{\partial V_i}{\partial \text{Cost} Q_i} = \frac{\partial V_i}{\partial Q_i} \cdot \frac{\partial Q_i}{\partial \text{Cost} Q_i} \quad (4.16)$$

The voltage sensitivities can be obtained in a distributed way and used by the management system to obtain how cost-effective each DER is to regulate voltage with their power injections adjustments.

4.5 Information Sharing

How the information is shared between LCs is a critical step for designing the control and coordination strategy. Supply and demand are constantly changing and consequently, the operational parameters, or state variables, such as voltage and power flows are also constantly changing. Therefore, it is a challenge to keep track of this variable condition for actively managing the network. This is a challenge for any approach (centralised, decentralised and distributed).

Besides the state variables, a network also has some fixed parameters such as line parameters and ancillary service agreements, such as the cost per unit of energy agreed by DERs. These parameters can be assumed constant for a given configuration and operation period. If a parameter is fixed, there is no need to keep updating their values over time, and they can be exchanged only once, or even simply pre-programmed into the controllers during its deployment.

The information sharing is divided in three steps. One is defined as *Network Evaluation Phase*, in which the controllers obtain the information regarding the fixed parameters of the network they are operating in; the other step is when the controllers exchange information regarding their operation in the network, defined as *Headroom Evaluation Phase*. The term headroom is used in this thesis to refer to the allowed adjustments to the DERs output that will not violate network constraints. Third step is the *LC operational parameters evaluation* and serves to determine which LC is available to act. Each step is described in the following sub sections.

4.5.1 Network Evaluation

According to (3.18) and (3.19), the line parameters needs to be known by all LCs in order to estimate voltage sensitivity. Additionally, from (4.15) and (4.16) it is clear that in order for the controllers to calculate the cost sensitivities to power adjustments, it is necessary to know contractual costs per unit of power change from all DERs participating in the ancillary service market. Therefore, it is possible to define the data vector to be exchanged as: $message = [R \ L \ Cost]$, where R and L are the line resistance and reactance between two consecutive nodes and $Cost$ is the vector for active and reactive ancillary service cost, per unit of power adjusted away from agreed set point, defined earlier as A^P and A^Q . Assuming that these parameters will remain constant during pre determined period and while no network reconfiguration happens, they can be shared only once during an initialization stage of the management system, defined in this work as “*Network Evaluation Phase*” and during every communication iteration, the LCs sends to closest neighbour all the information obtained. To illustrate the network evaluation phase, consider Figure 4.4. Note that, as iteration passes, the LCs will keep on learning from neighbours until having full knowledge of the constant network parameters.

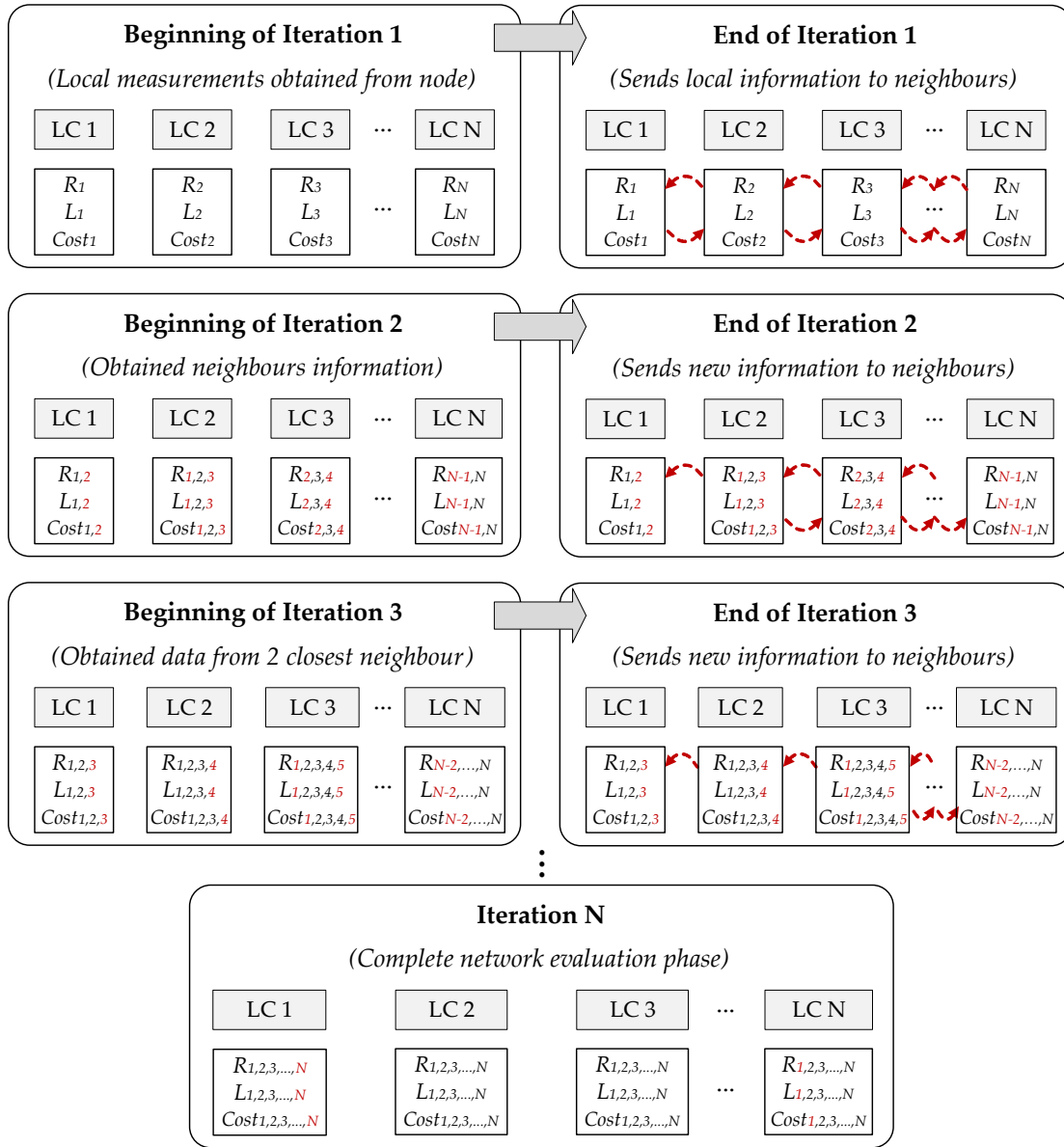


Figure 4.4: Example of communication iterations during the Network Evaluation Phase.

The red traced line in Figure 4.4 indicates communication link. It starts with local information obtained from measurement devices. At the end of first communication iteration, these local measurements are shared with closest neighbours. At the beginning of the second iteration, LCs are aware of closest neighbour's parameters, as indicated by the subscript numbers in red. Since they transmitted local data during the previous iteration, there is no need to send it again. This is represented by the absence of the red traced line between LCs, indicating that the LC has no new information to send. For instance, LC 1 have no new information to send it to LC 2 during the end of second iteration. At the beginning of the third communication iteration, aside from local information, LCs are also aware of conditions up to two closest neighbours.

In total, it is required N iterations, where N is the total number of LCs operating in the network, sending a packet with three variables for every neighbour, *i.e.* $message = [R \ L \ Cost]$, reminding that $Cost$ is composed of two (one for active and one for reactive power). In order to obtain all network parameters it is required to transmit $N.(N - 1)$ messages. Considering that each parameter is stored as floating number with double precision (using 64 bits = 8 bytes), then each message is 32 bytes. Consequently, the proposed network evaluation phase requires $32.N.(N - 1)$ bytes of data to be transferred. Alternatively, these information can be transmitted in a centralised fashion or pre-programmed in each LC during deployment since it is only required to do it once.

4.5.2 Headroom Evaluation

As seen from the distributed calculation in equation (3.11), it is possible to estimate local voltage due to local or non-local power change. It is not possible to estimate non-local voltage outcome since it would require voltage data from other nodes and this information is supposedly unknown in decentralised or distributed approaches. Therefore, a local controller is unable to estimate another node's voltage outcome due to power flow changes. However, this estimation is crucial for determining if a local action will bring a non-local node outside of constraint, in other words, it is crucial for determining the “headroom” available for DER adjustment, where the headroom is defined as the allowed changes ΔV and ΔS that can occur before a voltage or thermal limit is breached. For this reason the proposed management system requires state variables information sharing between controllers working to enable update of non local conditions without requiring direct communication with all nodes. This process is described in this sub-section.

Operational parameters are constantly changing and would require high amount of data transfer between LCs in order to keep them updated. Opposed to sharing operational parameters (voltage and power flows), in order to consider local and non-local constraints in a distributed approach, it is proposed that each LC shares its observed headroom with neighbours, *i.e.* the maximum power change that will not violate local constraints.

The voltage headroom is defined in (4.17) and (4.18) considering upper and lower limit while power flow headroom is shown in (4.19), where $\bar{V}_i$, $\underline{V}_i$ are the voltage higher and lower statutory limits and $\bar{S}_i$ is the power flow limit. In equations (4.17) and (4.19) operation on the safe side of a limit gives a positive value of headroom and an indication of how much further capacity the network possesses to increase penetration before reaching a constraint, whereas a negative value indicates the constraint has been breached. The opposite is true for equation (4.18).

$$\Delta V_i^U = \bar{V}_i - V_i \quad (4.17)$$

$$\Delta V_i^L = \underline{V}_i - V_i \quad (4.18)$$

$$\Delta S_i^{limit} = |\bar{S}_i| - |S_i| \quad (4.19)$$

For a voltage limit violation, the LC that detected the constraint checks for the most cost-effective DER, as calculated with equations (4.15) and (4.15) and sends a message in that direction to request power adjustment that will solve local constraint. Reminding that equations (4.15) and (4.15) takes into account the voltage sensitivity due to power change and the unit cost for procuring ancillary services for adjusting DER output. If the best solution (combination of highest voltage sensitivity and cheapest unit cost of ancillary service) lies upstream then a message is sent defining the ΔV that the upstream node is supposed to adjust. To do this, the constrained LC at node i uses equation (4.20) to determine the voltage change required at upstream, node $(i-1)$, to create the desired voltage change at local node (i) . This relationship is obtained in a distributed fashion for radial networks from the voltage drop equation presented in section 3 and in [37]. If the best solution lies downstream, then a message is sent downstream and the receiving LC uses the same equation (4.20) to convert the requested change from its upstream, ΔV_{i-1} , to a local ΔV_i . The nodal voltage change due to upstream voltage change, $\frac{\partial V_i}{\partial V_{i-1}}$, is obtained from partial derivation of (3.10) with respect to upstream voltage.

$$\frac{\partial V_i}{\partial V_{i-1}} \cong \frac{1}{2} + \frac{V_i + \frac{R_i P_i^{up} + X_i Q_i^{up}}{V_i}}{\sqrt{\left(V_i + \frac{R_i P_i^{up} + X_i Q_i^{up}}{V_i}\right)^2 - 4(R_i P_i^{up} + X_i Q_i^{up})}} \quad (4.20)$$

It is much simpler in case it is a thermal constraint because only downstream nodes can act to solve it and with a direct relationship between downstream power changes and upstreams' power change. The constrained LC only needs to send to its downstream the ΔS that it requires to relieve local constraint. The first downstream controller with lowest cost for adjusting power injection in an ancillary service market that receives it is already best placed to act, and will stop propagating the message to avoid simultaneous actions to solve constraint.

To become aware of constraint violation throughout the network without centralised data acquisition, each LC must compare headroom data it receives from neighbours with its own calculation of local headroom to assess which node is most closely approaching (or has exceeded) a constraint, defined here as critical headroom. Equations (4.21), (4.22) and (4.23) expresses how to obtain these critical headroom parameters. In summary, the terms $\Delta V_i^{U_{critical}}$ and $\Delta V_i^{L_{critical}}$ indicates the voltage change at node i that will cause voltage somewhere in the network to reach the maximum or minimum threshold respectively, while the term $\Delta S_i^{critical}$ represents the change in the power that is flowing to node i through its upstream $i - 1$ that will reach the limit. For the upper voltage limit and the thermal constraint, the critical headroom is the least positive headroom, after comparing the local estimations, obtained with (4.17) and (4.19), with the headroom obtained from upstream and downstream (observed by the LC at node i). For lower voltage limit, the least negative is the critical headroom, as shown in (4.22).

$$\Delta V_i^{U_{critical}} = \min \left[\Delta V_{i-1}^U \quad \Delta V_i^U \quad \Delta V_{i+1}^U \right] \quad (4.21)$$

$$\Delta V_i^{L_{critical}} = \max \left[\Delta V_{i-1}^L \quad \Delta V_i^L \quad \Delta V_{i+1}^L \right] \quad (4.22)$$

$$\Delta S_i^{critical} = \min \left[\Delta S_{i-1}^{limit} \quad \Delta S_i^{limit} \right] \quad (4.23)$$

Through the computation of critical headroom viewed from each node, the critical constraint can be addressed in an equivalent way to a local constraint, *i.e.*, a LC is made aware of the critical headroom and will try to determine, based on its estimates of sensitivities and offered DER services, which LC is best placed to relieve the constraint. As messages propagate between neighbours, if a local controller receives constrained headroom from one of the neighbours, it can then incorporate as if it is its own constraint, by altering $\bar{V}_i$ or $\underline{V}_i$ from (4.17) and (4.18),

and then update the calculation to send forward, in the direction that local controller estimates the most cost-effective controller to be. In this way, the controllers will be restricted based on its neighbour's neighbour headroom and so on, as data hops between nodes. In other words, LCs become aware of constraint violations across the entire network, without needing to know where the constraint is actually happening.

To convert $V_i^{U_{critical}}$, $V_i^{L_{critical}}$ from equations (4.21) and (4.22) into control actions of ΔP_i^G or ΔQ_i^G (DER output of active or reactive power), they must be divided by the voltage sensitivities obtained in (3.12) and (3.13), as shown in equations (4.24) through (4.27). The $\overline{\Delta P_i}$ and $\overline{\Delta Q_i}$ indicates that the adjustment will bring the most critical voltage seen by i to the upper voltage limit and the $\underline{\Delta P_i}$ and $\underline{\Delta Q_i}$ indicates that it will bring to the lower voltage limit.

$$\overline{\Delta P_i} \approx \frac{\Delta V_i^{U_{critical}}}{\partial V_i / \partial P_i} \quad (4.24)$$

$$\underline{\Delta P_i} \approx \frac{\Delta V_i^{L_{critical}}}{\partial V_i / \partial P_i} \quad (4.25)$$

$$\overline{\Delta Q_i} \approx \frac{\Delta V_i^{U_{critical}}}{\partial V_i / \partial Q_i} \quad (4.26)$$

$$\underline{\Delta Q_i} \approx \frac{\Delta V_i^{L_{critical}}}{\partial V_i / \partial Q_i} \quad (4.27)$$

This iterative procedure increases the knowledge of the network variables without requiring full system data to be transferred. The drawback of this distributed strategy is an inertial behaviour in the sense that a local controller will only be updated of a faraway node's constraint after K communication hops, where K is the number of nodes in between the two controllers. Additionally, the voltage headroom sent from the far away controller is obtained for a particular observation and as the messages hops, conditions may change. To overcome this inertial behaviour, every time a headroom message is received from neighbours, represented by the terms with $i - 1$ or $i + 1$ in equations (4.21), (4.22) and (4.23), the LC subtracts voltage and power changes measured before and after receiving the messages, and assumes this changes also happened at the closest neighbour. The changes can be due to a change in load or also an action taken by some of the LCs that found an ideal adjustment to solve constraints. This way the LCs maintain updated estimations of voltage headroom received from neighbours.

4.5.3 Operational Parameters Evaluation

As well as the headroom information from neighbours, LCs also require some operational data to determine which LC have achieved certain operating conditions. This data can be compiled into binary vectors to indicate whether or not a DER (overseen by a LC) is operating under any of the following conditions. The operational vectors are listed and described below.

1. Contract Satisfaction: Binary vector containing information regarding which DER is injecting according to contract, setting to (1) in affirmative case and (0) otherwise. The LC sends all of its downstream observations to its upstream and sends all of its upstream observations to its downstream. Therefore, the size of this vector is equal to the number of downstream DERs when sending message to upstream and equal the number of upstream DERs when sending message to downstream.
2. Curtailed: Binary vector containing information regarding which DER is injecting less than agreed in contract, setting to (1) in case it is and (0) in case it is not. Size of this vector follows the same principle described previously.
3. Max capacity: Binary vector containing information regarding which DER is injecting at full capacity, setting to (1) in affirmative case and (0) otherwise. The size of this vector also follows same principle described.
4. Min capacity: Binary vector containing information regarding which DER is injecting at guaranteed minimum capacity, setting to (1) in case it is and (0) otherwise. The size of this vector also follows same principle described.

Through sharing these vectors, the LC will update its internal representation of the system and take decisions coordinated with its neighbours. Its noteworthy that the binary vectors must be shared for active and reactive power information. The proposed distributed control and coordination discussed in this section is summarized in Algorithm 2. The algorithm is run repeatedly to allow that (i) small errors attributable to the approximations are gradually reduced, (ii) a new DER can take over as the best node to take action if a DER reaches an operational limit and (iii) the ANM can respond to changes in load demand and non-dispatchable generation.

Algorithm 2: Local Controllers Iterative Script

Obtain local measurements $\rightarrow (V_i, P_i^{up}, Q_i^{up})$;

for *all neighbours k* **do**

| Estimate $\frac{\partial V_i}{\partial P_k}$ and $\frac{\partial V_i}{\partial Q_k}$ according to Algorithm1

end

Calculate local headroom via equations (4.17), (4.18) and (4.19);

if *Exist message in upstream buffer* **then**

| Read $\left\{ \begin{array}{l} \text{Nework operational parameters} \\ \text{Upstream Headroom} \end{array} \right.$

end

if *Exist message in downstream buffer* **then**

| Read $\left\{ \begin{array}{l} \text{Nework operational parameters} \\ \text{Downstream Headroom} \end{array} \right.$

end

Compute critical headroom via equations (4.21), (4.22) and (4.23);

Find ideal to solve voltage constraint $\rightarrow \max \left[\frac{\partial V_i}{\partial P_k} \quad \frac{\partial V_i}{\partial Q_k} \right]$;

Find ideal to solve thermal constraint $\rightarrow$ closest to i;

Calculate allowable adjustment via equations (4.24)-(4.27);

if *i is ideal to solve Voltage* **then**

| Make local adjustment to regulate Voltage according to (4.24) or (4.26) in case of
| over voltage or according to (4.25) or (4.27) in case of under voltage

end

if *i is ideal to solve thermal* **then**

| Make local adjustment to regulate power flow

end

Send Headroom and operational data to neighbours;

Restart Iteration;

4.6 Communication burden analysis

From the described method, the required data exchanged by each LC are the headroom capacity allowed in the local node, i.e. equations (4.17), (4.18) and (4.19), plus the 8 binary operational vectors. Assuming that headroom variables are defined as floating number with double precision, which uses 64 bits (or 8 bytes), then to transmit the 3 variables it requires 24 bytes. The biggest binary vector exchanged will have length equal to the number of nodes, N , therefore, require N bits, or $\lceil N/8 \rceil$ bytes ($\lceil \cdot \rceil$ is the ceil function, which round up the result to the nearest integer) multiplied by the number of vectors, which is 8 (four for active and four for reactive power decisions). Defining the number of adjacent neighbours as b then the total size of data packet in bytes transmitted before taking a decision is defined as.

$$msg_{LC} = [(3 \cdot 8) + 8 \cdot \lceil N/8 \rceil] \cdot b \quad (4.28)$$

In the distributed approach, all messages are exchanged simultaneously between neighbours, then the size of this message can be used to estimate the communication burden of the channel. On the other hand, centralised approaches based on OPF, the communication burden is divided in two stages, one being the message sent from all LCs to the central coordinator and the other being the message sent from the CC to all LCs. Also neglecting voltage angles and assuming that voltage and power flow data are exchanged as floating numbers with double precision, the data packet size in bytes is shown in (4.29). All LCs are required to send voltage and power flow measurements to the CC to run the OPF, resulting in 3 variables of 8 bytes from each. Then after running the OPF algorithm, the CC sends back to each LC their operating set points, i.e. active and reactive power injections, which adds up to $2 \cdot 8$ bytes sent to each LC.

$$msg_{OPF} = \overbrace{(3 \cdot 8 \cdot N)}^{\text{from LCs to CC}} + \overbrace{(2 \cdot 8 \cdot N)}^{\text{from CC to LCs}} = 40N \quad (4.29)$$

Figure 4.5 shows the plots of amount of bytes requirement for the centralised and proposed approach, considering different number of neighbouring LCs. It is clear that size of data transfer to take a decision using the distributed approach is much lighter than relying on centralised OPF, specially for growing number of devices. Figure 4.6 presents the detailed plots of the data exchange requirement for the proposed approach.

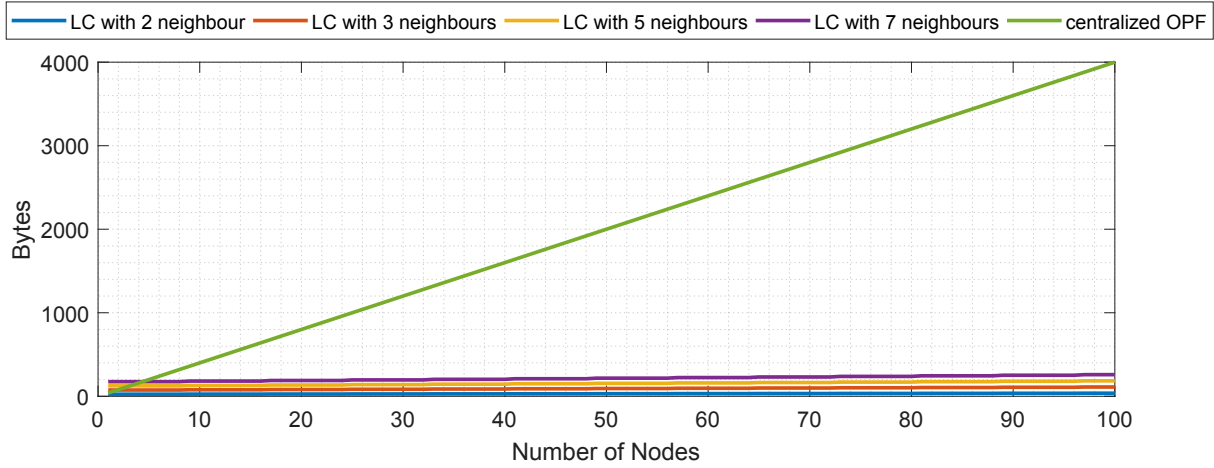


Figure 4.5: Data exchange comparison between centralised and proposed approach.

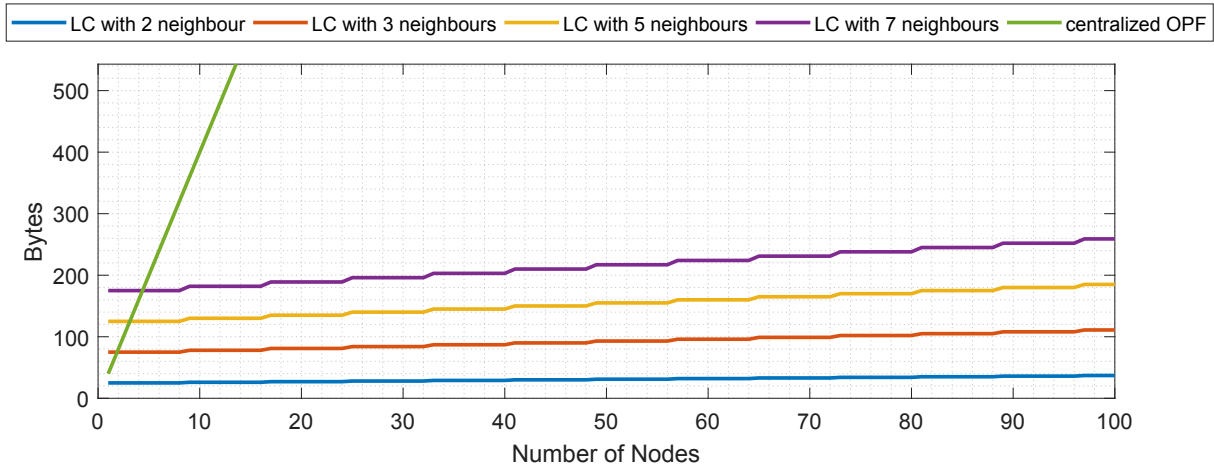


Figure 4.6: Detailed view of data exchange requirement from proposed approach.

Assuming that for distribution networks applications it is desired simplistic communication infrastructure, for instance, devices with capability of transmitting in the range of 1200 bytes per second, which are low cost and accessible options for embedding in LC attached to DERs participating in ANM [28, 74, 75]. With this communication speed and managing a 30 bus system, a centralised OPF would require 1 second just for communicating all of the required information back and forth between central controller and local controllers, not to mention the

computational time requirement. In the other hand, the same 30 bus system would require 0.16 seconds for the LC with 7 multiple neighbours and only 0.023 seconds for LCs with only 2 closes neighbours. This is a key feature that makes decentralisation of ANM desirable. Furthermore, in distributed approaches, since the data transmission is divided into multiple channels, more simplistic infrastructure can be readily implemented as also discussed [75].

It is noteworthy that the analysis made in this section is only focusing on the time requirement to transmit data based on the packet size, not considering latency delays from the physical layer nor the delay added due to routing of messages, which as described in [74] have high contribution to time delays and reliability in communication infrastructure. According to [74], the infrastructure cost for building a centralised or decentralised communication network is relatively similar, but the centralised scheme requires more routers and bigger length of transmission media, which increases latency and reduces reliability.

4.7 Summary of Control and Coordination Strategy

The presented control and coordination strategy relies on interaction between participating devices that are equipped with local controllers exchanging relevant information and obtaining local measurements. The summarised flowchart of Figure 4.7 presents each step of the strategy that enables coordination of multiple controllers to avoid hunting effect while ensuring operational limits of the network are within safe constraints. Furthermore, it minimizes reliance on ancillary services procurement, which in turn reduces costs of managing the network.

The managed network is assumed to have local controllers placed in every node, capable of obtaining local measurements and communicating with neighbouring controllers. Local controllers start by obtaining local measurements of voltage and power flow, *i.e.* V_i , P_i^{up} and Q_i^{up} . Then, every node evaluates for all other node k , including itself, the values of self voltage sensitivities, which as discussed in Chapter 3, is how voltage at node k is affected by power flow change at node k . This is accomplished via equations (3.18) and (3.19). This process is highlighted in the blue traced box of Figure 4.7.

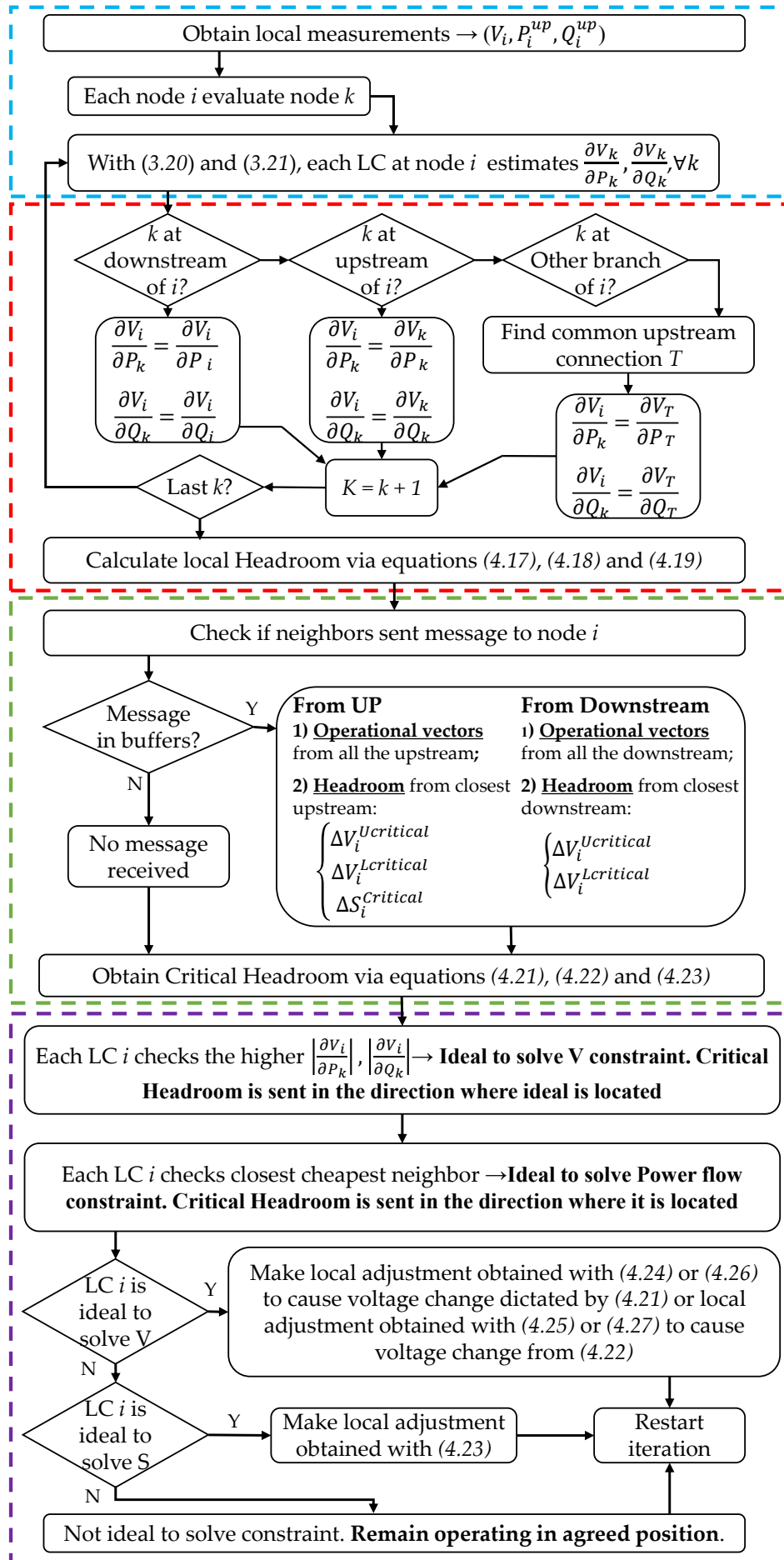


Figure 4.7: Summary flowchart for the proposed control and coordination strategy.

After every LC calculated all the $\frac{\partial V_k}{\partial P_k}$ and $\frac{\partial V_k}{\partial Q_k}$, then it must evaluate how the power flow alterations in non-local nodes affects local voltage, *i.e.* every node i obtains $\frac{\partial V_i}{\partial P_k}$ and $\frac{\partial V_i}{\partial Q_k} \forall k$. This is accomplished following the steps described in Algorithm 1, presented in Chapter 3, Section 3.4. This is the highest computational effort step in the proposed algorithm because it involves a *for loop* ranging at every node. However, centralised approaches requires more than one loop that ranges the number of nodes. In the next step, all LCs evaluate their local voltage and power flow measurements and compare with satutory limits specified, as shown in equations (4.17), (4.18) and (4.19). This process is marked inside red traced lines in Figure 4.7.

At this stage, all LCs have improved their perception of the network they are operating on by knowing how other nodes can influence its local voltage. Note that the LCs does not know how its local power changes affects other nodes, information which is critical for control and coordination. To overcome the lack of this information in distributed approaches, in the proposed strategy, each LC updates headroom information received from neighbours and evaluates as it is a local restriction. This process involves LCs checking their message buffer to obtain the headroom information sent from neighbours, (4.21), (4.22) and (4.23), plus their operational binary vectors containing information about certain status from neighbouring LCs. This process is represented inside the green traced lines of Figure 4.7.

The local controllers have all obtained their critical headroom, which as discussed in section 4.5.2, consists in the observed headroom that considers all obtained messages from neighbours, already converted to represent a local headroom. Therefore, at this stage, each LC is able to identify if there is an occurrence of constraint violation somewhere in the network, not knowing where exactly the constraint is happening. Each local controller can find the ideal to solve voltage constraint bay sorting its observation of voltage sensitivity matrix (respective row i for LC i of matrix shown in section 3.4). The higher voltage sensitivity to active or reactive power is considered the ideal to solve voltage constraint by the LC at node i . In case of constraint violation is observed, the critical headroom computed locally is sent in the direction (downstream or upstream) in which LC i found to have highest sensitivity. Similar process applies for identifying the ideal to solve thermal constraint controller, however, instead of evaluating voltage sensitivity, it is considered that any downstream controller has same

efficiency in solving thermal constraint. Therefore, message is sent downward only in case LC i observes a DER with cheaper price for adjusting power in the ancillary service market. In case a local controller observes itself as the ideal to solve voltage constraint is must act as follow. Adjust its power flow to solve over voltage situation indicated by critical headroom obtained in (4.21) with adjustment in active power flow as shown in (4.24) or with reactive power adjustment as shown in (4.26). Alternatively, in case of under voltage situation, LC must adjust its power flow to solve under voltage situation indicated by critical headroom obtained in (4.22) with adjustment in active power flow as shown in (4.25) or with reactive power adjustment as shown in (4.27). In case of thermal constraint violation, a direct relationship is valid and equation (4.23) can be readily applied. If LC at node i does not observe itself as ideal to solve any constraint, it remain operating unhindered, injecting the amount it intends upon contractual agreement. This process is marked inside purple traced lines in the flowchart of Figure 4.7. The complete process is repeated for every new local measurement.

Chapter 5

Results from Testing on Case-Study Networks

In order to validate the ANM proposed over the course of the last two chapter, a series of test will be run in a simulation environment with models of distribution networks and some of their practical characteristics, *e.g.* radial topology, variable loads and a resistance to reactance ratio for the lines of approximately 1. The networks also feature high penetrations of DER so that the ANM can be assessed as suitable to manage a large fleet of devices. The proposed ANM will be tested in terms of its ability to make optimal dispatch subject to network constraints and in the face of load changes. A commercial framework such as described in Section 4.3 is modelled so that costs of procuring ancillary services during decision making process can be taken into account. The counterfactual is a centralised approach to ANM and so this is also implemented. Validation can be carried out via comparison with this counterfactual or benchmark algorithm in terms of optimality of the solution. The centralised approach uses an Optimal Power Flow (OPF) solver based on a Primal Dual Interior Point Method, reviewed in [76], which is speed efficient and which guarantees convergence in polynomial time. The OPF can be considered as the best network operating condition that can be obtained (albeit with penalties in communication and computation in a practical setting). It is noteworthy that the objective function is the minimisation of the costs of procured ancillary service.

To evaluate performance and flexibility, simulations must consider varying load and generation profiles in which the proposed distributed management system is expected to decide upon the necessary adjustments of DERs' output. The load profile is based on benchmark systems presented by CIGRE in [77], spanning from low demand, reaching a peak load and then decreasing again over a 24 hour period, as is traditionally observed. Generation profile of PVs is constructed following trends obtained from the database presented in [78], which have maximum irradiance usually around midday and zero production during night time. Other traditional fossil fuel DGs are included, considering constant output (agreed with DSO) and able to be managed by the ANM. The combination of demand and generation profiles result in scenarios in which network constraints would be breached unless otherwise ANM takes the required adjustment decisions.

This chapter presents the simulation methodology and network modelling to implement and validate the distributed ANM. It also describes the implementation of OPF and its use as a centralised ANM for comparison purposes. Section 5.1 describes the simulation methodology, presenting how the communication and decision making are implemented. In Section 5.2 the main results are presented covering results obtained with the proposed ANM. This section is subdivided in 6 test cases, exploring features of active and reactive power control to solve voltage and thermal constraints, validating performance in different networks, ranging from 10 to 76 nodes, all with high penetration of DERs. Additionally, exploration is made of the capability of the ANM in regards of DERs participating or not in flexible connections thereby showing the flexibility of the distributed approach for dealing with particular contractual agreements. The final test cases explores control and coordination of "soft open points" to aid in constraint management. Later, in Section 5.3, 4 networks are studied for a variety of demand/generation conditions with randomly selected sets of operating points taken from a Gaussian distribution. A comparison of results is made between the proposed and the centralised approaches of DER adjustments used to solve constraints. Statistically relevant information is obtained, quantifying average errors and standard deviations of adjustment mismatch with centralised OPF. It is shown that the proposed ANM works over a wide range of conditions. Finally, in section 5.4 it is presented a summary of the findings.

5.1 Simulation Methodology

The proposed distributed ANM has been tested through a time-domain simulation. The network is modelled considering loads and distributed generators as PQ buses. The loads were varied according to typical daily profile presented by CIGRE in [77]. Dispatchable generators were set at assumed contract positions but could be varied through actions of the distributed ANM, through ancillary services provisions at certain agreed unit costs. The Matpower package [69] is used to obtain a power flow solution at each iteration to account for changes in demand, generation and control actions. The power flow tolerance is set at 10^{-8} using a Newton-Raphson algorithm. The algorithms for each local controller were implemented as scripted functions which obtains local measurements, V_i , P_i^{up} and Q_i^{up} , from the network model (data fed by the the Matpower load flow solution for each iteration) and compute new DERs set points, P_i^G and Q_i^G . All of the individual actions of the various local controllers are then fed to the network model for the beginning of the next iteration. This iterative procedure is summarised in Figure 5.1. Note that the red traced lines represents the message exchanged between neighbouring controllers.

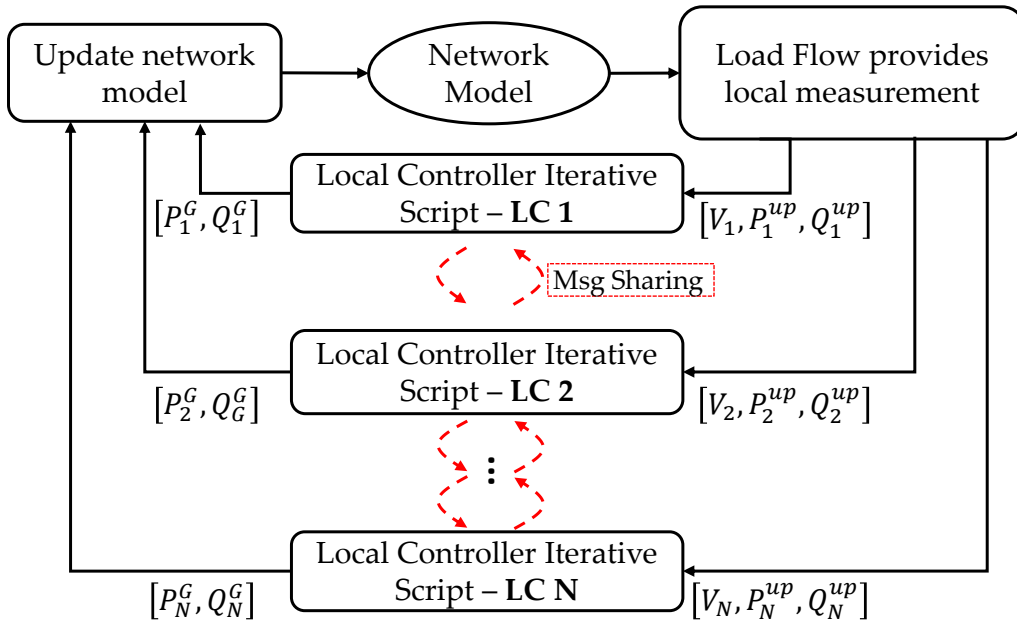


Figure 5.1: Iterative Procedure of LC and network update.

The communication between local controllers is modelled according to the asynchronous message-passing paradigm [79], where the sender can resume its processing immediately after an outgoing message is placed into the message buffer and that message will be read whenever the receiver is free to do so. Figure 5.2 illustrates how this message-passing scheme was implemented. Each LC reads the messages their neighbours have posted via the message buffers and then executes the control algorithm to determine new set points with which to update the network. Information for current iteration is written into their neighbour's buffers to be read in next iteration. Therefore, adjustments made by the receiving controller to solve non local constraints from sending controller can only be made in the next iteration.

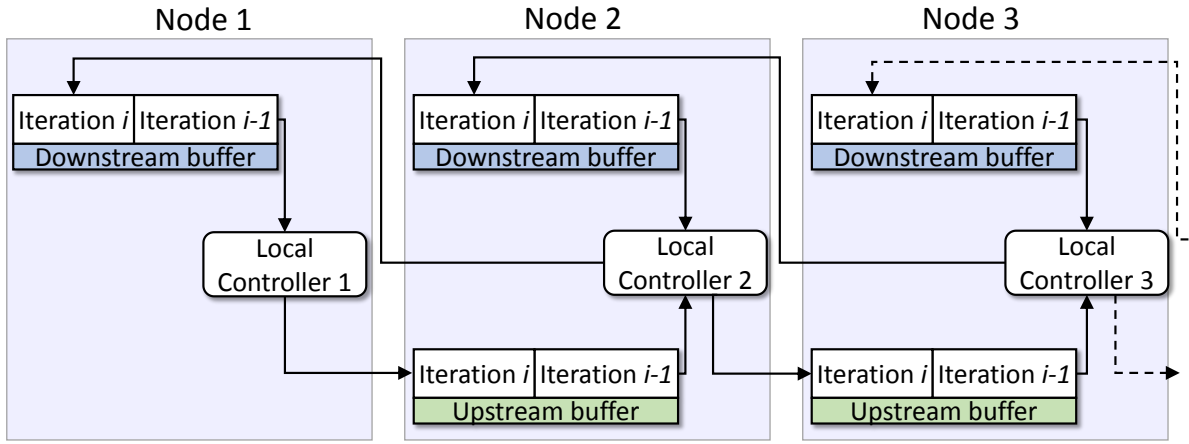


Figure 5.2: Modeling of the asynchronous message sharing between LCs.

5.2 Results of Distributed Control and Coordination

In this section it is explored the performance of the control and coordination methodology presented in this thesis. The aggregated demand from residential and industrial consumers (presented in [77]) are such that, for residential profile it is noted a typical first peak around 7am to 1pm followed by a reduction and later the peak demand around 6pm to 21pm and for industrial profile, peak demand is shifted towards working hours, during 8am to 1pm and a smaller peak during 1pm to 5pm. The aggregated residential demand profile used in the test cases is presented in Figure 5.3.

Loading factors are applied in different nodes of the network in order to have varying loading intensities along the feeders. For each test case discussed in the following subsections, the loading factors to which each demand profile multiplies the base profile of Figure 5.3 is presented. The industrial demand applied in some of the test cases is defined as flexible demand (FL), representing industrial consumers that participates in demand response schemes in which curtailment of demand can be considered by the ANM for a given cost of procuring this service. It is presented in Figure 5.4 together with profile for Electric Vehicle (EV) and Photovoltaic panels (PV) that are used in the simulation test cases. The PV generation profile is based on data provided by [78], having peak generation around mid day. Note that all the profiles are base profiles and are multiplied by different factors, for each test case scenario presented in this chapter, in order to generate relevant scenarios that causes multiple constraint violations. The aggregated residential EV profile is considered to have low demand during working hours, peak demand right after working hours, when customers are back home and plug EV for charging.

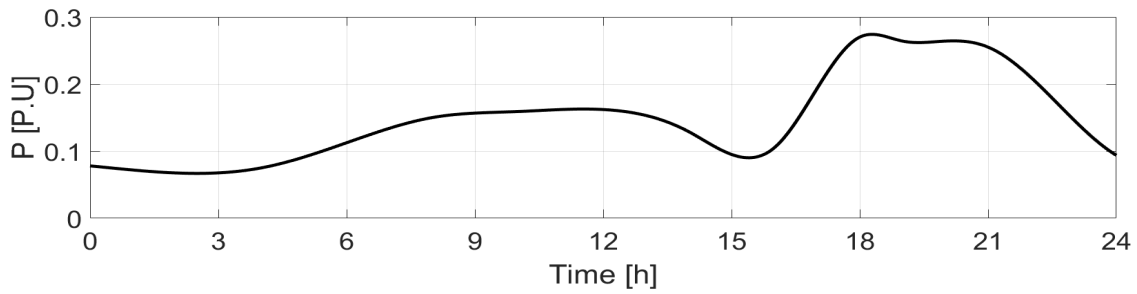


Figure 5.3: Base demand profile for aggregated residential loads.

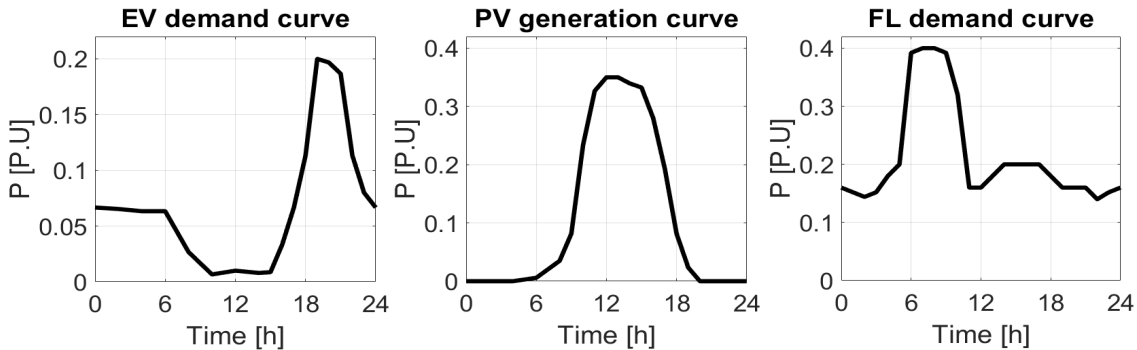


Figure 5.4: Curves for Electric Vehicle, Photovoltaic and Flexible Load.

5.2.1 Test Case 1: Active Power Control in IEEE 33 bus system

To assess performance of the proposed distributed control and coordination strategy, a dynamic scenario of the IEEE 33 bus network is established. The IEEE 33 bus network is modified to include seven controllable DERs as shown in Figure 5.5. The DERs are an EV parking lot connected directly at node 16, a PV generator at node 14, a flexible load (FL) at node 33 and four fossil fuelled distributed generators (DG) located at nodes 18, 22, 24 and 28. The base power for this test case scenario is $S_{base} = 1MVA$ and the base voltage is $V_{base} = 12.66kV$. The line parameters were identical to the original model [65], shown in Appendix A.

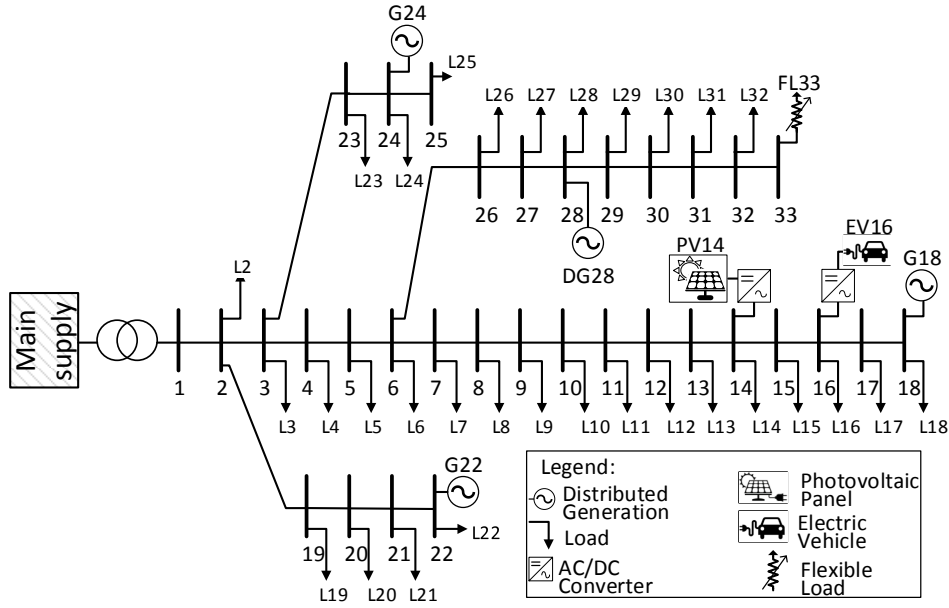


Figure 5.5: IEEE 33 bus network with seven controllable DERs.

To illustrate the ability to accommodate various market arrangements, two types of contract between customers and DSO were considered. One was a firm connection contract in which the customer contributes toward the costs of reinforcing the network in order to secure a firm connection, *i.e.*, no curtailment expected. The other was a non-firm connection in which the customer connects to a constrained area of the network without paying for reinforcement on the understanding that it can be required by the DSO to adjust its power output. In the test, only the PV at node 14 and the EV at node 16 had firm connections. The aggregated residential loads connected at each node vary over a 24-hour period according to the residential profile shown in Figure 5.3 but having different load scaling factors (multipliers of the standard

load). The scaling factors for each location are as set out in Table 5.1. The profiles for the EV demand, the PV generation and the flexible load (FL) at nodes 16, 14 and 33 are the same as shown in Figure 5.4 for a 24-hour period (no scaling factor is applied). The terms of the flexible contracts are presented in Table 5.2.

Table 5.1: Loading factor to multiply base demand profile of Figure 5.3.

Nodes	Loading Factor	Nodes	Loading Factor
2,3,4	2.0	19,20	1.3
5,6	0.5	21,22,23	0.9
7,8,9,10	0.6	24,25	0.7
11,12	0.5	26,27,28,29,30	0.25
13,14,15,16,17,18	0.2	31,32,33	0.1

Table 5.2: Connections agreement specifications for Test Case 1.

DER type	Contract type	Agreed P injection [p.u]	Maximum P adjustment [p.u]
DG 18	Non-firm	0.5	± 0.2
DG 22	Non-firm	0.4	± 0.2
DG 24	Non-firm	0.3	± 0.2
DG 28	Non-firm	0.7	± 0.2
EV16 & PV14	Firm	Following profiles of Figure 5.4	0
FL 33	Non-firm	Follow FL profile of Figure 5.4	Until full disconnection

Results obtained from applying the distributed ANM to this test case are presented in Figure 5.6. The top plot shows the curves of PV and Demand (only the highest and lowest demand obtained by multiplying the base profile in Figure 5.3 by load scale factors in Table 5.1). The second plot shows the two most critical node voltages across the 24 hour period. In the last three rows it is presented the adjustments from each controllable DER that changed its injection to solve network constraint. The other DERs not shown in the plots operated in their agreed capacity, without being requested by the ANM to solve constraints. For comparison, the three last plots shows the adjustments obtained by a centralised OPF solver, considered as the benchmark solution. Key points in the results are pin pointed with letters in the figures and the importance of what is seen at these points is explained in the following paragraphs.

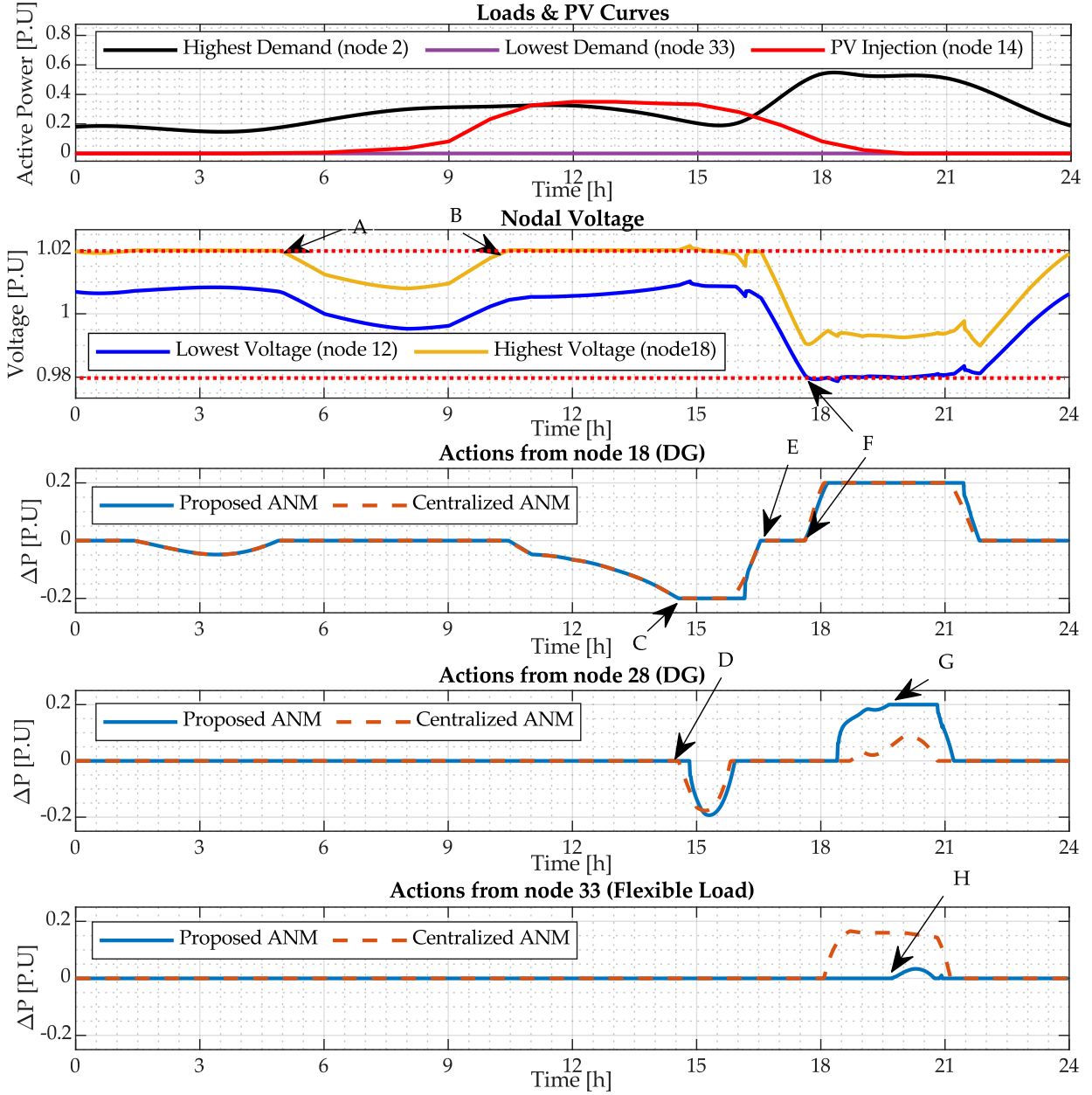


Figure 5.6: Network measurements and LC actions considering proposed distributed scheme and centralised OPF to maintain compliant operation.

To configure the OPF, adjustment cost curves were set for each DER such that operating at the contracted power output is equivalent to a zero cost (to the OPF ANM system) and adjusting power output as an ancillary service required a payment to the DER to make good the loss it would suffer from not meeting its contracted power. This arrangement is discussed during 2.2.4 and 4.3. This first set of results explored in test case 1 considers equal ancillary service unit costs among all participating DERs in order to evaluate decisions from ANM based only on constraint management efficiency.

It can be seen in the voltage results (second plot of Figure 5.6) that, initially and up until point A, the low demand and the output of local generation caused the voltage at node 18 to rise. LC 18 estimated that the node for which a power change has the highest sensitivity seen at 18 is node 18 itself, and thus, curtailed its active power injection just enough to remain with voltage level below the upper limit, as seen in the third row graph, containing the information regarding the adjustments from DG 18. Note that the decisions based on equation 4.24 maintained flat voltage right below statutory limit, indicating minimal disruption of DG 18, as seen in the second row plot. After point A, demand across the feeder starts increasing, as seen in the top graph, and consequently the voltage starts decreasing as seen in the second graph. Between points A and B, the network operates without breaching voltage limits at any node and is thus able to accommodate all the DERs at their agreed or contracted injection.

From point B to C, the PV at node 14 reach its peak production and demand started decreasing (as seen in the Loads & PV curves in the first row plot), resulting in the voltage at node 18 rising to the point where action by the ANM is again needed to hold the voltage at its limit. DG 18 is curtailed again, until at point C, the maximum curtailment of 0.2 p.u agreed by this DG with DSO is reached (as recorded in Table 5.2). So far, only local actions have been needed, namely a voltage limit violation at node 18 was solved by action taken by the DG at node 18. By point D however further action is needed and the local node can no longer act. Node 18 estimates that the next most effective to regulate local voltage is node 28 and sends its critical headroom upstream until it reaches node 28, which adjusts its injection downward upon receiving the information. This process continues until point E, whereupon the DERs set-points and demand are such that no adjustment is needed. Note that DG 18 only starts moving back to its agreed capacity after receiving the operational information from DG at node 28 that it is satisfying its agreement.

At point F, demand has increased in such a way that an under-voltage arises at node 12 (blue curve of second plot of Figure 5.6). Based on the proposed voltage sensitivity estimation, node 12 assesses node 18 as best placed to solve this and sends its local headroom downstream until reaching at node 18, which ramps up its power injection up to 0.2 p.u above the 0.5 p.u that was agreed with DSO. This represents the maximum alteration that it can undertake by DG 18

as noted in Table 5.2. With under-voltage still persisting, the next LC expected to act, based on the estimated voltage sensitivity, is node 28, which then inject power above contracted injection and does so until reaching its maximum adjustment of 0.2 p.u, at point G. Even with full injection of DG at node 28 and 18, the under-voltage at node 12 still persists, requiring the next LC to act, which is estimated to be at 33.

Node 33 has a flexible load, and can have its demand adjusted, with the result that its power consumption is reduced in magnitude as seen at point H, until the voltage at node 12 is brought up to the lower limit of 0.98. After point H, demand in the feeder starts to fall back from its peak, allowing LCs to reduce adjustments and return to their agreed injections, one by one in the reverse order to that in which they were deployed. Between points D and G we see examples of actions at non-local nodes being used to solve a problem at a particular node and examples of the burden of acting being passed from one DER to another as DERs reach their adjustment limits.

The main difference between the proposed approach and the centralised OPF happens between points F and G, when DER 18 reached maximum injection while attempting to solve under-voltage at node 12. The centralised approach opts to rely on adjustments of power injections from flexible load at node 33 instead of DG from node 28 as done in the proposed approach (as observed by comparing the blue line and traced orange lines from the three last plots of Figure 5.6. The reason is that, in the proposed ANM, the LC at node 12 estimated sensitivities of voltage at node 12 to power injection at nodes 28 and 33 to be the same *i.e.* $\frac{\partial V_{12}}{\partial P_{28}} = \frac{\partial V_{12}}{\partial P_{33}}$. The distributed ANM opted to request adjustments from 28 because in the approximations discussed in Chapter 3, downstream nodes are assumed to have equal effects in voltage regulation with power injection changes and therefore its more practical to select the closest. In contrast, the centralised OPF (with no approximations and consequently no loss of precision) found node 33 to be slightly better than 28 for regulation of voltage at node 12.

To evaluate the total adjustment considered by the ANM platform, obtained from the proposed and from the centralised approaches, it is presented Figure 5.7, where the summation of all the changes made by the three local controllers is shown in the blue line for the proposed approach

and in traced orange line for the centralised approach. When comparing the total curtailment resulting from each approach, it can be seen that the improvement of the OPF over the proposed ANM is minor. Although the proposed method selected a different LC to act, it resulted in a very small additional curtailment that makes little difference in practical implementation of the ANM.

This result confirms that the many LC participating in the distributed ANM required minimum adjustments from DERs power injection to regulate voltage, as showed by the comparison with centralised OPF. There are small mismatches when an LC takes action due to iterations required for messages to reach the newly preferred node for action when transferring between acting DERs.

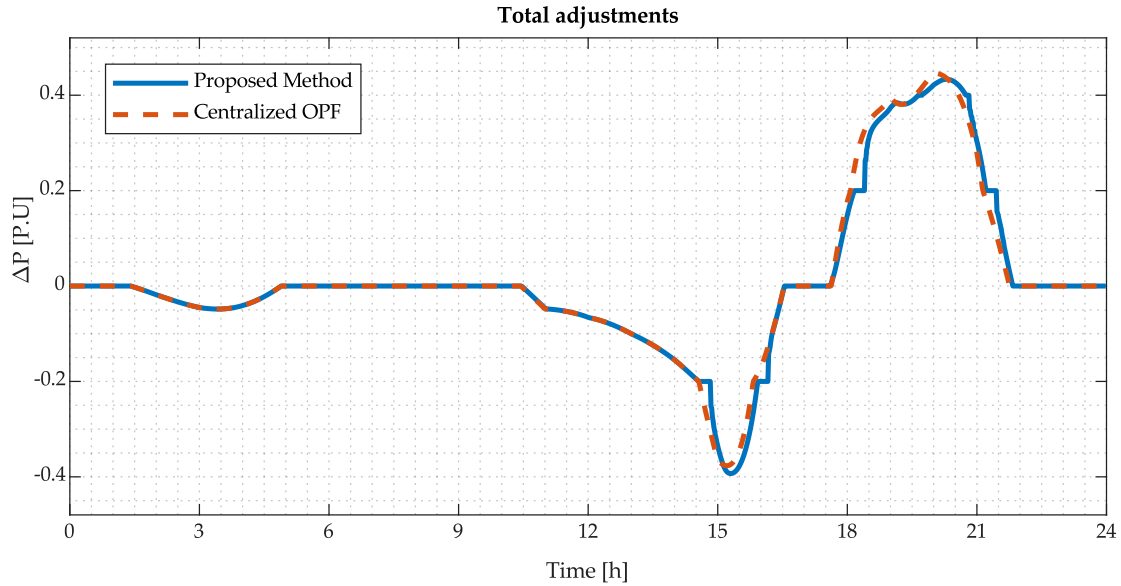


Figure 5.7: Mismatches of total adjustments between proposed approach and centralised OPF for the scenario shown in Figure 5.6.

Higher Voltage Deviation

In order to show that the proposed approach can cope with higher voltage deviation and still obtain reliable results, the voltage threshold is increased to + 10% and - 6% of the nominal, as is the maximum tolerable limit imposed by regulators. To do so, the test case 1 is slightly modified by stretching the peaks from demands and from the PV injection curves. The result is shown in Figure 5.8.

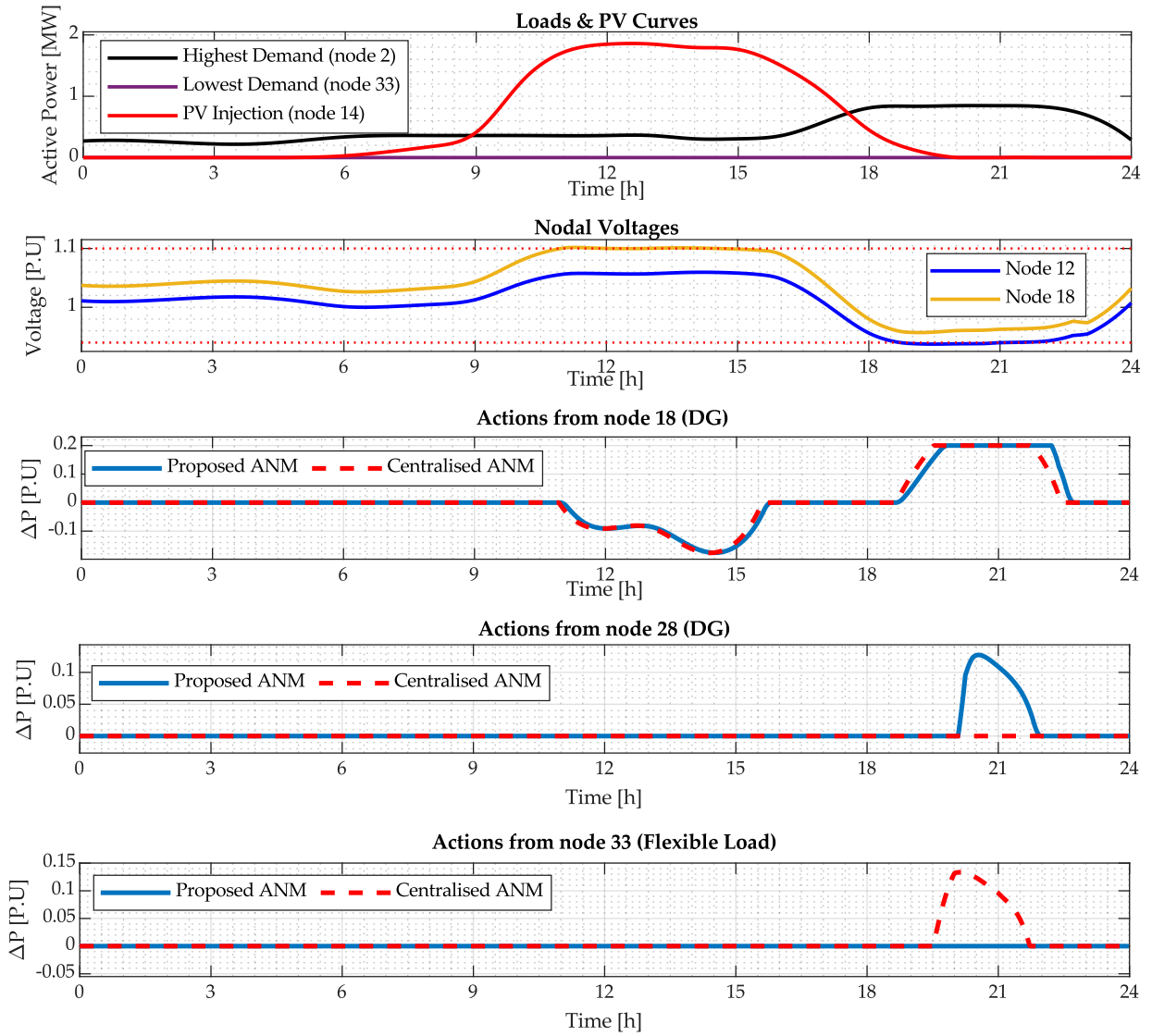


Figure 5.8: Results of modified test case 1 to cause higher voltage deviation.

The peak demand increased in almost 30% for all nodes, reaching the highest demand in node 2 with 1 MW. The peak PV injection increased by 3 times, reaching its peak at 1.9 MW. These curves are shown in the first plot of Figure 5.8. The second row graph shows the two most critical voltages (node 18 because it reached the upper limit and node 12 because it reached the lower bound). The last three graphs show the adjustment considered by three DERs, using the proposed method (as shown in blue line) and using the benchmark centralised approach (shown as traced orange lines). Comparing the cases with higher and lower voltage deviation, it is possible to observe that although errors in estimation are higher, the convergence process is not hindered, since the decisions are taken incrementally and iteratively in order to maintain voltage within limits. The estimation errors are corrected with each new headroom information update received from neighbours.

Computational Time Requirements

The 24 hours period simulated were accomplished taking adjustment decisions every minute, totalling 1440 iterations looping the flowchart of Figure 4.7. The time taken by each local controller, to send, receive and process messages exchanged with neighbours, is measured for each iteration and for all LC. The time requirement for the centralised OPF is also measured for every iteration. The plots are presented in Figure 5.9, where the plots for each individual LC are blended in the lower portion while the centralised OPF is presented as traced blue lines. Individual plots for every individual LC is impossible to see, but on average they operate with similar time requirement, having slightly slower response obtained from those LCs actually adjusting injections. This is reasonable, because as can be seen from the summary flowchart of Figure 4.7, LCs that are ideal to solve constraints have additional lines of codes to run, while others can just remain operating in their agreed set points. It is noteworthy, that besides the computational time, the communication infrastructure to support centralised schemes are more complex and expensive to build, requiring robust channels connecting centralised coordinator and all other participating controllers [34,71,75]. Highest average time required by LC running the proposed strategy is of 0.0182s from LC at node 28. The average time taken for the centralised approach is 0.0486s.

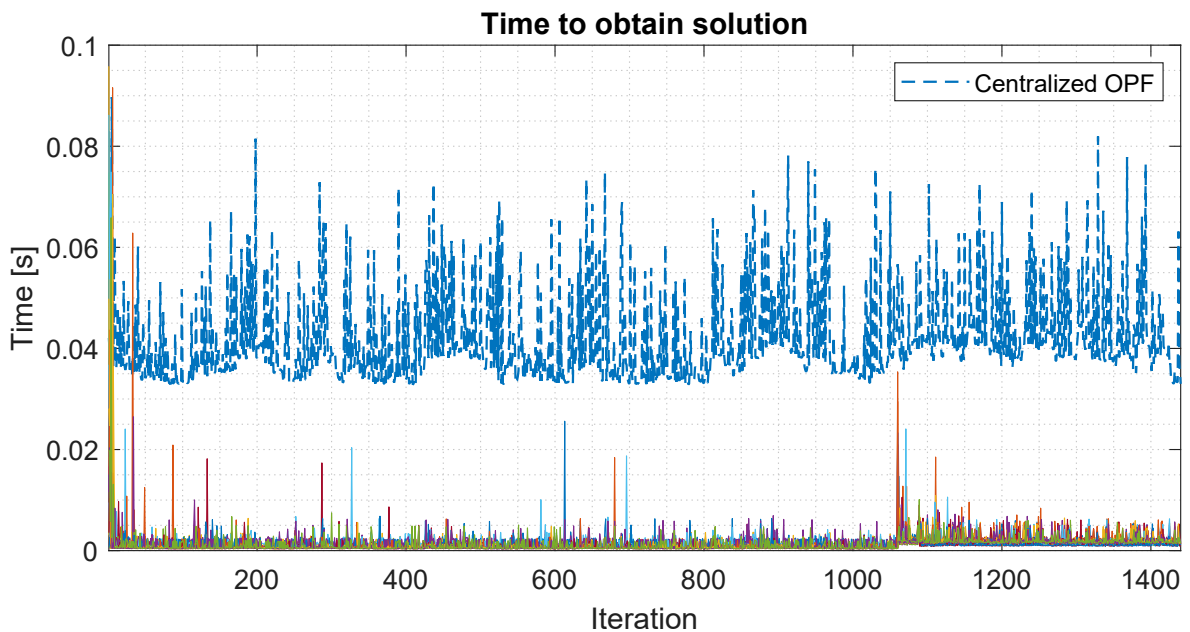


Figure 5.9: Time required per iteration of the 33 bus system for the centralised approach compared with iteration time for each LC based on the proposed method.

5.2.2 Test Case 2: Active & Reactive Power Control

The proposed strategy is also capable of dispatching reactive power, managing thermal constraints, and defining different costs for adjusting active and reactive powers for each DER. To explore these features, a simpler network with fewer nodes and line capacity of 6 MVA is used, as shown in Figure 5.10.

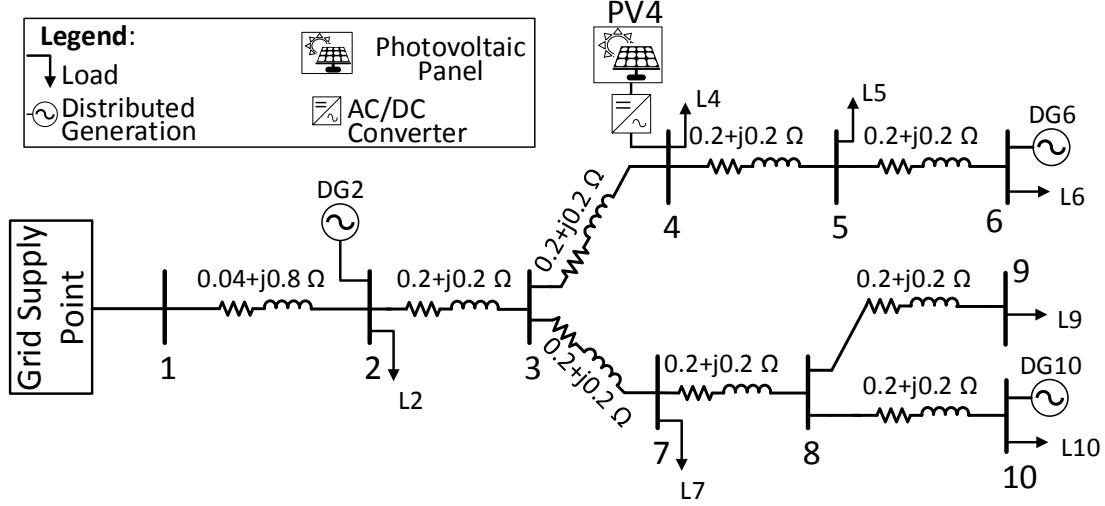


Figure 5.10: Network with 10 nodes and 4 controllable DERs for Test Case 2.

The network has $V_{base} = 11kV$ and $S_{base} = 1MVA$. Loads were set to follow the same profile as shown in Figure 5.3 with the loading scaling factors of 6.0 at nodes 2 and 3; 4.5 at nodes 4, 5 and 6 and 3.0 at nodes 7,8,9 and 10. All the DERs were operated with non-firm contracts. Table 5.3 sets out the contractual details of each DER, such as the payments for adjusting active or reactive power and the size of the maximum adjustment they agreed. The last two rows are the unit costs for procuring ancillary services discussed in Chapter 4.

Table 5.3: Connections agreement specifications for Test Case 2.

DER type	DG2	PV4	DG6	DG10
P contracted [MW]	3.0	Max PV	2.5	3.5
Q contracted [MVar]	0	0	0	0
Max ΔP [MW] or ΔQ [MVar]	± 0.5	± 0.5	± 0.5	± 0.5
Cost P [\$/MWh]	150	500	200	250
Cost Q [\$/MVarh]	100	150	80	60

Figure 5.11 shows the results over a 24-hour period. From top to bottom, the demand profiles; two node voltages; active and reactive power injections; the active power flowing to node 2 through its upstream branch and finally, a comparison of costs per hour incurred in using the DER services of adjusting power injections. The detailed adjustments are shown separately in Figure 5.12, compared with the respective adjustments taken by the centralised OPF.

From the outset at midnight up until point A, the voltage at node 10 is high due to excess generation from DGs and held at its upper limit by dispatch of reactive power from the DG at node 10 itself. The bottom plot compares the costs incurred by the two algorithms, principally the cost of using reactive support from DER 10. From point A to point B, the increasing load reduces the voltage at node 10 and the network is able to accommodate all DERs at their contracted power and supply all load demand without any interventions by the ANM and thus the cost of procuring DER ancillary services drops to zero, as seen in the bottom plot. From point B onward, the increased power injection by the PV again threatens an over-voltage at node 10 and so again dispatch of reactive power at node 10 is used.

Later, at point C, node 6 also reaches the upper voltage limit, which estimates local adjustment best placed to solve constraint. This is an example of multiple LCs acting together to maintain operation within statutory limits. At point D, the power flowing from node 1 to node 2 reached its line capacity limit of 6 MVA (as shown in the fifth plot, reminding that the base power for this test case is 1MVA). Therefore, the LCs started curtailing active power injection.

Note that for dealing with thermal constraint, there is no need to evaluate voltage sensitivity and therefore the LCs only evaluate their costs for adjusting active power and/or their proximity to constraint. Using this criteria, DG 2 is selected for curtailment in order to solve thermal constraint. When, at point E, DG 2 reaches its agreed curtailment limit, leaving the DG at node 6 as the next to be curtailed. Note that due to high cost of curtailing PV at node 4, the LCs decided to curtail a DER located further along the feeder. The reverse power flow is maintained at 6 p.u and all voltages are held within limits. As demand increases and the constraints ease, the DERs can return to their contractual positions and the network becomes able to host all DERs without interventions.

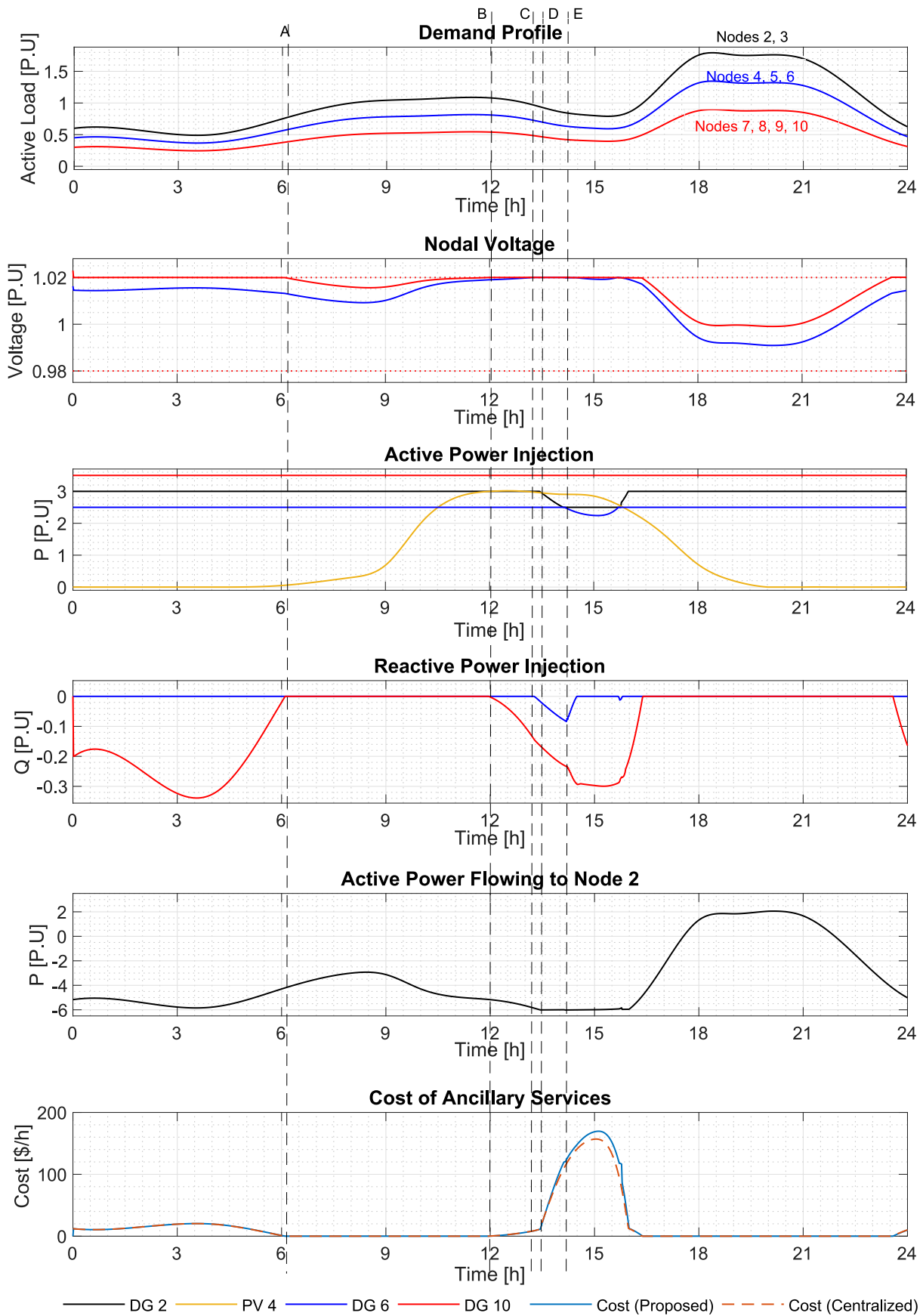


Figure 5.11: Network measurements and LC actions to satisfy voltage and thermal limits across a 24-hour test period in Test Case 2.

To evaluate with more details, consider Figure 5.12, where the individual adjustment taken by each LC (shown as black line plots) are compared with decisions made via centralised decision making based on centralised OPF (shown as red traced line plots). It is possible to conclude that although decisions of active and reactive power adjustment are not exactly the same, the mismatch is minimal. The decisions of LCs to operate were concise, better even than during test case 1, where no prices for ancillary services were considered. This can be justified due to the fact that with bigger ancillary service price differences between participating DERs, the errors obtained during voltage sensitivity estimations are not as critical for determining most effective node, since price difference diminishes small errors. The DERs were selected with same precision as made by the central controller based on OPF. The small mismatches between centralised and proposed approaches is due to small delays for message hops between LCs.

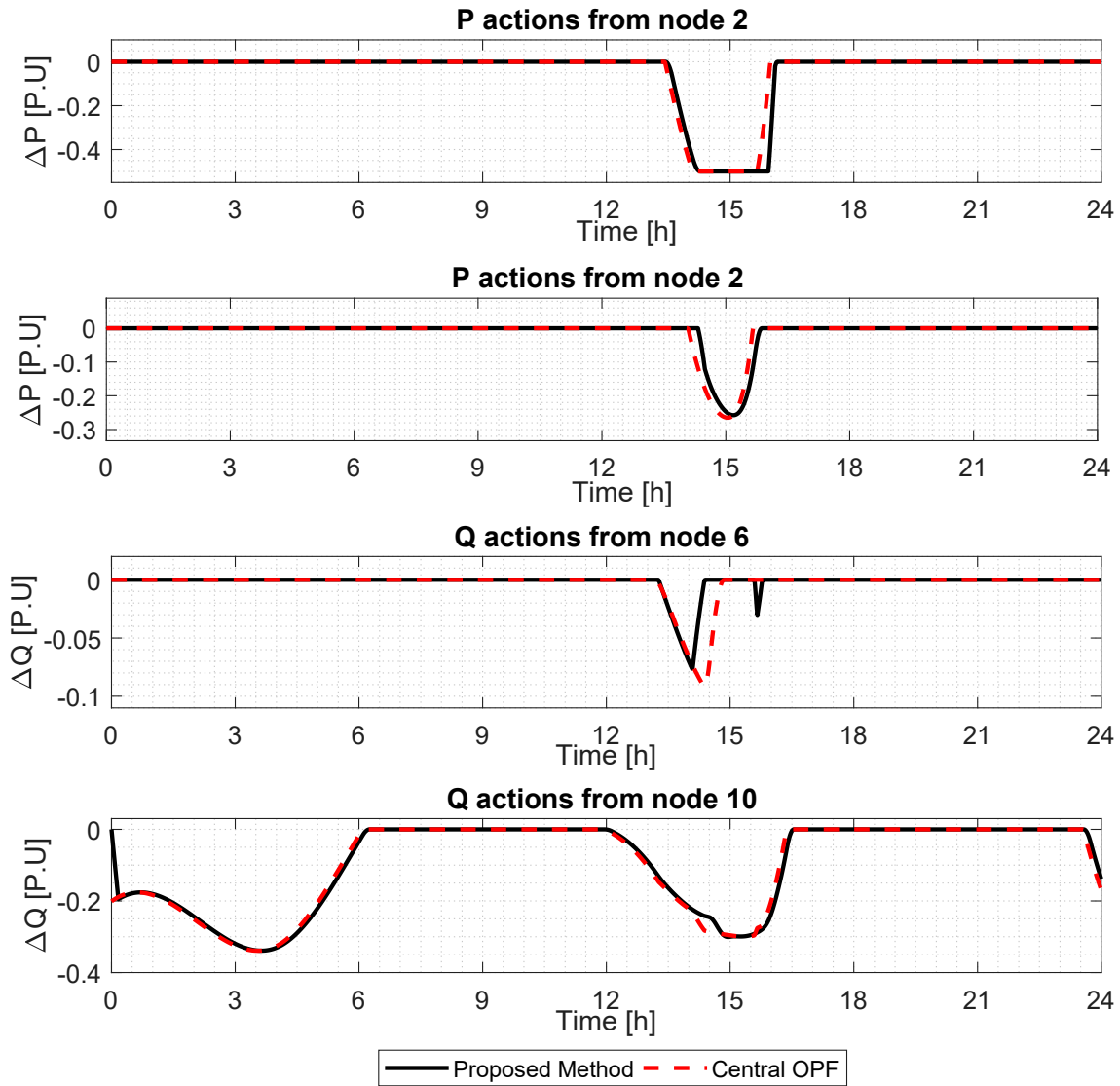


Figure 5.12: Detailed adjustments performed by the proposed ANM compared with centralised OPF.

The 24 hour period considered for the simulation is also accomplished taking adjustment decisions every minute, subdividing in 1440 iterations running the proposed approach (summarised in the flow chart of Figure 4.7). The methodology follows the same principle described in the previous subsection, measuring the time taken by each LC to obtain a decision and compare with the time required to obtain an adjustment decision with the centralised OPF. The plots are shown in Figure 5.13, where the blue traced line represents the time taken by the centralised approach in each one of the 1440 iterations and the other plots are from the LCs. Although they are indistinctly from one another, it validates that LCs operate nearly at the same time, regardless if they are the ideal to solve a constraint or not. Since a smaller network is now being evaluated, it is practical to show average time requirements from all LCs in Table 5.4.

Table 5.4: Time requirements for all local controllers and central OPF for Test Case 2.

Node	2	3	4	5	6	7	8	9	10
Mean time requirement [s] (proposed)	0.0008	0.0008	0.0013	0.0013	0.0008	0.0012	0.0013	0.0015	0.0015
Mean time requirement [s] (OPF)	0.0387								

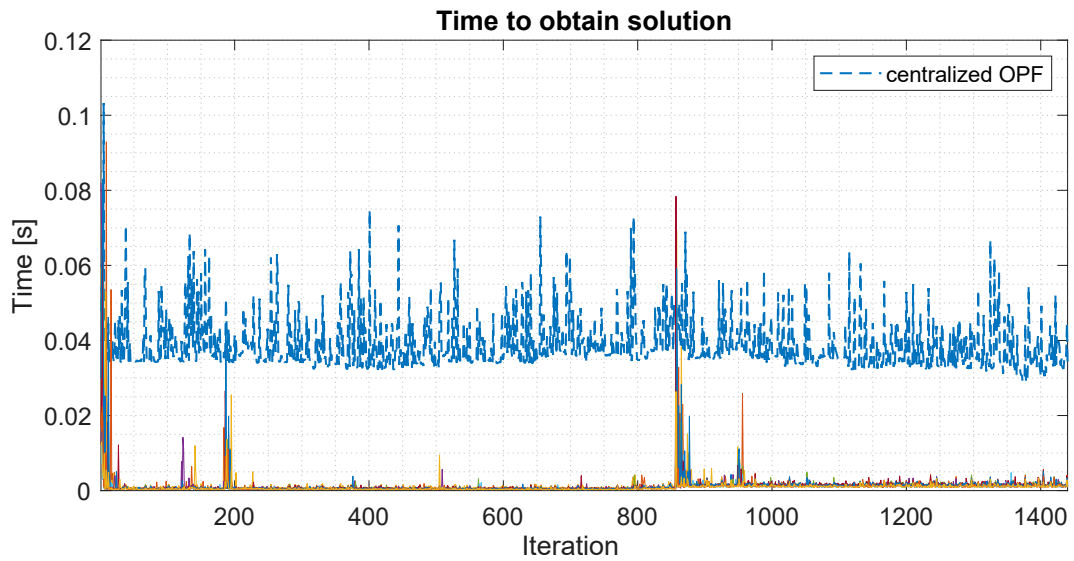


Figure 5.13: Time required per iteration of Test Case 2 for the centralised approach compared with iteration time for each LC based on the proposed method.

5.2.3 Test Case 3: Varying Ancillary Service Unit Costs

It is yet not clear how ancillary services framework for distributed energy resources will turn out. In order to explore flexibility of the proposed distributed approach under a bidding mechanism for ancillary services instead of fixed pricing defined upon contract, it is proposed this test case scenario, which considers same network conditions from previous test case, *i.e.* 10 bus network shown in Figure 5.10. However, in the test case presented in this section, the costs for procuring ancillary services can change at certain periods of the day. It is now considered that ancillary service cost is based on a bidding process. Each participating DER owner can bid different costs along the day. The distributed ANM can share the information of these costs moments before in such a way that after the period for price change, the LCs are informed of the different prices for procuring services. The process for sharing information that is used only once is discussed during section 4.5.1.

The connection agreement are the same as presented in the previous test case in Table 5.3. However the unit costs of ancillary services offered by the DERs at nodes 2 and 10 are changed during 5 different intervals, as shown in Table 5.5. Only distributed generators from nodes 2 and 10 are included since they were the only ones that bid different prices in the ancillary service market framework considered in the present Test Case (the others kept same bids as in Table 5.3). The adjustments considered from the proposed approach and the centralised OPF are shown in Figure 5.14.

Table 5.5: Ancillary service costs changes for Test Case 3.

	Interval 1		Interval 2		Interval 3		Interval 4		Interval 5	
DER	2	10	2	10	2	10	2	10	2	10
Q cost [\$/MVArh]	100	60	100	120	100	60	15	60	100	60

The first plot of Figure 5.14 shows the demand profile (same as derived in the Test Case 2), with arrows indicating which nodes are superimposed in the plots. The second plot shows the voltage of node 10, which is the only node that reached critical voltage constraint at upper limit of 1.02 p.u. It is shown the plots obtained when applying the proposed distributed approach

and the voltage profile obtained when relying on the centralised approach. Both approaches ensures voltage within safe limits, but as expected, the centralised approach obtains a more flat profile, which indicates better performance and is considered the benchmark result. The active power injections from all DERs are presented in the third row plot. The centralised and distributed approaches obtained same dispatch as no active power injection is adjusted throughout the simulation. Last two plots presents the reactive power injection adjustment taken by the proposed distributed approach and the centralised OPF respectively. The intervals described in Table 5.5 are separated by traced lines and indicated with text.

Around hour 4 the ancillary service cost offered by the owner of DER 10 increased, from 60 \$/MVar to 120 \$/MVar while DER 2 remained the same, as shown in Table 5.5. The distributed ANM decided to move its injection back to agreement in order to reduce costs of procuring services. To move back to agreed set point of zero reactive power injection without violating voltage limit, LC 10 start sending request for adjustment and only start moving towards agreed set point when perceives available headroom to do so. This way the voltage remain inside safe constraint. The centralised approach made abrupt simultaneous change, which is practically unfeasible, but it is shown in the simulation just to have a sense what the ideal case should be. The new ideal to solve voltage constraint is now seen as DER 6, which has lower cost for adjusting (80\$ as indicated in Table 5.3). Therefore, instead of DER 10, ANM requested actions from DER 6 to solve the same voltage constraint at node 10 during interval 2. Note that higher volume of adjustment is procured from node 6, but the total cost is still lower than remain requesting from node 10 with increased offered service.

Around hour 9 (beginning of interval 3) the ancillary service cost for reactive power adjustment from DER 10 is back to original value of 60\$, and right after hour 12, node 10 is again the preferred DER to solve over voltage condition from node 10. Around hour 14 the price of DER 2 reduces to 25% of prices from 10 and 6, so the ANM decides to move back 10 to agreed set point and start relying on reactive support from node 2 to reduce ancillary service costs (even though more reactive power is requested from node 2 due to its worst voltage sensitivity to alter voltage at node 10, but with reduced cost). During interval 5, conditions are back to original.

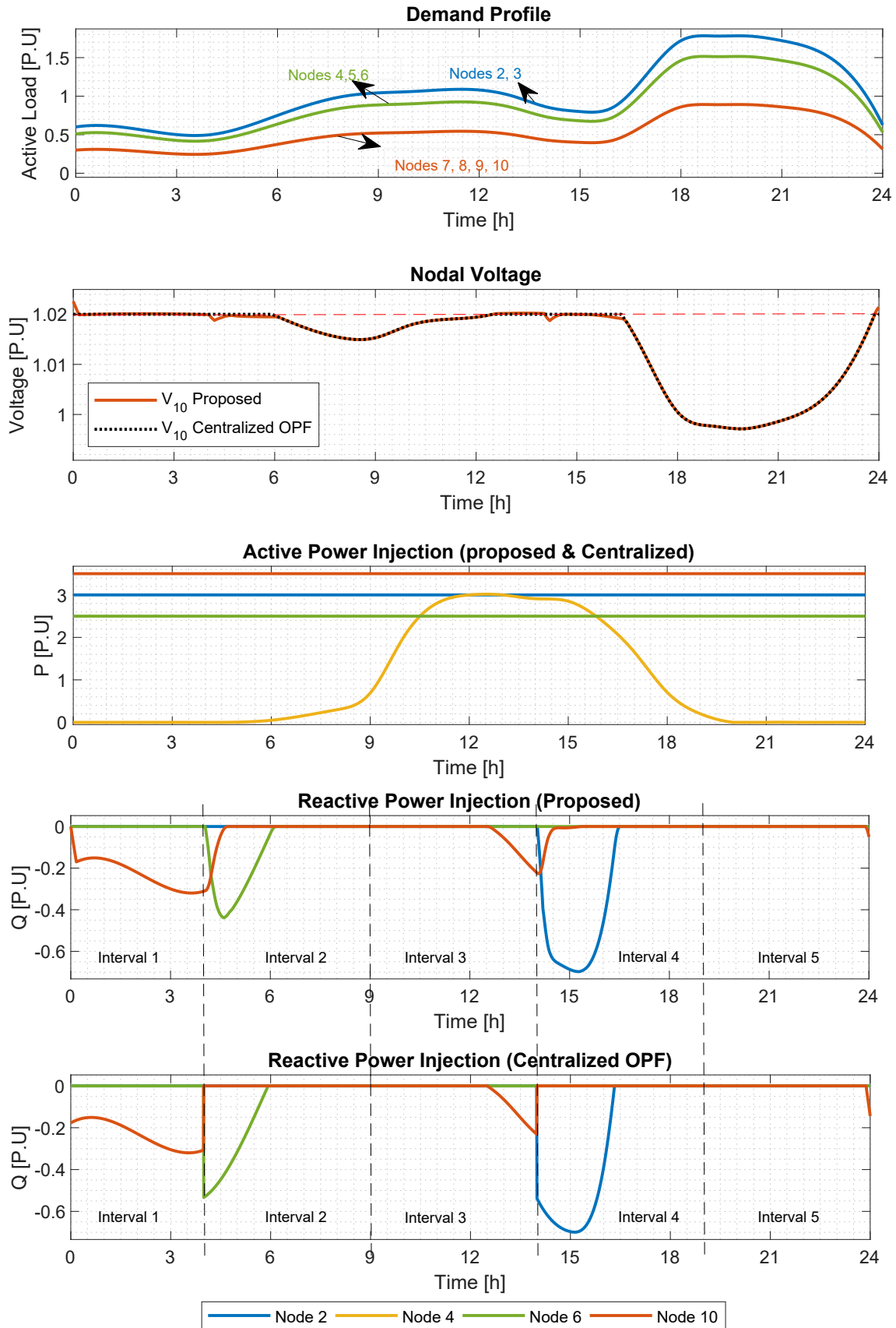


Figure 5.14: Network measurements and LC actions to satisfy voltage and thermal limits across a 24-hour test period in Test Case 3.

5.2.4 Test Case 4: UKGDS 76 bus network

The United Kingdom Generic Distribution Networks containing 76 nodes in 11 kV supplied by a 33 kV substation is modelled for testing the proposed approach. The network details can be obtained in [80] and are summarized in Appendix B. Figure 5.15 shows the schematic diagram with distributed generation locations.

For this test case, the same base demand profile for a 24 hour period with 1440 measurements shown in Figure 5.3 is multiplied by the original demand of each node, also available in [80] and presented in Appendix B. This results in a variable profile applied in every node. The distributed generators are allocated as shown in Figure 5.15, all injecting 1.73 MW as indicated in the original file from [80]. All distributed generators are participating in a flexible connection scheme, coordinated via the proposed ANM. The prices for adjusting active power flow is set at 500 \$/MWh while the cost for procuring reactive power adjustment are defined as 50 \$/MVArh for all LCs. The adjustment taken by the proposed ANM and a centralised OPF are presented in Figure 5.16.

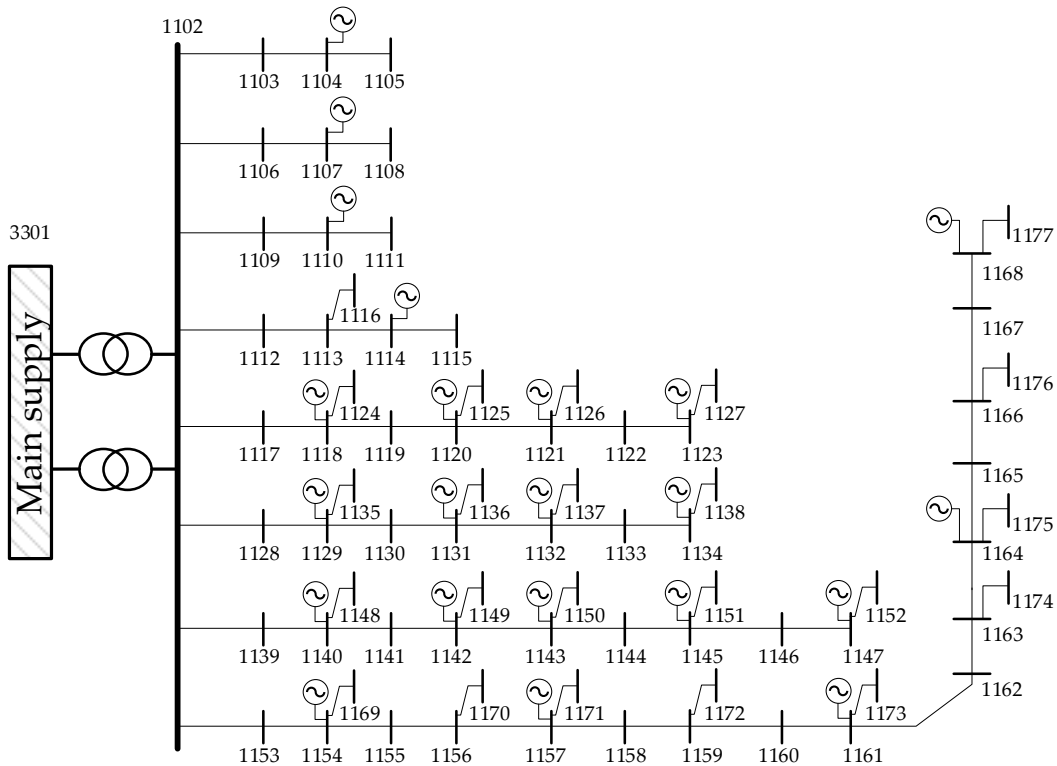


Figure 5.15: UKGDS 11 kV 76 bus network for Test Case 4.

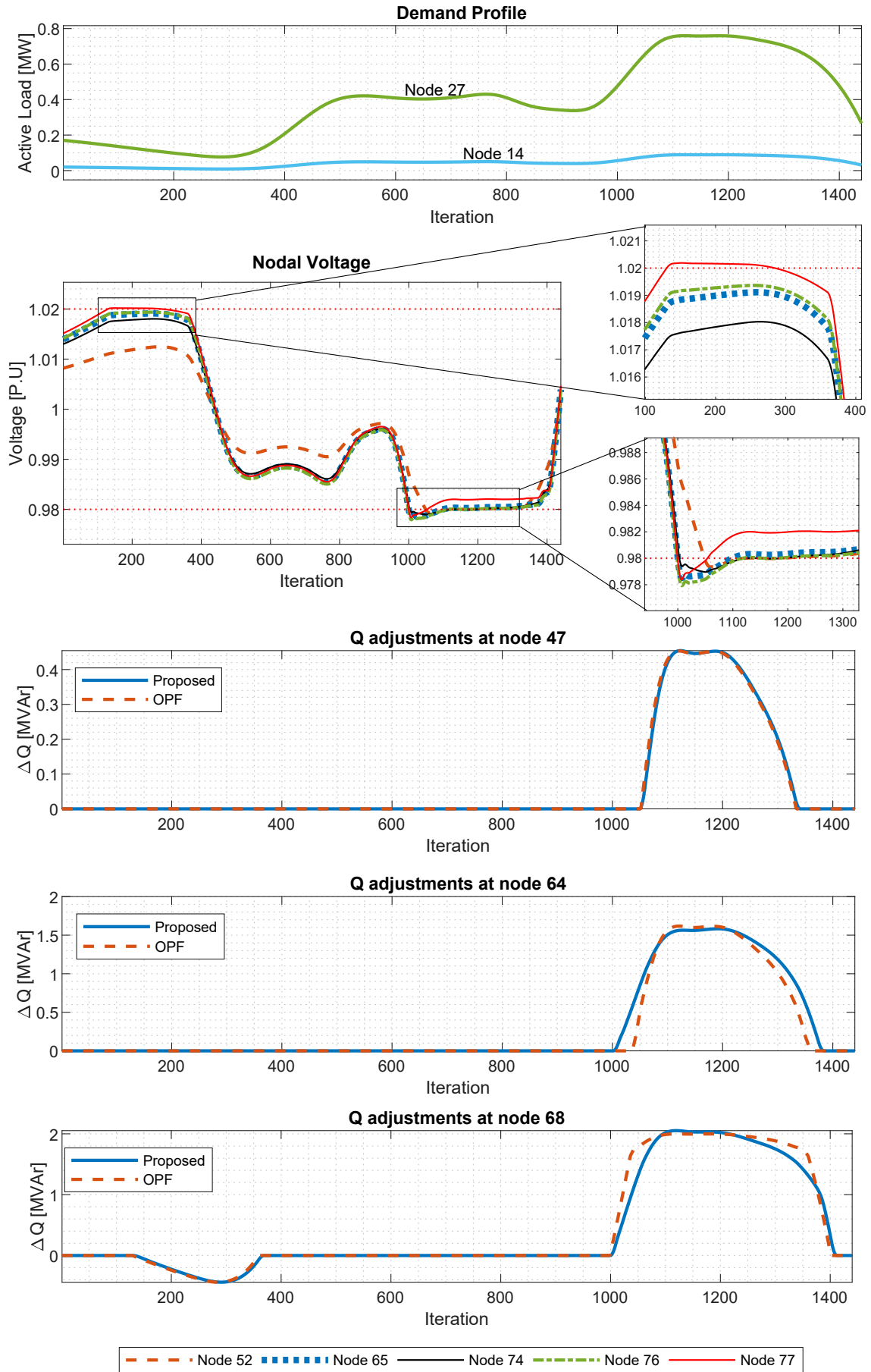


Figure 5.16: Networks measurements and LC actions to satisfy compliant operation in Test Case 4.

The first plot of Figure 5.16 shows the higher and lower demand profile, result of multiplying original demand from [80] and base demand profile of Figure 5.3. In the second row it is presented the most critical voltage measurements. Since voltage plots are overlapping one another, it is presented in the sides, adjusted scales of two regions of interest, one during over voltage and the other during under voltage. The last three plots presents the adjustments in reactive power flow from DGs that moved away from agreed set points, namely DGs at nodes 47, 64 and 68.

The starting set points for demand and generation are such that unhindered operation is possible, as evidenced by voltages within constraints and all DGs operating at agreed set points. With decrease of demand around iteration 100, the voltage at node 77 reached voltage constraint, as shown in the zoomed voltage plots of Figure 5.16. In response, the LC at node 77 sends the critical headroom from its perspective, computed via equation (4.21), to its neighbour, LC 68 (as seen in the network diagram of Figure 5.15). When LC at node 68 becomes aware of voltage violation, it adjusts its reactive power flow according to (4.26). Note that reactive power is preferred over active power adjustment, not only because of reduced costs of ancillary services, but due to the combined effect of low cost and high voltage sensitivity, as shown in equation (4.15) and (4.16). The change in reactive power flow taken by LC 68 is sufficient to maintain voltage at node 77 close to the safe limit of 1.02 p.u. Around iteration 400 the demand and generation are again such that network is being operated in safe conditions without procuring ancillary services from participating DGs.

Approaching iteration 1000, the aggregated demand ramps up until its peak around iteration 1200. This increase in demand caused voltage throughout the network to drop, reaching critical values at nodes 77, 76, 74 and 65. These nodes have no controllable device capable to alter power flow and therefore requests adjustments to LCs that they have estimated to be ideal. Nodes 77, 76 and 74 send messages in the direction of LC at node 68, since that in their estimations, this LC is the most fit to solve their voltage constraints. Whenever LC at node 68 receives the critical headrooms sent, it computes the most critical via equation (4.22) and adjusts its reactive power flow via equation (4.27).

Almost during same period, LC at node 64 also receives critical headroom information from node 65 and adjusts its reactive power flow to solve under voltage situation. This is seen at the two lower plots of Figure 5.16 and the voltage response to these adjustments is shown in the second row plot, with voltage measurements increasing towards safe constraint. A few iterations after, node 52 also observes under voltage situation, and sends message in the direction of node 47. Upon receiving the message, node 47 injects reactive power to ramp voltage at node 52 up. Note that node 68 injected more reactive power than necessary to solve under voltage at node 77, as can be seen with its voltage profile above safe constraint. This is because when comparing the most critical headroom, LC 68 decided to solve constraint from node 76 which in turn also solved the less critical nodes that sent messages.

The adjustments considered by the coordinated cooperation of LC under the proposed distributed strategy is comparable with the adjustments defined by a benchmark centralised approach, as it is possible to evaluate in the three lower plots of figure 5.16. The traced line matches the blue line with small differences. Sources of mismatch includes message hop delay and errors in calculating voltage sensitivities which might cause wrong power flow adjustments when relying on equations (4.24) to (4.27).

By measuring the time required by each LC to obtain an adjustment decision and also measuring the time required to obtain the decision based on the centralised OPF, Figure 5.17 is generated.

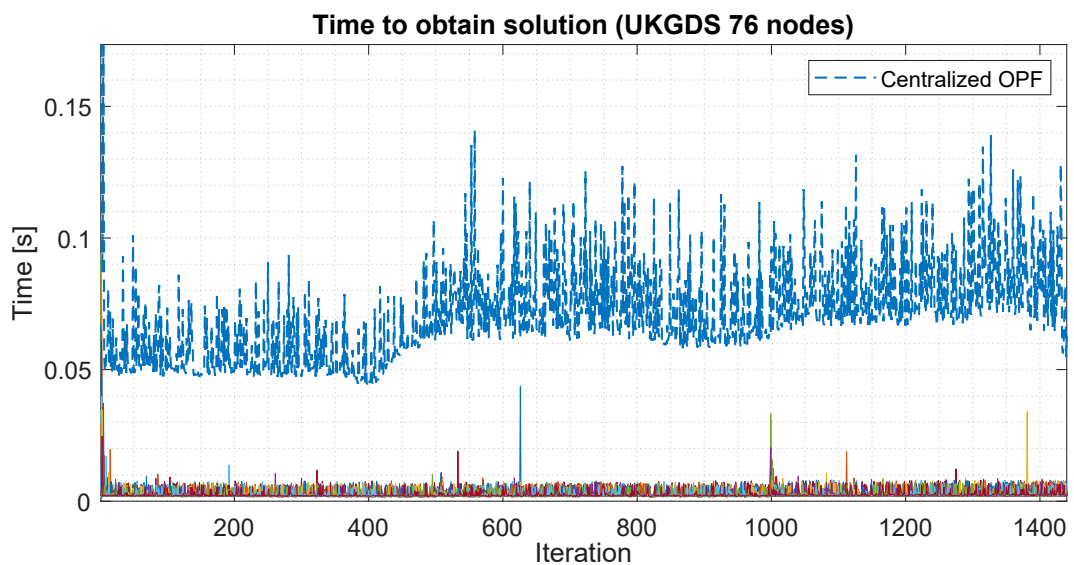


Figure 5.17: Time required per iteration of Test Case 4 for the centralised approach compared with iteration time for each LC based on the proposed method.

The traced blue line represents the centralised approach time requirement and the other plots are for each of the local controllers. The fact that they are overlapping indicates that they all have similar time requirements. The average time taken by the worst LC is of $0.0029s$ (from LC at node 70) while the average time taken by the centralised approach is of $0.0686s$

5.2.5 Test Case 5: Soft Open Point Participating in Active Network Management - 10 bus network

As discussed in Section 2.1, the traditional distribution network is designed in such a way to have radial feeders with possibility of reconfiguration through operation of normally open point (NOP) switches. Soft Open Points (SOP) are power electronic devices installed in the network capable of replacing these NOP enabling “soft mesh” of feeders in which the power flowing from one another is controlled [67]. It can be designed as a back-to-back voltage source converter capable to provide flexible active or reactive power control through the SOP terminals [66,68].

In this Test Case, it is explored the capacity of including control and coordination of SOP into the proposed strategy. Results are first explored in the 10 bus network, which due to its simplicity, becomes easier to evaluate response from local controllers. The network with all controllable DERs and communication links between LCs is presented in Figure 5.18.

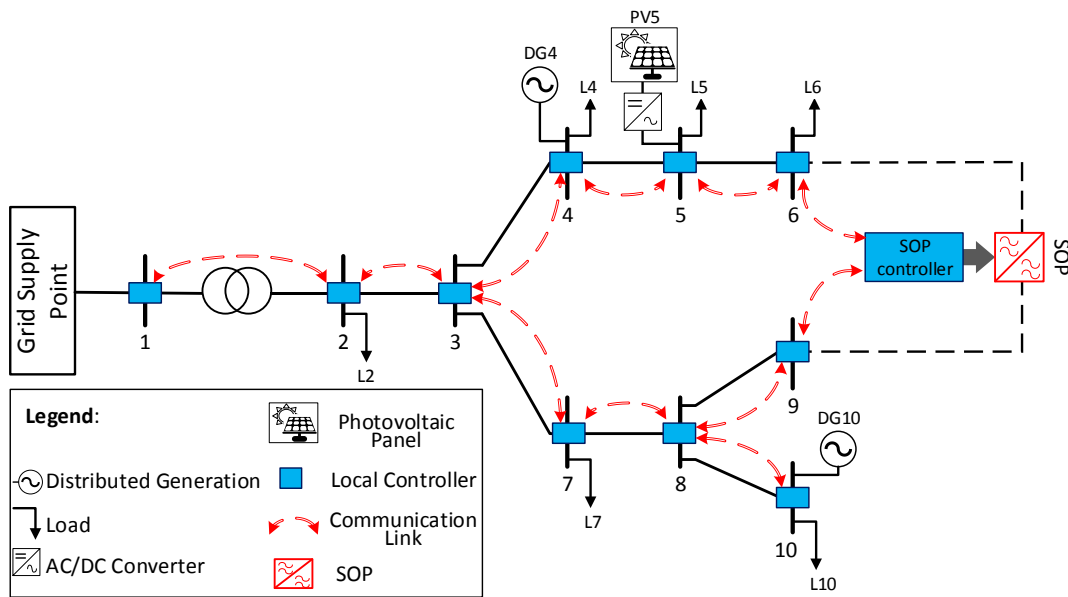


Figure 5.18: 10 bus network with Soft Open Point between nodes 6 and 9.

The test case has 4 controllable DERs, one of which is a SOP enabling controllable flow between nodes 9 and 6. Note that two LCs are placed to control and coordinate the SOP. An additional communication link must be considered between nodes 9 and 6 in order to share their headrooms and allow safe decisions to be made.

The SOP can absorb power from other feeder and inject locally to solve over voltage constraint from the other terminal or to solve under voltage at local node. Alternatively, the SOP can be instructed to drain power flow from local node and inject the the other terminal in order to solve under voltage at the other terminal or to solve over voltage at local node. Note that the control of SOP requires two local controllers to agree on the adjustment of power flow. The implementation consider only one active LC (that will decide on the amount of power transfer between two terminals). The active LC operating the SOP can be chosen arbitrarily, and is required to enable coordination, avoiding multiple decisions of adjustments (due to their different observability of system). The controllers are always sending their headroom observability to one another. In case the active LC is constrained, it will alter its position subject to the other terminal headroom. In case the other terminal is constrained, the active LC will also alter power flow at SOP to satisfy headroom restrictions from both ends.

When active terminal is solving the constraint of the passive terminal, the active terminal is reaching closer and closer to its own constraint. The same process applies when active terminal is solving its own constraint and brings the passive terminal closer to its constraint. For example: suppose that node 9 has under voltage and to solve it, power flows from node 6 to node 9 through the SOP. As power is drained from node 6, voltage decreases at the point of having under voltage at 6 as well. Or in case of over voltage at node 9, to solve it, it would require to drain power flow from node 9 to node 6, and the extra injection will increase the voltage at node 6, possibly causing over voltage situation there as well. During these situations when one terminal is no longer able to support the other, the SOP should be considered unfit and no longer able to act. This information is passed along other LCs via the *operational parameters* binary vectors discussed in Section 4. The SOP terminals remain operating in voltage control mode, ensuring that both terminals have same voltage level and expects that another LC will adjust its power flow to solve the constraint.

The simulation to access performance of the proposed control and coordination strategy including SOP is now explained. The demand at each node is constructed considering the base residential demand from Figure 5.3 multiplied by the loading factors at each node. Loading factors of nodes 2 and 3 are equal to 6.0; loading factors of nodes 4, 5 and 6 are equal to 4.5 and at nodes 7, 8, 9 and 10 the loading factors are all equal to 3.0. The PV connected at node 5 follows the PV injection curve shown in Figure 5.4 multiplied by 15 to force over voltage during peak solar radiation. The DERs follows the connection agreement as shown in Table 5.6. The PV has high cost in ancillary services to avoid adjustment of a renewable source (incentivizing energy production from RES). The cost of operating the SOP is considered lower than all other DERs because most likely the SOP will be owned by the network operator and will not require high cost of operating it. SOP should be have preference in solving constraints before having to rely on ancillary services procurement. It is not completely free in order to consider practical losses that may occur while operating the SOP. It is noteworthy that losses from SOP is not modelled in the present work since the objective is not regarding SOP operation *per se*, but how it can be included into the distributed control and coordination algorithm proposed.

Table 5.6: Connections agreement specifications for Test Case 5.

DER type	DG 4	PV 5	DG 10	SOP
P contracted [MW]	3.0	Max PV	2.0	0.0
Q contracted [MVar]	0	0	0	0
Max ΔP [MW] or ΔQ [MVar]	± 1.0	± 1.0	± 1.0	± 5.0
Cost P [\$/MWh]	150	5,000	100	10
Cost Q [\$/MVArh]	50	150	80	10

The simulation results are presented in Figure 5.19. The first row presenting the demand profile at every node. Second row presents the nodal voltages at every node. Third plot presents the active power injections from every DER. Fourth plot shows the reactive power injection from the only DER that decided to make adjustments and finally it is shown the power flowing to each node. Last plot is going to be useful to explore thermal constraint management later.

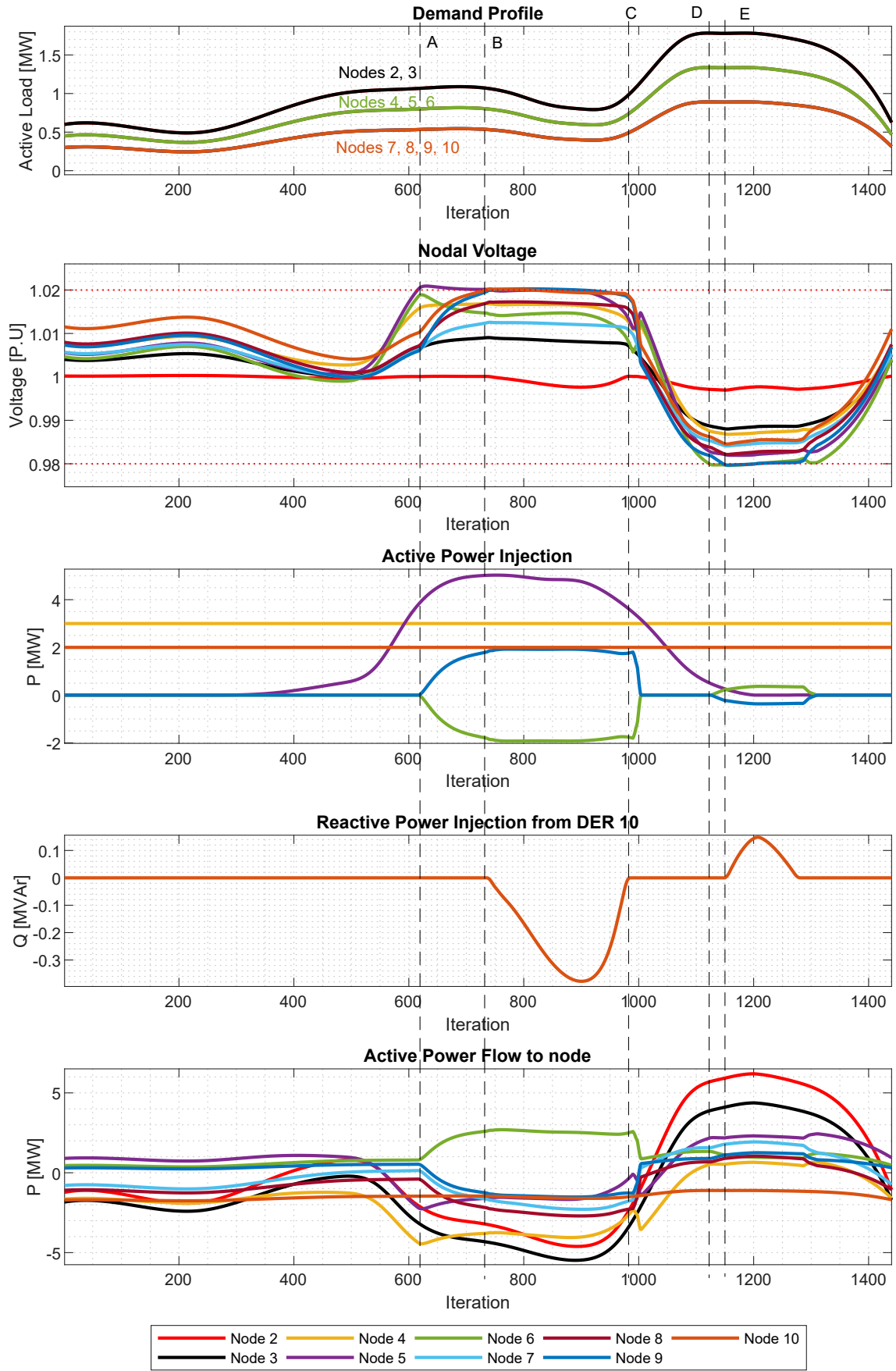


Figure 5.19: Network measurements and LC adjustments to satisfy compliant operation considering inclusion of SOP control.

From Figure 5.19 it is possible to see that until around iteration 600 the network is operated without constraint violation and all DERs are accommodated unhindered. At point A over voltage situation observed by LC at node 5, which estimates that operating the SOP at node 6 is more cost-effective than curtailing its PV injection, and sends its headroom information downstream. When LC at node 6 receives this critical headroom information from LC 5 it instructs the SOP to realize power sharing between nodes 6 and 9, draining power flow from node 6 and injecting into node 9, as can be seen in the third row plot of Figure 5.19, where injection from DER 6 assumes a negative value indicating absorbing power flow while the injection from DER 9 assumes a positive value of equal magnitude (since no loss is modelled) indicating injecting power at node 9. In the second row plot it is possible to see that by injecting power at node 9, the voltages at nodes 9 and 10 also approaches unsafe constraint.

At point B, both terminals of the SOP are observing over voltage and therefore cannot continue its operation and enters the voltage control mode in which both terminals maintain same voltage and requests another LC to solve their constraint. Both terminals estimated node 10 to be the ideal to solve their voltage constraint. Note that, in case DG at node 4 had a cheaper price for adjusting reactive power injection, LC 6 could have requested adjustment from it instead of LC 10. When LC at node 10 receives the headroom information from LC at node 9 (after its messages hops from 9 to 8 and from 8 to 10), it decides to adjust its reactive power flow and solve the most critical constraint that it receives, according to equation (4.21). From points B and C, voltages from nodes 5, 9 and 10 are kept near safe limit, while the SOP kept terminal voltages same. After point C, the increase in demand and reduction of PV injection caused voltages to decrease at the point that safe operation is possible without any adjustments from DERs. The SOP controllers realized that it is now safe to move back to the natural state of no power flowing through the SOP. Unhindered operation can be noted from points C and D, when the peak demand and reduced PV injection caused under voltage condition firstly detected at node 6. The LCs controlling the SOP decides to have power flowing from node 9 to node 6 in order to solve under voltage. However, quickly node 9 also observes under voltage and is no longer able to inject power at node 6 through the SOP terminals. This is seen at point E, when again, LC at node 10 is best fit to solve constraint, this time by injecting reactive power.

Thermal constraint with SOP

Relying on SOP to share power between two branches can solve voltage constraints in those branches of the network, however it is ineffective to solve thermal constraint from upstream of the node that connects those branches. Referring back to Figure 5.19, the last row plot shows the power flowing to each node. Note for example that the over voltage occurred due to excess generation and caused reverse power flow at most nodes during points A to C. Relying on SOP power sharing between branches to solve over voltage did not alleviate the reverse power. If instead DG curtailment had been requested, the under voltage constraint would be solved and the reverse power flow would be lessen. It is now explored how SOP participating in the proposed ANM can deal with thermal constraint together with voltage constraint.

Considering the same network details for generating results of Figure 5.19 with an additional thermal limit constraint of 4 MW (direct or reverse power flow) in the line connecting node 2 to node 3 of the 10 bus system of Figure 5.18, it is possible to create a test case to evaluate how SOP participating in the proposed strategy behaves in presence of thermal constraint violation. For sake of simplicity, only the line connecting nodes 2 to 3 have thermal constraint. Result is shown in Figure 5.20.

Up until point A the results shown in Figure 5.20 is the same as the one shown in Figure 5.19. However, the thermal constraint of 4 MW from the line connecting nodes 2 to 3 is reached in the reverse direction. Although the SOP has the cheapest cost to be operated (according to Table 5.6), it is not effective to solve thermal constraint of node 3. The LCs decide to request adjustments from DG at node 4 to curtail and alleviate the reverse power flow level. It does so until its maximum agreed curtailment of 1 MW (also shown in Table 5.6). The binary vector of LC 4 is updated to inform other LCs that it is no longer able to solve. When LC at node 10 receives this information (after 4 iterations), it estimates itself as the new ideal to curtail and solve thermal constraint, as seen in point B. Note that the SOP kept focusing on solving voltage constraint of node 5 in order to reduce the amount of curtailment from DGs 4 and 10. These set of decisions resulted in flat voltage profile and flat power flow profile, indicating that unnecessary curtailment is minimized. Until point C the network is not facing any critical constraint violation and can resume its normal operation.

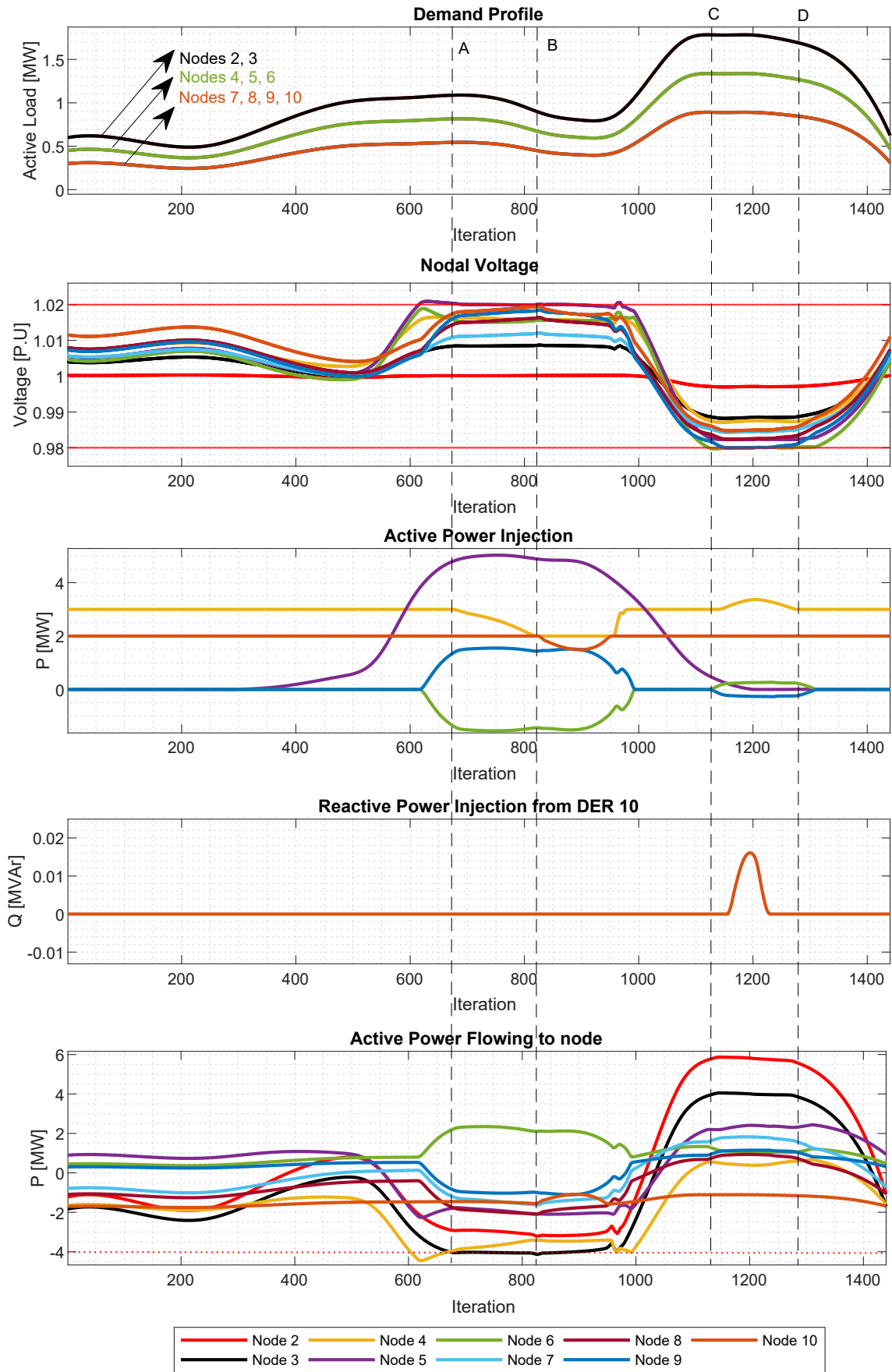


Figure 5.20: Network measurements and LC adjustments to satisfy compliant operation considering inclusion of SOP control and thermal constraint.

The high demand caused under voltage in node 6, as seen in point C. The SOP start solving but is constraint by the second SOP terminal since node 9 is also observing under voltage and can no longer inject power to node 6. Voltage constraint begins to be solved by reactive power support from DG 10 while at the same time, thermal constraint observed in node 3 is dealt via additional injection of active power from DG at node 4 (alleviating direct power flow requested by the main power supply). at point D the only constraint left is under voltage at node 6, which the SOP is best placed to solve it. Afterwards, safe operation is possible with unhindered DERs.

It is possible to see how the proposed distributed control and coordination strategy, including SOP controlled actions could manage multiple constraint violation maintaining safe operation while attempting to minimize DER injections requests.

5.2.6 Test Case 6: Soft Open Point participating in Active Network Management - 33 bus network

To show that the SOP controlled actions participating in the proposed ANM is able to operate in larger networks, it is presented in this Test Case a similar simulation but in the IEEE 33 bus system shown in Figure 5.21. SOP is placed between nodes 33 and 18, connecting two different branches and increasing the options to manage the network. Additionally to the SOP, there are 8 other controllable DERs. The connection agreement details are presented in Table 5.7.

Table 5.7: Connections agreement specifications for test case 6.

DER type	Contract type	Agreed P injection [p.u]	Maximum P adjustment [p.u]
DG 5	Non-firm	0.55	± 0.5
DG 8	Non-firm	0.45	± 0.5
DG 12	Non-firm	0.55	± 0.5
PV 14	Non-firm	Max PV injection	± 0.5
DG 17	Non-firm	0.10	± 0.5
SOP (18-33)	Non-firm	0	± 0.5
DG 21	Non-firm	0.50	± 0.5
DG 24	Non-firm	0.65	± 0.5
DG 31	Non-firm	0.20	± 0.5

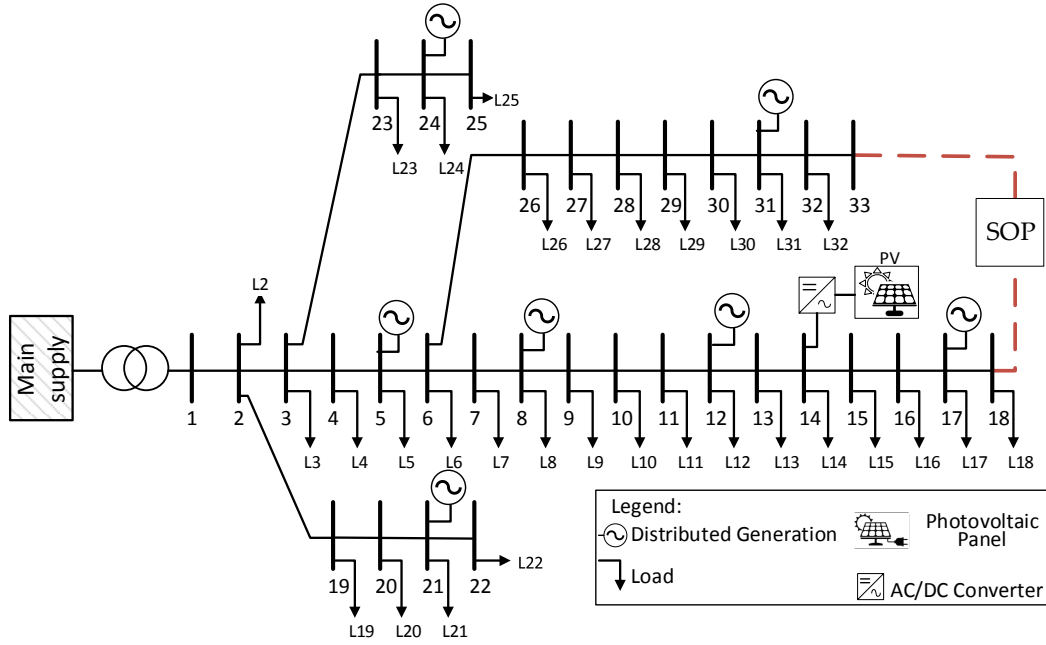


Figure 5.21: IEEE 33 bus network with Soft Open Point between nodes 18 and 33.

The demand profile from nodes 4 to 15 are considered industrial profile, with a base profile such as shown in Figure 5.4. The other nodes have a typical residential profile, shown in Figure 5.3. In the present simulation, the base industrial profile and base residential profile are multiplied by factors in order to have different loading conditions at different nodes. The factors are shown in Table 5.8. The PV injection follows the curve also shown in 5.4, multiplied by a factor of 1.3. Simulating these conditions for a 24 hour period (subdivided into 1440 simulations), it is obtained results presented in Figure 5.22. The top plot shows residential demand profiles from nodes 2 and 3 (highest and lowest demands) as well as the highest industrial demand profile at node 4. Middle plot presents voltage profile with over and under voltage occurrences. The last box shows the active power injection performed by all participating DERs, including the SOP.

Table 5.8: Loading factor to multiply base industrial and residential demand profiles.

Nodes	Loading Factor	Nodes	Loading Factor
2,3	3.0	16,17,18	0.1
4,5	1.2	19,20,21,22	2.0
6,7	0.6	23,24,25	1.8
8,9,10,13,14	0.24	26,27,28, 29,30	0.5
11,12,15	0.18	31,32,33	0.3

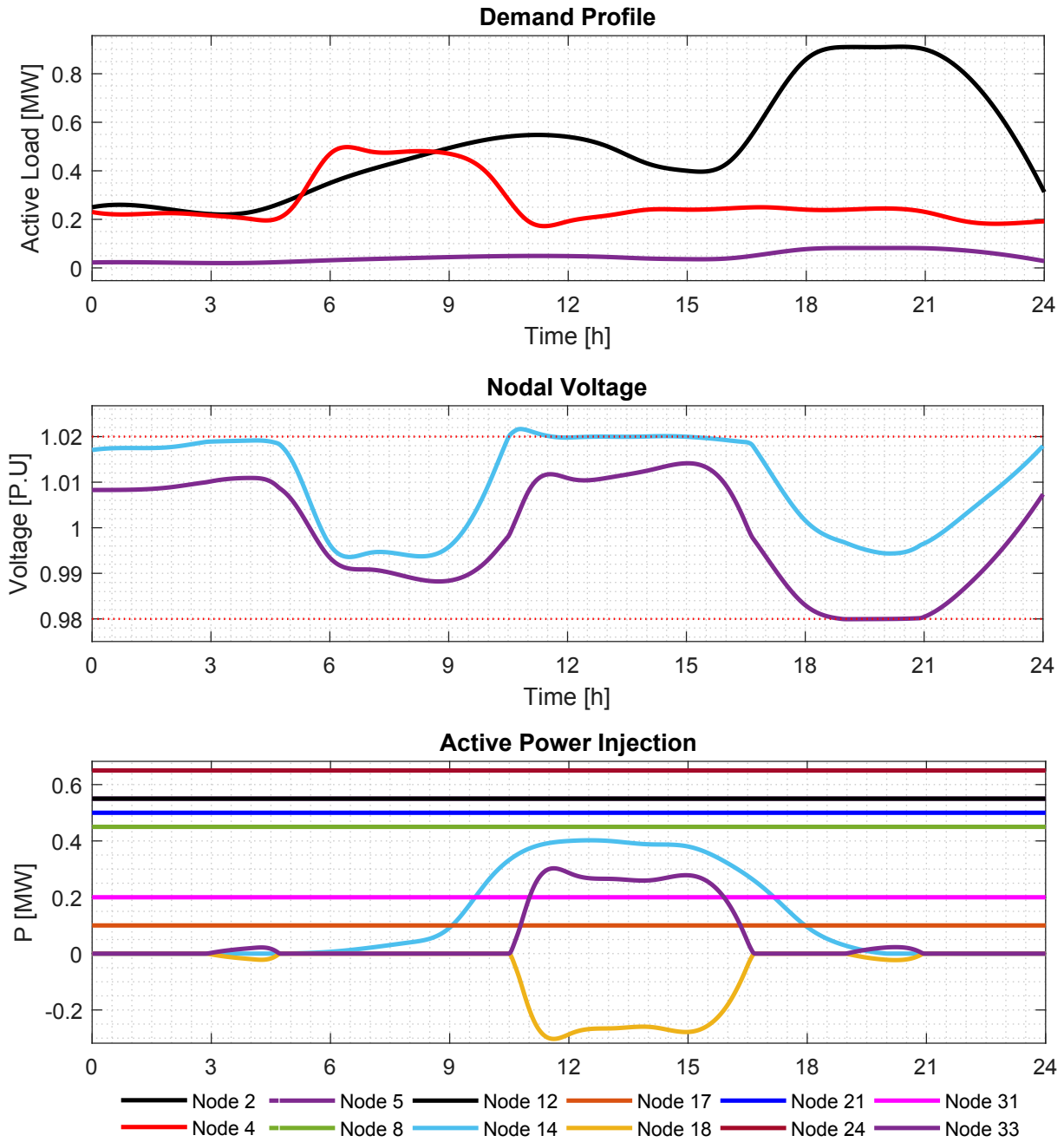


Figure 5.22: SOP results in IEEE 33 bus network.

It is possible to observe that around mid day the peak PV injection combined with low demand from industrial profile during this period caused intense over voltage at node 14. One solution would be curtailment of PV, which results in waste of clear source of energy. Other solution, as presented in previous test cases, is adjustment of power flow injections from other participating DERs by procuring ancillary services. The new option discussed in this test case is to rely on the soft open point to redirect power flow between branches to solve constraints.

The excess generation from node 18 (due to excess generation from PV) is drained to node 33 via the SOP. This caused a reduction in voltage level from the critical node 14 and caused an elevation of voltage level at node 33, making sure that the elevation in voltage level at node 33 does not constrain any other node in its branch. Small voltage violations also occurred around 4-5 am and 8-9 pm, with an over voltage and under voltage respectively. The solution follows the same process of redirecting power flow between different branches to alleviate constraints.

5.3 Multiple Simulations with Normally Distributed Demand Variation

To access robustness of the proposed approach in a variety of conditions, multiple simulations with various demand dictated by a Gaussian distribution curve is tested. The proposed ANM must obtain the necessary adjustment to keep compliant operation. Again, adjustments from proposed approach are compared with centralised OPF for validation.

This process is applied in 3 standard networks, namely, IEEE 33 bus system, IEEE 15 bus system and a UKGDS 76 bus network, whose parameters can be obtained in [65, 81] and [80] respectively. Also it is tested in the simplified 10 bus network used in some of the proposed test case scenarios. The original demand from all of the 4 networks are used as center of the Gaussian distribution curve. The standard deviation applied in each node i , (σ_i) , is selected in such a way that the cumulative σ_i causes a σ_{total} equal to 50% of original total demand.

To clarify with an example, consider the simple 10 bus system from Figure 5.10 with active demands at nodes 2 and 3 of 2MW; demands at nodes 4, 5 and 6 of 1.5MW and demands at nodes 7, 8, 9 and 10 of 1MW. All nodes have controllable DER injecting 1MW. This scenario is such that no constraint violation is observed. Generating a Gaussian distribution with N cases with σ_i equal to 2 and centred in each node's base demand it is obtained Figure 5.23. N is chosen as 500 because its a sufficient number of runs that allows clear Gaussian fit. The cumulative effect of σ_i resulted in a σ_{total} of 6 MW, which is around 50% of the base total demand, as seen in Figure 5.24. Negative values indicate generation, positive indicate consumption.

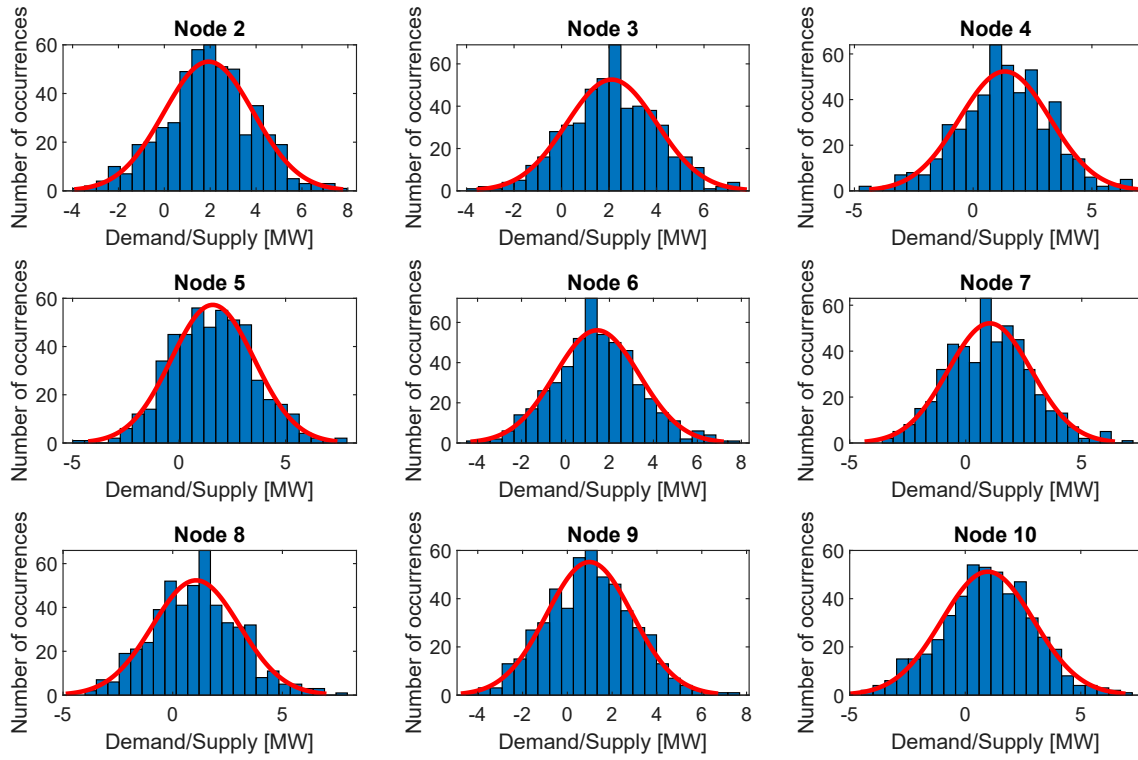


Figure 5.23: Histogram with Gaussian fit for all loads of the 10 bus system.

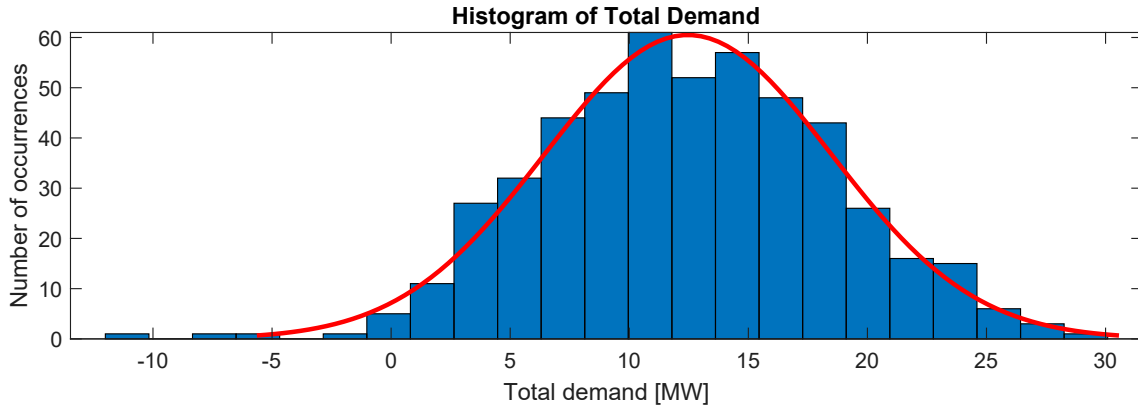


Figure 5.24: Histogram with Gaussian fit for total demand.

During each run, the proposed approach adjusts the DERs to keep operation within constraints. The total mismatch with the centralised OPF is measured (similar to what is done to generate Figure 5.7) for every run to obtain an average and standard deviation of mismatches ($\sigma_{mismatch}$).

Figure 5.25 shows all mismatches obtained during all 500 simulations with variable demands, randomly selected from Figure 5.23. An appropriate zoom is given, in the scale of 10^{-6} in order to show majority of mismatches.

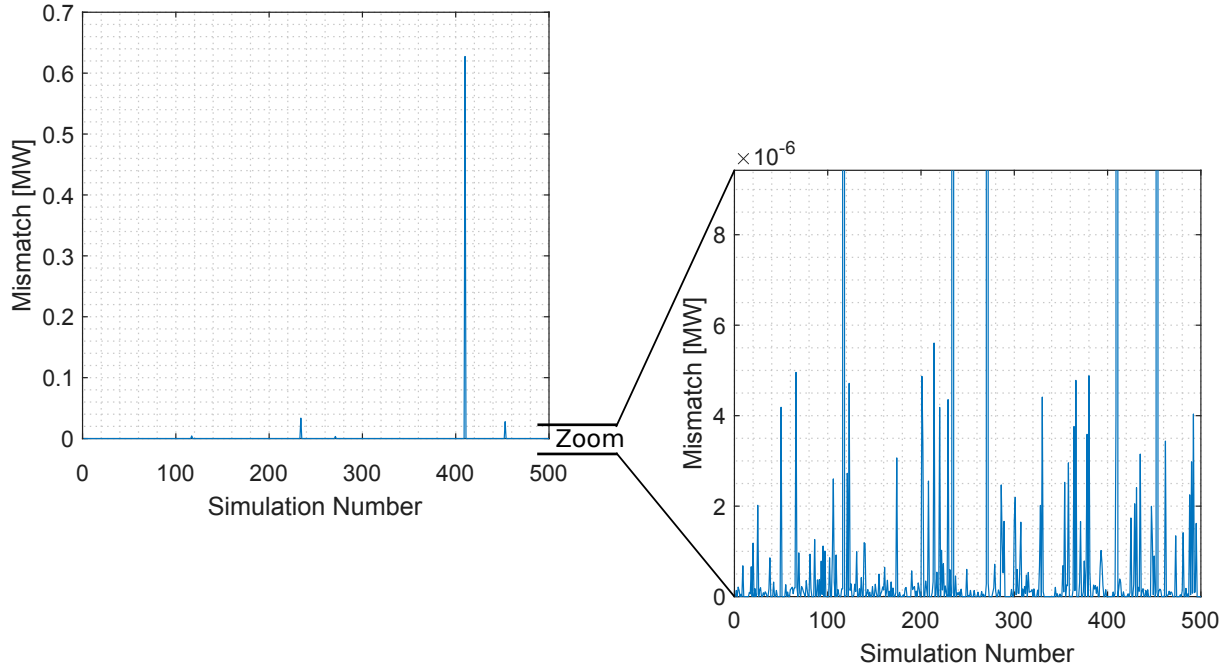
Mismatch of dispatches from Centralized and Proposed approaches (10 nodes case)

Figure 5.25: All mismatches from centralised and proposed approach for 500 simulations with randomly selected demands from Figure 5.23.

Around simulation number 400, it can be observed a mismatch much higher than the overall values, with a maximum mismatch of 0.6274 MW. This particular case is evaluated in details. The decisions of power flow adjustments taken by the centralised and proposed approach are shown in Table 5.9, together with the voltage readings and randomly selected demand that culminated in constraint violation.

From Table 5.9 it is seen that for a particular case, the network detected over voltage and under voltage simultaneously. The over voltage happened around the end of the feeder, at node 6 and the under voltage happened at the beginning of the feeder, at node 2. The proposed approach decided to absorb reactive power at node 6 to solve over voltage of node 6. However, the reactance at the beginning of feeder is larger than resistance and therefore, voltage sensitivity to reactive power is much higher at node 2. The fact that node 6, located at downstream of node 2, decided to absorb reactive power, caused an under voltage at node 2 due to excess of reactive power being absorbed from main supply. The local controller at node 2 decides to inject reactive power from its own DG to solve its under voltage situation. The centralised approach on the other hand, decided to absorb reactive power at node 6 up until a certain point, when node 2 is constrained with under voltage. At this point, instead of node 2 injecting reactive

power, node 6 decided to solve its locally observed over voltage with active power curtailment. This decision was not made in the proposed approach due to lack of observability. Node 6 did not know that local actions done to solve its over voltage were causing an under voltage situation at node 2.

The distributed approach enables LCs to know that constraints are detected, but do not enable them to know where the constraint exists. In case LC at node 6 knew that the under voltage is detected in node 2, it could evaluate the estimated sensitivity due to reactive power and realize that active power curtailment could have solved its local constraint of over voltage without compromising node 2 with under voltage. The maximum adjustment made by the proposed approach was of 4.671 MVar and no adjustment in active power. The maximum adjustment made by the centralised approach was of 3.402 MVar plus 0.216 MW. Therefore, the proposed approach required an additional of 0.6274 MVA. It is noteworthy that this represents an unusual scenario and that although more adjustment was procured by the proposed approach, the voltages were kept within safe constraints.

The normally distributed selection of demands might not cause a constraint violation and thus,

Table 5.9: Detailed decisions from centralised and proposed approaches for the highest mismatch case shown in Figure 5.25.

Node	Demand	Proposed			centralised		
		Voltage	ΔP	ΔQ	Voltage	ΔP	ΔQ
2	2.1060	0.9700	0	+0.7791	0.97	0	0
3	0.0014	0.9864	0	0	0.9904	0	0
4	-0.6838	1.0090	0	0	1.0090	0	0
5	-4.6530	1.0250	0	0	1.0250	0	0
6	-5.6610	1.0300	0	-3.988	1.0300	-0.7384	-3.402
7	-0.9218	0.9914	0	0	0.9917	0	0
8	2.2560	0.9885	0	0	0.9888	0	0
9	0.0649	0.9905	0	0	0.9908	0	0
10	2.0000	0.9864	0	0	0.9867	0	0

mismatch is zero as no adjustment is required. These occurrences are neglected since they do not represent statistical relevance for mismatch analysis. The ratio between number of relevant occurrences and the total number of simulations can give a sense of how susceptible to constraint violation a network is. For instance, out of the 500 simulations of the 10 node network, 255 had constraint violation and are used to obtain statistical information of mismatches, the ratio in this case is 51%. This process is repeated for all the 4 test networks and results are compiled in Table 5.10. All tests were performed on a 64-bit operating system with 3.5 GHz CPU and 32 GB RAM.

Table 5.10: Multiple simulations summary results.

Network	$\sigma_{mismatch}$ [p.u]	Mean [p.u]	Violation Cases [%]	Average Time [s]	
				(proposed)	(OPF)
Simple 10 bus system	0.0394	0.0027	51	0.0012	0.0471
IEEE 15 bus system	0.0118	0.0035	58.2	0.0012	0.0436
IEEE 33 bus system	0.0313	0.0094	64	0.0015	0.0638
UKGDS 76 bus system	0.0223	0.0053	64	0.0014	0.0883

The time required per LC to obtain a decision is measured and compared with the time taken by the central OPF in order to validate that the proposed approach has lower computational burden. The IEEE 33 bus system case resulted with slight higher time requirement per LC possibly due to more multiple adjustments, where multiple constraint violation, in different branches caused multiple LCs to adjust their injections. From Figure 4.7, it is possible to see that LCs that are ideal to solve constraint have extra steps to define how much power flow adjustment is required. The initial conditions of each tested network makes them more or less prone to constraint violation due to demand variation. In the case of IEEE 33 bus system, the initial condition is such that voltages at nodes 33 and 18 are close to lower voltage limit, which causes under voltage with small demand changes.

5.4 Summary of Results

It has been presented a series of test cases, involving coordination of active and reactive power injections from multiple DERs, operating with different unit costs offered in ancillary services, which are procured by the proposed ANM to mitigate voltage and line thermal constraints. By comparing with centralised OPF it could be observed coherent decisions made by the proposed ANM, obtaining reduced costs for adjusting power injections by participating DERs without compromising network statutory limits. The computational time requirements by centralised architecture is also compared with the time requirements by each local controller composing the system and is shown considerable reduction as the number of controllable devices increases. It is noteworthy that besides the computational time, it exists the communication time requirements, which could be accessed in the results. It was estimated during end of chapter 4 based on the data packet size transmission, showing that distributed communication systems requires less sophisticated communication channels which can act in favour of distributed approaches of ANM in distribution networks.

The results presented in this chapter comprises both time domain simulations and statistical analysis across multiple scenarios. For time-domain simulations, a distribution network is modelled that combines the variable demand and generation profiles during a 24hour period, with DERs output adjusted by the ANM every minute to maintain compliant operation. As results pointed out, the mismatches with centralised OPF are minimal, having the selection of most cost effective DER (chosen by the proposed distributed voltage sensitivity calculation) and the volume of adjustment required to solve local and non-local constraint consistent with decisions made by the counterfactual centralised OPF. For the statistical analysis, multiple simulations of static conditions are performed to four different networks, *i.e.* the initial conditions of demands connected in each node are randomly selected from a Gaussian distribution curve, and the proposed ANM is expected to obtain the ideal dispatch to solve any existing constraint violation. The Gaussian curve is constructed in such a way to have a standard deviation of 50% of the original total demand. Results showed that the average mismatch of adjustments, when compared with counterfactual centralised approach, is in the order of $10^{-2}p.u$ with standard

deviation in the order of $10^{-1}p.u.$, which validates that the proposed method have tolerable accuracy. Additionally, the time requirements is also measured and compared across multiple simulations, showing that the increase in computational time due to increase in the number of controllable devices is not significant when applying the proposed distributed approach, being a valuable feature for future applications in active distribution networks.

Finally, it was also demonstrated in this chapter that the proposed algorithm is also capable to control and coordinate new devices, such as the SOP, for voltage and thermal constraint management. To include the SOP, an additional communication link is required, one that channels the two terminals of the SOP so that constraints can be observed and solved by different branches of the feeder. Additionally, both controllers (in each terminal of the SOP) should ensure that the same amount of power that is injected in one side of the terminal must be drained in the other side (and vice-versa). So both controllers must agree in the amount of power flow is shared via SOP terminals.

Chapter 6

Conclusion

This thesis sets out a new approach to create a distributed form of ANM for addressing voltage and thermal constraints in a network that arise from the growing penetrations of DER. The proposed ANM algorithm is based on distributed calculation of voltage sensitivity (derived in chapter 3, assuming a network that is radial) combined with message passing (derived in chapter 4) that enables each participating DER controller to become aware of network conditions (termed constraint headroom in the method) at other locations. Each local controller (LC) can then decide whether or not to solve a constraint locally or request actions from other DER deemed more effective. The effectiveness of each DER is evaluated by each LC by considering the voltage sensitivities they estimated and the costs agreed by each DER owner in the ancillary service market. This way the cost-effective DER is selected based on how costly to change voltage by adjusting its output. Therefore, the ANM developed in this thesis includes minimisation of cost of ancillary service procurement in its objective function.

It has been shown that the proposed ANM can achieve efficient management of DERs without requiring high complexity communication and computational infrastructure. This stems from the distributed design of the algorithm which means that computation is performed in parallel by each LC and data is shared only among neighbouring LCs. This represents a more realistic design for active distribution networks that are called on to host growing numbers of DERs for attaining environmental and governmental targets of decarbonising the electricity sector.

The novelty of the proposed approach is that LCs are able to calculate voltage sensitivities based on local measurements to not only determine the volume of power flow adjustment needed for constraint management, but also to share and use these estimates to coordinate the choice of which DER is most effectively located in relieving a constraint. The voltage sensitivities can also be combined with how costly it is to procure services from each DER so that the ANM can find the most cost effective DER, the one that is capable to cause the highest voltage change for the lowest cost of service. Furthermore, voltage sensitivity calculations are not based on historical data nor specific modelling of demand and generation, but based on mathematical approximations of the inverted Jacobian matrix for radial distribution feeders. These sensitivity values enable the ANM to respond with the correct power flow interventions to unexpected changes such as load loss or intermittent generation from renewable sources. The formulation of the ANM does envisage that a rich set of actions (ancillary services), covering real and reactive power, are available from controllable loads, generators and storage across the network. The proposed form of ANM can therefore aid in the process of unlocking full benefits of DER integration participating in future ancillary services market.

It is shown that the proposed calculation of voltage sensitivities due to local power flow changes (main diagonal of the Jacobian) produces accurate results (*i.e.*, in agreement with the benchmark centralised approach based on Jacobian matrix inversion) provided that the node voltage is close to its nominal value, obtaining errors of circa 4-6% when the node voltage is at maximum deviation of $\pm 5\%$. These errors decrease as voltages are brought within normal range. The estimates of off-diagonal terms of the Jacobian (*i.e.* $\partial V_i / \partial P_j$ where $i \neq j$) require further approximation and are seen to have somewhat higher error due to the fact that less information from the respective node is known. Errors are shown to be around 15% during worst conditions, *i.e.*, estimations of distant nodes, and around 5% for estimation of voltage sensitivity from nodes which are close neighbours. The outcome of larger errors of off-diagonal estimations is that DERs might, as a consequence, choose action at a node that is not the most effective location to solve a constraint. Reminding that the errors are larger when estimations are made for nodes distantly located, so as the message propagates among the LCs, estimations of cost effective location improves and for this reason, dispatch closely matches the centralised OPF.

Consideration was also given to contractual agreements for non-firm connections, also known as a principle of access (PoA). A comparison was made between a simple but widely applied Last-In-First-Out (LIFO) PoA, which is a scheme that curtails based on chronological order of connection, and a scheme that curtails based on voltage sensitivities to select DER for the problem at hand. Results from a test case scenario showed that a LIFO scheme used up to 43% more volume of adjustments to DER output than the scheme based on sensitivity estimation.

The appropriateness of the overall solution found by the proposed distributed ANM was assessed by comparing the solution to that from a centralised OPF. The tests were in the form of time-domain simulations across daily load cycles of various network configurations. The proposed distributed ANM produced near identical control actions in response to constraints and could successfully identify the most appropriate node to take action and to pass action to another node once the limit of action of a DER was reached. The proposed ANM is tested for variety of scenarios, considering demand change according to a Gaussian curve, and the proposed ANM is requested to solve DER dispatch to mitigate voltage and thermal constraint violation for 500 runs and for 4 standard networks. The results shows small average mismatch in the total cost for procuring services from DERs. The mismatches obtained were in the order of 10^{-2} p.u with standard deviation in the order of 10^{-1} p.u. The time required per LC to obtain a decision of adjustment is relatively small regardless of the number of controllable devices, which enables closer to real time applications, key improvement for future ANM designs. It is noteworthy that for the time estimates, it was not considered the latency of communication, which is pointed out to be higher (and less reliable) for centralised architectures. These results provide confidence that the algorithm is applicable to a range of network conditions and its outputs correlate well with centralised implementations while having the advantages provided by decentralisation.

6.1 Summary of Achievements

The thesis has described a series of technological advances through which the final form of the proposed control and coordination strategy based on voltage sensitivity has been realised. Those steps are summarised here.

1. **Formulation of mathematical approximations for calculation of voltage sensitivities to power flow adjustments based on local measurements.** Errors obtained from the proposed decentralised estimation for self-sensitivity of voltage, *i.e.* how local voltages change due to local power change, is shown to be around 5 % when compared to results from centralised algorithms. Errors obtained for estimating other elements from the full voltage sensitivity matrix vary depending on the electrical distance between the node being estimated and the node performing the estimation. The error ranges from 5% to 10% under worst case (*i.e.*, high voltage deviation from nominal and long distances between nodes). These approximations are only possible by considering key aspects of radial topology networks. These estimations are later used to define power adjustments that will cause voltage changes to solve voltage constraint, at a local node or requested by others via peer-to-peer message passing.

2. **Modelling the ancillary service market framework to be utilised in the optimisation formulation.** Costs are considered for procuring ancillary services from participating DERs, in which they agree to have their power output adjusted for a period of time by the ANM. It envisages that DERs can offer adjustments of their power (real and reactive) for a quoted unit cost (cost per unit of energy) for adjusting its power output, requested by the ANM. The OPF must obtain the lowest cost of procuring these services in such a way that the voltage and line thermal constraints are observed.

3. **Design of a simple voltage-sensitivity-based principle of access that improves efficiency with which adjustments are chosen in flexible connections.** It is pointed out how efficiency in curtailment can be improved if instead of pro-rata or chronological order of curtailment, the ANM evaluates the voltage sensitivity of nodes with DER connection so that it is possible to obtain the locations in which changes in power injections will cause higher voltage changes, meaning that less adjustment will be required to cause the required voltage adjustment to maintain compliant operation. The aim is to reduce unnecessary curtailments and also to reduce the total costs to the DSO for procuring ancillary services.

4. **Creation of a coordination scheme of DERs connected under flexible arrangements using the voltage sensitivity calculation.** This approach to coordination is based on highest to lowest sensitivities, which requests adjustments from more sensible nodes which in turn causes higher voltage regulation with the least amount of disruption from their intended contracted position. The voltage sensitivities can be weighted by ancillary service costs offered by DER owners in future implementations of ancillary service framework.
5. **Definition of a message passing scheme that enables LCs to become aware of constraint violations along the network.** The proposed scheme ensures that LCs can determine a power flow adjustment every time it receives new messages, enabling LCs to update its observation of constraints from further nodes. It is not necessary an LC to know where the constraint is actually happening but it does know whether or not it can and should assist in resolving the constraint. This fact facilitate real time implementations of ANM.
6. **Creation of distributed ANM through combination of the voltage sensitivity estimation and message-passing.** A design was proposed for network management using power flow adjustment based on voltage sensitivity in which LC are made aware of the ability of others to act through message passing. The management system operating with the proposed algorithm minimises ancillary service procurement by selecting most effective actions from DERs that have a combination of high voltage sensitivity and low unit costs for adjusting its power output (offered in ancillary service market). This results in lower cost for procuring services to maintain compliant operation. In the proposed ANM, all LCs are constantly updating its local measurements (power flows and voltages) and constantly updating the ideal DER to act in case of constraint violation. This is done for both active and reactive power flows. Additionally, with the message passing scheme, local controllers can inform of inability to continue operation, maybe due to contractual breach (disruption reached maximum agreed upon contract) or maybe due to physical capacity of certain DER.

In summary this thesis proposed and evaluated an ANM design which (i) is distributed and suitable for controlling larger fleet of DER in shorter time-scale without complex communication infrastructure, (ii) minimises the cost of procuring ancillary services and (iii) allows unhindered DER operation to the greatest extent possible. The distributed design is only possible due to the proposed simplifications for voltage sensitivity calculations, that can be achieved with tolerable errors based only on local measurements. Combining the proposed voltage sensitivity, obtained in a distributed manner, with the message sharing, non-local constraints can be estimated and tracked so that local adjustment respects local and non-local constraints.

By deploying the proposed form of ANM, a DSO can ensure that its network is safely operated but, further, through minimising its interventions the DSO reduces the costs of procuring ancillary services (cost is subsequently passed on as use-of-system charges) and ensures that DERs are free to operate in their own best interests to the greatest extent possible.

6.2 Future Work

The intended application of this research in future scenarios of active network management is to have real world deployment. However, to this end, there are some steps that must be implemented and tested. These steps are listed as future works in this field of research and a brief description of its role for practical implementations is given.

Constraint management in Transmission/Distribution As discussed throughout the thesis, the aggregated effect of actively managed distribution networks is now starting to provide support services for transmission network, being seen as Virtual Power Plants (VPP) or providing frequency response with demand adjustment. For future works, it is recommended further investigation in regards capability of having the proposed ANM reacting to transmission networks signals. For instance, in case transmission networks requires extra injection of active or reactive power in a specific node to solve a higher voltage level constraint, where an actively managed distribution network is connected, how can the proposed ANM interpret the signal and readjust power flows from partici-

pating DERs to cause the requested variation seen in the beginning of feeder. A quick solution is to consider the requested adjustment as a local constraint seen by the beginning of feeder node and passed along neighbouring controllers for adjusting their DER injection. However, maybe the selected DERs should be those with lower voltage sensitivity in such a way that adjustments can be made without compromising security of the lower voltage network.

Inclusion of Tap-changers in the decision-making: Model a cost function for adjusting the transformer's tap ratio in the beginning of the feeder as an additional option to regulate voltage constraints. The LCs would have to take into account if it is more cost effective to perform tap-change rather than procure ancillary services from other DERs. The benefit is that by operating DNO owned assets the total costs for managing the network via procuring ancillary services should be reduced.

Inverter interfaced DERs: The methodology developed and described in this thesis does not consider the interaction between local controllers and its respective controllable DER. The control and coordination algorithm finds the required change of power flow to solve network constraints and assumes that the inverter is capable to make the adjustment. In reality, it might occur additional restrictions from the inverter side that might limit the requested adjustments. For future works it is then proposed an evaluation of the inverter capabilities and control architectures that enables to shift power flows to satisfy requests from the ANM.

Modelling of communication channels: As discussed in the methodology section of this thesis, the communication between local controllers has been modelled considering an asynchronous message passing paradigm, sharing vectors of information between local controllers. However, the communication channel per se, was not modelled, neglecting therefore the time requirements and error rate of the message exchange process during the validation of the proposed algorithm. For future works, detailed models of communication infrastructure might give a better understanding of implementation of ANM, providing additional information such as how well the algorithm behaves depending on different communication protocols and/or communication technologies.

Finally, in this thesis, it has been shown that there are still a great deal of research to be undertaken in the field of active network management that includes different forms of interactions between system operators and customers with growing number of controllable devices being integrated. In the thesis we tackled some of the challenges arising with high penetration of DERs, particularly those related to simplification of communication and computational complexity by moving away from centralised designs and challenges regarding inclusions of more realistic regulatory scenarios into the decision-making of ANMs, more specifically distributed forms of ANM. It is presented methods for simplifying of power flow solutions that facilitates future implementations of distributed ANM, enabling it to be deployed in distribution grid in a more practical way. Additionally, one example of distributed control and coordination, that relies on the proposed voltage sensitivities estimations, is designed and validated through a series of simulations in a variety of situations.

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Appendix A

IEEE 33 bus diagram

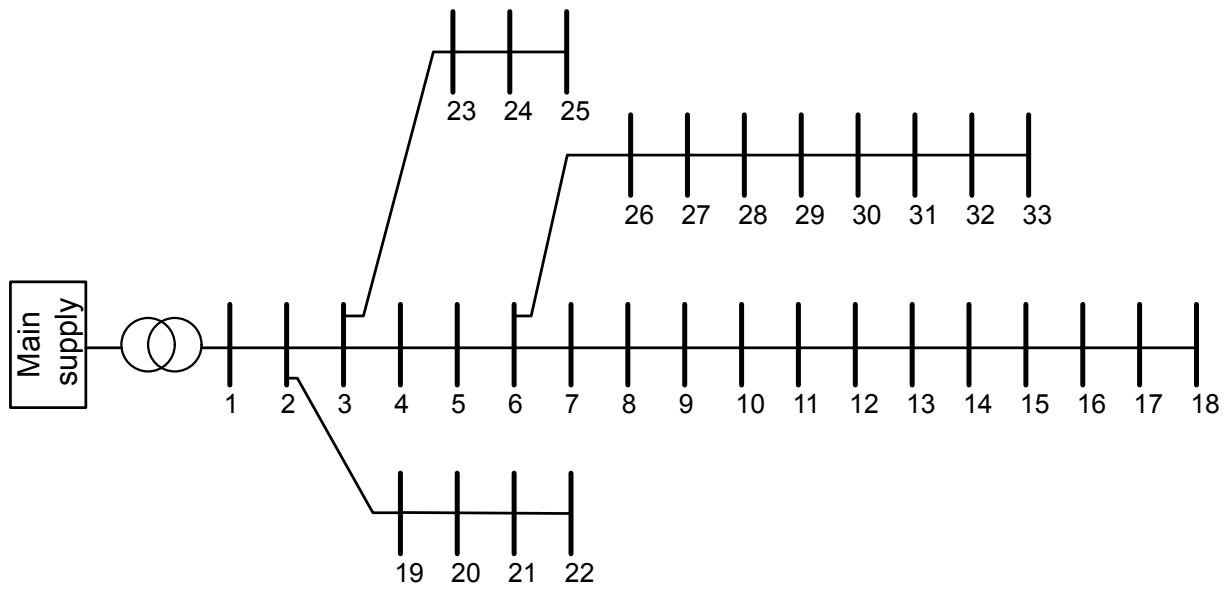


Figure 1: IEEE 33 bus network connection diagram.

IEEE 33 bus Demands

Table 1: Active and reactive demand connected to each node of IEEE 33 bus system

Node	P (MW)	Q (MVar)	Node	P (MW)	Q (MVar)
2	0.100	0.060	18	0.090	0.040
3	0.090	0.040	19	0.090	0.040
4	0.120	0.080	20	0.090	0.040
5	0.060	0.030	21	0.090	0.040
6	0.060	0.020	22	0.090	0.040
7	0.200	0.100	23	0.090	0.050
8	0.200	0.100	24	0.420	0.200
9	0.060	0.020	25	0.420	0.200
10	0.060	0.020	26	0.060	0.025
11	0.045	0.030	27	0.060	0.025
12	0.060	0.035	28	0.060	0.020
13	0.060	0.035	29	0.120	0.070
14	0.120	0.080	30	0.200	0.600
15	0.060	0.010	31	0.150	0.070
16	0.060	0.020	32	0.210	0.100
17	0.060	0.020	33	0.060	0.040

IEEE 33 bus Line Impedance

Table 2: Line parameters for IEEE 33 bus system

From	To	R(Ω)	X(Ω)	From	To	R(Ω)	X(Ω)
1	2	0.0922	0.047	2	3	0.493	0.2511
3	4	0.366	0.1864	4	5	0.3811	0.1941
5	6	0.819	0.707	6	7	0.1872	0.6188
7	8	0.7114	0.2351	8	9	1.03	0.74
9	10	1.044	0.74	10	11	0.1966	0.065
11	12	0.3744	0.1238	12	13	1.468	1.155
13	14	0.5416	0.7129	14	15	0.591	0.526
15	16	0.7463	0.545	16	17	1.289	1.721
17	18	0.732	0.574	2	19	0.164	0.1565
19	20	1.5042	1.3554	20	21	0.4095	0.4784
21	22	0.7089	0.9373	3	23	0.4512	0.3083
23	24	0.898	0.7091	24	25	0.896	0.7011
6	26	0.203	0.1034	26	27	0.2842	0.1447
27	28	1.059	0.9337	28	29	0.8042	0.7006
29	30	0.5075	0.2585	30	31	0.9744	0.963
31	32	0.3105	0.3679	32	33	0.341	0.5302

Appendix B

UKGDS 76 bus diagram

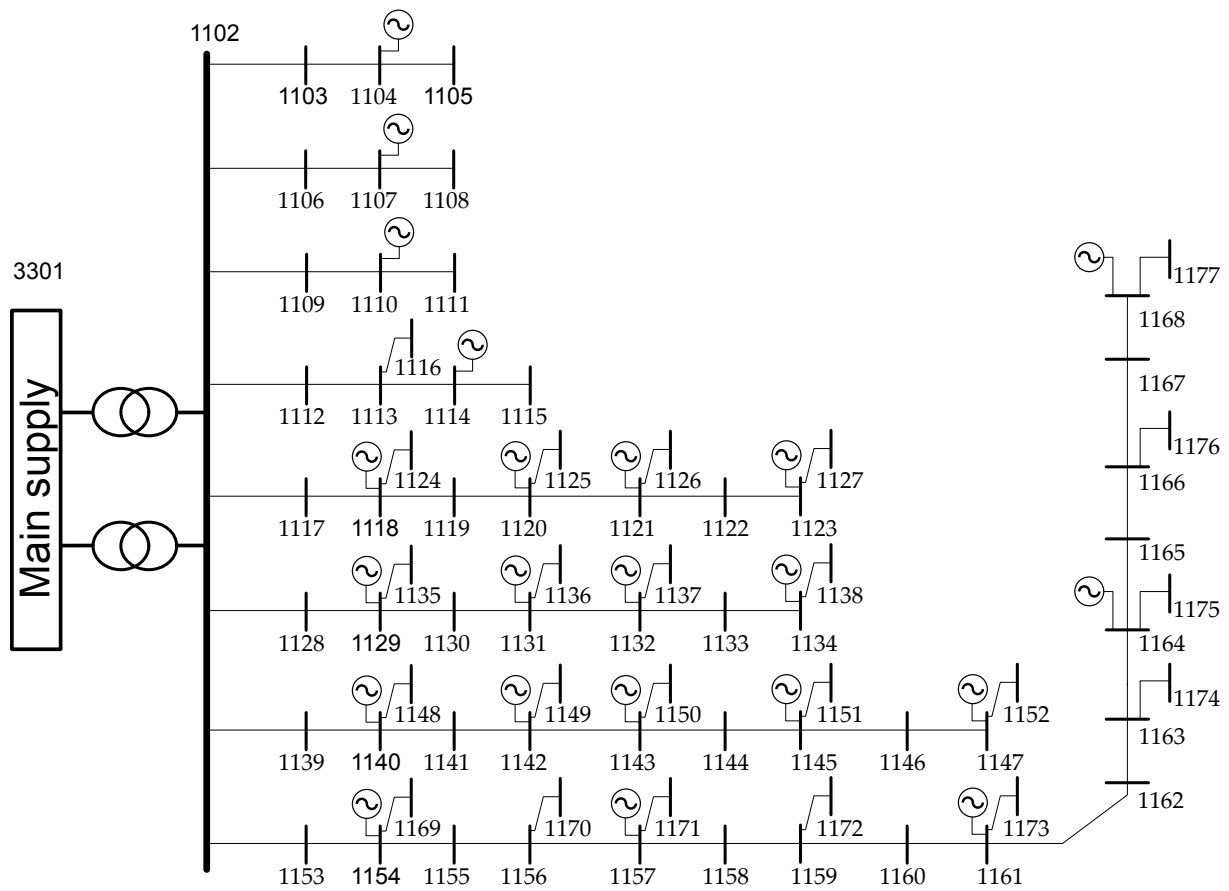


Figure 2: UKGDS 76 bus network connection diagram.

UKGDS 76 bus Demands

Table 3: Active and reactive demand connected to each node of UKGDS 76 bus system

Node	P (MW)	Q (MVar)	Node	P (MW)	Q (MVar)	Node	P (MW)	Q (MVar)
1102	0.392	0.078	1128	0.426	0.085	1154	0.344	0.069
1103	0.392	0.078	1129	0.426	0.085	1155	0.344	0.069
1104	0.116	0.023	1130	0.426	0.085	1156	0.344	0.069
1105	0.392	0.078	1131	0.426	0.085	1157	0.344	0.069
1106	0.392	0.078	1132	0.426	0.085	1158	0.344	0.069
1107	0.116	0.023	1133	0.426	0.085	1159	0.344	0.069
1108	0.392	0.078	1134	0.212	0.042	1160	0.344	0.069
1109	0.392	0.078	1135	0.212	0.042	1161	0.344	0.069
1110	0.116	0.023	1136	0.214	0.043	1162	0.344	0.069
1111	0.394	0.079	1137	0.214	0.043	1163	0.344	0.069
1112	0.394	0.079	1138	0.434	0.087	1164	0.344	0.069
1113	0.396	0.079	1139	0.434	0.087	1165	0.344	0.069
1114	0.100	0.020	1140	0.436	0.087	1166	0.344	0.069
1115	0.102	0.020	1141	0.436	0.087	1167	0.344	0.069
1116	0.426	0.085	1142	0.436	0.087	1168	0.222	0.044
1117	0.426	0.085	1143	0.436	0.087	1169	0.222	0.044
1118	0.426	0.085	1144	0.436	0.087	1170	0.224	0.045
1119	0.426	0.085	1145	0.436	0.087	1171	0.224	0.045
1120	0.426	0.085	1146	0.436	0.087	1172	0.224	0.045
1121	0.426	0.085	1147	0.216	0.043	1173	0.224	0.045
1122	0.426	0.085	1148	0.218	0.044	1174	0.224	0.045
1123	0.212	0.042	1149	0.218	0.044	1175	0.224	0.045
1124	0.212	0.042	1150	0.218	0.044	1176	0.224	0.045
1125	0.214	0.043	1151	0.218	0.044	1177	0.224	0.045
1126	0.214	0.043	1152	0.342	0.068	Total:	24.498	4.900
1127	0.426	0.085	1153	0.342	0.068			

UKGDS 76 bus Line Impedance

Table 4: Line parameters for UKGDS 76 bus system

From	To	R(p.u)	X(p.u)	From	To	R(p.u)	X(p.u)
3301	1102	0,0235	0,3270	1139	1140	0,0917	0,0706
1102	1103	0,2038	0,1056	1140	1141	0,0917	0,0706
1103	1104	0,2038	0,1056	1141	1142	0,0917	0,0706
1104	1105	0,0624	0,017	1142	1143	0,0917	0,0706
1102	1106	0,2038	0,1056	1143	1144	0,0917	0,0706
1106	1107	0,2038	0,1056	1144	1145	0,0917	0,0706
1107	1108	0,0624	0,017	1145	1146	0,0917	0,0706
1102	1109	0,2038	0,1056	1146	1147	0,0917	0,0706
1109	1110	0,2038	0,1056	1140	1148	0,0571	0,0155
1110	1111	0,0624	0,017	1142	1149	0,0571	0,0155
1102	1112	0,266	0,1378	1143	1150	0,0571	0,0155
1112	1113	0,266	0,1378	1145	1151	0,0571	0,0155
1113	1114	0,266	0,1378	1147	1152	0,0571	0,0155
1113	1115	0,0663	0,018	1102	1153	0,0665	0,0512
1114	1116	0,0663	0,018	1153	1154	0,0665	0,0512
1102	1117	0,0745	0,0574	1154	1155	0,0665	0,0512
1117	1118	0,0745	0,0574	1155	1156	0,0665	0,0512
1118	1119	0,0745	0,0574	1156	1157	0,0665	0,0512
1119	1120	0,0745	0,0574	1157	1158	0,0665	0,0512
1120	1121	0,0745	0,0574	1158	1159	0,0665	0,0512
1121	1122	0,0745	0,0574	1159	1160	0,0665	0,0512
1122	1123	0,0745	0,0574	1160	1161	0,0665	0,0512
1118	1124	0,0542	0,0147	1161	1162	0,0665	0,0512
1120	1125	0,0542	0,0147	1162	1163	0,0665	0,0512
1121	1126	0,0542	0,0147	1163	1164	0,0665	0,0512
1123	1127	0,0542	0,0147	1164	1165	0,0665	0,0512
1102	1128	0,0745	0,0574	1165	1166	0,0665	0,0512
1128	1129	0,0745	0,0574	1166	1167	0,0665	0,0512
1129	1130	0,0745	0,0574	1167	1168	0,0665	0,0512
1130	1131	0,0745	0,0574	1154	1169	0,0729	0,0198
1131	1132	0,0745	0,0574	1156	1170	0,0729	0,0198
1132	1133	0,0745	0,0574	1157	1171	0,0729	0,0198
1133	1134	0,0745	0,0574	1159	1172	0,0729	0,0198
1129	1135	0,0542	0,0147	1161	1173	0,0729	0,0198
1131	1136	0,0542	0,0147	1163	1174	0,0729	0,0198
1132	1137	0,0542	0,0147	1164	1175	0,0729	0,0198
1134	1138	0,0542	0,0147	1166	1176	0,0729	0,0198
1102	1139	0,0917	0,0706	1168	1177	0,0729	0,0198