Novel Decentralized Operation Schemes for Smart Distribution Systems

by

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AUTHOR'S DECLARATION

I hereby declare that I am the sole author of this thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

I understand that my thesis may be made electronically available to the public.

Abstract

Recently, there have been many initiatives to incorporate advanced controls, two way communications, digital technologies and advanced power system components in the operation and control of power distribution systems. These initiatives are aiming to realize what becomes known as the “Smart grid”. It is expected that a Smart Grid will lead to enhancement in the reliability and efficiency of the power system. The movement towards the Smart Grid is motivated by many factors; the need to integrate more renewable power to mitigate the global warming, the increasing interest in connecting more distributed generation (DG) as a way to postpone large investment in transmission and bulk generation, and the need to increase the reliability of the power system overall to minimize disturbance costs.

It is the overall goal of this research to introduce novel distribution system operation techniques to assist in the effort of realizing the “Smart Distribution System” in both normal and system restoration modes. In particular, three main operation functions are dealt with in this research work; Voltage Control, Reactive Power Control and Distribution System Restoration.

First for Voltage Control, a reliable and efficient method is proposed to control voltage regulators in order to enable the regulation of multiple feeders with diversified loads using only one regulator provided that no DG is connected to the feeders. Regulator’s tap is selected based on the solution of an integer linear optimization problem. The method has a closed form solution for the optimal tap; that is valuable for real time operation. In addition, necessary condition for feasible solutions is examined.

Next, a novel coordinated voltage control scheme is proposed to enable the voltage regulator to efficiently regulate the voltage of multiple feeders in the presence of DGs. The proposed technique is based on placing a Remote Terminal Unit (RTUs) at each DG and each line capacitor. These RTUs coordinate together, through communication, and form a multi-agent system. An important contribution of this research is that the proposed scheme

provides the minimum hardware requirement to efficiently estimate the voltage profile of a feeder with DGs. The proposed scheme enables the integration of more DGs into the system by, efficiently, coordinating the operation of voltage regulators and DGs to mitigate voltage rise problem caused by the connection of DGs to the system.

Second, for Reactive Power Control, a decentralized reactive power control scheme is proposed to optimally control switched shunt capacitors of the system in order to minimize system losses and maintain acceptable voltage profile. The proposed algorithm provides capacitors with “Advanced Voltage Sensing” capability to enable capacitors to switch in and out according to the global minimum and maximum voltage of the feeder. The proposed technique utilizes the same RTU used for voltage control and relies on the voltage profile estimation technique proposed in this research for the coordinated voltage control. In addition, novel decentralized algorithm is proposed to estimate the feeder voltage profile change as a result of injecting reactive power at the capacitor bus. The proposed reactive power control scheme can be used to coordinate the operation of any number of capacitors connected to the distribution system.

Combining voltage control and reactive power control schemes, generalized coordinated voltage control is proposed to coordinate between DGs, shunt capacitors and voltage regulators in order to achieve optimal voltage control for the distribution system and solve the steady state voltage rise problem caused by the connection of DGs, hence, allowing more DGs to be connected to the system.

Over and above, the proposed generalized coordinated voltage control enables the realization of a new *operation-time* DG connection impact assessment concept. Based on this concept, the system will carry out a real-time assessment and decide, based on the available control actions, the maximum DG power that can be allowed to connect to the system at particular operating conditions. This new concept will allow great flexibility to the connection of DGs, most notably, when, due to a change in system configuration, the DG is needed to be connected to a feeder other than the one it was planned for during the planning stage.

The last operation function dealt with in this research work is the distribution system restoration. Novel decentralized distribution system restoration scheme is proposed. The proposed scheme is based on dividing the distribution system into zones based on the availability of disconnecting switches. Each zone is controlled by an Agent. The restoration is done based on the coordination between these Agents. Proposed communication protocols between Agents are discussed in details. The goal of the proposed restoration scheme is to maximize the restored power while preserving the radial structure of the distribution system and without exceeding the thermal limit of any equipment in the system. As the proposed technique does not assume any supervision from any central point, this technique will enable the realization of a self-healing distribution system restoration.

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Dedication

To my beloved parents, my dear wife and my little daughter.

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Nomenclature

V_{reg} : regulator output voltage.

V_{ref}^{n} : reference voltage of the regulating point of feeder n.

K_n : K-factor of feeder n (pu VD/ kva.mi)

l_n : loading factor of feeder n (l = 0 means no load, l = 1 means rated load)

S_n : rated load of feeder n.

L_n : length between the regulator and the regulating point of feeder n.

N : The number of feeders.

$V_{\min}^{n}$: : minimum allowed voltage for feeder *n*

$V_{\max}^{n}$: : maximum allowed voltage for feeder *n*

$V_{regulating-\mathrm{point}}^{n}$: voltage of the regulating point of feeder *n*.

V_{input} : input voltage for the regulator. (pu)

V_{tap} : voltage corresponding to one tap step. (pu)

T : Tap position (Integer number between T_{max} and T_{min}).

T_{min} : minimum tap position that not violate the voltage regulator bus range.

T_{max} : maximum tap position that not violate the voltage regulator bus range.

V_{reg}^{min} : minimum allowable voltage of regulator bus.

V_{reg}^{max} : maximum allowable voltage of regulator bus.

$V_{max,n+1}$: value of feeder's maximum voltage received from downstream RTU_{n+1}.

min_flag : a flag indicating whether the condition for minimum voltage point was satisfied by the downstream RTU_{n+1}.

$V_{min,n+1}$: value of feeder's minimum voltage received from downstream RTU_{n+1}.

$V_{est,n+1}$: the estimate value calculated by RTU_{n+1} for the minimum voltage point in between RTU_{n+1} and RTU_n.

V_n : the voltage of the bus at which RTU_n is connected.

$P_{n,n+1}$: the active power flow from RTU_n bus to RTU_{n+1} bus.

$Q_{n,n+1}$: the reactive power flow from RTU_n bus to RTU_{n+1} bus.

$V_{neightbor,n+1}$: the voltage of the immediate neighbor bus of RTU_n in direction of RTU_{n+1}.

$V_{est,n,n+1}$: the estimation of the minimum voltage between RTU_n and RTU_{n+1} calculated by RTU_n.

$V_{min,n}$: the value of the minimum voltage for the feeder calculated by RTU_n.

$V_{neightbor,n-1}$: the voltage of the immediate neighbor bus of RTU_n in direction of RTU_{n-1}.

$V_{est,n,n-1}$: the estimation of the minimum voltage between RTU_n and RTU_{n-1} calculated by RTU_n.

$V_{max,feeder}$: the maximum voltage of a feeder.

$V_{min,feeder}$: the minimum voltage of a feeder.

$V_{max,feeder,Q}$: the maximum voltage of a feeder if reactive power injected from the capacitor is Q_c.

$V_{min,feeder,Qc}$: the minimum voltage of a feeder if reactive power injected from the capacitor is Q_c.

$max(V_{max,feeder})$: the absolute maximum voltage of all feeders.

$min(V_{min,feeder})$: the absolute minimum voltage of all feeders.

$V_{max,perm}$: the permissible maximum voltage of the system.

$V_{min,perm}$: the permissible minimum voltage of the system.

$V_{(n)old}$: the voltage of bus *n* prior to the connection of the capacitor.

$V_{(n)new}$: the voltage of bus *n* after connecting the capacitor.

$V_{n,Qc}$: the voltage of bus *n* if reactive power injected from the capacitor is Q_c.

$X_{n-1,n}$: the reactance of the line segment between bus *n-1* and bus *n*.

$R_{n-1,n}$: the resistance of the line segment between bus *n-1* and bus *n*.

$Q_{(n-1,n)old}$: the reactive power flow from bus *n-1* to bus *n* prior to the connection of the capacitor.

Q_C : the reactive power injected by the capacitor.

Q_{levels} : list of the reactive powers a capacitor can inject.

$P_{(n-1,n)old}$: the active power flow from bus *n-1* to bus *n* prior to the connection of the capacitor.

Losses-index$_{Qc}$: the losses index corresponding to a reactive power injection at the capacitor bus equals Q_c.

TotalLosses$_{Qc}$: the total estimated losses of a feeder if reactive power injected from the capacitor is Q_c.

ΔP_G : Extra active power that the DG request to inject.

$\Delta P_{G,max,perm}$: Extra active power that the system permits the DG to inject.

$V_{min,estimated,upstream}$: the value estimated by a certain RTU for the minimum voltage point between itself and its upstream RTU.

$V_{min,downstream}$: the value of the minimum voltage point downstream of a certain RTU.

$V_{min,estimated,Qc}$: the value of the minimum voltage point downstream of a certain RTU if reactive power injected from the capacitor is Q_c.

$V_{neighbour,upstream}$: the voltage of the immediate point upstream of certain RTU.

$V_{neighbour,downstream}$: the voltage of the immediate point downstream of certain RTU.

Zone : a part of the distribution feeder bounded by one or more disconnecting switches.

Zone's Agent (Agent) : the Agent which control the respective zone.

$P_{demand,n}$: demand power, or load, of bus (zone) n.

$P_{supply,n}$: supply power available at bus (zone) n.

$P_{excess,n}$: extra power available at bus (zone) n which will be sent to other zones.

Agent's Neighbours : the set of Agents which are connected to a certain Agent by direct communication links.

Isolated Agent : an Agent which has lost power.

Isolated neighbour Agent : a neighbour Agent which has lost power.

Supply neighbour : a neighbour Agent which is still having power after the clearance of the fault.

Still-connected neighbour : same as Supply neighbour.

Distribution Station Agent : the Agent which controls the distribution station.

Leaf Agent : an isolated Agent which has only one isolated neighbor.

Middle Agent : an isolated Agent which has more than one isolated neighbors.

Upstream Agent : the Agent which controls the zone upstream of a certain Agent's zone.

Chapter 1

Introduction

1.1 General

Recently, power network is undergoing a complete reconstruction. Motivated by different factors; technical, economical and environmental, this reconstruction will lead to the creation of a “Smart Grid”. Among others, Smart Grid will be more reliable and will allow the integration of Distributed Generation more efficiently. Automation represents one of the main areas of development in order to realize the Smart Grid. It is crucial to invent new automation techniques to provide more flexibility to the operation of the power system. Depending on advanced controls and suitable communication infrastructure, optimal operation of the system can be achieved.

1.2 Research Motivations

In operating the power system of today, electric utilities faces unprecedented challenges. The first challenge is the need to have a highly reliable system without having to invest a lot in large infrastructures. Truth told, the dependency of modern society on electricity is profound and hence the cost of losing electricity is huge, for instance, the northeast blackout of 2003 had a total cost of about $6 billion [1]. As a result, it is of utmost importance for the welfare of the society to have a very reliable electric system. Unfortunately, for the last decades the electric system has not been suitably upgraded to cope with its increasing importance.

A second challenge that faces the operation of the electric system is the widespread introduction of Distributed Generation (DG). While Distributed Generation provides many benefits to the power system, they come with their own technical challenges. Concerning distribution systems, where the level of automation is minimal compared to other parts of the power system, DG challenges the basic design philosophy of the distribution system by introducing active power sources and introducing bidirectional power flow in the distribution system. In addition, renewable-based DGs, e.g. wind and solar DGs, have variable output power and hence the distribution system has to deal with fluctuations of the injected power and, as a result, fluctuations of the voltage profile. Presently, given the low level of automation and control capabilities of the distribution system, strict requirements are being applied when assessing the connection of new DGs. On one hand, these requirements assure utilities that system constraints will not be violated at any time, e.g. voltage levels of the system, short circuit levels and power reverse power flow levels. But on the other hand, these strict requirements prevent the integration of more DG power into the system or, at least, necessitate expensive upgrades to the system in order to allow the connection of the DG.

In reality, to address these challenges, it has become clear more than ever that the adoption of advanced distribution system automation techniques is vital. It is the goal of this research work to introduce advanced distribution system operation techniques to address these challenges by enhancing the reliability of the system and efficiently integrating DGs into the system.

1.3 Research Objectives

This research study, motivated by facing the current system operation challenges, focuses on developing advanced distribution system operation techniques. The set of objectives of this research are;

1- Development of an efficient voltage control for multiple feeders using one regulator.
2- Development of a coordinated voltage control methodology to deal with the voltage control of feeders with DGs.
3- Development of optimal real-time reactive power control scheme for shunt capacitors considering the effect of DGs.
4- Integration of the developed voltage control and reactive power control schemes to achieve a generalized coordinated voltage control for feeders with regulator, capacitors and DGs.
5- Development of operation-time DG connection impact assessment methodology to provide more flexibility to the connection of DGs.
6- Development of an efficient decentralized distribution system restoration technique in order to automate the restoration process and hence increase the reliability of the system.

1.4 Thesis Outline

This thesis is organized as follows;

Chapter 2 provides required background information about three main topics relevant to the subject of this research; Smart Grid, Distributed Generation and Distributed processing.

Chapter 3 is concerned with the concept of Distribution Automation and Advanced Distribution Automation. In addition, in this chapter literature survey for the three main distribution operation functions dealt with in this research, voltage control, reactive power control and system restoration, will be presented to highlight the shortcomings of the current operation techniques.

Chapter 4 presents the problem of optimal voltage control of multiple feeders using one regulator. Efficient voltage control algorithm is proposed in this chapter to tackle the problem. During this chapter it will be assumed that no DG is present in the system.

Chapter 5 deals with the general case of optimal voltage control of multiple feeders using one regulator in the presence of DGs. In this chapter novel voltage profile estimation technique will be presented and it will be used throughout the thesis.

Chapter 6 presents an optimal reactive power control technique to control the reactive power injections of shunt capacitors taking into account the effect of DGs of the system.

Chapter 7 combines the results of Chapters 5 and 6 to propose a generalized voltage control technique by coordinating the operation of voltage regulators, shunt capacitors and DGs.

Chapter 8 presents the new concept of operation-time DG connection impact assessment to provide flexibility to the connection of DGs to the distribution system.

Chapter 9 presents the proposed decentralized distribution system restoration scheme. Hardware requirements and communication protocols are described in details in that chapter.

Chapter 10 provides thesis summary, contributions and future research directions.

Chapter 2

Smart Grid, Distributed Generation and Distributed Processing

2.1 Introduction

This Chapter provides a background information about three main topics; Smart Grid, Distributed Generation and Distributed Processing. These three topics are closely related; the overall goal of this research work is the realization of the Smart Grid in order to facilitate, among others, the connection of Distributed Generation utilizing the power of distributed processing.

The flow of the chapter starts off by introducing the concept of smart Grid. Definition, characteristics, benefits, and challenges facing the development of the Smart Grid are discussed in details. One of the main goals of the development of the Smart Grid is to enhance the integration of Distributed Generation (DG). In section 2.3 we will review the basic concepts of DGs including the most popular DG technologies and the main technical challenges that face the integration of DGs in the distribution system. An important *tool* that is believed to be crucial in the development of the Smart Grid is distributed processing. Distributed processing is reviewed in section 2.4 along with its advantages and disadvantages. Multi-Agent systems, as a special formulation of distributed processing, is discussed in section 2.5 followed by presenting a survey for the applications of Multi-agent system in power systems. Chapter’s conclusions are drawn in section 2.6.

2.2 Smart Grid

The term Smart Grid has been, lately, used by the governmental agencies, industry and research institutes to refer to a new trend in the energy sector to upgrade the power network in order to tackle the new challenges that face the operation of the current network. In this section we will discuss the definition, the characteristics, the benefits of the smart grid and the challenges facing the development of the smart grid.

2.2.1 Definition

There is currently no consensus on a global definition of the Smart Grid. However, it is usually defined by its characteristics and benefits. For example, the Energy Independence and Security Act of 2007 [1], described the "Smart Grid" as: the modernization of the electricity delivery system so that it can result in increased reliability, security, efficiency, grid operation optimization, integration of distributed generation and storage options, incorporation of demand response techniques, allowing for the active participation of customers and deployment of "smart" technologies for metering, communication and distribution automation. Fig (2.1) shows the results of a survey carried out by the Electric Power Research Institute (EPRI) for the terms that mostly used to define the Smart Grid for different utilities [2]. It is worthy to note from Fig (2.1) that the terms that are mostly associated with the Smart Grid are; the utilization of emerging/intelligent devices, Efficiency, Reliability and Power Quality, Improved Communications, Customer Experience/Involvement, and Sustainable/Renewable Energy.

2.2.2 Characteristics of the Smart Grid

One of the main characteristics of the Smart Grid is the self-healing capabilities. Self-healing describes the automatic response of the grid to any disturbance or unwanted operation conditions. An example of the self-healing is, a wind generator increases its injected power

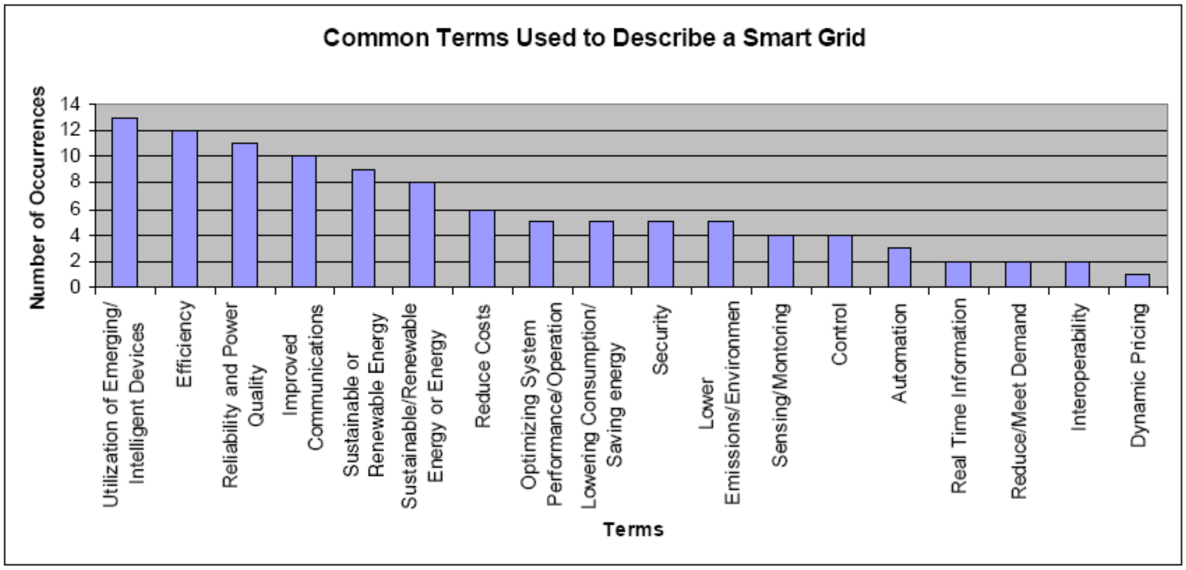


Figure (2.1) Common terms used to define the Smart Grid [2]

so the voltage profile of the system is disturbed, the grid should detect that condition and take appropriate remedy to restore acceptable voltage profile; may be by operating the tap of a voltage regulator in a certain way.

Another characteristic of the Smart Grid is the two way power and communication flow. In traditional networks power usually flow in one direction; from the bulk generators to the consumers. In a Smart Grid, the power flows in two directions; from bulk generation to the consumers and from customer generation to bulk power system. In other words, the Smart Grid allows the integration of more distributed generation in an efficient manner. Along with the two way power flow; there is a two-way information flow through a robust communication structure that allows for the monitoring and the control of grid equipment. Moreover, the communication system will allow for the active participation of the consumers by introducing load side management techniques and time-of-use electricity prices utilizing smart meter.

One last, but not the least, characteristic of the Smart Grid is the ability to optimize the assets. In fact, having a large amount of information about the status of the overall system and about each specific component, the Smart Grid will be able to apply innovative asset management techniques in order to allow its assets to operate longer with less human interaction.

2.2.3 Benefits of the Smart Grid

There are many benefits of adopting the smart Grid. In [3], five main categories have been identified; enhancing power reliability and power quality, safety and cyber security benefits, energy efficiency benefits, environmental and conservation benefits, and direct financial benefits. For example, for the environmental benefits, it has been reported in [4] and [5] that the adoption of the Smart Grid could result in a CO2 reduction that ranges from 5% to 18%.

2.2.4 Challenges facing the development of the Smart Grid

The development of the Smart Grid faces many challenges. These challenges have been categorized in [3] as Procedural and Technical challenges. From the procedural point of view, the challenges range from the complexity of the Smart Grid to the need for a consensus on the Smart Grid Standards passing by managing the transition to the Smart Grid. As a matter of fact, due to the complexity and the scale of the power system, the development of the Smart Grid has to be gradual, considering the vitality of the power system; the change has to be planned and coordinated not to affect the operation of the existing system.

Some of the technical challenges are the need to introduce new “smart” equipment, like the Remote Terminal Units (RTU) and the Intelligent Electronic Devices (IED) or equip the currently used equipment with intelligent capabilities. In addition, there is a need for innovative algorithms and operation schemes to coordinate and control the operation of various power systems' equipment in order to achieve the self-healing characteristic of the Smart Grid.

2.3 Distributed Generation (DG)

2.3.1 Introduction

One of the main characteristics and goals of the Smart Grid is the integration of more distributed generation. For the last 15 years, distributed generation has been the most attractive subject for research in power systems. In [6], distributed generation has been defined as, "an electric power generation source connected directly to the distribution network or on the customer side of the meter". Many factors led to the increasing interest in connecting more DGs; firstly, there has been a steady growth in electricity demand while the growth in building new assets, such as bulk generation and transmission lines, faces many difficulties, mainly economical. In addition, DG units are always located closer to load center, hence transmission and distribution losses are reduced. Moreover, the investment risk in DG is not high because project's time is usually small compared with bulk generation projects beside that the total cost is relatively low and the expected efficiency is typically high.

Another factor is that there is a growing concern about the climate change. The emerging need is for integration of more renewable energy sources in the power system that introduced specific technical challenges. Renewable energy sources, such as wind and solar, are usually characterized by small or medium sizes which are more suitable to be connected to the distribution system. Lastly, it is evident that new innovations in DG technologies led to the increasing interest in DGs; in the past 10 years, there has been a rapid development in several DG technologies, most notably the solar generation, which led to significant increase in its efficiency while reducing its cost.

2.3.2 DG technologies

In this section we will review briefly the most popular DG technologies.

A. Wind Turbine:

Wind energy is considered one of the most important renewable type generations. Although, historically, it is not new to the power system, the recent development in its technologies made it an attractive option for DG investors. Typically, wind turbine ratings vary from 0.3 kW to 5 MW [7]. Sometimes Wind turbines are gathered in the form of Wind farms. Wind farms usually exist in windy areas, or even offshore. Wind farm size of as high as 640 MW has been reported in the literature [8]. The main challenge that faces the integration of Wind energy into the power system is the fact that the output power of the wind turbine varies with the wind speed.

B. Photovoltaic Systems (PV systems):

Beside the Wind generation, PV systems represent another very important renewable power source. Generating its energy from the sunlight, photovoltaic systems represent one of the cleanest energies on earth. On the other hand, Photovoltaic systems are considered one of the most expensive DG technologies [9]. The high cost of photovoltaic system is attributed to; first, the low efficiency and inherent high cost of PV material and also the need to have a vast land space to install the PV arrays. Second, PV arrays works during the daytime and shut off during night which limits the amount of energy generated. Third, the output power of PV arrays is DC, hence, there is a need for a power conditioning unit in order to interface the PV with the grid; a factor that will adds to the total cost.

Small scale roof-top Photovoltaic systems, less than 10 kW, are becoming more and more popular in distribution systems. Photovoltaic systems face the same varying output power challenge that faces the wind generation.

C. Small Hydro Power Generators:

Small-Hydro, or micro-hydro, generators are essentially a small size version of the traditional hydro-electric power generators. This type of generation represents one of the most attractive DG options. From one hand, small-hydro generation is fully controllable in terms of its output power. Moreover, this type of generation is clean, renewable and among the cheapest energy sources.

D. Other DG technologies:

Other DG technologies include; Micro-turbines, Fuel cell, biomass, geothermal, tidal and Ocean thermal power. Each of these technologies has its own advantages and disadvantages [10]. Nevertheless, research is ongoing on all of these technologies with the aim to obtain higher efficiencies at lower costs.

2.3.3 Technical challenges faces the integration of DG

The root of all technical problems that faces the integration of DGs in distribution systems is that the distribution system has traditionally been designed as a one-direction passive system, i.e. the power flows from the transmission station towards the loads. The introduction of DG has changed the design philosophy of the distribution system. As a result, several technical problems face the integration of DG in the distribution system. The first of these challenges is the steady state voltage rise [11]. As will be shown in Chapter 5, connecting a DG on a distribution feeder raises the voltage of the feeder, hence, put a burden on the voltage regulating devices in the system especially for intermittent DGs, i.e. wind and solar. The second challenge is the complexity of the protection system in the presence of DGs. In fact, the connection of DG increases the short circuit fault current and disturbs protection coordination [12], [13]. Another problem is that the connection of DG can affect the power quality of the distribution system; the frequent start and stop operation and frequent variation of power output can result in voltage flicker problem [13]. Reverse power flow caused by the connection of DG remains a problem to be solved. Distribution system equipment and metering need to be upgraded in order to be compatible with reverse power flow.

One of the main goals of the development of the Smart Grids is to overcome these technical challenges in order to facilitate the integration of DG in distribution systems.

2.4 Distributed Processing

According to [14], to implement the concept of Smart Grid there will be a need to have a processor associated with each component of the power system. Each processor will be connected with sensors associated with its component in order to monitor the operating conditions of that component. These processors will communicate and cooperate together in order to form a large distributed processing platform in which the power system operation functions are to be carried out. Actually, distributing processors throughout the power network represents, although roughly speaking, distributing the intelligence through the network. In this section will be discuss briefly the basic concepts of distributed processing.

2.4.1 Parallel and Distributed Processing

Technically, parallel processing is different from distributed processing. On one hand, parallel processing is mainly concerned with systems where processing units are arranged in a small physical space that can mean a parallel machine, a machine with several processors, or it can mean processing units connected by a small computer network. Due to the tightly coupled processors, the communication of data between processors is very reliable and communication delays between processors are, usually, negligible or at least predictable. On the other hand, distributed processing describes systems where processing units are distributed along a large, or even very large, physical space. Communication delays represent an important issue in the distributed processing case.

In light of the above difference, parallel processing is a sort of “centralized” processing in the sense that all the data required for the computation is needed to be transmitted to a certain place no matter this place is one machine or even a small computer network.

2.4.2 Message passing paradigm

In distributed systems, where processing units are distributed over a large physical area, there is no shared memory available for all of processing units. In such situation coordination between processors is done using communication. Essentially, this communication is done using message-passing among processors. In message-passing based distributed systems, the programmer has to decide when and what to send from one processor to another based on the task which is programmed.

There are different types for message passing-based communication [15]. Synchronous message-passing describe the case where some sort of hand-shaking is to be done between sender and receiver processors. On contrary, asynchronous message-passing takes place when the sender processor will send the message and resume the execution of its own algorithm without waiting for an acknowledgment from the receiving processor.

2.4.3 Distributed algorithms

Distributed algorithms are those kinds of algorithms designed for execution in distributed systems. A distributed algorithm is designed to be executed on different processors simultaneously. The heart of distributed algorithms is the coordination between the processors in order to achieve the global goal of the algorithm. Usually, distributed algorithm is attributed with the following characteristics [16], [17];

1- No processor is assumed to have the complete information about the whole system.
2- Processors make their decisions based on local information only.
3- Failure to one processor should not ruin the system.

Based on the used clock in the distributed algorithm, there are two types of distributed algorithms; synchronous and asynchronous algorithms. Synchronous algorithms describe the case when all distributed processors use one global clock. However, asynchronous algorithms are designed for the case when each processor has its local independent clock. Although asynchronous algorithms are, generally, more difficult to design, they are more immune against communication delays than their synchronous counterpart.

2.4.4 Advantages and disadvantages of distributed processing

The basic advantage of distributed systems over centralized systems is the performance/cost ratio. Using many inexpensive machines can result in a better performance/cost ratio than using one expensive super-machine. Even more, a distributed system can achieve a performance that no single machine can ever achieve [16]. Distributed systems can be especially advantageous when applied to systems which are inherently distributed, power system for example. Another advantage of distributed systems is the enhanced reliability. In distributed systems if one machine fails the whole system should be able to survive, with less performance of course, comparing with centralized systems where, if the only machine fails, the whole system will be dawn. One last advantage for the distributed systems is the ability of incremental expansion; in distributed systems the power of the system can be increased by adding more machines to the system, the added machine will take a part of the work so it needs not to be large or expensive. On the other side, if the central machine in a centralized system is needed to be expanded, then it must be replaced by a larger machine.

On the other hand, distributed systems have some disadvantages. First, coordination between distributed machines requires a lot of communication; hence communication network between distributed machines is a critical part in distributed processing. Also security of data in distributed systems is often a problem[16]. In distributed systems data can be shared easily between machines, therefore the security of the data must be considered in design and implementation of the distributed systems. Despite these disadvantages, it is believed that advantages of distributed systems overweight its disadvantages and that distributed systems will gain more potential in the coming years [16].

A particular important formulation of the distributed processing is the Multi-Agent System which is presented in the next section.

2.5 Multi-agent Systems

2.5.1 Overview

An agent can be considered as anything that can perceive its environment through sensors and acts upon that environment through actuators [18] . The term autonomous is usually used to refer to an agent whose decision making relies to a larger extent on its own perception than on prior knowledge given to it at design time [18]. There is a little interest in the existence of an isolated agent as in such case it will be a traditional controller. However, usually, several agents exist together and work in cooperative and coordinated fashion. A system that consists of such agents is called a Multi-agent System (MAS). The branch of artificial intelligence that deal with the analysis and design of MAS is called distributed artificial intelligence.

The design of each agent in a MAS can be divided into three main parts; perception, processing and communication. Perception deals with how the agent will collect information about its environment. Processing define the way in which the agent will process the collected data. In MAS systems some sort of decentralized control is used to allow the whole system of agents to achieve their objective. Usually, design of decentralized control scheme and allocation of tasks among agents represent the most challenging part in MAS design. Finally, communication represents an essential part in MAS design. Basically, each agent has only local information about the whole problem so communicating with others is an inevitable task to achieve the global goal of MAS.

2.5.2 MAS application in power systems

Recently, there has been a considerable interest in investigating the applications of MAS in power systems. A two part paper, [19, 20], introduced by the IEEE Power Engineering Society's Multi-Agent Systems (MAS) Working Group, examined the potential of the MAS technology for the power industry. Many researches were reported using MAS techniques in different areas of the power system engineering. Such areas are; Reactive power control, Marketing, Protection, System monitoring and power system restoration. In this section, the application of MAS in each area is reviewed.

In[21], the authors suggested a MAS to control the reactive power dispatching of the DG units installed on the feeder. Each DG unit has an agent which monitors the voltage and communicates with other agents to set the reactive output power of the DG unit in order to satisfy the voltage constraints of the whole feeder. MAS techniques are also used in the monitoring of the power system. In [22] and[23], MAS is used for the real time monitoring and analysis of the SCADA system data specially the post fault data. The paper divides the solution between different agents each responsible for certain function. Similar to [22, 23], [24, 25] have proposed the use of MAS for condition monitoring of power transformers and [25] discusses the use of MAS for distribution substation automation.

Protection of power system is another field which has seen applications of MAS. The concept of "Relay Agent" was introduced in [26] to facilitate the coordination between different power system parts to achieve adaptive protection function. Different types of agents were defined; equipment agent, mobile agent, protector agent and reorganizer agent. In [27], a protection scheme based on the MAS was proposed. The scheme was based on a structure of three types of agents; Agent Expert, Agent Communication and Agent interactive. The paper discusses, descriptively, the operation of the system. However, the design of the system for general network is not clear. Ref. [28] also describes a MAS structure for the coordination of the distribution network protection system in the presence of distributed generation units. In another work, [29], the authors combines MAS basic ideas with the supervisory control techniques of Discrete Events Systems (DES). The paper has a detailed discussion for the design of the supervisors. However, the method becomes very complicated for large power systems as already mentioned in the paper. In [30], the coordination between the protection devices and the determination of the protection zones are calculated by an expert system based on a graph theory representation of the network. MAS are used to provide coordination between the relays, which are treated as "Relay Agent", in order to detect, locate and trip fault. This paper introduces useful ideas in the adaptive determination of the protection zones of the network.

Based on the success of the MAS in solving economics problems, MAS techniques have been used in the marketing of the power system. In a two parts paper [31, 32], the authors presents an approach for designing MAS to perform negotiations in the electricity power market. In [33], the authors presents a MAS for the coalition formation in multilateral trades. In [34], the authors discuss the implementation of an agent-based model for testing the economic reliability of the Wholesale Power Market Platform (WPMP). In [35], MAS are used in the allocation of the costs of the transmission system to its users. A decentralized approach for the optimal cross-border electricity planning is proposed in [36]. A MAS modeling of the electricity trading arrangement of England and Wales has been presented in [37]. In [38], an autonomous adaptive agent scheme is presented for the generation markets. Modeling the real-world market based on a MAS is discussed in [39]. The authors of [40] have discussed an agent-based approach to deal with the complexity of the US wholesale power market. Motivated by the anticipated importance of the micro-grid concepts, the authors of [41] have proposed a MAS system to control the market of the micro-grid.

2.6 Conclusions

This chapter provided background information about Smart Grid, Distributed generation and distributed processing. Efficient integration of distributed generation is one of the main goals of the development of the Smart Grid, while, distributed processing is one of the main tools for the realization of the Smart Grid. The benefits and challenges facing the development of the Smart Grid were discussed. Distributed generation technologies were reviewed along with the technical negative impacts DGs have on the distribution system. In addition, the basic concepts of distributed processing were presented and the Multi-Agent system was discussed briefly. Moreover, a literature review was carried out to show the applications of Multi-Agent systems in solving power system problems.

Chapter 3

Advanced Distribution Automation

3.1 Introduction

In [42], Advanced Distribution Automation (ADA) is described as the "Heart of the Smart Power Delivery System". Generally speaking, ADA is a concept that will make the distribution system fully controllable and flexible. In this Chapter we will review the concepts of Distribution Automation and Advanced Distribution Automation. In addition, a literature survey for the main distribution automation functions is presented in this Chapter. Specifically, we will review the literature of Voltage control, Reactive power control and Distribution system restoration functions of the distribution automation.

This Chapter is organized as follows; Basics of Distribution Automation are reviewed in section 3.2. Advanced distribution automation is introduced in section 3.3. Literature surveys for Voltage Control, Reactive Power Control and Distribution System Restoration are presented in sections 3.4, 3.5 and 3.6 respectively. Conclusions are drawn in section 3.7.

3.2 Distribution Automation (DA)

The IEEE definition of the DA is [43], "It is a system that enables an electric utility to remotely monitor, coordinate, and operate distribution components in real-time mode from remote locations". DA consists of certain control functions which are executed from a control center in a remote fashion. These functions include [44]; load management, Peak load pricing, network reconfiguration, voltage regulation, transformer load management, feeder load management, capacitor control, distributed generation control, fault detection, location and isolation, system monitoring, automatic customer meter reading and remote service connect and disconnect. To perform these functions, advanced control strategies and communication systems are usually required. Currently, DA works in a centralized fashion. In other words, a control center is required to read all the data of the system and to carry out the remote monitoring and control actions. Processing all the data at a central place represents a bottleneck in the operation of the DA because of the huge amount of information that needs to be processed. With the increase in distribution network sophistication and the advances in communication and information systems, the concept of Advanced Distribution Automation was proposed to enable a reliable and efficient distribution system.

3.3 Advanced Distribution Automation (ADA)

The ADA concept was proposed as a scheme to achieve a fully controllable and flexible distribution system [42]. In ADA all controllable equipment and control functions are to be automated to achieve the optimal operation of the system. Incorporating advanced control strategies, new technologies and communication schemes, ADA will result in higher reliability, minimal losses, optimization of the distribution system assets and integration of larger amounts of renewable energy into the existing distribution systems [45].

In order to achieve the ADA concept, it is essential for many distribution system equipment to become "intelligent". These devices will range from power quality management devices and monitoring devices to voltage and Var control equipment. Hence, the ADA concept, in part of it, will evolve as a large distributed intelligence platform in which the distribution system operation functions will be achieved. As a result, the operation of the distribution system will be carried out in a distributed manner by coordination and communication between distribution system devices.

Five areas of development were identified in order to realize the ADA [46], [47];

- Electronic/electrical technology development for the distribution system of the future.
- Sensor/monitoring/data processing systems for ADA.
- Communication systems and standards for ADA.
- Advanced distribution control systems.
- New distribution system configurations and reconfiguring capabilities.

It is the goal of this research work to propose innovative advanced distribution control systems applicable in the setting of advanced distribution automation. Among distribution automation functions, we are concentrated on Voltage control, Reactive Power control and Distribution System Restoration. The next three sections present a literature survey for these functions in order to investigate the current state of development in each of these fields. We will start by Voltage control, and then move to Reactive Power Control and finally Distribution System Restoration.

3.4 Distribution System Voltage Control

Maintaining satisfactory voltage levels for the customers is one of the main tasks of electric utilities. In distribution systems several equipment controls the voltage. The most important voltage controls are voltage regulators and shunt capacitors. Considerable research work was conducted to address the voltage control problem along distribution feeders. The operation of the voltage regulator with the line drop compensator (LDC) is already well established [44]. Research concerning voltage regulators concentrates on determining the optimal locations and optimal tap setting of voltage regulators in order to improve the voltage profile and minimize the losses [48], [49].

The problem of having one voltage regulator for multiple feeders has been addressed in [50]. The problem was formulated as an optimization problem to solve for the optimal tap setting. However, the method requires the knowledge of the active and reactive power at each node in every feeder for the computation. This assumption is not practical from several prospective; first, to assume that all the loads at all nodes are monitored by a central computer is not practical. Second, even if these data is available, it is not realistic to assume that it is accessible for the voltage regulator. Also, the method in [50] requires a load flow solution at every time the tap setting changes which represents a large computational burden.

The introduction of DGs has complicated the voltage control of distribution systems. Among others, steady state voltage rise problem has been identified as one of the most crucial technical difficulties that face the integration of DG into distribution system [51].

Several solutions were proposed to tackle the steady state voltage rise problem. Two main approaches can be observed in literature. In the first approach the DG is used in the voltage control process by controlling the reactive power injection, or absorption, of the DGs utilizing the control capabilities of the interfacing power electronics equipment [52],[21] ,[53],[54],[55]. This approach has two main disadvantages; first, current operation policies in most utilities require the DG to operate at a fixed power factor especially for renewable based DGs. Even more, as the rating of the DG is fixed; injecting reactive power necessitates a reduction in the active power injection hence a reduction in the net revenue of the DG. Therefore, this is an expensive approach and can only be justified if the voltage cannot be regulated using voltage control devices such as voltage regulators.

In the second voltage control approach, only voltage control devices such as voltage regulators are used to regulate the system voltage. The challenge in this approach is how to modify the conventional operation of the voltage control devices to accommodate the presence of DGs.

When a DG is installed on a certain feeder, the Line Drop Compensators (LDC), conventionally used for voltage regulation, will not function properly, because LDC estimates the voltage drop at the remote point based on the local measurements at the voltage regulator without considering any power injection from any point on the feeder.

To enable the voltage regulator to function properly when DG is installed, coordinated voltage control schemes, or sometimes called active management schemes, were proposed in literature. The basic concept behind coordinated voltage control is to coordinate the operation of the voltage regulator and the DG.

Forming the voltage control problem as a centralized optimization problem was proposed in [56]. This method formulates an optimization problem to solve for the optimal tap setting along with the optimal DG outputs over a certain horizon of time. Such a technique cannot be implemented in real-time, as it is not possible to read the information of all the nodes of the distribution system.

In [57], a modification for the conventional voltage regulator control was proposed to allow the voltage regulator controller to take into account the effect of DG. The basic idea was to estimate the output of the remote DG based on local measurements at the voltage regulator site. In such a scheme there is no need for RTU unit or communication links between the DG and the voltage regulator. However, this scheme cannot deal with multiple DG units on the same feeder. Also, the error in the estimation of the DG output can be significant based on the load characteristics of the network [57]. Moreover, in that scheme the focus is on regulating the voltage of the DG connecting point only. However, even if there is a DG installed on a certain feeder, there is a possibility of the existence of a low voltage point at other node on the feeder. So, in general, it is not enough to regulate the DG connecting point only.

In [58] the authors used a state estimation technique to estimate the highest and lowest voltages of the feeder and to operate the voltage regulator according to that. The main advantage of this method is that only few measurements are needed for the state estimation. However, the method itself is complicated and load models have to be built based on load profiles in order for the estimation to be accurate.

3.5 Distribution System Reactive Power Control

For decades reactive power control, or Var control, has been identified as one of the crucial operation functions of the distribution system. Efficient Var control reduces system losses, improves voltage profile and hence enhances the delivered power quality and overall system reliability.

As a matter of fact, the increasing penetration of distributed generation (DG) in distribution systems in recent years makes it even more crucial to have efficient reactive power operation schemes. In reality, the presence of DG in distribution feeders change its voltage profile greatly and hence interrupt the voltage sensing capabilities of capacitor banks which, basically, depends on ever-decreasing feeder's voltage profile. On the top of that, efficient coordination between feeder's capacitors and DGs can allow for the integration of more DGs in the system.

Most of the research in Var control area was concerned with the planning of the reactive power. The optimal capacitor sizing and allocation problem has been studied extensively in the literature [59], [60],[61].

On the other hand, the operation of the reactive power control equipment had received little attention. It has been the usual practice in utilities to operate capacitor banks based on local signals such as time of day or current with the aim to have them connected for maximum load and disconnected for minimum load. Currently, there is a need to adopt a more efficient reactive power control schemes in order to achieve the goals of the Smart Grid by having a more efficient and reliable distribution system.

Several solutions have been reported in literature to achieve the optimal reactive power control in the presence of DG. Forming the reactive power control as a centralized optimization problem has been proposed in different works [62],[63], [64], [65]. In these techniques, a central point monitors the status of the reactive power control equipment, perform a load forecast for a certain horizon, solve a reactive power optimization problem based on the forecasted conditions and finally determine the optimal settings for the reactive power control equipment. Problems with this approach are; first, for large system, the centralized approach will be too cumbersome. Second, given that this approach is based on load forecasting, there is no guarantee for the accuracy of the solution especially in the presence of renewable-based DG with varying output power.

Another emerging approach is solving the problem in a decentralized manner. In [21], a Multi-Agent decentralized reactive power DG dispatch for the support of the system voltage was proposed. The problem with that approach is that it assumes the existence of a moderator point which takes bids from DGs and calculates the optimal overall solution which is, more or less, a centralized way of solving the problem. In another work [66], a decentralized approach for the control of DG reactive power output was proposed to mitigate the voltage rise due to the connection of the DG. Therefore, this work is not applicable for the control of other reactive power control equipment of the system such as Capacitors.

3.6 Distribution System Restoration

Generally speaking, distribution network restoration refers to the actions taken by the network operator to restore the power to the maximum number of un-faulted loads after the tripping of the protection equipment due to a fault somewhere in the network. One of the most crucial factors in power system restoration is time; it is always required to restore the maximum number of load in the minimum possible time.

Distribution system power restoration problem can be formulated as an optimization problem. The resulting problem is combinatorial nonlinear constrained problem. This optimization problem can be proved to be an NP-complete problem.

In formulating the restoration problem, the objective function, usually, is to maximize the number of restored loads. The constraints on the optimization problem are;

- The power balance constraint: the generated power must be equal to the consumed power, at any time.
- The radial network constraint: during and after the restoration, the network must preserve its radial structure.
- Voltage constraint: voltages at different buses must be within the permissible range.

Research in distribution system restoration can be divided into four main categories; Heuristic approaches, Mathematical programming, Soft computing and Expert systems. The conventional method of pre-prepared restoration plans represents the basic heuristic method widely used in the past. The method suffers from some drawbacks; first, it is difficult to prepare plans for all restoration possibilities in advance. Second, due to the dynamic nature of the distribution network, adjusting the pre-determined plans becomes as difficult as solving the real restoration problem from scratch [67]. As a modification for this method, some research was reported to search, heuristically, through a set of the pre-determined plans in order to reduce the time of restoration [68].

Research was reported trying to solve the restoration problem using some mathematical optimization techniques [69]. However, for large scale networks, the computational burden becomes overwhelming to consider the method suitable. The same computational burden problem applies to the soft computing techniques, as well. However, some works was reported using Fuzzy logic based restoration [70] and [71], neural network was also used in [72]. Evolutionary algorithms were also examined for power system restoration problem [73]. On the other hand, Expert systems are considered the most successful approaches for restoration however they suffer from two drawbacks; optimal solution is not guaranteed and the maintenance of the large expert system is costly [74, 75].

Different studies report using MAS techniques for the distributed systems restoration. Ref. [76], and [77] suggest a MAS based restoration method based on using two types of Agents; Bus Agent, BAG, and Facilitator Agent, FAG. The restoration process is done by simple negotiation among the BAG with the supervision of one FAG in order to facilitate the restoration process. But these papers have some drawbacks. First; it is assumed that the FAG agent has knowledge about the structure of the network to classify the tie switches. Assuming that any agent has a complete knowledge about the network, contradicts the nature of MAS as a distributed control scheme. Second, these papers have not discussed a general method for the restoration of any distribution network rather it seems that the algorithms fits much with the simulation example given. Finally, optimal power restoration, in the sense of maximizing the number of restored loads, is not considered in the proposed method.

Other works were reported using MAS for system restoration [78], [79], [80] and [81]. However, the restoration algorithms proposed in those works are not based on formal mathematical analysis rather it depends on heuristic rules which have no guarantee of reaching optimal solution for the case of general network.

On the other hand, a commercial solution for distribution system restoration has been introduced by S&C Electric Company, [82], to enable the automatic restoration of distribution feeders based on the cooperation of "teams" located in the distribution system in the context of Multi-Agent system. While system's performance was presented in different works, [83], there are limited resources about the details of the restoration strategy.

3.7 Conclusions

It is clear, from the discussion of this chapter, that to realize the concept of the Advanced Distribution Automation with all its benefits, it is necessary to associate some intelligence to each component of the distribution system along with an efficient communication system between the power system components. Power system operation will be carried out by the coordination between these components. Literature survey for the three main distribution operation functions were presented in this chapter to clarify the weakness of the current operation schemes and justify the need for innovative operation techniques involving the concept of Advanced Distribution Automation.

Chapter 4

Optimal Voltage Control of Voltage Regulators for Multiple Feeders

4.1 Introduction

In this Chapter, a new voltage control technique is proposed to enable voltage regulators to regulate the voltage of multiple feeders assuming that no DGs are connected in the system. The tap position of the regulator is determined based on the solution of an integer linear optimization problem. The main advantage of the method is that the optimal tap has a closed-form solution; an advantage which is valuable in real-time operation. In addition, the required data for this method is considerably less compared with [50]. The loading of the feeders needed for the proposed algorithm can be readily calculated from the measurements of the total current of each feeder at the voltage regulator bus. Also, the design specifications of feeders, represented by the k-factor, are required. The proposed method does not need a power flow solution thus reducing the computational burden of the algorithm allowing a possible hardware implementation using a small inexpensive microcontroller. The extension of this method to handle the existence of DG will be addressed in Chapter 5.

This chapter is organized as follows; the voltage control problem is formulated in the next section. Following that, a condition for the existence of a feasible solution is derived in order to determine beforehand if it is possible to regulate a certain group of feeders by one regulator. Overall summary of the problem is presented in section 4.4. Section 4.5 is concerned with discussing possible solution methods for the proposed optimization problem. Simulation results are presented in section 4.6 to show the validity of the proposed algorithm. Chapter's conclusions are drawn in section 4.7.

4.2 Problem Formulation

In this section we discuss the proposed control algorithm for operating the voltage regulator in order to regulate the voltage of different points on multiple feeders having different loading schemes.

4.2.1 Statement of the problem

Fig (4.1) shows the system under study. The system consists of multiple feeders with different loading, different lengths and different conductor types. The function of the control block is to choose the tap position of the voltage regulator in order to achieve the following goals:

(a) Bring the voltage of a given point on each feeder (usually the end point) as close as possible to a reference value and in the worst case maintaining its value within certain given range for that feeder, if possible.

(b) Achieve (a) without violating the permissible voltage range of the regulator bus.

(c) Achieving (a) constrained with the given available number of steps of the voltage regulator.

In the following analysis we assume, without loss of generality, that loads are uniformly distributed along the feeders.

4.2.2 Objective Function

To achieve the above mentioned goals, the selection of the tap position is solved as a linear constrained optimization problem. The objective function is formulated as [84]:

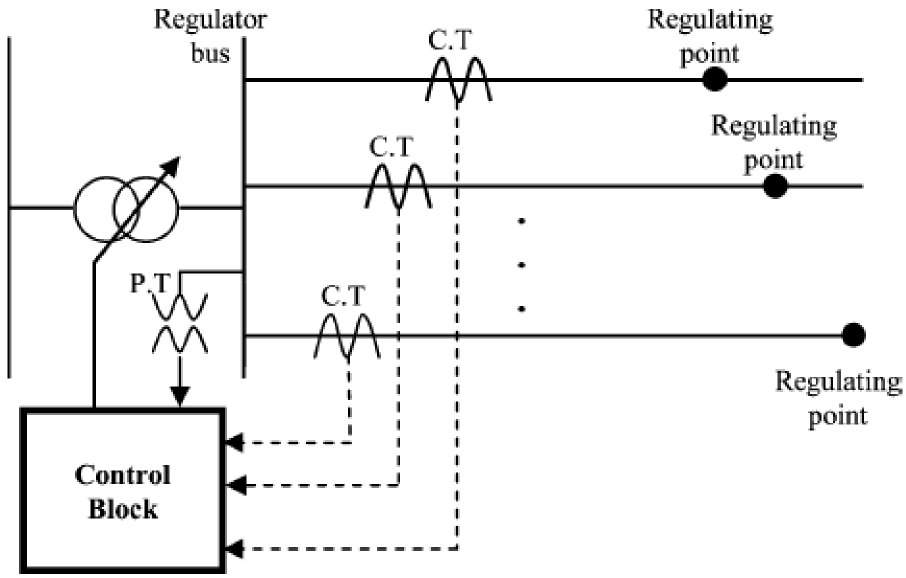


Figure (4.1) System under study

$$Min_{V_{reg}} \sum_{n=1}^{N} (V_{reg} - (V_{ref}^{n} + K_n l_n S_n \frac{L_n}{2}))^2 \tag{4.1}$$

Notice that the term $K_n l_n S_n \frac{L_n}{2}$ represents the voltage drop along a feeder having a length of L_n with uniform distributed load of $l_n S_n$ and a K-factor of K_n [44]. Although the proposed method is based on equation (4.1) which is valid for uniformly distributed loads feeder, it was proven in the literature that a non-uniform load feeder can be readily converted to an equivalent uniform load feeder [85, 86]. In reference [85] a feeder with different wire sizes and non-uniform loads was transformed into an equivalent uniform feeder using the normalized equivalent feeder concept and the normalized current distribution function concept. In reference [86] the authors transformed a non-uniform feeder into an equivalent uniform feeder using the “base resistance” technique. Therefore, without loss of generality, we will use the uniform feeder model to simplify the analysis.

The term $V_{ref}^{n} + K_n l_n S_n \frac{L_n}{2}$ represents the voltage regulator output value which if realized will bring the voltage of the regulating point of feeder *n* to its reference value. This last term is called here the reference output voltage of the regulator according to feeder *n*.

The objective function (4.1) aims to choose the best V_{reg} which will yield a minimum absolute difference between the value of the V_{reg} and the reference output voltage of the regulator according to all the feeders. That value will yield the best possible voltage regulator output voltage for all the feeders simultaneously.

The unconstrained optimization problem (4.1) could be solved easily using basic calculus by differentiating (4.1) with respect to V_{reg} and equating by zero; that yields:

$$V_{reg}^{optimum} = \frac{\sum_{n=1}^{N} V_{ref}^{n} + K_n l_n S_n \frac{L_n}{2}}{N} \tag{4.2}$$

4.2.3 Constraints

To maintain the voltage of the regulating point of each feeder within certain limits, the following constraints are intuitive:

$$V_{\min}^{n} \le V_{regulating-\text{point}}^{n} \le V_{\max}^{n} \tag{4.3}$$

Equation (4.3) represents a set of N constraints. But,

$$V_{regulating-\text{point}}^{n} = V_{reg} - K_n l_n S_n \frac{L_n}{2} \tag{4.4}$$

then,

$$V_{\min}^{n} \le V_{reg} - K_n l_n S_n \frac{L_n}{2} \le V_{\max}^{n} \tag{4.5}$$

$$V_{\min}^{n} + K_n l_n S_n \frac{L_n}{2} \le V_{reg} \le V_{\max}^{n} + K_n l_n S_n \frac{L_n}{2} \qquad (4.6)$$

The set of constraints in (6) could be combined in one constraint as follows:

$$\max_{n} \; (V_{\min}^{n} + K_n l_n S_n \frac{L_n}{2}) \le V_{reg} \le \min_{\mathrm{n}} \; (V_{\max}^{n} + K_n l_n S_n \frac{L_n}{2}) \qquad (4.7)$$

Equation (4.7) represents the necessary constraint for (4.1).

4.3 Condition for feasible solution

It is clear from (4.7) that the necessary condition to have a possible solution is:

$$\max_{\mathrm{n}} \; (V_{\min}^{n} + K_n l_n S_n \frac{L_n}{2}) \le \min_{\mathrm{n}} \; (V_{\max}^{n} + K_n l_n S_n \frac{L_n}{2}) \qquad (4.8)$$

If V_{min}^{n} is constant for all feeders and equals V_{min} and V_{max}^{n} is equals V_{max}, then (4.8) could be written as:

$$\max_{n}(K_n l_n S_n \frac{L_n}{2}) - \min_{n}(K_n l_n S_n \frac{L_n}{2}) \le V_{\max} - V_{\min} \qquad (4.9)$$

Equation (4.9) states the necessary condition for the solution as; the difference between the maximum and minimum voltage drop along the feeders must be less than the difference between the maximum and minimum allowable voltages for the regulating points.

The discrete nature of the V_{reg} can be expressed as:

$$V_{reg} = V_{input} + T * V_{tap} \qquad (4.10)$$

Using (4.10), (4.7) could be written as:

$$\max_{n} \; (V_{\min}^{n} + K_n l_n S_n \frac{L_n}{2}) \le V_{input} + T * V_{tap} \le \min_{n} \; (V_{\max}^{n} + K_n l_n S_n \frac{L_n}{2}) \tag{4.11}$$

And (4.11) could be written as:

$$\frac{\max_{n}(V_{\min}^{n} + K_n l_n S_n \frac{L_n}{2}) - V_{input}}{V_{tap}} \le T \le \frac{\min_{n}(V_{\max}^{n} + K_n l_n S_n \frac{L_n}{2}) - V_{input}}{V_{tap}} \tag{4.12}$$

Consider that *T* must be an integer number greater than zero; then the necessary condition for the feasibility of a solution could be written as:

$$ceil\left(\frac{\max_{n}(V_{\min}^{n} + K_n l_n S_n \frac{L_n}{2}) - V_{input}}{V_{tap}}\right) \le floor\left(\frac{\min_{n}(V_{\max}^{n} + K_n l_n S_n \frac{L_n}{2}) - V_{input}}{V_{tap}}\right) \tag{4.13}$$

4.4 Problem Summary

We can summarize the optimization problem as follows:

$$Min_T \sum_{n=1}^{N} (V_{reg} - (V_{ref}^{n} + K_n l_n S_n \frac{L_n}{2}))^2 \tag{4.14}$$

Subject to:

$$\frac{\max_{n}(V_{\min}^{n} + K_n l_n S_n \frac{L_n}{2}) - V_{input}}{V_{tap}} \le T \le \frac{\min_{n}(V_{\max}^{n} + K_n l_n S_n \frac{L_n}{2}) - V_{input}}{V_{tap}} \tag{4.15}$$

$$T_{\min} \le T \le T_{\max} \tag{4.16}$$

Where,

$$V_{reg} = V_{input} + T * V_{tap} \tag{4.17}$$

$$T_{\max} = \frac{V_{reg}^{\max} - V_{input}}{V_{tap}} \tag{4.18}$$

$$T_{\min} = \frac{V_{reg}^{\min} - V_{input}}{V_{tap}} \tag{4.19}$$

4.5 Solution

The abovementioned optimization problem is an integer programming problem which can be solved using integer programming solvers like the Branch and Bound method. Also, it is possible to relax the integer requirement of the solution and solve the relaxed linear programming one. In addition, it is possible to use the closed form solution of (4.2) provided that the following constraint is fulfilled:

$$V_{reg}^{\min imum} \le V_{reg}^{optimum} \le V_{reg}^{\max imum} \tag{4.20}$$

Then the optimal tap will be selected as follows:

Let $x = \dfrac{V_{reg}^{optimum} - V_{input}}{V_{tap}}$, then

$$T_{optimim} = \begin{cases} round(x) & if\,, T_{\min} \le round(x) \le T_{\max} \\ ceil(x) & if\,, round(x) \le T_{\min} \\ floor(x) & if\,, T_{\max} \le round(x) \end{cases} \tag{4.21}$$

Fig.(4.2) shows a flowchart for the algorithm.

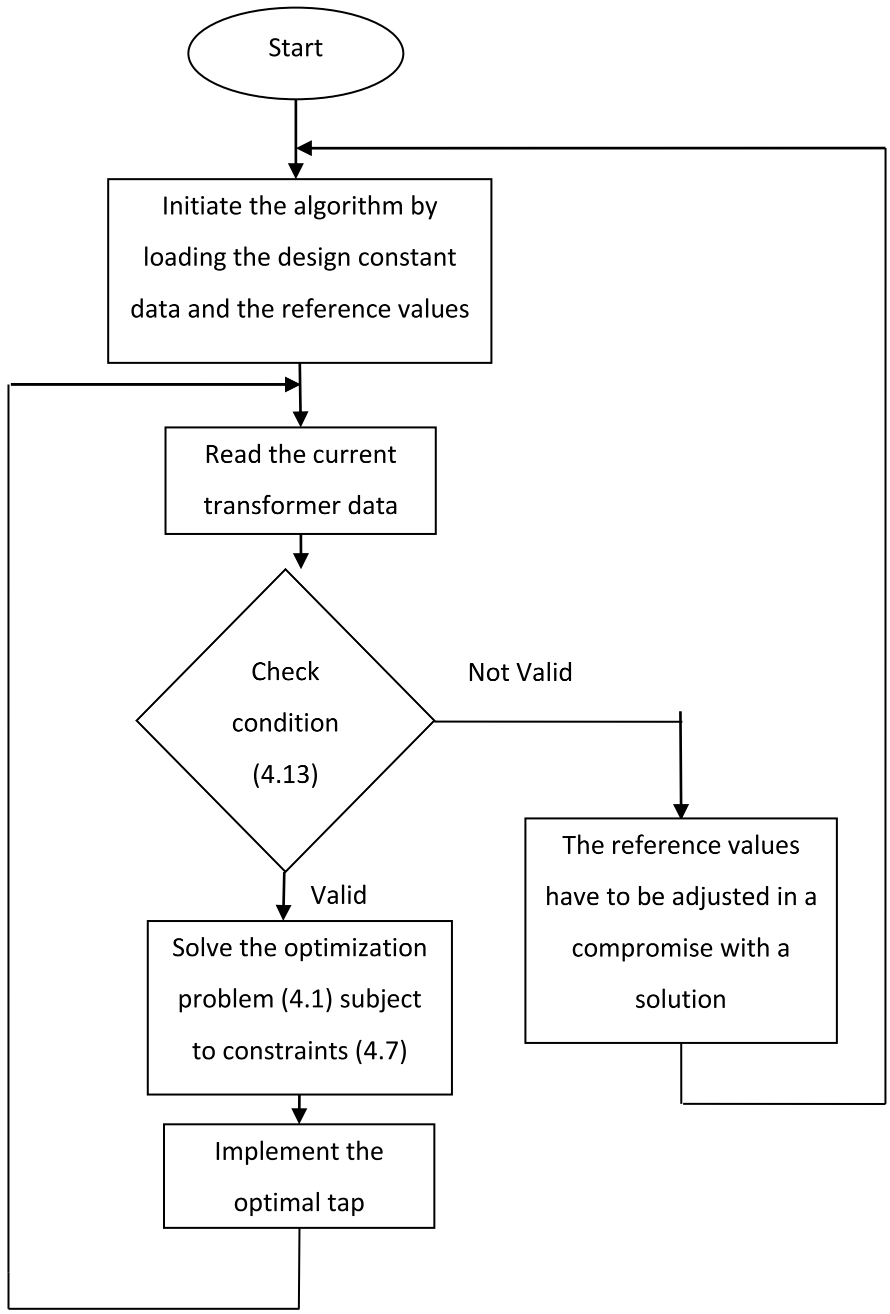


Figure (4.2) Flowchart of the proposed algorithm

4.6 Simulation Study

In this section we present several simulations results to show the validity of the proposed method for the study systems in Fig. (4.1).For all the following cases we will assume the following data:

The input voltage of the regulator = 1.01 pu.

The maximum permissible voltage at the regulator point = 1.05 pu.

The minimum permissible voltage at the regulator point = 0.95 pu.

The number of taps = 32.

The tap ratio = 0.00625 pu

Four cases will be simulated below to show the performance of the algorithm under different loading diversity.

<u>Case 1:</u>

For this case, system's data is shown in Table 4-1 and the voltage profiles for the 4 feeders are shown in Fig (4.3). This case shows the basic operation of the proposed algorithm, the regulator was able to regulate the voltage of the four feeders efficiently.

Table 4-1 Data for the system studied in case 1

	Feeder 1	**Feeder 2**	**Feeder 3**	**Feeder 4**
Load kVA	4500	5000	6000	4000
Length of feeder	8 mi	10 mi	6 mi	9 mi
K-factor of feeder	3.88e-6	3.88e-6	3.88e-6	3.88e-6
Ref. Voltage	0.95	0.96	0.97	0.95

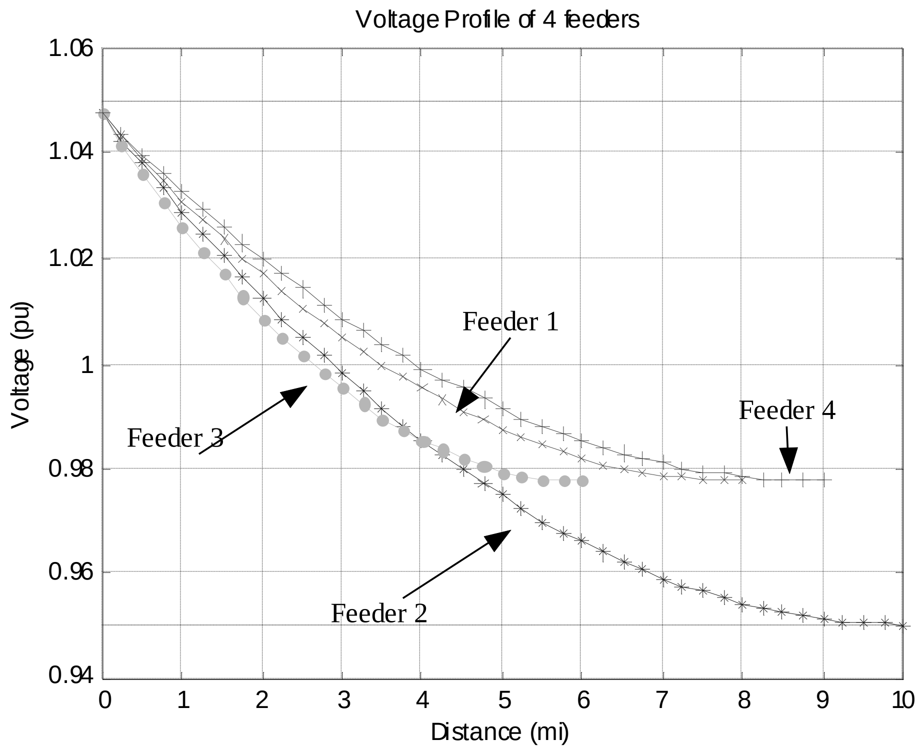


Figure (4.3) Voltage profile for case 1

Case 2:

Here we have increased the load diversity between feeders and changed their lengths. The data is shown in Table 4-2 and the voltage profiles for the four feeders are shown in Fig (4.4). Under these conditions, still the regulator was able to regulate all four feeders' voltages.

Table 4-2 Data for the system studied in case 2

	Feeder 1	**Feeder 2**	**Feeder 3**	**Feeder 4**
Load kVA	4500	5000	6000	1000
Length of feeder	8 mi	10 mi	6 mi	6 mi
K-factor of feeder	3.88e-6	3.88e-6	3.88e-6	3.88e-6
Ref. Voltage	0.95	0.96	0.97	0.95

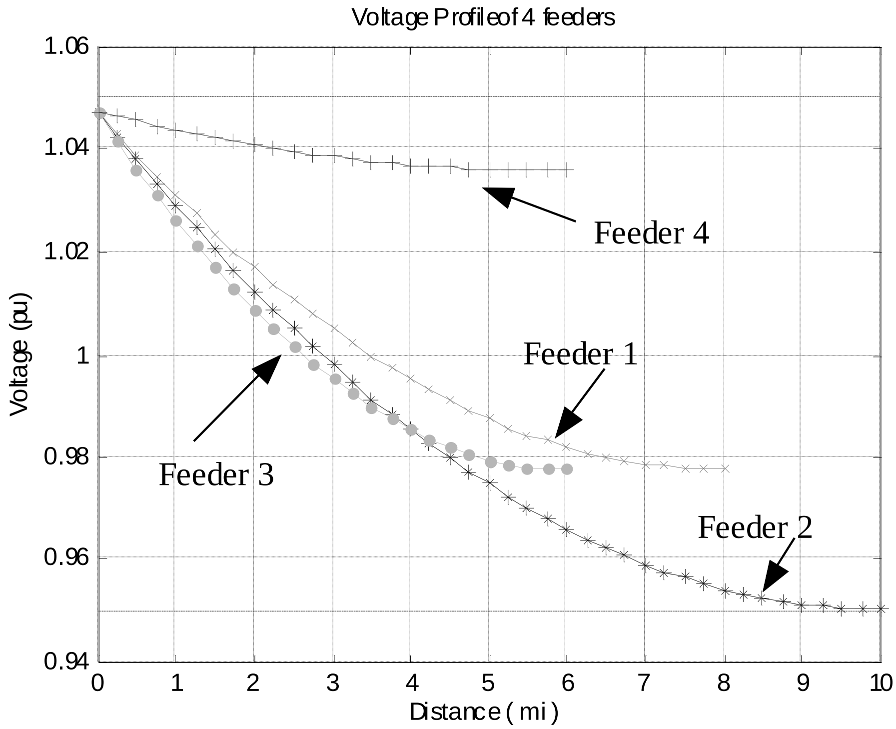


Figure (4.4) Voltage profile for case 2

Case 3:

In this case we have changed the load diversity and the lengths of the feeders, as shown in Table 4-3. For this case, there was no solution that does not violate the voltage limit at the regulator bus as shown in Fig (4.5). To obtain Fig (4.5) we removed the voltage regulator bus constraint from the optimization problem. This case represents one of the cases where it is not possible to regulate the voltage of multiple feeders with only one regulator due to large voltage drop along the feeders.

Table 4-3 Data for the system studied in case 3

	Feeder 1	Feeder 2	Feeder 3	Feeder 4
Load kVA	7000	5000	4500	4000
Length of feeder	10 mi	10 mi	6 mi	9 mi
K-factor of feeder	3.88e-6	3.88e-6	3.88e-6	3.88e-6
Ref. Voltage	0.95	0.96	0.97	0.95

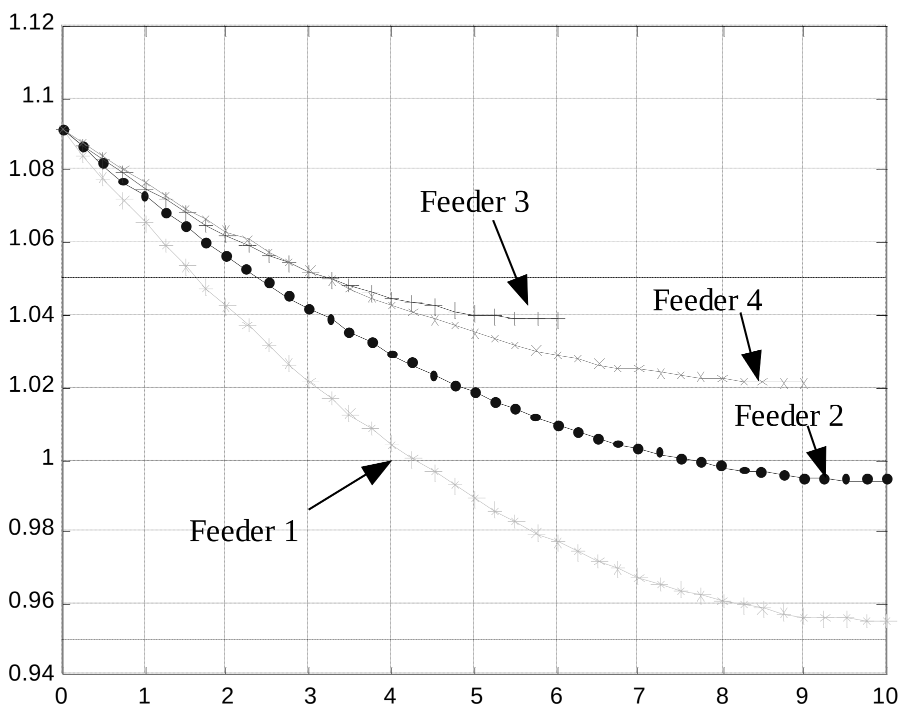


Figure (4.5) Voltage profile for case 3

Case 4:

Again, we increase the load diversity between the feeders to explore the extreme case. The data for this case is shown in Table 4-4.

Table 4-4 Table 4-4 Data for the system studied in case 4

	Feeder 1	Feeder 2	Feeder 3	Feeder 4
Load kVA	4500	7000	6000	1000
Length of feeder	8 mi	10 mi	6 mi	6 mi
K-factor of feeder	3.88e-6	3.88e-6	3.88e-6	3.88e-6
Ref. Voltage	0.95	0.96	0.97	0.95

The regulator could not regulate the four feeders in this case and there was no solution, this is due to:

$$ceil\left(\frac{\max\limits_{n}\left(V_{\min}^{n}+K_{n}l_{n}S_{n}\frac{L_{n}}{2}\right)-V_{input}}{V_{tap}}\right)=13$$

and

$$floor\left(\frac{\min\limits_{n}\left(V_{\max}^{n}+K_{n}l_{n}S_{n}\frac{L_{n}}{2}\right)-V_{input}}{V_{tap}}\right)=8$$

Therefore, condition (4.13) fails for this system and there is no feasible solution. In other words, it is not possible to use one voltage regulator to adjust the voltages of the four feeders within the permissible range with the given set of system parameters. In this case the parameters, especially the reference voltages of the regulating points, have to be changed in a compromise for a solution.

4.7 Conclusions

Based on the above analysis, it is evident that the proposed method could be used to optimize the operation of voltage regulators for the regulation of multiple feeders. The method is simple with regard to the computational burden. It enables, in certain cases, the use of the substation under load tap changer transformer to adjust the voltage of all feeders while keeping the substation voltage within the permissible range. An added advantage of the method is the closed form condition for solution feasibility which enhances the operation of the voltage regulator and can assist in the planning of the system.

Chapter 5

Novel Coordinated Voltage Control for Smart Distribution Networks with DG

5.1 Introduction

There is currently an increased interest in connecting more Distributed Generation (DG) to the distribution system. As detailed in Chapter 2, DG poses new challenges for the operation of the distribution system despite their many benefits. One of the main factors that limit the amount of DG connected to the system is the steady state voltage rise problem. In this Chapter, we propose a new coordinated voltage control technique that can be implemented in real-time. The proposed technique is based on locating Remote Terminal Unit (RTU) at each DG unit and at each shunt capacitor bank. It is shown in this Chapter that based on the readings of these RTUs, the voltage regulator controller will be able to determine the maximum and minimum voltages of the feeder and, hence, will be able to efficiently regulate the voltage of multiple feeders. Also, in this Chapter we will investigate the conditions under which it will not be possible to regulate the voltage of the feeder using one voltage regulator and then, we will propose solutions for such a situation.

This Chapter starts off by discussing the steady state voltage rise problem caused by the connection of DGs. In Section 5.3, two important results regarding the estimation of the voltage profile of distribution feeders are to be proved. Based on the results of section 5.3, the details of the proposed scheme are presented in section 5.4 and the proposed coordinated voltage control algorithm is presented in section 5.5. Section 5.6 is concerned with the details of the voltage regulator control algorithm. The condition for the existence of a feasible solution, based on the proposed technique, is discussed in section 5.7. After that, a simulation study is presented, in section 5.7, to validate the proposed technique. Chapter's conclusions are drawn in section 5.8.

5.2 DG Voltage Rise Problem

It is known that when a DG injects power at a certain point of the system, the voltage of this point rises. This fact can be shown as follows. Consider the part of the distribution system shown in Fig (5.1).

The voltage drop *V1 – V2* can be written as,

$$V_1 - V_2 = \frac{PR+QX}{V_2} \tag{5.1}$$

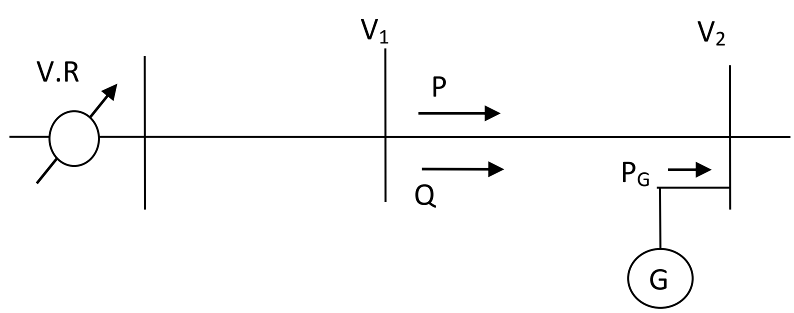


Figure (5.1) Explanation of the steady state Voltage Rise caused by DG connection

In per unit, equation (5.1) is usually approximated as,

$$V_1 - V_2 = PR + QX \tag{5.2}$$

Now, if the DG injects active power into the system, equation (5.2) can be modified as,

$$V_1 - V_2 = (P - P_G)R + QX \tag{5.3}$$

If the power of the DG increases, the term $P\text{-}P_G$ can become negative, thus V_2 becomes greater than V_1. In short, the voltage at the DG injection point can rise and, this voltage rise depends on the DG injected power. If the voltage rise problem is solved efficiently, then higher DG levels could be allowed to be installed on distribution feeders, theoretically, up to the feeder thermal limit.

5.3 Voltage Profile Estimation

If the injected power of one, or more, of the DGs installed on a certain feeder changed, then the voltage profile will change and that could result in a violation of the voltage at a certain node, or nodes along the feeder. In order for the voltage regulator to regulate the voltage of the feeder it needs to estimate the voltage profile. It is worthy to note here that, the knowledge of the maximum voltage and the minimum voltage of the feeder is enough in order to achieve this voltage regulation. First, we focus on maximum voltages. The next Lemma proves that maximum points of the voltage profile can only happen at the DG connecting buses or at a capacitor connecting buses.

Lemma 5.1: For the voltage profile of a radial feeder, maximum voltage can happen only at the DG connecting buses, capacitors connecting buses and the substation bus, provided that the R/X ratio of the feeder is constant along the whole feeder.

Proof:

Assume that DG units are connected at buses 1 and 3 as shown in Fig (5.2). First, if P and Q are being transferred from bus 1 to bus 2, then V_1 must be greater than V_2. Therefore, V_2 cannot be a maximum point.

Second, assume that P and Q are being transferred in two different directions as shown in Fig (5.2). In seeking a contradiction, let V_2 be a maximum point, then $V_2 > V_1$ and $V_2 > V_3$, then,

$$V_2 - V_1 = P_0 r_0 - Q_0 x_0 \tag{5.4}$$

$$V_2 - V_3 = -P_1 r_1 + Q_1 x_1 \tag{5.5}$$

Therefore,

$$P_0 r_0 > Q_0 x_0 \tag{5.6}$$

$$\frac{P_0}{Q_0} > \frac{x_0}{r_0} \tag{5.7}$$

and,

$$P_1 r_1 < Q_1 x_1 \tag{5.8}$$

$$\frac{Q_1}{P_1} > \frac{r_1}{x_1} \tag{5.9}$$

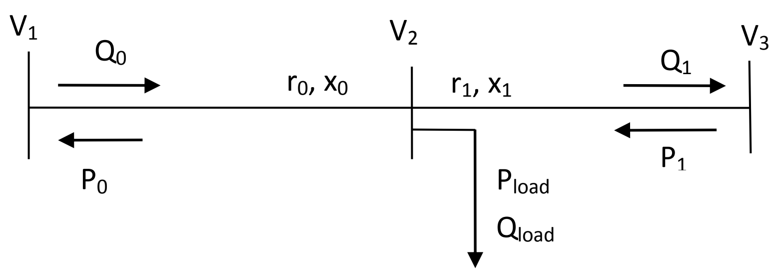


Figure (5.2) System used to prove Lemma 5.1

But at bus 2 there is neither DG nor capacitor, then $P_1 > P_0$ and $Q_0 > Q_1$, then,

$$\frac{P_1}{P_0} > 1 \tag{5.10}$$

$$\frac{Q_0}{Q_1} > 1 \tag{5.11}$$

Now, multiplying (5.7) by (5.9) and (5.10) by (5.11), the result is,

$$\frac{P_0 Q_1}{P_1 Q_0} > \frac{x_0 r_1}{x_1 r_0} \tag{5.12}$$

$$\frac{P_1 Q_0}{P_0 Q_1} > 1 \tag{5.13}$$

Then, (5.12) and (5.13) can be combined in one equation as follows,

$$1 < \frac{P_1 Q_0}{P_0 Q_1} < \frac{r_0 x_1}{r_1 x_0} \tag{5.14}$$

Equation (5.14) is the necessary condition for bus 2 to have a maximum voltage. Then,

$$\frac{r_0 x_1}{r_1 x_0} > 1 \tag{5.15}$$

Equation (5.15) is a necessary but not sufficient condition for the existence of a maximum voltage at bus 2. But (5.15) can be written as,

$$r_0 x_1 > r_1 x_0 \tag{5.16}$$

Then,

$$\frac{r_0}{x_0} > \frac{r_1}{x_1} \tag{5.17}$$

Equation (5.17) means that R/X ratio of the line between buses 1 and 2 is greater than the R/X ratio of the line between buses 2 and 3, which contradicts the assumed constant R/X ratio of the whole feeder.

Also note that, even if equation (5.17) holds, still the sufficient condition for the existence of the maximum point at bus 2 requires that, as it is clear from equation (5.14),

$$\frac{P_1 Q_0}{P_0 Q_1} < \frac{(R/X)_0}{(R/X)_1} \tag{5.18}$$

Condition (5.18) is even harder to be true as the left hand side is likely to be much greater than 1 as $P_1 > P_0$ and $Q_0 > Q_1$. That completes the proof. ∎

Now we turn to the minimum voltage points. In general, minimum voltage points can occur only at the end of the feeder as well as in between any DG connecting buses. The voltage of the end points can be read using RTU or alternatively it can be estimated the same way as minimum points in between the DG units, as will be detailed later.

For the minimum points in between DG or capacitor connecting buses, the following Lemma gives the necessary and sufficient condition for the existence of these points.

Lemma 5.2:

There exists a minimum voltage point in between two DG connecting buses if and only if, for both DGs, the voltage of the DG neighboring bus, in the direction of the other DG, is less than the voltage of the DG bus. In other words, for Fig (5.3) and based on this Lemma, there will be a minimum voltage point at one of the buses 2, 3, 4, 5 or 6, if and only if, the voltage of bus 1 is greater than the voltage of bus 2 and that the voltage of bus 7 is greater than the voltage of bus 6.

Similarly, the same result will apply to the points in between two capacitors as well as between one capacitor and one DG.

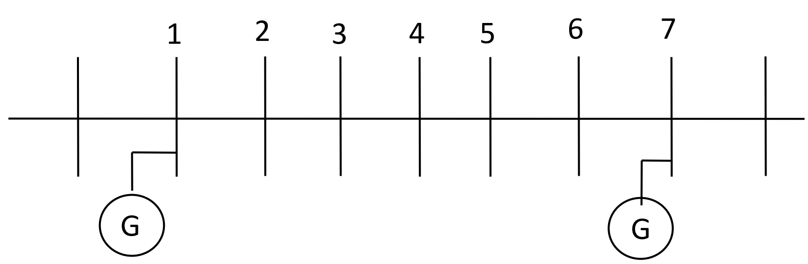


Figure (5.3) System used to prove Lemma 5.2

Proof:

If the condition of the Lemma holds true that means, obviously, there must be a minimum point. To achieve the uniqueness of the minimum point, consider the opposite. If there is more than one minimum point that will imply the existence of a maximum point as well, but that is not possible according to Lemma 1. This proves the (if) part of the Lemma.

For the (only if) part, consider the case if the condition does not hold. In this case, the voltage profile will be decreasing at one DG side and increasing at the other side. So the only way to have a minimum point in between the DGs is to have a maximum point as well. Again, according to Lemma 5.1, this is not possible. This proves the (only if) part and completes the proof. ∎

Note that, it is not important, from the point of view of voltage regulation, to know the exact location of the minimum voltage point. The importance of the above Lemma is that it provides a guaranteed method to check for the existence of a minimum voltage point. In fact, knowing the mere existence of minimum voltage points is not enough. It is necessary to know the value of the minimum voltage point as well.

We propose to estimate the value of the minimum voltage point using the readings available at the DG or the capacitor bus only. In fact, this part of the proposed method can be tailor-designed for each network based on whatever available information about its loading characteristics. Nevertheless, we will use an estimation method which gives the worst case value for the minimum voltage point thus it is considered as a good lower bound.

In this part it is assumed that the load between the two elements (DG or capacitor) is concentrated halfway between them. For Fig (5.4), based on this assumption, the value of the minimum voltage point between DG1 and DG2, if exists, as calculated by DG_1 can be given as,

$$V_{min,DG1} = V_{DG1} - (P_1 \frac{r}{2} - Q_1 \frac{x}{2}) \tag{5.19}$$

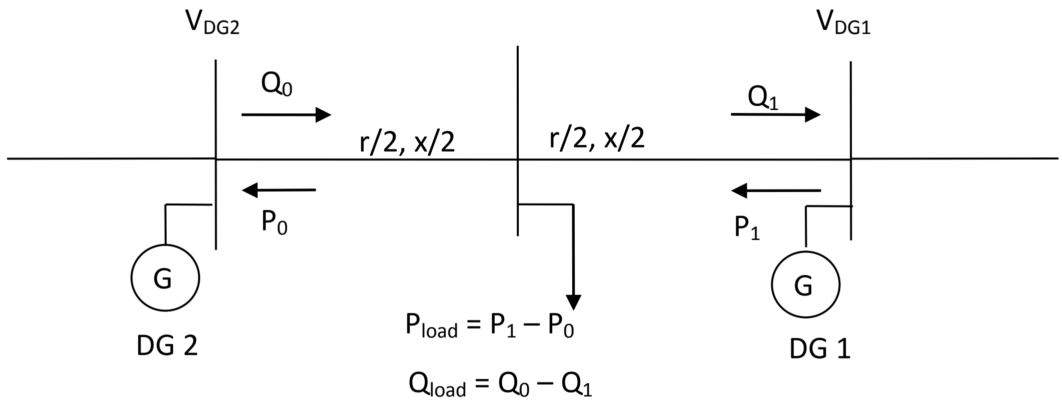


Figure (5.4) Estimation of minimum voltage points of the voltage profile

Also, the value of the assumed minimum voltage point calculated by DG_2 is given by,

$$V_{min,DG2} = V_{DG2} - (-P_0 \frac{r}{2} + Q_0 \frac{x}{2}) \tag{5.20}$$

Then we can take the average of these two values to get a better estimation,

$$V_{min} = \frac{V_{min,DG1} + V_{min,DG2}}{2} \tag{5.21}$$

Finally substitute equations (5.19) and (5.20) in equation (5.21) we get,

$$V_{min} = \frac{V_{DG1} + V_{DG2}}{2} - \frac{r}{4}(P_1 - P_0) - \frac{x}{2}(Q_0 - Q_1) \tag{5.22}$$

Equation (5.22) gives an estimation for the value of the minimum voltage point, if exist, between two elements using the data measured at elements' buses only. It is worthy to mention that, different loading schemes could have been assumed between the two elements, e.g. uniformly distributed. The choice of the assumed loading scheme should be network-specific.

5.4 Proposed System Structure

In the light of the results of section 5.3, we propose the system structure depicted in Fig (5.5), [87]. The system consists of an RTU at each DG, each capacitor and at each lateral point in addition to a communication link between each two RTUs that have a power line connection between their elements (DGs, capacitors or lateral points). Each RTU is responsible to take local measurements at its element, perform calculations, execute some logical statements and communicate with its neighbor RTU or the voltage regulator. Fig (5.6) shows a detailed view for the parameters measured by each RTU. Namely, each RTU measures the voltage of its element's bus, active and reactive power flow in lines connected to its element's bus and the voltages of the immediate neighbor buses of its element's bus. Note that, the voltage of the immediate neighbor buses is needed only in order for the RTU to get the trend of the voltage profile, increasing or decreasing. Therefore, measuring a point on the feeder adjacent to the RTU could be sufficient.

Based on the measurements of each RTU, it will be able to,

1. Measure a maximum voltage point; the DG or the capacitor bus voltage.
2. Check *one part* of the condition for the possibility of the existence of a minimum voltage point between its element and any neighbor element.
3. Estimate the value of the minimum voltage point on each side of its element, if exists.

The communication structure between RTUs can be represented by the graph of Fig (5.7). This communication structure represents a tree in which the voltage regulator is the root of the tree, each feeder is a branch and each RTU is a node. In this structure, data will propagate from the farthest RTU towards the voltage regulator. It is worthy to note that, in the proposed algorithms, each RTU knows only its immediate neighbors, upstream and downstream. Hence, no RTU has the whole picture of the feeder structure.

In the rest of this chapter, we will concentrate on the operation of voltage regulator in the presence of DG and, hence, we will assume that there are no capacitors existing on the feeder. The general case of the coordination between capacitors, DGs and voltage regulators will be deferred to Chapter 7.

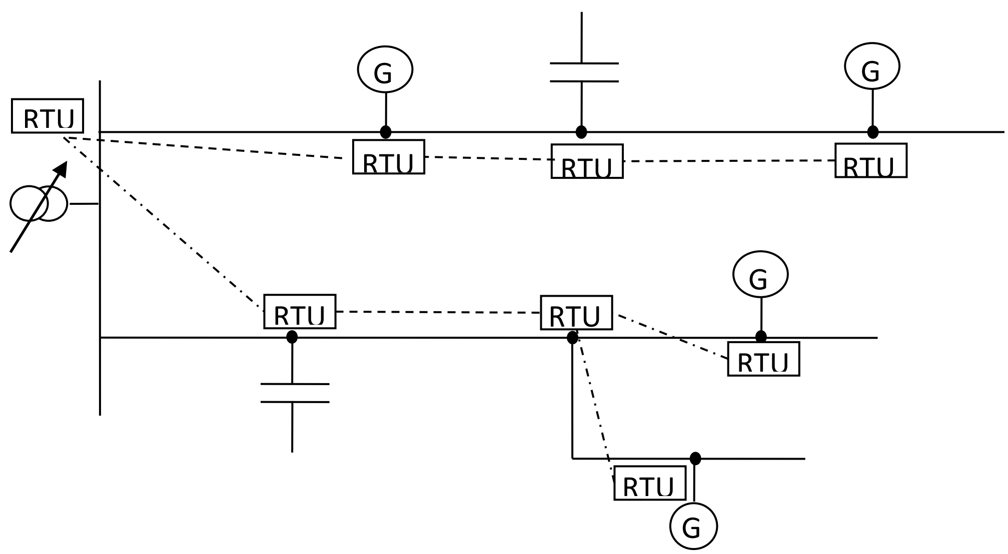


Figure (5.5) Proposed hardware structure for coordinated voltage control

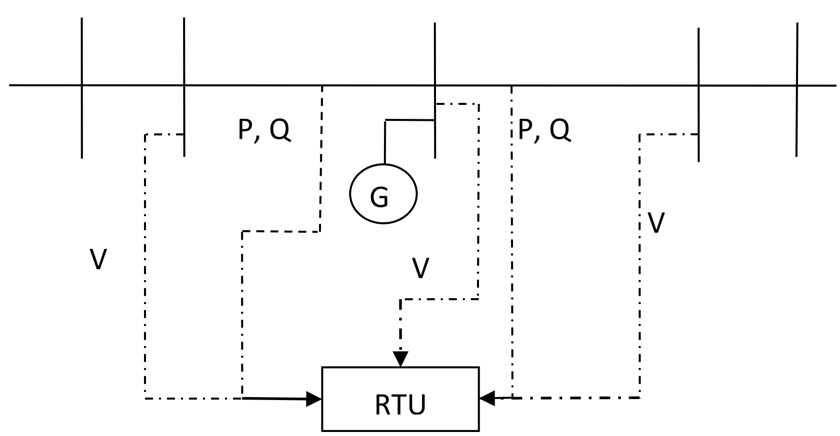


Figure (5.6) Details of RTU measurements

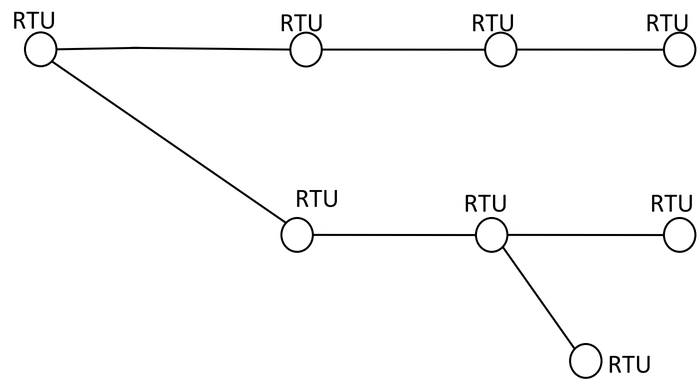


Figure (5.7) A graph representing the communication structure between the RTUs

5.5 Proposed Coordinated Voltage Control Algorithm

The goal of the algorithm executed by the RTU is to send to the voltage regulator the maximum and minimum voltages of each feeder. Let RTU_n be the RTU connected to a certain DG and define $RTU_{(n-1)}$ to be the immediate upstream RTU, the *parent* RTU. Also, define the RTU_{n+1} as the RTU connected immediately downstream of RTU_n, the set of *children* RTU. The algorithm is described below and is stated formally in Appendix A as Algorithm#5.3. The flow chart depicted in Fig (5.8) shows the routine executed by RTU_n.

Basically, the algorithm can be explained as follows; the farthest DG RTU's assumes that the maximum voltage of the feeder equals to its own DG voltage. Also, it checks for any minimum voltage point between itself and the upstream DG, then it estimates this minimum point and sends it to the upstream DG accompanied with a flag indicating the possibility of the existence of a minimum voltage point. Upon receiving these data from its downstream RTU, the upstream RTU will check if its voltage is greater than the received downstream voltage and update the maximum voltage of the feeder accordingly. Also, if the minimum voltage flag is high, then the upstream RTU will check the condition for the existence of a minimum voltage point from its own side and calculate an estimate for the minimum voltage value and hence, update the minimum voltage of the feeder.

For the RTU located at the lateral point, it will repeat the above algorithm with all of its immediate downstream RTU. In other words, it will receive a set of maximum voltages, set of minimum voltages, and set of minimum voltage flags from all of its downstream RTU. Based on these data, it will decide the overall maximum and minimum voltages in the same way as described above.

In summary, along the way from the farthest RTU to the voltage regulator, each RTU updates the maximum voltage value and the minimum voltage value of the feeder according to its readings. As a result, the voltage regulator controller will receive the maximum voltage and the minimum voltage of each feeder. Based on these values, the voltage regulator will change the tap position accordingly as follows;

- If the absolute maximum voltage is greater than maximum permissible voltage, then the voltage regulator will decrease the current tap position till the maximum voltage of the feeder is within the permissible range.
- If the minimum voltage of the feeder is below the minimum permissible voltage, then the voltage regulator will increase the tap position to bring the minimum voltage into the permissible range.

Mathematical formulation of this process is detailed in Appendix A as Algorithm 5.1, 5.2 and 5.3.

5.6 Condition for Feasible Solution

The basic condition that has to be satisfied in order for the voltage regulator controller to find a suitable tap that will regulate the maximum and the minimum voltages of all the feeders is,

$$\max(V_{max,feeder}) - \min(V_{min,feeder}) < V_{max,perm} - V_{min,perm} \qquad (5.23)$$

If condition (5.23) does not hold then one regulator cannot handle the voltage regulation of the whole system. In such situation there might be a need to install more voltage regulators in the system. Installing extra voltage regulators in the system will provide more flexibility for voltage control. Each voltage regulator in the system will be responsible for regulating the part of the system downstream of it down to the next voltage regulator as shown in Fig (5.9). In this case, RTUs installed in each control zone will report to the voltage regulator responsible for that zone. The planning of the location of the extra voltage regulators are to be carried out such that maximum and minimum voltages of the original system will occur in two different control zones, in other words, the maximum voltage point will be handled by a voltage regulator different than the voltage regulator that will handle the minimum voltage point.

Another solution will be to utilize the capacitors existing in the system, if any. This solution will be discussed in section 6.5.

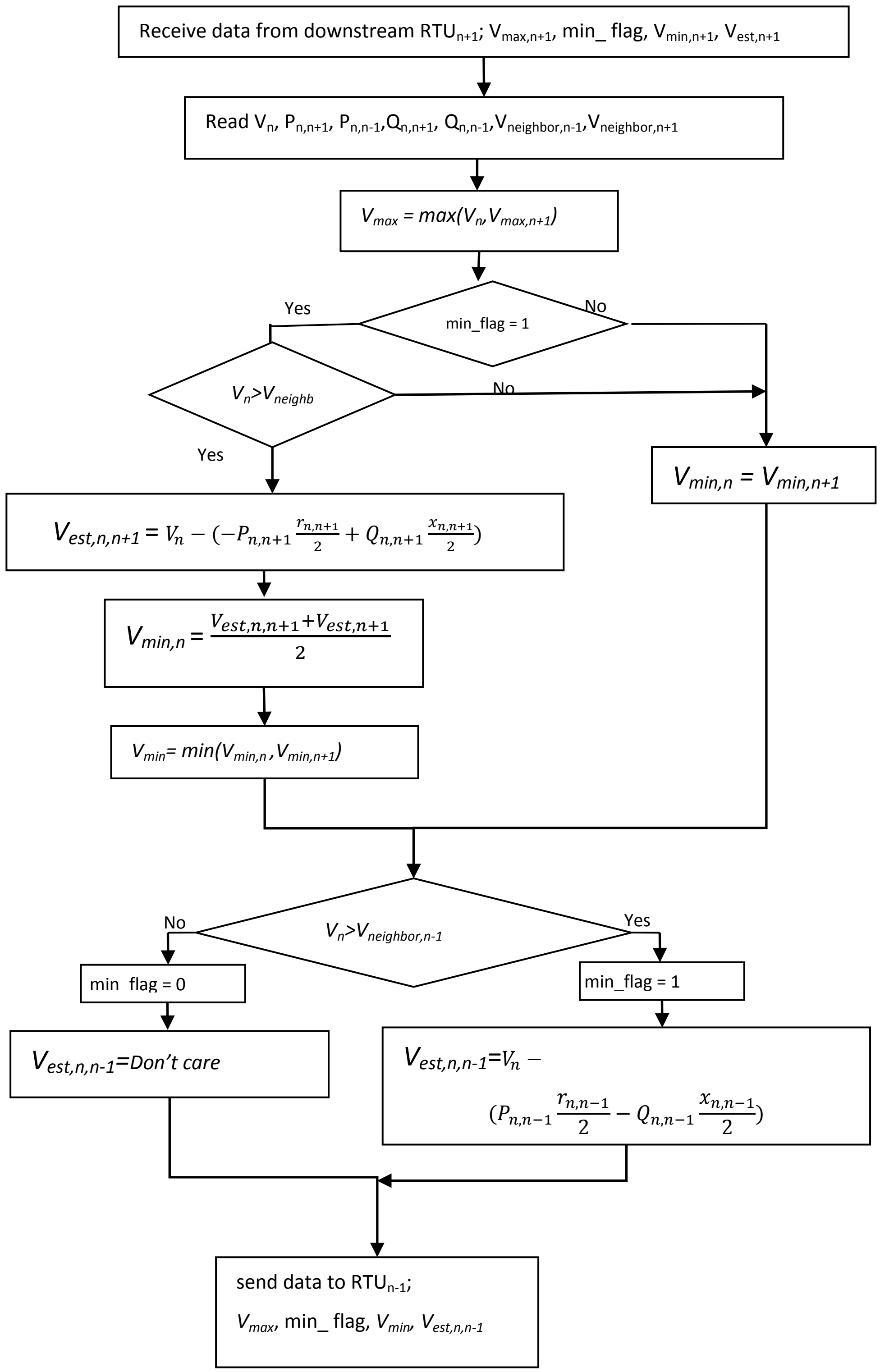


Figure (5.8) Flow chart for the proposed coordinated voltage control algorithm

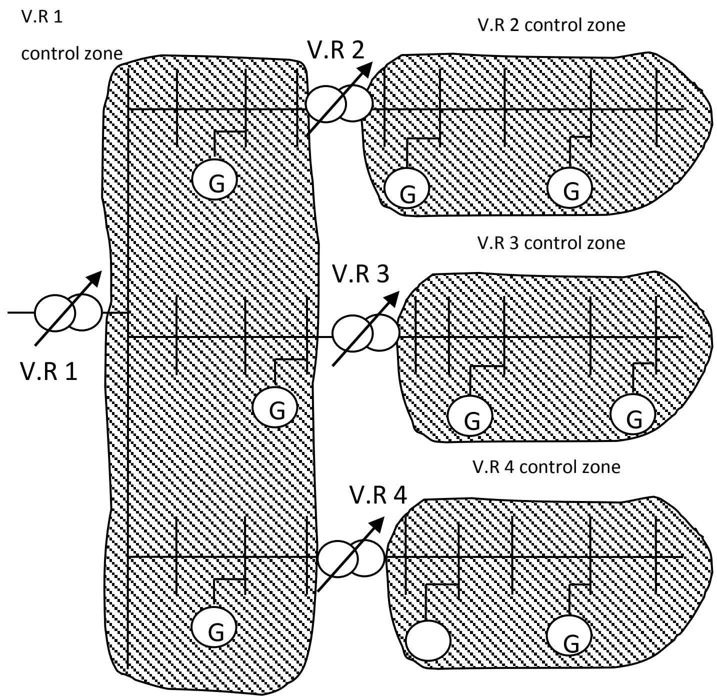


Figure (5.9) Control zones for multiple voltage regulators

5.7 Simulation Study

In this section several simulation results will be reported to validate the proposed voltage regulation scheme. Fig (5.10) shows the system under study; four DGs are connected to buses 5 and 9 on the first feeder and buses 4 and 8 on the second feeder. Loads connected at each bus are given in Table 5-1. For all of the following cases we assume the following data:

The input voltage of the regulator = 1.0 pu.

The maximum allowable voltage = 1.05 pu.

The minimum allowable voltage = 0.95 pu.

The number of taps = 32.

The tap ratio = 0.00625 pu.

Base KVA = 100 kVA

The impedance of any line section = 0.00344 +j 0.0029 p.u

5.7.1 Voltage profile estimation

This sections starts by testing the voltage profile estimation capabilities of the proposed algorithm. Fig (5.11) shows the voltage profile of the two feeders based on a power flow solution and the estimated voltage profile based on the readings of the RTU installed at the four DGs. It is clear that the estimation of the voltage profile captured all maximum and minimum voltage points of the feeders.

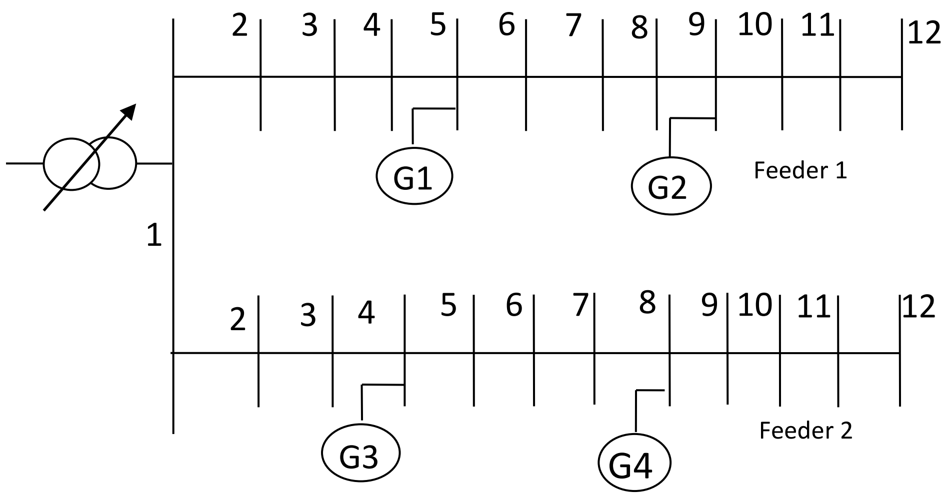


Figure (5.10) System used for simulations

Table 5-1 Active and reactive power load values at each bus of the simulated system

Bus # Feeder 1	P(kW)	Q(kVar)	Bus #Feeder 2	P(kW)	Q(kVar)
2	26	60	2	100	60
3	40	30	3	40	30
4	55	55	4	-250	55
5	-80	0	5	90	0
6	60	15	6	80	15
7	55	55	7	55	55
8	45	45	8	-400	45
9	-250	0	9	45	0
10	35	30	10	35	30
11	40	30	11	40	30
12	30	15	12	30	15

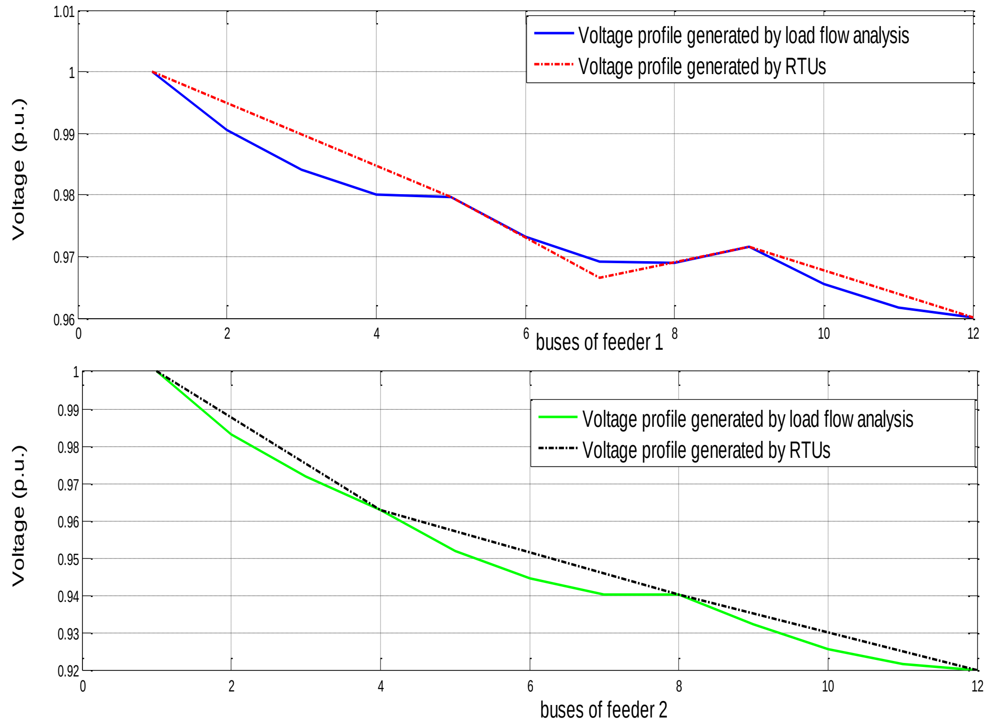


Figure (5.11) Voltage profile generated from power flow solution versus voltage profile estimated using RTUs readings

5.7.2 Voltage Regulator control

Case1:

In this case we will test the basic voltage regulation capability of the proposed technique. It is clear from Fig (5.11) that the voltage profile of feeder 2 is not acceptable due to a minimum voltage value of about 0.92p.u. Based on the proposed voltage regulation technique, the voltage regulator will change the tap setting in order to correct the voltage profile of feeder 2 without violating that of feeder 1. Fig (5.12) shows the voltage profiles of the two feeders before and after the voltage regulator action. In this case the voltage regulator raised the tap setting to tap number 5.

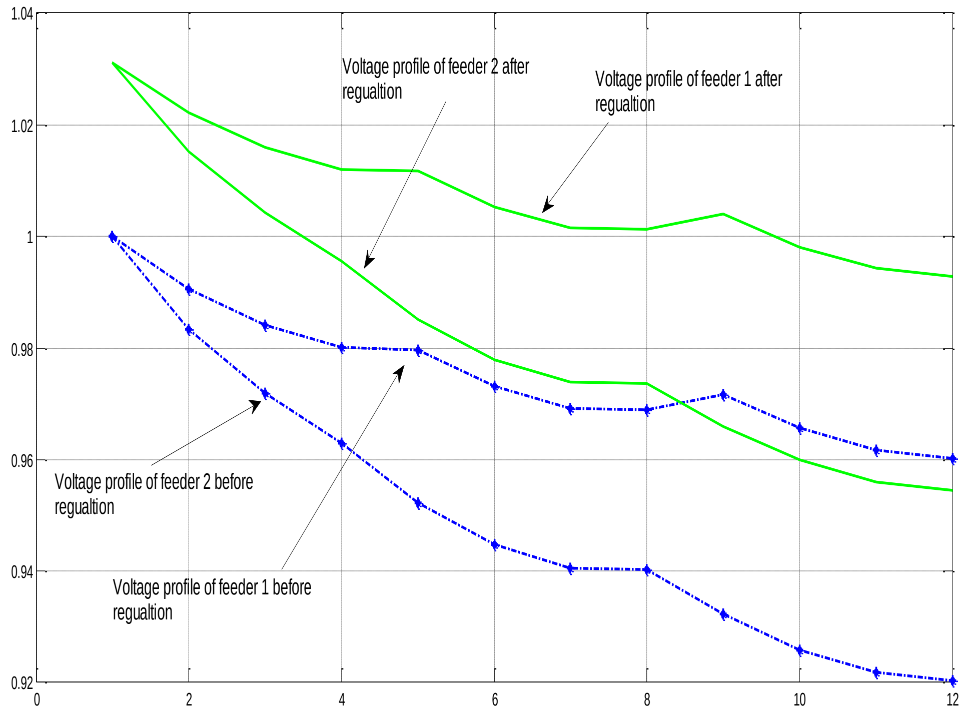


Figure 5.12) Voltage profile for the simulated system before and after regulation for case 1

Case2:

In this case we will test the performance of the proposed technique in reaction to a change in DG output power. Based on case 1 results', the voltage regulator output is at tap setting 5, i.e. regulator voltage = 1.0313 p.u. In this case, DG4 injects 350 kW and DG2 injects 430 kW active power, both with unity power factor. Fig (5.13) shows the voltage profile for this case. It is clear from Fig. 13 that the voltage profile is at its limit and any further increase in the active power injection at DG2, a violation of the voltage will occur. Traditionally the active power of DG2 will be limited to about 430 kW. In Fig (5.14) the output of DG2 is increased to 540 kW and the voltage profile of the two feeders are plotted before and after the voltage regulator action. It is clear in this case that based on the proposed coordinated voltage control technique about 110 extra kW of active power injection is allowed for DG2.

What really limits the increase in DG2 injected power, in this case, is the minimum voltage at the end of feeder 2. As if the regulator reduces the voltage any more, a minimum voltage violation will occur at that point. If DG2 is required to inject even more power, then an extra voltage regulator is needed in order to separate the voltage of DG2 bus from the voltage of the end point of feeder 2, i.e., locate these two points in two different voltage control zones.

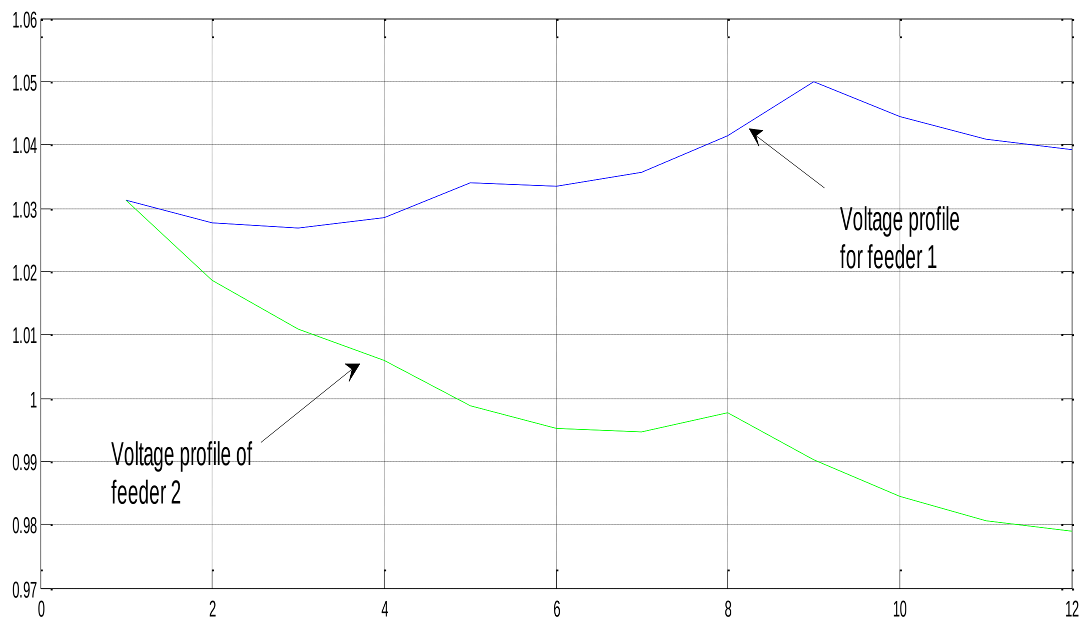


Figure (5.13) Voltage profile for the simulated system before increasing the output power of DG2

Case3:

In this case we will test the operation of the proposed algorithms in response to multiple changes in DGs outputs and load values, as follows: DG2 reduce its power to 400 kW, DG4 increases its power to 400 kW while the load at bus 7 feeder 1 increases its active power demand to 500 kW with its reactive power unchanged. Fig (5.15) shows the voltage profile of the two feeders before and after the regulation. Again, it is clear that the coordinated voltage control managed to communicate the data efficiently thus allowing the voltage regulator to take the proper decision. In this case the voltage regulator increases its output voltage to 1.0438p.u, which corresponds to tap 7.

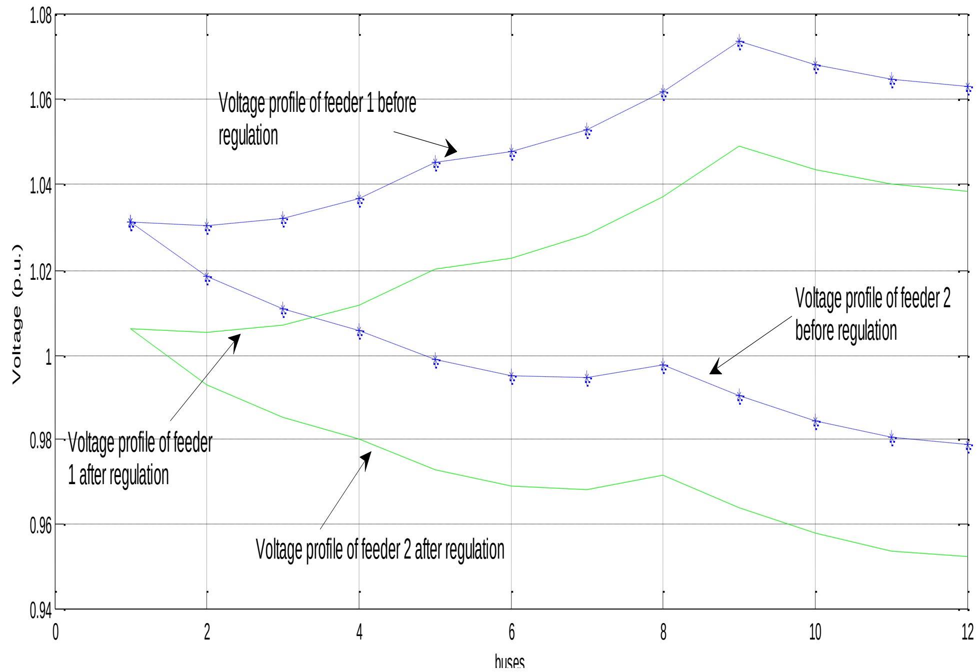


Figure (5.14) Voltage profile for the simulated system before and after regulation for case 2

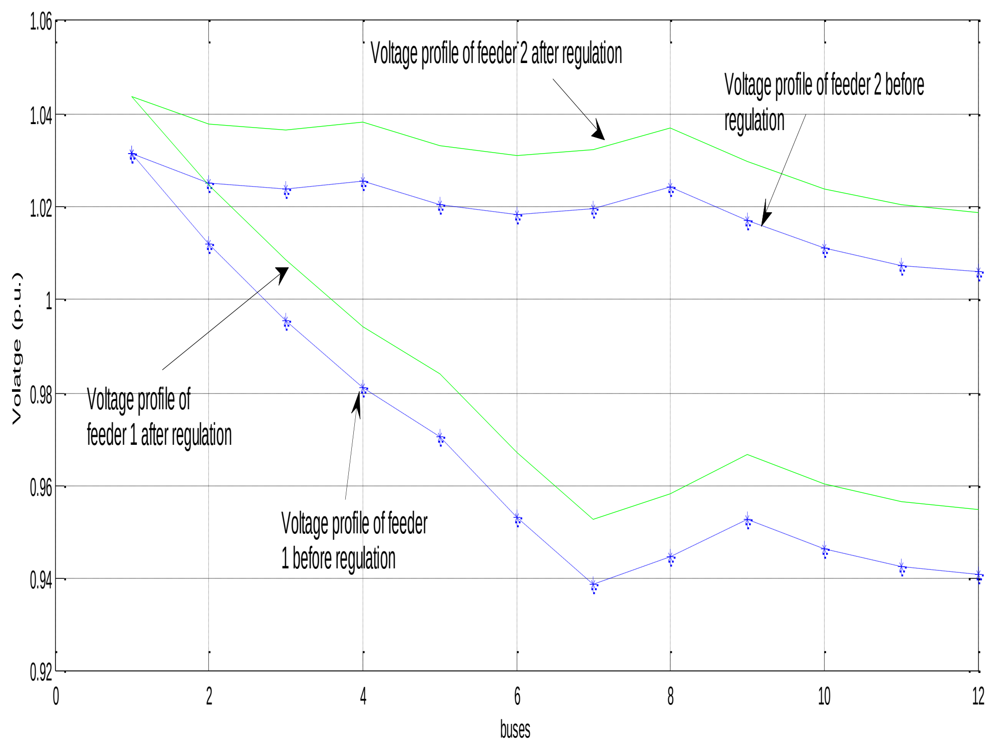


Figure (5.15) Voltage profile for the simulated system before and after regulation for case 3

5.8 Comments on Simulation Results

Several key points should be noted from the above simulation results;

1. The algorithm was able to capture all the maximum and minimum points of the voltage profile.
2. The voltage regulation was carried out based on maximum and minimum voltage points only. This is a great advantage of the proposed algorithm as there is no need to have a complete power flow solution or to measure the voltage at each and every node of the feeder.
3. It is clear from case 2 that, the proposed algorithm allowed more DG power to be injected to feeder 1 by reducing station's voltage to reduce feeder 1 voltage and accommodate the extra DG power. Meanwhile, other feeders' voltages were observed to make sure that the decrease in the station's voltage will not result in low voltage at other feeders.

5.9 Conclusions

A novel coordinated voltage control technique is proposed in this chapter to achieve efficient voltage regulation for multiple feeders in the presence of DGs. The technique is based on locating RTU at each DG. Each RTU communicate with its neighbors. It is proved in this chapter that based on the measurements of the RTU maximum and minimum voltages of the feeder can be estimated without having to measure the voltage of each and every bus of the system. Moreover, based on the analytical analysis, it is clear that locating RTU at each DG of the feeder represents the minimum number of RTU needed to estimate the voltage of the feeder accurately. Simulation results show the efficiency of the proposed technique in regulating the voltage of multiple feeders in real-time when DGs and loads change their values. Moreover, the proposed technique allows an increased DG penetration without violating the voltage profile of the system.

Chapter 6

Decentralized Reactive Power Control for Advanced Distribution Automation Systems

6.1 Introduction

Among others, the connection of DG on distribution feeders alters the operation of switched shunt capacitors. In this Chapter, we propose a decentralized optimal reactive power control scheme including the effect of DG. The same hardware structure used in Chapter 5 to achieve voltage control will be used in this Chapter to achieve the reactive power control. The proposed scheme controls switched capacitor banks, and possibly other reactive power sources, of the distribution feeder in real-time based on the loading conditions to minimize system losses while maintaining acceptable voltage profile for the feeder.

This Chapter is structured as follows; section 6.2 discusses the impact of DG on the operation of shunt capacitors. Section 6.3 details the estimation of the change of the voltage profile due to the injection of reactive power at the capacitor bus. Based on the results of sections 6.3, the proposed decentralized algorithm for reactive power control is discussed in sections 6.4 for the case of single capacitors. The general case of multiple capacitors is discussed in section 6.5. Simulation study is provided in section 6.6 to validate the proposed technique. This chapter ended with conclusions in section 6.7.

6.2 Impact of DG on the operation of shunt capacitors

The connection of DG on distribution feeders changes the voltage profile of the feeder significantly and hence alters the operation of shunt capacitors. More specifically, for a feeder without a DG, the maximum voltage of the feeder is at the station's regulator, the line regulator or at the capacitor bus. Based on this fact, voltage sensing control of capacitor measures the voltage of the capacitor bus and compare it with the maximum permissible voltage of the system. If capacitor's bus voltage exceeds the maximum voltage of the feeder, then the capacitor is switched off in order to reduce the maximum voltage of the feeder. If a DG is connected on the same feeder, the voltage sensing control of the capacitor will not work properly because the maximum voltage of the feeder might not be at the capacitor bus. In reality, there is a possibility that the DG's bus voltage exceeds the feeder permissible voltage while the capacitor's bus voltage is within the allowable voltage range. In such case, voltage sensing control of the capacitor will not disconnect the capacitor and the voltage of the feeder will remain unacceptable.

As a matter of fact, the main problem is that voltage sensing control of distribution feeder capacitors depends on local information; capacitor's bus voltage. While this approach is acceptable if there is no DG on the feeder, it is not acceptable if a DG exists on the same feeder. There is a need for coordination between DG and capacitors in order to disconnect the capacitor if the overall maximum voltage of the feeder is unacceptable. In addition, for switched capacitor banks, there is a need to determine the value of the optimal capacitance to be connected on the feeder based on real-time conditions of the system in order to minimize system's losses while maintaining system's voltage within the acceptable range. It is the goal of this Chapter to propose a solution to these problems based on the coordination between DGs and capacitors.

6.3 Estimation of Voltage Profile Change due to the Injection of Reactive Power

In order to develop a decentralized reactive power control scheme, it is imperative to develop a decentralized method to estimate the change in voltage profile due to the injection of reactive power at the capacitor connecting bus.

Due to the connection of a capacitor to the feeder, the reactive power flow from station bus will be reduced by the amount of the reactive power injected at the capacitor bus, assuming the losses are negligible. Also, all reactive power flows between any two buses upstream of the capacitor bus will be reduced by the amount of the reactive power injected at the capacitor bus. On the other hand, the reactive power flow downstream of the capacitor will not be affected. Hence, the injected Q_C can be looked at, in a superposition fashion, as if it is flowing towards the supply.

Based on this concept we can analyze the voltage profile of any feeder as follows; the voltage difference between any two buses *n* and *n-1*, upstream of the capacitor, can be written as, as shown in Chapter 5:

$$V_{(n-1)old} - V_{(n)old} = P_{n-1,n}R_{n-1,n} + Q_{(n-1,n)old}X_{n-1,n} \tag{6.1}$$

After connecting the capacitor, equation (6.1) can be written as:

$$V_{(n-1)new} - V_{(n)new} = P_{n-1,n}R_{n-1,n} + \left(Q_{(n-1,n)old} - Q_C\right) X_{n-1,n} \tag{6.2}$$

Subtracting (6.1) from (6.2) and rearranging, we get,

$$V_{(n)new} - V_{(n)old} = V_{(n-1)new} - V_{(n-1)old} + Q_C X_{n,n-1} \tag{6.3}$$

Similarly,

$$V_{(n-1)new} - V_{(n-1)old} = V_{(n-2)new} - V_{(n-2)old} + Q_C X_{n-1,n-2} \tag{6.4}$$

Ultimately,

$$V_{(1)new} - V_{(1)old} = V_{(0)new} - V_{(0)old} + Q_C X_{0,1} \tag{6.5}$$

However bus 0 is the station bus, which is assumed to be stiff, then;

$$V_{(1)new} - V_{(1)old} = Q_C X_{0,1} \tag{6.6}$$

Applying equation (6.6) recursively in equation (6.3) we can write:

$$V_{(2)new} - V_{(2)old} = Q_C X_{0,1} + Q_C X_{1,2} \tag{6.7}$$

Generalizing (6.7), we get;

$$V_{(n)new} - V_{(n)old} = Q_C X_{0,1} + Q_C X_{1,2} + Q_C X_{2,3} + \cdots + Q_C X_{n-2,n-1} + Q_C X_{n-1,n} \tag{6.8}$$

Put in compact form,

$$V_{(n)new} = V_{(n)old} + Q_C \sum_{k=1}^{k=n} X_{k-1,k} \tag{6.9}$$

Equation (6.9) gives the change in the voltage of any bus upstream of the capacitor in terms of the amount of reactive power injected at capacitor bus and feeder reactance.

On the other hand, the voltage change at any bus downstream of the capacitor bus is the same as the voltage change at the capacitor bus itself. This result follows directly from the fact that the reactive power flow downstream of the capacitor will not be changed due to the connection of the capacitor.

6.4 Optimal Operation of Switched Capacitor Banks in Distribution Feeders: Single Capacitor Case

In this section, the decentralized optimal reactive power control algorithm is discussed. The algorithm utilizes the hardware proposed in chapter 5 and depicted in Fig (5.5). The main goal of the algorithm executed by the RTUs is to enable the capacitor to determine the optimal reactive power injection based on system conditions. Discussion will be limited to the case of single capacitor in this section; the general case is deferred to the next section.

The optimal reactive power is defined as the value that will:

1- Minimize the losses of the feeder.
2- Does not cause a violation of the voltage profile along the feeder.

Firstly, we have to introduce a measure for the losses corresponding to each reactive power injection at the capacitor bus. In this work, as we do not measure the voltage at every node of the system, we cannot measure or calculate the exact amount of losses. However, knowing which reactive power will minimize the losses is enough for our calculations. Therefore, voltage difference between buses is considered as an *approximate* measure for the losses of the lines. As the difference between buses' voltages is reduced, losses will be reduced. Hence, in the following algorithms, we are looking for the reactive power injection from the capacitor that will minimize the voltage difference between feeder's buses. In other words, the optimal reactive power injection at the capacitor is the one that will minimize the losses-index defined as:

$$losses\_index = \sum_{n=1}^{N-1} (V_n - V_{n+1})^2 \tag{6.10}$$

Where N is the total number of minimum and maximum voltage points of the voltage profile of the feeder.

Secondly, to determine the optimal reactive power injection that will not violate the voltage profile, maximum and minimum values of the voltage profile corresponding to each possible reactive power injected at capacitor's bus have to be known. Note that, it is sufficient to study the effect of reactive power injections on maximum and minimum points of the voltage profile only. In addition, recall that, as was shown in Chapter 5, the proposed hardware structure can capture all maximum and minimum points of the voltage profile.

In summary, the goal of the proposed algorithm is to enable the capacitor to determine three main values corresponding to each possible reactive power injection; the maximum voltage of the feeder, the minimum voltage of the feeder and the value of the losses-index.

The algorithm is described below and it is formally stated in details in Appendix A as Algorithm #6.1 and Algorithm #6.2.

The Algorithm starts off at the farthest RTU from the station. There are five different types of RTU according to their locations relative to the capacitor. These types are; End of feeder RTU, RTU located downstream of the capacitor, Capacitor’s RTU, RTU located upstream of the capacitor and the station’s RTU. In the following, the algorithm executed by each RTU type is described.

End of feeder RTU will:

1- Read and store its bus voltage.
2- Check the condition for the minimum voltage point between itself and its upstream RTU, using the result of section 5.3, then it will estimate the value of that minimum point, if exists.
3- Send to its upstream RTU its own voltage and the estimated voltage of the minimum point accompanied with a flag indicating the possibility of the existence of a minimum voltage point.

RTU downstream of the Capacitor will:

1- Read and store its bus voltage.
2- If the minimum voltage flag received from the downstream RTU is high, check the condition for the existence of a minimum voltage point from its own side and calculate an estimate for the minimum voltage value and hence, update the voltage of the minimum point between itself and the RTU downstream of it.
3- Check for minimum voltage point between itself and its upstream RTU then it will estimate this minimum voltage point, if exists.
4- Send to its upstream RTU the following: the value of its voltage, the values of the voltages received from any downstream RTU and the estimated voltage of the minimum point between itself and the upstream RTU accompanied with a flag indicating the possibility of the existence of a minimum voltage point.

Following the above procedure, the capacitor's RTU will receive all the maximum and minimum points of the voltage profile of the part of the feeder downstream of the capacitor.

The Capacitor's RTU will:

1- Carry out the first three tasks same as the RTU downstream of the capacitor as described above.
2- Create a variable called the Overall Maximum Feeder Voltage corresponding to each of the possible capacitor's reactive power injection.
3- Create a variable called the Overall Minimum Feeder Voltage corresponding to each of the possible capacitor's reactive power injection.
4- Calculate the new capacitor's bus voltage corresponding to each possible reactive power injection utilizing equation (6.9).
5- As noted in section 6.3, voltage change for the points downstream of the capacitor is the same as voltage change of the capacitor bus. So the capacitor can update the voltages of the points downstream of its bus based on the data it had received from its downstream RTU.
6- Having the new voltages corresponding to the possible reactive power injection for the part of the feeder downstream of the capacitor, the capacitor's RTU can update the Overall Maximum and the Overall Minimum Feeder Voltage variables.
7- Having the new voltages corresponding to the possible reactive power injections for the part of the feeder downstream of the capacitor, the capacitor's RTU can calculate the losses-index for that part using equation (6.10).
8- Send to its upstream RTU the following: Overall Maximum Feeder Voltage, Overall Minimum Feeder Voltage, the losses-index, list of all the possible reactive power injections at its bus, the voltage of the capacitor bus.

RTU upstream of the Capacitor will:

1- Carry out the first three tasks same as the RTU downstream of the capacitor as described above.

2- Calculate its new voltages corresponding to the possible reactive power injections at the capacitor using (6.9).
3- If there is a minimum voltage point downstream of the subject RTU, the subject RTU will calculate the new voltages of the minimum point corresponding to the possible reactive power injection at the capacitor using equation (6.9).
4- Update the Overall Maximum and Overall Minimum feeder voltages variables according to its calculations of the new voltages at its bus and at the minimum point downstream of it.
5- If there is a minimum point downstream of the subject RTU, the subject RTU will calculate the losses-index between that minimum point and the downstream RTU in addition to the losses-index between itself and that minimum point. Otherwise, it will calculate the losses-index between itself and the downstream RTU. In any case, it will update the losses-index received from the downstream RTU accordingly.
6- Send to its upstream RTU the following: Overall Maximum Feeder Voltage, Overall Minimum Feeder Voltage, the losses-index, list of all the possible reactive power injections at its bus, the voltage of its own bus.

<u>The station RTU will:</u>

1- Carry out the first three tasks same as the RTU downstream of the capacitor as described above.
2- If there is a minimum voltage point downstream of the subject RTU, the subject RTU will calculate the new voltages of the minimum point corresponding to the possible reactive power injection at the capacitor using equation (6.9).
3- Update the Overall Maximum and Overall Minimum feeder voltages variables according to its calculations of the new voltages at its bus and at the minimum point downstream of it.

4- If there is a minimum point downstream of the subject RTU, the subject RTU will calculate the losses-index between that minimum point and the downstream RTU in addition to the losses-index between itself and that minimum point. Otherwise, it will calculate the losses-index between itself and the downstream RTU. In any case, it will update the losses-index received from the downstream RTU accordingly.
5- At this point the station RTU will have the Overall Maximum Feeder Voltage, Overall Minimum Feeder Voltage, the losses-index for the whole feeder. So the station's RTU will determine the optimal reactive power injection which corresponds to the minimum losses and, at the same time, does not violate the voltage profile.
6- Send to the downstream RTU the optimal reactive power injection to pass it to the capacitor.

<u>Comments</u>:

1- Limiting the number of switching operations of the capacitor can be incorporated easily in the proposed algorithm. Simply, there could be a counter at the capacitor RTU to count how many switching operations took place in a certain predetermined period. If the number of allowable switching operations is reached the capacitor will convert to the idle status.
2- It is not necessary to predefine the RTU as upstream or downstream of the capacitor. In fact, that can be done dynamically. One way of doing that is to have a capacitor-flag that indicates that the capacitor is downstream. The only RTU that is allowed to set this flag high is the capacitor's RTU. As messages propagate from the end of feeder, each RTU will decide its location as follows: As long as the capacitor flag is low, then the location is downstream of the capacitor.
3- For the RTU of lateral points, i.e. the points where two laterals of the feeder join, it needs to classify the downstream laterals, based on the received reactive power lists, as laterals that have capacitors and laterals that have no capacitor. Laterals with capacitors

will be dealt with in section 6.5.2. For the laterals with no capacitors, the change of their voltage will be the same as the change in the voltage of the lateral point itself. So the lateral point RTU's will calculate the change in its own voltage and then updated the voltage of the lateral that has no capacitors.

4- It is to be noted that, the change of reactive power injections might produce or remove minimum points from the voltage profile. Hence, each time an RTU calculates the change in its voltage due to the injections of reactive power, it also calculates the change of the voltage of the points just downstream and upstream of it, recall from Chapter 5 that each RTU measures the voltages of the points just upstream and downstream of it in order to check for minimum points of the voltage profile. Based on these calculated values, each RTU sends to its upstream RTU the possibility of the existence of minimum voltage point, from its point of view, corresponding to each reactive power injection.

6.5 Optimal Operation of Switched Capacitor Banks in Distribution feeders: Multiple Capacitors Case

6.5.1 Multiple capacitors on the same lateral

In this section we extend the algorithm presented in section 6.4 to include the case when more than one capacitor exists on the feeder. Two different methods are discussed here to tackle this problem. These methods are explained below;

6.5.1.1 Proposed Method #1:

To illustrate the idea of this method, consider Fig (6.1). Without loss of generality, and only to make the illustration clearer, we arbitrarily placed two capacitors at buses 5 and 9. Close analysis of the reactive power flow yields the following; for the part of the feeder downstream of C2, voltage change will be the same as the voltage change at bus

9. For the part of the feeder between the two capacitors, i.e. buses 6, 7 and 8, voltage change will depend on the reactive power injections of C1 and C2. Finally, for the part of the feeder upstream of C1 voltage change will depend on the reactive power injections of C1 and C2, as well. Based on this view, equation (6.8) can be written, in a general form, as;

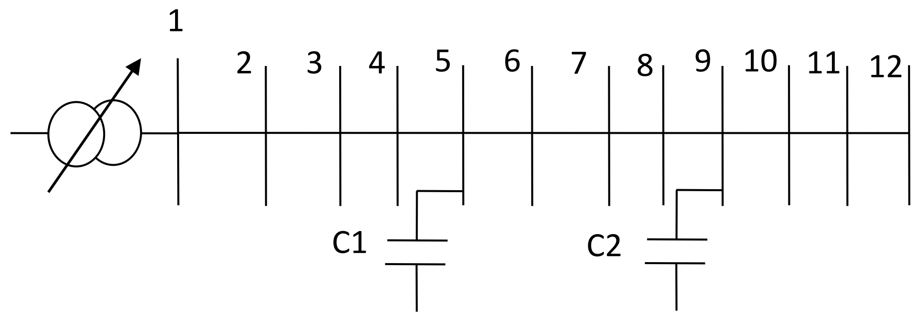


Figure (6.1) Illustration of the case of multiple capacitors on the same lateral

$$V_{(n)new} - V_{(n)old} = Q_{(C),0,1}X_{0,1} + Q_{(C),1,2}X_{1,2} + Q_{(C),2,3}X_{2,3} + \cdots + + Q_{(C),n-2,n-1}X_{n-2,n-1} + + Q_{(C),n-1,n}X_{n-1,n} \quad (6.11)$$

Applying equation (6.11) for bus 9 of Fig (6.1) yields,

$$V_{(9)new} - V_{(9)old} = (Q_{(C1)} + Q_{(C2)})X_{1,2} + (Q_{(C1)} + Q_{(C2)})X_{2,3} + (Q_{(C1)} + Q_{(C2)})X_{3,4} + (Q_{(C1)} + Q_{(C2)})X_{4,5} + Q_{(C2)}X_{5,6} + Q_{(C2)}X_{6,7} + Q_{(C2)}X_{7,8} + Q_{(C2)}X_{8,9} \quad (6.12)$$

Rearranging we get,

$$V_{(9)new} - V_{(9)old} = Q_{(C1)}(X_{1,2} + X_{2,3} + X_{3,4} + X_{4,5}) + Q_{(C2)}(X_{1,2} + X_{2,3} + X_{3,4} + X_{4,5} + X_{5,6} + X_{6,7} + X_{7,8} + X_{8,9}) \quad (6.13)$$

Similarly, for any bus from 6 to 9, we can write;

$$V_{(n)new} - V_{(n)old} = Q_{(C1)} \sum_{k=2}^{5} X_{k-1,k} + Q_{(C2)} \sum_{k=2}^{n} X_{k-1,k} \quad (6.13)$$

Note that, the first term of the right hand side of equation (6.13) is constant for each value of Q_{c1}. Therefore, these constants can be calculated at the design time and be given for RTUs 6 till 9 to be used as a correction factor for equation (6.9).

Utilizing these correction factors, the exact algorithm described in section 6.4 might be used here except that to calculate the change of feeder's voltage profile due to reactive power injections for buses 6 to 9, equation (6.13) will be used to include the effect of C1 and C2. For buses 2 to 5 the summation of all the combinations of the possible reactive powers of both capacitors will be used in equation (6.9) and for buses 10 to 12, the change of the voltages is the same as the change of bus 9 voltage. In a side note, in all of the calculations, RTUs of buses 6 to 8 will identify themselves as RTUs upstream of a capacitor and will execute their calculations accordingly.

Effectively, RTU of C1 will have to combine the possible reactive power injections list received from its downstream RTU with its own possible reactive power list and pass the new combined list to its upstream RTU.

Finally, Station's RTU will get the maximum voltage of the feeder, the minimum voltage of the feeder and the losses-index corresponding to all the possible combinations of the reactive powers of both capacitors. Therefore, station's RTU will be able to determine which combination of the reactive power injections of the two capacitors is optimal and hence it will send its decision back to C1 and C2 for implementation.

6.5.1.2 Proposed Method #2:

Following the same analysis of section 6.3, one can notice that equation (6.3) is a general equation that gives the voltage change at a certain bus in terms of the voltage change at its upstream bus. This equation can be used to estimate the voltage change at a certain bus given the reactive power flow between this bus and its upstream bus.

$$V_{(n)new} - V_{(n)old} = V_{(n-1)new} - V_{(n-1)old} + Q_C X_{n,n-1} \quad (6.3)$$

In order to calculate the voltage change due to the reactive power injections at a certain RTU using equation (6.3), it is necessary to know the voltage change at the RTU upstream of the subject RTU. Therefore, the algorithm of this method is carried out in two phases; Forward phase and backward phase. These two phases are described below, while, the details of these phases can be found in Appendix A as Algorithm # 6.3.

A. Forward Phase:

This phase can be described in the following points;

1- RTUs will utilize the voltage estimation algorithm presented in Chapter 5 to estimate the voltage profile of the feeder, the details of this algorithm can be found in Appendix A as Algorithm#5.2.

2- In addition, each capacitor will send a list of its possible reactive power injection to its upstream RTU.

3- Each RTU will store the received reactive power injections list to be used in the backward phase.

4- When a capacitor's RTU receives a list of possible reactive power injections from the downstream RTU, it will combine the received list with a list of the possible reactive power injections of its own capacitor and forward the combined list to the upstream RTU.

Effectively, at the end of the forward phase each RTU will have stored its voltage and a list of the combined reactive power injections from capacitors downstream of it. Hence, for each RTU to calculate the change in its voltage due to the reactive power injections using equation (6.3), it only needs to have the change in the upstream RTU voltage. The forward phase will end at the station.

B. <u>Backward Phase:</u>

The backward phase starts at the station and propagates in the downstream direction. This phase can be described as follows;

1- Each RTU will receive the voltage change of its upstream RTU. Note that as the station bus is assumed to be stiff, the change in its voltage is zero.
2- After receiving the change of the upstream RTU voltage, each RTU will be able to calculate the change in its own voltage corresponding to the list of the reactive power injection stored at the forward phase using equation (6.3).
3- The RTUs will be able to calculate the losses index in the same way described in section 6.4.
4- Ultimately, the most downstream capacitor will have the maximum and the minimum voltages, in addition to, the losses index of the feeder corresponding to each possible combination of the reactive power injections from feeder's capacitors.
5- Therefore, the most downstream capacitor will be able to determine which combination of reactive power injections of feeder's capacitors is optimal and hence it will send its decision back to upstream capacitors, C1 in the case of the system of Fig (6.1).

6.5.2 Multiple capacitors on different laterals

The most general case for the algorithm is the case when the capacitors are located on different feeder laterals, as shown in Fig (6.2). The two methods described in section 6.5.1

can be used here. The application of method 1 should be a straight forward extension of the case discussed in section 6.5.1. Therefore, only method 2 will be discussed in details below. The forward and the backward phases of method 2 of section 6.5.1 are modified in the following. While the algorithm can be applied for any general configuration, to clarify the method, it will be explained for the system shown in Fig. (6.2). Note that, in the following, for simplicity; RTU5 means the RTU associated with bus 5 and so on.

A. ***<u>Forward Phase:</u>***

The forward phase of the algorithm will be essentially the same as the one discussed for method 2 of section 6.5.1 with the following changes:

1. Two forward phases will start from bus 12 and bus 18 at the same time.
2. These two forward phases will combine at RTU5.
3. The messages propagated upstream of bus 5 will carry all combinations of the possible reactive power injections at C1 and C2 to be used later in equation (6.3) during the backward phase.

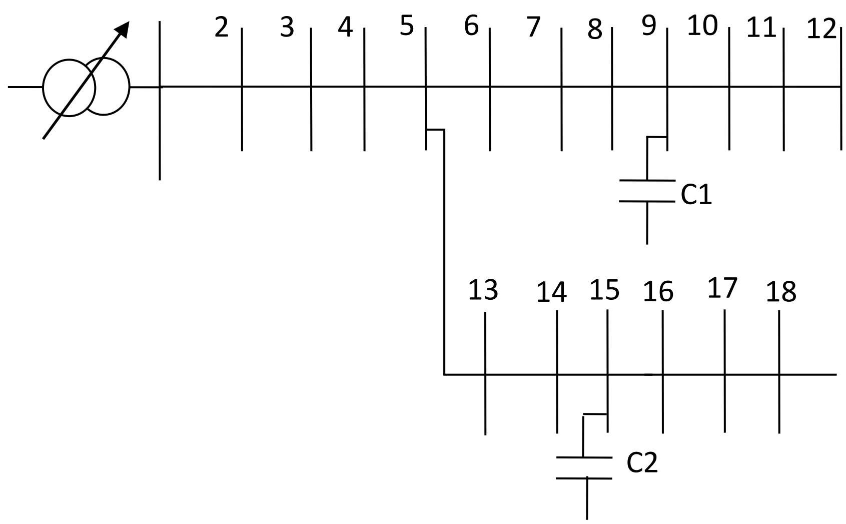


Figure (6.2) Illustration of the case of multiple capacitors on the different laterals

B. Backward Phase:

The difference between this case and the case described at section 6.5.1 is that in this case we need to calculate the change in the voltage profile for the two laterals and hence calculate the maximum voltage, minimum voltage and the losses index of the whole feeder. For the part of the feeder from the station till bus 5 the exact same algorithm discussed in section 6.5.1 will be used. Starting at bus 5 two backward waves will be initiated one for each lateral. However, to include the effect of each lateral on the losses, backward waves will be initiated sequentially. In other words, RTU5 will initiate the first backward wave towards C1 and wait to get back from C1, and then it will initiate the second backward phase towards C2. This process is described below;

1- RTU5 will carry out the following tasks:

   a. Calculate the voltage change at bus 5 due to all the possible combination of reactive power injections at C1 and C2 in a same manner as all buses upstream of bus 5.

   b. Move the backward wave of calculations towards bus 6. In other words, RTU5 will assume that there is just one lateral and ignore, for now, the existence of the lateral downstream of bus 13.

2- The backward wave from bus 6 till bus 9 will be carried out exactly in the same manner as the method 2 discussed in section 6.5.1 with the possible reactive power injections of C1 alone used in equation (6.3).

3- RTU9 will determine the maximum voltage of the feeder, the minimum voltage of the feeder and the losses-index corresponding to the possible combinations of the reactive powers of both capacitors. However, in these calculations, the second lateral is not included yet.

4- RTU9 will send back to RTU5 the values of the maximum voltage of the feeder, the minimum voltage of the feeder and the losses-index which RTU9 has calculated in step 3.

5- Now, RTU5 will initiate the second backward wave towards bus 13.

6- The backward wave from bus 13 till bus 15 will be carried out exactly in the same manner as method 2 of section 6.5.1 with the possible reactive power injections of C2 alone used in equation (6.3).

7- Finally, RTU15 will be able to calculate the overall maximum voltage of the feeder, overall minimum voltage of the feeder and overall losses-index for all the possible combinations of the reactive powers of both capacitors. Hence RTU15 will be able to determine the optimal reactive power injection of C1 and C2.

8- Ultimately, RTU15 will send its decision about the optimal reactive power of C1 to RTU5 which will propagate that information back to RTU9 to end the algorithm.

The generalization of the above procedure for any feeder structure with arbitrary number of capacitors can be formalized based on the concept of the Depth First Search (DFS) [88]. DFS is a well-known algorithm to search a graph. The idea of the DFS algorithm is to start at the root of the graph and explore as far as possible along each branch followed by backtracking till the whole graph is explored. For example, for the system of Fig (6.2), based on the DFS, the search order is RTU1-RTU5-RTU9-RTU5-RTU15.

Another example for a more complicated feeder structure is shown in Fig (6.4) and the corresponding graph is shown in Fig (6.5). For this system, based on the DFS sequence, the flow of the backward phase of calculations for the proposed algorithm will be as follows: RTUS-RTUA-RTUC-RTUE-RTUC-RTUD-RTUA-RTUB-RTUF-RTUH-RTUI-RTUH-RTUF-RTUG.

In other word, the forward phase of the algorithm will be carried out as explained earlier in this section observing the values of propagated reactive power. For instance, for the part of the feeder between RTUF and RTUH, the reactive power value of Capacitor I alone will be used. On the other hand, for the part of the feeder between RTUA and RTUB, the reactive power value of Capacitor I, G and B will be used. For the backward wave, the sequence of the calculations will follow the DFS. For example, RTUA will forward the backward wave towards RTUC which will forward it to RTUE. RTUC will wait to get the results back from RTUE and then forward the updated results to RTUD. Once RTUC get the updated results back from RTUD, it will get back to its *parent*, RTUA. Once RTUA gets back from RTUC, it will forward the calculations of the backward wave towards the other child, RTUB. The algorithm will continue in this manner till RTUG, assumingly the last RTU in the sequence, do its calculations and determine the optimal settings for all the capacitors. These settings will propagate back towards the respective capacitor in a reverse sequence.

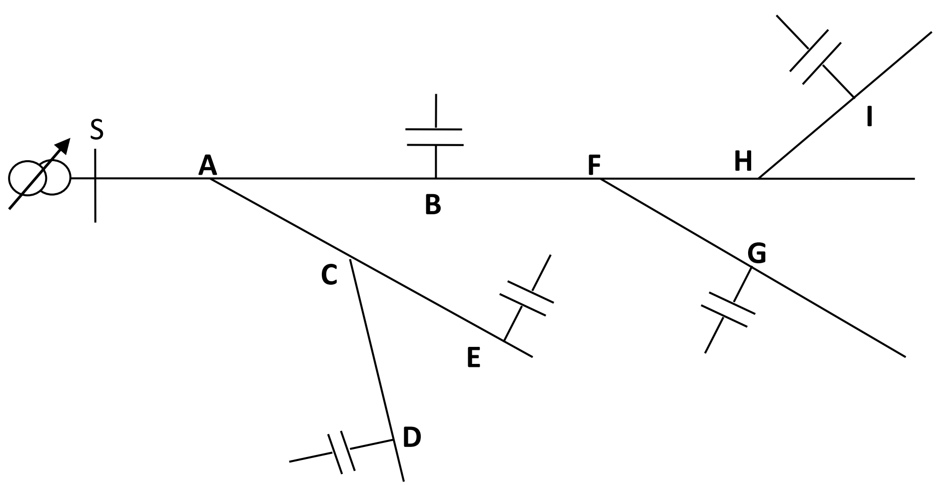


Figure (6.3) General case for multiple capacitors on a feeder

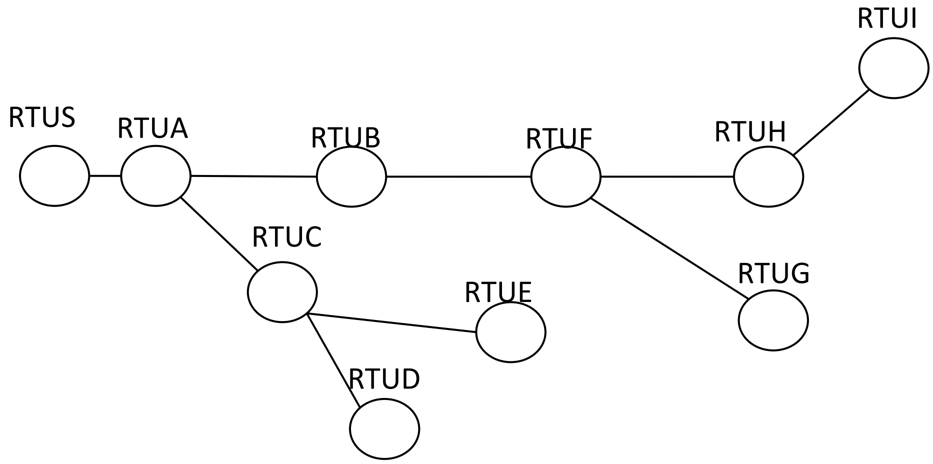


Figure (6.4) Graph corresponding to the system of Figure (6.3)

Comments:

1- No centralized supervisor is needed to carry out the above algorithm as each RTU knows its upstream and downstream neighbors, *its Parent and children*.

2- Each capacitor will take a partial decision and returns to its parent. After all, the station will get back from its children RTUs, take the final decision and propagate it back to the capacitors.

3- The DFS provides a formal, and systematic, way to explore the whole feeder in order to include the effect of all capacitors and calculate globally optimal solution.

4- The sequence generated by the DFS is not unique. Each RTU will rank and explore its children branches in an arbitrary way.

5- Although the algorithm above can handle arbitrary number of capacitors in any radial feeder structure, it should be noted that for any practical feeder it is rare to have more than three shunt capacitor banks installed.

6.6 Simulation Study

In this section several simulation results will be reported to validate the proposed reactive power control scheme. We will start by testing the ability of the proposed technique to estimate the change of the voltage profile due to change in reactive power injection at the capacitor bus. Following that, we will test the capability of the proposed algorithm in controlling the operation of single and multiple capacitors.

6.6.1 Voltage profile change due to reactive power injection

Fig (6.5) shows the system under study; two DGs are connected to buses 5 and 9 and a capacitor is connected to bus 7. Loads and generation values are given in Table 6-1. For all of the following cases we assume the following data:

The station bus voltage = 1.05 pu.

The maximum allowable voltage = 1.06 pu.

The minimum allowable voltage = 0.94 pu.

The impedance of any line section = 0.00344 +j 0.0029 p.u

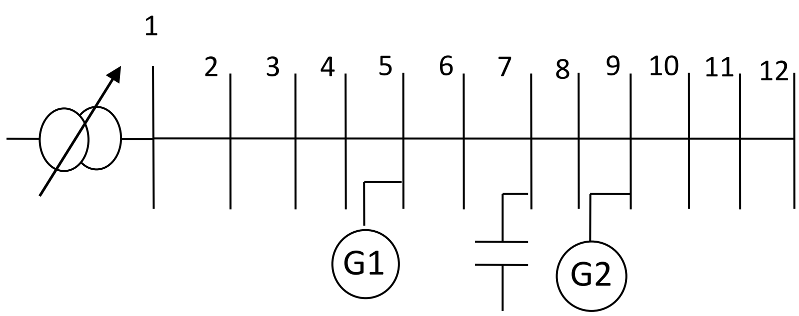


Figure (6.5) System used for the simulation study

In this section, we will test the ability of the algorithm to estimate the change in voltage profile due to the injection of reactive power at the capacitor bus. Different reactive power values are injected at the capacitor bus and the voltage profile estimated by the proposed algorithm, Appendix A Algorithm #6.1, is compared with the voltage profile obtained from a standard power flow algorithm. Figures (6.6), (6.7) and (6.8) show the results.

Table 6-1 load and generation value for the system of Figure (6.5)

Bus #	P(kW)	Q(kVar)
2	26	60
3	40	30
4	55	55
5	-80	0
6	60	15
7	55	0
8	45	45
9	-250	0
10	35	30
11	40	30
12	30	15

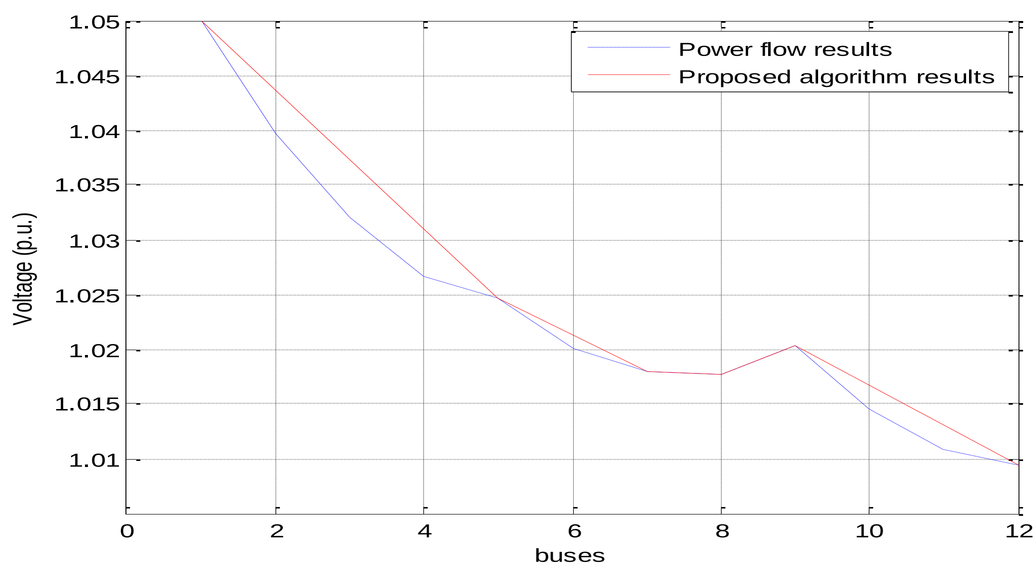


Figure (6.6) Voltage profile generated from power flow algorithm versus voltage profile obtained from the proposed algorithm. Capacitor reactive power = 0

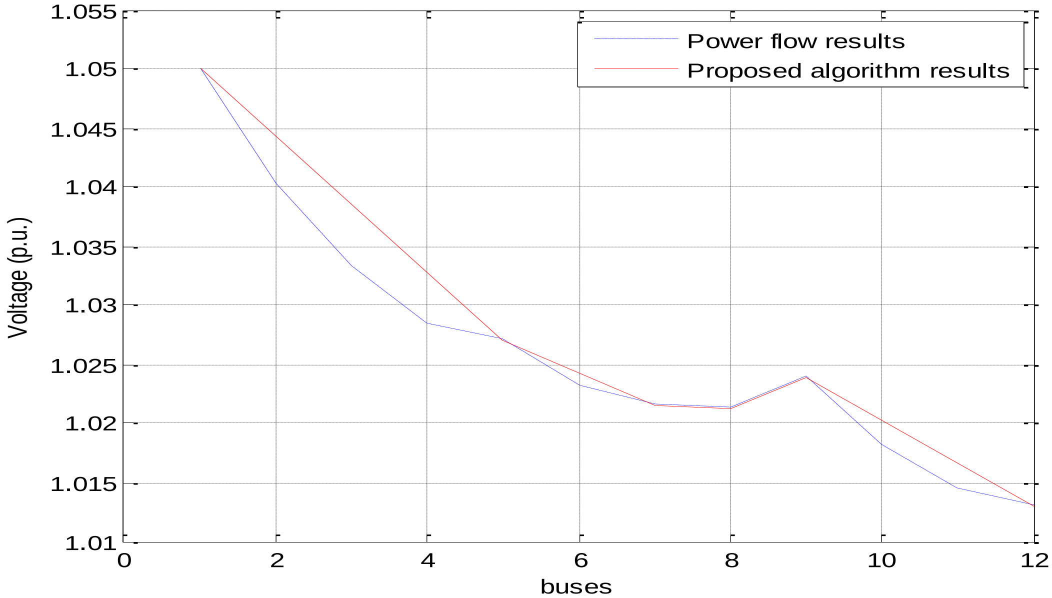


Figure (6.7) Voltage profile generated from power flow algorithm versus voltage profile obtained from the proposed algorithm. Capacitor reactive power = 20 kVAR

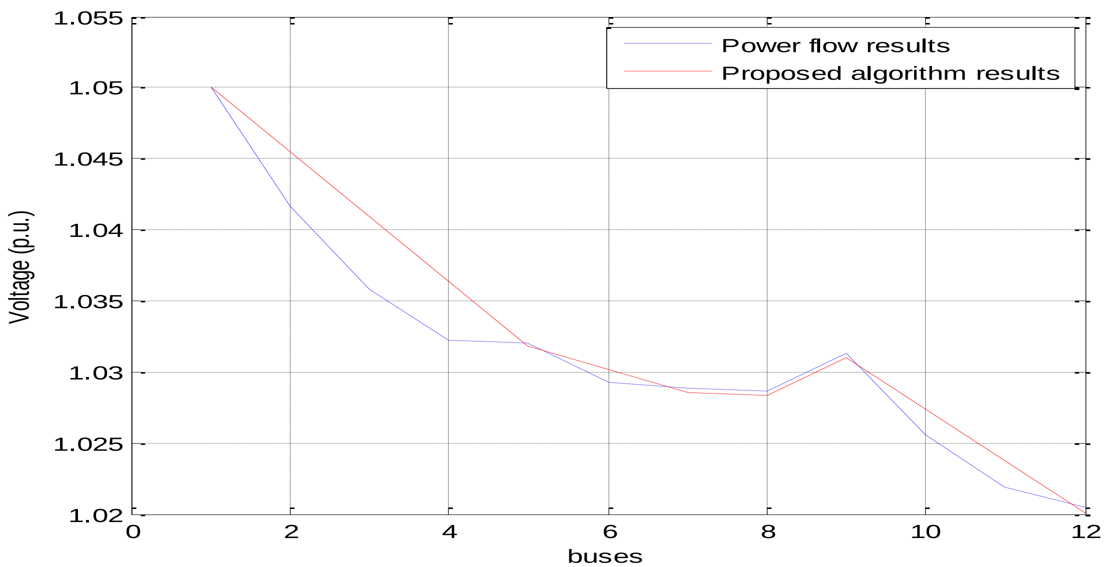


Figure (6.8) Voltage profile generated from power flow algorithm versus voltage profile obtained from the proposed algorithm. Capacitor reactive power = 65 kVAR.

6.6.2 Optimal reactive power control

6.6.2.1 Single Capacitor case:

In this section we will test the proposed reactive power control algorithm.

Case 1:

For the same system used in section 6.6.1, the goal is to determine the optimal reactive power which will minimize the losses while maintaining the voltage profile of the feeder. It is assumed here that the switched capacitor banks at bus 7 can inject reactive power of 20, 40 or 65 kVAR. After running Algorithm #6.1 of Appendix A, station's RTU will get the following data for each possible reactive power injection;

	Q = 0	Q = 20	Q = 40	Q = 65
Feeder Max Voltage (p.u)	1.05	1.05	1.05	1.05
Feeder Min Voltage (p.u)	1.0094	1.0130	1.0165	1.0210
Losses index	0.8136	0.6847	0.5698	0.4460

It is apparent that the optimal setting is Q = 65 kVAR. To validate this results a power flow algorithm was used to calculate the losses corresponding to each reactive power injection, the results are tabulated below;

	Q = 0	Q = 20	Q = 40	Q = 65
Losses(kW)	10.1	8.7	7.4	6.1

Case 2:

In this case we will test the performance of the proposed technique in reaction to a change in DG output power. For the sake of simulation, assume that DG1 injects 200 kW and DG2 injects 300 kW. Based on the new power injections and after running Algorithm # 6.1 of Appendix A, the capacitor RTU will get the following data for each possible reactive power injection;

	Q = 0	Q = 20	Q = 40	Q = 65
Feeder Max Voltage (p.u)	1.05	1.0523	1.0559	1.0603
Feeder Min Voltage (p.u)	1.0413	1.0417	1.0452	1.0425
Losses index	0.370	0.356	0.0353	0.0350

Although, Q = 65 kVar causes less losses, the corresponding voltage profile is not acceptable. It is apparent that the optimal setting is Q = 40 kVAR. To validate this results a power flow algorithm was used to calculate the losses corresponding to each reactive power injection, the results are tabulated below;

	Q = 0	**Q = 20**	**Q = 40**	**Q = 65**
Losses(kW)	14.3	12.9	11.7	10.4

Fig (6.9) shows the voltage profile obtained from the power flow algorithm and from the proposed voltage estimation algorithm.

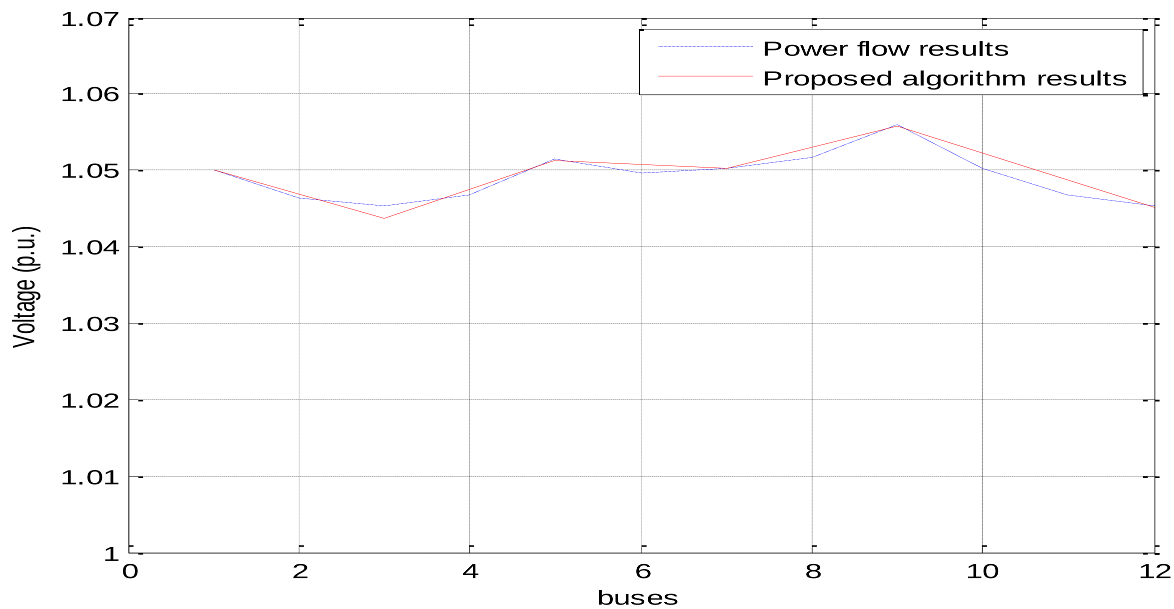


Figure (6.9) Voltage profile of the system of Fig (6.5) with capacitor reactive power = 40 kVAR

6.6.2.2 Multiple Capacitors on the same lateral

Fig (6.10) shows the system under study. Loads and generation values are given in Table 6-2. For all of the following cases we assume the following data:

The station bus voltage = 1.055 pu.

The maximum allowable voltage = 1.06 pu.

The minimum allowable voltage = 0.94 pu.

The impedance of any line section = = 0.00344 +j 0.0029 p.u

Reactive power values of Capacitor 1, connected to bus 5 = 0, 20 and 35 kVAR.

Reactive power values of Capacitor 2, connected to bus 10 = 0, 30 and 40 kVAR.

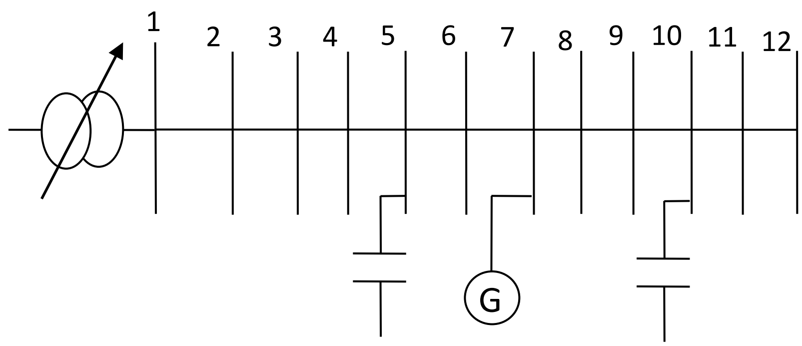


Figure 6.10 System used for simulation study of section 6.6.2.2

Table 6-2 Load and generation values of the system of Figure (6.10)

Bus #	P(kW)	Q(kVar)
2	26	60
3	40	30
4	55	55
5	20	0
6	60	15
7	-400	0
8	45	45
9	35	0
10	35	0
11	40	30
12	30	15

After running the algorithm described in section 6.5.1.1, also refer to Algorithm #6.1 of Appendix A, regulator's RTU will get the following data corresponding to each possible reactive power injection;

Possible reactive power injection	Maximum voltage of the feeder	Minimum voltage of the feeder	Estimated Losses index	Actual losses using a power flow program (kW)
Q1 = 0 , Q2 = 0	1.0550	1.0275	0.6823	11.6
Q1= 0, Q2 = 40	1.0592	1.0381	0.5843	9.1
Q1= 0, Q2 = 30	1.0574	1.0355	0.6030	9.7
Q1= 20, Q2 = 0	1.0550	1.0299	0.6764	10.7
Q1= 20, Q2 = 40	1.0616	1.0405	0.5916	8.5
Q1= 20, Q2 = 30	1.0598	1.0379	0.6068	8.9
Q1= 35, Q2 = 0	1.0562	1.0316	0.6760	10.1
Q1= 35, Q2 = 40	1.0633	1.0423	0.6017	8
Q1= 35, Q2 = 30	1.0592	1.0381	0.6142	8.4

Based on these data, the optimal reactive power is Q1 = 0 and Q2 = 40. The estimated and actual voltage profiles corresponding to this case are shown in Fig (6.11). It should be noted that, based on the actual losses obtained from a standard power flow program, the losses corresponding to the case of Q1 = 35 kVar and Q2 = 40 kVar is less than the losses of the case selected by the proposed algorithm. The algorithm could not get to the best reactive power combination due to the error in estimating the minimum voltage points of the voltage profile, thus, the calculation of the losses index is approximate. Even though the error is not significant, it is possible by efficient incorporation of network specific data to get a better estimation for minimum points by assuming a more realistic load distribution between RTUs.

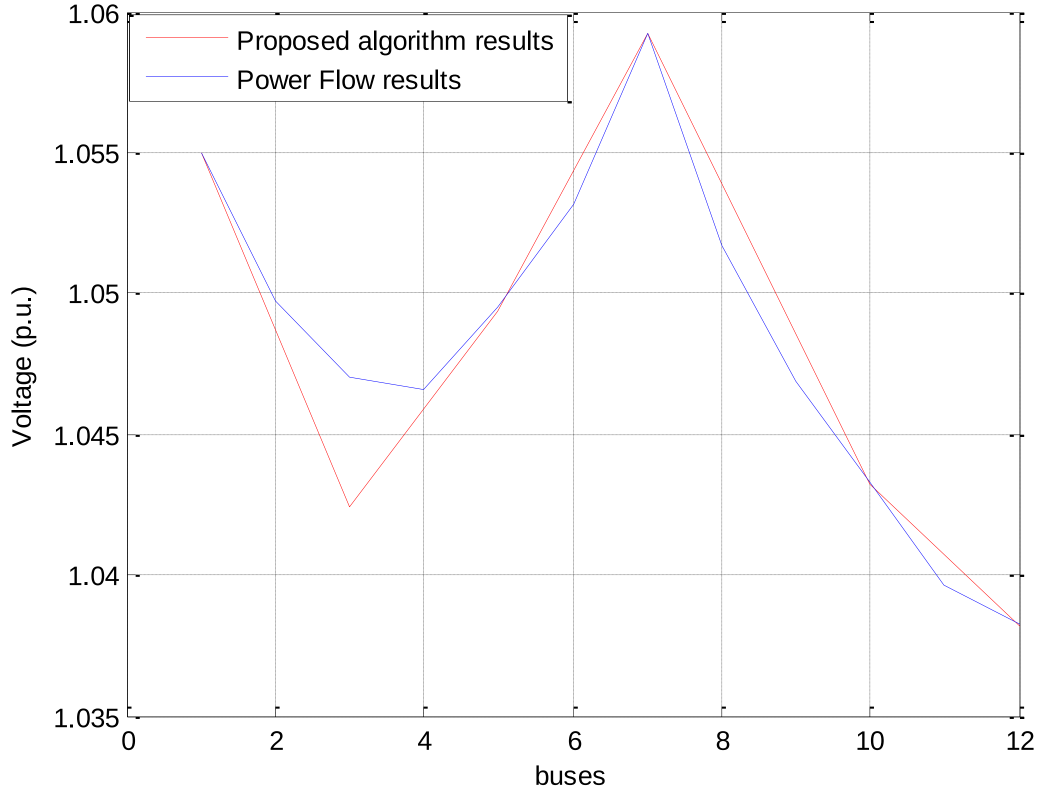


Figure (6.11) Voltage profile of the system of Fig (6.10) with Q1 = 0, Q2 =40kVar

6.6.2.3 Multiple Capacitors on different laterals

Fig (6.12) shows the system under study. Loads and generation values are given in Table 6-3. For all of the following cases we assume the following data:

The station bus voltage = 1.055 pu.

The maximum allowable voltage = 1.06 pu.

The minimum allowable voltage = 0.94 pu.

The impedance of any line section = = 0.00344 +j 0.0029 p.u

Reactive power values of Capacitor 1, connected to bus 5 = 0, 20 and 35 kVAR.

Reactive power values of Capacitor 2, connected to bus 10 = 0, 30 and 40 kVAR.

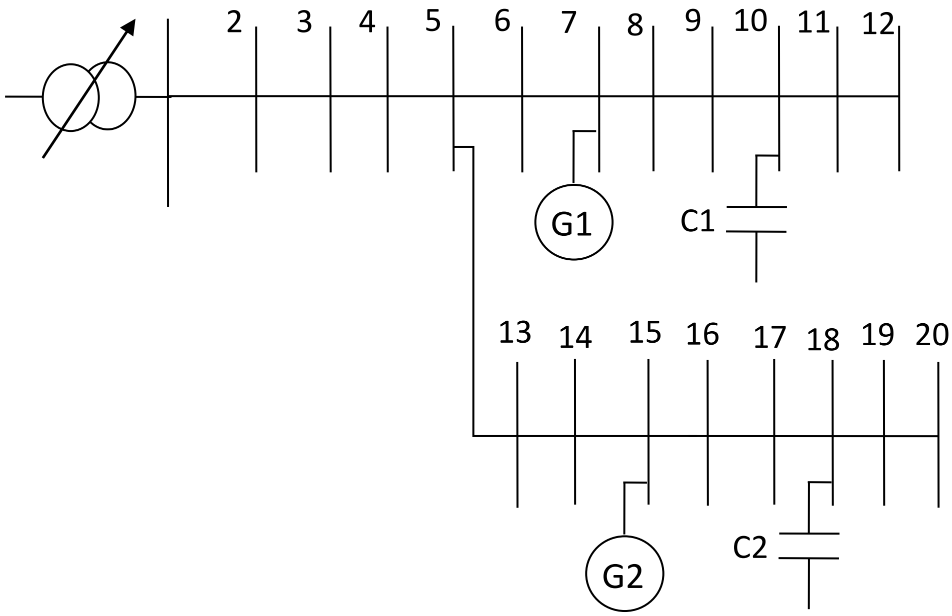


Figure (6.12) System used for simulation study of section 6.6.2.3

Table 6-3 Load and generation values of the system of Figure (6.12)

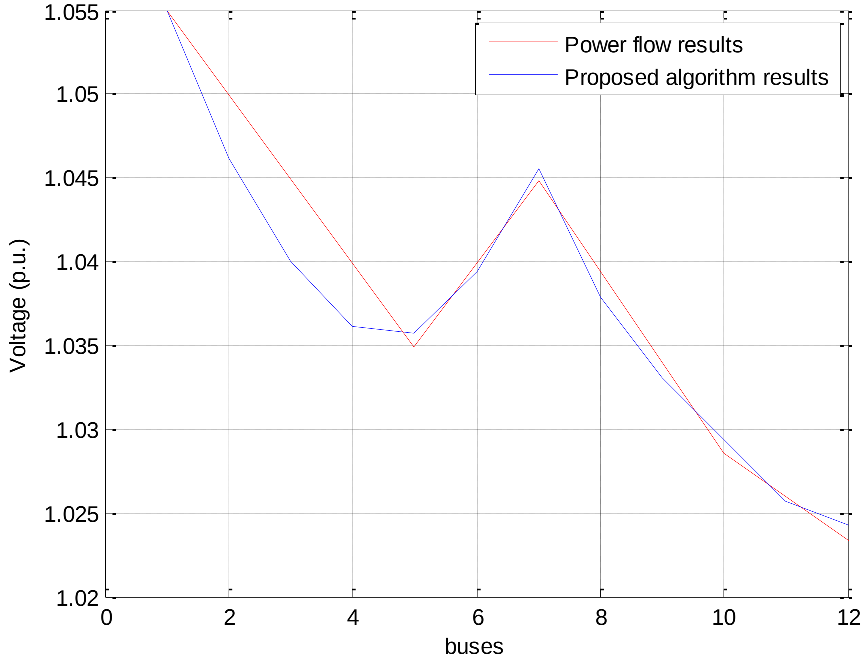
Bus #	P(kW)	Q(kVar)	Bus #	P(kW)	Q(kVar)
2	26	60	13	40	25
3	40	30	14	35	15
4	55	55	15	-350	0
5	20	0	16	30	15
6	60	15	17	15	30
7	-420	0	18	40	0
8	45	45	19	30	25
9	35	0	20	30	15
10	35	0			
11	40	30			
12	30	15			

Case 1:

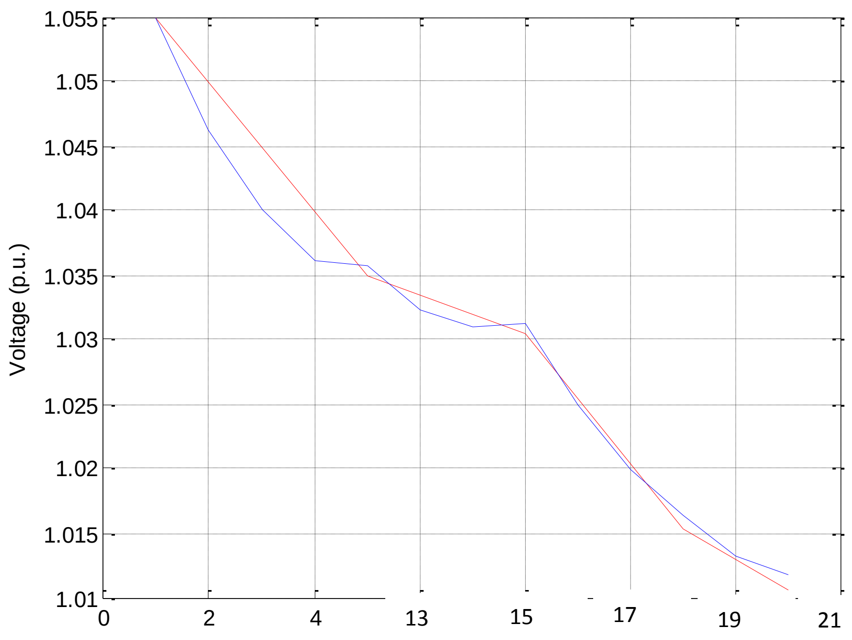
After running the algorithm described in section 6.5.2 the regulator RTU will get the following data corresponding to each possible reactive power injection;

Possible reactive power injection (kVar)	Maximum voltage of the feeder (p.u)	Minimum voltage of the feeder (p.u)	Estimated Losses index	Actual losses using a power flow program (kW)
Q1 = 0 , Q2 = 0	1.0550	0.9955	1.7	23.3
Q1= 0, Q2 = 30	1.0550	0.9991	1.4	20.2
Q1= 0, Q2 = 40	1.0550	1.0002	1.3	19.3
Q1= 20, Q2 = 0	1.0550	1.0014	1.5	21
Q1= 20, Q2 = 30	1.0550	1.0050	1.2	18.1
Q1= 20, Q2 = 40	1.0550	1.0062	1.2	17.2
Q1= 35, Q2 = 0	1.0550	1.0059	1.3	19.4
Q1= 35, Q2 = 30	1.0550	1.0094	1.1	16.6
Q1= 35, Q2 = 40	1.0550	1.0106	1.0	15.9

Based on these results, the optimal reactive power is Q1 = 35 and Q2 = 40. The estimated and actual voltage profiles corresponding to this case are shown in Fig (6.13.a) for buses 1 to 12 and Fig (6.13.b) for buses 1 to 5 and then 13 to 20. The power flow solution confirms the solution obtained by the proposed algorithm.



(a)



(b)

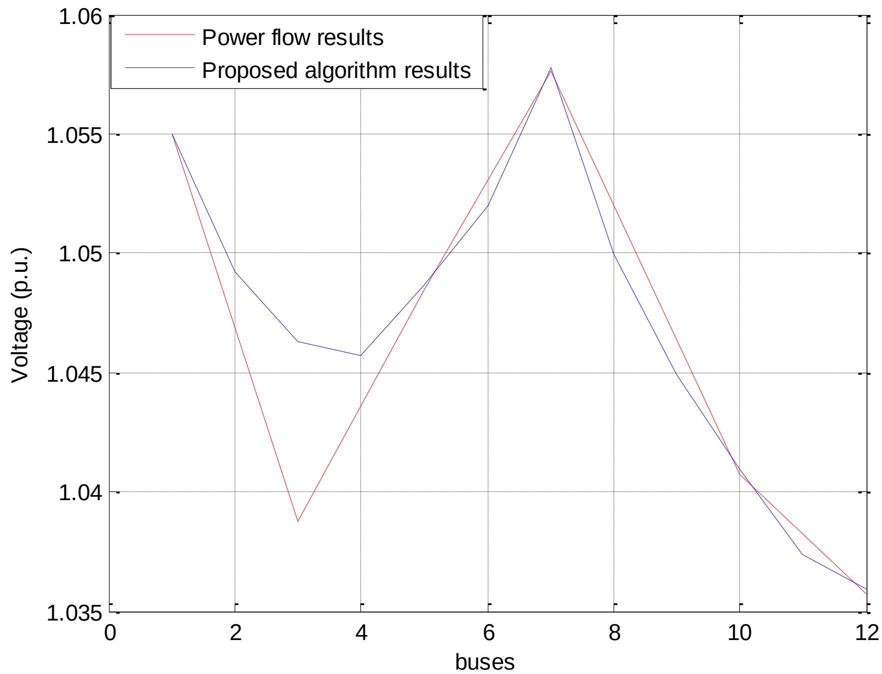
Figure (6.13) Voltage profile of the system of Fig (6.12) with Q1 = 35, Q2 =40kVar; (a) for buses from 1 to12, (b) for buses 1 to 5 and from 13 to 20.

Case 2:

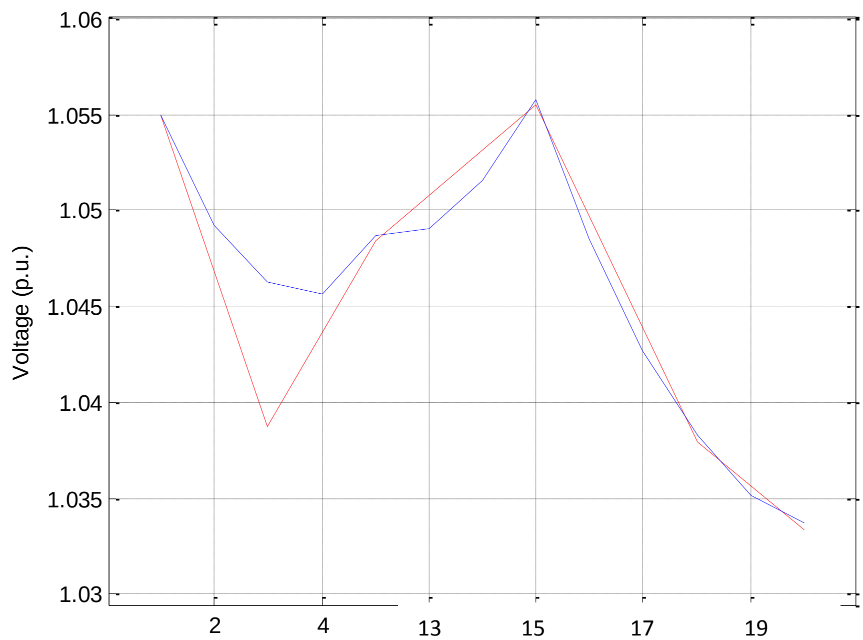
In this case the generation of G2 is increased to 350 kW and the algorithm is executed again. After running the algorithm described in section 6.5.2 the regulator RTU will get the following data corresponding to each possible reactive power injection;

Possible reactive power injection (kVar)	Maximum voltage of the feeder (p.u)	Minimum voltage of the feeder (p.u)	Estimated Losses index	Actual losses using a power flow program (kW)
Q1 = 0 , Q2 = 0	1.0550	1.0277	1.2	30.2
Q1= 0, Q2 = 30	1.0576	1.0334	1.1	27.1
Q1= 0, Q2 = 40	1.0594	1.0345	1.1	26.2
Q1= 20, Q2 = 0	1.0561	1.0301	1.2	27.9
Q1= 20, Q2 = 30	1.0600	1.0381	1.1	25
Q1= 20, Q2 = 40	1.0618	1.0405	1.1	24.2
Q1= 35, Q2 = 0	1.0592	1.0318	1.1	26.4
Q1= 35, Q2 = 30	1.0628	1.0398	1.1	23.6
Q1= 35, Q2 = 40	1.0640	1.0414	1	22.8

Based on these results, the optimal reactive power would have been Q1 = 35 and Q2 = 40, however, the voltage corresponding to this case is outside the permissible limit. The next minimum losses rank is shared between several options. Thus, the most appropriate voltage will be considered as the solution. Although the voltages of the cases (Q1=0, Q2 = 40) and (Q1 = 35, Q2=0) are acceptable, it might be more suitable to select the case of (Q1=0, Q2=30), which corresponds to a maximum voltage of 1.0576 p.u, in order to have an adequate margin between the system's maximum voltage and the maximum permissible voltage. The estimated and the actual voltage profiles corresponding to this case are shown in Fig (6.14.a) for buses 1 to 12 and Fig (6.14.b) for buses 1 to 5 and then 13 to 20.



(a)



(b)

Figure (6.14) Voltage profile of the system of Fig (6.12) with Q1 = 35, Q2 =40kVar; (a) for buses from 1 to12, (b) for buses 1 to 5 and from 13 to 20

6.7 Comments on Simulation Results

Several key points should be noted from the above simulation results;

1. The proposed algorithm was able to accurately estimate the voltage profile of the system after each change in reactive power injection from the capacitor.
2. It is clear from the simulation that the proposed algorithm provided an efficient way to coordinate the operation of DGs and switched capacitors to allow more flexibility to the operation of DGs on distribution feeders.
3. The ability of the algorithm to deal with the case of multiple capacitors and multiple DGs was also highlighted with the simulation study. In fact, in the next two chapters of this thesis we will build on the proposed algorithm to introduce a general framework for the voltage control of distribution feeders with DGs.

6.8 Conclusions

A decentralized reactive power control scheme was proposed in this chapter to efficiently control the switched capacitors of distribution feeders in order to minimize system losses while maintaining feeder's voltage profile. The proposed scheme is based on the coordination between RTUs located at DG buses and capacitor buses. Novel decentralized algorithm for the estimation of change of voltage profile due to the injection of reactive power at capacitor bus was presented. The algorithms were presented for the cases of single and multiple capacitors on the same feeder and hence are applicable for any real feeder. Simulation results showed the effectiveness of the proposed technique in optimally managing the reactive power resources of the system. The proposed technique will help in the realization of Advanced Distribution Automation by optimally control switched capacitors of the system to maintain acceptable voltage profile, minimize system losses and integrate more DGs in distribution systems by effective coordination between DGs and capacitors.

Chapter 7

Generalized Coordinated voltage Control involving DG, Voltage Regulators and Shunt Capacitors

7.1 Introduction

In this Chapter, the results of Chapters 5 and 6 are combined to propose a generalized coordinated voltage control involving voltage regulators, shunt capacitors and DGs. This coordination allows for the integration of more DG into the distribution system.

This chapter is organized as follows; the basic voltage regulator/shunt capacitor coordination concept is explained in section 7.2. Following that the coordination algorithm is detailed in section 7.3. Simulation results for the generalized coordinated voltage control algorithm are presented in section 7.4. The Chapter ended with conclusions in section 7.5.

7.2 Basic concept of Coordination between Voltage Regulators and Shunt Capacitors for voltage control

As mentioned in Chapter 5, the condition for feasible solution for the voltage control of the multiple feeders using one regulator is:

$$\max(V_{max,feeder}) - \min(V_{min,feeder}) < V_{max,perm} - V_{min,perm} \quad (7.1)$$

The condition of equation (7.1) may not be satisfied for a certain operating conditions of the system. However, if the feeder that has the minimum voltage of the system has a capacitor bank installed, then this capacitor bank can be used to increase that minimum voltage in order to make the condition true again.

To illustrate the basic idea, consider the system shown in Fig (7.1) and assume that the DG connected to Feeder 1 is injecting power such that the voltage of the feeder increases beyond the acceptable limit. The voltage regulator of the station needs to lower its tap in order to correct the voltage of Feeder 1. However, if we assume that the regulator lowers its tap, the voltage of Feeder 2, assumingly being heavily loaded, will be lower than the acceptable limit. In this case, the capacitor of Feeder 2 might solve the problem by injecting more reactive power to support the voltage of Feeder 2, hence allowing station's voltage regulator to lower its tap. This process is called coordinated voltage control for shunt capacitors and voltage regulator.

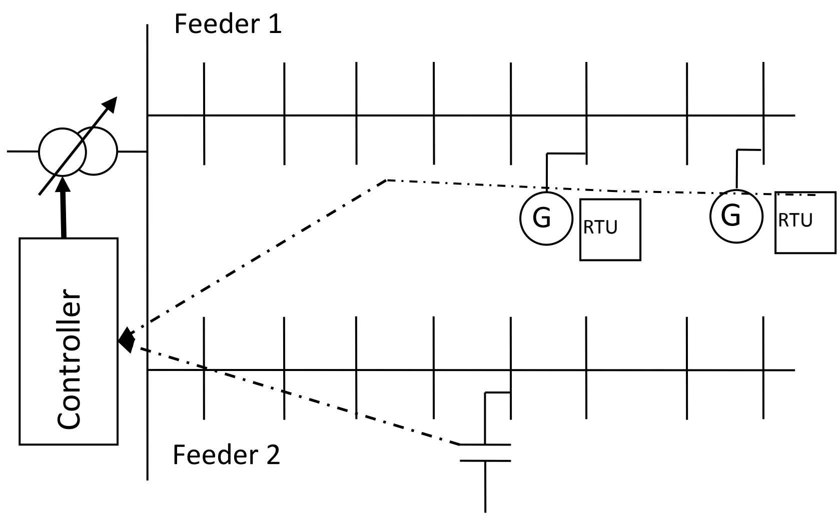


Figure (7.1) Illustration of the coordination between voltage regulator and capacitor

7.3 Proposed Algorithm for Voltage Regulators and Shunt Capacitors Coordinated Voltage Control

For this algorithm, we assume that at the beginning the voltage profile of the system was acceptable and then a new DG is connected or a connected DG increased its injected power.

As a result, the voltage increased and there is a need to correct the situation. To clarify the concept, we will start with the special case when the capacitor is connected on the same feeder with the DG and then move to more general cases.

7.3.1 DG and Capacitor on the same feeder

This is basically the case of the reactive power control algorithm proposed in Chapter 6. By executing the algorithms explained in chapter 6, station's RTU will get the overall maximum and minimum feeder voltages corresponding to each reactive power injected at the capacitor. The voltage control algorithm involving the capacitor is described below and it is detailed in Appendix A as Algorithm# 7.1.

The regulator's RTU will carry out the following,

1- If the maximum voltage corresponding to the reactive power that caused the minimum losses is acceptable, terminate the algorithm.
2- Otherwise, based on the estimated overall minimum voltage of all feeders, check if it is possible to reduce the tap of the regulator to make the voltage identified in (1) acceptable.
3- If (2) fails, consider the maximum voltage corresponding to the reactive power that caused the second minimum losses and repeat steps 1 and 2 above.
4- Repeat step (3) to ultimately get the reactive power that will not cause violation for the voltage profile while at the same time minimizes the losses. Note that, the result might be to disconnect the capacitor totally. Also, note that if the system is planned properly, a solution must exist.

7.3.2 DG and Capacitors on different feeders

In this case, the algorithm is basically a combination of the voltage regulator control algorithm and the optimal reactive power control algorithm. The system will execute voltage profile estimation algorithms for all feeders taking into account the existence of the capacitor. Having the maximum and minimum voltages of all feeders, the regulator's RTU will be able to determine the optimal setting of the capacitor that will boost the minimum voltage of the system in order to allow the regulator tap to be reduced to accommodate the DG. The steps of the algorithm are described below and the algorithm is formulated in Appendix A as Algorithm #7.2. A step-by-step application of this algorithm is provided in the simulation study of section 7.5.

The algorithm can be described as follows;

1- Voltage profile estimation including the effect of the capacitor algorithm, Algorithm#6.1 in Appendix A, will be executed for the feeder with capacitors and the basic voltage profile estimation algorithm, Algorithm#5.2 in Appendix A, will be executed for other feeders.
2- As a result, the Regulator's RTU will have the following data:
    a. Overall maximum voltage, overall minimum voltage and losses index corresponding to all possible reactive power injections from capacitors for feeders with capacitors.
    b. Overall maximum and minimum voltages for all other feeder.
3- If condition (7.1) fails, proceed to step 4. Otherwise, use the voltage control algorithm discussed in Chapter 5.
4- Identify the feeder with the overall minimum voltage.
5- If the feeder that has the overall minimum voltage of the system has a capacitor, proceed to step 6. Otherwise, there is no solution.
6- Calculate the optimal tap of the voltage regulator without including the feeder with the capacitor.

7- Adjust the voltages of the feeder with the capacitor, received from the voltage profile estimation algorithm, by reducing each voltage value by the same amount of reduction in the station's bus voltage.
8- Based on the adjusted voltages of step (7), decide the optimal reactive power of the capacitor that will not violate the voltage profile while minimizing the losses in the same manner discussed in Chapter 6.

Comments:

1- The failure of the algorithm to get a solution means that the planning of the system was not carried out properly; as a result, the DG amount allowed to connect is overly estimated. We will revisit this case in Chapter 8.

2- In the case that capacitors exist on the same feeder with the DG and on the other feeder as well, the regulator will consider the capacitor on the same feeder first. In other words, the regulator will execute the algorithm presented in section 7.3.1 then, if not successful, will execute the algorithm of this section.

7.4 Simulation Study

Fig (7.2) shows the system under study; two DGs are connected to feeder 1 another DG is connected to Feeder 2 and a fourth DG is connected to feeder 3 along with a capacitor bank. Load and generation values are shown in Table 7-1. For this simulation we assume the following data:

The station bus voltage = 1.05 pu.

The maximum allowable voltage = 1.06 pu.

The minimum allowable voltage = 0.94 pu.

The impedance of any line section = 0.00344 +j 0.0029 p.u

Reactive power values of the Capacitor, connected to feeder 3 = 0, 20, 40 and 65 kVAR.

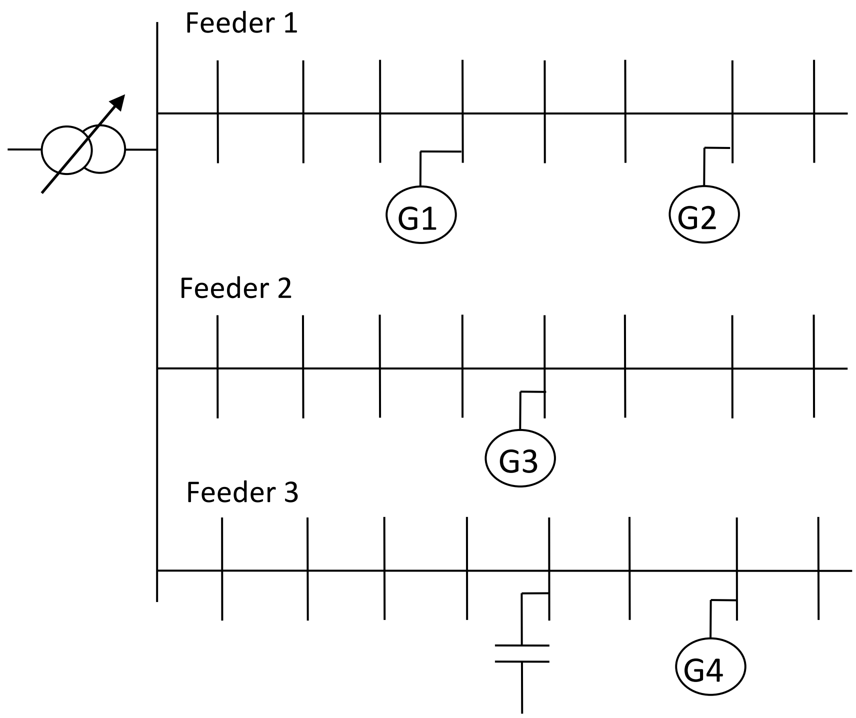


Figure (7.2) System used for the simulation study

Table 7-1 Load and generation values of the system of Figure (7.2)

Feeder#1 Bus #	P(kW)	Q(kVar)	Feeder#2 Bus #	P(kW)	Q(kVar)	Feeder#3 Bus #	P(kW)	Q(kVar)
2	60	60	2	60	60	2	60	60
3	60	30	3	60	30	3	60	70
4	55	55	4	55	55	4	75	55
5	-250	0	5	60	20	5	90	50
6	60	55	6	-250	0	6	30	0
7	85	45	7	85	45	7	85	45
8	-350	0	8	65	35	8	-65	45
9	90	45	9	90	45	9	90	45

After running the voltage estimation algorithms, the voltage regulator will get the following data:

Feeder 1:

Maximum voltage of the feeder	Minimum voltage of the feeder
1.0687	1.0418

Feeder 2:

Maximum voltage of the feeder	Minimum voltage of the feeder
1.0500	0.9767

Feeder 3:

Reactive power of the capacitor	Maximum voltage of the feeder	Minimum voltage of the feeder	Losses-index
0 (the current status)	1.0500	0.9430	8.3
20	1.0500	0.9460	7.8
40	1.0500	0.9489	7.3
65	1.0500	0.9526	6.7

As a result, the regulator will find that the maximum voltage of feeder 1 is not acceptable, more than 1.06*p.u.* The regulator will try to lower its tap in order to bring this maximum voltage down to at least 1.06*p.u.* To do that, the regulator must lower station's voltage by; $1.0687 - 1.06 = 0.0087\ p.u$. However, the overall minimum voltage of the system, the minimum voltage of feeder 3, is 0.943*p.u*. If the station's voltage is reduced by 0.0087*p.u*, this minimum voltage point will be 0.9343*p.u* which is not acceptable, less than 0.94*p.u*.

To solve the problem, the regulator will check if the feeder with the overall minimum voltage has a capacitor. If not, then there is no solution. If a capacitor exists, which is the case in this example, the regulator will consider other reactive power options for that feeder. In our simulation case, the regulator will decrease the minimum voltage of feeder 3 corresponding to each possible reactive power injection by 0.0087*p.u*, the results will be;

Reactive power of the capacitor (kVar)	Minimum voltages of the feeder in the current situation	Minimum voltages after reducing station's voltage by 0.0087 *p.u*	Losses-index
0 (the current status)	0.9430	0.9343	8.3
20	0.9460	0.9373	7.8
40	0.9489	0.9402	7.3
65	0.9526	0.9439	6.7

As can be seen in these results, two cases results in acceptable minimum voltages namely; Q= 65 kVar and Q= 40 kVar. However, for Q= 65 kVar the losses index is lower. Therefore, the optimal solution is to set the capacitor to inject Q= 65 kVar and then lower the regulator tap by 0.0087*p.u.* The voltage profile of the final system after implementing the voltage control solution is shown in Fig (7.3). It is clear from that figure that the proposed technique was able to control the voltage of the system and accommodated extra DG power utilizing the capacitors of other feeders.

It is evident from this example that more DG power was allowed to connect to the distribution system by efficient coordination between voltage regulators and capacitors. As a matter of fact, the proposed technique provides great flexibility to the operation of distribution systems with DGs by efficiently utilizing all the voltage controls of the system.

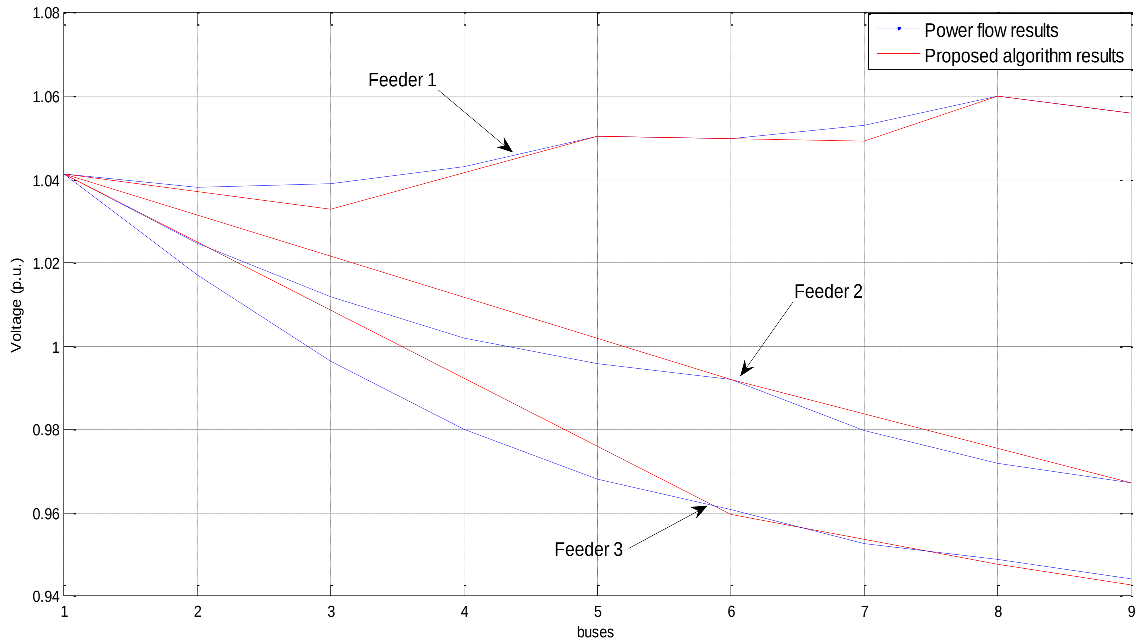


Figure (7.3) Voltage profile of the system of Fig (7.2) after the execution of the voltage control algorithm.

7.5 Conclusions

In this Chapter a novel coordinated voltage control involving voltage regulators and shunt capacitors was presented based on the voltage control and the reactive power control algorithms proposed in chapters 5 and 6. The proposed scheme allows for more DGs to get connected to the network by adjusting the voltage regulator tap and capacitors output reactive power in order to maintain the voltage of the system within acceptable range after the connection of the DG. By optimally controlling voltage control equipment of the system, this scheme will allow DGs to connect with less upgrades to the system, hence, make the connection of DGs more economically feasible. Simulation study shows the effectiveness of the proposed coordinated voltage control scheme.

Chapter 8

Novel Operation-time DG connection Impact Assessment

8.1 Introduction

During the process of issuing a permit for a DG to connect to a distribution feeder, electric utilities perform an impact assessment study to identify any negative effects the DG might have on the system. All DGs connected on the feeder are included in the assessment study and are assumed to inject their maximum rated power at all times. On the top of that, once approved to connect, DG is required to connect only to the feeder which it was planned. Therefore, if a reconfiguration happened in the system due to any reason, restoration following a fault for example, the DG has to be out of service until the system is returned to the original configuration.

In this Chapter we will propose a new operation-time DG connection impact assessment concept to allow DGs to inject extra power to the system if the extra injected power will not have adverse impact on the system based on real-time conditions. Novel coordinated voltage control scheme will be introduced to allow for the proposed concept. The main goal of the proposed concept is to introduce more flexibility to the process of DG connection assessment and allow efficient utilization of feeder's capacity.

This Chapter is organized as follows; the proposed operation-time connection impact assessment concept is introduced in the next section. Novel coordinated voltage control technique is proposed in section 8.3 to allow the system to determine, in real-time, whether or not it is acceptable to inject extra power from the DG. Detailed simulation study is proposed in section 8.4 to validate the proposed concept. Chapter conclusions are presented in section 8.5.

8.2 Proposed operation-time DG connection impact assessment concept

When a DG project planned to connect to a distribution feeder, a connection assessment study is carried out. For the sake of this study, the DG is assumed to inject maximum output power, and hence, a feeder capacity equals to the project's maximum output power will be reserved for that project. As a result, when considering the next project on the same feeder, the assessment study will consider that the first project is working at its maximum power and finds the required system upgrades to allow the second project to connect.

By following this planning approach it is guaranteed that system constraints, i.e. voltage limits, short circuit ratings, etc., will be respected at any time because the assessment was carried out for the absolute worst case of all DGs at maximum output power.

On the other hand, one can argue that by following that strict approach, the capacity of the feeder is not fully utilized. In reality, DGs are not working at maximum power at all time, especially renewable-based DGs. For example, solar DGs shut off totally for the whole night in addition to having a very low output power on cloudy days. In fact, in some cases based on the strict planning approach, DG projects are cancelled, or been downsized, because the cost required for system upgrades makes the project economically infeasible.

Another problem that faces the connection of DG projects is that; when a DG is being planned to connect to the distribution system, it is planned for a specific feeder, for which the connection impact assessment study was carried. If a reconfiguration happened for the DG's feeder, possibly due to restoration after a fault, the DG is not allowed to connect to any other feeder, and hence, is forced to shut down until the original system configuration is restored. From one hand, this approach assures utilities that the DG will only be connected to the feeder for which it was planned in the first place. Because if the DG is allowed to connect to other feeders, there is a possibility that the DG will have negative impacts on these feeders. In addition, it is not possible to plan the operation of the DG on more than one feeder, as in such case multiple capacities will be preserved for the DG on multiple feeders which is not usually possible.

On the other hand, it is known that the configuration of the distribution system changes from time to time due to faults, maintenance and other reasons. Therefore, the DG will be asked to shut down frequently as the system configuration changes and that will translate to loss of revenue for DG investors.

To utilize feeder's capacity more efficiently and to provide more flexibility for the connection of DGs, we propose *operation-time* DG connection impact assessment concept, or "*connect if system conditions permit"* concept. The basic idea can be explained as follow; new DG will be planned based on the usual maximum output power approach to find the maximum size of the new DG that will incur *acceptable* connection upgrades expenses; this will be the basic size of the DG. Then, based on system's nature, the existence of other DGs, their types, and their sizes, determine the extra power that can be injected from the new DG without violating system constraints assuming that other DGs on the feeder are injecting *low* output power. Finally, the new DG will be granted an *unconditional* connection permit for the basic size and a *conditional* connection permit for the extra size. In other words, DGs will be permitted to inject more than the originally planned power, if the system conditions permits or, more preciously, if the extra injected power has no negative impact on the system. Obviously, details of the planning procedure and whether or not it will be feasible for a certain case remains case-specific.

On the top of that, when the configuration of the system changes, DG will send a connection request to the new station that feeds DG's point of connection. Based on the real-time conditions of the system, the new station will determine how much power the DG can connect without having negative impact on the new configuration of the system.

The big question that must be answered prior to the application of the proposed concept is; how to determine, in real-time, whether system conditions permit the injection of extra DG power.

As a matter of fact, in most of the cases, the main technical problem that necessitates expensive system upgrades is the voltage rise problem. Usually, short circuit ratings of system's breakers and reclosers are high enough to allow the connection of extra DGs without a real problem. In reality, DGs sizes are usually not too high, 10 MW is the usual large size in distribution systems, and their short circuit contributions are not usually a big concern, as many DG are inverter-based. Therefore, for this proposed technique we will assume that the short circuit ratings of system's equipment will be assessed in the planning stage against the worst case of all DGs at maximum output power.

In the rest of this chapter a coordinated voltage control algorithm is introduced to test, in real-time, how much extra DG power can be injected in any distribution feeder without violating voltage profile of the system.

8.3 Voltage Profile Change due to the injection of extra power from the DG

In order to assess the impact of the extra DG injected power, it is imperative to calculate the change in feeder's voltage profile due to the injection of active power at the DG bus. By analogy to the capacitor case discussed in section 6.3, due to the connection of the DG to the feeder, the active power flow from station bus will be reduced by the amount of the active power injected at the DG bus, assuming the losses are negligible. Also, all active power flows between any two buses upstream of the DG bus will be reduced by the same amount of the active power injected at the DG bus. On the other hand, the active power flow downstream of the DG will not be affected. Hence, the injected active power can be looked at, in a superposition fashion, as if it is flowing towards the supply. Therefore, to find the effect of the DG injected active power on the voltage profile, we can proceed with similar analysis to the one presented in section 6.3. Specifically, equation (6.1) to equation (6.9) can be modified easily for the DG case. Finally, we get to equation (8.1) which corresponds to equation (6.9) as follows;

$$V_{(n)new} = V_{(n)old} + \Delta P_G \sum_{k=1}^{k=n} R_{k-1,k} \tag{8.1}$$

Equation (8.1) gives voltage change at any bus due to the injection of extra amount of power at the DG.

8.4 Proposed operation-time DG connection impact assessment process

The goal of this process is to determine, for specific system conditions, how much extra power a certain DG is allowed to inject into the system without violating system's voltage profile. For the following, we will assume that the voltage profile of the system is acceptable and then a certain DG asks to increase its injected power.

The operation-time DG connection impact assessment process is described in the following, while, algorithm details can be found in Appendix A as Algorithm # 8.3,

1- The DG which request permission to inject extra power will initiate the process. For the DG's feeder, voltage profile estimation including DG effect algorithm will be executed, the details of this algorithm can be found in Appendix A as Algorithm #8.1. In the case that a capacitor existed on the same feeder as well, voltage profile estimation including DG and capacitor effects algorithm will be executed, the details of this algorithm can be found in Appendix A as Algorithm #8.2.

Briefly, these algorithms are the same as the basic voltage profile estimation algorithms described in Chapter 5 and Chapter 6 except that DG's RTU will pass its requested extra power injection along with its message to the upstream RTU. In addition, each RTU upstream of the DG, including the DG's RTU, will calculate the change in the voltage of their respective bus due to the extra power injected at the DG using equation (8.1) or due to injections of the capacitor and the DG by combining equation (6.9) and (8.1) as shown in Appendix A.

2- For feeders without capacitors, the basic voltage profile estimation algorithm will be executed, the details of this algorithm can be found in Appendix A as Algorithm #5.2. For feeders with capacitors, the voltage profile estimation algorithm including capacitor effect, Algorithm #6.1 in Appendix A, will be executed.

3- As a result of (1) and (2), the station's voltage regulator will have the maximum and minimum voltages of all feeders as well as maximum and minimum voltages corresponding to each possible reactive power injections for feeders with capacitors. In addition, the station's RTU will have the maximum and the minimum voltage of the DG feeder if the extra power requested by the DG is permitted to be injected.

4- As it was assumed that prior to the execution of the algorithm the voltage profile of the system was acceptable, then the only problem that the extra power of the DG may cause is an unacceptable maximum voltage for the DG feeder.

5- At this point, the regulator will execute the operation-time DG connection impact assessment algorithm in order to find a remedy for the unacceptable maximum voltage of DG's feeder, if possible. This algorithm is described below;

    a. Depending on the estimated maximum voltage of DG's feeder due to the extra power injection, called DG's maximum voltage for short, and the overall minimum voltage of the system, the regulator's RTU will determine based on condition (5.19) whether or not it is possible to reduce its tap to solve the projected unacceptable DG's maximum voltage. If successful, the regulator will change its tap and grant the DG permission to inject the extra power.

b. If solving the DG's maximum voltage problem was not successful using the regulator tap only, then there must be a minimum voltage point which prevents the regulator from reducing its voltage, i.e. if the regulator reduced its voltage, this minimum voltage point will be below the acceptable limit.

c. If there is a capacitor connected to the DG's feeder, then proceed to step (d), otherwise proceed to step (e).

d. The regulator will consider the maximum voltage of the DG's feeder corresponding to all the possible reactive power injections of the capacitor connected to the DG's feeder. By reducing the reactive power injection, the DG's maximum voltage will be reduced. if for a certain reactive power injection, the DG's maximum voltage is reduced such that condition (5.19) is valid, then the algorithm succeeded and that reactive power will be selected by regulator's RTU and the DG will be granted permission to connect. If after disconnecting the capacitor still condition (5.19) is not valid, then proceeds to step (e).

e. The regulator will determine for which feeder the overall minimum voltage of the system belongs, we will call this feeder the minimum voltage feeder.

f. If the minimum voltage feeder has a capacitor connected, then proceed to step (g), otherwise proceed to step (h).

g. The regulator will consider the minimum voltage of the minimum voltage feeder corresponding to all the possible reactive power injections of the capacitor connected to the minimum voltage feeder. By increasing the reactive power injection from that capacitor, the overall minimum voltage of the system will be increased. If for a certain reactive power injection, the overall minimum voltage of the system is increased such that condition (5.19) is satisfied, then the algorithm succeeded and that reactive power will be selected by regulator's RTU and the DG will be granted permission to connect. If after exploring all the possible reactive power injections at the minimum voltage feeder still condition (5.19) is not satisfied, then proceeds to step (h).

h. Arriving to this step means that it is not possible by the controls of the system alone, regulator tap and capacitor reactive powers, to correct the projected voltage of the system. Then, it is not possible to inject the whole extra active power requested by the DG and therefore the task now is to find the maximum acceptable active power that can be injected from the DG.

i. The regulator will implement the results of steps (d) and (g). So the maximum DG's voltage will be reduced as much as possible and the overall minimum voltage of the system will be increased as much as possible. Then the regulator will determine the maximum possible reduction of its voltage that will not cause the overall minimum voltage of the system to go outside of the permissible voltage range, this value will be called regulator's minimum possible voltage. The regulator will implement this value, calculate the change in the station's voltage and pass the calculated change in station's voltage downstream to the RTUs of the DG's feeder.

6- RTU's of DG's feeder will receive the change in station's voltage. Messages will propagate back from station's RTU towards the DG. Along the ways towards the DG each RTU will;

a. Reduce the value of the measured voltage of its bus by the same amount as the change in station's voltage.

b. Calculate the permissible DG power using the following equations;

$$V_{perm,sys} = (V_{(n)old} - \Delta V_{station}) + \Delta P_{G,max,perm} \sum_{k=1}^{k=n} R_{k-1,k} \qquad (7.2)$$

c. Pass the value of the maximum permissible DG power downstream till it reaches DG's RTU.

d. The value of the maximum permissible DG power will be altered as it travel downstream towards the DG depends on the measured voltages at each RTU.

e. Ultimately, DG's RTU will calculate its maximum permissible DG power according to the voltage measured at the DG bus.

7- Finally the DG will be permitted to inject the minimum of the maximum permissible DG powers calculated by the RTU of the DG's feeder.

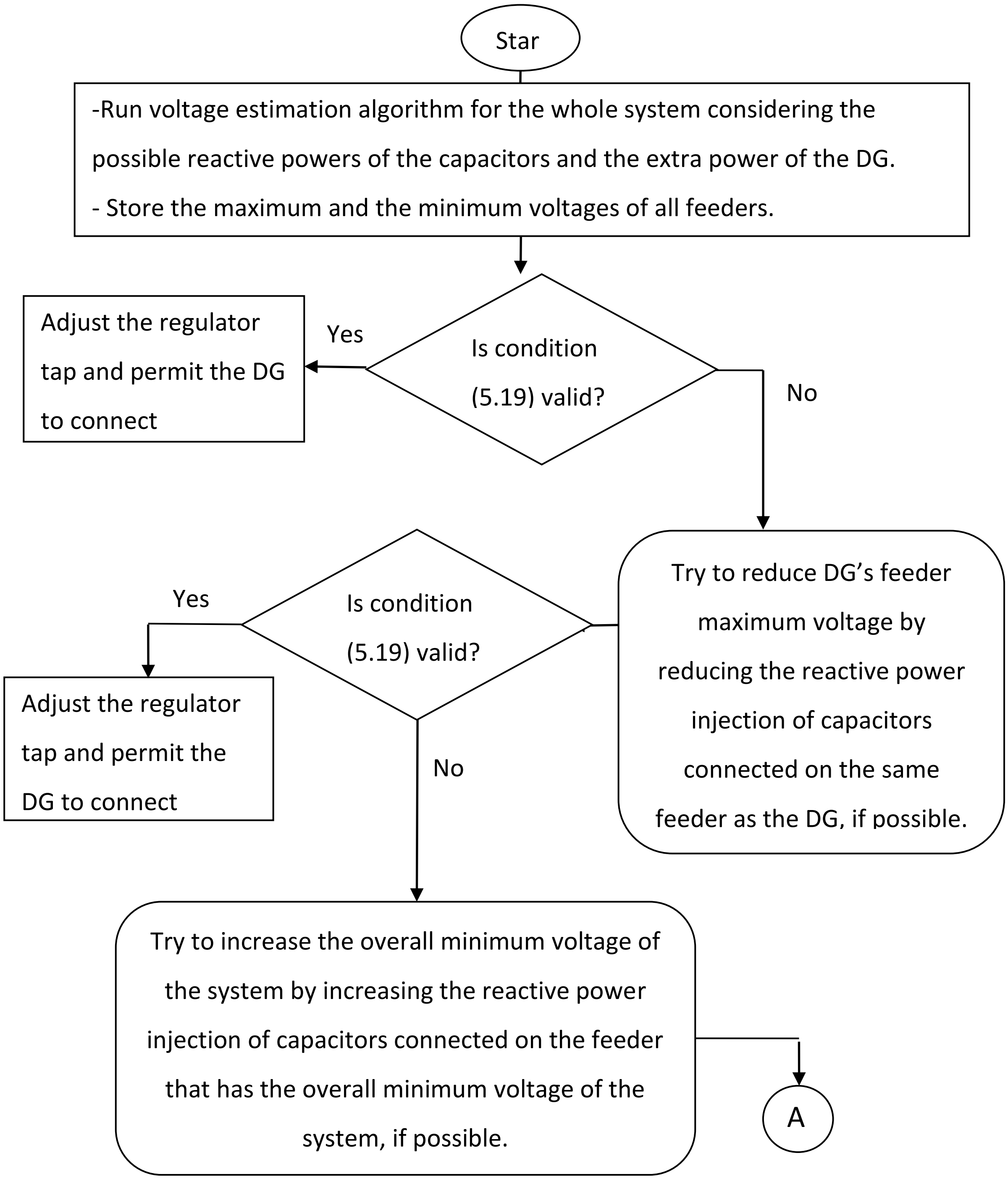
Fig (7.2) shows a flowchart for the proposed operation-time DG connection impact assessment process.

8.5 Simulation Study

For this simulation study we will build on the results of the simulation study of section 7.4. After the voltage control process discussed in section 7.4 is implemented, the voltage of all feeders is acceptable.

Case 1

Now, assume that DG3 requested to increase its injected power to 450 kW from 250 kW. Voltage estimation algorithms will be executed for feeder 2 considering the requested value of DG3. The regulator will get the following data:


Star
-Run voltage estimation algorithm for the whole system considering the possible reactive powers of the capacitors and the extra power of the DG.
- Store the maximum and the minimum voltages of all feeders.
Is condition (5.19) valid?
Yes
Adjust the regulator tap and permit the DG to connect
No
Try to reduce DG's feeder maximum voltage by reducing the reactive power injection of capacitors connected on the same feeder as the DG, if possible.
Is condition (5.19) valid?
Yes
Adjust the regulator tap and permit the DG to connect
No
Try to increase the overall minimum voltage of the system by increasing the reactive power injection of capacitors connected on the feeder that has the overall minimum voltage of the system, if possible.
A

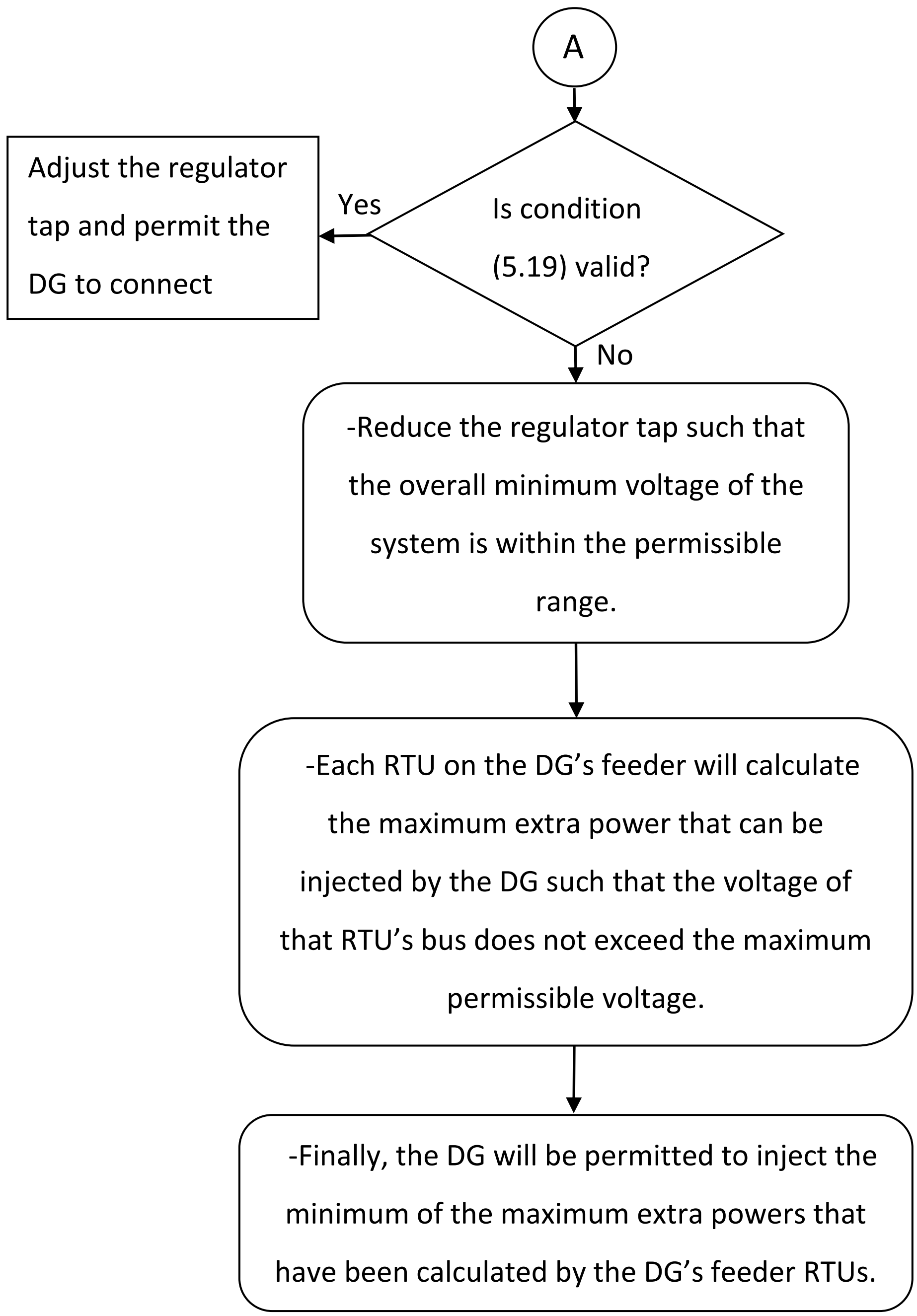


Figure (8.1) Flow chart for the proposed operation-time DG connection impact assessment process

Feeder 1:

Maximum voltage of the feeder	Minimum voltage of the feeder
1.06	1.033

Feeder 2:

Active power of DG3	Maximum voltage of the feeder	Minimum voltage of the feeder
250 (the current status)	1.0413	0.9673
450 (the requested level)	1.0413	1.0017

Feeder 3:

Reactive power of the capacitor	Maximum voltage of the feeder	Minimum voltage of the feeder	Losses-index
0	1.0413	0.9343	8.5
20	1.0413	0.9373	8
40	1.0413	0.9402	7.4
65 (the current status)	1.0413	0.9439	6.8

As can be seen from the results above, the voltage profile of the system will be acceptable if DG3 injects 450 kW. Therefore, DG3 will be granted a permission to increase its power to the requested level. Fig (8.1) shows the voltage profile of the system after DG3 increases its power to 450 kW.

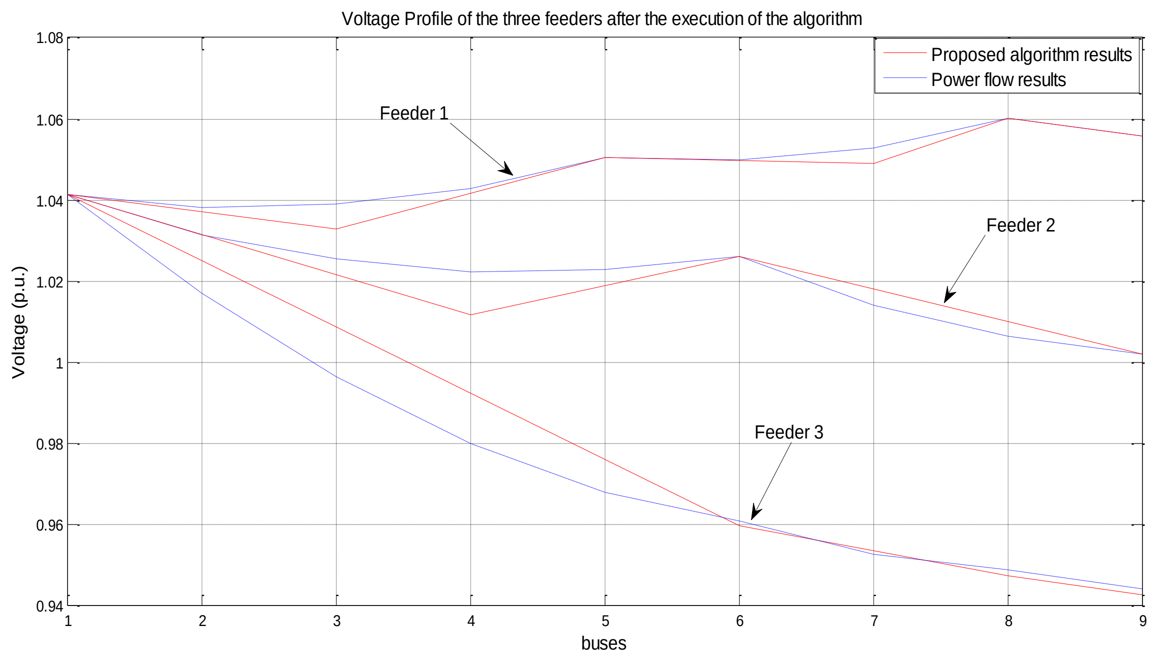


Figure 8.2 Voltage profile of the simulated system after DG3 is permitted to increase its injected power to 450 kW

Case 2

For this case, assume that, after the DG3 was permitted to inject 450 kW, DG4 requested an increase in its injected power level by 200 kW. Again, voltage estimation algorithms will be executed for feeder 3 considering the requested value of DG4. The regulator will get the following data:

Feeder 1:

Maximum voltage of the feeder	Minimum voltage of the feeder
1.06	1.033

Feeder 2:

Active power of DG3	Maximum voltage of the feeder	Minimum voltage of the feeder
450 (the current status)	1.0413	1.0017

Feeder 3:

Active power of DG4	Reactive power of the capacitor	Maximum voltage of the feeder	Minimum voltage of the feeder	Losses-index
65	0	1.0413	0.9343	8.5
65	20	1.0413	0.9373	8
65	40	1.0413	0.9402	7.4
65 (the current status)	65 (the current status)	1.0413	0.9439	6.8
265	0	1.0413	0.9814	3.2
265	20	1.0413	0.9844	2.9
265	40	1.0413	0.9874	2.6
265	65	1.0413	0.9911	2.2

As can be seen from the results above, the voltage profile of the system will be acceptable if DG4 injects 200 kW extra. In addition, keeping the capacitor at 65 kVar is still optimal from the losses point of view. Therefore, DG4 will be granted a permission to increase its power to 265 kW. Fig (8.2) shows the voltage profile of the system after DG4 increases its power to 265 kW.

Case 3

For this case assume that DG4 has reduced its injected active power to 100 kW and then DG1 is requesting to increase its injected power to the level of 350 kW. Again, voltage estimation algorithms will be executed for all of the feeders considering the requested value of DG1. The regulator will get the following data:

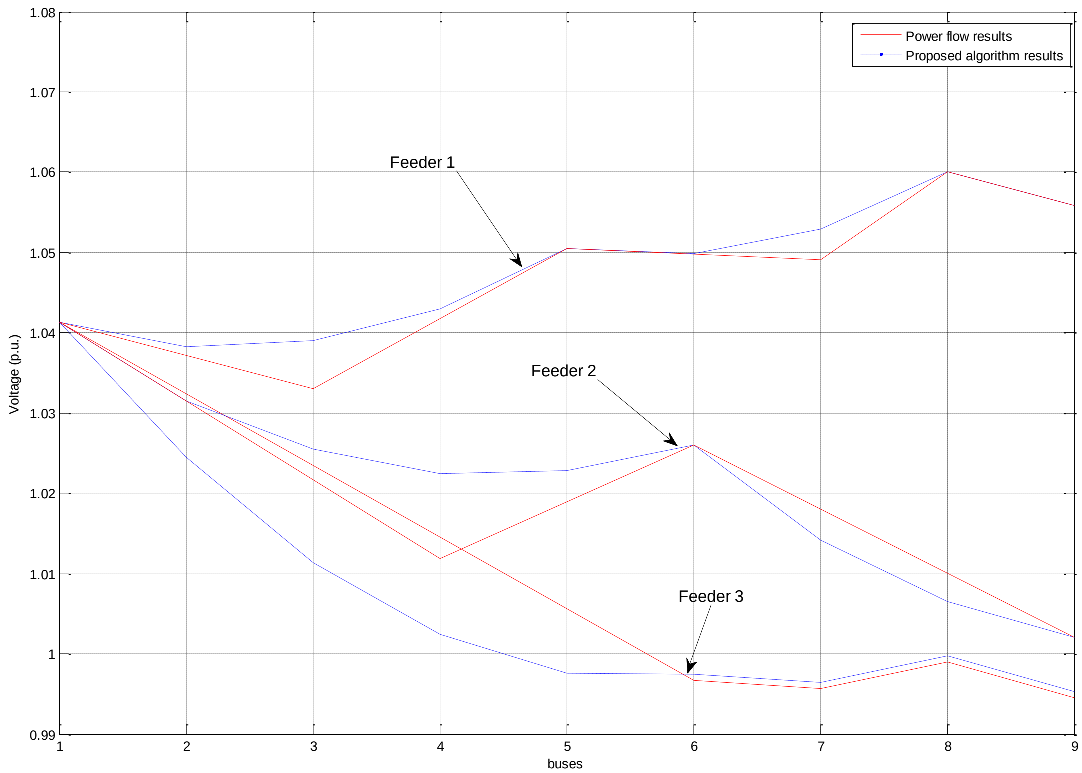


Figure (8.3) Voltage profile of the simulated system after DG4 is permitted to increase its injected power to 265 kW

Feeder 1:

Active power of DG1	Maximum voltage of the feeder	Minimum voltage of the feeder
250 (current status)	1.06	1.033
350 (requested level)	1.0738	1.0399

Feeder 2:

Active power of DG3	Maximum voltage of the feeder	Minimum voltage of the feeder
450 (the current status)	1.0413	1.0017

Feeder 3:

Active power of DG4	Reactive power of the capacitor	Maximum voltage of the feeder	Minimum voltage of the feeder	Losses-index
100	0	1.0413	0.9374	7.9
100	20	1.0413	0.9404	7.4
100	40	1.0413	0.9433	6.9
100 (the current status)	65 (the current status)	1.0413	0.9470	6.3

As can be seen from the results above, the voltage profile of feeder 1 will not be acceptable, more than 1.06p.u, if DG1 is granted permission to increase its injected active power to 350 kW. Hence, the voltage regulator will try to reduce its tap in order to reduce the maximum voltage of feeder 1. Therefore, the regulator will search for the overall minimum voltage of the system which is on Feeder 3 and has a value of 0.947*p.u.* The regulator will calculate the required decrease in station's voltage as; $1.0738 - 1.06 = 0.0138 p.u.$ However, the maximum decrease that can be implemented without reducing overall minimum voltage of the system below the permissible minimum voltage is; $0.947 - 0.94 = 0.007 p.u.$ As results, the regulator will try to increase the minimum voltage of the system. Regulator's RTU will check whether the capacitor of feeder 3 can inject extra reactive power to elevate voltage of feeder 3. However, regulator's RTU will realize that the current status of the capacitor is 65 kVar which is the maximum possible reactive power injection of the capacitor. Hence, it is not possible to grant the DG permission for the requested amount.

By arriving to this conclusion, regulator's RTU will decide to lower station's voltage by 0.007p.u, the maximum possible decrease. Following that, regulator's RTU will send the change in station's voltage, which is $0.007p.u$, to RTUs of feeder 1 in order for them to calculate the maximum allowable extra active power that can be injected from DG1.

RTU of DG 1, the first RTU downstream of the station on feeder 1, will receive the new station's voltage and then will calculate the maximum extra DG power that can be injected from DG1 as follows;

$$1.06 = (V_{(n)old} - 0.007) + \Delta P_{DG1,max,perm} \sum_{k=1}^{k=n} R_{k-1,k}$$

Where $V_{(n)old}$ is the voltage of DG1 bus without any extra power of DG1 been considered. As a result of this calculation $\Delta P_{DG1,max,perm} = 119.5\ kW$.

In this case as the assessment is being done for DG1, then the change in the voltages of the points downstream of DG1 will be the same as the voltage change at DG1. Therefore, the RTU of DG1 can calculate the permissible maximum power using the maximum voltage of the part of the feeder downstream of DG1, which was stored at RTU of DG1 during the execution of the voltage estimation algorithms, as follows,

$$1.06 = (V_{(feeder1,max)old} - 0.007) + \Delta P_{DG1,max,perm} \sum_{k=1}^{k=n} R_{k-1,k}$$

For Feeder 1, from the voltage estimation algorithm results, the maximum voltage of the part of the feeder downstream of DG1, without considering the extra power of DG1, is 1.06p.u, hence, RTU of DG1 will perform the following calculation, for the part of the feeder downstream of it;

$$1.06 = (1.06 - 0.007) + \Delta P_{DG1,max,perm} \sum_{k=1}^{k=n} R_{k-1,k}$$

As a result $\Delta P_{DG1,max,perm} = 50.7\ kW$.

This last value is less than the result obtained before using the voltage of DG1 bus. Therefore, DG1 will be granted an increase in its power equals 50.7 kW only. Fig (7.14) shows the voltage profile of the system after DG1 increase its injected power by 50.7 kW. It is clear from the voltage profile that no extra power could ever be injected as the maximum voltage of the feeder is at *1.06p.u* and it is not possible to reduce regulator's tap because the minimum voltage of the system is at *0.94p.u*. This result confirms that the proposed algorithm successfully determined the maximum power certain DG can inject without violating the voltage profile of the system.

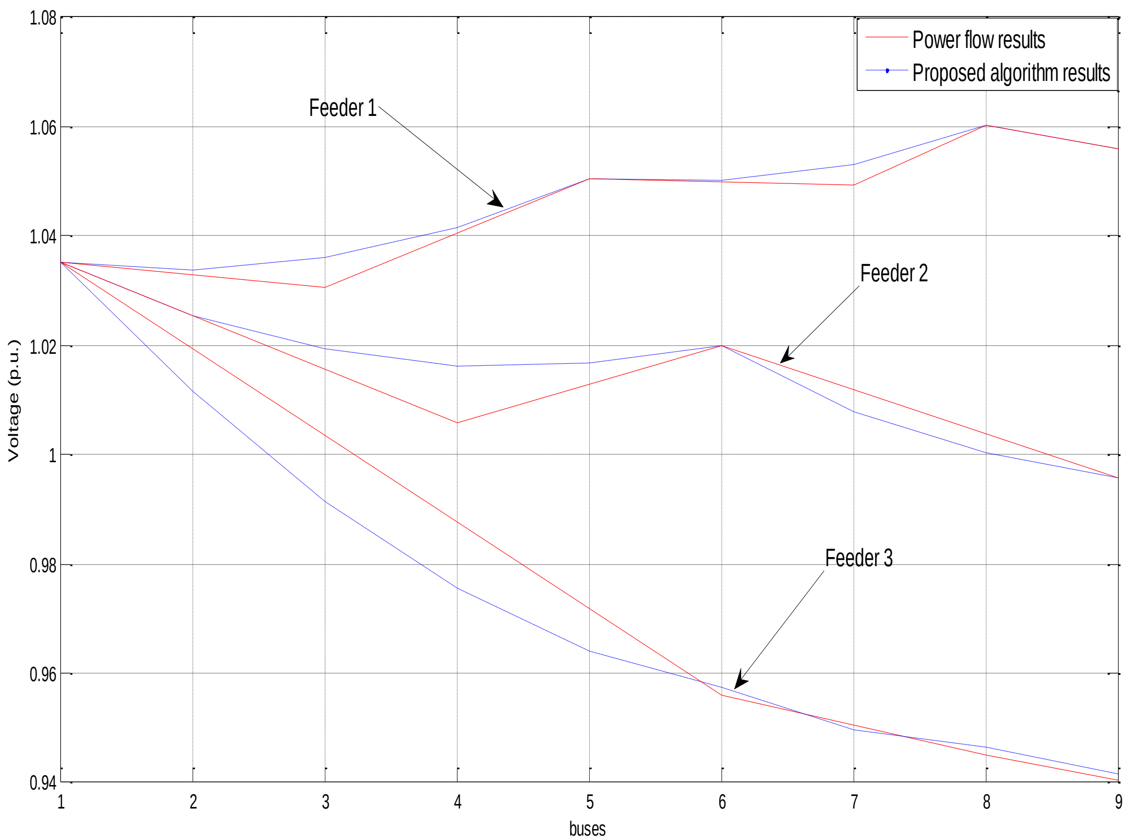


Figure (8.4) Voltage profile of the simulated system after DG1 is permitted to increase its injected power to 300.7 kW

8.6 Conclusions

In this chapter a new concept of *operation-time* DG connection assessment was proposed. The idea of the proposed concept is; while in the planning-time the assessment must consider the worst case scenario, it is possible that during the actual operation of the system to inject more DG power without the need for any upgrades. Two main justifications were made for the proposed concept; first, the planning of DGs always consider that all other DGs on same feeder injects maximum power, while in reality this is not perfectly true. For instance, solar-based DGs shut down for the whole night and for cloudy days. In addition, DGs might go out for maintenance or other reasons. Therefore, it might be economically feasible to install certain amount of DG power that will work on conditional basis. The second justification for the operation-time assessment is that, currently, if DG's feeder is out of service for any reason, e.g. fault, the DG must disconnect even if its point of connection with the system is restored from another station. The proposed concept provides a solid method to assess the impact of connecting DGs on feeders other than the one it was planned for originally; hence, provides much more flexibility in the planning and the operation of DGs. Detailed algorithms were proposed to allow for the operation-time assessment. Simulation study shows the validity of the proposed scheme and provided in sight details about the proposed concept.

Chapter 9

Novel Decentralized Distribution System Restoration

9.1 Introduction

In this Chapter, a distribution system restoration scheme implemented in a Multi-agent environment is proposed. The proposed scheme depends on dividing the distribution system into zones each is controlled by an Agent. System restoration is carried out based on the coordination between Agents. The goal of the proposed restoration scheme is to maximize the restored power while preserving the radial structure of the distribution system and without exceeding the thermal limit of any equipment in the system. The proposed technique does not assume any supervision from any central point; hence this technique will enable the realization of a self-healing distribution system power restoration.

This Chapter is organized as follows; section 7.1 discusses the structure of the proposed restoration system. Presentation of the communication protocols between Agents will take place in section 7.2. In section 7.3, the restoration algorithm will be detailed. In section 7.4, simulation study is presented to validate the proposed algorithm. Finally, conclusions are discussed in section 7.5.

9.2 Structure of the Proposed Restoration System

The proposed algorithm solves the restoration problem based on the cooperation of several agents placed in the distribution system. In this work, the distribution system is divided into several zones; each zone is controlled by an Agent. A zone is defined in this work as: a part of the distribution system bounded by one or more disconnecting switches. In other words, from switches point of view, zones are the building blocks of the feeder. Fig (9.1) illustrates the division of the distribution system into zones.

For the sake of distribution system restoration, each zone represents one lump sum load. Due to the lack of switches inside the zone, it is not possible to restore a part of a zone; either restore the whole zone or disconnect it.

Based on the zone concept, the proposed algorithm is valid for any network regardless of disconnecting switches availability in the network. Actually, based on disconnecting switches availability, zones can be as fine as a zone for each feeder tapping point, or as coarse as a zone for a whole feeder. In any case, the restoration algorithms presented later will be valid and applicable.

Further, as shown in Fig (9.1), each Agent controls several switches in its zone. These switches disconnect or connect the respective zone from other zones to perform restoration.

A communication channel is assumed to exist between each two zones directly connected by a power line, whether this connecting power line is energized or not.

Fig (9.2) shows the corresponding graph of Fig (9.1). From graph theory point of view, each zone is represented by a node and each communication link is represented by an edge.

9.3 Communication Protocols

This section details the communication protocols and procedures executed by Agents in order to achieve efficient system restoration. Firstly, for each Agent we define the set of Neighbours as: the set of Agents with which the respective Agent has a communication link. For example, referring to Fig (9.1), the neighbours of Agent 1 are {Agent 2, Agent3}. In the proposed restoration scheme, each Agent can communicate with its Neighbours only.

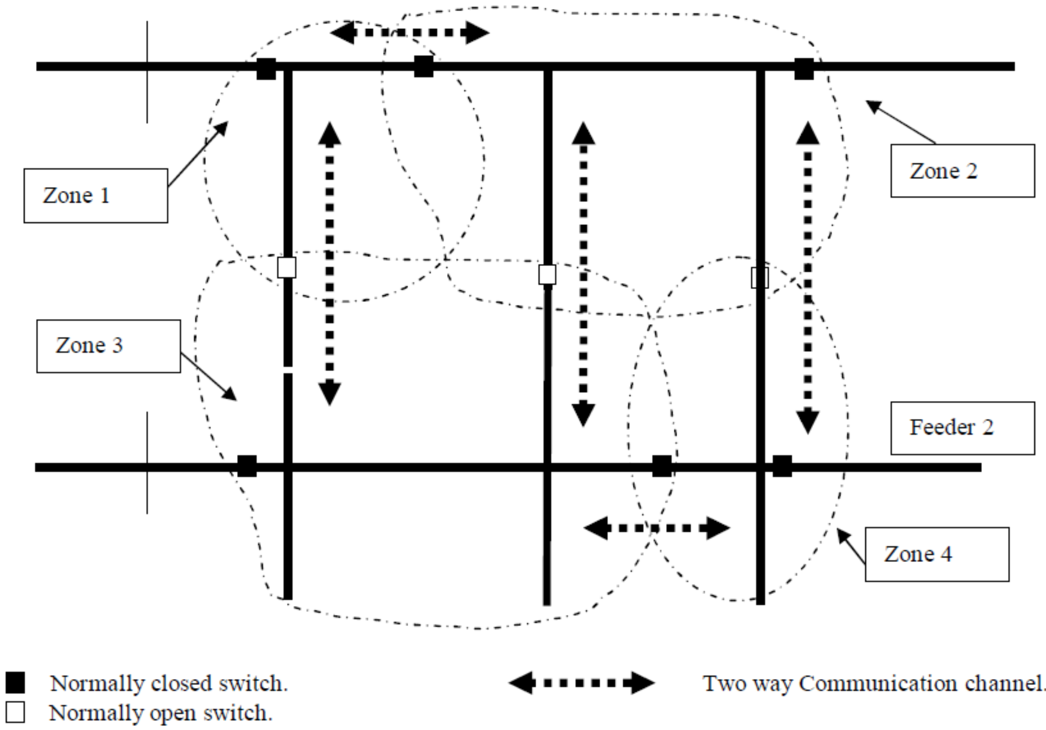


Figure (9.1) Distribution system partitioned according to the proposed zones concept

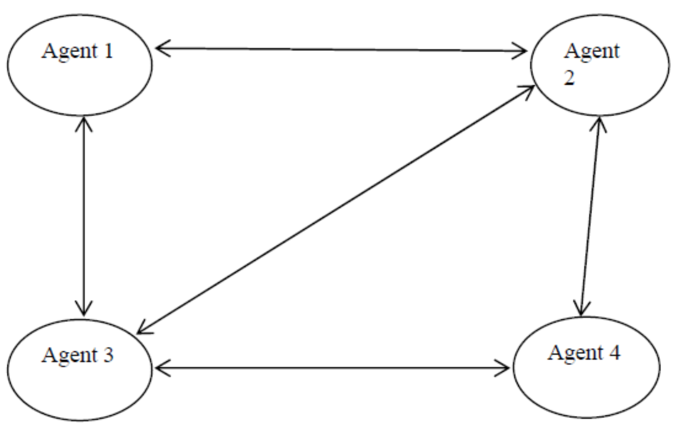


Figure 9.2) Graph representation for the network of Fig.1

The procedure executed by each Agent can be described as follows; once the Agent senses a power loss in its zone, it sends a “power lost” message to all of its neighbours. If a neighbour lost its power as well, it will send a “power lost” message to the original Agent. On the other hand, if the neighbour is still energized, it will calculate the amount of power that it can supply to the original Agent and reply with a “power offer” message. Based on neighbours’ replies, each Agent classifies its neighbours as: isolated neighbours or supply neighbours. Only isolated Agents are involved in the execution of the restoration algorithms.

Obviously, neighbours who replied with a “power offer” message, the supply neighbours, are in a still-energized part of the system. Prior to sending the “power offer” message these neighbours communicate with their own neighbours in the energized part of the system to calculate how much power can be supplied from the energized part of the system to the isolated part of the system. One simple way to calculate this power is as follows; the supply neighbour send “power request” message to its upstream neighbour, the upstream neighbour for each Agent can be predefined or determined by each Agent based on the power flow direction in the normal situation. The upstream Agent channels the message to its upstream Agent and so on. Eventually, the “power request” message will reach the supply station which its Agent should be able to calculate the extra power the station can supply without overloading the transformer. The station Agent will reply with the maximum amount of power that can be supplied to the isolated part of the system from this particular distribution station. Station Agent’s message will be channelled back to the original supply neighbour. Through its way back, each Agent in the middle from the station Agent to the supply neighbour will modify the message to make sure the extra power that will be supplied to the isolated part of the system will not cause thermal overloading for the conductors or the equipment in that middle Agent zone. In fact, that is how the proposed algorithm considers the thermal load constraint for distribution system equipment during system restoration.

Now that each Agent that lost power classified its neighbours to isolated or supply neighbours, the restoration algorithm will be executed by the isolated Agents.
For clarity we will divide the discussion of the restoration algorithms between two parts. The first part discusses the sequence of message transfer between Agents, while the second part discusses the contents of the messages. The second part will be postponed to section 9.4.

The communication protocol that governs the communication between isolated Agents is based on the so-called k-1 rule [89]

Definition 1, [89], k-1 rule: “ if agent X_i has k neighbours, X_i will send out a message to its k^{th} neighbours only after having received the other k-1 messages from the other k-1 neighbours”.
In other words, each agent waits till it receives a k-1 messages from its k neighbours before sending its message to its k^{th}, last, neighbour.

Two important results are concluded from this rule; first, Agents which will send the very first messages, to initiate the restoration algorithm, are those Agents which have one isolated neighbour only. Following a graph theory notations, those Agents will be called Leaf Agents. The second result of the k-1 rule is, dealing with a radial distribution system, there will be one, and only one, Agent which will receive messages from all its neighbours before been able to send a single message to any of its neighbours. This Agent will be called the Root Agent. All other Agents, other than the leaf and the root, will be called Middle Agents.

Effectively, the handling of messages based on the k-1 rule, allows the construction of an implicit tree structure of the isolated Agents. For each Agent, the k-1 neighbors who send him the messages first are his *children agents*: the vertices appear under him in the tree, while his last neighbor is considered his *parent Agent:* the single vertex appears above him in the tree.

Two important attributes about the tree structure created by the above discussed scheme are; first, while each agent classifies his own neighbors as children or parent, it has no information about the structure of the rest of the tree nor does it have information about the Root Agent. Second, the determination of the root agent is done dynamically in real time; it depends solely on the time taken by each Agent to execute its algorithm and send its messages in real time. In other words, prior to the execution of the restoration algorithm, it is not possible to know which Agent will be the Root Agent.

Once the Root Agent is identified, it will process the messages it received from its neighbours. Then, a second wave of messages will start originating from the Root Agent, this second wave will be called here the backward wave as opposed to the initial forward wave which originates from Leaf Agents. The Root Agent will send its decision message to its children Agents. Following that, each Agent receive a message from its parent Agent, will process it, prepare its own decision message and send it back to its own children Agents. Finally, the Leaf Agent will receive the decision of its parent Agent, take its own decision and the restoration algorithm will terminate.

Based on the above communication protocol, it is clear that, in the proposed algorithms no Agent has global knowledge about the whole problem. Furthermore, the algorithm is totally autonomous and general, in the sense that, there is no need to predefine certain structure for the communication or pre-select certain Agent to act as a moderator or to execute special tasks.

In summary, leaf Agents initiates the restoration algorithm. Following the k-1 rule, messages will propagate between Agents of the isolated part of the network. Eventually, a Root Agent will be identified automatically. The root Agent will process the received messages and initiate a new wave of messages which, this time, will be in the backward direction towards the leaf Agents where the algorithm will be terminated.

9.4 Proposed Restoration Algorithm

In the previous section we discussed how communication protocols between Agents form an implicit tree structure in which each Agent identify its children and parent Agents. In this section we will discuss algorithms which each Agent will execute in order to create their messages.

Basically, the restoration algorithms can be divided into the following steps:

1- *Creation of the Demand power list:* each Agent receives a demand power list from each of its children Agents and then combines the received demand power lists to create an overall demand power list for the part of the tree downstream of the respective Agent. For example, a certain Agent received two demand lists as follows, DemandList#1 = [L1 L2] and DemandList#2 = [L3], while the Agent's own load = [L4]. Then, the combined demand power list that this Agent will create will be, [L1+L3+L4, L2+L3+L4, L3+L4, L1+L3, L2+L3, L1+L4, L2+L4, L3+L4, L1, L2, L3, L4].
Note that, in this new demand power list there are power values which do not contain L4. To implement such a value the Agent will have to disconnect its own load. In a system where disconnecting own load is not possible, for instance due to a lack of automated switch on the low voltage side, the demand power list should be created such that it contains the respective Agent demand power in all of its entries.

For instance, for the above example the demand power list will be: [L1+L3+L4, L2+L3+L4, L3+L4, L1+L4, L2+L4, L3+L4, L4].

Furthermore, another crucial list which propagates with the demand power list is the demand power identification list. The demand power identification list contains reference to the Agents which their demand powers is involved in each of the demand list values. To clarify this last concept, assume that L1 to L4 represents the load, or demand power, of Agent#1 to Agent#4 respectively. According to the above, DemandList#1 will be accompanied with the identification list#1 as [Agent#1 Agent#2]. For DemandList#2 the identification list is [Agent#3]. Then, the new formed identification list corresponding to the new demand power list will be, [(Agent#1&Agent#3&Agent#4), (Agent#2&Agent#3&Agent#4), (Agent#3&Agent#4), (Agent#1&Agent#3), (Agent#2&Agent#3), (Agent#1&Agent#4), (Agent#2&Agent#4), (Agent#3&Agent#4), (Agent#1), (Agent#2), (Agent#3), (Agent#4)]

As mentioned in the previous section, the Leaf Agents will initiate the restoration algorithm. In fact, the demand power list of a leaf Agent will include its demand power only.

2- *Creation of the supply list:* the second important step which the Agents have to execute is the creation of the supply list. For each Agent, this list contains the amount of power offered by the still-connected neighbor, called previously the supply neighbor. Also, this list contains the power, if any, received from any children Agents as will be explained later.

3- Demand-supply comparison: during the forward wave of messages, each Agent creates its demand and supply power lists and it finds the maximum value in its demand power list that the maximum supply, from its supply list, can satisfy. Each Agent stores this demand power as its initial decision.

Once the maximum supply is identified, other supplies are discarded. In fact, based on this step, it is guaranteed that the restoration solution will preserve the radial structure of the system, i.e. any point in the system will be supplied from one supply only.

Following that, each Agent sends to its parent Agent, the demand power that the respective Agent cannot satisfy based on its own supply. The rational is, if the child Agent can satisfy a certain demand power, then there is no need to send this power value to the parent Agent. If, on the other hand, a certain Agent can not satisfy a certain demand power from its demand power list, then it will send this demand power value to its parent Agent in a hope that the resources at the parent Agent can satisfy that demand power.

In addition, each Agent will send to its parent Agent a supply offer with a value equals to the Agent's maximum supply less the maximum demand power that it can satisfy. The parent Agent will add this supply offer to its supply list.

4- *Root Agent decision taking:* Based on step 3, each Agent creates its initial decision in the forward wave of messages. Once the Root Agent is identified, as discussed earlier, it will execute step 3 in a similar fashion as other Agents. Except that, as the Root Agent is the top Agent in the tree structure, its initial decision will be same as its final decision. Namely, the Root Agent will decide which demand power, from its demand power list, will be satisfied and which supply, from its supply list, to use. Once the decision is taken, the Root Agent will send its decision to its children

Agents. Additionally, the Root Agent will implement its decision. For example, if the chosen supply is one of the Root's supply neighbors, then the Root Agent will close the switch that will connect this neighbor. Also, based on the chosen demand power, the Root Agent will identify which children Agents are involved in the chosen demand power, from the demand identification list. Then, the Root Agent will close the switches between itself and Agents involved in the chosen demand power and it will open the switches between itself and Agents not involved in the chosen demand power.

5- *Other Agents decision taking:* Based on the received decision of its parent Agent, each Agent will proceed with the final decision making process. Actually, for any Agent, the message received from its parent Agent will be one of the following:

a- "DISCONNECT": that will be the case if this respective Agent is not in the list of the Agents involved in the demand power chosen by the parent Agent. In this case, the respective Agent will consider its initial decision, decided during the forward wave of messages, as its final decision and it will send its decision to its own children Agents and, finally, it will implement the decision in a similar fashion as the Root Agent did.

b- "SUPPLY": that will be the case if the parent Agent decided to use the extra power that was sent to it from this respective children Agent. In this case, this respective Agent will execute its initial decision using its previously decided supply.

c- "DEMAND POWER": that will be the case if this Agent is in the list of the Agents involved in the demand power chosen by the parent Agent. In this case, the respective Agent will abandon its initial decision, disconnect all of its possible supplies, and it will consider the decision received from the parent Agent.

Ultimately, Leaf Agents will receive the decision of their parent Agents, decide their final decision, execute it and the algorithm will terminate.

9.4.1 Detailed Illustrative Example

To illustrate the basic idea of the proposed restoration algorithm, consider the following simple example. Fig (9.3) shows a graph corresponds to an isolated part of a network. Each of the Agents 1, 2, 3 and 4 knows the amount of demand power of their respective buses, $P_{demand,n}$. Also, each of these agents had received a value of the extra power available for restoration from one of their still connected neighbors, denoted $P_{supply,n}$.

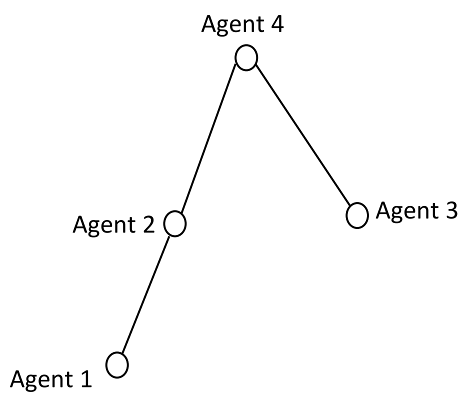


Figure (9.3) Graph representing the isolated part of the network

It is clear that Agents 1 and 3 are leaf agents, they only have one neighbor each, namely Agent 2 and 4 respectively. So Agent 1 and 3 initiate the restoration algorithm. Basically, Agents 1 and 3 will determine whether their P_{demand} is greater than their P_{supply} or not, if so then they will set,

$$P_{excess} = P_{supply} - P_{demand}$$

Otherwise, $P_{excess} = P_{supply}$

Then they will send to Agent 2 and 4, respectively, the values of their P_{demand} and P_{excess}. For Agent 1 and 3, in this example, assume that,

$$P_{supply} < P_{demand}$$

After receiving massages from Agents 1 and 3, Agents 2 and 4, thus received massage from one of their two neighbors, will start the execution of their algorithms. Note that, up to this point both Agents 2 and 4 are considering themselves middle agents. Each of Agents 2 and 4 will start to construct a demand power list that contains all the possible combinations of the power of itself and the power of all of its children. Consider Agent 2, for example, the combined demand power list will be as follows,

$$P_{demand,combined,Agent2} = \begin{bmatrix} P_{demand,Agent2} + P_{demand,Agent1} \\ P_{demand,Agent2} \\ P_{demand,Agent1} \end{bmatrix}$$

Agent 4 will construct a similar list contains the demand power values of Agents 3 and 4. Consider Agent 2; Agent 2 has two possible supply values, namely, P_{supply} from its still connected neighbor and $P_{excess,Agent1}$ received from Agent 1. Agent 2 will find the maximum demand power from the demand power list that it can satisfy using its largest possible supply, this demand power will be called $P_{satisfied,Agent2}$. Then, Agent 2 will truncate the demand power list at $P_{satisfied,Agent2}$.

Assume that the maximum power that Agent 2 can satisfy is Agent 2 demand power and that the maximum possible supply is $P_{excess,Agent1}$ received from Agent 1. Note that, we are assuming here that $P_{demand,Agent1}$ is greater than $P_{demand,Agent2}$. The new demand power list will be,

$$P_{demand,combined,Agent2} = \begin{bmatrix} P_{demand,Agent2} + P_{demand,Agent1} \\ P_{demand,Agent1} \end{bmatrix}$$

Also, Agent 2 will prepare a $P_{excess,Agent2}$ value as follow,

$$P_{excess,Agent2} = max(P_{supply,Agent2}, P_{excess,Agent1}) - P_{satisfied,Agent2}$$

Note that, Agent 4 will be doing the same thing as above in the same time and will come up with certain $P_{demand,Agent4}$ and $P_{excess,Agent4}$. Based on execution times taken by Agents 2 and 4, one of them will be able to prepare and send his massage to the other first. The case in which both Agents finish at the exact same time can be avoided by taking proper measures, one possible solution would be to ask each Agent to count some random time before sending out its message.

Assume here for the sake of discussion that, Agent 2 was able to send his massage to Agent 4 first. Thus, Agent 4 will be the Agent that have received two massages from his two neighbors before been able to send any massage. Therefore, Agent 4 will recognize itself as the root Agent.

Basically, Agent 4 will have the following demand power list, formed by combining the demand powers received from its children, namely, Agents 2 and 3,

$$P_{demand\_list} = \begin{bmatrix} P_{demand,Agent4} + P_{demand,Agent3} + P_{demand,Agent2} + P_{demand,Agent1} \\ P_{demand,Agent4} + P_{demand,Agent2} + P_{demand,Agent1} \\ P_{demand,Agent3} + P_{demand,Agent2} + P_{demand,Agent1} \\ P_{demand,Agent4} + P_{demand,Agent3} \\ P_{demand,Agent3} + P_{demand,Agent1} \\ P_{demand,Agent4} \\ P_{demand,Agent1} \\ P_{demand,Agent3} \end{bmatrix}$$

Also Agent 4 will have a supply power list as follows,

$$P_{\text{supply\_}list} = \begin{bmatrix} \mathrm{P}_{\text{supply,Agent4}} \\ \mathrm{P}_{\text{supply,Agent2}} \\ \mathrm{P}_{\text{supply,Agent3}} \end{bmatrix}$$

Agent 4 will simply pick the maximum of supply power list and try to satisfy the maximum possible power demand from the demand power list. Then Agent 4 will implement its decision and inform its children about its own decision. For example, assume that Agent 4 will use $P_{supply,Agent4}$, received from its still connected neighbor. Also assume that Agent 4, based on the value of $P_{supply,Agent4}$, can satisfy the demand power value of ($P_{demand,Agent4}$ + $P_{demand,Agent3}$). Then, Agent 4 will connect to its still connected neighbor. In addition, Agent 4 will connect to Agent 3 and will supply its demand power. Finally, Agent 4 will disconnect the line between Agent 4 and Agent 2, as Agent 4 cannot satisfy the demand power of Agent 2. Being disconnected from Agent 4, Agent 2 will have the ability to use any other supply as the link between Agents 2 and 4 is disconnected so the network will preserve its radial structure.

Now considering Agent 3, in our particular example here, Agent 3 will receive an offer of power from its parent so it will disconnect the link between itself and any still connected neighbor, if any.

On the other hand, having received a “disconnect” massage from its parent, Agent 2 will implement the decisions it had taken during the forward wave. Recall that, Agent 2 decided, initially, that it should use $P_{excess,Agent1}$ received from Agent 1 and that the maximum power that can be satisfied is $P_{demand,Agent2}$, therefore, Agent 2 will connect the link between itself and Agent 1. In addition, Agent 2 will disconnect any link between itself and its still-connected neighbors.

Lastly, in this particular example, Agent 1 received “Excess” massage from its parent, that means that the parent will make use of the $P_{excess,Agent1}$ sent previously by Agent 1. Therefore, Agent 1 will implement the decision it had taken during the forward wave. In particular, as $P_{supply,Agent1}$ was less than $P_{demand,Agent1}$ then, Agent 1 will disconnect its own load. In addition, Agent 1 will connect the link between itself and its still-connect agent and the power will flow from the still-connected agent of Agent 1 to Agent 2 directly without feeding Agent 1 load. The algorithm terminate when all the leaf agents, Agent 1 and 3, executed their decision making algorithms.

9.5 Simulation Study

In this section we present several simulation cases that were carried out to validate the proposed system. In order to get a true multi-agent simulation, the algorithm was implemented in Java language using the JADE software framework. JADE, [90], is a middle-ware that compile with the FIPA standard, [91], for developing multi-agent software.

A. <u>Case 1</u>

Consider the network shown in Fig (9.4). Assume that, a fault happened along feeder 2. The part of feeder 2 downstream of the fault will be isolated. This part is divided between 6 zones based on locations of the disconnecting switches; each zone is controlled by an Agent. Agent 1 has a possible connection with feeder 1, Agent 3 has a possible connection with feeder 4 and Agent 6 has two possible connections with feeder 5 and feeder 3.

The demand powers for each zone and the available supply powers for each zone, from its still-connected neighbors, are shown in Table 9.1. It is clear that, Agents 1 to 6 are isolated, so only these Agents are involved in the execution of the restoration algorithm. Agent 1 and Agent 6 are leaf Agents, so they will initiate the restoration algorithms. Based on the execution of the restoration algorithms, one of the Agents 2, 3, 4 or 5 will identify itself as the Root Agent.

Table 9-1 Demand and supply power values for Case 1

Agent #	Demand Power	Possible supply	Possible supply power value
1	7	feeder 1	4
2	2	-	0
3	7	feeder 4	30
4	10	-	0
5	7	-	0
6	4	feeder 3/ feeder 5	3/5

The restoration solution is shown in Fig (9.5). Essentially, the solution is to connect feeder 4, through Agent 3, and let its extra power feeds the entire isolated loads except Agent 5 loads which will remain isolated.

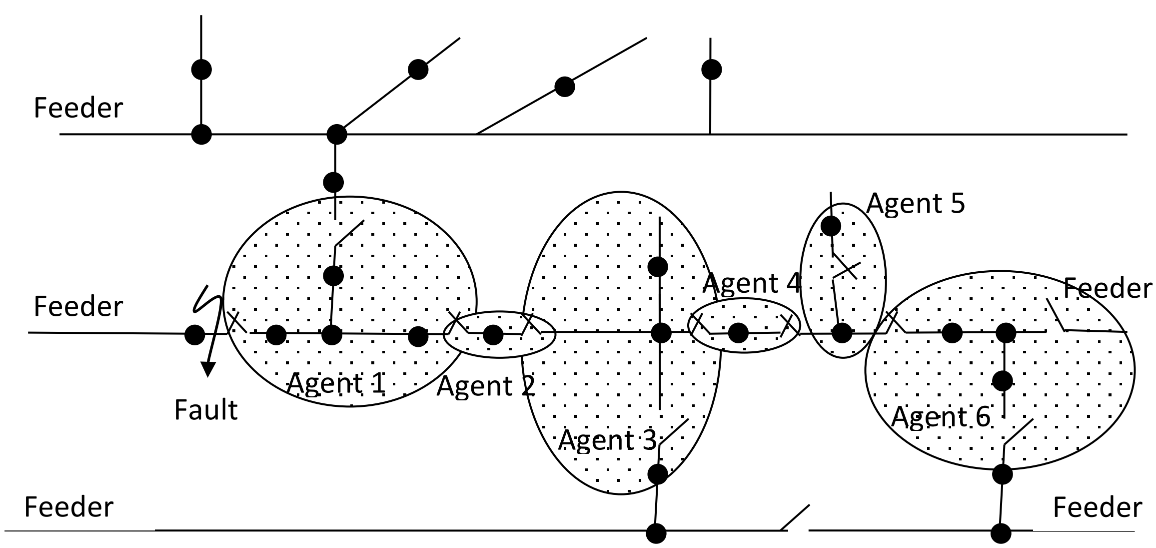


Figure (9.4) Distribution network under study

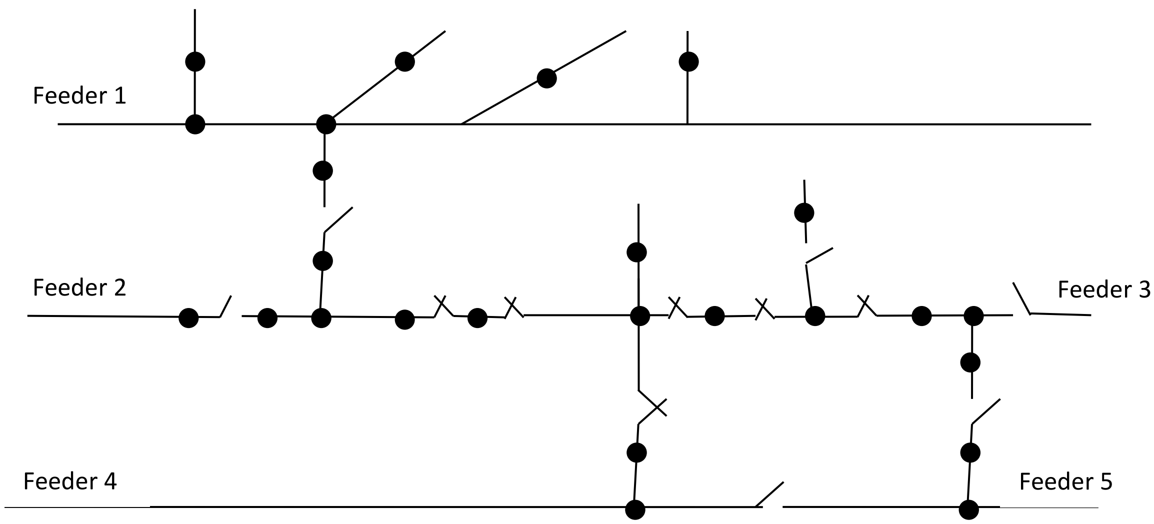


Figure (9.5) Restored system for Case 1

It is worthy mention that, the summation of the available extra power is 37 units and the summation of the demand power is 37 units. However, it is not possible to restore more power than 30 units due to the radial network constraint, i.e. to restore more power we have to relax the radial network constraint which is not acceptable from the network operation point of view.

B. <u>Case 2</u>

In this case we will repeat case 1 but now the demand power of each zone is shown in table 9-2. Also, the available supply powers for each zone, from its still-connected neighbors, are shown in table 2.

The restoration solution is shown in Fig (9.6). Essentially, the solution is to connect feeder 4, through Agent 3, and let its extra power feeds Agents 1 and 2. Then connect feeder 3 and let its extra power feeds Agent 4 and 6. Agents 3 and 5 cannot be restored.

Note that, the summation of the available extra power is 23 units and the summation of the demand power is 33 units. However, it is not possible to restore any more power than 17 units due to the radial network constraint. For instance, the extra power at feeder 1 cannot be used, because in our solution feeder 4 will be connected to Agent 1, through Agent 2 and 3, so feeder 1 cannot be connected to Agent 1, otherwise the radial structure of the network will be lost.

Table 9-2 Demand and supply power values for Case 2

Agent #	Demand Power	Possible supply	Possible supply power value
1	6	feeder 1	5
2	2	-	0
3	9	feeder 4	8
4	4	-	0
5	7	-	0
6	5	feeder 3/ feeder 5	10/8

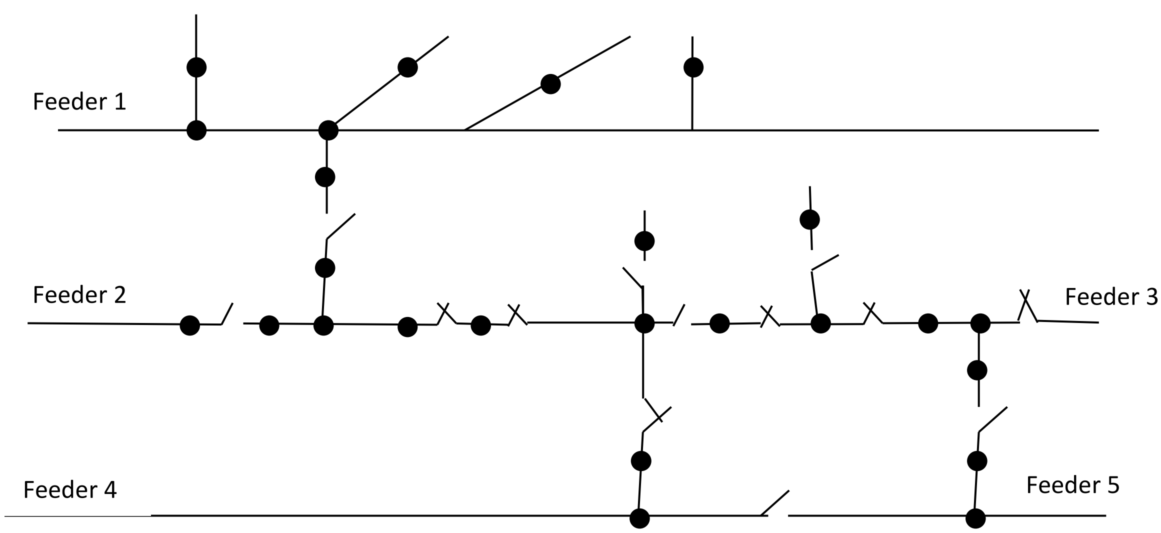


Figure (9.6) Restored system for Case 2

9.6 Conclusions

In this chapter a decentralized distribution system restoration scheme was proposed. A technique for dividing the network into zones was introduced. Communication protocol and distributed restoration algorithm were discussed in details. The scheme has several advantages; first, the scheme is applicable to any network regardless the availability of disconnecting switches in the network. Second, the scheme does not assume any supervision from any pre-determined point. Third, two main constraints are taken into consideration in the proposed restoration scheme, namely, the restored network must preserve the radial structure and thermal capacity for any equipment should not be exceeded. The proposed algorithm enables the restoration of the distribution system in a self-healing mode without the intervention of a central control center which is a key feature for smart distribution systems. Simulation study was presented showing the efficiency of the proposed algorithm in solving distribution network restoration.

Chapter 10

Summary, Contributions and Future Work

10.1 Summary

The main goal of this research work was to develop novel decentralized operation techniques for the distribution system in an attempt to meet the current challenges facing the operation of distribution systems. The set of objectives of the proposed techniques was to enable efficient integration of DG in the system as well as increase the efficiency and the reliability of the system. In that scope, this research work concentrated on three main distribution system operation functions namely; Voltage Control, Reactive Power Control and Distribution System Restoration.

Voltage Control is the first operation function dealt with in this research work. In Chapter 4, a voltage control scheme was proposed for the control of multiple feeders using one regulator. Regulator's tap selection was formulated as an integer linear optimization problem. The proposed scheme has a closed form solution and can be easily applied in real-time operation. The main disadvantage of that scheme, though, is its inability to deal with the presence of DGs. Therefore, in Chapter 5, coordinated voltage control scheme was proposed to deal with the regulation of multiple feeders in any distribution network. That scheme depends on the measurements of Remote Terminal Units (RTUs) located in the system. Mathematical proofs were presented to prove that the assumed number and locations of the RTUs are optimal in order to estimate the voltage profile of the system efficiently. The set of RTUs, with proper communication protocols, forms a Multi-Agent system to estimate the voltage of the feeder and hence operate the voltage regulator.

Utilizing the same RTU used in Chapter 5 for voltage control, reactive power control scheme was proposed in Chapter 6. Novel technique for the estimation of voltage profile change due to the injection of reactive power from capacitors was developed. The proposed technique controls the reactive power in real-time in order to minimize system losses while maintaining acceptable voltage profile.

Building on solid voltage control and reactive power control schemes, generalized voltage control scheme was proposed in Chapter 7 to coordinate the operation of voltage regulators, shunt capacitors and DGs. Detailed analysis and simulation studies were presented to show the operation of the voltage regulator and shunt capacitors in response to change in DG injected power in order to maintain voltage profile of the system while minimizing the losses.

Based on the generalized voltage control technique proposed in Chapter 7, a new concept of operation-time, or real-time, DG connection impact assessment was proposed in Chapter 8. By coordinating the operation of voltage regulators, shunt capacitors and DG, the proposed technique determine the maximum allowable extra power that can be injected from a certain DG under certain system conditions. The proposed technique provides great flexibility for the connection of DGs to the distribution system. For example, based on the proposed technique, certain DG can inject more power at times when other DGs on the feeder are out of service or are injecting less power than originally planned. Another example would be a DG that need to connect for a feeder other than the one it was planned for in the planning stage due to a fault that force a reconfiguration of the system.

Concerning the operation of the system in the restoration state, Chapter 9 proposed a decentralized distribution system restoration scheme to determine the optimal reconfiguration of the system in order to restore as much loads as possible. The scheme is based on the coordination of several RTU located in the system. Communication protocols and restoration algorithms were presented in details.

10.2 Contributions

The main contributions of this research work can be summarized as follows;

1- The development of a reliable and efficient optimal voltage control scheme for multiple feeders using one regulator. The proposed scheme eliminates the need for multiple regulators, thus reducing system costs and removing the complications associated with coordinating the operation of multiple regulators.

2- The development of a novel voltage profile estimation technique based on the reading of *optimally* located RTUs in the system. The developed technique enables coordination between DG and voltage control equipment of the system. In this research, it was proved that the readings required by the proposed technique are the minimum number of readings required to estimate the voltage profile efficiently.

3- The development of a novel coordinated voltage control scheme for the regulation of multiple feeders with DGs utilizing the proposed voltage profile estimation technique. This scheme enables voltage regulators to operate in response to DG power variation and, hence, provide a solid method to mitigate the steady state voltage rise problem associated with the integration of DGs. Ultimately, the proposed scheme allow more DG power to be connected to the distribution system.

4- The development of an optimal reactive power control scheme in order to minimize the losses while maintaining the voltage profile of the system taking into account the effect of DGs. The proposed scheme enables capacitors to operate in response to minimum and maximum voltages of the feeder as opposed to operating in response to the voltage of capacitor's bus. In fact, this is a valuable change taking into account that when a DG is present on a feeder, the maximum voltage of the feeder will not be necessarily at the capacitor bus as opposed to the case when no DG is present.

5- The development of a generalized coordinated voltage control algorithm to coordinate the operation of voltage regulators, shunt capacitors and DGs. This algorithm provides general solution for the voltage control for feeders with DG. The proposed algorithm realizes the concept of Active Network Management (ANM) in which system's controls react to changes in system operating conditions in real-time by taking optimal corrective actions in order to respect all system constraints.

6- The introduction of a new concept of operation-time DG connection impact assessment. This concept, which is based on the Active Network Management concept, will allow the assessment of DG connection in real-time based on system operating conditions. DGs will be granted the permission to increase their injected power or, even, to connect to other feeders if operation-time assessment determines that there is no adverse impact on system constraints. This is great flexibility compared to the way DGs are planned and operated in the current utility practice.

7- The development of a decentralized distribution system restoration technique to determine the optimal configuration of the system in order to restore as much load as possible after the occurrence of a fault. The proposed technique, based on formal mathematical formulation, allows much faster restoration of the system compared to the current utility practice and, hence, much shorter service interruption time. Ultimately, the proposed technique improves the reliability of the system.

10.3 Future Work Directions

Building on the results of this research work, the following summarizes some of the research points that can carried out in the future;

1- Application of this thesis results and proposed concepts to other distribution system operation functions such as load management.
2- Development of new planning techniques in order to formally determine the extra DG power that might be connected and operated based on the proposed operation-time DG connection impact assessment concept.
3- Extension of the proposed operation-time DG connection impact assessment for micro-DG scales taking into account their impact on system unbalance beside voltage profile.
4- Study of the implementation issues related to the proposed techniques in real distribution systems.

Appendix A

Details of the proposed algorithms

For the following algorithms, let RTU_n be the RTU connected to bus *n* and define $RTU_{(n-1)}$ to be the immediate upstream RTU, the *parent* RTU. Also, define the set $\{RTU_{n+1}\}$ to be the set of RTU connected immediately downstream of RTU_n, the set of *children* RTU.

Algorithm# 5.1: Estimation of voltage profile minimum points

1- Receive the following data from RTU_{n+1}: min-flag, $V_{min,estimated\_upstream}$.
2- If min-flag = 1, then
3- Estimate $V_{min,estimated\_downstream}$ using (5.19).
4- Calculate $V_{min\text{-}downstream}$:

$$V_{\min-\mathrm{downstream}} = \frac{V_{\mathrm{min-estimated-upstream}} + V_{\mathrm{min-estimated-downstream}}}{2}$$

5- if($V_n > V_{neighbour\text{-}upstream}$), then min-flag = 1, otherwise, min-flag = 0.
6- Estimate $V_{min,estimated\_upstream}$ using (5.19).
7- Send to RTU_{n-1} the following; min-flag, $V_{min,estimated\_upstream}$

Algorithm# 5.2 Voltage profile estimation

A. End of feeder RTU

1- Read V_n; the voltage of the bus.

2- $V_{feeder,max} \leftarrow V_n$

3- $V_{feeder,min} \leftarrow V_n$

4- if($V_n > V_{neighbour-upstream}$), then min-flag = 1, otherwise, min-flag = 0.

5- Estimate $V_{min,estimated\_upstream}$ using equation (5.19).

6- Send to RTU_{n-1} the following; $V_{feeder,max}$, $V_{feeder,min}$, min-flag, $V_{min,estimated\_upstream}$

7- Terminate the algorithm.

B. General RTU

1- $\forall RTU_{n+1} \in \{RTU_{n+1}\}$:

  a. Receive the following data from RTU_{n+1}: $V_{feeder,max}$, $V_{feeder,min}$, min-flag, $V_{min,estimated\_upstream}$.

  b. Read V_n; the voltage of the bus.

  c. If (V_n) > $V_{feeder-max}$, then $V_{feeder-max} \leftarrow V_n$.

  d. Execute Algorithm#5.1.

  e. If ($V_{min-downstream}$) < $V_{feeder,min}$, then $V_{feeder,min} \leftarrow V_{min-downstream}$

2- Send to RTU_{n-1} the following; $V_{feeder,max}$, min-flag, $V_{min,estimated\_upstream}$

3- Terminate the algorithm.

C. Voltage Regulator RTU

1- $\forall RTU_{n+1} \in \{RTU_{n+1}\}$:

  a. Receive the following data from RTU_{n+1}: $V_{feeder,max}$, $V_{feeder,min}$, min-flag, $V_{min,estimated\_upstream}$.

  b. Read V_n; the voltage of the bus.

c. If (V_n) > $V_{feeder\text{-}max}$, then $V_{feeder\text{-}max} \leftarrow V_n$.

d. Execute Algorithm#5.1.

e. If ($V_{min\text{-}downstream}$) < $V_{feeder,min}$, then $V_{feeder,min} \leftarrow V_{min\text{-}downstream}$

<u>Algorithm# 5.3 Coordinated Voltage control</u>

1- The system will estimate the voltage profile of the system by executing Algorithm # 5.1.

2- The station's RTU will decide the optimal tap as follow;

a. If max($V_{feeder,max}$) > $V_{max,perm,}$, then lower the regulator tap to correct the voltage.

b. If min($V_{feeder,min}$) < $V_{min,perm,}$, then raise the regulator tap to correct the voltage.

Algorithm #6.1: Voltage Profile Estimation including the effect of Shunt Capacitor

A. End of feeder RTU

1- Read V_{end}; the voltage of the bus.

2- if(V_{end} > $V_{neighbour\text{-}upstream}$), then min-flag = 1, otherwise, min-flag = 0.

3- Estimate $V_{min,estimated\_upstream}$ using equation (5.19).

4- Send to RTU_{n-1} the following; V_{end}, min-flag, $V_{min,estimated\_upstream}$

5- Terminate the algorithm.

B. RTU Downstream of the Capacitor

1- $\forall RTU_{n+1} \in \{RTU_{n+1}\}$:

   a. Receive the following data from RTU_{n+1}: min-flag, $V_{min,estimated\_upstream}$, V_{n+1},V_{n+2}, ….., V_{end}.

   b. Read V_n; the voltage of the bus.

   c. Execute Algorithm#5.1.

2- Send to RTU_{n-1} the following; min-flag, $V_{min,estimated\_upstream}$, V_n, V_{n+1},V_{n+2}, ….., V_{end}.

3- Terminate the algorithm.

C. Capacitor RTU

1- $\forall RTU_{n+1} \in \{RTU_{n+1}\}$:

   a. Receive the following data from RTU_{n+1}: min-flag, $V_{min,estimated\_upstream}$, V_{n+1},V_{n+2}, ….., V_{end}.

   b. Read V_n; the voltage of the bus.

   c. Execute Algorithm#5.1.

   d. Initiate $V_{feeder,max,Qc}$ and $V_{feeder,max,Qc}$ corresponding to each $Q_c \in Q_{levels}$

   e. $\forall Q_c \in Q_{levels}$

      i. Calculate $V_{n,Qc} = V_n + Q_c \sum_{k=1}^{k=n} X_{k-1,k}$

ii. Calculate $V_{min,downstream,Qc} = V_{min,downstream} + Q_c \sum_{k=1}^{k=n} X_{k-1,k}$

iii. $V_{feeder,max,\ Qc} \leftarrow V_{n,\ Qc}$

iv. $V_{feeder,min,\ Qc} \leftarrow V_{nmin,downstream,Qc}$

f. Store: $\{V_{dowstream}\} \leftarrow [V_{n+1}, V_{n+2}, \ldots, V_{end}]$.

g. $\forall V_{dowstream} \in \{V_{dowstream}\}$

i. $\forall Q_c \in Q_{levels}$

1. Calculate $V_{downstream,Qc} = V_{downstream} + Q_c \sum_{k=1}^{k=n} X_{k-1,k}$
2. If $V_{downstream} > V_{feeder,max,\ Qc}$, then $V_{feeder,max,\ Qc} \leftarrow V_{downstream,Qc}$
3. If $V_{downstream} < V_{feeder,min,\ Qc}$, then $V_{feeder,min,\ Qc} \leftarrow V_{downstream,Qc}$

h. $\forall Q_c \in Q_{levels}$, let $i \in \{1,2,\ldots,m = size(V_{downstream})\}$.

i. Calculate:

$$lossesQc = (V_{n,Qc} - V_{downstream}(1))^2 + \sum_{i=1}^{m-1} (V_{downstream}(i) - V_{downstream}(i+1))^2$$

i. $TotalLosses_{Qc} = \sum lossesQc$, $\forall Qc$

2- Send to RTU_{n-1} the following; min-flag, $V_{min,estimated\_upstream}$, Q_{levels} , $V_{feeder,max,Qc}$, $V_{feeder,min,Qc}$, $TotalLosses_{Qc}$, Q_{levels}.

3- Terminate the algorithm.

D. RTU Upstream of the Capacitor

1- $\forall RTU_{n+1} \in \{RTU_{n+1}\}$:

a. Receive the following data from RTU_{n+1}: min-flag, $V_{min,estimated\_upstream}$, $V_{feeder,max,Qc}$, $V_{feeder,min,\ Qc}$, V_{n+1}, $TotalLosses_{Qc}$, Q_{levels}.

b. Read V_n; the voltage of the bus.

c. Execute Algorithm#5.1.

d. $\forall Q_c \in Q_{levels}$

i. Calculate $V_{n,Qc} = V_{n,old} + Q_c \sum_{k=1}^{k=n} X_{k-1,k}$

ii. Calculate $V_{min,downstream,Qc} = V_{min,downstream,old} + Q_c \sum_{k=1}^{k=n} X_{k-1,k}$

iii. If $V_{n,Qc} > V_{feeder,max,Qc}$, then $V_{feeder,max,Qc} \leftarrow V_{n,\,Qc}$

iv. If $V_{min,downstream,Qc} < V_{feeder,min,Qc}$, then $V_{feeder,min,\,Qc} \leftarrow V_{nmin,downstream,Qc}$

v. Calculate:

$$lossesQc \ = (V_{n,Qc} - V_{min,downstream,Qc})^2 + (V_{min,downstream,Qc} - V_{n+1})^2$$

2- $TotalLosses_{Qc} = \mathrm{TotalLosses}_{Qc} \ + \sum lossesQc \ , \quad \forall Qc$

3- Send to RTU_{n-1} the following; min-flag, $V_{min,estimated\_upstream}$, Q_{levels} , $V_{feeder,max,Qc}$, $V_{feeder,min,Qc}$, $TotalLosses_{Qc}$

4- Terminate the algorithm.

E. <u>Station's RTU</u>

1- Receive the following data from RTU_{n+1}: min-flag, $V_{min,estimated\_upstream}$, $V_{feeder,max,Qc,}V_{feeder,min,\,Qc}$, V_{n+1}, $TotalLosses_{Qc}$, Q_{levels}.

2- Read V_n; the voltage of the bus.

3- Execute Algorithm#5.1.

4- $\forall Q_c \in Q_{levels}$

   a. Calculate $V_{min,downstream,Qc} = V_{min,downstream} + Q_c \sum_{k=1}^{k=n} X_{k-1,k}$

   b. If $V_{min,downstream,Qc} < V_{feeder,min,Qc}$, then $V_{feeder,min,\,Qc} \leftarrow V_{nmin,downstream,Qc}$

   c. Calculate:

   $$lossesQc \ = (V_{n,Qc} - V_{min,downstream,Qc})^2 + (V_{min,downstream,Qc} - V_{n+1})^2$$

5- $TotalLosses_{Qc} = \mathrm{TotalLosses}_{Qc} \ + \sum lossesQc \ , \quad \forall Qc$

Algorithm #6.2: Optimal Reactive Power Control:

1- The system will execute Algorithm # 6.1 to estimate the voltage of the feeder corresponding to each possible reactive power injection from the capacitor.

2- The station's RTU will then find $Q_{optimal} \in Q_{levels}\ such\ that$,

$$TotalLosses_{Q_{optimal}} = \min\left(TotalLosses_{Qc}\right), \qquad \forall Q_c \in Q_{levels}$$

And,

$$V_{feeder,max,Q_{optimal}} < V_{feeder,max,perm}$$

$$V_{feeder,min,Q_{optimal}} > V_{feeder,min,perm}$$

3- The station's RTU will send to the Capacitor's RTU the value of $Q_{optimal}$.

Algorithm # 6.3: Optimal Reactive Power Control for multiple capacitors using proposed Method 2:

1. *Forward Phase*

A. *End of feeder RTU*

1- Read V_{end}; the voltage of the bus.

2- if($V_{end} > V_{neighbour\text{-}upstream}$), then min-flag = 1, otherwise, min-flag = 0.

3- Estimate $V_{min,estimated\_upstream}$ using equation (5.19).

4- Send to RTU_{n-1} the following; V_{end}, min-flag, $V_{min,estimated\_upstream}$

5- Terminate the algorithm.

B. *RTU Downstream of the Capacitor*

1- $\forall RTU_{n+1} \in \{RTU_{n+1}\}$:

   a. Receive the following data from RTU_{n+1}: min-flag, $V_{min,estimated\_upstream}$, V_{n+1},V_{n+2}, ..., V_{end}.

   b. Read V_n; the voltage of the bus.

   c. Execute Algorithm#5.1.

2- Send to RTU_{n-1} the following; min-flag, $V_{min,estimated\_upstream}$, V_n, V_{n+1},V_{n+2}, ..., V_{end}.

3- Terminate the algorithm.

C. *Capacitor RTU*

1- $\forall RTU_{n+1} \in \{RTU_{n+1}\}$:

   a. Receive the following data from RTU_{n+1}: min-flag, $V_{min,estimated\_upstream}$, V_{n+1},V_{n+2}, ..., V_{end}.

   b. Read V_n; the voltage of the bus.

   c. Execute Algorithm#5.1.

   d. Store: $\{V_{dowstream}\} \leftarrow [V_{n+1}, V_{n+2}, ..., V_{end}]$.

2- Send to RTU_{n-1} the following; min-flag, $V_{min,estimated\_upstream}$, Q_{levels} .

3- Wait for the parent reply.

D. RTU Upstream of the Capacitor

1- $\forall RTU_{n+1} \in \{RTU_{n+1}\}$:

a. Receive the following data from RTU_{n+1}: min-flag, $V_{min,estimated\_upstream}$, Q_{levels}.

b. Read V_n; the voltage of the bus.

c. Execute Algorithm#5.1.

2- Combine Q_{levels} lists received from all *RTU*s in $\{RTU_{n+1}\}$ to form $Q_{levels,\ combined}$ and store the new list.

3- Send to RTU_{n-1} the following; min-flag, $V_{min,estimated\_upstream}$, $Q_{levels,\ combined}$.

4- Wait for the parent reply.

E. Station's RTU

1- Receive the following data from RTU_{n+1}: min-flag, $V_{min,estimated\_upstream}$, $Q_{levels,\ combined}$.

2- Read V_n; the voltage of the bus.

3- Execute Algorithm#5.1.

4- $\forall Q_c \in Q_{levels,combined}$

a. Calculate $V_{min,downstream,Qc} = V_{min,downstream} + Q_c \sum_{k=1}^{k=n} X_{k-1,k}$

b. Calculate:

$$losses_{\ Qc} = (V_{n,Qc} - V_{min,downstream,Qc})^2 + (V_{min,downstream,Qc} - V_{n+1})^2$$

5- If $V_{min,downstream}$ exists, then $\{V_{parent}\} \leftarrow V_{min,downstream}$ and $\{V_{parent,Qc}\} \leftarrow V_{min,downstream,Qc}$ otherwise $\{V_{parent}\} \leftarrow V_n$ and $\{V_{parent,Qc}\} \leftarrow V_n$.

6- Calculate $\Delta V_{parent} = V_{parent,Qc} - V_{parent}$

7- Initiate $V_{feeder,max,Qc}$ and $V_{feeder,max,Qc}$ corresponding to each $Q_c \in Q_{levels,combined}$

8- Send to RTU_{n+1} the following; $V_{parent,Qc}$, ΔV_{parent} , $losses_{Qc}$, $V_{feeder,max,Qc}$ and $V_{feeder,max,Qc}$.

9- Terminate the algorithm.

2. Backward Phase

A. RTU Upstream of the Capacitor

1- Receive the following data from RTU_{n+1}: ΔV_{parent} , $losses_{Qc}$, $V_{feeder,max,Qc}$ and $V_{feeder,max,Qc}$.

2- $\forall Q_c \in Q_{levels,combined}$

i. Calculate $V_{n,Qc} = V_{n,old} + \Delta V_{parent} + Q_c X_{n,n-1}$

ii. Calculate $V_{min,downstream,Qc} = V_{min,downstream,old} + \Delta V_{parent} + Q_c X_{n,n-1}$

iii. If $V_{n,Qc} > V_{feeder,max,Qc}$, then $V_{feeder,max,Qc} \leftarrow V_{n,Qc}$

iv. If $V_{min,downstream,Qc} < V_{feeder,min,Qc}$, then $V_{feeder,min,Qc} \leftarrow V_{nmin,downstream,Qc}$

v. Calculate:

$$lossesQc = (V_{n,Qc} - V_{parent,Qc})^2 + (V_{min,downstream,Qc} - V_n)^2$$

3- $TotalLosses_{Qc} = \text{TotalLosses}_{Qc} + \sum losses_{Qc}$, $\forall Qc$.

4- If $V_{min,downstream}$ exists, then $\{V_{parent}\} \leftarrow V_{min,downstream}$ and $\{V_{parent,Qc}\} \leftarrow V_{min,downstream,Qc}$ otherwise $\{V_{parent}\} \leftarrow V_n$ and $\{V_{parent,Qc}\} \leftarrow V_n$.

5- Calculate $\Delta V_{parent} = V_{parent,Qc} - V_{parent}$

6- Initiate $V_{feeder,max,Qc}$ and $V_{feeder,max,Qc}$ corresponding to each $Q_c \in Q_{levels,combined}$

7- Send to RTU_{n+1} the following; $V_{parent,Qc}$, ΔV_{parent} , $losses_{Qc}$, $V_{feeder,max,Qc}$ and $V_{feeder,max,Qc}$.

8- Terminate the algorithm.

B. Capacitor's RTU

1- Receive the following data from RTU_{n+1}: ΔV_{parent} , $losses_{Qc}$, $V_{feeder,max,Qc}$ and $V_{feeder,max,Qc}$.

2- $\forall Q_c \in Q_{levels,combined}$

i. Calculate $V_{n,Qc} = V_{n,old} + \Delta V_{parent} + Q_c X_{n,n-1}$

ii. Calculate $V_{min,downstream,Qc} = V_{min,downstream,old} + \Delta V_{parent} + Q_c X_{n,n-1}$

iii. If $V_{n,Qc} > V_{feeder,max,Qc}$, then $V_{feeder,max,Qc} \leftarrow V_{n,Qc}$

iv. If $V_{min,downstream,Qc} < V_{feeder,min,Qc}$, then $V_{feeder,min,Qc} \leftarrow V_{nmin,downstream,Qc}$

v. Calculate:

$$lossesQc = \left(V_{n,Qc} - V_{parent,Qc}\right)^2 + \left(V_{min,downstream,Qc} - V_n\right)^2$$

vi. TotalLossesQc = $\mathrm{TotalLosses}_{\mathrm{Qc}} + \sum \mathrm{losses}_{\mathrm{Qc}}$, $\forall$Qc.

3- $\forall V_{dowstream} \in \{V_{dowstream}\}$ and $\forall Q_c \in Q_{levels}$

vi. Calculate $V_{downstream,Qc} = V_{downstream} + (V_{n,Qc} - V_{n,old})$

vii. If $V_{downstream} > V_{feeder,max,Qc}$, then $V_{feeder,max,Qc} \leftarrow V_{downstream,Qc}$

viii. If $V_{downstream} < V_{feeder,min,Qc}$, then $V_{feeder,min,Qc} \leftarrow V_{downstream,Qc}$

4- $\forall Q_c \in Q_{levels}$, let $i \in \{1,2,\ldots,m = size(V_{downstream})\}$.

i. Calculate:

$$lossesQc = (V_{n,Qc} - V_{downstream}(1))^2 + \sum_{i=1}^{m-1}(V_{downstream}(i) - V_{downstream}(i+1))^2$$

5- TotalLossesQc = $\mathrm{TotalLosses}_{\mathrm{Qc}} + \sum \mathrm{losses}_{\mathrm{Qc}}$, $\forall$Qc.

6- Find $Q_{optimal} \in Q_{levels}$ $such\ that,$

$$TotalLosses_{Q_{optimal}} = \min\left(TotalLosses_{Qc}\right), \qquad \forall Q_c \in Q_{levels}$$

And, $$V_{feeder,max,Q_{optimal}} < V_{feeder,max,perm}$$

$$V_{feeder,min,Q_{optimal}} > V_{feeder,min,perm}$$

Algorithm #7.1: Generalized Voltage Control with DG and Capacitor on the same feeder

1- The system will estimate the voltage profile of the feeder corresponding to each possible reactive power injections of the capacitor by executing Algorithm #6.1.

2- The station's RTU will carry out the following;

   i. Rank Q_{levels} according to their corresponding TotalLossesQc.

   ii. Select $Q_c \in \{Q_{levels}\}$ such that,

$$TotalLosses_{Q_{optimal}} = \min\left(TotalLosses_{Qc}\right), \qquad \forall Q_c \in Q_{levels}$$

And, $$V_{feeder,max,Q_{optimal}} < V_{feeder,max,perm}$$

$$V_{feeder,min,Q_{optimal}} > V_{feeder,min,perm}$$

Algorithm #7.2: Generalized Voltage Control with DG and Capacitor on different feeders

1- Feeders with capacitors will execute Algorithm # 6.1.

2- All other feeders will execute Algorithm # 5.2.

3- The station's RTU will carry out the following;

   i. If $V_{max,feeders} - V_{min,feeders} < V_{max,perm} - V_{min,perm}$; regulator tap will be selected as follows, otherwise go to step ii.

   - If max($V_{feeder,max}$)>$V_{max,perm,}$, then lower the regulator tap to correct the voltage.
   - If min($V_{feeder,min}$) < $V_{min,perm,}$, then raise the regulator tap to correct the voltage.

ii. Let min-feeder be the feeder that has the value of min($V_{feeder,min}$).

iii. If a capacitor is connected to min-feeder, proceed to step (iv), otherwise, there is no solution.

iv. Reduce station's voltage by $\Delta V_{station}$ = max($V_{feeder,max}$) – $V_{max,perm}$.

v. Reduce the voltages received from the min-feeder corresponding to each reactive power injection of the capacitor by the value of $\Delta V_{station}$.

vi. Based on the reduced voltages of the min-feeder, The station's RTU will then find $Q_{optimal} \in Q_{levels}\ such\ that$,

$$TotalLosses_{Q_{optimal}} = \min\left(TotalLosses_{Qc}\right), \qquad \forall Q_c \in Q_{levels}$$

And,

$$V_{feeder,max,Q_{optimal}} < V_{feeder,max,perm}$$

$$V_{feeder,min,Q_{optimal}} > V_{feeder,min,perm}$$

vii. The station's RTU will send to the Capacitor's RTU the value of $Q_{optimal}$.

Algorithm #8.1: Voltage Profile Estimation including the effect of DG

A. *End of feeder RTU*

1- Read V_{end}; the voltage of the bus.

2- if($V_{end} > V_{neighbour,upstream}$), then min-flag = 1, otherwise, min-flag = 0.

3- Estimate $V_{min,estimated,upstream}$ using equation (5.19).

4- Send to RTU_{n-1} the following; V_{end}, min-flag, $V_{min,estimated,upstream}$

5- Terminate the algorithm.

B. *RTU Downstream of the DG*

1- $\forall RTU_{n+1} \in \{RTU_{n+1}\}$:

   a. Receive the following data from RTU_{n+1}: min-flag, $V_{min,estimated,upstream}$, V_{n+1},V_{n+2}, ….., V_{end}.

   b. Read V_n; the voltage of the bus.

   c. Execute Algorithm#5.1.

2- Send to RTU_{n-1} the following; min-flag, $V_{min,estimated,upstream}$, V_n, V_{n+1},V_{n+2}, ….., V_{end}.

3- Terminate the algorithm.

C. *DG RTU*

1- $\forall RTU_{n+1} \in \{RTU_{n+1}\}$:

   a. Receive the following data from RTU_{n+1}: min-flag, $V_{min,estimated,upstream}$, V_{n+1},V_{n+2}, ….., V_{end}.

   b. Read V_n; the voltage of the bus.

   c. Execute Algorithm#5.1.

   d. Initiate $V_{feeder,max,DG}$ and $V_{feeder,max,DG}$

   e. Calculate $V_{n,DG} = V_n + P_{DG}\sum_{k=1}^{k=n} R_{k-1,k}$

   f. Calculate $V_{min,downstream,DG} = V_{min,downstream} + P_{DG}\sum_{k=1}^{k=n} R_{k-1,k}$

g. $V_{feeder,max,\ DG} \leftarrow V_{n,\ DG}$

h. $V_{feeder,min,\ DG} \leftarrow V_{nmin,downstream,DG}$

i. Store: $\{V_{dowstream}\} \leftarrow [V_{n+1}, V_{n+2}, \ldots.., V_{end}]$.

j. $\forall V_{dowstream} \in \{V_{dowstream}\}$

   i. Calculate $V_{downstream,DG} = V_{downstream} + P_{DG} \sum_{k=1}^{k=n} R_{k-1,k}$

   ii. If $V_{downstream} > V_{feeder,max,\ DG}$, then $V_{feeder,max,\ DG} \leftarrow V_{downstream,DG}$

   iii. If $V_{downstream} < V_{feeder,min,\ DG}$, then $V_{feeder,min,\ DG} \leftarrow V_{downstream,DG}$

2- Send to RTU_{n-1} the following; min-flag, $V_{min,estimated,upstream}$, P_{DG} , $V_{feeder,max,DG}$, $V_{feeder,min,DG}$.

3- Terminate the algorithm.

D. RTU Upstream of the DG

1- $\forall RTU_{n+1} \in \{RTU_{n+1}\}$:

a. Receive the following data from RTU_{n+1}: min-flag, $V_{min,estimated,upstream}$, $V_{feeder,max,DG}$, $V_{feeder,min,DG}$.

b. Read V_n; the voltage of the bus.

c. Execute Algorithm#5.1.

a. Calculate $V_{n,DG} = V_{n,old} + P_{DG} \sum_{k=1}^{k=n} R_{k-1,k}$

b. Calculate $V_{min,downstream,DG} = V_{min,downstream,old} + P_{DG} \sum_{k=1}^{k=n} R_{k-1,k}$

c. If $V_{n,DG} > V_{feeder,max,DG}$, then $V_{feeder,max,DG} \leftarrow V_{n,\ DG}$

d. If $V_{min,downstream,DG} < V_{feeder,min,DG}$, then $V_{feeder,min,\ DG} \leftarrow V_{nmin,downstream,\ DG}$

2- Send to RTU_{n-1} the following; min-flag, $V_{min,estimated,upstream}$, P_{DG} , $V_{feeder,max,DG}$, $V_{feeder,min,DG}$.

3- Terminate the algorithm.

*E. **Station's RTU***

1- Receive the following data from RTU_{n+1}: min-flag, $V_{min,estimated,upstream}$, $V_{feeder,max,DG}$, $V_{feeder,min,DG}$, P_{DG}.

2- Read V_n; the voltage of the bus.

3- Execute Algorithm#5.1.

4- Calculate $V_{min,downstream,DG} = V_{min,downstream} + P_{DG}\sum_{k=1}^{k=n} R_{k-1,k}$

5- If $V_{min,downstream,DG} < V_{feeder,min,DG}$, then $V_{feeder,min,DG} \leftarrow V_{nmin,downstream,DG}$

Algorithm #8.2: Voltage Profile Estimation including the effect of DG and Shunt Capacitors

This algorithm is the same as the Algorithm #6.1, except that the equations used to calculate the new voltage due to Q_c will be replaced as follows;

$$V_{n,Qc,DG} = V_{n,old} + P_{DG}\sum_{k=1}^{k=n} R_{k-1,k} + Q_c\sum_{k=1}^{k=n} X_{k-1,k}$$

Algorithm #8.3: Operation-time DG connection impact assessment

1- The feeder that has the DG that requested an increase in its power will execute Algorithm # 8.1.

2- Feeders with capacitors will execute Algorithm # 6.1.

3- All other feeders will execute Algorithm # 5.2.

A. Station's RTU

1- If $V_{max,feeders} - V_{min,feeders} < V_{max,perm} - V_{min,perm}$; regulator tap will be selected as follows and the DG will be permitted to connect, otherwise go to step (2)

   i. If max($V_{feeder,max}$)>$V_{max,perm,}$, then lower the regulator tap to correct the voltage.

   ii. If min($V_{feeder,min}$) < $V_{min,perm,}$, then raise the regulator tap to correct the voltage.

2- Let min-feeder be the feeder that has the value of min($V_{feeder,min}$).

3- If a capacitor is connected to min-feeder, proceed to step (4), otherwise, calculate $\Delta V_{allowed}$ = min($V_{feeder,min}$) - $V_{min,perm}$ and then proceed to step (10).

4- Set, $\Delta V_{station}$ = max($V_{feeder,max}$) – $V_{max,perm}$.

5- Reduce the voltages received from the min-feeder corresponding to each reactive power injection of the capacitor by the value of $\Delta V_{station}$.

6- Based on the reduced voltages of the min-feeder, find $Q_{optimal} \in Q_{levels}$ $such\ that$,

$$TotalLosses_{Q_{optimal}} = \min\left(TotalLosses_{Qc}\right), \qquad \forall Q_c \in Q_{levels}$$

And,
$$V_{feeder,max,Q_{optimal}} < V_{feeder,max,perm}$$
$$V_{feeder,min,Q_{optimal}} > V_{feeder,min,perm}$$

7- If step (6) succeeded, set the capacitor to $Q_{optimal}$, reduce the voltage of the station's bus by $\Delta V_{station}$ and allow the DG to connect. Otherwise proceed to step 8.

8- Set the capacitor's reactive power to the one corresponding to the highest minimum voltage of the min-feeder. Also, calculate $\Delta V_{allowed}$ as the difference between the highest minimum voltage of the min-feeder and the minimum permissible voltage of the system.

9- Reduce the voltage of the station by the value of $\Delta V_{allowed}$.

10- At this point, it is determined that the DG cannot inject the whole amount that it has asked for.

11- Send to RTUs of the DG's feeder the new value of the station's voltage.

B. RTU Upstream of the DG

1- Receive from RTU_{n-1} the following; $\Delta V_{station}$ and $\Delta P_{G,max,perm,received}$

2- Calculate the permissible DG power as follow;

$$V_{perm,sys} = (V_{(n)old} - \Delta V_{station}) + \Delta P_{G,max,perm,calculated} \sum_{k=1}^{k=n} R_{k-1,k}$$

3- $\Delta P_{G,max,perm} \leftarrow min\ (\Delta P_{G,max,perm,received}, \Delta P_{G,max,perm,calculated})$

4- Send to RTU_{n+1} the following; $\Delta V_{station}$ and $\Delta P_{G,max,perm}$.

C. DG RTU

1- Receive from RTU_{n-1} the following; $\Delta V_{station}$ and $\Delta P_{G,max,perm,received}$

2- Calculate the permissible DG power as follow;

$$V_{perm,sys} = (V_{(n)old} - \Delta V_{station}) + \Delta P_{G,max,perm,calculated} \sum_{k=1}^{k=n} R_{k-1,k}$$

3- $\Delta P_{G,max,perm} \leftarrow min\ (\Delta P_{G,max,perm,received}, \Delta P_{G,max,perm,calculated})$

4- Increase the injected power by $\Delta P_{G,max,perm}$.

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