Reconfiguration and Self-healing Mechanisms in Distribution Systems with High Distributed Generation (DG) Penetration

by

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A thesis
presented to the University of Waterloo
in fulfillment of the
thesis requirement for the degree of
Doctor of Philosophy
in
Electrical and Computer Engineering

Waterloo, Ontario, Canada, 2013

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, interest in Smart Grid (SG) as a tool for modernization and automation of the current distribution system has rapidly increased. This interest can be explained by the common belief that SG technologies greatly enhance system reliability, power quality and overall efficiency. One of the most important objectives of an SG is to accommodate a wide variety of generation options. This objective aligns with the new trends and policies that encourage higher penetration levels of Distributed Generation (DG) according to environmental, regulatory and economical concerns. Most DG units are either renewable or low emission energy sources, thus meeting the Canadian emission portfolios, while they remain attractive for both utilities and customers for different reasons. DG units can postpone large investment in transmission and central generation, reduce energy losses, and increase system reliability and power quality.

SG is centered on several objectives such as self-healing, motivating consumers to participate in grid operation, resisting attacks, accommodating a wide variety of DG units and storage devices, and optimizing assets. Yet, one of the main goals of SG is to increase the reliability of power systems. Reliability is a vital factor in power system performance, due to the full dependence of today's life on electricity and the high cost of system outages, especially for critical loads. Therefore, one of the main salient features of SG is its ability of self-healing.

The insertion of DG units changes distribution networks from being passive with unidirectional power flow and a single power source (the primary substation) towards active networks with multi-directional power flow and several power sources (the primary substation, along with DG units). As a result, the interconnection of DG units creates several impacts on different practices such as voltage profile, power flow, power quality, stability, reliability, fault detection, and restoration. Current policies call for the direct disconnection of all DG units once any failure occurs in the network. However, with a high DG power penetration, the utilities cannot operate the system efficiently without the DG units' support. Furthermore, automatic disconnection of the DG units during faults reduces the expected benefits associated with DG units drastically.

Motivated by the above facts, the overall target of this thesis is to introduce distribution system mechanisms to facilitate realizing the concept of Smart Distribution System (SDS) in both normal and emergency modes. In particular, three main functions are dealt with in this research work: distribution network reconfiguration, DG allocation and self-healing.

First, for distribution network reconfiguration, a method based on genetic algorithm is presented to address the reconfiguration problem for distribution systems while the effect of load variation and the stochastic power generation of renewable-based DG units are taken into consideration. The presented method determines the annual distribution network reconfiguration scheme considering switching operation costs in order to minimize annual energy losses by determining the optimal configuration for each season of the year.

Second, for DG allocation, a joint optimization algorithm has been proposed to tackle the DG allocation and network reconfiguration problems concurrently, as these two issues are inherently coupled. The two problems are dealt with together while the objectives are minimizing the cost, as an economic issue, and greenhouse gas emissions, as an environmental issue. The proposed method takes the probabilistic nature of both the renewable energy resources and loads into account.

The last operation function dealt with in this thesis is distribution system restoration. In order to accomplish this function, two stages are presented:

In the first stage, numerous practical aspects related to service restoration problem have been investigated. These aspects include variations in the load and customer priorities, price discounts for in-service customers based on their participation in a load-curtailment scheme that permits other customers to be supplied, the presence of manual and automated switches, and the incorporation of DG units (dispatchable and wind-based units) in the restoration process.

In the second stage, the smart grid concept and technologies have been applied to construct a self-healing framework to be applied in smart distribution systems. The proposed multi-agent system is designed to automatically locate and isolate faults, and then decide and implement the switching operations to restore the out-of-service loads. Load variation has been taken into consideration to avoid the need for further reconfigurations during the restoration period. An expert-based decision-making algorithm has been used to govern the control agents. The rules have been extracted from the practical issues related to the service restoration problem, discussed in the first stage.

Acknowledgements

Firstly, all my gratitude and thanks to Allah almighty who guided and aided me to bring forth this thesis.

I wish to express my deepest thanks and gratitude to my supervisor, Prof. Ehab F. El-Saadany, for his constructive guidance, advice, comments, support and discussions throughout the development of my PhD program.

I would like to thank my doctoral committee members for their insightful comments and suggestions.

I would like also to thank all my colleagues for being extremely supportive. Special thanks go to Dr. Rashid Alabri, Dr. Yasser Attwa, and Eng. Mostafa Farouk.

I feel indebted to my master's degree advisors Prof. Mazen Abdel-Salam, Prof. Adel Ahmed and Prof. Mohamed Nayel. Through their dedication, enthusiasm and hard work, I have learned how to carry out academic research in the first place.

Finally, I would like to thank my parents, my wife, and my children for their understanding, encouragement and continuous support.

Dedication

To my beloved parents, my dear wife, and my children

And

Memory of Prof. Dr. Mohamed Zaki El-Sadek, Assiut University, Egypt

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List of Acronyms

ACL	Agent Communication Language
ACSs	Automatically Controlled Switches
ADA	Advanced Distribution Automation
ADNs	Active Distribution Networks
AI	Artificial Intelligence
ANN	Artificial Neural Network
ARC	Available Remaining Capacity
CC	Central Controller
CCC	Central Control Center
CFP	Call for Proposal
CIC	Customer Interruption Cost
CNP	Contract Net Protocol
DA	Distribution Automation
DG	Distributed Generation
DNO	Distribution Network Operator
DR	Demand Response
ELC	Energy Loss Cost
EMS	Energy Management System
ENS	Energy Not Supplied
FAG	Feeder Agent
FIPA	Foundation for Intelligent Physical Agent
FLISR	Fault Location, Isolation and Service Restoration
FSC	Feeder Switched Capacitor
GA	Genetic Algorithm
GT	Gas Turbine
IEDs	Intelligent Electronic Devices
IEEE	Institute of Electric and Electronic Engineers
JADE	Java Agent Development Framework
KQML	Knowledge Query and Manipulation Language
LTC	Load Tap Changer
MAS	Multiagent System
MBR	Model Based Reasoning

MCSs	Manually Controlled Switches
MINLP	Mixed Integer Non-linear Problem
NDSGA	Non-dominated Sorting Genetic Algorithm
NPV	Net Present Value
PDF	Probability Density Function
PF	Power Factor
PLC	Power Line Communication
PMU	Phasor Measurement Unit
PV	Photovoltaic
RTS	Reliability Test System
RTUs	Remote Terminal Units
SCADA	Supervisory Control and Data Acquisition
SCL	Switch-to-be-Closed List
SDS	Smart Distribution System
SG	Smart Grid
SOC	Switching Operation Cost
SOL	Switch-to-be-Opened List
SVR	Step Voltage Regulator
TL	Transferred Load
WT	Wind Turbine
ZAG	Zone Agent

Chapter 1
Introduction

1.1 General

Power networks are undergoing significant changes and reconstructions. Those changes are motivated by several factors such as aging of the electrical components used in present systems, introduction of innovative technologies in energy sources, information and communication sectors, increasing pressure to comply with environmental requirements, and trends to extensive rulemaking after the restructuring of the energy business. These factors are speeding up the realization of the smart grid concept, which will provide modernization process of the electricity infrastructure [1].

The continuous growth of load demand requires installation of new generation power plants and expansion of the existing transmission and distribution systems. However, neither of these requirements is recommended from an economic or environmental perspective. This is because of the challenges facing electricity generation due to the limitation of fossil fuels and the desire for many countries to meet the environmental constraints established by the Kyoto Protocol and other governmental initiatives in order to reduce greenhouse gas emissions. Therefore, interest in the integration of distributed generation (DG) into distribution systems has increased rapidly [2]. DG can be defined as small-scale electricity generation fueled by renewable energy sources (i.e., wind and solar), or by low-emission energy sources (i.e., fuel cells and micro-turbines). DG units are typically connected in parallel with the utility grid, and are mostly situated in close proximity of the load. To date, DG operation has not been permitted without a utility grid. Due to the economic advantages of utilizing DG units and with the advancement in DG control techniques, these units can operate in the autonomous mode (microgrid) as well. Therefore, distribution systems with embedded DG units can operate in two modes: grid-connected and autonomous mode. In the grid-connected mode, the voltage and frequency are typically controlled by the grid since the DG units are synchronized with the grid.

Integrating DG units can have an impact on the practices used in distribution systems, such as the voltage profile, power flow, power quality, stability, reliability, and protection. Since DG units have a small capacity compared to central power plants, their impact is minor if the penetration level is low (1-5%). However, if the penetration level increases to the anticipated level of 20~30%, the impact of DG units may be profound.

1.2 Research Motivations

With the integration of DG units in distribution systems, these distribution systems are expected to face problems related to distribution network reconfiguration, fault location detection and isolation, and service restoration. Some of these problems are as follows:

- The current reconfiguration practices are conducted with both generation and loads assumed to be constant and predefined. The effect of both load and generation variability are not stochastically considered.
- DG allocation is currently only performed based on system operational practice focusing on voltage profile and system losses. Correlation between system reconfiguration and DG allocation is not considered.
- Currently, in most distribution systems, the corrective actions that are required for fault location, isolation and service restoration (FLISR) functions are performed manually by human operators. Therefore, they take longer times than the self-healing feature of a smart grid.
- Currently, FLISR function works in a centralized fashion, which means that only one Central Controller (CC) reads all the data collected from the system, and then decides and implements the required control actions. Processing all data in a central place limits the efficiency and reliability of operation. A new distributed operation of FLISR function is needed.
- The policies, currently in use, disconnect all existing DG units once any failure occurs in the network. Therefore, DG units' impact needs to be investigated in order to benefit from their contribution in the restoration process.

1.3 Thesis Objectives

Motivated by the above problems, the ultimate goal of this research is to enhance the operation of distribution systems with high DG penetration through introducing innovative planning and operation mechanisms in both normal and emergency modes of operation. Therefore, this research is targeting the following objectives:

- To investigate the impacts of renewable-based DG units and load variation on distribution network reconfiguration.

- To introduce a guide to place and size the DG units together with network reconfiguration simultaneously in order to minimize the cost as an economic issue and greenhouse gas emissions as an environmental issue as much as possible.
- To investigate the impact of variable load demand, type of switches and DG units on restoration plans.
- To develop a cooperative multi-agent framework for self-healed distribution systems.

1.4 Outline of the Thesis

The remainder of this thesis is organized as follows:

Chapter 2 presents a literature survey on distribution system automation, smart grid, distributed processing, fault location and isolation, service restoration, DG, centralized and distributed restoration methods, and multi-agent systems. In the DG part, different definitions and types of DG units are discussed.

Chapter 3 proposes a method based on genetic algorithm to address the reconfiguration problem in distribution systems while the effect of load variation and stochastic power generation of renewable-based DG units are taken into account. The presented method determines the annual distribution network reconfiguration scheme considering switching operation costs in order to minimize the annual energy losses by determining the optimal configuration for each season of the year.

Chapter 4 analyzes the impact of network reconfiguration on the DG allocation problem. It starts by introducing the problem formulation and the models of system components. Then, the simulation results are presented to analyze the impacts of network reconfiguration on DG allocation.

Chapter 5 studies the effect of load variation, switch type, and DG units on building and implementing restoration plans for distribution systems.

Chapter 6 develops a cooperative multi-agent framework for self-healed distribution systems. It starts by highlighting some of the important aspects related to the operational practices of the restoration problem, which were used in extracting the rules for designing the expert-based decision makers for the control agents. Then the structure of the proposed multi-agent and the proposed operation mechanism and coordination between control agents has been presented. Different case studies and scenarios are presented to show the effectiveness of the proposed algorithm.

Chapter 7 presents the thesis summary, and highlights the contributions.

Chapter 2

Literature Survey

2.1 Introduction

This chapter provides a comprehensive background survey related to distribution automation (DA), Smart Grid and DG. The chapter will start by introducing DA and its main functions. DA which is currently based on centralized control fashion will be discussed in order to shed the light on its weaknesses that need to be avoided in order to cope with smart grid paradigm. Next, smart grid concept will be introduced, focusing on the importance of the self-healing capability. In the following section, the potential of using multiagent system as a tool to improve the reliability and efficiency of the existing distribution systems will be discussed.

2.2 Distribution Automation (DA)

Distribution automation (DA) refers to monitoring, control, and communication functions located out on the feeder. The IEEE definition of DA is given in [3] as “systems that enable an electric utility to monitor, coordinate, and operate distribution network components in real-time mode from remote control centers”. The subject of DA embraces all aspects of the distribution system including, but not limited to, distribution planning, design, protection, operations, reliability, economics, load management, computer systems, graphics, etc. The objectives of DA were conservation of energy, including reduction of consumption and losses in the distribution and transmission circuits, reduction of peak load, improvement in the reliability and quality of service, deferral of new construction, and recovery of lost revenue. The functions of the DA encompass [4]:

- Optimal Voltage Control
- Optimal Var Control
- Optimal Feeder Reconfiguration
- Emergency Area Voltage/Var/Load Control
- Substation Supervisory Control
- Fault Isolation and Service Restoration
- Routine Remote Circuit Switching
- Automatic Meter Reading
- Automatic Load Survey

- Automatic Connection and Disconnection
- Load Control

Sophisticated computer software, control strategies and a communication system are required to perform these functions. Currently, DA systems work in a centralized fashion, which means that only one Central Controller (CC) reads all the data collected from the system through the remote monitoring, and then decides and implements the required control actions. Processing all data in a central place represents a drawback and limits the efficiency and reliability of DA operation. This is because of the huge amount of information that needs to be processed to decide the proper control actions. In addition, it requires a considerable amount of human intervention during faults [5].

2.2.1 Fault location and isolation approaches under the current DA approach

If a fault is detected but the faulty component doesn't be isolated from the rest of the system by the protection system (i.e. it is a permanent fault not temporary fault), it has to be located and isolated as quickly as possible. Then, the restoration algorithm starts to recover the power delivery to the customers that have been affected. Without enough knowledge on the nature of a fault and its accurate location, making the appropriate decision is a challenge. The conventional manual fault analysis method, which is based on sending a repair crew to find the trouble-spot and then fix the problem, is time-consuming [6]. The most commonly-used fault-location method is the apparent impedance-based method which uses the local voltage and current measurements at the substation. Using an iterative solution of a set of complicated three-phase circuit equations, which describe the steady-state fault condition, the fault location can then be found [7][8]. The main drawbacks of this method are: 1) it is affected by many factors other than fault location (i.e. fault path resistance, line loading, and interconnection to multiple sources), and 2) its accuracy is limited.

The travelling-wave-based method is another commonly technique to be used for fault location [9][10]. High frequency transients generated by the fault propagate outwards into both sides. Then, the method estimates the distance to the fault location based on the time interval between the travelling waves and their reflections arriving from the fault. The main drawbacks of this method are: 1) the method cannot accurately separate the travelling wave which reveals the fault position from other waves of different frequencies that are generated due to multiple reflections by fault transients, and 2) since the fault-originated traveling waves propagate along the distribution paths in both directions away from the fault point and they are reflected at line terminations, junctions between feeders, laterals, and the fault location, it is hard for this method to distinguish between the waves reflected from the fault and the ones coming from the other places.

Although, these approaches may obtain optimal solutions, the computation time often exceeds the practically allocated time, especially with the complexity of distribution system due to their continuous increase in size and the penetration of DG units. This high computation time as well as the limited accuracy in determining the fault location in some approaches delay the restoration process, and in consequence decrease system reliability.

2.2.2 Service restoration approaches under the current DA approach

After the isolation of a fault in the distribution network, the task of the Distribution Network Operator (DNO) is to restore the maximum possible out-of-service loads with minimum load shedding within a very short time. This task is known as the distribution system service restoration, which is defined as finding suitable backup feeders and laterals to transfer the loads in out-of-service areas using operational criteria through a series of switching operations [11] . Hence, efficient service restoration can enhance the system reliability by maximizing the restored loads and reducing the outage time. On this basis, it appears that it is very important to have a fast and effective restoration algorithm, especially for critical loads (i.e. hospitals, airports, etc.), where restoration time is essential. Performing the restoration task under emergency conditions makes it a time limited and complex problem. In addition, solving the restoration problem will be more demanding/difficult with the growing of the system, both in size and complexity [11].

Various approaches have been proposed for the service restoration problem in a centralized way, including optimization methods, genetic algorithm, expert system, etc. The methods proposed to solve the restoration problem can be classified into four categories:

- Heuristics [12][13][14][15]
- Expert system [16][17]
- Meta-heuristic (soft computing) [18][19][20]
- Mathematical programming [21][22]

For the first category, the heuristic approach is intuitively rule of thumb, to limit the search space. The expert’s knowledge and experience are translated into programming logic to solve the problem. For example, Ref [12] proposed a method to solve the configuration problem for loss reduction and service restoration based on switching indices. These switching indices were derived by using branch voltage drops, line constants and weighting factors. The drawbacks of heuristic methods are: 1) optimal solution is not guaranteed, 2) they have great difficulties in maintaining the software, since the size of the software is large and the algorithm is complex [15].

For the second category, expert system is basically a knowledge-based technique. It involves the representation of expert knowledge as rules and an inference engine to infer from these rules. The rules are written as IF-THEN statements. For example, Ref [16] developed an expert system integrated with object-oriented programming technique for solving the restoration problem. Although the algorithm has taken load variation into account, it did not assume any priority for the load zones. Expert system approaches can be considered as successful approaches to solve the restoration problem; however, maintenance of large-scale expert systems has turned out to be costly. In addition, expert system rules are system-specific, and they change with system variations.

For the third category, a considerable number of studies have been made to use soft computing techniques for solving the restoration problem. Soft computing includes: neural networks, genetic algorithm, fuzzy theory, tabu search, particle swarm optimization, simulating annealing, and ant colony. For example, Ref. [19] presented a method based on non-dominated sorting genetic algorithm-II to solve the service restoration problem. The objectives were to minimize the out-of-service area, number of manually controlled switch operations, number of remotely controlled switch operations and losses. Although soft computing methods are used to solve large-scale combinatorial optimization problems, they still require larger computational time when applied for practical problem of distribution system restoration. In addition, they require a power flow program to check the operational constraints.

Finally, the last category is the mathematical programming approach. Determining the target configuration for restoration is formulated as a mixed integer non-linear problem (MINLP). Each branch represented by a binary variable (0: opened & 1: closed). Other constraints, such as supply and demand balance, are formulated in terms of continuous variables. For example, Ref. [21] proposed service restoration algorithm for unbalanced distribution systems. The problem was formulated as a mixed integer non-linear optimization problem which was solved using LINGO commercial optimization package. Although, this approach can obtain optimal solutions under operational constraints, the computation time often exceeds the practically allocated time due to the combinatorial expansion problem. The computational time increases exponentially with the size of the de-energized area.

2.2.3 Advanced DA (ADA)

The ADA concept was proposed to enhance the present DA and operating its functions in a distributed manner, benefiting from enhanced deployment of information, two-way communication technologies and data management. Therefore, in ADA all controllable equipment and control functions will be automated to achieve the optimal operation of the system. ADA will result in higher reliability, minimal losses, optimization of the distribution system assets and integration of higher penetration of renewable resources into the existing distribution systems [23]. In order to achieve the ADA concept, it is required for many distribution system equipment (i.e., power quality management devices and monitoring devices) to become intelligent. As a result, the operation of the distribution system will be carried out in a smart manner by coordination and communication between distribution system devices.

2.3 Smart Grid (SG)

Recently, SG concept has been used by governments, industry and research institutes. This term is used to refer to the new trend in the energy sector to modernize and automate the current power network. The BC Hydro definition of smart grid is “A modern, intelligent electricity transmission and distribution system that incorporates elements of traditional and advanced power engineering, sophisticated sensing and monitoring technology, information technology, and communications to provide better grid performance and to support a wide array of additional services to customers and the economy” [24]. In other words, SG is actually the “Modernization and automation of the current power delivery system”. In the following sections, an overview of the SG objectives, functions, and technologies are presented.

2.3.1 SG objectives

The SG vision will focus on meeting the following key objectives [25]:

1. The grid must be more reliable: it provides power when and where its users need it with the quality they need. It withstands most disturbances without failing. It also takes corrective actions before most users are affected.
2. The grid must be more secure: it withstands physical and cyber-attacks without suffering massive blackouts or exorbitant recovery costs. It is also less vulnerable to natural disasters and recovers more quickly.

3. The grid must be more economic: it operates under the basic laws of supply and demand, resulting in fair prices and adequate supplies.
4. The grid must be more efficient: it takes advantages of investments that lead to cost control, reduced transmission and distribution electrical losses, more efficient power production, and improved asset utilization. In addition, it uses the methods that provide control of the power flow to reduce transmission congestion and allow access to low-cost generating sources including renewable resources.
5. The grid must be more environmentally friendly: it reduces environmental impacts through initiatives in generation, transmission, distribution, storage and consumption. It expands the usage of renewable energy sources. Furthermore, the future design of the grid assets occupies less land to reduce the physical impact on the landscape.
6. The grid must be safer: it does not harm the public and grid workers. It is sensitive to users who depend on it as a medical necessity.

2.3.2 SG functions

In order to achieve the above objectives, the SG needs to perform the following functions [25][26]:

1. Self-healing: this function represents the heart of the SG. The grid instantly responds to system problems in order to avoid or mitigate power outages and power quality problems. This will be achieved by performing continuous self-assessment to detect, analyze, respond to, and as needed restore the grid components and network sections. It will act as "immune system" in order to maintain grid reliability, security, affordability, power quality and efficiency. Therefore, self-healing function will minimize disruption of service. It will employ modern technologies that can acquire data, execute decision-support algorithms, limit interruptions, dynamically control the flow of power, and restore service quickly. In addition, probabilistic risk assessment based on real-time measurements will be used to identify the equipment, power plants and lines that are most likely to fail. Also, real-time contingency analysis will be used to determine the overall grid health, trigger early warning of trends that could result in grid failure and identify the need for immediate investigation and action. To implement these technologies, communication with both local and remote devices will be used. This communication system will provide the ability to analyze faults, low voltages, poor power quality, overloads, and any undesirable system condition. Then, appropriate control actions will be taken based on these analyses.

2. Motivate the consumers to participate in the grid operation: consumers are expected to play an active role in SG. This active participation in electricity market will benefit the utility, customers, and environment and reduce the cost of electricity. Customers will have the ability to decide on their consumption according to the electricity price. Hence, this will shift the peak demand and help utilities to reduce or clip their peak demands, which in consequence, will minimize the capital and operating costs. The environment will benefit by reducing line losses and the operation of inefficient peaking power plants. Demand response (DR) programs will satisfy the basic customer needs. Over time, DR will encourage customers to replace the inefficient end-use devices by better ones. Incorporating plug-in hybrid vehicles will improve the load factor. Also, SG will allow integrating small DG units, so that, customers will sell their electricity back to the grid.
3. Resist attacks: as a benefit of self-healing function of the SG, the grid will be able to resist both man-made and natural attacks. It will identify the risk, and then isolate the affected area and restore the unaffected parts. Modern grid security protocols will contain elements of prevention, detection, response, and mitigation to minimize the impact of attacks on the grid and the economy.
4. Accommodate a wide variety of DG and storage options: the grid will accommodate a wide variety of generation options, especially the renewable energy based DG units. Increasing DG penetration level will be beneficial in reducing the capital investment in generation and transmission. Also, integrating more renewable DG units will benefit the environment by reducing the impact of the fossil based electricity generation.
5. Optimize the assets: the grid will benefit from the information about the status of the overall system through optimizing the operation of the assets in order to make the best use of them. Therefore, asset management and operation will be fine-tuned to deliver the desired functionality at the minimum cost. Improved load factors and lower system losses will be cornerstone aspects of optimizing assets. For example, re-route the flow of power to relieve the stress on overloaded transformers and lines.

2.3.3 SG technologies

To perform the above functions properly, the SG must be equipped with several types of technologies. The smart grid technologies include [27]:

1. Two way communication techniques to achieve the required monitoring of the grid and to enable the participation of the customers.
2. Advanced metering and sensors such as smart meters, meter reading equipment, phasor measurement units (PMU), and wide area measurement system. These digital meters which are installed at all customer service locations, will have two way communications. Hence, they will be able to remotely connect and disconnect services, record waveforms, monitor voltage and current. The large amount of measured data will be used to achieve better reliability and better asset management. In addition, these meters will enable automatic demand response (DR) by interfacing with smart appliances.
3. DA which includes monitoring, control and communication functions located out on the feeder as explained before.
4. Substation automation which provides the ability to reduce energy consumption and enable customer loads to draw less power and consume less energy.
5. Advanced power components such as advanced power electronic devices, super conductor based equipment, storage devices, plug-in hybrid vehicles, smart houses, web services and grid computing.
6. Weather prediction such as wind forecasting and solar power density forecasting.
7. Advanced distributed control to provide the decentralized and on-line control of the grid components instead of the current central fashion.

2.3.4 Challenges facing the implementation of SG

The implementation of the SG faces many challenges. These challenges can be categorized as procedural and technical [28]. The procedural challenges range from the complexity of the SG to a unified SG standards. Furthermore, due to the complexity and the large scale of real power systems, the implementation of the SG has to be gradual. In addition, this planned change should not affect the operation of the existing system. On the other hand, the technical challenges present the need for new intelligent devices (i.e., Remote Terminal Units (RTUs) and the Intelligent Electronic Devices (IEDs)) or modifying the currently-used devices with smart capabilities. In addition, there is an urgent need for distributed algorithms and operation mechanisms to coordinate and control the various system components in order to achieve the objectives of the SG.

2.4 Distributed Algorithms

Distributed algorithm is designed to be executed in a distributed manner such that it is executed on different processors simultaneously. Coordination among these processors is done using message-passing communication. The timing and contents of the messages among processors are decided by the programmer based on the task. The main characteristics of distributed algorithms are [29]:

1. No processor has the complete information about the whole system.
2. Processors make their decisions based on only local information.
3. Failure of one processor does not ruin the algorithm.

The advantages of distributed algorithms compared to centralized algorithms can be summarized as the following points:

1. Performance/cost ratio: using many inexpensive machines (i.e. control centers) provides a better performance/cost ratio than using one expensive super-machine. For example, distributed algorithms can achieve a performance that no single machine can achieve [29].
2. Distributed algorithms provide enhanced reliability (no single point of failure). For example, if one machine fails, the whole system will be able to survive with less performance. For the centralized system, however, the whole system will collapse when the only machine fails.
3. The ability of incremental expansion (modularity). For example, in distributed algorithms each added machine will perform a part of the work. Hence, it will not be large or expensive. But for the expansion in centralized systems, the centralized machine will be replaced by a larger one [29].

The disadvantages of distributed algorithms compared to centralized algorithms can be summarized as follows:

1. Coordination among distributed machines requires a lot of communication.
2. Security of data in distributed algorithms is often a problem [29].

The main difference between distributed and decentralized control algorithms is [30]:

1. In a distributed control: the overall system is decomposed into subsystems, each with its own controller. These subsystems work cooperatively through the communications medium in order to satisfy the system objectives.
2. In a decentralized control: the overall system is decomposed into subsystems, each with its own controller. The interaction among these subsystems is assumed to be negligible. This means that the effect of the external subsystems on the local subsystem is ignored and there is

no communication among them. In many cases this assumption is not valid, which leads to reduced control performance.

Therefore, the distributed control algorithm will be used for realizing the self-healing capability. The next section will discuss the benefits of applying distributed algorithm in power systems.

2.4.1 Distributed processing in power systems

Distributed processing can greatly enhance the reliability and improve the flexibility and efficiency of power system monitoring and control [31]. The distributed control would first divide the whole system into several control areas, each area with one control center that is responsible for its real-time monitoring and control. The disturbance in individual control areas will be processed locally to minimize its impact on other control areas. Even when an area control center is malfunctioning, its neighboring control centers in the same hierarchical level can take over the functions of the faulted center. Few control centers in the distributed areas will operate as coordinators of local area control centers. Therefore, reliability will be enhanced and less information is required by the upper level control centers. On the other hand, centralized control requires all data to be transmitted to the central control center (CCC) within a stringent period. If a major communication linkage to CCC is malfunctioning and a major power plant data cannot be transmitted to the CCC, the EMS/SCADA at CCC would not be able to function properly.

In distributed control, a disturbance occurring in any control area will be processed by its local control center. However, the upper level control centers intervene in handling disturbances that may affect more than one control area. This makes the upper level control centers have a better chance to focus on major disturbances compared to centralized control where every problem, no matter how serious it is, needs to be processed by the CCC. This makes the CCC overwhelmed by trivial affairs and may overlook the most serious issues [31].

From the economical point of view, centralized control requires a complex communication system that is able to cover the entire power system. All data should be sent to the CCC, no matter how far the location of the data collection is from the CCC. This requires a massive amount of long distance communication links with large capital investment in the communication system. The problem of such systems is that a faulty communication link can cripple the entire EMS/SCADA system. But, in distributed control the data in each control area are sent to its local area control center. Therefore, each area control center will be much simpler and the data communication distances are much shorter. The limited number of communication links among area control centers and the upper level control centers will save investments in communication systems. This partial saving can be used to establish the distributed control centers.

The centralized control center (CCC) can easily become overwhelmed by a large number of tasks, even if powerful computers are used. The distributed control divides the task into a number of subtasks according to the number of control areas. These subtasks are processed concurrently in a distributed manner. Also, with more computers to solve the task, the efficiency is greatly improved.

2.5 Multiagent Systems

Multiagent systems (MAS) are one of the most interesting new fields of computer science and distributed artificial intelligence. MAS are composed of multiple interacting computing elements, known as agents. These agents are located in some environment and react to the changes in this environment and are capable of acting (taking decisions) in order to achieve their goals [32]. Recently, MAS have been the subject of extensive research and investigation. MAS can be considered as the platform of distributed processing, parallel operation, and autonomous solving. Further, it can be much faster in solving discrete and nonlinear problems.

2.5.1 Basic concept of agents

The concept of agent is related to the property that makes its name, "agency" which means to represent another organization. To exercise this representation, the agent must have a minimum of autonomy. Thus, the agency and autonomy are the two main properties of an agent. Out of many definitions available for an agent, a comprehensive definition is given below:

"Agents are simply computer systems that are capable of autonomous action in some environment in order to meet their design objectives. An agent will typically sense its environment (by physical sensors in the case of agents situated in part of the real world, or by software sensors in the case of software agents), and will have an available range of actions that can be executed to modify the environment" [33].

Based on the previous definition, agent means, a software entity which perceives its environmental changes and acts on it diligently to achieve its organizational objectives. Multiagent system means the collection of these agents which communicate and coordinate to solve a particular problem according to their objectives. In our study, the agent environment will be the power system. Thus, the agent senses different power system parameters and based on the sensed data it acts to achieve its goals, as shown in Figure 2.1.

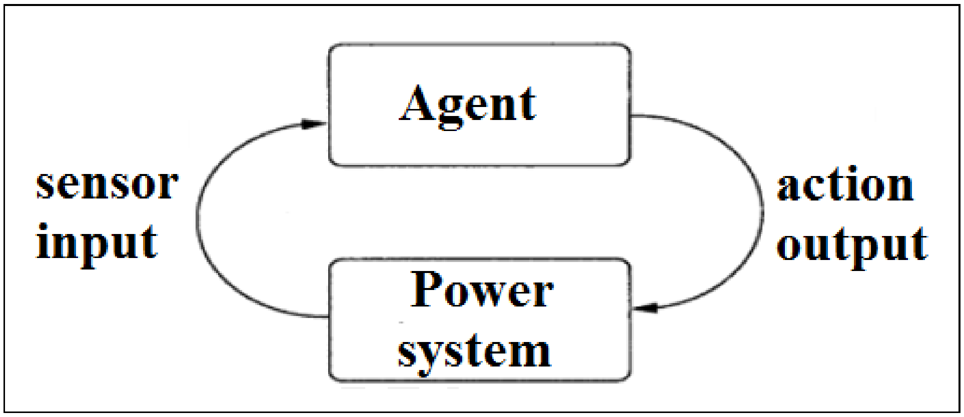


Figure 2-1: Agent application for power system

The main characteristics of agents are [33]:

- Autonomy: An agent is autonomous when it operates without the direct intervention of humans or other agents. It can decide by itself what it needs to do in order to achieve its objectives.
- Social ability: An agent must have the capability to cooperate, coordinate and negotiate with the other agents using a communication language. This characteristic is an important aspect of agent societies.
- Reactivity: An agent perceives its environment and responds in a timely fashion to the changes that occur in it.
- Proactiveness: The capability to exhibit a goal-directed behavior by taking the initiative (it does not wait to receive an order) for advancing towards an objective.

Based on the above characteristics, comparing agents to the present computer systems, every action a computer performs is planned for and coded by a programmer. When a computer encounters a new sort of problem, which is not anticipated, then the system will crash. This is because the computer systems do not have embedded intelligence. Conversely, agents are intelligent enough to take up the flexible autonomous actions to satisfy their objectives. For example, expert systems are the most important Artificial Intelligence (AI) technology of 1980s. An expert system is one that is capable of solving problems or giving advice in some knowledge rich domain. The main difference between expert systems and agent technologies is that an expert system cannot sense its environment directly; instead, it needs a middle man to input data. In the same way, an expert system cannot act directly on its environment; however, it just give certain instructions to the operator [33]. Therefore, the key difference between MAS and its counterparts such as AI techniques, expert systems, Model Based

Reasoning (MBR) systems, and Artificial Neural Networks (ANNs) is the notion of autonomy and interaction protocols available in MAS. MAS offer a great amount of autonomy feature to its agents, where agents can independently decide on actions to achieve their goals. Another great feature of MAS is that, it has a richer set of interaction protocols which supports negotiations. This makes MAS technology applicable to any engineering discipline that requires a distributed problem solving mechanism.

2.5.2 Agent communications

It was mentioned in the earlier section that an agent will communicate to coordinate and negotiate to achieve its organizational objectives. There are two basic message types: assertions and queries. Every agent, whether active (i.e. initiates the communication or negotiation with another agent) or passive (i.e. responds to the initiator agent), must have the ability to accept information. This information is communicated to the agent from another agent by means of an assertion. For a passive role in a dialog, an agent must additionally be able to answer questions such that it must be able to:

- Accept a query from another agent
- Send a reply by making an assertion.

For an active role in a dialog, an agent must be able to issue queries and make assertions. With these capabilities, the agent can potentially control another agent by causing it to respond to the query or to accept the information asserted [33]. Communication protocols are very important in any communication systems. The Multiagent communication is specified by a data structure with the following five fields [33]:

1. Sender.
2. Receiver(s).
3. Language in the protocol.
4. Encoding and decoding functions.
5. The action to be taken by the receiver(s).

The communication protocols (languages) that are followed for the agent communication are [33]:

- Agent Communication Language (ACL) by the Foundation for Intelligent Physical Agents (FIPA).
- Knowledge Query and Manipulation Language (KQML), but the support for KQML has been discontinued in favor of FIPA ACL [34].

FIPA is an IEEE Computer Society standards organization that promotes agent-based technology and the interoperability of its standards with other technologies. FIPA was originally formed as a Swiss based organization in 1996 to produce software standards specifications for heterogeneous and interacting agents and agent-based systems [35]. FIPA has developed standards for agent communications. FIPA agent communication specifications deal with Agent Communication Language (ACL) messages, message exchange interaction protocols, speech act theory based communicative acts, and content language representations. Agent Communication Language (ACL) developed by FIPA is based on speech act theory. Here the messages are actions, or communicative acts, as they are intended to perform some action by virtue of being sent. The FIPA ACL specifications consist of a set of message types and the description of their pragmatics, which is the effect on the mental attitudes of sender and receiver agents.

2.5.3 **Multiagent system applications in power systems**

Recently, there has been an interest in investigating the potential value of MAS technology to power system applications. A two-part paper was published by the IEEE Power Engineering Society's Multiagent Systems (MAS) Working Group, examining the potential of the MAS technology for the power industry [36][37]. This section will discuss the applications of MAS in voltage and reactive power control, power system monitoring, protection and electricity power market.

2.5.3.1 MAS in voltage and reactive power control

Keeping voltages at different system nodes within a specified range is one of the main tasks in power system operation. Voltage regulators and capacitor banks are usually used to adjust the voltage in distribution systems. Currently, with DG units' integration, updated voltage control techniques are required. MAS were proposed to provide coordination between voltage regulators, capacitors, and DG units.

In [38][39] authors proposed a coordinated voltage control scheme to enable the voltage regulator to efficiently regulate the voltage of multiple feeders in the presence of DG units. 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 links and form a multi-agent system in order to minimize system losses and maintain acceptable voltage profile.

In [40][41] a distributed control scheme has been proposed to provide proper voltage and reactive power control in active distribution networks. Each device (LTC, SVR, FSC and DG units) is considered as a control agent. An intelligent Belief-Desire-Intention (BDI) model has been proposed for the interior structure of each control agent. The distributed control scheme is applied for voltage regulation in distribution feeders at which LTC or step voltage regulators are installed at the beginning of the feeder. In this case, the proposed control aims to modify the local estimation of the line drop compensation circuit via communication. Also, the control scheme takes into consideration the case of multiple feeders having a substation LTC and unbalanced load diversity.

2.5.3.2 MAS in monitoring power control

MAS technology is also proposed in the monitoring of the power system. Authors in [42] used MAS for the real time monitoring and analysis of the SCADA system data and the post fault data. The paper divided the solution between different agents such that each agent is responsible for a certain function. The paper was valuable on its own. However, it does not tackle the distributing processing of the power system problems between different controllers distributed along the system.

2.5.3.3 MAS in protection

Ref. [43] used multiagent for relay protection setting calculation system for power plant. Each agent which runs in one plant consists of four modules: 1) Setting calculation module: completes all functions of traditional single-plant relay protection setting calculation system graphic modeling; short-circuit current calculation, setting calculation, setting value check, fault simulation. 2) Knowledge base module: stores all information about relay setting calculation, including equipment information, relay protection information, short-circuit current calculation information, setting calculation result information, setting rules. 3) Knowledge analysis module: is used for analyzing and verifying knowledge. Thus, it is used for determining whether knowledge will be accepted by the agent. 4) Communication module: completes the communication among agents to transfer knowledge. Through cooperation among agents, manual operation in the relay protection setting calculation system for a single power plant was greatly reduced and system intelligence was improved.

2.5.3.4 MAS in electricity power market

In [44], an agent-based computational model of the Italian wholesale electricity market was proposed. A two parts paper [45][46] presented an approach for designing MAS to perform negotiations in the electricity power market. Agents perform negotiations on behalf of their human counterparts, and then suggest market strategies that humans can adopt. A distributed approach for the optimal cross-border electricity planning is proposed in [47].

2.5.4 **Multiagent system applications in self-healing**

Self-healing represents the heart of the SG. Self-healing can be described as a system that when subjected to a fault, it will be able to automatically and intelligently perform corrective actions to restore the system to the best possible state, thus enabling it to perform its basic functions. Therefore, the ability to quickly and flexibly reconfigure the network to restore the de-energized loads by the fault represents the key component of self-healing function. MAS is an interesting candidate to realize this capability. MAS will serve as an automatic fault locator and restoration entity for the distribution system. When a fault occurs, the distributed agents in the distribution system will communicate with each other to come up with the fault location. Once they locate and isolate the fault, they start to execute a restoration algorithm to restore the out-of-service loads as much as possible. The following two sections will focus on discussing the application of MAS for solving the fault location detection and isolation, and service restoration problems.

2.5.4.1 MAS application in fault location detection and isolation

Automatic fault location detection and isolation represents a key factor in enhancing reliability, survivability, availability, and efficiency of power systems. The rest of this section will focus on discussing the work which was reported using MAS technique for solving this problem.

Reference [48] proposed a MAS system for fault detection and prognosis problem by using two types of agents: diagnosis agents and prognosis agents. Diagnostic agents are developed to continuously assess the health of the machinery components covered by their diagnostic knowledge bases. The tasks performed by diagnostic agents include: 1) monitoring equipment sensors; 2) detecting anomalous device behavior; 3) continuously analyzing alarm conditions; 4) alerting user upon fault detection; and 5) recording diagnostic events to historical log. The main function of the prognostic agents is to detect subtle equipment performance anomalies and to predict future machinery faults before they actually occur, so unexpected breakdowns can be avoided. The tasks performed by a prognostic agent include: 1) Recording historical data for equipment sensor signals; 2) Performing trending analysis of historical equipment performance; 3) Detecting machinery performance anomalies; 4) Predicting future alarms over a predefined time horizon; 5) Predicting future equipment faults based on predicted alarm conditions; 6) Calculating the remaining useful life (time to failure);

7) Alerting the user upon fault prediction; 8) Recording prognostic events to historical log. The drawback of this work was that the centralized particle swarm optimization (PSO) approach was applied to perform the diagnosis.

Reference [49] established a multilayer and distributed alarm processing and fault diagnosis system. The agent with responsibility for fault diagnosis is called Fault Diagnosis Agent (FDA). The tasks of FDA include: 1) Region chief Agent: takes charge of global aims/functions in the region; makes region specific responsibility Agents work together; makes subregion chief Agent work together; 2) Region specific responsibility Agent: responses to the instructions of region chief Agent; takes charge of some subgoals/functions in the region; make subregion specific responsibility Agents work together; 3) Subregion chief Agent: responses to the instructions of region chief Agent; takes charge of subregion specific responsibility Agents work together; 4) Subregion specific responsibility Agent: responses to the instructions of subregion chief Agent; responses to the instructions of region specific responsibility Agents; takes charge of some subgoals/functions in the subregion. Therefore, the whole fault diagnosis function can be implemented by multilevel FDAs. Every FDA works harmoniously with other FDAs according to the instructions of higher level agents and the knowledge of itself. The goals of lower level alarm processing and fault diagnosis systems are: 1) processing alarms, analyzing local faults and finding out the location, reason and disposal method; 2) providing symptoms of serious blackout to higher level alarm processing and fault diagnosis systems; 3) accepting the global precaution from higher level alarm processing and fault diagnosis systems and delivering to dispatchers. The aims of higher level alarm processing and fault diagnosis systems are: 1) exploring and finding out the linkage between partial faults based on the results of lower alarm processing and fault diagnosis systems; 2) giving precautions and suggestions of potential large blackouts; 3) sending the disposal schemes to be executed by local dispatchers to lower level alarm processing and fault diagnosis systems; 4) communicating with other higher alarm processing and fault diagnosis systems to avoid multi-region accidents. This work focused on describing the hierarchal structure of the MAS and did not discuss a general procedure for the problem or how each agent type works (i.e. how to build its actions based on the measured or input data).

Reference [50] proposed a multi-agent based protection scheme for distribution systems with high penetration of distributed generators (DGs). In the proposed protection scheme, various relays designed as relay agents cooperate to locate and isolate fault zone. Binary state signal (i.e. the current direction and magnitude) is determined autonomously just by sensing a sudden change of the current at the agent relay. Each agent relay simultaneously utilizes binary state signals provided by the other relays at breakers involved to the same zone for detecting a fault location. A monitoring agent observes the current flow at its location. When a fault occurs, the current flow status (i.e. the direction and magnitude) changes suddenly. Then monitoring agents located near the faulty point create and provide two types of signals by using a direction relay and over-current relay: one indicates that the magnitude of the current exceeds a certain value; and another one indicates the direction of the current. Communication agents collect signals from other agents at other breakers connecting to the same zone. Finally breaker agents simultaneously utilize all the collected state signals together with the local signal in a logic circuit, and make a trip signal for their own breaker if it should be tripped.

Reference [51] presented an agent based protection scheme to detect and isolate the faults in a distribution system with high penetration of DGs. Wavelet coefficients of the transient fault currents are used for the identification of faulted sections. The algorithm include two parts: one that determines the direction of fault currents based on the sign of wavelet coefficients and the other that estimates the distance to a fault based on the time interval between the travelling waves (and their reflections) arriving from the fault. If a relay agent identifies a fault on its busbar as an internal fault, it immediately clears the fault by tripping all circuit breakers connected to the busbar and communicates its decision to the other relay agents. For a fault on any arbitrary network segment, relay agents determine the faulty section using the fault direction information. The relay agents are able to share fault direction information via communication links and thus cooperatively determine the faulty section. Once the faulty segment is identified, the agents send signals to the relevant breakers to isolate the faulted segment. Although, this work benefits from the communication capability among relay agents, it used wavelet to determine the fault location which has been already used as a centralized method before.

From this discussion, it is found that the state-of-the-art fault location detection and isolation algorithms proposed in the literature are still depending on the previous centralized methods, and consequently, they solve the problem in a centralized manner in spite of using agents to benefit from their communication capability in transferring information.

2.5.4.2 MAS application in service restoration

Distribution network restoration refers to the actions taken by the distribution network operator (DNO) to restore the power to the maximum number of out-of-service loads after isolating the fault. Time is one of the most important factors in power system restoration. Therefore, it is recommended to restore the maximum number of customers in a minimum possible time. Distribution system restoration problem is a combinatorial nonlinear constrained problem, which is formulated as mixed integer nonlinear problem (MINLP). Thus, it presents an NP-complete problem. There is no available algorithm to solve NP-complete problems in polynomial time.

Reference [52] suggested a MAS system for the restoration problem by using two types of agents: Bus Agent (BAG) and Facilitator Agent (FAG). BAG is developed to decide a suboptimal target configuration after a fault occurrence by interacting with other BAGs based on only locally available information, while FAG is to act as a manager in the decision process. Thus, the restoration process is done through simple negotiation among BAGs with the supervision of one FAG in order to facilitate the restoration process. If there are many branches for energizing the bus, the BAG selects a branch with the largest amount of restorative-available power. The drawbacks of this work were: 1) It did not consider the losses of lines. 2) It did not mention how to consider the different priorities of loads. Reference [53] proposed a MAS system for the restoration problem by using two types of agents: Load Agent (LAG) and Feeder Agent (FAG). LAG corresponds to the customer load, while a FAG is developed to act as a manager for the decision process. The drawbacks of this work were: 1) It assumed that the FAG agent has knowledge about the structure of the network, so it can classify the tie switches of the network as: Type A (connect two feeders which were energized from the same transformer in the same substation), Type B (connect two feeders which were energized from different transformers in the same substation), and Type C (connect two feeders which were energized from different substations) and to determine the restoration strategy based on this classification. Yet, assuming that any agent has a complete knowledge about the network contradicts the nature of MAS as a distributed control scheme. 2) This work did not discuss a general procedure for the restoration of any distribution network; rather, it seems that the algorithm fits with an example given in these papers. 3) The optimal power restoration in terms of maximizing the number of restored loads is not considered in the suggested method. Also, it did not mention how to consider the different priorities of loads.

In [54] the proposed multi-agent system is constructed with two-level hierarchical architecture. Local-area Management Agents (LMAs) and Remote-area Management Agents (RMAs) are located at the upper level, which are corresponding to the local/remote area management system, while several Load Agents (LAGs) and Generator Agents (GAGs) are located at the lower level. The restoration process is done by repeating four procedures as follows in each time interval: 1) Planning of restoration in each local area, 2) Planning of extensive restoration except remote areas, 3) Planning of extensive restoration includes remote areas, and 4) Execution of restoration plan. They did not mention how to consider the different priorities of loads.

In [55], an agent model for the power system restoration problem was proposed. The Multi-agent platform is developed in Java Agent Development Framework (JADE) and the power system test case is developed in Virtual Test Bed (VTB). In their work, three agents named Switch Agents (SAs), Load Agents (LAs), and Generator Agents (GAs) were proposed. The agents communicate only to their neighboring agents and act locally. The restoration algorithm has certain objectives and constraints like the limit on generation, priority of loads, and transfer capacity of lines.

In [56], the application of MAS for planning the service restoration of a distribution system was proposed; however, the authors did not consider load shedding, load priorities, or the obtaining of extra available capacity through load transfers from the main backup feeders to their neighbors. Their work was limited to service restoration and did not include the use of agents for the detection and isolation of fault locations.

From this discussion, it is found that the state-of-the-art restoration algorithms proposed in literature are not based on formal mathematical analysis, but they depend on system-based heuristic rules, for which there is no guarantee to reach satisfied solution for the case of general network. In addition, most of them did not consider the load priority and load variation.

2.6 Distributed Generation (DG)

The literature did not provide consistent definition for distributed generation (DG), but the term is generally used to describe small-scale generation units located near or at loads. The definition can vary with respect to the voltage level, the unit connection, the type of prime mover, whether generation is being dispatched, and the maximum power rating.

IEEE [57] defined DG as “the generation of electricity by facilities that are sufficiently smaller than central generating plants so as to allow interconnection at nearly any point in a power system”. IEEE compared the size of the DG to that of a conventional generating plant. Another definition is provided by the International Council on Large Electric Systems (CIGRE) [58] and The International Conference on Electricity Distribution (CIRED)[59], which defined DG based on size, location, and type. CIGRE defined distributed generation as “all generation units with a maximum capacity of 50 MW to 100 MW, that are usually connected to the distribution network and that are neither centrally planned, nor dispatched”. However, CIRED defines DG to be “all generation units with a maximum capacity of 50 MW to 100MW that are usually connected to the distribution network”.

The interconnection of more DG units with distribution systems is attracting increasing interest. This interest is motivated by several factors such as: the continuous growth in electricity demand, while the expansion by installing new generation and transmission lines faces many difficulties, mainly economical. In addition, DG units are located closer to load centers; hence transmission and distribution losses are reduced. From the environmental point of view, there is an urgent concern about the climate change. Therefore, there is a strong need for integrating more renewable energy sources in the power system because these renewable sources are inexhaustible and nonpolluting.

2.6.1 **Types of distributed generation sources**

Research mentioned two main types of DG sources that are used in distribution systems: dispatchable and non-dispatchable, as shown in Figure 2.2. In this section we will review briefly the most popular DG types.

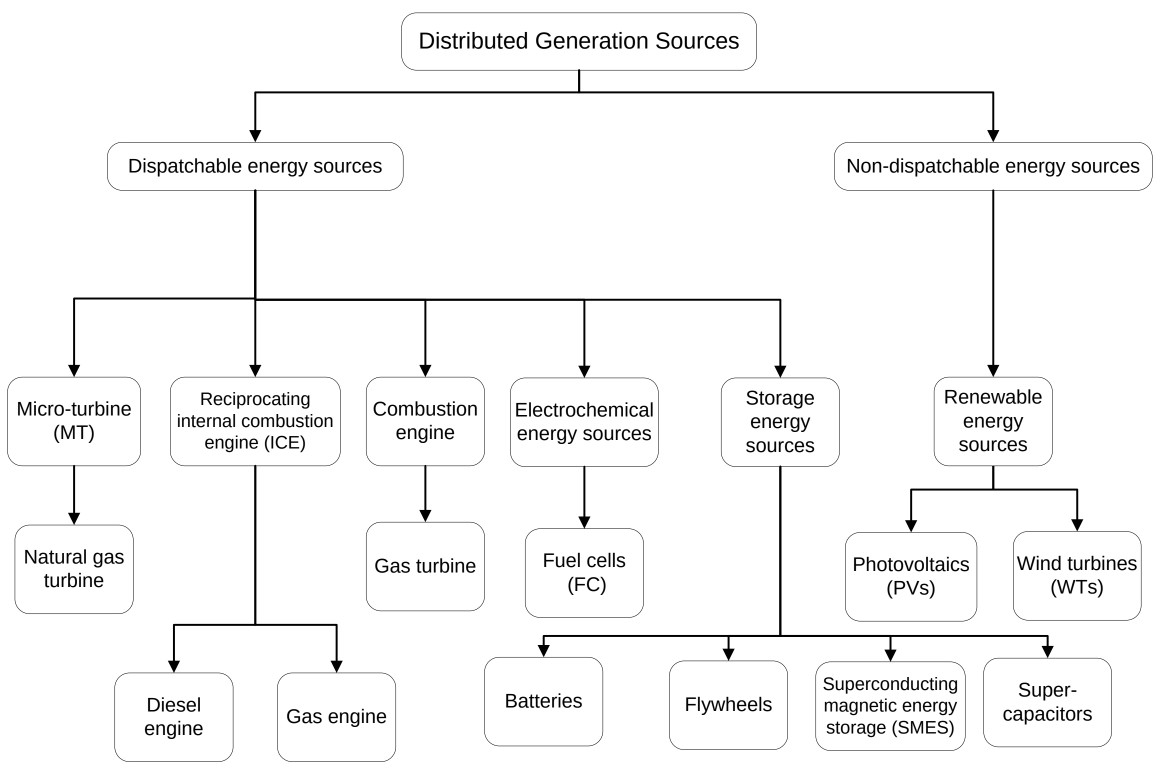


Figure 2-2: Distributed Generation sources

2.6.1.1 Wind turbines

Wind energy is the most widely used renewable source. The concept of operation for a wind turbine is to convert the kinetic energy of wind into mechanical energy, and then into electrical energy, using ac generators such as induction and synchronous machines. These ac generators are mechanically coupled to the wind turbine. Typically, wind turbines are gathered in a form of wind farms. These wind farms are usually installed in a windy place, because their electric generation capacity/efficiency is affected by the wind speed. The overall efficiency of wind turbines ranges from 20% to 40%, and their power rating varies between 0.3 to 7 MW [60]. The main advantages of wind energy are: it is a clean power source, and it can be considered as the cheapest technology compared to other types of renewable energies. However, the fact that its output power fluctuates with wind speed variation still challenges its integration into power systems.

2.6.1.2 Photovoltaic (PV systems)

Solar cells represent the basic component of a photovoltaic system. Because these cells generate their electricity from sunlight, PV systems represent the cleanest source of energy. Solar cells are arranged in the form of panels or modules. These modules are connected in series/parallel configurations to form a solar array. The photovoltaic rating can be found in small solar cells of 0.3 kW and all the way up to multi-megawatt in large systems [61]. Compared with wind turbines, PV systems are considered one of the most expensive DG types [62]. This high cost is because of the low efficiency and high cost of PV materials, the vast land space required to install these PV arrays. Also, PV systems work during daytime and are off during night, which limit their generated power. Furthermore, PV systems need interfacing to the power system using power electronic converters, which adds to their total installation cost.

2.6.1.3 Small hydro power generators

A small-hydro generator is one of the existing DG technologies. It is basically a small size of the typical hydro generators. It is one of the most interesting DG types. This interest is motivated by several factors, for instance it is fully controllable in terms of its output power. It is also a clean, renewable and cheap source of energy.

2.6.1.4 Other DG types

There are several types of DG units such as Fuel cells, biomass, geothermal, tidal power and storage devices. Each of these technologies has its own characteristics. Furthermore, research is still going on in this regard to realize higher efficiencies with lower costs.

2.6.2 **Challenges facing the integration of DG units in power systems**

Distribution systems have traditionally been designed based on the assumption that the primary substation is the only source of power (i.e., the power flows from the transmission station towards the loads). The insertion of DG units into the distribution system changed the design philosophy of the distribution system (i.e. multi-direction power flow). As a result, several technical problems face the integration of DG in the distribution system. Examples of these problems are: the steady state voltage rise, the complexity of the protection system in the presence of DG units (i.e., the increased short circuit fault current and coordination), voltage flicker due to variable output power from renewable resources and reverse power flow.

For example, regarding the restoration problem, the policies currently in use provide for the disconnection of DG units when any failure occurs in the network [63]. DG units are disconnected during a fault for the following reasons: 1) to avoid an increase in the fault current due to the DG; 2) to prevent an extension of the flow of the fault current for a longer period of time (i.e., continuation of the fault current flow from the DG after the utility isolates the fault from the main substation); 3) to reduce the risk of additional damage to the equipment or the conductor; and 4) to avoid the possibility of a temporary fault becoming permanent [64]. Such disconnection is performed primarily in order to nullify the effects of the DG units on protection practices and to restore the typical system topology and unidirectional power flow practices. However, with a high penetration level of DG units, the utility system cannot operate effectively with respect to overload, generation/load balance, and voltage level without the support of the DG units' capacity. Therefore, the automatic disconnection of the DG units during faults drastically reduces the expected benefits associated with DG units (i.e., maintaining power quality and reliability, improving system security, and providing a variety of ancillary services). Furthermore, this process leads to an unnecessary loss of DG power, which increases the difficulty of restoring normal operation [65].

2.6.3 **DG allocation**

The limitation of fossil fuels and the environmental constraints established by the Kyoto Protocol and other governmental initiatives made the allocation of DG units to be a dominant pillar in power system planning. DG allocation means to decide the optimal size and location of DG units to be installed in distribution systems. DG units are installed in distribution systems for the following benefits: reduction of losses, enhancement of voltage profile, peak demand shaving, relieving the overloaded distribution lines, reduced environmental impacts, increased overall energy efficiency, and deferred investments to upgrade existing power systems (i.e., generation, transmission, and distribution) [66]. Therefore, appropriate allocation of these DG units should be computed to achieve most benefits as much as possible without violating system constraints.

Network reconfiguration is one of the most important distribution automation functions, which is generally used for loss reduction and system security improvement. Network reconfiguration is defined as the change in network topology by opening the normally closed sectionalizing switches and closing the normally opened tie switches [67][68]. Reconfiguration schemes are implemented in order to achieve the following benefits: follow the variations in load and power generated from DG units, utilize the loading of transformers and lines in the best possible way, aid adaptive procedures to adequate protection systems during faults, guarantee low losses, achieve high level of power quality, supply the maximum number of customers, and avoid islanding operations [67].

Since network reconfiguration and DG allocation are complex combinatorial optimization problems, several algorithms are proposed in the literature [66][67][68][69][70][71][72]. Because of the dynamic nature of system loads, which vary from time to time, energy loss will not be minimum for a fixed network configuration. Hence, reconfiguration of the network from time to time is required [66]. Furthermore, the continuous load demand growth may lead to the system feeders' overloading and/or voltage constraints violation, where installing DG units can be beneficial. A review of the literature shows that most of the published work has considered DG allocation and reconfiguration problems independently [66][70]. Hence, DG units have been allocated in an individual network configuration that could be considered as original configuration [70].

A review of the literature also reveals that few studies have considered DG allocation and network reconfiguration simultaneously. Ref [66] used Harmony Search Algorithm to solve the network reconfiguration problem in the presence of DG units with an objective of minimizing the real power losses. The simulation results were based on the assumption that the load is fixed (i.e., one snapshot). This assumption may lead to sub-optimal solution because of the time-varying nature of loads in distribution systems. To assess the performance, three different simulations were presented at three loading levels (i.e., 0.5 (light), 1.0 (nominal), 1.6 (heavy)). The work also considered only dispatchable DG units. Ref [69] used genetic algorithm to solve the expansion planning problem in a distribution systems with the use of one or more of the following: topology changes, DG installation (thermal and wind generation are only considered), the rewiring of specific lines, and the addition of new load points.

Since the thermal and voltage constraints can limit DG penetration, ref [67] proposed a genetic algorithm based reconfiguration method to maximize the allowable DG penetration at given nodes. In [70], DG allocation and network reconfiguration were achieved simultaneously. In both [67][70], the authors did not, however, consider load variation or variable DG output in their investigation. In [71], the effect of coordinating network reconfiguration and voltage control on increasing the maximum allowable DG penetration at a given node was presented. The work reported in all these papers also covered only balanced distribution systems.

From the above discussion, it can be concluded that sufficient work has been done with respect to DG allocation and network reconfiguration problems independently. Few studies have addressed the two problems simultaneously. Moreover, the uncertainty associated with renewable DG units and load variations are not considered in most studies. Therefore, the impact of network reconfiguration on DG allocation should be investigated in order to achieve the benefits of inserting renewable DG units to the distribution system as much as possible.

2.7 . Summary

In conclusion, DG units can impact the reconfiguration, fault detection and isolation, and restoration problems in distribution systems. The literature studied these impacts; however, the presented work only focused on dispatchable DG units with pre-defined capacities and constant load representation. Furthermore, the presented work in the literature was based on centralized algorithms, which limit the efficiency and reliability of operation. Yet, the impact of DG units while considering the probabilistic nature of both generation units and loads has not been well addressed and should be examined.

Also, based on the vision of the smart grid, there must be a shift from centralized hierarchy of power system towards a distributed version. Especially that smart grid provides real-time monitoring and reaction such that the network will be able to monitor itself and be able to correctively react to any disturbance. This self-healing capability will achieve fast and efficient power restoration and in consequence improve the reliability of the system. Thus, it is recommended to study these issues with the integration of distributed generation. Therefore, the next chapters will tackle these issues.

Chapter 3

Network Reconfiguration in Distribution Systems with Variable Load Demand and Variable Renewable Resources Generation for Energy Loss Reduction

3.1 Introduction

Due to the continuous load demand growth, distribution systems are often operating under heavily loaded conditions which may lead to system feeders' overloading and/or voltage constraints violation. Furthermore, the majority of losses in power systems (generation, transmission, and distribution) come from distribution systems. For example, for a typical system in a developing country, distribution system losses account for around 13 % of the total energy produced [68]. Therefore, loss reduction in distribution systems has been considered as one of the most important objectives for researchers and engineers. The typical distribution systems have normally closed sectionalizing switches and normally open tie switches (i.e., to interconnect feeders and allow load transfer among them) [73]. The existence of these tie lines has led to the idea of network reconfiguration for loss reduction. Network reconfiguration problem is to find the best configuration of distribution systems that gives minimum energy loss with satisfying the imposed operating constraints.

The goal of the work presented in this chapter is therefore to propose a reconfiguration method for distribution systems in a manner that will include:

1. Load variation by considering the hourly, daily, weekly and monthly change of the season.
2. The uncertainty associated with renewable DG units by considering all possible operating conditions with the probability of their occurrence.
3. The switching operation cost to allow the reconfiguration scheme to improve or at least balance the benefit from system loss reduction against the cost of switching.

The chapter starts by presenting the models used for the system components (loads and DG units), and the combined generation-load model. Then, the formulation of the reconfiguration problem is explained. After that, the results of a simulation conducted in order to validate the proposed algorithm, and a conclusion that summarizes the main contributions of this research are presented.

Figure 3-1 summarizes the proposed method. It starts by modeling the load and the DG generation considering the probabilistic nature of the renewable DG units and the load variation. After that, network reconfiguration is formulated, with an objective function of minimizing seasonal energy loss. The reconfiguration problem will be subjected to several system constraints in order to make sure that the normal operating practices of the distribution system are not violated. The constraints considered in this study are the system voltage limits, feeders' capacity, feeding all loads, and keeping radial topology.

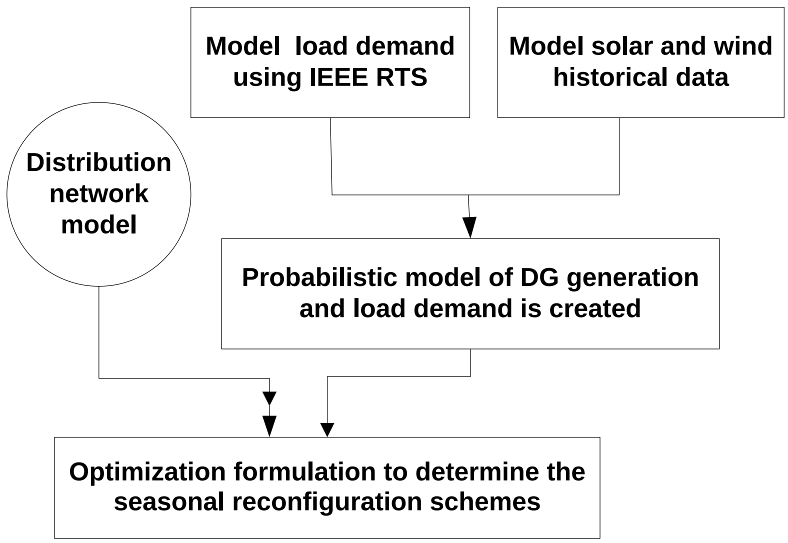


Figure 3-1: A diagram providing a brief description about the reconfiguration problem.

3.2 Modeling of loads and DG units

In order to determine the reconfiguration schemes with minimum energy loss, the characteristic of all system components (i.e., DG units and load) should be modeled and included in the formulation of the problem in a proper way. In this work, DG units are modeled as photovoltaic (PV) modules, wind turbines, and biomass generators, which are the most commonly used DG units in distribution systems. However, other DG types can be modeled with similar approaches. The steps taken to model DG units and loads are described in the next subsections.

3.2.1 Renewable generation modeling

Renewable DG refers for those DG units which generate power from wind and solar energy. These sources are characterized by their fluctuating output power due to the changes in wind speed and solar irradiance. There is no unique model for renewable resources, but different approaches can be used to model them. For example, wind speed and solar irradiance can be modeled chronologically using time-series methods (i.e., suitable for applications that require time series representation such as unit commitment and storage scheduling). Also, they can be modeled probabilistically using a proper probability density function during a certain time segment (i.e., suitable for short and long time planning problems) [74]. Mont Carlo Simulation technique or analytical technique can be utilized to carry out this probabilistic model. Mont Carlo Simulation technique is straightforward while it is computationally intensive (time consuming, needs so much memory, great number of runs). Analytical technique is computationally more efficient, use convolution technique, and the distribution used in simulations is the actual historical distribution recently observed. In this work, the probabilistic model using analytical technique has been used to model wind and PV based DGs.

3.2.1.1 Wind turbine generators

The output power of wind turbines depends on the wind speed. Most of the literature recommend modeling the behavior of wind speed using the Weibull PDF since it gives the best fit required for the planning studies [75]. This is because of its two adjustable parameters (*k* and *c*), which provide a great flexibility in fitting the Weibull PDF to the measured values with different behaviors:

$$f_w(v) = \frac{k}{c}\left(\frac{v}{c}\right)^{k-1} \exp\left[-\left(\frac{v}{c}\right)^{k}\right] \tag{3.1}$$

where k and c are the shape and scale parameters, respectively and v is the wind speed (m/s). These Weibull parameters are calculated as follows [75]:

$$k = \left(\frac{\sigma}{v_m}\right)^{-1.086} \tag{3.2}$$

$$c = \left(\frac{v_m}{\Gamma(1+1/k)}\right) \tag{3.3}$$

where v_m is the mean wind speed (m/s), σ is the standard deviation, and Γ is the gamma function.

In this study a selected study period of one year is divided into four seasons, and a typical day is generated for each season in order to represent the random behavior of the wind speed during this specific season. For the site of the distribution network under study, the hourly wind speed data is modeled by a Weibull PDF. This PDF is based on (Y) years of real historical data that have been collected from the site. The entire year is divided into 4 seasons, and each season is represented by a day within that season. Then, the historical data are used to generate for each season a typical day's frequency distribution of the wind speed measurements (i.e., 24 PDFs, one PDF for each hourly time segment of the day). For example, considering a month to be 30 days, each hourly time segment will have (90*Y) wind speed level data points (Y years x 30 days per month x 3 months per season).

From this historical wind speed data, the mean and standard deviation for each hourly time segment are calculated as shown in (3.2) and (3.3). Then from them, the Weibull PDF is generated for each hour as shown in (3.1).

The strength of this model is that it provides the correlation between the wind speed and the load profile and can be accompanied with solar irradiance modeling.

Once the PDF of each time segment is generated, it is divided into states. As shown in Table 3-1, for each time segment, the number of states is selected by adjusting each step to be 1 m/s for wind speed. Then, the wind turbine output power for each time segment during different states for the wind speed can be obtained from the wind turbine power performance curve. For the sake of simplicity, the average value of each state is used to calculate the output power for this state (i.e., if the wind speed is from 5 to 6 m/s, v_{av}=5.5 m/s is used). An example of a typical wind turbine power performance curve is illustrated in Figure 3-2. The output power can be calculated using equation (3.4) [74]:

$$P_w(v_{ax}) = \begin{cases} 0 & 0 \le v_{ax} \le v_{ci} \\ P_{rated} * \dfrac{(v_{ax} - v_{ci})}{(v_{co} - v_{ci})} & v_{ci} \le v_{ax} \le v_r \\ P_{rated} & v_r \le v_{ax} \le v_{co} \\ 0 & v_{co} \le v_{ax} \end{cases} \tag{3.4}$$

where v_{ci}, v_r, v_{co}: cut-in speed, rated speed, and cut-off speed of the wind turbine, respectively; $P_w(v_{ax})$: output power during state x, and v_{ax}: average speed of state x.

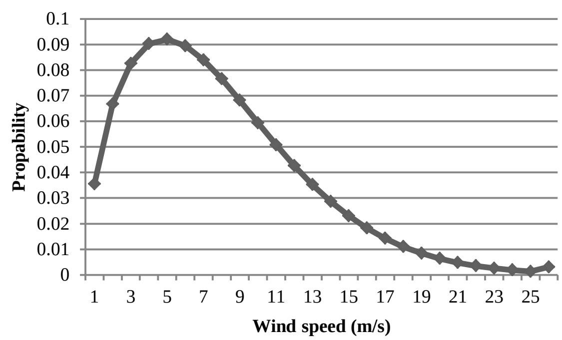
3.2.1.2 PV modules generators

The output power of PV modules depends on the amount of irradiance. Based on the literature, Beta distribution best fits the irradiance data [74][76]:

$$f_b(s) = \begin{cases} \dfrac{\Gamma(\alpha+\beta)}{\Gamma(\alpha)\Gamma(\beta)} * s^{(\alpha-1)} * (1-s)^{(\beta-1)} & 0 \le s \le 1,\ \alpha \ge 0, \beta \ge 0 \\ 0 & otherwise \end{cases} \tag{3.5}$$

where s: solar irradiance kW/m^2; $f_b(s)$: Beta distribution function of s; α, β: parameters of Beta distribution function.

Table 3- 1: Example of a Weibull PDF for specific hour during winter season

<table>
<tr><th>Weibull PDF for hour 12-1 AM during winter season</th><th colspan="4">Probabilities and output power for different states</th></tr>
<tr><td rowspan="13">
</td><td>State</td><td>Wind speed (m/s)</td><td>Probability</td><td>P_{gen} (MW)</td></tr>
<tr><td>1</td><td>0-4 & 24-∞</td><td>0.2794</td><td>0</td></tr>
<tr><td>2</td><td>4-5</td><td>0.0920</td><td>0.055</td></tr>
<tr><td>3</td><td>5-6</td><td>0.0895</td><td>0.165</td></tr>
<tr><td>4</td><td>6-7</td><td>0.0840</td><td>0.275</td></tr>
<tr><td>5</td><td>7-8</td><td>0.0766</td><td>0.385</td></tr>
<tr><td>6</td><td>8-9</td><td>0.0681</td><td>0.495</td></tr>
<tr><td>7</td><td>9-10</td><td>0.0594</td><td>0.605</td></tr>
<tr><td>8</td><td>10-11</td><td>0.0507</td><td>0.715</td></tr>
<tr><td>9</td><td>11-12</td><td>0.0426</td><td>0.825</td></tr>
<tr><td>10</td><td>12-13</td><td>0.0352</td><td>0.935</td></tr>
<tr><td>11</td><td>13-14</td><td>0.0287</td><td>1.045</td></tr>
<tr><td>12</td><td>14-24</td><td>0.0939</td><td>1.1</td></tr>
</table>

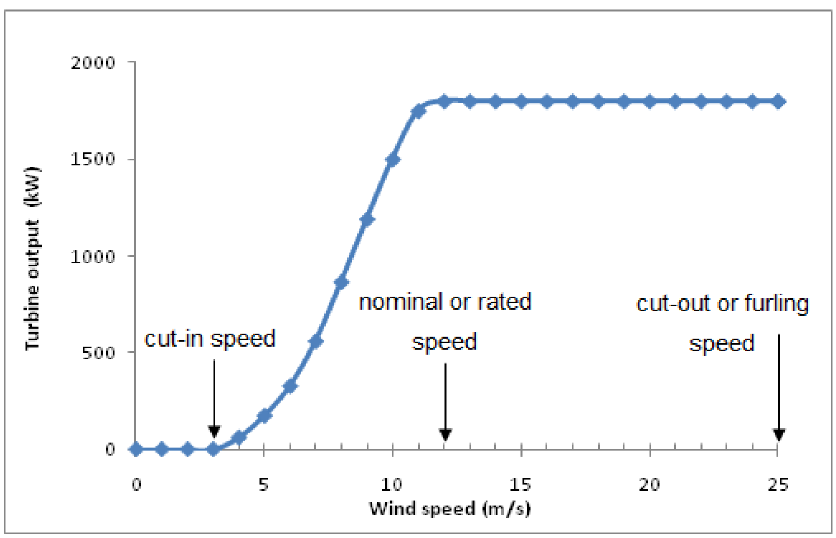


Figure 3-2: An example of typical wind turbine power output curve (Vestas V90-1.8 MW)

These Beta parameters are calculated as follows [74][76]:

$$\beta = (1-s_m)*\left(\frac{s_m*(1+s_m)}{\sigma^2}-1\right) \tag{3.6}$$

$$\alpha = \frac{\beta * s_m}{1-s_m} \tag{3.7}$$

where s_m and σ are the mean and the standard deviation of the random solar irradiance.

Similar to wind speed, the entire year is divided into four seasons, and a typical day is generated for each season in order to represent the random behavior of the solar irradiance during this specific season. For the site of the distribution network under study, the hourly solar irradiance data is modeled by a Beta PDF. This PDF is based on (Y) years of real historical data that have been collected from the site. The entire year is divided into 4 seasons, and each season is represented by a day within that season. Then, the historical data are used to generate for each season a typical day's frequency distribution of the solar irradiance measurements (i.e., 24 PDFs, one PDF for each hourly time segment of the day).

From the historical solar irradiance data (i.e., Y years x 30 days per month x 3 months per season), the mean and standard deviation for each hourly time segment are calculated as shown in (3.6) and (3.7). Then from them, the Beta PDF is generated for each hour as shown in (3.5).

Once the PDF of each time segment is generated, it is divided into states. Thus, for each time segment, the number of states is selected by adjusting each step to be 0.1 kW/m^2 for solar irradiance. Then, the PV module output power for each time segment during different states for the solar irradiance can be obtained using equation (3.8) [74]:

$$\begin{gathered} T_{cy} = T_A + s_{ay}\left(\frac{N_{OT}-20}{0.8}\right) \\ I_y = s_{ay}[I_{sc} + K_i(T_{cy}-25)] \\ V_y = V_{oc} - Kv*T_{cy} \\ FF = \frac{V_{MPP}*I_{MPP}}{V_{oc}*I_{sc}} \\ P_s(s_{ay}) = N_m * FF * V_y * I_y \end{gathered} \tag{3.8}$$

where T_{cy}: cell temperature ºC during state y; T_A: ambient temperature ºC; K_v: voltage temperature coefficient V/ ºC; K_i: current temperature coefficient A/ºC; N_{OT}: nominal operating temperature of cell in ºC; FF: fill factor; Nm: number of modules; I_{sc}: short circuit current in A; V_{oc}: open circuit voltage in V; I_{MPP}: current at maximum power point in A; V_{MPP}: voltage at maximum power point in V; $P_s(s_{ay})$: output power during state y, and s_{ay} : average irradiance of state y.

3.2.2 Biomass generators and load modeling

The biomass (dispatchable) generators are considered to be firm generators without uncertainty (i.e., constant output power at its rated value) [74][77]. However, the load profile is assumed to follow the IEEE-RTS 8760 hourly load model. The hourly, daily, and weekly load variation during the weeks of each season and different load profiles during each season for the entire year are represented as a percentage of the annual peak load [78]. However, the load profile for all hours of the entire year varies within the range from 30% to 100% of the annual peak load. Therefore, the load model is represented by 71 states to reflect this load variation range (i.e., the 1st state refers to 30% and with a step of 1% the last state refers to 100%).

3.2.3 Combined generation-load model

Three years of real historical data have been used to model the solar irradiance and wind speed by Beta and Weibull PDFs, respectively, as explained before.

After modeling the different types of DG units and the load, these models are utilized to generate a combined seasonal generation-load model. The output power of biomass DG units during each hour is constant; thus, its probability of occurrence is one. Furthermore, the load level during each hour is constant at one of the 71 levels/states; thus, its probability of occurrence is one for its specific level and zeros for the remaining load levels. Furthermore, assuming that wind speed states and solar irradiance states are independent, the probability of any combination of them is obtained by convolving the two probabilities. Then, a power flow is run for each state and the power loss is calculated and weighted based on its probability of occurrence in order to calculate the total expected seasonal energy loss. The total number of states (N_s) is 8520 (71 load state x 12 wind state x 10 PV state). However, because the load profile does not reach its peak value in all seasons, the number of states for each season will be lower or equal to this number.

3.3 Reconfiguration problem formulation

This section explains the proposed reconfiguration problem formulation (objective function, control variables and constraints). The proposed formulation accommodates the probabilistic generation load model into the deterministic power flow equations (i.e., the number of active/reactive power flow equations is equal to the total number of states). In each state, the power loss is calculated and weighted based on its probability of occurrence during the entire season, in order to calculate the energy losses. The optimal configuration is then determined so that for all operating conditions the total seasonal energy losses are minimized without violating the constraints.

3.3.1 **Objective function**

The objective of the reconfiguration problem is to minimize the seasonal/annual energy loss with the consideration of switching operation costs in the distribution system for all possible combinations of load and DG output power. The objective function can be described as follows:

$$Minimize \quad F = C_{losses} + SW_{\cos t} \tag{3.9}$$

where C_{losses}: seasonal energy loss cost; and SW_{cost}: switching operation cost.

The power loss for each of the combined generation and load states (N_s) is evaluated. Then the seasonal energy loss is evaluated according to the following methodology:

The power loss for the season is represented by a vector of length (N_s), in which each element i represents the power loss corresponding to the state i.

$$P_{loss} = [P_{loss(1)} \; P_{loss(2)} \ldots P_{loss(N_s)}] \tag{3.10}$$

A variable (ST) is defined as:

$$ST = [\;]_{24D_s x N_s} \tag{3.11}$$

For the variable in (3.11), each row represents the different probability values of all states for each hour of the season. The strength of this variable is that it is generated only once for certain wind or solar regimes, and it allows for the hourly evaluation of the energy loss. The seasonal energy loss is evaluated by:

$$C_{losses} = C_e \sum_{1}^{24D_s} ([ST]_{24D_s \times N_s} \times [P_{loss}]_{N_s \times 1})^T \times [Ones]_{24D_s \times 1} \tag{3.12}$$

where C_e: energy cost ($/kWh) and D_s: total number of days per season;

The power loss for each state s ($P_{loss(s)}$) is calculated as follow [79]:

$$P_{loss(s)} = \sum_{i=1}^{N_{br}} [I_{s,i}]^T \times [R_i] \times \left[I_{s,i}\right] \tag{3.13}$$

where N_{br}: total number of branches; $[Ri]$: three-phase resistance matrix of branch i, $[I_{s,i}]$ three-phase current matrix of branch i during state s.

The second term (i.e., switching operation costs) is calculated as follows:

$$\mathrm{SW_{cost}} = SW_c * \sum_{i=1}^{N_{sw}} |x_i - x_{io}| \tag{3.14}$$

where SW_c: switching cost ($/switching operation) which is based on the required cost of operator/engineer to implement this switching action, maintenance required, and the effect of each switching action on shortening lifetime of a switch (i.e., based on the data sheet for some switches, the switch can turn on/off 1000 times during its life cycle [80]); N_{sw}: the total number of switches; x_i: status of the ith switch in the reconfigured network (i.e., equals 1 for a closed one and 0 for an opened one); and x_{io}: status of the ith switch before reconfiguration.

3.3.2 **Constraints**

Each closing or opening of a switch creates a new network topology with a new set of voltages, line currents, and active/reactive power balance. Hence, due to the varying topology and the connected loads, bus voltages and line currents change during the reconfiguration process. To obtain satisfactory system operation and to maintain the safety and security of different system components (i.e., transformer and lines), the following constraints are included:

1) *Power flow equations:*

$$\begin{gathered} P^p_{slack(s)} + PW^p_{(s,i)} + PS^p_{(s,i)} + P^p_{bio(i)} - PD^p_{(s,i)} = \\ \sum_{j=1}^{n} x_{(ij)} * V^p_{(s,i)} \sum_{m=a}^{c} V^m_{(s,j)} [G^{pm}_{(ij)} \cos\delta^{pm}_{(s,ij)} + B^{pm}_{(ij)} \sin\delta^{pm}_{(s,ij)}] \;\; \forall p,s \end{gathered} \tag{3.15}$$

$$\begin{gathered} Q^p_{slack(s)} \pm QW^p_{(s,i)} \pm QS^p_{(s,i)} \pm Q^p_{bio(i)} - QD^p_{(s,i)} = \\ \sum_{j=1}^{n} x_{(ij)} * V^p_{(s,i)} \sum_{m=a}^{c} V^m_{(s,j)} [G^{pm}_{(ij)} \sin\delta^{pm}_{(s,ij)} - B^{pm}_{(ij)} \cos\delta^{pm}_{(s,ij)}] \;\; \forall p,s \end{gathered} \tag{3.16}$$

The sign for reactive power from each DG type depends on its power factor (i.e., positive for leading pf, negative for lagging pf, and zero for unity pf). where:

p: set of phases *a,b,c*;

$P_{slack}(s)$, $Q_{slack}(s)$: substation active and reactive powers injected during state *s*;

PW(s,i), QW(s,i): active and reactive powers injected during state s of wind-based DG connected at bus *i* ;

PS(s,i), QS(s,i): active and reactive powers injected during state s of solar-based DG connected at bus *i*;

Pbio(i), Qbio(i): active and reactive powers of biomass-based DG connected at bus *i*;

PD(s,i), QD(s,i): active and reactive powers of load connected at bus i during state s;

$G_{(ij)}$ *and* $B_{(ij)}$: the real and reactive parts of the 3x3 admittance matrix of the branch between node *i* and node *j*;

$\delta_{(ij)}^{pm}$: difference in voltage angles between phases p and m of nodes *i* and *j*;

$x_{(ij)}$: status of branch *ij* (0: opened and 1: closed);

V(s,i): voltage at bus *i* during state *s*;

n: total number of buses.

2) *Radial structure of the network:*

Representing radial constraint in reconfiguration problem is not an easy task. Most heuristic based methods start with all the switches closed, forming a completely meshed distribution network, and then employing step-by-step heuristics to retain the radial topology by opening a branch in each step. The drawback of these procedures is that they do not consider the solution as a whole. This characteristic is restricted to a fraction of the solutions' search space. Therefore, the optimal solution is not guaranteed. Another way of representing the radial constraint is to apply summation of the binary variables of lines that enter into the node to be one [81][82]. However, this procedure cannot account for reverse power flow that may occur in the presence of DG units. Furthermore, it represents each line with two-way direction of power flow (i.e., for two nodes i and j there will be $x_{(ij)}$ and $x_{(ji)}$); and one of the directions should exist.

Distribution network topology can be represented as a tree (i.e., connected graph without loops). A tree of a graph consisting of N_{br} branches and *n* nodes is a sub-graph connected with *(n-1)* branches. Therefore, the topology of a network with *n* nodes is radial if [83]:

$$\sum_{ij \in N_{br}} x_{(ij)} = n - 1 \tag{3.17}$$

In order to guarantee the connectivity of the generated configurations (i.e., radial without loops and connected without isolated loads from the main source), the following rules are used with eq. (3.17):

- All switches that do not belong to any loop are to be closed, and all switches connected to the system substation are also to be closed.
- Only one switch from a common branch vector (set of elements that are common between any two loops) can be selected to open to prevent islanding of the interior nodes [84]. For example, in Figure 3-3, vector L12 can have only one opened switch to prevent islanding of one of its nodes as node b.
- Only one switch from a non-common branch vector (set of elements that are not common with other loops) can be selected to open to prevent islanding of the exterior nodes. For example, in Figure 3-3, vector L11 can have only one opened switch to prevent islanding of one of its nodes as node a.
- All the common branch vectors of a prohibited group vector (set of common branch vectors that incident to common interior nodes) cannot simultaneously have opened switches [84]. For example, in Figure 3-3, each one of vectors L12, L13, and L23 cannot have one opened switch at the same time to prevent islanding of one of their common nodes as node c.

Therefore, the feasibility of the generated solutions is checked using those filtering rules. Only the solutions which have passed are evaluated using power flow.

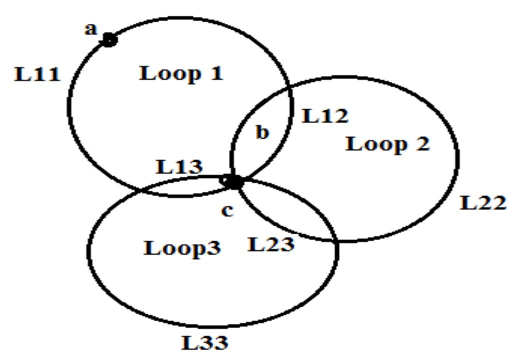


Figure 3-3: Venn-diagram of distribution network

3) *Bus voltages and line currents limits:*

The bus voltages and line currents must be kept within their respective operational limits. These voltage and current constraints make sure that voltages and currents throughout the distribution network will remain within the desired range in the new configuration. This ensures that this new configuration will not result in an undesired temporary or permanent voltage/current profile.

$$V_{\min} \leq V_{s,i}^{p} \leq V_{\max},\ V_{slack} = 1 \tag{3.18}$$

$$0 \leq x_{(ij)} * I_{s,ij}^{p} \leq I_{\max} \tag{3.19}$$

where p: set of phases a,b,c; $V_{s,i}^{p}$: voltage at bus i during state s in phase p; V_{max}, V_{min}: maximum and minimum acceptable bus voltages (i.e., 1.05, 0.9 p.u., respectively); and I_{max}: upper limit of line current as defined by the manufacturer.

3.3.3 **Application of GA in the reconfiguration problem**

As mentioned in chapter two, section 2.2.2, many studies have shown that soft computing methods can often find good solutions for complicated problems. As shown in Figure 3-4, for this type of approaches, the population of individuals is updated through the application of operators according to fitness functions, so that the individuals in the population can be expected to move toward better solution areas. Genetic algorithm (GA) is a popular meta-heuristic method that is well suited for combinatorial optimization problems with discrete/continuous variables.

In this work, a GA has been applied in order to solve the reconfiguration problem based on the proposed formulation. As shown in Figure 3-4, the algorithm includes the following steps:

Step 1: Read the following information that has been input to the algorithm: load, generation and probabilities values from the combined generation-load model, base configuration of the season under study, population size, chromosome length, and maximum number of iterations (MI).

Step 2: Generate an initial population (P_0) with the following characteristics: 1) as shown in Figure 3-5, the chromosome length equals the total number of decision variables (status of switches $x_{(ij)}$, ij=1,…., N_{br}); 2) each gene accepts only either zero or one, implying that the corresponding switch is either open or closed, respectively; and 3) the first individual in (P_0) is the chromosome corresponding to the base configuration of the distribution network. The remainders of the individuals are generated randomly.

Step 3: Check the radiality of the distribution networks that correspond to the individuals in (P_0). Infeasible combinations are then removed from the solution space through the assignment of a large penalty cost. Only feasible connections are evaluated further and checked for their feasibility with respect to the remaining constraints (i.e., voltage and current limits) based on power flow.

Step 4: Evaluate the fitness functions for individuals in (P_0) using equation (3.9). The population is then denoted by iteration number t (i.e., population = P_t).

Step 5: Generate a new population (P_{t+1}) through the application of the following operators to (P_t): selection (i.e., chooses some parents to participate in the next generation based on their fitness function values), elitism (i.e., guarantees the presence of the best individuals of the current generation in the new one), crossover (i.e., combines parts of two parents to produce children that contain some parts from both parents), and mutation (i.e., applies random changes to a single chromosome to create a child).

Step 6: Check the radiality of the distribution networks that correspond to the individuals in (P_{t+1}).

Step 7: Evaluate the fitness functions for the individuals in (P_{t+1}).

Step 8: Check for the termination condition. If the optimal pattern remains unchanged after the preset number of iterations or the MI has been reached, go to step 9; otherwise go to step 5.

Step 9: Report the results

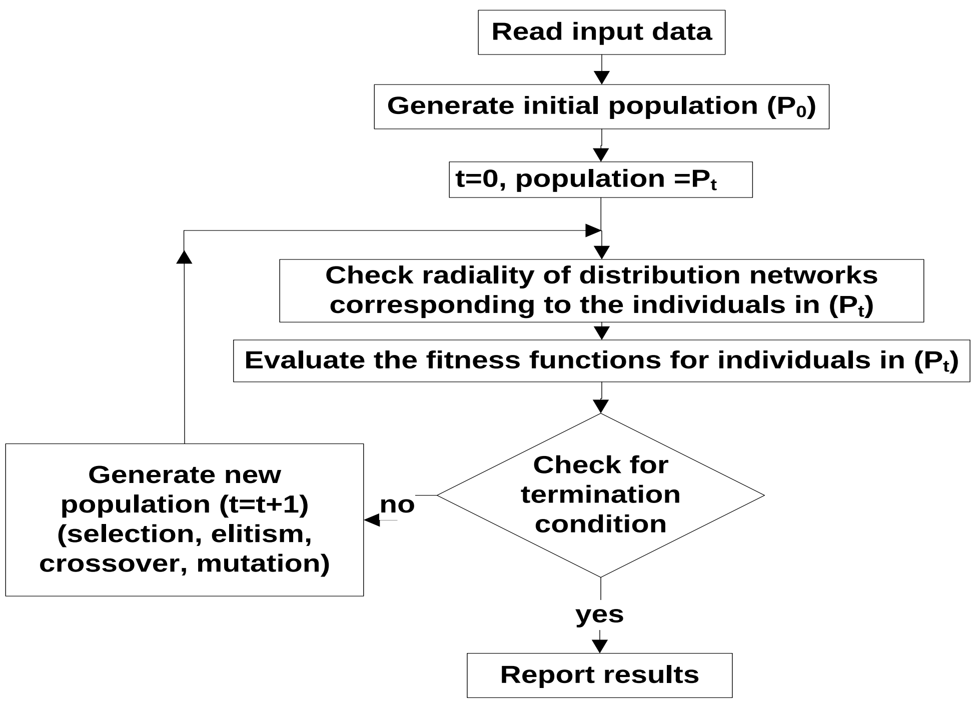


Figure 3-4: Flow chart for GA-based reconfiguration algorithm

$X_{(1)}$	$X_{(2)}$	……………………	$X_{(Nbr)}$

Figure 3-5: Typical chromosomes structure with control variables

3.4 Test results

The proposed method was tested on two different systems that were used in other technical papers: a 119-bus balanced system [85], and a 25-bus unbalanced system [86]. The two systems were modified by integrating specific DG units of different types (biomass, wind, and photovoltaic) in order to test the performance of the proposed method. The following factors were taken into consideration:

1. *Reconfiguration time frame*: based on the operational practices, seasonal configuration is used [87]. This is because seasonal configuration decreases the required number of switching operations. Therefore, it reduces the possibility of switching surges, the risk of outages, and the number of transient disturbances in the system due to multiple switching operations. From another hand, it lowers the operational cost of these switching operations.
2. *Cost:* the cost of electricity is 6.5625 cents/kWh, and the cost of one switching operation is $203 [87]. However, these values can be easily adjusted in the reconfiguration algorithm based on each utility price.
3. *Yearly reconfiguration procedure:* in this work, the base network topology is used as an initial configuration for winter season. Then, the obtained configuration for winter season will be the initial configuration for the spring season, and so on. The configuration of each season is achieved based the load profile and DG units output power profiles during that season.

For the sake of investigating DG units' effect on the reconfiguration problem, four different case studies are demonstrated:

Case 1: network without DG (base case);

Case 2: network with wind and biomass DG;

Case 3: network with solar and biomass DG;

Case 4: network with wind, solar and biomass DG;

Furthermore, for the sake of verification and comparison, within each case the following scenarios will be implemented:

Scenario I: this scenario does not consider the time-varying nature of both load and renewable-based generators. However, it finds the configuration that will minimize losses for peak loads and maximum allowable output power from DG (i.e., biomass DG units have constant output, and each renewable DG has its rated output power).

<u>Scenario II</u>: this scenario finds the configuration that will minimize losses for peak loads and minimum allowable output power from DG (i.e., biomass DG units have constant output, and each renewable DG has zero output power).

<u>Scenario III</u>: this scenario considers the time-varying nature of both load and renewable-based generators based on the proposed formulation. However, it has no limit on the number of switching operations (i.e., equation (3.14) is not included in the objective function).

<u>Scenario IV</u>: this scenario is similar for scenario III. But, it has limit on the number of switching operations (i.e., equation (3.14) is included in the objective function).

As a result, in the following results, for each case (i.e., without DG, wind-biomass, solar-biomass, and wind-solar-biomass) there will be four different annual reconfiguration schemes based on the four proposed scenarios. These four annual schemes will be compared with the base network topology (i.e., without reconfiguration for all the year). A distribution system power flow program was used to calculate the objective function and check the operational constraints in simulation results [88].

3.4.1 **119-Bus balanced distribution system**

Figure 3-6 shows the 119-bus system. The installation nodes, capacities, and power factor (pf) of the DG units are shown in Table 3-2. In these simulation results, both the wind and photovoltaic DG units were operating at unity pf. The used wind turbine is 1.1 MW, and the photovoltaic module is 75W, however, other wind and PV ratings can be considered without loss of generality. The utilized DG units' ratings and characteristics are obtained from [74].

Table 3- 2: Installation nodes and capacities/pf of DGs for the 119-Bus balanced system

Bus		27	54	77	113	29
Wind- Biomass	Wind (MW)	0	0	3.3/1	0	0
	Biomass (MW)	1/1	1/1	0	1/1	0
Solar- Biomass	Solar (MW)	0	0	3.3/1	0	0
	Biomass (MW)	1/1	1/1	0	1/1	0
Wind- Solar- Biomass	Wind (MW)	0	0	0	0	3.3/1
	Solar (MW)	0	0	3.3/1	0	0
	Biomass (MW)	1/1	0	0	1/1	0

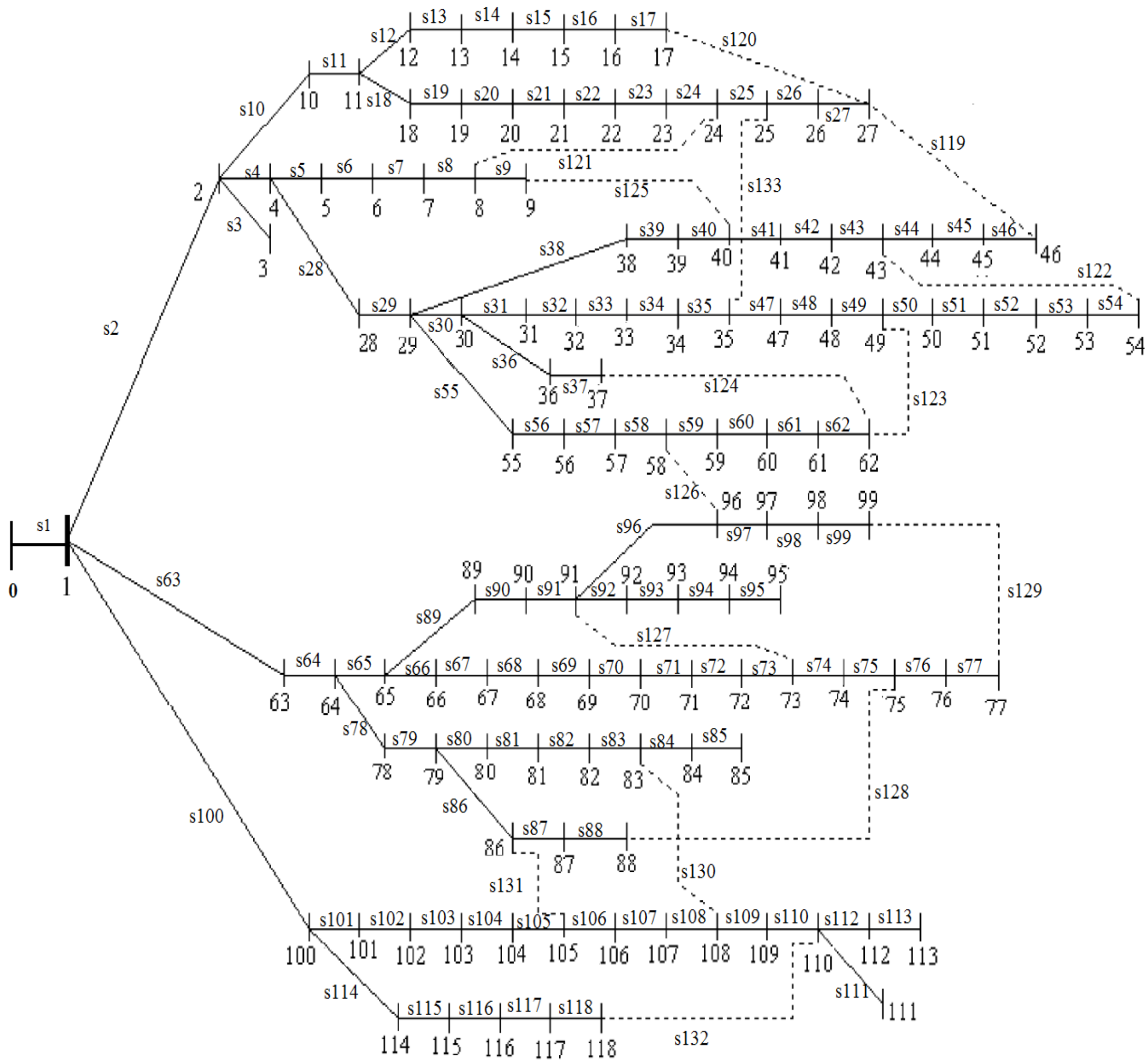


Figure 3-6: 119-Bus balanced system

3.4.2 **25-Bus unbalanced distribution system**

Figure 3-7 shows the 25-bus unbalanced test system. The installation nodes, capacities, and power factor (pf) of the DG units are shown in Table 3-3.

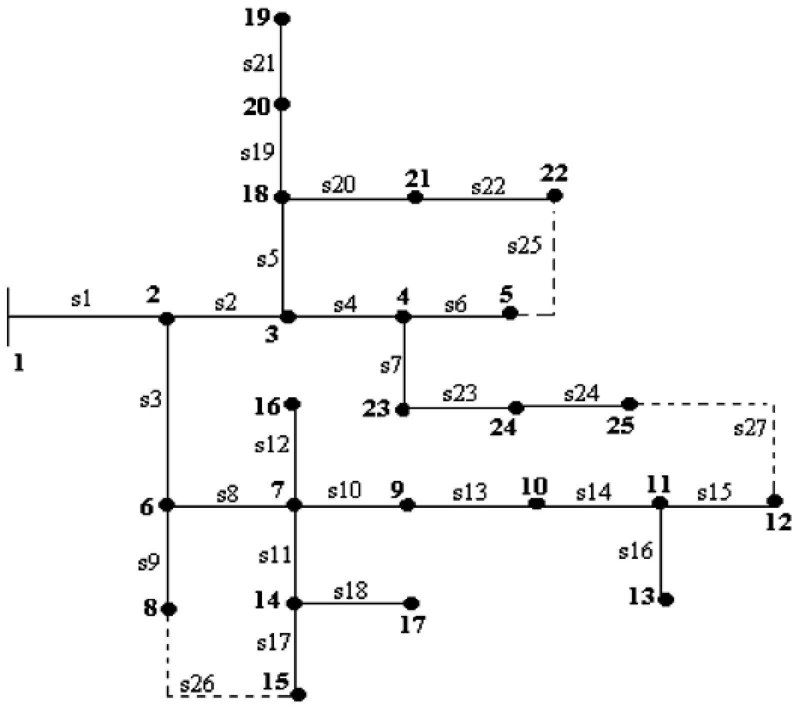


Figure 3-7: 25-bus unbalanced system

Table 3- 3: Installation nodes, capacities, and pf of DG units for the 25-bus system

Bus		12	15	22	18
Wind-Biomass (all are 3-ph)	Wind (MW)	1.1/1	0	0	0
	Biomass (kW)	0	200/0.9	200/0.9	0
Solar-Biomass (all are 3-ph)	Solar (MW)	1.1/1	0	0	0
	Biomass (kW)	0	200/0.9	200/0.9	0
Wind- Solar-Biomass (all are 3-ph)	Wind (MW)	0	0	0	1.1/1
	Solar (MW)	1.1/1	0	0	0
	Biomass (kW)	0	200/0.9	0	0

3.5 Results discussion

3.5.1 **Benefits of network reconfiguration**

3.5.1.1 Results of 119-Bus balanced distribution system

The base network topology case (i.e., without the DG units and without reconfiguration) annual active and reactive energy losses are 4217.5 MWh and 3193.2 Mvarh. Table 3-4 shows the loss reductions, minimum voltage, and the number of switching operations for the annual reconfiguration schemes [Base: 11 kV, 100 MVA]. Figure 3-8 shows the annual operation cost (i.e., total cost of losses and switching for the four seasons of the year as shown in (3.9)) for all scenarios.

Table 3- 4: Loss reduction, minimum voltage, and number of switching operations for the 119-bus system annual reconfiguration schemes

Case/ Scenarios		V_{min} p.u	% Loss reduction		N. of switching operations
			MWh	Mvarh	
Case 1 (without DG)	base	0.870	-	-	0
	I&II	0.932	30.25	31.43	54
	III	0.932	31.72	34.94	32
	IV	0.932	31.28	34.81	22
Case 2 (wind-biomass)	base	0.870	24.99	27.62	0
	I	0.935	37.06	36.76	44
	II	0.934	36.11	36.69	50
	III	0.940	38.93	39.24	46
	IV	0.938	38.35	38.30	30
Case 3 (solar-biomass)	base	0.870	26.05	27.14	0
	I	0.931	37.59	37.16	44
	II	0.929	37.57	37.46	50
	III	0.931	40.05	40.54	32
	IV	0.931	39.88	40.86	24
Case 4 (wind-solar-biomass)	base	0.870	20.32	17.64	0
	I	0.931	37.14	41.26	34
	II	0.931	37.53	41.36	34
	III	0.940	41.02	43.41	32
	IV	0.940	40.67	43.43	24

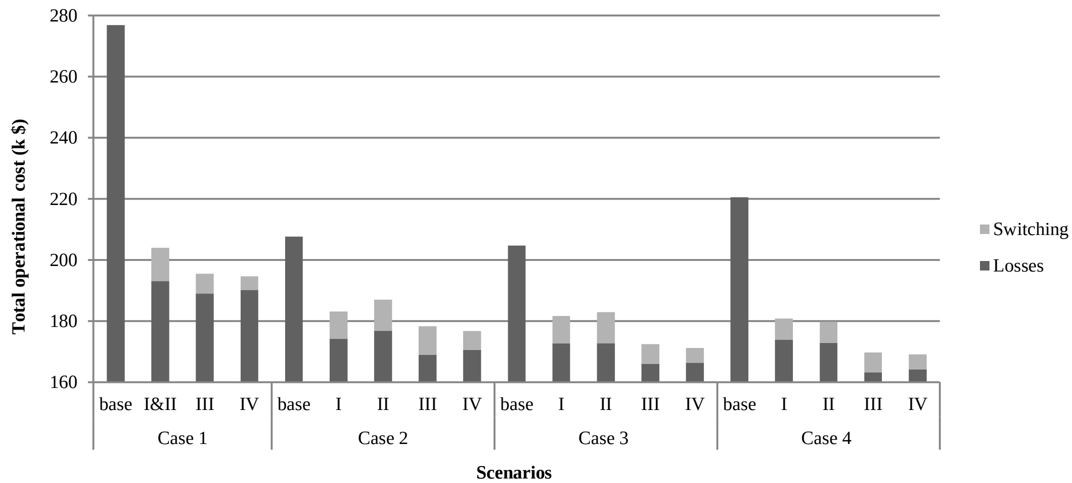


Figure 3-8: Annual operational cost for 119-bus balanced system

3.5.1.2 Results of 25-Bus unbalanced distribution system

The base case (i.e., without DGs and without reconfiguration) annual active and reactive energy losses are 502.7 MWh and 561.0 Mvarh. Table 3-5 shows the loss reductions, minimum voltage, and the number of switching operations for the annual reconfiguration schemes [Base: 4.16 kV, 30 MVA]. Figure 3-9 shows the annual operation cost for all scenarios.

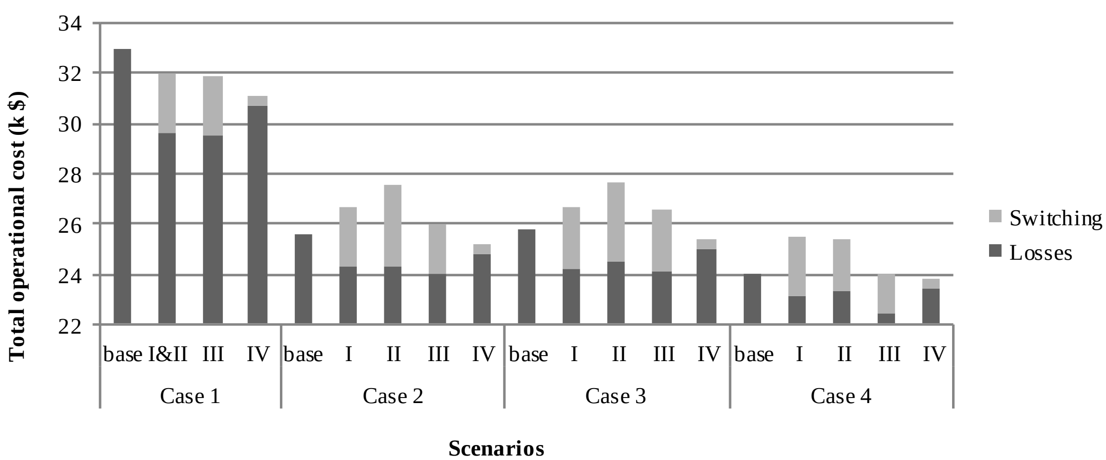


Figure 3-9: Annual operational cost for 25-bus unbalanced system

Table 3- 5: Loss reduction, minimum voltage, and number of switching operations for the 25-bus system annual reconfiguration schemes

Case/ Scenarios		Vmin p.u			% Loss reduction		N. of switching operations
		Ph. a	Ph. b	Ph. c	MWh	Mvarh	
Case 1 (without DG)	base	0.928	0.928	0.937	-	-	0
	I&II	0.939	0.940	0.946	10.28	5.40	12
	III	0.939	0.940	0.946	10.64	5.44	12
	IV	0.937	0.938	0.938	6.86	3.19	2
Case 2 (wind-biomass)	base	0.931	0.931	0.938	22.46	23.21	0
	I	0.934	0.934	0.941	26.48	25.45	12
	II	0.934	0.934	0.941	26.30	24.17	16
	III	0.934	0.934	0.941	27.29	25.67	10
	IV	0.934	0.934	0.939	24.93	24.24	2
Case 3 (solar-biomass)	base	0.931	0.931	0.938	21.72	21.64	0
	I	0.934	0.934	0.941	26.50	23.98	12
	II	0.934	0.934	0.941	25.88	22.35	16
	III	0.935	0.934	0.938	26.99	23.44	12
	IV	0.935	0.934	0.938	24.27	22.55	2
Case 4 (wind-solar-biomass)	base	0.930	0.931	0.938	27.13	28.48	0
	I	0.933	0.934	0.941	30.02	30.07	12
	II	0.928	0.929	0.938	29.22	27.90	10
	III	0.933	0.934	0.941	32.07	30.04	8
	IV	0.930	0.930	0.938	29.14	29.04	2

Based on the simulation results for the two balanced and unbalanced test systems and on the results listed in Tables 3-4 and 3-5 and Figures 3-8 and 3-9, it appears that network reconfiguration has the following advantages:

- It reduces the energy losses;
- It improves the voltage profile at most buses;

- It reduces the current drawn from the substations and at most branches, hence increasing line flow capacity margins.

Furthermore, as shown in Figures 3-8 and 3-9, this reduction in energy losses translates into reduced system operation costs. From another point of view, the resistive losses raise the temperature of feeder components. Therefore, if this temperature exceeded the thermal limits (i.e., during overloading conditions), it can be harmful to these elements, particularly to their insulation and increases the failure rate of components which speed up their ageing. As a result, the improvement in the reconfigured networks over the original ones in terms of system losses, voltage profile and line flow capacity margins will have a positive impact on relieving the feeders (i.e., reducing the system congestion) resulting in improving life span and hence system reliability.

3.5.2 **Effect of DG units on reconfiguration schemes**

The results presented in Tables 3-4 and 3-5 demonstrate the positive effect of DG units on energy loss reduction, the improvement they create in the voltage profile, and the effectiveness of DG units in reducing the current drawn from main substations even without reconfiguration. However, reconfiguration with DG units makes this improvement more significant. Based on the simulation results for both the 119-bus balanced and the 25-bus unbalanced systems, the configurations obtained for energy loss reduction in case 1 and in cases 2, 3 and 4 (i.e., without and with DG units) differ, as do the configurations obtained for loss reduction in cases 2, 3 and 4 (i.e., with different combinations of DG types). Therefore, it can be concluded that the topological structure of the optimum networks without DG units differs from that of the networks with DG units. Also, this optimum network configuration for minimum energy losses may vary with the changes in DG type, location, and size. Furthermore, the configurations obtained for loss reduction differ from season to season due to changes in both the hourly load profile and the power output from the renewable DG units. As an example, as shown in Tables 3-4, case 2 (wind & biomass DG units) produces higher losses than case 3 (solar & biomass DG units). This is because the output power of solar-based DG units is correlated with the peak demand during daytime hours compared to wind-based DG units, which have higher output at night (i.e., due to high wind speeds during the night). This difference in output power between different DG technologies (i.e., wind, solar, and biomass DG units) explains the differences in the configurations obtained. However the number of switching operations for cases 2 and 3 is the same in some scenarios, the open switches are different.

3.5.3 **Effect of variable load and output power from DGs on reconfiguration schemes**

As shown in Tables 3-4 and 3-5, all the proposed four scenarios provide lower losses, higher voltage profile, and lower current drawn from the substation when they are compared with the base configuration. However, because scenarios I and II look for a configuration that will minimize losses for peak loads and maximum or minimum allowable output power from DG units and do not consider the time-varying nature of both load and renewable-based generators; they gave higher losses in most cases compared to scenarios III and IV. Because, scenario III which considers the time-varying nature of both load and renewable-based generators has not switching limits, it gave the lowest losses in all case studies. But, it may require a switching cost higher than the reduced cost from energy loss reduction. For example, as shown in Figure 3-9, the configurations obtained based on scenario III in cases 2 and 3 for the 25-bus unbalanced system have higher operational cost compared to the base configuration (i.e., in case 2, the operational cost of base configuration is $25580.63, and for the configuration of scenario III is $26015.94). From the operational cost point of view, scenario IV which considers both the time-varying nature of load and renewable-based generators and the switching cost gave the lowest operational cost in all case studies.

3.5.4 **Monthly versus seasonal reconfiguration**

For the sake of verification and comparison, the summer season is divided into three months, and the optimal configuration is determined for each month. Three sets of probability density functions are used such that 24 PDFs (i.e., one PDF for each hour of the day hours) are calculated for each month. These PDFs are repeated for all of the month days in order to represent the variable behavior of renewable DG units during that month.

The results listed in Table 3-6 represent the active and reactive power losses, the number of switching operations and the operational cost for the two scenarios: seasonal and monthly for the 119-bus balanced system (case 2: wind and biomass DG). Based on these results, the seasonal and monthly reconfigurations required 8 and 14 switching operations, respectively. The reductions in losses are almost identical. However, the monthly reconfiguration required a higher number of switching operations, leading to the conclusion that a seasonal reconfiguration is a good alternative to a monthly one.

Table 3- 6: Losses, number of switching and operational cost for the monthly and seasonal configurations during the summer season for 119-bus balanced system

Case 2 (wind-biomass)		Seasonal loss		N. of switching	Cost (k$)
		MWh	Mvarh		
seasonal		**786.7**	**581.8**	**8**	**53.25**
monthly	1st month	255.9	189.6	8	18.42
	2nd month	297.1	220.6	2	19.90
	3rd month	232.6	171.3	4	16.08
	Total:	**785.6**	**581.5**	**14**	**54.40**

3.5.5 **Effect of the cost per switching operation on reconfiguration schemes**

In order to show the effect of the cost per switching operation (SWc) on the reconfiguration results, the reconfiguration scheme for scenario IV in case 1 for the 25-bus unbalanced system was determined at different values of this cost. Figure 3-10 shows the effect of switching cost on both the annual energy losses and the number of switching operations.

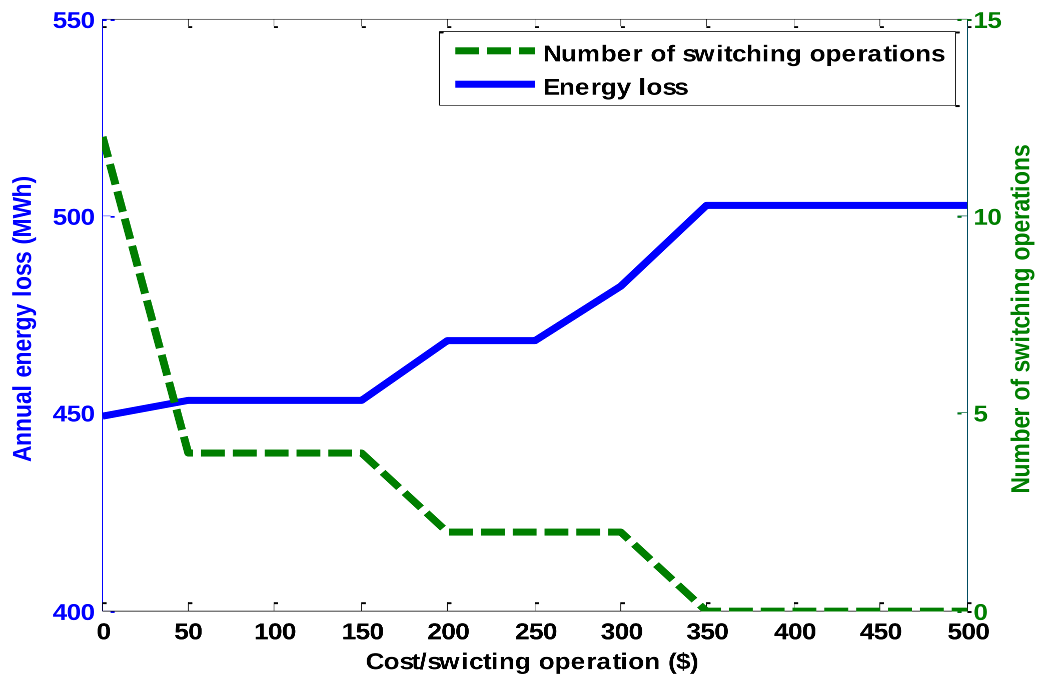


Figure 3-10: Effect of switching cost on the annual energy losses and the number of switching operations for the 25-bus unbalanced system (case 1)

Furthermore, Figure 3-11 shows the effect of this switching cost on the annual operational cost for all scenarios. Figure 3-10 shows that as the cost per switching operation increases, the number of switching actions required by scenario IV decreases, and the annual energy losses increases. Therefore, as shown in Figure 3-11, switching actions are implemented in scenario IV only when their costs are balanced/lower than the reduced cost from system loss reduction. As a result, the total operational cost of scenario IV is always lower or at least equal (i.e., when the cost of the required switching actions is higher than the reduced cost due to loss reduction, hence, switching will not be allowed) to the cost of the base case (i.e., without reconfiguration). However, scenario III always gives the lowest losses compared to other scenarios because it does not take the switching cost into consideration.

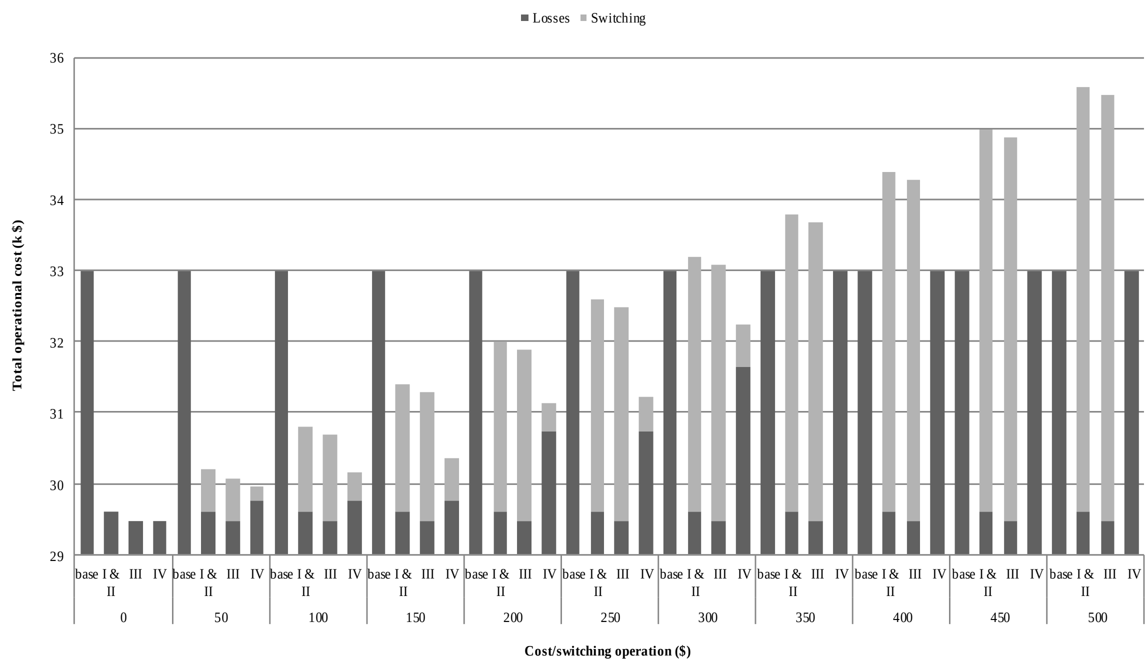


Figure 3-11: Effect of switching cost on annual operational cost for 25-bus unbalanced system (case1)

3.6 Conclusion

In this chapter, a network reconfiguration methodology, considering the stochastic nature of renewable based DG units and load variation is proposed. This method aims to determine the optimal seasonal reconfiguration schemes to minimize the annual energy losses. The load is modeled by the IEEE-RTS system, while the renewable DG resources are modeled by using a set of historical wind speed and solar irradiance data. These data are used to model the solar irradiance and wind speed by Beta and Weibull probability distribution functions, respectively. The formulation of the problem provides satisfied solutions and avoids any violation of the system limits, such as buses' voltage and feeders' current. Based on the simulation results, the following conclusions can be drawn:

- Scenarios I and II give sup-optimal solutions compared to the other scenarios, because they look for a configuration that minimizes losses for peak loads and maximum or minimum allowable output power from DG units and do not consider the time-varying nature of both load and renewable-based generators.
- Scenario III gives the lowest losses compared to the other scenarios because it does not take the switching cost into consideration.
- Scenario IV gives the lowest operational cost compared to the other scenarios because it takes the switching cost into consideration.
- The topological structure of the optimum network configuration for minimum energy loss may vary with changes in DG type, location, and size; also, it differs from season to season due to changes in both the hourly load profile and the power output from the renewable DG units.
- The seasonal configuration is more effective than monthly because the former realizes lower losses with a lower number of required switching operations, thereby aligning more closely with operational practices.
- Due to the unbalanced loading throughout different phases for unbalanced system, the effect of reconfiguration in reducing annual energy losses is higher for the balanced system than for the unbalanced one.
- A by-product of the proposed method is a power flow solution for all possible operating conditions, which can provide a useful database for system operators.

Chapter 4
Long-Term Multi-objective Distribution System Planning by Joint Network Reconfiguration and DG Allocation

4.1 Introduction

DG units are being increasingly connected at low and medium voltage level distribution systems. Renewable based DG units (i.e. wind power, solar photovoltaic, biogas, and fuel cells) become a dominant choice in power systems. This is because these renewable energy sources have inexhaustible nature. In addition, they have positive effect in reducing the greenhouse gas emissions because of their nonpolluting nature.

From the detailed discussion in section 2.6.3, it is obvious that sufficient work has been done with respect to DG allocation and network reconfiguration problems independently. Few publications have addressed the two problems simultaneously. No attempts have been made thus far to include the greenhouse gas emissions, multi-year load growth, and the uncertainty associated with renewable DG units and load variations on the joint network reconfiguration and DG allocation problem. However, planning of DG integration together with network reconfiguration is a requirement for the modern active distribution networks (ADNs) in order to maximize the benefits as much as possible.

Therefore, this chapter proposes a planning algorithm using non-dominated sorting genetic algorithms (NDSGA) for distribution systems by joint network reconfiguration and DG allocation. The main contribution of this work is twofold:

- The work proposes a multi-year multi-objective joint reconfiguration and DG allocation. The considered objectives are: economic (costs of line upgrades, energy losses, switching operations, and DG capital, operation and maintenance costs) and environmental (emissions from both grid and DG units).
- Unlike, previous work on joint reconfiguration and DG allocation that considered the load is fixed or used one year only, the effect of stochastic nature of renewable DG output power, load variability, and load growth across the planning horizon have been considered in evaluating the different planning objectives.

The algorithm takes the following into consideration:

- Uncertainty of the renewable DG units' output power.
- Load variation and customer sector type (industrial, commercial, and residential).

- Different types of DG units (natural gas turbine, wind, photovoltaic) which are the most commonly used DG units in distribution systems.

The chapter starts by the problem description. Then, the models used for the system components are presented, followed by the problem formulation. Finally, the detail test results and the conclusions are presented.

4.2 Problem description

Local distribution companies (LDCs) seek optimal configurations to minimize energy losses in their distribution networks. As discussed in chapter 3, DG units affect the reconfiguration schemes in distribution networks. On the other hand, the reconfigured network has lower losses, better voltage profile, and lower currents in most branches compared to the base network topology. Hence, the reconfigured network can accept higher DG penetration level. This means that the DG allocation and network reconfiguration problems have an inherent coupling relationship. Therefore, considering the two problems simultaneously is more effective than considering them separately. Figure 4-1 summarizes the proposed planning method. It starts by modeling the load and the DG generation with the consideration of the probabilistic nature of renewable DG units. Then, the planning problem is formulated, with objective functions of minimizing the overall cost and the greenhouse gas emissions. Furthermore, the problem will be subjected to several system constraints in order to make sure that the normal operating practices of the distribution system are not violated.

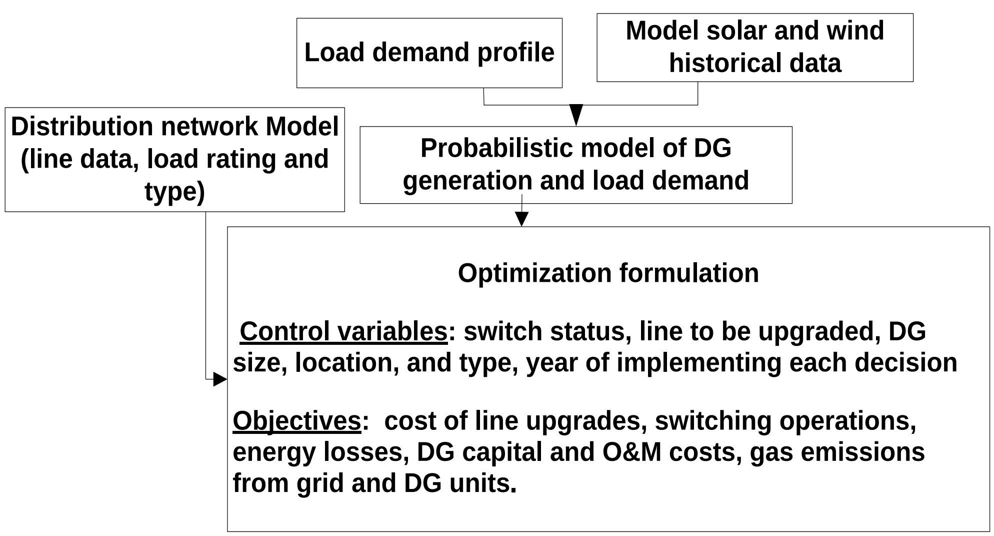


Figure 4- 1: A brief description for the proposed planning problem

4.3 Modeling of loads and DG units

In this work, both dispatchable and non-dispatchable DG units are considered. The non-dispatchable types of DG units considered are photovoltaic (PV) modules and wind turbines (WT). The dispatchable type of DG units considered is natural gas turbines (GT). These three types are the most commonly used DG units in distribution systems. However, other DG types can be modeled with similar approaches. The hourly average load, wind speed, and solar irradiance are considered. The variations within the hour are neglected which is a common practice in long term planning studies. Also, the wind-based and solar-based DG output powers and load are modeled as multi-state variables in order to integrate them in the planning formulations.

4.3.1 **DG units modeling**

4.3.1.1 Renewable generation modeling

As explained in details in section 3.2 in the previous chapter, the wind speed and solar irradiance for each hour of the day are modeled by Weibull and Beta probability density functions (PDFs) respectively, using historical data. The probabilistic models for both wind and PV-based DG units' output power are described as follows [74]:

- The entire year is divided into 12 months, and each month is being represented by one day.
- The day representing each month is further subdivided into 24 hours segments.
- The mean and standard deviation for each time segment are calculated utilizing the historical wind speed and solar irradiance data.
- The Weibull and Beta PDFs are generated for each hour using the mean and standard deviation for each segment.
- In order to integrate the output power of wind turbines and PV modules as multistate, the continuous PDF of each is divided into a proper number of states. Then the probability of each wind speed and irradiance state is calculated.
- The corresponding output power of the wind turbine and PV module in each state are calculated using the wind turbine and PV module characteristics.
- Therefore, these wind and solar generated states (PDFs) which calculated based on the historical data for the site under study remain the same after the year of DG installation.

4.3.1.2 Natural gas turbine modeling

The natural gas turbines generators are assumed to be firm generators without uncertainty (i.e., constant output power at its rated value), which is the typical model in this type of studies [74][77].

4.3.2 **Load modeling**

For this research, three types of system load customers are assumed, which are residential, commercial, and industrial. However, due to lack of customers' hourly load data, the residential customers' load curve is represented by the IEEE reliability test system load model [78] , while the commercial and industrial customers' load curves are given in [89]. These historical data of load demand are utilized to calculate the probability of each load state during each hour. For example, in the first hour of a day, the probability of each load state is calculated based on the values of this load levels in this specific hour during the 30 days of this month. In this work a definite number of states are chosen to represent each type of load, and the states values are calculated based on the central centroid sorting process developed in [90]. Further, these load states are updated every year based on the load growth rate.

4.3.3 **Combined generation-load model**

The generation-load model describes all the expected generation and load system combinations/states and their probabilities of occurrence. The year is divided into 12 months; further each month is modeled by 24 hours. Therefore, each load state or generation state has a probability of occurrence in each of the 288 hours (i.e., 12 month per year x 24 hour per month).

The system states are defined by including all combinations of load and generation states in each hour. For example, assume that each load type is represented by 4 states; wind-based DG with 7 states; PV-based DG with 6 states and gas turbine with 1 state. Therefore, the system is represented by 4x4x4x7x6x1=2688 states during each hour of the 288 hours which representing the year, as in (4.1). For each hour the 2688 states (load-generation levels) are the same, but the probabilities vary from hour to hour. The probability of each state is calculated by the convolution of all the probabilities associated with this state assuming independency in this particular hour as in (4.2). Further, to reduce the computational effort, the system can be modeled by the 2688 states/year only for each year instead of (2688 states/hour x 288 hour/year).

This can be performed by calculating the probability of each state ($PB_{(s)}$) as the average of the probability of this state in each hour (i.e., the sum of its probabilities of occurrence during the 288 hours of the year divided by the total number of year hours) as in (4.3).

$$s_{SYS(s)} = [s_{R(s)}\,,\ s_{C(s)}\,,\ s_{I(s)}\,,\ s_{GT(s)}\,,\ s_{WT(s)}\,,\ s_{PV(s)}]_{s\times 6} \quad \forall s \tag{4.1}$$

$$\begin{aligned} pb_{(h,s)} &= prob_{(h)}(s_{R(s)} \mid s_{C(s)} \mid s_{I(s)} \mid s_{GT(s)} \mid s_{W(s)} \mid s_{PV(s)}) \\ &= prob_{(h)}(s_{R(s)}) \times prob_{(h)}(s_{C(s)}) \times prob_{(h)}(s_{I(s)}) \\ &\times prob_{(h)}(s_{GT(s)}) \times prob_{(h)}(s_{WT(s)}) \times prob_{(h)}(s_{PV(s)}) \quad \forall h, s \end{aligned} \tag{4.2}$$

$$PB_{(s)} = \left(\frac{1}{288}\right) \times \sum_{h=1}^{288} pb_{(h,s)} \tag{4.3}$$

where $PB_{(s)}$ is the probability of each state in a year; $pb_{(h,s)}$ is the probability of state s in hour h; s_{SYS} is the combined system state; s_R, s_C, and s_I are the fraction of the peak demand for residential, commercial, and industrial loads respectively. s_{GT}, s_{WT}, and s_{PV} are the fraction of the output power corresponding to a certain state for the natural gas turbine, wind turbine, and solar DG units respectively.

4.4 Problem formulation

This section explains the proposed multi-year multi-objective problem formulation for the planning problem. The following assumptions are considered:

- Most utilities force DG units to operate in constant power factor mode. In this work, DG units are assumed to operate at unity power factor [74]. In addition, a simulation for DG units that operate at 0.95 leading or lagging pf is presented.
- DG units’ capacities are discretized at a definite step, which is assumed to be 100 kW for natural gas turbines and wind turbines. Therefore, the penetration of the natural gas and wind-based DGs can be a multiple number of the selected definite step. However, due to the small ratings of PV modules, the solar-based DG units can be modeled to the required size.

The following subsections describe the multi-objective mixed-integer nonlinear programming problem.

4.4.1 **Objective functions**

Two objectives are considered in this work: 1) economic (costs of line upgrades, energy losses, switching operations, and DG capital, operation and maintenance costs), and 2) environmental (emissions from both grid and DG units) as shown in equation (4.4).

$$Minimize\,(OF_1, OF_2) \tag{4.4}$$

$$OF_1 = C_{upgrades} + C_{losses} + C_{RC} + C_{O\&M} + C_{Capital} - C_{EDG} \tag{4.5}$$

$$OF_2 = E_{grid} + E_{DG} \tag{4.6}$$

where, OF_1*(cost)* and OF_2*(emission)* are the objectives required to be minimized; $C_{upgrades}$, C_{RC} and C_{losses} are the net present value (NPV) of the upgrades, reconfiguration and losses costs respectively; $C_{O\&M}$ is the NPV of the operation and maintenance costs including the fuel cost of the DG units; $C_{Capital}$ is the NPV of the capital costs of the DG units installed in the system; C_{EDG} is the NPV of the produced energy cost from DG units; E_{grid} and E_{DG} are the emissions due to energy supplied from grid and DG units emissions in kg CO_2, respectively.

4.4.1.1 Cost of upgrades

Upgrades are required for load growth and voltage security. Also, it may be required for high penetration of DG units.

$$\left|I_{(l,s,y)}\right| \le I_{\max(l,y)} \qquad \forall\, l, s, y \tag{4.7}$$

$$I_{\max(l,y)} = \begin{cases} I_{CAP(l)} & \forall\, y < Y_{UP(l)} \\ M_{(l)}\, I_{CAP(l)} & \forall\, y \ge Y_{UP(l)} \end{cases} \qquad \forall\, l, y \tag{4.8}$$

$$C_{Upgrades} = \sum_{l} \frac{KM_{(l)}.C_{KM}}{(1+d)^{Y_{UP(l)}}} \qquad \forall\, l \tag{4.9}$$

where $I_{(l,s,y)}$ is the magnitude of the current for state *s* and year *y* flowing from certain bus *i** to bus *j**, which are defined according to the system under study, $I_{max(l,y)}$ is the maximum allowed current to flow in line *l* in year *y*; $Y_{UP(l)}$ is the year when upgrade of line *l* is essential; $M_{(l)}$ is the factor by which the line is upgraded (assumed to be 2 in this work); $I_{cap(l)}$ is the current capacity of line *l* in the first year; $KM_{(l)}$ is the length of line *l* in km; C_{KM} is the cost of line upgrade in \$/km, and *d* is the discount rate.

4.4.1.2 Cost of losses

$$P_{loss(s,y)} = \sum_{l} I^2{}_{(l,s,y)}\ R_{(l)}\, x_{(l,y)} \qquad \forall s, y \tag{4.10}$$

$$C_{losses} = \sum_{y} \frac{8760 \times \sum_{s} (P_{loss(s,y)} \times PB_{(s)} \times c_e)}{(1+d)^y} \qquad \forall y \tag{4.11}$$

where $R_{(l)}$ is the resistance of line l ; $P_{loss(s,y)}$ is the power loss corresponding to state s and year y, c_e is the cost of energy, $x_{(l,y)}$ is a binary variable representing the reconfiguration switching decision for line l of year y.

4.4.1.3 Cost of reconfiguration

$$C_{RC} = \sum_{y=1}^{Yr} \frac{c_{sw} \sum_{l} \left| x_{(l,y)} - x_{(l,y-1)} \right|}{(1+d)^y} \tag{4.12}$$

where c_{sw} is the cost per one switching operation; $x_{(l,y=0)}$ is defined as the base configuration of the system under study, and $x_{(l,y)}$ is the configuration of year y.

4.4.1.4 Cost of DG

$$C_{Capital} = \sum_{i=1}^{n} \left(\frac{GT_{cap} P_{GT(i,Y_{GT(i)})}}{(1+d)^{Y_{GT(i)}}} + \frac{WT_{cap} P_{WT(i,Y_{WT(i)})}}{(1+d)^{Y_{WT(i)}}} + \frac{PV_{cap} P_{PV(i,Y_{PV(i)})}}{(1+d)^{Y_{PV(i)}}} \right) \tag{4.13}$$

$$\begin{aligned} C_{O\&M} = \sum_{i=1}^{n} 8760 \Bigg(& \sum_{y=Y_{GT(i)}}^{Yr} \frac{GT_{OM} CF_{GT} P_{GT(i,y)}}{(1+d)^y} + \sum_{y=Y_{WT(i)}}^{Yr} \frac{WT_{OM} CF_{WT} P_{WT(i,y)}}{(1+d)^y} \\ & + \sum_{y=Y_{PV(i)}}^{Yr} \frac{PV_{OM} CF_{PV} P_{PV(i,y)}}{(1+d)^y} \Bigg) \end{aligned} \tag{4.14}$$

$$\begin{aligned} C_{EDG} = \sum_{i=1}^{n} 8760\, c_e \Bigg(& \sum_{y=Y_{GT(i)}}^{Yr} \frac{CF_{GT} P_{GT(i,y)}}{(1+d)^y} + \sum_{y=Y_{WT(i)}}^{Yr} \frac{CF_{WT} P_{WT(i,y)}}{(1+d)^y} \\ & + \sum_{y=Y_{PV(i)}}^{Yr} \frac{CF_{PV} P_{PV(i,y)}}{(1+d)^y} \Bigg) \end{aligned} \tag{4.15}$$

where GT_{cap}, WT_{cap}, PV_{cap} are capital costs of installing GT, WT, and PV DG units respectively; Yr is the planning horizon in years; GT_{OM}, WT_{OM}, PV_{OM} are operational and maintenance costs including fuel (if applicable) of installed GT, WT, and PV DG units respectively; Y_{GT}, Y_{WT},Y_{PV} are the years of installation for GT, WT, and PV DG units respectively; $P_{GT(i,y)}$, $P_{WT(i,y)}$ and $P_{PV(i,y)}$ are the kW capacity of the installed GT, WT, and PV DG units respectively on bus i in year y.

4.4.1.5 Emissions from grid and DG units

$$E_{grid} = \sum_{y=1}^{Yrs}\sum_{s=1}^{N_s} P_{G(i=1,s,y)} \times PB_{(s)} \times 8760 \times K_{GRID} \tag{4.16}$$

$$E_{DG} = \sum_{y=1}^{Yrs}\sum_{i=1}^{n}\sum_{s=1}^{N_s} P_{GT(i,y)}\ s_{GT(s)} \times PB_{(s)} \times 8760 \times K_{GT} \tag{4.17}$$

$$K_{GRID} = K_{CO2-GRID} + M_{CO2/NO2}\, K_{NO2-GRID} \tag{4.18}$$

$$K_{GT} = K_{CO2-GT} + M_{CO2/NO2}\, K_{NO2-GT} \tag{4.19}$$

where K_{GRID} is the carbon footprint for the energy purchased from the grid in equivalent kg CO_2/kW.hr; K_{GT} is the emission from natural gas turbine DG in equivalent kg CO_2/kW.hr; $M_{CO2/NO2}$ is the Carbon dioxide equivalency factor for NO_2; $K_{CO2-GRID}$ and K_{CO2-GT} are the CO_2 emissions due to energy purchased from grids and from GT units respectively in kg/kW.hr; $K_{NO2-GRID}$ and K_{NO2-GT} are the NO_2 emissions due to energy purchased from grids and from GT units respectively in kg/kW.hr.

4.4.2 **Constraints**

4.4.2.1 Power flow constraints

$$P_{G(i,s,y)} - P_{L(i,s,y)} = \sum_{i=1}^{n} V_{(i,s,y)} V_{(j,s,y)} Y_{(i,j,y)} x_{(i,j,y)} \cos(\theta_{(i,j,y)} + \delta_{(j,s,y)} - \delta_{(i,s,y)})\ \forall i,s,y \tag{4.20}$$

$$Q_{G(i,s,y)} - Q_{L(i,s,y)} = -\sum_{i=1}^{n} V_{(i,s,y)} V_{(j,s,y)} Y_{(i,j,y)} x_{(i,j,y)} \sin(\theta_{(i,j,y)} + \delta_{(j,s,y)} - \delta_{(i,s,y)})\quad \forall i,s,y \tag{4.21}$$

$$P_{G(i,s,y)} = P_{GT(i,y)}\ s_{GT(s)} + P_{WT(i,y)}\ s_{WT(s)} + P_{PV(i,y)}\ s_{PV(s)} \quad \forall s,y,\ i>2 \tag{4.22}$$

$$\begin{aligned} Q_{G(i,s,y)} = {} & P_{GT(i,y)}\ s_{GT(s)} \tan(\cos^{-1} pf_{GT}) + P_{WT(i,y)}\ s_{WT(s)} \tan(\cos^{-1} pf_{WT}) \\ & + P_{PV(i,y)}\ s_{PV(s)} \tan(\cos^{-1} pf_{PV}) \quad \forall s,y,\ i>2 \end{aligned} \tag{4.23}$$

$$P_{L(i,s,y)} = \begin{cases} p_{(i,y)} \times s_{R(s)} & \forall s, y, i \in RSB \\ p_{(i,y)} \times s_{C(s)} & \forall s, y, i \in CMB \\ p_{(i,y)} \times s_{I(s)} & \forall s, y, i \in INB \end{cases} \tag{4.24}$$

$$Q_{L(i,s,y)} = \begin{cases} q_{(i,y)} \times s_{R(s)} & \forall s, y, i \in RSB \\ q_{(i,y)} \times s_{C(s)} & \forall s, y, i \in CMB \\ q_{(i,y)} \times s_{I(s)} & \forall s, y, i \in INB \end{cases} \tag{4.25}$$

where, i and j are bus numbers; n is total number of buses; y is the year; P_G and P_L are the generated and load active powers respectively; V and δ are the voltage magnitude and angle respectively; Y and θ are the admittance magnitude and angle respectively; $x_{(i,j)}$ is a binary variable representing the reconfiguration switching decision for the line between buses i and j; Q_G and Q_L are the generated and load reactive powers respectively; n is the total number of buses; $P_{GT(i,y)}$, $P_{WT(i,y)}$ and $P_{PV(i,y)}$ are the kW capacity of the connected GT, WT, and PV DG units respectively on bus i in year y; p and q are the peak active and reactive powers demands respectively; *RSB*, *CMB*, and *INB* are the sets of residential, commercial, and industrial load buses respectively.

4.4.2.2 Load rise constraints

$$p_{(i,y)} = p_{L(i)}\ (1+r)^{y-1},\ q_{(i,y)} = q_{L(i)}\ (1+r)^{y-1} \qquad \forall i, y \tag{4.26}$$

where p_L and q_L are the peak active and reactive powers demands in the first year respectively; r is the load growth rate.

4.4.2.3 Voltage limit constraints

$$V_{\min} \le V_{(i,s,y)} \le V_{\max} \qquad \forall i, s, y \tag{4.27}$$

V_{min} and V_{max} are the minimum voltage and maximum voltage limits on all system buses respectively.

4.4.2.4 Maximum reverse power flow constraints

There is no unique definition for DG penetration. Thus, there is no absolute penetration limit. Further, the most commonly definition used from distribution system point of view is to represent the DG penetration as a ratio between the DG capacity and the system peak load or the main substation rating. The constraint of maximum reverse power flow limits the DG penetration in the system for every year. The DG technical interconnection requirements in Ontario, Canada limit the maximum allowable DG penetration to a value that causes certain reverse power flow. According to [91], the maximum DG penetration is taken so as to limit the maximum reverse power flow at 60% of the main substation rating during minimum load condition (i.e., 30% of peak load).

$$\sum_{i=1}^{n} P_{GT(i,y)} + P_{WT(i,y)} + P_{PV(i,y)} \leq 0.6P_{main} + 0.3\sum_{i=1}^{n} p_{(i,y)} \qquad \forall y \tag{4.28}$$

where P_{main} is the main substation rating.

4.4.2.5 Years of DG placement constraints

$$P_{GT(i,y)} = \begin{cases} 0 & \forall y < Y_{GT(i)} \\ P_{0-GT(i)} & \forall y \geq Y_{GT(i)} \end{cases} \tag{4.29}$$

$$P_{WT(i,y)} = \begin{cases} 0 & \forall y < Y_{WT(i)} \\ P_{0-WT(i)} & \forall y \geq Y_{WT(i)} \end{cases} \tag{4.30}$$

$$P_{PV(i,y)} = \begin{cases} 0 & \forall y < Y_{PV(i)} \\ P_{0-PV(i)} & \forall y \geq Y_{PV(i)} \end{cases} \tag{4.31}$$

where $P_{0\text{-}GT(i)}$, $P_{0\text{-}WT(i)}$ and $P_{0\text{-}PV(i)}$ are the kW capacity of the installed GT, WT, and PV DG units respectively on bus i.

4.4.2.6 Discrete size of DG constraints

$$P_{GT(i)} = z_{GT(i)} \times a_{GT(i)} \times \Delta P_{GT} \;\; MW \qquad \forall i \tag{4.32}$$

$$P_{WT(i)} = z_{WT(i)} \times a_{WT(i)} \times \Delta P_{WT} \;\; MW \qquad \forall i \tag{4.33}$$

$$P_{PV(i)} = z_{PV(i)} \times a_{PV(i)} \times \Delta P_{PV} \;\; MW \qquad \forall i \tag{4.34}$$

where, z_{GT}, z_{WT}, and z_{PV} are integer variables indicating the capacity of the installed GT, WT, and PV DG units respectively; a_{GT}, a_{WT}, and a_{PV} are binary variables indicating the decision of installing GT, WT, and PV DG units respectively; ΔP_{GT}, ΔP_{WT}, and ΔP_{PV} are the discretized step of installed capacity for GT, WT, and PV DG units respectively.

4.4.2.7 Number of DG units limit

$$\sum_{i=1}^{n} a_{GT(i)} \leq n_{GT} \ , \quad \sum_{i=1}^{n} a_{WT(i)} \leq n_{WT} \ , \sum_{i=1}^{n} a_{PV(i)} \leq n_{PV} \tag{4.35}$$

where, n_{GT}, n_{WT}, and n_{PV} are the maximum allowable number of units from GT, WT, and PV DG units respectively. This constraint avoids outcomes with small DG units sizes spread all over the candidate buses in the system, which is not practical.

4.4.2.8 Candidate buses limit

$$z_{GT(i)} = 0 \ , \quad a_{GT(i)} = 0 \qquad \forall i \in GTB \tag{4.36}$$

$$z_{WT(i)} = 0 \ , \quad a_{WT(i)} = 0 \qquad \forall i \in WTB \tag{4.37}$$

$$z_{PV(i)} = 0 \ , \quad a_{PV(i)} = 0 \qquad \forall i \in PVB \tag{4.38}$$

where *GTB*, *WTB*, and *PVB* are the sets of buses that are not allowed to install GT, WT, and PV DG units respectively. Typically these sets of candidate buses to connect different types of DG units are determined based on a detailed planning analysis including technical, environmental and economic issues. The outcomes of these studies are assumed as an input and are beyond the scope of the presented study.

4.4.2.9 Maximum bus connection constraint

$$P_{GT(i)} + P_{WT(i)} + P_{PV(i)} \leq P_{bus(i)} \qquad \forall i \tag{4.39}$$

where $P_{bus(i)}$ is the maximum allowable connected capacity at bus i. This value depends on the system voltage level [91].

4.4.2.10 Reconfiguration constraint

The suggested configuration must have radial topology (i.e., without loops and all loads are connected to the main source). This constraint is explained in details in the previous chapter (section 3.3.2).

4.4.3 **Implementation of non-dominated sorting genetic algorithm-II (NSGA-II)**

In optimization problems, the designed choices are encoded as valuations of decision variables and the relative merits of each choice are expressed via a utility/cost function over the decision variables. However, in most real-life optimization situations, the cost function is multidimensional. For example, a computer that we want to purchase can be evaluated according to its price, size, features and performance. Therefore, any choice can be better than another choice according to one criterion, may be worse according to another criterion. Consequently, there is no unique optimal solution but rather a set of efficient solutions which known as Pareto solutions, characterized by the fact that their cost cannot be improved in one dimension without being worsened in another. The multi-objective aspect of the problem can be converted to a single objective with the use of weighting factors. However, the major difficulty in this approach is the incompatibility of different criteria. For example, the values assigned to the weighting factors depend on the importance of each objective and on the scaling of the objectives that result from the differing values/ranges of the objectives. The scaling factors vary from network to network so that the weighting factors change and must be tuned.

In this work, NSGA-II is utilized to solve the proposed problem. The strength of this technique is that the multi-objective nature of the problem is retained. Usually, the solution is not unique and consists of a set of acceptable optimal solutions (Pareto-front). The set of all Pareto solutions represents the problem trade-offs. Therefore, it is a very useful aid in decision making, which helps the local distribution company to make an informed decision by visualizing an extensive range of options as shown in Figure 4-2. However, local distribution companies that are interested for a single solution can use one of several techniques that are proposed in literature to determine a compromise solution which yields a single solution point. This compromise solution entails minimizing the distance between the potential solution and the utopia point (i.e., ideal point given by the intersection of the minima of the independent objective functions). The detailed philosophy and technique of NSGA-II is described in [92].

As shown in Figure 4-3, each individual or chromosome in the population consists of five parts:

- The first part carries the DG capacities integer variables z_{GT}, z_{WT}, and z_{PV}.
- The second part carries the decisions' binary variables a_{GT}, a_{WT}, and a_{PV}. The lengths of these two parts are equal and depend on types of DG units and number of candidate buses for each type.
- The third part carries the year of DG installation Y_{GT}, Y_{WT}, and Y_{PV}.
- The fourth part carries the network configuration x.
- The fifth part carries the year of upgrading lines Y_{UP}.

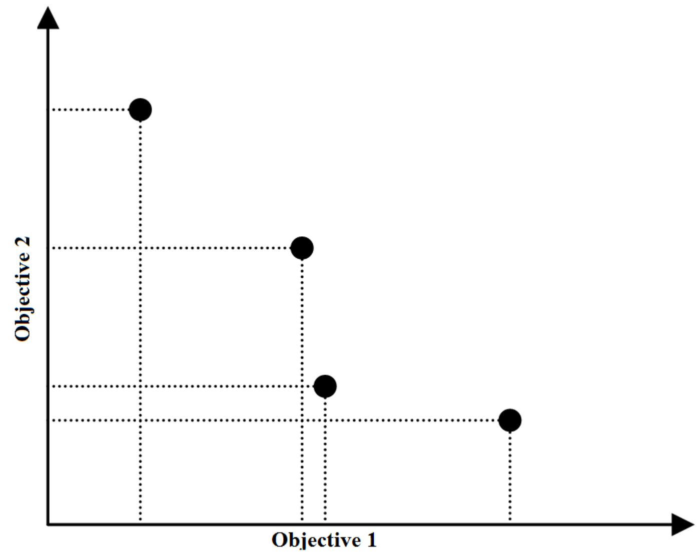


Figure 4- 2: A Pareto-front of a bi-objective problem

(1) Capacity of DG units	(2) Location of DG units	(3) Year of DG installation	(4) Network configuration	(5) Year of upgrading lines

Figure 4- 3: Typical chromosome structure with control variables

4.5 Simulation results

A distribution system which contains a mix of residential, commercial and industrial customers being supplied from a common supply point is used as shown in Figure 4-4 [93]. The system data and type of customers are available in [93]. The total system peak load is 4.37 MVA. For this study, all the system buses are assumed as candidate buses for natural gas turbine and photo-voltaic DG units. However, five buses only (34, 35, 36, 37, and 38) are assumed to be candidate for WT units to reflect the limitations of installing WT in highly populated areas. Moreover, without loss of generality the maximum number of DG units in the system is limited to 5 units for each type of DG, as described in equation (4.35). The system voltage level is 12.66 kV; therefore, the individual DG connection at each bus is limited to be 10 MW as described in (4.39) [91].

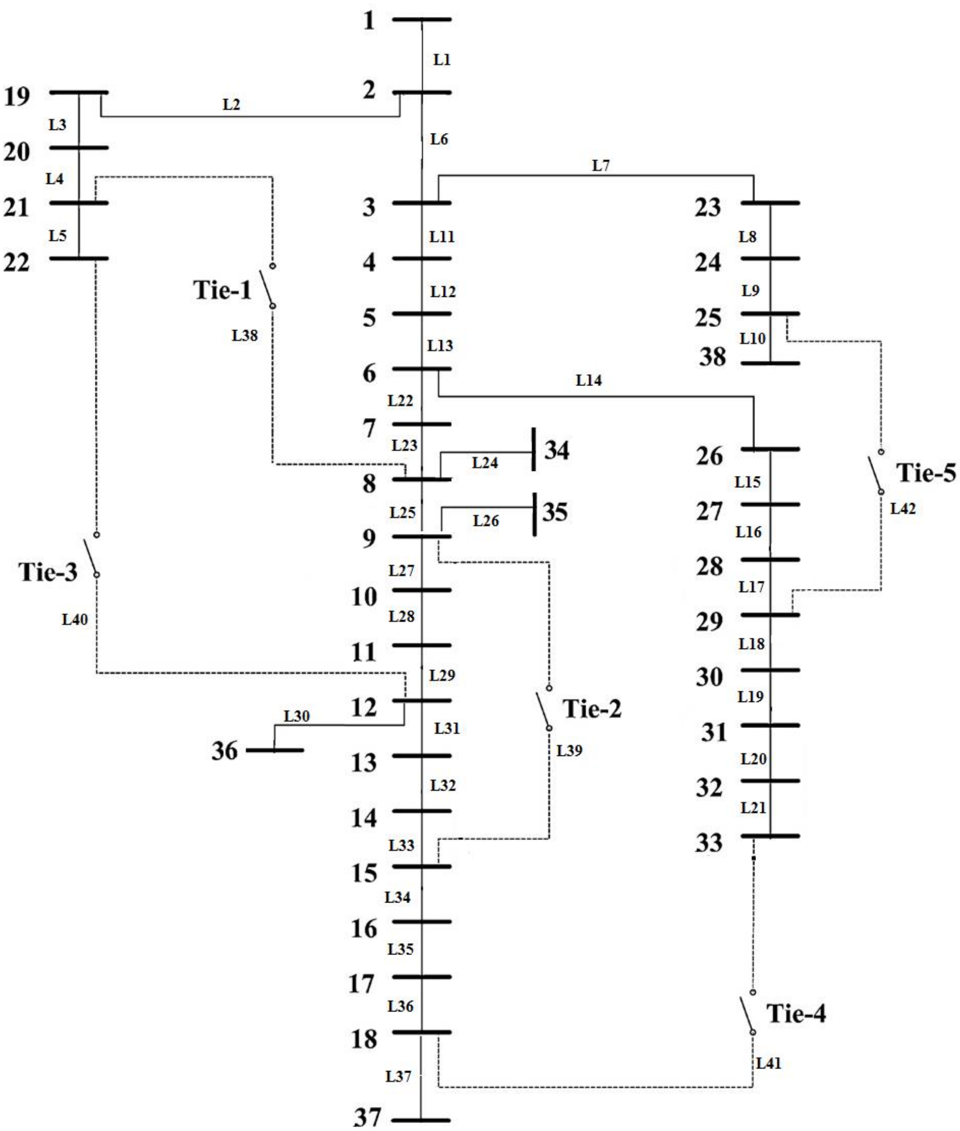


Figure 4- 4: System under study

Four different cases are presented in this work which are:

Case 1: base case (base configuration) without DG and without reconfiguration.

Case 2: network reconfiguration only (i.e., no DGs connected).

Case 3: only DG allocation based on the base network configuration.

Case 4: with DG allocation and reconfiguration achieved simultaneously.

Table 4-1 presents the parameters used for calculating various costs in the simulation study. The feeders upgrade cost is taken as 250,000$/km, which is the typical feeders' upgrade cost for the system under study in Ontario, Canada. These values can be easily adjusted according to the system under study and local distribution company.

Table 4- 1: Parameters for calculating costs and environmental attributes of DG units

Parameter	Value
Capital cost of natural gas turbine (GT_{cap})	750 \$/kW [94]
Capital cost of wind (WT_{cap})	1882 \$/kW [95]
Capital cost of solar (PV_{cap})	4004 \$/kW [95]
O&M cost of natural gas turbine (GT_{cap})	0.04 \$/kWh [94]
O&M cost of wind (WT_{cap})	0.01 \$/kWh [95]
O&M cost of solar (PV_{cap})	0.01 \$/kWh [95]
CO_2 emissions ($K_{CO2\text{-}GRID}$)	143 kg/MWh [96]
NO_2 emissions ($K_{NO2\text{-}GRID}$)	0.18 kg/MWh [96]
CO_2 emissions ($K_{CO2\text{-}GT}$)	307.67 kg/MWh [96]
NO_2 emissions ($K_{NO2\text{-}GT}$)	0.2365 kg/MWh [96]
$M_{CO2/NO2}$	298 [96]
Cost of energy (c_e)	6.56 cents/kWh [87]
Switching cost (c_{sw})	203 \$/switching [87]

4.6 Results discussion

The outcomes of the planning problem for a 20-year study period are shown in Figure 4-5. The load growth rate r in equation (4.26) of each year is assumed to be 1%.

4.6.1 Case 1: base case results

The base case means the base configuration without DG and without reconfiguration. In this case, the total cost of system upgrade and energy losses is \$$1.228\times10^6$. The system upgrade share is 74.67%, while the energy losses share is 25.33%. These costs are system dependent. The values show that upgrade cost has the highest share in the total cost (i.e., 74.67% of the total cost). For greenhouse gas emissions, the total amount of greenhouse gas emissions is 78.977×10^6 kg CO_2.

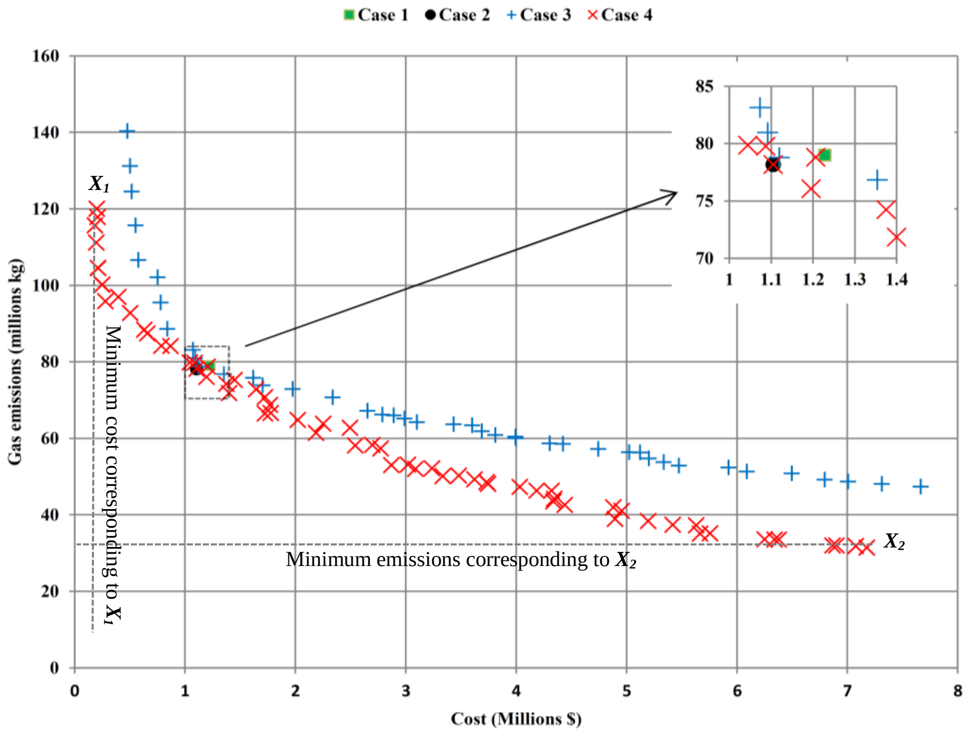


Figure 4- 5: A Pareto-front for a bi-objective planning problem

4.6.2 Case 2: with reconfiguration only

For this case only reconfiguration is considered and no DG units installed. The total cost of system upgrade, switching operations and energy losses is \$ 1.105×10^6. The contributions of each part in the total cost are: the system upgrade share is 81.08%, while the energy losses share is 18.73% and the switching for reconfiguration share is 0.18%. Therefore, by comparing these costs with the base configuration case, the upgrade cost is decreased by 2.32%, the cost of losses decreased by 33.47%, and the total cost decreased by 10.05%. Furthermore the total amount of greenhouse gas emissions is 78.158×10^6 kg with a percentage reduction of 1.04% compared with base case.

The results show that the reconfiguration has a significant effect in reducing the energy losses compared to the cost of upgrades. This is because the reconfiguration effectively reduces the current drawn from the substations and at most branches; hence increasing line flow capacity margins. Therefore, the reduction in system upgrade costs is due to the deferral of most of the lines upgrades to further years. For example, lines L1 should be upgraded in year 11 in case 1; however, it is deferred to year 13 in case 2. Also, lines L6, L11, L12, and L13 require upgrade in years 12, 10, 15, and 18, respectively in case 1; however, they don't need to be upgraded during the planning horizon in case 2.

From another side, some lines require upgrade in earlier years, such as L7, which requires upgrading in year 7 in case 1 and in the 1st year in case 2. Finally, the total system resultant upgrade cost is reduced by 2.32% in case 2 compared to case 1.

4.6.3 **Results of case 3 and case 4**

As shown in Figure 4-5, the Pareto front solutions of case 4 (joint reconfiguration and DG allocation) are better than case 3 (DG allocation only using the base configuration) with respect to the two objectives (i.e., total cost and the greenhouse gas emissions). This difference in the obtained results between the two cases can be explained due to two main reasons:

- As mentioned in the previous case (case 2 with reconfiguration only), reconfiguration has a positive effect on reducing the energy losses and deferring the upgrade requirements of some lines.
- The thermal and voltage constraints are among the barriers that may limit DG penetration in distribution systems. However, as explained in details in chapter 3, reconfiguration represents a good option to enhance the voltage and current profiles in the system components. Therefore, it can increase the allowable DG penetration without violating those constraints. For example, in this case study the penetration due to all DG types in the system under study based on the Pareto solutions in Figure 4-5 is ranged from 0.1 MW to 3.5 MW in case 3; however, it is ranged from 0.6 MW to 3.7 MW in case 4. These results are totally system dependent and significant differences can occur for other systems.

As shown in Figure 4-5 (the zoomed box), there are very few solutions better than case 1 regarding the two considered objectives. This is totally system dependant, as the system under study couldn't accommodate both dispatchable and renewable DG units to simultaneously reduce both costs and emissions. Moreover, the few better solutions than case 1 are mostly due to reconfiguration and the DG penetration is very low for these outcomes.

As shown in Figure 4-5, there are two boundary solutions X_1 and X_2 represent minimum system costs and minimum system emissions, respectively. The details of cost, emissions and installed DG units of these two solutions are shown in Table 4-2.

As shown in Table 4-2, in solution X_1 (i.e., the minimum cost solution), the system costs are reduced by 83.46% which is very significant. However, the system emissions are higher by 52.79%. This increase in system emissions is due to emissions from GT units (in this solution all the installed DG units are GTs). For the other side, solution X_2 (i.e., the minimum emissions solution) shows 60.74%

reduction in emissions. However, the system costs are almost five times higher than the base case. This huge increase in the system overall cost is due to high cost of renewable DG units installed in the system (in this solution all the installed DG units are renewable based ones).

The results in Table 4-2 reveal that the natural gas turbines are more effective than the renewable based DG units in reducing the cost objective. This difference between natural gas turbines and the renewable ones on the cost objective can be explained due to two main reasons:

- The dispatchable nature of natural gas turbines which provide higher output energy than the renewable one.
- The natural gas turbines are cheaper.

From another side, renewable based DG units are more effective than natural gas turbines in reducing the greenhouse gas emissions objective. This difference between natural gas turbines and the renewable ones on the greenhouse gas emissions objective can be explained due to two main reasons:

- The clean and environmental friendly nature of the renewable DGs.
- The contribution of renewable based DG units in feeding loads will reduce the amount of required energy drawn from the main grid. Hence, the emissions from the grid will be reduced proportionally with its reduced generation.

Furthermore, it is worthy to mention that all DG units in the two solutions are installed in the first year. Also, the two solutions have implemented the same network reconfiguration in the first year only (i.e., the opened lines for this new configuration are: L17, L21, L23, L27 and L33).

Table 4- 2: Details of the two boundary solutions X_1 and X_2

		Solution X_1	Solution X_2
Total cost ($)		0.20316×10^6	7.1764×10^6
Saving in system costs		83.46%	-484.40%
Total emissions (kg)		1.2067×10^8	0.3101×10^8
Saving in system emissions		-52.79%	60.74%
Size of DG in MW (Bus number)	GT	0.1 (17), 0.5 (19), 0.1 (23), 0.4 (32), 0.1 (37)	None
	WT	None	1.7 (36), 0.6 (37), 0.9 (38)
	PV	None	0.004 (3), 0.25 (10), 0.001 (23), 0.09 (36), 0.063 (37)

The results show both WT and PV units installed in the system. However, the outcomes show dominating WT penetration. This is because, WT has higher capacity factor, and are cheaper. On the other hand, PV units are not totally avoided in the planning problem outcomes because they are more flexible as they can be installed in any size and on any bus in the system. For example, solution X_2 which represents minimum system emissions, installs three WT units with total capacity of 3.2 MW and five PV units with total capacity of 0.408 MW.

Furthermore, the simulation results of DG units that operate at fixed power factor mode (0.95 lagging or 0.95 leading) are included. The details of the two boundary solutions X_1 and X_2 are given in Table 4-3. These results show that in the minimum cost solution X_1, DG units with leading pf provide lower cost than the case of unity pf. However, the DG units with lagging pf provide higher cost than the case of unity pf. From these results it is obvious that the reactive power of DG units has effect in the energy losses, line current values and the cost of upgrades.

Table 4- 3: Details of the two boundary solutions X_1 and X_2 at different power factors

		Solution X_1	Solution X_2
DGs operate at unity pf	Total cost ($)	0.20316x 106	7.1764x 106
	Saving in system costs	83.46%	-484.40%
	Total emissions (kg)	1.2067x108	0.3101x108
	Saving in system emissions	-52.79%	60.74%
DGs operate at 0.95 lagging pf	Total cost ($)	0.2333x 106	7.9378x 106
	Saving in system costs	81%	-546.4%
	Total emissions (kg)	1.1599x 108	0.28199 x 108
	Saving in system emissions	-46.87%	64.29%
DGs operate at 0.95 leading pf	Total cost ($)	0.11316 x 106	7.6912x 106
	Saving in system costs	90.78%	-526.32%
	Total emissions (kg)	1.19798x 108	0.2737x 108
	Saving in system emissions	-51.69%	65.34%

4.6.4 **Results of case 3 and case 4 (Scenario of Ontario, Canada)**

In this part, the results of case 3 and case 4 are repeated without considering the costs related to DG units (i.e., only cost of losses, upgrading and switching are considered). This is the typical scenario in Ontario, Canada, because the utility does not pay the cost for installing DGs and their O&M costs. However these costs are covered by DG owner/investor. Therefore, the main goal from the utility point of view is to find the optimal DG locations and sizes in order to maximize their benefits (i.e., minimum losses and upgrading cost, and minimum emissions). The outcomes of the planning problem for this scenario are shown in Figure 4-6. The details of cost, emissions and installed DG units of these two boundary solutions X_1 and X_2 are shown in Table 4-4.

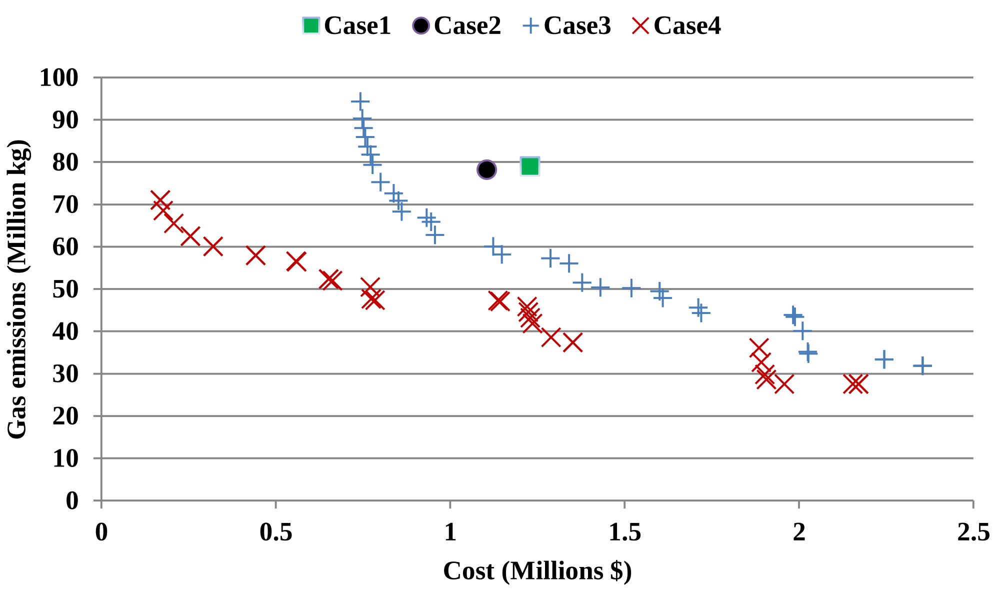


Figure 4- 6: A Pareto-front for a bi-objective planning problem (scenario of Ontario, Canada)

In minimum cost solution X_1, the system costs are reduced by 86.22% which is very significant; on the other hand, the system emissions are reduced by 10.14%, as shown in Table 4-4. The minimum emissions solution X_2 shows 65.21% reduction in emissions, while the system costs are almost twice of the base case. This is due to the required cost for upgrading lines to install the renewable based DGs in the system. Furthermore, most DG units in the two solutions are installed in the first year with view ones installed in the second year. Also, the first solution X_1 have implemented a network reconfiguration in the first year only (i.e., the opened lines for this new configuration are: L21, L23, L27, L33 and L42) and the same for the second solution X_2 (i.e., the opened lines for this new configuration are: L17, L21, L23, L27 and L33).

Finally, as a general comment based on all these previous results, the two objectives are contradicting. Therefore, it is challenging to get an optimal solution which minimizes both of them. This is because installing natural gas turbines to minimize the cost will increase the emissions. Also, installing renewable DG units minimizes the emissions but it increases the cost to high values due to their high capital cost. Therefore, this study used the Pareto-front by applying NSGA to keep the multi-objective nature of the problem. The advantage of this algorithm is that it gives several options for the local distribution company to choose among them based on its policy and priority of each objective.

Table 4- 4: Details of the two boundary solutions X_1 and X_2(scenario of Ontario, Canada)

		Solution X_1	Solution X_2
Total cost ($)		0. 16920x 10^6	2.17155x 10^6
Saving in system costs		86.22%	-76.84%
Total emissions (kg)		0.70966x10^8	0. 27476x10^8
Saving in system emissions		10.14%	65.21%
Size of DG in MW (Bus number)	GT	0.2 (15), 0.1 (25), 0.1 (28), 0.2 (32), 0.1 (37)	0.1 (10), 0.1 (12), 0.1 (14)
	WT	0.3 (36), 0.1 (38)	1.7 (36), 0.1 (37), 0.9 (38)
	PV	0.62 (2), 0.99 (8), 0.46 (23), 0.51 (32)	0.033(3), 0.45 (10), 0.022 (23), 0.1 (36), 0.06 (37)

4.7 Conclusion

In this chapter, a multi-objective multi-year optimization method based on NSGA for optimal planning using DG allocation and network reconfiguration is proposed. The two main objectives of the optimization problem are:

- To minimize the NPV of lines upgrade costs, cost of energy losses, cost of switching for reconfiguration, and cost of DG units (capital, O&M costs);

- To minimize the total greenhouse gas emissions from the main grid and DG units as an environmental issue.

The problem is formulated and then solved by applying NSGA in order to obtain several optimal solutions (Pareto-front). This is to avoid using weighting factors, which are usually questionable and may result in misleading solutions. Furthermore, using NSGA allows obtaining a set of satisfactory feasible solutions of the planning problem for the local distribution company, identifying the best solutions for lower cost or lower greenhouse gas emissions to choose based on its priorities.

The proposed method is based on generating probabilistic combined generation-load model in order to include all possible operating conditions of the system. The uncertainty of the renewable based DG units' output power is taken into consideration, as well as, load types and load variability. The system's technical constraints, lines upgrade, annual load growth rate are all considered.

The results reveal the effectiveness of the proposed multi-year multi-objective planning algorithm in significantly reducing the mentioned costs and the greenhouse gas emissions, taking into consideration all aspects as possible that affect the considered planning problem. The effectiveness of the reconfiguration in reducing losses, line upgrading and increasing penetration level of DG units was proven by numerical results.

Finally, the results show that both WT and PV based DG units are used. Each type has its advantages and disadvantages. For example, WT DG units have limitations with respect to the candidate locations. This is because; it is not recommended to install WT DGs in populated areas. But, from another side WT has higher capacity factor and cheaper than PV ones. For PV DG units, they are completely flexible to be installed at any location with any required rate. But, from another side PV has lower capacity factor and more expensive than WT ones.

Chapter 5

Effect of Load Variation, Switch Type and Wind Generation on Service Restoration Plans for Distribution Systems

5.1 Introduction

Fault in distribution system may cause power supply interruption to some customers. Distribution systems encounter high frequency of faults due to several reasons such as weather, component wear and accidents. Therefore, restoration plans are implemented to reduce the outage time caused by faults in order to provide better service to customers. Customer requirements for a qualified service are constantly growing. As an example, sensitive load customers (i.e., hospitals, traffic signal plants, communication centers, schools, industrial plants, etc.) are very sensitive to power supply interruptions. Furthermore, faults have impacts on the utility profit such as the loss in customer sales and the increased maintenance expenses.

As mentioned in section 2.2.2, a great deal of research related to the service restoration problem has already been conducted, and the advantages and disadvantages of the methods proposed have been established. The main goal of this chapter is to study and analyze the impact of numerous practical aspects related to service restoration, such as variations in the load and the priorities of the customers, price discounts for in-service customers based on their participation in a load-curtailment scheme that permits other customers to be supplied, the presence of manual and automated switches, and the incorporation of distributed generation (dispatchable and wind-based DG units) in the restoration process. The remainder of this chapter starts by discussing some practical issues related to the service restoration problem. Then, the formulation of the restoration problem is presented. Finally, the detail test results and the conclusions are presented.

5.2 Practical issues related to the service restoration problem

This section highlights important aspects of the operational practices related to the restoration problem.

5.2.1 **Load variation**

The literature shows that there are two common scenarios in considering load for building restoration plans:

- *Peak load scenario* which builds the restoration plan based on the daily peak loads; although, these daily peaks do not occur at the same time for different customer types [97]. Therefore, this scenario can provide a restoration plan with superior performance regarding the operational constraints (e.g., higher voltage profile, lower branch currents, and lower losses). On the other hand, it requires a higher number of switching operations in order to redistribute the loads among the feeders without violating operational constraints. Furthermore, the peak load scenario may entail unnecessary load shedding due to the limited capacity available from the supporting feeders.
- *Pre-fault load scenario* which builds the restoration plan based on the load level at the time just prior to the occurrence of the fault. Therefore, it may cause overloading in some supporting feeders [16]. In consequence, this overloading may trigger further undesirable consequences, such as the tripping of overloaded/under-voltage components of the network, the spreading of the outage, and/or the loss of sensitive loads. Furthermore, the restoration plan in this case will require provisions for responding through load management with the use of load transfers to other supporting feeders and/or load shedding. This further switching causes temporary interruptions in the transferred loads.

Moreover, loading level of distribution systems varies with the time of the day according to the behavior of customer needs. Therefore, to prevent further switching operations, consideration of load variation is a key factor of switching decisions for the restoration problem. In the present restorative operations, shedding in-service customers in order to restore others is not permitted. However, different types of customers have different reliability requirements. For example, a 1 h outage costs 0.482 \$/kW for residential, 8.552 \$/kW for commercial and 9.085 \$/kW for industrial loads [98]. Thus, it is more economical for the utility to pay an incentive amount of money to an in-service residential customer in order to restore another out-of-service commercial and/or industrial customer.

For comparison purposes, this work included the effect of load variation based on four scenarios:

<u>*First scenario*</u>, does not consider the load variation during the outage period and builds its restoration plan based on the pre-fault load (i.e., the load value for each customer type at the moment of fault occurrence).

<u>*Second scenario*</u>, does not consider the load variation during the outage period and builds its restoration plan based on the peak load (i.e., the daily peak load value for each customer type).

<u>*Third scenario (proposed)*</u>, with variable load. Each solution will be checked for the whole specified time frame for the restoration period-by-period. If violation occurred during any period among these

periods, this solution will be excluded. Furthermore, two schemes will be applied (scheme A: building one overall restoration plan for the whole outage period, and scheme B: building multiple restoration plans, one for each time unit (i.e., 1 h) during the outage period).

Fourth scenario (proposed), with load control and management: the in-service customer can sign up to allow the utility to shut off their major loads during an emergency period. As an incentive, the participating customers who are subjected to load shedding during the restoration period will receive a price discount proportional to consumption for this period. This arrangement benefits both the utility and the customer. The customer receives this reduction in the bill as an incentive for voluntary participation. The utility enjoys the opportunity to provide a superior restoration plan (i.e., lower switching operations and/or increasing the number of re-energized customers).

5.2.2 Effect of presence of DG units

As discussed in section 2.6.2, there is an emergent trend of keeping DG connections during fault. The literature reveals that few studies have considered DG units as part of the restoration problem. However, the published work assumed that the output of DG units is dispatchable and controllable. No attempts have been made thus far to include the effect of non-dispatchable DGs on the restoration problem. Therefore, this work included the effect of the presence of DG units on service restoration plans, as follows:

- The output power of dispatchable DG units is assumed to be firm generation (i.e., constant at its rated value).
- Wind-based DG units are characterized as fluctuating power sources due to the changes in wind speed. Three models are proposed as representations of the probable output power of wind-based DG units for use in the restoration process:
    - *Mode 1 (perfect mode)* is used as base case for comparison with the other two modes. It is based on the assumption that wind speed can be perfectly forecasted, thus, actual wind speed data are used for this mode.
    - *Mode 2 (forecasting-based mode)* uses the forecasted wind speed for the following 24 h based on the historical data for the site under study. Furthermore, if the fault does not occur during the first 12 h, the forecasted wind speed can be updated at 12 h intervals [99].
    - *Mode 3 (probabilistic-based mode)* uses an appropriate probability density function (PDF) to represent the behavior of the wind during each hour of the day, based on

the actual historical wind speed data for the site under study. As mentioned in details in chapter 3, a Weibull probability density function is used because it provides the best fit. For each time segment that refers to a specific hourly interval for the day, the PDF of the wind speed is divided into an appropriate number of states. The probability of each wind speed state is calculated [74]. Then, the output power of each wind speed state is calculated. For each time interval, the probability of each state can be multiplied by its output power and all of the resulting products can be totaled, thus enabling a determination of the expected value of the output power during that hour.

$$P_{out_h} = \sum_{s=1}^{n_s} prop_s * P_{out_s} \tag{5.1}$$

where $Pout_h$: expected output power at hour h; $prop_s$: probability of state s for hour h; n_s: total number of states for hour h; and $Pout_s$: output power at state s.

5.2.3 **Effect of switch type**

From several years ago, only manually controlled switches (MCSs) were commonly available in distribution systems. However, with the trend to increase the automation and reliability of distribution systems, utilities began to replace these MCSs with automatically controlled switches (ACSs). Due to the high cost of replacing all these MCSs by ACSs in one stage, most utilities implement this upgrading in a gradual way. Therefore, in some locations, MCSs have not been completely replaced by ACSs. The implementation of any restoration plan should therefore include consideration of both types. This is because the time required for MCS and ACS switching operations differs. For example, the duration for manual switching operations depends on the location of the switch and the associated travel time required for an operator/engineer to arrive and operate the switch (i.e., the typical operating times for an ACS and an MCS are 50 s and 1200-1500 s, respectively) [19]. The authors in [100] arrived at the following conclusions:

- If all switches in the system are of the same type (i.e., all switches are manual as in the case of fully manual system or all switches are automated as the case of fully automated system), the switching operations for implementing the restoration plan are applied in a single stage.
- In the case of partially automated systems (i.e., the distribution network contains both automated and manual switches), the restoration plan is implemented in two stages:
    - Stage 1: quickly restores a limited number of customers using automated switches.

- Stage 2: restores the remainder of the customers based on a restoration plan that uses manual switches.

5.3 The restoration problem in distribution system

5.3.1 **Problem formulation**

The service restoration problem can be formulated as a multi-objective multi-constraint optimization problem. Service restoration algorithm should provide the control operator with a single restoration proposal. Several possible solutions are unsuitable, because of excessive involvement of the operators in analyzing them. Therefore, the multi-objectives can be converted to a single objective using weighting factors. The values of these weighting factors depend on the importance of each objective and on the scaling of the objectives that result from the different values/ranges of the objectives. In this work, a dollar/cost based weighting factors are used in order to convert the problem from multi-objectives to a global objective one. Then, the solution for the restoration problem can be focused on achieving the minimum total cost. The proposed objectives and the constraints considered are as follows:

5.3.1.1 Objective functions

1) Customer interruption cost (CIC):

$$CIC = \sum_{t=1}^{T} \sum_{i=1}^{N_{bus}} CIC_i * L_{i,t} * (1 - y_i) \tag{5.2}$$

where N_{bus}: number of buses; $L_{i,t}$: load at the i^{th} bus during time interval t; y_i: status of the load at the i^{th} bus (i.e., equals 1 for restored and 0 for unrestored); CIC_i: cost of customer interruption ($/kW) at the i^{th} bus: and T: the outage period.

2) Switching operation cost (SOC):

This objective can be translated as a reduction in both the time and the operational cost required for the restoration process.

$$SOC = C_{sw} * \sum_{i=1}^{N_s} \left| x_i - x_{io} \right| \tag{5.3}$$

where N_s: the total number of switches; x_i: status of the i^{th} switch in the restored network (i.e., equals 1 for closed and 0 for opened); x_{io}: status of the i^{th} switch immediately after the fault has been isolated; and C_{sw}: cost per switching operation ($/switching operation). This switching cost is based on the required cost of operator/engineer to implement this switching action for MCSs, maintenance requirements, and the effect of each switching action on shortening lifetime of switches.

3) For the completeness of the problem formulation, the third objective is energy loss cost (ELC):

$$ELC = C_e \sum_{t=1}^{T} \sum_{i=1}^{N_{br}} I_{i,t}^2 R_i \tag{5.4}$$

where N_{br}: total number of branches; $I_{i,t}$: current in the i^{th} branch during time interval t; C_e: cost of energy losses in \$/kWh; and R_i: resistance of the i^{th} branch.

Since, restoration is expected to attain a system configuration that is temporary in nature and it addresses an emergency condition; the loss reduction calculated according to equation (5.4) is used in normal operating conditions and is not appropriate for service restoration.

$$Min \quad Cost = \text{cost of objectives} + 10^8 \times \sum_{\text{c}}^{\text{nc}} \text{x}_\text{c} \tag{5.5}$$

where x_c is a binary variable corresponding to constraint "c" (the second term represents a penalty factor for violating constraint "c") and "nc" is the total number of constraints.

5.3.1.2 Constraints

1) Bus voltages at all buses should be kept within limits:

The bus voltages and line currents must be kept within their respective operational limits. These voltage and current constraints make sure that voltages and currents throughout the distribution network will remain within the desired range in the new configuration. This ensures that this new configuration will not result in an undesired temporary or permanent voltage/current profile.

$$V_{\min} \le V_{i,t} \le V_{\max} \tag{5.6}$$

where $V_{i,t}$: voltage at the i^{th} bus during time interval t, and V_{max}, V_{min}: maximum and minimum acceptable bus voltages (in the case study for this research, 1.05 p.u. and 0.9 p.u., respectively).

2) All branch currents should be kept within limits:

$$I_{j,t} \le I_{\max} \tag{5.7}$$

where $I_{j,t}$: current in branch j during time interval t, and I_{max}: maximum line current.

3) Radial topology constraint:

This constraint is included for locating and isolating the fault and coordinating the protection device. As shown in Figure 5-1, a distribution network consists of switches and zones. A zone represents a segment of a distribution feeder that is bounded by two or more switches (i.e., contain no switches). Therefore, violation of the radial topology of distribution networks can occur for two reasons:

- The existence of closed loop(s) and/or
- The existence of at least one island that is not connected with the main source.

Loops can be either of two types:

- A type 1 loop starts from one substation, passes every node only once, and returns to the same or another substation;
- A type 2 loop starts from a specific node, passes every node only once, and returns to the same start node.

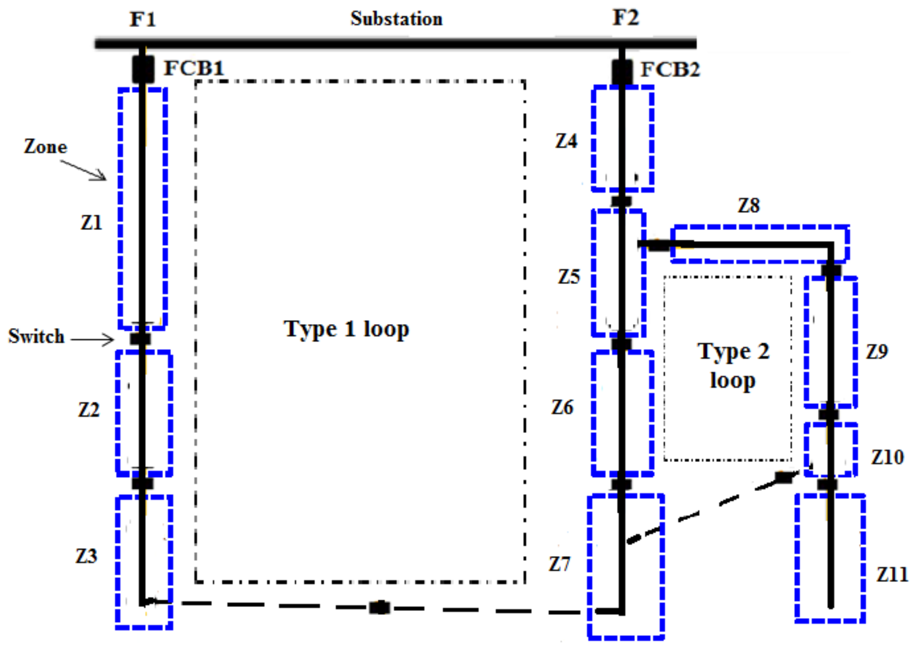


Figure 5- 1: Types of loops in distribution systems

The restoration process begins after the faulty zone(s) have been isolated and the radial constraint has been checked, as follows:

1. As shown in Figure 5-2, the procedure starts with a Feeder List (FL) that includes the root zones (i.e., zones connected directly to the substation(s)) for all system feeders. For example, for the network shown in Figure 5-1, the FL includes two elements: zone Z1 as a root zone for feeder F1 and zone Z4 as a root zone for feeder F2.
2. For each root zone FL(i) in the list, the procedure determines all zones that are reachable from this root zone and adds them to a Zone List (ZL_i). The Zone List (ZL_i) for each root zone thus

includes all of the zones physically connected with this root zone. For example, the network shown in Figure 5-1 will have two Zone Lists: Zone List ZL1, which includes zones Z1, Z2, and Z3, and Zone List ZL2, which includes zones Z4 to Z11.

3. This process is repeated for all root zones in the (FL) list., The network connection is then evaluated as follows:
   - If any zone is reported more than once (i.e., a Type 2 loop), or if one Zone List (ZL_i) contains two root zones (i.e., a Type 1 loop), the presence of a loop is indicated.
   - If the number of unique zones reported is less than the total number of zones, the presence of an island is indicated.

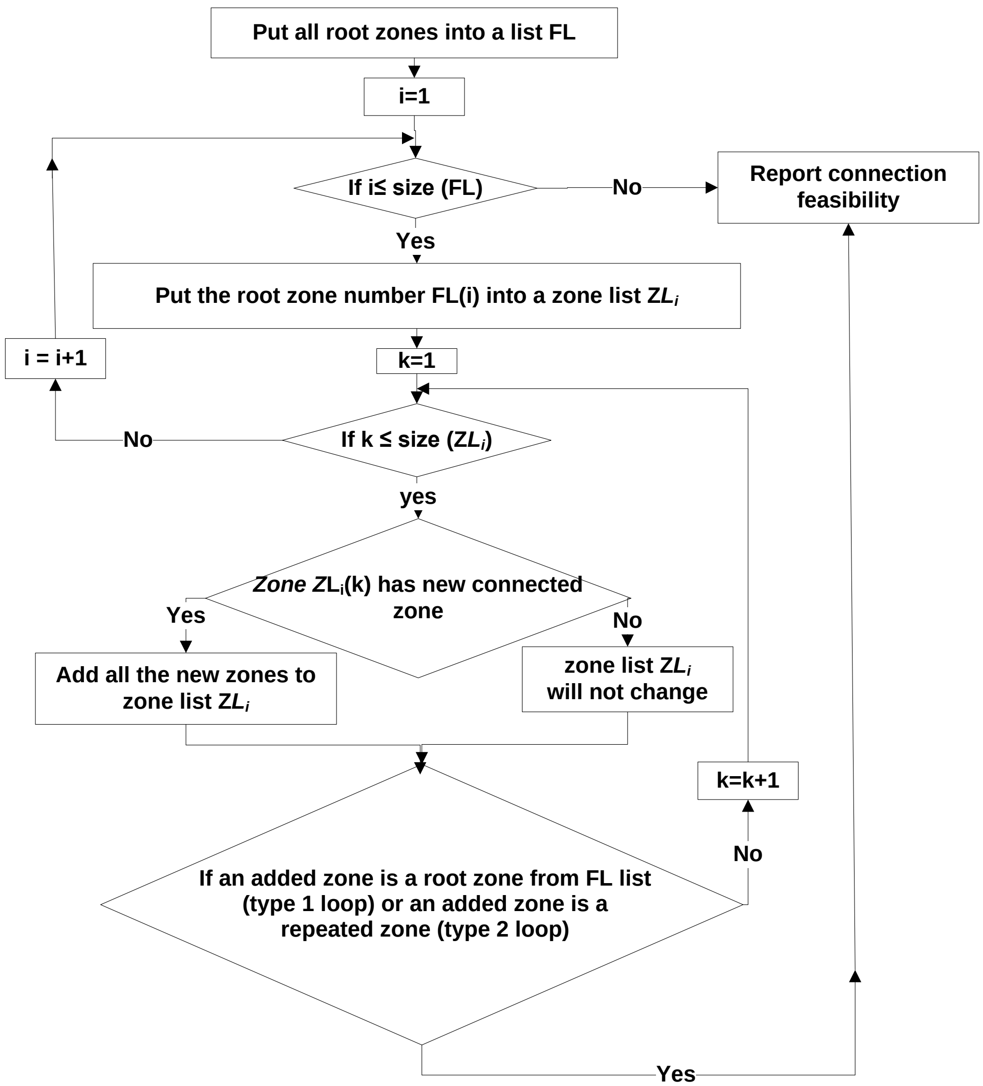


Figure 5- 2: Radial constraint checking in distribution problem

5.3.2 **Implementing genetic algorithm (GA) in the restoration problem**

In this work, a GA has been applied in order to solve the restoration problem based on the proposed formulation. As shown in Figure 5-3, the algorithm includes the following steps:

Step 1: Read the following information that has been input to the algorithm: load data (power and type), DG output power, pre-fault configuration, population size, chromosome length, and maximum number of iterations (MI).

Step 2: Generate an initial population (P0) with the following characteristics: 1) as shown in Figure 5-4, the chromosome length equals the total number of decision variables (i.e., x_i: status of switches in equation (5-3) and y_i: load state in equation (5-2)); 2) each gene accepts only either zero or one, implying that the corresponding switch/load is either open/unrestored or closed/restored, respectively; and 3) the first individual in (P0) is the chromosome corresponding to the pre-fault configuration of the distribution. The remainders of the individuals are generated randomly.

Step 3: Check the radial topology of the distribution network that correspond to the individuals in (P0), as shown in Figure 5-2. Infeasible combinations are then removed from the solution space. Only feasible connections are evaluated further and checked for their feasibility with respect to the remaining constraints based on power flow.

Step 4: Evaluate the fitness functions for individuals in (P0) using (5-5). The population is then denoted by iteration number t (i.e., population = Pt).

Step 5: Generate a new population (Pt+1) through the application of the GA operators to Pt (i.e., selection, elitism, crossover, and mutation).

Step 6: Check the radiality of the distribution networks that correspond to the individuals in (Pt+1).

Step 7: Evaluate the fitness functions for the individuals in (Pt+1).

Step 8: Check for the termination condition. If the optimal pattern remains unchanged after the preset number of iterations or the MI has been reached, go to step 9; otherwise go to step 5.

Step 9: Report the results

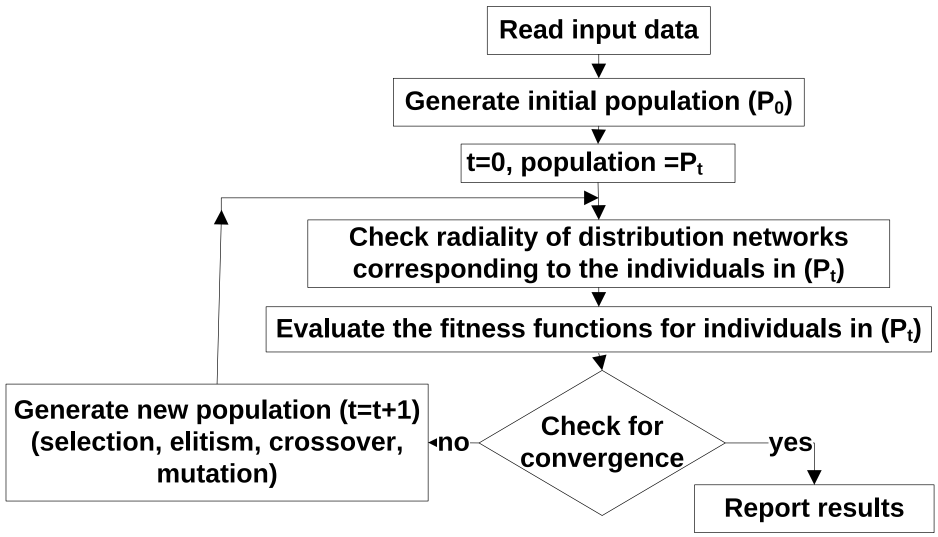


Figure 5- 3: Flow chart for GA-based service restoration

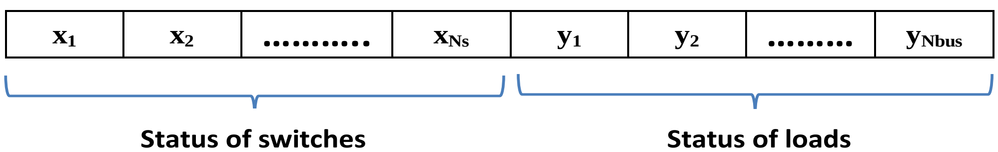


Figure 5- 4: Chromosome structure for service restoration

5.4 Test results

The proposed restoration method was tested on a distribution system that has two substations, four feeders, and 70 nodes [101]. Four factors were taken into consideration:

1. The typical hourly load patterns of residential, commercial, and industrial customers were used [89] in order to include the load priorities and to represent the variable loading of the zones along each feeder.
2. The following amounts were selected: the average interruption cost for one hour is 0.482 $/kW for residential, 8.552 $/kW for commercial and 9.085 $/kW for industrial loads; and the cost of one switching process is $50.75 [98]. These values can be easily adjusted in the restoration algorithm based on specific utility prices.
3. The islanded operation of DG units was not included in this work.
4. The GA parameters applied were population size: 50; crossover rate: 0.8; mutation rate: 0.05; MI: 150; selection type: roulette wheel; and crossover type: two points.

5.4.1 **Simulation results without DG units**

Figure 5-5 shows the 70-Bus distribution system with zone numbers. Feeders F1 and F2 are considered to be residential feeders, feeder F3 is considered to be an industrial feeder and feeder F4 is considered to be a commercial feeder. A fault is assumed to have occurred at Z1 in feeder F4. For the purposes of comparison, two outage periods were selected: one during the lightest loading period of the system (i.e., from 1:00 a.m. to 6: a.m.) and the other during the highest loading period of the system (i.e., from 5:00 p.m. to 10:00 p.m.).

5.4.1.1 Case 1: fault occurring during the lightest loading period

Table 5-1 shows the open switches, losses, minimum voltage, switching operations, and load shed during the restoration plan [Base: 11 kV, 1 MVA]. The first, third, and fourth scenarios have identical restoration plans. However, based on the results shown in Table 5-1, the restoration plan based on the second scenario (rated load scenario) provides higher voltage and lower losses. This is because it has been built based on the peak load. But, it needs a higher cost and a greater number of switching operations than other scenarios (seven switching operations versus only one).

Table 5- 1: Results of case 1

<table>
<tr><td colspan="2">Outage period</td><td colspan="5">1:00 a.m. to 6:00 a.m.</td></tr>
<tr><td colspan="2" rowspan="2">Scenario</td><td rowspan="2">1st scenario (pre-fault)</td><td rowspan="2">2nd scenario (rated)</td><td colspan="2">3rd scenario (variant)</td><td rowspan="2">4th scenario (with LC)</td></tr>
<tr><td>Scheme A</td><td>Scheme B</td></tr>
<tr><td colspan="2">Outage zones</td><td>Zones 2-10</td><td>Zones 2-10</td><td>Zones 2-10</td><td>Zones 2-10</td><td>Zones 2-10</td></tr>
<tr><td colspan="2">Min. voltage</td><td>0.9277</td><td>0.9679</td><td>0.9277</td><td>0.9277</td><td>0.9277</td></tr>
<tr><td colspan="2">Switching actions</td><td>Close s43</td><td>Open s14, s32, s34
Close s41,s39, s43,s38</td><td>Close s43</td><td>Close s43</td><td>Close s43</td></tr>
<tr><td rowspan="2">Loss</td><td>MWh</td><td>0.2435</td><td>0.1675</td><td>0.2435</td><td>0.2435</td><td>0.2435</td></tr>
<tr><td>MVARh</td><td>0.2048</td><td>0.1481</td><td>0.2048</td><td>0.2048</td><td>0.2048</td></tr>
<tr><td colspan="2">Load shed</td><td>None</td><td>None</td><td>None</td><td>None</td><td>None</td></tr>
<tr><td colspan="2">Run time (sec)</td><td>4.5</td><td>5.7</td><td>13</td><td>18.5</td><td>17.5</td></tr>
<tr><td colspan="2">Total cost ($)</td><td>50.75</td><td>355.25</td><td>50.75</td><td>50.75</td><td>50.75</td></tr>
</table>

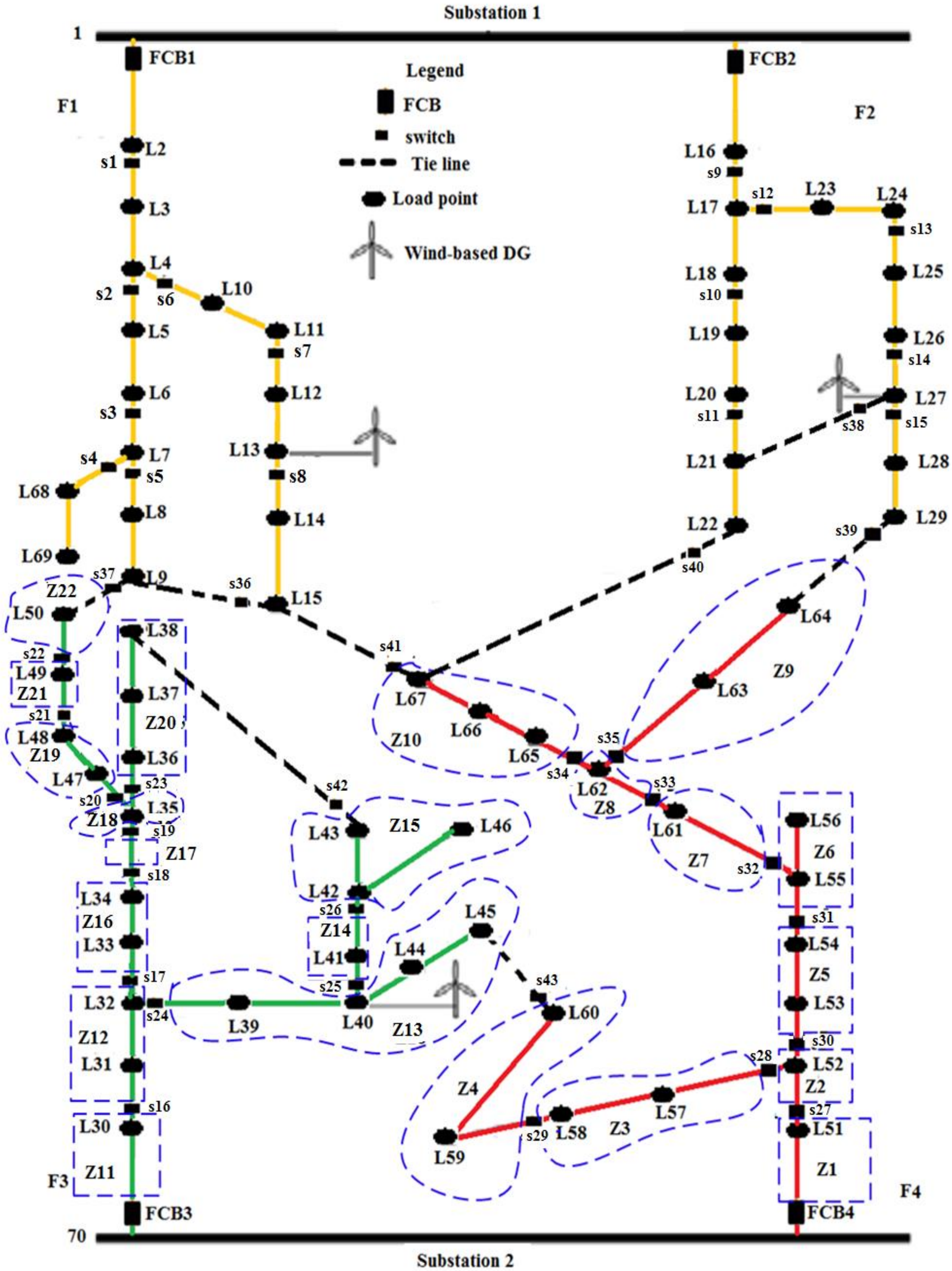


Figure 5- 5: Four-feeder test system with zone numbers

5.4.1.2 Case 2: fault occurring during the highest loading period

Table 5-2 shows the open switches, losses, minimum voltage, switching operations, and load shed during the restoration plan.

Table 5- 2: Results of case 2

Outage period		5:00 p.m. to 10:00 p.m.				
Scenario		1st scenario (pre-fault)	2nd scenario (rated)	3rd scenario (variant)		4th scenario (with LC)
				Scheme A	Scheme B	
Outage zones		Zones 2-10	Zones 2-10	Zones 2-10	Zones 2-10	Zones 2-10
Min. voltage		0.8789	0.9104	0.9079	0.9001	0.9002
Switching actions		Open s33, Close s43, s41	Open s14, s32, s34 Close s41, s39, s43,s38	Open s32,s34 Close s41, s39,s43	At 5:00 p.m.: Open s33 Close s41, s43. At 6:00 p.m.: Open s34 Close s39 At 7:00 p.m.: open s22, close s37	Open s33, Close s41,s43
Loss	MWh	1.3983	1.2643	1.3421	1.3303	1.3431
	MVARh	1.2275	1.1498	1.1714	1.1640	1.1784
Load shed		None	None	None	None	Load L10
Total cost ($)		Not applicable due to violation of constraints	355.25	253.75	355.25	201.88
Run time (sec)		4.7	5.7	22.5	45.5	28.5
Remarks		F1 overloaded at 6:00 p.m.; voltage violates its limit.	None	None	None	None

Scenario 1 (pre-fault) suffered from under-voltage and overloading of feeder F1 at 6:00 p.m. This is because, this scenario built its restoration plan based on the load profile at the fault occurrence (i.e., at 5 p.m.) and it doesn’t take the expected increase of load during the following hours into consideration. In the third scenario (scheme A), the switching actions were implemented at the beginning of the restoration period. However, in scheme B, the switching actions had to be implemented in three stages: at 5:00 p.m., 6:00 p.m., and 7:00 p.m. As a result, some customers were interrupted during the switching actions at 6:00 p.m. and 7:00 p.m. (i.e., zones Z8 and Z9 are interrupted at 6:00 p.m., and load L50 is interrupted at 7:00 p.m.). Although the second scenario results in a cost that is identical to that of the third scenario (scheme B), its switching actions are implemented at the beginning of the restoration plan (i.e., at 5:00 p.m.), thus avoiding further interruption of the loads during the remainder of the restoration period. The fourth scenario provides the best solution with respect to cost and number of switching operations. This is because the in-service customers (i.e., customers of feeders F1, F2, and F3) are included in the restoration process (i.e., can be included in load shedding). As a result, the residential customer load (L10) is subjected to load shedding during the restoration period in order to increase the supporting restorative power of feeder F1. This customer also receives a bill reduction proportional to consumption for this period.

5.4.1.3 Effect of switch type

In order to show the effect of the type of switch (MCS or ACS), the restoration plan for the third scenario (scheme A) in case 2 was implemented for three situations:

1) All system switches are manual switches (fully manual);
2) Both switch types exist (partially automated); and
3) All system switches are automated switches (fully automated).

Table 5-3 shows the energy not supplied (ENS) for these three situations based on the following equation [102]:

$$ENS = \sum_{k=1}^{K} t_k * PNS_{k-1} \tag{5.8}$$

where t_k: time required for the *k-th* switching operation (50 s and 1500 s for an ACS and an MCS, respectively[20]); K: total number of switching operations; PNS_0: power not supplied after a fault; and PNS_k: power not supplied after implementation of the *k-th* switching operation.

For the fully automated or fully manual systems, the restoration plan is implemented in one stage. However, for partially automated systems, the restoration plan is implemented in two stages (the first stage uses the ACSs, after which the second stage is implemented using the MCSs). To avoid the creation of loops during the implementation of the restoration plans, the switches to be opened are implemented first, followed by the switches to be closed. The restoration plans for the three situations are thus implemented as follows:

1) Fully manual: The switches to be opened (i.e., switches s32 and s34) are opened in 1500 s, then the switches to be closed (i.e., s41, s39, and s43) are closed in 1500 s. The out-of-service loads are hence restored in 3000 s with an ENS of 556.48 kWh.

2) Fully automated: The switches to be opened are opened in 50 s, and then the switches to be closed are closed in 50 s. The out-of-service loads are hence restored in 100 s with an ENS of 18.55 kWh.

3) *Partially automated*: In this case, two automated switches exist (switches s32 and s43). Therefore, in the first stage, switch s32 is opened in 50 s, and then switch s43 is closed in 50 s. The loads at zones Z2-Z6 are thus restored in 100 s. Then, in the second stage, switch s34 is opened in 1500 s, after which switches s41 and s39 are closed in 1500 s so that the loads at zones Z7-Z10 are restored in 3000 s.

Table 5- 3: Comparison of restoration strategies based on different levels of automation

Automated switches	ENS (kWh)		
	1-stage	2-stage	% reduction
None (fully manual)	556.48	-	-
Switches s32 and s43	411.32	266.16	35.31
All (fully automated)	18.55	-	-

5.4.1.4 Case 3: simultaneous faults occurring during the highest loading period

Although, simultaneous faults are uncommon, they are possible during bad weather conditions (i.e., storms). To evaluate the performance of the proposed algorithm for multiple faults, a case study of two simultaneous faults was tested.

As shown in Table 5-4, two simultaneous faults are assumed: at Z1 in feeder F4 and at Z17 in feeder F3. The results indicate that the algorithm is able to provide a proper restoration plan which ensures the power supply to priority customers. Furthermore, the fourth scenario still provides a superior solution with respect to cost and the number of switching operations.

Table 5- 4: Results of case 3

Outage period		5:00 p.m. to 10:00 p.m.		
Scenario		2nd scenario (rated)	3rd scenario (scheme A)	4th scenario with LC
Outage zones		Zones 2-10, 18-22	Zones 2-10, 18-22	Zones 2-10, 18-22
Min. voltage		0.9060	0.9039	0.9039
Switching actions		Open s14, s32,s34,s21 Close s41, s39,s43, s38, s37, s42	Open s21,s14,s33 Close s38,s39,s43,s37,s42	Open s21,s31 Close s37,s42,s40,s43
Loss	MWh	1.3905	1.4223	1.3472
	MVarh	1.2441	1.2761	1.1865
Load shed		None	None	Load L19
Run time (sec)		10	27	31.5
Total cost ($)		507.5	406	336.76

5.4.2 **Simulation results with DG units**

For the sake of comparison with case 2, the outage period and fault location were selected to be the same as those in case 2. Three wind-based DG units, each with a rating of 0.5 MW were inserted at load points L13, L27, and L40, as illustrated in Figure 5-5.

Figures 5-6 and 5-7 show the load and the total generation from these DG units over 24 hours for the three proposed modes (i.e., 1st: actual; 2nd: forecasted; and 3rd: probabilistic) respectively. Table 5-5 shows the open switches, losses, minimum voltage, switching operations, and load shed during the restoration plan.

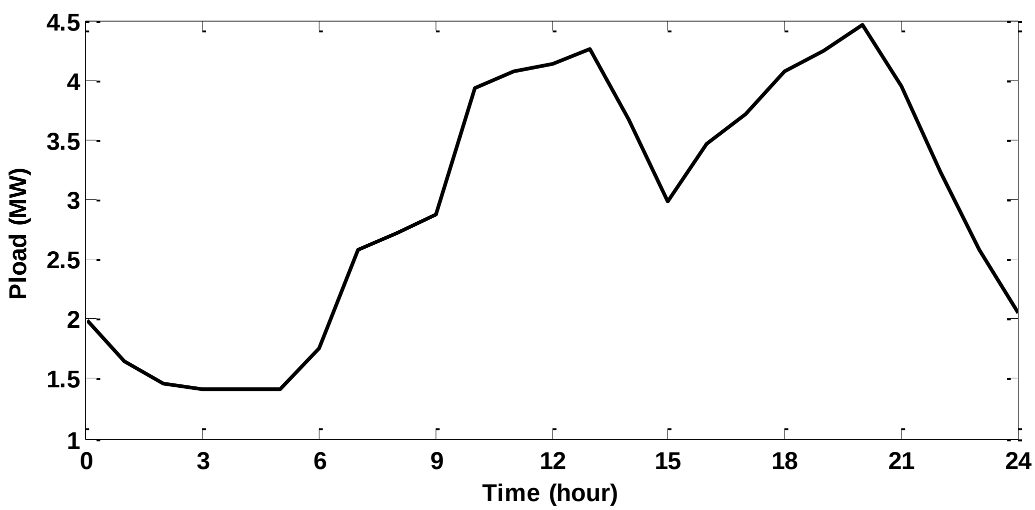


Figure 5- 6: Load profile over the 24 hours

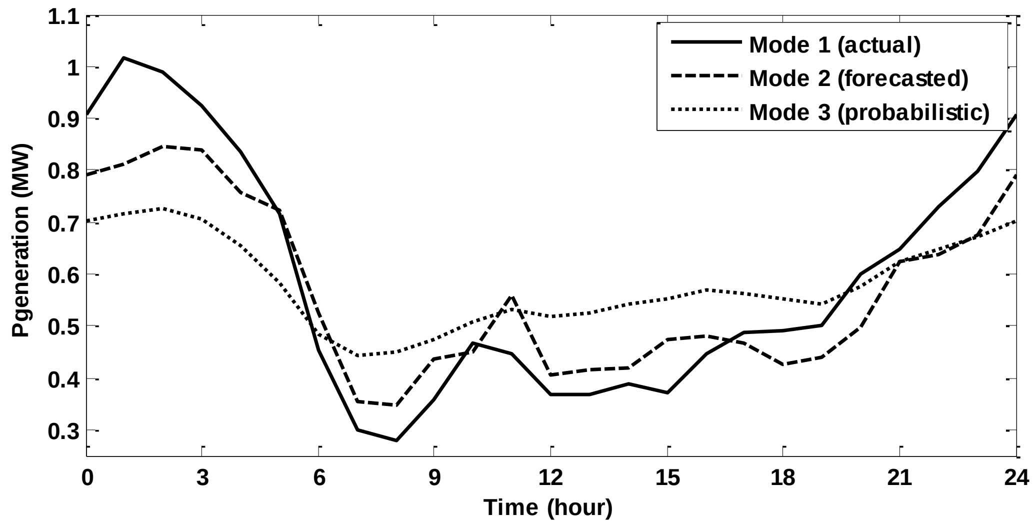


Figure 5- 7: DG power profiles over the 24 hours

Table 5- 5: Results of case with DG

Outage period	5:00 p.m. to 10:00 p.m.							
Mode	Wind-based DG units						Disp. DG units	
	1st (actual)		2nd (forecasted)		3rd (probabilistic)			
	A	B	A	B	A	B	A	B
Outage zones	Zones 2-10	Zones 2-10	Zones 2-10	Zones 2-10	Zones 2-10	Zones 2-10	Zones 2-10	Zones 2-10
Min. voltage	0.9071	0.9071	0.9043	0.9034	0.9076	0.9001	0.9085	0.9025
Switching actions	Open s33 Close s41, s43	At 5:00 p.m.: Open s33 Close s40, s43 At 6:00 p.m.: Open s40 Close s41	Open s33 Close s41, s43	At 5:00 p.m.: Open s32 Close s40,s43 At 6 PM: Open s40 Close s41	Open s32 Close s41, s43	At 5:00 p.m.: Close s40, At 6:00 p.m.: Open s33 Close s43	Open s32 Close s40, s43	At 5:00 p.m.: Close s40 At 6:00 p.m.: Open s32, Close s43
Loss MWh	1.1110	1.0916	1.1350	1.1077	1.0425	1.1009	0.8156	0.8428
Loss MVARh	0.9843	0.9708	1.0047	0.9849	0.9422	0.9756	0.7363	0.7621
Load shed	None	None	None	None	None	None	None	None
Run time (sec)	18	33.5	17.5	34	17.8	34.7	18.4	33.8
Total cost ($)	152.25	253.75	152.25	253.75	152.25	152.25	152.25	152.25

The results in Table 5-5 show that the restoration plans using scheme A for the three modes are almost identical with respect to the number of switching operations and the total cost. However, mode 3 provides a bit higher voltage and lower losses. For applying scheme B, the restoration plans for the three modes differ. For example, mode 3 requires three switching operations compared to the five required for the other two modes. Furthermore, compared with the case without DG (Table 5-2), scheme A restoration plans shows the effectiveness of DG units in reducing the number of switching actions (i.e., in the case without DG, five switching operations were required, and in the case with DG, only three were needed).

In another case study, the three wind-based DG units were replaced by three biomass DG units (i.e., at the same locations and each with a rating of 0.5 MW). Based on the results shown in Table 5-5, due to the dispatchability nature of these biomass DG units, they provide a restoration plan with higher voltage, lower losses, and lower cost compared with wind-based DG units.

For a further evaluation of the efficiency and effectiveness of the proposed algorithm, a summary of the data for a set of case studies was obtained by varying the faulty zone, as presented in Table 5-6. The results reveals that as the number of out-of-service zones increases, the number of switching actions required also increases, as do the losses, cost, and running time. In addition, these outage zones increase the loading in the healthy feeders, which causes further voltage drops and lower voltages at some buses.

Table 5- 6: Summary of data for a set of case studies obtained by varying the faulty zone

<table>
<tr><td colspan="2">Outage period</td><td colspan="6">5:00 p.m. to 10:00 p.m.: scheme A (overall plan)</td></tr>
<tr><td colspan="2" rowspan="2">Faulty component</td><td colspan="2">Single fault at Z7 (less severe)</td><td colspan="2">Single fault at Z1 (more severe)</td><td colspan="2">Simultaneous faults at Z1, Z17</td></tr>
<tr><td>1st actual</td><td>3rd (prob.)</td><td>1st actual</td><td>3rd (prob.)</td><td>1st actual</td><td>3rd (prob.)</td></tr>
<tr><td colspan="2">Outage zones</td><td>8-10</td><td>8-10</td><td>2-10</td><td>2-10</td><td>2-10,18-22</td><td>2-10,18-22</td></tr>
<tr><td colspan="2">Min. voltage</td><td>0.9349</td><td>0.9351</td><td>0.9071</td><td>0.9076</td><td>0.9028</td><td>0.9031</td></tr>
<tr><td colspan="2">Number of switching actions</td><td>1</td><td>1</td><td>3</td><td>3</td><td>6</td><td>6</td></tr>
<tr><td rowspan="2">Loss</td><td>MWh</td><td>0.8058</td><td>0.7981</td><td>1.1110</td><td>1.0425</td><td>1.1720</td><td>1.1589</td></tr>
<tr><td>MVARh</td><td>0.7354</td><td>0.7287</td><td>0.9843</td><td>0.9422</td><td>1.0387</td><td>1.0272</td></tr>
<tr><td colspan="2">Load shed</td><td>None</td><td>None</td><td>None</td><td>None</td><td>None</td><td>None</td></tr>
<tr><td colspan="2">Run time (sec)</td><td>7.5</td><td>8</td><td>18</td><td>17.8</td><td>25.5</td><td>24.8</td></tr>
<tr><td colspan="2">Total cost ($)</td><td>50.75</td><td>50.75</td><td>152.25</td><td>152.25</td><td>304.5</td><td>304.5</td></tr>
</table>

5.5 Results discussion

Based on the previous different case studies shown in Tables, it appears that the proposed restoration algorithm provides the following advantages:

- During the mean time to repair the fault, it provides a restoration plan that includes the following:

1) Consideration of variable demand and generation of wind-based DG units
2) Consideration of differing load priorities
3) Satisfaction of operational constraints so that voltages and currents do not violate their limits
4) Beneficial support power derived from DG units

The following conclusions can be drawn from the test results:

- As shown in Table 5-2, scenario 3 (scheme A: overall plan) is more effective than scenario 1 because the former results in a restoration plan that does not require further reconfigurations and customer interruptions due to the overloading and/or under-voltages that may occur in the case of scenario 1 (pre-fault).
- As shown in Tables 5-1, 5-2 and 5-4, scenario 3 (scheme A) is more effective than scenario 2 because the former results in a restoration plan that involves a lower number of switching operations, and it avoids the unnecessary load shedding that may result with scenario 2. Therefore, scenario 3 (scheme A) aligns with operational practices.
- As shown in Tables 5-2 and 5-5, scenario 3 (scheme A) is more effective than scenario 3 (scheme B) because the former results in a restoration plan that involves a lower number of switching operations and avoids further reconfigurations and customer interruptions. From practical application point of view, scheme B is not effective/practical for systems with MCSs. For example, if a plan is to be implemented for one hour, after the time necessary for the implementation of this plan has elapsed, the plan can hardly still be valid.
- As shown in Tables 5-1, 5-2 and 5-4, scenario 4 is the most effective scenario with respect to cost and number of switching operations because the voluntary participation of in-service customers creates flexibility in the restoration process in terms of alternative restorative paths and in the securing of what might be a sufficient margin to enable backup feeders to restore the unrestored loads.
- As shown in Table 5-3, implementing the restoration plans in two stages enhances system reliability because of the benefits derived from the quick response of ACSs to enable the restoration of power to some customers during the first stage.
- DG units provide a source of support power during the restoration process and therefore decrease the number of switching operations required and increase the opportunity for restoring additional unrestored customer loads.

5.6 Conclusion

In this chapter, a method of service restoration is proposed. This method targets to investigate the effect of load variation, switch type, and DG units in building restoration plans. Based on the simulation results, important rules are concluded: 1) consideration of load variation is a key factor of switching decisions for the restoration problem, 2) DG units provide a source of support during the restoration process and therefore decrease the number of switching operations required and increase the opportunity for restoring additional unrestored customer. These rules will be used in the design of self-healing algorithm in Chapter 6.

Chapter 6

A Cooperative Multi-Agent Control for Self-Healing Mechanisms in Smart Distribution Systems

6.1 Introduction

Nowadays, there is a full dependence on electricity. Therefore, increasing the reliability of power systems is an essential goal. This goal can be achieved by realizing one of the most attractive features of smart grid, which is its self-healing ability. The centralized operation of fault location, isolation and service restoration (FLISR) function which is performed manually by human operators will be converted to automated FLISR or self-healing function. As result, a system subjected to a fault will be able to automatically and intelligently perform corrective actions to restore itself to the best possible state in order to perform the basic functions without violating any constraints.

In this Chapter, a self-healing scheme for distribution systems is implemented in a multi-agent environment. The proposed scheme divides the distribution system into zones each is represented by an agent. A zone indicates a segment of a distribution feeder that is bounded by two or more switches. The proposed control structure has two layers: zone and feeder. System restoration is carried out based on the coordination between these two layer agents. The goal of the proposed multi-agent system is to locate and isolate faults, then decide and implement the switching operations to maximize the out-of-service loads restoration. The proposed technique does not assume any supervision from any central controller. The restoration scheme maximizes the restored load while preserving the radial structure of the distribution system and without violating any of the system operational limits.

This chapter starts by presenting the formulation of the restoration problem followed by a discussion of related practical issues. Then the structure of the proposed multi-agent control is described. The operating mechanism of each control agent has been defined according to the concept of intelligent agents, and the decision makers of the control agents are coordinated using expert-based Foundation for Intelligent Physical Agents (FIPA) communication protocols. Then, a discussion for important issues related to the practical implementation of the proposed algorithm is presented. Finally, the results and conclusions of this research have been discussed.

6.2 Restoration problem in distribution systems

6.2.1 **Problem formulation**

The service restoration problem can be formulated as a multi-objective multi-constraint optimization problem. The proposed objectives and the constraints considered are as follows:

6.2.1.1 Objective functions

1) Maximizing the load restored with consideration of load priority:

$$Max \sum_{i=1}^{N_{bus}} w_i * L_i * y_i \tag{6.1}$$

where N_{bus}: number of buses; L_i: load at the i^{th} bus; y_i: status of the load at the i^{th} bus (i.e., equals 1 for restored and 0 for unrestored); w_i: priority or importance level of the load at i^{th} bus.

2) Minimizing the number of switching operations to reduce both the time and the operational cost required for the restoration process.

$$Min \sum_{i=1}^{N_s} \left| x_i - x_{io} \right| \tag{6.2}$$

where N_s: the total number of switches; x_i: status of the i^{th} switch in the restored network (i.e., equals 1 for closed and 0 for opened); x_{io}: status of the i^{th} switch immediately after the fault has been isolated.

3) Minimizing losses during the restoration period:

$$Min \sum_{i=1}^{N_{br}} I_i^2 R_i \tag{6.3}$$

where N_{br}: total number of branches; I_i: current in the i^{th} branch and R_i: resistance of the i^{th} branch.

6.2.1.2 Constraints

1) Bus voltages at all buses should be kept within limits:

$$V_{\min} \le V_i \le V_{\max} \tag{6.4}$$

where V_i: voltage at the i^{th} bus, and V_{max}, V_{min}: maximum and minimum acceptable bus voltages.

2) All branch currents should be kept within limits:

$$I_j \le I_{\max} \tag{6.5}$$

where I_j: current in branch j, and I_{max}: maximum line current.

3) Radial network structure should be maintained.

6.2.2 **Practical rules for designing the decision makers for the control agents**

Based on the discussion in the previous chapter and based on the problem formulation, this section highlights some of the important aspects related to the operational practices of the restoration problem, which were used in extracting the rules for designing the expert-based decision makers for the control agents. The related issues are as follows:

- The radial network topology should be maintained during the restoration process. This is for coordinating the protection device and for easily locating and isolating any fault [19].
- Practically, a feasible service restoration plan which restores all of the out-of-service loads is not guaranteed to exist due to the limited available capacity for restoration. Partial restoration plans are implemented (i.e., restoring a percentage of the affected customers). In this case, the restoration process should begin with the highest priority customers first (i.e., hospitals, industrial loads, etc.) as formulated in equation (6.1) [19].
- As we discussed in details in the previous chapter, load variation during the restoration period should be considered in building the restoration plan. This is because using the pre-fault and peak load scenarios which are the typical used scenarios in the literature has its drawbacks (i.e., using the daily peak load may lead to limited restoration of some loads and using the pre-fault load may cause overloading in some backup feeders). *In this work, in order not to violate the operational constraints from one side and to benefit from the available capacity for restoration from another side, the peak load over the restoration period (i.e., the average duration for fault repair) is used to build the restoration plan [16][103].*
- Any restoration plan is accomplished by transferring the affected loads in the out-of-service area to their neighboring backup feeders through a set of switching actions (i.e., opening sectionalizing switches and closing tie switches). Thus, the time required for completing the implementation of the restoration plan depends on the required number of its switching operations. Therefore, this number should be as low as possible, as formulated in equation (6.2). Furthermore, as mentioned in chapter 3, reducing the number of switching operations reduces the possibility of switching surges, the risk of outages, and the number of transient disturbances in the system due to multiple switching operations.

- The configurations of the restoration plans are temporary ones which are applied during the duration of fault repair only. As soon as the faulty section is repaired, the reverse switching sequence is applied in order to return to the normal configuration. Therefore, the restoration plan which provides a network configuration with a topology closer to that of the pre-fault configuration will be more recommended and easier to return to the normal configuration after the fault is cleared.
- Based on the last two points, if the available restorative capacity of any one of the backup feeders is sufficient, the out-of-service area can be restored as a single group through one switching operation using this backup feeder (i.e., group restoration) [97]. If no backup feeder has the capacity required for group restoration, the out-of-service loads can be restored as multi-groups (i.e., zone restoration). Zone restoration is accomplished by finding a plan to restore as many zones as possible through suitable paths[97].
- Due to the limited available capacity for restoration, some zones may not be restored after zone restoration. In this case, loads can be transferred from the main backup feeders to their neighbors. This load transfer can secure what might be a sufficient margin for the main backup feeders to restore the remainder of the unrestored loads, as shown in Figure 6-1.

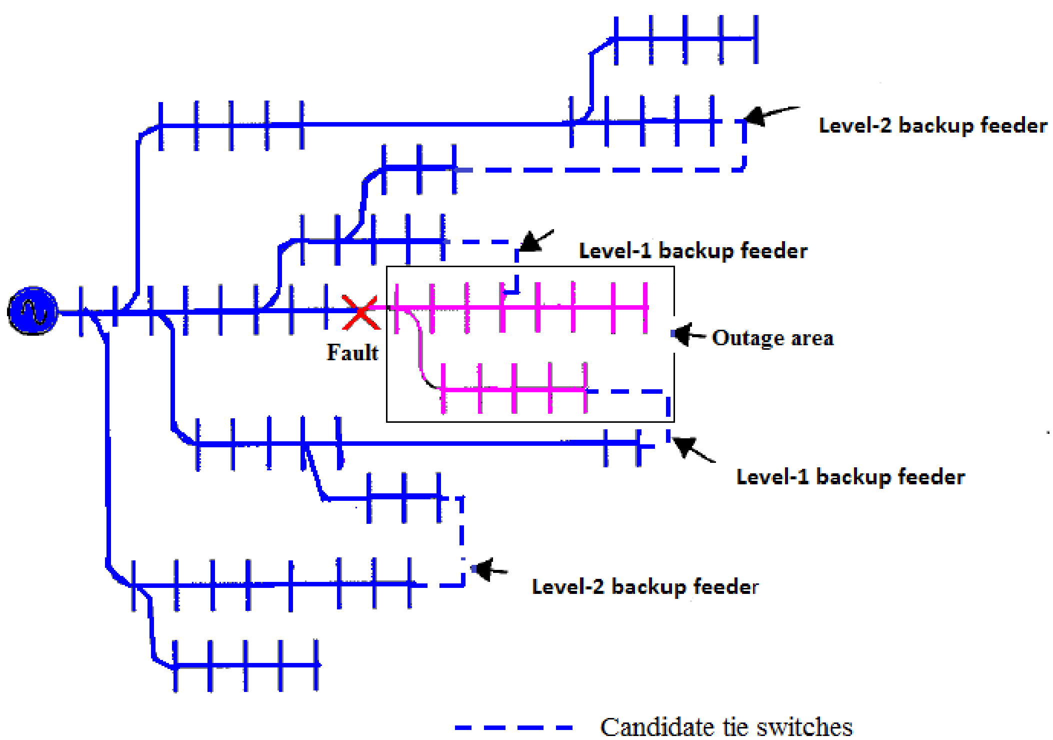


Figure 6-1: Levels of backup feeders for the restoration process

- After checking the previous steps, if any zones are still unrestored, shedding of the least priority loads can enable the remainder of the unrestored loads to be restored with the remaining limited capacity.
- As mentioned in chapter 5, the loss reduction calculated according to equation (6.3) is used in normal operating conditions and is not appropriate for emergency restoration situation.

6.3 The proposed multi-agent control structure

6.3.1 Structure of the proposed multi-agent system

The proposed algorithm solves the self-healing problem based on the cooperation among several agents placed in the distribution network. The control agents possess the intelligent ability to use communication and negotiation in order to determine the current and predicted states of the system and then set their actuators and switches in a way that will achieve their own objectives as closely as possible while satisfying any constraints.

In the proposed structure of the multi-agent system, each distribution feeder is divided into a number of zones based on the location of protective devices. The zone is a section bounded by two or more switches and contains no switches inside its section. The boundaries between neighboring feeders would be tie switches that would help of the restoration process during a fault. The division of responsibilities between individual agents is designed in a hierarchical way which aligns with the structure of distribution networks. Two layers of agents are used to represent distribution feeders:

- Zone agents in the first layer for monitoring, making simple calculations, and implementing control actions. In order to reduce the required communication and delay time, the algorithm does not allow zone agents to communicate with one another. However, these zone agents communicate to their feeder agent only.
- Feeder agents in the second layer which assigned to negotiation in order to build the appropriate restoration plan and determine the fault location. Then they send the control actions to their appropriate zone agents for implementing them.

Each feeder agent communicates only with its neighbored feeder agents which are connected with them by tie switches. Figure 6-2 shows the proposed agents and their two-way communication.

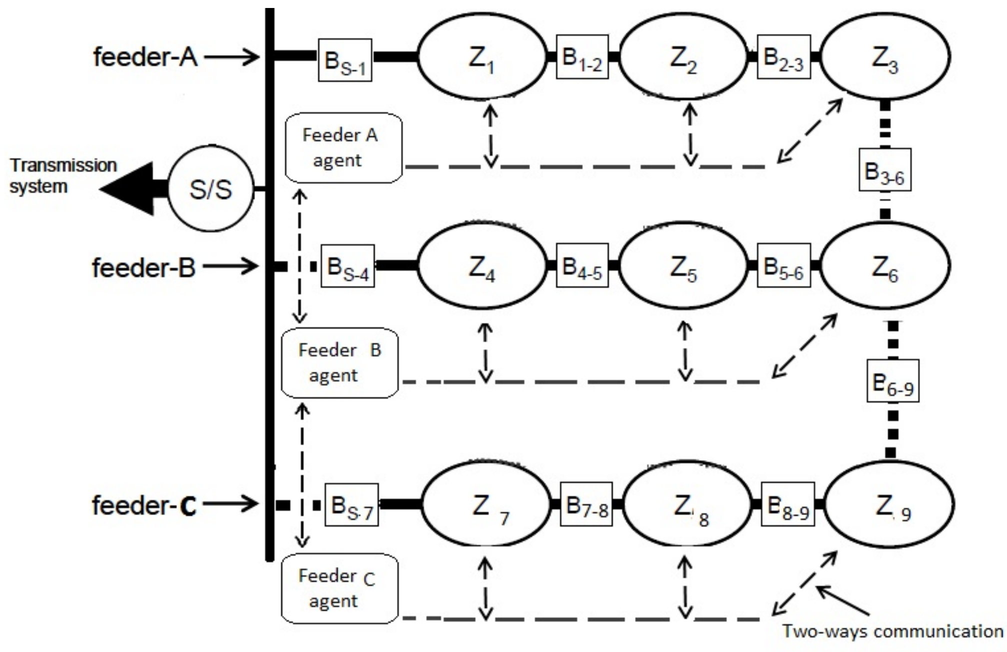


Figure 6-2: Concept of the distributed control structure

6.3.2 **Coordination among control agents via two-way communication**

As mentioned in section 2.5.2 the Foundation for Intelligent Physical Agents (FIPA) developed an Agent Communication Language (ACL) for agent communications, which consists of 20 ACL message types (e.g., informing, requesting, and composite speech acts). These messages have been used in this work as a means of coordinating the proposed intelligent control agents in order to achieve self-healing.

Furthermore, negotiation is the main interaction during the self-healing problem in multi-agent system. The Contract Net Protocol (CNP) which is one of the pre-agreed message exchange protocols defined by FIPA will be used in the proposed algorithm [33]. The sequence diagram of FIPA Contract Net Protocol is shown in Figure 6-3.

This protocol describes the typical negotiation sequence between two agents. The initiator agent wishes to have a task performed by one or more of the neighboring agents (i.e., participants). The initiator starts the negotiation process by sending out a call for proposal (CFP) message, which specifies the task to be performed to *m* participants. Then responding participants can choose to reply by submitting a proposal (the *j* participants) to perform the action or they can refuse if they cannot perform the action (the $i= n\text{-}j$ participants refuse).

The initiator waits till the end of a deadline for receiving replies or proposals. Negotiations then continue with the *j* participants that proposed. Then, the initiator evaluates the received proposals based on a certain evaluation method to select one or more proposal. After evaluating the proposals, the initiator rejects some proposals (by sending reject-proposal message to the k participants) and accepts the best one or more of them (by sending accept-proposal message to the l=j-k participants). Participants who receive an accept-proposal message from the initiator become committed to perform the task and they send inform message to the initiator if the action has been performed successfully or a failure message if they fail to perform the task.

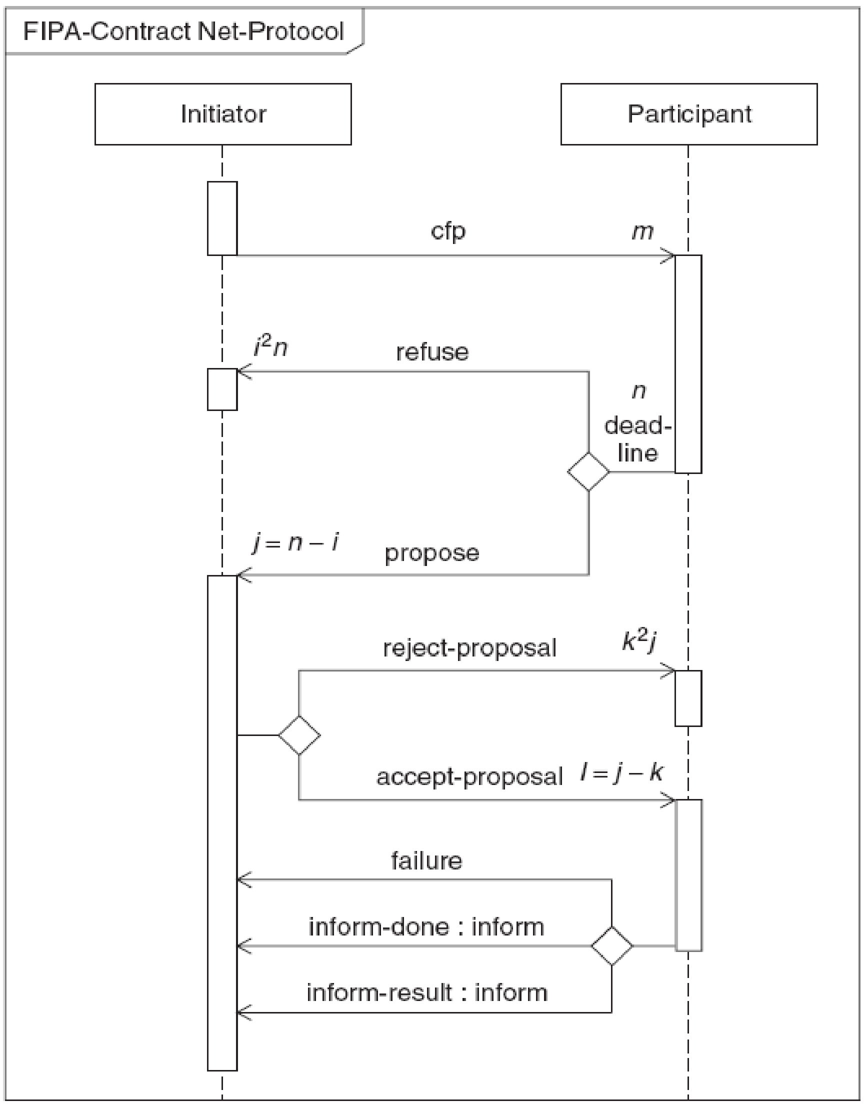


Figure 6-3: Sequence diagram of FIPA Contract Net Protocol (CNP)

6.4 The proposed operation mechanism and coordination between control agents.

Figure 6-4 shows the objectives and the two-way communication among the proposed control agents. The common objectives among all agents are: the maximization of the loads restored and the minimization of the number of switching operations. Furthermore, each agent has an additional objective. The initiator feeder agent represents the feeder that has been subjected to a fault at one of its components and hence has at least one out-of-service zone. This initiator agent will locate and isolate the faulty zone before beginning the restoration process. The responder feeder agent represents level-1 or immediate-neighbor backup feeders of the initiator and the subcontractor feeder agent represents level-2 or immediate- neighbor backup feeders of the responder feeders. These two types of agents will provide whatever capacity they have to assist with the restoration without violating their operational constraints.

The remaining of this section will describe the operating mechanism of each agent and the mechanism for their coordination using two-way communication during the two stages of the self-healing operation (i.e., the first stage, which is the detection and isolation of the fault location, and the second stage, which is the restoration of the out-of-service load).

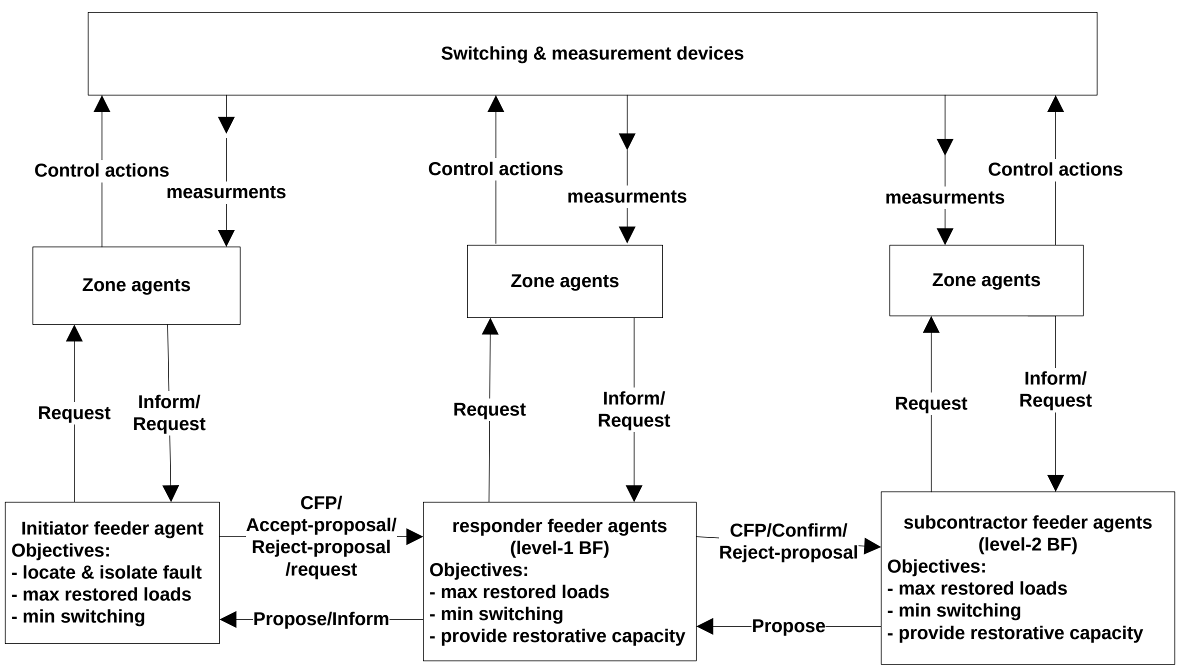


Figure 6-4: Coordination via two-way communication among proposed control agents

6.4.1 **Stage 1: fault location and isolation algorithm**

The typical sequence of actions when a permanent fault occurs in a distribution feeder is:

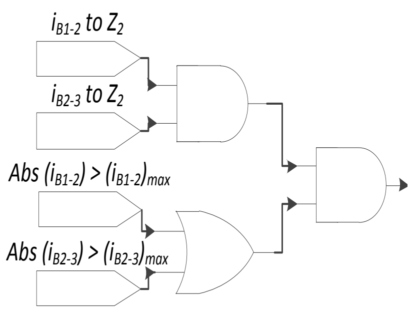
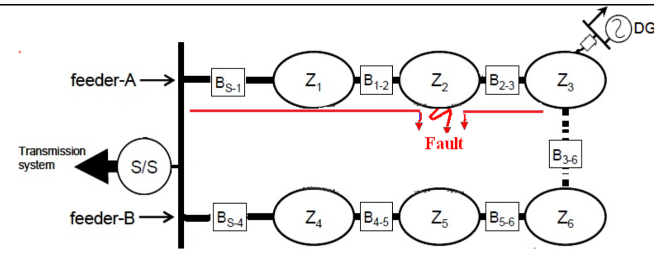
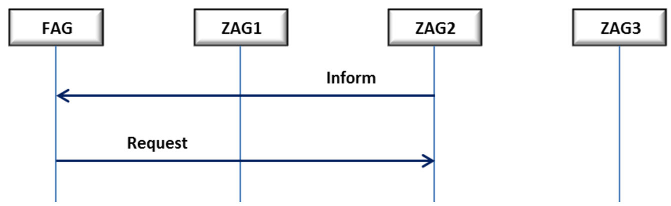
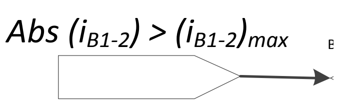
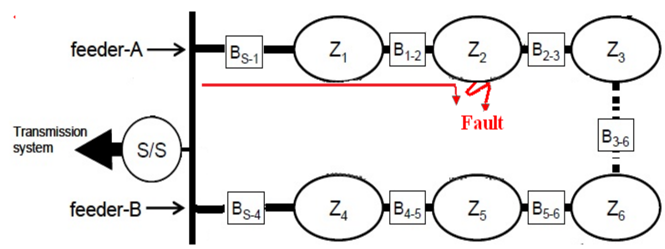
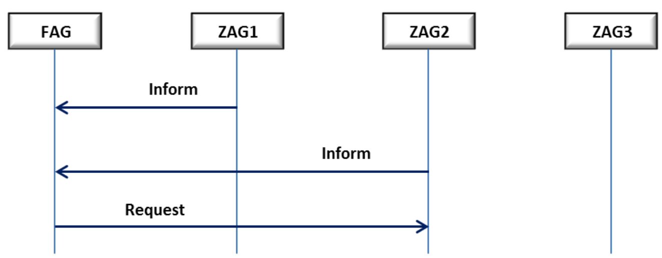
1. First, the feeder circuit breaker is tripped in real-time operation to stop feeding/energizing the faulty component from the main source.
2. Second, the fault location detection and isolation algorithm is applied in order to locate and isolate the faulty section from both directions by opening its boundary first upstream and downstream switches.
3. Third, the upstream out-of-service loads are restored through the closing of the feeder circuit breaker.
4. Fourth, a restoration algorithm is applied to restore the downstream out-of-service loads.
5. Fifth, when the faulty section is repaired, the reverse switching sequence is applied so that the distribution system is returned to its normal configuration.

The distribution feeders are normally operated in radial topology. Therefore, the occurrence of a fault in a distribution feeder affects only its sections (i.e., the sections that fault current flow through them such as sections between the substation and the faulty component as well as the downstream sections, when distributed generation units (DGs) are present). As result, only the control agents of the affected feeder that has the faulty section will participate at this stage. The normal current flow is unidirectional from the source to the grid. However, DG units may change the direction of current flows from unidirectional to bidirectional. A fault occurs somewhere in the distribution system changes the current flow magnitude and direction. The fault current will flow from the substation and DG units to the fault location which has the lowest potential point. Therefore, as shown in Table 6-1, when a fault occurs in one of the zones between the substation and other zones that involve DG units, the following two conditions apply [50]:

1) The fault is fed by both the substation and the DG units in the downstream zones. The current in both boundary breakers of this zone will thus flow into the zone.
2) The current in at least one of its breakers will exceed its limit.

The first condition means that there is no fault outside this zone. However, this condition only is not enough. This is because it can be implemented under normal conditions (i.e., a reverse power flow due to a high generation level produced from DG units in the downstream zones). Therefore, the second condition always applies. Furthermore, when a fault occurs in a zone that has no downstream zones containing DGs, its entrance breaker current will exceed its limit.

Table 6-1: Logic circuit for zone binary signal and fault current flow

Zone binary signal	Fault current flow
	 Type 1: zone between the substation and other zones with DG  Messages between feeder and zone agents
	 Type 2: zone has no zones with DGs downstream  Messages between feeder and zone agents

Based on these possible conditions for fault occurrence and on the proposed control structure in Figure 6-4, the fault location detection and isolation algorithm for a single fault at a time can be described as follows:

- The monitoring devices using direction and over-current relays provide two signals to indicate a change in the status of the current flow. One signal indicates that the magnitude of the current exceeds its limit, and the other indicates the direction of the current.

- Zone agents use these signals as inputs to a logic circuit in order to generate simplified binary status signals (0 or 1), as shown in Table 6-1.
- Zone agents then send these binary signals to their feeder agent through inform messages.
- After the feeder agent receives these binary signals from its zone agents, it determines which zone is the faulty zone, as shown in Table 6-1:
    - ➢ If it receives a binary signal with a value of one from a type 1 zone, it sends a request message to this zone agent asking it to open its boundary breakers.
    - ➢ If it receives a binary signal with a value of one from a type 2 zone, it sends a request message to this zone agent asking it to open its boundary breakers.
    - ➢ If it receives a binary signal with a value of one from more than one type 2 zones, it sends a request message to the last zone agent at the feeder end side asking it to open its boundary breakers.

6.4.2 Stage 2: service restoration

The restoration plan has two primary objectives: 1) to provide as much service as possible to the customers with consideration of their priorities as formulated in equation (6.1); and 2) to be implemented as fast as possible. The second objective can be translated into minimization of the required number of switching operations as formulated in equation (6.2). Therefore, the search space of the problem has many combinations (i.e., candidate solutions) of possible switching operations. Furthermore, these possible combinations increase with the increase of networks' dimensions. As a result, the majority of the published work in this area proposed expert or heuristic based algorithms and they didn't apply global optimization algorithms (i.e., meta-heuristic & mathematical programming). The reasons of preferring expert-based algorithms over global optimization algorithms in the service restoration problem are [19][97]:

- The global optimization algorithms may arrive at high quality solutions. But, they take an inappropriately long time to reach a solution. Therefore, they considered as a slow tool especially for realistic distribution networks. From another side, a well-designed expert-based algorithm can arrive at equally good solution and the benefit from the computational burden of global techniques may not always be realized.
- The global optimization algorithms propose the final configurations without details about how to implement this solution. However, expert-based algorithms provide the restoration

plan with a feasible sequence of switch operations in order to guarantee that implementing them will not cause unwanted effects on the network.

In this work, an expert-based decision-making algorithm has been proposed to govern the control agents. The rules have been extracted from the practical issues as presented in section 6.2.2. Therefore, based on the problem objectives, the proposed algorithm implements a multi-step procedure while avoiding visits to infeasible solutions as follows:

1. *Group restoration:* the outage loads are restored as a single group with one switching action if there is one of the supporting feeders that have enough capacity.
2. *Zone restoration:* if group restoration is not valid, zone restoration is implemented by restoring as many zones as possible through suitable paths.
3. *Load transfer:* some zones are transferred from the main backup feeders to their neighbors to restore the remainder of the unrestored loads.
4. *Load shedding:* the least priority loads are shed to restore the remainder of the unrestored loads with the remaining limited capacity.

In this way, the algorithm can build a restoration plan with re-energizing as much as possible of the out-of-service loads taking their priorities into consideration and minimizing the number of switching operations as much as possible.

Figure 6-5 shows the overall procedure for the proposed agents. The remainder of this section describes the operating mechanism of each agent type during the restoration process.

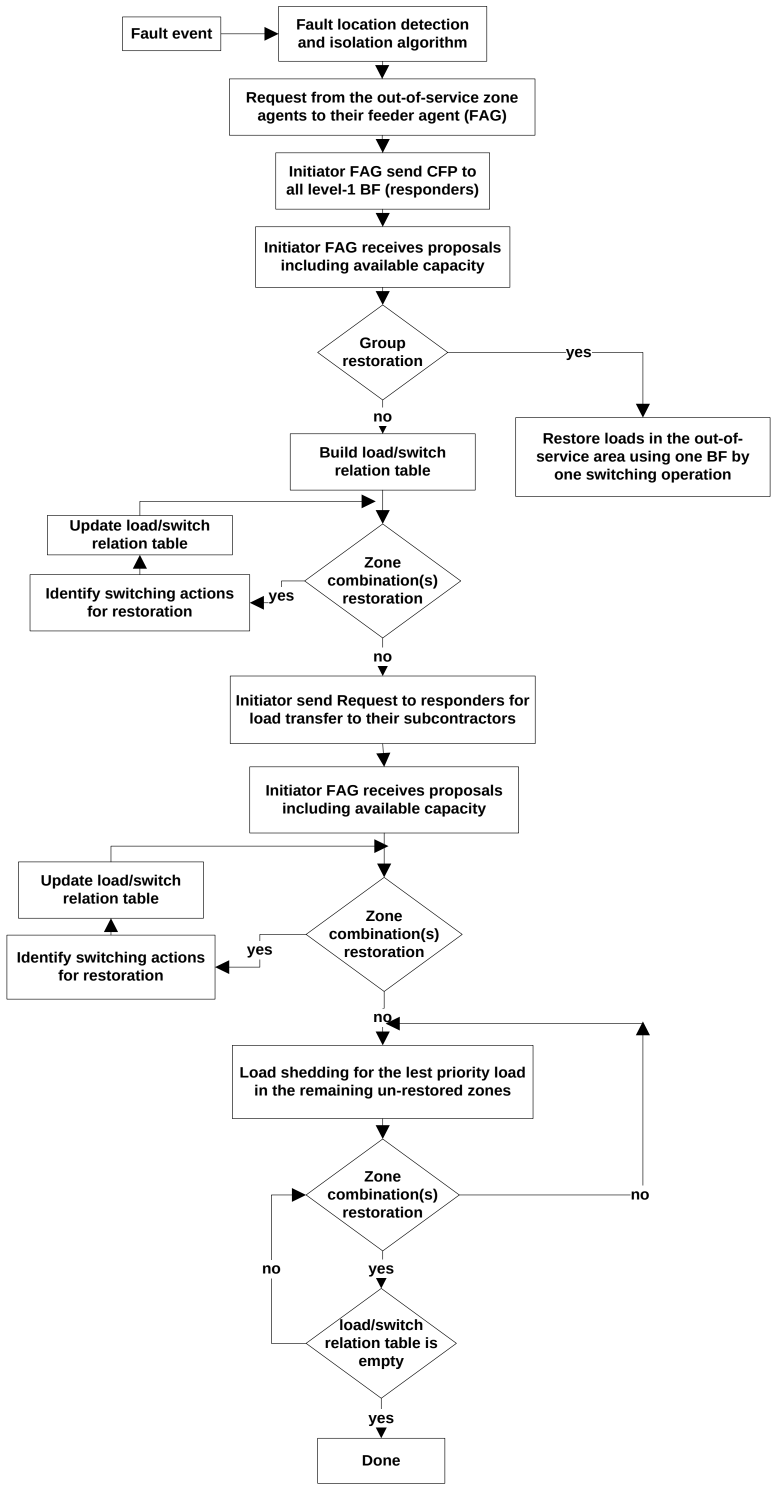


Figure 6-5: Overall self-healing procedure using the proposed agents

6.4.2.1 Initiator control agent operating mechanism

After isolating the faulty component, the downstream zones of the affected feeder are isolated. These affected zones communicate with their feeder agent (initiator) in order to build a restoration plan. The details of the proposed architecture are as follows:

1. Each zone agent in the out-of-service area sends a request message including its load demand and priority to the initiator:

$$Zoneindex_i = \sum_{j=1}^{ns} wf_i^{\,j} * S_i^{\,j} \tag{6.6}$$

   where wf_i^j, S_i^j: weighting factor and load demand of customer *j* in zone *i*, respectively, and *ns*: total number of customers in zone *i*.

2. The initiator feeder agent starts the negotiations process using a contract net protocol (CNP) by sending *call for proposal* (*CFP*) messages to its neighboring responder feeder agents.
3. After the responder feeder agents reply with their *proposal* messages, which contain their available remaining capacity (ARC), the initiator agent sends these two input items to its decision maker. The input consists of the load demands and priorities from the out-of-service zone agents, and the ARCs from the responder agents.
4. Using the rules that have been extracted from the practical issues with the inputs, the decision maker component in the initiator agent can determine its output.
5. To check for group restoration, the initiator agent compares the maximum ARC with the total demand from the out-of-service zones:

$$Is \ \max_{i \in n_{BF1}} (ARC_i) \geq \sum_{i=1}^{nz} S_i \tag{6.7}$$

   where S_i: load demand of zone *i*; *nz*: the total number of out-of-service zones; and n_{BF1}: the total number of responder agents.

6. If equation (6.7) is satisfied, the initiator decides to implement group restoration by restoring all out-of-service zones through one switching operation.
7. In this case, the initiator agent sends an *accept-proposal* message to the responder agent that has the highest ARC and sends a *request* message to its zone agent that is the neighbor of the selected backup feeder asking it to close its tie switch for the completion of the restoration plan.

8. If equation (6.7) is not satisfied, the initiator decides to implement zone restoration by building a zone/switch relationship table [56]. Therefore, the initiator starts to identify all possible out-of-service zone combinations (Z_C) as follows:

$$Z_C = \left\{ Z_{Ci} = \bigcup_{j=1}^{i} Zone_i \right\} i = 1, \ldots, nz - 1 \tag{6.8}$$

where Z_{Ci} : a collection of *i* adjacent zones bounded by two or more switches, at least one of which is a tie switch. After the elements in Z_C are identified, the initiator builds its zone/switch relationship table. The information in this table is 1) the zones in each combination Z_{Ci}, 2) the bounded switches for each combination Z_{Ci}, 3) the load demand S_{Ci} in each combination Z_{Ci} according to equation (6.9), and 4) the equivalent priority index for each combination Z_{Ci} according to equation (6.10).

$$S_{Ci} = \sum_{j=1}^{i} S_j \tag{6.9}$$

$$Zcindex_i = \sum_{j=1}^{i} Zoneindex_j \tag{6.10}$$

9. Based on the zone/switch relationship table and the ARCs received from the responder agents, the initiator agent searches for possible combinations of zone restoration. It compares the ARCs with the elements of Z_C, which are listed in descending order based on their priority indices in order to restore the highest priority first.
10. After checking for all available restoration possibilities, the initiator agent does the following 1) sends accept-proposal messages to those responders that will be used in the restorations, 2) places tie switches between the feeder agents that have accepted proposals and the selected combinations for the restoration in a switch-to-be-closed list (SCL), 3) places the bounded sectionalizing switches of the selected combinations for restoration in a switch-to-be-opened list (SOL) in order to satisfy the radial constraint, and 4) updates the zone/switch relation table.
11. Then it checks to determine whether all zones have been restored (i.e., the table is empty) or not.
12. If the table is empty, the initiator sends request messages to the appropriate zone agents asking them to open their sectionalizing switches that are included in the SOL list in order to partition the outage area and then to close their tie switches that are included in the SCL list.
13. If the table is not empty, the initiator sends request messages to the responder feeder agents that are neighbors of the remaining unrestored zone combinations. This request makes these

responders to start negotiations with their neighbors (subcontractors) to find load transfers that can provide additional ARC. The request message includes the load demand required for the remaining unrestored zone combinations.

14. After these responders reply with their new ARC, the initiator agent repeats steps 9-11.
15. If the table becomes empty, the initiator sends request messages to the appropriate zone agents to open their sectionalizing switches included in the final SOL list and then to close their tie switches included in the final SCL list.
16. If the table is not empty, the initiator determines the necessity for load shedding of zones with the lowest priority zone index in the remaining unrestored zone combinations. It then checks to determine whether all zones have been restored, as in step 9.
17. The initiator agent repeats step 16 until the zone/switch relationship table becomes empty, when it then executes step 15 in order to implement the switching actions required for the completion of the restoration process.

Figure 6-6 shows the overall procedure for the operation of the proposed initiator control agent.

6.4.2.2 Level-1 backup feeder operating mechanism

Load transfer from the out-of-service area to neighboring feeders makes these supporting feeders loaded heavier than before. In the same time, each feeder has a maximum amount of current it can sustain before it becomes overloaded or a protection device operates. Therefore, the available remaining capacity (ARC) of each supporting feeder is used. The ARC term represents the maximum load that can be supplied by each feeder without violation of its current and voltage constraints. Each closing or opening of a switch creates a new network topology with a new set of voltages, line currents, and active/reactive power balance. Hence, due to the varying topology and the connected loads, bus voltages and line currents change during the service restoration process. For example, higher currents will appear only in branches between the root node (i.e., substation) and the correspondent node at the tie switch with the affected feeder (i.e., restoration path o-a-b as shown in Figure 6-7. Therefore, the maximum additional load, which will not lead to overloading in the supporting feeder, can be obtained by considering the current constraint at zones of this restoration path only [22]. Furthermore, because of the radial topology of distribution networks, as the load point comes far away from the substation, its voltage drop increases, and it becomes maximum at points located at the end of the feeder (i.e., point *w* as shown in Figure 6-7). Therefore, the maximum additional load, which will not lead to unpermitted low voltages in the supporting feeder, can be obtained by considering the voltage constraint at zones including these points only [104].

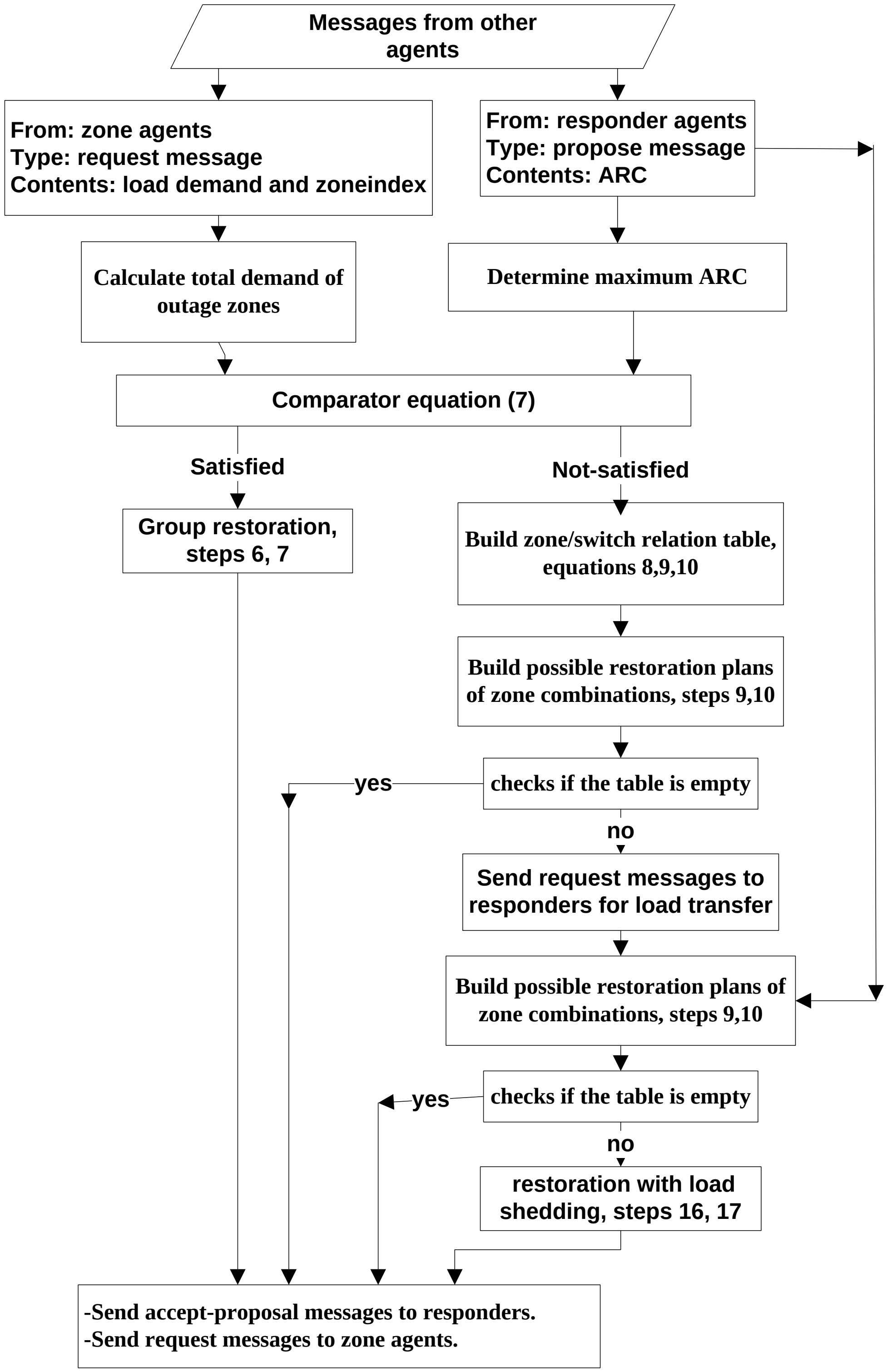


Figure 6-6: Procedure for the proposed initiator control agent

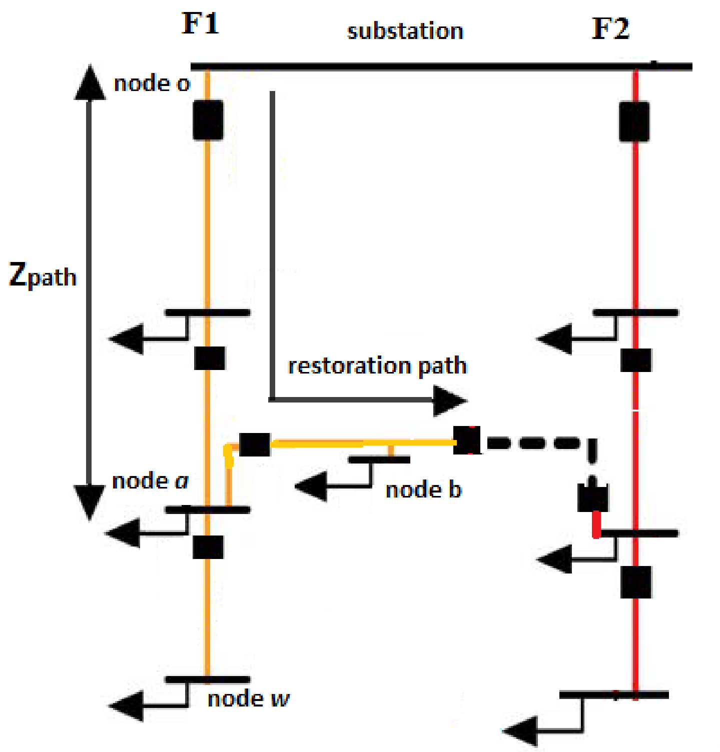


Figure 6-7: Restoration path Z_{path} for supporting feeder

The operating mechanism of level-1 backup feeder agents (responders) will be as follows:

1. After the responder agent receives a *CFP* message from the initiator, it starts to build its proposal (ARC).
2. In order to determine its ARC, the responder agent sends *query* messages to its appropriate zone agents about their spare capacities and bus voltage values.
3. Each zone agent replies by sending an inform message that includes the spare capacity $I_M(k)$ of its branch and/or the bus voltage magnitude of its bus:

$$I_M(k) = I_{\max}(k) - I(k) \tag{6.11}$$

   where $I_M(k)$: represents the available capacity of each zone before it becomes overloaded and before its protection device operates; Imax(k): upper bound current in branch k; and I(k): magnitude of the current flow in branch k.
4. In the case of having more than one branch, the zone agent sends the minimum spare capacity of its branches. Furthermore, a zone with more than one bus sends the lower voltage magnitude of its buses.

5. After the responder agent receives these replies from its zone agents, it calculates its ARC as follows [22]:

$$I_C = \min_{k \in j}(I_M(k)) \tag{6.12}$$

$$I_V = \frac{V_w - V_{\min}}{Z_{path}} \tag{6.13}$$

$$I_{available} = \min(I_C, I_V) \tag{6.14}$$

where j: zones along the restoration path (i.e., path o-a-b in Figure 6-7); V_w: the lowest bus voltage magnitude of the values received from zone agents; V_{min}: minimum allowable voltage magnitude in the network (i.e., 0.9 p.u.); Z_{path}: series impedance of the path between the substation and the node closest to node w on the restoration path (i.e., part of the restoration path between root node o and node a in Figure 6-7). Furthermore, this impedance could be determined by carrying out offline simulation if the forecasted load is available (i.e., to determine which point among the points located at the end of the feeder will have minimum voltage, hence, its Zpath will be used). Another option is to determine Zpath for those possible points in advance and based on the received minimum voltage value, the appropriate impedance is used. In this work the first option was used to determine this Zpath; I_C: maximum spare capacity of the restoration path without overloading to satisfy the current limit constraint; I_V: maximum spare capacity of the restoration path to avoid under-voltage at any node to satisfy the voltage limit constraint; and $I_{available}$: maximum spare capacity of the restoration path without violating both current and voltage operating constraints.

6. This spare capacity ($I_{available}$) from this supporting feeder will be used to restore an out-of-service load $S_L = P_L + jQ_L$ at voltage V_L,

$$|S_L| = |V_L| * |I_{available}| \tag{6.15}$$

In order to include the voltage limit $V_L \geq 0.9$ pu. Therefore, the ARC for this feeder will thus be

$$|S_L|_{\max} = 0.9 * |I_{available}| \tag{6.16}$$

As a result, this value of ARC guarantees that voltage limits will not be violated for the restored zones.

7. Each responder sends to the initiator agent a propose message that includes its ARC.

8. In case that the responder receives an accept-proposal message from the initiator, it replies to the initiator by sending an inform message to indicate that it is committed to the completion of the task.
9. In case that the responder receives from the initiator a request message for additional ARC through load transfer, it begins negotiations by sending CFP messages to its neighboring subcontractor feeders if available.
10. Load transfer from a level-1 backup feeder (responder) to a level-2 backup feeder (subcontractor) may secure a margin that could enable to restore the remaining out-of-service zone combinations. The best amount of the transferred load (TL) is then

$$TL = (\text{load of remaining unrestored zone combinations}) - (\text{remaining ARC of this level-1 backup feeder}) \tag{6.17}$$

11. The TL cannot be exactly the same as what is required. This is because of the discrete nature and the limited ARC of the level-2 backup feeders. The responder thus selects its zones to be transferred to the level-2 backup feeder as follows:

$$\text{Transferred zone(s)} \approx \min(TL, \text{ARC of level-2 BF}) \tag{6.18}$$

12. The responder determines the zones to be transferred to the subcontractor side, then it sends a propose message to the initiator with its new ARC.
13. If the responder receives an accept-proposal message from the initiator, it sends a confirm message to the subcontractor agent and request messages to the appropriate zone agents asking them to open the bounded sectionalizing switches for the selected zones to be transferred and to close the tie switch to complete the load transfer to the subcontractor.

Fig. 6.8 shows the overall procedure for the proposed responder control agent.

6.4.2.3 Level-2 backup feeder operating mechanism

The operating mechanism of the subcontractor agents is similar to steps 1-7 in the mechanism of the responder agents, and subcontractor agents also negotiate with responder agents.

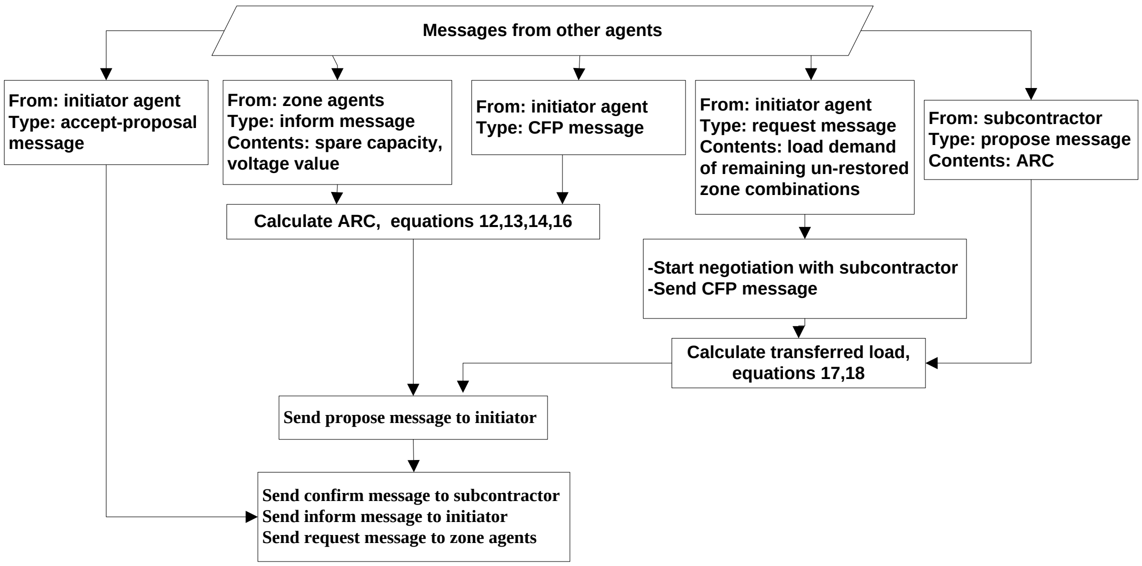


Figure 6-8: Procedure for the proposed responder control agent

6.5 Practical issues related to the implementation of the proposed self-healing algorithm

This section discusses some issues related to the practical implementation of the two-way communication control algorithm.

6.5.1 Implementation of two-way communication

Most of smart grid functions depend on utilizing distributed algorithms. Moreover, the different tasks are executed in a distributed manner on different processors/controllers simultaneously. Coordination among these controllers is done using message-passing communication. Therefore, two-way communication is the key technology in the implementation of the smart grid concept. The appropriate design for the physical, data, and network communication layers is still a topic of intense debate. There are several candidate communication technologies to be used such as fiber optics, wireless, and wire line. Although, wireless communications are the most recent type to be used, they face significant challenges with respect to the reliability due to the harsh and complex power system environment [105]. From other side, power line communication (PLC) may be considered a good candidate for smart-grid applications. This is because the lines already exist. Therefore, a power grid will be the information source and the information delivery system[106].

6.5.2 Communication link failure issue

In order to have good decisions, enough information about the system is required. This information is collected from different subsystems through communication. For reliable control system, if communication between any two agents fails for any reason, the system should be able to continue the execution of the algorithm. Therefore, a time-out procedure can be introduced for communication between agents. The time-out procedure is simply the expectation of executing specific tasks within a specific maximum predetermined time interval. Thus, when the time expected for the receipt of a message from another agent is exceeded, the receiving agent will modify the execution of its algorithm in order to tackle the problem. For example, in this proposed work, communication among agents is limited to two levels: the first level between the feeder agent and its zone agents, and the second level between neighboring feeder agents. The algorithm does not allow zone agents to negotiate/communicate with one another. This is because of their high numbers in practical systems. Therefore, this limitation reduces the amount of communication and hence the delay time during the negotiation process. Furthermore, as a backup algorithm, if one zone agent were to lose its ability to communicate with its feeder agent, it can reroute the communication path by sending its message to its neighboring zone agent. In consequence, the latter agent will forward this message to their feeder agent and then forward its reply to the former zone agent.

6.6 Case studies

The proposed self-healing algorithm was tested on a distribution system having two substations, four feeders, and 70 nodes [101]. The following factors were taken into consideration:

1. The renewable based DG units (i.e., wind based and solar based units) are characterized as fluctuating power sources due to changes in wind speed and solar irradiance. *Therefore, at each time interval depending on the accuracy of the forecasting, a zone agent with this type of DG sends an inform message containing the power predicted to be generated during this time interval to its feeder agent.*
2. In order to represent different customer types and to include their priorities and to estimate accurately the loading of zones along each feeder as well as the ARC of the supporting feeder, the typical hourly load patterns of residential, commercial, and industrial customers are used [89].
3. Based on the policies of each utility regarding the number of switching operations allowed and the forecasting accuracy with respect to renewable DG units and load demand, the service restoration

algorithm can provide an overall plan for the whole restoration period or multiple plans, one plan for each time interval.

4. *As mentioned in section 6.2.2, the peak load and the lowest generated power from renewable-energy-based DGs over each restoration plan period are used to build this restoration plan.*
5. The islanded operation of DGs is not included in this work.

For automated systems, utilities have installed intelligent electronic devices (IEDs) such as modern protective relays and recloser controls in order to provide local measurement and control capabilities. These devices provide the required input and output signals for the control system, such as switch open/close indication, live/dead voltage indication, fault current indication, load current and open/close commands. In this work, the data required for the simulation were obtained from load flow calculations in Matlab software. The algorithm for each control agent was implemented in a Java Agent Developing Framework (JADE), which provides the required communication and platform services, and the distribution system was modeled with Matlab. Figure 6-9 shows the simulation sequence. The forecasted load demand and DG generation are fed into the distribution network. Then the generated data are sent to the MAS in JADE. The MAS executes the algorithm, and the switching actions are sent back to the distribution network and held until the end of the plan time interval.

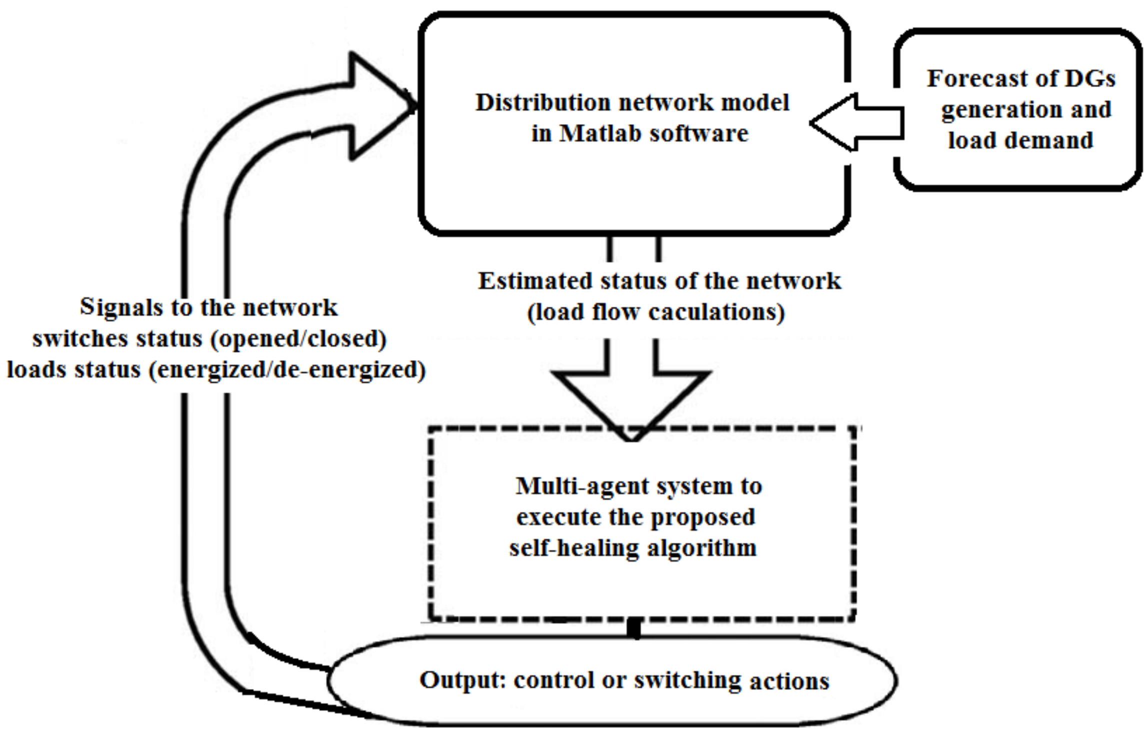


Figure 6-9: Simulation sequence and data flow between the MAS and the distribution network

For the sake of verification and comparison, three scenarios are considered in the simulation results:

- First proposed scenario with consideration of variant load.
- Second scenario builds its restoration plan based on the pre-fault values, and then responds to any overloading through post-restoration load management using load transfers and shedding.
- Third scenario builds its restoration plan based on the maximum known daily values of loads.

The first scenario implements the proposed algorithm so that:

1. The peak load at each out-of-service zone over the restoration time interval is determined.
2. For the candidate supporting feeders, the distribution network simulator runs hourly power flow over the restoration time interval.
3. The branch current flow and voltage for each zone per any candidate supporting feeder are estimated (i.e., the highest branch current and lowest voltage).
4. In case that all zones in a candidate supporting feeder have similar load patterns, only one power flow for the peaking hour will be required.
5. These estimated currents and voltages are sent to responder agents so that they can calculate their ARC, as explained in section 6.4.2.2.

Therefore, based on the simulation sequence shown in Figure 6-9, the forecasted load and generation data are fed to the power flow program in Matlab to run power flow for the supporting feeders with 1 hour time step. Then the output voltages and currents from power flow program are sent to MAS. The MAS executes the algorithm and send the switching decisions to the distribution system model in Matlab. The distribution network held until the end of the plan time interval. Also, in case that another fault happens or the system violates its operational limits (voltage and current limits); the new information will be forwarded to the MAS to take the appropriate actions.

6.6.1 **Simulation study without DG units**

Figure 6-10 shows the system with zone numbers. Feeders F1 and F2 are residential feeders, feeder F3 is an industrial feeder, and feeder F4 is a commercial feeder. A fault is assumed to have occurred at Z1 in feeder F4. Two outage periods were selected:

- During the lightest loading period of the system (i.e., from 1 AM to 6 AM); and
- During the highest loading period of the system (i.e., from 5 PM to 10 PM).

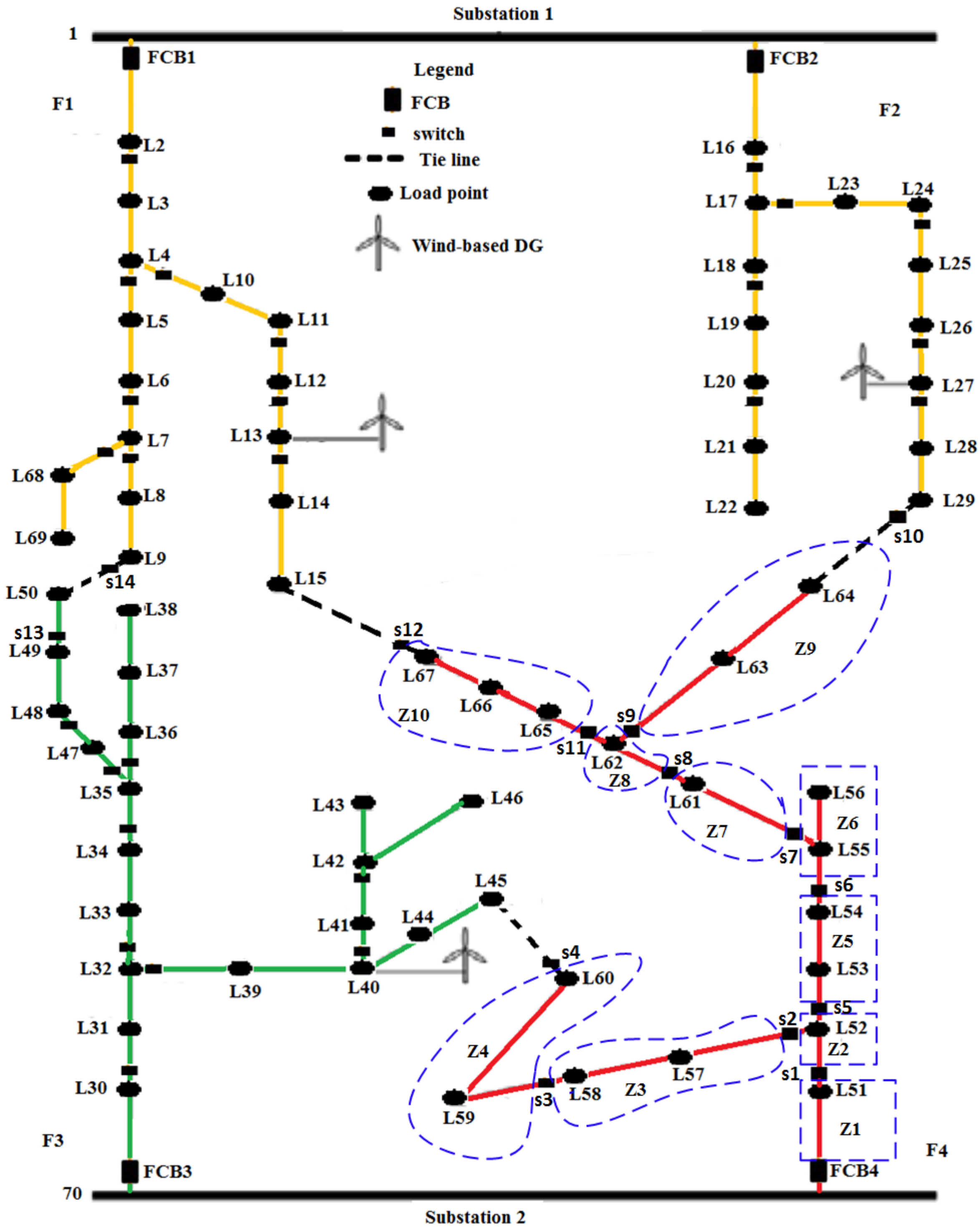


Figure 6-10: System under study

6.6.1.1 Case 1: fault occurred during the lightest loading period

a) First scenario

Based on the proposed fault location and isolation algorithm, the Z1 agent (ZAG1) sends an inform message to its feeder agent (FAG4) that includes a binary signal with a value of one. Then FAG4 sends a request message to ZAG1 to open its sectionalizing switch s1 for fault isolation, and FCB4 will also open in response to the fault. After the fault has been isolated, the out-of-service zones (zones 2-10) start the restoration algorithm by sending request messages to their FAG4. The contents of the request messages are load demand and priority index. FAG4 (initiator) starts the negotiation process by sending CFP messages to its neighbors FAG1, FAG2, and FAG3 (responders).

FAG1, FAG2, and FAG3 send query messages to their ZAGs to obtain their ARCs. These ZAGs then send inform messages to their FAGs. The contents of the inform messages are spare capacity and voltage magnitudes. Each responder FAG calculates its ARC using these data and sends a propose message to the initiator. FAG4 evaluates these proposals by comparing the proposed ARCs with its required demand. In this case, the available ARC from FAG3 is sufficient compared to that required; FAG4 thus determines to use group restoration by closing only s4. FAG4 sends accept-proposal message to FAG3. FAG3 then reply with inform message to indicate that it is committed to completing the task. FAG4 places switch s4 on the switch-to-be-closed list (SCL). In consequence, FAG4 sends a request to ZAG4 to close its tie switch s4 for restoration.

b) Second scenario

The sequence is the same as in the first scenario. Based on the pre-fault data, group restoration is implemented by closing s4. No constraint violation occurs till the end of the restoration period.

c) Third scenario

Based on the daily peak load demand, zone restoration and load transfer are implemented. FAG3 transfers its load (L50) to FAG1 by opening switch s13 and then closing switch s14. Thus, it will enable FAG4 to restore all outage zones. FAG4 will implement zone restoration by restoring zones (2-7) from FAG3, zones (8-9) from FAG2, and zone 10 from FAG1. The switching operations to be implemented are: opening switches s8 and s11 to divide the outage area into three groups; then closing switches s4, s10, and s12 to complete the restoration process. There is no constraint violation occurrence till the end of the restoration period. Table 6-2 shows the open switches, losses, minimum voltage, switching operations, and the load shed during the restoration plan [Base: 11 KV, 1MVA].

Table 6-2: Open switches, loss, minimum voltage, switching operations, and load shed for case 1

Outage period		1 AM to 6 AM		
Scenario		1st scenario (proposed)	2nd scenario (Pre-fault)	3rd scenario (peak load)
Outage zones		Zones 2-10	Zones 2-10	Zones 2-10
Min. voltage (p.u)		0.9277	0.9277	0.9690
Switching actions		close s4	close s4	open s13, close s14 open s8,s11 close s4,s10,s12
Loss	MWh	0.2435	0.2435	0.1747
	MVARh	0.2048	0.2048	0.1486
Load shed		None	None	None
Remarks		None	None	None

Based on the results, the second scenario (pre-fault) has the same restoration plan as the first scenario. Furthermore, the third scenario provides higher voltage and lower losses because it has been built based on the peak load. However, the third scenario required a higher number of switching operations (7 switching operations compared to the first scenario that required one switching operation only). Therefore, first scenario is a good alternative to the third one and aligns more closely with operational practices.

6.6.1.2 Case 2: fault occurred during the highest loading period

Table 6-3 shows the open switches, losses, minimum voltage, switching operations, and the load shed during the restoration plan for the three scenarios.

Table 6-3: Open switches, loss, minimum voltage, switching operations, and load shed for case 2

Outage period		5 PM to 10 PM		
Scenario		1st scenario (proposed)	2nd scenario (pre-fault)	3rd scenario (peak load)
Outage zones		Zones 2-10	Zones 2-10	Zones 2-10
Min. voltage (p.u)		0.9087	0.9001	0.9071
Switching actions		open s8,s11 close s4,s10,s12	open s8, close s4,s12, then at 6 PM: open s11, close s10	open s13, close s14 open s8,s11 close s4,s10,s12
Loss	MWh	1.3419	1.3501	1.3129
	MVARh	1.1717	1.1798	1.1486
Load shed		None	None	None
Remarks		None	F1 overloaded at 6 PM	None

Based on the results, both of the first and the second scenarios required the same switching actions (i.e., opening s8, s11 and closing s4, s10, s12). However, in the first scenario, these switching actions were implemented at the beginning of the restoration period. In the second scenario, the switching actions had to be implemented in two stages: opening s8 and closing s4, s12 at the beginning of the restoration period and then opening s11 and closing s10 at 6 PM in order to relieve the overloading of feeder 1. Therefore, the restoration plan by the second scenario causes customers at zones Z8 and Z9 to be interrupted again during the switching actions at 6 PM. Furthermore, as shown in Table 6-3, the first scenario provides a higher voltage and lower losses during the restoration period. Also, the third scenario required a higher number of switching operations (7 switching operations compared to the first scenario that required 5 switching operations).

6.6.2 **Simulation study with DG units**

For the sake of comparison with cases 1 and 2, the outage periods and fault location were selected to be the same as in the previous cases. As shown in Figure 6-10, three wind-based DG units, each with a rating of 0.5 MW were inserted at load points L13, L27, and L40. Figure 6-11 shows the load and the total generation from these DG units over 24 hours. The sequence among agents is the same as in the previous cases. Table 6-4 shows the open switches, losses, minimum voltage, switching operations, and the load shed during the restoration plan.

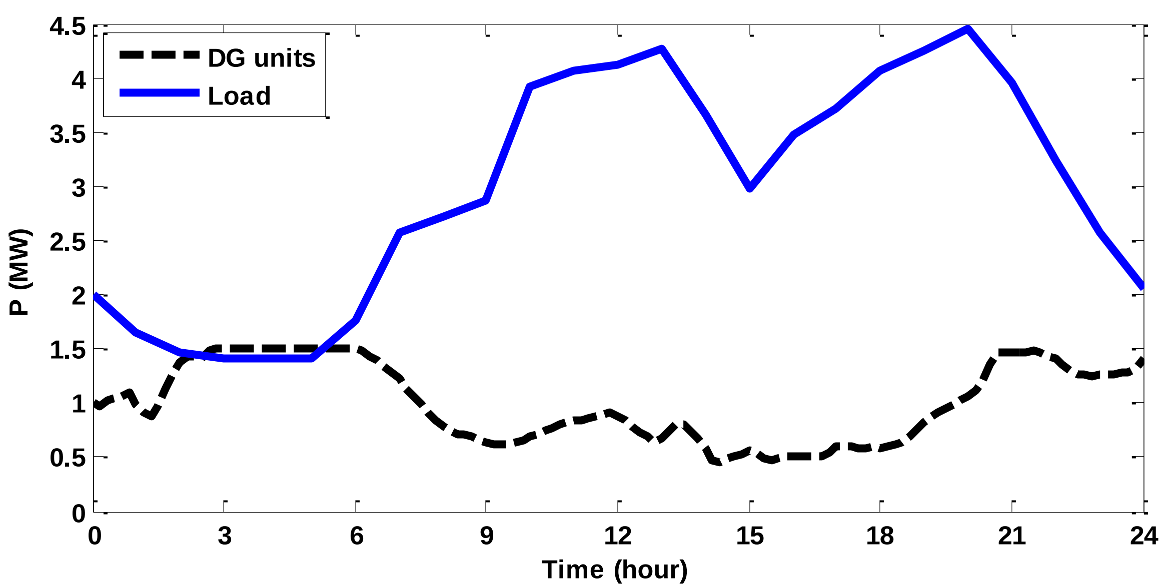


Figure 6-11: Load and DG power profiles over 24 hours

Table 6-4: Open switches, loss, minimum voltage, switching operations, and load shed with DG

Outage period		1 AM to 6 AM	5 PM to 10 PM
Outage zones		Zones 2-10	Zones 2-10
Min. voltage (p.u)		0.9370	0.9106
Switching actions		close s4	open s8, close s4,s12
Loss	MWh	0.2090	09623
	MVARh	0.1659	0.8555
Load shed		None	None
Remarks		None	None

For the case when the fault occurred during the lightest loading period from 5 PM to 10 PM, the required number of switching actions is reduced from 5 in the case without DG to be 3 only. Therefore, DG units provide an effective support to the ARC for responder feeder agents.

6.7 Conclusion

From the case studies and based on the results shown in Tables 6-2, 6-3, and 6-4, it appears that the proposed algorithm has the following advantages:

- At fault occurrence, the affected feeder agent receives binary signals from its zone agents. Thus, it can determine which zone is the faulty zone and isolates this faulty zone.
- During the mean time to repair the fault, it builds a restoration plan that includes the following:
    1. Consideration of variable demand and generation
    2. Consideration of different customer priorities
    3. Satisfaction of operational voltages and currents constraints
    4. Provision of the minimum number of switching operations to reduce operational costs and to avoid further switching that causes interruption to some customers
    5. Benefits of supporting power derived from DG units

Finally it can be concluded that:

Scenario 1 (proposed) with consideration of variant load is more effective than scenario 2 based on the pre-fault values because the former results in a restoration plan that may involve a lower number of switching operations and that does not require further reconfigurations and customer interruptions.

Scenario 1 (proposed) is more effective than scenario 3 based on the peak daily load because the former results in a restoration plan that involves a lower number of switching operations and it avoids unnecessary load shedding that may be required by scenario 3. Therefore, scenario 1 is aligning with the operational practices.

Chapter 7
Conclusions, Contributions and Future Work

7.1 Conclusions

The research in this thesis tackled the problem of distribution system planning and self-healing with distributed generation. The following points summarize the work presented in this thesis:

1. This work started with a literature survey on distribution automation, smart grid, distributed processing, fault location and isolation, service restoration, distributed generation, centralized and distributed restoration methods, multiagent system. The different approaches used to solve the service restoration problem, accompanied by the advantages and the disadvantages are discussed.

2. In order to optimally reconfigure distribution systems, a genetic algorithm based technique is proposed taking into consideration the effect of load variation and the stochastic power generation of renewable based DG units. The presented method determines the annual reconfiguration scheme considering switching operation costs in order to minimize the annual energy losses by determining the optimal configuration for each season of the year. The key idea in this work is to generate a probabilistic generation-load model that includes all possible operating conditions; hence, this model can be accommodated into a deterministic power flow formulation. The main contributions of this technique can be summarized in the following points:
    - The proposed technique guarantees no violation of any of the system constraints under any operating conditions.
    - The technique guarantees satisfied solution for all possible operating conditions.
    - A by-product of the proposed technique is a power flow solution for all possible operating conditions, which will provide a useful database for the system operator.
    - The switching operation cost is considered to allow the reconfiguration scheme to improve or at least balance the benefit from system loss reduction against the cost of switching.

3. A probabilistic planning technique was proposed in order to allocate renewable DG units (i.e., wind, solar, and natural gas turbine) simultaneously with network reconfiguration in distribution systems. The objective of the proposed technique was to minimize: cost as an economic issue (costs of line upgrades, energy losses, switching operations, and DG capital, operation and maintenance costs) and greenhouse gas emissions as an environmental issue (emissions from both grid and DG units), while the constraints included the voltage limits, the thermal limits of the feeder, the maximum investment capacity on each bus, the discrete size of the DG units, and the maximum penetration limit of the DG units. The main contributions of this technique can be summarized in the following points:
    - The work proposes a multi-year multi-objective joint reconfiguration and DG allocation. The considered objectives are: economic one (costs of line upgrades, energy losses, switching operations, and DG capital, operation and maintenance costs) and environmental one (emissions from both grid and DG units).
    - Unlike, previous work on joint reconfiguration and DG allocation that considered the load is fixed or used one year only, the effect of stochastic nature of renewable DG output power, load variability, and load growth across the planning horizon have been considered in evaluating the different planning objectives.

4. Regarding the impact of load variation, wind generation and switch type on the service restoration problem, a methodology was proposed to investigate the effect of numerous practical aspects such as variations in the load and the priorities of the customers, price discounts for in-service customers based on their participation in a load-curtailment scheme that permits other customers to be supplied, the presence of manual and automated switches, and the incorporation of DG units (dispatchable and wind-based DG units) in the restoration process. The results show that building one overall restoration plan for the whole outage period with the consideration of load variation is more effective than the traditional scenarios in literature (i.e., peak load scenario and a scenario that employs the pre-fault load (i.e., the load level at the time just prior to the occurrence of the fault)). The results also show that DG units provide a source of support power during the restoration process and may therefore decrease the number of switching operations required and increase the opportunity for restoring additional unrestored customer loads.

5. Finally in this work, the smart grid concept and technologies have been applied to construct a self-healing framework for use in smart distribution systems. The proposed multiagent system is designed to automatically locate and isolate faults, then decide and implement the switching operations to restore the out-of-service loads. The proposed control structure has two layers: zone and feeder. The function of zone agents in the first layer is monitoring, making simple calculations, and implementing control actions. Feeder agents in the second layer are assigned to negotiation. Load variation has been taken into consideration to avoid the need for further reconfigurations during the restoration period. An expert-based decision-making algorithm has been used to govern the control agents. The rules have been extracted from the practical issues related to the service restoration problem. The main contributions of this technique can be summarized in the following points:
   - It can locate and isolate the faulty component.
   - During the mean time to repair the fault, it builds a restoration plan that includes the following:
     a. Consideration of variable demand and generation
     b. Consideration of different customer priorities
     c. Satisfaction of operational voltages and currents constraints
     d. Provision of the minimum number of switching operations to reduce operational costs and to avoid further switching that causes interruption to some customers
     e. Benefits of supporting power derived from DG units

7.2 Contributions

The main contributions of this thesis can be highlighted as follows:

1. Developed a method to determine the optimal reconfiguration scheme of distribution systems to minimize the annual energy losses taking into consideration the switching operation cost. The method considers the probabilistic nature of the DG units which are fueled by renewable energy sources and load variation.

2. A novel multi-year multi-objective framework was introduced for joint DG allocation and network reconfiguration. The proposed framework combines the random behavior of renewable DG units, the discrete size of the available DG, and the load profile into a

deterministic optimal power flow formulation. The model has the privilege of maintaining no violation of any of the system constraints under any operating condition.

3. A novel cooperative multi-agent framework was proposed for self-healing operation for smart distribution feeders. The proposed framework is designed to automatically locate and isolate faults, then decide and implement the switching operations to restore the out-of-service loads. Load variation has been taken into consideration to avoid the need for further reconfigurations during the restoration period.

7.3 Future work directions

Building on the results and the proposed algorithms of this research work, the following summarizes some of the research points that can be carried out in the future:

1. Application of these proposed concepts to other distribution automation functions such as load management.
2. Extension of the proposed work for micro-grids.
3. Extending the planning algorithms to further objectives such as system reliability and harmonics.

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