Multi-Microgrids Reliability and Islanding Operation Enhancement, under Different Dispatchable-Renewable DG Units Penetration Levels

by

Mohammed Essam Abdelkhalek Abdelaty

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AUTHOR'S DECLARATION

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

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

Abstract

Electrical reliability assurance is a very important aspect of electrical power systems; significant consideration should be given to reliability at both the planning and operation stage of power systems. A decrease in reliability levels can lead to enormous economic losses, especially for certain industrial facilities, and utilities could be penalized for violation of the mandatory reliability standards.

Besides the traditional methods for electrical reliability enhancement, it is highly recommended to consider the adoption of innovative technologies, such as the integration of Distributed Generation (DG) units into the electrical network, especially those which are based on renewable energy source (wind and photovoltaic).

Distributed Generation technologies can be beneficial to the electrical distribution system performance. However, these pose certain technical challenges to the reliable operation of the system. In this work, we also focus on the micro-grid operation security during islanding mode of operation in the presence of DG units.

In this thesis, the unique aspects of reliability evaluation for an electrical distribution system has been performed using system-independent analytical expressions, considering probabilistic load and DG unit modeling, under different scenarios including dispatchable and renewable DG units with reasonable penetration levels.

Further, a modified adequacy formulation has been adopted during the islanding mode of operation in order to consider micro-grid load correlation and an additional load curtailment level introduced in this work. The extra curtailment is needed to ensure adequate technical constraints and allow successful micro-grid operation, when the dispatchable DG units rating in a micro-grid is less than a defined percentage of the micro-grid peak load at time of islanding. Afterwards, during islanding, a second load curtailment level is adopted as needed to ensure service continuity under

different operational conditions. A distribution test system is considered, and accordingly reliability indices are evaluated for both the worst case load scenario (islanding occurs at peak load), and for a realistic case (islanding might occur at any load level). Further, Expected Energy Not Served is evaluated.

In conclusion, the impacts of DG units and islanded operation of micro-grids have been analyzed for the enhancement of the overall reliability of the distribution system and the successful islanding mode of operational conditions.

Acknowledgements

Thanks to God for giving me the opportunity to reach this point.

In first place, I would like to express my deep and sincere gratitude, and owe my most honest thanks to my supervisor, Prof. Ehab. El-Saadany. His wide knowledge, patience, and personal guidance have been of great value for me. His understanding and constructive comments have provided continuous support from the early beginning to the end of the present thesis.

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Last, but definitely not least, my love and gratitude go to my parents and my family who have always sustained and trusted me whatever my decisions might be. And as music cannot be written in words, similarly it is not possible for me to express completely my true thankfulness towards them.

Dedication

This thesis is dedicated to my beloved parents.

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i	load Point (LP) location;
k	branch fault location;
$\lambda_{i,k}$	LP *i* annual inter freq due to a fault in component *k;*
$U_{i,k}$	LP *i* annual inter duration for a fault in component *k;*
$\mathrm{n_k}$	number of branches in the distribution system;
n_{LP}	number of load points (LPs);
N_i	number of customers connected to the *i*-th LP;
f_k	branch *k* failure rate;
$t_{r,k}$	repair time for a single failure in branch *k* expressed in hours;
$t_{s,j}$	switching time of sectionalizer *j*;
$t_{S,sc}$	switching time of the sectionalizer (indicated by the subscript *sc*) closest to the fault.
$t_{AV,j}$	time needed for DG units in island *j* to be available;
$t_{AV,sc}$	time needed for DG units in island *sc* to be available;
ρ_{sc}	adequacy probability DG units downstream from sectionalizer *sc* after
j	island index after circuit breaker *A* tripping;
sc	island index after sectioalizer *sc* tripping;
d	Distributed Generator unit (DG) location;
$f_{l.u}$	failure rate per length unit (km) for overhead lines;
l_k	length of branch k in miles;
t_r	repair time for a single failure expressed in hours;
$t_{AV,j}$	time to be available for the local DG of island *j* (time needed to connect or reconnect the generators);

$\rho_{AV,d}$ hardware availability probability of generator *d*;

$\rho^{L}_{j,l}$ load level *l* probability for island *j* during a year;

$\rho^{R}_{d,l}$ power level *l* probability of renewable DG *d*, without considering it's FOR (forced outage rate);

$\rho^{D}_{d,l}$ power level *l* probability of dispatchable DG *d* annual model, without considering it's FOR;

$\rho^{G}_{d,l}$ probability related to the power level *l* for DG *d* (dispatchable or renewable) after considering FOR;

$\rho_{A,j}$ adequacy probability for island *j* formed after switch *A* has tripped, neglecting 1st load curtailment, and when islanding might occur at any load level (%);

$\rho_{j,m}$ probability related to *m*-th combination for island *j*;

N_j number of working points at which island *j* can operate (number of combinations);

m one combination, with $m \in [1, N_j]$;

$nl_{L,j}$ number of annual load model levels for island *j* ;

NG_j number of DG units belonging to the island *j*;

$nl_{G,d}$ number of output power levels for DG *d*;

$P^{G}_{d,l}$ level *l* output power of DG *d*;

$P_{GN,d}$ DG *d* nominal power output;

MTTF mean time to failure;

MTTR mean time to repair;

MTBF mean time between failures;

Seg Segment defined by an upstream recloser;

$f_{l.u}$ failure rate per length unit (km) for overhead lines;

l_k length of branch k in miles;

$P_{j,l}^{L}$ island *j* demand when islanding occurs at load level *l*;

$P_{j,l}^{L_{new}}$ island *j* load demand at level *l*, after 1st curtailment;

$P_{j,c}^{G}$ conventional DG units power generation in island *j*;

$P_{j,m}^{L_{new}}$ island *j* demand after the 1st curtailment, at state *m*;

$P_{j,m}^{G}$ island *j* total DG units power, at state *m*;

$P_{seg\ i,peak}^{L}$ peak power load demand for segment *i*;

$R_{j,i}$ recloser at LP *i*, and by tripping forms island *j*;

$P_{j,peak}^{L}$ peak power load demand for island *j* (kVA);

$P_{j,peak,curt\ 1}^{L}$ 1st load curtailment when islanding occurs at peak power load demand level for island *j* (kVA);

$P_{j,curt\ 2\ max}^{L}$ maximum 2nd load curtailment for island *j* (kVA);

$\rho_{A,j,peak,new}$ island *j* new adequacy probability, after 1st load curtailment, when islanding occurs at peak load (%);

$\rho_{A,j,new}$ adequacy probability for island *j*, formed after switch *A* has tripped, considering 1st load curtailment, and when islanding might occur at any load level (%)

$P_{j,l,curt\ 1}^{L}$ 1st load curtailment when islanding occurs at power load demand level *l* for island *j*;

$P_{j,m,curt\ 2}^{L}$ 2nd load curtailment for island *j*, at m*th* combination;

$U_{j,1}$ annual interruption duration for fault within island *j;*

$U_{j,2}$ annual interruption duration for fault upstream island *j;*

$F_{j,1\_case}$ yearly number of faults occurred within island *j*;

$F_{j,2\_case}$ yearly number of faults occurred upstream island *j*;

$f_{j,a}$ annual failure rate of the physical components within island *j*;

$f_{j,b}$ annual failure rate of the physical components upstream island *j*;

n_1 components n◦ within island *j*;

n_2 components n◦ upstream island *j*;

$EENS_{j,1}$ EENS of island *j*, due to a fault within island *j*;

$EENS_{j,2}$ EENS of island *j*, due to a fault upstream island *j*;

$\rho_{U_{j,1}}$ annual probabilities of having $U_{j,1}$, given by dividing $U_{j,1}$ over 8760;

$\rho_{U_{j,2}}$ annual probabilities of having $U_{j,2}$, given by dividing $U_{j,2}$ over 8760;

$\rho_{c1,l}$ correlation probabilities for EENS 1st case which expresses the probability of having a service interruption when island load demand is at level *l*;

$\rho_{c2,l}$ correlation probabilities for EENS 2nd case which expresses the probability of having a service interruption when island load demand is at level *l*;

$U_{j,no\ DGs}$ interruption duration due to a fault, either within or upstream island *j* (1st & 2nd cases), when no DG units are installed in it;

$EENS_{j,no\ DGs}$ EENS due to a fault, either within or upstream island *j* (1st & 2nd cases), when no DG units are installed in it;

$U_{j,DG1}$ interruption duration after DG units installation in island *j*, due to fault within the same island;

$U_{j,DG2}$ interruption duration after DG units installation in island *j*, due to fault upstream the same island;

$EENS_{j,DG1}$ EENS of island *j* after installation of DG units, due to a fault within the island;

$EENS_{j,DG2}$ EENS of island *j* after installation of DG units, due to a fault upstream the island.

Chapter 1
Introduction

1.1 Research Motivation

Energy is number one concern in most of current elections in North America provinces; therefore, major attention to the future energy plan is given. Environmental representatives are supporting mainly renewable energy, known as non-dispatchable sources, since they believe that renewable energy would bring more job opportunities, and minimise risks on health impacts in the provinces. Electrical Reliability analysis has recently been under interest and major consideration for both utility industries and customers. It is necessary for the distribution utility to continuously supply the electricity with acceptable degree of power quality for customers.

Electric system reliability implies that all of the power system components should be reliable in order to insure a high degree of service continuity of the electrical power supply. Electric reliability is comprised of the following concepts [1]:

- **Adequacy**: This refers to how much the supply or the generation units are adequate to meet the electrical system load demand. In [2], a case study has been developed in order to assess the adequacy of generation units responsible for the load demand of a distribution system test system. In [3], an evaluation of the system adequacy has been performed when distributed generation are connected to the system. In [4], an assessment has been done when non-dispatchable renewable DGs (both wind and photovoltaic) are connected to the system in both grid-connected and islanding (or micro grid) modes of operation.

- **Operating Reliability**: This is related mainly to the power system infrastructure; for an accepted operating reliability, it is required that the system withstands disturbances or contingencies, and be able to continue operating even if there are problems with the infrastructure or other interconnected systems. In [5] it is shown how an assessment of an electrical power system reliability is performed.

In practical, systems are planned to meet standards for adequacy and also operational reliability. Both adequacy and reliability aspects should be considered when balancing the costs of reliability efforts and the economic impact of power outages.

Outages might occur in the generation, transmission, or distribution systems. However, generation and transmission systems are much more flexible in dealing with outages than the distribution system, so that system operators can compensate for contingencies; unless there are exceptional circumstances, consumers will not be aware of the disturbance [1]. Indeed an outage can occur in:

- *generation system:* for example if there is a technical problem in a generating unit and it must shut down, the system operator can call on reserve margins to meet demand in order not to have a loss in the supply.
- *transmission system*: for example, if a transmission line trips off, the power can flow across different lines so that demand is still satisfied in each area.
- *distribution system*: these have less flexibility in dealing with electrical outages. In fact in [6], it is reported that on average, approximately 75% of all customer number of failure and 85-90% of all customer failure durations (hours) were due to distribution system problems. The remaining failures were due to loss of supply, experienced in either transmission or generation systems. The rationale behind this diminished flexibility in the distribution systems is mainly due to *lack of redundancy* in the infrastructure built into them. That is because the cost of duplicating the infrastructure is high, and failures on these parts do not affect as many people, hence the benefits would be small.

A distribution system would experience an outage related to reasons as follows:

- lightning;
- tree contact;
- loss of supply;
- adverse weather;
- scheduled outages;
- defective equipment;
- human element (errors in system installation or operation, and deliberate damage).

An outage or blackout is known as the interruption of electricity for a certain period of time. These interruption events are both inconvenient and costly. The effects of outages on different facilities can be as follows [1]:

- *At customer level*: the inconvenience might be limited to a few moments of darkness, or loss of heat that might lead to water pipes damage, depending on the outage extent and duration. Loss of air conditioners might lead to heat stroke and loss of refrigeration might lead to food spoilage;
- *At public level*: traffic light outages might lead to car accidents, with all the economic loss for insurance companies, etc...
- *At industrial level*: delay in the arrival time of some merchandise due to trucks being stuck in traffic may involve losses of millions of dollars for industries and manufactories.

Table I shows the interruption cost for some industrial and traditional premium power users:

TABLE I: ELECTRICAL POWER INTERRUPTION COST FOR DIFFERENT CUSTOMER CATEGORIES [7].

Customer Segment	Average cost for 1 hour interruption
Cellular Communication	$41,000
Telephone Ticket Sales	$72,000
Air Reservation System	$90,000
Semiconductor Manufacturer	$2,000,000
Credit Card Operation	$2,580,000
Brokerage Operation	$6,480,000

1.1.1 Reliability in Ontario-Canada

Before spring 2002, Ontario had a traditional industry structure, where a single vertically integrated utility (Ontario Hydro) was dominating the market. At that time, the electricity market in Ontario was opened, and the market structure has changed so that Ontario has had an unbundled industry structure, characterized by [1]:

- A clear separation between responsibility for generation and transmission/distribution of electrical power. In Ontario, licensed transmission companies are Great Lakes Power, Canadian Niagara Power (Fortis), Cat Lake Power and Five Nations Energy, and Hydro One, which owns and operates 97% of the Ontario transmission grid, and serves as well as the largest distribution company in Ontario.
- The Independent Electricity Market Operator has become responsible for both the operation of the wholesale/operation market, where prices are set by market forces, and the operation of the transmission grid.
- The Ontario Energy Board (OEB) sets regulations for both IMO and all electricity market participants, such as generators, transmitters, distributors, and wholesalers of electrical power.

- Allowing generators and bulk power buyers (distribution utilities and large industrial customers) to have direct access to the Ontario wholesale electricity market.
- Allowing retailers to access the customers connected to the distribution system, with the possibility of varying terms and conditions of the electricity commodity sales contracts. In this way, competition is enabled at the retail level.

According to [1], electricity represents 18% of the end use energy demand in Ontario, and the share of each sector is almost equal. That is to say, that residential, commercial, and industrial user each account for one third of the total electricity demand in Ontario.

Green energy has definitely remarkable environmental benefits, as well as major contribution in the electrical reliability enhancement. However the presence of such renewable generation facilities introduces different technical challenges in terms of reliability evaluation. Therefore, in this thesis, a modified electrical reliability evaluation technique is proposed, in order to consider some challenges that hinder electrical reliability enhancement, in presence of DG units, both renewable and dispatchable, during islanding mode of operation. Two main criteria are previously set in literature to prohibit islanding operation. These criteria are as follows:

- When dispatchable DG units rating, in an island, is less that a certain percentage of the island load level at time of islanding;
- When power generation level of DG units, during successful islanding operation, is less than the island load level at a certain time.

Further, classical techniques of electrical reliability evaluation, does not provide general expressions for electrical reliability parameters, since annual interruption frequency and duration expressions depend on the electrical system configuration.

1.2 Research Objectives

The objective of this work is to perform electrical reliability evaluation for a distribution system using system-independent analytical expressions, under various scenarios characterized by different dispatchable and renewable Distributed Generation (DG units) penetration levels. Accordingly, reliability indices are to be evaluated for both a worst case load scenario (islanding occurs at peak load level), and for a realistic case (islanding occurs at any load level). Further, new adequacy formulation will be adopted during the islanding mode of operation, in order to take into account load correlation and a different load curtailment level. This new curtailment is needed to ensure adequate reactive power supply and operational stability for micro-grids, in order to allow successful islanding when the dispatchable DG units rating in a micro-grid is less than a certain percentage (defined as 60%) of the micro-grid peak load at time of islanding. In this way, the probability of a successful islanding operation is increased, since an islanding operation could easily fail without the introduction of this further load curtailment. A second curtailment could be required during islanding operation according to the new (after first curtailment) load and generation level of the considered micro-grid. Afterwards, the reliability indices and expected energy not supplied (EENS) for the systems under study are evaluated.

1.3 Thesis Outline

This section aims to provide a brief description of the goal and the content of each chapter in this thesis. In Chapter 1 the main reasons for interest in reliability assessment and enhancement are discussed, especially with Distributed Generation units installation in electrical distribution systems, along with the research objective. Then the research problem literature review is presented in Chapter 2, for both reliability and adequacy evaluation, with and without the installation of DG units.

In Chapter 3 the adopted annual probabilistic models of different micro-grid components are presented. First an annual load model is presented, and then a renewable DG unit output power model will be described, followed by a dispatchable DG unit output power model.

In Chapter 4, a description of the adopted methodology for the evaluation of electrical system reliability indices of the adopted distribution test system during different operating scenarios and under different fault conditions is given. Further adequacy assessment formulation is presented for different DG units categories during islanding mode of operation. Finally, an Expected Energy Not Served (EENS) evaluation procedure is described for different operation modes (with and without DG units), and based on the first and second curtailment load needed for successful islanding operation.

In Chapter 5, some assumptions and technical considerations which have been considered for the assessment of electrical system reliability indices and for EENS evalation, are presented. Further, a description for the adopted electrical distribution test system is provided in this chapter. Last, electrical reliability evaluation results are presented and discussed for the different proposed scenarios of operation, including different DG units penetration levels, as well as EENS evaluation results, in this chapter.

Finally, in Chapter 6 are the main conclusions and contributions that have been achieved in this thesis.

Chapter 2
Literature Survey

In this chapter, the relevant importance behind the major interest in different electrical reliability analysis and enhancement methods will be described, especially adopting DG technologies at the electrical distribution systems level.

First, general definitions will be presented for electrical reliability from different viewpoints, such as the generation and the distribution system perspectives. Afterward, there is a brief discussion of different electrical reliability measurements and factors that affect electrical reliability indices evaluation.

Considering Ontario, Canada as a case study, entities that are responsible for electrical reliability assurance are then listed. Afterwards different electrical Reliability Enhancement techniques are examined, with a more detailed explanation for the Distributed Generation (DG) technology, which is considered at present one of the most effective ways for electrical reliability enhancement. Then DG's basic definitions are discusses, including the different technologies used for these generation facilities, and factors encouraging the diffusion of Distributed Generation.

Then polices that are related to Distributed Generation are discussed, both promoting polices (such as RPS & FIT) and technical interconnection requirements polices (such as system performance requirements, protection devices coordination requirements, et c).

2.1 Electrical Reliability Measurement

Reliability indices may be used not only for the characterization of a system as a whole, but may also have some of indices an intermediate character. For example, the system considered as an independent object might be characterized by an availability coefficient. If a small system is part of a more complex structure, it may be more reasonable to characterize it separately with the mean-time-to-failure (MTTF) index and the mean-time-to-repair index (MTTR), because they might be used to more accurately express the complex system's availability index [8].

Some of the more common reliability indices for distribution systems that might help us to evaluate the system performance are shown in TABLE II. Further, the same table reports the Canadian averages for these indices published by the Canadian Electricity Association (CEA) [6].

Typical quantitative indices to evaluate distribution systems reliability include System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI), Average Service Availability Index (ASAI), Average Service Unavailability Index (ASUI), Energy Not Supplied (ENS), and Average Energy Not Supplied (AENS)[9].

All of these indices are obtained from the annual outage rate (λi) and annual outage duration (Ui) at each load point (i) of the electrical distribution network. As for SAIFI and SAIDI calculation, the corresponding expressions are [5]:

$$SAIFI = \frac{total\ number\ of\ customer\ interruptions}{total\ number\ of\ customers\ served} = \frac{\sum_{i=1}^{n_{LP}} \lambda_i N_i}{\sum_{i=1}^{n_{LP}} N_i} \tag{2.1}$$

SAIFI expresses the average number of interruptions of electrical service that a customer would experience over the course a year.

$$SAIDI = \frac{sum\ of\ customer\ interruption\ durations}{total\ number\ of\ customers} = \frac{\sum_{i=1}^{n_{LP}} U_i N_i}{\sum_{i=1}^{n_{LP}} N_i} \tag{2.2}$$

SAIDI expresses the average interruption duration of electrical service that a customer would experience over the course a year.

$$CAIDI = \frac{sum\ of\ customer\ interruption\ durations}{total\ number\ of\ customer\ interruptions} = \frac{\sum_{i=1}^{n_{LP}} U_i N_i}{\sum_{i=1}^{n_{LP}} \lambda_i N_i} = \frac{SAIDI}{SAIFI} \quad (2.3)$$

CAIDI is considered as the average restoration time of electrical service, and expresses the average outage duration that a customer would experience. It is noted that

n_{LP} is the number of load points (LPs);

N_i is the number of customers connected to the i-th LP;

λ_i is the annual outage rate of the i-th LP (number of outages/year);

U_i is the annual outage duration of the i-th LP (sum of the outages time/year).

$$\lambda_i = \sum_k \lambda_{i,k} \quad (2.4)$$

$$U_i = \sum_k U_{i,k} \quad (2.5)$$

where

$\lambda_{i,k}$ LP *i* annual outage rate due to a fault in branch *k*;

$U_{i,k}$ LP *i* annual outage duration due to a fault in branch *k*.

TABLE II: RELIABILITY INDICES AVERAGE IN CANADA [6].

Measure	What it measures	Canadian average (2002)
Index of reliability (IOR)[2]	Portion of Time The System Is Available	0.9995
System average interruption frequency index (SAIFI)	Number of Interruptions	2.4 per year
System average interruption duration index (SAIDI)	Number of Hours of Interruptions	4.4 per year
Customer average Interruption duration (CAIDI)	Average Length of Each Interruption	1.8 hours

where IOR= [(8760-SAIDI)/8760] - the number of hours in a year being 8760.

According to the (CEA) report, published in 2002, the Canadian distribution system had an overall reliability index (IOR) equal to 0.9995, which means that the system was available for 99.5% of the time (excluding the impact of the Québec/Ontario ice storm, which reduced availability to 99.65%).

2.2 Electrical Reliability Assurance

Entities that are responsible for electrical reliability assurance in Canada could be summarized in the following list [1]:

- electric industry;
- provincial governments with their regulators;
- territorial governments with their regulators;
- federal government.

In the following section, each one of these entities will be defined, and the way these entities are responsible for reliability assurance will be presented.

2.2.1 Electric Industry

In the traditional electricity market, the electric industry was represented in a vertically-integrated utility, which was responsible for the reliability assurance; that is to say ensuring power was delivered to consumers respecting certain limits and standards. This utility was responsible for generation, transmission, and distribution tasks.

In Figure 1, the different power system components are shown, starting from the generation (colored in black), the transmission (colored in blue), and finally the distribution (colored in green) [10].

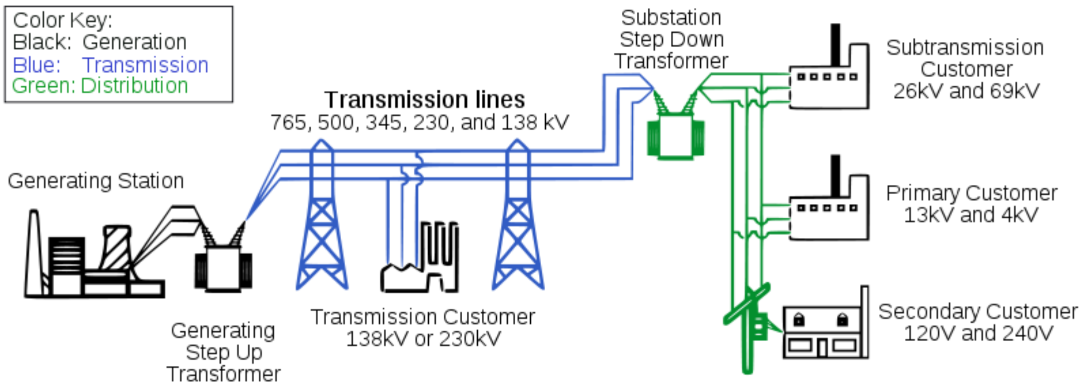

FIGURE 1: ELECTRICAL INDUSTRY [11].

During the last decade, and after the opening of the electricity market, many provinces (such as Ontario and Alberta) have had a net separation in how the responsibilities of ensuring electrical reliability are shared between the generation, transmission, and distribution companies. Since these electric industries are responsible for ensuring electrical reliability, they should issue reliability standards and policies.

The North American Electric Reliability Council (NERC), founded in 1968, plays a major role in the development of such reliability polices and standards. Moreover, members of this council are mostly electric utility and system operators, and most of them have interconnections with other regions. NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional Areas [11].

In Figure 2, the different NERC regions in North America are shown. In TABLE III, North American electric reliability corporation regions entities are listed and defined.

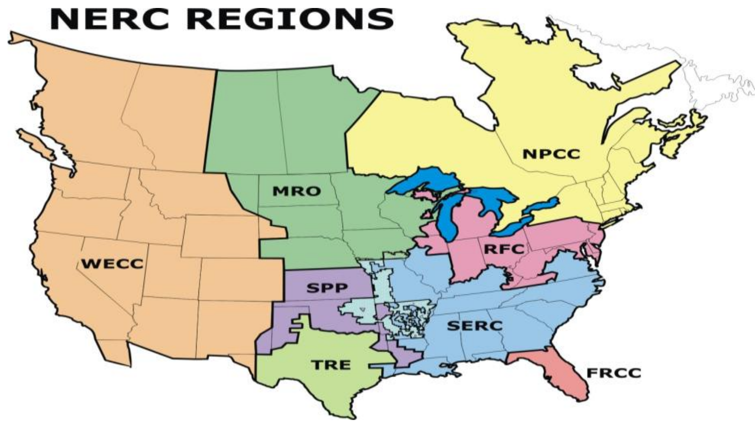

FIGURE 2: NERC REGIONS IN NORTH AMERICA [11].

TABLE III: NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION REGIONS [11].

Region Acronym	Region Acronym Definition
FRCC	Florida Reliability Coordinating Council
SERC	SERC Reliability Corporation
MRO	Midwest Reliability Organization
SPP RE	Southwest Power Pool Regional Entity
NPCC	Northeast Power Coordinating Council
TRE	Texas Reliability Entity
RFC	Reliability *First* Corporation
WECC	Western Electricity Coordinating Council

2.2.2 The Provinces and Territories

Provinces and territories governments' and their respective regulator agencies are greatly involved in ensuring acceptable levels of electric reliability towards end users. The reason behind this kind of involvement is related to the fact that the electric industry in Canada has evolved along provincial lines.

2.2.3 The Federal Government

Since the electrical network of Canadian provinces are interconnected one to the other, the federal government is involved in ensuring electrical reliability by developing general reliability policies, as well as other interprovincial and international electrical trade policies. In the federal government system, there are two main organizations that are responsible for the reliability and interconnection policies. These departments are:

- Natural Resources Canada;
- Department of Foreign Affairs and International Trade.

Regarding the international power lines (IPLs) construction and operation, the National Energy Board (NEB) inspects the federal regulatory authorization related to these operations.

2.2.4 Electrical Reliability Enhancement

Electrical Reliability can be enhanced through the following methods [1]:

A. *Investment:*

Investing generally in infrastructure and in new technologies can improve the electric system reliability. Two criteria are set by the system planners in order to identify the appropriate amount of investment in reliability:

- System planners set a criterion of reliability to be achieved, which is to have no more than one day of outage every ten years. Then companies compare between different methods to achieve the desired level of reliability; among these methods, the lowest cost method will be adopted.
- System planners compare the costs of outage (lower reliability) with the cost of providing a greater reliability level. Outage costs include a broad range of economic and social costs. Economic costs might include lost industrial production, equipment damage, and spoilage of raw materials or food. Social costs might include the inconvenience of lost transportation, the loss of leisure time, uncomfortable building temperatures and personal injury. Outage and infrastructure investment cost curves vs the reliability level is shown in Figure 3.

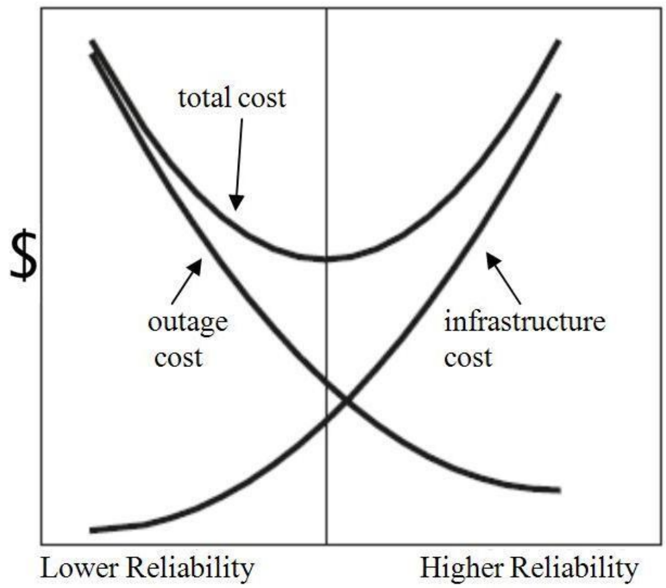

FIGURE 3: RELATION BETWEEN INVESTMENT COST AND RELIABILITY LEVEL [12].

It is noticed from the previous diagram that a low reliability level corresponds to more frequent failures and more outage costs. When investing in infrastructure, the reliability level increases, as do the infrastructure costs, but the outage costs would decrease. Moreover, investing in reliability yields benefits, but after some point, the benefits are less than the costs. Hence a compromise and an equilibrium point should be identified.

B. Technology

Adopting new technologies would enhance the electric system reliability. For example the adoption of [1]:

- FACTS (Flexible AC Transmission System) is meant to improve the control and stability of the transmission grid, which means increasing the ability to direct power flow and having a very fast response to system conditions in order to enable the transmission system to be operated closer to thermal limits, thus improving transmission efficiency;

- New communications and control tools in order to improve the monitoring of the real-time operation of the grid. In this way, the system operator would be able to better understand the operating conditions of the system, and be more aware of contingencies in the immediate and adjacent control areas.
- New Dispersed Generation (DG units) technologies, specially the renewable ones installed close to load centers. Such a solution would require reverse metering devices in order to consider the scenario where these generation units sell power back to the grid in the grid-connection mode of operation. This solution will be discussed in detail in the following section.

C. Inter-regional trade

System reliability can be further improved when interconnecting adjacent provinces one to the other. This would not only help in enhancing the overall reliability of the system, but also in some cases optimizing the construction and utilization of generation resources. Indeed, reserve margin requirements tend to be lower in an interconnected environment, since a large pool of generation is available to respond to system disturbances.

Further, interconnecting different regions means different generation facilities, which can be of use in exporting and importing electrical power. This is due to the fact that some generation facilities, like various hydro power plants, can store water in off peak-periods, and use it to generate and export power in peak periods to other connected provinces. On the other hand, sometimes interconnections might imply risks, when disturbances might cascade from one region to another, as happened most recently in 2003.

D. Demand-side management (DSM), and demand response (DR):

All of the previous methods of electric reliability enhancement are related to the supply generation side, but the consumption pattern might have a very significant impact on the system reliability and on the supply-demand balance.

The demand side management (DSM) concentrates on encouraging customers to use more efficient equipment and appliances, which consume less electrical power or shift the loads to off-peak periods.

DSM started initially as a non-priced program offered to customers by the utility. Then utilities recognized that they might be able to reduce costs if customers are encouraged to apply DSM, hence they started funding conservation programs, such as energy audits and providing subsidies for the usage of such more efficient equipment and appliances. In some provinces (e.g., British Colombia and Manitoba), DSM implies that utilities signal to customers to reduce consumption in times of tight supply.

Another effective practice from the customers side view is the demand response (DR), which took place thanks to the competitive power markets. This program mainly consists of providing incentives for customers to encourage them to reduce consumption at higher price levels during peak periods or when electricity prices reaches a certain level, as is the case in Ontario mechanisms administered by the Independent Electricity Market Operator (IMO) [13].

DS programs benefits mainly larger consumers who have the capability to shift demand to off-peak periods and who have the necessary metering equipment. The Reliability benefit behind the DR program is complemented by price benefits as shown in Figure 4.

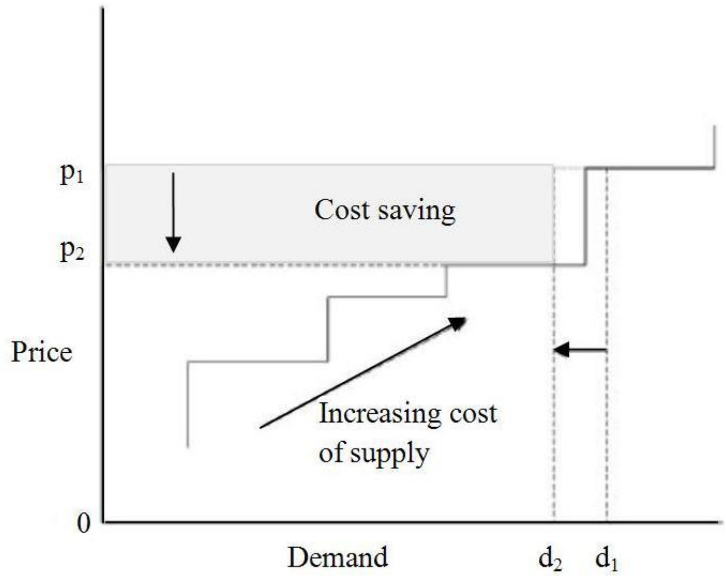

FIGURE 4: IMPACT OF PEAK DEMAND REDUCTION ON ELECTRICITY PRICE SAVINGS [14].

This figure, valid for a competitive bulk power market, shows the demand vs electricity price; the supply cost is represented as a "stepped" curve. By analyzing the previous figure, as customers who are able to respond to the DR program decrease their demand, the demand level would decrease from d1 to d2, making the price step down from p1 to p2 with cost savings given by the shaded area. It can be noticed that a small change in the demand might lead to a remarkable reduction of the electricity price. Even for customers who were not able to respond to DR programs, such as residential customers, the reduction in the price would benefit them as well.

E. Integration of Distributed Generation units

Properly installed and operated, Distributed Generation units (DGs) in the electrical distribution system can significantly improve the overall system reliability. DGs installation can benefit both customers and the utility. From the customer prospective, an industrial site would benefit from the installation of generation units (DGs) by satisfying its base load demand or by having backup electrical power in case of interruption or disconnection form the main utility grid. Further, customers can benefit from DGs installation by aggregating backup assets for sale to grid.

From the other perspective, the utility or energy company could purchase electrical power during peak periods in order to meet the power demand of their costumers during peak hours [15]. In doing so, the yearly loss of energy would decrease, hence reliability would increase, and utilities would not be penalized for not respecting the reliability standards.

I. DG definition:

Distributed Generation (DG) is the term used to describe small-scale power generation, usually in sizes up to around 50 MW, located on the distribution system close to the point of power consumption. Such generators may be owned by a utility or, more likely, by a customer who may use all of the power on site or who may sell a portion, or all of it, to the local utility. When there is waste heat available from the generator, the customer may be able to use it for applications such as process heating, space heating, and air conditioning, thereby increasing the overall efficiency from fuel to electricity and useful thermal energy [16].

The IEEE has defined Distributed Generation 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.

DG is not a new concept, even though some issues still need to be further investigated. It is an approach for providing electric power in the heart of the power system. It mainly depends upon the installation and operation of a portfolio of small size, compact, and clean electric power generating units at or near an electrical load (consumer) [17].

Besides the environmental concern, the possibility of supplying electrical power at peaking periods, and reducing electricity costs, DG units can significantly contribute to the enhancement of power system reliability, as well as power quality levels [18].

Different reports expect that between 2010 and 2020, the number of distributed generation units worldwide is going to be doubled. In 2020, 170 TWh of U.S. energy is expected to be produced by decentralized power sources [19].

There is no generally accepted definition of distributed generation yet. Some countries define DG on the basis of the voltage level, whereas others start from the principle that DG is connected to circuits from which consumer loads are supplied directly. Other countries define DG as having some basic characteristic (for example, using renewable, cogeneration, being non-dispatched, etc.). This section reviews the definitions of DG proposed by different institutes, associations, and scholars in regards to the rating of DG power units [19]:

- The Electric Power Research Institute defines DG as generation “from a few kilowatts up to 50 MW” [20];
- According to the Gas Research Institute, distributed generation is “typically between 25 and 25 MW” [21];
- Preston and Rastler define the size as “ranging from a few kilowatts to over 100 MW” [22];
- Cardell defines DG as generation “between 500 kW and 1 MW” [23];
- The International Conference on Large High Voltage Electric Systems (CIGRE) defines DG as all generation units with a maximum capacity smaller than 50-100 MW that are usually connected to the distribution network and that are neither centrally planned nor dispatched [24];
- Chambers [25] also defines distributed generation as relatively small generation units of 30 MW or less. These units are sited at or near customer sites to meet specific customer needs, to support economic operation of the distribution grid, or both;

- Dondi et al. [26] defines distributed generation as a small source of electric power generation or storage (typically ranging from less than a kW to tens of MW) that is not a part of a large central power system and is located close to the load. These authors also include storage facilities in the definition of distributed generation, which is not conventional;
- Ackermann et al. [27] defines distributed generation in terms of connection and location rather than in terms of generation capacity. They define a distributed generation source as an electric power generation source connected directly to the distribution network or on the customer side of the meter.

II. Distributed Generation Technologies:

A critical survey done in [17] aims at proposing new DG types and technologies classification according to either the type of fuel used by the DG, or according to the type of technology itself. Reporting the different classifications of the DGs and comparing them to each other helps in making decisions with regard to which kind is more suitable to be chosen in different situations.

According to the fuel used, DG can consist of Fossil Fuels Technologies, like Micro Turbines (MT) and some types of Fuel Cells (FC), or Non-Fossil Technologies, such as Storage Devices and Renewable Generation Systems. From the constructional and technological points of view, different kinds of DGs could be classified as noted below.

Conventional technologies: The traditional choice for on-site generation and remote power applications is the diesel generator. Although the name “diesel” is always associated with light fuel, these generators can actually be tuned to use a wide variety of liquid and gaseous fuels, including natural gas, propane, and residual fuel oil. Advanced diesel engines using electronic injection control promise to improve system efficiency when used in a load-following mode.

Advanced fossil technologies (Micro turbine-MT): Over the past decade, two new fossil-fuel generation technologies have been developed to the point of commercialization or near commercialization: the micro-turbine and the fuel cell. Micro turbines are small capacity combustion turbines, for example a scaled-down version of the Brayton cycle gas turbine used in large-scale central generation. Although primarily designed to use natural gas and propane, these systems also can be designed to use a variety of gaseous and liquid fuels as fuel oil.

Renewable technologies: The most renewable technologies used as distributed generation units are wind turbines, and photovoltaic.

III. Factors encouraging DGs Diffusion:

For many years, power systems were vertically operated. Large power generation plants produced all the electrical power. This kind of generation is often related to adequate geographical placement (water sources, technical constraints, etc.). The power is then transmitted toward large consumption centers over long distances and using different high-voltage transmission levels. This operating structure was built on the basis of economy, security, and quality of supply. This very centralized structure is operated by hierarchical control centers and allows the system to be monitored and controlled continuously. The generation is instantly adjusted to the consumption (by monitoring the frequency and on the basis of very elaborate load forecasting models) [28].

The voltage is also controlled to be within specific limits by means of appropriate coordinated devices, generators, online tap changers, reactive compensation devices, etc. This operating mode is changing, due to electric utilities as well as to public organizations. There are several reasons for these changes, some of which are as follows [29]:

- Saturation of the existing network and reduction of security margins;

- Geographical and ecological constraints;
- Stability and security problems (need for expensive preventive measures, increase in short-circuit currents);
- Continuous growth of demand, especially in the emerging countries;
- Need for investment to sustain the development in the power demand. This development has led to the breaking up of investments (small generation units, cogeneration);
- Privatization, deregulation, and competitive markets;
- Emergence of new, rational, generation techniques with small ratings, ecological benefits, increased profitability, and which can be combined with heat generation.

Due to these reasons, the electric power system planners are oriented to use other alternatives to the traditional method of planning. Distributed Generation appeared as one of the most important alternatives. The main reasons for the increasingly widespread use of DG can be summarized as follows [15]:

- DG units are closer to customers so that transmission and distribution assets costs are avoided or reduced;
- The latest technology has made available plants with high efficiency and ranging in capacity from a few kW to a few tens of MW.
- It is easier to find sites for small generators;
- Natural gas, often used as fuel in DG stations, is distributed almost everywhere and stable prices are to be expected;
- Usually DG plants require shorter installation times and the investment risk is not so high;
- DG plants yield fairly good efficiencies especially in cogeneration and in combined cycles (larger plants);

- The liberalization of the electricity market contributes to creating opportunities for new utilities in the power generation sector;
- Transmission and distribution costs have risen while DG costs have dropped; as a result the avoided costs produced by DG are increasing;
- DG offers great values as it provides a flexible way to choose a wide range of combinations of cost and reliability;
- Minimize transmission and distribution losses costs;
- Potentially lower emissions in case of renewable DG units;
- Improved reliability via disruption prevention;
- Potential to save energy producers and consumers money, and allows wider user choice;
- May be developed more quickly than central station generators.

IV. Polices promoting DGs:

i) Renewable Portfolio Standard-RPS

Renewable Portfolio Standard (RPS) is one of the most popular policy models by witch governments fund renewable energy and uses a target or quota for renewable energy that is legislated and determined by policy regulations [30]. Other common names for the same concept include Renewable Electricity Standard (RES) at the United States federal level and Renewable Obligation in the UK.

RPS accelerates the deployment of renewable energy technologies (such as wind, solar, biomass, and geothermal), builds economies at low carbon economy of scale that reduce technology costs, and carves out a space for solar within the electricity market [31].

Further, in many cases, RPS is based on a system of tradable renewable credits and bidding processes for companies, with the value of the credits determined by a wide range of factors. This description has been given by Galiteva, listed in the Alt Car Expo program as an energy expert in a talk titled “Strategies for the Successful Integration of Renewable Energy Sources into the Power Grid" [30].

Additionally, most RPS laws require states or countries to increase the percentage of renewable power sources used from the current amount to between 10 and 20% over about 20 years. Increasing the required amount of renewable power required over time allows industry to grow into the demand and can put the power industry on a path toward increased sustainability.

In this way RPS laws ensure not only that a minimum amount of renewable energy is included in the portfolio of the electricity resources serving a state, but also ensure that states will have a diverse energy portfolio to protect us into the future [32]. In Europe, RPS policies are called quota-based mechanisms, quota obligations, or renewables obligations, and they require electric utilities to provide renewable electricity to their customers, typically as a percentage of total energy use [33].

ii) Feed in Tariffs-FIT

The feed-in tariff program is one of the promoting polices for encouraging customers towards the installation of Distributed Generation units, specially the renewable technologies, such as wind and solar panels. A general definition of the feed-in tariff is as follows [34]:

“A feed-in tariff is a pricing mechanism whereby an electricity utility pays a customer for electricity that is generated by the customer and exported to the grid.

The objectives behind having a feed-in tariff can include:

- encouraging local, distributed generation, thereby reducing load on the network and reducing distribution losses associated with the transmission of electricity from centralised generators through the distribution network to customers;

- encouraging uptake of, and stimulating innovation in, renewable energy technology (either generally, or a specific type of technology) and reducing greenhouse gas emissions by lessening reliance on non-renewable energy sources.

Generally, feed-in tariffs are based on a premium price being paid to the customer that is in excess of the normal wholesale cost of generation, and sometimes in excess of the normal retail price of electricity. Feed-in tariffs are generally available to residential customers, or to those customers below a given consumption threshold, and are not likely to be available to commercial scale electricity generation".

V. *Policies for sucsessful integration of DG units.*

The interconnection of DG units with electric power systems is most often regulated by national and international standards (such as the IEEE 1547), which do not permit islanded operation of parts of a public feeder. This means that following a fault or an outage in the electric system, the DG has to disconnect and remain disconnected until the fault is cleared.

Recently in Europe, and for example in Italy, Norm CEI 0-16 which does not exclude the possibility of islanding operation for a portion of a Medium Voltage (MV) public distribution system has been issued. According to this Italian norm, islanding operation is temporarily allowed (e.g., for maintenance purposes), provided that specific agreements between the distribution operator and the active (generators owners) and passive (e.g., very relevant loads) customers connected to the considered MV network are made.

Interconnection of the DG units must comply with relevant Ontario and Canadian regulations and international design standards. In the following list, the main technical requirements for a successful integration of these facilities to Hydro one's utility distribution grid are reported [35].

i) Technical Interconnection Requirements:

(a) General requirements:

The *connection to the ground* of DG units should not make the voltage level exceed the rating of equipment connected to Hydro One's distribution system. The *transformer responsible for the interfacing* of DG units with the grid should not disrupt the coordination of the protection related to ground faults of Hydro One's distribution system. The installation of DG units should not make the fault levels exceed the limits set by the transmission system code (TSC). DG units should be protected by proper insulation coordination against lightning and transient over-voltage.

(b) Performance requirements

Regarding the reliability issue, the installation of DG units should not compromise or restrict the existing reliability and operation level of the distribution system. The interconnection of a DG unit should not make the power quality performance go below the accepted levels. DG units should be equipped with devices that can measure, record and report the overall performance, and demonstrate observance of the necessary technical requirements. This should be assured by the DG unit owner. In case the interconnection of DG units deteriorates the performance of Hydro One's distribution system, the DG might be disconnected until negative impacts are alleviated, according to received and reported measures.

(c) Protection requirements

Hydro One is responsible for reviewing the protection schemes designs and protection devices settings related to the DG units. Since system configuration might change over time, DGs protection devices settings must be adequate to the system change. A very important aspect that should be observed is that after a fault or outage occurrence, DGs protection devices must assure the isolation from the Hydro One distribution system within the required time. A communication facility between protection device (e.g., recloser), transformation station, and the DG unit itself might be required.

2.3 Reliability assessment in presence of DG units

Reliability indicates the ability of an electrical system to respond to unexpected contingencies, therefore, reliability of distribution systems has become a very important issue, not only from a technical viewpoint, but also from an economical one, for both users and network operators.

As for Systems Reliability Evaluation, in [36] and [37], annual interruption frequency and duration at load points (LPs) of a network where islanded operation of DG units is allowed are explained by means of practical examples only, derived from specific networks, without providing system independent general expressions that can be applied at any electrical network configuration. The work in [38] proposed a systematic approach for reliability assessment with general analytical expressions. Such expressions have been provided for the calculation of annual interruption frequency and duration for LPs of traditional networks, without considering the presence of DG units. Then in [39], these expressions have been provided considering the presence of dispatchable DG units only, and not the renewable ones. Later on, [40] proposed more detailed systematic analytical expressions for a distribution network where islanded operation of microgrids is allowed with both renewable and dispatchable DG units; nevertheless, correlation among different loads and protection devices' failure have been neglected.

The capability of a generation system to make available an adequate and qualitatively acceptable supply of electrical energy is measured by the generation system adequacy. Since in the present work the islanding mode of operation is assumed to be allowed, islands adequacy assessment is of concern, as well as islanding success and failure conditions.

In order to perform micro-grid adequacy assessment, during islanding mode of operation, an appropriate modeling for both dispatchable and non-dispatchable DG units is required. Dispatchable DG units are modeled based on their forced outage rate due to both maintenance and hardware failure as explained in [41]. On the other hand, renewable DG units output power are much more difficult to be modeled due to the uncertainty associated with their primary source.

In [42] and [43], renewable energy sources are modeled by means of an analytical approach, considering the correlation between such renewable sources and the load. In [44], wind turbine generators are modeled as a multi-state unit utilizing an analytical approach. The work in [45] presents a probabilistic approach to capture the uncertainty associated with the renewable generation primary sources. In [46] two probabilistic techniques are proposed to model the wind generation system. In [47], a wind farm generation system is modeled utilizing a general probabilistic approach. Then [48] proposed a probabilistic model for a hybrid renewable generation units composed of wind and photovoltaic (PV) systems. In [49] and [50], Monte-Carlo Simulation technique (MCS) is presented to model wind output power. In [51], wind farm performance is assessed utilizing Monte Carlo simulation (MCS) during grid-connected mode of operation. In [53] is presented a probabilistic model for wind based DG unit output power through the estimation of the wind speed profile, utilizing a novel constrained Grey predictor technique.

As for DG units Adequacy Assessment in a micro-grid, during an islanding mode of operation, [4] considered that any deficit in generation during islanding mode will result in islanding failure, without considering either load *shedding*, or load curtailment. In [41], only user load disconnection, known as load shedding, has been considered. Then in [40], both load shedding and load reduction, known as load *curtailment*, have been taken into account for the adequacy assessment during islanding mode of operation. However, this previous work did not ensure adequate reactive power supply and operational stability during islanding mode of operation by neglecting operational stability constrains.

In the previous works, it is obvious that sufficient work has been done to assess both adequacy and reliability with renewable DG units during different modes of operation. However, new generalized systematic approach for electrical reliability evaluation, especially considering load correlation did not receive full attention. Further, islanding success condition enhancement by adopting different levels of load curtailment, at time of islanding and during islanding operation, is a relatively new concept.

Chapter 3
Annual Probabilistic Models

In this chapter the adopted annual probabilistic models of different micro-grid components will be presented. First the annual load model is presented, then the renewable DG unit output power model will be described, followed by the dispatchable DG unit output power model. Annual load model has taken into consideration the variability of load demand during a year based on previous historical data. On the other hand, DG units' annual models considered units' hardware failure, along with the uncertain nature of the primary source in the case of renewable DG units.

3.1 Annual load modeling

Since LPs' power demand level varies during a year, and does not assume always the peak value, annual load modeling is required. An annual model presents different load demand levels associated with their probability of occurrence during a year. Load levels are assumed to be constant during a given time, and change discretely for every time segment (one hour). TABLE IV shows an annual load model with ten levels of power; first column contains levels number, second column shows power demand load levels in percentage of peak load, and last column shows the probability related to each load level [53].

TABLE IV: ANNUAL LOAD MODEL[53].

Level	Power demand (%)	$\rho^L_{j,l}$
1	100	0.01
2	85.30	0.056
3	77.40	0.1057
4	71.30	0.1654
5	65	0.1654
6	58.50	0.163
7	51	0.163
8	45.10	0.0912
9	40.60	0.0473
10	35.10	0.033

3.2 Annual Dispatchable DG unit modeling

Since dispatchable DG units are very similar to traditional generating systems connected to a transmission supply, they can assume an annual model based on DG units hardware availability [54]. Through the historical data of a generating unit, it is possible to estimate a forced outage rate (FOR) that defines the probability to have the unit on forced outage at some distant time. Hence, the probability of being available for a dispatchable DG is simply the complement of its FOR, which is equivalent also to the ratio between the mean time to repair (MTTR), and the mean time between failures (MTBF), as follows [41]:

$$\rho_{AV,d} = 1 - FOR = \frac{MTTF}{MTBF} \tag{3.1}$$

TABLE V shows the annual model for a dispatchable DG characterized by two power output levels, both when FOR hardware is neglected and when it is considered.

TABLE V: ANNUAL GENERATION MODEL FOR A CONVENTIONAL DG.

Level	Power output (kW)	$\rho^D_{d,l}$ (%)	$\rho^G_{d,l}$ (%)
1	0	0	2
2	$P_{GN,d}$	100	98

3.3 Annual Renewable DG Unit Modeling

Renewable DG units are much more difficult to model than dispatchable ones. This difficulty is due to the uncertainty of the DG units' primary source (e.g., wind speed or solar irradiance), which leads to complication in finding a suitable annual model that well describes the behavior of the renewable DG. TABLE VI shows an annual generation model for wind-based DG [53], where each power output level, described as a percentage of power rating is associated with both following probabilities: ($\rho^{G}_{d,l}$), when FOR is considered, and ($\rho^{R}_{d,l,}$), when FOR is not taken into account. The used wind speed data is based mainly on average hourly values, so that wind speed variations within an hour are not considered.

TABLE VI: ANNUAL GENERATION MODEL FOR A WIND DG [53].

Level l	Power output (%)	$\rho^{R}_{d,l,}$	$\rho^{G}_{d,l}$
1	100	0.073	0.0761
2	94.96	0.024	0.0252
3	84.97	0.032	0.0331
4	74.97	0.044	0.0457
5	64.97	0.046	0.04837
6	54.98	0.075	0.0783
7	44.98	0.089	0.0923
8	34.98	0.109	0.1136
9	19.99	0.101	0.105
10	14.99	0.109	0.1137
11	4.99	0.062	0.0648
12	0	0.236	0.2039

Chapter 4

Methodology

In this chapter a description of the adopted methodology for the evaluation of electrical system reliability indices of the adopted distribution test system will be given. The proposed methodology will be implemented during different operating scenarios and under different fault conditions. Further, adequacy assessment formulation is presented for different DG units categories during islanding mode of operation. Finally, the EENS evaluation procedure is described for different operation modes (with and without DG units), and based on first and second curtailment load, needed for successful islanding operation.

The adopted methodology for distribution system reliability indices assessment is based on calculating the base parameters defined as the annual frequency of interruption and annual interruption duration at each Load Point LPi. The equations for these two parameters are given respectively by the following expressions [55]:

$$\lambda_i = \sum_{k=1}^{n_k} \lambda_{i,k} \qquad U_i = \sum_{k=1}^{n_k} U_{i,k} \tag{4.1}$$

Then reliability indices are calculated as follows [55]:

$$SAIFI = \frac{total\ number\ of\ customer\ interruptions}{total\ number\ of\ customers\ served} = \frac{\sum_{i=1}^{n_{LP}} \lambda_i N_i}{\sum_{i=1}^{n_{LP}} N_i} \tag{4.2}$$

$$SAIDI = \frac{sum\ of\ customer\ interruption\ durations}{total\ number\ of\ customers} = \frac{\sum_{i=1}^{n_{LP}} U_i N_i}{\sum_{i=1}^{n_{LP}} N_i} \tag{4.3}$$

For the calculation of the base parameters expressed in (4.1), the classical method can be used, as explained in [36] - which is mainly a system dependent methodology, since it is described through general examples. Another method of base parameters assessment is to use the restoration of time-based classification of LP*s* in a distribution system with DG units presented in [56].

In this work, a set of wider system independent classification has been adopted, which is based on the relative positions of a considered LP*i*, a faulted branch or component, and a protection device of a generic distribution network [40]. This methodology classifies five different cases for the calculation of LP*s* annual interruption frequency and duration, with or without both dispatchable and renewable DG units, as detailed in the following section.

4.1 Electrical Reliability Parameters Assessment

Radial distribution system consists of a set of series components, including lines, cables, disconnects (or isolators), bus-bars, etc. In a radial system, in order to ensure the service continuity of providing electrical energy to a consumer connected to any load point, is required that all components between that user and the supply point to be operating effectively.

Basic reliability parameters can be described as follows, are given by:

- λi (num. failures/year) : *average annual frequency of interruption* for a certain load point (LP*i*) of the distribution system. This parameter considers the failure rates of all components (in failure state) that could cause an interruption of electrical energy supply for the considered load point. Moreover, λi takes into account the probabilities of the different protection devices to isolate the failure away from the load point.
- *Ui* (hours/year): *average annual interruption or outage duration* time in a certain load point (LP*i*) of the distribution system. This parameter expresses the average number of hours that LP*i* can experience in outage state during a year.

To better explain how to perform the evaluation of distribution system reliability indices, first, basic reliability parameters are calculated utilizing traditional approach according to the system configuration. After that, same parameters calculation will be presented utilizing the a system independent systematic approach, adopted in this thesis.

4.1.1 Reliability Parameters without DG units (traditional approach)

Based on the traditional approach [36], for a simple radial network without any DG units, shown in Figure 5, calculation of the basic reliability parameters λi, and Ui for load point number 2 (LP2) is presented by means of practical system configuration examples, as follows:

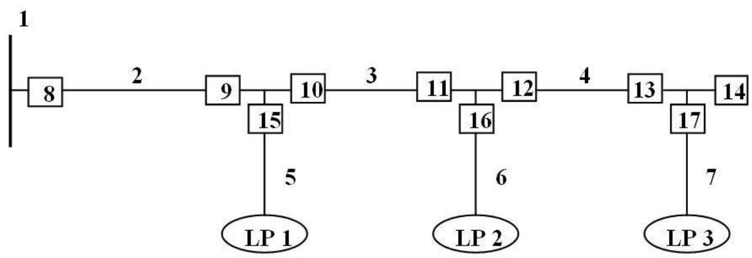

FIGURE 5: SIMPLE RADIAL DISTRIBUTION SYSTEM

Calculation of the average frequency of interruption λ_2: Generally, failure rate of a certain load point LP*i*, is given by the summation of all failure rates *f*, of all network components that can affect its service continuity (causing an outage). In the following expressions are reported different cases for calculation of the frequency of interruption at LP_2:

- When elements 15 and 17 are protection devices not able to isolate possible faults in elements 5 and 7, annual frequency of interruption at LP2 is given by:

$$\lambda_2 = \sum_{i=1}^{17} f_i \tag{4.4}$$

- When protection device elements 15 and 17 are circuit breakers (CBs), able to "instantly" isolate possible faults in elements 5 and 7, annual frequency of interruption at LP2 is given by:

$$\lambda_2 = \sum_{i=1}^{4} f_i + f_6 + \sum_{i=8}^{17} f_i \tag{4.5}$$

- When protection device elements 15 and 17 are circuit breakers (CBs), able to "instantly" isolate possible faults in elements 5 and 7 with a certain probability P_{15} and P_{16}, respectively, annual frequency of interruption at LP2 is given by:

$$\lambda_2 = \sum_{i=1}^{4} f_i + (1 - P_{15}) f_5 + f_6 + (1 - P_{17}) f_7 + \sum_{i=8}^{17} f_i \tag{4.6}$$

Calculation of total interruption duration U_2: In general, interruption duration rate of a certain load point could be obtained by the summation of failure rate *f* and repair time t_r product of all components that could cause an outage in LP_2. Therefore, expressions of total interruption duration U_2 in load point 2 for different system configurations are resented as follows:

- When protection device elements 15 and 17 are not able to isolate possible faults in elements 5 and 7, annual interruption duration of LP2 is given by:

$$U_2 = \sum_{i=1}^{17} f_i * t_{ri} \tag{4.7}$$

where t_{ri} is the required repair time for the element *i* .

- When protection device elements 15 and 17 are sectionalizers, annual interruption duration of LP2 is given by:

$$U_2 = \sum_{i=1}^{4} f_i * t_{ri} + f_6 * t_{r6} + \sum_{i=8}^{17} f_i * t_{ri} + f_5 * t_{sc\ 15} + f_7 * t_{sc\ 17} \tag{4.8}$$

Where $t_{Sc\ i}$ is called switching time, and stands for the required time sectionalizer *i* to isolate the downstream faulted area.

- When protection device elements 13 and 15 are sectionalizes, annual interruption duration of LP2 is given by:

$$U_2 = \sum_{i=1}^{4} f_i * t_{ri} + f_6 * t_{r6} + \sum_{i=8}^{13} f_i * t_{ri} + f_5 * t_{sc\ 15} + (f_7 + f_{14} + f_{17}) * t_{sc\ 13} \tag{4.9}$$

It can be clearly noticed from the above presented practical examples of different possible distribution systems configurations, that classical electrical reliability evaluation technique is strongly system configuration dependent, and does not provide general expressions, for annual interruption frequency and duration, hence reliability indices assessment. Therefore, the following methodology is adopted in order to consider most of electrical distributions system configurations and to examine the effect of a fault in branch *k* on a load point LP*i*. For each LP*i* of the system, such an examination should be performed, taking into consideration the relative position of the LP*i* with the faulted branch *k*, and the involved protection device, either circuit breaker or sectionalizer, or both. Therefore, analytical expressions for annual interruption frequency and duration are presented for different cases related to different situations with different fault consequences on LP*i* depending on their relative position, as mentioned earlier.

In the following subsection, a systematic approach for the evaluation of annual interruption frequency and duration in LP*i* is presented: once with no DG units are installed in the system, and again when DG units are installed in the system. Further, the possibility of operating in islanding mode of operation is assumed.

The system presented in [57] has been adopted to illustrate different methodology cases, which are presented in the following subsections. Modifications have been performed mainly in the layout configuration, in order to avoid system ring pattern, and to make the system have a radial scheme.

4.1.2 Reliability Parameters without DG units (systematic approach)

When it is supposed that no DG units are installed in the system, a failure in a branch could affect the interruption frequency and duration of a considered LP*i* in five different ways. The branch fault effect depends mainly on the fault position with respect to LP*i*, and on the type/installation point of the involved protection device. Therefore a classification of five classes is presented as follows:

- **Case I (without DG units):**

When no protection device, either Circuit Breaker or Sectionalizer, is installed between the faulted branch *k* and LP*i* under study, the fault directly affects LP*i*, and customers connected to this load point will remain unsupplied for all the time required to repair the fault *k*, and the frequency of interruption of LP*i* will be equal to the failure rate of the faulted branch *k*, as expressed in the following set of equations:

$$\lambda_{i,k} = f_k$$

$$U_{i,k} = f_k * t_{r,k} \tag{4.10}$$

In Figure 6 a practical example of *Case I* occurrence in a distribution test system is shown, where the load point under study is LP_{20}, and the faulted branch is supposed to be L_{19}.

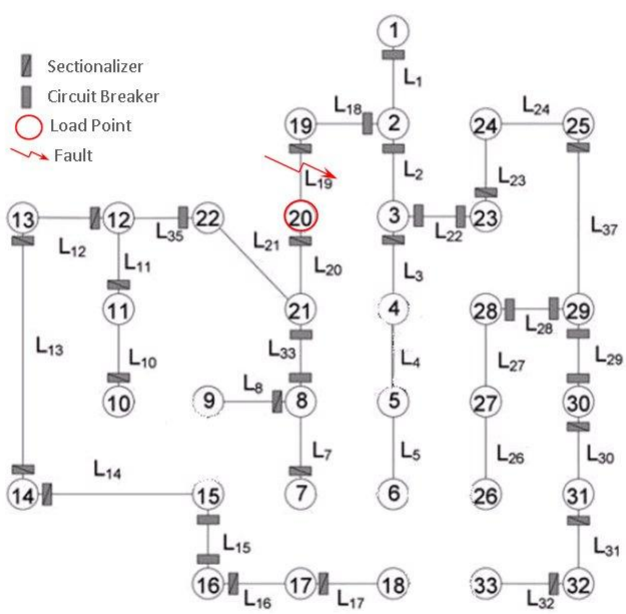

FIGURE 6: ILLUSTRATIVE EXAMPLE OF CASE I EVENT IN A DISTRIBUTION TEST SYSTEM [57].

- **Case II (without DG units):**

When at least one circuit breaker is installed between a faulted branch k and load point LPi, and at the same time, that circuit breaker should not be placed between LPi and the upstream main supply substation. In this case the fault is not going to affect the service continuity of Lpi, since the involved circuit breaker can clear the fault and isolate the faulted area from LPi power flow. Therefore, the interruption frequency and duration in this case will be equal to zero as shown below:

$$\lambda_{i,k} = 0$$

$$U_{i,k} = 0 \tag{4.11}$$

In Figure 7 an illustrative example for *Case II* is shown. In the adopted distribution test system, the considered load point for this case is LP_{20}, and the faulted branch is supposed to be L_{33}.

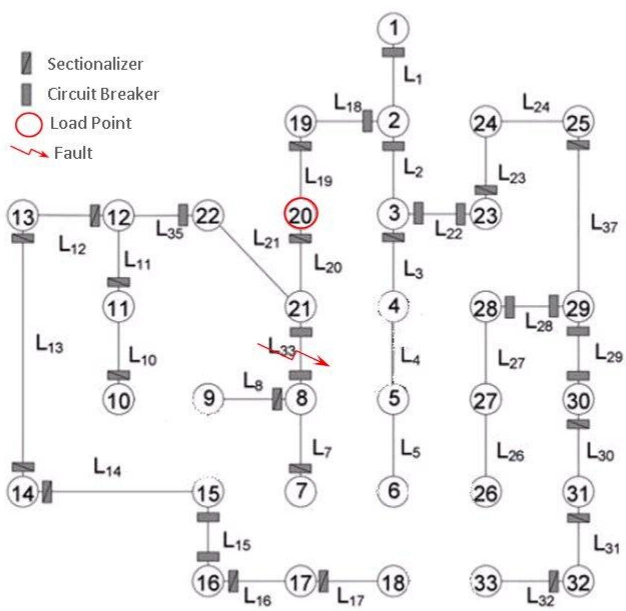

FIGURE 7: ILLUSTRATIVE EXAMPLE OF CASE II EVENT IN A DISTRIBUTION TEST SYSTEM [57].

- **Case III (without DG units):**

The third case occurs when one or more circuit breakers are installed between the faulted branch k and the load point under study LPi. At the same time, these circuit breakers are installed between the main supply substation and LPi. Since no DG units are installed in the system, third case reliability parameters will be equal to the first case ones, so that the interruption frequency and duration at LPi, with a fault in branch k, will be dependent on branch k failure rate, f_k, and branch k repair time, respectively. Reliability base parameters, of the third case are given by the following expressions:

$$\lambda_{i,k} = f_k$$

$$U_{i,k} = f_k * t_{r,k} \tag{4.12}$$

Figure 8 shows an applicable example for *Case III* on the adopted test system, where LPi is supposed to be LP_{20}, and the faulted branch is considered to be L_1.

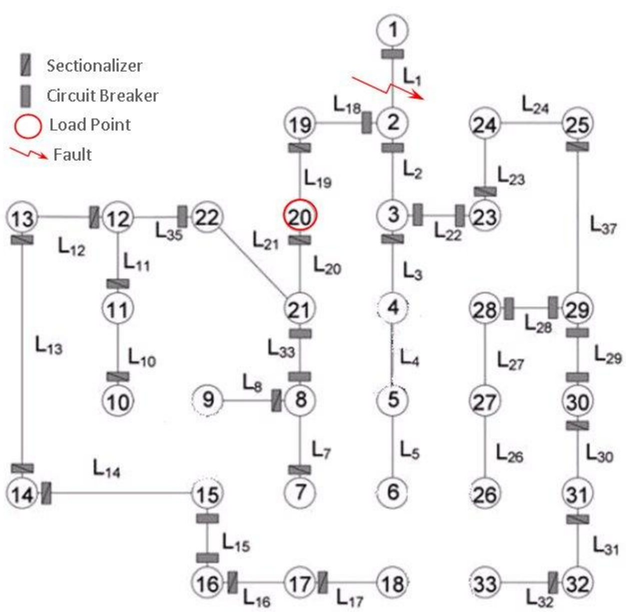

FIGURE 8: ILLUSTRATIVE EXAMPLE OF CASE III EVENT IN A DISTRIBUTION TEST SYSTEM [57].

- **Case IV (without DG units):**

When there is at least one sectionalizer installed between LPi and the faulted branch k, and it is not placed between the main supply substation and LPi. At the same time, no circuit breakers are installed between LPi and the faulted branch k. Therefore, in case branch k is faulted, the upstream circuit breaker, with respect to the sectionalizer placed between LPi and branch k, will trip first, then the involved sectionalizer will clear the faulted area, so that finally the upstream circuit breaker could be closed again and restore the power supply to LPi. This means that LPi will remain unsupplied for the sectionalizing time $t_{s,j}$, and the interruption frequency of LPi will be equal to branch k failure rate. On the other hand, the interruption duration at LPi will be proportional to $t_{s,j}$, as expressed in the following equations.

$$\lambda_{i,k} = f_k$$

$$U_{i,k} = f_k * t_{s,j} \tag{4.13}$$

Figure 9 shows an illustrative example for the aforementioned *case IV* on the adopted test system, where the considered load point is LP_{20}, and L_{20} is supposed to be the faulted branch k.

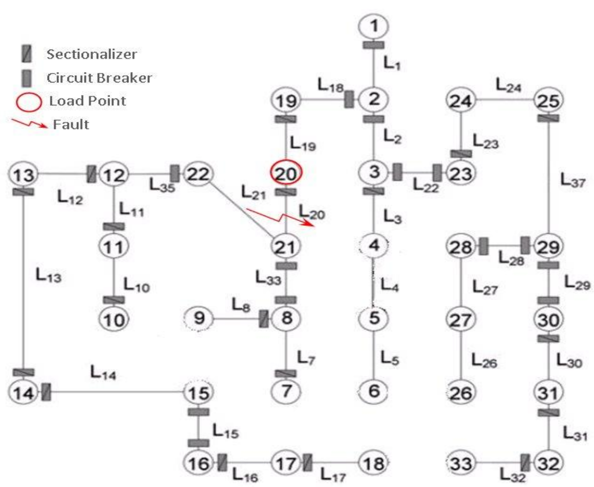

FIGURE 9: ILLUSTRATIVE EXAMPLE OF CASE VI EVENT IN A DISTRIBUTION TEST SYSTEM [57].

- **Case V (without DG units):**

When at least one sectionalizer is installed between LPi and the faulted branch k, and is placed between the main supply substation and LPi. At the same time, no circuit breakers are installed between LPi and the faulted branch k. Therefore in the case that branch k is faulted, the upstream circuit breaker, with respect to the sectionalizer placed between LPi and branch k, will trip first; then that sectionalizer will clear the faulted area, and finally the upstream circuit breaker can be closed again. Since the sectionalizer is placed between LPi and the main substation supply, hence LPi will remain unsupplied for the fault repair time duration $t_{r,k}$, even after the fault has been cleared. Therefore LPi interruption frequency and duration will be proportional to branch k fault rate and repair time, respectively. Expressions for interruption frequency and duration, in this case, of LPi when branch k is faulted are reported as follows:

$$\lambda_{i,k} = f_k$$

$$U_{i,k} = f_k * t_{r,k} \tag{4.14}$$

Figure 10 shows a fault event in the adopted distribution test system according to *case V*, where the load point under study is considered to be L_{20}, and the faulted branch is supposed to be L_{18}.

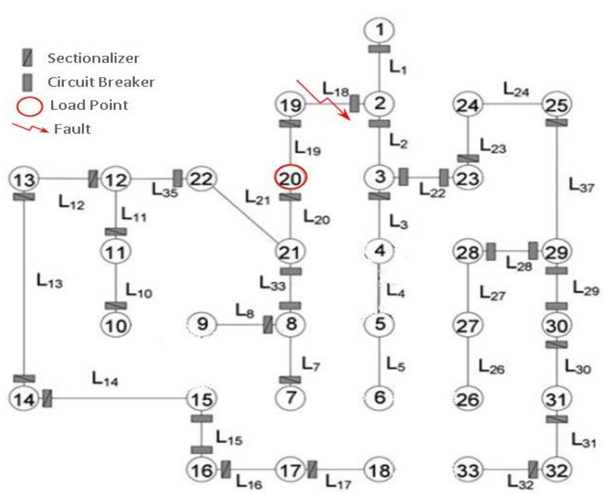

FIGURE 10: ILLUSTRATIVE EXAMPLE OF CASE V EVENT IN A DISTRIBUTION TEST SYSTEM [57].

4.1.3 Reliability Parameters with DG units (systematic approach)

When micro-grids with DG units installed are allowed to operate in an islanding mode of operation, a faulted branch k could affect the interruption frequency and duration of a certain Load point LPi depending on the following:

1) location of LPi;
2) power demand of LPi;
3) location of the faulted branch k;
4) rating of the installed DG units;
5) type of the DG units (dispatchable or renewable);
6) DG units installation position in the distribution system.
7) type of the involved protection devices (circuit breaker, sectionalizer, or both);
8) involved protection devices installation position (circuit breaker, sectionalizer, or both);

The first four points of the previous list determine the choice of the adequate case classification, as mentioned in the previous subsection. On the other hand, the last four points of the previous list determine the DG units' adequacy probability, $\rho_{A,j,new}$, of a micro-grid, which is going to be used accordingly for reliability parameters evaluation in *Case III* and *Case V*, when DG units are installed.

For *Case I*, *Case II*, and *Case IV*, expressions for annual interruption frequency, $\lambda_{i,k}$, and duration, $U_{i,k}$, of LPi, when branch k is faulted, will remain invariant even after DG units installation in the micro-grid containing LPi. Therefore, *Case III* and *Case V* formulations are modified as follows when DG units are installed in the system.

- **Case III (with DG units):**

When a fault occurs in branch k (L_1), the upstream circuit breaker will trip to clear the fault, and another circuit breaker *A*, upstream LPi (LP_{20}), will trip to isolate the faulted area and create island *j*, which includes LPi and all the downstream load points. Therefore LPi can be supplied during islanding mode of operation of island *j*, according to the adequacy probability, $\rho_{A,j,new}$, of DG units installed in island *j*. Expressions for interruption frequency and duration of LPi in this case become:

$$\lambda_{i,k} = f_k(1 - \rho_{A,j,new})$$

$$U_{i,k} = f_k(1 - \rho_{A,j,new}) * t_{r,k} \tag{4.15}$$

The previous set of formulations are valid only in the case that no sectionalizers are installed between faulted branch k and circuit breaker *A*. Otherwise, when one or more sectionalizers are installed in that position, *Sub- Case III.I* and *Sub-Case III.II* are presented as follows:

- **Sub-Case III.I (with DG units)**:

In addition to the description given above for *Case III*, this sub-case applies when one or more sectionalizers are installed between the faulted branch *k* and circuit breaker *A* (upstream LP*i*), and at the same time between the circuit breaker *A* and the main supply substation. When a fault occurs in branch *k*, the following procedure list shows the sequence of fault clearance and islanding operation.

1) circuit breaker *A*, installed upstream LPi, trips first forming island *j*. Therefore DG units, installed in island *j*, can supply LPi in an islanding mode of operation according to their adequacy probability, as explained previously in *Case III* with DG units.

2) then sectionalizer *sc*, closest to the fault, will be opened;

3) after that, DG units, installed between the opened sectionalizer sc and circuit breaker *A*,

will be connected, or reconnected in case they were operating during grid connected mode of operation before the fault occurrence;

4) afterwards, circuit breaker *A* will be closed directly;

5) thus, sectionalizer *sc* will be forming a bigger island sc after time equal to $(\mathrm{t}_{\mathrm{S,sc}} + \mathrm{t}_{\mathrm{AV,sc}})$ since the fault occurred.

Since sectionalizer *sc* is upstream from circuit breaker *A*, obviously, island *sc* includes load points and DG units situated between sectionalizer *sc* and circuit breaker *A* along with island *j* created previously by circuit breaker *A* tripping. Therefore, before circuit breaker *A* is closed, LPi was belonging to island *j*, then after the circuit breaker *A* closure, LPi belongs to island *sc*.

As a result, before circuit breaker *A* closure, LPi is affected by a fault in branch *k* according to the adequacy probability of island *j* DG units $(\rho_{A,j,new})$, and after the closure of *A*, LPi is affected by branch *k* fault according to the adequacy probability of island *sc* DG units (ρ_{sc}). Expressions for interruption frequency and duration of LPi, for *Sub-CaseIII.I*, are given by the following equations:

$$\lambda_{i,k} = f_k max\big[\big(1 - \rho_{A,j,new}\big); (1 - \rho_{sc})\big]$$

$$U_{i,k} = f_k\big[t_{r,k} - \rho_{A,j,new}(t_{S,sc} + t_{AV,sc}) - \rho_{sc}(t_{r,k} - t_{S,sc} - t_{AV,sc})\big] \qquad (4.16)$$

A practical example on the adopted distribution test system for *Sub-CaseIII.I* is shown in Figure 11, where the load point under study is LP_8 , and the faulted branch is supposed to be L_{19}. Further, circuit breaker *A* is the one right upstream from load point LP_8, and sectionalzer *sc* is right downstream from the faulted branch L_{19}.

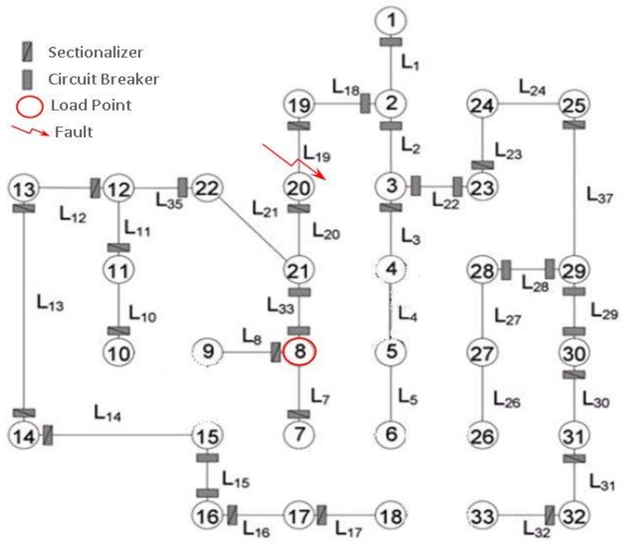

FIGURE 11: ILLUSTRATIVE EXAMPLE OF SUB-CASE III-I EVENT IN A DISTRIBUTION SYSTEM [57].

- **Sub-Case III.II (with DG units):**

In addition to the description given for *Case III*, this sub-case applies when at least one sectionalizer is placed between the faulted branch *k* and circuit breaker *A* (installed right upstream LP*i*). At the same time, this sectionalizer should not be placed between the circuit breaker *A* and the main supply substation.

The sequence of fault clearance and islanding operation is listed as follows:

1) first, circuit breaker *A* trips, consequently will be forming island *j*;

2) therefore, DG units installed in island *j* will supply LP*i* based on their adequacy probability, as mentioned in the description of *Case III*.

3) then sectionalizer *sc*, closest to the faulted branch *k*, will be tripped, allowing LP*i* to be supplied from the main supply substation.

Expression for interruption frequency and duration in this Sub-Case are given by the following equations:

$$\lambda_{i,k} = f_k(1 - \rho_{A,j,new})$$

$$U_{i,k} = f_k(1 - \rho_{A,j,new}) * t_{S,sc} \tag{4.17}$$

An applicable example on the adopted distribution test system is shown in Figure 12, where the load point under study is considered to be L_{23}, and the faulted branch is supposed to be L_{24}; circuit breaker *A* is right upstream from L_{23}, and sectionalizer *sc* is right upstream from L_{23}.

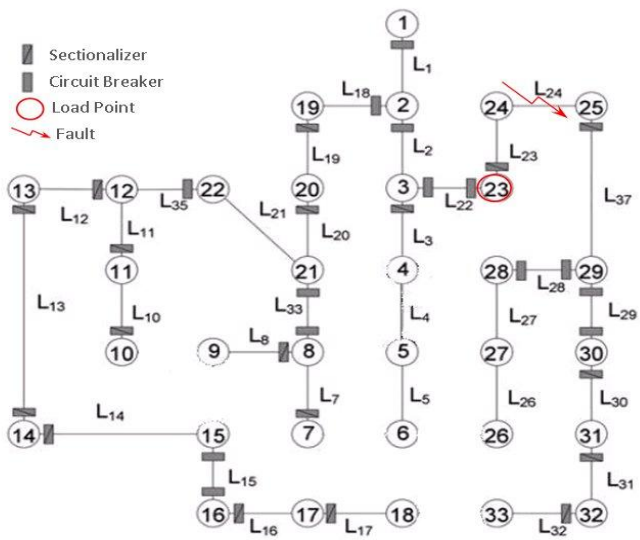

FIGURE 12: ILLUSTRATIVE EXAMPLE OF SUB-CASE III-II EVENT IN A DISTRIBUTION SYSTEM [57].

- **Case V (with DG units):**

In addition to the description given previously for Case *V*, when DG units are installed in the micro-grid that contains LP*i*, the sequence of fault clearance and islanding operation is listed as follows:

4) The circuit breaker upstream from the faulted branch *k* will sense the fault and trip first;
5) sectionalizer *sc*, placed between the faulted branch *k* and LP*i* will be opened after the required switching time $t_{S,sc}$, forming island *sc* with all downstream load points and DG units;

6) then DG units, installed in island *sc*, will be connected or reconnected again in case they were not operating before the fault occurrence during grid connected mode of operation. Therefore, the time required for DG units to be available is $t_{AV,sc}$;
7) at that stage, LPi can be supplied, during islanding mode of operation, by DG units installed in the island *sc*, based on their adequacy probability ρ_{sc}, after time given by $(\mathrm{t_{S,j}} + \mathrm{t_{AV,sc}})$;
8) finally, LPi can be supplied again by the main power supply after the failure in branch *k* has been repaired by $t_{r,k}$.

When the islanding mode of operation is allowed and in the presence of DG units, analytical expressions for interruption frequency and duration of LPi, in C*ase V*, are modified with respect to the case where no DG units were present as follows:

$$\lambda_{i,k} = f_k$$
$$U_{i,k} = f_k\left[\rho_{sc}\left(t_{S,j} + t_{AV,sc}\right) + t_{r,k}(1 - \rho_{sc})\right] \tag{4.18}$$

4.2 Assessment of Micro-Grids Adequacy during Islanding Mode of Operation

According to [58], during islanding mode of operation, dispatchable DG units' penetration level in a micro-grid should be equal at least to 60% of micro-grid total peak load demand at time of islanding, otherwise islanding would not be allowed. The main reason behind this condition is both the ensuring of required reactive power, and operational security constraints (voltage and frequency control during islanding mode of operation).

In order to allow islanding even if the previous condition is not verified, part of the total micro-grid load could be curtailed until the above condition is verified. Thus a first curtailment level is defined, and since islanding might occur at any load level, and not necessarily at peak load, the first load curtailment is defined with reference to the actual micro-grid load at time of islanding ($P_{j,l}^{L}$) by the following expression:

$$P_{j,l,curt\ 1}^{L} = P_{j,l}^{L} - \frac{P_{j,c}^{G}}{0.6} \tag{4.19}$$

Therefore, a remaining power load demand in island j ($P_{j,l}^{L_{new}}$), after first curtailment, will represent a new load demand to be considered for the assessment of island *j* adequacy probability. Such new power load demand is given by the following expression:

$$P_{j,l}^{L_{new}} = P_{j,l}^{L} - P_{j,l,curt\ 1}^{L} \tag{4.20}$$

The adequacy assessment of DG units that belong to a certain island expresses how much those DG units are able to supply the micro-grid load during eventual islanding mode of operation. An analytical formulation is now presented to assess DG units adequacy in each portion of the network that could operate in islanding mode. The *adequacy probability* of DG units installed in a potential island is calculated based on the following parameters related to the micro-grid or island under study:

- loads probabilistic modeling;
- dispatchable DG units probabilistic modeling;
- renewable DG units probabilistic modeling;
- rating of each DG unit in the island;
- micro-grid's load demand at time of islanding.

A similar formulation has been previously presented in [40] without considering both load correlation and first load curtailment that island *j* might require in order to respect technical constraints. The formulation is based on the combination of all possible operating conditions of *LPs* and DG units with their probabilities. In this work, correlation between loads has been taken into consideration, which means that for an island *j*, only one annual load model for all micro-grid *LPs* total load is considered.

First, the adequacy probability of DG units installed in island *j*, formed after the upstream protection device *A* has tripped, has been evaluated using the island *j* new load demand. Thus, the adequacy probability formulation would be computed as follows:

$$\rho_{A,j} = \sum_{m=1}^{N_j} \frac{min\left(P_{j,m}^{L_{new}} \, ; P_{j,m}^{G}\right)}{P_{j,m}^{L_{new}}} \rho_{j,m} \tag{4.21}$$

where $N_j = nl_{L,j} * \prod_{d=1}^{NG_j} nl_{G,d}$ is the number of working points at which island *j* can operate, i.e., the number of combinations considering the annual load model and DG units with their $nl_{L,j}$ and $nl_{G,d}$, respectively;

$P_{j,m}^{L_{new}} = P_{j,l_1}^{L_{new}} \; or \; P_{j,l_2}^{L_{new}} \; or \; \dots . P_{j,l_{10}}^{L_{new}}$ is island *j* load demand at the m-th combination, which corresponds to any of island *j* load levels because of the load correlation; $P_{j,m}^{G} = P_{1,l}^{G} + P_{2,l}^{G} + \cdots \dots \dots + P_{NG_j,l}^{G}$ is the total generated power out of any category of DG units available in island *j* at the *m*-th combination (e.g. $P_{1,6}^{G} + P_{2,8}^{G} + \cdots + P_{NG,5}^{G}$); $\rho_{j,m} = \rho_{j,l}^{L} * \; \rho_{1,l}^{G} * \rho_{2,l}^{G} \dots \dots \dots \rho_{NG_j,l}^{G}$ is the probability related to the *m*-th combination for island *j* (e.g. $\rho_{j,m} = \rho_{j,4}^{L} * \; \rho_{1,6}^{G} * \rho_{2,8}^{G} \dots \dots \dots \rho_{NG_j,5}^{G}$). It is worth noting that

$$\sum_{m=1}^{N_j} \rho_{j,m} = 1 \tag{4.22}$$

Considering working point *m*, if the total available power output is:

1. Equal or greater than the total power demand, then the local DG units can supply all local LP*s*. Hence, $min\left(P_{j,m}^{L_{new}} ; P_{j,m}^{G}\right) = P_{j,m}^{L_{new}}$;

2. Lower than the total power demand, and then the local DG units can supply some LPs only. Hence, $min\ \left(P_{j,m}^{L_{new}}; P_{j,m}^{G}\right) = P_{j,m}^{G}$. In this case, some customers are left unsupplied and their load demand would be curtailed further, so that DG units cannot fully supply their island load demand (after the first load curtailment) at islanding time occurrence. Therefore, a second level of load curtailment is defined as

$$P_{j,m,curt\ 2}^{L} = P_{j,m}^{L_{new}} - P_{j,m}^{G} \tag{4.23}$$

When, for all combination of working points, the total available power output is equal or greater than the total power demand, the ρ_{oA} is equal to one ($\rho_{A,j} = 1$). On the other hand, if there are not DG units in the island, the ρ_{oA} is equal to zero ($\rho_{A,j} = 0$). In this case, CB *j* does not trip because no fault current flows through it, so that no island is formed.

In this way, the resulting adequacy probability, expressed in (4.15), is not expressing the real state of island *j*, since the considered load is not the actual power demand ($P_{j,l}^{L_{new}}$) of island *j*. Therefore, a *new adequacy probability* is defined to take care of the first curtailed load as expressed in the following equation:

$$\rho_{A,j,new} = \rho_{A,j} * \left(1 - \frac{P_{j,l,curt\ 1}^{L}}{P_{j,l}^{L}}\right) \tag{4.24}$$

When, for all combination of working points, the total available power output is equal or greater than the total power demand, the ρ_{oA} is equal to one ($\rho_{A,j} = 1$). On the other hand, if there are not DG units in the island, the ρ_{oA} is equal to zero ($\rho_{A,j} = 0$). In this case, CB *j* does not trip because no fault current flows through it, so that no island is formed.

4.3 Expected Energy Not Served Evaluation

Before going through the details of the Expected Energy Not Served (EENS) evaluation, a definition of two cases, based on the service interruption source, is presented as follows:

1st case: when interruption is caused by a fault which occurred within island *j* under study;

2nd case: when service interruption is caused by a fault which occurred upstream from island *j* under study.

The annual interruption duration for an island is a function of the number of failures that might trigger a service interruption, and the required time to repair such faults in order to restore customers' service. Interruption duration expressions for the 1st and 2nd case are described respectively as follows:

$$\begin{cases} \mathrm{U}_{j,1} = F_{j,1\_case}\ (\mathrm{n°/year}) * \mathrm{t_r}\ (\mathrm{h/fault}) \quad (\mathrm{h}) \\ \mathrm{U}_{\mathrm{j},2} = F_{j,2\_case}\ (\mathrm{n°/year}) * \mathrm{t_r}\ (\mathrm{h/fault}) \quad (\mathrm{h}) \end{cases} \tag{4.25}$$

Repair time t_r is the same for all components, and is equal to 5 hours [59].

Since the test system under study is radial, elements of any segment or island are connected in series; therefore *faults* for the 1st and 2nd case are expressed respectively as follows:

$$\begin{cases} F_{j,1\_case} = \sum_{a=1}^{n_1} f_{j,a} \\ F_{j,2\_case} = \sum_{b=1}^{n_2} f_{j,b} \end{cases} \tag{4.26}$$

EENS due to a fault within an island *j* under study or upstream are given respectively by

$$EENS_{j,1} = \sum_{l=1}^{nl_{L,j}} \rho_{j,l}^{L} * \rho_{U_{j,1}} * 8760 * P_{j,l}^{L} = \sum_{i=1}^{nl_{L,j}} \rho_{c1,l} * 8760 * P_{j,l}^{L} \tag{4.27}$$

$$EENS_{j,2} = \sum_{l=1}^{nl_{L,j}} \rho_{j,l}^{L} * \rho_{U_{j,2}} * 8760 * P_{j,l}^{L} = \sum_{i=1}^{nl_{L,j}} \rho_{c2,l} * 8760 * P_{j,l}^{L} \tag{4.28}$$

The result of multiplying the i^{th} correlation probability $\rho_{c1,l}$ or $\rho_{c2,l}$ times 8760 h gives the fraction of the total interruption duration, for first or second case fault, that occurs at the load level *l*.

The evaluation of total EENS and interruption duration with and without DG units for island *j* are presented below.

4.3.1 EENS Evaluation without DG Units

EENS and *U* for island *j* when no DG units are installed in it are given by the total EENS and *U*, for island *j*, caused by the 1st and 2nd case interruption source as reported below

$$\begin{cases} U_{j,no\ DGs} = U_{j,2} + U_{j,1} \\ EENS_{j,no\ DGs} = EENS_{j,1} + EENS_{j,2} \end{cases} \tag{4.29}$$

4.3.2 EENS Evaluation with DG Units

Since EENS for island *j* depends on the interruption origin, then

- ***When faults occur within island j (first case), EENS and interruption duration are given by***

$$\begin{cases} U_{j,DG1} = U_{j,1} \\ EENS_{j,DG1} = EENS_{j,1} \end{cases} \tag{4.30}$$

- ***When faults occur within island j (second case), EENS and interruption duration are given by***

$$\begin{cases} U_{j,DG2} = U_{j,2} \\ EENS_{j,DG2} = \left(\sum_{l=1}^{nl_{L,j}} (\rho_{j,l}^{L} * P_{j,l,curt\ 1}^{L}) + \sum_{m=1}^{N_j} (\rho_{j,m} * P_{j,m,curt\ 2}^{L})\right) U_{j,2} \end{cases} \tag{4.31}$$

Chapter 5
Case study and results

In this chapter, some assumptions and technical considerations which have been considered for the evaluation of electrical system reliability indices and EENS will be presented. Also, a description for the adopted electrical distribution test system will be provided.

Afterwards, electrical reliability evaluation results will be presented and discussed for the different proposed scenarios of operation, including different DG units penetration levels. Moreover, EENS evaluation results will also be presented.

5.1 Assumptions and Considerations

The technical and practical assumptions and considerations which have been taken into account during the evaluation of both operation reliability indices and annual EENS are listed as follows:

- Islanding mode of operation has been assumed to be allowed for micro-grids;
- N-1 contingency has been assumed which means that a fault is repaired before a subsequent one occurs [42];
- Failure rates of protection devices, such as circuit breakers (CBs) and sectionalizers, have been taken into consideration for the evaluation of both reliability indices and EENS; unlike the assumption made in [60] and [61], where protection devices are considered fully reliable;
- No fuses are installed in the system, which is a practical assumption for a medium voltage system with 27.6 kV and higher;
- The distribution network is radially operated;
- Presence of advanced techniques, able to perform proper load curtailment when required.

5.2 Test System Description

Based on [62], a 69-bus is considered as a test system for this work. This system consists of eight lateral distribution feeders with a few modifications in the connection scheme in order to ensure a radial system configuration for the distribution network. Total nominal feeder load is 3.8 MW.

In order to simplify the reliability assessment procedure, a segmentation concept will be adopted, which means that LP*s* will not be treated separately, rather the system will be modeled as a set of segments. Each segment is defined as a set of LP*s* or components whose entry component is a switch or a protective device. In this way, any faulted part of a segment will have the same effect on the rest of the system, and similarly all LP*s* of a segment will be affected equally by any fault occurring in the rest of the system [4].

The adopted distribution test system layout, before segmentation has been performed and without the placement of any recloser, is shown in Figure 13.

The system layout, after segmentation has been performed, is shown in Figure 14, where six segments have been identified according to the installed reclosers positions, as explained earlier. After segmentation has been performed, peak power demand for each segment, $P^{L}_{seg\ i,peak}$ is identified and presented in Table VII, along with the load points that each segment contains.

When a recloser $R_{j,i}$ installed at load point LPi trips, all of the downstream segments would be forming potentially an island j. Accordingly, reclosers that can form possible islands are reported inTable VIII along with segments characterizing each island.

To be assumed firstly, two DG units are installed in each segment at buses 26, 34, 38, 41, 54 and 90. Such DG units are one conventional (diesel) of rating 200 kVA, and another renewable (wind-based) of rating 200 kVA.

The calculation procedure for reliability indices is as follows:

First, all system branches' failure rates are calculated based on their length and the average failure rate per unit length, taken from [59], as follows:

$$f_k = f_{l.u} * \ l_k * 1.61 \tag{5.1}$$

where the factor *1.61* is for conversion from one mile to one kilometre, and the repair time per one failure is equal for all branches, and is given by 5 hours as reported in [59].

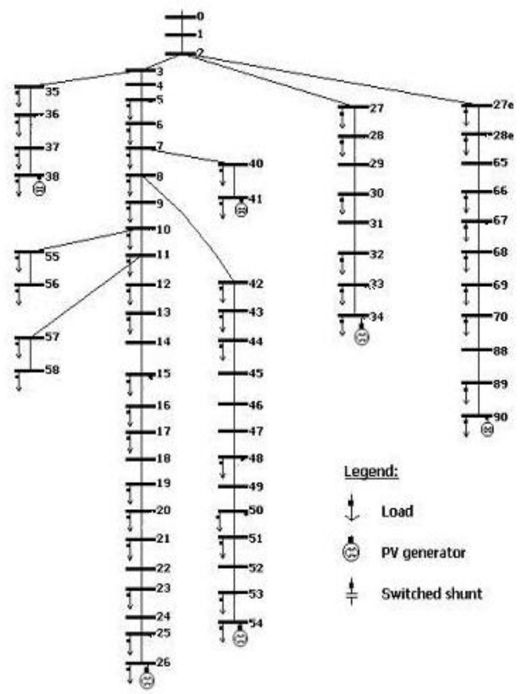

FIGURE 13: LAYOUT OF THE CASE STUDY DISTRIBUTION FEEDER BEFORE SEGMENTATION [62].

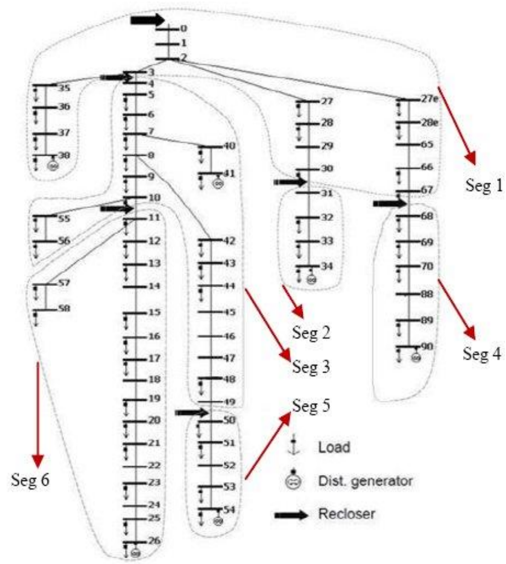

FIGURE 14: DISTRIBUTION TEST SYSTEM SEGMENTS DEFINED BY DASHED LINES [62].

TABLE VII: SEGMENTS LOAD POINTS AND POWER DEMAND.

	Seg 1	Seg 2	Seg 3	Seg 4	Seg 5	Seg 6
LOAD POINTS	1	31	4	68	50	11
	2	32	5	69	51	12
	3	33	6	70	52	13
	27	34	7	88	53	14
	28		8	89	54	15
	29		9	90		16
	30		10			17
	27e		40			18
	28e		41			19
	65		42			20
	66		43			21
	67		44			22
	35		45			23
	36		46			24
	37		47			25
	38		48			26
			49			57
			55			58
			56			
N° of LPs/Segment	16	4	19	6	5	18
$P^{L}_{seg,peak}$**(kVA)**	1962.118	42.924	605.611	92.423	797.041	603.546

TABLE VIII: SEGMENTS INCLUDED IN EACH ISLAND.

Island j	$R_{j,i}$	Segments Included in Island *j*
Island 1	$R_{1,0}$	Segment 1; 2; 3; 4; 5; 6
Island 2	$R_{2,31}$	Segment 2
Island 3	$R_{3,4}$	Segment 3; 5; 6
Island 4	$R_{4,68}$	Segment 4
Island 5	$R_{5,50}$	Segment 5
Island 6	$R_{6,11}$	Segment 6

5.3 Electrical Reliability Evaluation Results

After considering the technical constraints for a successful operation of micro-grids in islanding mode, reliability evaluation is performed. In order to evaluate the effect of the presence of DG units on the system behavior, and hence on the system reliability, two scenarios have been proposed and are described as follows:

1st scenario: In this scenario, the total penetration level of DG units in each segment has been maintained constant, however the penetration percentage for each DG category (dispatchable and non-dispatchable) has been changed through three case studies, as shown in Table IX.

Table X reports the ratings for DG units, dispatchable and non-dispatchable ones, installed in each island for each case study. In Table XI to Table XIII, the three cases results of this first scenario are shown. For each case, and for each island, the 1st load curtailment (at peak load), the max 2nd load curtailment, and adequacy probability at different operational conditions are reported.

TABLE IX: 1ST SCENARIO DG UNITS PENETRATION PERCENTAGE

1st scenario	**DG unit type**	
	Dispatchable per segment (Diesel)	Non-Dispatchable per segment (Wind-based)
Case 1	75%	25%
Case 2	50%	50%
Case 3	25%	75%

TABLE X: 1ST SCENARIO DG UNITS PENETRATION LEVELS FOR EACH ISLAND

		1st scenario		
		Case 1	Case 2	Case 3
Island 1	**Diesel** (kW)	1800	1200	600
	Wind (kW)	600	1200	1800
Island 2	**Diesel** (kW)	300	200	100
	Wind (kW)	100	200	300
Island 3	**Diesel** (kW)	900	600	300
	Wind (kW)	300	600	900
Island 4	**Diesel** (kW)	300	200	100
	Wind (kW)	100	200	300
Island 5	**Diesel** (kW)	300	200	100
	Wind (kW)	100	200	300
Island 6	**Diesel** (kW)	300	200	100
	Wind (kW)	100	200	300

TABLE XI: 1ST SCENARIO--CASE 1

Island j	$P^L_{j,peak}$ (kVA)	$P^L_{j,peak,curt\ 1}$ (kVA)	$P^L_{j,curt\ 2\ max}$ (kVA)	$\rho_{A,j}$ (%)	$\rho_{A,j,peak,new}$ (%)	$\rho_{A,j,new}$ (%)
Island 1	4103.67	1103.7	3000	94.47	69.06	93.14
Island 2	42.9242	0	42.92	99.46	99.46	99.46
Island 3	2191.05	691.048	1500	94.09	64.41	91.58
Island 4	92.4238	0	92.42	99.25	99.25	99.25
Island 5	797.042	297.041	500	93.78	58.83	89.11
Island 6	603.547	103.546	500	95.91	79.46	95.62

TABLE XII: 1ST SCENARIO--CASE 2

Island j	$P^L_{j,peak}$ (kVA)	$P^L_{j,peak,curt\ 1}$ (kVA)	$P^L_{j,curt\ 2\ max}$ (kVA)	$\rho_{A,j}$ (%)	$\rho_{A,j,peak,new}$ (%)	$\rho_{A,j,new}$ (%)
Island 1	4103.67	2103.67	2000	96.07	46.82	82.64
Island 2	42.9242	0	42.9242	99.55	99.55	99.55
Island 3	2191.05	1191.05	1191.05	96.06	43.84	80.17
Island 4	92.4238	0	92.4238	99.45	99.45	99.45
Island 5	797.042	463.71	333.333	96.06	40.17	76.84
Island 6	603.547	270.21	333.333	96.08	53.07	87.16

TABLE XIII: 1ST SCENARIO--CASE 3

Island j	$P^{L}_{j,peak}$ (kVA)	$P^{L}_{j,peak,curt\ 1}$ (kVA)	$P^{L}_{j,curt\ 2\ max}$ (kVA)	$\rho_{A,j}$ (%)	$\rho_{A,j,peak,new}$ (%)	$\rho_{A,j,new}$ (%)
Island 1	4103.67	3103.7	1000	97.39	23.73	61.19
Island 2	42.9242	0	42.9242	99.58	99.58	99.58
Island 3	2191.05	1691	500	97.39	22.22	59.68
Island 4	92.4238	0	92.4238	99.52	99.52	99.52
Island 5	797.042	630.375	166.667	97.39	20.36	57.82
Island 6	603.547	436.88	166.667	97.39	26.89	64.35

2nd scenario: In this scenario, the penetration percentage for each DG category (dispatchable and non-dispatchable) has been maintained constant, however the total penetration level of DG units in each segment has been changed through three case studies, as shown in TABLE XIV. TABLE XV tabulates the ratings for the DG units installed in each island, dispatchable and non-dispatchable, for each case study. The results of the three cases of this second scenario are shown in TABLE XVI to TABLE VIII, presenting the same parameters mentioned in the 1st scenario.

TABLE XIV: 2ND SCENARIO DG UNITS PENETRATION PERCENTAGE

2nd scenario	DG unit type	
	Dispatchable per segment (Diesel) (kW)	Non-Dispatchable (Wind-based) per segment (kW)
Case 1	300	300
Case 2	200	200
Case 3	100	100

TABLE XV: 2ND SCENARIO DG UNITS PENETRATION LEVELS FOR EACH ISLAND

		2nd scenario		
		Case 1	**Case 2**	**Case 3**
Island 1	**Diesel** (kW)	1800	1200	600
	Wind (kW)	1800	1200	600
Island 2	**Diesel** (kW)	300	200	100
	Wind (kW)	300	200	100
Island 3	**Diesel** (kW)	900	600	300
	Wind (kW)	900	600	300
Island 4	**Diesel** (kW)	300	200	100
	Wind (kW)	300	200	100
Island 5	**Diesel** (kW)	300	200	100
	Wind (kW)	300	200	100
Island 6	**Diesel** (kW)	300	200	100
	Wind (kW)	300	200	100

TABLE XVI: 2ND SCENARIO--CASE 1

Island j	$P^L_{j,peak}$ (kVA)	$P^L_{j,peak,curt\,1}$ (kVA)	$P^L_{j,curt\,2\,max}$ (kVA)	$\rho_{A,j}$ (%)	$\rho_{A,j,peak,new}$ (%)	$\rho_{A,j,new}$ (%)
Island 1	4103.67	1103.7	3000	96.59	70.61	95.24
Island 2	42.9242	0	42.9242	99.58	99.58	99.58
Island 3	2191.05	691.04	1500	96.34	65.95	93.76
Island 4	92.4238	0	92.4238	99.52	99.52	99.52
Island 5	797.042	297.042	500	96.11	60.29	91.33
Island 6	603.547	103.547	500	97.45	80.73	97.14

TABLE XVII: 2ND SCENARIO--CASE 2

Island j	$P^L_{j,peak}$ (kVA)	$P^L_{j,peak,curt\,1}$ (kVA)	$P^L_{j,curt\,2\,max}$ (kVA)	$\rho_{A,j}$ (%)	$\rho_{A,j,peak,new}$ (%)	$\rho_{A,j,new}$ (%)
Island 1	4103.67	2103.67	2000	96.07	46.82	82.64
Island 2	42.9242	0	42.9242	99.55	99.55	99.55
Island 3	2191.05	1191.05	1191.05	96.06	43.84	80.17
Island 4	92.4238	0	92.4238	99.45	99.45	99.45
Island 5	797.042	463.709	333.333	96.06	40.17	76.84
Island 6	603.547	270.213	333.333	96.08	53.07	87.17

TABLE XVIII: 2ND SCENARIO--CASE 3

Island j	$P^{L}_{j,peak}$ (kVA)	$P^{L}_{j,peak,curt\ 1}$ (kVA)	$P^{L}_{j,curt\ 2\ max}$ (kVA)	$\rho_{A,j}$ (%)	$\rho_{A,j,peak,new}$ (%)	$\rho_{A,j,new}$ (%)
Island 1	4103.67	3103.7	1000	96.05	23.41	60.35
Island 2	42.9242	0	42.9242	99.47	99.47	99.47
Island 3	2191.05	1691	500	96.05	21.92	58.86
Island 4	92.4238	0	92.4238	99.25	99.25	99.25
Island 5	797.042	630.375	166.667	96.05	20.08	57.02
Island 6	603.547	436.88	166.667	96.05	26.52	63.46

Since an islanding mode of operation might occur at any load demand level (out of the ten states that define the annual load model as explained previously in section 3.1), $P^{L}_{j,l,curt\ 1}$, $P^{L}_{j,m,curt\ 2}$, $P^{L}_{j,curt\ 2\ max}$, $\rho_{A,j}$, and $\rho_{A,j,new}$ have all been computed for each load level that island j might be exposed to.

On the other hand, $P^{L}_{j,peak,curt\ 1}$ and $\rho_{A,j,peak,new}$ have been evaluated considering that islanding occurs at the peak level demand of island j under study. Such assumption represents the worst case load scenario that islanding might occur at.

Afterwards, based on LP*s* relative position with respect to both protection devices and faulted branches, annual interruption frequency $\lambda_{i,k}$ and duration $U_{i,k}$ for all LPs are calculated according to the appropriate case formulation of the adopted methodology.

Finally, Reliability indices (i.e., SAIFI and SAIDI) of the system are calculated using equations 1 and 2. The indices have been computed once during grid connection mode, when no DG units are installed anywhere, and another time for each of the three case studies of the two proposed scenarios during islanding mode and after installing DG units.

Table XIX shows the final results of the test system reliability indices in different case scenarios as described earlier, for both worst case load (islanding occurs at peak load) and real case (islanding might occur at any annual load model) conditions. In FIGURE 15 and FIGURE 16, results of reliability indices (SAIFI and SAIDI) for the different scenarios and cases are presented in comparison.

TABLE XIX: RELIABILITY INDICES FINAL RESULTS

Scenarios			Reliability Indices			
			Using $\rho_{A,j,peak,new}$ (worst load condition)		Using $\rho_{A,j,new}$ (real load condition)	
			SAIFI_1 Interruptions per customer/year	SAIDI_1 Interruption duration per customer(hours)/year	SAIFI_2 Interruptions per customer/year	SAIDI_2 Interruption duration per customer(hours)/year
Without DG units			**2.44**	**12.21**	**2.44**	**12.21**
With DG units	**1st Scenario**	Case1	1.50	7.52	1.09	5.49
		Case 2	1.80	9.01	1.27	6.34
		Case 3	2.11	10.56	1.56	7.79
	2nd Scenario	Case 1	1.48	7.42	1.07	5.33
		Case 2	1.80	9.01	1.27	6.34
		Case 3	2.12	10.58	1.57	7.86

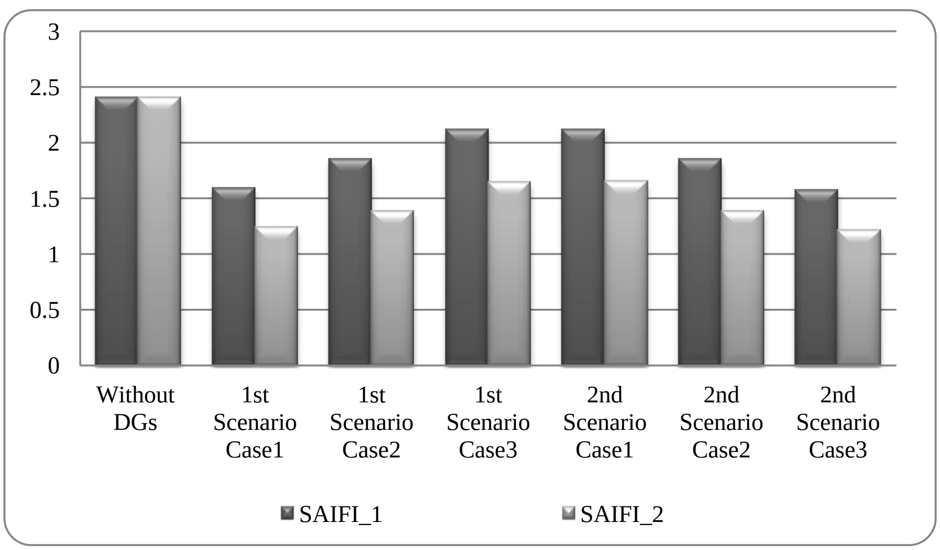

FIGURE 15 RESULTS FOR SAIFI UNDER DIFFERENT SCENARIOS

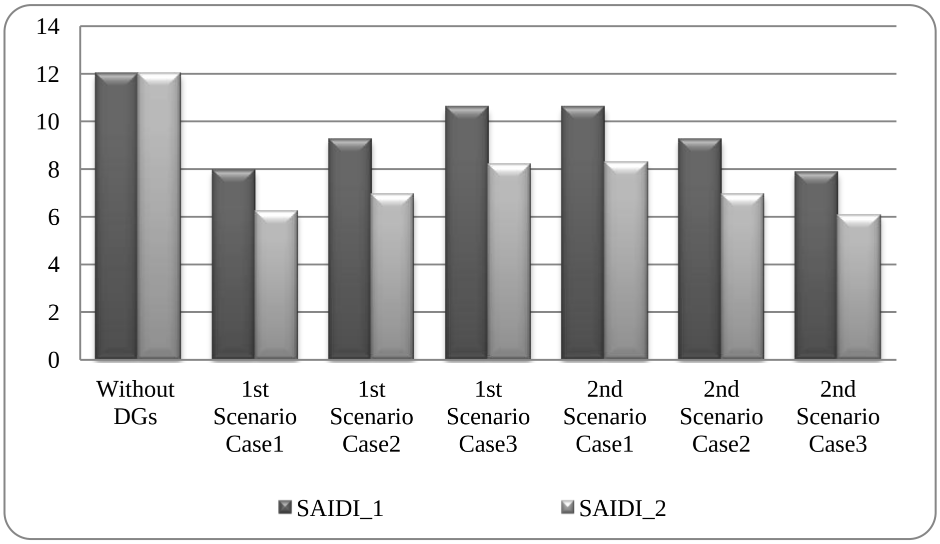

FIGURE 16 RESULTS FOR SAIDI UNDER DIFFERENT SCENARIOS

Since the islanding mode of operation is not allowed for the base case (without DG units), therefore reliability indices (SAIFI and SAIDI) will remain invariant for both worst and real load conditions. Further, it can be noticed from the above results that when no DG units are installed in the system, reliability indices are inherently high with respect to the other cases. Hence, the presence of DG units when islanding mode of operation is allowed, has significantly improved the overall system reliability level.

Allowing a 1st load curtailment, whenever needed, improves the overall reliability level by allowing different micro-grids a successful operation in islanding mode, regardless of the micro-grid loading condition and dispatchable DG units rating at islanding occurrence.

5.4 Expected Energy not Served Evaluation Results

As for DG units penetration level used for the evaluation of EENS, case 2 of the 1st scenario discussed in section 5.3 is adopted. Applying the aforementioned proposed methodology, EENS evaluation is performed. Based on the adopted test system, components that are responsible for an interruption occurrence for island *j*, in general, are of different nature. In fact, they could be *switches*, *branches* belonging to different segments, or main supply *substation*. In Table XX, the system components that might imply island *j* service interruption for both 1st and 2nd case are reported.

TABLE XX: SYSTEM COMPONENTS INVOLVED IN A SERVICE INTERRUPTION

		Possible Service Interruption Source		
		Segment **Seg**	Recloser $R_{j,i}$	Substation
Island 1	1st case	Seg 1; 2; 3; 4; 5; 6	$R_{1,0}$; $R_{2,31;}$ $R_{3,4;}$ $R_{4,68\,;}$ $R_{5,50;}$ $R_{6,11.}$	-
	2nd case	-	-	Substation
Island 2	1st case	Seg 2	$R_{2,31}$	-
	2nd case	Seg 1	$R_{1,0}$	Substation
Island 3	1st case	Seg 3; 5; 6	$R_{4,68;}$ $R_{5,50;}$ $R_{6,11}$	-
	2nd case	Seg 1	$R_{1,0}$	Substation
Island 4	1st case	Seg 4	$R_{4,68}$	-
	2nd case	Seg 1	$R_{1,0}$	Substation
Island 5	1st case	Seg 5	$R_{5,50}$	-
	2nd case	Seg 1; 3	$R_{1,0,}$; $R_{3,4}$	Substation
Island 6	1st case	Seg 6	$R_{6,11}$	-
	2nd case	Seg 1; 3	$R_{1,0,}$; $R_{3,4}$	Substation

Table XXII reports the results of EENS evaluation along with some related calculation parameters. The assessment is performed for both grid-connected (without DG units) and islanding (with DG units) mode of operation:

TABLE XXI: EENS RELATED PARAMETERS UNDER DIFFERENT CASES

Island j	**$P^L_{j,peak}$ (kVA)**	**Fault within island j (1st case)**		**Fault upstream island j (2nd case)**			
		$U_{j,1}$ h	**EENS$_{j,1}$** MWh	**$U_{j,2}$** h	**$P^L_{j,l,curt\,1}$** kVA	**$P^L_{j,m,curt\,2}$** kVA	**EENS$_{j,2}$** MWh
1	4103.67	47.9	120.994	0.5	573.4	57.6	1.263
2	42.9242	8.83	0.23327	2.98	0	0.08	0.079
3	2191.05	33.9	45.8459	2.98	362.3	28.9	4.014
4	92.4238	2.60	0.14802	2.98	0	0.22	0.169
5	797.042	5.07	2.48899	16.2	159.4	9.64	7.948
6	603.547	15.7	5.83113	16.2	56.02	9.53	6.018

TABLE XXII: TOTAL EENS FINAL RESULTS FOR EACH ISLAND

Island j	**$U_{j,no\ DGs}$ (h)**	**$U_{j,DG1}$ (h)**	**$EENS_{j,no\ DGs}$ (kWh)**	**$EENS_{j,DG1}$ (kWh)**	**$EENS_{j,DG2}$ (kWh)**
Island 1	48.41	47.91	122256.36	120993.62	315.485
Island 2	11.81	8.830	311.8982	233.26957	0.23687
Island 3	36.98	33.99	49859.49	45845.919	1164.45
Island 4	5.579	2.602	317.3206	148.01812	0.64715
Island 5	21.28	5.074	10436.92	2488.986	2739.15
Island 6	31.90	15.69	11849.57	5831.1278	1062.15

From the previous results it can be noticed that islands 2, 3, and 4 share the same upstream components; hence their interruption duration due to an upstream fault $U_{j,2}$ is the same. Further, for a fault occurring within island *j*, both EENS$_{j,1}$ and $U_{j,1}$ will not be reduced with the installation of DG units in the considered island *j*. On the other hand, when service interruption is caused by a fault upstream island *j*, the interruption duration $U_{j,2}$ will not change after DG units have been installed in island *j*. However, the unserved power load demand in island *j* would be reduced, therefore the $EENS_{j,2}$ would be reduced to $EENS_{j,DG2}$, which is given by the summation of 1st and 2nd load curtailment during the year (each with the corresponding probability) multiplied by the annual interruption duration for an upstream fault $U_{j,2}$.

Chapter 6
Conclusion

In this work, a systematic approach with a set of system independent analytical expressions has been adopted in order to perform reliability evaluation for distribution systems. The evaluation considered annual probabilistic models for micro-grid components during islanding mode of operation. Therefore, the variable load profile has been considered, expressed through an annual load model that associates a certain probability of occurrence during a year at each adopted load demand level.

Further, the stochastic nature of the primary source of the renewable DG units has been taken into account by adopting an annual output model for a wind-based DG unit. Moreover, the failure probabilities of DG units hardware, for both dispatchable and renewable DG units, have been taken into account for the development of their annual probabilistic output power model.

Also, the success condition for islanding has been improved by introducing an additional level of load curtailment, in order to allow islanding when the stability condition is not fulfilled. Hence, a new adequacy probability has been introduced in order to take into account such additional load curtailment, and the correlation between different loads within the island under study. Based on the improved islanding success condition, reliability indices have been evaluated for the system (SAIFI and SAIDI) with reasonable penetration levels and ratios of DG units.

EENS assessment has been performed, adopting a new modified formulation when DG units are installed, and the island *j* under study is operating in islanding mode. Such formulation is based on the total annual 1st and 2nd possible curtailed loads, along with their respective probabilities.

Load correlation and failure rate of protection devices has been taken into consideration in this work, for both reliability indices evaluation and EENS assessment.

Therefore, the contribution of the first load curtailment introduction is to guarantee the necessary security level for micro-grid islanding operation in presence of hybrid DG units, regardless of the island load demand condition and generation capacity of the installed DG units at time of islanding. Consequently, this implies significantly in the improvement of the overall system reliability level through the enhancement of the system interruption frequency and duration indices.

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Appendix A: Distribution Test System Data

TABLE XXIII POWER LOAD DEMAND OF THE DISTRIBUTION TEST SYSTEM

Load point	Active Power P (kW)	Reactive Power Q (kVar)	Apparent Power S (kVA)	Load point	Active Power P (kW)	Reactive power Q(kVar)	Apperant Power S (kVA)
1	0	0	0	**47**	0	0	0
2	0	0	0	**48**	100	43.2	108.932
3	0	0	0	**49**	0	0	0
27	26	11.16	28.293	**55**	18	7.8	19.617
28	26	11.16	28.293	**56**	18	7.8	19.617
29	0	0	0	**68**	1.2	0.6	1.341
30	414.67	177.6	451.101	**69**	0	0	0
27e	26	11.13	28.282	**70**	6	2.58	6.531
28e	0	0	0	**88**	0	0	0
65	0	0	0	**89**	39.22	15.78	42.275
66	24	10.2	26.077	**90**	39.22	15.78	42.275
67	24	10.2	26.077	**50**	414.67	177.6	451.101
35	414.67	177.6	451.101	**51**	32	13.8	34.848
36	79	33.84	85.942	**52**	0	0	0
37	384.7	164.7	418.473	**53**	227	97.2	246.934
38	384.7	164.7	418.473	**54**	59	25.2	64.156
31	0	0	0	**11**	145	62.4	157.856
32	14	6	15.231	**12**	8	3.3	8.653
33	19.5	8.4	21.232	**13**	8	3.3	8.6539
34	6	2.4	6.462	**14**	0	0	0
4	0	0	0	**15**	45.5	18	48.931
5	2.6	1.32	2.915	**16**	60	21	63.568
6	40.4	18	44.228	**17**	60	21	63.568
7	75	32.4	81.699	**18**	0	0	0
8	30	13.2	32.775	**19**	1	0.36	1.062
9	28	11.4	30.231	**20**	114	48.6	123.927
10	145	62.4	157.856	**21**	5.3	2.1	5.7008
40	40.5	16.98	43.915	**22**	0	0	0
41	3.6	1.62	3.947	**23**	28	12	30.463
42	4.53	2.1	4.993	**24**	0	0	0
43	26.4	11.4	28.756	**25**	14	6	15.231
44	24	10.32	26.124	**26**	14	6	15.231
45	0	0	0	**57**	28	12	30.463
46	0	0	0	**58**	28	12	30.463

TABLE XXIV FAILURE RATE AND REPAIR TIME OF THE BRANCHES

Segment 1		**Segment 2**		**Segment 3**		**Segment 6**	
Branch *k*	**f_k (f/yr)**	**Branch k**	**f_k (f/yr)**	**Branch *k***	**f_k (f/yr)**	**Branch *k***	**f_k (f/yr)**
1	0.00064	31	0.14097	4	0.01029	11	0.28581
2	0.00064	32	0.33667	5	0.14677	12	0.41392
3	0.00064	33	0.68622	6	0.1532	13	0.41907
27	0.00193	34	0.59223	7	0.0373	14	0.42486
28	0.02574	**Segment 4**		8	0.01995	15	0.07917
29	0.15964			9	0.32894	16	0.15063
30	0.02832	68	0.29225	10	0.07531	17	0.00193
27e	0.00193	69	0.12424	40	0.03733	18	0.13132
28e	0.02574	70	0.01673	41	0.13325	19	0.08432
65	0.04248	88	0.03283	42	0.07016	20	0.13711
66	0.01223	89	0.04377	43	0.08175	21	0.00579
67	0.00064	90	0.00064	44	0.11394	22	0.06373
35	0.00128	**Segment 5**		45	0.11329	23	0.13904
36	0.03411			46	0.63858	24	0.30062
37	0.11651	50	0.20406	47	0.31478	25	0.12424
38	0.03283	51	0.03926	48	0.12231	26	0.06952
		52	0.05793	49	0.15514	57	0.29676
		53	0.28517	55	0.08111	58	0.00193
		54	0.41842	56	0.00193		