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NEMAT DEHGHANI

MODELING OF SIMULTANEOUS FAULTS TO RELIABILITY ENHANCEMENT AND RISK ASSESSMENT IN DISTRIBUTION SYSTEM

Master of Science thesis

Examiner: Prof. Sami Repo
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ABSTRACT

NEMAT DEHGHANI: Modeling of Simultaneous Faults to Reliability Enhancement and Risk Assessment in Distribution System
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The main purpose of an electric power system is to provide electricity from the generation source to the customer point. Security and adequacy are the two most important requirements in power system reliability. As most of the faults that happen in a distribution network are experienced by the customers, improving the security of the distribution side can have a beneficial effect on the entire network. Faults can occur in single or multiple, faults can also occur at the same time in many different places in the network. It is the simultaneous faults that can drastically affect the security of a network, and directly decrease the reliability. This thesis work studied the modelling of simultaneous faults by using the Monte-Carlo Simulation (MCS) algorithm in a distribution network. This makes it possible to evaluate the effect of the repair time in different situations, and also to model various solutions to enhance the reliability of the network. An actual overhead line feeder in a distribution network from a rural electricity distribution company was chosen for modelling the MC algorithm and to study the reliability procedures based on it. The calculations in the simulation model are based on number of the faults and the availability of maintenance and repair crews in the case of simultaneous faults. The algorithm can also be used for calculating the reliability indices in radial and mesh configurations with radially operated feeders. As the investment is one of the important parts of planning, evaluation of outage cost also applied to find a valuable view of network for future investment. Risk assessment is a second goal of this thesis to study and analyze future planning of network. Probability and consequence are two main functions of risk studies, three classes of major storm described and analyzed to find the effect on the network reliability based on the percentage of customers without electricity and outage time. These are two tools which are using in financial studies to make investment decision and applicable in power systems are Value-at-Risk (VaR) and Conditional Value-at-Risk (CVaR). The Final result shows an improvement in reliability indexes of the network which shoes the capability of thesis work to apply in practical aspects.

PREFACE

This master thesis has been carried out as a part of ID4L project in Department of Electrical Engineering (DEE) at Tampere University of Technology (TUT). The supervisor of thesis was Prof. Sami Repo which I would like to express my gratitude to him for his support and valuable feedback during the research work; he always accepted my ideas with an open mind and gave me the maximum opportunity to contribute on the topics.

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Finally the most important is thanks to my beloved family, my parents, my sister and my brothers which remind me that the life itself is an advantage.

Nemat Dehghani

Tampere-Finland

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LIST OF SYMBOLS AND ABBREVIATIONS

AMR	Automatic Meter Reading
ASIFI	Average system interruption frequency index
ASIDI	Average system interruption duration index
AIT	Average interruption time
AIF	Average interruption frequency
AID	Average interruption duration
ASAI	Average service availability index
CAIDI	Customer average interruption duration index
CTAIDI	Customer total average interruption duration index
CAIFI	Customer average interruption frequency index
DMS	Distributed Management System
DPLVC	Daily peak load variation curve
ENS	Energy not supplied
LDC	Load duration curve
MAIFI	Momentary average interruption frequency index
MV	Medium Voltage
MCS	Monte Carlo Simulation
OC	Outage Cost
PDF	probability density function
SAIFI	System average interruption frequency index
SAIDI	System average interruption duration index
VaR	Value-at-Risk

CVaR	Conditional Value-at-Risk

1. INTRODUCTION

The societies are getting large to compare the past and in same time they are going to be more related to electricity. Power system nowadays is one of the complicated systems in engineering. Demand is increasing in many countries and investment for supply should be increase to support customer needs. The main task in power system is to supply customers continuously. Electrical companies want to improve the quality and reliability of their system to gain more economical benefit from customers.

Nowadays Electrical energy has direct effect on economic and also politic situation of every country. Now more than ever, it is crucial in the electrical power industries to have a solid understanding of designing the reliable and cost effective utility, industrial and commercial power system. The necessity to provide reliability in the distribution system and in power can be defined as the system's capability in generation, transmission and distribution of electricity energy to the consumers. In the distribution part, fault frequent (frequency of occurrence of faults and interrupts), the time period of each fault and the rate of consumption for each consumer needs, in the lack of consumer service and lack of feeding system are the main factors to judge about systems reliability. Many factors are important in the determining the reliability of a system which some of them are controllable. These factors are depend on variable such as the reliability of the equipment components, networks length its loading, networks configuration loads characteristic, etc. Other factor are also important in reduction of network's reliability such as disorder in distribution by third part for example atmospheric and environmental condition like temperature, humidity, air pollution, wind, rain, snow ,ice, and thunderbolt.

The financial and public effects of loss of electric service have significant influence on both the utility supplying electric energy and the end users. Just a major outage or blackout in one area can cost millions of euros. Therefore, designing a reliable power supply is a very important issue for power systems long term planning and operation.

1.1 Object of research

One object of this research is to assessment different aspects that can effect on reliability of distribution system like location of the line, switching time, repair time and backup connection. The system model is from local distribution company and the algorithm designed to cover selected feeders for different fault situation and also evaluate how is possible to use Existing technology like distribution automation to improve reliability of network model. However, investment and adding new situation also modeled on the network model to have better final result.

Modeling the major storm and simultaneous faults is the other objects of this analyze. In Finland and other Nordic countries winter is the longest season that means the possibility of storm and extreme whether condition is higher than other places in Europe. In this study simultaneous faults modeled by using Monte Carlo Simulation (MCS) to analyze the effect on reliability of system.

1.2 Definition of reliability study

Security and adequacy are two important requirements in power system reliability. Adequacy is how a system can supply the customer with a higher level of satisfaction by the components that are available in the system. Security is the ability of the system to respond to unexpected disturbances to the normal working condition. All of the presented methods are analyzing these two capabilities of networks in different situations.

In the other word reliability is the probability that a system or component will perform its required function under stated conditions for a specified period of time. Basic steps in reliability analysis for each engineering system are:

- understanding the operation of system
- system failure possibilities
- assume the result of failure
- determine a simulation model
- choose an appropriate reliability solution

1.3 Thesis contents

Chapter 1 is introduction and basic idea of thesis. Chapter 2 “analysis model” is a brief general review of evaluation methods which are using for reliability study in different level of power system. Chapter 3 is “enumeration method “describe the mathematical calculation and numeral example of reliability in the small power systems. Chapter 4 “Reliability Assessment” presents several reliability assessment method and also result of simulation model. Chapter 5,”simultaneous faults” devoted to analyze the modeling of simultaneous fault in modeled network. Chapter 6 is “Risk Assessment” and cost analysis by using optimization methods. Chapter 7 is the final conclusion.

2. Analysis methods for Distribution network reliability

The power system is divided in tree hierarchical levels to study reliability assessment based on the separated goals in each level. Figure 2.1 represents each level. Generation is in hierarchical one or HLI, generation and transmission are in HLII and generation transmission and distribution are included in HLIII.

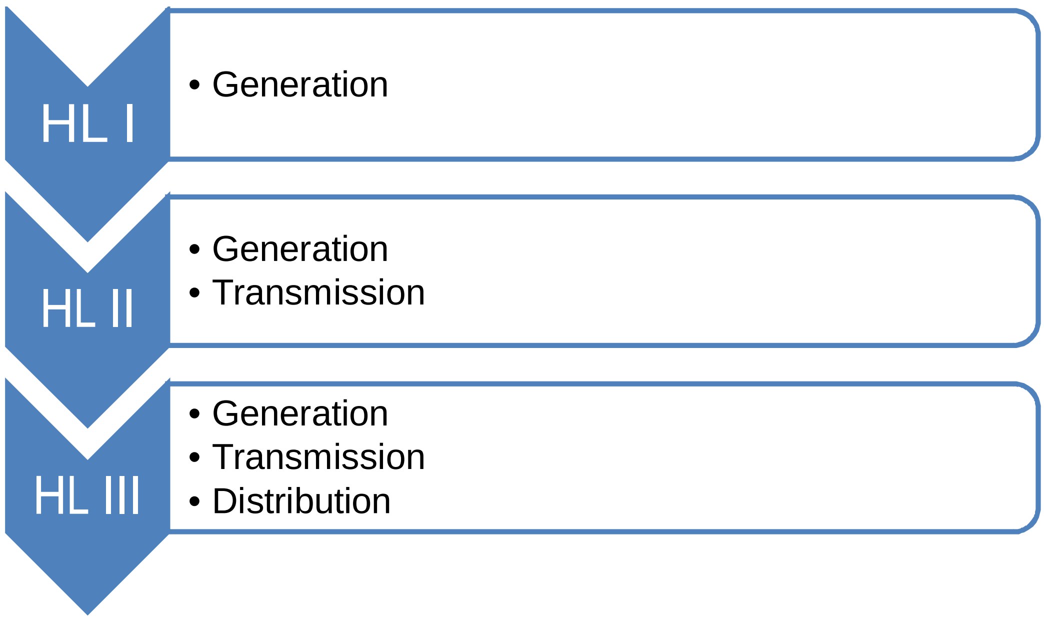


Figure 2.1: *Reliability study in different level*

2.1 Generation

In terms of reliability assessment of the generation system the main task is evaluating the capability of the generation system to supply the load side. By assuming that the transmission and distribution sides are totally in operational mode can model generation capacity and load point to measure the reliability of the system. In this level any failure in the generation system can directly effect on reliability calculation.

The calculation of reliability of the generation side has three steps:

1-probabilistic model of generation system

2-Model of load in the system

3-combine generation and load to evaluate reliability of system

Each generation unit has two modes: UP: operation mode and DOWN: failure mode based on total generation capacity and condition of generation units. Energy not supplied (ENS) of the system can be identified, any areas that load is not higher than generation capacity in operation is not any problem but the duration of energy not supplied (ENS) is important to assess the reliability of system.

Modeling the total load of system has a different category.

• Constant load model (the easiest way)

• Modeling the load by hourly in one year that means 8760 points

• Daily maximum load in one year that means 365 load points

• Load duration curve (LDC)

• Daily peak load variation curve (DPLVC)

2.2 N-1 Reliability Criteria in transmission

A useful technique in transmission system planning is the N-1 principle [1- 2].This principle means if just one component of the system goes out of service the system should remind in operation mode. This will continue even after losing one of the most important components with the largest generation or highest capacity like a generation unit, a transmission line or a transformer going out of services. Generally if the system can stay in normal condition after losing the largest unit, this can approve that it is possible for system to cover it even in the unusual moment. The system should be back to the normal situation in a short time and that would be possible by a proper reserve unit. The N-1 criteria are counted as system security and to evaluate the adequacy of complex system including both generation and transmission has four main aspects.

- Determination of component failures and load curve models.

- Selection system states 2^n

- Identification and analysis of system problem

- Calculation of reliability indices

The transmission contingency analysis is more complex because the purpose is to calculate line flows and node voltage following one or more component failures and identify if there is any overloading, voltage violation, isolated bus, or split island [3].

2.3 Distribution network reliability

Customer study shows that distribution system has the highest possibility of fault which make customers out of services. For example, the outage measurements of year 2009 in Finland show that 88% of the interruptions were caused in Medium Voltage (MV) lines, 7% in secondary substations and 5% in primary substations. Therefore most of the effort should be based on distribution behavior to improve overall system performance [4].

2.3.1 Type of the fault and solution in distribution system

Basically modeling of faults in distribution is divided in two groups in terms of cause and duration. Faults are either transient or permanent. However, in traditional networks many percentage of faults was cleared by auto reclosing and trial switching which directly effect on switch life time.

To prevent unsuccessful switching and somehow increase Performance of system, re-closer is a suggested device. Many researches have optimized the best location for installing re-closer in the distribution network. There are two visions to study this allocation:

- Allocation based on cost reduction
- Optimization to decrease interruption time for customers and also not distributed energy

The optimal solution is to avoid repeated switching and also not switching off the load because of a transient fault [5].

Generally a typical single radial feeder consists of series lines and also maybe underground cable, transformers, switching devices, which every single customer is connected to a single power source or substation. All of sections are interconnected to each other which has different fault rate because those are located in different area, age of component, Maintenance and etc.

A fault can occur in any part of system and main breaker is the first component which can get the action in case of no distribution system, connected customers to that feeder will be out of service during repair time. Automatic restoration which include Fault Location, Isolation and Restoration (FLIR) can play a significant role in fault situation to speed up supply restoration by disconnecting the faulted section from the rest of system. In this order only faulted area will be out of service [6]. These explained the aspects that can effect on outage duration and outage area.

2.3.2 Markov chain modelling

Markov model is useful to define failure rate of system and also the probability of failure. Markov process is one of the most precise processes to estimate and calculate system reliability which can apply for systems that discrete in space and continues in time [7].The process is a constant stochastic procedure which every step are separate from previous and future step can be expected just by current step as an input. Markov process can be called Markov property also. Markov Chain process has limited number of states in a specific time. The probability of moving from one state to another one is P_{ij} and probability of stating in same position isP_{ii}.

Availability, reliability and maintainability of systems can be calculated by Markov model. Each system has some components which are in two modes (working or failure) and the final status can be one of them. In the state-space method of system reliability assessment a system is defined by its state and by the possible changeovers between them. A system state symbolizes a particular condition where every component is in a given operating state of its own: it is working failed, in maintenance, or in some other condition of significance. If the state of any of the component changes (or a change occurs in a relevant environmental factor), the system is ingoing another state [8].Although, all of the steps can be covered which include the changeover between each step .On the other hand one of the disadvantages of this process is difficulty for system with large number of components since each step has two states that means 2^n combinations. Such modeling provides a clear representation of all the states of a system as well as the transition between these states. The failure of individual components in a system is also readily modeled using this method. One disadvantage, however, is that for large systems with many components, it is difficult to draw a diagram. This is because for a system of n components, each with a failed or operating state, the number of states that exist is equal to 2^n [9].

2.3.3 Distribution System Reliability Measurement

Indices are divided in in five categories**:**

2.3.4 Sustained interruption indices

- System Average Interruption Frequency Index (SAIFI) of transformer,
- equivalent number of interruptions related to the installed capacity (NIEPI),
- customer interruption,
- system average interruption duration index (SAIDI),
- transformer SAIDI,
- equivalent interruption time related to the installed capacity (TIEPI),
- customer minutes lost (CML),
- customer average interruption duration index (CAIDI),
- customer total average interruption duration index (CTAIDI),
- customer average interruption frequency index (CAIFI),
- average service availability index (ASAI),
- customers experiencing multiple interruptions (CEMIn)

2.3.5 Energy-based indices

- energy not supplied (ENS),
- average energy not supplied(AENS),
- average customer curtailment index (ACCI)

2.3.6 Load-based indices

- average system interruption frequency index (ASIFI)
- average system interruption duration index (ASIDI)

2.3.7 Indices for transmission system

- average interruption time (AIT)
- average interruption frequency (AIF)
- average interruption duration (AID)

2.3.8 Indices for short interruption

- momentary average interruption frequency index(MAIFI),
- momentary average interruption event frequency index (MAIFIE),

- customers experiencing multiple sustained interruption and momentary interruption events (CEMSMIn)

SAIFI, SAIDI, and CAIDI are called standard indices in many countries. SAIFI and SAIDI are number of customers and continuous power supply is the base of the calculation. Decrease in SAIFI and SAIDI will affect the CAIDI value.

The measuring of both duration and frequency of a customer in different level of the system can help to find the performance of the system. Usually SAIFI, SAIDI, CAIDI and ASAI are used for calculating the average performance of the system but some companies calculate based on the feeder data to have detailed information for future planning. However in some situation detail data has more benefit to compare with average data for serious decisions. Analyzing specific a customer can be support by the average outage study [5].

In the power system structure beside the voltage level and frequency behavior, network companies are responsible of power quality in customer connection points. Power quality includes reliability. There is many measurement and indices for measuring reliability. Duration of outage and frequency, number of customers affected by outage in each faulted repairing time are measured by reliability indices. IEEE defines the standard reliability indices and covered several classifications like temporary outage and permanent outage.

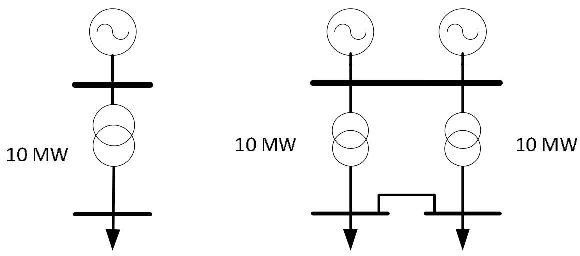
3 Reliability Assessment by using enumeration method

3.1 Reliability in different situation

Engineering systems combined from different components which has same goal, each component has an important role in the system. In this chapter reliability assessment of power system from component point of view by using enumeration methods will be discussed.

3.1.1 Design

In Figure 3.1 system B has more reliability to compare with system A, but is not clear exactly how much that means if one of the components like generation unit, transformer or cable damaged the whole system can stay in operation mode. System B is also more expensive.



A B

Figure 3.1 *Two different design style*

3.1.2 Operation

Outage of operation for maintenance reason is very common in engineering system. In power system operators should remove one line from the system and by calculating reliability of system the best option will be in outage of calculation. Figure3.2 shows that the marked line could be the best option for illustrated system.

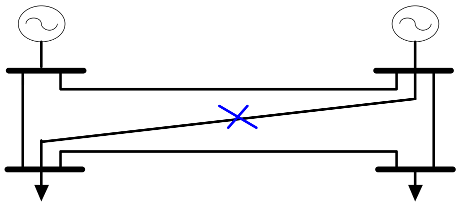


Figure 3.2 *Basic designed power system*

3.2 State Space Method

In the state space method of system reliability assessment a system is defined by its state and by the possible changeovers between them. A system state symbolizes a particular condition where every component is in a given operating state of its own: it is working failed, in maintenance, or in some other condition of significance. If the state of any of the component changes (or a change occurs in a relevant environmental factor), the system is ongoing to another state. Figure 3.3 shows state-space diagram of two components system which each of them has two states. All the possible state of a system make up the state space and the change between the state, a state space diagram of a system of two independent components illustrated in Figure 3.4 [9].

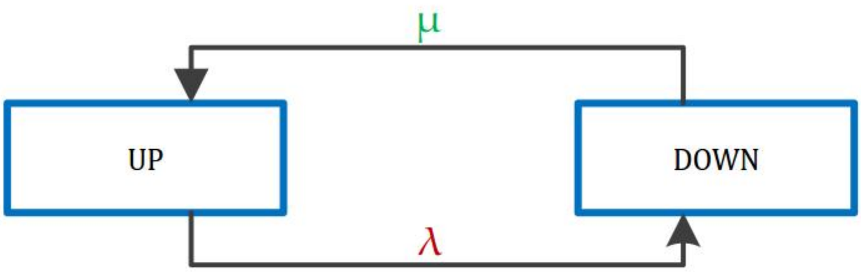


Figure 3.3. *State space model of one component*

$$\text{Failure Rate, } \lambda = \frac{No.of\ failures\ of\ the\ component\ in\ a\ given\ period\ of\ time}{Total\ period\ of\ time\ the\ component\ was\ operating}$$

$$\text{Repair rate, } \mu = \frac{No.of\ repaire\ of\ the\ component\ in\ a\ given\ period\ of\ time}{Total\ period\ of\ time\ the\ component\ was\ under\ repair}$$

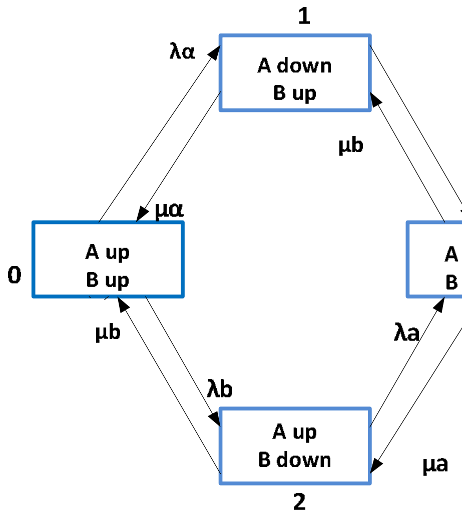


Figure3.4. *state-space diagrams of two independent components*

At first to calculate state probability of system the transition intensity matrix A is:

$$A = \begin{bmatrix} -(\lambda a+\lambda b) & \lambda a & \lambda b & 0 \\ \mu a & -(\lambda a+\lambda b) & 0 & \lambda b \\ \mu b & 0 & -(\lambda a+\lambda b) & \lambda a \\ 0 & \mu b & \mu a & -(\lambda a+\lambda b) \end{bmatrix} \quad (3.1)$$

For reduce the structure of matrix for each entry the states it ends the set of liner equation are the following:

Where λ is the failure rate and μ is the repair rate and P is the probability factor

$$-(\lambda a+\lambda b)\ P\ 0 + (\mu a)\ P\ 1\ + (\mu b)\ P\ 2 = 0 \quad (3.2)$$

$$(\lambda a)\ P0 - (\lambda a+\lambda b)\ P1 + (\ \mu b)\ P3 = 0 \quad (3.3)$$

$$(\lambda b)\, P0 - (\lambda a+\lambda b)\, P2 + (\mu a)\, P3 = 0 \tag{3.4}$$

$$(\lambda b)\, P1 + (\lambda a)\, P2 - (\lambda a+\lambda b)\, P3 = 0 \tag{3.5}$$

After arranged by each column of matrix A and by multiplying each column to vector P=[P0, P1,P2 ,P3] and as it is clear that they are not independent can be seen :

$$P+P1+P2+P3= 1 \tag{3.6}$$

The results for calculation of probability of each component is :

$$D= (\lambda a+\mu a)(\lambda b+\mu b) \tag{3.7}$$

$$P0 = \frac{\mu a\ \mu b}{D} \qquad P1 = \frac{\lambda a\ \mu b}{D} \qquad P2 = \frac{\lambda b\ \mu a}{D} \qquad P3 = \frac{\lambda a\ \lambda b}{D} \tag{3.8}$$

The mean duration of stay in each state are calculated in below:

$$T0 = \frac{1}{\lambda a\ \lambda b} \qquad T1 = \frac{1}{\lambda b\ \mu a} \qquad T2 = \frac{1}{\lambda a\ \mu b} \qquad T3 = \frac{1}{\mu a\ \mu b} \tag{3.9}$$

The frequency of facing each state:

$$D= (\lambda a+\mu a)(\lambda b+\mu b) \tag{3.10}$$

$$F0= \mu a\ \mu b\ (\lambda a+ \lambda b)\ /D \tag{3.11}$$

$$F1= \lambda a\ \mu b(\lambda b+\mu a)/D \tag{3.12}$$

$$F3= \lambda b\ \mu a(\lambda a+\mu b)\ /D \tag{3.13}$$

$$F4= \lambda a\ \lambda b(\mu a\ \mu b)/D \tag{3.14}$$

3.3 The state Enumeration method

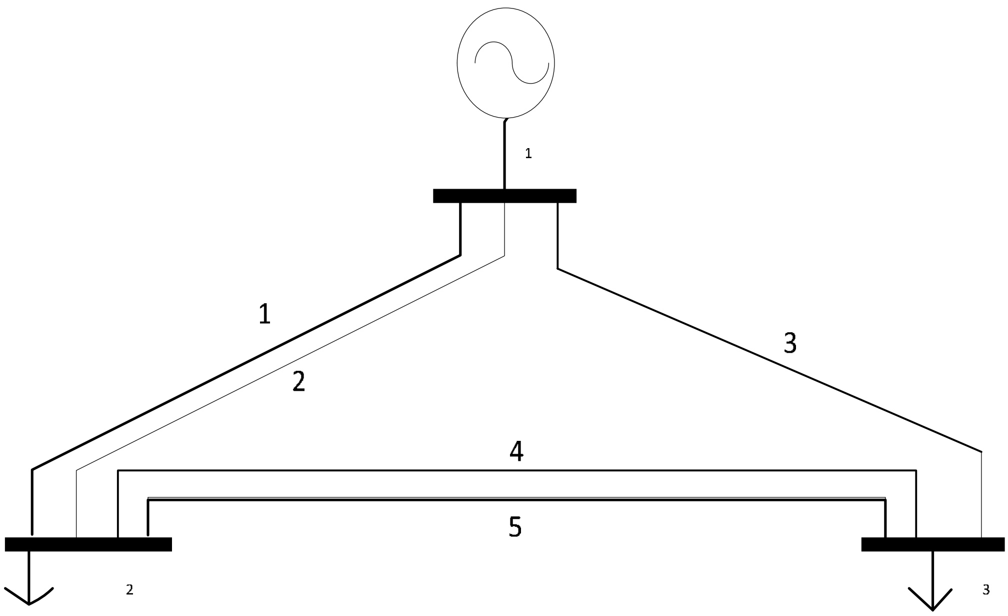


Figure 3.5 *Network of 5 transmission lines*

By this simple example can find the exact equation in steady state. The power system transmission system shown in Figure 3.5 comprises three nodes, five transmission lines, one synchronous generator and two load points. Node 1 contains generation and nodes 2 and 3 contain loads. The transmission line parameters and loads are given in Tables 3.1 and 3.2. The transmission system is rated at 500 kV and the base power is taken to be 100 MVA.

Table3.1.*Transmission line parameters*

	sending node	receiving node	Resistance (pu)	Reactance (P:U)	Susceptance (P:U)	Power limit
Transmission line 1	1	2	0.02	0.06	0.06	
Transmission line 2	1	2	0.02	0.06	0.06	
Transmission line 3	1	3	0.06	0.18	0.04	
Transmission line 4	2	3	0.06	0.18	0.04	
Transmission line 5	2	3	0.06	0.18	0.04	

Table 3.2.*Nodal power generation and load*

	Node type	Nodal voltage	active power	Reactive power
Node 1	slack	1+j0	±∞	±∞
Node 2	Load	1+j0	-0.20	-0.10
Node 3	Load	1+j0	-0.45	-0.15

The following criteria for system failure will be adopted:

1-system fail if any of the two loads left without supply.

2-The system fails if any in service transmission line carriers exceed 50 MW

3-The system fails the voltage magnitude at any node exceeds the limits: v=100 ± 5%

Based on above criteria, the following success/failure states are arrived, with the help of a power flow computer program:

By taking only criterion 1 and 2 into account .The success and failure modes given in table 3.3, have been identified with the help of a power flow suitably modified for reliability studies. Table 3.3 represent the success and failure states for example the first column is “None” means the state that none of lines are out or all of the lines are in working condition, the second column is shows when just one line is out or in failure mode ,the third column is for the option when two lines are on failure mode and all of the states are identified by number of lines in figure 3.5, the last situation is when all of the lines are in failure mode in same time and in this case the system is in failure states.

Table 3.3.*Success and failure states*

Success		Failures states			
None	1	1,2	1,2,3	1,2,3,4	1,2,3,4,5
	2	1,3	1,2,4	1,2,3,5	
	3	1,4	1,2,5	1,2,4,5	
	4	1,5	1,3,4	1,3,4,5	
	5	2,3	1,3,5	2,3,4,5	
		2,4	1,4,5		
		2,5	2,3,4		
		3,4	2,3,5		
		3,5	2,4,5		
		4,5	3,4,5		

For instance when transmission lines 1 and 2 experience a Failure, transmission line 3 carries 68.406 MW and transmission lines 4 and 5 carry 10.082 MW each. However, when transmission line 1 and 4 come out of operation, the power flow sharing between transmission lines 2 and 3 is 36.943 MW and 5 is 16.647 MW, respectively. Similar situation arise for the remaining two lines outage in the system, with the system being either in success or failure modes. It is clear that more transmission line come out of operation, simultaneously, the more likely that the system will fail. For example when the transmission lines 1, 2 and 5 comes out of operation then both transmission lines 3 and 4 carries 46.486 MW.

Taking all criterions 1, 2 and 3 into account, the success and failure modes given in table 3.4, have been identified with the help of a power flow suitably modified for reliability studies.

Table 3.4.*Success and failure states*

Success		Failure States			
None	1	1,2	1,2,3	1,2,3,4	1,2,3,4,5
	2	1,3	1,2,4	1,2,3,5	
	3	1,4	1,2,5	1,2,4,5	
	4	1,5	1,3,4	1,3,4,5	
	5	2,3	1,3,5	2,3,4,5	
		2,4	1,4,5		
		2,5	2,3,4		
		3,4	2,3,5		
		3,5	2,4,5		
		4,5	3,4,5		

Further to the cases when two transmission lines come out of operation and the system undergoes failure due to transmission line overloading ;the system state that have remained healthy will be checked in regards of nodal voltage magnitudes.

- with transmission lines 1 and 4 out of operation :
  V1=100 %   V2=98.63%   V3=96.798 %
  Hence, the system remains in the healthy state. The same is true for the following case of transmission line pairs 1-5 , 2-4 , 2-5 .
- When the transmission line pair 3-4 comes out of operation, the nodal voltage are:
  V1=100 %   V2=98.699 %   V3=92.908 %
  There is no overload in of the remaining in service three transmission lines but the system is not operational because of too-low a voltage at node 3. The same is true for the following case of transmission line pair: 3-5. The situation is not dissimilar when the transmission line pair 4-5 comes out of operation; The nodal voltage are :
  V1 = 100 %   V2=99.676%   V3=94.313%
- What remains to be checked is the situation when three transmission lines come out of operation (either 1-4-5 or 2-4-5) and the system is not overloaded in any of two remaining transmission lines. The nodal voltage are :
  V1=100%   V2=99.134%   V3=94.313 %
  The system is not operational because of too-low a low in node 3 even though there is no power flow overload.

By solving the state space model for the long-run state probabilities Pi, i ϵ F. After combining all state in the subset F, the system failure probability Pf in the probability of combined state F is:

$$\mathrm{Pf} = \sum_{i\epsilon F} \mathrm{Pi} \tag{3.15}$$

The system Failure frequency Ff is the frequency of the combined state F Using 3.15 can be expressed as:

$$Ff_{\lambda} = \sum_{i\epsilon F} \mathrm{Pi} \sum_{j\epsilon w} \lambda\mathrm{ij} \tag{3.16}$$

In other words, the system failure frequency is the sum of the system failure state probabilities, each multiplied by the rate of transitions from the respective state to the success domain. If environmental effects (weather and load) are of no concern, it is reasonable to assume that every transition from a state in F to a state in W involves repair which F is Failure and W is working condition. Figure 3.7 shows the changing between statuses. Using the conventional notation, can be written as:

$$Ff_{\mu} = \sum_{i\epsilon F} \mathrm{Pi} \sum_{j\epsilon w} \mu\mathrm{ij} \tag{3.17}$$

The mean duration of system failure, Tf equals the mean duration of stays in the combined state, F. therefore [9]:

$$TF = \frac{\mathrm{Pf}}{\mathrm{Ff}} = \frac{\sum_{i\epsilon F} \mathrm{Pi}}{\sum_{i\epsilon F} \mathrm{Pi} \sum_{j\epsilon w} \lambda\mathrm{ij}} \tag{3.18}$$

While this technique is general, it may not be all that practical. The number of system components and states can be many; a system of n independent components has 2^n states. Therefore, a 100 components system can be over 10^{30} states. A calculation of that many states especially the study of failure effect in each state, may not be easy.

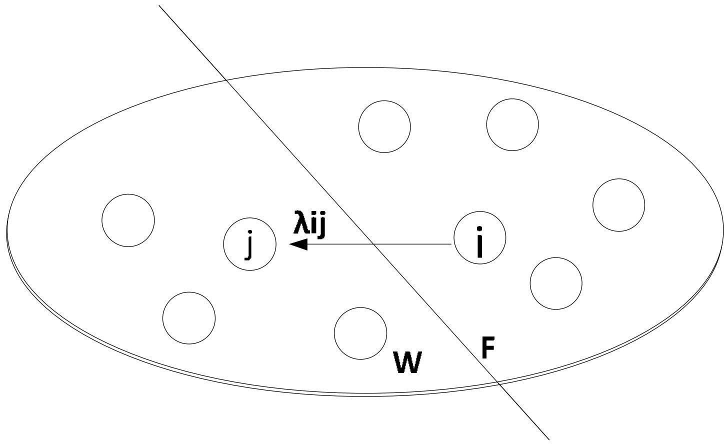


Figure 3.7 *Partition of the state space of system into working (w) and failed (F) domains*

In large power system single and double-failure states are all calculated, but it is not necessary to study the triple-and higher failure states because their probabilities are small. Imagine that a system of N components with independent failures, and unavailability of a component be Ā. Therefore, its availability be A=1-Ā, the probability of state where r out of N components have failed is $\bar{A}^{r}\boldsymbol{A}^{\boldsymbol{N-r}}$, then there are $\binom{N}{r}$ states illustrate an r failure[13]. The total probability Pr of an r-fold failure is:

$$\mathrm{Pr}=\binom{N}{r}\bar{A}^{r}\boldsymbol{A}^{\boldsymbol{N-r}} \tag{3.19}$$

For example an electric power system is supplied from several generating stations with a total of 150 generating units. Assuming that the outage probability of each unit is 6%, what is the probability of exactly two units (any two) being out of service? The answer is given by:

$$P(X=2;\ 150,\ 0.06)=\binom{150}{2}(0.06)^{2}(0.94)^{148}=0.00424 \tag{3.20}$$

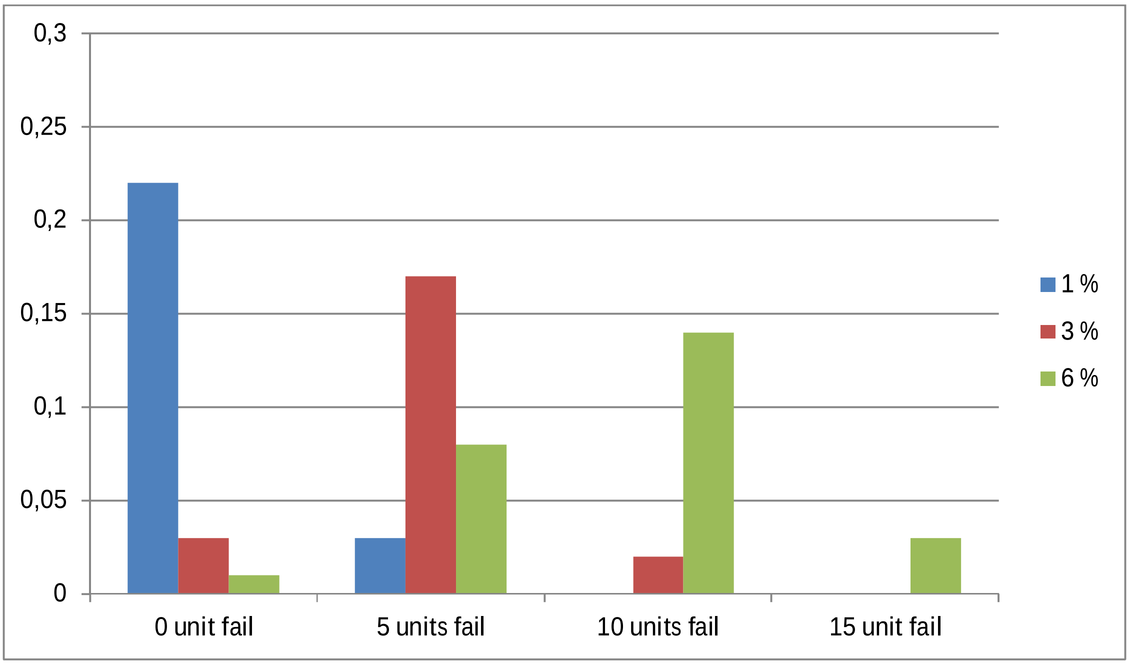


Figure 3.8 *Probability distributions for the number of failed generators out of a total of 150*

Figure 3.8 represent the result of probabilities study is shown for the case when the failed unit number 0 , 1, 2 and so on and if the unit outage probability is 3% , and if it is 1% and 6% which is calculated based on equation(3.19)[13].

4 Reliability Assessment of Distribution Network

4.1 Simulation model

An actual overhead medium voltage feeder in a distribution network from a rural distribution company has chosen to use for modeling and study reliability process based on mentioned algorithms in chapter three. Feeder contains 258 buses with total number of 1304 customers including single-family houses, residential building companies, farming, industry, Business, Service private, transport and public place. Figure 4.1 shows the selected total overhead feeder model. The topology of network model is mesh by radially operated. The black point in bus 245 is a switch which works in normal open condition. Also the fault rate of each section of the network is provided by using a typical fault rate for an overhead line (per 100 km) in Finland [14], In all 103.2 km length of feeder local geographic coordinates system and environment information (field, beside a road or forest) of the overhead line is used to get more accurate result.

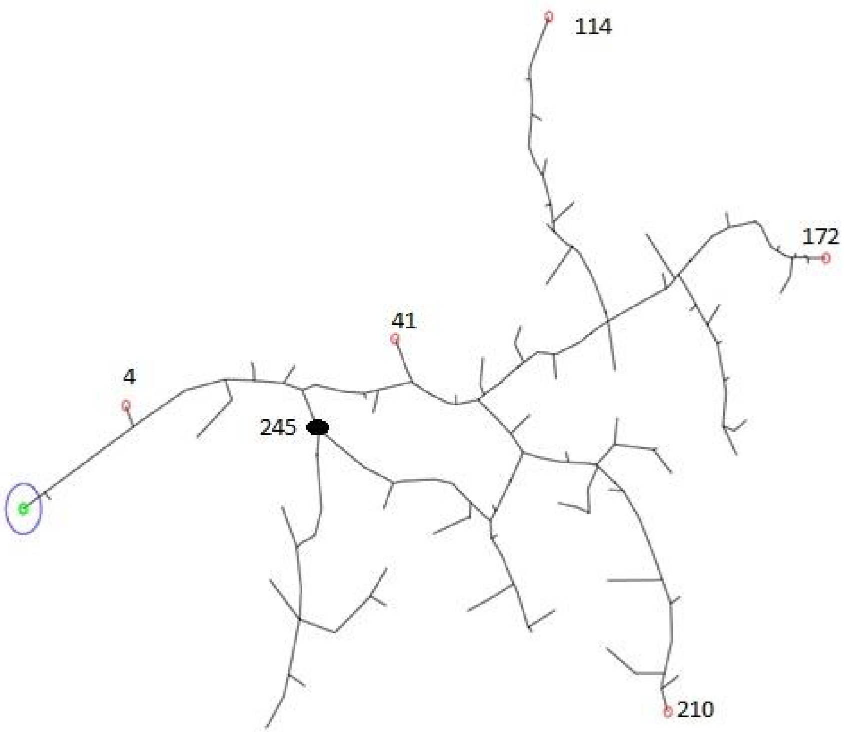


Figure 4.1 *The selected feeder model from rural company*

The next step is to calculate fault rate based on actual distance and also environmental condition. The location of the line directly affects the fault rate in the overhead line. Usually overhead lines are located in three different areas forest, field or roadside with different fault rate which presented in table 4.1

Table 4.1 *Fault rate based on location [15, 16]*

Type of Conductor	Forest	Field	Road side
Overhead (100km)	7	1	2.3
Underground(100km)	0.79	0.78	0.82

Two types of switches are remote controlled with switching time of 0.1 hour and manual switch with switching time of 1 hour. Re-closer also could be good option to increase reliability in a distribution network [5]. As the topology of the system model is meshed then it's possible to use switching to supply the customers from other neighbor feeders. There are 5 buses with backup possibility bus number 4, 41, 114, 172, 210. In this case switching time is the time that customers are out of service from fault moment till switching and supplying from different side of a feeder which has backup connection possibility. The effect of increasing repair time, switching time and also backup connection possibility simulated and analyzed in this chapter. The first step is to calculate reliability indices for network model by using both manual switches and automatic switches and compare the simulation results. Then the same procedure repeated by using MCS (Monte Carlo Simulation) to generate the switching and repair time. The final result of simulation by using actual data and MCS compared in the last step of analyze.

4.2 simulation methods

4.2.1 Monte Carlo Simulation (MCS)

The way to calculate reliability indices for analytical and simulation approach are different. Mathematical model of a system is the result of analytical techniques witch use mathematical solutions to solve reliability problems. In the simulation methods, by using simulated actual processes and also the random performance of the system can be evaluate the reliability indices. In this way it is possible to use simulation methods to approximate the reliability indices by calculating the number of times which event happens. Generally each method has some advantage and disadvantage.

The Final result for analytical methods is always the same when the model and input data are same but in simulation methods the input is from a random number generator and can be changed by number of simulations. The mathematical models in analytical methods are simplification of the main system but in a simulation you can model different types of systems. By simulating a system can find an extensive variety of output and also the probability density functions, whereas by using an analytical model the results are limited. It is clear that each method has advantages and disadvantage and the decision should be based on the system. The Monte-Carlo (MC) is a stochastic process and the model can use stochastic simulation.

Monte Carlo methods are a broad class of computational algorithms that are based on repeated random sampling to gain numerical results. For example by running simulations many times in order to calculate those same probabilities. They are often used on physical and mathematical problems and are most suitable to be applied when it is impossible to obtain a closed-form appearance to apply on deterministic algorithm. Monte Carlo methods are mainly used in three distinct problems: optimization, numerical integration and generation of samples from a probability distribution. [13]. MCS applied in this thesis to generate the fault rate of each line in the network and also outage time, as the fault rate is probabilistic variable MCS is the best option. In this thesis Monte Carlo Simulation used to generate fault rate and outage time in simultaneous faults study. The output of simulation can be use in analyzing cost study and also risk assessment of distribution system in storm situation.

4.2.2 Random numbers

Modeling a real system events study in the system is based on the characteristic behavior of components and also variables. However, when the system is simulated the behavior of events depends on the model and also probability distribution. Using random numbers for symbolizing the behavior of components and variables should convert them to a density function. The essential part of MCS is to know how to generate random numbers and conversion.

4.2.3 Probability Distributions

The definition of distribution in probability means how the output of an event is extended around expected values and the function to show how the probability is called probability distribution function. Based on the event probability distribution function can be separate or constant a function. During a special study if the random variable is an independent variable. Then the probability distribution function also will be separate and it's same for a constant variable and constant probability distribution function. Cumulative distribution function and the probability density function are two functions that are characteristic for a distribution.

Probability distributions can be use in theory for mathematical aspect and practice in numerical applications. Many probability distributions are used in various practical applications. One of the most useful one is the normal distribution, which is also called as the Gauss distribution.

4.3 Basic results

4.3.1 Switching Operations

The analysis to restoration of power is a part of an evaluation implemented for reliability analysis. In this study we assume that switch operation time is less than repair time, so the healthy sections can reconnect easily and faster by operation of a switch or changes in the configuration of the network. There are two kinds of switches. One type is Manual switches that can operate locally which means operators should find the nearest switch to fault and operate it from the control panel in switch location, it considered the longest switching time in the reliability study. The second is automatic switch or remote control switch. It is the switch that can operate from the control center. Switches can disconnect a fault area from other side of the feeders. That means just some part of feeder would be effect by fault. The table 4.2 shows how reliability indices can be changed by the number of switches. SAIFI calculation is with assumption that switches do not have faults during operation time. The position of switches for each step from 5 switches to 40 switches is shown in pictures 4.2 to 4.9.

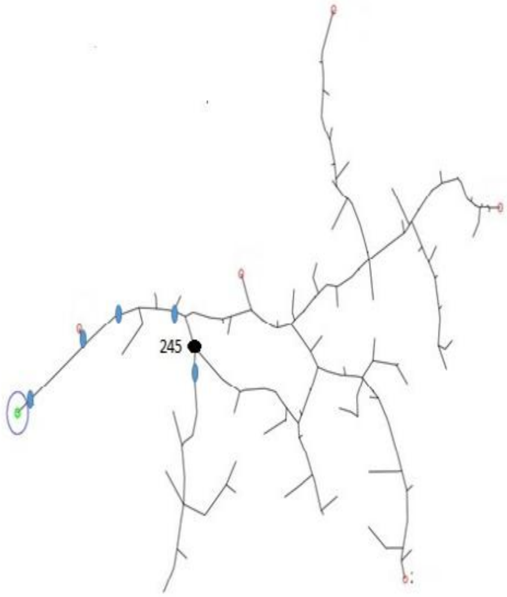


Figure 4.2*, 5 switches*

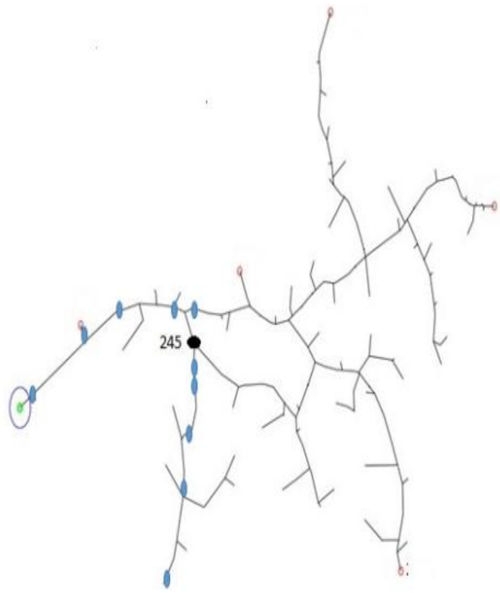


Figure 4.3, *10 switches*

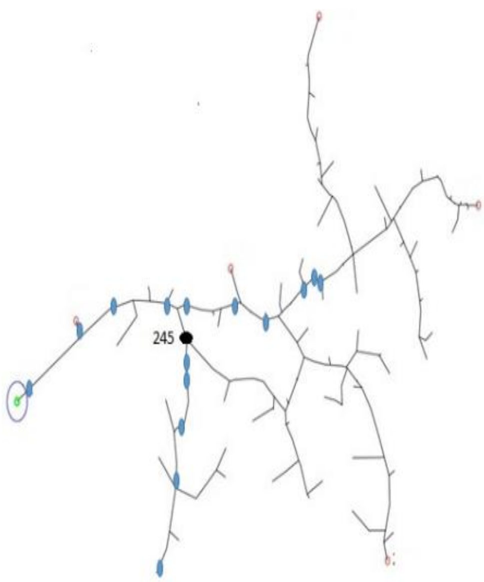


Figure 4.4, *15 switches*

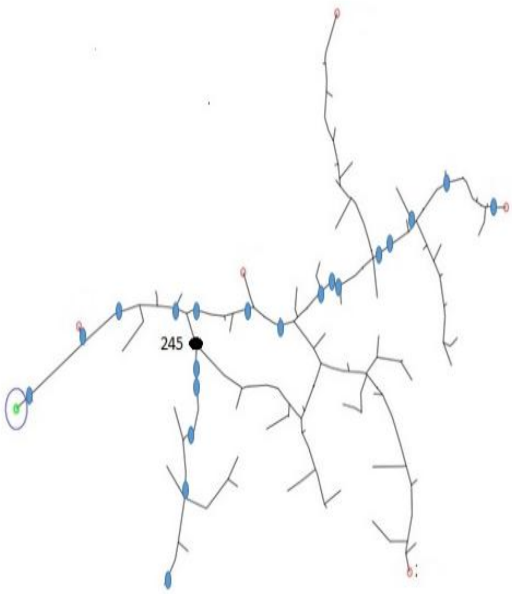


Figure 4.5, *20 switches*

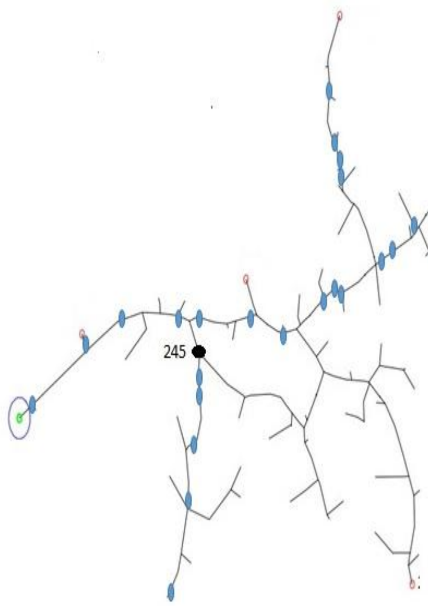


Figure 4.6, *25 switches*

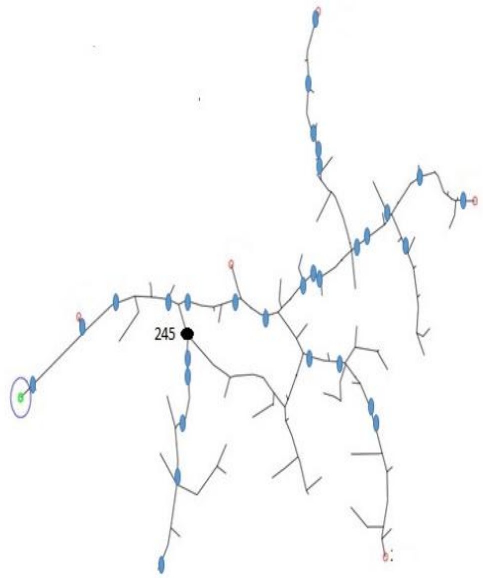


Figure 4.7, *30 switches*

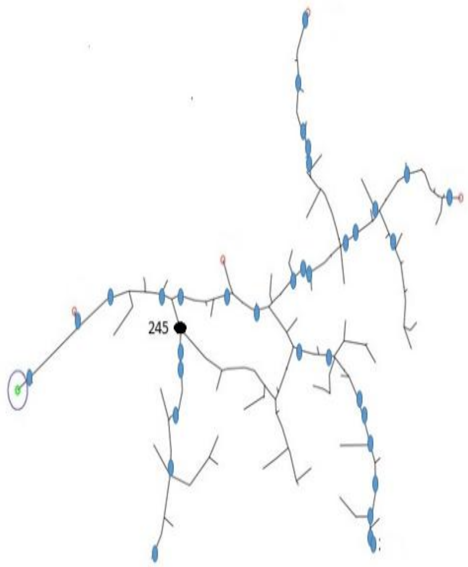


Figure 4.8, *35 switches*

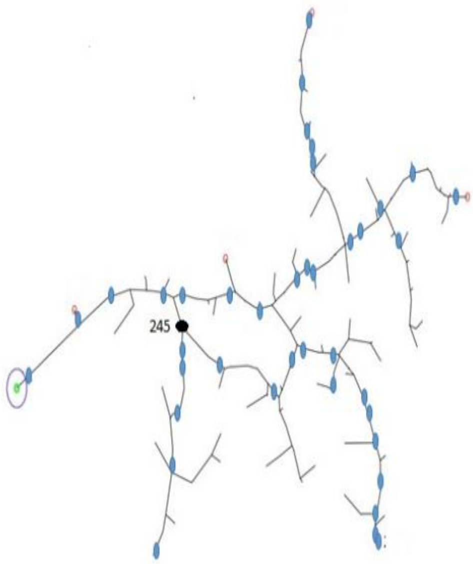


Figure 4.9, *40 switches*

Table 4.2 *Indices and different number of manual switches*

Number of switches	SAIFI	SAIDI(hr)	CAIDI(hr)
No switch	3.1676	147.8261	51.8213
5 switches	3.1676	56.1280	17.7194
10 switches	3.1676	94.4049	29.8033
15 switches	3.1676	128.1773	40.4651
20 switches	3.1676	139.3364	43.9879
25 switches	3.1676	123.1612	38.8815
30 switches	3.1676	83.1476	26.2494
35 switches	3.1676	63.6584	20.0967
40 switches	3.1676	39.5784	12.4948

Figure 4.10 represent the graph for changing the value of SAIDI and CAIDI by increasing the number of switch. Usually increasing number of switch in the feeder means investment to improve reliability but as it is clear that in some part the value of SAIDI and CAIDI increased for example in 20 switches and by adding 25 switches the value of SAIDI and CAIDI decreased to compare with 20 switches. Optimal allocation is important for adding new component to the network. Otherwise the result of investment will be worse.

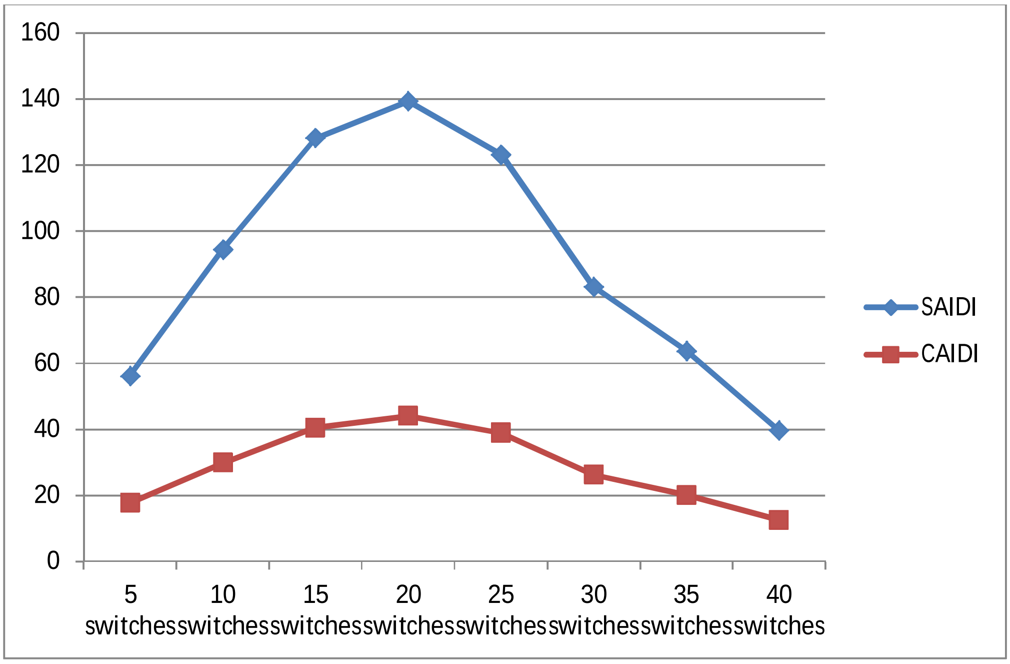


Figure 4.10 *The effect of switches on SAIDI and CAIDI*

Switching time is the time that a customer should be out of services from the fault moment to the moment that operators try to open or close switches for isolating the fault. Switching should be just for operating one switch or maybe a number of switches. It depends on the fault location and topology of the network. Table 4.3 shows how SAIDI and CAIDI can change by increasing the switching time

Table4.3 *switching time effect*

Switching time	SAIFI	SAIDI(hr)	CAIDI(hr)
1 hour	3.1676	39.5784	12.4948
2 hours	3.1676	54.6880	17.2648
3 hours	3.1676	69.7976	22.0348
4 hours	3.1676	84.9072	26.8049

Remote controlled switches can improve reliability by decreasing the switching time, distribution automation is one of the efficient way to reduce the time for switching action. DMS (Distributed Management System) Operators in control center can find the nearest switch to the fault and operate it to open mode for subsiding the fault area. Table 4.4 shows indices with manual switches by one hour switching time and the remote controlled with switching time of 0.1 hour.

Table 4.4 *The result of changing switch remote control*

Type of switches	SAIFI	SAIDI	CAIDI
Manual switches	3.1676	39.5784	12.4948
Remote switches	3.1676	25.9798	8.2017

4.3.2 Backup connection

Backup connection means connecting a faulted feeder to the neighboring feeder or line to support disconnected customers. The capacity of a healthy line and also the number of disconnected customers are important for backup connection. In the modeled feeder nodes 7, 41,114,172,210 and 245 have backup possibility; those are actual back up connection which provided from rural network company. Figure 4.11 is the graph for showing the change value of SAIFI, SAIDI and CAIDI by extra backup connection. SAIFI is same but SAIDI and CAIDI decreased, that means the reliability indices improved and the investment result is same as expectation.

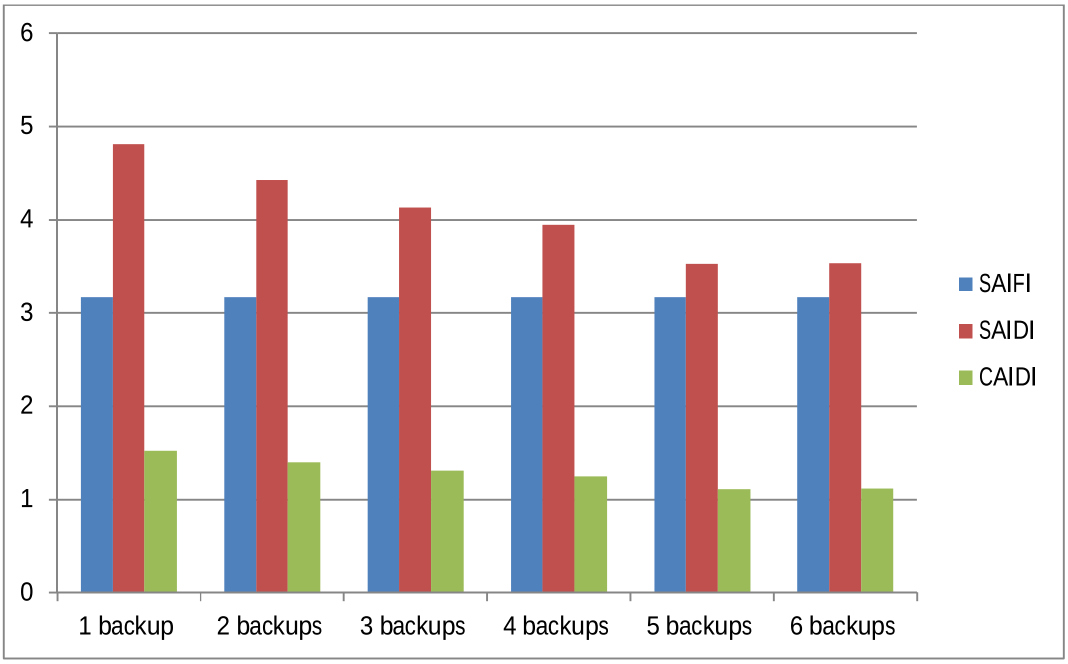


Figure 4.11 *The value of SAIFI, SAIDI and CAIDI for different backup connection*

4.3.3 Repairing Time

Repairing time is the time that customer will be out of the service from the moment of fault happens until the situation is back to normal condition, that means reconnecting to the network. However, repairing time is the time that customers are disconnected. Generally different functions affect it like the availability of a repair group, distance to control center and climate situation. This is true for those customers which are located within the outage area Supply restoration may reduce the outage area. Switching time plays an important role in decreasing outage time. During the repairing time customers located at isolated part of network are out of service and should wait for reconnecting to the network that means repairing time directly affected on customer's life, on the other hand SAIDI and CAIDI are two important indexes for Network Company which is rise by increasing the repairing time. Figure 4.12 represent how the indices increased by increasing the repair time from 3 hours to 9 hours. By rising up the repair time from 3 hours to 5 hours the SAIDI and CAIDI increased to 55.89 and 17.64 that mean 41.21% growing in SAIDI and CAIDI. The maximum repair time assumed 9 hours in this step which change the SAIDI and CAIDI to 88.51 and 27.54, by compare these two values to the default repair time, the effect is an upward of 123.66%.

Figure 4.12 represent how the value of reliability indexes changed by increasing the repair time.

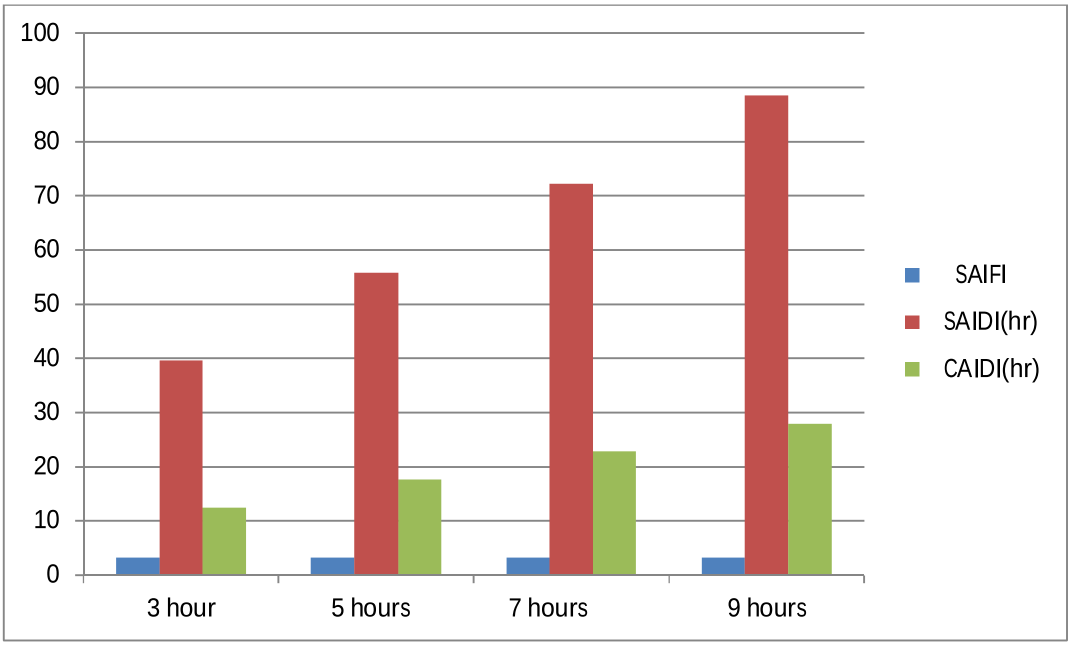


Figure 4.12 *The effect of increasing repairing time*

4.4 Simulation Analysis

The output of this study is divided in two sections: The first study is related to modeling the effect of fault in each section on other sections of the network or other customers (Chapter 4). The second part models simultaneous faults in a major disturbance (Chapter 5). Based on environmental conditions each line has a special fault rate which is simulated for one year. To increase accuracy of the simulation total duration of faults for one year divided into 8760 sections that represent hours in one year [17]. Each lines has the same possibility to be in the fault situation that means the implemented program calculate reliability indexes by considering the fault location in each part of network separately and the final result include all possible faults scenarios. The simulation has been done for 10, 100, 1000 and 10000 times which each time is shown one year of study.

4.4.1 Switching Analysis

Weibull distribution has the capability to follow different kind of statistic situation [18]. As the possible repair time is different for each area or line then randomly generated repair time generated separately is also different for each section based on the Weibull distribution. Shape parameter and the scale parameter are two special characters in Weibull distribution. In order to have more accurate and real repair times shape parameter is considered 1 and scale parameter is 1.By using Monte-Carlo simulation (MCS) to generate fault rate it is possible to compare the results with previous studies. The rule of switches in the program is based on the location of fault, the implemented algorithm can find the nearest switch before the fault, in this way the customers before the fault can consider to reconnected customers after the switching time in the network reliability calculation.

Table 4.7 *Indices and different number of switches by using MCS*

Number of switches	SAIFI	SAIDI(hr)	CAIDI(hr)
5 switches	3.1770	56.6758	17.8392
10 switches	3.1475	94.8538	30.1367
15 switches	3.1725	129.3471	40.7716
20 switches	3. 1676	139.3364	43.9879
25 switches	3.1550	116.1315	36.5577
30 switches	3.1777	88.6705	27.9043
35 switches	3.2060	74.3660	23.1956
40 switches	3.1509	40.5847	13.4413

By comparing SAIFI, SAIDI and CAIDI values when the fault rates are practical value from table 4.2 to the randomized fault rates by MCS, it’s clear that the two values are close to each other. Figures 4.13, 4.14 and 4.15 represent the comparison by showing the graphs. In figure 4.13 the value of SAIFI for 25 switches is 3.1676 exactly same values for default fault rate and also MCS fault rate, by comparing the other values they are close to each other. The position of switches for each step from 5 switches to 40 switches is shown in pictures 4.2 to 4.9.

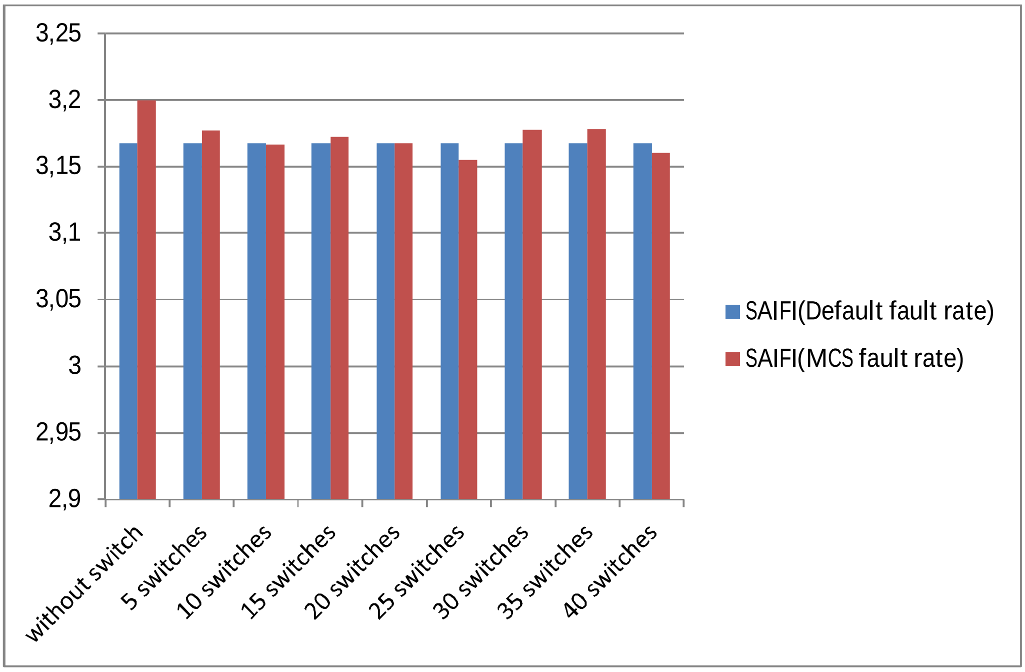


Figure 4.13 *The comparing value of SAIFI in two different modes*

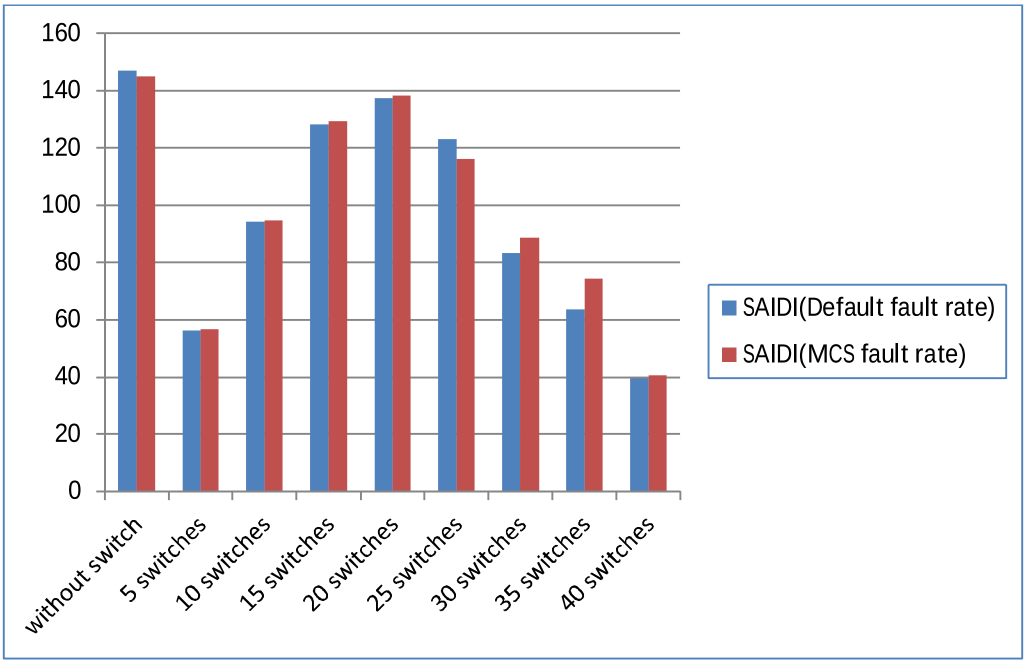


Figure 4.14 *The comparing value of SAIDI in two different modes*

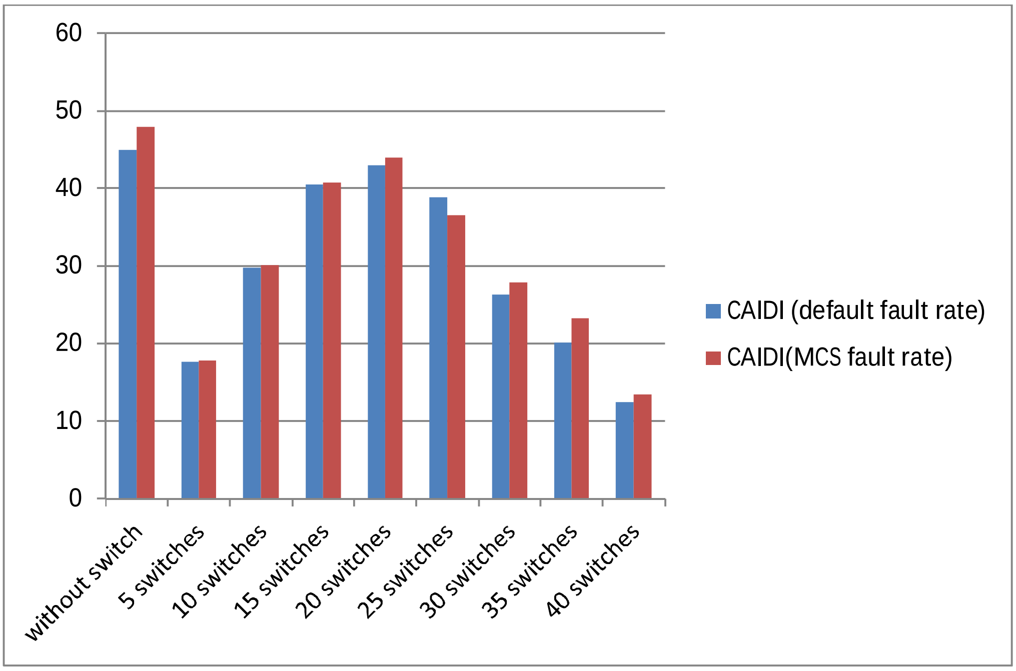


Figure 4.15 *The comparing value of CAIDI in two different modes*

By comparing the value of SAIDI and CAIDI for MCS in table 4.7 to the table 4.2 can find the similar or close values which shows the MCS is enough accurate and trustable.

In this part switched time increased step by step and simulation analyzed separately in each step. Table 4.8 shows the simulation results and Figure 4.16 represent compare it with using default fault rate which is in Table 4.3. In both cases increasing switching time has direct effect on increasing the indexes value and all of the steps have close value to compare it to each other.

Studying switching time effect by using randomized fault rate can show the difference between using manual and remote controlled switch. Figure 4.17 is showing the different value of indices by changing switches to remote control switches the decreasing is 156.18 % in SAIDI and also CAIDI.

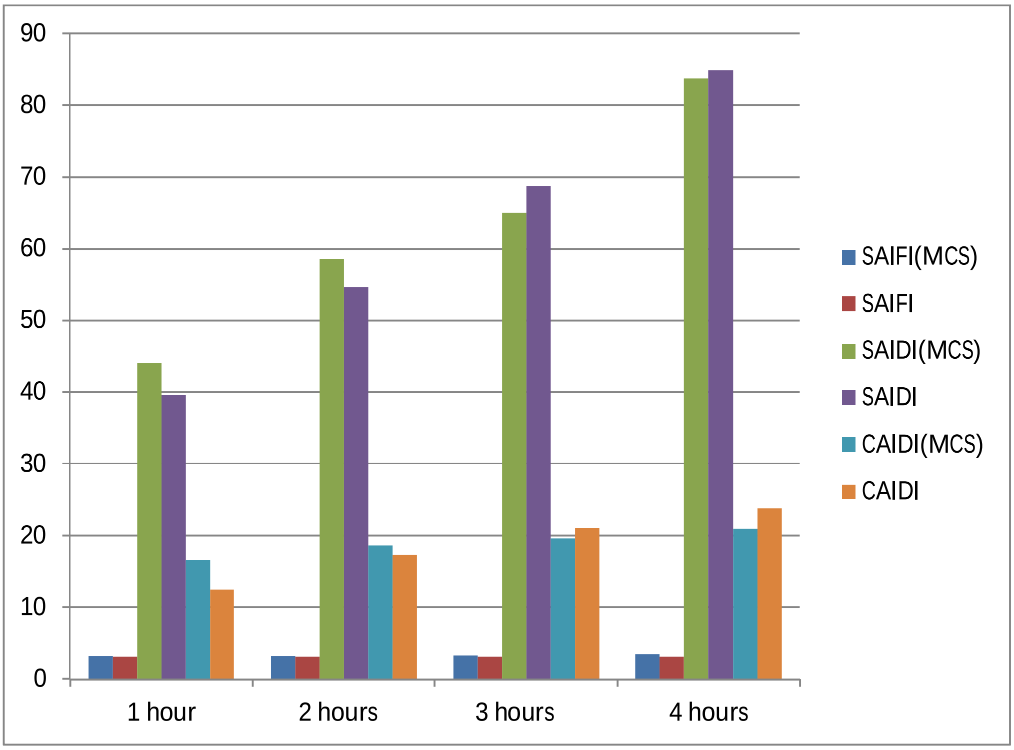


Figure 4.16 *switching time effect*

Table 4.8 *switching time effect (MCS)*

Switching time	SAIFI	SAIDI(hr)	CAIDI(hr)
1 hour	3.2516	54.0176	16.6124
2 hours	3.2580	60.6394	18.6124
3 hours	3.2693	64.0286	19.5846
4 hours	3.5223	73.7077	20.9261

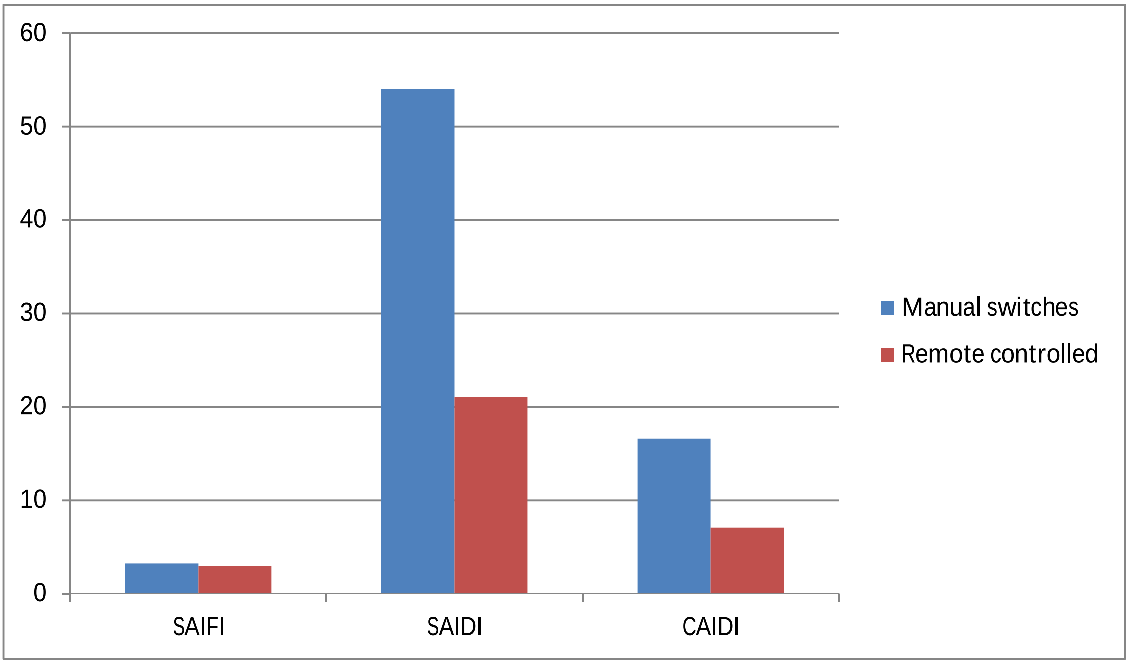


Figure 4.17 *different values of SAIFI, SAIDI and CAIDI by changing the switch type*

4.4.2 Repairing time (MCS)

Repairing time means the time when repair group receive the fault call from customer to control center until last step when the fault is clear and customers in fault area are back to normal condition. Many factors can increase the repairing time table 4.10 and Figure 4.18 shows how repair time influence on the reliability indices. By increasing repairing time gradually from 3 hours to 9 hours with step of 2 hours both SAIDI and CAIDI increased, the values for 3 hours in order are 40.5847 hours and 13.4413 hours. When the repairing time is 9 hours the final values for SAIDI and SAIDI are 87.5252 hours and 30.6459 hours. The value of SAIFI changed because of other random parameters in simulation but repairing time doesn't effect on SAIFI.

Table 4.10 *Repairing time effect (MCS)*

Repairing time	SAIFI	SAIDI(hr)	CAIDI(hr)
3 hour	3.0194	40.5847	13.4413
5 hours	3.2453	64.8264	19.9754
7 hours	3.1075	68.2051	21.9486
9 hours	2.8560	87.5252	30.6459

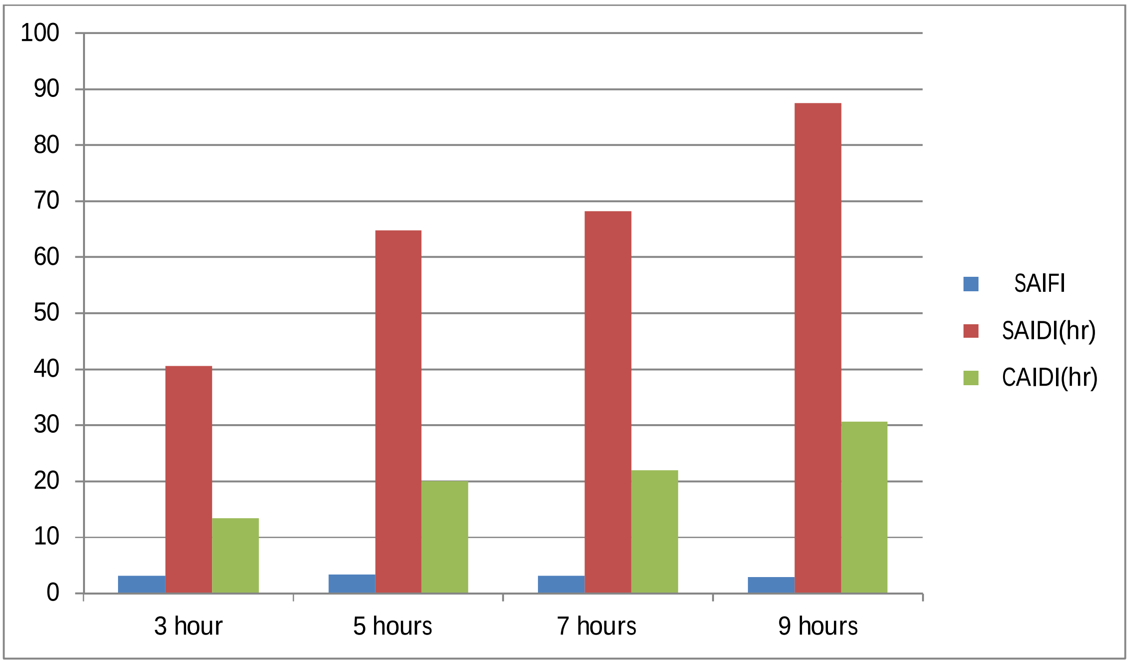


Figure 4.18 *Repairing time effect*

4.4.3 Modeling Combined effect of repair time and Fault rate by MCS

In this chapter the accuracy of the simulation increased by generating the repairing time beside the fault rate by MCS for the duration of one year. The fault rate is based on 8760 hours for a year but the repairing time is generated separately for each fault [19].

Same as before the simulation will repeat for different number of switches, switching time and also remote controlled switches (auto switch). Table 4.12 shows how the number of switches affected on indices by using MCS for fault rate and switching time.

Table 4.11 *Indices and different number of switches by using MCS for fault rate and switching time*

Number of switches	SAIFI	SAIDI(hr)	CAIDI(hr)
No switchs	3.246	246.4583	97.4292
5 switches	3.4368	92.1738	38.4887
10 switches	3.2487	84.9065	26.1352
15 switches	3.3132	194.3516	58.6604
20 switches	3.1366	219.9685	70.1298
25 switches	3.2398	176.8665	54.5919
30 switches	3.2329	33.8684	10.4761
35 switches	3.1791	75.5562	23.7668
40 switches	3.3292	42.5956	12.7946

4.4.4 Switching time in MCS

Switching time can increased because of chock in mechanical side of switch or due to other fault in the switching mechanism or maybe operation of faults like distance, number of faults and available working groups, etc. Table 4.12 and Figure 4.19 show how increasing switching time can effect on reliability indices when both fault rate and repairing time are generated by MCS. As it clearer in Figure 4.19 the value of SAIDI and CAIDI increased gently by increasing the switching time.

Table 4.12 *Switching time effect*

Switching time	SAIFI	SAIDI(hr)	SAIDI(hr)
1 hour	3.1990	33.2623	10.3976
2 hours	3.3124	46.2363	13.9583
3 hours	3.0826	62.2378	20.1899
4 hours	3.0896	72.8619	23.5827

By comparing the value of indices in default fault rate, randomized fault rate and also both randomized fault rate and repairing time can find how simulation is close to default data. Figure 4.19 shows the changing of indices value in different situations.

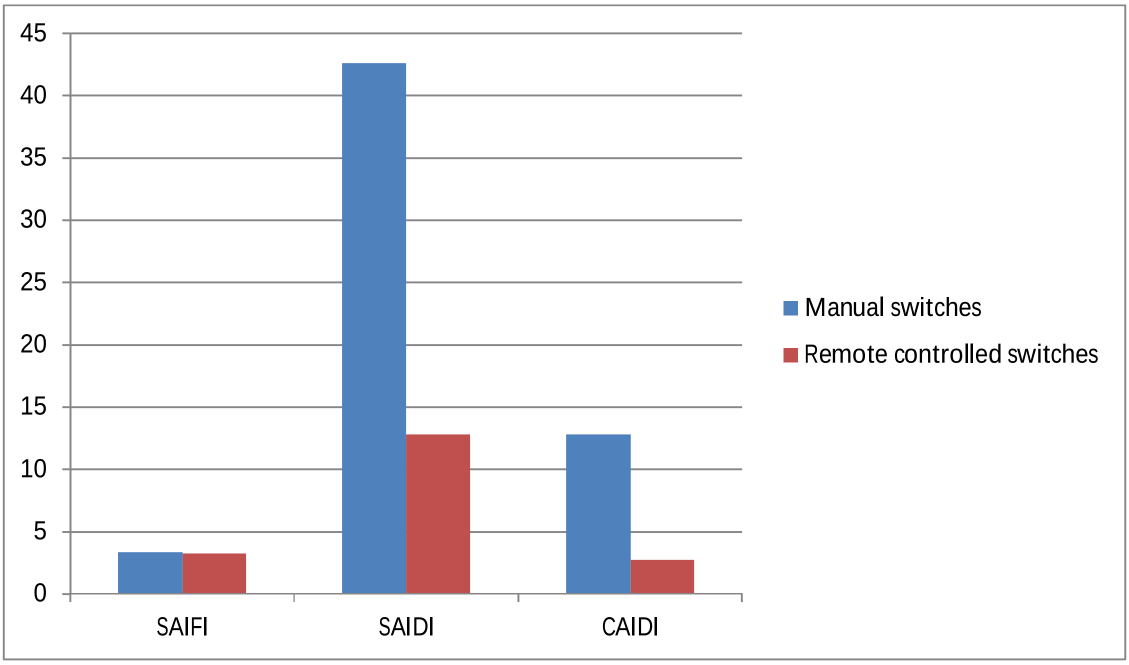


Figure 4.19 *Shoes the result of changing switch to remote controlled (MCS)*

5 Simultaneous faults

5.1 Blackout

Power outage that could be called power blackout is an intentional or unintentional loss of electric power to an area for short or long term [21].

In This situation a large number of customers will be out of service for undetermined time. When the system is more complex and larger the level of importance for blackout will be increase because of the economic and technical effects. This requires getting more engineering action to in power system reliability.
Studying the history of different system in a blackout condition would be helpful to expect future action but even studying and analyzing cannot help to prevent a future one. Evaluating past events can be used to decrease the probability and consequence of failure to improve reliability in planning.

5.1.1 Blackouts in Helsinki

August 23, 2003 - Finland's capital Helsinki and suburbs, including the international airport in Vantaa, were blacked out [21].

5.1.2 Storms Pyry and Janika in Finland, November 2001

The storm which named according to name day of that day ”Pyry” happened on first of November 2001 in western Finland. The speed of the wind was measured at 14-18 m/s in the direction of north-northwest for duration of ten minutes. Most of the damage was in Ostrobothnia and Keski-Suomi region but the wind speed didn’t reach the storm limit. Two weeks later the other storm happened on the 15th of November 2001.

The second storm also reached the storm limit but the damage was more than before because the wind speed increased to 30-50 m/s for a short time. Pirkanmaa, Tavastia and Uusimaa regions had more damage. A number of trees fell on over overhead lines and more than 90,000 to 800,000 customers were affected by an outage in which 1,600 customers effected for more than five days. Maintenance cost reached 11 million euros for 30,000 repaired faults and 140 km of medium voltage overhead line was rebuilt [22].

5.2 Different storm categories

Interruptions in the network are divided in to three categories:

• Long interruptions, which are more than three minutes

• Short interruptions, which are less than three minutes

• Voltage fluctuation

Usually storms are divided in three categories based on the duration of the outage and how many customers getting out of service in the outage time. By analyzing the data it's possible to find a mathematical model which can be suitable for modelling the duration of interruption and number of outage customers in blackout situation.

5.2.1 Class I major storm

In this type of interruption customers are out of service for maximum two days and the outage area is small. Based on the model near 40 % of customers are out of services in the begging of storm. This means after some hours the percentage should be decreased to 10 % because of repairing and after 48 hours the power is supplied to all customers but network may needs repairing. Figure 5.1 illustrate the mathematical model of customers without electricity during repairing time.

Many factors have effect on the repair time, like the number and Intensity of faults and the availability of repair group but the most effective one is the number of fallen trees which should be clear from the network. The probability of Class I major storm can be assumed once every five years [23].

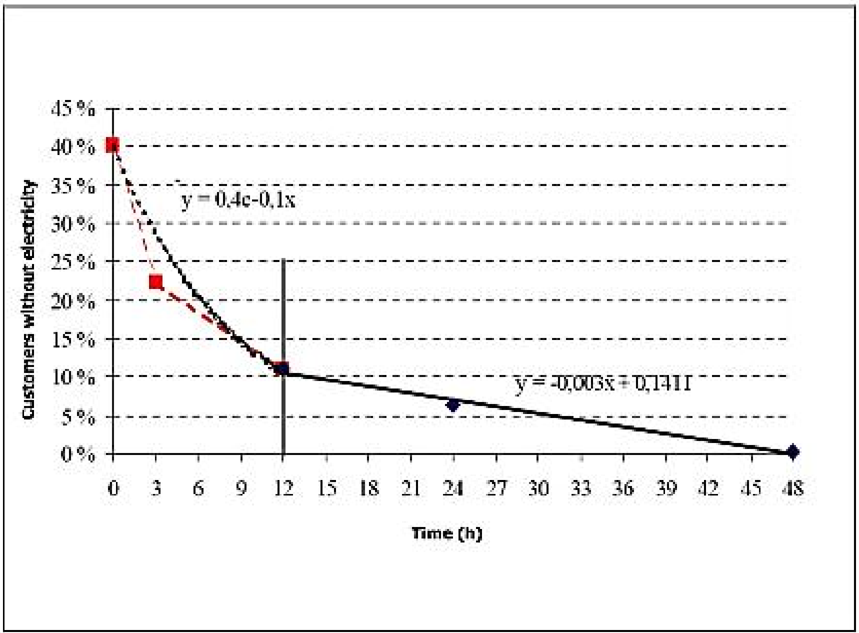


Figure 5.1 *Customers out of service in class I major storm, Red: actual data. Black: calculated data.*

5.2.2 Class II major storm

The total outage time for class II is maximum five days and this includes the whole network area of one specific company but maybe the underground cable network in the city area can be supplied continuously. Basically 50 % of customers will be disconnected but after 12 hours decreased to 23 % and after one day around 90 % of customers will receive power but still near 120 hours is needed to clear all the faults and reconnect the customers. Figure 5.2 shows the model customers which are out of service during the repair time.

Three causes that have most effect on repair time are listed in below:

- Fault with serious damage in the network that takes a long time to repair.
- Simultaneous faults in the same area which affect the network independently.
- Several minor faults in wide area that affect a small number of customer in Low Voltage (LV) usually they have less priority compared to others.

The probability of a class II major storm is less than a class I major storm and can be expected once every twenty years [22].

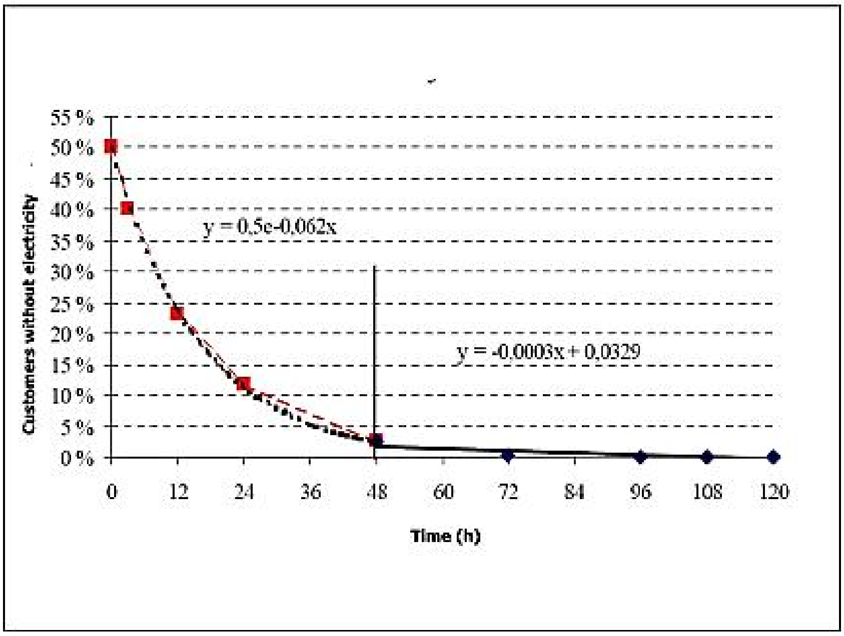


***Figure 5.2** customers out of service in class II major storm, Red: actual data. Black: calculated data.*

5.2.3 Class III major storm

This type of storm has significant effect on people's life and customers are left for total 18 days or 2.5 weeks without electricity connection from the beginning of storm till the last day. The area of damage is the whole country's power system network with several type of faults in the local distribution networks, that means cities and many populated areas are in blackout conditions. The number of interrupted customers increases to 95 % before repairs but after three days repairs, 50 % of customers still remains out of service and repairs will continue to reconnecting 90 % of customers for two weeks.

Recovering and repairing time are mostly affected by availability of all repair groups and if repairs are possible, replacement or maybe rebuilding entire lines in required situations. Figure 5.3 represent the customers without service at major storm class III situation during repair time.

This type of storm has very small probability but still it could be occur once in a century.

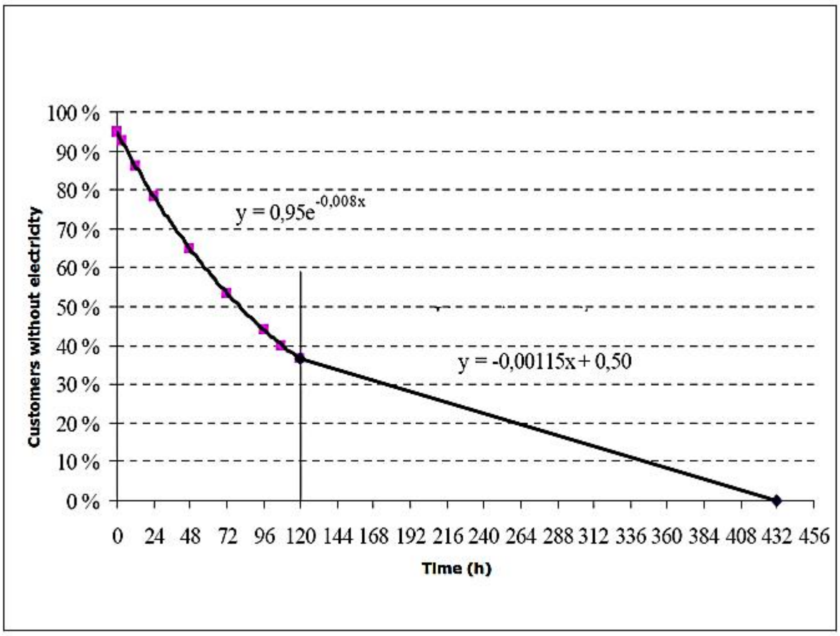


Figure 5.3 *Customers without electricity class III major storm [23].*

5.2.4 Storm and modelling fault finding

The fault finding location methods are an essential procedure in order to avoid unnecessary outages and losses during a fault situation on a transmission and distribution systems. Automation based methods are not useful when the number of faults are huge. The only way to understand where the faults are is to see them:

- During the storm working groups might find some locations, but they are not allowed to start repairing there.
- When the storm is over, a helicopter is used to locate faults. Wind speed has to be low enough, when helicopter may run.

A number of techniques have been published for fault analyses, but the effects of simultaneous faults have been neglected. It is required that the simultaneous faults are taken into account in the planning and protection system assessment algorithms [24].

Modeling the simultaneous faults has same procedure to compare with other fault modes. Each part has separated fault rate which generated by using MCS. The study of fault in unusual situations required large amount of statistic data from technical and environment sources. Weibull distribution has enough flexibility to fit and model the statistical data. To define the simultaneous faults each healthy sections has same possibility to fail in fault situations in same time as a faulty section, as the fault rates are different the result also will be different and it is depend on the fault location.

5.3 Repairing time in Storm situation

Many functions have effect on repair time in simultaneous situations. In the previous chapters we studied that when there is just one fault in the system it is clear for the repair group and the control center to decide what is the right decision to correct it and also reconnecting the customers to the system, the availability of a repair group has direct effect on repair time. That means when we have two or more available repair groups the control center can send them to work on two separate faults in same time and many customers in two different locations will be reconnect in same time. In the situation of when just one repair group is available control center should decide based on their priority which fault should be cleared first and then the others. The highest priority can be nearest fault to repair group, the most important customer, the fault that has less damage and it requires less work to clear it or the fault that may reconnect many customers when repaired.

Transport from one fault to other fault is also can be counted as repair time for the second fault and the others. During the winter time and in snow area is not easy to reach the fault location and forest can also slow down the procedure.

Monte-Carlo Simulation (MCS) is used to model the repair time but repair time is not separate and each fault is affected by the last fault and also can effect on next fault. Generally the repair time increases based on faults distance and number of simultaneous faults.

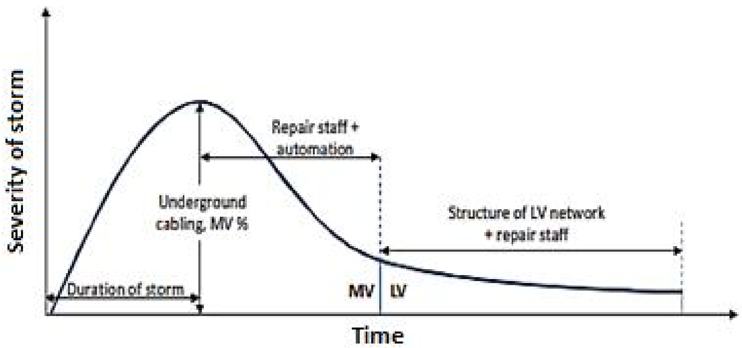


Figure 5.4 *The expected situation of customers in MV and LV during the storm*

Figure 5.4 shows the aspects that effect outage time in the storm situation [25]. Most of simultaneous faults happen due to a storm condition but the probability of a storm is low during the one year study. By increasing the simulation duration the possibility of a storm condition is increased during the simulation. The minimum duration of study is one year and maximum duration of study is 100 years to cover all of three storms type which each year divided in 8760 hours.

5.4 Simulation result

To provide the probability density function (PDF), the cumulative form of data should fit in the static data. Figure 5.5 includes the outputs of MCSs (SAIFI) with different number of MCS sequences. The SAIFI has a normal distribution and the required number of sequences is at least 10000. By increasing the number of sequence more than 10000 times the simulation time also will be increased but the final result is the same as 10000 sequences. Each sequence represents one year of study and the result for each year is independent. The Table 5.1 represents the value of reliability indices for probability of 95 %, from this table can be found that by probability of 95 % the value of SAIFI will not exceed from 3.6515. This condition is the same for lowest value of system indices. The red circle in Figure 5.5 shows that in some points when the number of sequences is 10 (Blue curve) which means by less probability, the value of SAIFI is high. It is one of the interesting part of analyzing SAIFI for modeled network in simultaneous faults condition. As it is clear in the Figure 5.5 fewer faults has more effect on reliability index of modeled network and the problem could be from the configuration of network.

The distributions of SAIDI and CAIDI are represented in Figures 5.6 and 5.7 The value of SAIDI and CAIDI will never exceed from highest and lowest values during the simulation which are represented in Table 5.1, Figure 5.6 and 5.7. For example the minimum value of SAIDI never goes lower than 0.2452 h during the 10000 sequences and the value of CAIDI is same or less than 0.0775 h by probability of 95 % during the simulation.

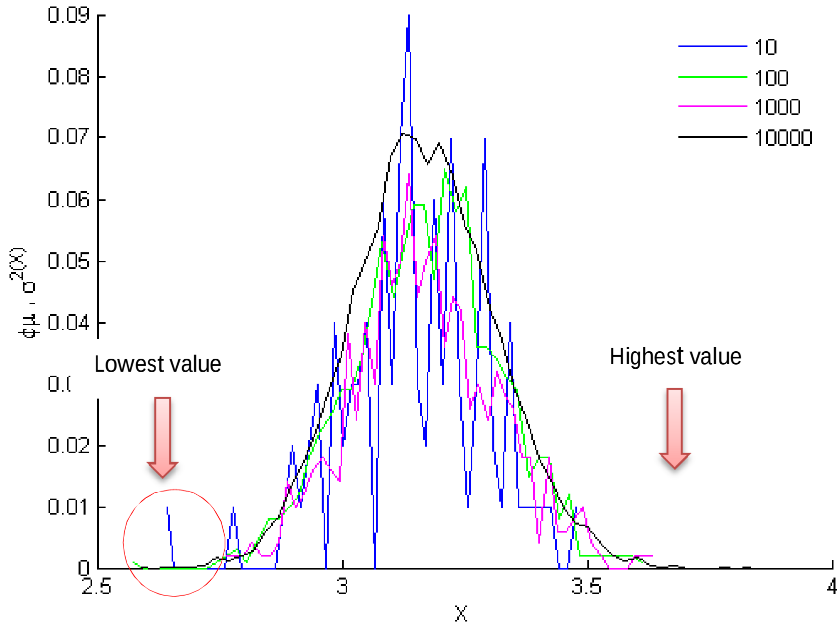


Figure 5.5 SAIFI for different number of simulations

Table 5.1 The value of indices in 95% presents probability

Indices	Probability	*Highest value*	*Lowest value*
SAIFI	*95 %*	*3.6515*	*2.7034*
SAIDI(h)	*95 %*	*0.5356*	*0.2452*
CAIDI(h)	*95 %*	*0.1678*	*0.0775*

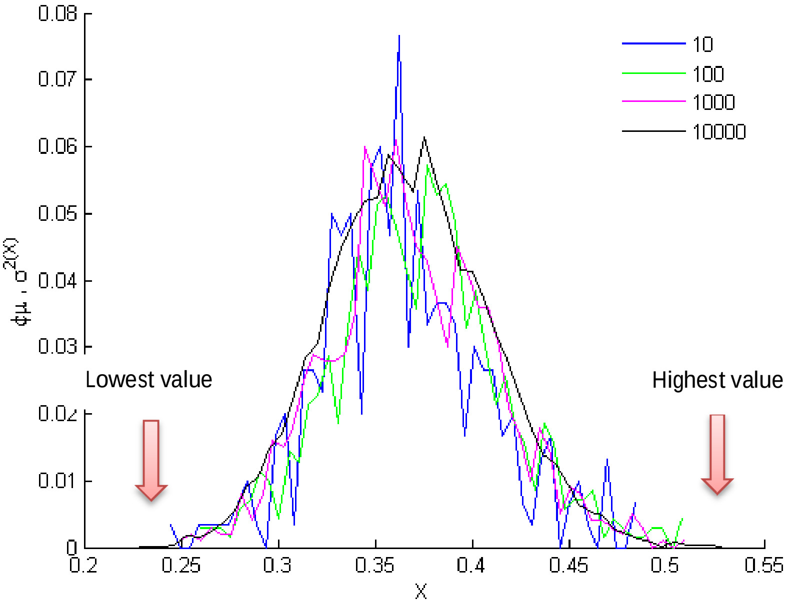


Figure 5.6 SAIDI for different number of simulation

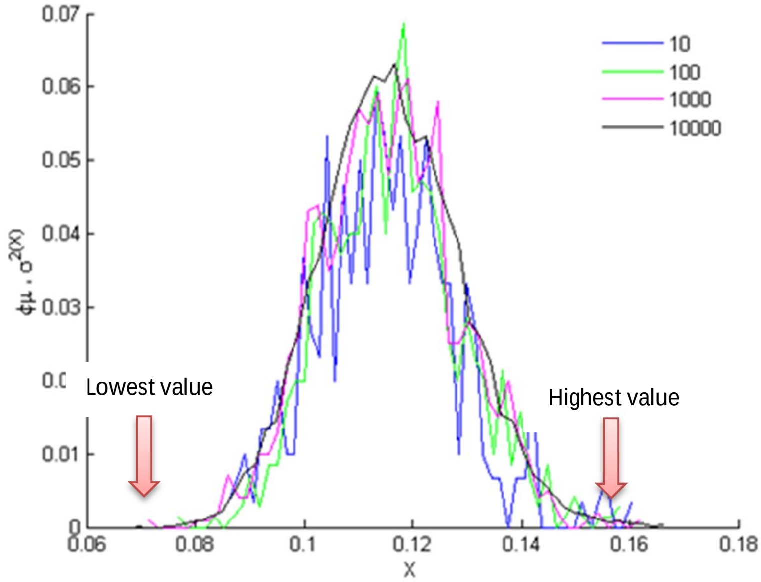


Figure 5.7 CAIDI for different number of simulations

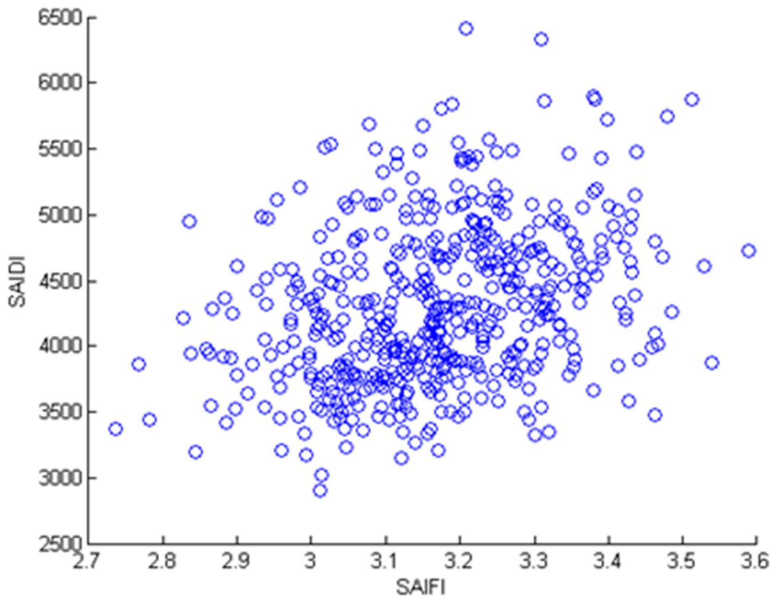


Figure 5.8 The correlation between SAIFI and SAIDI

Figure 5.8 shows the correlation between the values of SAIFI and SAIDI during the simulation. The correlation value is 0.3158 and it is obvious that there is no strict relation between fault frequency (SAIFI) and fault duration (SAIDI), which means in this network it is possible to have low fault rate but still long average outage duration or vice versa that mentioned in description of Figure 5.5.

Figure 5.9 shows the outage time of network in simulation procedure during the storm situation; by compare it to figure 5.4 it is clear that the simulation result is same as expected study. The outage time and number of outage customer in the figure 5.9 represent storm class I because the maximum outage time is 43 hours. The total number of simulation was 100 years and modeled system experienced 20 times storm class I, 5 times storm class II and one time class III. During one years of study for 8760 hours the mean value is 3.87 hours, the maximum outage time is 14.15 hours and the minimum is 0.26 hours but the maximum outage time during the whole simulation is 273 hours. The number of interrupted customers and the outage time of storm class III represented in figure 5.10, the mean value for outage customer are 818.46 and the maximum number of outage is 946 customers which are 73% of total 1304 customers.

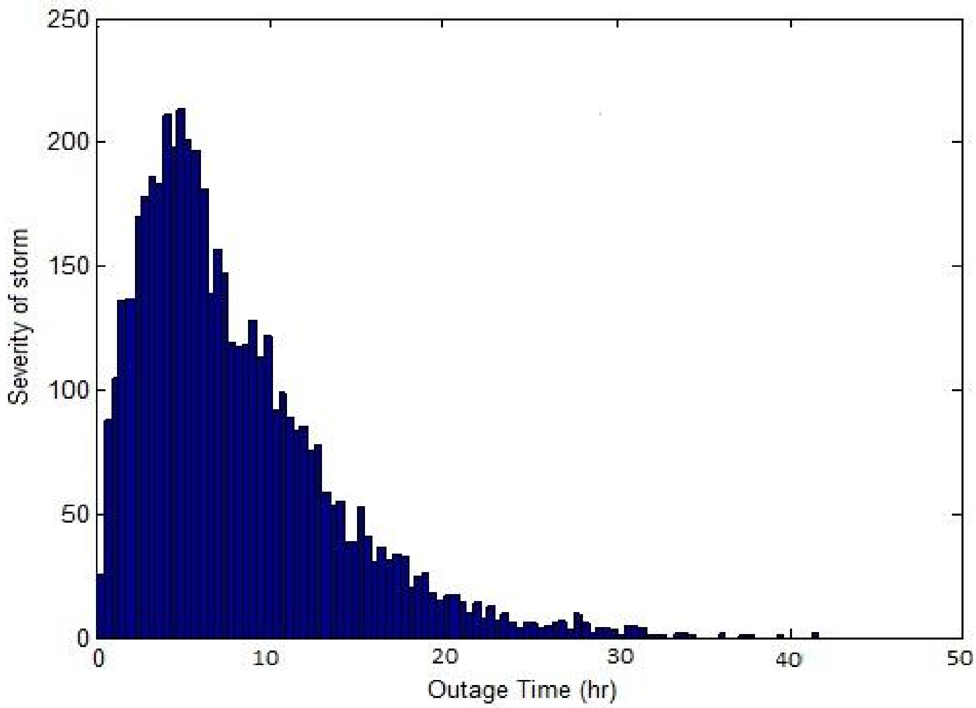


Figure 5.9 Outage time and severity of storm

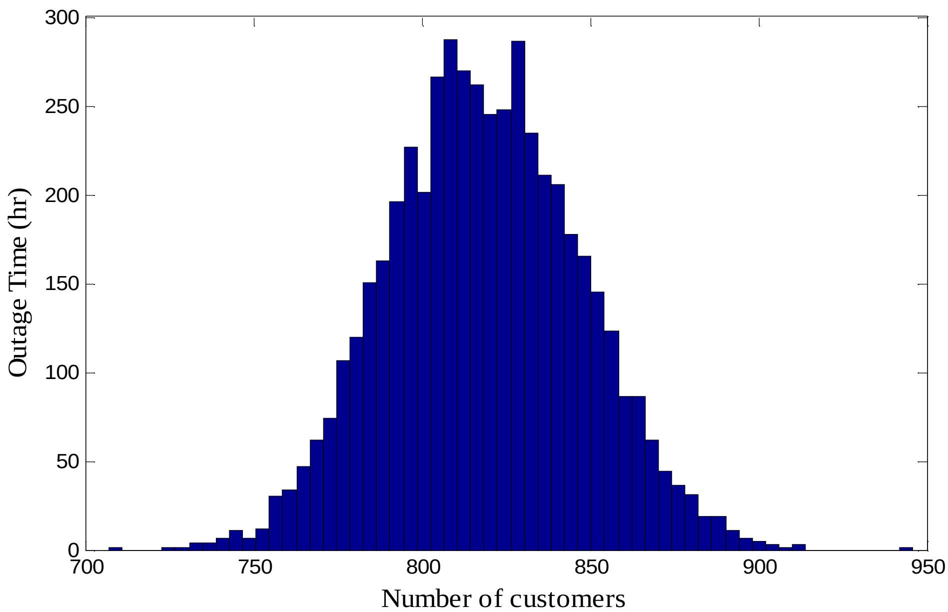


Figure 5.10 Outage time and number of outage customer during storm class III

5.4.2 Analysis of network reliability

The fault rate of each line in the modeled network has represented in different color by Figure 5.11. Green color shows the line sections by fault rate from zero to 1.2120 and the red color indicate the line sections by fault rate from 6.0600 to 7.2720 during the major storm; we can call the red color area the most fault prone area of network which can effect on the average outage of whole network. Based on Figure 4.1 nodes 114, 210 and 172 have already backup connection possibility from neighbor feeders; one suggestion could be installing remote controlled switches on the mentioned places in Figure 5.11 to decrease the average outage of network (SAIDI) by decreasing the switching time and isolating the rest of network from fault area.

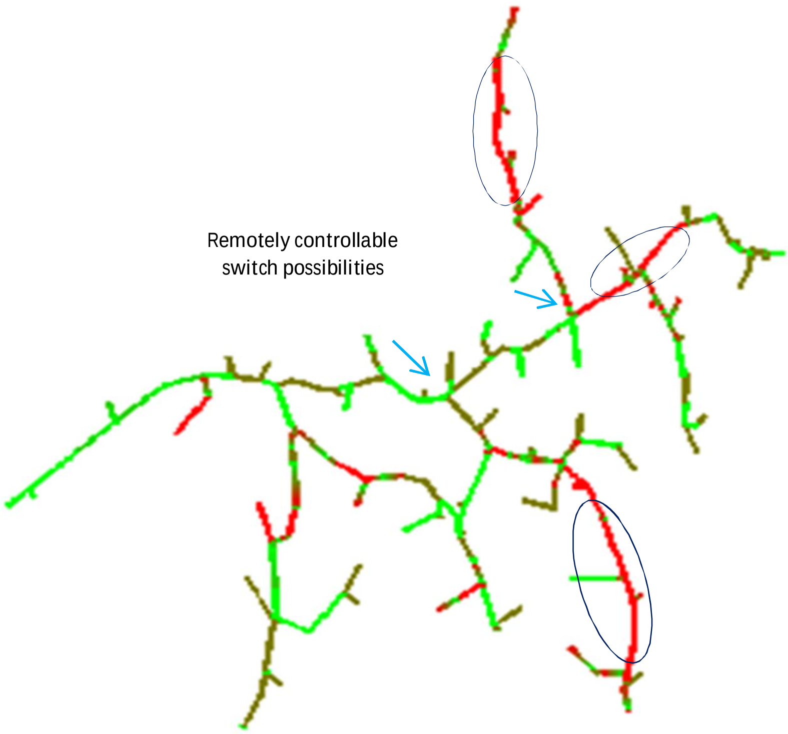


Figure 5.11 fault frequencies of each line section

5.5 Improvement and main challenges

The weakness (vulnerability) of power lines in the weather based condition like major storm or other unexpected condition should be count in quality and ability assessment. The main challenges are the possibility of fall tree on the line, dependency or independency of the generation, communication and shipping during unusual condition or renovation. In the smart grids topology network this dependency will be increase. It can be expected from past that will be extreme weather condition in the future and dependency level of society to the continuous supply is increasing. the studies shows that the ability of getting right actions improved during the past major storms such as 1992 in Norway till Janika (2001) and Asta (2010) in Finland to compare with Dagmar (2011) in Nordic countries. This is point out by decreasing the duration of repair time or fault clearance and reconnection time [26]. This has affected on reliability improvement in such cases like:

- Increasing number of sectionalisers
- Automation and remote controlled devices
- Proper cabling for distribution system
- Design principles and monitoring of situations
- Line location management in forest area

For unusual and extreme weather condition:

- Alert for warning from forecast
- Risk assessment and weakness analysis
- Improve cooperation between companies ,emergency and rescue organizations
- Analyze actions and feedback from previous situations

The reliability of network for each company is linked to the environment condition and also network structure aspects, the most important impact factor of environment is storm weather that is intensely related to the duration of outage SAIDI [27], and therefore the major storm condition should be count for long time planning study.

6 Risk Assessment

6.1 Risk in power system

Risk and reliability have a significant connection in meaning; both of them are the facts for one inference. High level of risk is resource of lower reliability. Risk management in power system has a variety of different subjects including models, methods and applications. Risk is a mixture of probability of disturbance event and the negative effect of that occurrence. Usually it counted for random accident which has harmful effect on people’s life and environment [8]. In this chapter risks that are related to business, finance, and life safety are not involved. Random failures in power system are the origin of risk and cannot control by staff. It is not possible to predict the precise amount of load value, Concerns of power outage in local area and possibility of a general blackout. Nowadays interruption has many indirect economic impacts on the society and environment. Power utility industry counted risk assessment as a challenge and vital assurance today.

The management of risk has three steps:

- Performing calculable risk analyses
- Defining evaluation to decrease the risk
- Modifying a suitable risk level

The aim of calculated analyses is to generate an index to signify the risk of system. Nevertheless, a complete and standard index has to be a mixture of probability and consequence that means it would distinguish the failure and also the severity of their consequences. Generation companies are in touch with risk analysis for their long time planning. Most of methods were based on deterministic principles in the past and the simple problem of them is that they cannot support the probabilistic events like load variation and also component failures. One of the important facts in risk assessment is that because of probabilistic random faults zero risk can never be happen in the power system. The process of risk analysis is not only related to the technical aspect but also economic, societal, and environmental evaluations are needed [23].

The mathematical model of risk can be signified by:

$$\text{Risk} = C \times P \tag{6.1}$$

Where C represented the range of consequences and P is the probability of the measured occurrence. Range of consequence can be the amount of economic detriment or number of damage in the system during a specific time. Figure 6.1 shows the risk analysis based on probability and consequence of event, the area of small risk probability is small.

The main principle idea of risk study is to make a distinction between what is the suitable and standard area of system performance. Many methods developed in engineering systems to apply for improvement of risk standard in different areas. Figure 6.1 represent also a tolerable area which is demanded but maybe not necessary and

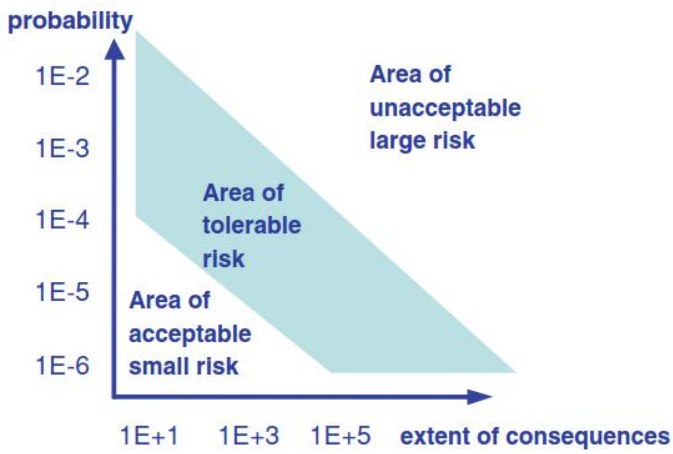


Figure 6.1 *Tolerable risk areas*

The risk model can be expanded to different events from i to ii:

$$\text{Risk} = \sum_{i=i}^{i=ii} C_i \times P_i \qquad (6.2)$$

The probability of event plays a key rule for risk analysis when consequences are constant. But both probability and consequence are two necessary objective functions in risk study.

6.2 Risk assessment of distribution system

As mentioned in Chapter 6.1 risk assessments in power system is a multi-objective problem. In the unit 5.2 of this thesis explained that major storms are divided in three levels: class I, class II and class III. Figures 5.1, 5.2 and 5.3 represents three storms based on duration of repairing time and the percentage of customers without electricity during the faults. In sections 5.2.1, 5.2.2 and 5.2.3 described that the probability of major storm class I is each 5 years ,major storm II is each 20 years and major storm class III is each 100 years. As the risk assessment and reliability study in power system is for long term planning by choosing 100 year as a base for duration analyzes it would be easy to calculate the probability of each major storm in duration of 100 years. Table 6.1 introduces the major storm probability idea.

Table 6.1 *major storms probabilities [22]*

Major storms	Outage time prediction(h)	Probability in 100 years	Outage customers
Class I	48	0.2	40 %
Class II	120	0.05	50%
Class III	432	0.01	90%

By combining figures 5.1, 5.2, 5.3 and table 6.1 it is possible to find the relation of probability and number of outage customer in each storm. Hens, the relation between outage time and number of outage customers can be finding in the same procedure. Figure 6.4 shows the probability and the percentage of customers without electricity and 6.5 present the maximum outage time and the percentage of customers without electricity.

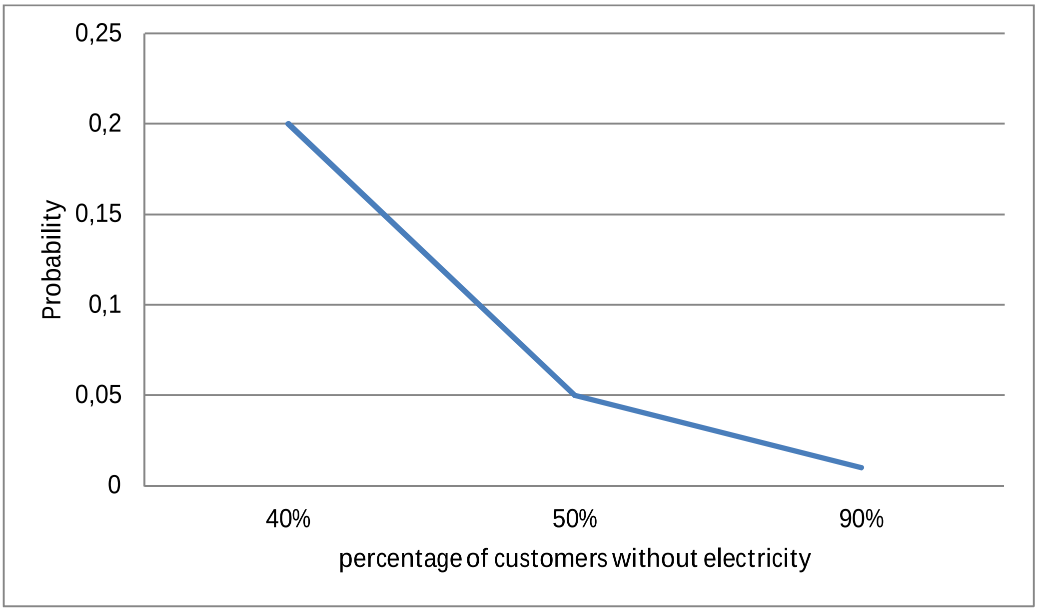


Figure 6.2 *Probability and the percentage of customers without electricity*

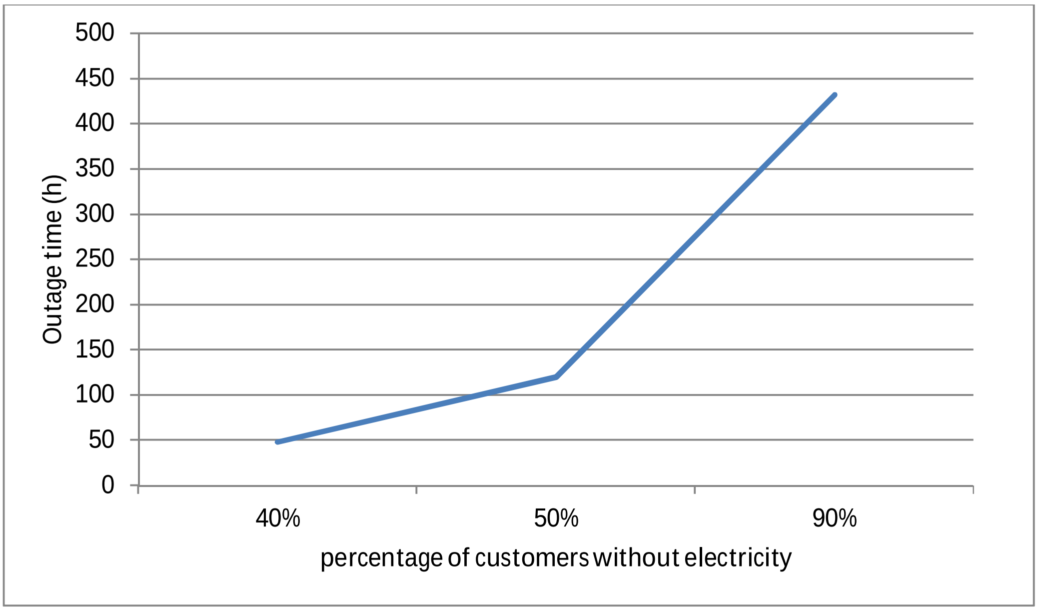


Figure 6.3 *Repairing time and the percentage of customers without electricity*

Based on mathematical model of risk analysis probability and consequence are two objective functions to study risk in the system.

The exclusive property in practice, network companies can choose one output based on their future plan and investment strategies and that would be the risk level of company. Outage cost will be calculated in this chapter. The basic idea of risk assessment reviewed and requirement functions modeled based on the available data of network, which shoes the algorithm can apply in practical manner.

6.3 Risk estimation in distribution System

The best way to estimate the risk in distribution system is to estimate both probability of outage and also the severity of the consequence should be estimate. Many methods have been published to calculation risk assessment in power distribution system [29], in this thesis customer outage during major storm and the effect on reliability of system modeled in previous chapters. The next step is to analysis risk assessment based on the customer outage cost and effect on investment planning.

6.4 Customers interruption costs

Four steps can be described to find how the customer interruption cost can effect on reliability planning. First is to identify the issues which can effect of interruption cost, then different kind of outage cost in the network. Thirdly, identifying type of customers that can effect in a different ways based on type of outage. Finally, analyzing the risk assessment based on the effect of outage cost in financial and investment planning of the network.
Customer interruption costs are function of several aspects and that makes it demanding work to evaluation [29]. The factors which effect on outage cost shows on table 6.2

Table 6.2 *Customer outage cost factors*

Customer attributes	Outage attributes	Geographical attributes
- Customer type -Level of preparedness	- Duration - Frequency - Timing - Magnitude	- Outdoor temperature

Every customer has different kind of activity. By dividing customers in different groups can find the features of customers and their effect from interruption. The preparation of customer by itself for interruption beforehand has impact on cost beside the features of outage like duration, time, magnitude and frequency which presented on table 6.2. Moreover, the outdoor temperature is a geographic attributes which may affect the consequences for residential customers [29].

Customer survey is the other way to find the factors which can change the interruption costs. It is evident that a large number of customers experienced outages to very small or interruption cost is not necessarily to seen at all. In fact, they also are not willing to pay for it, but the current level or even lower quality would be sufficient. For some other customers reliability is important phenomena because of resulting in their business market. The latest survey also can be seen that customers who experience interruptions of supply of electricity in large case, to some extent already prepared for interruptions.

Evaluation of unplanned and planned outages of electricity to the customers is a complex task. For some customers outage means interruption of production or loss of working hours and for some group of customers even it is difficult to measure. In the evaluation methods, customers are requested to state how much they are Willing To Pay (WTP) to avoid an outage or how much they are Willing To Accept (WTA) in compensation for an outage. This information from customer survey influenced to add outage cost parameters in outage cost evaluation [23].

6.5 Outage Cost Study

Outage cost in this study is the cost which wills imposition to the network company when each line of system is out of service. One of the important tasks for electric power system is to supply power to customers in reasonable price with acceptable level of reliability. These two aspects make power utility planners and designers to face a wide range of challenge. Outage cost or cost of interruption in electricity has direct and indirect effects. Direct impacts are the cost which is increasing directly from electricity like lost industrial production and indirect could be the cost of loss in life quality for customers. Several methods developed to evaluate customer influence by electricity outage, a simplified outage costs equation presented in below.

$$\text{COST} = \lambda.(A+B.t).P_{ave} \tag{6.3}$$

λ : Failure frequency

A: Outage cost parameter [€/kW]

B: Outage cost parameter [€/kWh]

t: Outage time

P_{ave}: Average power

The cost equation is related to both system and customer variables, failure frequency and outage time are from network point of view, outage parameters and average power are the cost from customer side. Failure frequency (λ) and outage time (t) can be use from MCS for simultaneous faults. In the modeled network six types of customers contain residential house, summer house, farms, industry, public services and commercial are connected to the nodes. Table 6.3 shows the value for unexpected and scheduled outage cost parameters which found from customer survey. Industry and services are more expensive customers in unexpected outage parameter compare to the other customers, but most of the customers in modeled feeder are residential house customer. Outage cost evaluation in this study is based on unexpected parameters.

Table 6.3 Customers and outage cot parameter [23]

Customers	**Unexpected**		**Scheduled**	
	A(€)	B(€)	A(€)	B(€)
House	0.45	5.32	0.23	2.23
Summer house	0.28	3.35	0.14	1.72
farm	0.64	13.27	0.33	6.79
Industry	2.16	15.00	0.84	7.04
Public	1.48	11.77	1.04	5.74
Services	2.27	25.53	0.19	19.49

Average power of each node can be calculate by power flow analyses for no loss average power and considering annual energy of every single customer which connected to that node. In this line, node without any customer connected doesn't consider in this study. The values are based on AMR measurement to not consider network losses in cost analyze. The average power of each single customer can calculate by using the average power of the node and annual energy consumption of each single customer. However, the outage cost of each node would be found by evaluate the outage cost of customers which are connected to the same node. Outage cost for MCS study of nodes are represented in figure 6.6 , the minimum cost is 1,3298 € and maximum outage cost is 106675,9366 €, the values are divided in three groups and indicated by three colors like light green for low cost, red for high outage cost and dark green for middle range cost. Figure 6.6 is showing the modeled feeder in different view by comparing figures 6.6 and 5.6 can find in some point the fault rate is not high but outage cost is high which means how type of customer and outage cost are relating to each other.

Outage cost (OC) analysis is using in the reliability assessment of power system. In this order it is important to consider customer aspect on cost evaluation which showed in this study, based on reliability assessment outage cost calculation can be used for planning, investment and reconfiguration of the network [30].

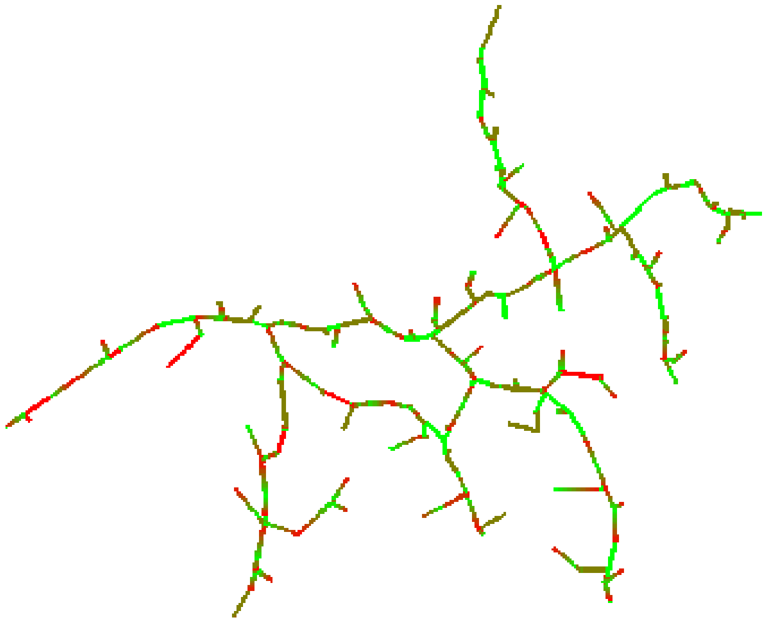


Figure 6.4 *Outage cost of each line section*

6.6 Risk strategies

A risk strategy shows the companies decision approach concerning to the “risk”. One of the common methods is investment based on the expected values from the reliability indexes or expected cost. In this way the consequence of each event multiplies by its probability which means an event with high frequency and low consequences will have the same weight as an event with low frequency and high consequences.

Generally power interruptions in the power system are rare events. In most of the years some small number of interruptions happens and in during the years with extreme condition like a major storm many interruptions can happen, using the average values which is not possible to occur in any year can makes ambiguous in the study. Therefore the more frequently occurring but less severe events can have more priority instead of low probability events in the investment decisions.

The two tools which are using in financial studies to make investment decision and applicable in power systems are Value-at-Risk (VaR) and Conditional Value-at-Risk (CVaR) [31,32]. VaR is defined as the total reliability risk which will not be exceeded for 95% of all the investment. [31]. CVaR is the estimated total risk during the specific period, for example the 5% of the calculation periods with the highest probability risk. See figure 6.7.

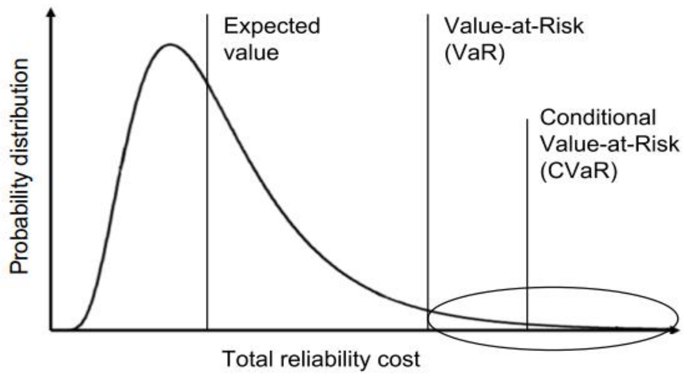


***Figure** 6.5 VaR , CVaR and expected value*

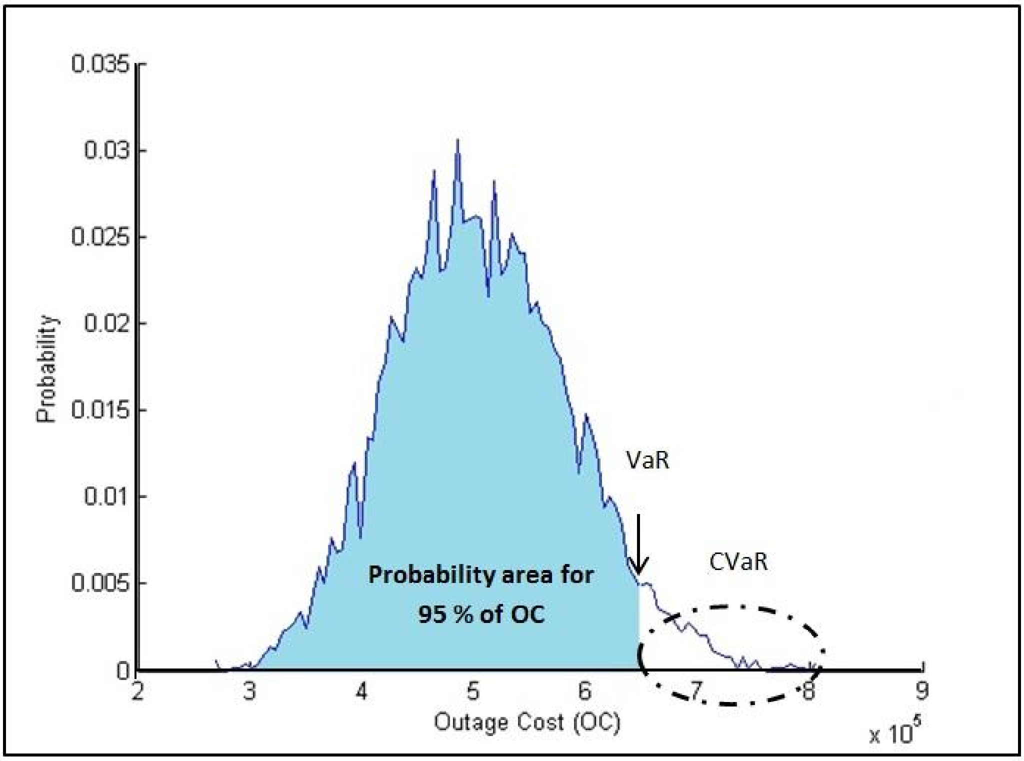


Figure 6.6 *Total outage cost of modelling system and* VaR , CVaR *values*

The calculation of reliability indexes by using MCS in major storm situation for entire modelled network was the first step of technical visualizing the condition of system. Outage Cost (OC) analyzing from the system point of view calculated to find the first financial of network in outage situation. For implementation the risk strategies to find the investment planning frame work. Figure 6.8 represent the Probability Density Function (PDF) of risk assessment based on outage cost and probability of outage, the mean value for outage cost is 506801 €. VaR strategy applied for the 95% of cost which indicated on figure 6.8 , that means for the 95 % the outage cost will not exceed from 637780 € and in conditional case for the rest 5% of outages the CVaR will not be more than 807220 €. Using risk strategies give the wide view and good advantage to do a deep analyzing for risk assessment and investment planners to do enough satisfaction for decision makers in long term investment planning. Financial tools which is useful in business studies is also a benefit for improving the power system studies in economic aspects. The next step could be a detailed study about the performance of network topology based on reliability and risk to find a safe and economic network.

7 CONCLUSIONS

Every fault in the radial distribution network can change the configuration of network and cause interruption for customers. The variety of faults and solutions makes it a challenge for power utilities to take the proper action. The reliability performance of distribution network is usually calculated based on analytical assessment of reliability indices like SAIFI, SAIDI and CAIDI assuming a single fault occurrence at time. However analytical method is unable to consider extreme conditions like the impact of major storms in overhead medium voltage networks. Also they are unable to correctly estimate the maximum outage times strongly regulated in some countries. Many methods and algorithms have been presented until yet to solving probabilistic criteria of reliability assessment. Increasing the number of switch, backup connection from healthy neighbor feeder, changing the switches type from manual to remote controlled switch can help to decrease the outage time and repairing time if the changes happen in optimal location.

Monte-Carlo (MC) algorithm is a method which can use computer to generate random number sampled failure rate of network component and repair time by using historical data of fault situation to expect future possibility of whole or some part of network. The simultaneous faults modeled by using MCS as a main source for failure rate and also repairing time for each fault separately because the repairing time and also the outage time are affecting to each other in simultaneous faults. The final result of simulation shows that SAIFI, SAIDI and CAIDI have the normal distribution which can be useful for future study to assume the simultaneous faults model as a normal distribution.

Risk Assessment study is a multi-objective study in engineering system. Probability and consequence of event are the two objective functions. Three classes of storm, their probability, the percentage of outage customers and the outage time in each storm was the main characters to use in risk assessment study. Outage Cost is an important factor for investment planning of the network, VaR and CVaR are useful financial tools to analyze the risk assessment based on outage cost. The final result of calculation shows the applicability of mentioned tools in power system. Investment planner in the network company can decide to choose the best option among the different risk categories. By changing the network topology the outage cost-probability curve will be change and decision would be easier for planer. It is possible to advice the network companies for using outage cost risk assessment based on their strategy and long term planning.

APPENDIX 1: Probability Distributions

Normal Distribution or Gauss Distribution

The most important probability distribution among science is Gauss distribution. Repeated independent measurements with random uncertainties of almost any quantity follow this distribution. When the number of reiteration it is high in Binomial distribution it possible to drive Gauss distribution. In the probability density function equation x is $-\infty < x < \infty$

$$f(x) = \frac{1}{\sigma\sqrt{2\pi}} * e^{\frac{(x-\mu)2}{2\sigma^2}} \qquad (4.1)$$

The standard deviation Var of variable x is σ and mean value E of variable x is μ.

$$E[X]=\mu \qquad (4.2)$$

$$Var(X) = \sigma^2 \qquad (4.3)$$

Uniform Distribution

When it needs to find a value between two numbers uniform distribution is a useful option.

$$f(x) = \frac{1}{x_{max} - x_{min}} \qquad (4.4)$$

$$E(X) = \frac{x_{max} + x_{min}}{2} \qquad (4.5)$$

Binomial Distribution

Binomial distribution is the discrete probability distribution of the number of successes in a sequence of *n* separate events with parameters *n* and *p* , each of success has probability of *p*.

$$p(k) = (X = k) \quad = \binom{n}{k} p^k (1-p)^{n-k} \qquad (4.6)$$

$$E(X) = n \times p \qquad (4.7)$$

$$Var(x) = n \times p \times (1- p) \qquad (4.8)$$

Weibull Distribution

The Weibull Distribution is the following below equation:

$$f(t) = \frac{\beta}{\mu} \times \left(\frac{t-\gamma}{\mu}\right)^{\beta-1} \times e^{\left[-\left(\frac{t-\gamma}{\mu}\right)^{\beta}\right]} \quad (4.9)$$

β shape parameter

μ scale parameter

γ location parameter

When b = 1 Weibull distribution becomes exponential distribution. The Weibull distribution for b \ 1 becomes gamma distribution. The Weibull distribution for b = 2 becomes lognormal distribution.

Exponential Distribution

Usually Exponential Distribution is widely used for modeling and analyzing the failure time of systems when t> 0

$$f(t) = \lambda \times e^{-\lambda t} \quad (4.10)$$

$$E[X] = \frac{1}{\lambda} \quad (4.11)$$

$$Var(x) = \frac{1}{\lambda^2} \quad (4.12)$$

The use of exponential distribution is suitable when primary failures are not particularly measured.

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