A Cost to Benefit Analysis of a Next Generation Electric Power Distribution System

by

Apurva Raman

A Thesis Presented in Partial Fulfillment
of the Requirements for the Degree
Master of Science

Approved July 2015 by the
Graduate Supervisory Committee:

Gerald Heydt, Chair
George Karady
Raja Ayyanar

ARIZONA STATE UNIVERSITY

August 2015

ABSTRACT

This thesis provides a cost to benefit analysis of the proposed next generation of distribution systems- the Future Renewable Electric Energy Distribution Management (FREEDM) system. With the increasing penetration of renewable energy sources onto the grid, it becomes necessary to have an infrastructure that allows for easy integration of these resources coupled with features like enhanced reliability of the system and fast protection from faults. The Solid State Transformer (SST) and the Fault Isolation Device (FID) make for the core of the FREEDM system and have huge investment costs.

Some key features of the FREEDM system include improved power flow control, compact design and unity power factor operation. Customers may observe a reduction in the electricity bill by a certain fraction for using renewable sources of generation. There is also a possibility of huge subsidies given to encourage use of renewable energy. This thesis is an attempt to quantify the benefits offered by the FREEDM system in monetary terms and to calculate the time in years required to gain a return on investments made. The elevated cost of FIDs needs to be justified by the advantages they offer. The result of different rates of interest and how they influence the payback period is also studied. The payback periods calculated are observed for viability. A comparison is made between the active power losses on a certain distribution feeder that makes use of distribution level magnetic transformers versus one that makes use of SSTs. The reduction in the annual active power losses in the case of the feeder using SSTs is translated onto annual savings in terms of cost when compared to the conventional case with magnetic transformers.

Since the FREEDM system encourages operation at unity power factor, the need for installing capacitor banks for improving the power factor is eliminated and this re-

flects in savings in terms of cost. The FREEDM system offers enhanced reliability when compared to a conventional system. The payback periods observed support the concept of introducing the FREEDM system. All cases studied in chapters one to five in this thesis are tabulated in APPENDIX F.

ACKNOWLEDGEMENTS

I would like to sincerely thank Dr. Gerald Heydt for giving me this amazing opportunity to pursue research and culminate my Master's experience with a thesis. He has been very motivating, encouraging, patient with my questions and passionate about his work. I have learnt a great deal professionally working under his guidance. I want to thank Dr. George Karady and Dr. Raja Ayyanar for investing their time in being a part of my defense committee and for their valuable suggestions.

This thesis would not have been possible without the funding provided by National Science Foundation (NSF) and the FREEDM center. I am honored to be a part of the Electrical Engineering department at Arizona State University. I want to thank all the staff members, my academic advisors and teachers who have taught me a wide range of courses specializing in power systems that have sharpened my knowledge of power system concepts.

I dedicate this thesis to my parents, late Mr. V.S. Raman and Mrs. Lata Raman as well as my elder brother Mr. Aditya Raman who have been constant pillars of strength and a major reason behind me pursuing my Master's. Without their support, motivation and confidence in my abilities, I could not have reached this stage. Lastly, I would like to thank all my relatives, friends and colleagues who have helped me at every step of my life in shaping me into a strong individual.

TABLE OF CONTENTS

CHAPTER Page

LIST OF TABLES

LIST OF FIGURES

Figure Page

Figure Page

Figure Page

NOMENCLATURE

a	Constant used in Third Degree Curve Approximation of Expected Number of Customers Served
b	Constant used in Third Degree Curve Approximation of Expected Number of Customers Served
Benefit	Total Benefits Associated with the FREEDM System
BIL	Basic Insulation Level
c	Constant used in Third Degree Curve Approximation of Expected Number of Customers Served
C	Capacitance in μF
CBEMA	Computer Business Equipment Manufacturer's Association
Cost	Total Costs Related to the FREEDM System
CP	Annual Reduction in Cost due to Elimination of Installation of Capacitor Banks
d	Constant used in Third Degree Curve Approximation of Expected Number of Customers Served
DESD	Distributed Energy Storage Devices
DGI	Distributed Grid Intelligence
DLMP	Distribution Locational Marginal Price
DRER	Distributed Renewable Energy Resource
E	Number of Customers Served
E(.)	Expectation
ERCOT	Electric Reliability Council of Texas
freq	Frequency in Hertz
f	Variable used in Iterative Calculations of Payback Periods

f_0	Variable used in Iterative Calculations of Payback Periods
f_1	Variable used in Iterative Calculations of Payback Periods
F	Total Cost of Fault Interruption Devices Installed in a given Configuration of System
FID	Fault Isolation Device
FO	Forced Oil Cooled Units
FREEDM	Future Renewable Electric Energy Delivery and Management
G	Subsidy of 10 % of the Customer's Annual Bill to Encourage Utilization of the FREEDM System
H	Annual Savings in Electricity Bill per Customer due to use of Renewables
i	Annual Rate of Interest in %
I	Current Flowing in the Conductors
IEC	International Electrotechnical Commission
l	Length of the Feeder
L	Annual Reduction in Cost of Active Power Losses When Compared with a System Consisting of Conventional Transformers
LOLE	Loss of Load Energy
L_n, L_m, L_k	Load at Points n, m and k
MOSFET	Metal Oxide Semiconductor Field Effect Transistor
n	Number of Customers served
$n^{'}$	Payback Period in Years
n_0	Variable used in Iterative Calculations of Payback Periods
n_1	Variable used in Iterative Calculations of Payback Periods

NEMA National Electrical Manufacturers Association

pf Power Factor

P Active Power

PSERC Power Systems Engineering Research Center

P_{lost} Active Power Losses

P_{max} Maximum Loading in Watts for a Given Year

P_{scaled} Scaled Loading of Transformer
Q Reactive Power in kVAr

$Q_{compensation}$ Reactive Power to be Compensated while Improving Power Factor

r RMS Error in Curve Approximation

R Resistance of the Conductors

RB Value of Enhanced Reliability Benefit for all the Customers Served in a Given System for a Given Year

RPS Renewable Portfolio Standards

$R_{section}$ Resistance of a Given Line Section

S Total Cost of Solid State Transformers Installed in a Given Configuration of System

SAIDI System Average Interruption Duration Index

SAIFI System Average Interruption Frequency Index

SST Solid State Transformer

US DoE Unites States Department of Energy

V Variable Used in Third Degree Curve Approximation of Expected Number of Customers Served that Represents Number of Fault interruption devices in service

V_{op} Operating Voltage at a Given Bus

y	Constant Used for Calculating the Value of kVARs Required to Improve the Operating Power Factor of the Feeder
ω	Frequency in rad/s

CHAPTER 1 THE FREEDM SYSTEM: COSTS AND BENEFITS

1.1 Motivation

This thesis relates to electric power distribution systems. With the increasing need for integration of renewable energy resources, it is necessary that an architecture that facilitates some automated features will be used. These automated features include: 'plug and play' of distributed renewable energy resources and storage devices, central monitoring and control and advanced instrumentation [1]. The next generation of distribution system is exemplified by the Future Renewable Electric Energy Delivery and Management (FREEDM) system which uses solid state transformers and other semiconductor switched distribution system components to achieve the cited features. The automated features come with costs. The main motivation of this thesis relates to the study of the costs versus benefits of a solid state controlled power distribution system. The FREEDM system shall be used as the test bed for the study.

1.2 Project Objectives

The FREEDM system has been envisioned as the next generation of power distribution system architecture laying emphasis on solid state transformers (SSTs). While this system has many obvious advantages to offer in terms of enhancing control of the power distribution grid, these controls come with investment as well. This thesis attempts to provide a detailed cost to benefit assessment of such a distribution system. Figure 1.1, taken directly from [2] shows the envisioned FREEDM distribution system. The backbone of the technology behind creating this system is the use of SSTs that encourage four quadrant power flow control [2]. Figure 1.2 is a pictorial of the focus of this thesis. A heavy investment is involved when considering implementing the use of solid state transformers, high speed electronic switches and advanced instrumentation in the envisioned FREEDM distribution system. An attempt is made to check if the costs associated with these investments are justified by the functionalities offered by this system. These functionalities include addition of storage capability, conception of the system as the ' internet for energy' making use of high bandwidth digital communication as well as plug and play of distributed generation [2].

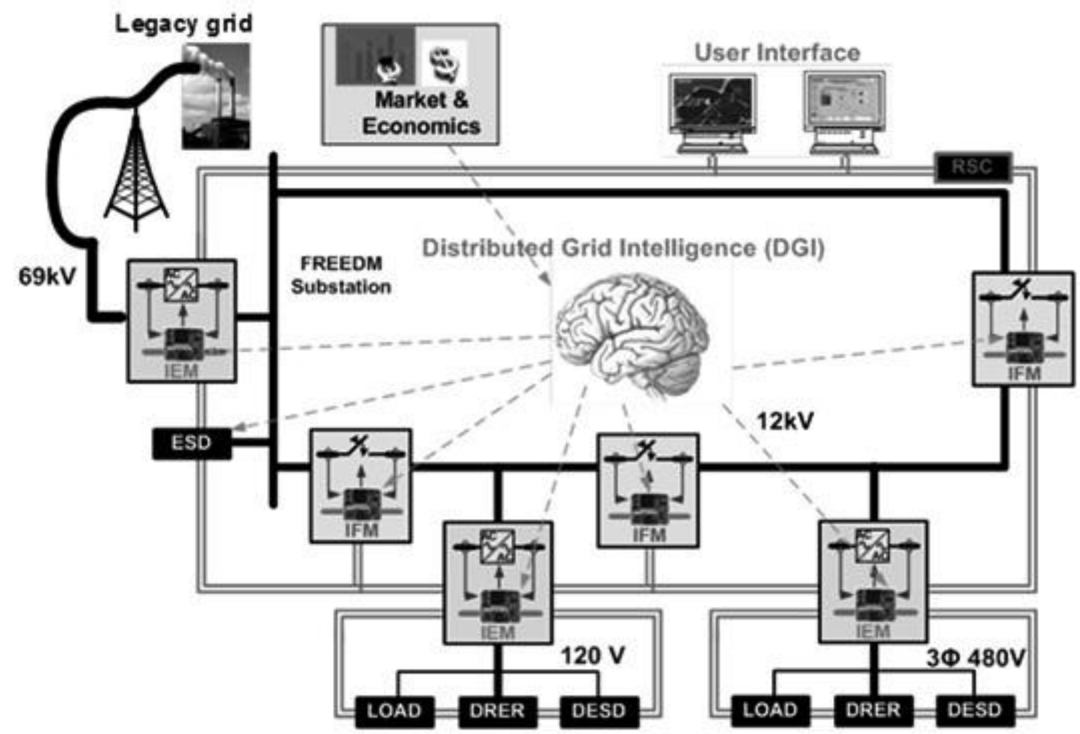


Figure 1.1 The Envisioned FREEDM Distribution System

1.3 Cost to Benefit Analysis

The cost to benefit analysis technique is used to evaluate if a certain investment decision is a sound decision by incorporating all factors in terms of costs. The time value of money is taken into consideration while evaluating the costs and benefits. Benefits as well as costs are quantified in monetary terms. Another technique popularly known as the life cycle analysis is a method used to assess measurable quantities of a particular system through its entire cycle from cradle to grave [3]. At times it becomes difficult to quantify all factors in terms of a number for the purpose of analysis and the data for the same may not be easily available or accurate. In order to decide which one of the two methods should be executed for the analysis of the prototype distribution system suggested, certain advantages and disadvantages of both the methods are discussed. The following are certain advantages and disadvantages of using the cost to benefit analysis method [4]:

Advantages of the cost to benefit analysis method:

1. Commonly used in electrical power industry.
2. Gives a calculated estimate of payback period to determine feasibility.
3. Easy and fast method to recognize if a project is viable.

Disadvantages of the cost to benefit analysis method:

1. Certain factors are difficult to quantify in dollars- pollution, time and human life.
2. Difficult to assess indirect benefits.
3. Accuracy – if inaccurate it results in false estimation of payback period thereby risking project feasibility.
4. Uncertainty in data and risk factors may add to the costs.
5. Short term analysis.

The following are certain advantages and disadvantages of using the life cycle analysis method [3]:

Advantages of the life cycle analysis method:

Factors in all the costs right from initial costs to the operation, maintenance and decommission costs.

1. Detailed analysis of costs and benefits over the entire life cycle of the project (cradle to grave cost).

Disadvantages of the life cycle analysis method:

1. It may get difficult to limit the scope of the project at times.
2. Uncertainty in data.
3. Tricky to envisage the risks and uncertainties in future.
4. It is difficult to predict the value of dollar in future.
5. Technology may become obsolete.

The cost to benefit method is a straightforward and fast method to recognize if a project is viable and since it also gives a calculated estimate of the payback period, it is favorable to proceed with the cost to benefit analysis for the suggested FREEDM distribution system. References [21] – [23] further document cost to benefit analysis in power distribution systems.

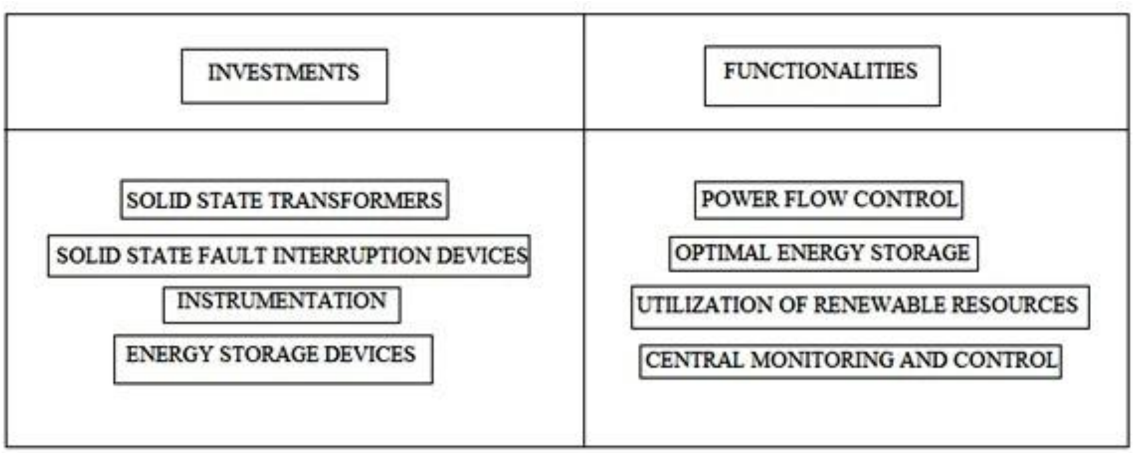


Figure 1.2 A Pictorial of Investments and Functionalities

1.4 The FREEDM System

Figure 1.3, inspired from [11] shows the FREEDM distribution system which implements the use of an SST instead of a conventional magnetic transformer as the distribution level transformer. In addition to the blocks shown in Figure 1.3, Distributed Grid Intelligence (DGI) as well as Distributed Energy Storage Devices (DESD) control the effective functioning of the FREEDM system. The FREEDM system ensures seamless integration of renewable energy resources and facilitates storage of energy. High frequency isolation, AC/AC converters and high power converters have made the power grid very robust and active [6]. The zonal DC micro grid concept being applied to the FREEDM system is highlighted in [8]. The integration issues in the DC micro grid and SST are analyzed and measures are suggested to minimize burden on the existing AC grid. The problem with the existing system is that utilization of power converters is very low in current transmission and distribution systems [7].

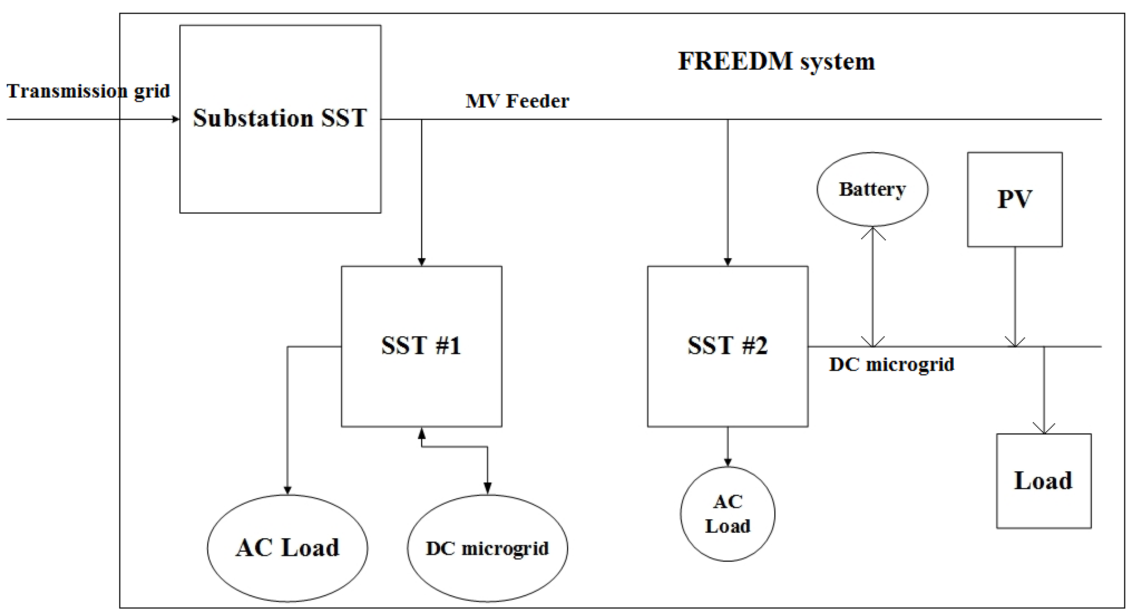


Figure 1.3 FREEDM System

To evaluate the benefits of the system indicated in Figure 1.3, an effort is made to quantify them in terms of cost as follows:

Costs easily quantifiable:

- Elimination of capacitors for reactive power compensation can be translated as a reduction in cost for the FREEDM system.
- Reduction in size and weight by comparison of prototype SST with a conventional low frequency transformer.
- Material and parts cost.
- Cost is quantifiable if a target renewable level is mandated or there are other mandates to be implemented.
- Savings due to improvement in load factor.
- For some cases, loss of load energy (LOLE) is quantifiable and the FREEDM system could reduce LOLE.
- Reduced shipping costs.
- Potential for reduced manufacturing costs.

Costs quantifiable with difficulty:

- Costs associated with reduction of harmonic currents in SST supply (harmonic filtering).
- Labor and equipment costs involved in manufacturing SSTs.
- Control and monitoring equipment for two way power flow.
- Costs due to political and sociological influences on the project.
- Potential to achieve environmental goals.

- Achieving high safety standards via fast interruption and protection in comparison to conventional system using magnetic transformers.

The FREEDM project was funded mainly by the National Science Foundation as an Engineering Research Center. References [1], [2], [6] and [10] document the main efforts of the FREEDM project. Table 1.1 maps the potential features and functions of the proposed FREEDM system as benefits as follows and is taken directly from [31].

Table 1.1 Mapping of FREEDM Features/Functions to Benefits

FREEDM system features/functions	**Benefits**			
	Economics	Reliability & power quality	Societal	Energy security
Renewable integration · Manage high penetration · Plug & play				
Enhanced system protection · Looped primary · Fast protection with FID				
Enhanced fault protection · Fault locating, isolation, service restoration				
Real time load monitoring & management · Regulate service voltage				
Customer participation · DGI- price signals DLMP, demand side management				
Enhanced system control · DGI: power & energy management · DGI: volt/var control				
Resiliency · Microgrid at node, feeder section, whole feeder				

1.5 Cost and Attributes of Distribution Transformers

There exist few direct quantitative comparisons between a magnetic transformer and an SST of the same rating. This is because there is, in reality, no solid state transformer in production and for sale in large volume quantity. Nonetheless, some estimates can be made but it is important to admit that there is uncertainty in the estimates.

An attempt is made to provide a comparison between the volume, weight and cost of a 1000 kVA, 10 kV/ 400 V solid state transformer and a magnetic transformer of the same rating in [5]. The estimated values of cost only take into account the lower bound values of material costs, a major part of which is that of hardware. SST costs exclude installation costs, cost of protection equipment and final assembly costs. Reference [5] gives a comparison of losses in the transformers per kVA, material costs per kVA, volume per kVA as well as the weight per kVA. It was observed that the SST was 5 times more expensive when compared to the conventional transformer with 3 times higher losses. The weight was almost the same but the volume of the SST was only 80% of that of a conventional transformer.

As the losses in an SST are generally higher as compared to those in a magnetic transformer, the efficiencies of SSTs will be significantly lower than those of conventional transformers. This is specially the case for low operational loading. In spite of this, "SSTs can act as energy routers of a future smart grid" [5]. SSTs offer a high degree of intelligent control of power flows. This is indispensable considering recent developments in the fields of smart grid and distributed energy generation systems. SSTs are also useful in integrating renewable energy sources into distribution systems. SST is an emerging technology for the future of distribution systems and smart grids [6]. The SST offers AC as well as DC links that enhance the supply of power and allow both AC and DC networks to easily communicate with the SST [7]. Researchers involved in developing SSTs are interested in identifying which topology will be best suitable for field applications and are involved with improving and enhancing performance of high power converters. SSTs can help in replacing the oil used in conventional magnetic transformers and can enhance the functionality and power quality to justify its cost. This thesis attempts to quantify the costs and benefits and tries to prove if this is in fact possible.

An investigation on the application issue of SSTs in the future electrical grid is carried out in [8]. It attempts to explain how integrating multiple functionalities in the SST may justify its cost. It is suggested that increasing the switching frequency can enable reduction in size of SSTs in [9]. High voltage insulation needs to be carefully designed. The specified requirements for SST application at high frequency and voltage were optimized and a prototype achieving an efficiency of 96.9 % was suggested. Figure 1.4 shows the classification of different topologies of SSTs. The type D topology is suggested to be used extensively in the field applications of SST. Figures 1.5 shows the potential application of SST in the future electrical grid. Figures 1.4 and 1.5 were inspired by [7].

1.6 The Solid State Transformer

SSTs are an evolving topic of discussion in terms of ongoing research within the realms of improving the existing state of distribution systems. They can play an important role when used in smart grid applications to improve flexibility and controllability of the system. An SST may be defined as follows: "A solid state transformer is a collection of high-powered semiconductor components, conventional high-frequency transformers and control circuitry which is used to provide a high level of flexible control to power distribution networks" [10].

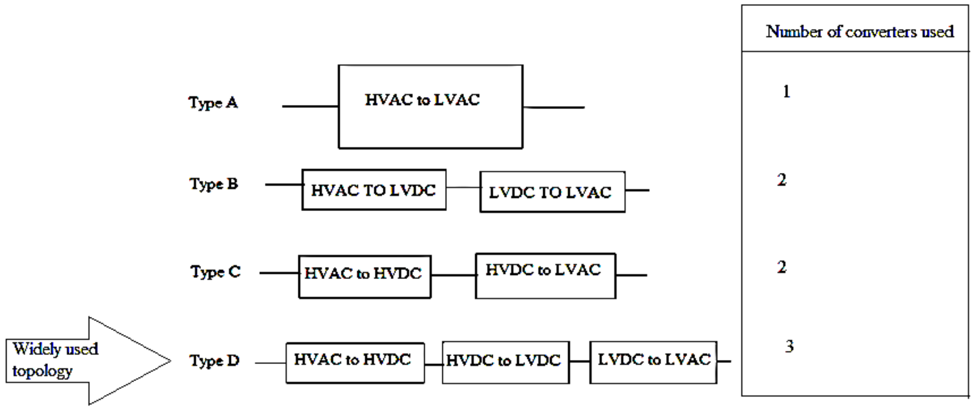


Figure 1.4 Topology Classification of an SST

Figure 1.6 demonstrates use of an SST and fault interruption devices (FIDs) in a prototype distribution system. The existing distribution system consists of magnetic transformers that have limited control possibilities. This system was proposed by Huang in 2007 [11].

With the advent of using renewable sources of energy to cope with the rapid depletion of fossil fuels and meet with the ever increasing energy demands, grid integration of these renewable sources is an area of concern. The issues to be considered for integrating renewable energy sources with the grid are variability of renewable energy, frequency response, oscillations arising in the system from high penetration of renewable sources, forecast of solar and wind energy and storage of energy. Increasing photovoltaic generation can result in many power quality problems when integrated with the system consisting of conventional magnetic transformers. The use of an SST on the other hand can help solve this problem. The importance of SSTs and their advantages depend on the specific application for which they are used. Smart Grids provide flexibility to allow greater levels of penetration of variable renewable energy sources such as wind and solar even without the addition of energy storage [12]. Thus, SSTs serve their purpose well in Smart Grid applications and offer the following advantages when installed in distribution systems:

- Fast interruption and protection of faults.
- AC-DC type SSTs may have some efficiency benefit.
- Integrate energy storage.
- Maintain unity power factor.
- Load transient and harmonic regulation (no/very low harmonic currents in SST supply currents).
- Smaller in size and weight as compared to conventional magnetic transformers.
- Potential for fast installation.
- Central monitoring and control via instrumentation.
- Encourage renewable energy.
- Protect load from power system disturbances.
- Voltage harmonic and sag compensation on the load side.
- Can take DC input from solar and batteries.
- Help in levelizing load and improving load factor. (For e.g. by varying the load voltage)
- Potential for support of the grid using distributed generation.
- "Next Generation” of distribution system.
- Potential for operating “off grid”.

- Implements RPS (Renewable Portfolio Standards).

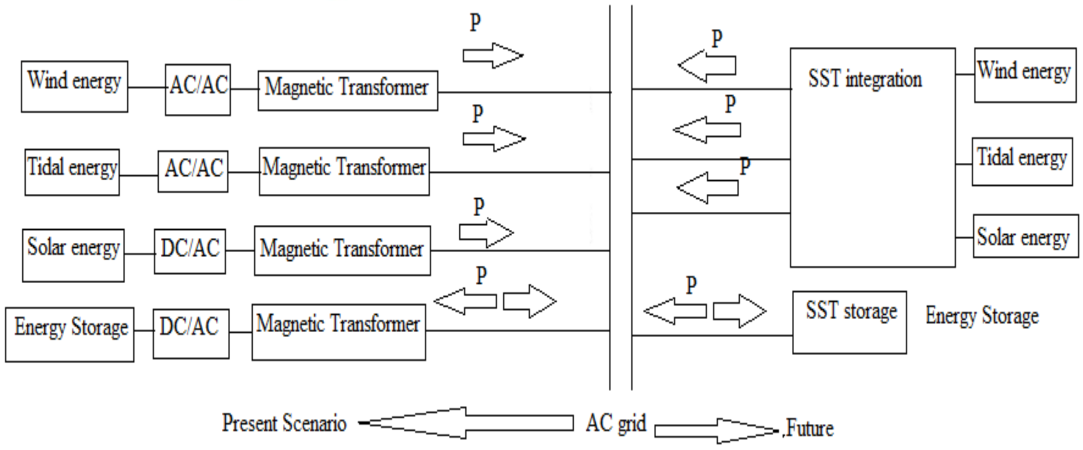


Figure 1.5 Potential Application of an SST in Future Electrical System

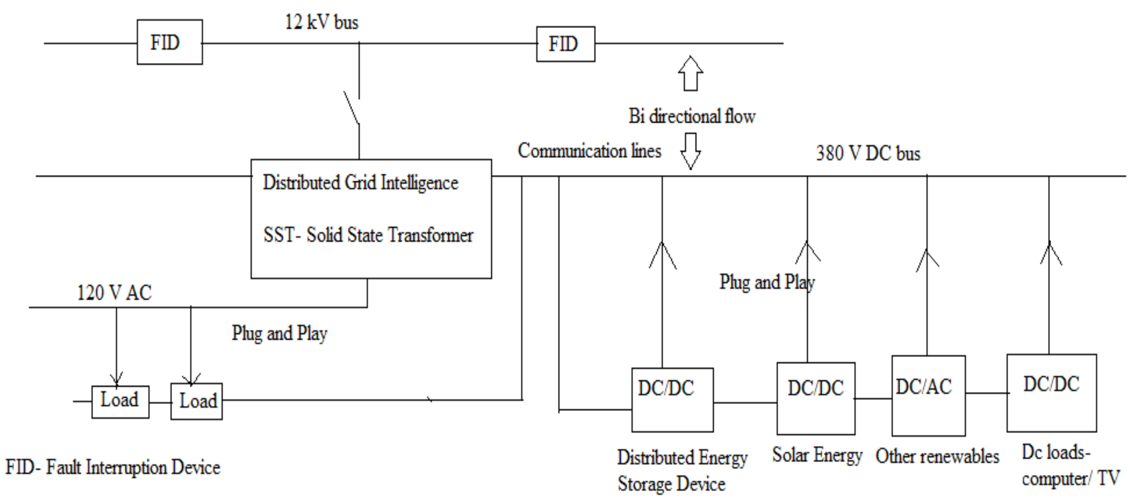


Figure 1.6 Application of SST in a Prototype Distribution System

1.7 Fault Isolation Devices

A solid state fault isolation device (FID) can interrupt full load current faster than mechanical circuit breakers and enables technology that makes use of high frequency, high voltage switching power converters that are compact and efficient [17]. The semi-conductor devices are connected in series to be able to withstand and block system level high voltages. According to [18], to validate the use of fault interruption devices in medium voltage distribution systems, a system with FID model is subjected to simulated tests for continuous current carrying capacity, rated fault current interruption and lightning impulse withstand tests. This semiconductor device driven power electronic interface facilitates connection of distributed generation sources to the network. The operation of the interface devices can be disrupted by transients and over-voltages caused in the system due to fault conditions. This disruption can be faster than the time taken by conventional circuit breakers to operate. The FID on the contrary provides high speed interruption to help solve the issue of loss of power during faults [18]. The basic philosophy of the use of a very high speed FID is to limit the duration of a fault in the distribution primary. As an example, the Computer Business Equipment Manufacturer's Association (CBEMA) curve allows a 100% low voltage (i.e. total outage) for one half cycle. This is $\frac{1}{120}$ second in a 60 Hz system. References [34]-[35] document the CBEMA curve and its applications. Figure 1.7 shows the CBEMA curve [36].

Reference [19] addresses the timely issues in modeling of and specifying the selection criteria for FIDs to be used in medium voltage power distribution systems. Major drawbacks of installing FIDs in place of mechanical circuit breakers are the high material costs and on-state losses (switching losses). Reference [19] validates selection of a suitable topology of FID installation and the feasibility of the proposed topology through simulations.

Thus, FIDs interrupt fault currents within a few 100 microseconds as compared to about 12 milliseconds for even the fastest operating conventional circuit breaker. It has been demonstrated in [17] that in a system consisting of FIDs, during fault conditions, the loss of voltage in distribution systems can be prevented thereby improving the power quality as compared to the case when conventional circuit breakers are used for interruption. The FID cost can range between 12000-24000 for installment in the FREEDM system operating at 15 kV three phase [20].

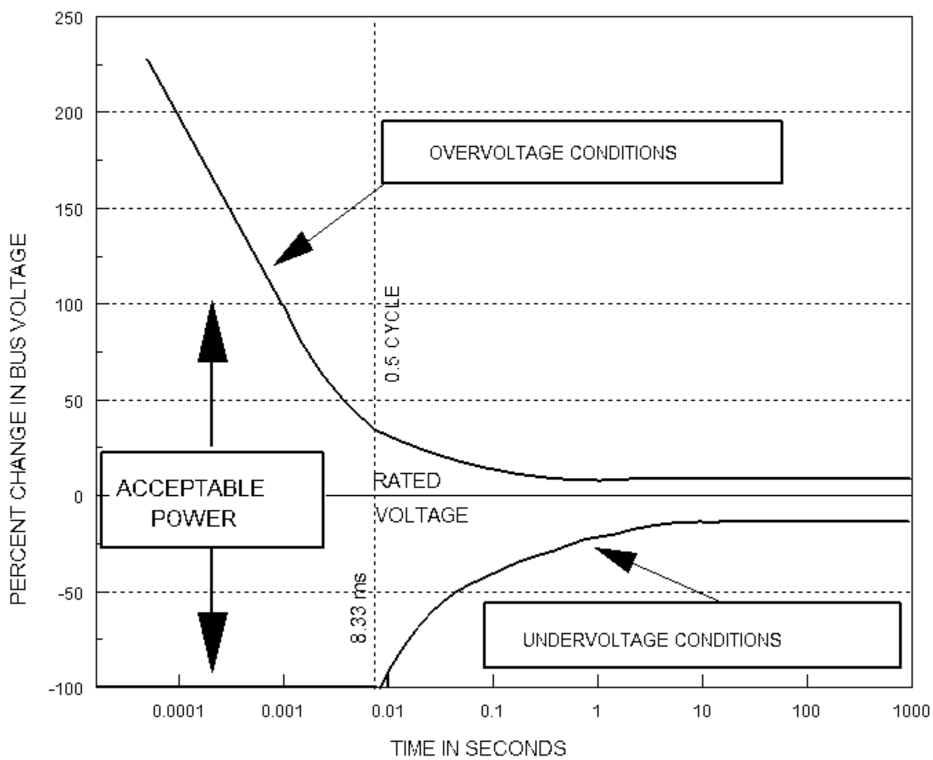


Figure 1.7 The CBEMA Curve

1.8 Principal Assumptions Made in the Cost to Benefit Analysis

In the cost to benefit analysis in this thesis, a number of assumptions have been made in order to reduce the number of cases studied to a manageable level. These assumptions are based on conversations and reports from the FREEDM research team. The assumptions are specific to the FREEDM system. The principal assumptions are:

Relating to components

- Switching losses in an SST are five times the active power losses of the I^2R losses in the semiconductor switches.
- Two loss cases are assumed for the SST, namely a 5% loss and a 1% loss (at 75% loading, the US Department of Energy standard).
- The cost of distribution class capacitors is 3.54$/kVAr (based on a 10 microfarad unit, 15 kV line – line class, single phase unit priced). To span the possible costs for capacitors, 35.4$/kVAr was also considered.
- The cost of FREEDM designed fault interruption devices (FIDs) was assumed to lie between 1000-10000 (assuming technology matures and a mass scale bulk order is placed for commercialization of the FREEDM system).
- The cost of the SST was estimated at 67$/kVA, single phase unit (estimated from the FREEDM research team).
- The distribution primary conductor was assumed to be No. 2 Aluminum as documented in [16].
- The life of capacitors was taken to be 10 years.
- The life of an SST as well as an FID was taken to be 12 years.
- The life of a magnetic transformer was taken to be 20 years.

Relating to feeder design

- The FREEDM feeder was assumed to have 2 sources of generation at the two ends of the feeder, 20 distribution transformers, 36 kVA each, with three to four individual services for each transformer, totaling 0.72 MVA of the total load.
- The load along the FREEDM feeder was assumed to be evenly distributed along the feeder.

- The FREEDM feeder was taken to be 10 miles long.

Relating to the feeder load

- The load data was a scaled version of assumed typical US residential load data. These load data were taken from the Electric Reliability Council of Texas (ERCOT). The data used were for the entire state of Texas, and appropriate scaling was used to obtain the FREEDM feeder loading.
- The load power factor was taken over a range of values in order to span actual load conditions, namely 60 to 100%.

1.9 Organization of this Thesis

Chapter 1 of this thesis discusses the motivation behind this research and outlines the project objectives. It explains how a cost to benefit analysis is conducted and how it can be applied to the FREEDM system. A brief introduction about FIDs and SSTs is given. The principal assumptions made in the cost to benefit analysis are also discussed. Chapter 2 discusses active power losses in transformers, magnetic as well as solid state and compares the annual active power losses for a 36 kVA magnetic transformer with that for a 36 kVA SST. The ERCOT loading data for the year 2013 is scaled to obtain the value of loading on a single 36 kVA transformer. The annual energy loss is calculated for both the transformers and compared. Chapter 3 discusses active power losses in a 10 mile long feeder fed from both the ends. The active power losses in the feeder are calculated for two cases: one with 36 kVA magnetic transformers at the 20 load points and the other with 36 kVA SSTs at the 20 load points. The annual energy lost in the feeder is compared for these two cases. Cost of installing capacitors banks to improve operating power factor of the feeder are calculated for the conventional system.

Chapter 4 establishes the relation between the reliability of service to customers versus the number of FIDs installed in the system for two different configurations- A and B. A closed form expression for the expected number of customers served is calculated for both the configurations and compared. A comparison of SAIFI between a radial conventional system and the FREEDM system is also provided. Chapter 5 calculates the payback period required to earn a return on investments for the FREEDM system by quantifying the benefits calculated in Chapters 2, 3 and 4 in terms of cost. It also discusses how different rates of interest affect the payback periods. Chapter 6 summarizes the results obtained in Chapter 5 as conclusions and explains why the FREEDM system is certainly a viable project based on the cost to benefit analysis. Appendices A through F support the analysis done in Chapters 2 through 5.

CHAPTER 2 ACTIVE POWER LOSSES IN DISTRIBUTION TRANSFORMERS

2.1 Introduction

This chapter focuses on active power losses in transformers. The objective of this chapter is to compare the active power lost in an SST versus the active power lost in a conventional magnetic transformer of the same rating. MATLAB simulations are done to arrive at the results. References [24] to [28] help in understanding the steps involved in calculation of active power losses in a conventional magnetic transformer.

2.2 Simulation Studies

Figure 2.1 is a pictorial of the approach taken in evaluating transformer losses for distribution systems in general and for the FREEDM system in particular. A more electrical view of a radial distribution system is shown in Figure 2.2. The approach taken to evaluate losses is described by focusing on each system component.

With reference to Figure 2.1, note that the required test bed has two main components: a model of the distribution transformer itself and a model of the load. The models for the distribution transformer are discussed in the subsequent section. The load model used is abstracted from published data for Texas [13]. The reasons for using the Texas data were: availability of the data on a published web site; assumed typical data for a mixed developed and rural region; an assumed benchmark of data used by other researchers.

The load profile for the state of Texas was obtained from the official website of ERCOT (Electric Reliability Council of Texas) [13]. It represents the hourly load in kW for the year 2013. Thus there were 8760 values of loading. The loading for 2013 divided by the peak load is as shown in Figure 2.3.

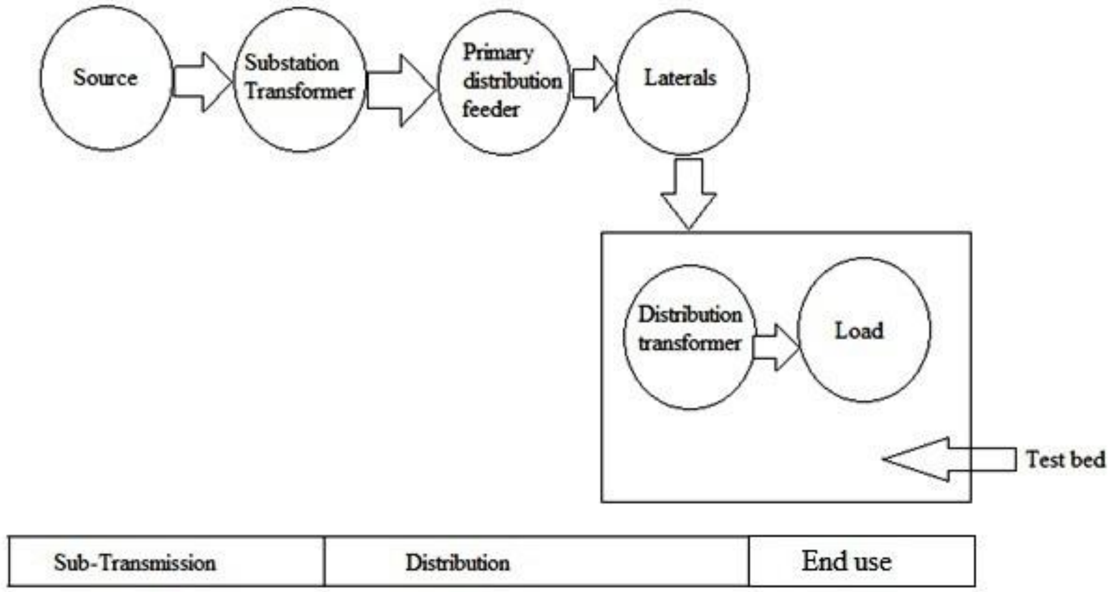


Figure 2.1 A Pictorial of the Approach Used to Evaluate Transformer Losses in Distribution System

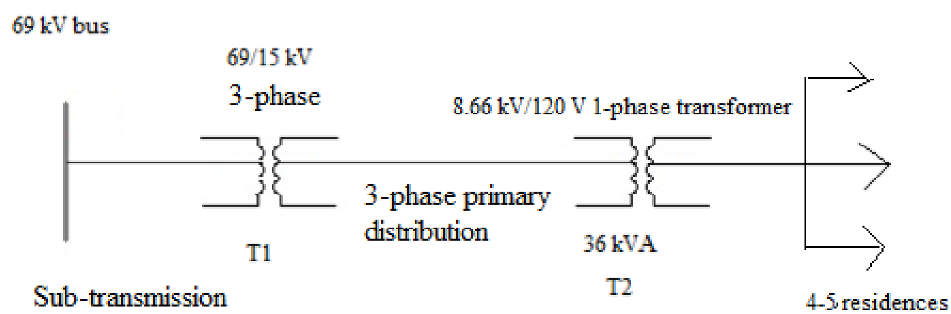


Figure 2.2 Distribution System Assumed for Loss Calculations for a Single 36 kVA Transformer, T2, Serving 4-5 Residences

The corresponding loading on a 36 kVA distribution transformer was calculated by using this data and dividing it by load in the peak load hour for that year. This value was then multiplied by 36 to give an approximate loading on the 36 kVA transformer for every hour of the year 2013. This meant that the peak load hour would load the transformer 100%, that is, the loading would be 36 kVA for the peak load hour.

The losses in a 36 kVA conventional transformer as well as SST of the same rating were calculated using the above obtained values of loading on the transformer. The transformer T2 is the transformer of interest for calculation of losses. Two cases are considered: T2 is a magnetic transformer and T2 is an SST.

2.3 Example Evaluation of Losses in a 36 kVA Magnetic Transformer

Figure 2.4 shows the assumed artifact distribution system. The total circuit rating is 0.72 MVA which was selected to agree approximately with the original FREEDM design. Figure 2.4 shows 20 single phase distribution transformers each rated at 36 kVA, 8660/120 V. There are two principal types of electrical losses in conventional transformers:

- Core losses: these depend on the magnetic properties of materials used to construct the core. Hysteresis loss and eddy current loss are the two types of core losses in a transformer.
- Copper losses: these vary depending on the loading of transformer.

Transformers are usually designed to utilize the core to the maximum. For purposes of this study, core losses are neglected because full load and 75% full load operation is considered. This section evaluates losses in the 36 kVA conventional transformer for the entire year of 2013 for different values of power factor- 60 %, 85 % and unity power factor. The calculation of active power losses is shown as follows for a magnetic transformer.

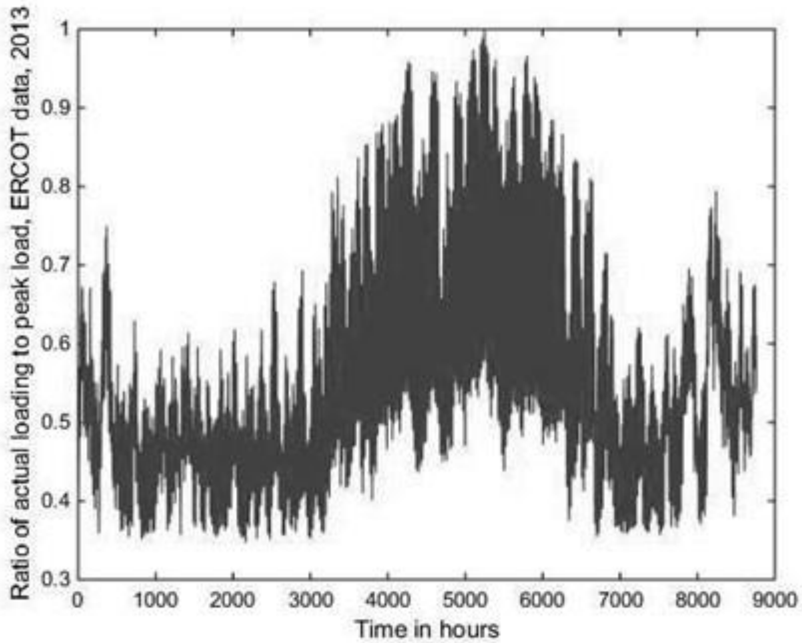


Figure 2.3 ERCOT Loading for the Year 2013 as Divided By Peak Load of the Year.

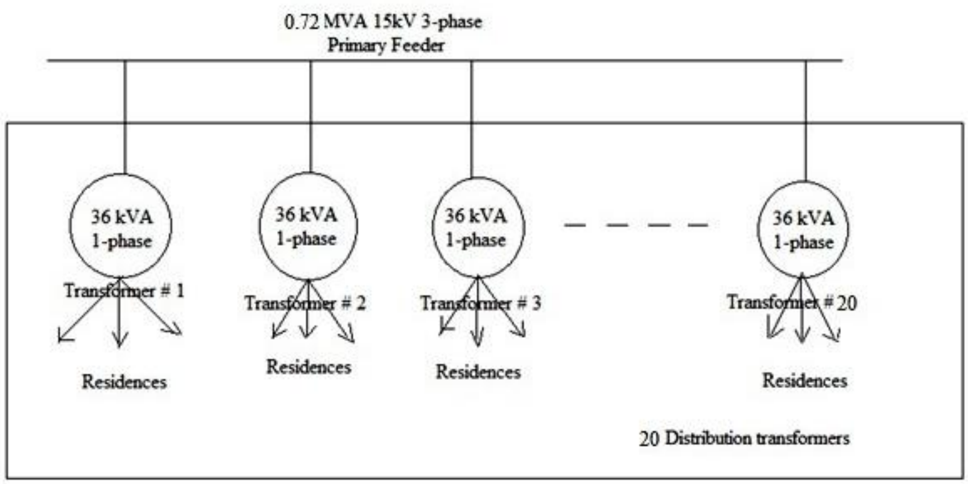


Figure 2.4 A Pictorial of a 0.72 MVA Feeder Showing 20 Distribution Transformers

Calculation of per unit resistance

The active power lost in a resistive element is,

$$P_{lost} = |I|^2 R \tag{2.1}$$

In per unit (p.u.), assuming $|V_{op}|$ = 1 p.u., $P = |V_{op}||I| \cos(\varphi)$, where P = active power, $|I|$ =

load current magnitude, $|V_{op}|$ = operating voltage magnitude and cos (φ) = operating power factor (assumed to be lagging).

Therefore,

$$P_{lost} = |I|\cos(\varphi) \tag{2.2}$$

$$P_{lost} = \frac{P^2 R}{(\cos(\varphi))^2} \tag{2.3}$$

The maximum distribution transformer loss in the United States is specified by the US Department of Energy [15]. For forced oil cooled (FO) units, the approximate, active power lost is 1% at 75% loading. Therefore, substituting 1% loss at 75% loading in (2.1),

$$0.01 = (0.75)\,(0.75)\,R.$$

Thus,

$$R = 0.0178 \text{ per unit.} \tag{2.4}$$

2.4 Scaled Loading on the 36 kVA Transformer for Every Hour Using ERCOT Load Data

The load data obtained from ERCOT is stored into an array and the following calculations are repeated for each element in the array. The result is stored into another array which will represent the actual loading on the transformer. The base rating of the transformer is 36 kVA (assumed). Let P_{max} represent the maximum loading in the year in watts. The per unit operating voltage is assumed to be 1 p.u.

$$I\,(p.u.) = \frac{per\ unit\ scaled\ loading\ in\ kVA}{per\ unit\ operating\ voltage} = \frac{\frac{actual\ scaled\ loading\ in\ kW}{power\ factor}}{base\ rating\ of\ the\ transformer} \tag{2.5}$$

From (2.1), (2.4) and (2.5),

$$I^2R \text{ loss (p.u.)} = |I|^2R \tag{2.6}$$

$$I^2R \text{ loss (actual)} = I^2R \text{ loss (p.u.)*base rating of the transformer.} \tag{2.7}$$

The above calculations are carried out for each hour of the year and are summed up to obtain the value of total energy lost per year in MWh/year.

2.5 Example Evaluation of Losses in a 36 kVA SST

This section evaluates losses in the 36 kVA SST for the entire year 2013. For estimating losses in an SST, 2 cases are considered:

A) 5% loss at 75% load.

B) 1% loss at 75% load.

Two types of losses are considered in the 36 kVA SST: switching losses and I^2R losses. For the sake of convenience, the switching losses are assumed to be 5 times the I^2R losses. Also, switching losses are proportional to the value of current flowing through the transformer while the I^2R losses are proportional to the square of the value of current flowing through the transformer. Thus, the power loss formula has been approximately formulated as follows:

$$P_{loss} = a\,|I| + b\,|I|^{2}, \text{ where } a, b \text{ can be considered as loss coefficients} \tag{2.8}$$

The first term, $a\,|I|$, represents the switching loss and the second term, $b\,|I|^{2}$ represents the copper loss. Two cases are now shown to illustrate the model used in (2.8). Two loss levels are illustrated.

Case A: Assuming 5% loss at 75% load

$$P_{loss} = a\,|I| + b\,|I|^2.$$

In per unit,

$$0.05 = a\,(0.75) + b\,(0.75^2). \tag{2.9}$$

Assuming switching loss = $5(I^2R)$ loss and substituting in (2.8),

$$a = 3.75\,b. \tag{2.10}$$

Substituting (2.10) in (2.9),

$$b=0.0148$$

$$a=0.0556$$

$$P_{loss}\,(p.u.) = 0.0556\,|I\,(p.u.)| + 0.0148\,|I\,(p.u.)|^2. \tag{2.11}$$

Now, the scaled loading on the transformer is given by

$$P_{scaled} = \frac{(\text{load data}*\text{rating of the transformer})}{Pmax}$$

and one finds that,

$$|I\,(p.u.)| = \frac{per\ unit\ scaled\ loading\ in\ kVA}{per\ unit\ operating\ voltage} = \frac{actual\ scaled\ loading\ in\ kVA}{base\ rating\ of\ the\ transformer} \tag{2.12}$$

P_{loss} *(Actual)* = P_{loss} *(p.u.)* x base rating of the transformer (converting from per unit to actual).

The above calculations are carried out for each hour of the year and are summed up to obtain the value of total energy lost per year in MWh/year.

Case B: Assuming 1% loss at 75% load

Repeating the loss calculation,

$$P_{loss} = a\,|I| + b\,|I|^{2.}$$

In per unit,

$$0.01 = a\,(0.75) + b\,(0.75)^2. \tag{2.13}$$

Substituting (2.10) in (2.13),

$$b = 0.00296$$

$$a = 0.01111$$

$$P_{loss}\,(p.u.) = 0.01111\ |I\,(p.u.)| + 0.00296\ |I\,(p.u.)|^{2}. \tag{2.14}$$

The scaled loading on the transformer is given by

$$= \frac{(\text{load data} * \text{rating of the transformer})}{Pmax}$$

From which one finds $|I\,(p.u.)|$ from (2.12). Therefore,

$P_{loss}\,(actual) = P_{loss}\,(p.u.)$ x base rating of the transformer (converting from per unit to actual).

The above calculations are carried out for each hour of the year and are summed up to obtain the value of total energy lost per year in MWh/year.

2.6 Annual Energy Loss for a 36 kVA Magnetic Transformer

The value of energy lost obtained in Section 2.4 is then multiplied with the average cost of energy to obtain the value of the cost of energy lost for the transformer for the entire year in $/year. Average cost of energy is taken as 10.27 cents/kWh as obtained from [14] for the year 2012. The MATLAB code used to obtain this value is attached in the Appendix A. A summary of resulting calculations over a range of power factors is presented in a subsequent summary section.

2.7 Annual Energy Loss: 36 kVA SST

The previous section related to magnetic transformer losses. In this section, the same calculation is repeated for an SST. The value of energy lost obtained in Section 2.5 is then multiplied with the average cost of energy to obtain the value of the cost of energy lost for the transformer for the entire year in $/year. Average cost of energy is taken as 10.27 cents/kWh as obtained from [14] for the year 2012. The MATLAB code used to obtain this value is attached in the Appendix B. A summary of resulting calculations over a range of power factors is presented in a subsequent summary section.

2.8 An Algorithm for Calculation of Annual Energy Loss in Transformers

Algorithms for the calculation of active power losses in a 36 kVA conventional (magnetic) transformer and also for an SST are as follows:

Algorithm for 36 kVA Magnetic transformer

Figure 2.5 shows a pictorial of the algorithm for the calculation of annual active power losses in a 36 kVA magnetic transformer.

Algorithm for 36 kVA SST

Figure 2.6 shows a pictorial of an algorithm for calculation of annual active power losses in a 36 kVA SST. Figure 2.9 gives a summary of annual energy lost in a 36 kVA SST. Figure 2.10 gives a summary of annual cost of energy lost in a 36 kVA magnetic transformer.

2.9 Calculation Summary for Transformer Active Power Losses

In this section, the active power losses for both the magnetic and electronic transformer are summarized. Table 2.1 shows the results for losses in a conventional 36 kVA transformer. Table 2.2 is a similar summary for an SST.

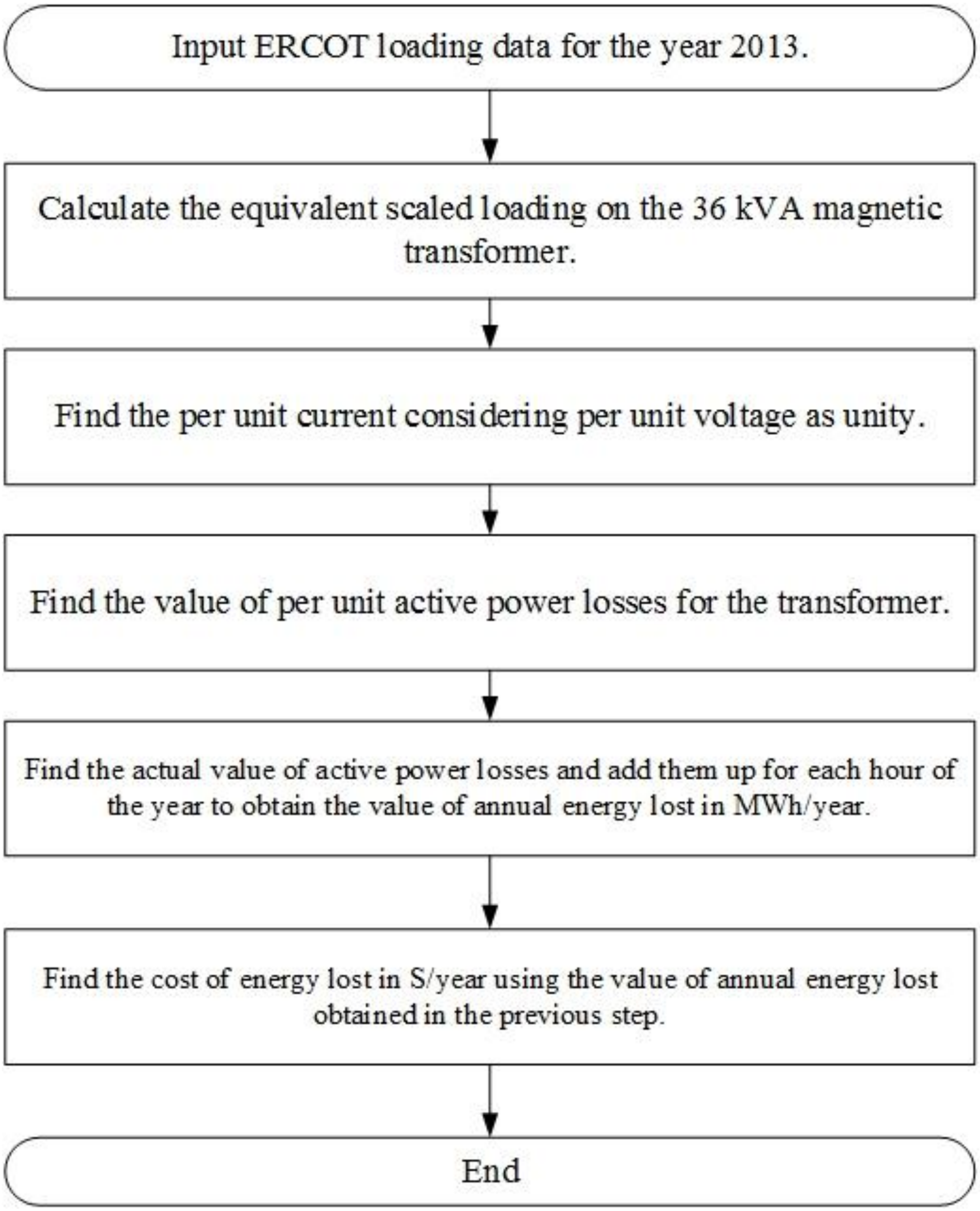


Figure 2.5 Algorithm for Calculation of Annual Active Power Losses in a 36 kVA Magnetic Transformer

`

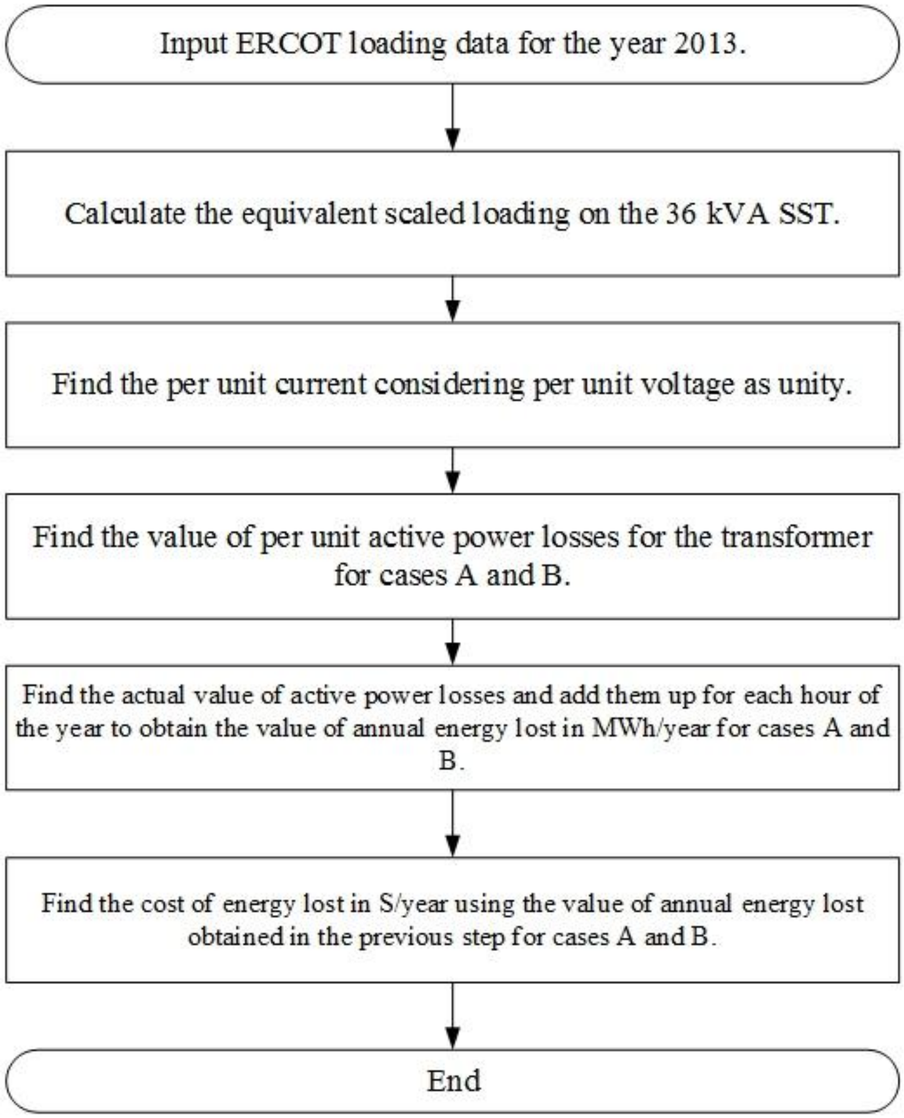


Figure 2.6 Algorithm for Calculation of Annual Active Power Losses in a 36 kVA SST

Table 2.1 Summary of Energy Loss and Cost of Energy Loss Obtained for 36 kVA Conventional Transformer

Conventional - 36 kVA*					
Energy lost (MWh/year)			Cost of energy lost ($/year)**		
pf = 0.60	pf = 0.85	pf = 1.00	pf = 0.6	pf = 0.85	pf = 1.00
5.2	2.59	1.87	534.12	266.14	192.28

* I^2R loss only, uses US DoE maximum distribution transformer loss, FO cooled, approximate. No core loss assumed. Loading according to ERCOT hourly load, Texas for the year 2013. All power factors are lagging.
** 10.27 cents/kWh annual average, US 2012.

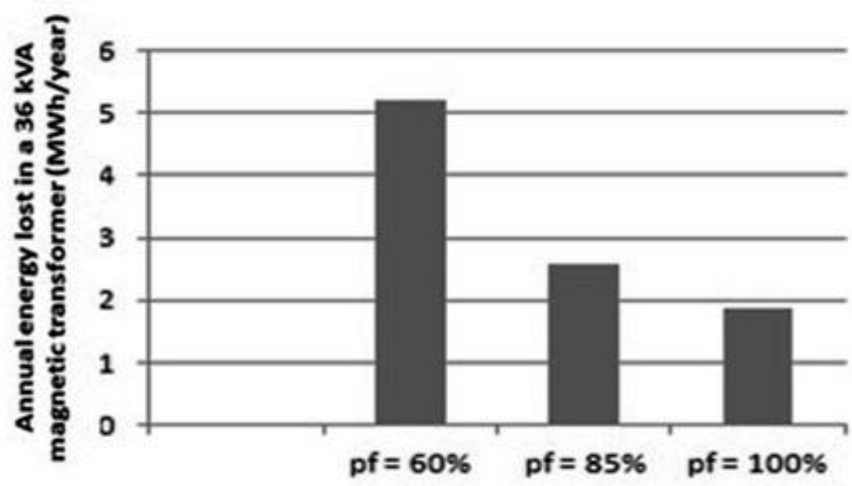


Figure 2.7 A Summary of Annual Energy Lost in a 36 kVA Magnetic Transformer Tabulated in Table 2.1(MWh/Year)

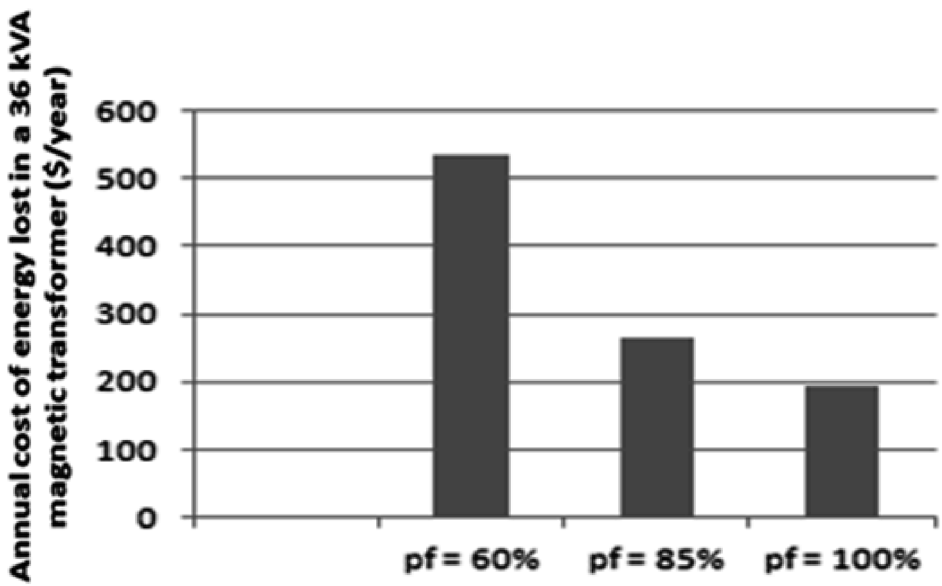


Figure 2.8 A Summary of Annual Cost of Energy Lost in a 36 kVA Magnetic Transformer Tabulated in Table 2.1($/Year)

Table 2.2 Summary of Energy Loss and Cost of Energy Loss Obtained for 36 kVA SST

SST - 36 kVA ¶			
Energy lost (MWh/year)		Cost of energy lost ($/year)	
5 % loss at 75 % loading	1 % loss at 75 % loading	5 % loss at 75 % loading	1 % loss at 75 % loading
11.41	2.2808	1172	234.2

¶ I^2R and switching loss included, approximate.

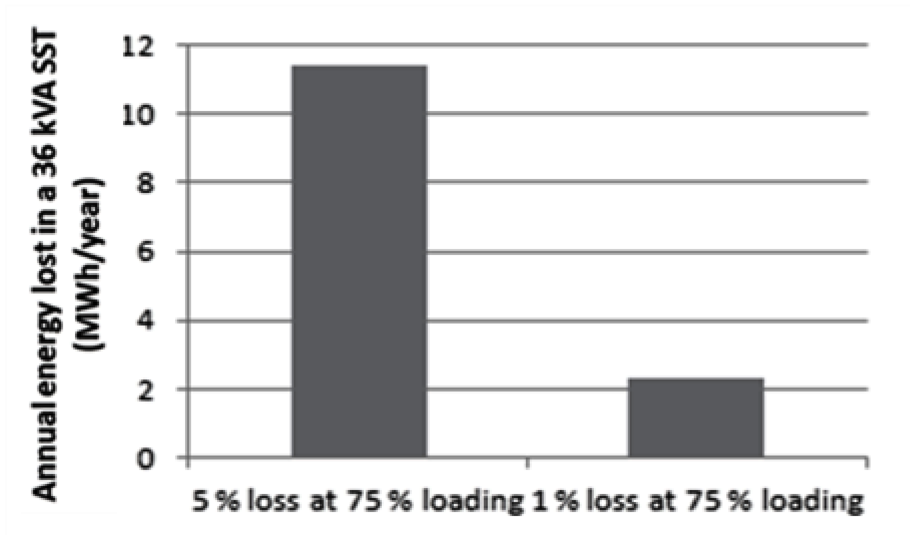


Figure 2.9 A Summary of Annual Energy Lost in a 36 kVA SST Tabulated in Table 2.2 (MWh/Year)

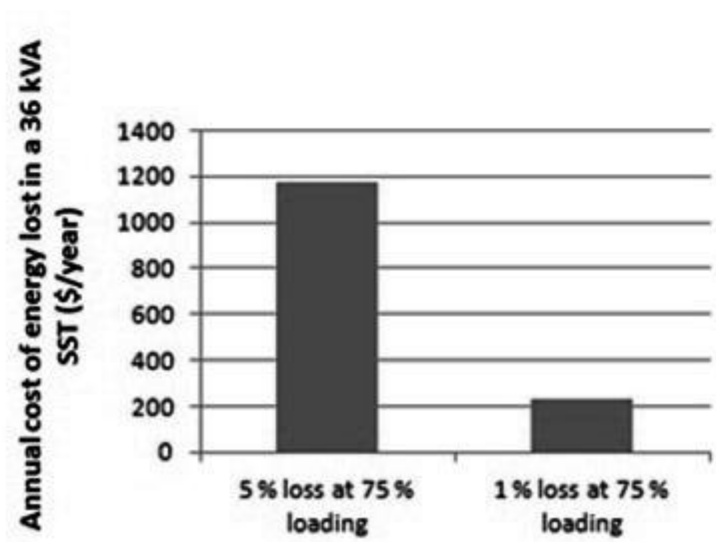


Figure 2.10 A Summary of Annual Cost of Energy Lost in a 36 kVA SST Tabulated in Table 2.2 ($/Year)

CHAPTER 3 ACTIVE POWER LOSSES IN DISTRIBUTION PRIMARY CONDUCTORS

3.1 A Test Bed for the Evaluation of Active Power Losses

This chapter focuses on active power losses in a test bed distribution system. The objectives are to illustrate the methodology used; a typical application; and the resulting costs and benefits for such a system. The test bed used is a single phase equivalent , 0.72 MVA, 10 mile long feeder consisting of 20 distribution transformers serving 4-5 residences each. The feeder is supplied by two generating sources fed from both the ends of the feeder. Figure 3.1 gives a pictorial of the test bed. With reference to the figure, the 10 mile long section of the feeder is divided into 19 sections. It is assumed that the loading of each transformer is identical, i.e., the load is equally distributed in each distribution 36 kVA transformer serving 4-5 residences each.

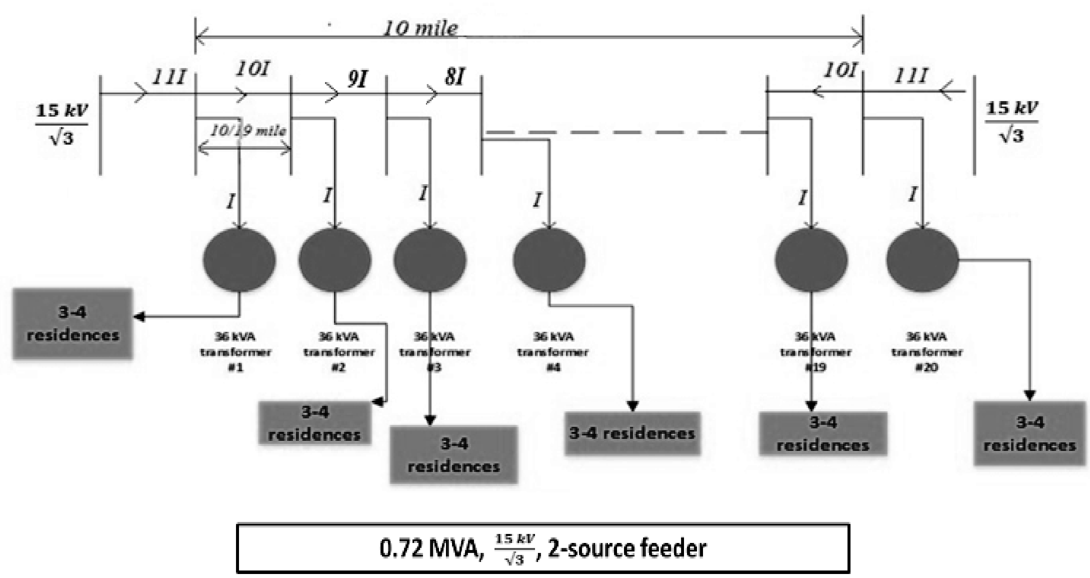


Figure 3.1 A Pictorial of the Test Bed Feeder Used for Active Power Loss Calculations

From the ERCOT load data obtained, for every hour of the year 2013 [13], the active power losses are calculated for each of the sections and are summed to obtain the total active power lost in the feeder for that particular hour. In a similar manner, active power lost in the feeder is calculated for every hour of the year 2013 and is summed to obtain the annual total active power lost in the feeder. These calculations are done for two cases: assuming that all the distribution level 36 kVA transformers are magnetic transformers; and assuming that all the distribution level 36 kVA transformers are SSTs. These calculations are then compared to identify in which case more active power losses are incurred. For the magnetic transformer, three cases are considered: transformer operating at 60% power factor lagging; transformer operating at 85% power factor lagging; and transformer operating at unity power factor. These use cases span the typical range of power factor of residential loads.

3.2 Example Evaluation of Feeder Losses with 36 kVA Magnetic Transformers

For the feeder shown in Figure 3.1, #2 Aluminum conductors are assumed. For this conductor, the resistance is 1.41 Ω/mile [16]. The 10 mile long section of the feeder is divided into 19 sections of equal length as seen in Figure 3.1. Each section starts and ends with a 36 kVA distribution transformer.

- Base rating of the transformer = 36 kVA (assumed)
- P_{max} represents the maximum loading in the year in watts
- The operating voltage is given by $\frac{15kV}{\sqrt{3}}$.

The load data are obtained from ERCOT loading data for the year 2013. These data give the load in MW for every hour of the year 2013. Thus, 8760 values of scaled loading on the 36 kVA transformer are obtained as follows:

$$|I| = \frac{scaled\ loading\ in\ kVA}{operating\ voltage} = \frac{\frac{scaled\ loading\ in\ kW}{power\ factor}}{operating\ voltage}\ . \tag{3.1}$$

The power factor term in (3.1) is varied in value as 60%, 85% and unity power factor. Three sets of values are obtained for each case. The calculation for active power lost in the feeder is calculated as follows:

As seen from Figure 3.1, the current flowing through the feeder in section 1 and section 11 is 11 $|I|$. The current flowing in each of the transformers has the same magnitude as the ratings of the transformers are the same. The feeder losses are evaluated as described in APPENDIX C. This approach assumes that all the individual load currents are equal in magnitude and phase.

Considering these values of current, for the load data for a certain hour in the year 2013 obtained from ERCOT load data, the active power lost in the feeder is calculated by adding up the active power lost in the feeder in each section of length 10/19 miles. This is done by evaluating the resistance in each section as,

$$R_{section} = (1.41)\ (10/19) = 0.7421\ \Omega.$$

The value of current, $|I|$ obtained from (3.1) is used to calculate the losses in each section of Figure 3.1. The active power losses in every section are added up together to obtain the total active power lost in the entire feeder for the ERCOT load data for every hour of the year 2013. The above calculations are carried out for each hour of the year and are summed up to obtain the value of total energy lost per year in MWh/year. The results are summarized in Table 3.1.

3.3 Example Evaluation of Feeder Losses with 36 kVA SSTs

For the feeder shown in Figure 3.1, #2 Aluminum conductors are assumed. For this conductor, the resistance is 1.41 Ω/mile [16]. The 10 miles long section of the feeder is divided into 19 sections of equal length as seen in Figure 3.1. Each section starts and ends with a 36 kVA distribution transformer.

- Base rating of the transformer = 36 kVA (assumed)
- P_{max} represents the maximum loading in the year in watts.
- The operating voltage is given by $\frac{15kV}{\sqrt{3}}$.

The load data is obtained from ERCOT loading data for the year 2013. It gives the load in MW for every hour of the year 2013. Thus, 8760 values of scaled loading on the 36 kVA transformer are obtained as follows:

Scaled loading on the 36 kVA transformer in kVA = $\frac{(\text{load data}*\text{base rating of the transformer})}{Pmax}$

$$|I| = \frac{scaled\ loading\ in\ kVA}{operating\ voltage}. \tag{3.2}$$

As seen from Figure 3.1, the current flowing through the feeder in section 1 and section 11 is 11 $|I|$. The current flowing in each of the transformers has the same magnitude as the ratings of the transformers are the same. The feeder losses are evaluated as described in APPENDIX C. This approach assumes that all the individual load currents are equal in magnitude and phase.

Considering these values of current, for the load data for a certain hour in the year 2013 obtained from ERCOT load data, the active power lost in the feeder is calculated by adding up the active power lost in the feeder in each section of length 10/19 miles. This is done by evaluating the resistance in each section as,

$$R_{section} = (1.41)(10/19) = 0.7421\ \Omega.$$

The value of current, $|I|$ obtained from (3.2) is used to calculate the losses in each section of Figure 3.1. The active power losses in every section are added up together to obtain the total active power lost in the entire feeder for the ERCOT load data for every hour of the year 2013. The above calculations are carried out for each hour of the year and are summed up to obtain the value of total energy lost per year in MWh/year. The results are summarized in Table 3.1.

3.4 Annual Energy Loss in Feeder: Using 36 kVA Magnetic Transformers

The value of energy lost obtained in Section 3.2 is then multiplied with the average cost of energy to obtain the value of the cost of energy lost in the feeder using 20 distribution level magnetic transformers for the entire year in $/year. Average cost of energy is taken as 10.27 cents/kWh as obtained from [14]. The MATLAB code used to obtain this value is attached in the Appendix C section. It assumes that the system is operating at unity power factor. The value of power factor is modified to obtain results for 60 % and 85 % power factor cases.

3.5 Annual Energy Loss in Feeder: Using 36 kVA SSTs

The value of energy lost obtained in Section 3.2 is then multiplied with the average cost of energy to obtain the value of the energy lost in the feeder. The assumption is that 20 distribution level SSTs operate for the entire year. The cost is in $/year. Average cost of energy is taken as 10.27 cents/kWh as obtained from [14]. The MATLAB code used to obtain this value is attached in the Appendix C section.

3.6 Algorithm for calculation of annual energy loss in the feeder

Figure 3.2 shows the algorithm for calculation annual cost of energy loss in a distribution feeder.

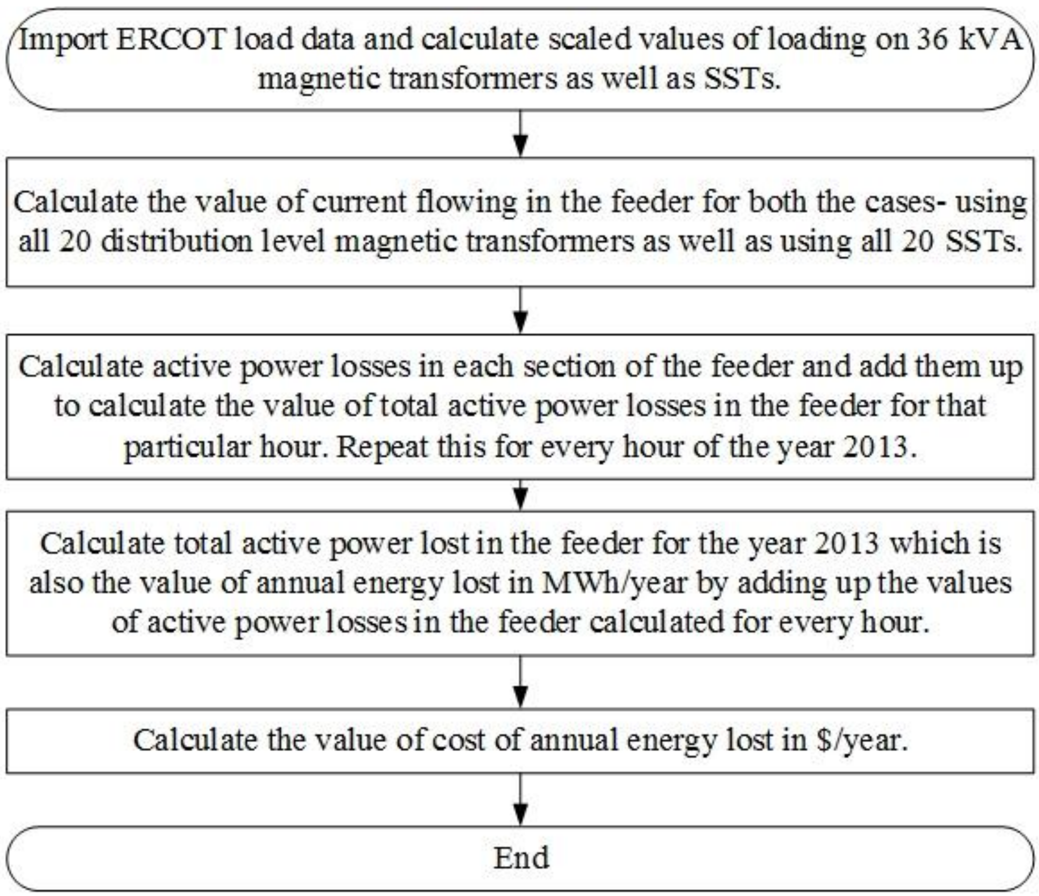


Figure 3.2 Algorithm for Calculation of Annual Cost of Energy Loss in a Distribution Feeder

3.7 Calculation of Feeder Losses with Capacitor Bank Compensation

In Section 3.2, for the feeder shown in Figure 3.1 using twenty 36 kVA distribution level magnetic transformers, values of energy lost per year were calculated for three cases: operation at 60% power factor, operation at 85% power factor and operation at unity power factor. Capacitor banks were introduced to improve the power factor as follows:

Case 1: Improve power factor from 60% to 85%.

For this case, the transformers will continue to operate at 60% power factor while the distribution lines will be operating at 85% power factor and the value of energy lost per year in the feeder in this case will be equivalent to the case when the system incurs losses at 85% power factor. The system will incur lesser losses as compared to the 60% power factor case due to reduction in the current flowing through the lines at 85% power factor. But this reduction in the cost of energy lost per year will also be accompanied by an increase in cost of installing additional capacitor banks.

Case 2: Improve power factor from 85% to 100%.

For this case, the transformers will continue to operate at 85% power factor while the distribution lines will be operating at 100% power factor and the value of energy lost per year in the feeder in this case will be equivalent to the case when the system incurs losses at 100% power factor. The system will incur lesser losses as compared to the 85% power factor case due to reduction in the current flowing through the lines at 100% power factor. But this reduction in the cost of energy lost per year will also be accompanied by an increase in cost of installing additional capacitor banks.

Case 3: Improve power factor from 60% to 100%.

For this case, the transformers will continue to operate at 60% power factor while the distribution lines will be operating at 100% power factor and the value of energy lost per year in the feeder in this case will be equivalent to the case when the system incurs losses at 100% power factor. The system will incur lesser losses as compared to the 60%

power factor case due to reduction in the current flowing through the lines at 100% power factor. But this reduction in the cost of energy lost per year will also be accompanied by an increase in cost of installing additional capacitor banks. These values are tabulated in Table 3.1.

3.8 Calculation of Cost of Capacitor Banks to Improve Power Factor of Feeder

For a distribution system using magnetic transformers, a reduction in active power losses can be achieved by improving the power factor at which the system is operating. The cost of adding capacitor banks is considered to be a onetime installment. An attempt is made to derive an approximate relationship between the costs of capacitors with regards to the kVAr they compensate. A single phase 15000 Volt, 10 μF capacitor costs approximately 1000$. The VAr compensated is calculated as follows,

$$Q = V_{op}^{2} \omega X, \tag{3.3}$$

where Q is the reactive power, ω is the angular frequency, and C is the capacitance. Then,

$$Q = \frac{15000^2}{3}(377)(10)10^{-6} \text{ VAr}$$

$$\omega = 2\,\pi\, freq = 2\pi(60) = 377 \text{ rad/s}$$

and,

$$Q = 283 \text{ kVAr.}$$

Thus, approximately a price of 1000$ corresponds to reactive power compensation of 283 kVAr. Assuming a linear relationship between cost of capacitor banks required and the reactive power compensated,

$$1000\$ = y\,(282) \text{ kVAr.}$$

Therefore,

$$y = \frac{1000}{283}$$

$$= 3.54\$/\text{kVAr}. \tag{3.4}$$

It can be approximated that for each kVAr that is compensated, roughly 3.54$ worth capacitor banks are added. Since this value is based on the approximation that a single phase 15000 Volts, 10 μF capacitor costs around 1000$, two extreme cases for the value of y obtained in (3.4) are considered. In the first case, the value of y is taken as 3.54$/kVAr while in the second case, the value of y is taken as 35.4$/kVAr. The life cycle of operation of capacitor banks is assumed to be 10 years. The associated cost of capacitor banks for improving the power factor of the distribution system given in Figure 3.1, operating at 0.72 MVA can be calculated for the following three cases:

Case 1: Improving power factor from 0.6 to 0.85

The value of reactive power required to be compensated by capacitor banks while improving power factor from 0.6 to 0.85 is calculated as,

$$Q_{compensation} = Q_{0.6} - Q_{0.85} = 0.72\text{MVA}(\sin(\cos^{-1}(0.6))) - 0.72\text{MVA}(\sin(\cos^{-1}(0.85)))$$

$$Q_{compensation} = 308.3 \text{ kVAr}.$$

Therefore, price of capacitor banks installed is within the range of = $y\ Q_{compensation}$ = (3.54)(308.3) = 1091$ to (35.4)(308.3) = 10910$. However, this price is a onetime price and needs to be divided by the number of years the capacitor would be in service. This is approximated as 10 years. Thus, cost of capacitor banks required to improve power factor from 0.6 to 0.85 is roughly in the range of 1091/10 = 109.1$/year to 10910/10 = 1091$/year. These values are tabulated in Table 3.1.

Case 2: Improving power factor from 0.6 to 1.00

The value of reactive power required to be compensated by capacitor banks while improving power factor from 0.6 to 1.00 is calculated as,

$$Q_{compensation} = Q_{0.6} - Q_{1} = 0.72\text{MVA} (\sin(\cos^{-1}(0.6))) - 0.72\text{MVA} (\sin(\cos^{-1}(1)))$$

$$Q_{compensation} = 576 \text{ kVAr.}$$

Therefore, price of capacitor banks installed is within the range of = $y\ Q_{compensation}$ = (3.54) (576) = 2039\$ to (35.4)(576) = 20390\$. However, this price is a onetime price and needs to be divided by the number of years the capacitor would be in service. This is approximated as 10 years. Thus, cost of capacitor banks required to improve power factor from 0.6 to 1 is roughly within the range of 2039/10 = 203.9\$/year to 20390/10 = 2039\$/year. These values are tabulated in Table 3.1.

Case 3: Improving power factor from 0.85 to 1.00

The value of reactive power required to be compensated by capacitor banks while improving power factor from 0.85 to 1 is calculated as,

$$Q_{compensation} = Q_{0.85} - Q_{1} = 0.72\text{MVA} (\sin(\cos^{-1}(0.85))) - 0.72\text{MVA} (\sin(\cos^{-1}(1)))$$

$$Q_{compensation} = 379.25 \text{ kVAr.}$$

Therefore, price of capacitor banks installed is within the range of = $y\ Q_{compensation}$ = (3.54)(379.25) = 1342.55\$ to (35.4)(379.25) = 13425.5\$. However, this price is a one-time price and needs to be divided by the number of years the capacitor would be in service. This is approximated as 10 years. Thus, cost of capacitor banks required to improve power factor from 0.85 to 1 is roughly within the range of 1342.55/10 = 134.255\$/year to 13425.5/10 = 1342.55\$/year. These values are tabulated in Table 3.1.

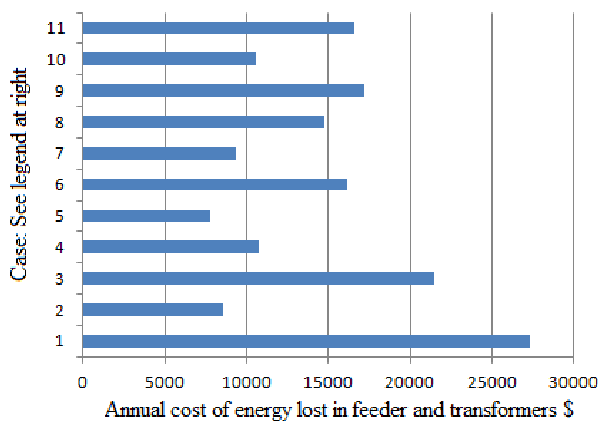
3.9 Calculation Summary of Line and Transformer Active Power Losses

Table 3.1 excludes cost of transformers. For an SST, typical cost of the transformer after technology matures can be estimated at around 67$/ kVA for a single phase unit [20]. Thus, a single 36 kVA SST will cost around 67*36 = 2,412$ after technology matures. As per [5], the ratio of cost of a 1 MVA SST to that of a magnetic transformer of the same rating is predicted to be 4.61. The average life expectancy of a medium voltage distribution level 36 kVA SST can be assumed to be 12 years while that of a magnetic transformer of the same rating can be assumed to be 20 years.

3.10 Summary of Results

The annual cost of active power losses in the 20 transformers as well as the distribution feeder for the system shown in Figure 3.1 are tabulated in Table 3.1 for both the cases: system having solid state transformers and system having magnetic transformers. This is done for the ERCOT load data for the year 2013 [13]. For the magnetic transformer case, operation at three different power factors is considered: 60%, 85% and unity power factor. Capacitor bank compensation is also provided to improve the power factor from 60% to 85%, 85% to 100% and 60% to 100%. The results obtained for these cases are summarized in Figure 3.3.

The feeder loss for the case with all SSTs is the same as the case with magnetic transformers operating at 100% power factor. This is because the current flowing in the system with SSTs would be the same as the current flowing in the system with magnetic transformers operating at unity power factor. The system incurs high losses in the magnetic transformer case for power factor operation at 60 % and 85%. as compared to the SST case. This is because, the current flowing in the feeder and transformers is higher in the case of system using magnetic transformers operating at any power factor apart from unity than it would be for system using SSTs. This increased current causes higher values of active power losses. When the system with magnetic transformers is provided with capacitor banks for reactive power compensation, it is observed that the cost of active power losses at unity power factor operation for the system with magnetic transformers is comparable with the cost of active power losses for the system with SSTs. This is after incorporating the annual cost of installment of these capacitors banks in the calculations.



1: SST- 5% loss at 75% loading (no caps)

2: SST- 1% loss at 75% loading (no caps)

3: Magnetic transformer- system operation at 60 % pf (no caps)

4: Magnetic transformer- system operation at 85 % pf (no caps)

5: Magnetic transformer- system operation at 100 % pf (no caps)

6: Magnetic transformer- system operation at 85% from 60% pf (caps at 3.54$/kVAr)

7: Magnetic transformer- system operation at 100% from 85% pf (caps at 3.54$/kVAr)

8: Magnetic transformer- system operation at 100 % from 60% pf (caps at 3.54$/kVAr)

9: Magnetic transformer- system operation at 85% from 60% pf (caps at 35.4$/kVAr)

10: Magnetic transformer- system operation at 100% from 85% pf (caps at 35.4$/kVAr)

11: Magnetic transformer- system operation at 100 % from 60% pf (caps at 35.4$/kVAr)

Figure 3.3 Annual Cost of Energy Lost in the Feeder as well as Transformers

Table 3.1 A Summary of Cost of Active Power Losses in Feeder and Transformers with and without Addition of Capacitor Banks.

ANNUAL COST OF LOSSES -- NO EQUIPMENT COST INCLUDED EXCEPT FOR COST OF CAPACITORS			
Costs in $/year due to active power losses	SST Design - cost of SST not included		
	Cost of feeder loss ($/yr)		
	3894.1		
	Cost of losses in transformer ($/yr, 20 distribution transformers over a ten mile feeder)		
	5 % loss at 75 % load		1 % loss at 75 % load
	23440		4684
	Total Cost (5 % loss at 75 % load)		Total Cost (1 % loss at 75 % load)
	27334.1		8578.1
	Design using Magnetic Transformer (Without capacitors cost of xformer not included)		
	Cost of feeder loss ($/yr)		
	pf = 60 %	pf = 85 %	pf = 100 %
	10817	5387.7	3894.1
	Cost of losses in transformer ($/yr, 20 distribution transformers over a ten mile feeder)		
	pf = 60 %	pf = 85 %	pf = 100 %
	10682.306	5322.672	3845.6
	Total Cost ($/yr without capacitors)		
	pf = 60 %	pf = 85 %	pf = 100 %
	21499.306	10710.372	7739.7
	Design using Magnetic Transformer (With capacitors in distribution lines cost of xformer not included)		
	Cost of feeder loss ($/yr)		
	pf = 60 % to 85 %	pf = 85 % to 100 %	pf = 60 to 100 %
	5,388	3894.1	3894.1
	Cost of losses in transformer ($/yr, 20 distribution transformers over a ten mile feeder)		
	pf = 60 %	pf = 85 %	pf = 60 %
	10682.306	5322.672	10682.306
	Cost of capacitors ($/yr one time installment no. of yrs in service=10,taking cost of capacitors=3.54 $/kVAr)		
	pf = 60 % to 85 %	pf = 85 % to 100 %	pf = 60 to 100 %
	109	134.25	203.9
	Cost of capacitors ($/yr one time installment no. of yrs in service=10,taking cost of capacitors=35.4 $/kVAr)		
	pf = 60 % to 85 %	pf = 85 % to 100 %	pf = 60 to 100 %
	1,091	1342.5	2039
	Total Cost ($/yr with capacitors,taking cost of capacitors=3.54 $/kVAr)		
	pf = 60 % to 85 %	pf = 85 % to 100 %	pf = 60 to 100 %
	16,179	9351.022	14780.306
	Total Cost ($/yr with capacitors,taking cost of capacitors=35.4 $/kVAr)		
	pf = 60 % to 85 %	pf = 85 % to 100 %	pf = 60 to 100 %
	17,161	10559.272	16615.406

CHAPTER 4 RELIABILITY OF SERVICE TO CUSTOMERS AND NUMBER OF FIDs

4.1 Service Reliability

This chapter provides a detailed discussion on the reliability of service to customers depending on how many FIDs are serving the system based on the selected configuration. The assumption is made that service disruption occurs only for faults in the distribution primary. Most service disruptions in distribution systems are attributable to weather. Two types of configuration are selected to illustrate the relationship between the number of FIDs used and the service reliability. They are shown in Figure 4.1.

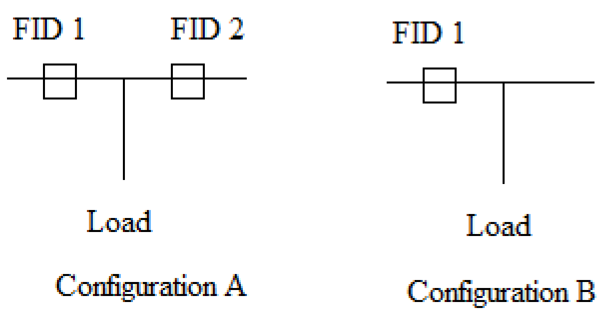


Figure 4.1 A Pictorial of the Configurations Used to Study Reliability of Service to Customers

A suitable test bed is selected to aid this study. The test bed consists of a system energized at both its ends. These sources serve 20 load points; each load point is equipped with either 2 FIDs or 1 FID depending on Configuration A or Configuration B respectively. There are two additional FIDs located at the generator buses on both the ends. Configuration A uses almost twice the number of FIDs as compared to Configuration B. Thus, Configuration A will have 2*n*+2 FIDS while Configuration B will have *n*+2 FIDs, where *n* represents number of load points or number of customers connected to the service.

The following test cases shown in Table 4.1 and Table 4.2 are studied for both the configurations. With more FIDs in the system, better protection can be provided from faults and hence the system will have an enhanced reliability. However, cost of FIDs is significantly high, in the order of 12000-24000$ per device [20]. A suitable tradeoff between the number of FIDs installed and reliability needs to be established. A discussion on the number of years required to recover the FID costs for both Configurations A and B versus reliability of the system is also provided in this chapter. Reliability is measured by expected number of customers remaining in service after occurrence and clearance of fault. The faults are assumed to occur uniformly with respect to length. Also, the load points are equally distributed along the length of the system.

Table 4.1 Test Cases for Configuration A

Configuration A			
Case	Number of FIDs used	Total customers	Number of points of energization
1A	$2n+2$	n	2
2A	$2n+1$	n	2
3A	$2n$	n	2
4A	3	n	2
5A	2	n	2

Table 4.2 Test Cases for Configuration B

Configuration B			
Case	Number of FIDs used	Total customers	Number of points system of energization
1B	$n+2$	n	2
2B	$n+1$	n	2
3B	n	n	2
4B	3	n	2
5B	2	n	2

4.2 Reliability Calculations for Configuration A

Configuration A is assumed for cases 1A-5A.

Case 1A: 2n+2 FIDs in service

Figure 4.2 shows a pictorial of the system consisting of two sources, 20 equally distributed load points consisting of 2 FIDs each and 2 additional generator bus FIDs. The distance between two consecutive load points is given by $\frac{l}{(n+1)}$ where l is the feeder length.

In Figure 4.2, *L1*, *L2*, *L3* and so on until *Ln* represent the customers served by the two generators at the extreme ends in the distribution system considered. Suppose that a single line to ground fault occurs between the loads *L1* and *L2*. The two FIDs located within the region between *L1* and *L2* will open to isolate the fault. When this happens, the number of customers still in service will continue to be *n*. This is because even though the section between *L1* and *L2* is isolated, *L1* will be continued to be fed by generator 1 while the loads *L2 to Ln* will be fed by generator 2. Similar logic can be applied to the location of a fault anywhere within *L1* to *Ln*. The system is capable of isolating any single fault within the region between *L1 to Ln* without causing interruption in service. Thus, the expected number of customers still energized after interruption = *n*. With 2*n*+2 FIDs in the system, occurrence of a single fault will not cause a disruption in service to customers.

The main result is,

$$\mathcal{E}(\mathrm{E}) = \sum n(\text{probability that a fault occurs in each section of length } \tfrac{1}{n+1})$$

where $\mathcal{E}(E)$ represents the expected number of customer served during a fault occurrence within one of the sections shown in Figure 4.2. Evaluating the expectation $\mathcal{E}(E)$ gives,

$$\mathcal{E}(E) = \frac{\frac{l}{(n+1)}}{l}(n)(n+1) = n.$$

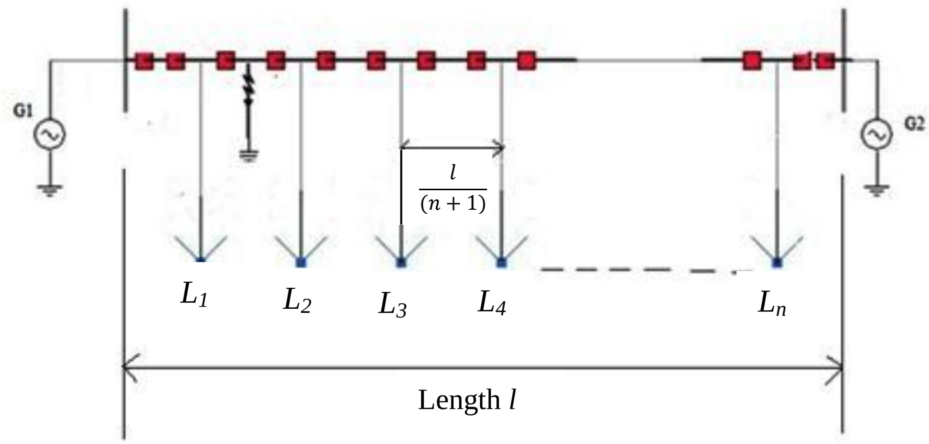


Figure 4.2 A Pictorial of the System Used to Calculate Reliability of Service Due to Faults with $2n+2$ Number of FIDs in Service (Case 1A)

Case 2A: (2n+1) FIDs in service- remove 1 FID

Figure 4.3 shows a two source system serving n customers and having $2n+1$ number of FIDs in service. At each load point, two FIDs are installed except for the section between loads L_{k-1} to L_k which has only one FID instead of two.

As seen in Figure 4.3, when a fault occurs within the section $L(k-1)$ and Lk, the breaker immediately to the right of load $L(k-1)$ and the breaker immediately to the right of load Lk will open to isolate the fault. As a result of this, service to customer Lk will be interrupted. Thus, with this arrangement, number of customers still energized after interruption is n-1. The probability of occurrence of a fault anywhere between section $L1$ to

Ln is $1/(n+1)$. The expectation of number of customers served given that a fault occurs is given by,

$\mathcal{E}(E)$ = (number of customers served when fault occurs within *L1* - *Ln*)(probability that fault occurs within *L1*- *Lk*)+(number of customers served when there is no fault)(probability that fault does not occur within *L1* - *Lk*)

$$= \frac{(n-1)}{(n+1)} + \left(1 - \frac{1}{n+1}\right)(n)$$

$$= \frac{n^2+n-1}{n+1}\,. \tag{4.1}$$

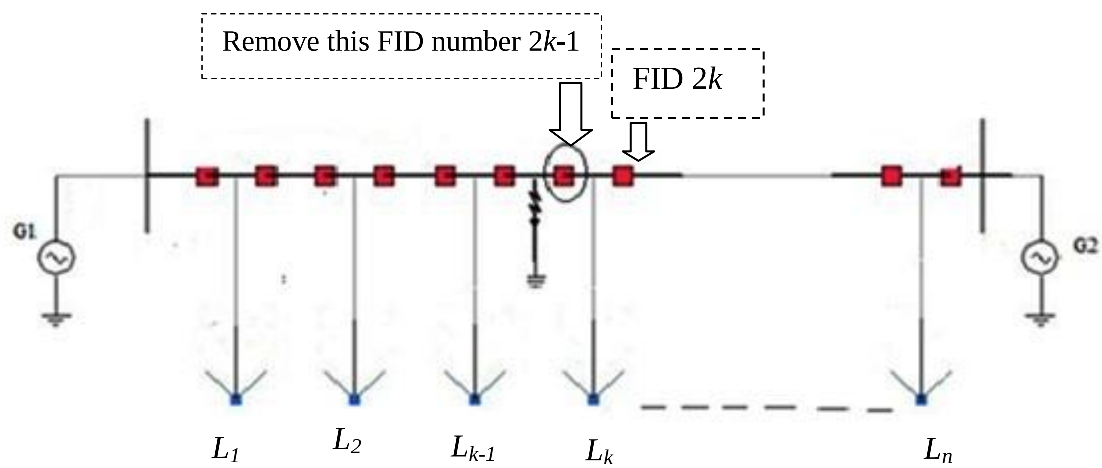


Figure 4.3 A Pictorial of the System Used to Calculate Reliability of Service Due to Faults with (2*n*+*1)* Number of FIDs in Service (Case 2A)

Case 3A: (2n) FIDs in service- remove two FIDs

Figure 4.4 shows a two source system serving *n* customers and having *2n-2* FIDs in service. As seen in Figure 4.4, when a fault occurs between the section *k-m* (let *m* > *k*), the 2 FIDs within the region *Lk* - *Lm* will open to isolate the fault. As a result of this, the number of customers still in service would be (*n*-(*m*-*k)*). The probability of occurrence of a fault within the section k to m is given by $\frac{(m-k)}{n+1}$. The expectation of number of customers served given that a fault occurs between k-m is given by,

$\mathcal{E}(E)$ = (number of customers served when fault occurs within k-m)(probability that fault occurs within k-m) + (number of customers served when there is no fault)(probability that fault does not occur within k-m)

$$= (n - m + k)\left(\frac{m-k}{n+1}\right) + n\left(1 - \frac{m-k}{n+1}\right). \tag{4.2}$$

Note that $\mathcal{E}(E)$ depends on k and m. For example, if $k = n/3$ and $m = 2n/3$,

$$= \frac{8n^2+9n}{9(n+1)}. \tag{4.3}$$

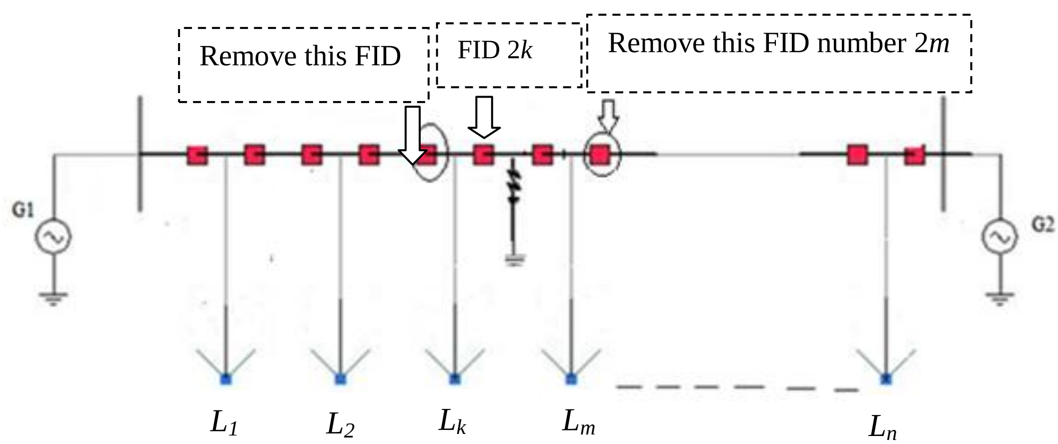


Figure 4.4 A Pictorial of the System Used to Calculate Reliability of Service Due to Faults with (2n) FIDs in Service (Case 3A)

Case 4A: three FIDs in service- remove (2n-3) FIDs

Figure 4.5 shows a two source system with three FIDS. This system feeds n loads. It is observed that when a fault occurs within the region between FID 1 and 2, n/2 customers are out of service. When a fault occurs within the region between FID 2 and FID 3, n/2 customers are out of service.

The probability of occurrence of a fault anywhere between FID 1 and FID 2 or between FID 2 and FID 3 is 1/2. The expectation of number of customers served given that a fault occurs can be given by (4.4). Then,

$\mathcal{E}(E)$ = (number of customers served when fault occurs within FID1 and FID2 or FID 2 and FID 3)*(probability that fault occurs within FID1 and FID2 or FID 2 and FID 3) … + (number of customers served when there is no fault)(probability that fault does not occur within FID1 and FID2 or FID 2 and FID 3)

$$= (1/2)(n/2) + (1/2)(n/2) = \frac{n}{2}. \tag{4.4}$$

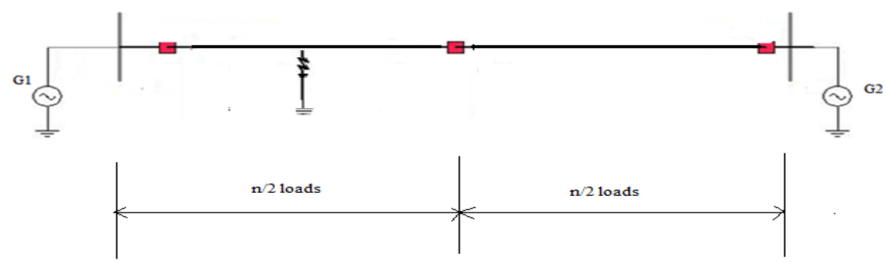


Figure 4.5 A Pictorial of the System Used to Calculate Reliability of Service Due to Faults With 3 FIDs in Service (Case 4A)

Case 5A: two FIDs in service- remove (2n-4) FIDs

Figure 4.6 shows a two source system with 2 FIDs. This system feeds *n* loads. It can be seen that when a fault occurs anywhere between the two FIDs, both the FIDs will open and all the customers will be out of service.

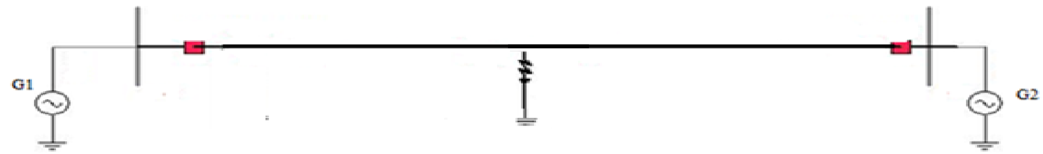


Figure 4.6 A Pictorial of the System Used to Calculate Reliability of Service Due to Faults with 2 FIDs in Service (Case 5A)

The main result in Case 5A is,

$$\mathcal{E}(E) = 0.$$

4.3 A Closed Form Expression for $\mathcal{E}(E)$ for Configuration A

Figure 4.7 can be approximated by a third degree polynomial such that $\mathcal{E}(E) = aV^3+bV^2+cV+d$ where V represents the number of FIDs in service. The values of results obtained in Section 4.2 can be substituted for n = 20 customers. The calculation of value of the parameters a,b,c and d are explained in Appendix D.

$$\mathcal{E}(E) = 0.0069V^3-0.5675V^2+12.6610V-23.0860.$$

The rms error in the approximation can be calculated by,

$$r = \sqrt{\frac{1(E(E)\ - \mathrm{a}V^3 - bV^2 - cV - d)^2}{5}}.$$

The value of the rms error is calculated in Appendix D and is given by (0.4725).

4.4 Summary of Results for Configuration A

Figure 4.7 is a graph of expectation of number of customers served versus number of FIDs in service. This graph combines the results obtained in cases 1A to 5A as calculated in section 4.2. For the graph, number of customers to be served is taken as n = 20. Thus, there will be 2(20)+2 = 42 FIDs in the system. For the intermediate values not calculated in Section 4.2, approximate results are predicted to lie within the extremes calculated.

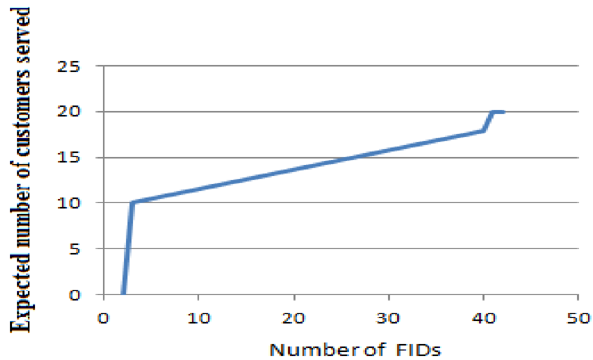


Figure 4.7 A Graph of Number of Customers Served Versus Number of FIDs in Service for Configuration A

4.5 Reliability Calculations for Configuration B

Configuration B is assumed for cases 1B-5B.

Case 1B: n+2 FIDs in service

Figure 4.8 shows a pictorial of the system consisting of two sources, 20 equally distributed load points consisting of 1 FID each and 2 additional generator bus FIDs. The distance between two consecutive load points is given by $\frac{l}{(n+1)}$.

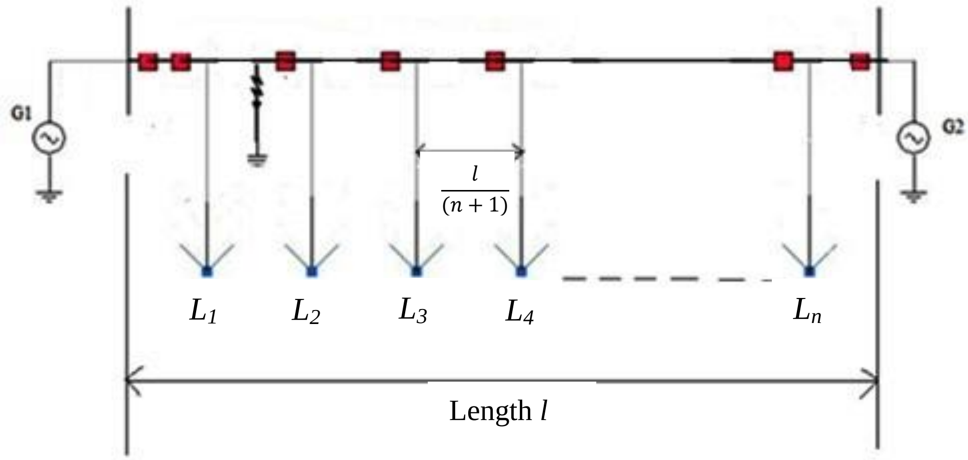


Figure 4.8 A Pictorial of the System Used to Calculate Reliability of Service Due to Faults with (*n+2*) Number of Fids in Service (Case 1B)

In Figure 4.8, *L1*, *L2*, *L3* and so on until *Ln* represent the customers served by the two generators at the extreme ends in the distribution system considered. Suppose that a single line to ground fault occurs between the loads *L1* and *L2*. The FIDs located at the left of loads *L1* and *L2* open to isolate the fault. When this happens, the number of customers still in service will be *n-1*. This is because *L*1 will be disconnected from both the sources while *L*2 will be continued to be fed by generator at the right end of the line. Similar logic can be applied to the location of a fault anywhere within *L1* to *Ln*. The system is capable of isolating any single fault within the region between *L1 to Ln* with interruption in service to just one customer. Thus, the number of customers still energized after interruption = *n-1*. If the fault occurs anywhere between the generator bus and load closest to the generator bus, the FIDs will open such that none of the customers will have interruption to their service. The main result is found as follows,

$\mathcal{E}(E)$ = (probability of fault in the first section)(number of customers in service due to this fault) +

(probability of fault in the last section)(number of customers in service due to this fault)+ (probability of fault in the remaining *n*-1 sections)(number of customers in service due to this fault)

where $\mathcal{E}(E)$ represents the expected number of customer served during a fault occurrence within one of the sections shown in Figure 4.2,

$$\mathcal{E}(E) = \frac{n}{n+1} + \frac{n}{n+1} + \frac{n-1}{n+1}(n-1) = \frac{n^2+1}{n+1}.$$

Case 2B: (n+1) FIDs in service- remove 1 FID

Figure 4.9 shows a two source system serving *n* customers and having *n+1* number of FIDs in service. At each load point, 1 FID is installed except for the section between loads *L (k-1) to Lk* which has no FID.

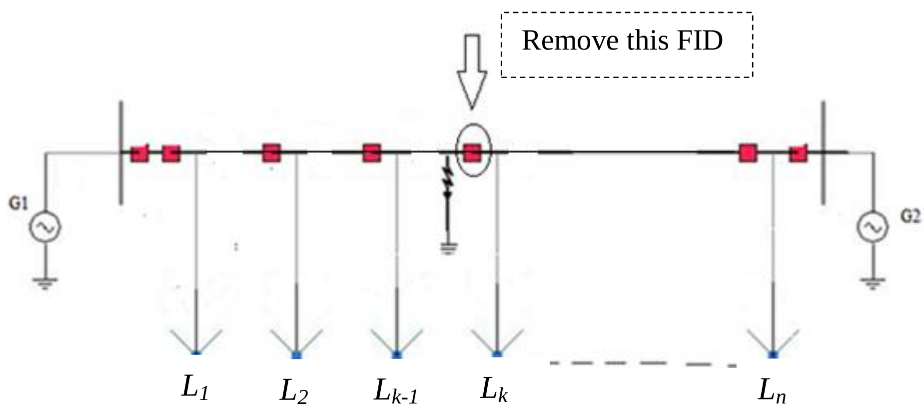


Figure 4.9 A Pictorial of the System Used to Calculate Reliability of Service Due to Faults with *(n+1)* FIDs in Service (Case 2B)

As seen in Figure 4.9, when a fault occurs within the section *L(k-1)* and *Lk*, the breaker immediately to the left of load *L(k-1)* and the right of load *Lk* will open to isolate the fault. As a result of this, service to customer *L(k-1)* and *Lk* will be interrupted. Thus, with this arrangement, number of customers still energized after interruption = *n*-2. The probability of occurrence of a fault anywhere between section *L1* to *Ln* is 1/ (*n+1)*. The expectation of number of customers served given that a fault occurs can be given by,

$\mathcal{E}(E)$ = (number of customers served when fault occurs within *L1 - Ln*)(probability that fault occurs within *L1- Lk*)+(number of customers served when there is no fault)(probability that fault does not occur within *L1 - Lk*)

$$= \frac{n-2}{n+1} + (n-1)\left(1 - \frac{1}{n+1}\right)$$

$$= \frac{n^2-2}{n+1}. \tag{4.5}$$

Case 3B: n FIDs in service- remove two FIDs

Figure 4.10 shows a two source system serving *n* customers and having *n* number of FIDs in service. As seen in Figure 4.10, when a fault occurs between the section *k-m* (let *m* > *k*), the FID to the left of load *Lk* and the FID to the right of load *Lm* will open to isolate the fault. As a result of this, the number of customers still in service would be (*n-*(*m-k+1)*). The probability of occurrence of a fault within the section *k* to *m* is given by $\frac{(m-k)}{n+1}$. The expectation of number of customers served given that a fault occurs between *k-m* can be given by,

$\mathcal{E}(E)$ = (number of customers served when fault occurs within *k-m*)(probability that fault occurs within *k-m*) + (number of customers served when there is no fault)(probability that fault does not occur within *k-m*)

$$= (n - m + k - 1)\left(\frac{m-k}{n+1}\right) + (n-1)\left(1 - \frac{m-k}{n+1}\right). \tag{4.6}$$

Thus, $\mathcal{E}(E)$ depends on *k* and *m*.

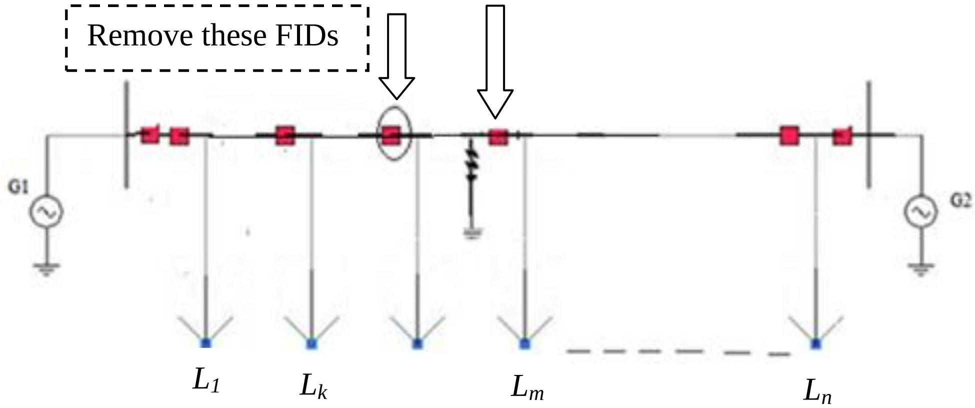


Figure 4.10 A Pictorial of the System Used to Calculate Reliability of Service Due to Faults with *n* Fids in Service (Case 3B)

Case 4B: three FIDs in service

Figure 4.11 shows a two source system with three FIDS. This system feeds *n* loads. It is observed that when a fault occurs within the region between FID 1 and 2, *n*/2 customers are out of service. When a fault occurs within the region between FID 2 and FID 3, *n*/2 customers are out of service.

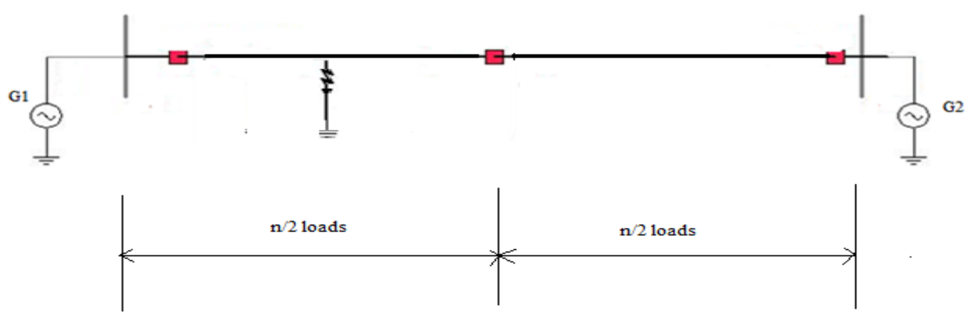


Figure 4.11 A Pictorial of the System Used to Calculate Reliability of Service Due to Faults with 3 FIDs in Service (Case 4B)

The probability of occurrence of a fault anywhere between FID 1 and FID 2 or between FID 2 and FID 3 = 1/2. The expectation of number of customers served given that a fault occurs can be given by (4.7). The main result in Case 4B is,

$\mathcal{E}(E)$ = (number of customers served when fault occurs within FID1 and FID2 or FID 2 and FID 3)*(probability that fault occurs within FID1 and FID2 or FID 2 and FID 3) … + (number of customers served when there is no fault)(probability that fault does not occur within FID1 and FID2 or FID 2 and FID 3)

$$= (1/2)(n/2) + (1/2)(n/2) = \frac{n}{2}. \tag{4.7}$$

Case 5B: two FIDs in service

Figure 4.12 shows a two source system with 2 FIDS. This system feeds *n* loads. It can be seen that when a fault occurs anywhere between the two FIDs, both the FIDs will open and all the customers will be out of service.

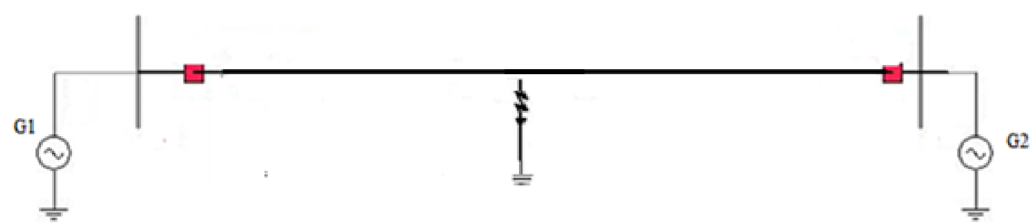


Figure 4.12 A pictorial of the system used to calculate reliability of service due to faults with 2 FIDs in service (Case 5B)

The main result in case 5B is,

$$\mathcal{E}(E) = 0.$$

4.6 A Closed Form Expression for $\mathcal{E}$(E) for Configuration B

Figure 4.13 can be approximated by a third degree polynomial such that $\mathcal{E}(E) = aV^3+bV^2+cV+d$ where V represents the number of FIDs in service. The values of results obtained in Section 4.5 can be substituted for n = 20 customers. The calculation of value of the parameters a,b,c and d are explained in Appendix D.

$$\mathcal{E}(E) = 0.0279V^3-1.2214V^2+15.4694V-26.226.$$

The rms error in the approximation can be calculated by,

$$r = \sqrt{\frac{1(E(E) - aV^3 - bV^2 - cV - d)^2}{5}}.$$

The value of the rms error for Configuration B is calculated in Appendix D and is given by (0.5501).

4.7 Summary of Results for Configuration B

Figure 4.13 is a graph of expectation of number of customers served versus number of FIDs in service. This graph combines the results obtained in cases 1B to 5B as calculated in section 4.5. For the graph, number of customers to be served is taken as n = 20. Thus, there will be (20) +2 = 22 FIDs in the system. For the intermediate values not calculated in Section 4.5, approximate results are predicted to lie within the extremes calculated.

4.8 Results for Configuration A and Configuration B

The results for all the test cases considered for both the Configurations A and B are summarized in Table 4.3.

Table 4.3 Results for Configuration A and B

	n = 20	
	Expected number of customers served	
Case	Configuration A	Configuration B
1A,B	20.00	19.09
2A,B	19.95	18.95
3A,B	17.88	16.88
4A,B	10.00	10.00
5A,B	0.00	0.00
Curve approximation, V is the number of FIDs in service	$0.0069V^3-0.5675V^2+12.6610V-23.0860$	$0.0279V^3-1.2214V^2+15.4694V-26.226$

4.9 Comparison of SAIFI Between a Certain Base Case and FREEDM System

The SAIFI (System Average Interruption Frequency Index) is a measure of reliability of service. It is given by the ratio of number of customers interrupted to that of the total number of customers in service. Studies done on a small residential feeder under enhanced fault protection aspect of this project by participation of universities under PSERC state that the reliability as measured by SAIFI on the FREEDM system will be improved by 32% on average [31]. As per [31], the number of expected sustained interruptions a customer encounters will be reduced from 2.4 outages per year to 0.78 outages per year. This can be shown in Figure 4.14 taken from [31].

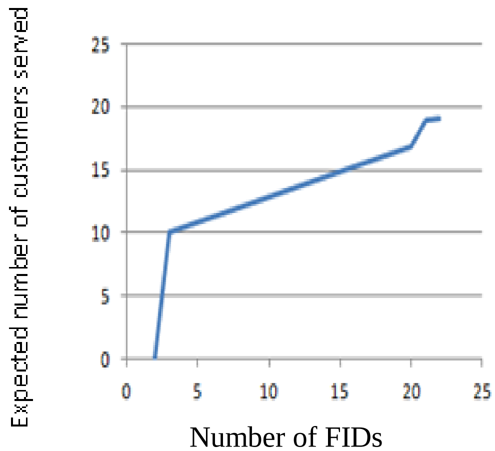


Figure 4.13 A Graph of Number of Customers Served Versus Number of FIDs in Service for Configuration B

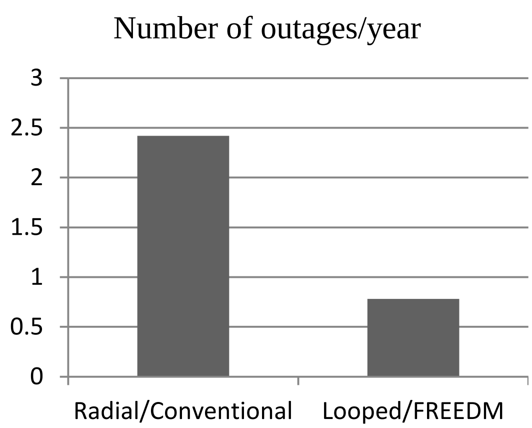


Figure 4.14 SAIFI Comparison of a Conventional Residential Feeder Versus the FREEDM System.

4.10 Solid State Fuses as an Alternative to FID

Solid state fuses are semiconductor switches used in a configuration that can interrupt fault current. They are mainly for DC applications. However, the German patent [28] is an AC device which is MOSFET based. There are a large number of commercial applications of solid state fuses commercialized by Cooper Bussmann industries. In single units, these fuses are available to 7500 A, 1250 V [29]. The use of solid state fuses in industrial applications remains uncertain. The interrupt speeds are very fast and adhere to IEC 60269 standards [32]. The costs of such fuses are very much lower than their FID counterparts.

As specified in Section 1.7, FIDs interrupt fault currents within a few 100 microseconds as compared to about 12 milliseconds for even the fastest operating conventional circuit breaker. However, C57.1200 [33] states that a fault of 0.25 second has to be accommodated, and NEMA ST20-1992 [30] states that a fault of 2 seconds needs to be accommodated. In C57.1259 [33], it implies 100 ms is a guideline for fuse interruption which is approximately 6 cycles of operation. This helps in stating that the extreme high speed protection of FIDs is not quite required and hence a compromise can be made on reliability by using solid state fuses. The lower level of performance of solid state fuses could be a real alternative.

CHAPTER 5 CALCULATION AND DISCUSSION OF PAYBACK PERIODS

5.1 Introduction

In this chapter an effort is made to quantify the benefits of the FREEDM system such as enhanced reliability of service to customers, reduction in active power losses in the feeder as compared to a case with magnetic transformers of the same rating, reduction in cost due to elimination of capacitor banks as well as reduction in cost due to use of renewables. The major investment involved in the FREEDM system comes from the SSTs and FIDs. As mentioned in Section 3.9, cost of an SST after technology matures can be estimated to be around 67$/ kVA. The FID cost can range between 12000-24000 for installment in the FREEDM system shown in Figure 3.1 [20]. Estimated cost for a single 15 kV prototype is roughly 50,000$ [37]. The cost of a single FID used for calculation of payback period for the system shown in Figure 3.1 is taken to be 5000$ assuming reduction in cost by a factor of 10 when a large scale bulk order is placed for massive commercialization of the FREEDM system as well as after technology matures. A range of cost of FIDs can also be studied for payback period using the same procedure mentioned in this chapter. Evaluating the value of providing enhanced reliability of service to customers in case of the FREEDM system is a difficult process. It is mostly psychological in the sense that it depends on how much of a disruption in service can be tolerated and also on how much is the cost of every outage per customer. Research done by the team at North Carolina State University has calculated the value of outage cost per customer by taking into consideration the reduction in SAIFI and SAIDI in case of the FREEDM system when compared to the conventional system [37]. Two values of benefit due to reliability per year per customer are considered to span a range: 40$ and 80$. For the Configurations A and B specified in Chapter 4, two cases are studied:

Case X: No subsidy.

Case Y: Subsidy of 10 % of the customer's annual bill to encourage utilization of the FREEDM system.

For each of the above cases, the value of benefit due to reliability is varied as 40$/customer/year and 80$/customer/year. The savings due to use of renewables in cost per year for all the customers is estimated to be around 10 % of the total annual bill of all the customers. The calculation of payback period is done for the following category of assumptions:

- Cost of a single FID for the system shown in Figure 3.1 is 5000$ [20]. This value is taking after considering that technology matures as well as reduction in cost when a mass scale bulk order is placed after going for commercialization of the FREEDM system.
- SST incurs 1 % active power losses at 75 % of loading.
- A single 36 kVA magnetic transformer is assumed to operate at 85 % power factor.
- Capacitors used in the system consisting of magnetic transformers shown in Figure 3.1 improve power factor to unity and cost 35.4$/ kVAr as described in Section 3.8.
- Value of $ does not change over the course of the payback period.
- 1% and 2% rates of interest are also taken into consideration while calculating payback period.

5.2 Calculation of Payback Period without Considering Rate of Interest

Consider:

F = number of FIDs in the system × cost per FID

S = number of SSTs in the system × cost per SST

RB = reliability benefit in $ per customer per year × number of customers

L = annual reduction in cost of active power losses when compared to system hav ing conventional transformers

CP = annual reduction in cost due to elimination of installing capacitor banks

H = annual savings in total electricity bill for all customers due to use of renewa-bles

G = subsidy of 10 % of the total customer's annual bill to encourage utilization of the FREEDM system

The payback period is calculated by the following formula which is applicable to both the configurations.

$$n^{'}, \text{ Payback period (years)} = \frac{F+S}{RB+L+CP+H+G} \tag{5.1}$$

For the case X, the value of G = 0. From the ERCOT loading data, the value of energy consumed per year per 36 kVA transformer as per APPENDIX A comes out to be around 177.24 MWh/year. The average value of cost of energy taken to be approximately 10 cents/kWh as mentioned in Chapter 3 gives the annual cost of energy per transformer to be around 17,700$/year. The FREEDM system assumed in Figure 3.1 has 20 customers with each transformer serving 3 residences. Thus, total cost of energy per year for all the customers is given by 17700*20/3 = 118,000$/year. Savings in annual bill for all customers as well as subsidy if applicable is taken to be 10% of this value.

5.3 Calculation of Payback Period Considering Rate of Interest

Consider, *Cost* = *F* + *S* (in $) and *Benefit* = *RB* + *L* + *CP* + *H* + *G* (in $/year). If *i* represents the annual rate of interest, the calculation of payback period is done using the following formula:

$$Cost\ (1 + \frac{i}{100})^{n'} = n' \times Benefit \tag{5.2}$$

- When $i = 0$, $n' = \frac{Cost}{Benefit}$
- When, i = small, n' = small;

$$Cost\ (1 + \frac{i}{100})^{n'} \approx Cost\ (1 + \frac{n'i}{100}) = n' \times Benefit$$

- General case; i and n' cannot be ignored

  For this case, the following method is used.

  Step 1: Let, $f = Cost\ (1 + \frac{i}{100})^{n'} - n' \times Benefit$

  Step 2: Guess n_0

  Step 3: $n_1' = n_0 - \frac{\partial f}{\partial n}^{-1} \times f_0$

  Step 4: $f_1 = Cost\ (1 + \frac{i}{100})^{n1'} - n1' \times Benefit$

Step 5: Keep repeating steps 2-4 for values of n_1', n_2', n_3' such that $f_{(n)}$ is within a certain tolerance value. This value can be 0.01 or 0.001 depending on the application for which it is used. A value of 0.01 is taken for calculation of payback periods with interest rates of 1% and 2% annually.

5.4 Results

The calculations for both cases X and Y for Configurations A and B are illustrated in Appendix E. These calculations are done for the following rates of interest: i = 0%, i = 1% and i = 2%. The results are tabulated in Table 5.1.

5.5 Summary and Conclusions

It is observed from the results tabulated in Table 5.1 that the fastest payback period of 5.82 years is expected for the enhanced reliability case for Configuration B without taking the rate of interest into consideration. The longest payback period of 36.45 years is observed for Configuration A with an annual rate of interest of 2% and for the lower range of reliability case. These results make sense as Configuration B has almost half the number of FIDs as Configuration A and hence the cost of the system in Configuration B is a lot less than that of Configuration A. Also, as the rate of interest gets introduced in the calculations, the payback period will increase. A payback period of 5 - 10 years for the FREEDM system is justified. According to that philosophy, adopting the FREEDM system thus would be viable.

Table 5.1 Calculation Summary of Payback Period for Both Configurations with and without Rate of Interest

Payback period, years		
Case X, NO subsidy, Configuration A		
	Value of reliability = 40$/customer/year	Value of reliability = 80$/customer/year
i = 0%	17.71	16.89
i = 1%	22.05	20.61
i = 2%	36.45	31.05
Case X, NO subsidy, Configuration B		
	Value of reliability = 40$/customer/year	Value of reliability = 80$/customer/year
i = 0%	10.85	10.29
i = 1%	12.26	11.54
i = 2%	14.45	13.42
Case Y, With subsidy, Configuration A		
	Value of reliability = 40$/customer/year	Value of reliability = 80$/customer/year
i = 0%	9.78	9.5
i = 1%	10.91	10.55
i = 2%	12.55	12.06
Case Y, With subsidy, Configuration B		
	Value of reliability = 40$/customer/year	Value of reliability = 80$/customer/year
i = 0%	5.9982	5.82
i = 1%	6.3921	6.19
i = 2%	6.8727	6.64

CHAPTER 6 CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

This thesis focuses on a future power distribution system, the FREEDM system. Electronic controls are used in the FREEDM system. Active power losses for a distribution feeder are calculated for both the FREEDM and conventional systems. The conventional system uses magnetic transformers; the FREEDM system uses SSTs. A reduction in the active power losses in the feeder of about a maximum of 18.76% is observed in case of the FREEDM system. A savings of about a maximum of 47.6 % in the cost of FIDs can be obtained by changing the configuration from A to B, by serving one load point less which typically consists of 3-4 residences. A further study regarding the effect of storage devices in coping with this contingency of loss of one load point as well as the duration for which the service is out needs to be quantitatively conducted. In [31], the reliability of a conventional system is compared with that of the proposed FREEDM system. The main observation relating to reliability is an improvement of 32% for the FREEDM system in terms of SAIFI.

A second area of comparison for the FREEDM system relates to cost/benefit, namely the payback period. For the FREEDM system, an optimistic value of payback period is 5.82 years. For a less optimistic scenario, the FREEDM system payback period is longer. The longest value of payback period for a scenario with reduced value of reliability is 36.45 years. A maximum of 10 years for payback period may be acceptable for the commercialization of the FREEDM system. The study in this thesis includes alternatives relating to

- Subsidy

- Rate of interest
- Configuration/design

The different values of payback periods are listed in Table 5.1. Configuration B is an alternative with approximately one-half the number of FIDs of that in Configuration A, and Configuration B has a lower value of payback period due to reduced number of FIDs by about 5.89 years. This reduction in payback period could be an alternative to Configuration A. Introducing the rate of interest increases the time required for payback typically by about three years. The payback period calculated without considering subsidy given by the state can increase by a maximum of 15 years when compared with that calculated with subsidy.

6.2 Recommendations and Future Work

The value of the dollar can be taken into account while evaluating the payback periods. The FIDs are cost intensive and technology needs to develop cheaper solutions that can introduce functionalities similar to that of the piezoelectric FIDs considered for the FREEDM system. A strong contender for FIDs could be solid state fuses.

The main recommendations for future work relating to the cost/benefit analysis of the FREEDM system are:

- Put the cost/benefit analysis into a real neighborhood setting, calculating the benefits and costs to the distribution supplier and home owner.
- Resolve the question of whether less expensive FID components are suitable for this application.
- Expand the sensitivity studies shown in this thesis by adding to the scenarios studied.

- Resolve any differences between cost/benefit analysis shown here and those conducted elsewhere.
- Add the benefit of DESD as well as real time load monitoring and management to this study.
- A study of the benefits if solar or wind is added needs to be conducted.
- A "cost" of SST failure versus a conventional transformer should be included.
- Identify what possible configurations can be used apart from the configurations A and B mentioned in this study.
- Include the costs of relay circuits used to trip the FID.
- What was studied is a single phase $\frac{15\ kV}{\sqrt{3}}$ equivalent, a study needs to be done to observe what happens in a real three phase 15 kV case.
- Include the study of re-closers and fuses in both the configurations.

REFERENCES

[1] Next Generation Power Distribution System Architecture, "The Future Renewable Electric Energy Delivery and Management (FREEDM) System". [Online], available: http://www.thinkmind.org/index.php?view=article&articleid=energy_2013_2_40_40134

[2] FREEDM systems center, "About: FREEDM Systems". [Online], available: http://www.freedm.ncsu.edu/index.php?s=1&p=6

[3] H. P. Barringer, P. E. Barringer & Associates, Inc. "A Life Cycle Cost Summary," Humble, Texas.

[4] R. Reis, "Pros and Cons of Performing a Cost-Benefit Analysis," [Online], available: http://www.docstoc.com/article/98795770/Pros-and-Cons-of-Performing-a-Cost Benefit- Analysis

[5] J. E. Huber, J. W. Kolar, "Volume/Weight/Cost Comparison of a 1 MVA 10kV/400 V Solid-State against a Conventional Low-Frequency Distribution Transformer," IEEE Energy Conversion Congress and Exposition, 2014, pp. 4545 – 4552.

[6] G. G. Karady, A. Q. Huang, M. Baran, "FREEDM System: An Electronic Smart Distribution Grid For The Future," IEEE Transmission and Distribution Conference and Exposition 2012, pp. 1 – 6.

[7] X. She, R. Burgos, G.Wang, F.Wang, A. Q.Huang, "Review of Solid State Transformer in the Distribution System: From Components to Field Application," IEEE Energy Conversion Congress and Exposition (ECCE), 2012, pp. 4077-4084.

[8] X. She, A. Q. Huang, S. Bhattacharya, M. Baran, "Performance Evaluation of Solid State Transformer based Micro Grid in FREEDM Systems," IEEE Applied Power Electronics Conference and Exposition (APEC), 2011, pp. 182-188.

[9] S. B. Y. Du, G. Wang, S. Bhattacharya, "Design Considerations of High Voltage and High Frequency Transformer for Solid State Transformer Application," IECON 36th Annual Conference on IEEE Industrial Electronics Society, 2010, pp. 421-426.

[10] FREEDM systems center, "News and Events: Solid-State Transformers Ready to Enable the Smart Grid?". [Online], available: http://www.freedm.ncsu.edu/index.php?s=2&t=news&p=121

[11] A. Q. Huang, "Wide Bandgap Power Semiconductor Devices and Future Electric Power Delivery System". [Online], available: http://nanohub.org/resources/21309/watch?resid=21310

[12] U.S. Department of Energy. "Smart Grid / Department of Energy," [Online], available: http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/DOE_SG_Book_Single_Pages%281%29.pdf

[13] ERCOT, "Hourly Load Data Archives," [Online], available: http://www.ercot.com/gridinfo/load/load_hist/

[14] U.S. Energy Information Administration, "Annual Energy Outlook 2012", [Online], available: http://www.eia.gov/forecasts/aeo/pdf/0383 (2012).pdf

[15] U.S. Department of Energy, "Supplement to the "Determination Analysis" (ORNL-6847) and Analysis of the NEMA Efficiency Standard for Distribution Transformers", [Online], available: http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf

[16] Westinghouse Electric Co., "Electrical Transmission and Distribution Reference Book," Westinghouse, Pittsburgh, PA, 1965.

[17] M. Kempkes, I. Roth, M. Gaudreau, "Solid-State Circuit Breakers For Medium Voltage DC Power," IEEE Electric Ship Technologies Symposium (ESTS), 2011, pp. 254-257.

[18] M. K. Madan and B. H. Chowdhury, "Study of Solid State Fault Interruption Device for Medium Voltage Distribution Systems with Distributed Generators," IEEE Power and Energy Society General Meeting, 2010, pp. 1-7.

[19] O. Vodyakho, M. Steurer, C. Edrington, G. Karady, B. Chowdhury and S. Bhattacharya, "Design of a Solid State Fault Isolation Device for Implementation in Power Electronics based Distribution Systems," North American Power Symposium, 2009, pp. 1-6.

[20] FREEDM conference call, "Cost/Benefit Project-ItemizedParts_updatedJan20.xls," 02/27/2015.

[21] G. Strbac, N. Jenkins, "Calculation of Cost and Benefits to the Distribution Network of Embedded Generation," IEE Colloquium on Economics of Embedded Generation, 1998, pp. 6/1 – 6/13.

[22] Y. Yang, N. Yang, H. Li, "Cost-benefit Study of Dispersed Battery Storage to Increase Penetration of Photovoltaic Systems on Distribution Feeders," IEEE PES General Meeting, 2014, pp. 1 – 5.

[23] C. Yang, P. Hu, Y. He, "Research on Cost-Benefit Analysis and Evaluation of Regional Distribution Network Planning," China International Conference on Electricity Distribution, 2010, pp. 1 – 6.

[24] S. Umans, W. Fitzgerald, G. Kingsley, “Electric Machinery,” The McGraw Hill Companies, Delhi, India, 2013.

[25] D. P. Kothari, I. J. Nagrath, “Electrical Machines,” The McGraw Hill Companies, Delhi, India, 2008.

[26] S. Chapman, “Electric Machinery Fundamentals,” BAE Systems Australia.

[27] F. Ioan, R. Nicolae, H. Viorel, “Experimental Correction of Transformer Losses which Operates in Harmonic Regime,” IET Conference Publications, 20th International Conference and Exhibition on Electricity Distribution - Part 1, 2009, pp. 1-4.

[28] M. Feldtkeller, “Electronic Fuse (protection device) DE 3705177 A1,” Siemens Ag, Application no. DE19873705177, Germany, 1987.

[29] **“**High Speed Fuses,**”** Cooper Bussmann Industries, [Online], available: http://www.cooperindustries.com/content/dam/public/bussmann/Electrical/Resources/solution-center/technical_library/BUS_Ele_Tech_Lib_High_Speed_Fuses.pdf

[30] National Electrical Manufacturers Association, 2007, [Online], available: http://infostore.saiglobal.com/store/Details.aspx?productID=1748487

[31] M. Baran, L. White, G. Heydt, M. Crow, S. Bhattacharya, M. Steurer, “Volume II-Core Project Summary,” Cost-Benefit project, FREEDM, 2015.

[32] International Electrotechnical Commission, “International IEC Standard 60269-1,” Reference Number IEC 60269-1:2006(E), Geneva, 2006.

[33] Waukesha Electric Systems, “New Diagnostic Concepts for Better Asset Management,” Weidmann-ACTI Inc. Technical Conference, 2005, [Online], available: http://www.weidmannsolutions.cn/huiyi/Seminar%202005%20San%20Antonio/2005simpresentation.pdf

[34] A. Kusko, M. Thompson, “Power Quality in Electrical Systems,” McGraw-Hill, New York, 2007.

[35] J. Kyei, “Analysis and Design of Power Acceptability Curves for Industrial Loads,” Power Systems Engineering Research Center, New York, 2001.

[36] G. T. Heydt, “Electric Power Quality,” Stars in a Circle, West Lafayette, Indiana, 1991.

[37] M. Baran, L. White, G. Heydt, M. Crow, S. Bhattacharya, M. Steurer, "FREEDM System Cost-Benefit Analysis," Site Visit Presentation, Year 07, Cost-Benefit project, FREEDM, 2015.

APPENDIX A

LOSS CALCULATION FOR A 36 KVA MAGNETIC TRANSFORMER

```
clc;
clear all;
close all;
cost=10.27 % cents/kwh as per data for the year 2012

% Also considering a 36 KVA distribution transformer in service.
rating=36000; % base rating of the distribution transformer
r1=0.0178; % per unit resistance
sum=0;
load = importfile4('2013_ERCOT_Hourly_Load_Data.xls','2013',2,8761);
for i=1:8760
   load(i)=load(i)*10^6;
   sum=sum+load(i);
end
pmax=max(load)
load_factor=sum/(pmax*8760)

%Actual Load on the transformer is denoted by load1
%Calculate the load on the transformer for all the 8760 hours
% of the year and store it in the matrix load1

for i=1:8760
   load_size_kw(i)= load(i)*rating/pmax;
end
   a=max(load_size_kw)
   b=min(load_size_kw)

% Calculate the value of  per unit current flowing through the
% transformer for every hour as well as the losses per hour in per unit
% as per loading on the transformer calculated above.

c1=0;c2=0;c3=0;
for i=1:8760
   current_pu_1(i)= load_size_kw(i)/(rating*1);
   current_pu_2(i)= load_size_kw(i)/(rating*0.85);
   current_pu_3(i)= load_size_kw(i)/(rating*0.6);
   loss_pu1(i)=current_pu_1(i)*current_pu_1(i)*r1;
   loss1(i)=loss_pu1(i)*rating;
   c1=c1+loss1(i);
   loss_pu2(i)=current_pu_2(i)*current_pu_2(i)*r1;
   loss2(i)=loss_pu2(i)*rating;
   c2=c2+loss2(i);
   loss_pu3(i)=current_pu_3(i)*current_pu_3(i)*r1;
   loss3(i)=loss_pu3(i)*rating;
   c3=c3+loss3(i);
```

```
end
display('Energy lost per year for the 36 KVA transformer operating at unity power factor is as follows');
c1
display('Cost of Energy lost per year for the 36 KVA transformer operating at unity power factor in$/year is as follows')
cost*c1*10^-5
display('Energy lost per year for the 36 KVA transformer operating at 85 % factor is as follows');
c2
display('Cost of Energy lost per year for the 36 KVA transformer operating at 85 % power factor in$/year is as follows')
cost*c2*10^-5
display('Energy lost per year for the 36 KVA transformer operating at 60 % power factor is as follows');
c3
display('Cost of Energy lost per year for the 36 KVA transformer operating at 60 % power factor in$/year is as follows')
cost*c3*10^-5
```

OUTPUT

```
cost = 10.2700

pmax = 6.7596e+10

load_factor = 0.5620

a = 36000

b = 1.2484e+04

Energy lost per year for the 36 KVA transformer operating at unity power factor is as follows

c1 = 1.8723e+06

Cost of Energy lost per year for the 36 KVA transformer operating at unity power factor in$/year is as follows

ans = 192.2815

Energy lost per year for the 36 KVA transformer operating at 85 % factor is as follows

c2 = 2.5914e+06
```

Cost of Energy lost per year for the 36 KVA transformer operating at 85 % power factor in$/year is as follows
ans = 266.1336

Energy lost per year for the 36 KVA transformer operating at 60 % power factor is as follows

c3 = 5.2007e+06

Cost of Energy lost per year for the 36 KVA transformer operating at 60 % power factor in$/year is as follows

ans = 534.1153

APPENDIX B

LOSS CALCULATION FOR A 36 KVA SST

```
clc;
clear all;
close all;
cost=10.27 % cents/kwh as per data for the year 2012

% Also considering a 36 KVA distribution transformer in service.

rating=36000; % rating of the distribution transformer
r=0.0178; % per unit resistance

% Considering 5 % loss at 75 % Load
a1=0.0556;
b1=0.0148148;

% Considering 1 % loss at 75 % Load
a2=0.01111;
b2=2.96296*10^-3;

load = importfile4('2013_ERCOT_Hourly_Load_Data.xls','2013',2,8761);

for i=1:8760
   load(i)=load(i)*10^6;
end

pmax=max(load)

% Load on the transformer is denoted by load1
% Calculate the load on the transformer for all the 8760 hours
% of the year and store it in the matrix load1

for i=1:8760
   load1(i)= load(i)*rating/pmax;
end
   a=max(load1)
   b=min(load1)

% Calculate the value of per unit current flowing through the
% transformer for every hour as well as the losses per hour in per unit
% as per loading on the transformer calculated above.
c=0;d=0;
for i=1:8760
   current_pu(i)=load1(i)/rating;
   loss_pu(i)=a1*current_pu(i)+(b1*current_pu(i)*current_pu(i));
   loss(i)=loss_pu(i)*rating;
   c=c+loss(i);
```

```
   loss_pu_1(i)=a2*current_pu(i)+(b2*current_pu(i)*current_pu(i));
   loss_1(i)=loss_pu_1(i)*rating;
   d=d+loss_1(i);
end
display('Energy lost per year for the 36 KVA SST transformer for 5 % losses at 75 % load is as follows');
c
display('Cost of Energy lost per year for the 36 KVA transformer in$/year is as follows')
cost*c*10^-5
display('Energy lost per year for the 36 KVA SST transformer for 1 % losses at 75 % load is as follows');
d
display('Cost of Energy lost per year for the 36 KVA transformer in$/year is as follows')
cost*d*10^-5
```

OUTPUT

```
cost = 10.2700

pmax = 6.7596e+10

a = 36000

b = 1.2484e+04

Energy lost per year for the 36 KVA SST transformer for 5 % losses at 75 % load is as follows

c = 1.1413e+07

Cost of Energy lost per year for the 36 KVA transformer in$/year is as follows

ans = 1.1721e+03

Energy lost per year for the 36 KVA SST transformer for 1 % losses at 75 % load is as follows

d = 2.2808e+06

Cost of Energy lost per year for the 36 KVA transformer in $/year is as follows

ans = 234.2413
```

APPENDIX C

ANNUAL ENERGY LOST IN FEEDER USING DISTRIBUTION LEVEL MAGNETIC TRANSFORMERS AND SSTS

```
clc;
clear all;
close all;
rating=36000; % rating of the distribution transformer
cost=10.27; % cents/kwh as per data for the year 2012
load = importfile4('2013_ERCOT_Hourly_Load_Data.xls','2013',2,8761);
for i=1:8760
   load(i)=load(i)*10^6;
end

pmax=max(load);

%Actual Load on the transformer is denoted by load1
% Calculate the load on the transformer for all the 8760 hours
% of the year and store it in the matrix load1

for i=1:8760
   load1(i)= load(i)*rating/pmax;
   current_sst(i)= load1(i)*sqrt(3)/(15000);
   current_magnetic(i)= load1(i)*sqrt(3)/(15000*0.85);
end
sum1_mag=0;
sum1_sst=0;

for k=1:8760

sum_mag(k)=0;
sum_sst(k)=0;
r=1.41;  % ohms per mile
d=11;

summ_mag=0;
summ_sst=0;

for n=1:11
   c=1.41*10/19 ;
   ploss_mag(n)=c*d*d*current_magnetic(k)*current_magnetic(k);
   ploss_sst(n)=c*d*d*current_sst(k)*current_sst(k);
    d=d-1;
   summ_mag=summ_mag+ploss_mag(n);
   summ_sst=summ_sst+ploss_sst(n);

end

sum_mag(k)=summ_mag;
```

```
sum_sst(k)=summ_sst;
sum_mag(k)=2*sum_mag(k);
sum_sst(k)=2*sum_sst(k);
sum1_mag=sum1_mag+sum_mag(k);
sum1_sst=sum1_sst+sum_sst(k);

end
display('The annual value of energy lost in the feeder with all 20 magnetic distribution trans-formers operating at unity power factor is')
sum1_mag
display('The annual value of energy lost in the feeder with all 20 distribution level SSTs is')
sum1_sst
display('The value of cost of energy lost in$/year in the feeder with all 20 magnetic dis-tribution transformers operating at unity power factor is')
cost*sum1_mag*10^-5
display('The value of cost of energy lost in$/year in the feeder with all 20 distribution level SSTs is')
cost*sum1_sst*10^-5
```

OUTPUT

The annual value of energy lost in the feeder with all 20 magnetic distribution trans-formers operating at unity power factor is

sum1_mag = 5.2480e+07

The annual value of energy lost in the feeder with all 20 distribution level SSTs is

sum1_sst = 3.7917e+07

The value of cost of energy lost in$/year in the feeder with all 20 magnetic distribution transformers operating at unity power factor is

ans = 5.3897e+03

The value of cost of energy lost in$/year in the feeder with all 20 distribution level SSTs is

ans = 3.8941e+03

APPENDIX D

CURVE APPROXIMATION OF RELIABILITY CALCULATIONS FOR CONFIGU-RATIONS A AND B

```
clc;
clear all;
close all;
A=[42*42*42 42*42 42 1; 41*41*41 41*41 41 1; 40*40*40 40*40 40 1; 3*3*3 3*3 3 1;
2*2*2 2*2 2 1];
D=[22*22*22 22*22 22 1; 21*21*21 21*21 21 1; 20*20*20 20*20 20 1; 3*3*3 3*3 3 1;
2*2*2 2*2 2 1];
B=[19.09;18.952;16.88;10;0]; % config B
C=[20;19.95;17.8819;10;0]; % config A
E=pinv(A)*C % config A
F=pinv(D)*B % Config B

expected(1)=E(1)*42*42*42+E(2)*42*42+E(3)*42+E(4);
expected(2)=E(1)*41*41*41+E(2)*41*41+E(3)*41+E(4);
expected(3)=E(1)*40*40*40+E(2)*40*40+E(3)*40+E(4);
expected(4)=E(1)*3*3*3+E(2)*3*3+E(3)*3+E(4);
expected(5)=E(1)*2*2*2+E(2)*2*2+E(3)*2+E(4);

expected_b(1)=F(1)*22*22*22+F(2)*22*22+F(3)*22+F(4);
expected_b(2)=F(1)*21*21*21+F(2)*21*21+F(3)*21+F(4);
expected_b(3)=F(1)*20*20*20+F(2)*20*20+F(3)*20+F(4);
expected_b(4)=F(1)*3*3*3+F(2)*3*3+F(3)*3+F(4);
expected_b(5)=F(1)*2*2*2+F(2)*2*2+F(3)*2+F(4);

sum_a=0;
sum_b=0;

for i=1:5
    x=(C(i)-expected(i))^2;
    sum_a=sum_a+x;
    y=(B(i)-expected_b(i))^2;
    sum_b=sum_b+y;
end
error_a=sqrt(0.2*(sum_a))
error_b=sqrt(0.2*(sum_b))
```

OUTPUT

```
E = 0.0069

   -0.5675

   12.6610

  -23.0860
```

F = 0.0279

-1.2214

15.4694

-26.2260

error_a = 0.4725

error_b = 0.5501

APPENDIX E

CALCULATION OF PAYBACK PERIOD WITH INTEREST RATES FOR CONFIG-URATIONS A AND B

```
clc;
clear all;
close all;
% Assuming configuration A
c = 258240;
b = 14581.17;
i=0.02;
n(1) = 5.653009395;
f(1)= c*(1.02)^n(1)-b*n(1);
i=1;
tolerance =1;
while (tolerance >= 0.01)
df(i)=c*(1.02)^n(i)*log(1.02)-b;
n(i+1)=n(i)-((df(i))^-1*f(i));
f(i+1)=c*(1.02)^n(i+1)-b*n(i+1);
tolerance = f(i+1)
n(i)=n(i+1);
f(i)=f(i+1);
end
n(i)
```

OUTPUT

```
tolerance =  3.6045e+04

tolerance =  4.0156e+03

tolerance =  91.6292

tolerance =  0.0531

tolerance =  1.7928e-08

ans = 36.4530
```

```
clc;
clear all;
close all;
% Assuming configuration A
c = 158240;
b = 14581.17;
i=0.02;
n(1) = 5.653009395;
f(1)= c*(1.02)^n(1)-b*n(1);
```

```
i=1;
tolerance =1;
while (tolerance >= 0.01)
df(i)=c*(1.02)^n(i)*log(1.02)-b;
n(i+1)=n(i)-((df(i))^-1*f(i));
f(i+1)=c*(1.02)^n(i+1)-b*n(i+1);
tolerance = f(i+1)
n(i)=n(i+1);
f(i)=f(i+1);
end
n(i)
```

OUTPUT

```
tolerance = 2.6776e+03

tolerance = 2.7124

tolerance = 2.8041e-06

ans = 14.4467
```

APPENDIX F

SUMMARY OF ALL THE TEST CASES USED

Case A) Evaluation of losses in a 36 kVA SST: 5% loss at 75% load, Chapter 2

Case B) Evaluation of losses in a 36 kVA SST: 1% loss at 75% load, Chapter 2

Case 1) Improving power factor from 60% to 85% by introducing capacitor banks, Chapter 3

Case 2) Improving power factor from 85% to 100% by introducing capacitor banks, Chapter 3

Case 3) Improving power factor from 60% to 100% by introducing capacitor banks, Chapter 3

Case 1A) Reliability of service to customer calculations for ($2n + 2$) FIDs and Configuration A, Chapter 4

Case 2A) Reliability of service to customer calculations for ($2n + 1$) FIDs and Configuration A, Chapter 4

Case 3A) Reliability of service to customer calculations for ($2n$) FIDs and Configuration A, Chapter 4

Case 4A) Reliability of service to customer calculations for 3 FIDs and Configuration A, Chapter 4

Case 5A) Reliability of service to customer calculations for 2 FIDs and Configuration A, Chapter 4

Case 1B) Reliability of service to customer calculations for ($2n + 2$) FIDs and Configuration B, Chapter 4

Case 2B) Reliability of service to customer calculations for ($2n + 1$) FIDs and Configuration B, Chapter 4

Case 3B) Reliability of service to customer calculations for (2*n*) FIDs and Configuration B, Chapter 4

Case 4B) Reliability of service to customer calculations for 3 FIDs and Configuration B, Chapter 4

Case 5B) Reliability of service to customer calculations for 2 FIDs and Configuration B, Chapter 4

Case X) Calculation of payback period without any subsidy, Chapter 5

Case Y) Calculation of payback period with 10% subsidy in electricity bill, Chapter 5

Table F.1 shows a summary of all the cases studied in this thesis.

Table F.1 summary of all the cases studied in this thesis

Test Case	Chapter	Main conditions of test
Evauation of losses		
Case A	2	36 kVA SST, 5% loss at 75% load
Case B	2	36 kVA SST, 1% loss at 75% load
Improvement of power factor		
Case 1	3	Improve power factor from 60% to 85%
Case 2	3	Improve power factor from 85% to 100%
Case 3	3	Improve power factor from 60% to 100%
Impact on reliability		
Case 1A	4	($2n$+2) FIDs, Configuration A
Case 2A	4	(2n+1) FIDs, Configuration A
Case 3A	4	($2n$) FIDs, Configuration A
Case 4A	4	3 FIDs, Configuration A
Case 5A	4	2 FIDs, Configuration A
Case 1B	4	($2n$+2) FIDs, Configuration B
Case 2B	4	(2n+1) FIDs, Configuration B
Case 3B	4	($2n$) FIDs, Configuration B
Case 4B	4	3 FIDs, Configuration B
Case 5B	4	2 FIDs, Configuration B
Calculation of payback period		
X	5	Without subsidy
Y	5	Subsidy of 10% in electricity bill