GUIDELINES FOR PERFORMANCE BASED DISTRIBUTION RELIABILITY ANALYSIS FOR PRESENT AND FUTURE GRID

A Dissertation by

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The following faculty members have examined the final copy of this dissertation for form and content, and recommend that it be accepted in partial fulfillment of the requirement for the degree of Doctor of Philosophy with a major in Electrical Engineering.

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DEDICATION

To my parents, my wife and my dearest son

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ABSTRACT

The electric power system has experienced many changes in the last decade. The notable changes are deregulation of the industry, penetration of renewable energy sources, demand side management, stricter regulations on the system performance, investigation of smart-grid applications, emission regulations on generation and penetration of electric vehicles. These changes have forced the utilities to look for innovative ideas to incorporate the changes while ensuring the performance requirements. One way to measure the performance requirements is in terms of customer satisfaction. In other words the utility is expected to provide uninterrupted power supply on demand. The challenges in achieving this are limited by the increasing load / demand on the system and the aging of the components. In US on average 80% of consumer interruptions are attributed to the failures at the distribution level.

Therefore, this work focuses on improving the performance of the distribution system using a preventive maintenance scheme based on the condition of the distribution level components. Impact on the system due to expected penetration of electric vehicles (EV) and the communication advancements for the smart-grid applications are also given noteworthy consideration in this work.

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CHAPTER 1

INTRODUCTION

During the late 20th century the electric power sector went through a significant change, when it became a deregulated industry. The traditional power system became three separate divisions each doing business separately in generation, transmission and distribution. Deregulation has resulted in increased competition between utilities that are operated under budgetary limitations. In order to reduce costs, some of the observed practices among utilities are to postpone preventive maintenance, spend less resources on training its staff, and wait until an equipment fails before replacement [1]. A common observation in the power industry is average load in the power system increasing (average demand increase per year is 1% of the total consumption and is expected to continue at this rate even with the addition of plug hybrid electric vehicles (PHEVs) [2]), along with increases in the average age of the components used in the power system (average component age for US utilities exceeds 35 years [3]). These are two major contributing factors to system reliability.

Power system reliability has different interpretations at different levels. The definition with relation to customers, and widely accepted, describes the reliability as 'uninterrupted power supply at demand'. Therefore more emphasis is given to system planning for minimum interruption with the failure of any component.

A typical power system is shown in Figure 1. It could be observed that at the transmission level and subtransmission level most of the components and switching are limited to the substation. This ensures easy accessibility and monitoring of the transmission system. On the other hand a distribution feeder, which connects the consumers to the system, contains distributed components / equipment connected throughout the feeder. This increases the complexity of component monitoring.

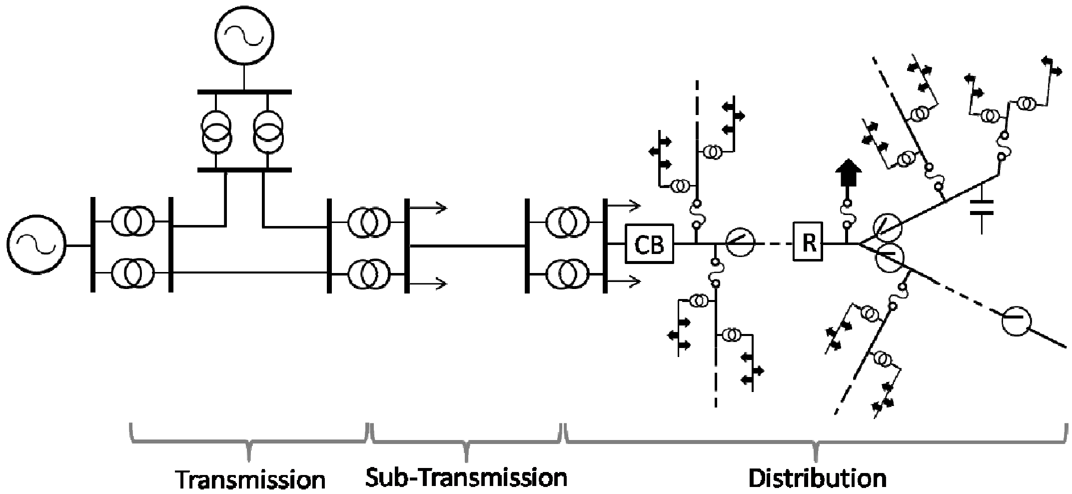


Figure 1: Typical Power System

1.1. Distribution Reliability

Even though reliability of the power system depends on the generation, transmission and distribution components, distribution has a larger effect on system reliability defined in terms of customer interruptions and satisfaction. Reliability of the generation and transmission systems is very high mainly because of the availability of redundant components. For example, the generating capacity of the system will be always higher than the maximum demand and the generators will be scheduled for at least the loss of one generator (N – 1 contingency), the transmission system is networked and the loss of one line will not affect the served energy. This is evident as on average 80% of the consumer interruptions are attributed to failures at the distribution level [4].

Figure 2 shows components of a typical feeder [5]. Most of the distribution systems in North America are radial as shown in the figure with three phase and single phase, overhead and underground line segments, power transformers, protection devices, switches, shunt capacitors and distributed energy sources. These complicate the reliability analysis of a distribution system.

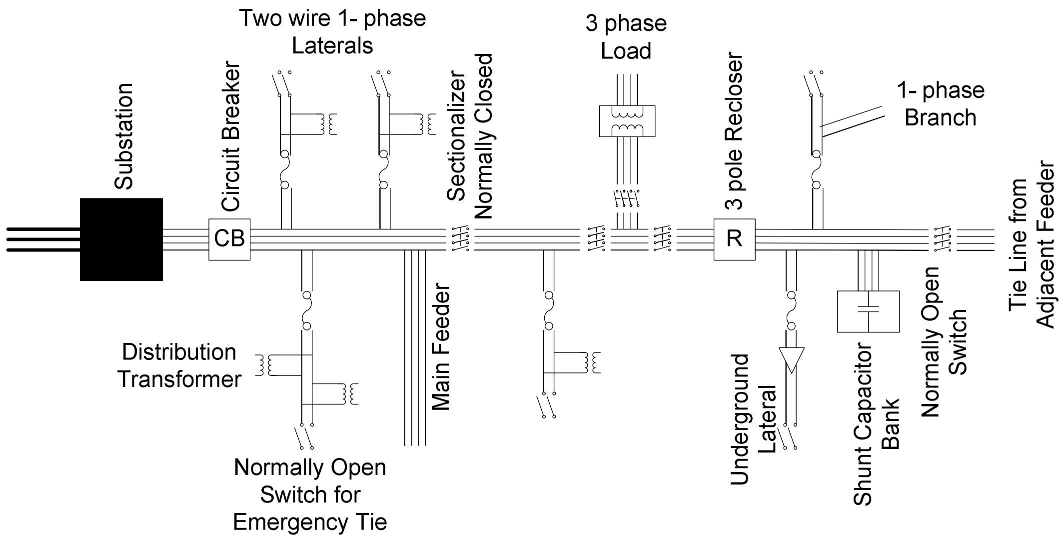


Figure 2: Typical Distribution Feeder

IEEE Standard 1366 – 2003 [6] gives the guidelines for power distribution system reliability analysis. This standard generalizes the terms to aid a consistent reporting practice among the utilities. Unfortunately due to geographical location, loading level (urban – greater than 93 customers/km, suburban – between 31 and 93 customers/km and rural – less than 31 customers/km), system design, and definition of sustained interruption used, reliability analysis differs among distribution companies.

Even though there are several reliability indices defined in IEEE 1366-2003, System Average Interruption Duration Index (SAIDI) [1] and System Average Interruption Frequency Index (SAIFI)[1] are the ones which are commonly used by the utilities. A study conducted by the Lawrence Berkeley National Laboratory in 2008 shows that out of 123 utilities surveyed, all of them report these indices to the state Public Utility Commissions (PUC) directly or indirectly and only 12 report the Momentary Average Interruption Frequency Index (MAIFI)[1]. This is due to the fact that, out of 37 state public utility commissions that provided information, 35 require the utilities to provide SAIFI and SAIDI, but only two require the utilities to provide the MAIFI [7]. Figure 3 shows the plot of the state reporting requirements vs. the reliability indices. It should be

[1] Check annexure 1 for the definitions of these indices

noted that CAIDI, SAIDI and SAIFI are directly related[1], therefore reporting of any two could be considered as reporting of SAIDI and SAIFI. This shows that if the utilities' performance / reliability is to be assessed the most common tools for this assessment are SAIDI and SAIFI.

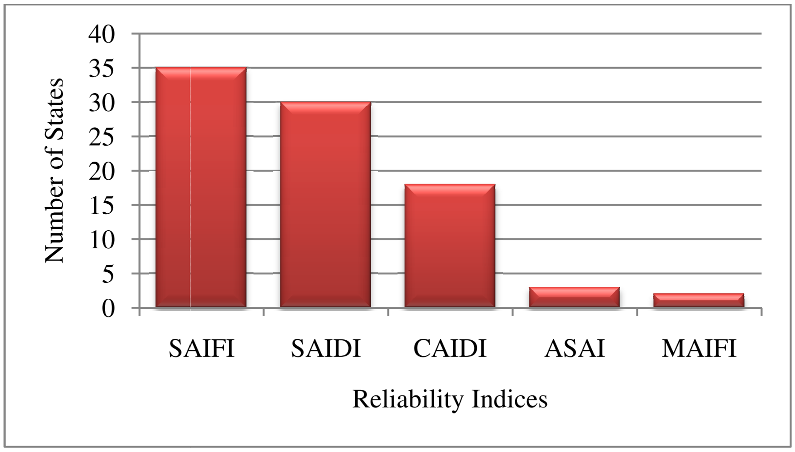


Figure 3: State Reporting Requirements for Reliability Indices [7]

Due to the fact that some utilities tend to neglect preventive maintenance and consumers requiring more reliable power supply, have prompted some system regulators (State Public Utility Commissions) to exert more control over the utility performance; either by scheduling maintenance tasks for the system components or imposing performance based tariffs instead of standard energy-based tariffs. For example, the Pennsylvania Public Utility Commission is regulating its utilities, Docket No L-00040167 dated May, 22 2008, by requiring the distribution utilities to file plans for inspection, maintenance, replacement and repair of components, which ensures that the utility will meet the benchmarks and standards [8].

Maintenance tasks of components could be scheduled by (a) waiting until the component fails (run to fail mode), (b) fixing the period between two maintenance tasks (time based maintenance), (c) inspecting the condition of components (condition based maintenance), (d) values of reliability indices (reliability based maintenance), and the latest approach (e) analyzing the performance / risk associated with the condition of the component (performance / risk based maintenance). There is no universal guideline / practice to develop benchmarks for the performance practice among different regulators, but the following are considered to be important factors when the performance of a component is determined: (a) outage duration, (b) sustained outage frequency (using 5 min. guideline) (c) momentary outage frequency, (d) customer complaints (e) storm outage response time and (f) hours lost due to accidents [9]. Based on the performance benchmarks, if the utility meets the benchmark it will neither be penalized nor rewarded, if the performance exceeds the benchmark then the utility would be rewarded and if the performance is below the benchmark the utility would be penalized. Figure 4 shows a typical performance based rate system.

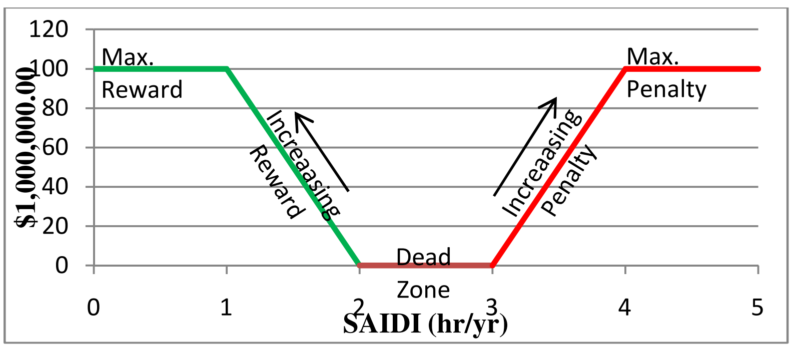


Figure 4: Example for a Typical Performance Based Rate [10]

1.2. Future Grid and Distribution Reliability

The power system is witnessing another major revolution in the 21^{st} century. Three of the dominant changes seen at the distribution level are: making the distribution system more measureable, observable, controllable and automatable – commonly known as Smart Grid, inclusion of electric vehicles (beginning with plug hybrid electric vehicles (PHEVs)) and integration of distributed energy sources.

A common question raised is “what is the smart grid?” There is a growing concern over the reliability and security of the power system, especially after the 2003 North American blackout. A grid which has the ability to efficiently supply the whole demand at request with minimum human intervention has high interest among regulators, utilities and consumers. As an alternative to the current grid structure, an autonomous (or at least partially) grid structure is proposed and called smart grid. Currently there is no single vision about the smart grid among different stakeholders. The prime reason behind this is that smart grid does not mean a single technology but is a collection of technologies to make the power grid more robust, reliable, secure and automated to perform the tasks with minimum human intervention. A general idea about the smart grid for a distribution system is given in Table 1. This shows that the current grid needs to have an integrated communication system, with more complex architecture. The complexity is expected to add more redundancy and thus result in better reliability.

TABLE 1

SMART GRID VISION [11]

	Current Grid	**Future Grid**
Communication	None / One-way, typically not real-time	Two-way, real-time
Customer Interaction	Limited	Extensive
Metering	Electromechanical	Digital (enabling real time communication)
Operation & Maintenance	Manual equipment checks, time based maintenance	Remote monitoring, predictive, condition based maintenance
Generation	Centralized	Centralized and distributed
Power flow control	Limited	Comprehensive, automated
Reliability	Phone to failures and cascading outages, essentially reactive	Automated, pro-active protection, prevents outages before they start
Restoration	Manual	Self-healing
System Topology	Radial, generally one-way power flow	Network, multiple power flow pathways

Hybrid electric vehicles (EV) have become a main discussion point among power professionals. The EV shares similarities with existing hybrid vehicles, with the addition of having a plug which could be connected to the external power supply (power grid) to charge the batteries. Currently no major automakers build commercial PHEVs, but there are manufacturers who convert existing hybrid vehicles to PHEVs. It is expected that major automakers will be ready with commercial PHEVs starting from 2010. Based on information given by the Energy Information Administration (average annual vehicle miles traveled – 12,000 miles [12]) and GM

Chevrolet Volt (all electric range – 40 miles, electric power to charge the battery to its full capacity 16 kWh (minimum) [13]), if a Volt runs for a whole month using all electric energy then it will consume 400 kWh, whereas the average household electric energy consumption is 936 kWh [14]. This shows how large a load the EV is going to be, which has implications for system reliability. In addition to the EVs being a large load, they are expected to be an emergency backup source for the grid, known as Vehicle-to-Grid (V2G) application. As a result of this, the EV is going to be a new type of load and storage for the distribution system and needs special attention when system reliability is analyzed.

1.3. Objective

Objective of this work is to develop and demonstrate a new technique for electric distribution system performance analysis, focusing on distribution asset management tasks and including electric vehicles, distributed resources, and smart grid applications. The technique will be a generic model that could be adapted to different maintenance / performance practices carried out by different utilities. This work has focused on two different issues, reliability of conventional systems and impacts of the future grid on reliability. Both will be combined into a guideline for the reliability of the future grid.

1.3.1. Conventional Distribution System Reliability

This research will cover the following areas:

- Investigate the available component condition assessment methodologies and if necessary develop a guideline that will be more robust and generic so that all the utilities will be able to adopt it.
- Study the impact of constant hazard rate models on aging components and investigate the best suited reliability model for a statistical approach.
- Develop an approach for optimal performance-based analysis under budget constraints.

This approach should ensure that the utility would meet the reliability benchmarks set by the state public utility commissions.

- Under strict budget constraints if the utility finds that it cannot complete scheduled maintenance for all components, develop an alternative strategy so that the utility would achieve the performance benchmarks and avoid any penalties.

Each of these parts will be tested and the numerical analysis will be validated. Due to the unavailability of the field data appropriate data was assumed based on the experience with the power system operation to validate the findings.

1.3.2. Reliability of Future Grid

This part of the work will focus on investigating the following factors:

- The ways to integrate two-way communications to improve system reliability. Both centralized and decentralized processing will be considered and a best possible topology will be identified.
- Impacts of EVs on distribution system reliability will be analyzed, including the impact of charging the batteries on the distribution components' loss-of-life, impact of vehicle-to-grid technology on distribution reliability, and mitigating the adverse effects of both.

Impact of distributed energy sources on distribution system reliability, and location of distributed resources to improve distribution system reliability.

1.3.3. Outside the Scope of this Work

The following are outside the scope of this work, mainly because either they are trivial or the inclusion will reduce the generalization of the guideline:

- Detailed analysis of condition assessment of all the distribution system components.

- Detecting and locating failure / fault based on the system model
- Analysis on EVs based on existing and future trends of battery capacity, charging time, etc.
- Cost and feasibility analysis of EVs. This work recognizes that the EVs will penetrate the vehicle fleet and leaves the cost analysis for others.
- Developing communication protocols, deciding the type of communication tools to be used, and identifying networking issues.

1.4. Summary & Organization of the Dissertation

A new approach for distribution reliability is needed to improve the reliability of the system with increasing demand and aging components. The primary objective for a utility is to achieve the benchmarks imposed by the regulators while meeting budget constraints. The future grid will be much complicated with EVs and the smart grid concept. Not only will these increase the complexity of the system but they will also open doors for better performance (communication, automation, etc.). Distribution system reliability analysis should include these changes.

Chapter 1 provides an introduction to this dissertation. Chapter 2 describes the work done in the area of distribution reliability and the motivation for this work. Chapter 3 provides detailed information about the guidelines for the performance enhancement for the present grid. Chapter 4 investigates the impact on electric vehicles and communication on the future distribution system. Numerical examples for the proposed guidelines are given in chapter 5 and finally chapter 6 concludes the dissertation with recommended future work.

CHAPTER 2

LITERATURE REVIEW

In order to predict the system performance it is necessary to determine the health of components accurately. In most of the distribution systems online monitoring is limited to measuring the system voltage and current at the substation level and availability of distribution component reliability / failure data is minimal. In addition the distribution system is operated with many uncertainties. As a result determining the condition of components becomes a difficult task.

Notable examples are, Moghe et al (2009) [15] showed that field data of monitoring a feeder current has shown more than 140 precursors to a fault with instantaneous peak currents in the range of a few thousands of amperes which lasted for less than 0.22 cycles during a period of nine months. Due to the short period, none of the protection devices functioned and the utility had no knowledge of these events until the catastrophic failure with 5000 A peak current, which resulted in the interruption of power.

Russell et al (2009) [16] shows an example where tripping and reclosing of a substation breaker did not attract the attention of a utility as the interruption was momentary and they did not receive any customer complaints. In most cases momentary self-clearing faults in the overhead lines are attributed to animal or tree contact and not investigated further. After a month a line-switch failed and analysis of the signals showed that all the events had similar signatures. Further investigation showed that a line technician had observed abnormalities during repair of an unrelated fault and a visual inspection thereafter had marked the component for maintenance that was never performed. In another case a pole mounted three phase recloser operated six times within 51 days with no impact on the substation level and thus no record available, until a catastrophic failure (the 6th operation of the recloser) which affected 907 customers for 35 minutes. Investigation show that each of these events stressed a bushing and accelerated its degradation and the final event was due to the failure of the bushing.

It should be noted that all these examples are field data not collected by the utilities but by distribution automation research groups. These examples show that there are ample data available in the system to predict component health but lack of knowledge transfer from the distribution system to the controllers is the prime factor for these failures.

These examples show that the distribution system needs not only better performance practices but also needs a system to transfer the component information for further analysis. Monitoring should be done at the component level rather than the feeder level as it will give more in-depth information. All these contribute to the possibility of predicting the reliability of components based on a statistical approach using the component monitoring data.

2.1. Component Condition Assessment

Gulachenski et al (1990) [17] developed a failure prediction model for transformers based on transformer age, electrical load and ambient temperate. The failure rate of the transformer was modeled using a Weibull distribution. Once the failure rate model is developed a calibration method is used to adjust the failure rate to give more realistic values, as it was more pessimistic at high ambient temperature operations. Sokolov (2000) [18] presented discussion on analyzing the condition of a transformer based on field assessment of the transformer. This work focused on condition based maintenance. The work identifies the typical failure modes which are presented in Table 2. This clearly shows that a simple model using the electrical load and ambient temperature is not sufficient to predict the component condition.

TABLE 2

POWER TRANSFORMER FAILURE MODES

System, Components	**Defects**
Electromagnetic circuit	Core, Lamination Age, Winding-turns, Insulation degradation, Insulation Strength
Current currying circuit	Winding strands, joints, poor contacts
Dielectric System	Oil contamination, Abnormal cellulose aging, Partial discharge, Moisture in oil and insulation, Electrostatic shields
Mechanical	Winding geometry, Loosening clamping
Cooling system	Malfunctioning of Pumps and Fans
Bushing	Aging, Local effect: moisture in air, Heating
Oil Preservation	Tank condition, Poor sealing

Brown et al (2004) developed a new approach for distribution component modeling using component inspection data [19]. The paper converts the inspection data into a condition score which is used to determine the failure distribution. Similar to Sokolov (2000) this work uses criteria which affect the health of the component. Based on the importance of each criterion to the health of the component, a weight is assigned. Weighted average condition, x, of the component is defined as,

$$x = \frac{\sum w_i r_i}{\sum w_i}.$$

Where w_i is weight of the component i and r_i is condition score of the component i. Once the weighted average of the component at a given time t is known then the failure rate of the component is defined as,

$$\lambda(x) = Ae^{Bx} + C$$

Authors suggest that the parameters A, B, and C can be determined using benchmarks and statistical analysis and they propose the following approach to determine A, B, and C. The given relationship could be used to initialize these parameters.

$$A = \frac{\lambda(^1/_2) - \lambda(0)^2}{\lambda(1) - 2\lambda(^1/_2) + \lambda(0)}$$

$$B = 2\ln\left(\frac{\lambda(^1/_2) + A - \lambda(0)}{A}\right)$$

$$C = \lambda(0) - A$$

Once these parameters are determined, then A, B, and C should be updated / calibrated using the historical failure data to develop a more exact model. The model developed was tested using reclosers by Jewell, et al, (2006) [20] and they developed a procedure to determine the worst performing components based on these failure rates.

This new approach to determine the component condition is promising as it incorporates more failure modes than Gulachenski et al (1990) and uses the idea of weighting the criteria based on its importance. However the proposed model has some significant drawbacks. The failure rate is modeled as exponential, a non standard random distribution model, but it should be noted that not all components will have exponential failure rate. Further the weighting procedure has a serious concern, for example tank condition is given the lowest weight. The tank has high reliability, however failure of tank is going to adversely affect the health of the transformer, for example any leak in the tank requires the transformer to be taken out of service. Therefore having less weight may not give a reasonable model. When the complete methodology is analyzed it is a model based analysis, and performance of this approach depends highly on calibration.

Dongale (2008) [21] established a procedure to indentify more realistic criteria for component assessment using manufacturer data, standards, guidelines and historical failure data.

In this work, in addition to the traditional criteria, some new criteria were identified, e.g. for a power transformer: experience with the transformer type is included as a criterion. Conditions developed for power transformers are given in Table 3.

TABLE 3

TRANSFORMER CRITERIA FOR CONDITION ASSESSMENT [21]

	Criterion
General	Age of the Transformer
	Experience with Transformer
	Noise Level
	Loading Condition
	Core & Winding Losses
Winding Condition	Winding Turns Ratio
	Condition of Winding
	Condition of Solid Insulation
	Partial Discharge (PD) Test

	Criterion
Oil Condition	Gas in Oil
	Water in Oil
	Acid in Oil
	Oil Power Factor
Physical Condition	Condition of Tank
	Condition of Cooling System
	Condition of Tap Changer
	Condition of Bushing

When these condition criteria are considered, two criteria used by the previous work, namely faults seen by the transformer and the geographical location, are missing. Therefore if complete criteria are to be selected these should be included.

2.2. Performance Based Maintenance Scheme

As the regulators are imposing performance constraints / performance based rates (PBR), it is important for the utility to meet these constraints. Brown (2009) shows how the performance based rates are going to affect the total cost of maintenance and operations and for what performance values the minimum cost would be reached [22]. Figure 5 shows the impact of performance based rates on the total cost. Based on the reward policy the global minimum would be at either the start of decreasing reward (in this example the local minimum) or at the start of increasing penalty (in this example the global minimum). The objective of the utility is to keep the performance requirements as close as possible to the global maximum. In the event this is impossible, then performance requirements should be kept in the dead zone, so that no additional expense due to penalty would be imposed on the utility. In this work and in [10], the authors use

SAIDI as the performance requirement. This is justifiable as the performance objective of a utility to minimize the interruption duration.

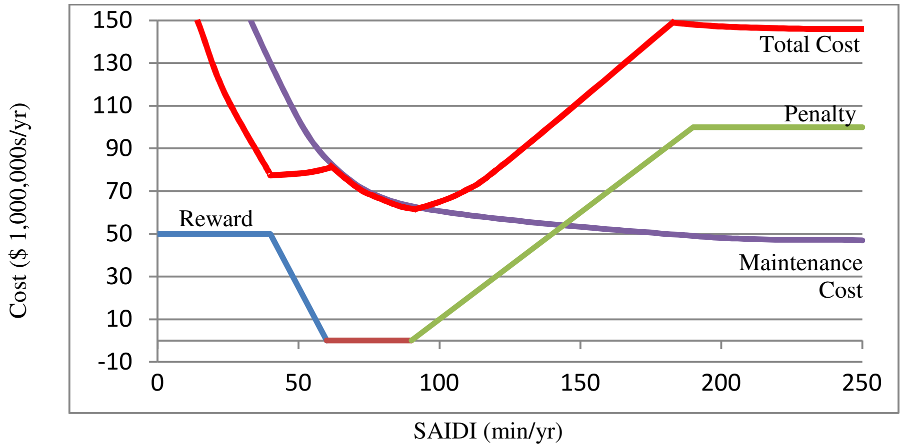


Figure 5: Total Maintenance Cost with Performance Based Rates [22]

There are two major drawbacks to using Performance Based Rates. First, PBR will ensure that the average performance of the system is above the benchmark but there will be some customers who will have poor performance. The second problem is that the utilities would be subjected to new financial risk that may affect the deregulated market [23]. However due to the necessity of the better performance, an approach similar to PBR being imposed by the state regulators is inevitable. If PBR or a similar technique is to be implemented the regulators will have to impose different reliability requirements for different sections within a utility to ensure that none of the customers are neglected. To overcome potential financial distress an optimal scheme to prioritize maintenance scheduling should be developed. There has been very little work done on power system risk based maintenance scheduling. Warner et al (2009) [24] developed an approach to rank the component condition based on minimizing the risk associated with the component. The risk is defined as,

$$Risk = w_1(SAIDI + SAIFI) + w_2(ENS) + w_3(COF)$$

where $w_1, w_2 \& w_3$ are weights based on the importance of the parameters SAIDI, SAIFI, Energy

Not Served (ENS) and Cost of Failure (COF). Since this work does not include the cost of maintenance, need for an optimization model including all these has become a critical task.

2.3. Budget Limitations and Derating

Derating is a common practice to minimize the mechanical and thermal stresses acting on the components [25]. However derating is not common in the electric power industry. If the budget constraints limit the utility's performance of maintenance, derating the current through the component would be a short term solution until the utility allocates the necessary funds. Distribution system components undergo three types of stresses, thermal and mechanical stresses due to the current through the component and the electrical stress mainly due to the voltage applied to the component [26]. The system voltage should be kept as close as possible to the nominal value, therefore derating the system voltage is not a possibility. Nevertheless the load current through a particular component could be reduced by distributing the current through other feeders. Except for shunt components, e.g. shunt capacitors and voltage transformers, the other components could be derated to a value which will improve the system reliability. Derating alone will have no effect until the load is redistributed. Therefore reconfiguration of the system is needed while ensuring the whole system load is supplied without exceeding rated and derated (if applicable) power through all the components. Not much work has been done in this area so a novel approach is necessary.

2.4. Communication Needs for Distribution Reliability

Distribution system needs an improved communication system to increase the system reliability. Increasing system reliability has two parts. First, periodic and abnormal event monitoring of components is needed to predict the condition of the component, and second, communicating failure information to the control center and the crew is needed to speed up the restoration. There has been very little work done on communication for the power distribution system, however guidelines have been created for substation internal communication. The new standard IEC 61850 is for substation application [27] along with its American counterpart DNP and DNP-3 which use a master (control center) slave (RTU) approach. As for the customer side, ANSI Standard C12 has been in use for more than ten years and the newly developed ANSI C12.22 has incorporated two-way communication especially for Advanced Metering Infrastructure (AMI) [28]. AMI and automated meter reading (AMR) applications are the next generation energy metering technology. AMI is already in use by many utilities. ANSI C12.22 is implemented over TCP/IP and is expected to give more flexibility for implementing AMI.

Little work has been done for feeder level communication and for substation, feeder and consumer level combined communication schemes. A preliminary study was conducted by Muthukumar et al [29] for the potential application of wireless sensor networks for distribution feeder communication. Stahlhut et al demonstrates that using inexpensive sensors for monitoring applications on the distribution system is feasible [30]. Using these as the foundation a better approach for determining the communication requirements for distribution reliability should be formed.

2.5. Plug-in Electric Hybrid Vehicles and Reliability

PHEVs are a new type of loads for the electric distribution system and the penetration is expected to be high. PHEVs will increase the residential load profile and the distribution components will need higher ratings or their lives will be reduced [31]. It has been recommended to use controlled charging of PHEVs to reduce the peak load in the system [32]. Charging the PHEVs during the off-peak hours will still increase the stress on many distribution components and the life of these components will be reduced. For example, higher loads off-peak will not allow the distribution transformer to cool down. In order to analyze the effect of PHEVs it is important to model the electric load on the grid due to the PHEVs. A load model developed by Meliopoulos et al [33] for charging PHEVs is given by,

$$P = \frac{BC}{(24 - A_T) + D_T}$$

$$Q = \frac{P}{0.99} \sin\left(\cos^{-1}(0.99)\right)$$

Where, P is the real power consumption of the EV, Q is the reactive power consumption, BC is the electric energy load of the EV, A_T is the charging start time and D_T is the charging end time. It is assumed that the power factor of the battery load is 0.99.

CHAPTER 3

CONDITION BASED ASSET MANAGEMENT

Initial focus was given to the development of performance based maintenance scheduling for the conventional distribution system. Figure 6 shows the performance based maintenance scheme to improve utility reliability. As shown, standards and regulations, component information from the manufacturer, equipment condition data from monitoring devices, and historical data and the system topology would be the input to the system. This work assumes that these data are all available for the utility.

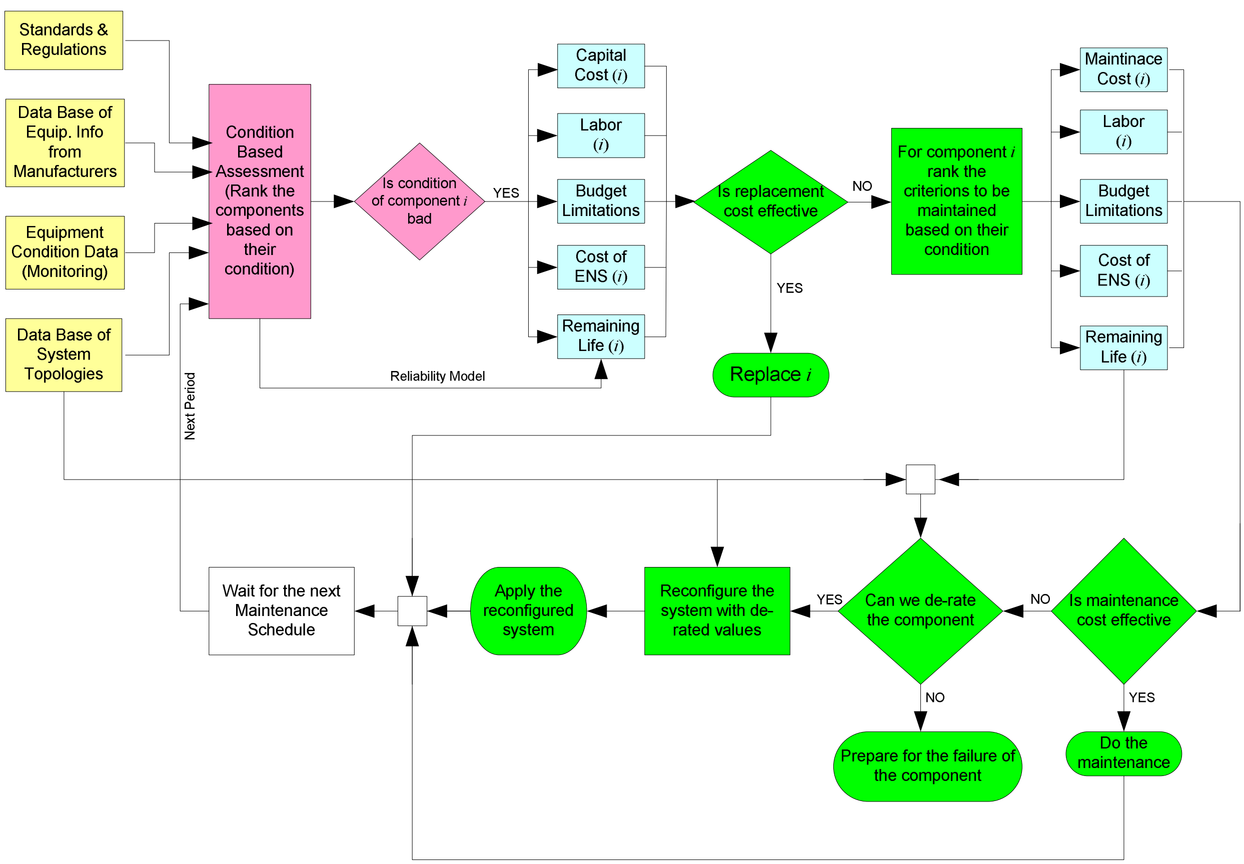


Figure 6: Expected Outcome of the Performance Based Maintenance Model

This work divides the analysis of the performance based component into three parts: component condition assessment, optimal maintenance scheduling and component derating. For analytical purposes the distribution transformer is taken as an example. A similar procedure could be used for other components. The criteria determined by Dongale (2008) [21] with the inclusion of geographical location and faults seen by the transformer are used in this work. Rationales behind the inclusion of these two criteria are:

Faults Seen by the Transformer: Fault currents will be on the order of a few thousand amperes, when the load current is a few hundred amperes. Therefore when fault currents flow through components due to the mechanical and thermal stress the insulation could be affected and cause unexpected failure.

Geographical Location of the Transformer: Moisture in air, ambient temperature, air contamination, and weather conditions will affect the components' health. For accurate predictions these effects should be incorporated into the reliability calculations.

3.1. Component Condition Assessment

As discussed in the chapter 2, reliability for each condition criterion is modeled using standard reliability functions. It could be noted that not all the criteria have increasing hazard rates. For example, when the geographical location is considered, probability of failure will not change in a given geographical location, thus for most cases the geographical location will have a constant hazard rate. More experience with a certain type of transformer will ensure that the prediction of the performance will be more accurate, thus the hazard rate would decrease with increasing experience (which would be related to time). Therefore each criterion should have a distribution which would represent its behavior. The Weibull distribution will be used for increasing, decreasing, and constant hazard rates. The hazard rate $h(t)$ for Weibull distribution is given by,

$$h(t) = \frac{\beta}{\theta}\left(\frac{t}{\theta}\right)^{\beta-1} \tag{3.1}$$

where β is known as the shape parameter and θ is known as the scale parameter. Figure 7 shows how the selection of these parameters affects the hazard rate. In general $\beta > 1$ will result in an increasing hazard rate, $\beta = 1$ will produce a constant hazard rate and $\beta < 1$ will result in a decreasing hazard rate.

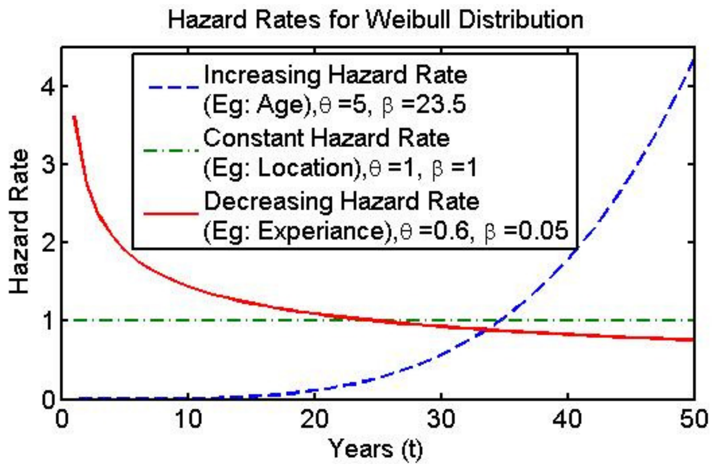


Figure 7: Hazard rate function for Weibull distribution

Another advantage of the Weibull distribution is that unlike most of reliability distribution functions, Weibull needs few data points to accurately model the distribution function [35]. Since only limited failure information is available for power distribution components, the Weibull distribution is expected to give a more accurate model.

For these reasons, the Weibull distribution is preferred. When computing the reliability functions, either historic data will be available, from which the reliability function could be determined, or certain guidelines or standards would be available and may need to be manipulated into the reliability model, or a hypothetical model may have to be developed in case nontraditional criteria are used. The following three examples are given to illustrate all three techniques.

3.1.1. Example 1: Reliability from historic data

In this case sufficient historic data is assumed to be available. For analytical purposes, the relationship between the hazard rate and the age of the transformer given in Barnes et al [36] is used. The following method determines the shape and scale parameters of the Weibull distribution hazard rate given in (3.1)

$$\log_{10} h(t) = \log_{10}\left(\frac{\beta}{\theta^{\beta}}\right) + (\beta - 1)\log_{10} t$$

The Weibull parameters θ and β are found for the given hazard rate from the historical data $H(t)$, using the least square method slope and y-axis intersection. For the data given in Barnes et al, the plot of $\log_{10} t$ verses $\log_{10} H(t)$ is given in Figure 8.

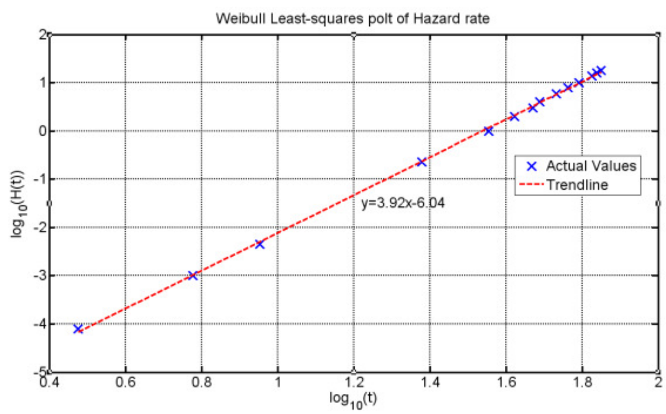


Figure 8: Weibull Least-square plot of Hazard Rate

From the plot we know the gradient,

$$(\beta - 1) = 3.92 \quad \Rightarrow \beta = 4.92,$$

then

$$\log_{10}(4.92) - 4.92\log_{10}(\theta) = -6.04 \quad \Rightarrow \theta = 23.35$$

The hazard rate values from Barnes et al and from the results of the proposed method are compared in Figure 9. It is seen that the generated hazard rate function follows the data given by Barnes et al well.

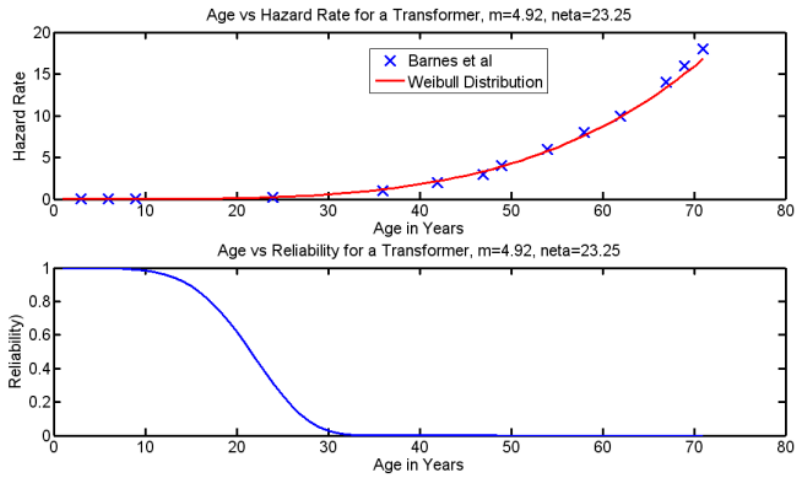


Figure 9: Comparing the hazard rate plot and reliability plot

Once the Weibull parameters are known, the reliability, $R(t)$ associated with the criterion could be defined by,

$$R(t) = e^{-\left(\frac{t}{\theta}\right)^{\beta}} \tag{3.2}$$

In place of the hazard rate, if the failure distribution or reliability distribution is known, then the relationship given in [35] could be used to model the known distribution function.

Even though most components' reliabilities can be modeled using the Weibull distribution, there are some components that cannot be modeled using the Weibull distribution. In this case the trend line in Figure 9 will not be a straight line. If the trend line is not a straight line, other distribution functions will be tried and the best fitting distribution will be used.

∎

3.1.2. Example 2: Reliability from guidelines / standards

For some of the criteria existing standards are available. Examples include NEMA standards for transformer noise level, IEEE 57.91-1995 for loss of insulation life, and IEEE C57.104-2008 for gas in oil. If no historic failure data are available for a criterion but a standard exists then the standard will be used as a tool to determine the reliability function. Gas in oil is taken as an example to illustrate the modeling. IEEE C57.104-2008 [37] provides four levels to classify the risk for oil – immersed transformers due to presence of gas in oil [37]. Table 4 shows the relationship of transformer condition and total dissolved combustible gasses in parts per thousand (ppk).

TABLE 4

DISSOLVED GAS STANDARDS (IEEE57.104-2008) [37]

Status	**TDCG (ppk)**	**Remarks**
Condition 1	< 0.72	Normal aging of oil
Condition 2	0.72 – 1.92	Decomposition and excess oil aging
Condition 3	1.92 – 4.63	Excessive oil aging
Condition 4	> 4.63	Very poor oil condition

Similar to the parameter estimation in example 1, parameters will be estimated using the reliability function. Based on the IEEE standard, reliability values for the four boundaries of Total Dissolved Combustible Gases TDCGs will be used to find the reliability distribution. Condition 4 indicates that the oil is in very poor condition; therefore a reliability value of 0.02 would be assigned for TDCG of 4.63 ppk.

For the variable TDCG (given by x) the following relationship is derived from (3.2):

$$\ln\left(\ln\left({}^{1}\!/_{R(x)}\right)\right) = \beta \ln x - \beta \ln \theta$$

The Weibull distribution has the following property for increasing hazard rate:

$$h(t) = \begin{cases} 1 < \beta < 2 & \text{Concave hazard rate} \\ \beta = 2 & \text{Linear hazard rate} \\ \beta > 2 & \text{Convex hazard rate} \end{cases}$$

Most of the physical criteria have convex hazard rates as the incremental rate of the hazard rate (rate of degradation) increases with time. Based on the expected incremental rate behavior the shape parameter β will be fixed. For this example, it should be noted that if the TDCG is higher than 4.63 ppk, then the gas in the oil is going to have an extremely adverse effect, and the oil should be treated as soon as possible. Therefore a higher incremental rate is expected and β will be fixed at 4. The scale parameter θ is found as,

$$\theta = \exp\left(\frac{\beta \ln x - \ln\left(\ln\left({}^{1}/_{R(x)}\right)\right)}{\beta}\right) = 3.3$$

Once the Weibull parameters are known the reliability for the criterion will be calculated.

■

3.1.3. Example 3: Hypothetical reliability

Some of the criteria proposed in this work are nonconventional and thus, neither historic data nor guidelines are available. In these cases hypothetical reliability will be found. Experience with the transformer type is a good example for this case. Experience with the transformer has a decreasing hazard rate; as more experience is gained with a transformer type, uncertainty decreases. To obtain a decreasing hazard rate we could use a Weibull distribution with the following conditions.

Let

F	– Total number of transformers failed
s	– Total number of similar transformers handled
S_F	– Total number of similar transformers failed
S_U	– Total number of similar transformers with unknown cause

Using the trivial expectations the scale parameter β could be defined as,

$$\beta = {}^{S_U}/_{S_F}$$

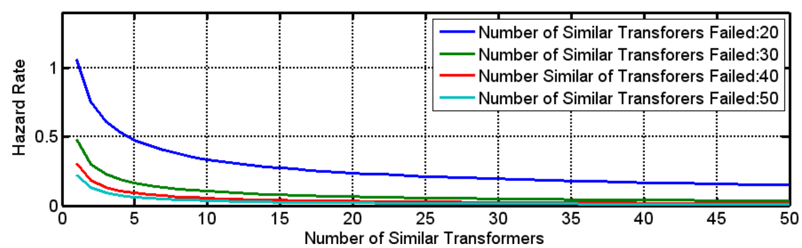
and the scale parameter θ could be defined as,

$$\theta = {}^{S_F}/_{F}$$

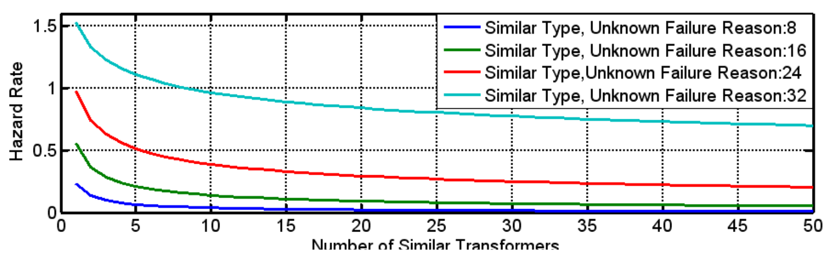
Therefore the hypothetical hazard rate for experience with the transformer type, as a function of similar type of transformers handled, s, will be,

$$h(s) = \frac{\beta}{\theta}\left(\frac{s}{\theta}\right)^{\beta-1}$$

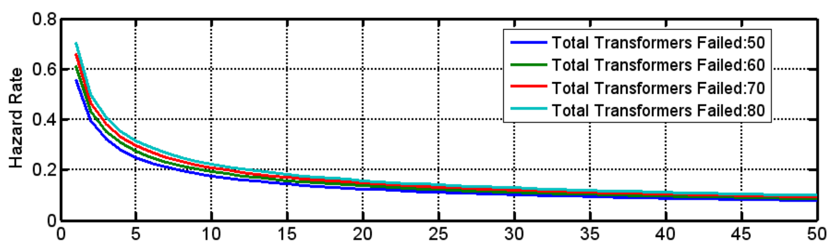
The hazard rate is a function of the number of similar transformers used and not a function of time. In other words the hazard rate will only change if the utility handles more similar transformers. To verify this hazard rate model, the following analytical study was done. Three different cases were considered: change S_F while keeping S_U & F constant, change S_U while keeping S_F & F constant, and change F while keeping S_U and S_F constant. When S_F, S_U and F are kept constant, the numerical values used are 40, 10 and 90 respectively. The constant values for the results are plotted in Figure 10.



(a) Change S_F for given S_U & F



(b) Change S_U for given S_F & F



(c) Change F for given S_F & S_U

Figure 10: Analytical study for the hypothetical hazard rate

As more transformers of similar type fail, while keeping the number of similar type transformers failed with unknown reason constant, the number of transformers failed with known reason will increase. This should decrease the insecurity with that transformer type and thus the hazard rate should decrease. Numerical analysis using the hazard rate in Figure 10 (a) agrees with this expectation. Similarly, as the number of similar transformers failed with unknown reason increases while the number of similar transformers failed is kept constant, the hazard rate will be higher, as the utility has less understanding about the transformer, which is in accordance with Figure 10(b). On the other hand, the total number of transformers failing should not have much impact on the hazard rate if the number of similar transformers failed and the number of similar transformers failed without the reason known does not change. Figure 10(c) is also in accordance with this expectation. Therefore, it could be concluded that this hypothetical hazard rate is an accurate model.

Using these Weibull parameters the reliability function will be developed. When the utility starts to observe / monitor these criteria it could update the parameters to obtain a more accurate model.

■

Using these modeling techniques reliability functions for all the criteria can be found. The next step will be to calculate the reliability of the component at the given time. The reliability model for the component is developed based on a series/parallel topology, examining the common grounds one criterion has with another [38]. As an example, if average transformer loading is less than rated loading, then the transformer should be healthy for more than the expected life span, thus "loading" and "age" criteria are connected in parallel. On the other hand, water or gas or acid in oil will adversely affect the transformer, thus they are connected in series.

The proposed reliability model for the transformer is given in Figure 11.

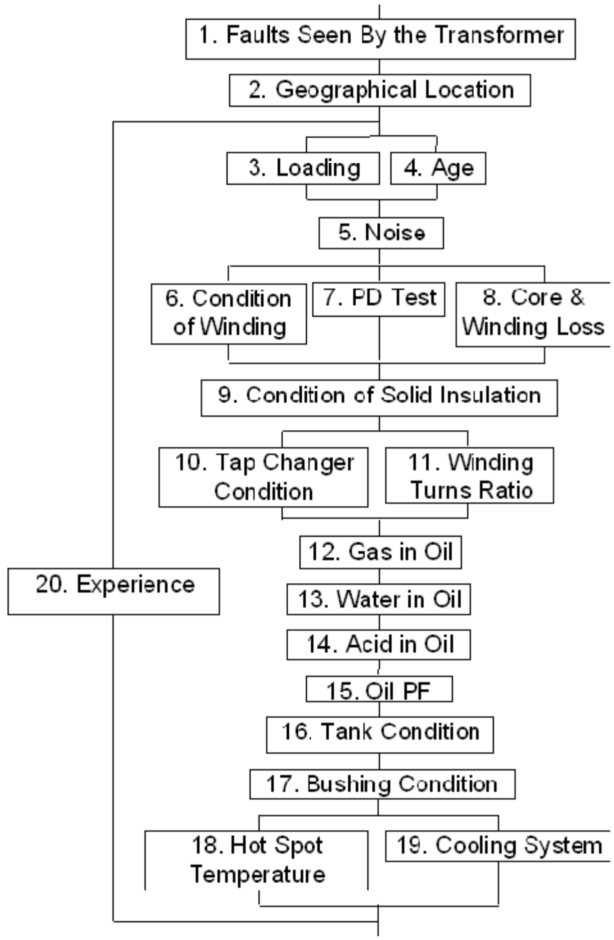


Figure 11: Series Parallel Topology for Transformer Criteria

Once the Reliability Model is formed, the next step is to allocate weights for each component based on the importance of the criterion for overall health of the component. The allocation of weights is more system specific; experience and manufacturer information should be used. The following guideline is used to allocate the weights,

1. The maximum possible weight for a component is one (1). The more the important the criterion to the healthy functioning of the component, the higher the weight is. For example, tank condition has a higher weight than gas in oil, ie. low ppk. of gas in oil will be less harmful than a crack in the tank.

2. Weight for a criterion *i* will have two parts.

   a. *Effect the criterion has on the failure of the component* (W_i^E)

   This part of the weight for each criterion should be allocated by experience. It is recommended that utility engineers should weight the criterion out of 50 possible points.

   b. *Average maintenance and replacement seen for a criterion during the life of a component* (W_i^M).

   The following relationship shall be used to determine this portion of the weight

$$W_i^M = \frac{MR_{same}}{MR_{total}} \times 50$$

where,

MR_{same} = Total number of maintenance tasks and replacements needed for *i* during the life of the component

MR_{total} = Total number of maintenance tasks and replacements for all criteria, during the life of the component.

Therefore the weight for a criterion *i* shall be given as,

$$W_i = \frac{W_i^E + W_i^M}{100}$$

Let $\widetilde{R_1}, \widetilde{R_2} \dots \widetilde{R_n}$ and $\widetilde{Q_1}, \widetilde{Q_2} \dots \widetilde{Q_n}$ be weighted reliabilities and failure distributions for each criterion (For the transformer $n = 20$). If the actual reliability of criterion i at the given time t is R_i then weighted failure distribution for the criterion i is,

$$\widetilde{Q_i} = W_i \times (1 - R_i)$$

Then the weighted reliability for the same criterion is given by,

$$\widetilde{R_i} = 1 - \widetilde{Q_i}$$

The next step is to calculate the reliability function of the component. Reduction of the series-parallel topology will result in the component reliability. When two criteria are connected in series, individual reliabilities ($\widetilde{R_i}$) are multiplied to determine the reliability of the combined criteria. When two criteria are connected in parallel their failure distributions $(1 - \widetilde{R_i})$ are multiplied to get the failure distribution of the combined criteria. The series-parallel connection of the power transformer is given in Figure 12 with the resulting reliability values.

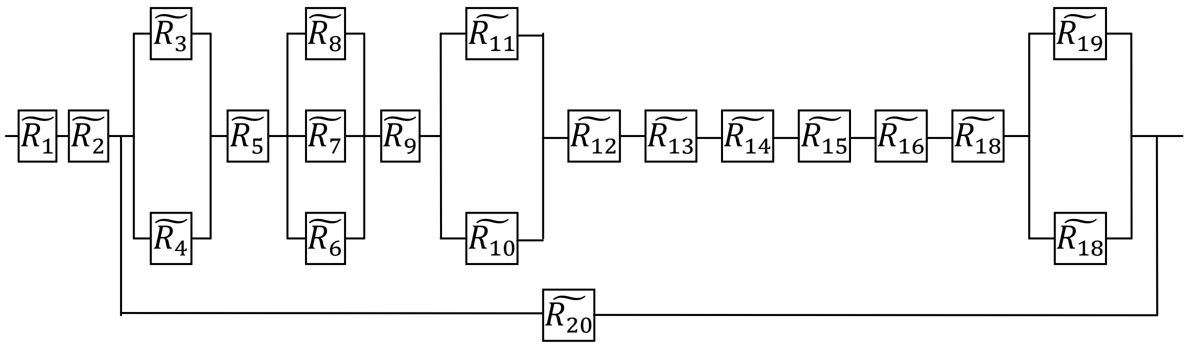


Figure 12*:* Series –Parallel topology of transformer with reliability

The transformer reliability is,

$$R_{sys} = \widetilde{R_1} \times \widetilde{R_2} \times \widetilde{R_{s20}}$$

where,

$$\widetilde{R_{34}} = 1 - (1 - \widetilde{R_3})(1 - \widetilde{R_4})$$

$$\widetilde{R_{678}} = 1 - (1 - \widetilde{R_6})(1 - \widetilde{R_7})(1 - \widetilde{R_8})$$

$$\widetilde{R_{1011}} = 1 - (1 - \widetilde{R_{10}})(1 - \widetilde{R_{11}})$$

$$\widetilde{R_{1819}} = 1 - (1 - \widetilde{R_{18}})(1 - \widetilde{R_{19}})$$

$$\widetilde{R_s} = \widetilde{R_{34}}\widetilde{R_5}\widetilde{R_{678}}\widetilde{R_9}\widetilde{R_{1011}}\widetilde{R_{12}}\widetilde{R_{13}}\widetilde{R_{14}}\widetilde{R_{15}}\widetilde{R_{16}}\widetilde{R_{17}}\widetilde{R_{1819}}$$

$$\widetilde{R_{s20}} = 1 - (1 - \widetilde{R_{20}})(1 - \widetilde{R_s})$$

3.1.4. Component Condition Score

Once the reliability of the component is determined, the next step is to interpret the reliability in terms of a feature that could be easily interpreted by the maintenance crew. The following relationship is defined as component condition score (CCS), which would give the relative condition of the component.

$$CCS(t) = \frac{R_{sys}(t) - R_{sys}(worst)}{R_{sys}(best) - R_{sys}(worst)}$$

Where, $R_{sys}(t)$ is the calculated weighted reliability at the given time period. $R_{sys}(worst)$ is the allowable worst weighted reliability calculated based on the historic data, and $R_{sys}(best)$ is the weighted reliability at the time of installation of the component.

3.1.5. Component Condition Report

Once the component condition score is calculated, it should be compared with a reference to determine the actions to be taken. Four grades established by CIGRE WG12.18 are used to decide the condition of a component [39], namely

a. *Normal Condition:* No obvious problems in the component. In other words defect-free condition.

b. *Defective Condition:* Component has reversible abnormalities. This will affect the life of the component in the long term.

c. *Faulty Condition:* Component has faults, and faults are irreversible. This will affect the reliability in the short term.

d. *Failed Condition:* The component can't remain in service. Remedial action must be taken before the component can be returned to service.

A condition reporting guideline similar to the above standard is used in this analysis. Table 5 shows the condition reporting guidelines.

TABLE 5

EQUIPMENT CONDITION REPORT

Normal 100-90 %	Defective 90–10 %							Faulty 20–10 %	Failed 10–0 %
	Fair	Mild	Satisfactory	Stable	Serious	Critical	Extremely Critical		

If a component is *Normal* there is no need to schedule a maintenance task; the next component maintenance should be planned after one year. If the component is *Defective*, then the maintenance task should be scheduled based on the subcategory. In order to give some choices and visual understanding *Defective* is divided into 7 sub-conditions. Depending on the severity of the condition and available resources, maintenance can be prioritized. If the component is *Faulty* then immediate attention should be given to that component. Resources should be wisely utilized to make sure no component falls into the Faulted condition as this will adversely affect reliability within a short time. If the component falls into the failed category, then its condition is critical and it could fail soon, therefore immediate replacement of the component is necessary.

3.2. Optimal Maintenance Scheduling

Most of the distribution systems in North America are radial and failure of a single component in a radial system will result in worse reliability indices compared to other topologies. Therefore we are limiting this analysis to radial distribution systems. A similar approach can be taken to other types of distribution systems.

A system is divided into zones which are physically not connected, except at the substation. Since these zones are not connected, failure in a zone will not affect other zones. As shown in Figure 13Figure 13, zone 1 is independent of zone 2 and 3. Any failure in zone 1 will not affect zone 2 or 3. The same applies for zone 2 and zone 3. Thus each zone could be considered as separate module.

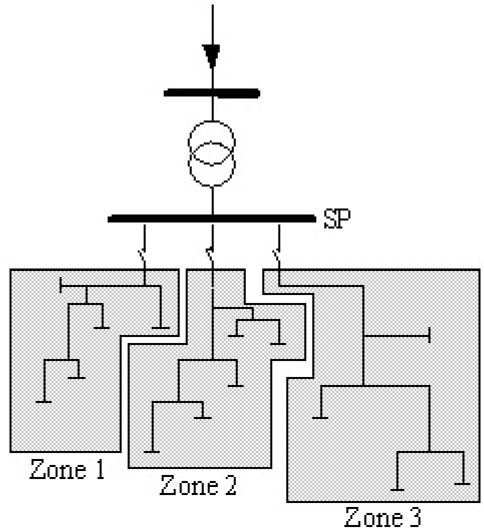


Figure 13: Radial Distribution System

Since failure in each zone is independent of other zones, the system SAIDI will be the summation of all the zonal SAIDI's [6], that is,

$$SAIDI_{sys} = \sum_{\forall i} SAIDI(i) = \sum_{\forall i} h(i) \frac{\sum_{\forall j} d_j}{N}$$

where, i = 1,2,3,… is the number of zones in the system, $SAIDI_{sys}$ is the system SAIDI, $SAIDI(i)$ is the SAIDI of the i^{th} zone, $h(i)$ is the hazard rate of component j, d_j is the interruption duration seen by customer j due to failure of component j, and N is the total number of customers served.

3.2.1. Optimal Allocation

The aim of this work is to allocate the component reliability indices in a least-cost manner and we take an approach similar to that given in [35]. The cost model is taken similar to that of [35] with the same argument.

$$\min z = \sum_{\forall i} c_i x_i^2$$

Where, x_i is the increase in the average hazard rate of zone i, and $c_i x_i^2$ is the cost of increasing the average hazard rate by x_i. Since SAIDI is a better measure for PBR, the aim of this work is to increase the system SAIDI above the required value (e.g. SAIDI for global minimum total cost).

Because of the financial limitations, SAIDI is kept at the desired value. Thus the constraint for the problem is formed as,

$$SAIDI_{sys}^{*} = \sum_{\forall\, i} h^{*}(i) \frac{\sum_{\forall\, j} d_j}{N} = SAIDI_{desired} (= S^{*})$$

Where, $h_i^{*}(i) = h_i^{*}(i) + x_i$, if we define the increase in SAIDI to reach the desired SAIDI as $\Delta S\left(S^{*} - SAIDI_{sys}\right)$, then the constraint is reformulated as,

$$\sum_{\forall\, i} x_i \frac{\sum_{\forall\, j} d_j}{N} = \Delta S$$

Considering the cost function and the constraint formed in this section, the Lagrangian is formed as,

$$\mathcal{L}(\mathbf{x}, \beta) = \sum_{\forall\, i} c_i x_i^2 - \beta \left(\left(\sum_{\forall\, i} x_i \frac{\sum_{\forall\, j} d_j}{N} \right) - \Delta S \right)$$

Necessary conditions for a minimum are found by,

$$\frac{\partial}{\partial x_i} \mathcal{L}(\mathbf{x}, \beta) = 2 c_i x_i^2 - \beta \frac{\sum_{\forall\, j} d_j}{N} = 0 \qquad (3.3)$$

$$\frac{\partial}{\partial \beta} \mathcal{L}(\mathbf{x}, \beta) = \left(\sum_{\forall\, i} x_i \frac{\sum_{\forall\, j} d_j}{N} \right) - \Delta S = 0 \qquad (3.4)$$

The solution to (3.3) and (3.4) would give the optimal increase in the hazard rate for each zone as,

$$x_i = \frac{\Delta S \alpha_i}{c_i \sum_{\forall\, i} \left(\frac{\alpha_i^2}{c_i} \right)}$$

where, $\alpha_i = \sum_{\forall\, j} d_j$

Therefore the allocated / desired hazard rate for each zone is:

$$h^{*}(i) = h(i) + \frac{\Delta S \alpha_i}{c_i \sum_{\forall\, i} \left(\frac{\alpha_i^2}{c_i} \right)} \qquad (3.5)$$

3.2.2. Component Reliability Allocation

Once zonal allocated hazard rates are obtained, the next and final step is to allocate the reliability to the components in each zone to meet the requirement. Even though physically these components may not be connected in series, when the reliability is calculated it is assumed all the components are connected in series in each zone. This assumption is fair as series topology gives the worst reliability and if the system is designed for the worst performance, then achieving minimum required reliability / performance will be assured. A popular engineering optimization approach, the ARINC method [40], to find the component level allocated reliability, is used. The allocated reliability of component *k* in the i^{th} zone is:

$$h_k^* = W_k \times h_i^* \tag{3.6}$$

Where, $W_k = h_k / \sum_{\forall j} h_k$. Using (3.5) and (3.6), the allocated reliability of component *k* is:

$$h_k^* = W_k \left(h_i + \frac{\Delta S \alpha_i}{c_i \sum_{\forall i} \left(\frac{\alpha_i^2}{c_i} \right)} \right)$$

In this analysis in order to find the zonal interruption duration (α_i), the following relationship is used. Since series topology was assumed for the components, the zone hazard rate is the summation of hazard rates of all the components in the zone.

$$\bar{h}_i = \sum_{\forall k} h_k$$

This will result in the zonal interruption duration as,

$$\alpha_i = \frac{SAIDI_i}{\bar{h}_i} = \frac{SAIDI_i}{\sum_{\forall k} h_k}$$

3.2.3. Suboptimal Solution

Component allocated hazard rate found in equation 4.6 may not always within practically achievable hazard rates for components. Thus optimal solution is not always feasible. In order to incorporate the limitations on hazard rates, modified hazard rates are used as given,

Step 1: Find the allocated hazard rates for all the components using

$$h_k^* = W_k\left(h_i + \frac{\Delta S \times \alpha_i}{c_i \sum_{\forall\, i}\left(\frac{\alpha_i^2}{c_i}\right)}\right)$$

Step 2: Check if any of the allocated hazard rates are below the minimum feasible hazard rate ($\hat{h}_k$). If all the allocated hazard rates are within the feasible range stop; else go to step 3.

Step 3: Fix the allocated hazard rates to $\hat{h}_k$ if ${h_k}^* < \hat{h}_k$

Step 4: Recalculate the allocated hazard rates. Since the network topology is assumed to be series the improvement in the hazard rate of a zone is the sum of improvements of all the equipment in that zone, ie, improvement in a zone *i* will be the sum of the improvement of all the equipment (*j*)

$$x_i = \sum_{\forall\, k} x_k$$

If *r* components in zone *i* reached their physical limitations when optimal allocation was done. Therefore improvement of these *r* components would be limited to their physical limitations. Let ***A*** be a set with all components which reached physical limitations

$$x_i = \sum_{\forall\, k \notin A} x_k + \sum_{\forall\, k \in A} \hat{x}_k$$

Where, $\hat{x}_k = \hat{h}_k - h_k$and let,

$$\tilde{x}_i = \sum_{\forall\, k \notin A} x_k \text{ and } \quad \tilde{x}_{i,A} = \sum_{\forall\, k \in A} \hat{x}_k$$

The improvement in SAIDI is rewritten as,

$$\Delta S = \sum_{\forall\, i}\left(\tilde{x}_i + \tilde{x}_{i,A}\right)\frac{\sum_{\forall\, j} d_j}{N}$$

$$\Delta S = \sum_{\forall\, i} \tilde{x}_i \frac{\sum_{\forall\, j} d_j}{N} + \sum_{\forall\, i} \tilde{x}_{i,A} \frac{\sum_{\forall\, j} d_j}{N} \tag{3.7}$$

Since $\tilde{x}_{i,A}$ is a known constant, (3.7) becomes:

$$\overline{\Delta S} = \Delta S - \sum_{\forall\, i} \tilde{x}_{i,A} \frac{\sum_{\forall\, j} d_j}{N} = \sum_{\forall\, i} \tilde{x}_i \frac{\sum_{\forall\, j} d_j}{N} \tag{3.8}$$

Thus the recalculated allocated hazard rates are,

$$h_k^* = W_k \left(h_i + \frac{\overline{\Delta S} \times \alpha_i}{c_i \sum_{\forall\, i} \left(\frac{\alpha_i^2}{c_i} \right)} \right)$$

Step 5: Check if any of the allocated hazard rates are below the minimum feasible hazard rate (h_k^*). If all the allocated hazard rates are within the feasible range stop; else go to step 3.

3.3. Short Time Performance Boost

3.3.1. Derating

Budget constraints may not allow the utility operations engineers to improve the component reliability to the required level. If the component is not maintained there is a high possibility that the component will fail in the near future. One way to extend the lifetime of a component is to derate the component. Once the component is derated the system should be reconfigured so that the new load on the system will not exceed the derated value. Since thermal stress is vital, this analysis is based on reducing the thermal stress. A similar analysis could be done for mechanical stress too. This section proposes a technique to derate the components to achieve the desired (allocated) hazard rate.

There are two relationships that could be used to find the relationship between the derating and hazard rates [41]

$$h_2 = h_1 e^{K\left(\frac{1}{T_1} - \frac{1}{T_2}\right)} \tag{3.9}$$

$$h_2 = h_1 \left(\frac{V_2}{V_1} \right)^n G^{(T_2 - T_1)} \tag{3.10}$$

In the distribution system the voltage cannot be changed, therefore the relationship between the operating temperature and the failure hazard rate given in (3.9) is used in this analysis. If the present hazard rate of the equipment is $h_{rated}$and $h_{allocated}$ is the allocated hazard rate of the component to obtain the desired system SAIDI then (3.9) could be modified as,

$$h_{allocated} = h_{rated} e^{K\left(\frac{1}{T_{rated}} - \frac{1}{T_{allocated}}\right)}$$

Thus,

$$\frac{1}{T_{allocated}} = \frac{1}{T_{rated}} - \frac{1}{K} \ln\left(\frac{h_{allocated}}{h_{rated}}\right)$$

If the manufacturer provides the relationship between the change in temperature and current through the component, then that relationship is used. Otherwise the generalized relationship given in Table 6 is used.

TABLE 6

RELATIONSHIP BETWEEN CURRENT AND TEMPERATURE RISE.

Component	**Relationship**
Overhead Lines	$I^2 = K(T_{conductor} - T_{ambient})$[42] [42]
U/G Cables	$(T_{conductor} - T_{ambient}) = R_{TH}(I^2 R)$ [42]
Transformer	$(T_{conductor} - T_{ambient}) = (P_\Sigma / A_T)^{0.833}$ [43]

Where,

K - Proportional constant.

R_{TH} - Total thermal resistance between conductor and the air.

R - Electric resistance of the conductor.

P_Σ - Total transformer losses.

A_T - Surface area of the transformer.

If the following relationship between the current and the temperature, which could be used for any component, is used,

$$T = \alpha I^2$$

Then,

$$\frac{1}{\alpha I_{allocated}^2} = \frac{1}{\alpha I_{rated}^2} - \frac{1}{K}\ln\left(\frac{h_{allocated}}{h_{rated}}\right)$$

$$\Rightarrow \frac{1}{I_{allocated}^2} = \frac{1}{I_{rated}^2} - \frac{\ln\left(\frac{h_{allocated}}{h_{rated}}\right)}{\underbrace{\frac{K}{\alpha}}_{K_\alpha}} \tag{3.11}$$

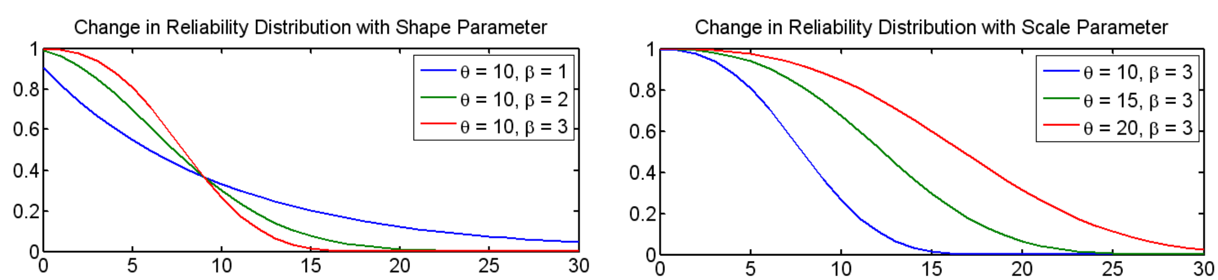
where, I_{rated} is the rated current, , and $I_{allocated}$ is the derated current to achieve $h_{allocated}$. K_α for each component can be found, and to find K_α the following relationship is used [44]:

"An 8% reduction in loading will double the expected lifetime;

similarly an 8% increase will halve the lifetime"

A relationship between the rated current and actual hazard rate and the derated current (by 8%) and the improved hazard rate is found to determine the value of K_α.

The relationship between the lifetime and the hazard rate is dependent on the reliability distribution model. It could be assumed that the doubled lifetime will result in doubling the Mean Time To Failure (MTTF). Since a Weibull distribution is used as the hazard distribution for most of the components, it is used to illustrate the relationship. Figure 14 shows how reliability varies with different shape and scale parameters.



(a) Shape Parameter varied for given scale parameter *(b) Scale Parameter varied for given shape parameter*

Figure 14: Reliability Function for different shape and scale parameters

Figure 14(b) shows that a change in scale parameter will improve the lifetime, and therefore the shape parameter is kept constant and the scale parameter is changed to achieve the new MTTF. The difference between the scale parameter before and after derating using the MTTF of Weibull distribution is found by the following relationship. MTTF for the Weibull distribution is,

$$MTTF^{Weibull} = \theta \times \Gamma\left(1 + \frac{1}{\beta}\right)$$

MTTF at rated power is,

$$MTTF^{Weibull}_{rated} = \theta_{rated} \times \Gamma\left(1 + \frac{1}{\beta}\right)$$

where, θ_{rated} is the scale parameter at rated lifetime.

MTTF at double the lifetime (8% less than the rated power),

$$MTTF^{Weibull}_{double} = \theta_{double} \times \Gamma\left(1 + \frac{1}{\beta}\right)$$

where, θ_{double} is the scale parameter when the lifetime is doubled. Since

$$MTTF^{Weibull}_{double} = 2 \times MTTF^{Weibull}_{rated}$$

Then,

$$\theta_{double} = 2\theta_{rated}$$

The hazard rate for the Weibull distribution at rated power at time t_1 (In this case the component is not derated),

$$h_{rated} = \frac{\beta}{\theta_{rated}}\left(\frac{t_1}{\theta_{rated}}\right)^{\beta-1}$$

The hazard rate at doubled lifetime at the same time t_1 (In this case the component is derated),

$$= \frac{\beta}{\theta_{double}}\left(\frac{t_1}{\theta_{double}}\right)^{\beta-1}$$

Therefore,

$$\frac{h_{double}}{h_{rated}} = \frac{\left(\frac{t_1}{\theta_{double}}\right)^{\beta-1}}{\frac{\beta}{\theta_{rated}}\left(\frac{t_1}{\theta_{rated}}\right)^{\beta-1}} = \left(\frac{\theta_{rated}}{\theta_{double}}\right)^{\beta} = \left(\frac{1}{2}\right)^{\beta}$$

Using the rated current before derating and 92% of the rated current (expected to double the remaining life of the component), K_α is determined,

$$\frac{1}{I_{92\%}^2} = \frac{1}{I_{rated}^2} + \frac{\beta \ln(2)}{K_\alpha}$$

$$K_\alpha = 0.6931\beta \frac{I_{92\%}^2 \times I_{rated}^2}{I_{rated}^2 - I_{92\%}^2} \tag{3.12}$$

Where, $I_{92\%}$ is the 92% of the rated current I_{rated}.

$$I_{92\%}^2 = 0.8464 I_{rated}^2 \tag{3.13}$$

(3.13) in (3.12) gives,

$$K_\alpha = 0.6931\beta \frac{0.8464 I_{rated}^2}{0.1536} = (3.8193\beta) I_{rated}^2$$

Once K_α is determined the required derated current is found using the following relationship,

$$\Rightarrow I_{allocated} = \sqrt{\frac{K_\alpha}{K_\alpha - \ln\left(\frac{h_{allocated}}{h_{rated}}\right) I_{rated}^2}} I_{rated}$$

3.3.2. Reconfiguration

Derating alone will not mean anything to the utility unless the load on the component is reduced to a value less than the derated value. Therefore the system should be reconfigured. The conditions that should be satisfied are the whole load should be supplied after the reconfiguration while minimizing the number of switching operations and improving the system reliability to the allocated values. A heuristic approach is taken for the reconfiguration.

Once the derated currents for all the necessary components are determined, these components should be ranked based on the risk to the system if that component goes out of service. The risk associated with the component is developed similar to [46]. The five conditions of the risk function are,

1. The difference between the allocated hazard rate and the actual hazard rate.
2. Inconvenience caused to the customers due to the failure of the component.
3. Revenue lost by the utility, due to the loss of load
4. Cost of emergency restoration and replacement of the component
5. Regulatory penalties due to violation of regulatory limits.

The health of the component is critical to the risk associated with the component's failure. The health of the component can be determined using the hazard rate. The following relationship is used to define the associated risk, $FR(k)$, with health of the component k .

$$FR(k) = \frac{h_k^{actual}(t) - h_k^{desired}(t)}{h_k^{desired}(t)}$$

Where $h_k^{actual}(t)$ is the actual hazard rate of the component before derating and $h_k^{desired}(t)$ is the desired hazard rate calculated by a maintenance cost optimization scheme similar to [10].

Inconvenience caused to the customers due to the failure of the component k could be given by the average time taken to restore the energy to the customers. IEEE standard 1366-2003 defines this as customer average interruption duration index (CAIDI) [6]. Li et al (2004) developed a technique to analyze the performance of the system based on component k's impact on the system [45]. Using the definition given in [6] impact on system average interruption frequency index (SAIFI) and system average interruption duration index (SAIDI) due to the failure of component k could be defined as,

$$\Delta SAIFI(k) = \left(\frac{\partial(h_k(t)}{\partial t}\right)\frac{S(k)}{N}$$

$$\Delta SAIDI(k) = \left(\frac{\partial(h_k(t)}{\partial t}\right)\frac{D(k)}{N}$$

Where, $h_k(t)$is the hazard rate of the component k as a function of time t, $S(k)$ is the number of customers experiencing sustained interruption due the failure of component k, $D(k)$ is the sustained interruption duration for all customers due to failure of component k and N is the total number of customers. Therefore the impact to the CAIDI could be given as,

$$\Delta CAIDI(k) = \frac{\Delta SAIDI(k)}{\Delta SAIFI(k)} = \frac{D(k)}{S(k)}$$

The risk component based on the system performance due to the failure of component k is the weighed (α_1 and α_2) summation of the risk associated with the hazard rate and the customer inconvenience, i.e.,

$$Risk_R(k) = \alpha_1 FR(k) + \alpha_2 \Delta CAIDI(k)$$

Normalized revenue lost by the utility determined in [46] is used in this work. This factor is given by,

$$RL(k) = \frac{\sum_{ENS\,k}[Load(i) \times Rate(i)]}{\sum_{Total}[Load(i) \times Rate(i)]}$$

Where the numerator is the summation of the total load, $Load(i)$, for each tariff rate, $Rate(i)$, that would not be served because of failure of component k. The denominator is the summation of the total load, $Load(i)$, for each tariff rate, $Rate(i)$, for the system.

Unexpected cost of emergency restoration and replacement ($CR(k)$) is a monetary factor. The costs will include any cost related to the unplanned event and not the total cost incurred.

Depending on the reliability requirements imposed by the regulators, risk due to the regulatory penalties could be determined. As an example, if the performance based rates are imposed on a utility then the utility must ensure that the system reliability is within the requirements. If a performance based rate similar to the one given in Figure 15 is used, then the utility has to make sure that the SAIDI is within S_3.

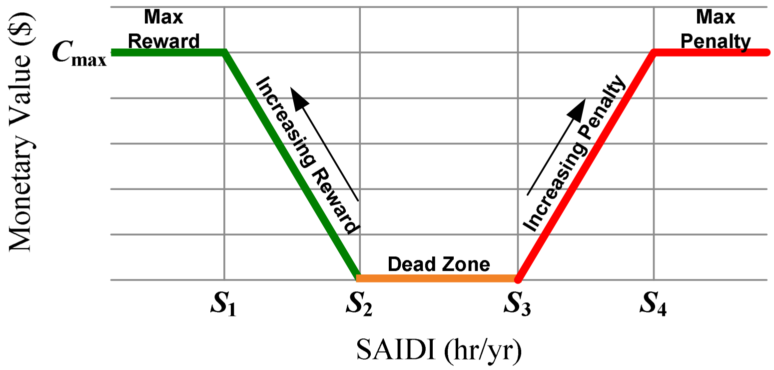


Figure 15: Example for a Typical Performance Based Rate [45]

Therefore the risk component due to regulatory penalties, $RP(k)$, based on is

$$RP(k) = \begin{cases} -1 & if\ S \leq S_1 \\ -\dfrac{S_1 - S}{S_2 - S_1} & if\ S_1 \leq S < S_2 \\ 0 & if\ S_2 \leq S < S_3 \\ \dfrac{S_3 - S}{S_4 - S_3} & if\ S_3 \leq S < S_4 \\ 1 & if\ S \geq S_4 \end{cases}$$

Where S is the actual performance index (SAIDI) of the system. S_1, S_2, S_3 and S_4 are the benchmark SAIDI values given in Figure 15. If the system is performing well and the performance index is above the benchmark, S_2, then there will be no penalty but the utility is rewarded, thus the risk due to regulatory penalties is negative.

The risk component based on the incurred cost to the utility due to the failure of component k is the weighed (α_3, α_4 and α_5) summation of the risk associated with the lost revenue, unexpected cost of emergency restoration and replacement and the regulatory penalties , i.e.,

$$Risk_C(k) = \alpha_3 RL(k) + \alpha_4 CR(k) + \alpha_5 RP(k)$$

The risk due to the failure of component k is defined as,

$$Risk(k) = Risk_R(k) + Risk_C(k)$$

Component with the maximum risk, $Risk(k)$, would be ranked first (high priority) and the one with the minimum risk will be ranked last (low priority). Derating and reconfiguration will start from the high priority component to the low priority component, skipping the ones which will result in component overloading after reconfiguration and reconfiguration of all the higher priority components.

In order to ensure that the effect of reconfiguration of the system has minimum effect on the component loading, the loading effect for each component on the system due to the reconfiguration which results in additional load on the path i is calculated as follows,

For the component j in the path i, determine $I(j)$, where $I(j)$is an identity function defined as,

$$I(j) = \begin{cases} 1 & \text{if } L_{new}(j) > Cap(j) \\ 0 & \text{otherwise} \end{cases}$$

Where $L_{new}(j)$ is the expected maximum loading on component j after redistribution of excess load on the derated component k to the path i and $Cap(j)$ is the capacity limit on the component j. Once $I(j)$ for all the components in path i, are known for every possible redistribution path i, the excess load effect $LE(i)$ due to the derating of component k will be calculated as shown,

$$LE(i) = \begin{cases} \max\limits_{j \in path\ i} \left\{ \dfrac{Cap(j) - L_{old}(j)}{Cap(j) - L_{new}(j)} \right\} & if \sum\limits_{j \in path\ i} I(j) = n_i \\ \infty & \text{otherwise} \end{cases}$$

Where $L_{old}(j)$ is the maximum load on the component j before redistribution and n_i is the total number of components in the path i. The path which has the lowest $LE(i)$ would be chosen as the reconfigured path. In case of a tie the option with the minimum number of switching operations would be chosen.

Figure 16 shows the proposed reconfiguration algorithm.

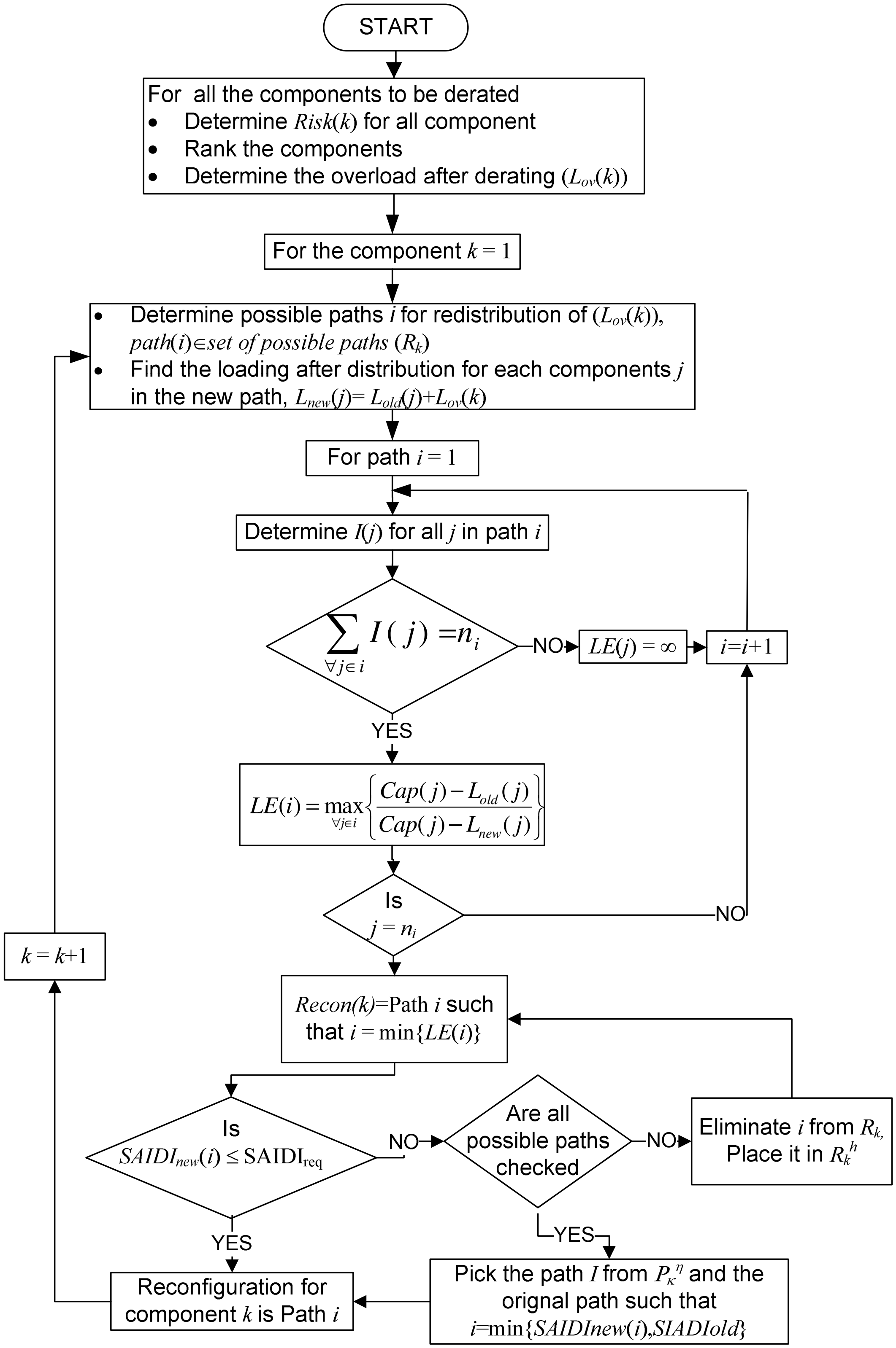


Figure 16: Reconfiguration Algorithm

CHAPTER 4

FUTURE GRID PERFORMANCE

4.1. Reliability Analysis of Nonconventional Loads

Power grid will experience a new type of load with the introduction of Electric Vehicles (EV), as these are large stochastic loads. According to Oak Ridge National Laboratory report dated October 2006, it is estimated that 25% of the vehicles in 2020 would be PHEVs [47]. According to a survey conducted by Duke Energy, demographic segments tend to use similar types of vehicles, which would result in locational importance of PHEVs [48]. Therefore it should be noted that even though the expected EV market share is 25% by 2020, certain geographical clusters will have higher penetration of EV and cause more threat to certain segments of the electric grid.

The introduction of non conventional loads, such as PHEVs will introduce new approach in distribution system analysis for the following reasons:

- Location and time of charging vehicles cannot be predetermined by utilities; these are determined by consumers, based on their need. Even today similar loads are used (eg. cell phone, ipod etc), but their power consumption is really low and do not affect the demand curve significantly. But few large loads like EV (~ 15 A) being charged at same time can affect system loading.
- The duration of a EV being charged is limited, thus the time of interruption for this type of load may not be equal to the total period of outage.

Since irregular loads are stochastic in nature, they are modeled through a probability distribution curve. Based on the loading in a given system, a probability distribution would be formed. For example, let's consider a residential area on a weekday. Since most of the consumers will be charging their EV's during off peak hours, after returning home, demand curve would have shape similar to the one given in Figure 17.

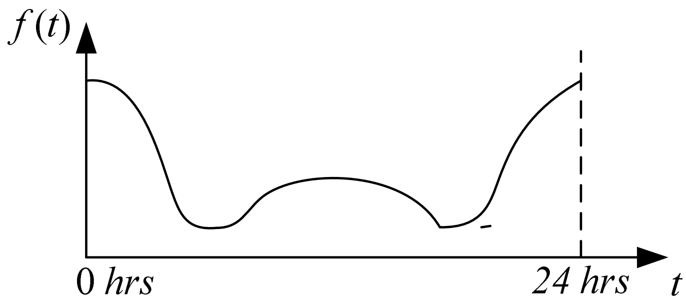


Figure 17: Probability of EV's connected to grid on a weekday

From Figure 17 number of EV's connected to grid from a geographical location i, at any given time interval $t_1 \sim t_2$ would be given as,

$$n_i = N_{IR} \int_{t_1}^{t_2} f(t)dt \tag{4.1}$$

where, N_{IR} is the total number of vehicles, on average, connected to the grid. These irregular loads are connected to the grid only for a limited time. Therefore the total irregular load during the interval $t_1 \sim t_2$ would be,

$$L_i = n_i r$$

Where r is the charging rate of EVs. In this work it is assumed that all vehicles have the same charging rate. If the charging rates are different, developed methodology is still valid with necessary modifications.

Risk and reward from the penetration of EV to the local distribution system should be properly managed by distribution utilities for the successful penetration of PHEVs. Therefore the need of proper pricing techniques, identification of charging venues and infrastructure management are the critical components for better adaptation of PHEVs [48].

This work focuses on developing a methodology to analyze the effect of EV charging based on the concerns given in [48] and optimize the number of PHEVs connected to the grid for charging based on the following concerns.

A. Additional Load: EV is expected to increase demand by 1.4 kW if it's charged at a slow rate and around 6 kW if charged at a faster rate. Based on charging efficiency and Locational Marginal Price (LMP) a relationship is needed.

B. Green House Gas Emission: Even though EVs will reduce green house gas emission from transportation industry, it will increase the green house gas emission of electricity industry. Based on the current developments to mitigate the green house gas emissions, the electricity industry may be penalized for the higher green house gas emission. Therefore emission limitations should be included.

C. Component Maintenance: Based on the loading condition, component life will be affected; therefore tools like component hazard rate, System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) should be monitored and controlled.

4.1.1. Performance and Emission Constraints

A. Transmission Congestion

Locational Marginal Pricing: In system point of view it is ideal to charge the vehicle when LMP is low at a particular bus. This will result in consumer charging the vehicle when transmission congestion is less, resulting in more efficient operation. Predicted LMPs for the next period (in this work one day, from 8:01 hrs to 9:00 hrs of following day, is considered as a period) is compared with minimum predicted LMP for that period. When LMP is lower more vehicles would be connected to grid. Effect of the LMP is derived using the following relationship;

$$h(P) = \frac{LMP(t_1)}{LMP(Min)} n_i$$

B. Loading Effects: Transformer Loss of Life

Using Arrhenius relationship, the loss of life of a transformer could be determined by the following formula [49],[50]

$$LOL(k) = \exp\left(-\left(A + \frac{B}{\tilde{T}}\right)\right)$$

where A and B are constraints depending on the transformer insulation and $\tilde{T}$ is the hotspot temperature. Since loss of life depends on the hot spot temperature, it is important to limit the hotspot temperature for longer life of the component. According to IEEE C57.91-1995 [51] the hot-spot temperature could be given as,

$$\theta_H = \theta_A + \Delta\theta_{TO} + \Delta\theta_H$$

where, θ_A is the average ambient temperature during the load cycle (hour) to be studied in ℃, $\Delta\theta_{TO}$ is the top-oil temperature rise over ambient temperature in ℃ and $\Delta\theta_H$ is the winding hot-spot temperature rise over top-oil temperature in ℃. Further, top-oil temperature rise over that ambient temperature in ℃, $\Delta\theta_{TO}$, and Winding hottest-spot temperature rise over top-oil temperature ℃, $\Delta\theta_H$, for a step increase in load is modeled using the following two formulas;

$$\Delta\theta_{TO} = \left(\Delta\theta_{TO,U} - \Delta\theta_{TO,i}\right)\left(1 - \exp\left(-{}^{t}/_{\tau_{TO}}\right)\right) + \Delta\theta_{TO,i} \tag{4.2}$$

$$\Delta\theta_H = \left(\Delta\theta_{H,U} - \Delta\theta_{TO,i}\right)\left(1 - \exp\left(-{}^{t}/_{\tau_W}\right)\right) + \Delta\theta_{H,i} \tag{4.3}$$

where

$\Delta\theta_{TO,U}$ - The ultimate top-oil rise over ambient temperature for load L in ℃

$\Delta\theta_{TO,i}$ - The initial top-oil rise over ambient temperature ℃

$\Delta\theta_{H,U}$ - The ultimate winding hottest-spot rise over top-oil for load L in ℃

$\Delta\theta_{H,i}$ - The initial winding hottest-spot rise over top-oil temperature in ℃

τ_{TO} - Oil Time constant

τ_W - Winding Time Constant

Since PHEVs can be considered step loads, this model could be used to determine the rise in hot spot temperature due to the addition of n_i number of PHEVs with charging rate of r_i kW/hr during a given hour. Without losing generality this work uses the steady state increase in the hot-spot temperature due to this step increase and compares with the maximum allowed hot-spot temperature increase for the given time period. It could be assumed that the tap position of the transformer will not be changed for a given time interval because of the addition of the PHEVs. Therefore, the steady state relationship for (4.2) and (4.3) could be simplified and related to the load (using IEEE C57.91) as

$$\Delta\theta_{TO} = \Delta\theta_{TO,U} = \Delta\theta_{TO,R}\left[\frac{{K_U}^2 R+1}{R+1}\right]^n \tag{4.4}$$

$$\Delta\theta_H = \Delta\theta_{H,U} = \Delta\theta_{H,R}{K_U}^{2m} \tag{4.5}$$

where

$\Delta\theta_{TO,R}$ - The top-oil rise over ambient temperature at rated load on a given tap position in ℃
K_U - The ratio of EV to the rated load in per unit.
R - The ratio of load loss at rated load and no load loss on the given tap position
$\Delta\theta_{H,R}$ - The winding hottest-spot rise over top-oil temperature at the given tap position in ℃
n - Empirically derived constant; for the effect of change in resistance to change in load
m - Empirically derived constant; for the effect of change in resistance to change in load

The suggested values for m and n for oil-immersed, natural circulation self cooled (OA), forced circulation self cooled (FA), forced oil, forced circulation, forced water (FOW) and forced circulation forced air (FOA) transformers are given in Table 7.

TABLE 7

m AND *n* VALUES USED FOR DIFFERENT TRANSFORMERS [51]

Type of Cooling	***m***	***N***
OA	0.8	0.8
FA	0.8	0.9
Non-Direct FOA or FOW	0.8	0.9
Directed FOA or FOW	1.0	1.0

Since most of the distribution transformers are cooled with natural circulation self cooling (OA), the values for *m* and *n* are fixed at 0.8. Therefore effect on the hot spot temperate due to the EV could be defined as;

$$\theta_{H,EV} = \Delta\theta_{TO,EV} + \Delta\theta_{H,EV}$$

$$\theta_{H,EV} = \Delta\theta_{TO,R}\left[\frac{\left(\frac{n_i r}{L_{rate}}\right)^2 R + 1}{R + 1}\right]^{0.8} + \Delta\theta_{H,R}\left(\frac{n_i r}{L_{rate}}\right)^{1.6}$$

$$\theta_{H,EV} = \frac{\Delta\theta_{TO,R}}{(R + 1)^{0.8}}\left[\left(\frac{n_i r}{L_{rate}}\right)^2 R + 1\right]^{0.8} + \Delta\theta_{H,R}\left(\frac{n_i r}{L_{rate}}\right)^{1.6}$$

Using the Binomial Expansion, the above relationship could be expanded as

$$\theta_{H,EV} = \frac{\Delta\theta_{TO,R}}{(R + 1)^{0.8}}\left(1 + 0.8\left(\frac{n_i r}{L_{rate}}\right)^2 R + 0.4\left(\frac{n_i r}{L_{rate}}\right)^4 R^2 + \cdots\right) + \Delta\theta_{H,R}\left(\frac{n_i r}{L_{rate}}\right)^{1.6}$$

Since the transformer will not be overloaded under normal operating conditions and the load from EV will be less than the transformer rating, the higher order terms in the above relationship could be neglected and the relationship could be rewritten as

$$\theta_{H,EV} = \frac{\Delta\theta_{TO,R}}{(R + 1)^{0.8}}\left(1 + 0.8\left(\frac{n_i r}{L_{rate}}\right)^2 R\right) + \Delta\theta_{H,R}\left(\frac{n_i r}{L_{rate}}\right)^{1.6}$$

C. Emission Regulations

PHEVs would move the CO_2 emission from the transportation sector to the power sector. Higher CO_2 emission from the power sector could result in higher penalty for to the utility. Green house gas emission differs for different energy sources and different time of day uses different combination of energy sources. Figure 18 shows how generation mix would change at different time of hour, rate of charging and location.

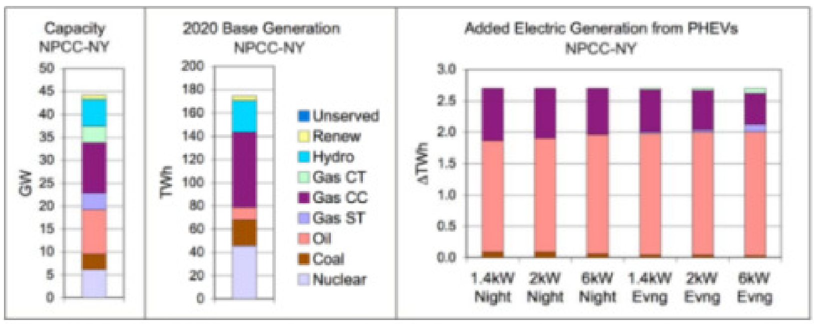


Figure 18: Projected Combinations of Dispatch with EV for Regions [47]

For a given time t hours at a location bus k, let the added normalized generation mix be: coal - P_c kW per one kW of generation, oil - P_o kW per hour per one kW of generation, gas - P_g kW per hour per one kW of generation, nuclear – P_n kW per hour per one kW of generation and renewable (including hydro) – P_r kW per hour per one kW of generation. The emission per one kWh of energy produced by each of the sources be, e_c – coal, e_o – oil, e_g – gas, e_n – nuclear and e_r – renewable. Then, CO_2 emission for n_i number of vehicles added at bus k at time t hours would be;

$$E_{CO_2} = \frac{r}{\eta} \times n_i \underbrace{\left(e_c P_c + e_o P_o + e_g P_g + e_n P_n + e_r P_r\right)}_{\tilde{P}} T \text{ lbs}$$

Generation mix at any given time would be known to the utility and it could be taken as a constant for a given time.

The CO_2 emitted by the conventional vehicle is given by the following relationship,

$$E_{Gas-Vehi} = \frac{Total\ Dist.Traveled}{Average\ MPG} \times Emission\ per\ Gallon$$

Based on the contract that utility has with EV consumers, CO_2 emission would be a weighted function. Therefore the weighed function for CO_2 emission at time *t* would be,

$$f(E) = w_t \frac{E_{CO_2}}{E_{Gas-Vehi}}$$

D. Component Condition

Load increase on a component could be attributed to more stress on components; and will result in reduced life. This will have a significant effect on the system performance. Due to the nature to PHEVs loads, large stochastic loads, the effect on the reliability cannot be modeled as regular loads. This work defines reliability index for the system when irregular loads are present.

System Average Interruption Duration Index (SAIDI) is taken as the reference for performance and same approach can be extended for other indices. Definitions for the performance indices are taken from [52], with the conventional load, effect of component k on the system SAIDI is given by,

$$SAIDI(k) = h(k)\frac{\sum D_i}{N_T}$$

where, $h(k)$ is the hazard rate of the component k, D_i *is* restoration time for each interruption event and N_T is the total number of customers. The SAIDI due to the addition of the EV for any component in the system could be given as, (Note: the hazard rate may change due to the addition of EV and the modified hazard rate be $h_t(k)$)

$$SAIDI = h_t(k)\frac{\sum D_i + r\sum n_k}{N_T + N_{IR}}$$

PHEVs are considered new customers and n_k is determined using (4.1)

4.1.2. Problem Formulation

It could be expected that the PHEVs will penetrate the grid in segments and each of these segments would be divided into zones in such a way that all the vehicles connected through one transformer is considered a zone. A day is decided based on the minimum number of vehicles needed to be connected to the grid. Based on the EPRI/NRDC study the daily charging availability profile is given in Figure 19. Using this as a guideline a *day* for the purpose of EV charging is defined from 9th hour to the 8th hour of the following day. For optimal operation, vehicles would be required to submit the available time of charging for the following *day* by midnight. The vehicles which submit their request would get higher priority in getting the time slot and could be given financial incentive as the utility gets a chance to plan its operation. Based on this the utility would be able to determine the expected number of vehicles to be charged at every hour i during the next charging period (*day*). This work assumes that every vehicle will be requested by utility to start charging at the beginning of an hour.

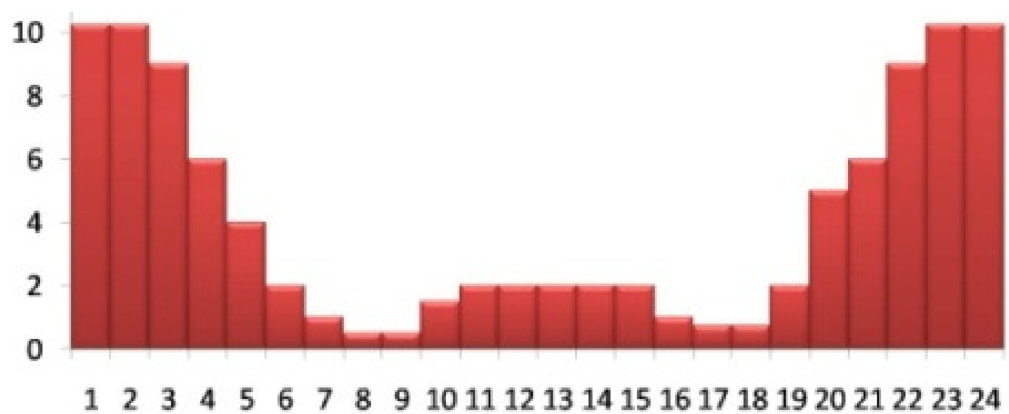


Figure 19: EV Daily Charging Availability Profile [53]

The objective of this work is to determine the expected optimum number of vehicles that each zone could handle at the each time period based on the expected LMP of each zone, impact on the SAIDI by addition of EV.

At each hour slot, all the vehicles requesting to be charged would be placed in a queue. The queue would be determined based on the total time that vehicle would be available for charging. Based on the availability of each vehicle, maximum number of vehicles that could be shifted to the next hour to start charging would be determined.

A. ***First Step:*** *Predict the number of vehicles for each zone at every period of the day*

Objective is to ensure all the vehicles are charged, while minimizing the impact in SAIDI due to the presence of PHEVs. Based on the historic data, component of the SAIDI for each day could be determined from the allowed SAIDI for a year. Allowed SAIDI is defined as the maximum SAIDI that could be allowed by the utility to ensure that it will not be penalized for performance requirements by the regulators. An additional contestant to ensure that the LMP at the bus must not exceed its limit and the addition of expected regular load and EV load is less than the transformer rating.

Minimize: the increase in system average interruption duration for the *day*

$$SAIDI_{day} = h_t(k)\frac{\sum D_i + \sum r_k N_k}{N_T + N_{IR}}$$

Since this analysis only considers the effect on the performance index, SAIDI, the component of the SAIDI due to the regular load could be neglected as it is independent of the number of vehicles connected to the grid at any given time. The minimization problem could be modified as,

$$\underbrace{S_{day}}_{\forall N_k} = \sum h_z(day)\frac{D_{z,k}}{D_{z,rated}}\frac{r_k N_k}{N_T + N_{IR}}$$

The objective could be rewritten as,

$$\min \underbrace{S_{day}}_{\forall N_k} = \sum \hat{h}(d) D_{z,k} N_k$$

Where $\hat{h}(d) = \frac{h_z(day) r_k}{D_{z,rated}(N_T + N_{IR})}$, based on the expected loading on the following day, constraints for optimization are:

1. Congestion on the transmission system should be limited. Therefore the following limit is imposed on the LMP.

$$\underbrace{\frac{LMP(d,t_1)}{LMP(Min,(d-1))}}_{\mu} N_k \leq C_m$$

2. To ensure all vehicles requested for charging during the following *day*, are charged; total vehicles charged in a day is,

$$\sum_{j=1}^{24} N_j = N_m$$

3. Each vehicle will be expected to turn in its expected time to charge and the duration for which they will be available for charging, for the following *day*. When E_k vehicles enter the queue at hour k, if V_k vehicles could not be charged during hour $k-1$, and N_k vehicles were charged during hour k, the vehicles uncharged during hour k and moved to the next hour $k-1$ will be,

$$V_{k+1} = V_k + E_k - N_k \quad \forall\, k = 1,2 \ldots 24$$

Note: to ensure that all the vehicles requested for charging on a day gets charged, the following are fixed: $V_1 = V_{24} = 0$

4. Sum of the expected regular load and the load component due to the EV at the given hour should be less than the maximum peak operating load of the transformer:

$$D_k + r(N_k + N_{k-1} + N_{k-2} + N_{k-3} + N_{k-4} + N_{k-5}) \leq TF_k \quad \forall\, k = 1,2 \ldots 24$$

Where TF_k is the maximum allowed peak loading of the given transformer.

5. Based on the requirements and the availability of the vehicles maximum limit on vehicles that could be carried to next hour for charging is imposed and given by:

$$V_{k+1} \leq V_{m,k}$$

Solution to the above optimization could be determined using linear program.

B. ***Second Step:*** *Maximum limit on the vehicles based on the operating conditions*

Uncertainties associated with the operation of a power system may require the utility to update the operations in a frequent interval. This part of the work determines the maximum limit on vehicles that could be connected to grid during the next hour, while ensuring: transformer loss of life is limited, CO_2 emission is within the limitations and required number of vehicles, N_i, are charged. The developed convex problem is solved using KKT conditions as given below;

Maximize: the number of vehicles charged during the hour *i*

$$\max \quad n_i$$

Constraints for optimization could be given as:

1. *Loss of life of the transformer:* To ensure the loss of life of the transformer is not accelerated due to the presence of PHEVs a maximum limit for the hotspot temperature is caped at Θ_i for hour i.

$$\frac{\Delta\theta_{TO,R}}{(R+1)^{0.8}}\left(1+0.8\left(\frac{n_i r}{L_{rate}}\right)^2 R\right)+\Delta\theta_{H,R}\left(\frac{n_i r}{L_{rate}}\right)^{1.6} < \Theta_i$$

To reduce the computational complexity without losing the generality of the problem the above constraint is modified as;

$$\frac{\Delta\theta_{TO,R}}{(R+1)^{0.8}}\left(1+0.8\left(\frac{n_i r}{L_{rate}}\right)^2 R\right)+\Delta\theta_{H,R}\left(\frac{n_i r}{L_{rate}}\right) \leq \Theta_i$$

This relationship holds true as $\left(\frac{n_i r}{L_{rate}}\right)^{1.6} < \left(\frac{n_i r}{L_{rate}}\right)$. The above equation is rewritten as,

$$\delta + \alpha \cdot {n_i}^2 + \beta \cdot n_i \leq \Theta_i,$$

where,$\delta = \frac{\Delta\theta_{TO,R}}{(R+1)^{0.8}}$ $\alpha = \frac{0.8\cdot\Delta\theta_{TO,R}\cdot r^2\cdot R}{(R+1)^{0.8}\cdot {L_{rate}}^2}$ and $\beta = \frac{\Delta\theta_{H,R}\cdot r}{L_{rate}}$. Determination of the cap Θ_i is dependent on the maximum allowed age acceleration factor F_{AA} for the transformer for an hour and ambient temperature Θ_A. Based on the IEEE std. C57.91 [51] the following relationship could be used to determine the maximum allowed hottest spot temperature rise.

$$\Theta_i = \frac{15000}{\frac{15000}{383} - \ln(F_{AA})} - (\Theta_A + 273) - (\Delta\theta_{TO} + \Delta\theta_H)_{reg.}$$

Where, $(\Delta\theta_{TO} + \Delta\theta_H)_{reg.}$ is the relevant temperature rise due to the regular loading.

2. *CO_2 emission*: a maximum cap is enforced on weighted CO_2 emission due to the addition of electric vehicles.

$$\underbrace{w_t \cdot \frac{r \cdot \tilde{P}}{30.5\eta}}_{\rho} \cdot n_i \leq E_m$$

3. *Equal Chance*: To ensure all the vehicles needed to be charged gets charged, a constraint is included to the minimum number of vehicles added to the grid for a given time based on the solution from the step one.

$$n_i \geq N_i$$

The Lagrangian is,

$$\mathcal{L}(n_i, \lambda_1, \lambda_2, \lambda_3) = n_i + \lambda_1(\Theta_m - \delta - \alpha \cdot n_i^2 - \beta \cdot n_i) + \lambda_2(E_m - \rho n_i) + \lambda_3(n_i - N_i)$$

KKT conditions for the above optimization could be given as,

Stationary Condition:

$$1 - 2\lambda_1 \alpha n_i - \lambda_1 \beta - \lambda_2 \rho + \lambda_3 = 0 \tag{4.6}$$

Complimentary Slackness:

$$\lambda_1(\Theta_m - \delta - \alpha \cdot n_i^2 - \beta \cdot n_i) = 0 \tag{4.7}$$

$$\lambda_2(E_m - \rho n_i) = 0 \tag{4.8}$$

$$\lambda_3(n_i - N_i) = 0 \tag{4.9}$$

Primal Feasibility:

$$\Theta_m - \delta - \alpha \cdot {n_i}^2 - \beta \cdot n_i \geq 0 \tag{4.10}$$

$$E_m - \rho n_i \geq 0 \tag{4.11}$$

$$n_i - N_i \geq 0 \tag{4.12}$$

Dual Feasibility:

$$\lambda_1 \geq 0 \tag{4.13}$$

$$\lambda_2 \geq 0 \tag{4.14}$$

$$\lambda_3 \geq 0 \tag{4.15}$$

When $\lambda_1 \neq 0$, $\lambda_2 = 0$ and $\lambda_3 = 0$ solution to the optimization problem could be determined by,

$$1 - 2\lambda_1 \alpha n_i - \lambda_1 \beta = 0 \tag{4.16}$$

$$\delta + \alpha \cdot {n_i}^2 + \beta \cdot n_i - \Theta_m = 0 \tag{4.17}$$

$$E_m - \rho n_i \geq 0 \tag{4.18}$$

$$n_i - N_i \geq 0 \tag{4.19}$$

$$\lambda_1 \geq 0 \tag{4.20}$$

From (4.17)

$$\alpha \cdot {n_i}^2 + \beta \cdot n_i - \Theta_m + \delta = 0$$

$$n_i = \frac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_m - \delta)}}{2\alpha}$$

For the solution to exist,

$$\beta^2 < \beta^2 + 4\alpha(\Theta_m - \delta)$$

$$4\alpha(\Theta_m - \delta) > 0 \;\; \Rightarrow \Theta_m > \delta$$

From (4.18),

$$\rho \frac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_m - \delta)}}{2\alpha E_m} \leq 1$$

From (4.19),

$$\frac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_m - \delta)}}{2\alpha N_i} \geq 1$$

From (4.16) and (4.20)

$$\lambda_1 = \frac{1}{2\alpha n_i + \beta} = \frac{1}{\sqrt{\beta^2 + 4\alpha(\Theta_m - \delta)}} \geq 0$$

Let, $g = g(\beta, \alpha, \Theta_m, \delta, \mathrm{E}_m) = \rho \frac{-\beta+\sqrt{\beta^2+4\alpha(\Theta_m-\delta)}}{2\alpha \mathrm{E}_m}$ and $h = h(\beta, \alpha, \Theta_m, \delta, N_i) = \frac{-\beta+\sqrt{\beta^2+4\alpha(\Theta_m-\delta)}}{2\alpha N_i}$,

then,

$$n_i = \frac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_m - \delta)}}{2\alpha} \quad if \;\; g \leq 1, h \geq 1 \text{ and } \Theta_m > \delta$$

When $\lambda_i^1 = 0$, $\lambda_i^2 \neq 0$ and $\lambda_i^3 = 0$ solution to the optimization problem could be determined by,

$$1 - \lambda_2 \rho = 0 \tag{4.21}$$

$$E_m - \rho n_i = 0 \tag{4.22}$$

$$\Theta_m - \delta - \alpha \cdot {n_i}^2 - \beta \cdot n_i \geq 0 \tag{4.23}$$

$$n_i - N_i \geq 0 \tag{4.24}$$

$$\lambda_2 \geq 0 \tag{4.25}$$

From (4.22)

$$E_m - \rho n_i = 0$$

$$n_i = \frac{E_m}{\rho}$$

For the solution to exist,

From (4.23)

$$\alpha \cdot {n_i}^2 + \beta \cdot n_i - \Theta_m + \delta \leq 0$$

$$n_i \leq \frac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_m - \delta)}}{2\alpha}$$

$$1 \leq \rho \frac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_m - \delta)}}{2\alpha E_m}$$

and

$$\beta^2 < \beta^2 + 4\alpha(\Theta_m - \delta)$$

$$4\alpha(\Theta_m - \delta) > 0 \ \Rightarrow \Theta_m > \delta$$

From (4,24),

$$\frac{E_m}{\rho N_i} \geq 1$$

From (4.21) and (4.25)

$$\lambda_i^2 = \frac{1}{\rho} = \geq 0$$

Let, $f = f(\rho, \mathrm{N}_i, \mathrm{E}_m) = \frac{E_m}{\rho N_i}$ then,

$$f = \frac{E_m}{\rho N_i} = \frac{h}{g} \geq 1$$

$$n_i = \frac{E_m}{\rho} \quad if \ \ g \geq 1, h \geq g \text{ and } \Theta_m > \delta$$

When $\lambda_i^1 = 0$, $\lambda_i^2 = 0$ and $\lambda_i^3 \neq 0$ solution to the optimization problem could be determined by,

$$1 + \lambda_3 = 0 \tag{4.26}$$

$$n_i - N_i = 0 \tag{4.27}$$

$$\Theta_m - \delta - \alpha \cdot {n_i}^2 - \beta \cdot n_i \geq 0 \tag{4.28}$$

$$E_m - \rho n_i \geq 0 \tag{4.29}$$

$$\lambda_3 \geq 0 \tag{4.30}$$

Solution is not possible as $1 + \lambda_3 \neq 0$

When $\lambda_i^1 = 0$, $\lambda_i^2 = 0$ and $\lambda_i^3 = 0$ solution to the optimization problem could be determined by,

$$1 = 0$$

$$\Theta_m - \delta - \alpha \cdot {n_i}^2 - \beta \cdot n_i \geq 0$$

$$E_m - \rho n_i \geq 0$$

$$n_i - N_i \geq 0$$

Solution is not possible as $1 \neq 0$,

The other combinations will not produce a unique solution. Further note,

$$N_i \leq n_i \leq \frac{E_m}{\rho}$$

$$\Rightarrow 1 \leq \frac{n_i}{N_i} \leq \frac{E_m}{\rho N_i}$$

Therefore if $\frac{E_m}{\rho N_i} \leq 1$ will result in violation of these conditions.

Similarly the following condition should be met for a non zero solution,

$$N_i \leq n_i \leq \frac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_m - \delta)}}{2\alpha}$$

Therefore if $\frac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_m - \delta)}}{2\alpha N_i} \leq 1$ will not generate a solution. Since, $\frac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_m - \delta)}}{2\alpha N_i} \leq 1$ or $\frac{E_m}{\rho N_i} \leq 1$ violates the necessary conditions, a solution would be to relax one of the conditions that is violated and fixing the other condition at the boundary. Fortunately, daily assignment of N_i is expected to minimize this effect. Therefore it could be expected that this case would be a rare possibility. Following section discusses the options if this case occurs with the possibility of not satisfying a condition in the solution.

Case 1: Relax $n_i \geq N_i$

In this case all the vehicles requested for charging will not be able to get charged. But the emission limits and limit on the loss of life of the transformer becomes hard limit. In order to ensure that the all the vehicles are get charged, these vehicles could be rerouted to the zones which have higher capacity for the vehicles than required or give an option to charge at a later time with incentives for the inconvenience due to delay. Therefore the number of vehicles charged at any given time i would be,

$$n_i = \begin{cases} \dfrac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_m - \delta)}}{2\alpha} \;\; and \;\; (N_i - n_i) \text{ backed off} & if \; g \leq 1, h \leq 1 \\ \dfrac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_m - \delta)}}{2\alpha} & if \; g \leq 1, h \geq 1 \\ \dfrac{E_m}{\rho} \;\; and \;\; (N_i - n_i) \text{ backed off} & if \; g \geq 1, f \leq 1 \\ \dfrac{E_m}{\rho} & if \; g \geq 1, f \geq 1 \end{cases}$$

Case 2: Relax $\Theta_m - \delta - \alpha \cdot {n_i}^2 - \beta \cdot n_i \geq 0$ and $E_m - \rho n_i \geq 0$

In this case it is ensured that all the vehicles are charged at the current location, but emission and the loss of life of the transformers increased. Due to this increase, the utility may impose additional charges on the vehicles charged at the given time. The extra burden would be shared by all the vehicles connected to the grid in that zone equally. The number of vehicles charged at any given time i would be,

$$n_i = \begin{cases} N_i & if \; g \leq 1, h \leq 1 \\ \dfrac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_m - \delta)}}{2\alpha} & if \; g \leq 1, h \geq 1 \\ N_i & if \; g \geq 1, f \leq 1 \\ \dfrac{E_m}{\rho} & if \; g \geq 1, f \geq 1 \end{cases}$$

4.2. Distribution Level Communication and Reliability

The need for communication has higher priority with the Smart Grid approach. There has been significant work done on power system communication needs and applications. IEC 61850 and DNP 3 standardize the communication within the substation. ANSI C12.22 networking standards are built for advanced metering infrastructure [54]. Even though 80% of the consumer interruptions are attributed to the distribution component failure, due to the lack of monitoring points and the communication infrastructure, observing the components in the distribution system, getting reliable information is a challenging task.

Due to the difficulties in harvesting information from the components, failure / abnormality analysis is done from the information captured at substation level. There had been a significant amount of work to analyze these data [15], [55]-[59], Due to the non trivial nature of the failures / abnormalities the exact prediction and location of the failure, independent of the feeder model, is still at premature stages. If the communication infrastructure is improved, a vital ingredient for the Smart Grid, a more reliable approach could be taken and this would aid a better asset management strategies.

The motivation of this work is to identify the needs for communication and at different levels in the distribution system, namely: substation level, feeder level distributed source level and consumer level. Further higher penetration of distributed sources in the distribution system will require high performance communication[60]. In addition to the asset and outage management tasks these will also require energy management and tariff related information.

Traditional SCADA level communication has limited bandwidth, 75 bits/s to 2400 bits/s [61], and the need of larger bandwidth is necessary, if the information from the components is going to be used for not only monitoring (abnormality detection), but also control and asset management, in general improve the intelligence of the system/grid. Intra Substation communication is moving from the binary or analog communication to Ethernet, TCP/IP, based Wide Area Network. IEC 61850 standardizes the communication network within a substation [62], [63]. IEC 61850 could be extended to distributed sources. Smart meter technology is capable of using the TCP/IP based communication to/from the control center. Emerging standard ANSI C12.22 will standardize the communication network in a smart meter [64]. Advancement in the signal processing through the low cost computers and the networking technology has made it cheaper effective communication through TCP/IP. Using a common networking technology for all the different levels in the distribution system will reduce the need of infrastructure at the control center and increase the performance. A common connection oriented layer 3 (OSI model) based reliable communication network would be a ideal solution for the smart-grid applications. IEC 61850 uses reliable TCP/IP and priority flags for GOOSE and SMV, using IEEE 802.1Q (VLANs) which offers more secured and intelligent usage of Ethernet switches [62]. Therefore this work recommends a similar approach for the entire distribution system communication. The proposed communication network is presented in Figure 20

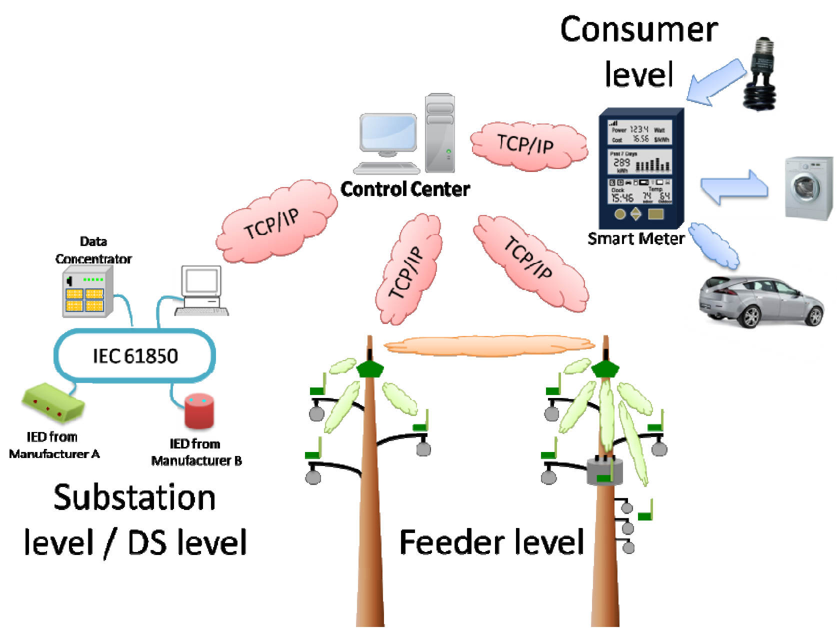


Figure 20: Communication Network for Distribution System

As shown in Figure 20, three different substation levels communication networks are needed. Each of these networks would have two states of communication. The higher priority state would be the abnormal event state, where a detected event with estimated location would be transmitted to the control center for further action. The low priority state will transmit component condition data for asset management tasks. Further, substation level communication will have higher priority than the feeder level and consumer level communication, which will be operated with lower priority. Data (packets) traffic in the communication network can be prioritized with the usage of IEEE 802.1Q standards similar to priority tagging in IEC 61850.

Except for the intra substation level communication the other parts lack standards; so that the usage of equipment from different vendors / manufacturers could be incorporated into a system. It is necessary to increase the security of the transmitted data to mitigate the effect of hacking and modifying data. The security and connectivity of the components should be given higher priority at the consumer level. The utility must ensure all the components used are connected to the appropriate smart meter. This will have a greater impact in choosing the medium of communication.

4.2.1. Choice of the Medium

Potential communication media for distribution system networking are power line communication (PLC), Wireless and dedicated wired. When the substation is considered due to the confined physical space dedicated wired medium such as Ethernet would be the best choice. The substation communication network would use the well-established IEC 61850 and thus this work will not discuss the requirements for substation level / distributed source level communication and medium.

When the distribution system is considered PLC could be considered as an ideal source because it will be a no cost medium for the utility and it's spread all along the distribution system. PLC has potential to transmit data at the maximum rate of 11 kbit/s, when the PLC has sufficient robustness and reliability and maximum data rate could be achieved only in a narrow frequency range of 9 kHz to 95 kHz [65]. The lower rate of communication is not ideal for secured communication. Therefore, if more information has to be sent from all the components in a feeder, higher bandwidth is required. The current developments in the Broadband over Power Line (BPL) would create an impression that this is the best technology. The distribution system will be affected by voltage transients and harmonics consistently which are unpredictable, therefore this is prone to high disturbance. High frequency signal (BPL) needs to be bypass transformers to avoid high attenuation [66]. The attenuation in a radial distribution feeder would increase the number of regenerators needed. It is expected that a typical rural feeder which is 20 miles long needs regenerators in the order of 30 – 100 [67]. This shows even though the medium is free, the communication does not occur free of cost. High Frequency signals may be blocked by voltage regulators, reclosers and shunt capacitors which are common in the long radial feeders [67]. Further when a pole goes down it takes the communication link also down. This would be a major concern when the communication is used for automatic fault location and system restoration. For smart grid application very high reliable communication is necessary and some work recommend having 99.995% availability of communication [68] for reliable system. The 99.995% requirement would result in unavailability of the communication per year to be less than 44 hours. This would further initiate the discussion on performance indices for the communication network as an additional measure of smart grid performance. All these concerns develop a case to explore other options for the communication medium for the feeder level and consumer level.

Another option would be to use dedicated wired communication, one of the problems with the copper wire connections will be the interference and attenuation, and fiber optic cables would be a solution for the interference but will increase the cost. It could be noted investment for fiber optic network would be in the order of $ 10-100 million for 100 nodes [69]. Newly developing communities could use fiber optic communication network close to the feeders, so that this infrastructure could be shared for both smart grid communication needs and the consumer communication needs. One of the advantages of this medium is that the utility has to bear only the terminal equipment cost and costs associated with leasing the line. This will reduce the overhead for the utility with improved communication. On the other hand utility will not have control over the medium as it will not own the dedicated wired medium in most cases. This will require physical connections and will reduce the flexibility. Further when a pole goes down, the communication link will be broken and may result in poor performance.

Wireless communication is another promising alternative for the distribution level communication. One of the important characteristics of the wireless communication is the communication without physical connection between two nodes. This would ensure the continued communication even with poles down. Further, Appropriate protocol will enable the continued communication even with a failed primary link. In other words redundant paths for communication are possible without additional cost. This will ensure more reliable communication than other media. Interference in the medium is still a concern in the communication. The discharges between the line components which occurs in power lines under 70 kV and the corona effect which occurs in power lines over 110 kV have the dominating frequency spectrum in the range of 10 – 30 MHz. Selection of medium with communication frequency spectrum above these limits would minimize the interference. Wi-Fi (IEEE Standard 802.11) which operates at 2.4 GHz or 5 GHz with data rate between 11 Mbps and 54 Mbps and the maximum communication link between two nodes of 150 meters, Zig Bee (IEEE Standard 802.15.4) which operates 868 MHz, 900 MHz or 2.4 MHz with data rate between 20 Mbps 240 Mbps and the maximum communication link between two nodes of 100 meters or Wi-Max (IEEE Standard 802.16) which operates at 2 GHz to 11 GHz with maximum data rate of 3 Mbps for a communication link of 7 km [70] could be utilized in the distribution system with minimal interference.

Another advantage of the Wireless communication is that the utility has to own only the terminal units, which are relatively cheap and could be integrated with cost effective local processors. When multi-hopping used in the wireless communication especially in Wi-Fi and Zig Bee the range of communication can be extended and the nodes located in the feeder could be able to communicate with the control center. Disadvantages of the wireless communication would be the interference in the presence of buildings and trees with could result in multi path; this could be avoided with improved receivers and directional antennas, which will increase the cost. Another major concern with the wireless medium is easy accessibility, which could result in security issues. This can be avoided by using secure protocols. The rural feeders sections would be long and the range of the communication could become a concern.

Both PLC and Wireless communication are promising in the distribution level communication. Based on the need and the availability of the technology a combination of both could be used for improved communication infrastructure.

4.2.2. Communication Requirements

At the feeder level, the need of communication is in three stages. A group of sensor nodes could be used as clusters for the measurement purpose. For example a pole with a transformer may have different sensors for line current in each phase, line voltages, transformer noise level and the vibration. To minimize the cost all these nodes will transmit the data to a master node which would process the data and transmit necessary information to the control center, which would be considered third stage of communication. In the process of assuring that the necessary information is not false alarm it could communicate with the neighboring masters which would be the second stage of the communication. It should be noted that any information loss in a cluster would result in missing an event and when the master is communicating with the control center, it should ensure that any abnormality in the system should reach the control center, requiring redundant paths for higher reliability. When the master node tries to send the asset management information, it could wait and ensure that a reliable communication is possible before sending the information. The expected communication need for the feeder level is shown in Figure 21.

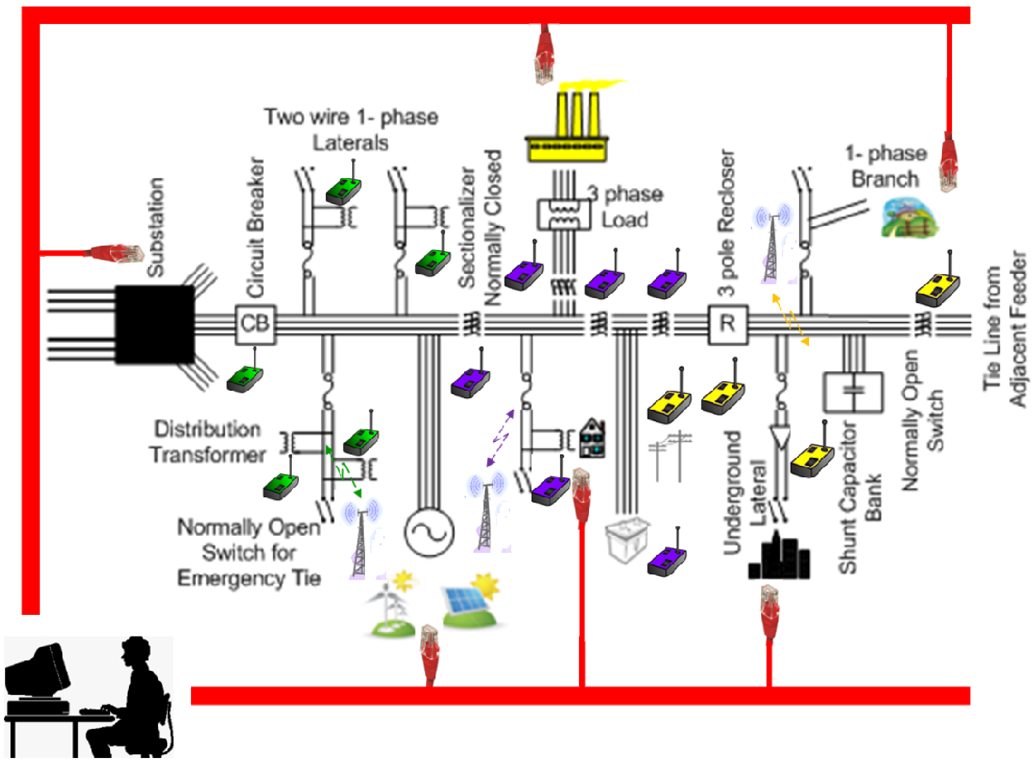


Figure 21: Communication Requirement at Feeder Level

At the smart meter level, a consumer will have three types of appliances, the ones which will not be controlled by the smart meter, e.g.: lights, cooker, etc, the ones which can be controlled by the smart meter, e.g.: washer, dryer, air condition, etc and the ones which needs to be controlled by the utility through the smart meter, eg EV. This work suggests three different types of communication for these three types.

The ones which need not controlled by the smart meter needs only unidirectional communication, whereas the other two will need bidirectional communication. In order to minimize the cost the ones which may not be controlled could use PLC as the medium for communication. Due to the large amount of data and the possibility to communicate with the smart meter form different locations PHEVs needs to have wireless capabilities and should be able to have a secured connection to the smart meter via internet.

4.2.3. Reliability

The communication infrastructure will affect the system performance. If the unavailability the of the communication system is higher than that of the power system, then the investment on the communication infrastructure does not serve any purpose for regulators, consumers and the utility. Therefore a way to measure the performance of the communication system and benchmarking it is very important. Communication requirements for the smart meter applications should be higher than that of the feeder level. Household appliances will depend on this information received by the smart meter for the operation and any error could cause unexpected outcomes. For example: Duke Energy's power management program, which controls the air condition units of the participating customers, shut itself down rather than ON-OFF cycling for three hours due to a communication error [71], this led to consumer inconvenience. Similar effect could be observed if smart meter communication is unreliable. Even if the same indices are used, the benchmarks should be different. In order to define the necessary reliability standards, the existing standards for the power system and communications should be analyzed.

4.2.3.1. Power Distribution Reliability Indices

Active Communication should be available both during the sustained interruption (any interruption longer than five minutes) and momentary interruptions. Momentary interruptions have minimum effect on the consumer satisfaction but it could accelerate the loss of life of the components.

Since sustained interruptions for the smart meter directly involves the consumer satisfaction, indices similar to sustained interruption indices formed in IEEE 1366-2003 should be developed. Based on the importance the following indices are developed.

4.2.3.2. Average number of customers interrupted

If the signal-to-noise ratio (SNR) at the receiver is below the threshold then that information could not be accessed by the smart meter. The each set of information sent to the smart meter needs to be received above the required SNR value. Therefore as a tool to ensure reliable communication, the number of times the SNR was less than the required as an average over all the components could be used. It should be noted that not all piece of equipment in a household will have same level of importance. For example information from a dryer is more important to the smart meter than an electric bulb. Therefore this work proposes a predefined weighed index to measure the reliability. In other words, this is defined as;

$$ACIFI = \frac{\text{Total weighted number of missed events}}{\text{Weighted number of appliances}}$$

Missed events include all the missed detections and false alarms of both the smart meter and all appliances. The following equation could be used to calculate this index,

$$ACIFI = \frac{\sum w_i n_i}{\sum w_i N_i}$$

where, w_i is the predefined weight for the appliance type i, n_i is the number of times a communication (packet) is missed or miss detected for appliance type i was less than the threshold and N_i is the number of appliances in a household of type i.

Consumer will be responsible for the reliable communication and may be penalized for less reliable smart meter system. The communication protocol must ensure the priority among different appliances.

4.2.3.3. Average interruption duration for a customer

If continuous communication is necessary, for example each node in a cluster at a feeder level communication would be continuously sending data to the master node and master node will process the data to detect any abnormality. Therefore rather than the number of times the SNR is poor, the length of time the SNR is poor has more significance. In this case all the nodes connected to the master node will have same priority. Therefore with the assumption each cluster operates independently, the reliability index for the cluster k with respect to the duration of poor SNR would be defined as,

$$ACIDI_k = \frac{\sum \text{Duration of communication failure for each node due defect } i \text{ in cluster } k}{\text{Total number of nodes in a cluster}}$$

Therefore the average interruption duration would be,

$$ACIDI = \sum ACIDI_k$$

4.2.3.4. Energy Not Served Due to the Communication Failure

The communication infrastructure needs to improve the total energy served by the utility. Therefore it is important to measure energy not served due to the communication failure and use it as a tool to determine the performance of the smart / automated grid.

$$ENS - C = \frac{\sum_i \text{Energy Not Served while Communication Failure } i}{\text{Total Energy Not Served}}$$

CHAPTER 5

NUMERICAL ANALYSIS

5.1. Component Condition Assessment

Due to limited availability of component condition data, numerical analysis is done using assumed numerical values for transformer. Based on the understanding of power transformer, weights were assigned for each criterion. 0.95 is used as best reliability for each criterion except for geographical location (0.80), experience with the transformer type (0.65) and the faults seen by the transformer (0.99) for trivial reasons. 0.10 is the worst possible reliability for each component except the experience with the transformer type and geographical location, which are kept the same as the best case. Table 8 shows the assumed weights and the calculated component reliability; highlighted criteria are connected in parallel. The component reliability is calculated using (IV.1).

Using similar analysis worst component reliability $\widetilde{R_{sys}}(worst)$ is determined to be 0.176. Therefore for the given system the developed CCS is given by,

$$CCS(t) = \frac{\widetilde{R_{sys}}(t) - 0.176}{0.800 - 0.176} 100$$

Let the transformer age be 18 years. Therefore the reliability of the criterion – age can be calculated using the reliability function developed in the example 1 as,

$$R(18) = e^{-\left(\frac{18}{23.35}\right)^{4.92}} = 0.76$$

TABLE 8

CONDITION WEIGHTS AND THE BEST CONDITION RELIABILITY

Criterion	**Weight**	$\boldsymbol{R(t^*)}$	$\boldsymbol{\tilde{R}(t^*)}$
Faults seen by the transformer	0.70	0.99	0.965
Geographical location	0.60	0.80	0.940
loading	0.80	0.95	0.960
Age	0.90	0.95	0.955
Noise	0.40	0.95	0.980
Condition of winding	0.90	0.95	0.955
PD test	0.75	0.95	0.963
Core and winding loss	0.80	0.95	0.960
Condition of solid insulation	0.80	0.95	0.960
Tap changer condition	0.60	0.95	0.970
Winding turns ratio	0.70	0.95	0.965
Gas in oil	0.90	0.95	0.955
water in oil	0.90	0.95	0.955
Acid in oil	0.90	0.95	0.955
Oil PF	0.90	0.95	0.955
Tank condition	0.90	0.95	0.955
bushing condition	0.90	0.95	0.955
hot spot temperature	0.70	0.95	0.965
cooling system	0.70	0.95	0.965
Experience	0.50	0.05	0.505
Component: $\widetilde{R_{sys}}(best)$			**0.800**

Further, if we assume that the TDCG is 1.8 ppk then using the reliability function developed in example 2, the reliability would be,

$$R(18) = e^{-\left(\frac{1.8}{3.3}\right)^4} = 0.92$$

From the example 3, the reliability of the criterion – experience with the transformer type could be determined. Using S_F = 40, S_U = 10, F = 90 and s = 60 (as defined in example 3) Weibull shape and scale parameters are found to be,

$$\beta = \frac{S_U}{S_F} = 0.25\,, \quad \theta = \frac{S_F}{F} = 0.44$$

Therefore the reliability of the experience with the transformer is,

$$R(60) = e^{-\left(\frac{1.8}{0.44}\right)^{0.25}} = 0.03$$

It could be noted that the reliability due to the experience is very low. This is expected as the experience with the transformer type only has slight advantage for healthy operation.

With similar analysis reliability of all the criteria could be determined. Due to the computational similarities, this work avoids these calculations. Table 9 shows the component reliability calculated for transformer using the calculated reliabilities for the three examples and the assumed values for the others.

Using reliability of the component estimated in Table 9, the CCS for the transformer will be,

$$CCS(t) = \frac{0.598 - 0.176}{0.800 - 0.176} 100 = 67.5\%$$

From the developed equipment condition report, assuming the defective region is uniformly distributed, the component is satisfactory, and needs to be constantly monitored and maintained as the component life can be affected in long term if neglected.

TABLE 9

COMPONENT RELIABILITY FOR A HEALTHY COMPONENT

Criterion	Weight	$\boldsymbol{R(t^*)}$	$\boldsymbol{\tilde{R}(t^*)}$
Faults seen by the transformer	0.70	0.80	0.86
Geographical location	0.60	0.90	0.94
loading	0.80	0.80	0.84
Age	0.90	0.76	0.784
Noise	0.40	0.90	0.96
Condition of winding	0.90	0.80	0.82
PD test	0.50	0.82	0.91
Core and winding loss	0.80	0.80	0.84
Condition of solid insulation	0.80	0.88	0.904
Tap changer condition	0.60	0.91	0.946
Winding turns ratio	0.70	0.95	0.965
Gas in oil	0.90	0.92	0.928
water in oil	0.90	0.87	0.883
Acid in oil	0.90	0.89	0.901
Oil PF	0.90	0.90	0.91
Tank condition	0.90	0.92	0.928
bushing condition	0.90	0.90	0.91
hot spot temperature	0.70	0.80	0.86
cooling system	0.70	0.80	0.86
Experience	0.50	0.03	0.515
Component: $\widetilde{R_{sys}}(t)$			**0.598**

If the gas in the oil is assumed to be 4 ppk, resulting in poor oil condition, the reliability of the criterion – gas in oil will be 0.12. Then the calculated component $\widetilde{R_{sys}}(t)$ will be 0.464. Resulting in $CCS(t)$ of 44.8%; this indicates that the component is seriously defective and needs attention in the near future.

5.2. Optimal Maintenance Allocation

Example 1: A single zone system with seven line segments is considered in this example. Modified example given in the Windmil User Manual [72], shown in Figure 22, is used with the outage data and switching data tabulated in Table 10 and Table 11 respectively. The required improvement for each component to bring the SAIDI to 7, 6, 5 and 3 were determined using the proposed technique. A validation of the proposed technique was conducted assuming that all the components were maintained and the required improvement is achieved.

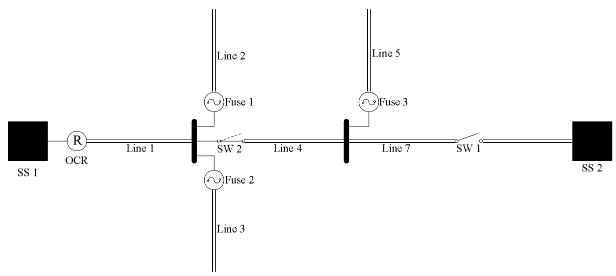


Figure 22: System with only one zone.

TABLE 10

OUTAGE DURATION DATA FOR SINGLE ZONE EXAMPLE

Element	Hazard rate	Outage Duration , Time to			No of Customers
		Fix	Find problem	Travel	
Substation	0.1	5.0	1.0	0.25	0
OSR	0.01	1.0	1.0	0.25	0
Line 1	0.4	2.0	1.0	0.25	100
Line 2	0.6	2.0	1.0	0.25	300
Line 3	0.2	2.0	1.0	0.25	400
Line 4	0.4	2.0	1.0	0.25	350
Line 5	0.6	2.0	1.0	0.25	200
Line 7	1.0	2.0	1.0	0.25	400
Fuses	0.01	3.0	1.0	0.25	0
Switches	0.005	1.0	1.0	0.25	0

TABLE 11

SWITCHING DATA SINGLE ZONE EXAMPLE

Element	Time to close	Time to open	Time to bypass
Switches	0.5	0.3	0.2
Fuse	0.5	0.3	0.2
OCR	0.5	0.3	0.2

Zonal hazard rate is the summation of hazard rates of all the components in the zone.

$$\bar{h} = \sum_{\forall i} h_i = 3.325$$

Step 1: Using Windmil, the initial SAIDI of the system is calculated to be 7.7781. Since $SAIDI_i = \bar{h} \cdot \alpha_i$, therefore the unknown parameter α_i could be determined as

$$\alpha_i = \frac{SAIDI_i}{\bar{h}} = 2.4$$

Step 2: Using the optimization technique the allocated hazard rates for the required SAIDIs are calculated using MATLAB and tabulated in Table 12.

TABLE 12

ALLOCATED HAZARD RATES FOR SINGLE ZONE EXAMPLE

Element	Allocated Hazard rates for the required SAIDI.			
	SAIDI = 7	SAIDI = 6	SAIDI = 5	SAIDI = 3
Substation	0.0900	0.0771	0.0643	0.0386
OSR	0.0090	0.0077	0.0064	0.0039
Line 1	0.3600	0.3086	0.2571	0.1543
Line 2	0.5400	0.4628	0.3857	0.2314
Line 3	0.1800	0.1543	0.1286	0.0771
Line 4	0.3600	0.3086	0.2571	0.1543
Line 5	0.5400	0.4628	0.3857	0.2314
Line 7	0.9000	0.7714	0.6428	0.3857
Fuses	0.0090	0.0077	0.0064	0.0039
Switches	0.0045	0.0039	0.0032	0.0019

Step 3: Using Windmil, the actual SAIDIs are calculated and tabulated in Table 13.

TABLE 13

REQUIRED SAIDIS COMPARED WITH ACHIEVABLE SAIDIS

Required SAIDI	Actual SAIDI with allocated hazard rates
3	3.0158
5	5.0252
6	6.0311
7	7.0363

It could be seen that if the hazard rate of the components are kept within the allocated hazard rate determined by the proposed technique the system performance index could be reduced to the required level for a single zone system. Therefore the proposed technique is a good option for a single zone system.

Example 2: A two zone system, shown in Figure 23, is employed in this example, modifying the data given in the Windmil User Manual. For this case it is assumed that all $C_i = 1$. This work assumes that the required SAIDIs are 3.25, 3, 2.5, 2 and 1.

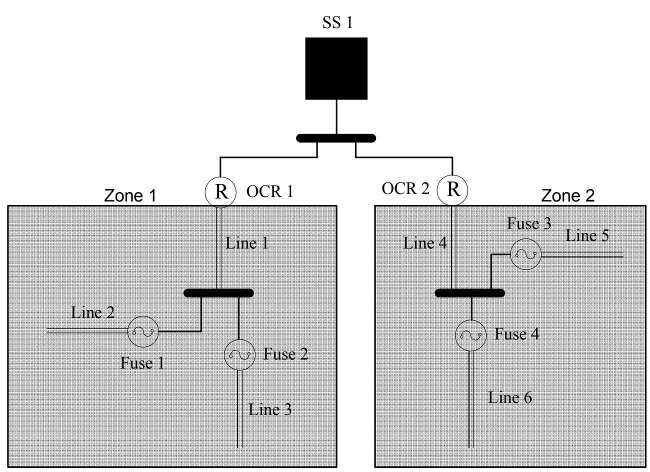


Figure 23: System with two zones.

The outage data for the given system is given in Table 14 and the switching data is given in Table 15.

TABLE 14

OUTAGE DURATION DATA FOR THE TWO ZONE EXAMPLE

Element	Hazard rate	Outage Duration , Time to			No of Customers
		Fix	Find problem	Travel	
Substation	0	5.0	1.0	0.25	0
OSR	0	1.0	1.0	0.25	0
Line 1	0.4	2.0	1.0	0.25	100
Line 2	0.6	2.0	1.0	0.25	300
Line 3	0.2	2.0	1.0	0.25	400
Line 4	0.4	2.0	1.0	0.25	350
Line 5	0.6	2.0	1.0	0.25	200
Line 6	1.0	2.0	1.0	0.25	400
Fuses	0.01	3.0	1.0	0.25	0

TABLE 15

SWITCHING DATA FOR THE TWO ZONE EXAMPLE

Element	Time to close	Time to open	Time to bypass
Fuse	0.5	0.3	0.2
OCR	0.5	0.3	0.2

Zonal hazard rate for each zone is the summation of hazard rates of all the components in the zone.

$$\overline{h_1} = \sum_{\forall\, i} h_i = 1.2 \quad \text{and} \quad \overline{h_2} = \sum_{\forall\, i} h_i = 2.0$$

Step 1: Using Windmil the initial SAIDI of the system is calculated to be 3.5211

Step 2: Using the optimization technique the allocated hazard rates for the required SAIDIs are calculated using MATLAB and tabulated in Table 16.

TABLE 16

ALLOCATED HAZARD RATES FOR TWO ZONE EXAMPLE

Element	**Allocated Hazard rates for the required SAIDI.**				
	SAIDI = 3.25	**SAIDI = 3**	**SAIDI = 2.5**	**SAIDI = 2**	**SAIDI = 1**
Line 1	0.3649	0.3326	0.2680	0.2033	0.0741
Line 2	0.5474	0.4989	0.4020	0.3050	0.1111
Line 3	0.1825	0.1663	0.1340	0.1017	0.0370
Line 4	0.3711	0.3444	0.2911	0.2378	0.1311
Line 5	0.5566	0.5166	0.4366	0.3566	0.1966
Line 6	0.9277	0.8610	0.7277	0.5944	0.3277
Fuse1	0.0091	0.0083	0.0067	0.0051	0.0019
Fuse2	0.0091	0.0083	0.0067	0.0051	0.0019
Fuse3	0.0093	0.0086	0.0073	0.0059	0.0033
Fuse4	0.0093	0.0086	0.0073	0.0059	0.0033

Step 3: Using Windmil the actual SAIDIs are calculated and tabulated in Table 17.

TABLE 17

REQUIRED SAIDIS COMPARED WITH ACHIEVABLE SAIDIS

Required SAIDI	**Actual SAIDI with allocated hazard rates**
1	1.0001
2	2.0000
2.5	2.5001
3	2.9998
3.25	3.2500

It could be seen the proposed technique works well for multiple zone cases too.

Example 3: For the same system in example 2, Let $c_1 = 1$ & $c_2 = 0.5$. The procedure is similar to that of pervious examples, Step 1 is will be the same as in the previous case.

Step 2: Using the optimization technique the allocated hazard rates for the required SAIDIs are calculated using MATLAB and tabulated in Table 18

TABLE 18

ALLOCATED HAZARD RATES FOR TWO ZONE EXAMPLE (3)

Element	**Allocated Hazard rates for the required SAIDI.**				
	SAIDI = 3.25	**SAIDI = 3**	**SAIDI = 2.5**	**SAIDI = 2**	**SAIDI = 1**
Line 1	0.3788	0.3592	0.3200	0.2809	0.2026
Line 2	0.5682	0.5388	0.4801	0.4213	0.3039
Line 3	0.1894	0.1796	0.1600	0.1404	0.1013
Line 4	0.3650	0.3327	0.2681	0.2035	0.0743
Line 5	0.5475	0.4990	0.4021	0.3052	0.1114
Line 6	0.9124	0.8317	0.6702	0.5087	0.1857
Fuse1	0.0095	0.0090	0.0080	0.0070	0.0051
Fuse2	0.0095	0.0090	0.0080	0.0070	0.0051
Fuse3	0.0091	0.0083	0.0067	0.0051	0.0019
Fuse4	0.0091	0.0083	0.0067	0.0051	0.0019

Step 3: Using Windmil the actual SAIDIs are calculated and tabulated in Table 19.

TABLE 19

REQUIRED SAIDIS COMPARED WITH ACHIEVABLE SAIDIS

Required SAIDI	**Actual SAIDI with allocated hazard rates**
1	1.0003
2	2.0001
2.5	2.5001
3	3.0001
3.25	3.2502

It could be seen the proposed technique works well for multiple zone cases too.

Example 3: For the same system in example 2, different values for c_i's are used in this example. Let $c_1 = 1$ & $c_2 = 10$

Step 1: Using Windmil the initial SAIDI of the system is calculated to be 3.5211

Step 2: Using the optimization technique the allocated hazard rates for the required SAIDIs are calculated using MATLAB and tabulated in Table 20.

TABLE 20

ALLOCATED HAZARD RATES FOR TWO ZONE EXAMPLE (4)

Element	Allocated Hazard Rates for the required SAIDI.				
	SAIDI = 3.25	SAIDI = 3	SAIDI = 2.5	SAIDI = 2	SAIDI = 1
Line 1	0.3153	0.2373	0.0811	-0.0750	-0.3872
Line 2	0.4730	0.3559	0.1217	-0.1125	-0.5809
Line 3	0.1577	0.1186	0.0406	-0.0375	-0.1936
Line 4	0.3930	0.3866	0.3737	0.3608	0.3351
Line 5	0.5895	0.5799	0.5605	0.5412	0.5026
Line 6	0.9825	0.9664	0.9342	0.9020	0.8376
Fuse1	0.0079	0.0059	0.0020	-0.0019	-0.0097
Fuse2	0.0079	0.0059	0.0020	-0.0019	-0.0097
Fuse3	0.0098	0.0097	0.0093	0.0090	0.0084
Fuse4	0.0098	0.0097	0.0093	0.0090	0.0084

Step 3: Using Windmil the actual SAIDIs are calculated and tabulated in Table 21.

TABLE 21

REQUIRED SAIDIS COMPARED WITH ACHIEVABLE SAIDIS

Required SAIDI	Actual SAIDI with allocated hazard rates
1 and 2	Not Achievable
2.5	2.4998
3	3.0001
3.25	3.2499

It could be noted that the optimal maintenance allocation will not generate feasible solutions for required SAIDI of 1 and 2. Some of the components (Line 1, Line 2, Line 3, Fuse 1 and Fuse 2) need negative allocated hazard rates, which are impractical. Therefore the developed sub-optimal scheme is used to determine the allocated hazard rates for each of the components when the required SAIDIs are 1 and 2. For this case the minimum achievable hazard rate for each component is tabulated in Table 22. The minimum achievable hazard rate is determined based on the physical limitations on the maintenance.

TABLE 22

MINIMUM ACHIEVABLE HAZARD RATES FOR THE COMPONENTS

Equipment	**Line1**	**Line2**	**Line3**	**Line4**	**Line5**	**Line6**	**Fuse**
h_{min}	0.04	0.06	0.02	0.04	0.06	0.10	0.001

Step 2: Using the sub-optimal technique the allocated hazard rates for the required SAIDIs are calculated using MATLAB and tabulated in Table 23.

TABLE 23

ALLOCATED HAZARD RATES FOR TWO ZONE EXAMPLE WITH SUB-OPTIMAL ROUTINE

Element	**Allocated Hazard rates for the required SAIDI.**	
	SAIDI = 2	**SAIDI = 1**
Line 1	0.0400	0.0400
Line 2	0.0600	0.0600
Line 3	0.0200	0.0200
Line 4	0.3100	0.1461
Line 5	0.4650	0.2192
Line 6	0.7749	0.3654
Fuse1	0.0010	0.0010
Fuse2	0.0010	0.0010
Fuse3	0.0077	0.0037
Fuse4	0.0077	0.0037

Step 3: Using Windmil the actual SAIDIs are calculated and tabulated in Table 24.

TABLE 24

REQUIRED SAIDIS COMPARED WITH ACHIEVABLE SAIDIS

Required SAIDI	Actual SAIDI with allocated hazard rates
1	1.0000
2	2.0000

It could be observed that when the optimal maintenance allocation fails to generate feasible solution the sub-optimal routine could be used and the results from the suboptimal solution would also improve the system reliability to the required level. Further it could be noted that the zone for which the suboptimal solution is used, for the future maintenance, component replacement would be essential in the future, or may have to include redundant paths to ensure that the zonal reliability could be improved.

5.3. Component Derating and Reconfiguration

The distribution system developed by Allan et. al., Reliability Test System - RBTS bus 4 [73], with the assumption of a 33kV system, is modified and used in this analysis. The modified system is given in Figure 24 with the reliability data shown in Table 25. Let's fix $\eta = 5$ and $\tau = 1$. It is assumed that the substation has zero unavailability.

Same analysis could be extended to non zero unavailability of the substation without losing any generality. Further it is assumed that the components to be derated based on the budget limitations are already known. It was recommended to improve the hazard rate of F7 to at least 0.200.

Due to budget limitations, maintenance of F7 was postponed. For short term performance boost F7 is derated. Nominal voltage of the system will not change due to derating and therefore derating is calculated in MVA using (V.7), with the assumption that the hazard rate of the feeder section has a Weibull distribution with shape parameter $\beta = 5$.

$$MVA_k^{\;*} = \sqrt{\frac{3.8193\beta}{3.8193\beta - \ln(\lambda_k^{\;*}/\lambda_k)}}MVA_k$$

Allocated rating of F7 to achieve the desired hazard rate of 0.200 is found to be 1.83 MVA. Present loading on F7 is 2.80 MVA, therefore it is necessary to reduce the loading on F7. If downstream load (Feeder section F8) is removed then loading on F7 is 1.35 MVA, which is less than derated value of F7.

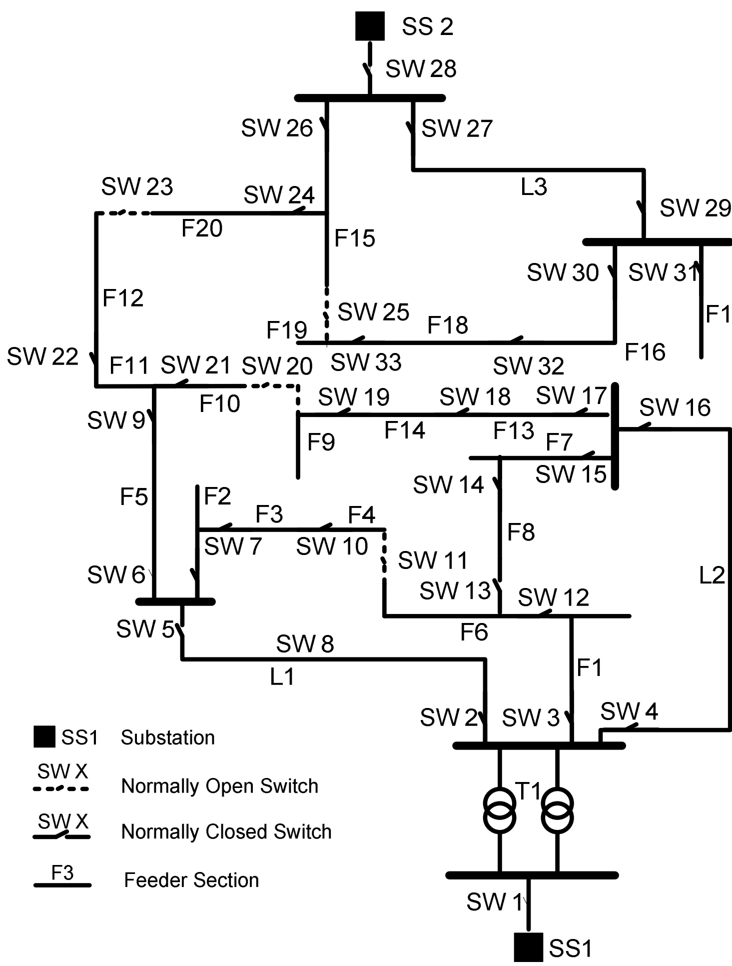


Figure 24: Test System for Derating and Reconfiguration

TABLE 25

DATA FOR THE TEST SYSTEM

	Avg. Load (MVA)	Cust.	Cum. Load (MVA)	Capacity (MTABLE 25VA)	Hazard rate
SS1	0.00	0	12.10	14	0.000
F1	1.05	103	2.15	3.9	0.187
F6	1.10	110	1.10	2.8	0.195
L1	0.00	0	3.65	6.25	0.000
F2	0.52	96	1.56	3.2	0.193
F3	0.51	92	1.04	2.7	0.187
F4	0.53	96	0.53	2.2	0.195
F5	0.53	96	2.08	3.2	0.193
F10	0.49	90	1.55	2.4	0.181
F11	0.54	98	1.06	1.7	0.197
F12	0.52	84	0.52	1.2	0.191
L2	0.00	0	6.30	7.5	0.000
F7	1.35	97	2.80	3.4	0.385
F8	1.45	103	1.45	2.0	0.122
F13	0.98	32	3.50	5.5	0.116
F14	0.93	20	2.52	3.5	0.112
F9	1.59	47	1.59	2.0	0.189
SS2	0.00	0	6.05	7.5	0.000
F15	1.32	3	2.70	3.2	0.110
F20	1.38	5	1.38	1.3	0.124
L3	0.00	0	3.35	5	0.00
F17	1.15	1	1.15	3.8	0.191
F16	0.56	46	2.20	1.4	0.124
F18	0.83	57	1.64	2.5	0.183
F19	0.82	54	0.82	1.5	0.181

Since only one component needs derating there is no need to rank the components. Paths (F8, F6, F1 and SS1) and (F8, F6, F4, F3, F2, L1 and SS1) can be used for redistributing the load on F8. Since there is more than one option to reconfigure, $\ell(i)$ for both the paths should be determined. Loading effect for path (F8, F6, F1 and SS1) is calculated as follows

1. *Determine the loading effect on the component:* Since

$$\frac{1}{3}\sum_{j\in path\ i}\left(\frac{L_n(j)}{\hat{L}(j)}\right)^5 = \frac{1}{3}\left(\left(\frac{2.45}{2.8}\right)^5 + \left(\frac{3.6}{3.9}\right)^5 + \left(\frac{12.1}{14}\right)^5\right)$$

$$\frac{1}{3}\sum_{j\in path\ i}\left(\frac{L_n(j)}{\hat{L}(j)}\right)^5 =< 1$$

Redistribution through (F8, F6, F1 and SS1) is possible

2. *The loading effect on F6 due to the redistribution of F8.*

$$LE_{F6}(P2) = \frac{Cap(F6) - L_{old}(F6)}{Cap(F6) - L_{new}(F6)}$$

$$LE_{F6}(P2) = \frac{2.8\ MVA - 1.1MVA}{2.8\ MVA - 2.55MVA} = 6.8$$

Loading effect of all the components in all the paths could be found using the same analogy and the calculated loading effects for all the related components are shown in Figure 25,

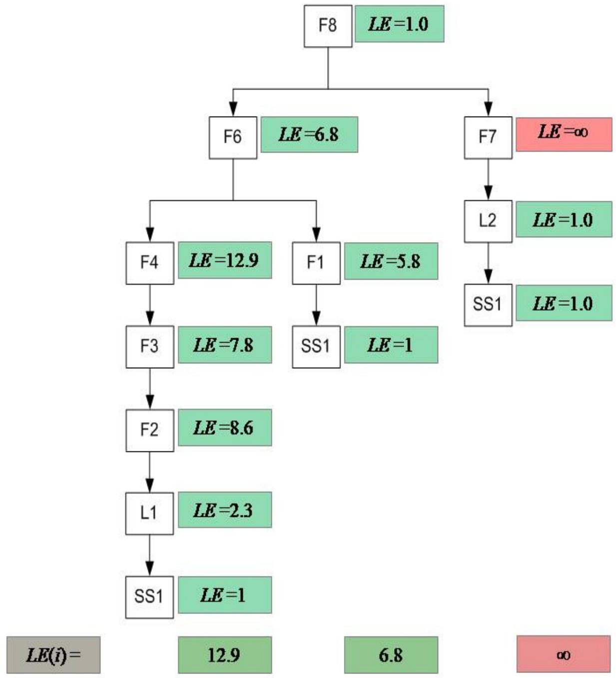


Figure 25: Loading factors for each component in every path

From the calculated loading factors it could be seen that F4 has the highest loading factor. Since (F8, F6, F1 and SS1) has the least maximum loading effect, feeder section F8 should be redistributed through this path. Thus reconfiguration would result in opening switch SW 14 and closing switch SW 13.

To verify that this would improve the performance the reliability analysis was done for the system using commercial distribution reliability software. It was assumed that all the feeder sections have equal repair times. The SAIDI's for all three options are given in Table 26.

TABLE 26

COMPARISON OF SAIDIS

Path	SAIDI
(F8, F7, L2 and SS1)	3.2386
(F8, F6, F4, F3, F2, L1 and SS1)	3.0227
(F8, F6, F1 and SS1)	3.0227

It could be seen that both the redistribution paths have the same system performance which is better than the initial system configuration as expected. This shows that the selection of (F8, F6, F1 and SS1) as the reconfigured path for the load in feeder section F8 is reasonable.

5.4. Optimal EV Charging

From Environmental Protection Agency (EPA) estimates shown in [74] the CO_2 emission for coal power plant (1999) is 2.095 lbs/kWh (e_c), CO_2 emission for petroleum power plant (1999) is 1.969 lbs/kWh (e_o) and CO_2 emission for gas power plant (1999) is 1.314 lbs/kWh (e_g). It is trivial that emission from Nuclear and Renewable is zero $(e_n = e_r = 0)$. Average efficiency of a EV (η) could is taken as 24.75% (Electric vehicle drive efficiency 75% electric grid efficiency 33%) [75].

For a midsize vehicle: CO_2 emission for gasoline vehicle is 19.4 pounds/gallon [76], average driving distance in US (2001) is 33 miles per day [77] and would travel 21 miles per gallon [78]. CO_2 emission per day from a midsize vehicle is taken as,

$$E_{Gas-Vehi} = \frac{33}{21} \times 19.4 = 30.5 \text{ lbs}$$

Weighted function for the emission could be given by,

$$f(E) = w_t \frac{E_{CO_2}}{E_{Gas-Vehi}} = w_t \cdot \frac{r \cdot \tilde{P}}{30.5\eta} \cdot n_i$$

Based on distribution system analysis subcommittee report [79], a 13 bus test feeder is used with a modification using ANSI/IEEE C57.92.1881 [80] and test feeder developed by Allan et.al. [73] to incorporate reliability data. One-line diagram of the system with six zones is given in Figure 26.

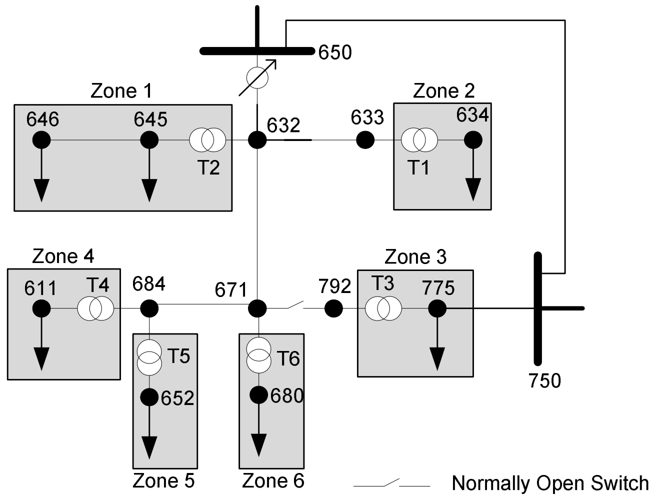


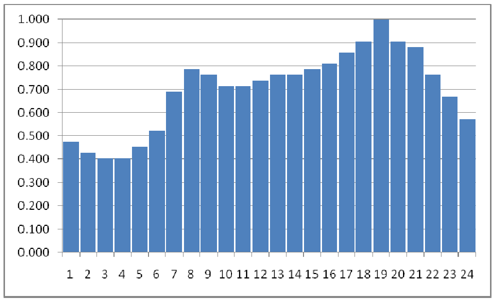
Figure 26: One-Line Diagram of the system

All the transformers in the system (T1 – T6) are assumed to be rated at $115\ kV : 13.2\ kV$. Based on the transformer locations the system is divided into 6 zones as shown in Figure 26. The maximum loading at each bus is tabulated in the Table 27. Normalized load profiles for each bus for the following day are given in Figure 27 with the assumed type of loading.

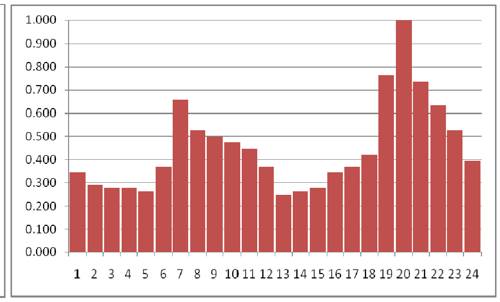
TABLE 27

MAXIMUM LOADING AT EACH BUS

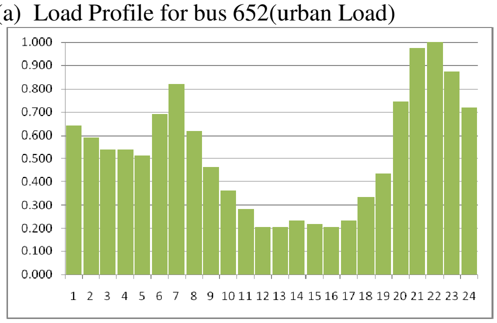
Node	634	645	646	680	775	652	611
Load (kVA)	196	120	145	265	320	450	225



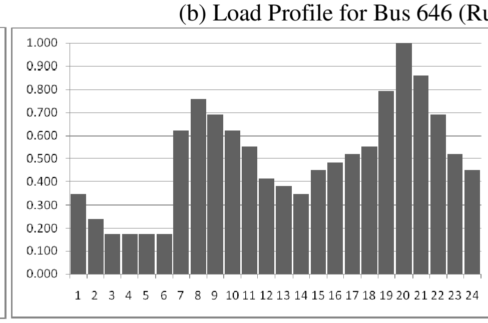
(a) Load Profile for bus 652(urban Load)



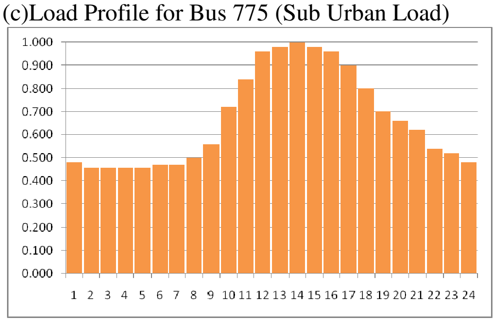
(b) Load Profile for Bus 646 (Rural Load)



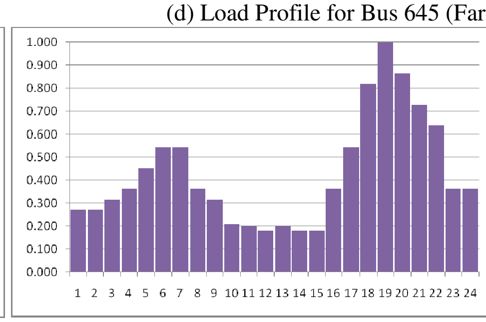
(c)Load Profile for Bus 775 (Sub Urban Load)



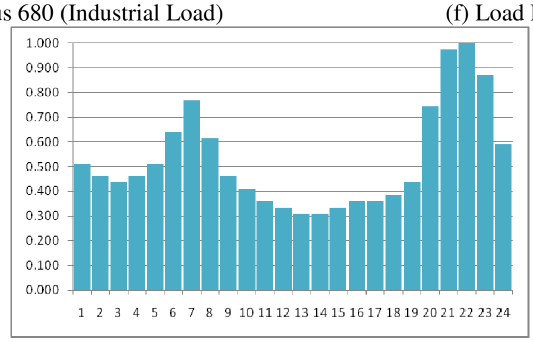
(d) Load Profile for Bus 645 (Farm Load)



(e) Load Profile for bus 680 (Industrial Load)



(f) Load Profile for bus 634(rural Load)



(g) Load Profile for bus 611 (Sub Urban Load)

Figure 27: Normalized Load Profiles for all the Busses

Transformer data for the given system is tabulated in Table 28. Daily failure rate calculated assuming constant failure rate model is used in the analysis. Due to the computational simplicity many utilities use constant failure rate model in their analysis. For more accurate analysis this could be determined using historic data and the actual failure rate for at least different seasons.

TABLE 28

TRANSFORMER DATA

	Rating kVA	Failure Rate f/ yr	Failure Rate 10^{-6} f/ day
T1	225	0.018	49
T2	300	0.016	42
T3	300	0.014	38
T4	300	0.015	41
T5	500	0.013	36
T6	750	0.010	27

Locational Marginal Price for all three cases for the following day are given in Figure 28. For the first case *Original LMP* is used for both buses 650 and 750. A *modified LMP* is used for both buses 650 and 750 for the second case to investigate the impact of LMP on charging. A distributed wind generator is included for the third case to illustrate the impact of distributed generation on the charging. *Wind for 750* is using for bus 650 and *original LMP* is used for bus 750 in the third case. Normalized LMPs for the optimization is given in Figure 29.

For the three zones in consideration, based on the loading and the transformer rating, Zone 3 will be operated above the rating of the transformer at the during the peak hours, Zone 4 will be always operated well below transformer rating and peak load during the peak in Zone 5 close to but less than the transformer rating.

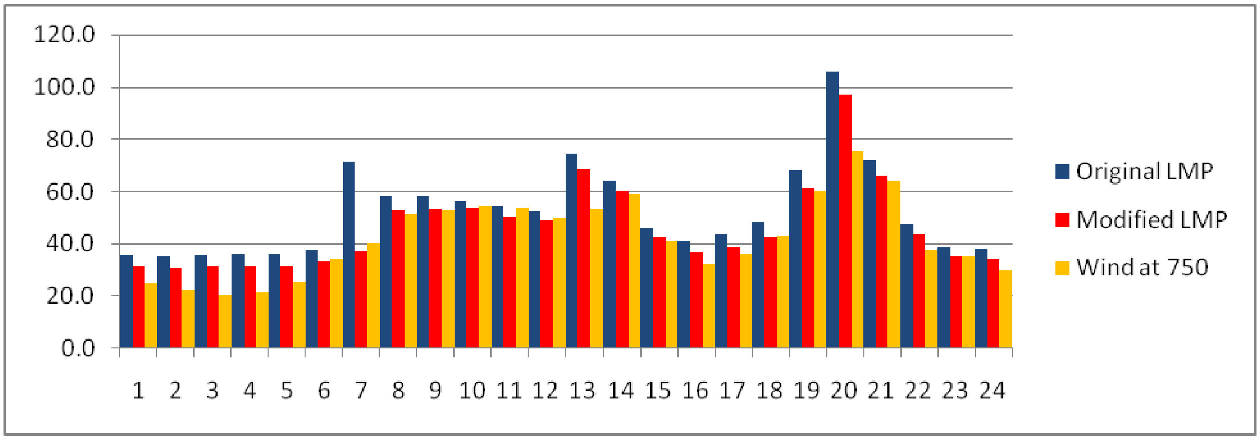


Figure 28: Locational Marginal Price for Three Cases

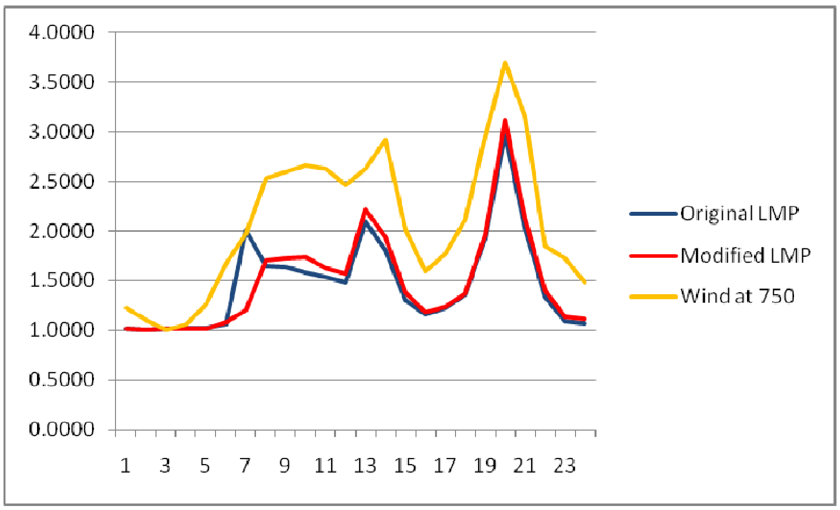


Figure 29: Normalized Locational Marginal Price for Three Cases

It is further assumed that the PHEVs are located in the urban and suburban areas and even though rural areas are capable of handling PHEVs there is no regular EV load in this area. The industrial load could see a small amount of PHEVs wanting to charge in the day time. Based on the average vehicles available for charging [80] and the assumption for the availability of the PHEVs given in Table 29 the number of vehicles available for charging is given in the Figure 30.

TABLE 29

TOTAL PHEVS AT EACH ZONE

Bus	634	646	645	775	611	652	680
Total EV	0	0	0	70	30	50	6

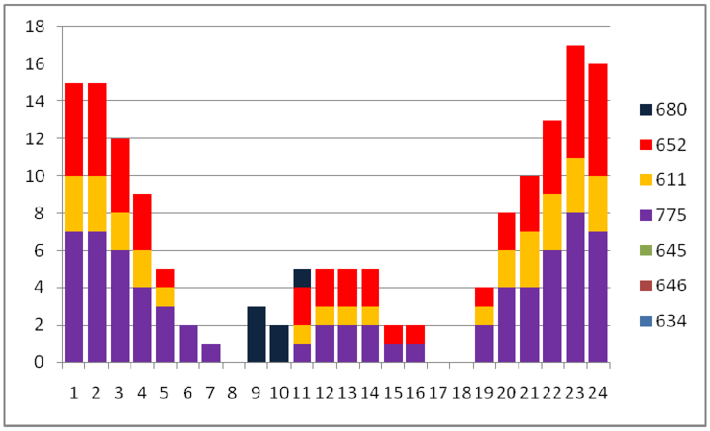


Figure 30: Number of PHEVs Requesting Charging at a Given Time

Generation dispatch results for IEEE reliability system from [81] are used in the first case to determine the maximum number of vehicles at a given hour. Figure 31 shows the dispatch schedule used.

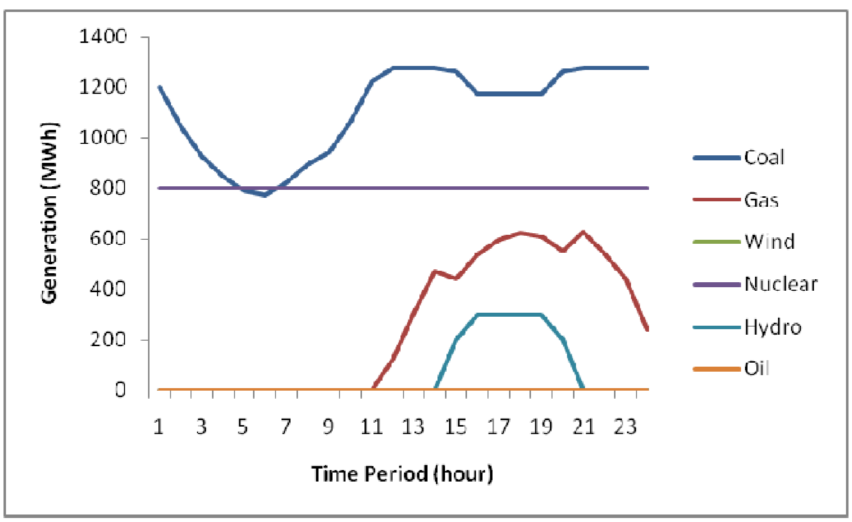


Figure 31: Generation Dispatch [81]

To determine the transformer loss of life parameters given in section III.B.1, the values given in the ANSI/IEEE std. C57.92.1881[80] are used. For more accurate analysis values calculated by the manufacturer could be used. The values given in ANSI/IEEE std. C57.92.1881 are reasonable and could be used in the practical applications, where actual data is not available.

From ANSI/IEEE C57.92.1881 [80], for natural circulation self cooled (OA) transformers, with rating up to 100 MVA, following values could be used, $R = 3.2,\ \Delta\theta_{TO,R} = 50°\text{C},\ \Delta\theta_{H,R} = 30°\text{C}$. Further, for analytical purpose let the charging rate of a battery, based on the Chevy Volt specifications [82], is used as, $r = 2.5\ kW$. The calculated δ, α, β for all the zones are given in Table 30,

TABLE 30

TRANSFORMER LOSS OF LIFE PARAMETERS

Transformer	**Rating kVA**	$\boldsymbol{\alpha}$	$\boldsymbol{\beta}$	$\boldsymbol{\delta}$
T1	225	0.00501	0.33	15.87
T2	300	0.00282	0.25	15.87
T6	*500*	*0.00102*	*0.15*	15.87
T3	*300*	*0.00282*	*0.25*	15.87
T5	*500*	*0.00102*	*0.15*	15.87
T4	*750*	*0.00045*	*0.10*	15.87

The effect of CO_2 emission (ρ) due to the addition is determined using efficiency of the EV calculated based upon the information given in [53], assuming that the weight w_t is 1. Choice $w_t = 1$ is justified, when the consumer has no liability on the CO_2 emission.

$$\rho = w_t \cdot \frac{r \cdot \tilde{P}}{30.5\eta} = \frac{2.5 \times \tilde{P}}{30.5 \times 0.2475} = \frac{\tilde{P}}{3}$$

$\widetilde{P}$ is dependent on the generation mix which is given in Figure 31. Based on generation mix ρ for every hour is given in Table 31

TABLE 31

TRANSFORMER EMISSION PARAMETERS

Hour	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*
ρ	*0.419*	*0.398*	*0.377*	*0.356*	*0.349*	*0.342*	*0.356*	*0.370*	*0.377*	*0.398*	*0.419*	*0.431*
Hour	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*
ρ	*0.434*	*0.432*	*0.398*	*0.377*	*0.378*	*0.376*	*0.378*	*0.402*	*0.429*	*0.434*	*0.435*	*0.428*

Zone 3 is taken as an example to show the calculations. Table 32 shows the values assumed for the zone 3. Vehicles requesting for charging (E_k) and maximum limit on vehicles that could be moved to next charging period (Vm_k) based on information received by vehicles are plotted in Figure 32.

TABLE 32

ASSUMED PARAMETERS FOR ZONES

Parameter	F_{AA}	E_m	C_m	TF_k	Θ_A
Zone 3	*3*	*2.5*	*14*	*360*	*40*
Zone 4	*3*	*2.5*	*9*	*360*	*40*
Zone 5	*3*	*2.5*	*9*	*600*	*40*
Zone 6	*3*	*2.5*	*9*	*840*	*40*

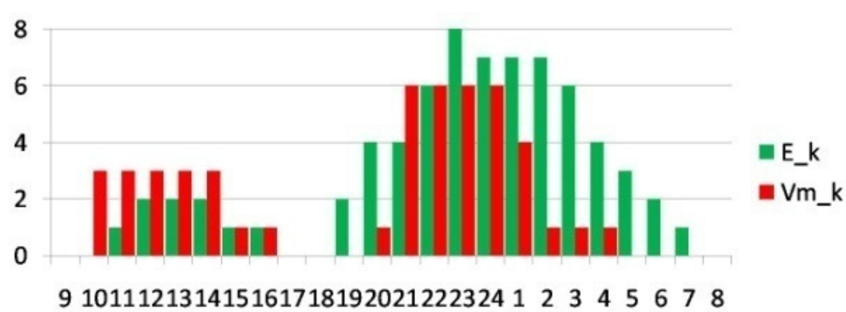


Figure 32: Vehicle Data for Zone 3

Detailed optimization of the vehicles in Zone 3 is used for the illustration purpose. The other zone results are given at the end for comparison purposes. Based on the optimization technique defined in the "*First Step: Predict the number of vehicles for each zone at every period of the day*" the optimum value of vehicles that could be connected to the grid for charging from zone 3 for the following *day* is plotted in Figure 33.

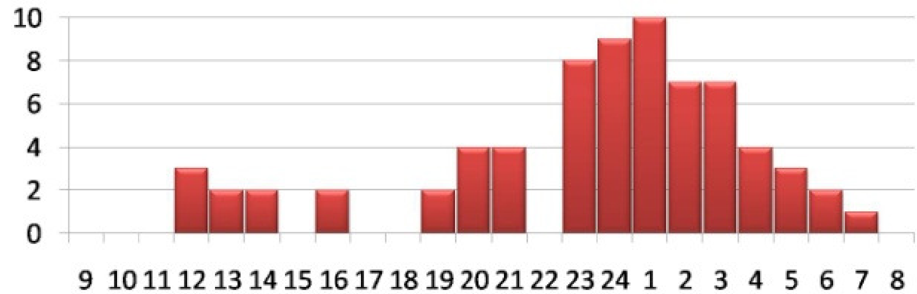


Figure 33: Hourly Optimum Number of Vehicles for the Following Day

The next part is to determine the maximum number of vehicles that could be connected to the grid on the next hour. This would be determined 15 minutes before the start of the hour. This analysis is based on the "*Second Step: Maximum limit on the vehicles based on the operating conditions*" Let's use the data given in Figure 34 as the load on the system (excluding the PHEVs) calculated 15 minutes ahead of each hour, where 8*p* represents the last hour of the previous *day*. This analysis is based on the case 1 where the utility will not relax the limitations on the emission, but will relax the limit on the number of vehicles charging.

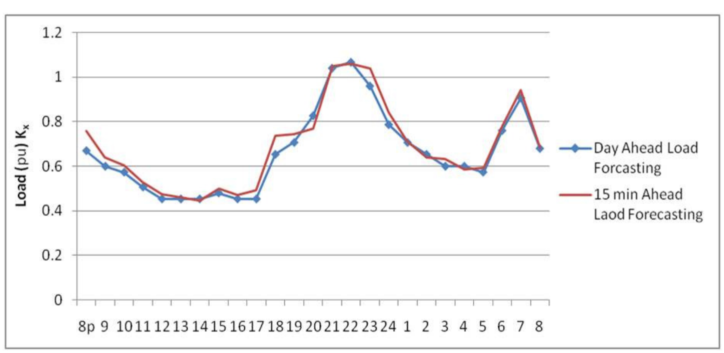


Figure 34: Per-Unit Zone 3 Loading

For illustration purpose, following calculation is made for the first hour 15 minutes ahead, based on the loading and CO_2 emission profile.

First the expected temperature rise due to the regular load is determined using IEEE C57.91-1995 based on the 15 minutes ahead load forecasting,

$$\Delta\theta_{TO,i} = \Delta\theta_{TO,R}\left[\frac{{K_i}^2 R + 1}{R + 1}\right]^n = 36.35℃$$

$$\Delta\theta_{TO,u} = \Delta\theta_{TO,R}\left[\frac{{K_u}^2 R + 1}{R + 1}\right]^n = 31.00℃$$

$$\Delta\theta_{TO} = \left(\Delta\theta_{TO,U} - \Delta\theta_{TO,i}\right)\left(1 - \exp\left(-{}^{t}/_{\tau_{TO}}\right)\right) + \Delta\theta_{TO,i}$$

$$\Rightarrow \Delta\theta_{TO} = 35.05℃$$

$$\Delta\theta_{H,i} = \Delta\theta_{H,R}{K_i}^{2m} = 19.34℃$$

$$\Delta\theta_{H,U} = \Delta\theta_{H,R}{K_U}^{2m} = 14.69℃$$

$$\Delta\theta_{H} = \left(\Delta\theta_{H,U} - \Delta\theta_{TO,i}\right)\left(1 - \exp\left(-{}^{t}/_{\tau_{W}}\right)\right) + \Delta\theta_{H,i}$$

$$\Rightarrow \Delta\theta_{H} = 14.69℃$$

Therefore the expected temperature rise due to regular load is,

$$(\Delta\theta_{TO} + e\,\Delta\theta_{H})_{regular\ load} = 35.05 + 14.69 = 49.74℃$$

Maximum allowable hottest spot temperature rise due to the addition of the PHEVs for that hour is,

$$\Theta_1 = \frac{15000}{\frac{15000}{383} - \ln(F_{AA})} - (\Theta_A + 273) - (\Delta\theta_{TO} + \Delta\theta_{H})_{reg.}$$

$$\Theta_1 = \frac{15000}{\frac{15000}{383} - \ln(3)} - (40 + 273) - 49.74 = 31.26℃$$

Since $\Theta_1(31.26) > \delta(15.87)$ non-zero vehicles could be allowed to charge. To determine the number of vehicles that could be charged, the next step is to determine g,

$$g = \rho \frac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_i - \delta)}}{2\alpha \mathrm{E}_m} 7.66 > 1$$

Since $g > 1$ the next step is to determine the f

$$f = \frac{E_m}{\rho N_i} = \frac{2.5}{0.419 \times 0} = \infty > 1$$

Therefore the number of vehicles to be charged at the first hour is,

$$n_i = \left\lfloor \frac{E_m}{\rho} \right\rfloor = \left\lfloor \frac{2.5}{0.419} \right\rfloor = 5$$

With similar argument the number of vehicles that could be connected in the Zone 3 is plotted in Figure 35. It could be seen for most of time of the day the maximum possible vehicles charged will be less than the estimated optimum vehicles planning to charge in that hour. During the peak hours (21, 22 and 23 hours) the loading on the transformer is above it's rating; therefore connecting any of the PHEVs will degrade the transformer and thus the maximum is kept at zero. Further due to the higher loading during the night, maximum number of vehicles in 7th hour is lower (4) compared to other hours, this is to allow transformer to cool-down.

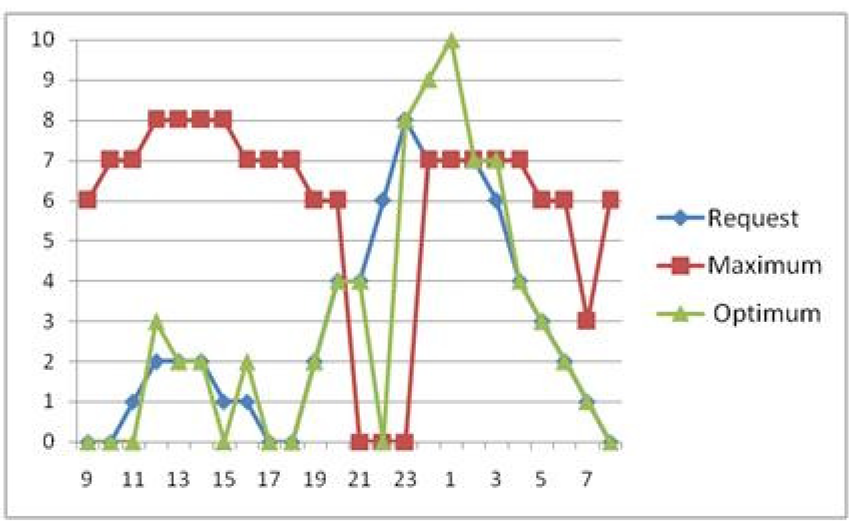
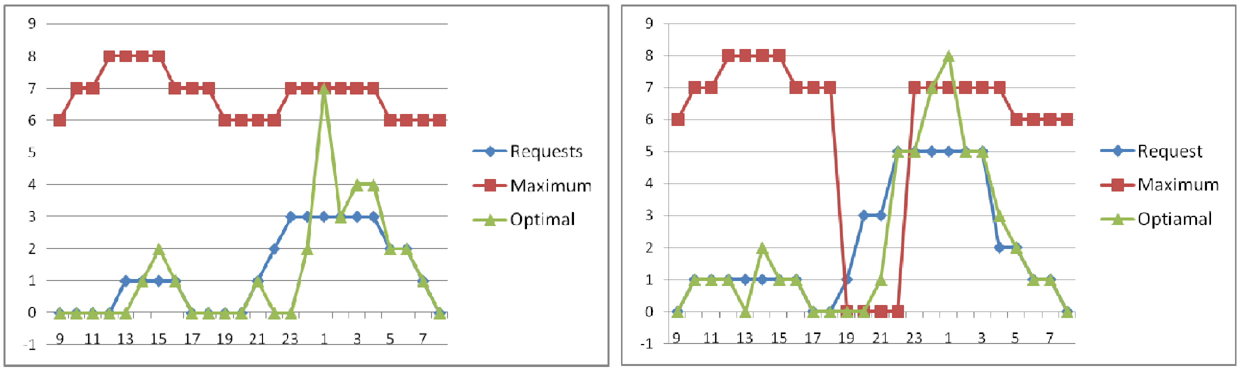


Figure 35: Optimum and Maximum Charging for Zone 3

Results obtained for zone 4 and 5 are shown in Figure 36. It could be seen that zone 4 is operated below the transformer rating and this is reflected by the maximum possible vehicles for any hour being greater than the optimum number of vehicles requesting to be charged. Since zone 5 is operated close to the transformer rating and this has resulted in the zero maximum charging during 19, 20, 21 and 22 hours.



(a) Zone 4 (b) Zone 5

Figure 36: Optimum and Maximum Charging for Zone 4 and Zone 5

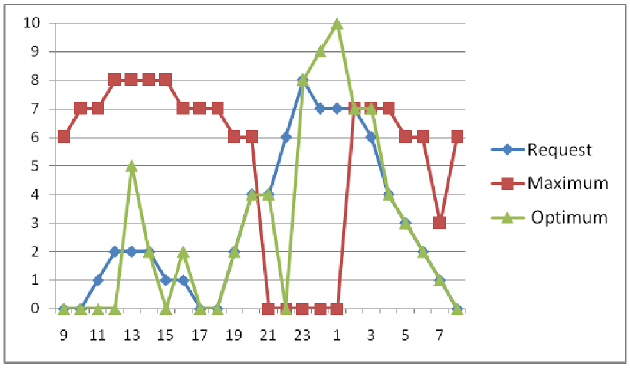
To compare the results with the change of LMP the second case was analyzed. In this case everything is kept the same but the *modified LMP* given in Figure 29 is used instead of original LMP is the first case. The minimum (base value) of the LMPs in both the cases are different. Therefore the maximum limit on the LMP is recalculated using the following relationship and tabulated in Table 33. Vehicles requiring to be charged for each hour are plotted along with the estimated optimum number of vehicles and maximum allowable number of vehicles in Figure 37

$$LMP_{min,orignal} \times C_{m,original} = LMP_{min,modified} \times C_{m,modified}$$

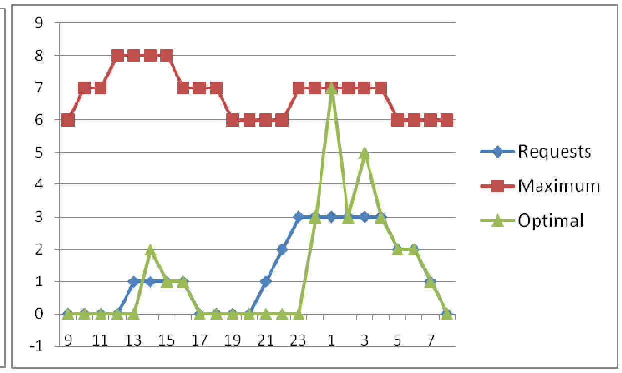
TABLE 33

MODIFIED MAXIMUM LIMITS ON LMPS

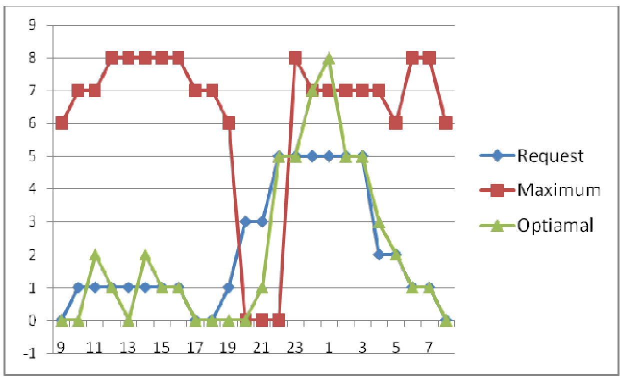
Zone	Zone 3	Zone 4	Zone 5	Zone 6
$C_{M,modified}$	16.0	10.3	10.3	10.3



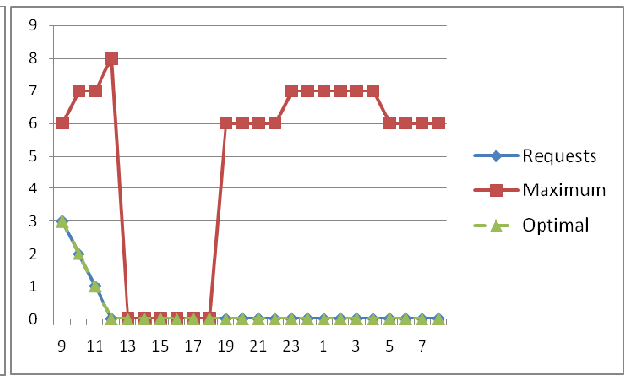
(a) Zone 3



(b) Zone 4



(a) Zone 5



(b) Zone 6

Figure 37: Optimum and Maximum Charging using Modified LMPs

From Figure 37 it is evident that the charging pattern will be affected by the LMPs if this optimization tool is used to determine the number of vehicles to be charged at a given hour.

Further to evaluate the effect on the charging based on the distributed generation a wind turbine is added on the bus 750 as shown in Figure 38

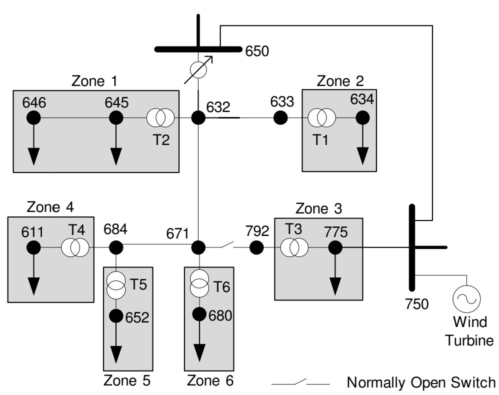


Figure 38: One-Line Diagram of the system with Wind Turbine at bus 750

Original LMP is used for bus 650 and *Wind at 750* is used for bus 750. Due to the difference in minimum (base) LMPs the maximum limit on the LMP at bus 750 ($C_{M,wind}$) is taken as 24.4. Since none of the limits for bus 650 changed optimal and maximum vehicles to be charged at zones 4, 5 and 6 will not change. Based on the optimization technique the optimum and maximum vehicles to be charged from the zone 3 for every hour is plotted in

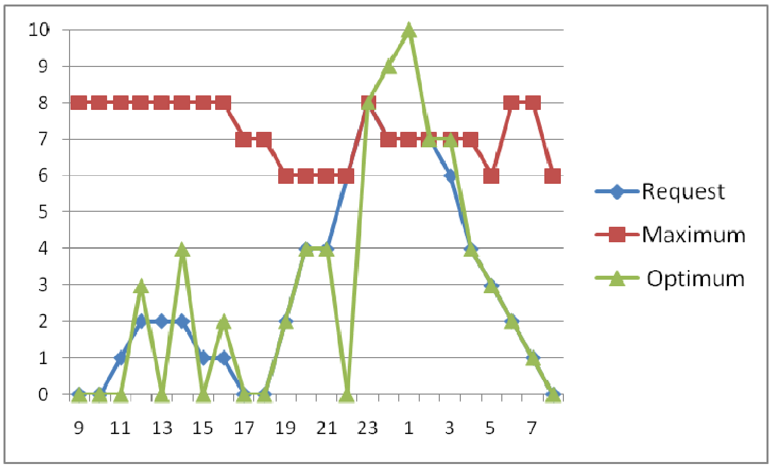


Figure 39: Optimum and Maximum Charging for Zone 3 with wind turbine at bus 750

It could be seen that still the optimal number of vehicles to be charged is higher during 23rd, 24th and 1st hours of the operation. This is due to the transformer loading limitations. If the wind turbine is located at the secondary of zone 3, this effect could be reduced.

CHAPTER 6

CONCLUSIONS AND FUTURE WORK

6.1 Conclusions

A guideline to improve the distribution system reliability based on a new statistical approach is presented in this work. Due to the uncertainties associated with the distribution system operation, limited availability of historical data and limitations on component monitoring has resulted in using a statistical approach for reliability assessment. The work addressed three important issues: improve the system reliability of the existing distribution system, mitigate the reliability concerns due to the addition of electric vehicles, and develop reliability requirements for distribution system communication. Based on the guideline developed, the primary outcomes of this dissertation are as follows:

- ☑ Investigating the condition of the criteria / failure modes will result in accurately predicting the reliability of the components. This work identifies traditional criteria such as age and loading effect, and nontraditional criteria such as geographical location of the component and experience with similar type components, all of which are used in this work. Based on the importance of a particular type of criteria for the healthy operation of a component a weight is assigned to each criterion. Once the weighted reliabilities of all criteria are estimated the condition of the component is determined.
- ☑ It is important to estimate the condition of all the components in a system to accurately predict the distribution system reliability. Minimal availability of historical data is addressed in this work by using Weibull distribution to model component reliabilities. One prime reason is Weibull distribution requires only a small sample space to accurately estimate the parameters.

- ☑ Once the conditions of the components are known the next step is to determine the required level of maintenance for each of the criteria to ensure that the benchmark reliability is achieved. This work uses a Lagrangian formed to minimize the cost of maintenance while ensuring reliability benchmarks. A sub-optimal routine is developed in this work to accommodate the physical limitations on the performance improvement of any component.
- ☑ It is not always possible to complete the required maintenance, mainly due to the budget constraints that the utilities undergo in the restructured electricity market. If any component cannot be maintained to the required level, them the component is derated. Derating should reduce the operating load on the component, and the reduced current will reduce the operating temperature of the component, which in turn will increase the life of the component.
- ☑ In general, derating is a short term solution. It is expected that the utility will schedule the maintenance of derated components as soon as possible. It should be noted that the extended period of deferring the maintenance schedule will affect the rest of the components in the long term.
- ☑ Derating alone will not make any change in the system reliability unless the excess load (difference between the operating load and the derated load) is redistributed through alternative paths. The available paths are ranked based on the risk associated with the addition of excess load to each path. Based on the ranking the path with minimum risk is checked for the loading effect. For a path to be accepted as the alternative path its loading effect should be less than that of the original path. If the loading effect is higher, then the next path based on the risk is checked.

- ☑ The power system is experiencing a new type of load with the introduction of electric vehicles. Since electric vehicles are large stochastic loads, both in time and geographical location, they have potential to adversely affect the reliability of the system. In order to minimize the effect of charging of electric vehicles an optimal schedule is proposed in this work.
- ☑ For the purpose of scheduling charging a 24 hour period is determined based on the requests for charging. Based on historical data, very few vehicles will be requesting charging in the morning, thus this work proposes 9:00 am – 8:59 am of the following day as one period (*day*) and vehicles should send their requests by 12:00 midnight.
- ☑ A two step optimization technique is developed in this work. Based on the requests for vehicle charging received for the following *day,* the duration of each vehicle's availability for charging, the expected LMPs for the following *day*, and the effect on system SAIDI, the optimum number of vehicles that could be charged at every hour will be determined.
- ☑ Due to the uncertainties involved with the vehicles requesting charging, a maximum number of vehicles that could be connected to the grid is determined based on the near real time transformer loading, CO_2 emissions, and equal chance for all the vehicles to charge. If the operating maximum for charging is less than the optimum value then the utility may have to impose a scheme to include the cost of reductions to system reliability.
- ☑ The utility could give incentives to charge at a different time or to move to a different location for charging. If this is not possible then either the utility has to bear the additional cost or impose higher rates. If a similar technique is applied for other large loads (washing machines, air conditioning, etc.) a better coordination could be implemented with reduced effects on the system.

- ☑ For the proposed technique to be highly utilized, a better communication scheme is necessary. This work identifies the necessary requirements for the distribution level communication. Communication over power line and dedicated wired communication are not ideal for distribution level feeder needs. Therefore wireless communication is proposed in this work as the ideal medium for distribution feeder level communication.
- ☑ If reliability of communication is less than that of power system, communication will not serve its purpose. Therefore this work proposes three indices to determine reliability of communication, namely: average number of customers interrupted, average duration of customer interruption and energy not-served due to communication interruption.

6.2 Future Work

To extend the work towards improving the distribution system reliability the following future work is recommended:

- Develop similar condition assessment techniques for other components in the distribution system. This would help to predict complete distribution system reliability
- Using historical data investigate, calibrate and improve the condition assessment technique. Using field data from a utility and calibrating it for future prediction should be the main objective.
- Compare the cost analysis for distributed charging similar to the one proposed and the centralized charging using a charging center with dedicated feeder. This work should include grid connected and off the grid charging using renewable energy sources.
- Develop protocols for feeder level and advanced metering infrastructure (AMI) communication needs. It would be beneficial to develop protocols for the applications that do not have solutions in the present grid, for example fault location.

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APPENDICES

APPENDIX A

RELIABILITY INDICES

IEEE 1366-2003 defines the reliability indices as follows [6],

- ***SAIFI: System Average Interruption Frequency Index***

  This is used to determine how often the average customer experiences a sustained interruption over a predefined period of time. The mathematical relationship is,

$$\text{SAIFI} = \frac{\text{Sum of Total Number of Customers Interrupted}}{\text{Total Number of Customers Serverd}}$$

- ***SAIDI: System Average Interruption Duration Index***

  This is used to determine the total duration of interruption for the average customer over a predefined period of time. The mathematical relationship is,

$$\text{SAIDI} = \frac{\text{Sum of Customer Interruption Duration}}{\text{Total Number of Customers Serverd}}$$

- ***CAIDI: Customer Average Interruption Duration Index***

  This is used to determine the average time required to restore service. The mathematical relationship is,

$$\text{CAIDI} = \frac{\text{Sum of Customer Interruption Duration}}{\text{Sum of Total Number of Customers Interrupted}} = \frac{\text{SAIDI}}{\text{SAIFI}}$$

- ***ASAI: Average Service Availability Index***

  This is used to determine the fraction of time (%) that the customer has received power during a predefined reporting period. The mathematical relationship is,

$$\text{ASAI} = \frac{\text{Customer Hours Service Availability}}{\text{Customer Hours Service Available}}$$

- ***MAIFI: Momentary Average Interruption Frequency Index***

  This is used to determine the average frequency of momentary interruptions. The mathematical relationship is,

$$\text{MAIFI} = \frac{\text{Sum of Total Number of Customer Momentary Interruptions}}{\text{Total Number of Customers Serverd}} = \frac{\text{SAIDI}}{\text{SAIFI}}$$

To use the above definitions the momentary interruptions and the sustained interruptions should be defined. IEEE 1366-2003 defines them as,

Momentary Interruption: A single operation of an interrupting device that results in voltage zero. For example two recloser operations (each operation being an open followed by a close), that momentarily interrupts the service to one or more customers is defined as two momentary interruptions.

Sustained Interruption: Any interruption that is not classified as a part of momentary event. That is, any interruption that lasts longer than 5 minutes.

Even though IEEE1366-2003 defines the boundary as 5 mins, this is not universally practiced. Figure 40 shows the different utility practices for defining the boundary. This clearly shows that the determined indices, needs other supporting information to be meaning full.

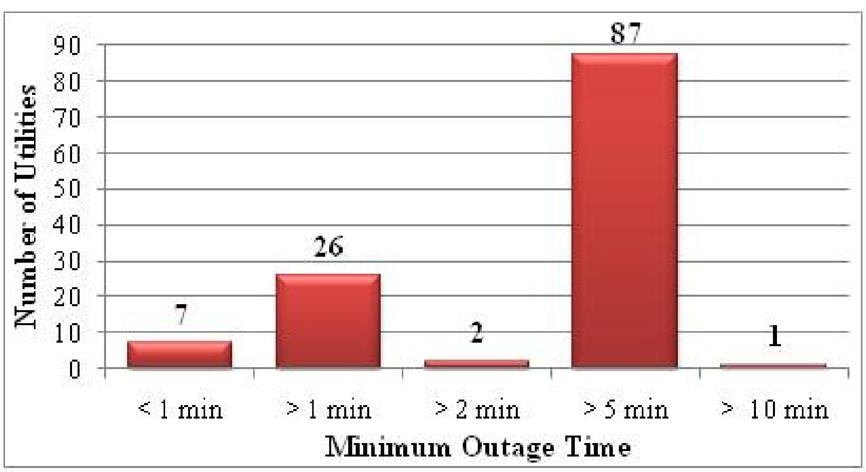

Figure 40*:* Utility Practices for Defining the Sustained Interruptions [7]

APPENDIX B

DEFINITIONS OF RELIABILITY

A. Reliability

Reliability of a component is defined as the probability of not failing in a specified time interval [1]. If the failure probability distribution function of a component is $f(t)$ then the cumulative distribution function (CDF), probability that the component will fail within the time t_1 is,

$$F(t_1) = \int_0^{t_1} f(t)dt$$

and the probability that the component will not fail at t_1, reliability of the component at t_1, is found as,

$$R(t_1) = \int_{t_1}^{\infty} f(t)dt$$

Since $f(t) = 0$ if $t \leq 0$, the relationship between the reliability and the cumulative distribution function is,

$$R(t_1) = 1 - \int_0^{t_1} f(t)dt = 1 - F(t)$$

B. Mean Time To Fail (MTTF)

MTTF is defined as the expected value of probability distribution function, which is defined as,

$$MTTF = \int_0^{\infty} t \cdot f(t)dt = \int_0^{\infty} t \cdot -\frac{dR(t)}{dt} dt$$

$$MTTF = t \cdot R(t)|_0^{\infty} - \int_0^{\infty} -R(t)dt = \int_0^{\infty} R(t)dt$$

C. Hazard Rate

Hazard rate $h(t)$ is defined as number of expected failures of similar type of components in a given time [1], i.e.,

$$h(t) = \frac{\text{Number of failures per unit time}}{\text{Number of components exposed to failure}}$$

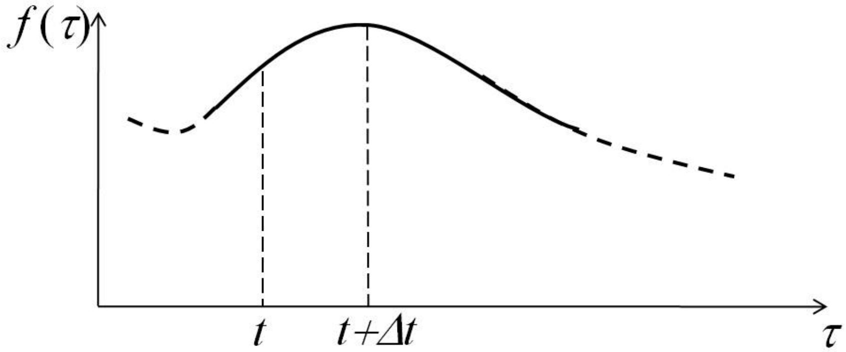

Figure 41*:* Probability Density Function of a Component

From Figure 41,

$$\text{Number of failures between } t \text{ and } t + \Delta t = F(t + \Delta t) - F(t)$$

$$\text{Number of failures per unit time} = \frac{F(t + \Delta t) - F(t)}{\Delta t}$$

$$\text{Number of components exposed to failure} = \int_{t}^{\infty} f(t)dt = R(t)$$

Therefore the hazard rate at time t could be determined when $\Delta t \rightarrow 0$,

$$h(t) = \lim_{\Delta t \to 0} \frac{\frac{F(t + \Delta t) - F(t)}{\Delta t}}{R(t)} = \frac{f(t)}{R(t)}$$