ENHANCEMENT OF ELECTRIC DISTRIBUTION NETWORKS RELIABILITY

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وعلية نتوكل

STATEMENT

This thesis is submitted to Ain Shams University in partial fulfillment of the requirement for the M.Sc. degree in Electrical Engineering. The included work in this thesis has been carried out by the author at the Electrical Power and machine department, Ain-Shams University. No Part of this thesis has been submitted for a degree or a qualification at other university or institute.

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Abstract

A large percentage of individual customer interruptions originate within the actual distribution network serving theses customers. It appears obvious; therefore, that this should be a fruitful area for detailed reliability evaluation and investigation. Protective equipment is located in a network to protect equipment and to isolate equipment failures and faults. The type of protective equipment used can have a direct effect on the frequency and duration of outages experienced by the customer.

The distribution system is an important part of the entire electric system, as it provides the final link between the bulk power sources and the customer's facilities. In many cases these links are radial in nature and therefore susceptible to outage due to a single event. It has been stated that 90% of all interruptions occurs due to failures in the distribution system. These outages usually resulted in customer interruptions which are relatively local in nature and have quite different effects to disturbances in the bulk power network.

The reliability evaluation of a distribution system consists of assessing how adequately the different parts of the distribution system are able to perform their intended function. Although many questions are being asked about the quality of service across the world, presently there are no standardized ways to track reliability between utilities. Some utilities are using EEI/IEEE approved indices but most utilities have different ways of calculating the data.

Reliability assessment of a distribution system is usually connected with the system performance at the customer end, i.e. at the load point. The basic indices normally used to predict the reliability of a distribution system are: load point failure rate, average outage duration, and annual unavailability. The basic indices are important from the individual customer's point of view but they do not provide an overall appreciation of the system performance. They are relevant for circuits that are mostly industrial or commercial. An additional set of indices can be calculated using these three basic indices and the number of customers/loads connected at each load point in the system. Most of these additional indices are weighted averages of the basic load point indices. The most common additional or system indices are: System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI), Average Service Availability Index (ASAI), Average Service Unavailability Index (ASUI), Energy Not Supplied (ENS), and Average Energy Not Supplied (AENS). These system indexes are also calculated by a large number of utilities from system interruption data and provide valuable indications of historic system performance. It is important to

calculate both sets of indices to get a true picture of reliability. The IEEE application of probability methods subcommittee published a Reliability Test System (RTS) in 1979 and extended in 1985 and 1989. Also a developed busbar test system defined as the RBTS is given in 1996. RBTS after its extension to include distribution system contains the main elements found in practical system.

The purpose of chapter 2 is to perform continuity analysis for a range of alternative design/operating configurations of the RBTS Bus2.

Both load point reliability indices and system indices have been evaluated. The effect of distribution facilities and feeder configuration/operation modes on improving load point and system reliability is assessed. A computer program has been developed which is capable of assessing reliability of practical distribution systems.

Electrical energy is a vital ingredient in the economic, social, and geographical development of a region, province, or country. The basic function of an electric power system is to meet its energy and load demand at the lowest possible cost to its customers while maintaining acceptable levels of quality and continuity of supply. What constitutes an "acceptable" level can be examined in terms of cost and worth to the customer of providing an adequate supply. The economic, social, and political climate in which the electric power industry now operates has changed drastically in the last few decades. Statistical evaluation of past system performance and probabilistic evaluation of further performance are of great value to power system planners and operators. This fact is now widely recognized and efforts are being made to quantify the worth of electric service reliability. The loss of energy expectation or Expected Energy Not Supplied (EENS) has been used in conjunction with and the Interrupted Energy Assessment Rate (IEAR) to estimate future interruption costs associated with power system deficiencies. The system IEAR is a factor that defines the cost to a representative customer of each unit of unsupplied energy due to power interruptions and is a useful index of making decisions related to system reliability.

The basic objective of chapter 3 is to illustrate how to obtain IEAR indices in the area of distribution systems for each customer load point and for the overall distribution system. The developed procedure is illustrated by application to the distribution system associated with the test system designated as the RBTS. The customer IEAR can be utilized in the conjunction with the system reliability (adequacy) indices in order to perform value-based reliability analysis and justify new system investment.

A variety of approaches have been used to determine the actual or perceived costs of customer interruptions. One method which has been used to establish acceptable reliability

worth estimate is to survey electrical consumers in order to determine the monetary losses associated with supply interruptions. The data compiled from these surveys is used to generate Sector Customer Damage Functions (SCDF). The cost interruption data in $/kW of peak demand for eight sectors is given in Appendix B. Chapter 3 utilizes the SCDF as the cost functions in relating the load point reliability indices to worth of service reliability.

Distribution system reliability assessment is a quickly maturing field. It has evolved from the first EPRI program in 1978, to programs developed and used in-house by utilities, to commercially available software products. These planning tools are able to predict the reliability of a distribution system based on system topology and component reliability data. Unfortunately, these products will never gain widespread use until utilities are confident that available data is representative of their actual system.

Ideally, a utility will have a large amount of historical data from which it can determine the reliability of various components such as lines, protection devices, and switches. Most utilities, however, do not have this information available. Values may be obtained from published data corresponding to other systems, but this data may not be representative of the system under consideration. This data discrepancy is most evident when predicted system reliability indices do not agree with historically computed reliability indices.

Most utilities do not have a substantial amount of historical component reliability data. Nearly all utilities, however, have historical system reliability data in the form of reliability indices (e.g., SAIFI, SAIDI, …). When a system is modeled, the reliability indices predicted by the assessment tool should agree with these historical values. If so, a certain level of confidence in the model is achieved and more specific reliability results (e.g., the reliability of a specific load point or the impact of a design change) can be trusted to a higher degree. When this confidence has been achieved and predicted results match historical results, the reliability model is said to be validated.

Chapter 4 presents a new method of distribution system reliability model validation. It first identifies which default component reliability parameters should be modified by performing a sensitivity analysis on the RBTS test system. It then presents a method of computing these parameter values so that predicted system index values match historically computed index values.

Contents

CHAPTER (1)

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INTRODUCTION

Basic Concepts of Power System Reliability Evaluation

1.1. Adequacy and Security

The term reliability has a very wide range of meaning and cannot be associated with a single specific definition such as that often used in the mission-oriented sense [1, 31]. It is therefore necessary to recognize this fact and to use the term to indicate, in a general rather than a specific sense, the overall ability of the system to perform its function. Power system reliability assessment can therefore be divided into the two basic aspects of system adequacy and system security as shown in Figure 1.1. The terms *adequacy* and *security* can be described as follows:

Adequacy relates to the existence of sufficient facilities within the system to satisfy the consumer load demand or system operational constraints. These includes the facilities necessary to generate sufficient energy and the associated transmission and distribution facilities required to transport the energy to the actual consumer load points. Adequacy is therefore associated with static conditions which do not include system dynamic and transient disturbances.

Security relates to the ability of the system to respond to dynamic or transient disturbances arising within the system. Security is therefore associated with the response of the system to whatever perturbations it is subject to. These include the conditions associated with both local and widespread disturbances and the abrupt loss of major generation or/and transmission facilities which can lead to dynamic, transient, or voltage instability of the system.

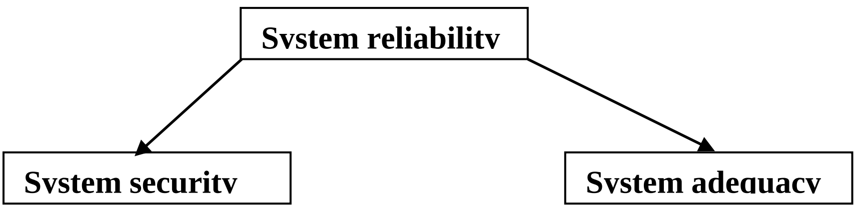

Figure 1.1. Subdivision of system reliability

It is important to appreciate that most of the probabilistic techniques presently available for reliability evaluation are in the domain of adequacy assessment. The ability to assess security is therefore very limited.

This limitation is due to the complexities associated with modeling the system in the security domain. Most of the indices used at the present time are adequacy indices and not overall reliability indices. Indices which are obtained by assessing past system performance encompass the effect of all system faults and failures irrespective of cause, and therefore include the effect of insecurity as well as those due to inadequacy. This fundamental difference is an important point which should be clearly recognized.

1.2. Functional Zones and Hierarchical Levels

The basic techniques for adequacy assessment can be categorized in terms of their application to segments of a complete power system. These segments are shown in Figure 1.2 and can be defined as the functional zones of generation, transmission, and distribution [2]. This division is an appropriate one as most utilities are either divided into these zones for the purposes of organization, planning, operation, and/or analysis or are solely responsible for one of these functions. Adequacy studies can be, and are, inducted in each or these three functional zones.

The functional zones shown in Figure 1.2 can be combined to give the hierarchical levels shown in Figure 1.3. These hierarchical levels can also be used in adequacy assessment. Hierarchical Level 1 (HL1) is concerned with only the generation facilities. Hierarchical Level 2 (HL2) includes both generation and transmission facilities while HL3 includes all three functional zones in an assessment of consumer load point adequacy. HL3 studies are not usually conducted directly due to the enormity of the problem in a practical system. Analysis is usually performed in the distribution functional zone in which the input points may or may not be considered to be fully reliable.

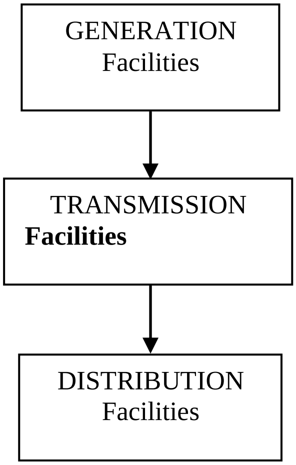

Figure 1.2. Basic functional zones.

Functional zone studies are often done which do not include the hierarchical levels above them. These studies are usually performed on a subset of the system in order to examine a particular configuration or topological change.

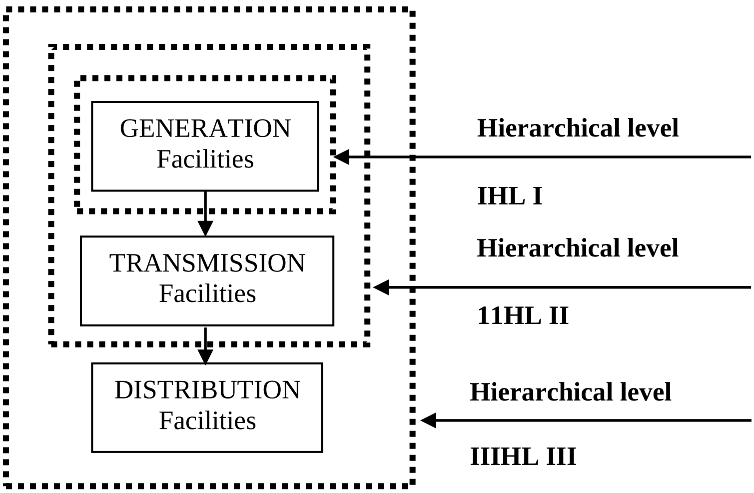

Figure 1.3. Hierarchical levels.