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# Outage Management Via Powerline Communication Based Automated Meter Reading Systems

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# OUTAGE MANAGEMENT VIA POWERLINE COMMUNICATION BASED AUTOMATED METER READING SYSTEMS

By

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OUTAGE MANAGEMENT VIA POWERLINE COMMUNICATION

BASED AUTOMATED METER READING SYSTEMS

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In many outage management systems, customer trouble calls have been used as the primary source of outages for distribution level outages. However the information from the trouble calls is not completely reliable as they lead to problems that cause extended outage times for the customers. But with the recent developments in communication and information technologies, utilities started to adopt Automated Meter Reading systems for their operational needs.

In this thesis, an algorithm is developed that makes efficient use information available from the customers and powerline communication based AMR systems for outage management. The work has taken advantage of the polling feature of powerline based AMR systems to identify the scope of the outages. The meters in the neighborhood of the trouble calls are polled to identify the affected customers and the outages are located by back tracking to common point.

In the first part of the algorithm, the distribution system is modeled as a tree and the meters are strategically polled based on the customers reporting the outages. The

outage areas are identified and escalated to find the actual outage location. The crew can be directed to the outage scene to fix the cause of the outage. The algorithm discusses the rules to identify single outages, single customer outages and multiple outages. The algorithm was tested on different test systems representing distribution systems of various sizes. The algorithm is tested for different outage scenarios for all the test cases.

# DEDICATION

I would like to dedicate this research to my beloved parents.

# ACKNOWLEDGEMENTS

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LIST OF ABBREVIATIONS

ABBREVIATIONS

| | |
|---|---|
| AMR……………….. | Automated Meter Reading |
| AM/FM…………….. | Automated Mapping/Facilities Management |
| CAPSOL…………… | Computer Applications of Power System Operations Laboratory |
| CIS………………… | Customer Information system |
| DCSI………………. | Distribution Control Systems Inc |
| DCU……………….. | Data Concentrator Unit |
| DFS………………… | Depth First Search |
| DMS……………….. | Distribution Management Systems |
| EMS………………... | Energy Management System |
| GIS…………………. | Geographic Information Systems |
| MWM……………… | Mobile Workforce Management |
| OMS………………. | Outage Management System |
| PFC………………... | Power Frequency Communications |
| PLC………………... | Powerline Communications |
| PSR………………… | Packet Success Rate |
| RTU………………... | Remote Terminal Unit |
| SCADA…………….. | Supervisory and Control and Data Acquisition Systems |
| UNB………………… | Ultra Narrow bandwidth technology |
| WMS……………….. | Work Management Systems |
| XFMR………………. | Transformer |

# CHAPTER I

# INTRODUCTION

## 1.1 Introduction

Outages on a power distribution system can cause many problems for utilities as well as customers. The problems are of greater importance when the utility is not able to restore power supply to the customers as quickly as possible. An uninterrupted power supply is essential to keep the customers lights on and enable revenue to the utility company.

The number of outages could be reduced by monitoring each device in a real-time and checking the condition of all the protective devices (reclosers, sectionalizers, breakers, remote terminal units, and fuses, etc.) in the distribution system frequently. Even though monitoring and control of each device is technically feasible, it involves an enormous amount of revenue to be invested. However, problems from unpredictable natural disasters, unpredicted loading in the distribution system or malfunctioning of the devices occasionally cause outages.

For a quick restoration of the system, information regarding the outages is important. The primary source of information about outages until recently and even now has been customer trouble calls. The outage information is also provided by the distribution Supervisory Control and Data Acquisition (SCADA). SCADA provides only the substation and the feeder level information. Due to costs associated with the installation of SCADA in the lower levels of the distribution system, its penetration is rather limited. With the unavailability of real-time data, the outages may not be located accurately and the number of customers affected cannot be estimated correctly. However, if the information of the outages from the trouble calls is utilized properly the system status after outages can be understood very easily. Recently, Automated Meter Reading (AMR) systems are used to learn more about the status of the system after outages. The outage information from the AMRs combined with the trouble call information improves the reliability of the services provided by the utility. The deregulation of the energy markets is forcing the utilities to be more reliable in terms of managing outages and customer service. The customers are demanding the utility to respond quickly to the outage and perform outage restoration. AMRs can play a critical role in this high expectation environment.

## 1.2 Power Systems and terminology

Figure 1.1 outlines the major parts of a typical power system. The generated energy is transported to the load through transmission and distribution systems.

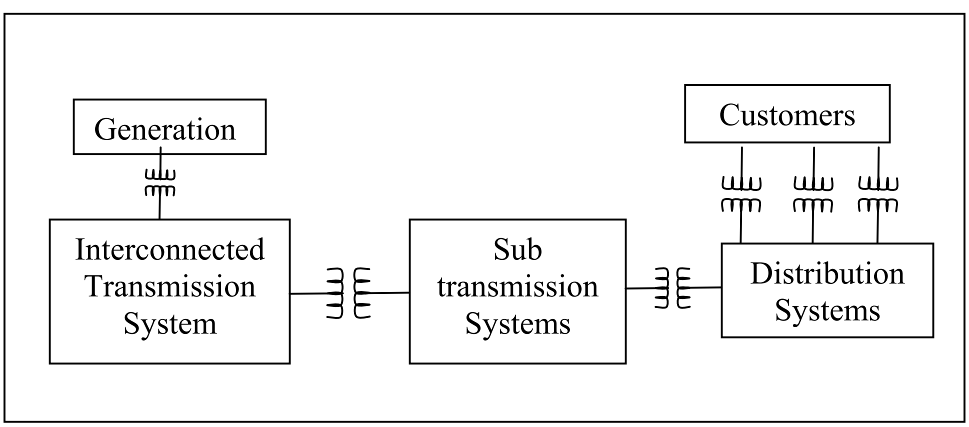



Figure1.1 Typical Power System Components [1]

The two major differences between the transmission and distribution systems are the voltage levels and the configuration of the network. The transmission systems are usually interconnected for near 100% reliability. In a transmission system, it is important to monitor all the parameters, as a single fault in the system would affect a large number of customers at a time. Long term research in power systems has focused on designing the system so that the faulted section can be isolated and the service be maintained at the transmission level. EMS (Energy Management Services) and SCADA (Supervisory Control and Data Acquisition) have been developed to monitor, control and operate the system from a remote control center. After extensive research on transmission systems, distribution systems have started receiving more attention during the past decade.

The distribution system begins with a substation serving one or more primary feeders. Almost all the feeders are radial which means customer has single path from the substation. A failure at a single point in the distribution system throws all the customers downstream into darkness because the system is radial. The distribution system is vast and diverse. Consequently, a complete or partial metered scheme to monitor the distribution system is currently not available. Usually circuit breakers and relays protect the primary distribution feeders against faults. Fuses, at the end of the lateral or sub lateral clear the faults occurring in the lower levels of the distribution system. The status of any fuse is not available to the utility, as they are not monitored. Also the real-time information regarding voltage and current at every point in the distribution system is not available. Such information, if available, may be used to identify the cause of a fault and also locate the outage. Figure 1.2 shows the available information provided by a distribution system. The radial distribution system is shown as a black box as not much is known about it. However with the distribution automation, RTUs (Remote Terminal Units) placed at some locations in the distribution system, provide information about the system status and outages. Figure 1.2 also shows the available sources of information: SCADA system, trouble calls and the AMR (Automated Meter Reading) system. In the lower levels of the distribution system, at the service level, customer calls and the AMR systems provide the information. The state of the distribution system between the feeder and the customer is not directly available. An Outage Management Systems (OMS) can use the available information to locate the source of outage.

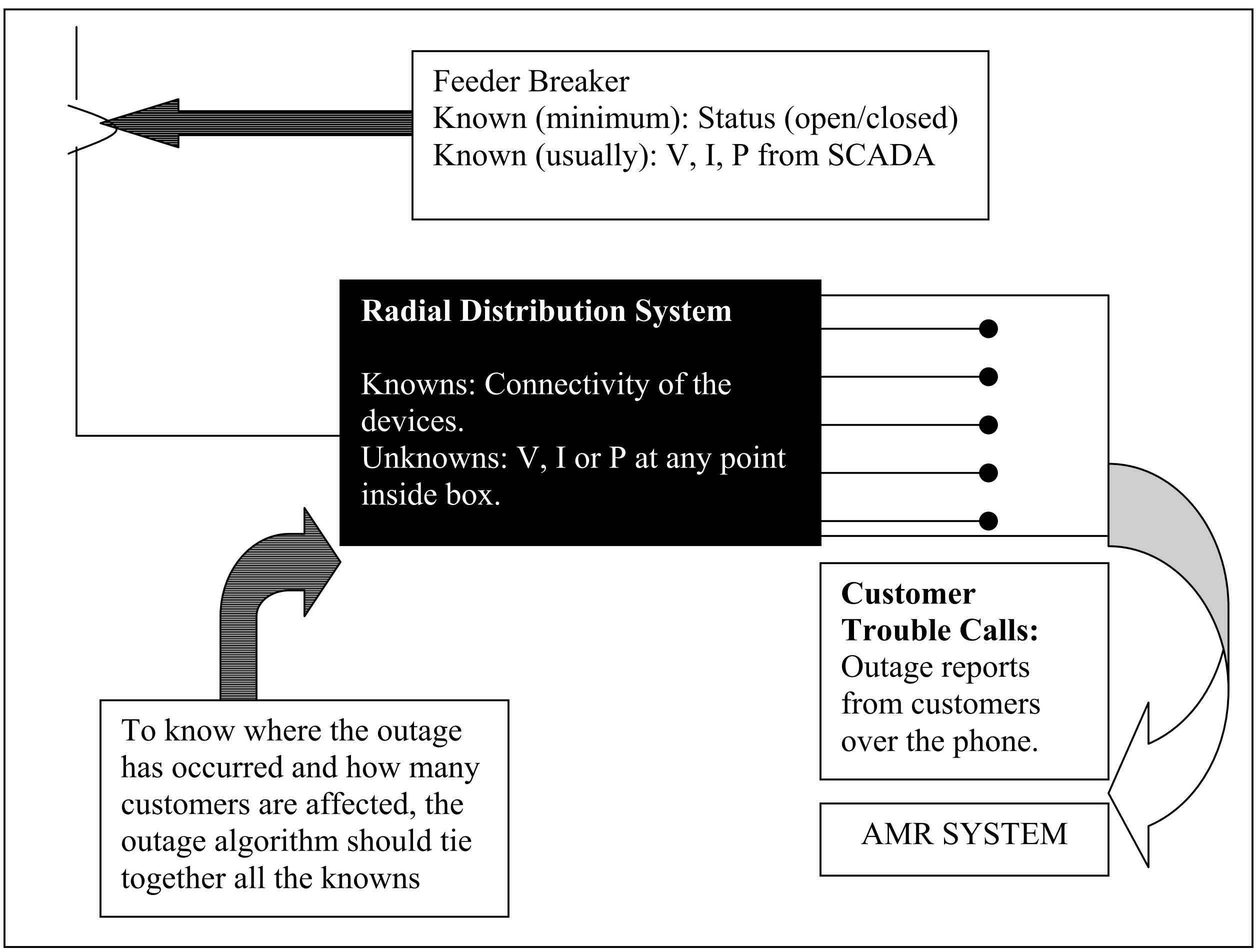



Figure 1.2 Available information in a typical distribution system [2]

## 1.3 Outage Management

### *1.3.1 Definition of Outage*

An outage is defined as an interruption in electric power supply to the customer. The cause of the outage can be manmade or natural, purposeful or accidental. The outages caused by storms and winds, branches falling on wires, or animals are considered natural while outages caused by operators for maintenance are considered purposeful or scheduled outages. During storms numerous outages occur in a given area. Storms constitute for about 20% of all the outages [3]. Outages are classified as sustained or momentary based their duration of the outage. Each utility defines the duration of “sustained” and “momentary” outages differently. Generally, an outage or an interruption of service for more than few minutes is sustained outage while less than few minutes is a momentary outage [4] .The primary causes of momentary outages are automatic switching and automatic reclosing operations of the circuit breakers and automatic circuit reclosers. These usually occur without human intervention. The momentary outages usually do not typically result in trouble calls from customers. Sustained interruptions or permanent outages are a result of failure of a component or equipment in the distribution system. They are generally restored by human intervention. The industrial customers are concerned about both the type of outages and residential customers are concerned about sustained outages.

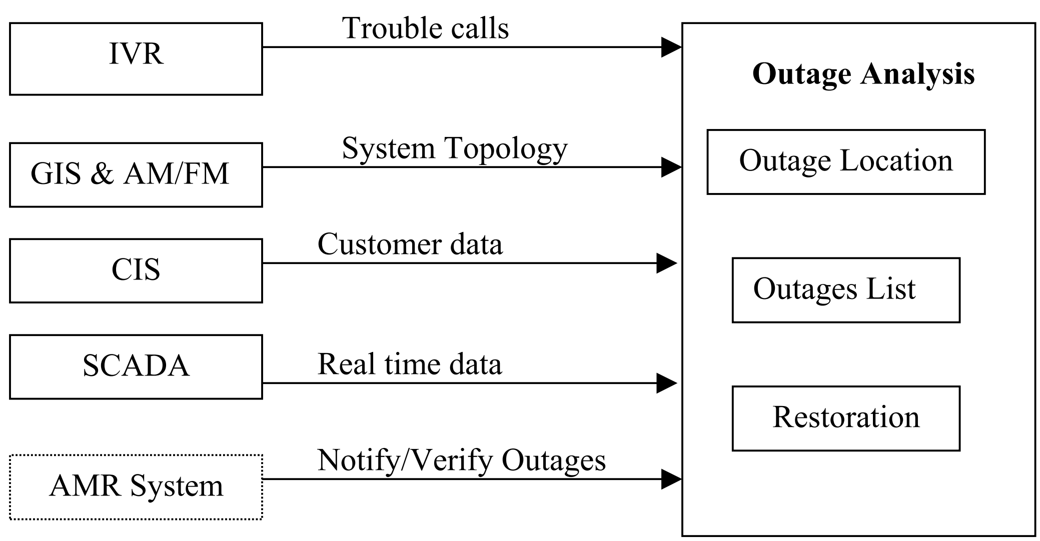
### *1.3.2 Different types of outages*

The outages can be classified based on the location of the failed device(s). They can be classified as single outages, single customer outages and transformer outages and multiple outages, which include any combination of the above type of outages. A switch or fuse opens as a result of a fault causing loss of power to all customers downstream. If only single device operates because of a fault then it is a single outage. Usual outage management algorithms assume that a single device operates and escalate the trouble calls to locate that outage. But during storms there are multiple outages occurring at a time. Failure of multiple devices also includes some isolated single customer outages. When the load increases, the distribution transformers heat up. The interior temperatures rise and cause the breakdown of the insulators, insulating oil or both. The heat storms cause multiple transformers on the same feeder to fail. If the heat storm continues to stress the equipment more number of failures are likely to occur.

### *1.3.3 Outage Management Systems (OMS)*

An Outage Management System (OMS) encompasses the process and interactions of necessary systems to analyze, process, and restore power to a customer that is affected by an outage. OMS aids in reducing restoration time during outages and, thereby, controlling costs, increasing revenues, and improving customer satisfaction [5]. In case of service level outages, the primary input to OMS is customer trouble calls in addition to the real-time information provided by the SCADA. Other information systems like AM/FM (Automated Mapping/Facilities Management) and GIS (Geographic Information Systems) provide the data that supplement the outage management process.

Figure 1.3 is an example of a typical outage management system currently in use. The figure shows the beginning of use of AMR systems in some outage management systems for outage analysis. With the deployment of an automatic meter at the customer house, it is possible to receive outage notification and restoration in near real-time from the customer level.




| | | |
|---|---|---|
| IVR | : | Interactive Voice Response Unit |
| GIS | : | Geographic Information System |
| AM/FM | : | Automated Mapping/Facilities Management |
| SCADA | : | Supervisory Control and Data Acquisition |
| CIS | : | Customer Information System |
| AMR | : | Automated Meter Reading |

Figure 1.3 Structure of an Outage Management System

## 1.4 Information systems for Outage Management

### *1.4. 1 Interactive Voice Response (IVR) System*

For efficient management of the customer trouble calls, a utility's trouble call system should be able to track all the calls as they receive, verify and forward them to the Outage Management System [6]. The trouble call system is the primary interface to the customer during an outage situation. Until recently the trouble call operators have directly received calls and logged. This process was completely manual. Nowadays, the processing of trouble calls is initiated by an automated calling system, Interactive Voice Response (IVR) system. The calls are verified and entered into the trouble call database and transferred to the OMS for further analysis. The OMS, with the help of connectivity information, attempts to trace the actual location using the outage escalation algorithms.

### *1.4.2 Supervisory Control and Data Acquisition (SCADA)*

The SCADA system collects the real-time data about the status and other parameters of various remote devices and update the operational data of the power system. Earlier SCADA systems were used to monitor transmission, sub transmission and substation equipment only but currently they provide data from some distribution terminals, with the use of RTUs. The SCADA system indicates the tripping of a breaker at the feeder level and notifies the outage management system.

### *1.4.3 Distribution Management Systems (DMS)*

As previously discussed, SCADA systems monitor and control transmission systems in real-time. Lately, Energy Management Systems (EMS) have been introduced which does the same task as SCADA but with more advanced features. Example applications include Load Forecasting (LF), Unit Commitment (UC), Economic Dispatch (ED), Automatic Generation Control (AGC), State Estimation, etc. These systems perform many functions similar to EMS but at the distribution level. Recently, Distribution Management Systems (DMS) are developed. Example applications include load flow, switching, motor starting and protection coordination analysis.

*1.4.4 Customer Information System (CIS)*

To ensure that a trouble call system works properly the utility should have a database that contains the information of every customer: name, physical address, phone number and any detail that may be used to identify the customer and his location. Customer Information System (CIS) helps the utility in billing and helps the calling center to identify the actual location of the calling customer. The utility CIS can be interfaced with billing, financial management, outage management, AM / FM and GIS software.

*1.4.5 AM/FM and GIS Systems*

Automated Mapping/Facilities Management (AM/FM) is an information management tool that helps the utility produce maps and provide digital inventories of the facilities. By pointing to a location on the map, the information regarding the equipment/device is retrieved easily. For example, a pole is pinpointed customer's street address is known. The surrounding poles as well as circuits can also be mapped. Geographic Information Systems (GIS) are similar to AM/FM systems in the aspect of digital mapping of the distribution network. To identify the cause of the outage connectivity data of the distribution system must be accurately modeled. Such a task can be easily accomplished by either of the above systems.

*1.4.6 Automated Meter Reading (AMR) Systems*

Recently, utilities have started deploying AMR systems for the purpose of meter reading. AMRs not only provide metering data but also provide data for notifying outages and restoration. Different types of AMR systems and their applications are discussed in chapter 2.AMRs help in real-time outage notification and restoration confirmation. AMRs also record the number of momentary outages (blinks) during a given period in the distribution system.

### 1.5 Overview of thesis and Organization

The main source of information regarding outages is trouble calls. SCADA usually provides information at the primary feeder and hence is not considered in the project. The outage analysis in this project is triggered by trouble calls. The trouble calls are combined with the responses from AMRs to identify the outage status of the customers. The research work consists of two parts: Identifying the total number of outage affected customers and location of the outage. The distribution system is modeled as a tree with the branches representing the connections between the protective devices and customer meters representing the leaves of the tree. A method to represent the distribution network as a tree is proposed and a strategy for polling the meters is developed to identify the system conditions after an outage. The polling is triggered with the first trouble call coming in and provides the utility with the customers affected by the outage and the possible location(s) of outage(s) within a short time. The main idea behind the research work is to understand the system conditions by polling the meters in the outage affected region. This information helps the dispatch of crew to the confirmed outage location. This data is more refined and can be obtained in much less time. The results of the outage analysis greatly complement any outage management system analysis. The work is not aimed at developing an OMS however, the developed algorithm can be used by OMS for analyzing the scope of the outage in the distribution system. Furthermore, in systems where OMS is not in place the crews could be directed to the actual outage location.

This thesis is organized as follows. Chapter 2 discusses Automated Meter Reading Systems (AMR), their applications in the electric utility industry and various AMR systems in the market. Chapter 3 provides an in-depth survey into research in outage management. The application of AMR systems in outage management is also presented. Chapter 4 describes the problems with the traditional outage escalation algorithms and discusses the approach to identify the outage meters and the accurate outage location. Chapter 5 describes a method to model the distribution system as a tree. A polling algorithm to identify the meters is proposed and a modified escalation algorithm to identify the outage location. Chapter 6 discusses the validity and analysis of the algorithms for various test cases and various outage scenarios. Chapter 7 summarizes the research work and discusses some promising avenues for the future work

## 1.6 Summary

This chapter has described the information available in the distribution system. It discussed the basic concept of outages, outage management and described various information systems used by the utilities for outage management. It summarized the research work undertaken and organization of the thesis.

# CHAPTER II

# AUTOMATED METER READING SYSTEMS

## 2.1 Introduction

Until recently the electric meter at the customer site was used only for one purpose, meter reading. The meter collected the cumulative data over a billing period and the data is processed to generate the customer bills. A meter reader visited each home and collected the consumption data. However, due to location and weather sometimes readers could not be reached. Location issues included locked doors, fenced-in yards and barking dogs. Weather issues might include large amounts of snow covering the meter or making it difficult to get to the meter. Without actual meter readings, utilities would estimate consumption for billing purposes. A solution that solved this issue and others for utilities is to automate meter reading, either by replacing the old meter with an AMR system or by retrofitting the existing meter with a communication module. With the advancements in communication technologies, the AMR system has become a gateway of information to the utility. With AMR systems becoming popular, the utilities reduce customer complaints on estimated bills, inaccurate billing, and the growing costs in investigating and resolving the complaints. The utilities have started introducing several value-added services that would improve the asset management, the reliability of the system, and their customer service. This chapter discusses Automated Meter Reading systems in general and powerline communication-based AMR systems in particular. It also discusses the need for AMR systems, the application of AMRs and the various types of AMR systems. The concept of outage management and polling in PLC AMR systems is introduced.

### 2.2 Need for AMR systems

The influence of the latest technology in every infrastructure system like transportation, banking, finance, telecommunication and defense is obvious in recent days. The energy markets, unlike other industries, have not adopted and made use of the technological advancements in data collection, data management and communications technologies for the services it provided [7]. But with deregulation gaining momentum and the ‘survival of the fittest’ trend prevailing, the utilities are adopting the technology to optimize the delivery of services. The economic downfall has made utilities consider ways to reduce the costs in energy delivery services. The costs are reduced if there is a reduction in estimated reads and energy theft, and improvement in performance-based indices measuring reliability and customer service. With customers demanding value-added services like time of use, real-time pricing, and load profiling, the need for real-time data is increasing. Such services can be provided only if the customer end is metered accurately and on a regular basis.

Automatic Meter Reading systems collect data remotely from customers’ meters using communication technologies like powerline, radio-frequency (RF), and telephone or a hybrid of the above. AMR systems are currently providing more data than is being processed. Utilities should be able to gather and apply the data in the ways most useful to them and the customers [8]. AMR systems allow the utilities to provide a wide range of services as shown in Table 2.1.

TABLE 2.1 APPLICATIONS OF AMR SYSTEMS

| Billing | Outage Management |
|---|---|
| • Time of Use and real-time energy pricing<br>• On Demand read<br>• Prepaid metering | • Outage detection<br>• Outage verification<br>• Restoration verification<br>• Restoration notification |
| **Load Control** | **Others** |
| • Load control switches<br>• Remote control thermostats<br>• Capacitor bank switching | • Distribution Automation<br>• Demand Side Management<br>• Load Forecasting<br>• Tamper detection<br>• Meter Maintenance<br>• Remote connect/disconnect |

**2.3 Types of AMR systems**

Based on the communication system used, the AMR systems are classified as shown in the following table.

TABLE 2.2 CLASSIFICATION OF AMR SYSTEMS

| **Radio Network** | **Powerline Communication** | **Telephone** |
|---|---|---|
| • Fixed Radio<br>• Drive-by, Walk-by | • Power Frequency Communication,<br>• Ultra Narrow Bandwidth | • Dial inbound<br>• Dial outbound systems |

Figure 2.1 shows the popularity of different types of AMR systems in North America. Statistics show that the deployment of powerline communication based AMR systems is increasing at a very high rate [9].

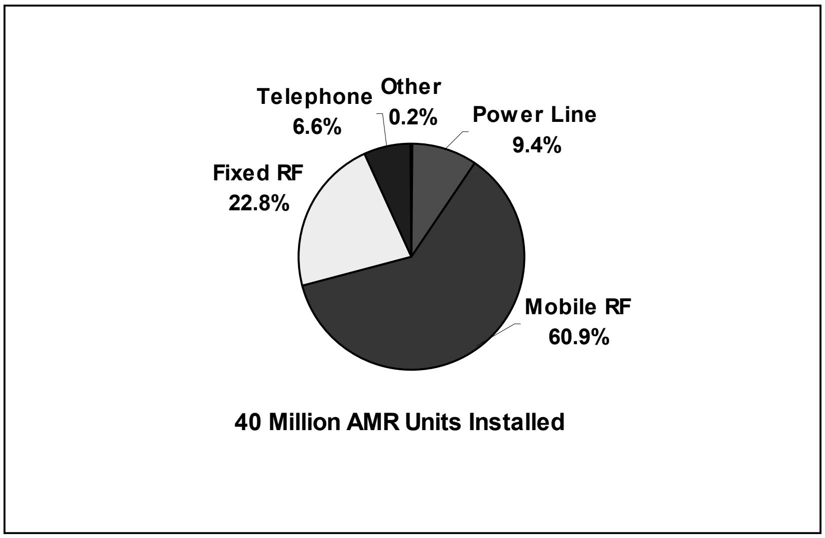



Figure 2.1 Installation of different types of AMR systems [9]

*2.3.1 Radio Frequency based AMR Systems*

Radio Frequency (RF) based AMR system involves a radio transmitter or a transceiver (for a two-way system) at each customer's site. A data concentrator unit (DCU), usually placed on a pole top, collects the metering data along with tamper or outage information from nearby meters in regular intervals. The data from the DCU is downloaded by the utility using a radio or cellular network or existing telephone network. The communication channel may contain one or more repeaters to avoid the loss of data. The data transmitted might include meter reading, tamper flags, outage flags and maintenance flags, if any, that may originate at the meter. The RF based AMR systems have been discussed in detail in references [10,11,12,13].

The wireless AMR systems work well only for dense urban areas and not a cost effective solution for isolated customers. In fixed wireless systems DCU is placed on a pole top. Mobile radio networks can be either vehicle-based or handheld. A van equipped with DCU goes across every street and collects the meter data. Mobile networks offer initial cost savings but the applications are limited when compared to fixed AMR systems. Mobile networks can only be used for basic billing operations, but not allow for advanced applications like one demand read and time of use. Also they can be used for outage notification and restoration confirmation.

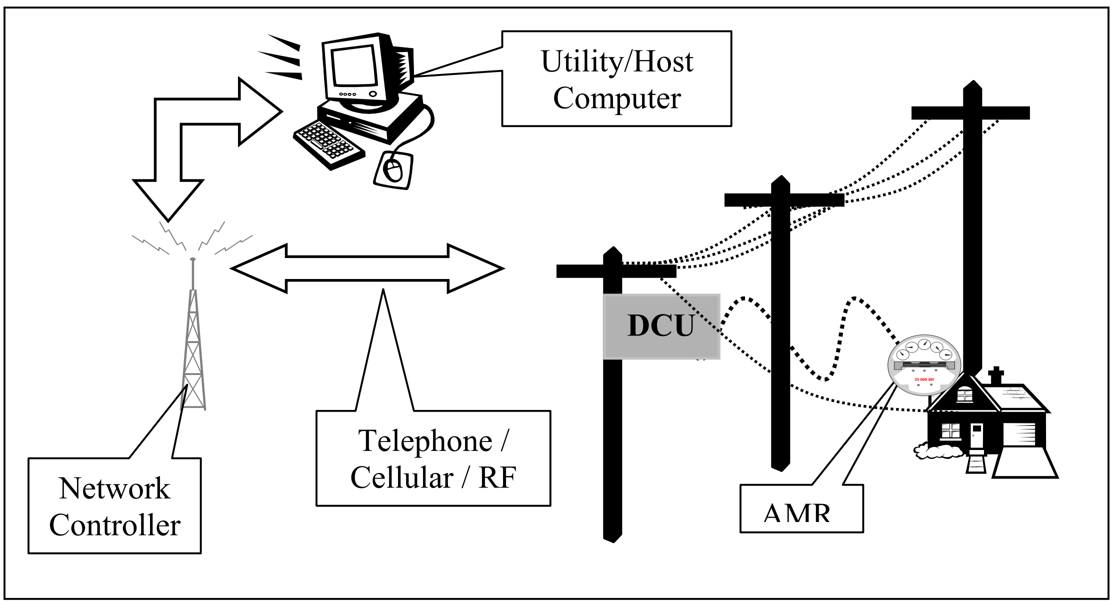



Figure 2.2 Flow of data in radio based AMR systems

*2.3.2 Powerline Communication based AMR*

Powerline based AMR utilizes the existing distribution power lines running from substation to customer for the transmission of data. Powerline based AMR systems do not involve high initial costs, because they use the existing infrastructure as the communication channel. As the powerlines reach every customer meter, the PLC AMR is more popular for rural dominated utilities. The PLC system can be used for a wide range of applications in outage management, distribution automation and load management.

The two dominant PLC based AMRs in North America, Power Frequency Communications (PFC) and Ultra Narrow Bandwidth technology are discussed below.

*2.3.2.1 Power Frequency Communication (PFC) based AMR system*

The communication system in a Power Frequency Communication (PFC) involves modulation of the power frequency voltage for outbound (substation to remote meter) communications and power frequency current modulation for inbound (remote meter to substation) communications. The Power Frequency Communications system uses the equipment at the electric substation to shift the zero voltage and current crossing point of the 60 Hz power wave form [14,15,16]. The substation equipment sends a polling command to a group of meters and the meters respond with the data collected at the customer level. As the data is sent by modulating the power frequency waveform, the signal may be distorted or lost because of power system transients generated by the switching of capacitor banks or change in loading, etc. If the data from a meter is lost because of the communication failure, the system performs a number of retries until the read is successful. Such a system has proven successful for load control operations and distribution automation. In the remaining part of our discussion the author refers to Power Frequency Communications system as PLC (powerline communication) system or PLC based AMR.

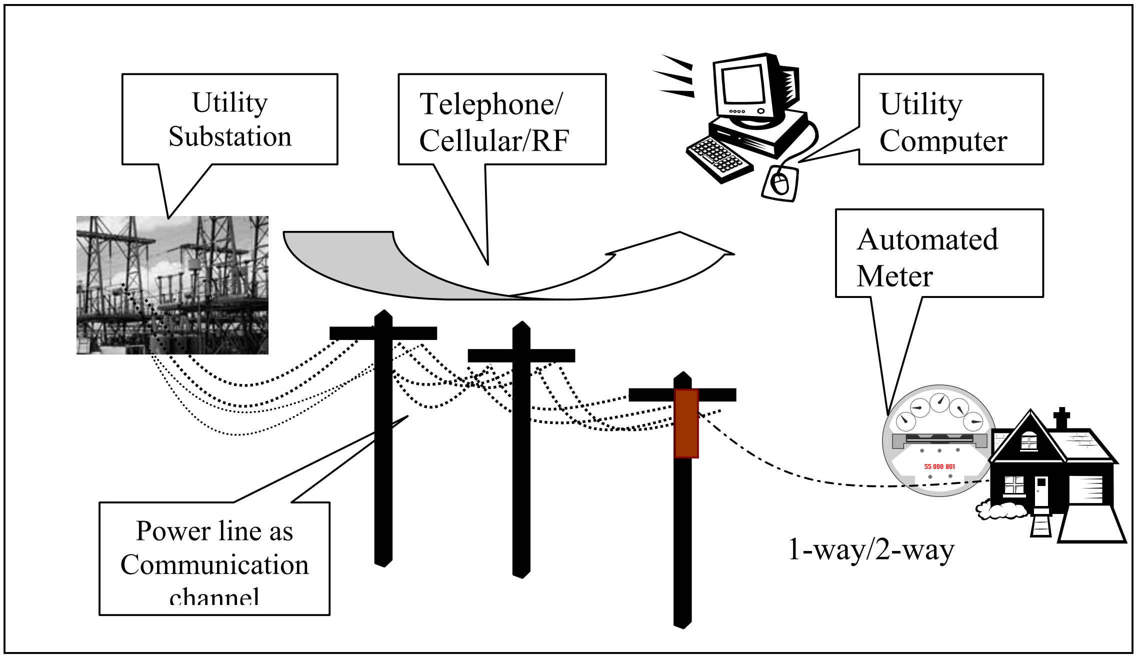



Figure 2.3 Flow of data in Powerline Carrier AMR Systems

*2.3.2.2 Ultra Narrow Bandwidth (UNB) technology based AMR*

UNB technology creates a very low frequency signal by switching a capacitor at the zero crossing point. By mixing with the 60Hz power signal the receiver at the substation can pick up these low frequency bands. In this system each transmitter continuously sends the metering data operating on its own frequency [17]. If the data is lost, the transmitter retries to send the data starting from the first bit. As it uses a very low frequency signal, the data rate is very low. UNB system works well for longer lengths of distribution lines, which is good for rural and isolated customers and provides a low cost metering solution. As the meter sends the data continuously, the signal loss can be assumed be an outage.

## 2.4 Trends in AMR Industry

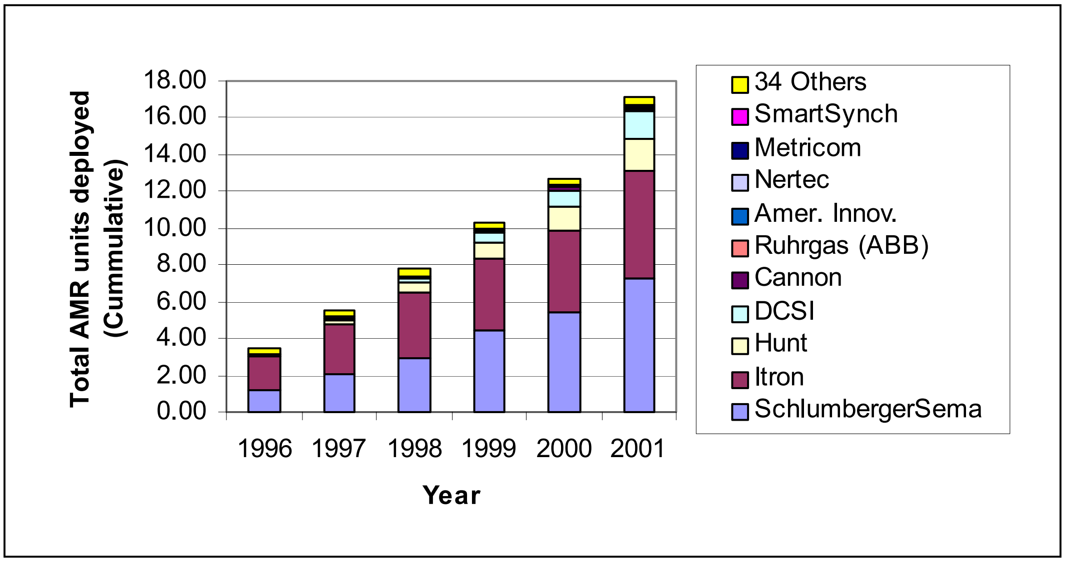



Figure 2.4 Electric AMR deployments in North America [8]

With the onset of deregulation, the deployment of AMRs is increasing day by day. According to 2002 Scott Report [9], approximately 17 million electric AMRs have been deployed since the inception of the technology. Itron and SchlumbergerSema AMR systems are based on radio technology while DCSI and Hunt AMR systems are powerline carrier based systems. Most of the AMR units are deployed in North America. The large-scale deployment shows that AMR vendors are providing solutions that meet the demanding customer service and operational need of utilities. Figure 2.4 shows the deployments in North American since 1996.

## 2.5 AMR in Outage Management

Almost all the types of AMR systems are capable of reporting outages and providing data for outage analysis. However, different systems use different ways to report and analyze the outages. The outage detection scheme in radio-based AMR systems is discussed in references [11,13]. The radio AMRs send a ‘last gasp flag’ as soon as they sense the loss of power at the meter. They send a ‘power up’ signal soon after the power is restored. In powerline based AMR systems, the outage detection is not a direct process. As the communication channel is the powerline, if an outage occurs there is no carrier for the signals. The retrofitted communication modules cannot communicate the status of the meters in real-time during outages. The outage analysis is usually triggered by trouble calls and the unresponsive meters that are obtained by initial AMR polling. Sometimes intelligent devices, capable of sensing the opening of a fuse, a recloser or a breaker, placed in a substation trigger the outage analysis. In practical cases the outage analysis is triggered by the trouble calls received from the customers. However, the customer calls are not always a good source of information. Thirty percent of the outage affected customers call within the first hour of the outage [2]. The number of customers reporting the outages soon after an outage has occurred is comparatively less. Also, some outage reports generated by customer calls sometimes result in “OKAY on arrival”. When fed with incorrect data, the outage management algorithms give incorrect results. False outage reports and incorrect outage data result in considerable loss to the utility. In utilities where the AMR system is in place, the trouble calls may be verified by polling the meters individually. If a meter responds the meter is assumed to be ‘ON’ and a non-response is assumed as loss of power supply to the customer. The meter responses can be used to analyze the scope of the outage in the distribution system. The meters can also be polled for restoration confirmation.

AMRs also provide information about momentary outages. Some AMR systems record the total number of blinks and this data can be retrieved when necessary. The number of blinks represents the total number of momentary outages occurring in the system. The utility can identify the cause of the blinks using a mapping software thus improving reliability of the distribution system. In fact an IEEE working group/task force is developing a standard to calculate reliability data based on this new information source of AMR data. However, our research is only concerned with sustained outages.

## 2.6 Integration of multiple information systems

As discussed previously in this chapter, there are wide ranges of data sources available for outage management. SCADA, customer calls and AMR systems provide outage data. Information systems such as the CIS and GIS systems, aid in processing the outage data and help the crew locate the outage accurately. Recently Work Management Systems (WMS) and Mobile Workforce Management (MWM) have been introduced to aid in work management. The data from all these sources should be integrated for the efficient operation of the outage management system.

With multiple sources of information, the exchange of information among the different information systems is a difficult task. The bulky customer data sometimes results in an incorrect data entry, which makes the data inconsistent. Some software systems are now available that integrate the data from all the sources but they are not cost effective. Also, the available software is not always compatible with the utility's distribution networks and has to be customized to fit the utility's needs.

## 2.7 Summer Internship with Itron

The author spent the summer of 2003 as a student intern at Itron Inc, in Spokane, WA. That summer he interacted with various issues on AMR system applications. He studied various AMR technologies popular in the industry and proposed some usecases on applications of radio based AMR in outage and restoration analysis. The author looked into various possibilities of telemetry opportunities in the distribution system. He also spent some time researching the possibility of using a transformer as a telemetry point for collecting aggregate consumption data and notifying outages. The author also looked into powerline based AMR systems and submitted an internal paper on PLC based AMR systems and their impact on Itron with respect to technology and marketing. This experience gave the author an opportunity to study the PLC based AMR systems and to identify potential applications of such systems for outage confirmation.

## 2.8 Summary

This chapter describes various AMR systems in use today. The classification of radio and powerline based AMR systems and the flow of data in various AMR systems is discussed. The trends in the AMR industry and the application of AMR systems in outage management are also discussed followed by author’s Itron internship experience

# CHAPTER III

# LITERATURE REVIEW AND PREVIOUS WORK

## 3.1 Introduction

This chapter details the previous work done by academia and the industry in AMR systems and outage management. Also, it discusses how trouble calls are analyzed by different researchers for outage management. Furthermore, the data communication in Power Frequency Communication (PFC) systems and the concept of polling are discussed.

## 3.2 Previous work in AMR Systems and Outages

Research has been done by academia and the industry on AMR systems and their applications in outage management. The papers [14,15] discuss the inbound and outbound communication technologies of the PFC based AMR system. The signal generation and propagation over powerlines has been explained in detail. The author, Dr. S. T. Mak , in his paper [18] discusses the automation of fault detection and outage mapping using advanced computer and communication technologies. The author discusses various operational models: the unsolicited inbound method, the total polling method, and the limited polling method for locating the outage.

The work done by CAPSOL (Computer Applications of Power System Operations Laboratory) at Michigan Tech University was based on wireless AMR systems. Krishna Sridharan has developed an intelligent data filter that processes the raw AMR data so that it can be reliably used by OMS [19]. Rochelle Fischer has developed a general polling algorithm for outage and restoration confirmation [11]. The research at CAPSOL used the performance index of the AMRs and took advantage of the on demand read feature for identifying the system conditions. Yan Liu [refs- paper & dissertation] proposed a fast and accurate outage locating method by integrating the available distribution outage information, which includes distribution SCADA, customer calls and AMR. This project was accomplished using a fuzzy filter to process the comprehensive information and expert systems for outage location. Eric Laverty in 1997 proposed [2] an improved escalation algorithm to aid the process of post heat storm restoration. The rules for escalation were well documented and compared storm and non-storm conditions. Eric author emphasized the use of all the available real-time information including the AMR data for reliable outage management solution.

### 3.3 Previous Work in Trouble Calls and Outage Management

Over the past two decades, there has been increased research activity on the issues related to outage management. It included the development of new algorithms and the use of computers to reliably locate outages thereby, decreasing the restoration times. Most of the algorithms use the upstream tracing method to identify the cause of the outage. This section discusses the previous work done in analyzing trouble calls for outage management.

W. G. Scott, in his paper [20], discussed the automation of vital stages of the restoration cycle such as automated answering of the calls, logging calls against protective devices and keeping the customers informed of the restoration status. The paper also discussed the importance of trouble call analysis and the necessity of the connectivity information for outage analysis.

Eric Martinez's paper [21] demonstrates the use of an expert system to optimize service restoration procedures. The system considers all the information available to assemble a database, and the failure device is located following a decision table. In paper [22] the authors used computer software techniques such as computer graphics, expert systems and object oriented programming for the implementation of the trouble call analysis and service restoration. In paper [23], a new method for trouble call analysis based on set covering theory is presented. To achieve this, a mathematical model based on trouble calls and the protective device location, is formulated. The most probable out device is located by tabu search. As this work is based on a local search algorithm, it may not identify correct outage locations. Also modeling of large distribution systems using this method appears to be impractical.

In reference [9], the author discusses how trouble calls can be integrated with SCADA and AMR data for quick location of outages. The research presents how artificial intelligence techniques can be used for outage analysis.

### 3.4 Power Frequency Communication System

As already discussed, much work has been done in AMR systems and especially in wireless AMR systems. The author researched various AMR systems and chose powerline communication based AMR system for his analysis in this project. Among the powerline-based technologies, Power Frequency Communication (PFC) is of particular interest to the author. The following sections discuss the data communication in PFC systems and some key concepts associated with the technology.

### *3.4.1 Data Communication*

The PFC system uses the existing powerlines for the transfer of AMR data. During the normal operation of an AMR system, a utility computer polls the communication module retrofitted in the electric meter and the transmitter responds with the metering data. Depending on the requirement of the utility, the meters are polled in the intervals of 30 minutes, or 60 minutes or once per day. The meters are also capable of storing the data over a pre-programmed period of time, so the interval data is logged and retrieved at a convenient time. In PFC based AMR systems, the success rate of data transfer is very high, consequently the loss of data is much less when compared to wireless AMR Systems [16]. Since the communication success rate is very high, if a transmitter is not responding after being polled, it is very likely that this indicates a power outage.

### *3.4.2 Polling in PFC systems*

In Power Frequency Communications (PFC) based AMR systems, the consumption data is obtained by polling the meter, the frequency of polling is dependent on the requirement of the utility. The meters are grouped and sequentially polled for the collection of data. If a customer requests the current reading, the utility can provide the customer with that information within 8 seconds. This information is available in DCSI' s product brochures and also been confirmed by speaking with DCSI staff. The on-demand read feature could be utilized by the PFC systems to confirm outages as well as restoration. When a meter is signaled to send on-demand read, the AMR's lack of response indicate that the customer is affected by an outage. Figure 3.1 illustrates this feature of PLC AMR systems. If the topology of the distribution system is available, the AMR responses can be mapped to find the actual outage location. The response time for polling each meter is approx eight seconds. This information is obtained from DCSI.

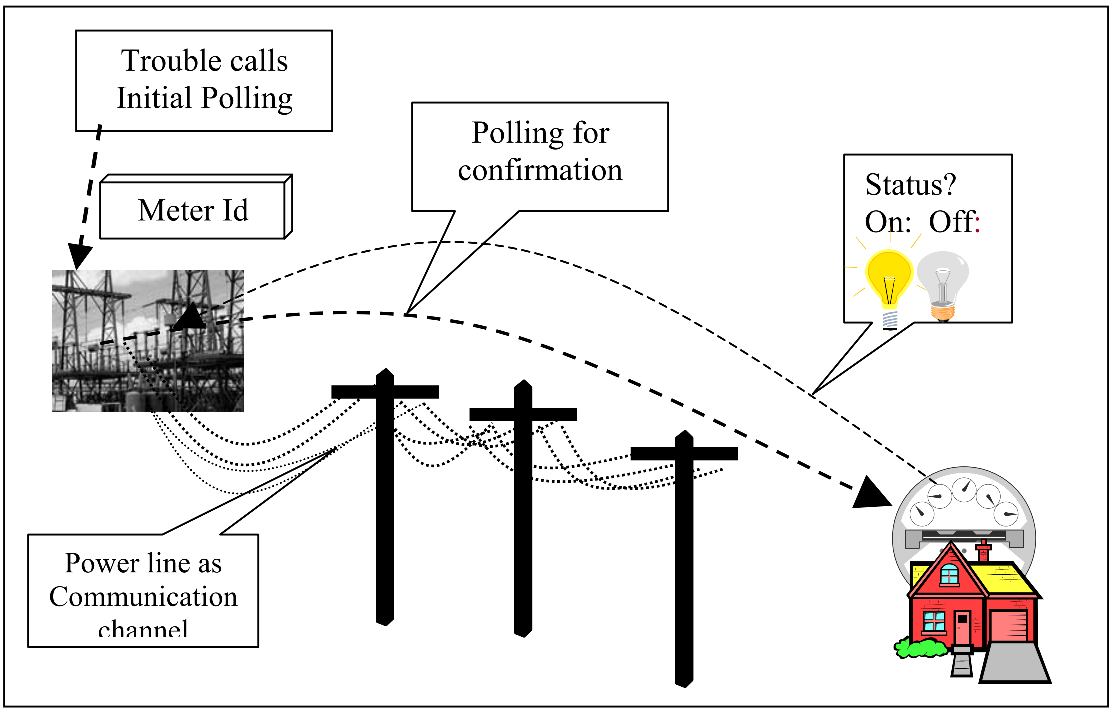



Figure 3.1 Polling in Powerline Communication based AMR Systems

The outage detection process in such systems can be initiated in a number of ways. First, the PFC system is used to poll several meters simultaneously. An 'ON' response from the group of meters leads to the conclusion that the region is not affected by the outage. A 'no' response from some/all of the meters polled indicates that an outage has occurred in that area. This technique is similar to the polling algorithms developed for communication networks [24]. Second, the customer trouble calls are usually used to trigger such outage analysis; based on the trouble calls received, some identified meters are polled to understand the extent of the outage. Finally, intelligent fault detection devices placed at strategic locations in the distribution system send signals to the control center when they experience a fault in the network [18]. Some of the meters in the vicinity of the intelligent device are polled to identify the actual outage location.

### 3.5. Modeling of Power Distribution Network

The modeling of the distribution system's physical structure is an essential part of an Outage Management System (OMS). For tracing the network connectivity a proper model to represent a distribution network is a vital issue [4]. GIS systems that represent the topology of the distribution network are used by the utility personnel to trace the cause of outage, and to dispatch of the crew to the actual location.

Graph-based and model-based approaches have been used to define the network topology for diagnosing the faults. In graph-based methods, the network model consists of a number of nodes, connected by edges. The edges of the tree represent the flow of connectivity like electric current. Sometimes the edges are attached probability to indicate the possibility of fault in the edge by taking various aspects like age of the equipment, outage history associated with the edge or some other feature.

The power distribution systems, designed with inherent hierarchical structure, are used to model the distribution network. The network is normally designed for selective coordination of protective devices such that minimum number of customers affected by the outage. The addressing of meters is based on their connectivity to different protective devices. Such an addressing scheme greatly reduces time and effort in identifying the actual fault location [18].

### *3.5.1 Modeling the Distribution System as a "tree"*

The physical structure of a distribution system consists of physical components such as the protective devices etc and their connectivity. A physical structure of a radial distribution network always has a tree topology and can be represented by a tree conveniently [25][12]. When a tree represents the distribution network, the roots are the initiating places of energy (substation) and the leaves are energy consumers (customers).

Detailed modeling of the distribution network as a tree is discussed in chapter 4. The flow of current starts from the substation and travels all the way to the customers. In a radial system, a single component failure in the distribution system will result in loss of power to all the customers downstream. Locating an unmonitored fuse or switch that opened because of an outage downstream is a difficult task if there is not sufficient information. The primary source of outage information is the customer trouble calls. If all the components of the distribution network can be traversed in a strategic manner then a plan can be developed to poll the meters sequentially served by those components to identify the outage affected customers. The common point of all the affected customers can be pointed as probable outage location.

A polling strategy is necessary to identify the meters to be polled. In a tree, starting from the root node, the nodes linked to root node and every other node is reachable from this root via a sequence of consecutive links. The leaves (customers) and the all the nodes of tree can be traversed in an organized manner, using one of the popular tree traversal methods. This project employs a depth first search strategy to represent the distribution network as a tree. Depth first search is chosen as it reaches the customers in an organized way starting from the extreme left and then traversing the leaves on the right side.

### *3.5.2 Preorder Traversal*

The preorder traversal is the depth first search algorithm that searches for the right most leaf of the tree from the root node. In preorder traversal the root is visited first and its descendents later. In case of a general tree structure, the traversal can be defined recursively as follows.

1. Visit the root first
2. Preorder traversal of the left most sub-tree followed by the right sub-trees in the given order.

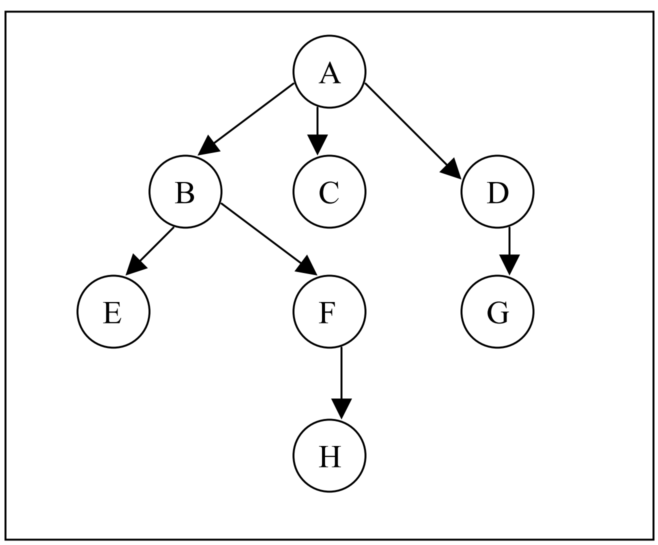



Figure 3.2 Example Tree [26]

The example tree shown in the Figure 3.2 illustrates the depth first traversal algorithm. We begin at the root node A, visit it and then select the leftmost child B and visit it. Before visiting the other children of A, the descendents of B are visited. E being the leftmost child of B, it is selected and visited (in a depth first manner). The nodes visited until now are A, B and E. Before visiting the other children of B we must visit the descendents of E. Because E has no children, we backtrack to B and visit its other child F (next right node of E) and then the descendents of H. As of now, the nodes traversed in pre-order are A B E F H. As all the descendents of B have been visited, now we can backtrack to last previously visited node along this search path namely A and begin visiting the rest of the descendents and finally visit D and its descendents. The pre-order traversal path for the example tree is defined as A B E F H C D G. If the data of all other nodes excepting the leaves are removed, the path contains only E H C G. Chapter 5 discusses how the pre-order traversal of a tree is used to represent the distribution system.

**3.6 Outage Management by Automated Meter Reading Systems (AMR)**

As already addressed, the information provided by AMRs placed at the customers' site could significantly aid in outage management. Several problems associated with using wireless AMRs for outage management have been addressed in previous papers [10,11,12]. Not many papers, except paper [18] discuss the applications of powerline communication based AMRs for outage management.

Earlier research in radio systems discussed verifying outages and restoration using systematic polling. The polling was prioritized based on the meter's communication capability called the Packet Success Rate (PSR). The meters with higher PSR are polled first and then the meters with lower PSR. The PLC based AMRs do not have a comparable index to measure their communication capabilities. The meters are proven to respond with a high success rate. In the present analysis the success rate of the AMRs has been assumed to be 100%, and so ranking based on success rate of polling meters is not possible. One other method to rank meters is based on their distance from the substation. A meter farthest from the substation would be given top priority as polling that meter would give information about the status of intermediate devices. Some polling schemes are prioritized on reliability of information the meters provided [10] [12].

### 3.7 Summary

This chapter reviewed the previous work in AMR systems and outage management. Discussed in this chapter are the concept of meter polling for the collection of metering data and outage data, the representation of distribution system as a tree preorder tree traversal technique is discussed.

# CHAPTER IV

# OUTAGE AND RESTORATION CONFIRMATION

## 4.1 Introduction

With the competition growing in the deregulated market, utilities are trying to overcome the increasing challenges in distribution system management. In the deregulated market the customers can switch their suppliers as per their interest. In order to retain the customers, there is a pressure on the utilities to see that the lights are always on. The customer satisfaction is based on the reliability of the services the utility offers.

The utilities rely on outage management systems for accurate outage location and quick restoration of the power supply. As seen in the earlier chapters, a variety of information systems began to be used for outage management. Such systems are integrated to provide an accurate solution accurate solution but sometimes tend to give erratic or misleading information about the actual status of the system because of vast amounts of data to be processed. Also, some of the outage management systems over-escalate or under-escalate with the available information about outages.

Many utilities began to see the possibility of using an AMR system during outage situations but they have not been successful in implementing a proper plan or strategy to identify the actual number of customers affected by the outage. Radio based AMRs have the capability to report the loss of power in near real-time. However, the loss of data because of colliding data packets makes the outage analysis complex. The powerline based AMRs do not have the ability to notify the utility, as they cannot communicate over de-energized lines. However, the meters in the affected region can be polled to confirm the status after an outage. The process of meter polling is usually initiated by trouble calls as discussed in section 3.4. After the system has been restored the meters can be polled to confirm if the customers have power. So the plan should integrate available outage information as well as the status of the meters as confirmed by meter polling.

## 4.2 Outage and Restoration Confirmation

The outage jobs are usually created from customer trouble calls. At times these reports are found to be incorrect, and sometimes there are not sufficient trouble calls to trace the outage to actual location. The outage location becomes a complex issue when storms cause multiple outages. The escalation algorithms considering such incorrect reports can determine a wrong outage location. The incorrect reports also lead to an "okay on arrival" situation. The crew is dispatched to probable place of outage and finds the system in working order. Such "okay on arrivals" cause financial losses to the utility as the crew visited a location that is in perfect order. Moreover, the restoration process has been delayed. So the utility should have a quick way to determine the status of the system before the crew is dispatched. Avoiding "okay on arrival" reports help the utility's efforts to restore supply to the customer quickly and improve the customer satisfaction.

Storms cause large-scale outages, which affect the distribution system adversely. Usually outage management algorithms operate under the assumption that it is more likely for one device to fail than several. But this assumption is not valid during storms as multiple outages do occur. The restoration of an upstream device may not lead to the restoration of all devices downstream. Near the end of restoration there would be a number of isolated outages at the service level. In such situations, it is necessary to see if the power has been restored to every customer.

### 4.3 Traditional Escalation Procedures for Outage Location

Escalation is roughly defined as raising the level of a job from a downstream device to a device upstream. This operation is usually based on the observation that it is more likely for one device to fail than several. With this observation the outage escalation tool searches other outage reports for common points of connectivity [2]. As a simple example of escalation, when only a customer served from a transformer reports an outage, an outage record is created and the outage location is escalated to the transformer. If a second customer calls, the outage is escalated to the upstream device that is common to both the calls. If a third call comes from a customer before the previous outage report is resolved the call is updated in the previous report else a new report is created. Any number of reports below the identified common point are attached to the same report if multiple calls are received from the same feeder within a time limit. Algorithms, assuming the failure of one device, fail to identify multiple outages. However the outage reports are also separated based on a predetermined time difference between the customer trouble calls and escalated to locate the multiple outages. During storm conditions the algorithm discussed above would group all trouble calls and group the calls into a single outage.

## 4.4 Problem with Traditional Escalation Procedures

### *4.4.1 The Dependency on Trouble Call Information*

The primary outage information is obtained when the customers affected by the outage call in. But from the utilities' experience it is shown that the customers will typically wait for 10-15 minutes before calling [2]. It has been observed that only thirty percent of the affected customers call the utility within the first hour of the outage. Also at any given time the number of people staying at home is varied. The number of customers responding to outages during normal working hours and nights is countable. The number of customers calling the utility as soon as an outage has occurred is small. There is every chance that there are no outage calls from any customers on the adjacent lateral lines on the same section actually affected by outage. In such a case results of the algorithm described in the previous section may not be most accurate locations possible. Even though the customer calls are instrumental in outage analysis, they alone cannot be used to predict and confirm the location of the outage.

The outage information can also be provided by the SCADA installed at the substation. The information from such real time monitoring systems is dependable but they provide information only about the region near the root of the network tree. If SCADA can provide information about the failure of any component there is no reason in expecting any calls from the customers. But the lack of automation in lower levels of the distribution system necessitates the use of trouble calls for the outage analysis. The trouble calls provide information about the leaves of the tree, but this information is incomplete and can lead to incorrect decisions. However if the trouble call information is combined with the responses from the Automated meters the status of many of the hierarchy levels of the network can be known.

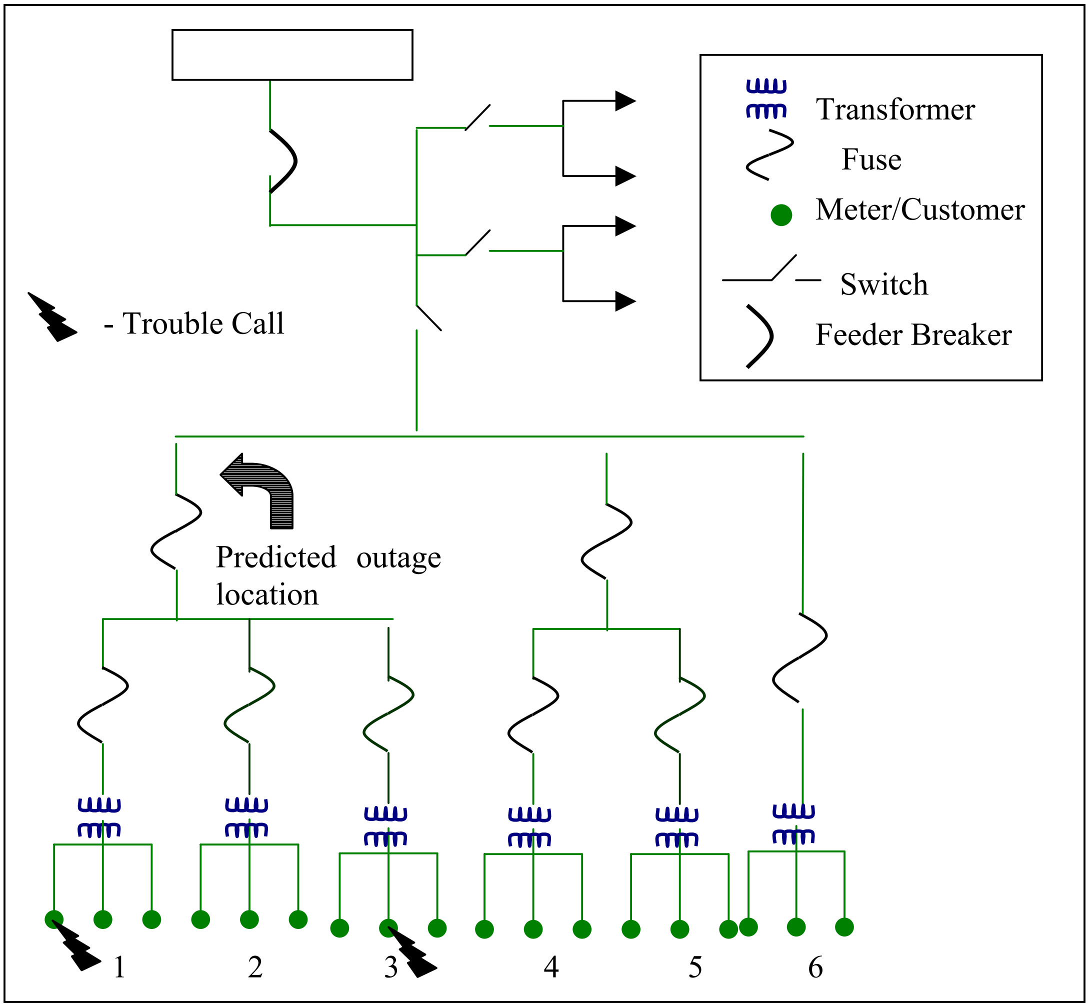



Figure 4.1 Example of Over escalation

### *4.4.2 Over escalation Problem*

During heat, wind or ice storms, multiple outages do occur in the distribution system. Transformer outages are common during heat storms and the chance that multiple outages occurring in a given area during the same time is high. This is because of the reason that the age of the transformers is almost same, as they would have been installed during the same time. If customer calls are from the same feeder the traditional algorithms trace back the connectivity of the trouble calls to find a common point. But to locate several outages downstream the utility personnel must investigate all downstream components served by the device. It is not an easy task for anyone to follow the top down approach in a distribution system to search for outages. Figure 4.1 explains the over escalation problem caused by traditional escalation algorithm. Suppose that there are trouble calls from sections 1 and 3.Conventional algorithms point the common node as the cause of the outage. In fact the trouble calls are reported separate outages each on sections 1 and section 3.Such multiple outages should also be determined by outage management algorithm.

### *4.4.3 Series Outages Problem*

It is a challenging task for any utility to identify the actual location of outage(s) particularly when there is no proper outage management system in place. The identification of faults becomes a more complex issue during storms. Numerous outages occur in a given area of distribution network during storms. Winds and storms can cause the trees to fall and cause cascading faults or series faults to occur. The conventional algorithms work on the assumption that the distribution system is protected in such a way that series faults do not occur. Such outages cannot be traced accurately with the trouble calls alone. Figure 4.2 shows an example of series outages caused in a simple distribution system.

There can be two cases in which the outages escalate only to a single outage. The other outage is not identified in either of the following two cases.

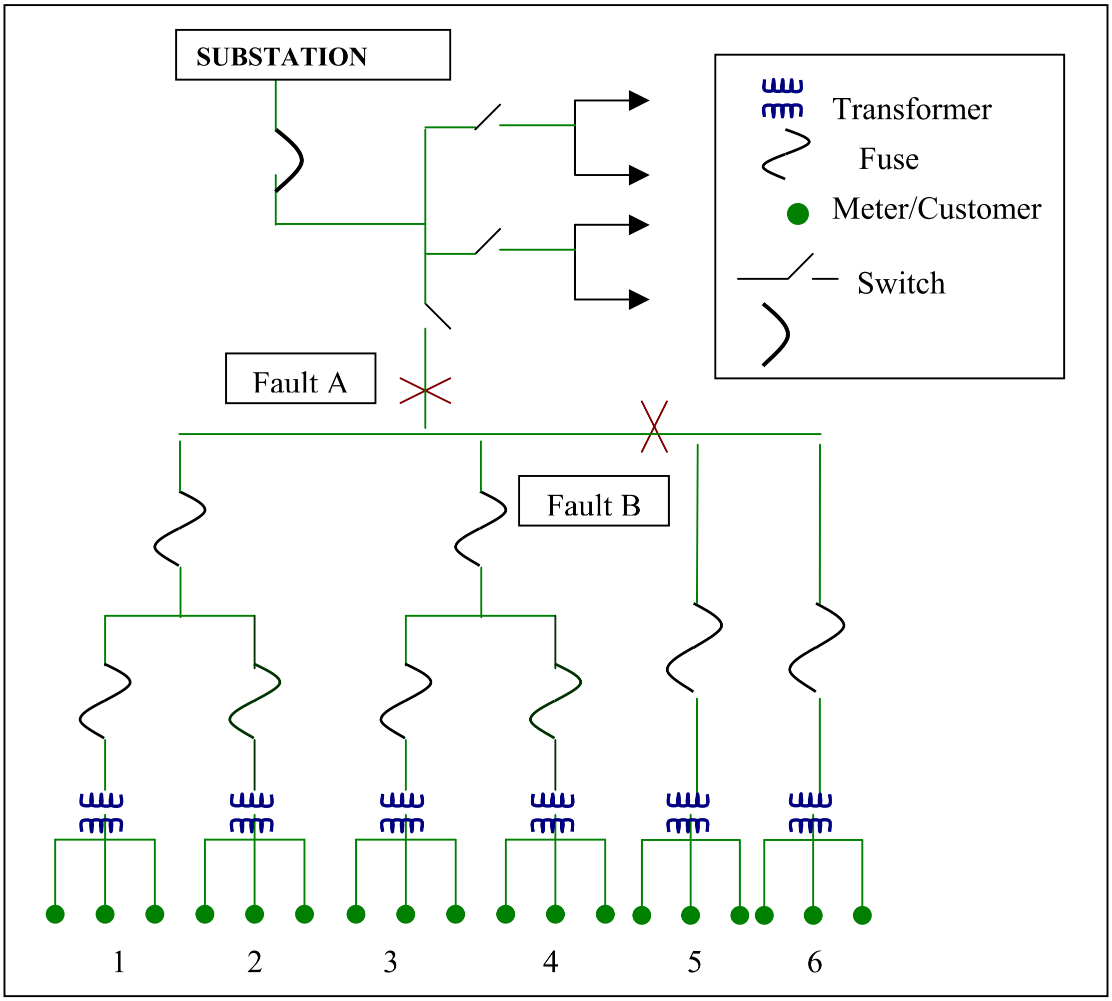



Figure 4.2 Example of Series Outages [13]

*Case A:* Assuming only customers under transformers 5 and 6 have reported the outage, the outage is escalated to fault B and in such a case fault A is not identified with that information.

*Case B:* If it is assumed that one customer from each transformer has reported the utility. Using the existing outage escalation algorithms the outage is identified to be at fault A. After fault A is repaired and it is wrongly concluded that all the customers have been restored, the customers under fault B are still out of power.

During multiple outages the traditional algorithms will report an over-escalation of the outage. If an AMR system is in place then the meters under the transformers one through six can be polled to confirm the outages. In either of the above two cases, only one of the outages is identified. But there are also other scattered outages below the identified outage, which need investigation. After the identified outage is fixed, the meters can be polled again to confirm the restoration. If some of the meters do not respond any of the meters then the cause of the outage can be easily identified.

**4.5 Development of the Model for the Distribution System**

As already discussed, the distribution network can be considered as tree with the meters as the "leaves" on the ends. Each node in the tree is represented by numbers and the group of meters of each transformer are tied up and represented as sections from A through F. Figure 4.3 represents the tree that is discussed in Figure 4.2.

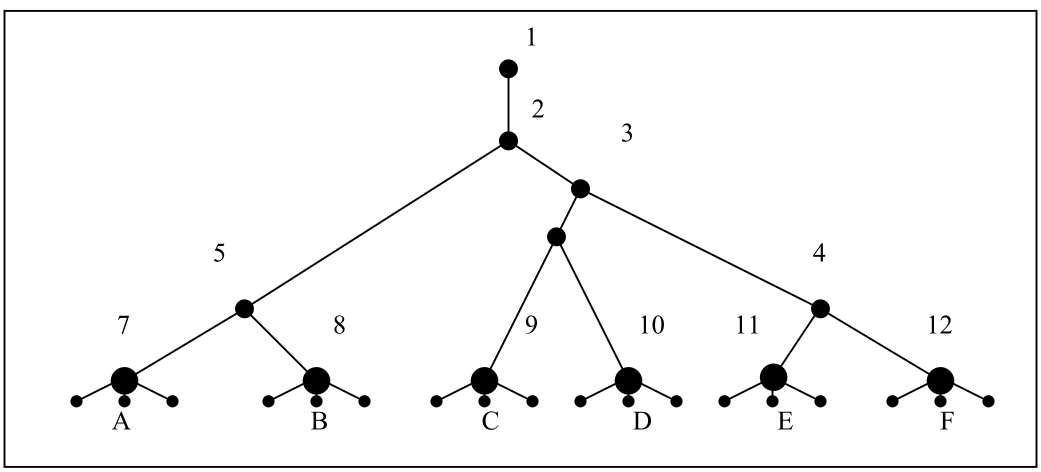



Figure 4.3 Network Example

Assume a case where a customer from sections C and D reported the outage. The meters of the reported meters need not be polled, as they do not provide any new information. Any meter adjacent to the trouble call customer can be polled to see if all the customers under the transformer are affected or it is only the reporting customer affected by outage. Polling the meters on the transformers B and E allow us to understand the scope of the outage. The response from the AMRs can be analyzed to locate the actual cause of the outage.

**4.6 Summary**

This chapter discussed the importance of outage and restoration confirmation in the distribution system. It also discussed the problems that are not solved by most of the outage management algorithms. To solve some of the issues discussed in this chapter, the use of automated meters to confirm the outages in such situations has been discussed. The following chapter discusses the development of the algorithm.

# CHAPTER V

# ALGORITHM DEVELOPMENT

## 5.1 Introduction

This chapter gives the summary of the algorithm used in the polling process and the steps taken to develop the algorithm. The tools used for the development of the algorithm, detailed description of the network model and the data needed in the process are discussed. A well-designed topology model of the distribution network is documented and an approach for identifying the total number of customers affected by an outage is discussed. A description of test cases used and the results of these tests are discussed in the following chapter.

## 5.2 Development Tools

The algorithm described in this chapter was implemented in C++ in a Microsoft Visual C++ environment. This project is implemented in C++ because proposed algorithm can be best implemented in an object-oriented environment. This project makes extensive use of the data structures especially linked lists in the implementation. One of the most popular tree traversal techniques, the preorder traversal, has been used to store the structure of the distribution system. The concept of recursion is used in the part of the algorithm that identifies the outage location.

**5.3 Topology Model of the Radial Distribution System**

The distribution system is normally operated in a radial structure with no loop connections. Figure 4.1 is a simple distribution system showing the connectivity among the fuses, transformers and the meters. The radial distribution system allows us to represent it as a tree conveniently [24]. The nodes of the tree can represent transformers, fuses, switches or any protection devices and the leaves of the tree can represent the meters at the customer level. This project does not particularly account for either fuses or switches. Every other protective device, including one at the transformer, is represented by a node. In order to identify single and transformer outages, a transformer is separately identified with a different nomenclature in addition to node name.

The simple distribution system can be modeled as a tree as shown in Figure 5.2.

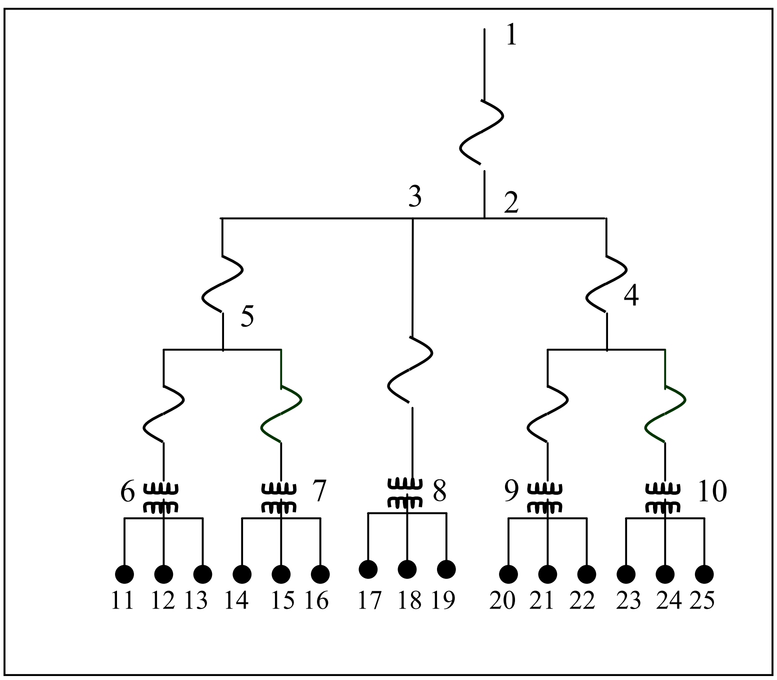



Figure 5.1 Simple Distribution System

The data needed for the analysis is the meter data and the connection data. The meter data includes the MeterID and the trouble call information, whether the customer at that meter reported the outage or not.

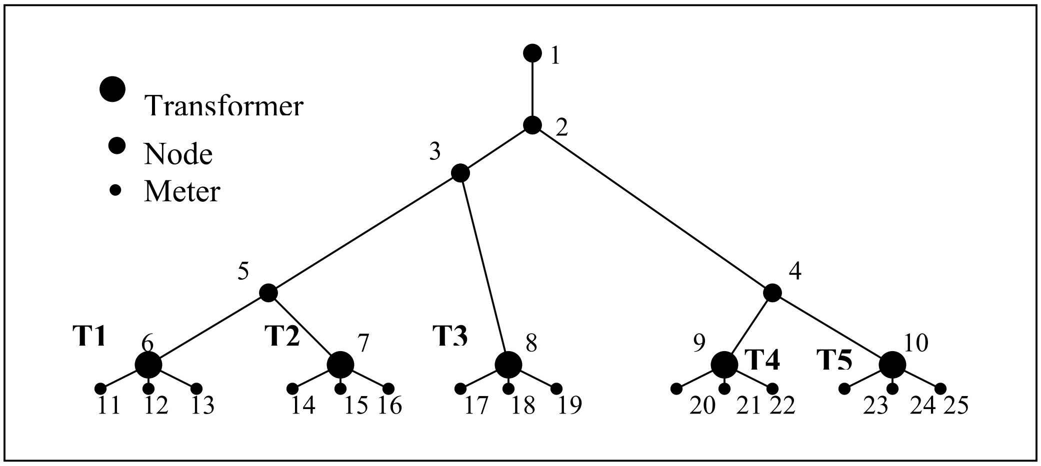



Figure 5.2 Representation of a Distribution Network

## 5.4 Sample Data

Table 5.1 gives the sample input data used in the analysis. It represents the simple distribution system as shown in Figure 5.2. Each node in the topology contains a field to check if a child is present at the node, a field to check if a transformer is present, and a pointer to the previous node. A tree with any number of sub-branches and nodes can be formed, thus making it possible to construct a distribution system of any depth and width dynamically.

TABLE 5.1 SAMPLE DATA NEEDED FOR THE ALGORITHM

| Node No | No. of children | IsTr | TrID | List of meters (MeterID) and IsTC |
|---|---|---|---|---|
| 1 | 1 | N | | |
| 2 | 2 | N | | |
| 3 | 2 | N | | |
| 5 | 2 | N | | |
| 6 | 3 | Y | T1 | Mtr11 N Mtr12 N Mtr13 N |
| 7 | 3 | Y | T2 | Mtr14 N Mtr15 N Mtr16 N |
| 8 | 3 | Y | T3 | Mtr17 N Mtr18 N Mtr19 N |
| 4 | 2 | N | | |
| 9 | 3 | Y | T4 | Mtr20 N Mtr21 N Mtr22 N |
| 10 | 3 | Y | T5 | Mtr23 N Mtr24 N Mtr25 N |

The required input data for the program is drawn from the input data table. The main advantage of using this input data table is its simplicity. The first column in the table contains the link numbers when the tree is traversed in preorder traversal. Refer section 3.5.1 for detailed discussion on preorder traversal technique. When the leaves of the tree are visited in the traversal they are placed in the last column containing the list of meters. For each row in the first column the table contains the number of links from the node (No. of children), 'Y' if the node is a transformer and 'N' if it is not a transformer (IsTr), transformer number (TrID) if the transformer is present. The last column contains the meter data (MeterID) for all the transformers. 'Y' follows each meter number if there is trouble call from that customer at that meter else by 'N' (IsTC).

As already discussed, this project makes use of linked lists. The transformer IDs in the third column of the table are placed in a list, *trans_list.* Any group of consecutive elements in the *trans_list* represent the customers downstream of a single node in the distribution network. If an outage is reported by any one of the customers, the meters served by the neighboring transformers can be polled to understand the scope of the outage. The meters with the trouble calls are placed in a separate list, *tc_list.* The *tc_list* is populated in the same order as the trouble calls are traversed in the tree. The following documentation aids understanding how the proposed algorithm works for different cases.

**5.5 Algorithm Overview**

The algorithm consists of three parts. First, the formation of the distribution network following the input data. Second, polling the meters in the neighborhood of the reported meter to identify the meters affected by the outage. Finally, the outage-affected customers are grouped and escalated to find the actual outage location.

*5.5.1 Assumptions*

Some of the assumptions have been made in the outage analysis. They include

1. The distribution system is radial. There are no loop networks.
2. A powerline communication based AMR system is in place on the distribution system.
3. The communication success rate of each automated meter is assumed to be 100%. There is no loss of data while transmitting the information and so a response from meter confirms that the meter is ON and non-response confirms that the customer affected by outage.
4. The total time taken for the utility to receive the polling response is eight seconds.
5. The faults do not cascade i.e. faults are localized.
6. The utility knows the connectivity information and any changes in the distribution system topology are updated in the input data table regularly.

*5.5.2 Obtaining Needed Information*

Initially the information about the distribution system structure is represented in a table as discussed in section 5.4. In normal situations, the information in the first four columns of the table does not change and the trouble call information is by default 'N' for every customer. With a customer calling to report the outage, trouble call information for that particular customer is updated by 'Y'. If there are any changes in the distribution network, it is assumed that the table is updated with the latest changes.

*5.5.3 Choosing the Meters to Poll to Determine Outage Affected Region*

When the outage analysis is triggered, the list-iterator points to the first trouble call in the *tc_list*. Initially the transformer linked to the customer trouble call is identified and one meter adjacent to the trouble call meter is polled. If the polled meter does not respond, one meter on each of the transformers on a side of trouble call meter until a 'ON' signal is reached and the process is repeated in the opposite direction as shown in Figure 5.3. The meter of the transformer with the lowest node number is polled if there is no trouble call associated with the transformer. This method of polling identifies the total number of customers affected by the outage in the neighborhood of the trouble call. Every time the iterator chooses a transformer, the *tc_list* is checked to see if any meter of that transformer has a trouble call. Each call in *tc_list* is visited only once. The next unvisited meter in *tc_list,* if present, is chosen after the process started by the initial trouble call meter is over. The same procedure is followed until all the meters in the *tc_ list* are visited. Figure 5.3 gives an overview of the polling algorithm for a single outage situation. The same algorithm can be extended to multiple outages, single customer outages and transformer outages with slight modifications, corresponding rules are discussed in the following sections.

Polling a meter other than a trouble call meter in the *tc-list* allow us to determine if it is a single customer outage or a higher-level outage. The following sections discuss the rules that are used by the algorithm to identify different types of outages occurring in the distribution system. A minimum of one trouble call is necessary for outage analysis. In case of multiple outages, as many number of trouble calls as the number of outages are required to initiate the polling. The control center does not need to wait for more number of outage calls to locate the outage.

### *5.5.4 Outage due to failure of a fuse or a switch*

RTUs may monitor some of the lateral fuses in the not too distant future and they already monitor most of the switches. The outages will be reported by the DMS in place. When the DMS reports the failure of any device, the outage is easily confirmed by polling one or more meters under the device in question. RTUs remotely monitor switches in the upper levels of the distribution system. As the occurrence of the outages at upper level is very less frequent as compared to the lower levels, the information from RTUs is currently not considered in this analysis. This analysis gives significant results when there are no reports from the switch or if there are unmonitored switches in the distribution system

As already discussed, the fuse or switch is represented by a node in the tree topology. To identify the cause of the outage the list-iterator based approach as described in the section 5.5 is used in the polling algorithm. The algorithm first polls the meters and identifies the customers affected by the outage. Then the node common to all the affected customers is identified by the outage location algorithm.

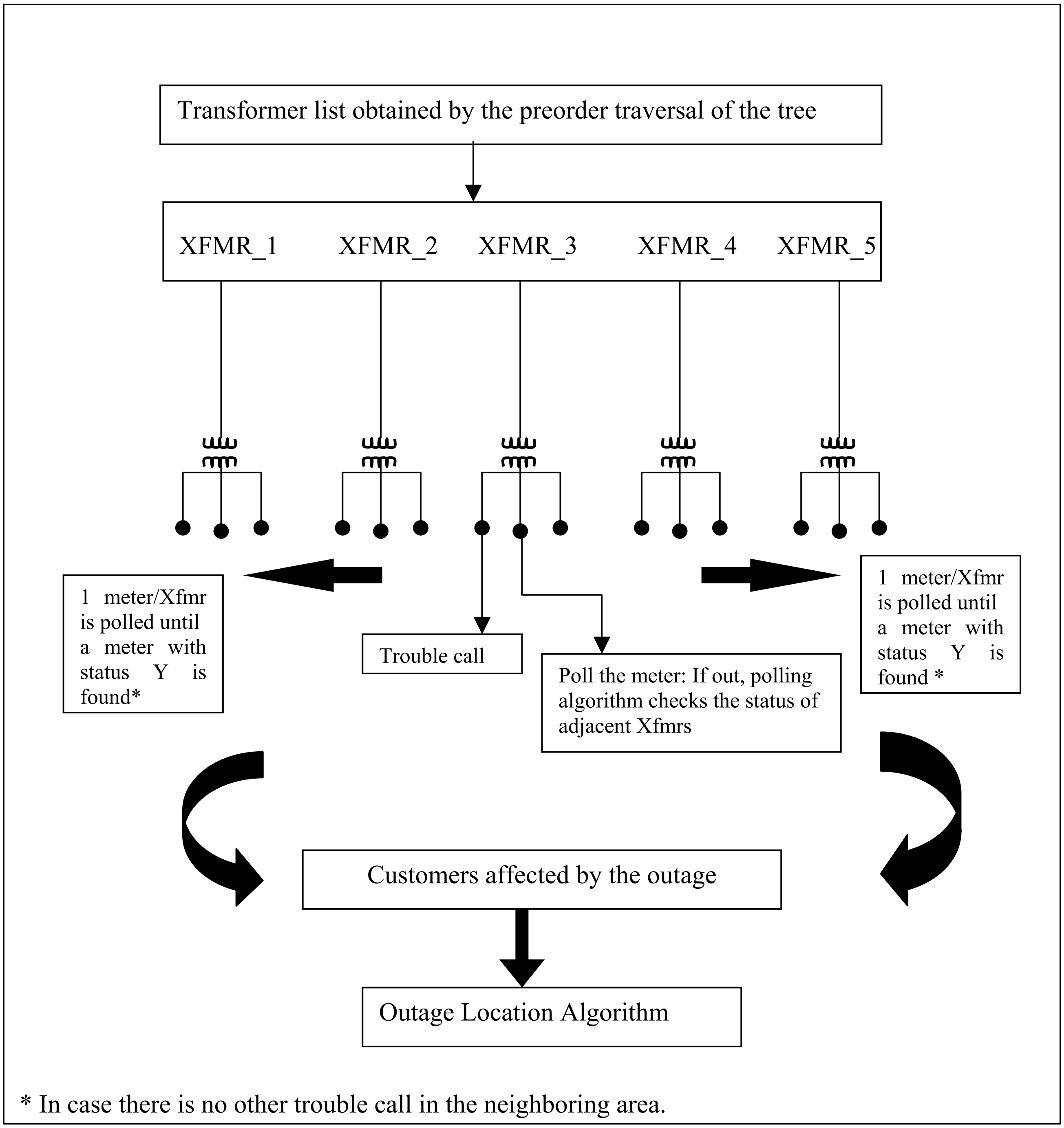



Figure 5.3 Polling strategy to identify outage-affected customers

*5.5.5 Outage at a transformer*

The distribution automation has not penetrated the network such that the distribution transformers are fitted with RTUs. The transformer outages will be determined by the customer trouble calls and polling responses confirming the outages. The transformer can be automatically declared as affected by an outage if two or more trouble calls are received from a single transformer (Figure 5.4). There is no need for additional checking in such a situation.

If a customer under a transformer has reported the outage as shown in Figure 5.5, one meter adjacent to the meter with the trouble call under the same transformer can be polled to confirm the outage. If no other customers on adjacent transformers are affected by outage, the transformer is declared out as shown in Figure 5.6 else the procedure described in section 5.5.4 is followed.

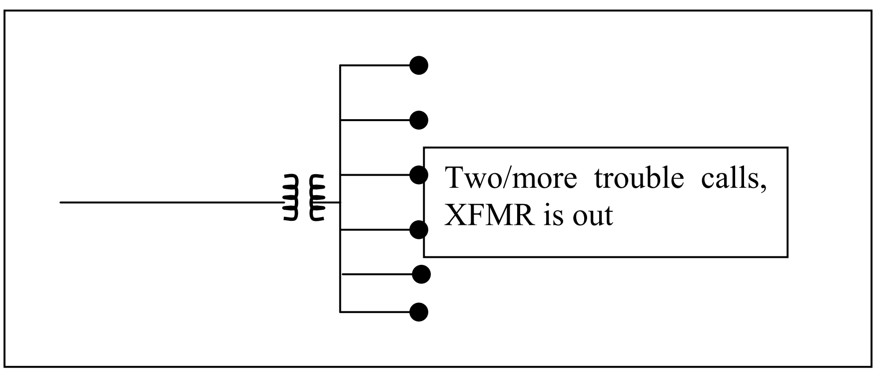



Figure 5.4 Transformer affected by outage confirmed without polling

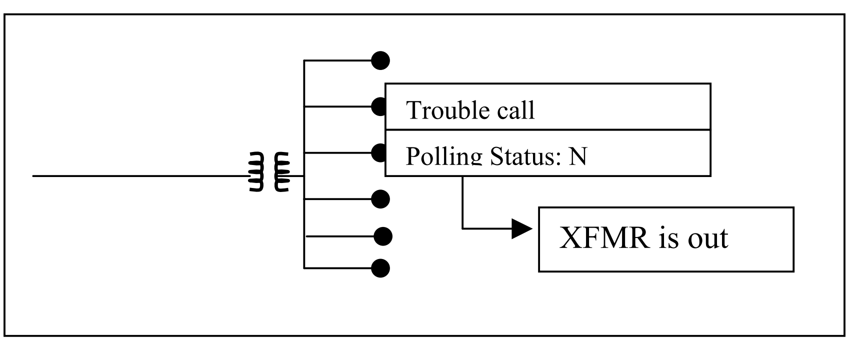



Figure 5.5 Transformer affected by outage confirmed with polling

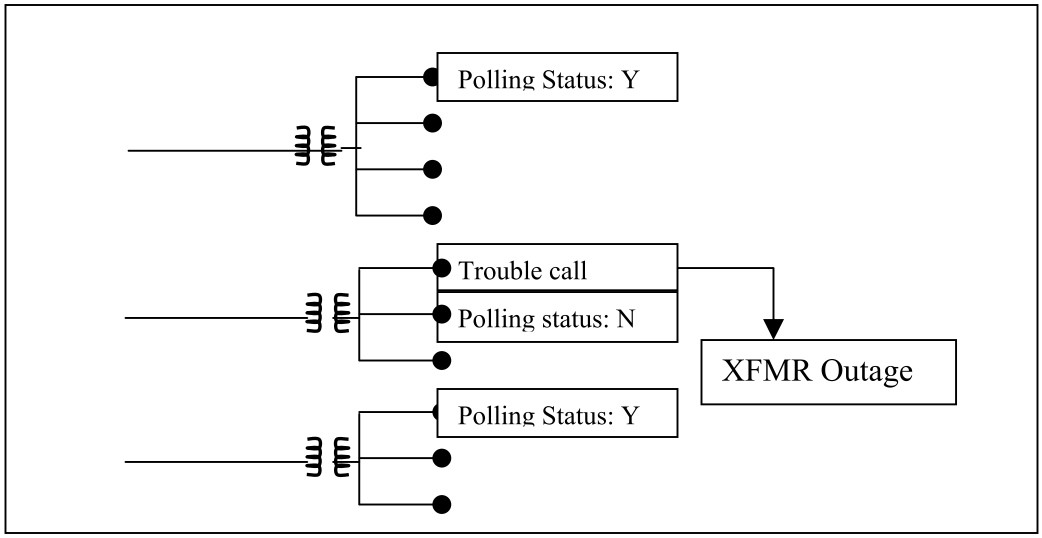



Figure 5.6 Transformer Outage

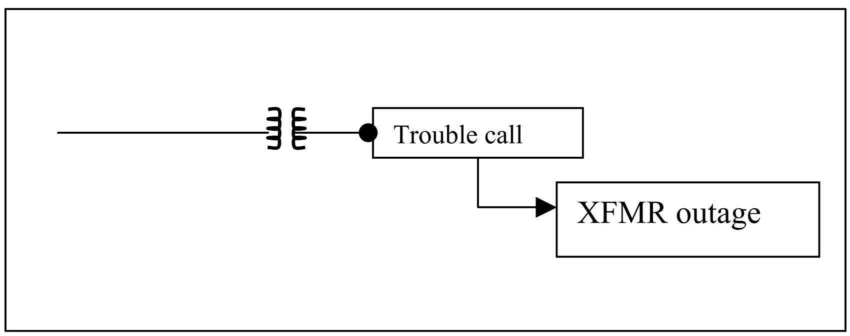



Figure 5.7 The case of a single service on a transformer

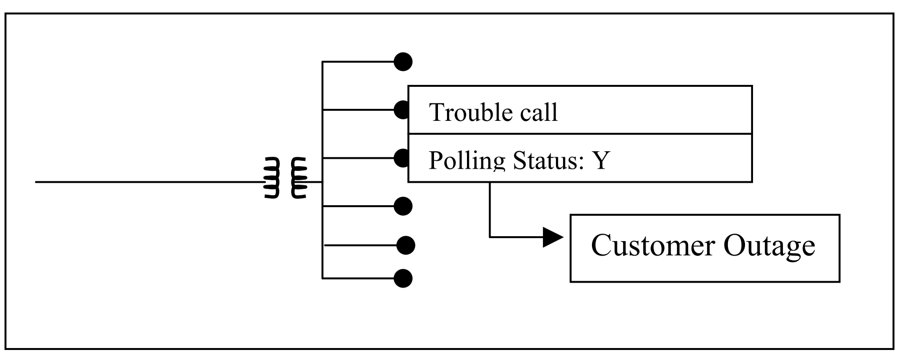



Figure 5.8 The case of a single customer outage

If the transformer has a single meter and it reports an outage the transformer can be declared to be outage affected. Polling is not necessary in such situations. Figure 5.8 illustrates this situation.

### *5.5.6 Single customer outage*

The algorithm also identifies single customer outages. The meter adjacent to the meter with a trouble call is polled. If the polling results in an 'on' status then it can be confirmed that only the meter with trouble call is out. Figure 5.8 illustrates the case of a single customer outage. If the result of polling the meter is 'off', the polling responses from the adjacent meters can be combined with this to determine if it is transformer level or a higher-level outage.

### *5.5.7 Total customers Affected by Outage*

The outage analysis can be triggered every 30 minutes or 60 minutes or at the utility's discretion. As discussed before, the outage analysis would work if there is at least one trouble call to initiate the polling sequence. The algorithm gives all the transformers affected by the outage along with single customer outages. All the outage-affected transformers excluding the transformers that serve the single customer outage customers are collected in a list called *faulty_list.* Each element in the *faulty_list* is traversed backwards recursively until a node that has a child with ON status is found. The previous of the node containing at least one meter with ON status is identified as the cause of the outage.

## 5.6 Outage Location Algorithm

In a radial distribution system failure of device(s) cause loss of power to all the customers downstream. The tree structure of the distribution system can be used to identify the location of the outage once the customers affected by the outage are identified. So the trouble call information and outage data from AMR systems are used to develop a plan to understand the scope of the outage. The node common to all the outage-affected meters is identified using the same tree structure with which the system is formed.

The outage location algorithm analyzes all the outage-affected customers to identify the most probable list of fault/outage locations. This is achieved by traversing the tree in a "bottom-up" fashion beginning at each element in the *faulty_list.* All the transformers affected by the outage excepting the ones affected by single customer outages are collected in *faulty_list.* Also all the nodes in the tree are assumed to be ON, except for the customers served by the outage-affected transformers and single customer outage meters. For every element in the *faulty_list* the previous node is selected and the status of all the children is checked. If no meter is ON, it backtracks to the previous node and checks the status of all its children. This backward traversal continues recursively until a node that has a child with 'ON' status is found and later the next element in *faulty_list* is chosen. All the nodes that are probably the cause of the outage are collected in *outage_list.*

## 5.7 Repolling for Restoration Confirmation

After the outage locations are identified and crew has successfully fixed all the outages, it is necessary to confirm that power supply is restored for all the customers. Polling the meters with the trouble calls would confirm if the power has been restored. Any number of trouble call meters still 'off' are collected in *tc_list* and the procedure is repeated to identify the cause of the outage. This is particularly significant in cases of series or cascading outages.

## 5.8 Summary

This chapter has described the step-by-step building of the algorithm to identify the scope of the outage and the algorithm for outage location. The development of the algorithm along with network model used and the data needed are also discussed. Some rules formulated to identify various outages are described. The following chapter presents various test cases that have been used to test the algorithm and the results of various scenarios that have been simulated.

# CHAPTER VI

# DISCUSSION OF TEST CASE RESULTS

## 6.1 Introduction

To determine how the algorithm would perform during different outage scenarios, various trouble call patterns were simulated to test the algorithm. As the practical test systems are not available, distribution systems with different sizes have been developed and tested. The first test case is a sample test case that explains how the algorithm works when simulated with variety of simulated outages and trouble call patterns. This chapter gives the description of the test cases and discusses the different test case results for various scenarios.

## 6.2 Test Case Descriptions

A variety of test cases have been developed based on the tree structure of the distribution system. The trees are of different sizes, lengths and widths. The test cases are also varied in terms of number of meters/network and number of meters/transformer. All the test systems except the first test case considered are asymmetrical trees. The test cases used in this thesis are adopted from Rochelle Fischer's work [27]. The test cases that cannot be represented graphically in this chapter are included in the Appendix A. Test cases one through four are included in the Appendix A. Table 6.1 gives a snapshot of the description of the test systems used in this analysis. Section 6.5 discusses the results of various test cases for various outage scenarios

TABLE 6.1 TEST CASE DESCRIPTIONS

| Test case | # of Meters | # of transformers | # of meters /transformer |
|---|---|---|---|
| Sample | 24 | 8 | 3 |
| Test Case 1 | 96 | 32 | 3 |
| Test Case 2 | 54 | 18 | 3 |
| Test Case 3 | 119 | 37 | 3-6 |
| Test Case 4 | 142 | 44 | 3-6 |

### 6.3 Sample Test Case

The sample test case is an asymmetrical tree so that it is more representative of an actual distribution system. The test case consists of 8 transformers and 24 meters. This is one of the smallest test cases and allows for the general testing of the algorithm.

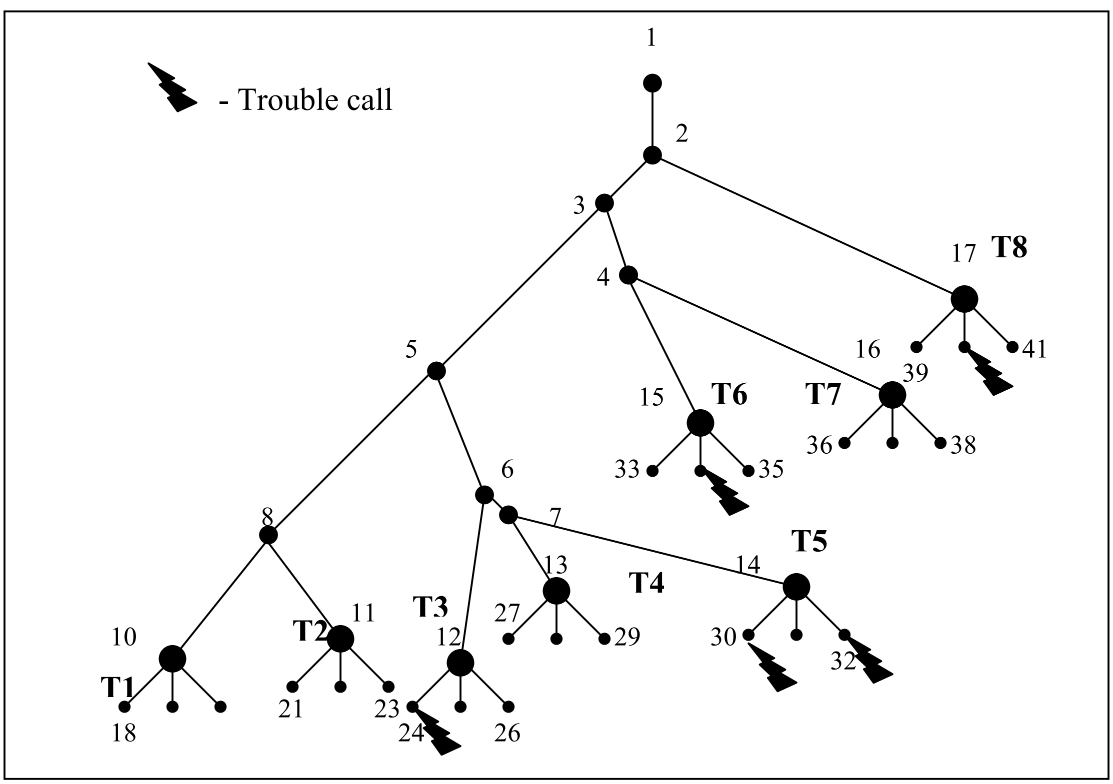



Figure 6.1 Sample Test Case

This system is rather small and so it is displayed in Figure 6.1 to give the reader a clear understanding of the working of the algorithm. Figure 6.2 shows the input data representing the distribution system. The first row contains the nodes when the tree is traversed in preorder traversal.

*6.3.1 Identification of the Outage Affected Region*

This test case is simulated for a transformer outage, a single outage and a single customer outage. The simulated outages are located at node 6, transformer T6 and Mtr40. In the following paragraphs the algorithm is explained to locate the simulated outages.

TABLE 6.2 INPUT DATA

| Node No | No. of children | IsTr | TrNo | List of meters and IsTC |
|---|---|---|---|---|
| 1 | 1 | N | | |
| 2 | 2 | N | | |
| 3 | 2 | N | | |
| 5 | 2 | N | | |
| 8 | 2 | N | | |
| 10 | 3 | Y | T1 | Mtr18 N Mtr19 N Mtr20 N |
| 11 | 3 | Y | T2 | Mtr21 N Mtr22 N Mtr23 N |
| 6 | 2 | N | | |
| 12 | 3 | Y | T3 | Mtr24 Y Mtr25 N Mtr26 N |
| 7 | 2 | N | | |
| 13 | 3 | Y | T4 | Mtr27 N Mtr28 N Mtr29 N |
| 14 | 3 | Y | T5 | Mtr30 Y Mtr31 N Mtr32 Y |
| 4 | 2 | N | | |
| 15 | 3 | Y | T6 | Mtr33 N Mtr34 Y Mtr35 N |
| 16 | 3 | Y | T7 | Mtr36 N Mtr37 N Mtr38 N |
| 17 | 3 | Y | T8 | Mtr39 N Mtr40 Y Mtr41 N |

When the outage analysis is triggered, the first meter in *tc_list, Mtr24* is chosen. The *tc_trans_list* contains the transformers of the meters reported to be out. The meter adjacent to *Mtr24 (*i.e. *Mtr25*) is polled. The *Mtr25* did not respond to the utility's signal.

T3 is therefore assumed to be out and is pushed into *faulty_list* (Refer to Figure 5.5 in the previous chapter for a corresponding rule). One meter on each of transformers following T4 is polled until a 'Y' response is received. Each time the next transformer is chosen, *tc_list* is checked to

*trans_list*: T1 T2 T3 T4 T5 T6 T7 T8 T9 T10
*tc_list*: Mtr24 Mtr30 Mtr32 Mtr35 Mtr40
*tc_trans_list*: T3 T5 T5 T6 T8

| Meter chosen from *tc_list* | Transformer chosen | Meters Polled | Status confirmed |
|---|---|---|---|
| Mtr24 | T3 | Mtr25 | N |
| | T4 | Mtr27 | N |
| | T5 | No meters polled | N |
| | T6 | Mtr35 | N |
| | T7 | Mtr36 | Y |
| | T2 | Mtr21 | Y |
| Mtr30 | | Already visited | |
| Mtr32 | | Already visited | |
| Mtr34 | | Already visited | |
| Mtr40 | T8 | Mtr41 | Y |

*Faulty_list*: T3 T4 T5 T6
*Outage_list:* 6,T6, Mtr40

Figure 6.2 Analysis of an outage scenario

see if any trouble call exists. No meter from T4 has reported an outage so *Mtr27, which is the meter with the lowest number on the transformer* is polled. As the status of *Mtr27* is 'N' the next transformer T5 is chosen. Because T5 has two trouble calls, none of the meters are polled (Figure 5.4). The next transformer, T6, has a trouble call from *Mtr34*. So *Mtr35* is polled. As the *Mtr35* is 'OFF', *Mtr36* on T7 is polled. The response is 'Y'.

Thus the entire right side of the original trouble call has been polled. Now the polling begins on the other side of the first trouble call. *Mtr21* of T2 is polled. The response is 'Y'. The process pertaining to the first trouble call comes to an end and the region affected in the neighborhood of the trouble call is identified. Now the next unvisited trouble call in *tc_list* (i.e. *Mtr40*) is chosen. *Mtr41* on the same transformer is polled. As the *Mtr41 is* ON the meter with the trouble call *Mtr40* can be declared out. All the transformers affected by the outage are contained in the *faulty_list.* The single outage affected customers are directly collected in *outage_list.*

*6.3.2 Locating outage(s)*

The *faulty_list* contains T3, T4, T5 and T6. The list contains all the outage-affected transformers in the distribution system. This list does not include single outage customers. The status of all the affected meters is 'N'. The first node T3 is chosen and all the meters of the previous node of T3 (i.e. 6) are visited. As every meter served by node 6 is without power the status of node 6 becomes 'N'. Later the node 5 (previous node of 6) is chosen, and as the meters of T1 have a 'Y' status, process breaks and the node 6 is pushed into the *outage_list*. The next element (i.e.T4), in *faulty_list* is chosen. Node 7 is the previous node of T4. As no child of node 7 has an 'ON' status, the previous node 6 is chosen and so on. For every node in the *faulty_list* the process is repeated. For T3, T4 and T5 the node 6 is the node that is without power. Next T6 is chosen and the children of the previous node of T6 (i.e.4) are visited. But some leaves of the node are ON so the recursive search comes to an end and records T6 (i.e.4) as a separate outage. The *outage_list* already contains single customer outages. Finally the outage_list contains 6, T6 and *Mtr40.*

## 6.4 Test Case Summaries

Table 6.1 gives a snapshot of the description of the test systems used in this analysis. Table 6.2 through 6.6 give a summary of some of the scenarios run on the four test cases for various trouble call patterns. The scenarios are set such that the algorithm is tested for various outage scenarios. The trouble calls, the meters polled, the customers affected by the outage and the outage locations are presented in the summarized table. The following section describes all the test cases along with an analysis of the results.

### *6.4.1 Test Case 1*

This test case is a symmetrical test case. This test case is chosen to simplify the understanding of the algorithm. The tree has 9 transformers with 3 meters per transformer making a total of 27 meters. This test case is included in the Appendix A.

The algorithm has been tested for various outage scenarios. In scenario 1 only one trouble call is received. When a single customer call is received the adjacent meter is polled. With ‘Y’ response from adjacent *Mtr24* the customer with outage call is declared out. In scenario 2, a single transformer outage is simulated. A trouble call is received from *Mtr33*. The adjacent meter *Mtr34* on the same transformer is polled first. Later, meter on one side of trouble call *Mtr35* is polled. As the status of *Mtr35* is ‘Y’, the meter *Mtr29* on other side of trouble call is polled. As the transformers on either side of the trouble call are ‘ON’ the transformer with a trouble call is declared as a transformer outage. In scenario 3, only two trouble calls are received and both of them are on the same transformer. So one meter on each of adjacent transformers are polled.

Scenario 4 is simulated for two separate transformer outages located at T6 and T7. A trouble call is received one from each one of the meters *Mtr30* and *Mtr*32. The *tc_list* contains *Mtr*30 and *Mtr*32. First *Mtr*30 is chosen and *Mtr*31 on same transformer is polled. As *Mtr31* did not respond T6 is pushed into *faulty_list*. *Mtr32*, on adjacent transformer T7, is chosen. As trouble call is received from *Mtr32*, *Mtr33* is polled. *Mtr33* is 'OFF', so T7 is pushed into *faulty_list*. Later *Mtr35* on T8 is polled. With 'Y' response from T8, the polling is shifted to other side of the trouble call. *Mtr26* on T5 is polled and the response is 'Y'. Then the next trouble call from *tc_list Mtr32* is chosen. As the Mtr32 is already visited and it is the last element in *tc_list,* the polling is stopped. The *faulty_list* contains T6 and T7. In the outage location part of the algorithm, the previous node of T6 is chosen and the status of all meters served by the node 10 are checked. From the polling responses we know that the meters served by T4 and T5 are ON. The search breaks and declares T6 as out. Next T7 is chosen and in a similar way it breaks out when it sees a meter with Y status and declares T7 as out. Finally the probable outages are identified as T6 and T7. The traditional outage algorithms that determine the location as node 1 are proven wrong with the proposed algorithm.

In scenario 6, three trouble calls are received. *Mtr19*, *Mtr20* and *Mtr14* are polled and the transformer T2 is pushed into the *faulty_list.* Meters *Mtr33*, *Mtr35*, *Mtr38* and *Mtr29* are polled to identify that T7, T8 and T9 are affected by outage. The *faulty_list* contains T2, T7, T8 and T9. The previous node of T2, node 6 is chosen and checked to see if any of its children has a ‘Y’ status. As the status of some children of 6 is ‘Y’ T6 declared out.

TABLE 6.3 OUTAGE SCENARIOS FOR TEST CASE 1

| Scenarios | Trouble Calls | Meters Polled | Affected customers | Outage location (s) | Approx. time for polling (sec) |
|---|---|---|---|---|---|
| **Scenario 1** Single customer outage | 23* | 24 (Y) | 23 | 23 | 8 |
| **Scenario 2** 1-transformer outage | 33 | 34, 35(Y), 29(Y) | T7 | T7 | 24 |
| **Scenario 3** 1-transformer outage | 30, 31 | 33(Y), 29(Y) | T6 | T6 | 16 |
| **Scenario 4** 2-transformer outages | 30, 32 | 31, 33, 35(Y), 26(Y) | T6, T7 | T6, T7 | 32 |
| **Scenario 5** 1-transformer and 1-single customer outage | 21, 24 | 22, 25 (Y), 17 (Y) | T3, 24 | T3, 24 | 24 |
| **Scenario 6** 1- single outage and 1-transformer outage | 18, 34, 36 | 19, 20 (Y), 14 (Y), 33, 35, 38 (Y), 29 (Y) | T2, T7, T8, T9 | 4,T2 | 56 |

* The use of prefix Mtr is avoided to improve readability

Next T7 is chosen. The previous node of T7 is node 4. All the children of node 4 are affected by the outage. So the previous node of 4 is chosen (i.e. node1). Node 2 and node 3 are children of Node 1 along with node 4. As at least one child of node 2 is ‘ON’, node 4 is declared as the cause of the outage. Finally the causes of outage are declared as node 4 and T2.

*6.4.2 Test Case 2*

This test case is asymmetrical and a very short and wide tree. This test case has 18 transformers, 54 meters and a variety of different length branches stemming from the main lines. Table 6.3 presents the results of two outage scenarios tested.

TABLE 6.4 OUTAGE SCENARIOS FOR TEST CASE 2

| Scenarios | Trouble Calls | Meters Polled | Affected customers | Outage locations | Approx. time for polling (sec) |
|---|---|---|---|---|---|
| **Scenario 1**<br>2 single outages | 35, 39, 51<br>63, 67 | 36, 40, 41, 44<br>47, 52, 53, 56 (Y)<br>64, 66, 68 (Y), 59 | T1, T2, T3, T4, T5, T6, T7, T10, T9, T11 | 6,12 | 91 |
| **Scenario 2**<br>1 transformer<br>&<br>1 single outage | 35, 39, 57 | 36, 40, 41, 44<br>47 (Y), 58, 59, 53 (Y) | T1, T2, T3, T4, T8 | 7,T8 | 64 |

*6.4.3 Test Case 3*

The test case 3 is an asymmetrical long tree with some short and long branches stemming from the center. This test case is a best test case representation of a typical distribution system, which has 37 transformers and 119 meters.

This test system is tested with three different outage scenarios. Consider the scenario1. Traditional escalation algorithms assuming the occurrence of a single outage declares the node 1 to be the cause of the outage. But in reality, the trouble calls are a result of two different outages occurring at the same time at two different places. The proposed algorithm identified the two separate regions affected by an outage and declared node 2 and node 4 as the probable causes of outage.

TABLE 6.5 TEST CASE 3

| Scenarios | Trouble Calls | Meters Polled | Affected customers | Outage locations | Approx. time for polling (sec) |
|---|---|---|---|---|---|
| **Scenario 1**<br>2 single outages | 66<br>74<br>131<br>139 | 67, 69, 73, 75, 79, 82, 85(Y), 61 (Y), 132, 134, 138, 140, 143, 146, 149 (Y), 128, 125, 119, 116 (Y) | T2, T3, T4, T5, T6, T7, T22, T21, T20, T23, T24, T25, T26, T27 | 2,4 | 152 |
| **Scenario 2**<br>3 transformer outages | 131<br>138<br>147 | 132, 134 (Y), 128 (Y) 139, 140 (Y), 148, 149 (Y), 143 (Y) | T22<br>T24<br>T27 | T22<br>T24<br>T27 | 64 |
| **Scenario 3**<br>1 transformer outage,<br>1 single outage,<br>1 single customer outage | 150<br>155<br>162 | 151, 152<br>156, 158 (Y), 146, 163 (Y) | T28, T29, T30<br>162 | 19,T30, 162 | 48 |

*6.4.4 Test Case 4*

This test case is similar to test case 3 except that a number of the branches extend for a longer distance with numerous short branches off these long branches. This system spreads over a slightly larger area with 44 meters and 142 transformers. The number of customers ranges from three to six. The test case has been tested for different outage scenarios all of which involve multiple outages. The results are presented in table 6.5.

### 6.5 General Observations and Discussion

Some interesting observations can be drawn from this analysis. Most of the outage calls result in over-escalated outages and sometimes point out misleading locations when traditional algorithms are applied. The proposed algorithm combines information from AMR systems and trouble calls and locates outages with more accuracy. A single trouble call is sufficient is trigger the outage analysis and the utility need not wait for more number of customers to telephone. As seen in many of the scenarios an over escalation or under escalation is avoided.

TABLE 6.6 TEST CASE 4

| Scenarios | Trouble Calls | Meters Polled | Affected customers | Outage locations | Approx. time for polling (sec) |
|---|---|---|---|---|---|
| **Scenario 1**<br><br>3-single outages | 78, 81, 97<br>103, 141<br>148 | 79, 82, 84, 87 (Y)<br>74 (Y), 98, 99, 104, 105, 108, 111 (Y), 93, 90 (Y), 142, 144, 147, 150, 153, 156 (Y), 138, 135, 132,<br>129, 125 (Y) | T3, T4, T5, T9, T8, T10, T11, T12, T13, T23, T22, T21, T20, T19, T24, T25, T26, T27 | 4,8,11 | 192 |
| **Scenario 2**<br>1-transformer outage and 1-single outage | 102<br>141<br>147 | 103, 105 (Y), 99 (Y), 142, 144, 147, 150, 153 (Y), 138,<br>135 (Y) | T11, T23, T22, T24, T25, T26, | T11, 13 | 80 |
| **Scenario 3**<br>1-singleoutage<br>1-transformer outage and 1-single customer outage | 159<br>163<br>170<br>181<br>184 | 160, 164<br>165, 169, 171, 174<br>177, 180, 185 (Y), 156, 153 (Y) | T29, T28, T30<br>T31, T32, T33<br>T34, T35, T36<br>184 | 19, T36, 184 | 88 |

The time taken to locate an outage dependent on the number of meters polled, which in turn depends on the extent of outage. One meter for each of the affected transformers, except for transformers with two or more trouble calls, is polled. So approximately, the number of meters polled equals the number of affected transformers. At least one trouble call is expected from each of the affected region. For a single customer outage in a region at least one customer must be polled. For a transformer outage at least three meters must be polled. It is also observed that most of the meters polled are in the outage region. Such a polling scheme avoids unnecessary polling in unaffected region.

### 6.6 Summary

This chapter has given a description of all the test cases and the results of various outage scenarios for various trouble call patterns. The proposed algorithm is described with a sample test case for an outage scenario that incorporates different types of outages. The test case 1 is also described with more emphasis on how the algorithm works for different outage cases. The results are presented for each of the test cases. The algorithm provides an efficient understanding of the distribution system status by polling fewer number of meters irrespective of the size and shape of the network.

# CHAPTER VII

# CONCLUSIONS AND FUTURE WORK

## 7.1 General Conclusions

The advancements in communication technologies have allowed utilities link to each and every customer through AMR systems. These systems are able to provide real time data about outages and thus shorten the duration of outages. Traditional algorithms for outage location failed to provide accurate results because of fewer number of trouble calls from the outage-affected region. Factors leading to extended outage times such as ok on arrival situations and multiple faults are common during storms. The new automated meters can help reduce these problems and improve customer satisfaction in deregulated environment.

The penetration of AMR systems in the electric industry is currently on rise, but the utilities do not have developed plans to include AMR data in their outage management systems. The utilities could make use of the enormous amount of information provided by AMR systems for their operational needs. This work chooses one opportunity to explore that can improve the reliability of services provided by the utility and leaves many opportunities for further work in outage management untouched.

The literature review showed that the majority of research in outage management mainly dealt with the outages in higher voltage levels. Most of the algorithms did not incorporate the data from AMR systems and particularly powerline communication based

AMR systems. In outage management systems, the modeling of distribution network is vital for fast tracking of the outage location. The hierarchical and radial nature of the distribution system allows it to be modeled it as a tree. The meters in the neighboring area of the trouble calls are polled based on the trouble calls received to identify the outage-affected region. The outage location algorithm groups the outage-affected customers and declares the common point as the probable cause of outage. The algorithm defines a set of rules to poll meters in a strategic manner to locate unconnected (not cascading) multiple outages in the distribution system which would otherwise have escalated to a wrong location. The algorithm also documents the escalation rules for different types of outages including transformer outages and single customer outages. The data from SCADA system is not used in the analysis, as it does not provide information about distribution level outages.

### 7.2 Benefits of this work

The current research is an extended part of work done on wireless AMR systems. However the system used for the analysis here is powerline communication based AMR system. This work provides the electric utilities an understanding of how the data from AMR systems can be used to manage outages. It also demonstrates how the AMR data can be used to eliminate problems faced by utilities during outages by using the most general source of outage information, i.e. trouble calls, to identify the scope of the outage. The outage locations identified by the algorithm are of highest accuracy and can be incorporated with SCADA information to develop a complete outage management system. In case of cascading outages, the established upstream outages can be restored initially and the meters can be repolled to identify the remaining outages. The developed algorithm can also be used for radio based AMR systems having on demand read feature with an assumption that the packet success rate of an automated meter is 100%.

### 7.3 Future Work

There are numerous opportunities to extend or continue this work. First and foremost, developing user-friendly application programs using the same algorithm to demonstrate the research goals.

Other work could involve prioritizing the polling based on the need of the services. The outages at emergency service providers like hospitals using life-supporting equipment and fire stations, industrial and commercial customers need to be restored at the earliest opportunity, and so such outages ought to have given higher priority. The communication success rate of the AMR systems is assumed to be 100% but strictly speaking the communication success rate is not exactly 100%. The signal is sometimes lost because of switching of various devices installed in the system and power quality issues. The inclusion of this uncertainty would be an interesting addition to the algorithm discussed in this work. The topology of the distribution system is assumed to be radial. But in some locations the distribution system is looped. Developing a similar algorithm for the looped systems is also an interesting aspect for future researchers.

These are only few among many of the ways to extend this work. AMR systems provide many exciting opportunities and challenges as the technology grows. A great deal of work needs to be done before the AMR data is completely integrated into an outage management system. This work is just the starting point and will hopefully open a door for future research and opportunities that AMR systems can provide.

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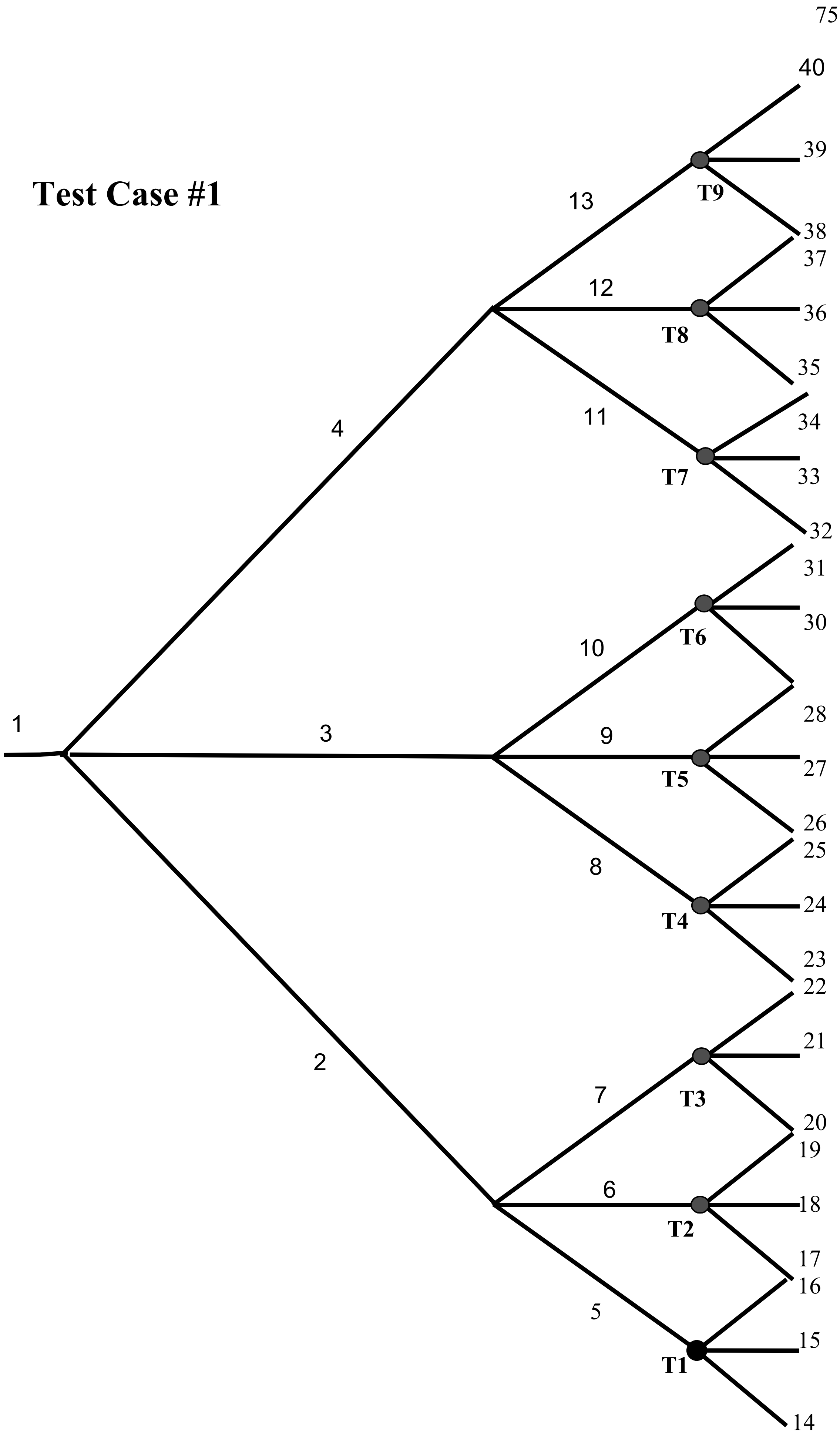
APPENDIX A

TEST CASES

# Test Case #1



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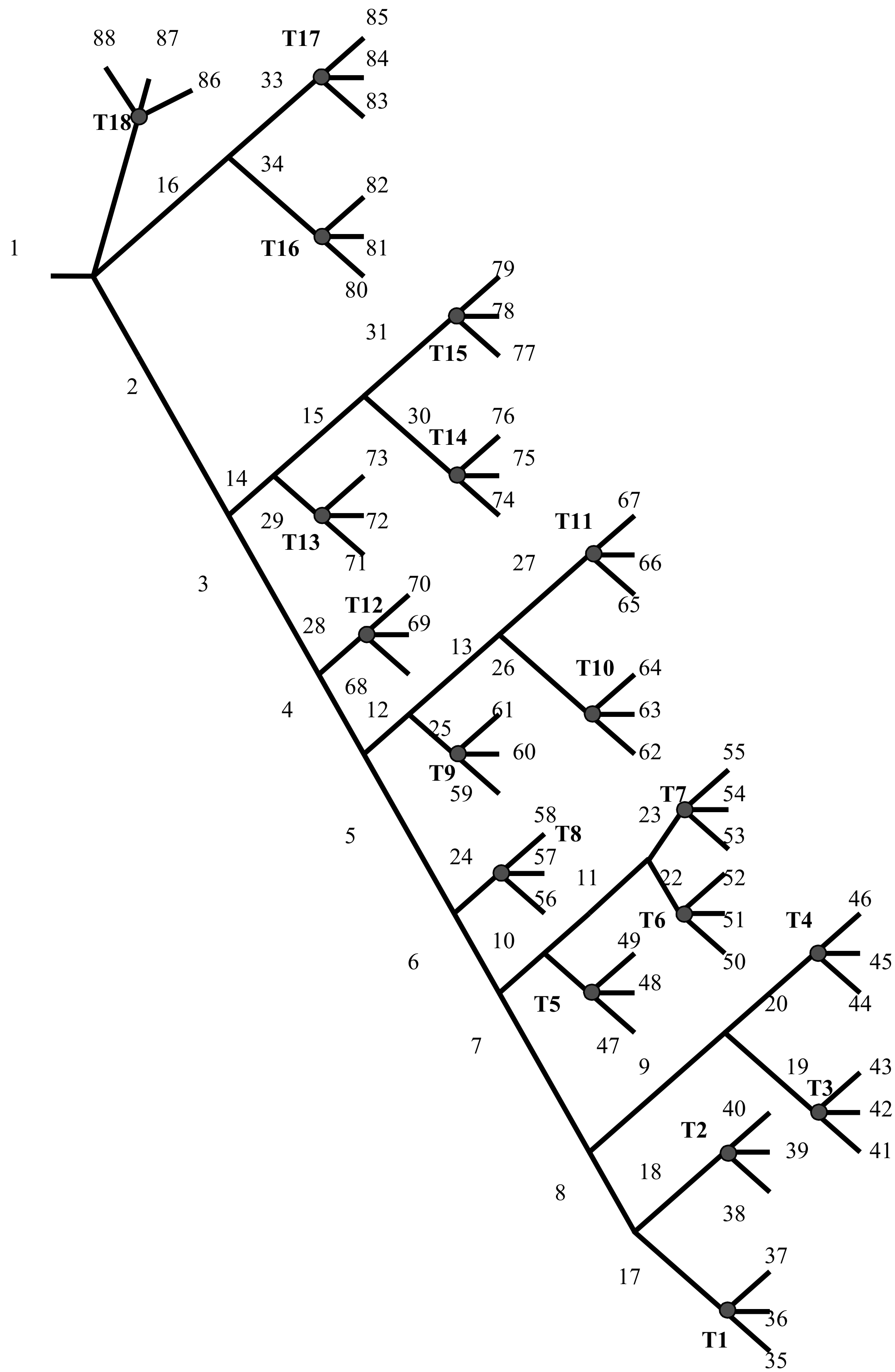
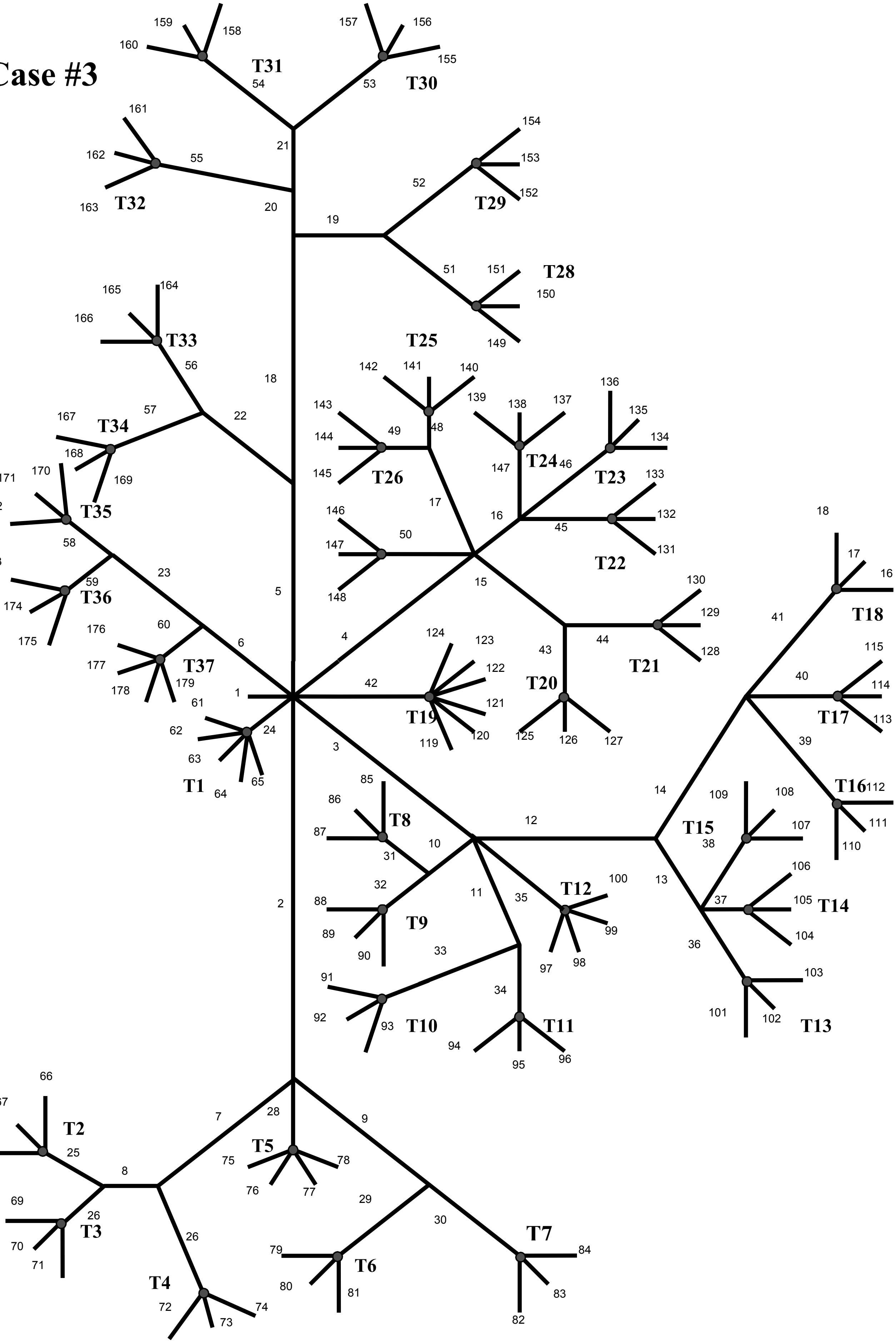
# Test Case # 2



# Test Case #3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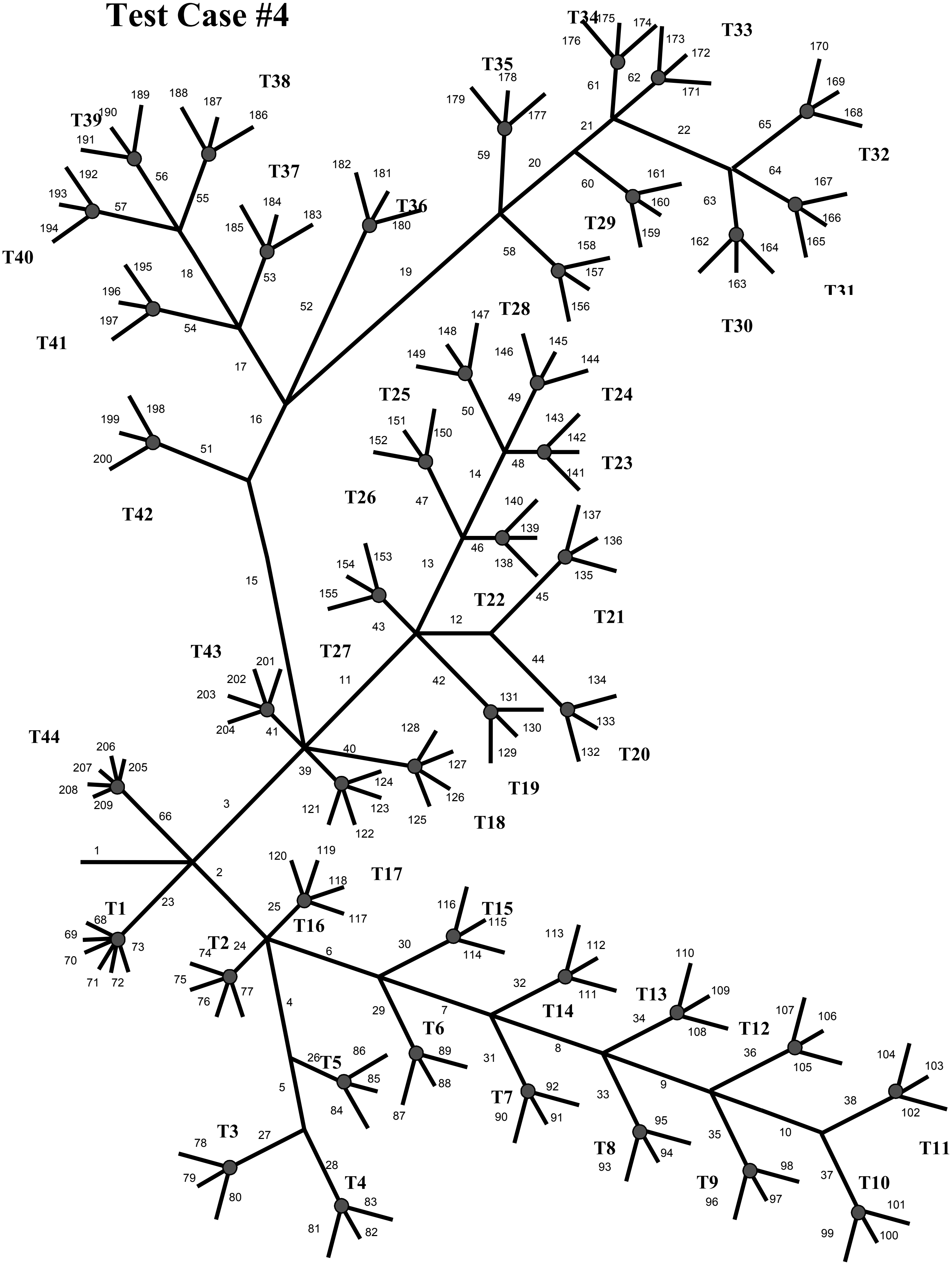
# Test Case #4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# APPENDIX B

# C++ CODE OF THE ALGORITHMS FOR IDENTIFICATION OF OUTAGE REGIONS AND OUTAGE LOCATION.

1. **Header file of the program**

```
#include<iostream>
#include<list>
#include<stack>
#include<fstream>
using namespace std;

class Node
{
public:
	class Meter
	{
	public:
		int MeterNo;
		char Status;
		char IsTc;
	};
	class Transformer
	{
	public:
		char TrNo[8];
	};
	int LinkNum;
	int numLinks;
	char IsTrPresent;
	char IsChildPresent;
	char Status;
	Meter MyMtr;
	Transformer MyTr;
	Node *PrevNode;
	list<Node *> MyNodeList;
	Node();
	virtual ~Node();
};

class Graph
{
public:
	Node *MyNode;
	Node *MyNodePointer;
	Node *MyTempPtr;
```

```
    stack<Node *> MyStack;
    list<Node *> MyQue;
    list<Node *> MyTrList,faultList;
    ifstream fin,fin1;
    Graph();
    virtual ~Graph();
    Node *CreateNode();
    void OutageDetect();
    void Outage(Node *);
    bool isOkay(Node *);
    Node * IsTrue(Node * , Node *);
    void EnGraph(Node *,Node *);
    bool isWorking(Node *);
    void traverse(Node *);
};
```

2. **Main function of the program**

```
#include<iostream>
#include<list>
#include"AmrProject.h"
using namespace std;
void main()
{
    char Input;
    Graph myGraph;
    do
    {
        cout<<"Input 'C' to create the graph\n" <<"Input 'O' to detect_outage\n";
        cout<<"Input 'X' to quit the program\n"<<"Your input is :::::>>>";
        cin>>Input;
        switch(Input)
        {
        case 'C':
            Node *rootNode;
            rootNode=myGraph.CreateNode();
            myGraph.fin>>rootNode->LinkNum;
            myGraph.EnGraph(rootNode,NULL);
            //myGraph.traverse(rootNode);
            break;
        case 'O' :
            myGraph.OutageDetect();
            break;
        }
    }while(Input !='X');
```

}

**3. Code file**

```
#include<iostream>
#include<list>
#include"AmrProject.h"
using namespace std;

Node::Node()
{
	PrevNode =NULL;
	MyNodeList.begin()=NULL;
	IsTrPresent='N';
	IsChildPresent ='N';
	Status = 'Y';
}

Node::~Node()
{
}

/*Graph Functions*/
Graph::Graph()
{

	//MyNode = NULL;
	fin.open("tc9_L15L11.txt");
	fin1.open("status9_L15L11.txt");
}
Graph::~Graph()
{
}
Node* Graph::CreateNode()
{
	Node *newMyLink = new (Node);
	return newMyLink;
}
void Graph::EnGraph(Node *node1,Node *node2)
{
	Node *newNode;
	int childCount;
	fin>>childCount;
	node1->PrevNode=node2;
	node1->IsChildPresent='Y';
	node1->numLinks=childCount;
	fin>>node1->IsTrPresent;
```

```
    if(node1->IsTrPresent=='Y')
    {
        fin>>node1->MyTr.TrNo;
        MyTrList.push_back(node1);
        while(childCount>0)
        {
            newNode=this->CreateNode();
            newNode->PrevNode=node1;
            newNode->numLinks=0;
            fin>>newNode->LinkNum;
            fin>>newNode->MyMtr.IsTc;
            fin1>>newNode->MyMtr.MeterNo;
            fin1>>newNode->MyMtr.Status;
            if(newNode->MyMtr.IsTc=='Y')
                MyQue.push_back(newNode);
            newNode->IsChildPresent='N';
            node1->MyNodeList.push_back(newNode);
            childCount--;
        }
    }
    else
    {
        while(childCount>0)
        {
            newNode=this->CreateNode();
            fin>>newNode->LinkNum;
            node1->MyNodeList.push_back(newNode);
            EnGraph(newNode,node1);
            childCount--;
        }
    }
}
void Graph::OutageDetect()
{
    list<Node *>::iterator i,k,j,l;
    list<Node *> faultyList,probOutageList;
    cout<<"My queue..\n";
    for(k=MyQue.begin();k!=MyQue.end();k++)
        cout<<(*k)->LinkNum<<endl;
    k=this->MyQue.begin();
    for(j=this->MyTrList.begin();j!=this->MyTrList.end();j++)
    {
        if((*k)->PrevNode->LinkNum==(*j)->LinkNum)
        {
            for(i=j;i!=this->MyTrList.begin();i--)
                if(isWorking(*i))break;
```

```
                        else
                        {
                                for(l=faultyList.begin();l!=faultyList.end();l++)
                                        if((*l)->LinkNum==(*i)->LinkNum)break;
                                if(l==faultyList.end())
                                {
                                        (*i)->Status='N';
                                        faultyList.push_back(*i);
                                        //cout<<(*i)->LinkNum<<endl;
                                }
                        }
        for(i=j;i!=this->MyTrList.end();i++)
                if(isWorking(*i))break;
                        else
                        {
                                for(l=faultyList.begin();l!=faultyList.end();l++)
                                        if((*l)->LinkNum==(*i)->LinkNum)break;
                                if(l==faultyList.end())
                                {
                                        (*i)->Status='N';
                                        faultyList.push_back(*i);
                                }
                        }
                if((++k)==this->MyQue.end())break;
        }
    }
    cout<<"Faulty list:  Faulty Transformer\n";
    for(i=faultyList.begin();i!=faultyList.end();i++)
    {
            cout<<(*i)->LinkNum<<"\t";//(*i)->Status<<endl;
       cout<<(*i)->MyTr.TrNo<<"\t"<<endl;
    }
    cout<<endl;
    i=faultyList.begin();
    do
    {
            Outage(*i);
            i++;
    }while(i!=faultyList.end());
    cout<<"Prob Outage List..\n";
    probOutageList.unique();
    for(i=faultList.begin();i!=faultList.end();i++)
            cout<<(*i)->LinkNum<<endl;
}

void Graph::Outage(Node *n)
```

```
{
        list<Node *>::iterator i,j;
        //cout<<"I am "<<n->LinkNum<<endl;
        while(isOkay(n->PrevNode)==false)
        {
                n=n->PrevNode;
        }
        for(i=n->PrevNode->MyNodeList.begin();i!=n->PrevNode-
>MyNodeList.end();i++)
        {
                if((*i)->Status=='N')
                {
                        for(j=faultList.begin();j!=faultList.end();j++)
                                if((*j)->LinkNum==(*i)->LinkNum)break;
                        if(j==faultList.end())faultList.push_back(*i);
                }
        }
}

bool Graph::isOkay(Node *n)
{
        if(n->IsTrPresent=='Y')
                if(n->Status=='Y')return true;
                else return false;
        for(list<Node *>::iterator i=n->MyNodeList.begin();i!=n-
>MyNodeList.end();i++)
                if(isOkay(*i)==true) return true;
        n->Status='N';
        return false;
}

bool Graph::isWorking(Node *n)
{
        for(list<Node *>::iterator i=n->MyNodeList.begin();i!=n-
>MyNodeList.end();i++)
                if((*i)->MyMtr.Status=='Y') return true;
        return false;
}

void Graph::traverse(Node *n)
{
        cout<<"Inside traverse function..\n";
        list<Node *>::iterator i,j;
        for(i=n->MyNodeList.begin();i!=n->MyNodeList.end();i++)
        {
                cout<<n->LinkNum<<endl;
```

```
        if(n->IsTrPresent=='Y')
            for(j=n->MyNodeList.begin();j!=n->MyNodeList.end();j++)
                cout<<(*j)->LinkNum<<endl;
        else traverse(*i);
    }
}
```