Communication Requirements and Integration Options for Smart Grid Deployment

Final Project Report

Power Systems Engineering Research Center

Empowering Minds to Engineer the Future Electric Energy System

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Executive Summary

All the visions of the Smart Grid share one common, critical need: *communications*. Without proper communications, the Smart Grid simply cannot exist. With communications, not only can the Smart Grid exist, but existing and new participants will be able to quickly and continuously define novel applications that will enhance any characteristics already defined, and create new characteristics not yet imagined.

The Smart Grid is a combination of the electric power and communications infrastructures. Many Smart Grid applications can be developed using both existing infrastructures. For example, a consumer connected to the existing electric distribution system can use existing telephone and internet systems to communicate with the utility or with anyone else involved in the application. In many cases, this may be all that is needed. A more efficient, reliable, and resilient solution is possible with an integrated approach where the energy and communications infrastructures are considered as one system. This approach enables far more extensive applications than would be feasible by separating the two systems.

This project establishes the communications needs and requirements specifications for Smart Grid development by studying the characteristics of the applications that will allow the Smart Grid to be realized. We identify existing and evolving communications systems that can best meet the needs of the Smart Grid for consumers and utilities.

To achieve this goal, we evaluated representative Smart Grid applications for both transmission and distribution systems. Using these two systems, the communication needs for the Smart Grid were defined and protocols for communications were recommended.

In the study of transmission-level applications, we evaluated new applications using new types of data. We focused on three principal questions.

- What improvements can be brought to control center functionality by collecting new data from the system?
- What are the communications challenges if such improvements are to be achieved?
- What can be done to adjust the communication solution to fulfill its mission under the new situation?

To answer these questions, we undertook the following research tasks.

- ***Selected sample applications in system monitoring, control, operation and protection.*** The selected applications were (1) Advanced Alarm Processing; (2) Automated Fault Location; (3) Detection and Mitigation of Cascading Events; and (4) Condition-Based Maintenance of Circuit Breakers. The applications were outcomes from previous research. They require Intelligent Electric Device data which is not widely available today.
- ***Studied requirements from the sample applications.*** To implement the sample applications, a large volume of data needs to be transmitted. The requirements

may vary. Some require high speed transmission, and some require synchronization. The communication must meet all the requirements.

- ***Studied the communication infrastructure***. The project covers the communication infrastructure, communication protocols and standards, as well as communication media and topologies that may suit the sample applications. Data modeling method and data processing architecture were also studied.

There were a number of outcomes from the research on the transmission level application.

- Use cases that are not in Smart Grid Interoperability Panel's (SGIP) list or EPRI's repository were generated.
- Suggestions regarding communication parameters such as bandwidth and transmission mode were offered. Communication media were selected for different levels of communication.
- A multi-level level communication hierarchy was proposed. New protocols and standards that are not on SGIP's list as Smart Grid standards were identified.
- Data integration was proposed. We introduced an Intelligent Electric Device modeling method based on a Common Information Model (CIM) and a data processing architecture.

In the study of distribution system applications, we selected:

- Optimized electric vehicle charging
- Condition assessment and optimized maintenance of distribution system components.

For distribution applications, we proposed a wireless mesh architecture utilizing feeder-level infrastructure. WiFi was chosen as the technology of choice after comparisons to existing wireline and other wireless technologies, and consideration of interference from power lines. Evaluations through simulations demonstrated adequate performance in terms of latency and successful data delivery. A feasible set of operating conditions was identified for use in practical deployments. In addition, we proposed a wireless-based home area network framework for the advanced metering infrastructure, including a communication and control model. Security and privacy requirements for the scenario and associated vulnerabilities were identified, followed by a set of recommendations.

Ongoing work related to this project includes:

- ***Development of a physical testbed for distribution smart grid communication and applications***. A 120V testbed will be housed in the research laboratory at Wichita State University. It will be a scale model, distribution feeder that includes generation sources and loads of varying types, and the ability to introduce voltage disturbances to the feeder.
- ***Development of a model of communication networks for future transmission operation, control and maintenance needs***. This model may be used to evaluate strategies for retrofitting existing networks as well as simulating new network

designs. Through simulation, it will be possible to assess performance and cost/benefits of various design options. The result will also guide development of communication system requirements for future expansions.

Project Publications

1. Visvakumar Aravinthan, Babak Karimi, Vinod Namboodiri, Ward Jewell, "Wireless Communication for Smart Grid Applications at Distribution Level - Feasibility and Requirements" in Proceedings of the Power and Energy Systems (PES) General Meeting (IEEE PES GM), Detroit, MI, July 2011.
2. Visvakumar Aravinthan, Vinod Namboodiri, Samshodh Sunku, Ward Jewell, "Wireless AMI Application and Security for Controlled Home Area Networks" in Proceedings of the Power and Energy Systems (PES) General Meeting (IEEE PES GM), Detroit, MI, July 2011.
3. Babak Karimi, Vinod Namboodiri, Visvakumar Aravinthan, Ward Jewell, "'Feasibility, Challenges, and Performance of Wireless Multi-Hop Routing for Feeder Level Communication in a Smart Grid", In Proceedings of the 2nd International Conference on Energy-Efficient Computing and Networking (e-Energy), New York, USA, May 2011.
4. Yimai Dong, Mladen Kezunovic, “Communication Infrastructure for emerging transmission-level Smart Grid applications” in Proceedings of the Power and Energy Systems (PES) General Meeting (IEEE PES GM), Detroit, MI, July 2011.

Student Theses

1. Visvakumar Aravinthan, *Guidelines for performance based distribution reliability analysis for present and future grid.* Ph.D Thesis, Wichita State University, College of Engineering, Dept. of Electrical Engineering and Computer Science. August 2010. hdl.handle.net/10057/3464
2. Babak Karimi, *A Wireless Communication Architecture and Associated Protocols for Smart Grid.* Ph.D Thesis, Wichita State University, College of Engineering, Dept. of Electrical Engineering and Computer Science, Expected Fall 2013
3. Surya Mohapatra, *Implementation of a Secure Home Area Network in Smart Grids.* MS Thesis, Wichita State University, College of Engineering, Dept. of Electrical Engineering and Computer Science. December 2011.

Table of Contents

Table of Contents (continued)

Table of Contents (continued)

List of Figures

List of Figures (continued)

List of Figures (continued)

List of Tables

Part I: Background

1 Introduction

1.1 Project Overview

All the visions of the Smart Grid share one common, critical need: communications. Without proper communications, the Smart Grid simply does not exist. With communications, not only will it exist, but existing and new participants will quickly and continuously define novel applications that will enhance any characteristics already defined, and create new characteristics not yet imagined. The Smart Grid could thus be thought of as a combination of the electric power infrastructure and the communications infrastructure. Many Smart Grid applications could be developed simply using the existing infrastructures for both. A consumer connected to the existing distribution system, for example, can use their existing telephone and internet systems to communicate with the utility or anyone else involved in the application. In many cases, this may be all that is needed. In an integrated approach where the energy and communications infrastructures are considered as one system, a more efficient, reliable, and resilient solution is possible. This approach enables far more extensive applications than what is feasible by simply looking at the two systems separately.

By studying the characteristics of the applications that will allow the Smart Grid to be realized, this project establishes the communications needs and requirements specification for the Smart Grid development to take place. Existing, and evolving communications systems that can best meet the needs of the Smart Grid, both for consumers and utilities, are identified.

Over the years, power system communications has evolved into the existing state-of-the-art SCADA systems, which use many different communications media, including wireless (VHF, UHF, microwave, and satellite), wired (cooper trunk cable, telephone twisted pairs, and Ethernet coaxial cables), fiber optic, and power line carrier. These systems are already challenged by the needs of new technologies and applications as illustrated by the following: a) Dedicated point-to-point communications systems developed for system integrity protection (SIP) applications are individually designed and applied, and are very expensive, limiting their practical uses, b) Master-slave communications developed for collection of recorded data from substation intelligent electronic devices (IEDs) are rather elaborate due to a large number of IEDs being deployed, requiring peer-to-peer fast communications, c) Communications developed for collecting data from phasor measurement units (PMUs) for system-wide applications are quite extensive due to increasing number of PMU functions being offered through relaying IEDs, requiring high speed broad band capabilities, and d) Extensive customer-level applications at homes and businesses, which present an increase in communications needs of at least one, and possibly two, orders of magnitude over existing needs.

The world's communications infrastructure, in particular the digital one, has also expanded significantly in recent years. Over half of all US households already have broadband internet subscriptions, and it is forecast that over three-quarters will be using broadband internet by 2012 [1]. Advances in technologies have also made possible even further growth, which is happening continuously. Hierarchical hybrid networks, for example, allow extension of the wired Internet through wireless mesh networks to smaller wireless sensor networks. Such networks can provide at a relatively low cost resilient and reliable communications with sensors and controllers over a wide geographical area with no legacy communication systems. The networks determine optimal methods of handling two-way data exchange based on priority, and also properly aggregate and disseminate data being communicated to and from a wide variety of devices. Existing and evolving communications systems, when integrated, are all candidates for Smart Grid communications uses.

Figure 1.1 Project Overview illustrates the purpose of this project: to assess the communications needs for the Smart Grid through study of overlaps, possible aggregation, and the use of common communication paths, all to reduce bandwidth and channel requirements and implement new Smart Grid Applications. Figure 1.1 illustrates how far the existing solutions are from what is needed in the Smart Grid environment.

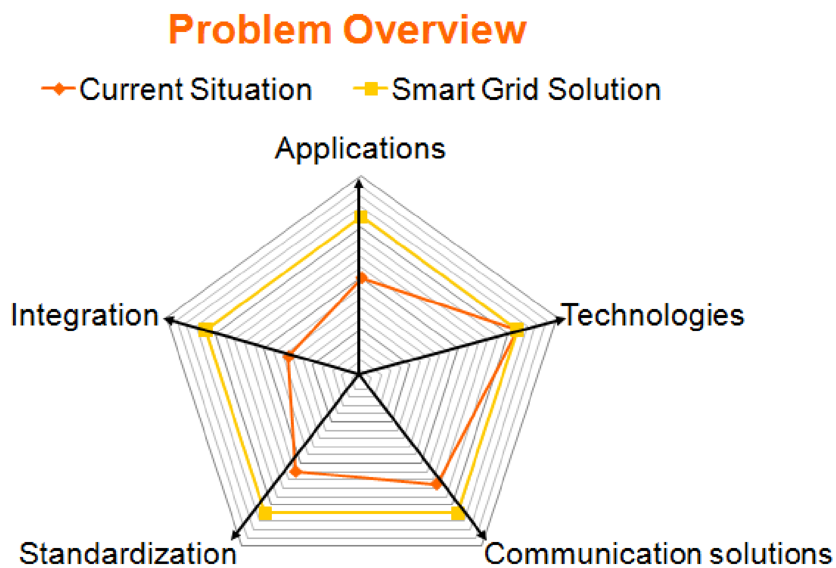


Figure 1.1 Project Overview

The study gives an inventory of the existing, emerging, and future communications options when complex system-wide applications are considered. The following is noted:

- Customer communication needs for optimized energy management applications are requiring interfacing to the grid control and electricity market participation through aggregated plans
- Distribution system communication needs for the automation of related demand side management, asset and outage management, as well as voltage and loss management tasks need to be considered in an integrated way
- Transmission system communication needs for improvement in system operation and protection, as well as maintenance of equipment are facing significant increase in data traffic
- Enterprise communication needs that allow integration of different technical systems for better management of data and human resources are emerging rapidly

- Communication needs for integration of renewables, microgrids, and advanced energy technologies such as plug-in hybrid electric vehicles represent quite new experience
- The role of data communication and data modeling standards in facilitating expansion of Smart Grid applications is absolutely critical for the future cost effective development of Smart Grids

1.2 The Development of Smart Grid

1.2.1 Title XIII of EISA 2007

The Energy Independence and Security Act of 2007 [2] (Pub.L. 110-140 originally named the CLEAN Energy Act of 2007) is an Act of Congress concerning the energy policy of the United States. The stated purpose of the act is "to move the United States toward greater energy independence and security, to increase the production of clean renewable fuels, to protect consumers, to increase the efficiency of products, buildings, and vehicles, to promote research on and deploy greenhouse gas capture and storage options, and to improve the energy performance of the Federal Government, and for other purposes,". Title XIII devoted to Smart Grids establishes our national policy for grid modernization, creates new federal committees, defines their roles and responsibilities, addresses accountability and provides incentives for stakeholders to invest.

The Title XIII also establishes the Smart Grid Advisory Committee, accountable to the Secretary of the U.S. Department of Energy (DOE). It assigns the Smart Grid Task Force, accountable to the Assistant Secretary for the DOE Office of Electricity Delivery and Energy Reliability, to bring focus to the advancement of the Smart Grid agenda, and puts the National Institute of Standards and Technology (NIST) in charge of establishing and coordinating the most important Smart Grid standardization efforts.

1.2.2 NIST Smart Grid Interoperability Panel (SGIP)

The National Institute of Standards and Technology (NIST) has been working on coordinating development of a framework that includes protocols and model standards for information management to achieve interoperability of Smart Grid devices and systems [3]. The Smart Grid Interoperability Panel (SGIP) was established by NIST to coordinate development of interoperability standards in the late 2009. In their report for Phase I of the NIST plan, "NIST Framework and Roadmap for Smart Grid Interoperability Standards", a high-level conceptual reference model for the Smart Grid, existing standards that are applicable (or likely to be applicable) to the ongoing development of the Smart Grid, high-priority gaps and harmonization issues (in addition to cyber security needs) for which new or revised standards and requirements are needed, and the strategy to establish requirements and standards to help ensure Smart Grid cyber security have been addressed [4]. Figure 1.2 Conceptual Reference Model Proposed by SGIP shows the conceptual model of Smart Grid proposed by SGIP' Architecture Committee (AC).

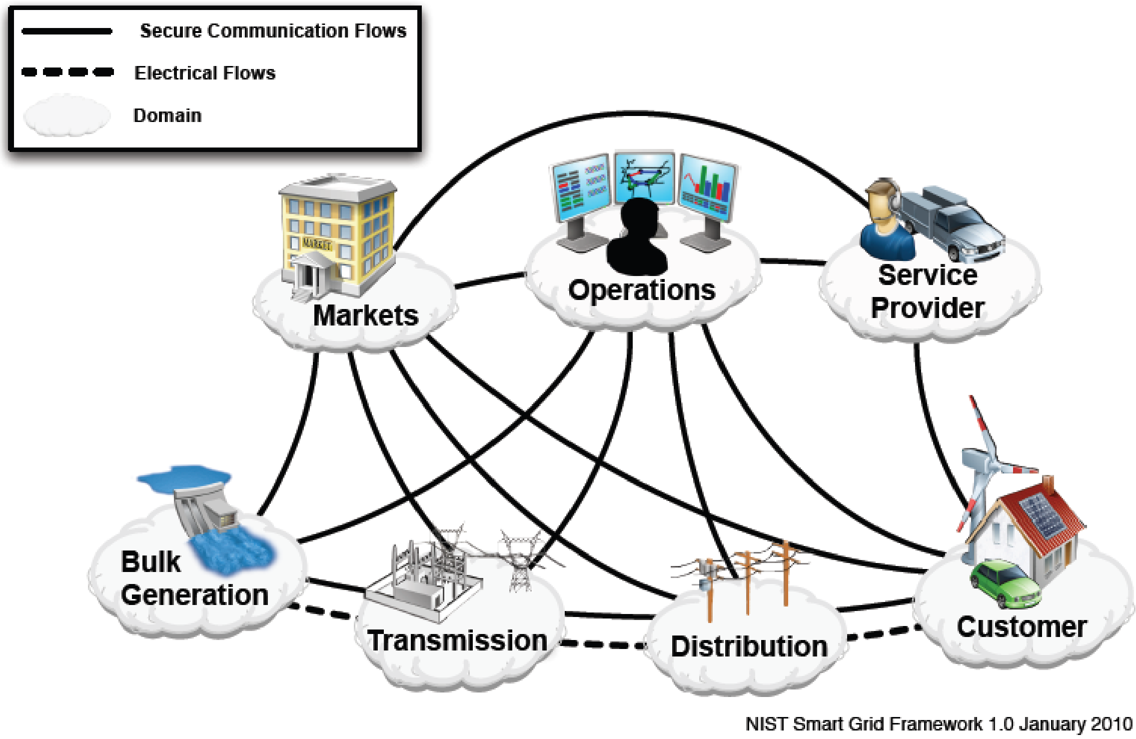


Figure 1.2 Conceptual Reference Model Proposed by SGIP AC

1.2.3 SGAC's Effort

The Smart Grid Architecture Committee (SGAC) SGAC is a part of the SGIP effort. Its main tasks are to define sources of industry policy and prior work that could impact Architectural Principles, and then to define a set of Smart Grid Architectural Principles that will provide guidance and help promote the interoperability and integrity of SG interfaces, and to Initiate Development/Adoption of Common Architecture Terminology. Current working parties of SGAC and their missions are:

- Semantic Model working party:
  - Define Charter and Approach of the Semantic Model Working Party
  - Identify existing Canonical Data Models (CDMs) and their SDOs
  - Establish a working relationship between the SGAC and each SDO owner of a Smart Grid CDM to assure that standards produced by SDOs collectively are going to achieve the semantic vision
  - Create a concept paper explaining the benefit of canonical data models to Smart Grid

- PAP Coordination working party:
  - Use conceptual model example architecture to map PAPs deliverables
  - Map PAPs against Grid Wise Architecture Committee (GWAC) stack
  - Perform Analysis to identify overlaps and gaps
  - Recommend opportunities for PAP convergence, creation, coordination or scope refinement to focus efforts and scope facilitating standards acceleration

- Cyber Security Architecture/CSWG Coordination working party:
  - Integrate the work of the NIST Cybersecurity working groups with the operations of the SGAC
  - Identify industry sources of security policy that have implications for SGIP SGAC requirements
  - Initiate defining management topics that are pertinent to managing SGAC infrastructure

1.2.4 EPRI's Effort

The Electric Power Research Institute (EPRI) assisted NIST in identifying issues and priorities for developing interoperability standards since 2009. To study the Smart Grid process definition and requirements development, a Use Case Repository has been built, which documented applications for customer service, distributed energy resources, distribution operations, federated system management functions, market operations and transmission operations [5].

The Smart Grid Use Case Repository is a public resource for the electric power industry to house Smart Grid related use cases as well as provide a forum for the industry to contribute to this effort by submitting their own use cases. Currently a total of 170 use cases are recorded in the repository, covering 6 categories of customer service, distributed energy resources, distribution operations, federated system management functions, market operations and transmission operations. This effort is now merged into the SGIP TWIKI under the Information Knowledge Center (IKB).

1.2.5 IEEE and IEC Work on Standardization

One of SGIP's tasks is to identify existing candidate Smart Grid standards for today, and identify standards requirements, gaps, and issues for future Smart Grid interoperability. SGIP is maintaining a "catalog of standards" [6]. The Catalog is a compendium of standards and best practices considered to be relevant for the development and deployment of a robust and interoperable Smart Grid. The Catalog may contain multiple entries that may accomplish the same goals and are functionally equivalent; similarly a single Catalog entry may contain optional elements that need not be included in all implementations. In general, compliance with a standard does not guarantee interoperability due to the above reasons. Though standards facilitate interoperability, they rarely, if ever, cover all levels of agreement and configuration required in practice.

Several standards have been identified by SGIP as existing "Smart Grid standards", a large portion of them are IEEE and IEC standards. In the mean time, IEEE and IEC are developing new Smart Grid standards. For example, the IEEE Power System Relaying Committee (PSRC) has working group C37.95 developing IEEE Guide for Protective Relaying of Utility-Consumer Interconnections that will take into account integration of renewables, and working groups C4 and C5 are developing standards for PDC requirements and testing, and PMU testing respectively. IEEE also has working group specialized in developing Smart Grid standards. The standards under development can be found in [7]. IEC has its own Smart Grid standardization roadmap, and the Strategy Group of SG3 provides advice on fast-moving ideas and technologies likely to form the basis for new International Standards or IEC TCs (Technical Committees) in the area of Smart Grid technologies [8].

1.3 Topics of research in Smart Grid

The ultimate goal of Smart Grid is to modernized electric power systems through developing and adopting new communication technologies. The joint effort of power engineers and communication engineers are needed. Following is a broad review of the on-going Smart Grid related research topics.

SG Solutions

The Smart Grid solutions refer to the studies that help utilities and customers to more effectively monitor and control energy use and costs. Substation automation, utility-level data management, home/business energy management are all examples of SG solutions.

Table 1.1 shows the Smart Grid solutions provides by some major companies.

Table 1.1 Smart Grid Solutions

Company	**Smart Grid Solutions**			
	Distribution	Transmission	Generation	Customer
Simens	Distribution Management Systems (DMS), Distribution automation and protection, Decentralized Energy Management System (DEMS), Smart Meter Solution	EMS, Substation Automation, Asset Monitoring, Communication Solutions, Blackout Prevention		Smart Building, Demand Response
ABB	Distribution Automation, Voltage/Var Control (VVC)	Protection, Substation Automation		Feeder automation, Substations, Distribution Energy Management Systems
SEL	Distribution Fault Locating, Power Quality Recording	Synchrophasors		Integrated Metering and Outage Management Systems
CISCO		Substation Automation, Asset Monitoring		Home Energy Management, Business Energy Management
IGS	Advanced Metering Management, Distribution Automation	EMS	Renewable Energy & Distributed Generation	Demand Response, Home Energy Management

Interoperability

EISA, which designates development of a Smart Grid as a national policy goal, specifies that the interoperability framework should be "flexible, uniform, and technology neutral." [2] The term "interoperability" refers to the capability of two or more networks, systems, devices, applications, or components to exchange and readily use information—securely, effectively, and with little or no inconvenience to the user. The Smart Grid will be a system of interoperable systems. That is, different systems will be able to exchange meaningful, actionable information. The systems will share a common meaning of the exchanged information, and this information will elicit agreed-upon types of response. The reliability, fidelity, and security of information exchanges between and among Smart Grid systems must achieve requisite performance levels [4]. Figure 1.3 GWAC Stack shows the layered interoperability categories according to the technical, informational and organizational groups. Referred to as the "GWAC stack," the eight layers comprise a vertical cross-section of the degrees of interoperation necessary to enable various interactions and transactions on the Smart Grid.

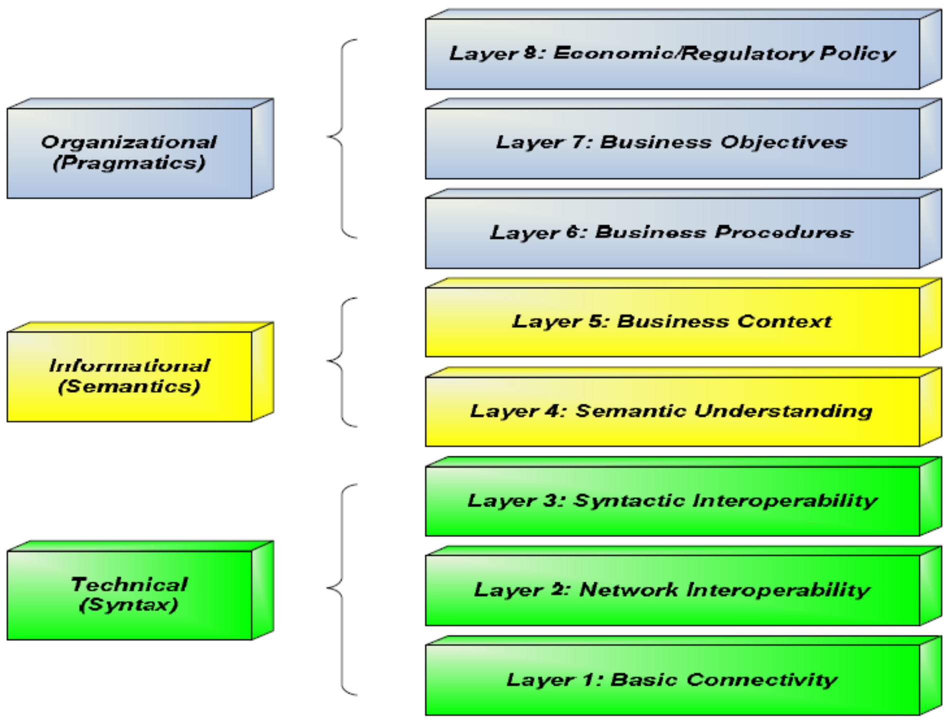


Figure 1.3 GWAC Stack

Cyber Security

Cyber security refers to protection of information and property from theft, corruption, malicious attacks, or natural disaster, while allowing the information and property to remain accessible and productive to its intended users. Since our modern society is exceedingly dependent on reliable electrical energy, it is essential to ensure the security of the Smart Grid against any cyber attacks. Study of cyber security includes development of cyber security strategies, policies for implementation, and methodology for assessing risks.

1.4 Conclusion

This section gives an introduction of the purpose of this project and a brief review of the state of art in the development of Smart Grid.

2 Communication Infrastructure

2.1 Introduction

This section introduces the background information for study of Smart Grid communication infrastructure.

2.2 Conceptual Reference Model

The conceptual model of Smart Grid Communication Network is adopted in our analysis of Smart Grid applications, which is further developed by the SGIP Smart Grid Architecture Committee (SGAC) [3]. Figure 2.1 Conceptual Reference Diagram for Smart Grid Information Networks [4] is a composite "box" diagram that combines attributes of the seven domain-specific diagrams proposed in [4]. Each domain—and its sub-domains—encompass Smart Grid *actors* and *applications*. Actors include devices, systems, or programs that make decisions and exchange information necessary for performing applications. Smart meters, solar (PV) generators, and control systems represent examples of devices and systems. Applications, on the other hand, are tasks performed by one or more actors within a domain. For example, corresponding applications may be home automation, solar energy generation and energy storage, and energy management. The diagram is a tool for identifying actors and possible communications paths in the Smart Grid, as well as a useful way for identifying potential intra- and inter-domain interactions and potential applications and capabilities enabled by these interactions.

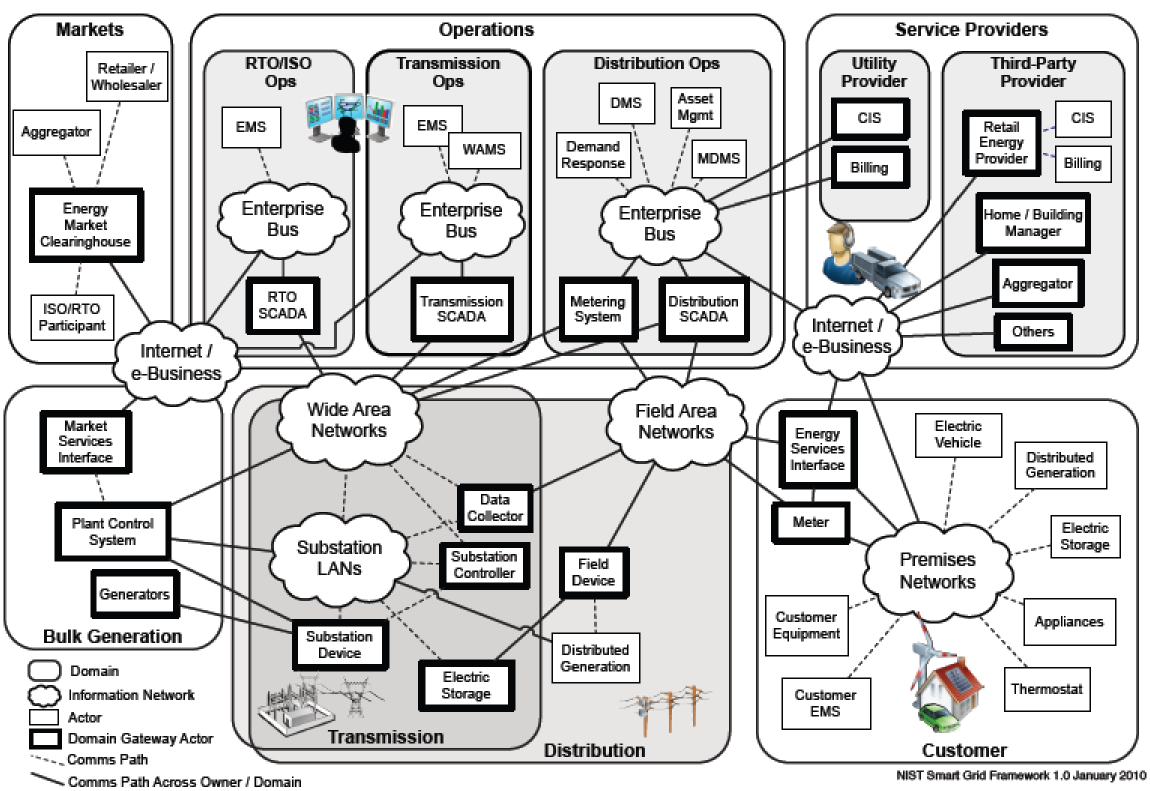


Figure 2.1 Conceptual Reference Diagram for Smart Grid Information Networks [4]

Our research is focusing on the transmission and distribution level applications, which involves the data exchange within and between the following domains: Transmission, Distribution, Operation and customer. The description of each domain and the actors is in Table 2.1 Description of Involved Domains.

Table 2.1 Description of Involved Domains

Domain	Description	Actors	Typical Applications
Operation	Actors in the Operations domain are responsible for the smooth operation of the power system. Today, the majority of these functions are the responsibility of a regulated utility. The Smart Grid will enable more to be outsourced to service providers; others may evolve over time. No matter how the Service Provider and Markets domains evolve, there will still be basic functions needed for planning and operating the service delivery points of a "wires" company.	Engineering department, control center, EMS, …	Network operations, monitoring, control, fault management, …
Transmission	Transmission is the bulk transfer of electrical power from generation sources to distribution through multiple substations. A transmission network is typically operated by a Regional Transmission Operator or Independent System Operator (RTO/ISO) whose primary responsibility is to maintain stability on the electric grid by balancing generation with load across the transmission network.	Remote terminal units, substation meters, protection relays, power quality monitors, phasor measurement units, sag monitors, fault recorders, and substation user interfaces, …	Substation Automation, system protection, control, maintenance, …
Distribution	The Distribution domain is the electrical interconnection between the Transmission domain, the Customer domain and the metering points for consumption, distributed storage, and distributed generation which may be arranged in a variety of structures, including radial, looped or meshed.	capacitor banks, sectionalizers, reclosers, protection relays, storage devices, and distributed generators, …	Outage management, asset management, measuring, …
Customer	The customer is ultimately the stakeholder that the entire grid was created to support. This is the domain where electricity is consumed. Actors in the Customer domain enable customers to manage their energy usage and generation as well as control and information flow between the customer and the other domains.		Building / Home Automation, Industrial Automation, Micro-generation, …

2.3 Generic Communication Architecture

Figure 2.1 Conceptual Reference Diagram for Smart Grid Information Networks [4] is a high-level vision for the information network for the Smart Grid proposed by SGAC [3]. The clouds represent the networks handling two-way communications between the network end points of seven different domains, as represented by rectangular boxes. Each domain is a unique distributed computing environment and may have its own sub-network to meet the special communication requirements for the domain. Within each network, a hierarchical structure consisting of network technologies, such as Home Area Networks, Personal Area Networks, Wireless Access Networks, Local Area Networks, and Wide Area Networks, may be implemented.

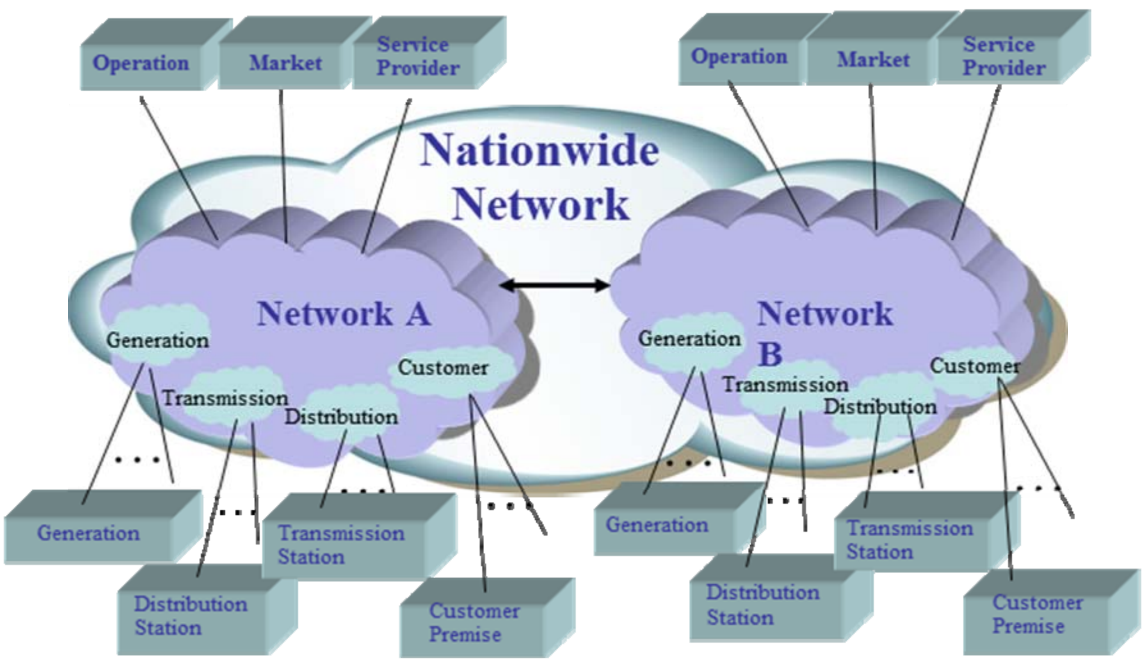


Figure 2.2 Generic Smart Grid Communication Network

2.4 Mapping Communication Infrastructure to SG applications

The implementation of SG applications requires a significant infusion of new measurements, and communications and control devices. A proper communication infrastructure should meet all the requirements of each of the selected applications while considering practical issues such as cost and life cycle. Focus on different aspects of communication solutions is needed: technical characteristics, cost, life cycle assessment, deployment strategy, standardization, interoperability, and utility performance impact.

Three steps are taken to establish a methodology to map applications to communication infrastructures: 1) In-depth evaluation for the application communications needs, which exposes any physical requirements such as speed of transmission, volume of data, error control and cybersecurity requirements, etc; 2) evaluation for overlaps in data and communications needs among the various applications, which allow the study of possible aggregation and the creation of common communication paths to Smart Grid applications to provide most of the data needed; 3) Selection of communication media, topology, bandwidth, and other features based on the overall requirement of the applications, which allows selection of proper design characteristics to meet the application requirements.

The communication requirements include:

- the amount of data to be transferred, how often, and at what speed
- whether the data needs to be transferred synchronously or asynchronously
- whether data flow is one-way or bidirectional
- what level of error control and cyber security is needed
- where on the grid, and on the communications infrastructure, the application is located.

2.5 Novelty of Our Work

The novelty of our work is the focus on the new applications, spanning from the distribution and customer levels to the transmission and market levels that can support the Smart Grid concept. Such applications present tremendous business and revenue possibilities for the industry, but require an adequate communication system to enable their development and deployment. Furthermore, this work focuses on the use of existing internet and other already-available communications systems to establish the least-cost integrated communications system for future Smart Grid development.

2.6 Conclusion

This section identifies SGIP's conceptual reference model and the definition of domains as the bases of our analysis. The focus of our research is the design and development of today's and the future communication infrastructure for fulfilling multiple transmission and distribution Smart Grid applications. The difference of our research from previous work is that new applications are studied which provides extra data and helps visioning the long-term strategies for communication.

Part II: Transmission Level Smart Grid Applications

3 New Applications of Interest

3.1 Introduction

This section discusses the new transmission level Smart Grid applications selected for this study. The applications are described in form of use cases. Actors, procedures and flow of data are given, followed by a discussion of the differences from existing applications and the benefits.

3.2 Selected Applications

Four applications are selected, covering transmission system operation, control, protection and maintenance. All the applications are proposed in recent studies but not yet been implemented. The applications are: Advance Alarm Processing, Automated Fault Location, Cascading Events Detection and Mitigation, and Condition based Maintenance of Circuit Breakers. Details of these applications are recorded as Use Cases provided in Appendix A.

Advanced Alarm Processing

As the power system get operated closer to the limits and operating conditions get more complex, operators are often overloaded with tremendous number of alarm messages generated by the events in the system. A major power system disturbance could trigger hundreds and sometimes thousands of individual alarms and events. Nowadays, many supervisory control and data acquisition (SCADA) systems have already employed Intelligent Alarm Processing (IAP) to assist system operators dealing with the overwhelming alarms. The Advanced Alarm Processing proposed in [9] outperforms other IAP methods with following pros:

- Reduces the number of alarms presented to the operator
- Conveys a clearer idea of the power system condition causing the alarms
- Recommends corrective action to the operator if such action is needed

Data and processing steps needed for this application can be found in Use Case 1 of Appendix 1. Figure 3.1 shows the implementation structure.

As it may be observed from Figure 3.1, the main advantage of the newly proposed Intelligent Alarm Processor comes from the use of additional data from substations coming from IEDs other than RTUs, and from additional data analytics aimed at determining cause-effect relationship between events in the power system and corresponding alarms.

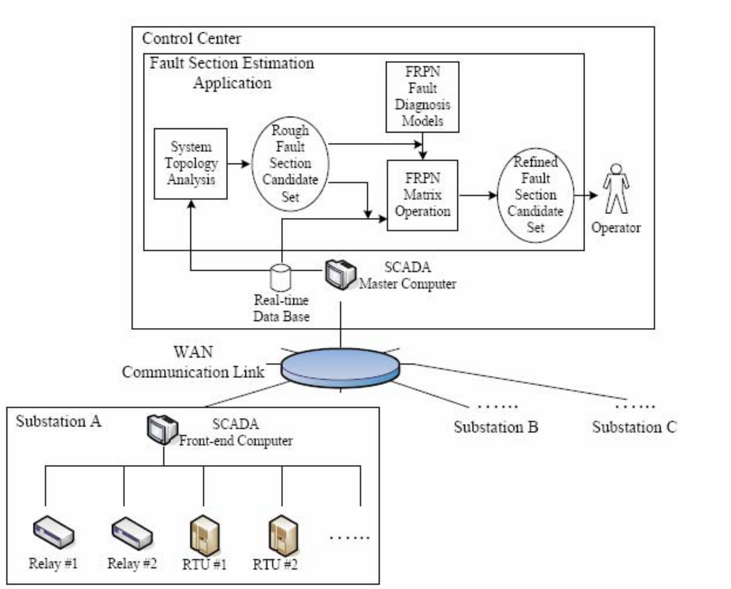


Figure 3.1 Implementation Structure of Advanced Alarm Processing

Automated Fault Location

Transmission line faults may be calculated either using power frequency components of voltage and current or higher frequency transients generated by the fault. The data requirements of different algorithms vary, so is the accuracy of their results. An optimal fault location approach which will select the most appropriate fault location algorithm depending on the availability and location of the data measured is proposed in [10]. The Automated fault location will select the best result among the following algorithms using the flowchart shown in Figure 3.2.

- Single-End Method [11]
- Double-End Methods [12-13]
- Sparse Measurement Method [14]

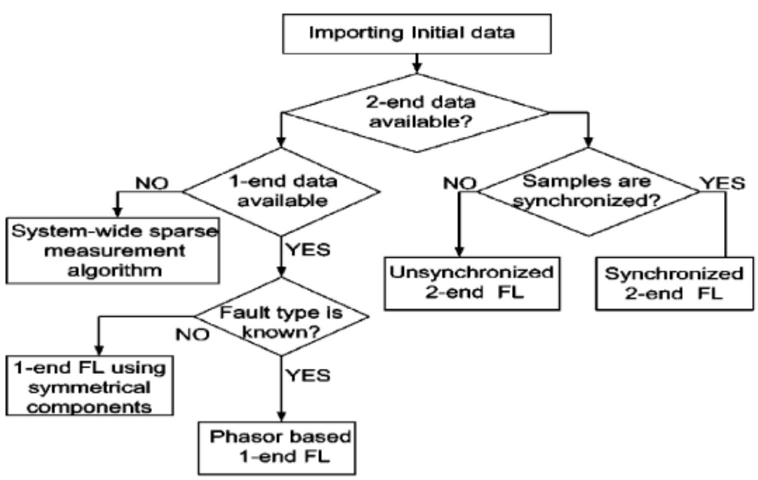


Figure 3.2 Flowchart of Automated Fault Location

Figure 3.3 shows the basic architecture of the automated fault location method. Description of data and processing steps are recorded in Use Case 2 of Appendix 1.

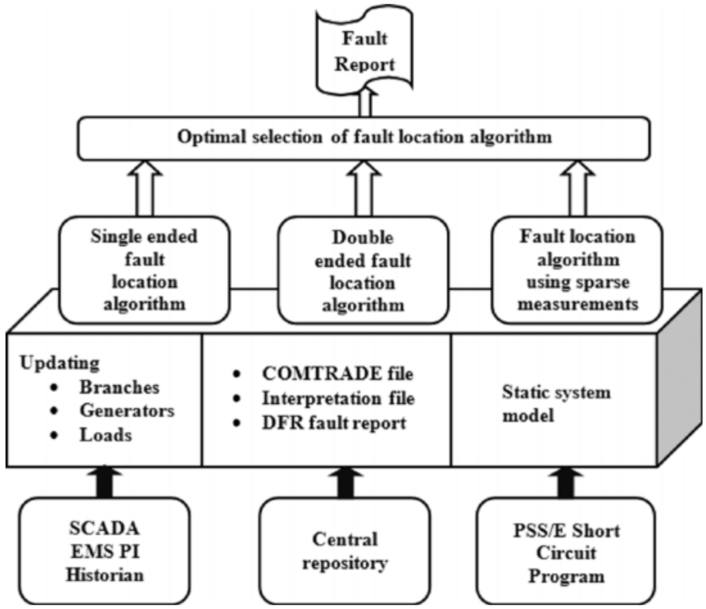


Figure 3.3 Architecture of Optimized Fault Location Algorithm

The main advantage of this approach when compared to any of the earlier proposed approaches is that it matches the selection of the algorithms to the best data available in a given system, and because of that the results are bound to be the most accurate and reliable.

Cascading Events Detection and Mitigation

The selected application for detecting and mitigating cascading events is proposed in [15].The system tool consists of the routine and event-based security analyses based on the power flow method and topology processing method, along with the security control schemes for expected and unexpected events. Framework for information exchange is shown in Figure 3.4. Description of data and processing steps are recorded in Use Case 3 of Appendix 1.

The advantage of this approach over any other existing approaches is that it is able to detect and mitigate cascading events as they unfold because the algorithm uses real-time data for on-line determination of the state of the power systems and its components and informs operator about any changes that are not detectable through SCADA.

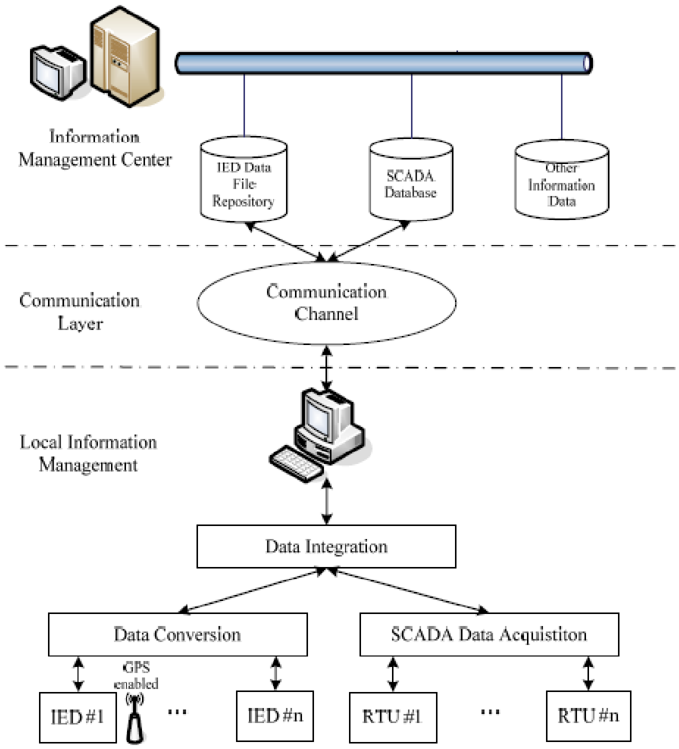


Figure 3.4 Framework of Information Exchange

Condition Based Circuit Breaker Maintenance

[16] proposed a system level maintenance strategy for circuit breakers based on probabilistic maintenance models. This method uses a 'bottom-up' approach and utilizes historical data and real-time condition based monitoring data in estimating failure rate. Description of data and processing steps are recorded in Use Case 4 of Appendix A.

Use Case 5 in Appendix A is the communication between substation and IEDs. This is not an application but rather a data collection function that serves the need of system level applications.

3.3 Summary of Actors

Table 3.1is a summary of the key Actors from the use cases discussed in this section and the domains they participate in.

Table 3.1 Actors

Actor	Domains	Description
IEDs	Transmission	A microprocessor-based device aimed at controlling and monitoring power system equipment and communicating with SCADA, as well as distributed intelligence applications for automatic operation.
Substation application	Transmission	Substation is a point in transmission and distribution system where voltage is transformed from high to low or the reverse using transformers. Electric power may flow through several substations between generating plant and consumer, and the voltage level may be chnaged in several steps. Substation application runs on a substation computer.
SCADA	Operations	A computer system that monitors and controls power system operations. SCADA database is updated via remote terminal units (RTUs) monitoring field inputs. Required scope, speed, and accuracy of real-time measurements are provided, supervisory and closed-loop control is supported.
Wide Area Monitoring and Control System	Operations	Measurements from phasor measurement units located in substations across a wide area of power systems and determining actions to perform with transmission actuators.
Metering System	Customer	The systems used for collecting revenue and operator metering information.
GIS	Operations	An information system that integrates, stores, edits, analyzes, shares, and displays geographic information.
Power System Control Center	Operations	Center for Power system central control operations.
EMS	Operations	Computer-aided tools used by operators in electric utility grids to monitor, control, and optimize the performance of the generation and/or transmission system. EMS also provides input to DMS with transmission/generation-related objectives, constraints, and input data from other EMS applications.

3.4 The Difference from Existing Applications and the Benefits

The selected applications have not been adopted by transmission utilities yet since they have been recently proposed. However, all the applications provide opportunity for distinct performance improvements and associated cost savings. Alarm processing and cascading analysis are newly introduced to deal with complicated fault situation and chain-reaction faults that cannot be easily detected and mitigated today. The fault location method yields more accurate results than existing methods, and the condition-based maintenance saves investment and labor when compared with the widely-adopted scheduled maintenance. These applications require data that is not collected only by SCADA system, which brings new challenge to SG communication.

3.5 Conclusion

This section discusses the concept, actors and processing steps of Advanced Alarm Processing, Automated Fault Location, Detection and Mitigation of Cascading Events, and Condition-Based Maintenance of Circuit Breakers. The selected application are new and differ from the ones recorded in EPRI use cases repository [5] or SGIP IKB Use Cases [17] in both the data needed and the performance required. Studying communication infrastructure for supporting these applications sheds light on what future communications requirements should look like.

4 Communication Requirements

4.1 Introduction

This section discusses the communication requirements related to the selected transmission level applications.

4.2 Data Flow Map

The flows of data are listed in Table 4.1 Flows of Data. Data is categorized into four classes: 1) raw data, 2) pre-processed data from substation 3) reports and 4) historical data. Raw data is the data collected by SCADA without pre-processing at substation level, and data collected by substation IEDs before sending to it centralized system. The raw data is not directly utilized in applications other than for archiving. Substation massage contains information about CB Status, Power Flow measurements, DFR event reports, alarms, relay operation reports, synchronized samples, real-time load and connectivity information. Reports refer to the analysis reports generated by different applications and exchanged among various users in the control center. Historical data is retrieved from the database and used in some of the algorithms for optimized fault location.

Table 4.1 Flows of Data

NO	Data	From	To	Class	Estimated Data Volume	Requirements
1	CB Status	Substation	Alarm Processing	2	10Kb	Real-Time
2	Over Current Alarm	Substation	Alarm Processing	2	10Kb	Real-Time
3	Relay Operation Report	Substation	Alarm Processing	2	10Kb	Real-Time
4	Power Flow Data	Substation	Fault Location	2	100Kb	Real-Time
5	Historian	Database	Fault Location	4	100Kb-1Mb	Offline
6	Event files	Substation	Fault Location	2	100Kb	Real-Time
7	System Info.	Substation	Fault Location	2	100Kb	Real-Time
8	Request	Fault Location	Database	--	10Kb	--
9	Synchronized Samples	Substation	Cascading Analysis	2	100Kb	Synchronization
10	Power Flow Data	Substation	Cascading Analysis	2	100Kb	Real-Time
11	System Information	Substation	Cascading Analysis	2	100Kb	Real-Time
12	Event files	Substation	Cascading Analysis	2	100Kb	Real-Time

Table 4.1 (cont.) Flows of Data

13	Alarm report	Alarm Processing	Fault Location	3	100Kb	--
14	Alarm Report	Alarm Processing	Cascading Analysis	3	100Kb	--
15	Alarm Report	Alarm Processing	Visualization Unit	3	100Kb	--
16	Fault Location Report	Fault Location	Visualization Unit	3	100Kb	--
17	Cascading Report	Cascading	Visualization Unit	3	100Kb	--
18	Raw Data	Substation	Database	1	1Mb	--
19	Condition information	Substation	Maintenance	2	10Kb	Real-Time
20	Request	Maintenance	Substation	--	10Kb	--
21	Over Current Alarm	DPRs	Substation	2	10Kb	Real-Time
22	Relay Operation Report	DPRs	Substation	3	10Kb	Real-Time
23	Power Flow Data	Smart Meters	Substation	1	100Kb	Real-Time
24	Power Flow Data	RTUs	Substation	1	100Kb	Real-Time
25	Power Flow Data	PQ meters	Substation	1	100Kb	Real-Time
26	Event files	DFRs	Substation	1	100Kb	Real-Time
27	System Info.	RTUs	Substation	1	100Kb	Real-Time
28	Synchronized Samples	PMUs	Substation	1	100Kb	Synchronization
29	Condition information	CBM/TM devices	Substation	1	10Kb	Real-Time
30	Request	Substation	IEDs	--	10Kb	--
31	Request	Substation	CBM/TM devices	--	10Kb	--

Figure 4.1 is a diagram of the communication paths. Arrows represent the direction of the data flow, and the numbers on the paths are consistent with the numbering of data in Table 4.1.

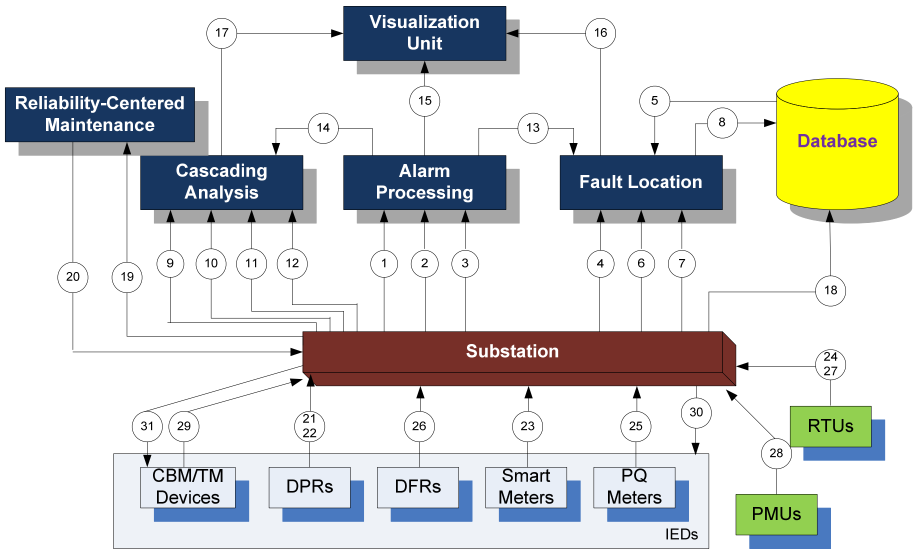


Figure 4.1 Communication Path

4.3 Communication Requirements

Among the four applications, cascading event analysis is the one that has the most critical requirement on communication latency. As cascading events develop very fast (often in minutes, sometimes in seconds) and the consequence is extremely severe, the speed for cascading analysis execution must beat the speed of system deterioration. This means that the total time from data being collected from different sensors to system operators receiving report from cascading analysis software must be less than a few minutes, otherwise cascading analysis would become meaningless.

Cascading analysis is activated by detection of cascading events, which is done by alarm processing, and results from alarm processing serve as part of the input for cascading event analysis, making alarm processing also time-critical.

Fault location has a more relaxed requirement on time, while communication for reliability-centered maintenance is the least time-critical.

Following is a generalized description of communication requirements of the various paths:

Between substations and among IEDs: Data is transmitted in broadcast-subscription mode. Requirement on data rate varies from several kbps to several Mbps, depending on features of IEDs.

Between control center and substation: data is transmitted in point-to-point mode. Requirement on data rate is several Mbps.

Between different applications in control center: data is transmitted in point-to-point mode. Requirement on data rate is several Mbps to several Gbps to deal with the large volume of data.

4.4 Challenges in existing communication infrastructure

Bandwidth

Most of the communications networks being deployed for the Smart Grid today are based on lower-bandwidth, lower-cost technologies. As new data is been collected and transferred to control center, extra bandwidth is needed to accommodate the large volume of IED data. For example bandwidth over 100Mbyte/sec is most likely to be the lower boundary with the upper boundary reaching 1Gbyte/sec.

Latency

As some of the selected applications are implemented to support system control and operation, latency becomes the most important issue in the data transfer, which is decided by the transfer rate and the number of switches the data passes. The most stringent requirement for the latency comes from the cascading event detection where the data may have to be transferred to the control center and an automatic command issued within a few milliseconds.

Data compression

Data integration is one solution to improve the efficiency of data flow and hence reduce latency. For the events that do not show much change in the waveforms or measurements. Data compression may be used to facilitate timely transfer of information.

Congestion management

Congestion management is another solution to reduce latency under the condition of heavy traffic. Data classification and prioritized communication channel are the key issue in congestion management since special high priority data transfer may be implemented for emergency situations.

4.5 Conclusion

This section addressed the concerns in communication. The flow map reveals the sender and receiver of data for the selected applications. Data are categorized and requirement for each of the data flow is discussed. The new applications bring new challenges to Smart Grid communication in the volume and speed of transmission. Designing a new communication infrastructure is discussed in the next section through a case study.

5 Communication Case Study

5.1 Introduction

This section discusses issues in designing communication infrastructure: the architecture, topology, communication media and protocols. Architecture that fits the applications in our research is also identified.

5.2 Layers of Transmission Communication

Figure 5.1 shows real-time information architecture. The communication system is shown as a multilevel hierarchy. Each substation has its own high speed local area network (LAN) which ties all the measurements and local applications together. Each substation also has a server that connects to the higher level communication network through a router. Thus all applications that require data from more than one substation, i.e. applications that are not local, have to use this higher level network for gathering input and sending output [18].

The applications in our research are all centralized solutions, i.e. data is transmitted to control center, where the applications are executed. Together with the control center level communication, there are four layers in total: inter-substation, intra-substation, substation-to-control center, and inter-control center.

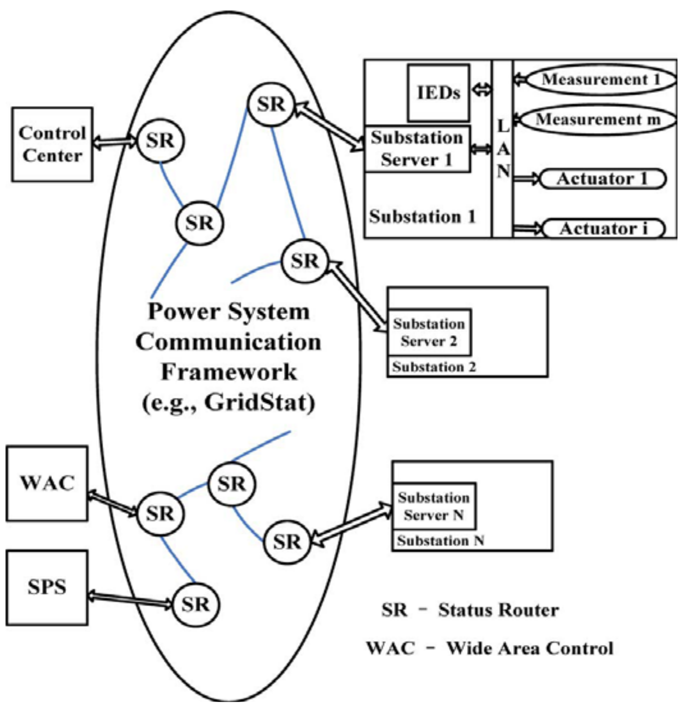


Figure 5.1 Generic Transmission Communication Architecture

Intra-substation Communication

Substation level communication includes communication between bay level and process level, and process level and substation level. Bays are defined as closely connected subparts of the substation with some common functionality. Examples are the switchgear between an incoming or outgoing line and the busbar, the buscoupler with its circuit breaker and related isolators and earthing switches, the transformer with its related switchgear between the two busbars representing the two voltage levels, etc. Process level is a virtual control level where all data processing and decision making functions within substation are interfacing to the process (switchyard), i.e. binary and analogue signal I/O functions such as data acquisition (including sampling) and issuing of commands. Substation level is where functions involving primary equipment of more than one bay or complete substation are placed. Human Machine Interface (HMI) and Interface with an outer network is also at the substation level [19].

Report generation and preprocessing may be done either at substation or at control center level. In the case of preprocessing at substation level (Figure 5.2), all IED data are automatically collected to centralized repository. The time range between different timestamps is checked and if it is less than 5ms and other parameters in the file name are the same it is concluded that all files corresponds to the same event. Those data are than stored to the IED database at the substation site. Simultaneously, IED data are analyzed by applications implemented for each type of device and results are stored into the IED database. Using that information, report for protection engineers and information of interests for applications at control center level are extracted and stored into database. Applications at control center level constantly monitor new data availability and after database is being updated with new files, those data are retrieved and merged with SCADA data by the applications. This kind of processing is suitable for utilities with limited communication infrastructure between substation and control center because size of the data that have to be transferred to control center level is drastically decreased by preprocessing at substation level.

In the case of preprocessing at control center level (Figure 5.3), only data validation is done at substation PC and all data are sent to control center location where further processing is done. This solution of processing at the control center level is appropriate for utility that has good communication infrastructure between substation and control center and where security policy forbids storing and processing data outside the control center location.

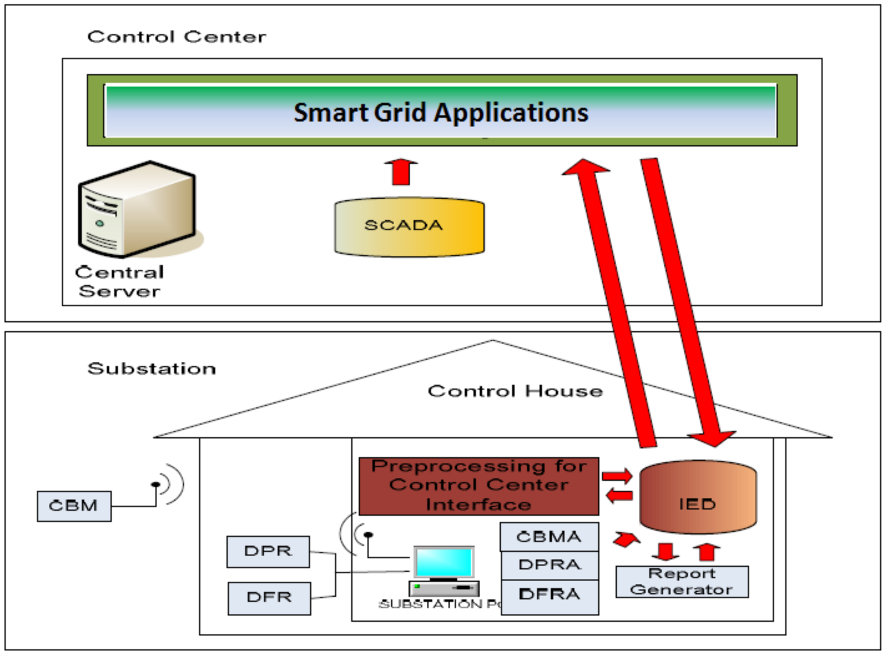


Figure 5.2 Data Preprocessing at Substation Level

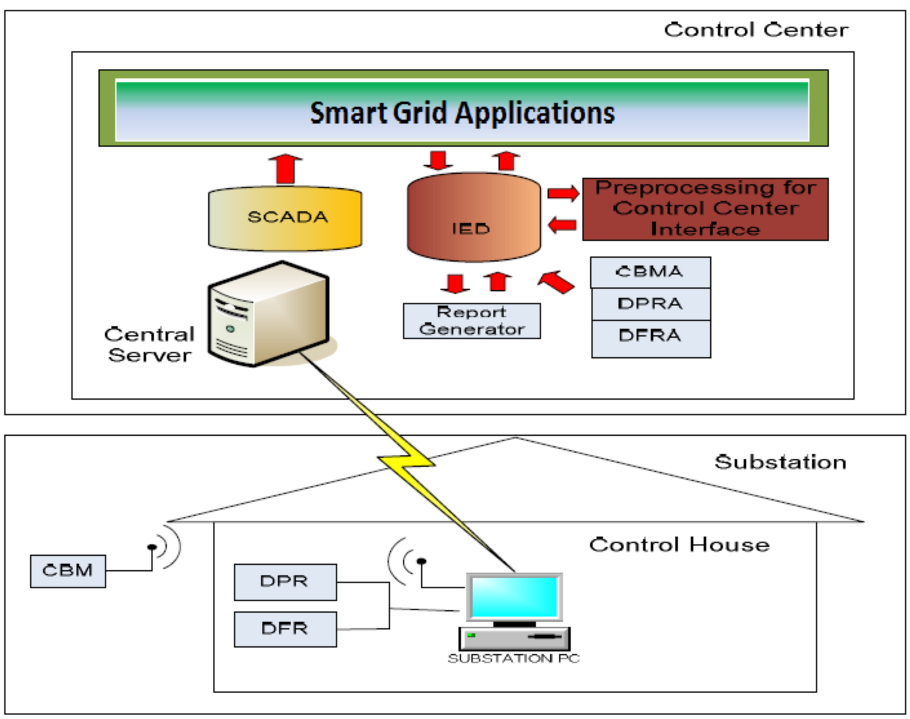


Figure 5.3 Data Preprocess at Control Center Level

Inter-substation and Substation-to-utility Communication

The inter-substation and substation-to-control center communication refer to the exchange of data for system-wide monitoring, protection and control (WAMPAC)applications such as voltage stability control, state estimation, and system integrity protection schemes.

Enterprise level communication

Enterprise level communication refers to the transmission of data to and exchange of information between different departments and personnel groups, as well as for visualization and HMI for system operators and engineers. Typically a private Ethernet based LAN is utilized for the enterprise level communication.

5.3 Communication Protocols and Standards

Table 5.1 lists all the standards concerned with communication for the selected applications. The standards cover data exchange, communication protocol and interface, and cyber security. Comparing this list with SGIP's list of identified Smart Grid Standards, one will find that some new standards are identified (the ones that are not checked at the last column). These standards are marked in a communication map as is shown in Figure 5.4. The SGIP standards are marked in red, the newly identified standards are in blue.

Table 5.1 Identified Standards

Standard	Description	Category	SGIP's list
IEC 61970	Common Information Model (CIM) necessary for exchange of data between devices and networks, primarily in the transmission domain. Information exchanged among control centers using CIM for application-level energy management system interfaces is also defined.	device - network	√
IEC 60870-6	Inter-Control Center Communications Protocol	control center-to- control center	√
IEC 60870 -5-10x (-5-104)	IEC 60870-5-101/102/103/104 are companion standards generated for basic telecontrol tasks, transmission of integrated totals, data exchange from protection equipment & network access of IEC101 respectively. -5-104 in particular is suitable for communication between control center and substation via a standard TCP/IP network.	Substation – control center	
IEEE C37.118	This standard defines the transmission format for reporting synchronized phasor measurements in power systems	PMU	√
IEEE C37.232	IEEE Recommended Practice for Naming Time Sequence Data Files. It provides a procedure for naming time sequence data (TSD) files, such as files produced by digital fault recorders, power swing recorders, power quality monitors, and so on is recommended. The sources of TSD files are described, and a survey of current naming techniques is provided.	substation	

Table 5.1 (cont.)

IEC 61850	A standard for the design of electrical substation automation system. The abstract data models defined in IEC 61850 can be mapped to a number of protocols. Current mappings in the standard are to MMS (Manufacturing Message Specification), GOOSE, SMV, and soon to Web Services. These protocols can run over TCP/IP networks and/or substation LANs using high speed switched Ethernet to obtain the necessary response times of < 4 ms for protective relaying uses.	Substation	√
IEEE 1588	Standard for time management and clock synchronization across the equipment needing consistent time management. Particularly the IEEE standard 37.238, which is the profile for power system applications	PMU	√
IEEE 1686	This standard defines the functions and features to be provided in substation Intelligent Electronic Devices to accommodate critical infrastructure protection programs.	Cyber security	√
IEC 62351	This standard defines handling the security of TC 57 series of protocols including IEC 60870-5 series, IEC 60870-6 series, IEC 61850 series, IEC 61970 series & IEC 61968 series.	Cyber security	√
IETF RFC 2460 (IPv6), IETF RFC 791 (IPv4)	These suites of standards define foundation protocol for delivery of packets in the Internet network.IPv6 is new version of the Internet Protocol that provides enhancements to IPv4 and allows a larger address space.	Internet network	√
IEEE P1525	Standard for Substation Integrated Protection, Control, and Data Acquisition Communications. Defines standard communication requirements, specifies message delivery time between intelligent electronic devices, and Abstract Syntax Notation (ASN) .1 data structures of information to be exchanged for substation integrated protection, control, and data acquisition.	Substation	
IEEE C37.111	Common Format for Transient Data Exchange (COMTRADE) for Power Systems. A common format for data files and exchange medium used for the interchange of various types of fault, test, or simulation data for electrical power systems transient events is defined.	Substation	
IEEE C37.239	IEEE Standard for Common Format for Event Data Exchange (COMFEDE) for Power Systems. A common format for data files used for the interchange of various types of event data collected from electrical power systems or power system models is defined.	substation	

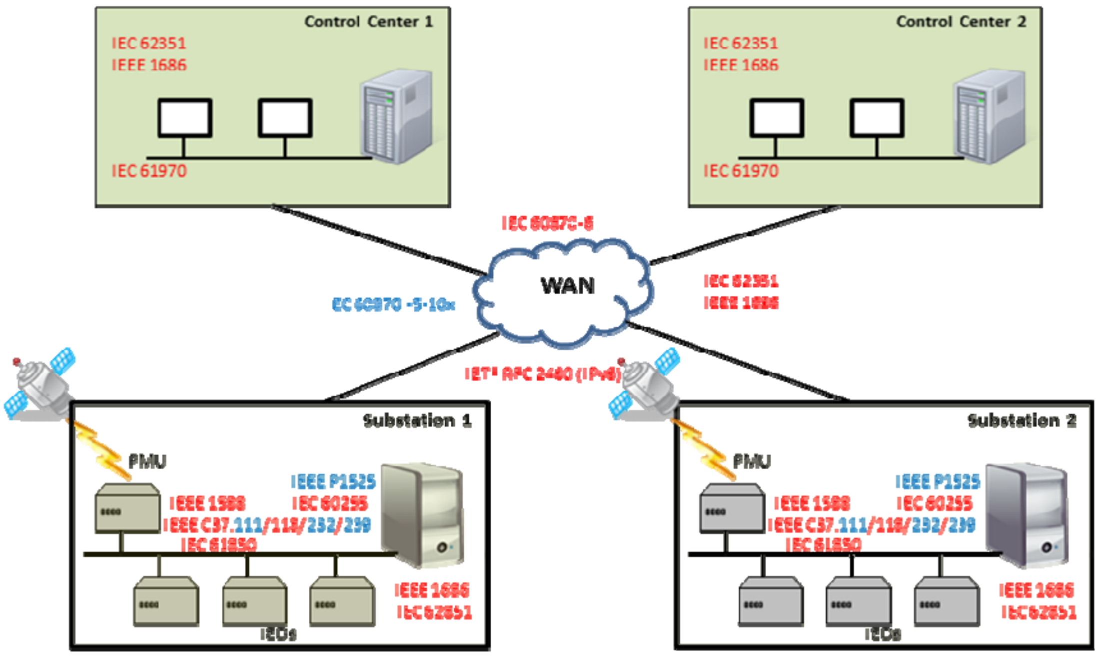


Figure 5.4 Identified Standards

5.4 Communication Media

5.4.1 Power Line Carrier (PLC) Communication

Power line Carrier is used in transmission, distribution and to reach customer premises. All power line communications systems operate by impressing a modulated carrier signal on the wiring system. Currently power line carrier communication is applied for local area network, home control, radio program transmission and other areas. Figure 5.5 shows a PLC implementation.

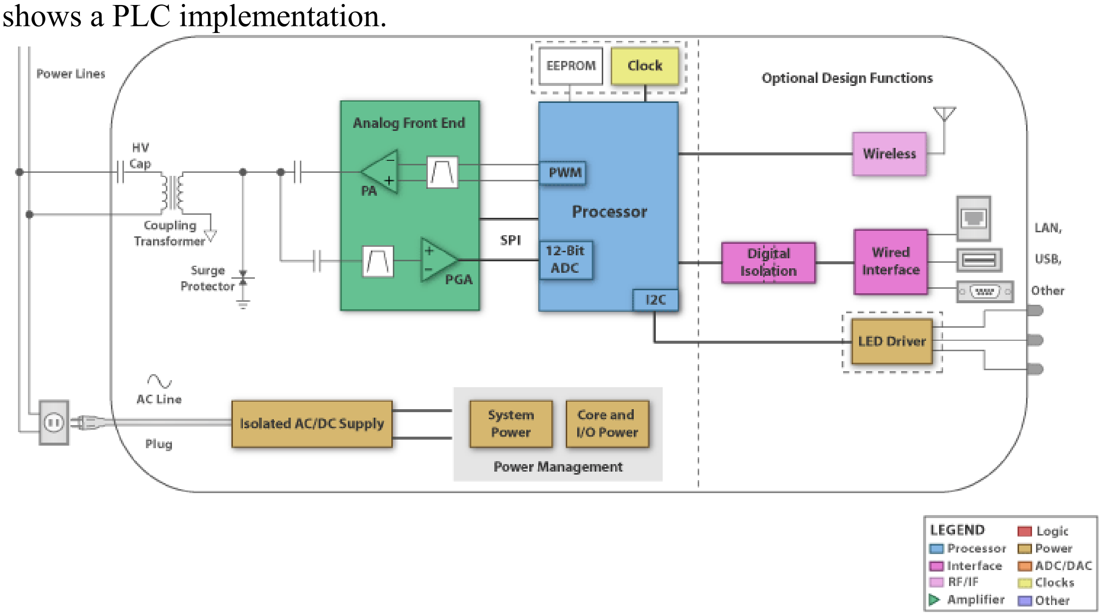


Figure 5.5 PLC Implementation

Different types of power line carrier communications use different frequency bands, depending on the signal transmission characteristics of the power wiring used. Since the power wiring system was originally intended for transmission of AC power, in conventional use, the power wire circuits have only a limited ability to carry higher frequencies. The propagation problem is a limiting factor for each type of power line carrier communications.

Data rates over a power line carrier communication system vary widely. Low-frequency (about 100-200 kHz) carriers impressed on high-voltage transmission lines may carry one or two analog voice circuits, or telemetry and control circuits with an equivalent data rate of a few hundred bits per second; however, these circuits may be many miles long. Higher data rates generally imply shorter ranges; a local area network operating at millions of bits per second may only cover one floor of an office building, but eliminates installation of dedicated network cabling.

Low frequency (<kHz) power line carrier systems have been used by many utilities for multiple applications, such as automatic meter reading, load control and demand response. The bit rate ranges from 50 Kbps to 350 Kbps. For transmission-level applications, the transmission rate may not meet the requirement of real-time monitoring and control operations, especially when large volume of data needs to be transmitted. However, it is applicable for applications that don't require fast-response, such as condition-based maintenance.

Pros and Cons

Pros: The investment in PLC is very low due to lower installation cost

Cons: The quality of communication is affected by the condition of the carrier; when faults occur on a power line or downstream on the line, part of the communication may be lost; security level is low; interference issue is not negligible.

5.4.2 Copper Wire (Network Cables)

Copper wire is the most common media for Internet and Ethernet (Figure 5.6). Category 5 cable includes 4 twisted pairs in a single cable jacket. This use of balanced lines helps preserve a high signal-to-noise ratio despite interference from both external sources and other twisted pairs often called "crosstalk". It is most commonly used for 100 Mbit/s networks, such as 100BASE-TX Ethernet, although IEEE 802.3ab defines standards for 1000BASE-T – Gigabit Ethernet over category 5 cable. Each of the four pairs in a Cat 5 cable has differing precise number of twists per meter based on prime numbers to minimize crosstalk between the pairs. On average there are 6 twists per 5 centimeters. The pairs are made from 24 gauge (AWG) copper wires within the cables.

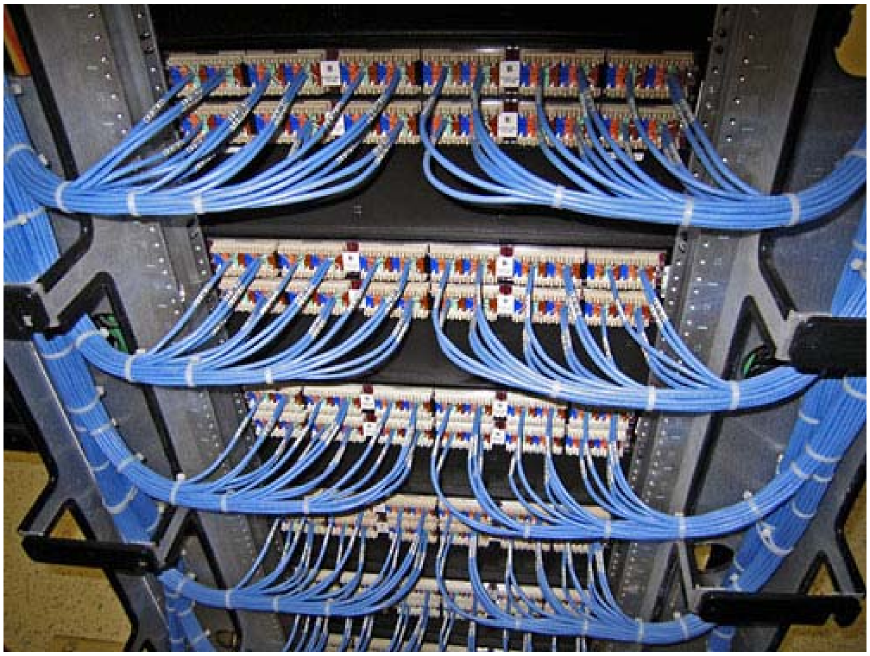


Figure 5.6 Network Cables

Category 6 cable, commonly referred to as Cat-6, is a cable standard for Gigabit Ethernet and other network protocols that are backward compatible with the Category 5/5e and Category 3 cable standards. Compared with Cat-5 and Cat-5e, Cat-6 features more stringent specifications for crosstalk and system noise. The cable standard provides performance of up to 250 MHz and is suitable for 10BASE-T, 100BASE-TX (Fast Ethernet), 1000BASE-T / 1000BASE-TX (Gigabit Ethernet) and 10GBASE-T (10-Gigabit Ethernet). Category 6 cable has a reduced maximum length when used for 10GBASE-T; Category 6a cable, or Augmented Category 6, is characterized to 500 MHz and has improved alien crosstalk characteristics, allowing 10GBASE-T to be run for the same distance as previous protocols. Category 6 cable can be identified by the printing on the side of the cable sheath.

<u>Pros and Cons</u>
Pros: transmission rate is fast; Security level is high; low loss.

Cons: high investment required.

5.4.3 Fiber Optic Cable

Fiber-optic communication is a method of transmitting information from one place to another by sending pulses of light through an optical fiber. The light forms an electromagnetic carrier wave that is modulated to carry information. First developed in the 1970s, fiber-optic communication systems have revolutionized the telecommunications industry and have played a major role in the advent of the Information Age. Because of its advantages over traditional transmission, optical fibers have largely replaced copper wire communications in core networks in the developed world. Figure 5.7 shows the components of a fiber optic cable.

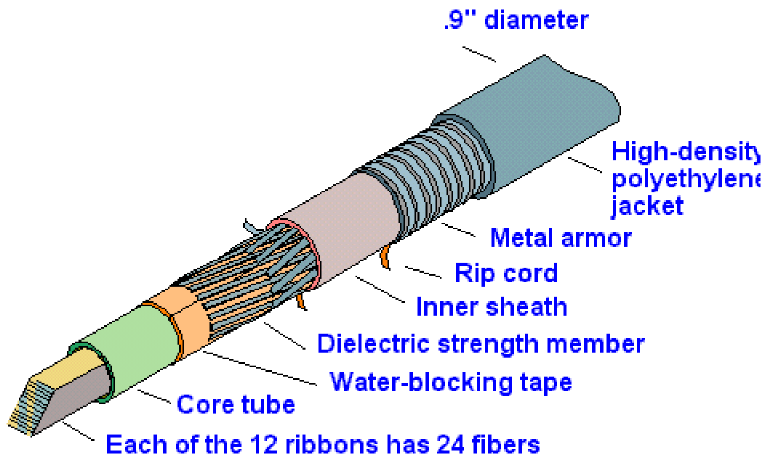


Figure 5.7 Fiber Optic Cable

The process of communicating using fiber-optics involves the following basic steps: Creating the optical signal involving the use of a transmitter, sending the signal along the fiber, ensuring that the signal does not become too distorted or weak, receiving the optical signal, and converting it into an electrical signal.

The transmission distance of a fiber-optic communication system has traditionally been limited by fiber attenuation and by fiber distortion. By using opto-electronic repeaters, these problems have been eliminated. These repeaters convert the signal into an electrical signal, and then use a transmitter to send the signal again at a higher intensity than it was before. Because of the high complexity with modern wavelength-division multiplexed signals (including the fact that they had to be installed about once every 20 km), the cost of these repeaters is very high.

An alternative approach is to use an optical amplifier, which amplifies the optical signal directly without having to convert the signal into the electrical domain. It is made by doping a length of fiber with the rare-earth mineral erbium, and pumping it with light from a laser with a shorter wavelength than the communications signal (typically 980 nm). Amplifiers have largely replaced repeaters in new installations.

Because the effect of dispersion increases with the length of the fiber, a fiber transmission system is often characterized by its bandwidth-distance product, often expressed in units of MHz×km. This value is a product of bandwidth and distance because there is a tradeoff between the bandwidth of the signal and the distance it can be carried. For example, a common multimode fiber with bandwidth-distance product of 500 MHz×km could carry a 500 MHz signal for 1 km or a 1000 MHz signal for 0.5 km.

Pros and Cons

Pros: Bandwidth capacity is greater; reliability of signal is higher.

Cons: sensitive to environment temperature; cost is higher; very good for limited distance.

5.4.4 Wireless

Wireless communication is the transfer of information over a distance without the use of electrical conductors. It encompasses various types of fixed, mobile, and portable two-way radios, cellular telephones, personal digital assistants (PDAs), and wireless networking. It permits services, such as long range communications, that are impossible or impractical to implement with the use of wires. Wireless communication can be via: radio frequency communication, microwave communication, or infrared (IR) short-range communication. Applications may involve point-to-point communication, point-to-multipoint communication, broadcasting, cellular networks and other wireless networks.

Wireless Wide Area Networks typically cover large outdoor areas. These networks can be used to connect branch offices of business or as a public Internet access system. They are usually deployed on the 2.4 GHz band.

Pros and Cons

Pros: very useful for communication over vast area.

Cons: comparatively slow; security level is low; has “multipath effect” that affects the reception strength.

The characteristics of each of the communication media are summarized in Table 5.2.

Table 5.2 Comparison of Communication Media

Media	Max Coverage (without repeaters)	Max Data rate	Security	QoS*	Cost	Field of application
Power line carrier	300m	45Mbps	Low	Low	Low	Between substations
Copper Wire	100m	Several Gbps	High	Relatively high	Relatively high	Between substation and utilities; within utility
Fiber Optics	--	160Gbps	High	High	High	Within substation and between substations
Wireless	50m	54Mpbs (but real-application data rate is lower)	low	Relatively low	Relatively high	Between substations; substations and utilities

* QoS; Quality of Service

5.5 Ethernet Based Network Topology

Some of the basic topologies that have the potential to be implemented in a transmission-level communication network include: bus, star, ring and hybrid.

5.5.1 Bus Topology

In a network where bus topology is used, each node is connected to a single cable. Each computer or server is connected to the single bus cable. A signal from the source travels in both directions to all machines connected on the bus cable until it finds the intended recipient. If the machine address does not match the intended address for the data, the machine ignores the data. Alternatively, if the data does match the machine address, the data is accepted.

Since the bus topology consists of only one wire, it is rather inexpensive to implement when compared to other topologies. However, the low cost of implementing the technology is offset by the high cost of managing the network. Additionally, since only one cable is utilized, it can be the single point of failure. If the network cable breaks, the entire network will be down.

5.5.2 Star Topology

In a network with a star topology, each network host is connected to a central hub with a point-to-point connection. All traffic that traverses the network passes through the central hub. The hub acts as a signal repeater. The star topology is considered the easiest topology to design and implement. An advantage of the star topology is the simplicity of adding additional nodes. The primary disadvantage of the star topology is that the hub represents a single point of failure. Star topology is widely utilized in various communication architectures.

5.5.3 Ring Topology

A network topology that is set up in a circular fashion in which data travels around the ring in one direction and each device on the right acts as a repeater to keep the signal strong as it travels. Each device incorporates a receiver for the incoming signal and a transmitter to send the data on to the next device in the ring. The network is dependent on the ability of the signal to travel around the ring.

The ring and star topologies are the most common topologies for substation communication networks ([20], Figures 5.9 and 5.10).

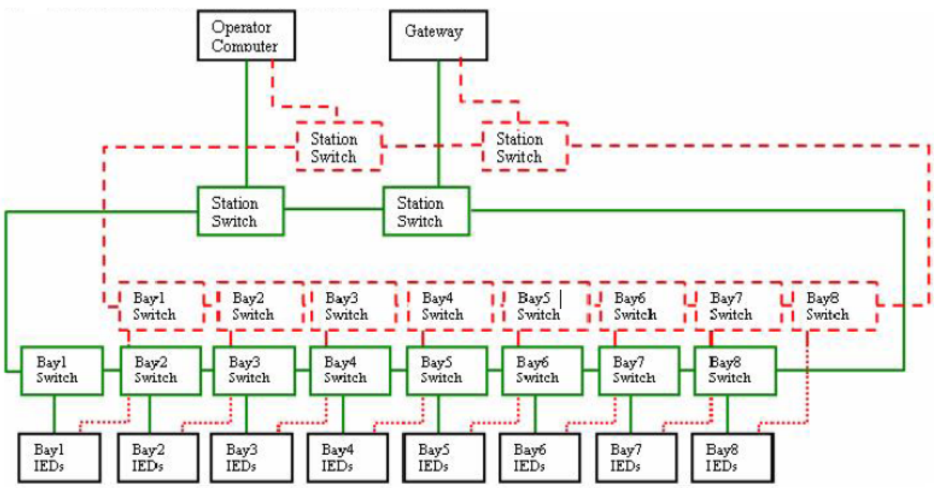


Figure 5.8 Redundant Ring Substation Communication Network [20]

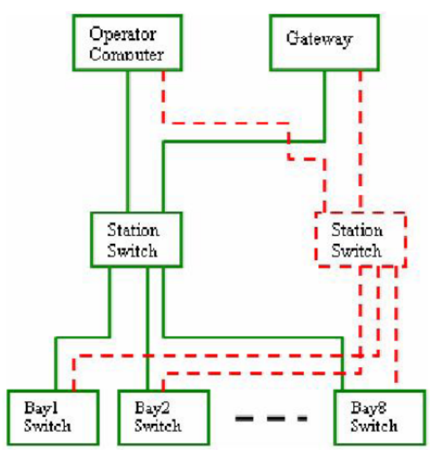


Figure 5.9 Redundant Star Substation Communication Network [20]

5.5.4 Mesh Topology

Mesh is the type of network topology in which some of the nodes of the network are connected to more than one other node in the network with a point-to-point link. Such attribute makes it possible to take advantage of some of the redundancy that is provided by a physical fully connected mesh topology without the expense and complexity required for a connection between every node in the network.

The “NASPInet”, which is being developed by North American SychroPhasor Initiative (NASPI), is an industrial grade, secure, standardized, distributed, and expandable data communications infrastructure to support synchrophasor applications in North America. NASPInet is a distributed & overlay digital communication network with mesh redundancy ([21] and Figure 5.8).

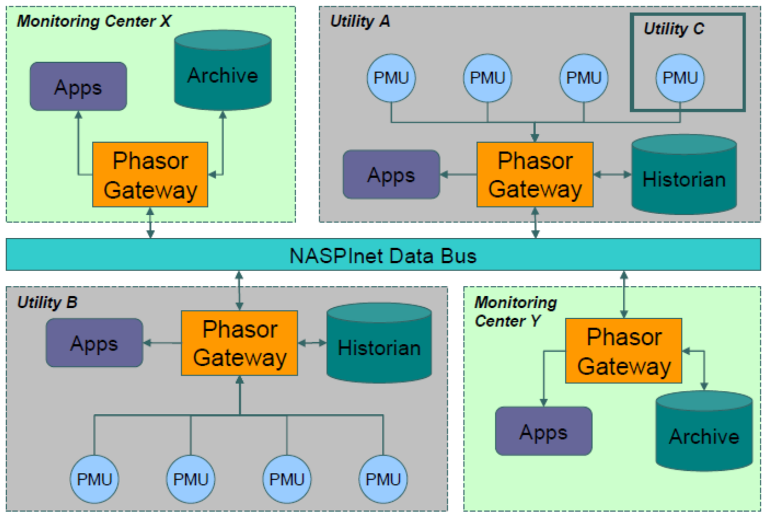


Figure 5.10 Architecture of NASPInet [21]

5.5.5 Hybrid Topology

Hybrid networks use a combination of any two or more topologies in such a way that the resulting network does not exhibit only one of the standard topologies (e.g., bus, star, ring, etc.). For example, a tree network connected to a tree network is still a tree network topology. A hybrid topology is always produced when two different basic network topologies are connected. Two common examples for Hybrid network are: star-ring network and star-bus network.

- A Star-ring network consists of two or more star topologies connected using a multistation access unit (MAU) as a centralized hub.
- A Star-Bus network consists of two or more star topologies connected using a bus trunk (the bus trunk serves as the network's backbone).

5.6 Data processing

5.6.1 IED Data Model

IEC61970 [22] is a standard for integrating number of complex applications developed by different vendors in the same or among multiple control centers using Common Information Model (CIM) to represent the data. CIM approach mainly focuses on modeling operational data and substation components. It is object oriented and extensions are possible. Practice shows that the published Common Information Model (CIM) version cannot meet the requirements of some important field device representations. CBM, DFR and other IEDs do not have CIM representation. Extension of CIM model is needed.

While IEC61970 provides a detailed description of connectivity between various equipment, substations and their static and dynamic information, IEC61850 ([19]) has the most detailed description of substation equipment and their monitoring and control aspects. IEC61850 defines a tree of objects for modeling of IEDs, starting from the server object (representing physical IEDs), and containing a hierarchy of Logical Devices (LDs), Logical Nodes (LNs) ad Data Objects (DOs). The issue of missing IED Model in CIM can be resolved through harmonization of CIM and IEC61850.

Figure 5.11 CIM IED Modelshows classes for IEDs and results of applications that can be included to the existing Power System CIM model. The IEDs are all subclasses of Intelligent Electronic Device, which is a subclass of Protection Equipment class that already exists in CIM Power System Model. The CBM class does, however, have relationship with Circuit Breaker class, which is called association. The circuit breaker can be connected to one or none Circuit Breaker Monitors and every Circuit Breaker Monitor can be in relation only with one Circuit Breaker.

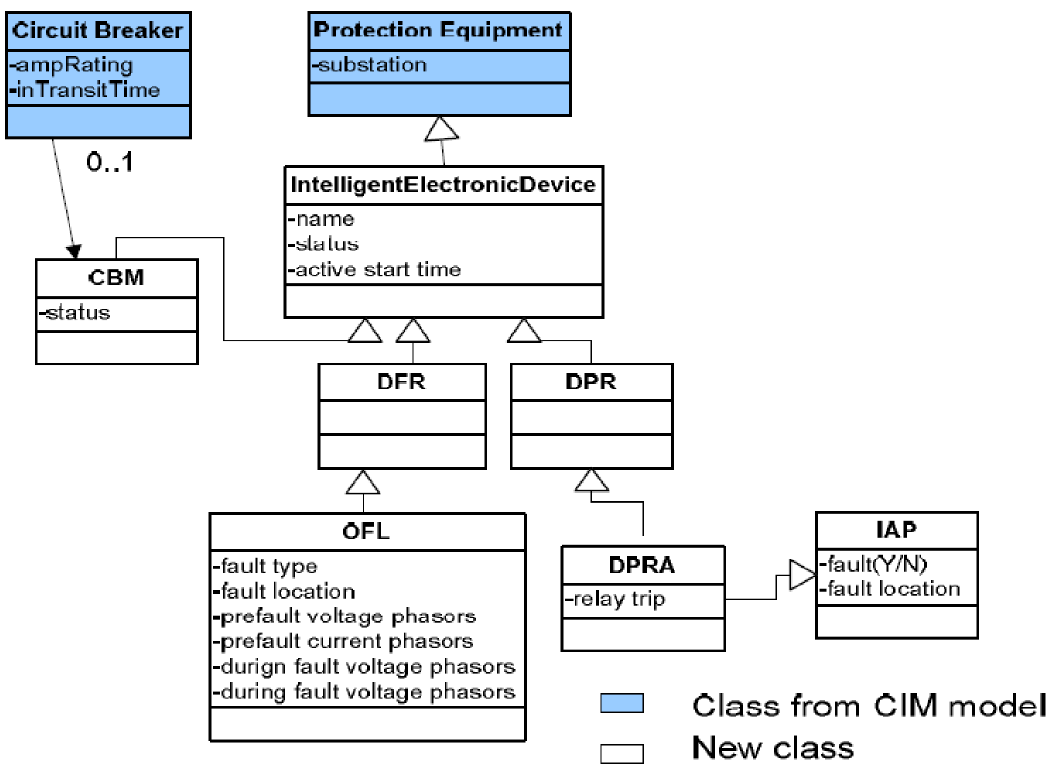


Figure 5.11 CIM IED Model

5.6.2 Data Preprocessing Architecture

A Control Center Interface module, which is based on control center level IED data pre-processing is shown in Figure 5.12. This module matches triggered data from IEDs and scanned data from SCADA by providing correlation regarding the time and topology reference.

Extended CIM Accessor module acquires and extracts data from Extended CIM model for control center applications. The data in Extended CIM module can guarantee the efficiency of access. If the applications require history data, Extended CIM model will acquire history data in Extended SCADA Database and return it to Extended CIM Accessor module. After Extended CIM Accessor module obtains all the data, it delivers the data to control center application by Resource Described Framework (RDF) which is defined in IEC61970. The applications access the data though CIM adapter which is in charge of converting CIM data format into the data format of the applications.

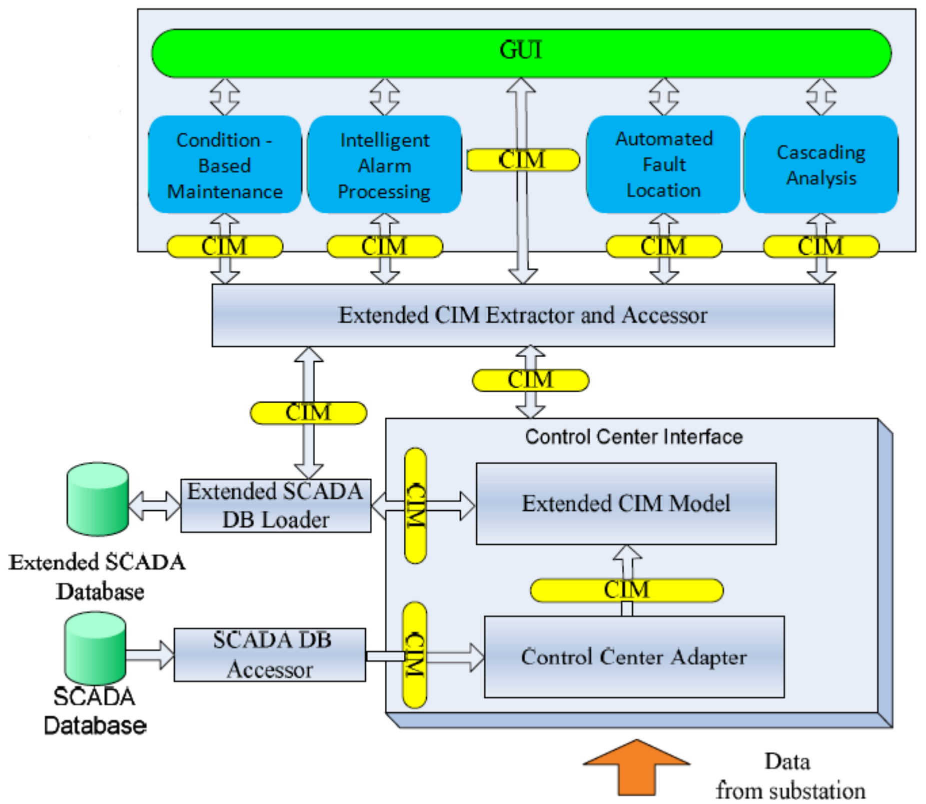


Figure 5.12 Control Center Level Communication Interfaces

5.7 Conclusion

This section provides discussion of communication infrastructure elements for the selected SG applications. The multi-level level communication hierarchy is proposed. Communication protocols and standards are identified, which contains standards not on the SGIP list. Comparison of communication media and topologies are presented next, with comments on the area of applications. This section also introduced a CIM based IED modeling method and the data processing architecture.

Part III: Distribution Level Smart Grid Applications

6 New Applications of Interest Addressed in this Project

6.1 Optimized Electric Vehicle Charging

Since Plug-in Hybrid Electric Vehicles (PHEV) are large stochastic loads, it is important to communicate with the distribution system (grid) and let the grid know the action requested by the PHEV. On the other hand when the grid needs power from the PHEV, known as Vehicle to Grid (V2G) mode, it is necessary to get the information about the status of the vehicles. This clearly shows that the PHEVs should be in regular communication with the distribution system.

Before developing the communication requirements, the first step is the build a model for PHEVs (both G2V and V2G) based on the system point of view. According to an Oak Ridge National Laboratory report dated October 2006, it is estimated that 25% of the vehicles in 2020 would be PHEVs [23]. Figure 1 shows the projected PHEV penetration into US markets. Therefore the PHEV has the potential to affect the system loading and thus the performance of the system.

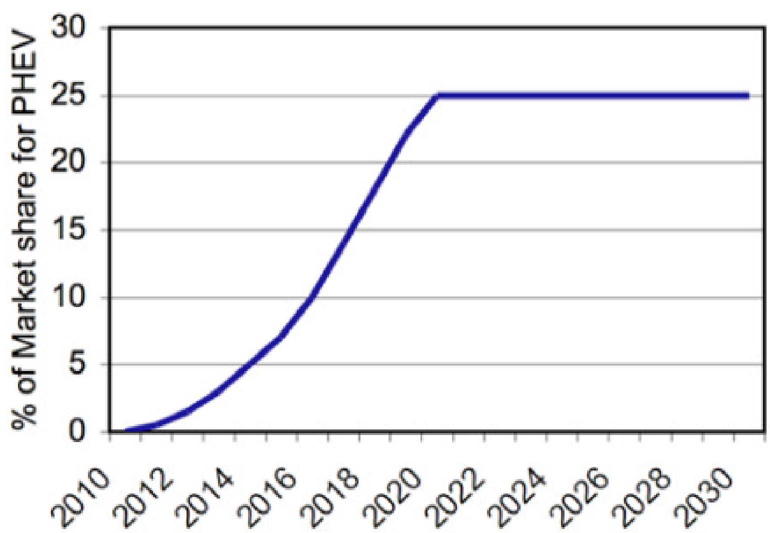


Figure 6.1 Projected Market Share of PHEVs [23]

According to a survey conducted by Duke Energy, demographic segments tend to use similar types of vehicles which would result in locational importance of PHEVs [24]. Therefore it should be noted that even though the expected PHEV market share is 25% by 2020, certain clusters will have higher penetrations of PHEVs and course present more of a threat to certain segments of the electric grid.
The risk and the reward from the PHEV to the local distribution system should be properly managed by the distribution utilities for the successful penetration of the PHEVs. Therefore the need for proper pricing techniques, identification of charging venues and infrastructure management are the critical components for better adaptation of PHEVs [24].

This work focuses on developing a methodology to incorporate these elements and identify a function which would be used for the communication between the control center and PHEV for charging and V2G operations. In order to include the concerns from [24] the following constraints are modeled and used:

1. **Additional Load:** Each PHEV is expected to increase the load by 1.4 kW if it is charged at a slow rate and around 6 kW if charged at a faster rate. Based on the charging efficiency and locational marginal price a function should be developed.
2. **Greenhouse Gas Emission:** Even though PHEVs will reduce the greenhouse gas emission from the transportation industry, they will increase the greenhouse gas emissions from the electricity industry. Based on the current developments to mitigate the greenhouse gas emissions, the electricity industry may be penalized for the higher greenhouse gas emission. Therefore a component to include the percentage change in greenhouse gas emission should be included in this function.
3. **Component Maintenance:** Based on the loading conditions and the location, component life can be affected by the introduction of PHEVs, therefore tools like hazard rate, and the system performance index, SAIDI and SAIFI should be included in this model.

<u>Facts about the vehicles used for private / household vehicles</u>,

- Average Driving Distance in US (2001) is 33 miles per day [25]
- Average distance to or from work in US (2001) is 12.08 miles [25]

<u>Facts about vehicle efficiency</u>

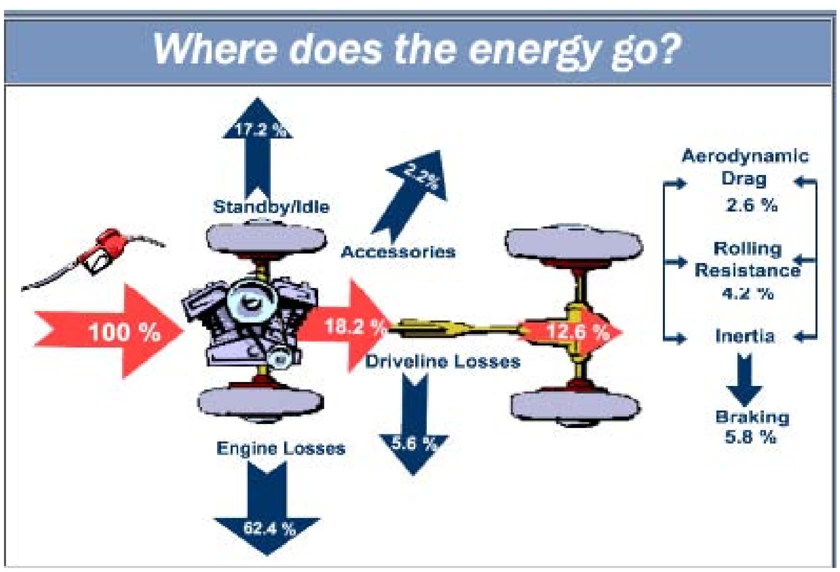


Figure 6.2 Energy Uses in Vehicle [26]

- Average efficiency of a household vehicle is 20% (Energy lost in the internal combustion engine 62.4%, standby idle usage 17.2%) [26]
- Average efficiency of a PHEV is 24.75% (Electric vehicle drive efficiency 75%, electric grid efficiency 33%) [27]

Emission (facts EPA estimate)

- CO_2 emission for gasoline is 19.4 pounds/gallon [28]
- CO_2 emission for coal power plant (1999) is 2.095 pounds/kWh [29]
- CO_2 emission for petroleum power plant (1999) is 1.969 pounds/kWh [29]
- CO_2 emission for gas power plant (1999) is 1.314 pounds/kWh [29]

Loading:

Locational Marginal Pricing: In the system point of view it is ideal to charge the vehicle when the locational marginal price (LMP) is low at the particular bus. This will result in the consumer charging the vehicle when the transmission congestion is less, resulting in more efficient operation. Since the minimum LMP for the current period (in this work one day from 0:00 hrs to 24:00 hrs is considered as a period) will not be known, the current LMP should be compared with the previous periods' LMP. A simple comparison of LMP is taken as a first step to model the LMP a simple ratio is used. This will be developed into a better model before next conference call.

$$h(P) = \frac{LMP(d, t_1)}{LMP(Min, (d-1))}$$

Where *d* is the current day.

Transformer Loss of Life: Using the Arrhenius relationship, loss of life of a transformer could be determined by the following formula [30-31];

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

where *A*, and *B* are constraints depending on the transformer insulation and T is the hot spot temperature. Let T_o be the hotspot temperature without PHEV at a given time *k*, and T_{EV} be the hotspot temperature with PHEV at a given time *k* and T_{min} be the minimum hotspot temperature with the addition of the same number of PHEVs for the previous period, then the loss of life component in the decision function would be;

$$m(L) = \underbrace{\frac{\exp\left(-\left(A + \frac{B}{\tilde{T}_{EV}(k)}\right)\right)}{\exp\left(-\left(A + \frac{B}{\tilde{T}_0(k)}\right)\right)}}_{\text{Current Period}} \cdot \underbrace{\frac{\sum_{k=1}^{24} \exp\left(-\left(A + \frac{B}{\tilde{T}_{EV}(k)}\right)\right)}{24 \times \exp\left(-\left(A + \frac{B}{\tilde{T}_{min}(k)}\right)\right)}}_{\text{Previous Period}}$$

Emission:

PHEVs would move the CO_2 emission from the transportation sector to the power sector. Higher CO_2 emission from the power sector could result in a higher penalty for to the utility. Greenhouse gas emissions differ for different energy sources. Different times of day use different combinations of energy sources. Figure 3 shows how the generation mix would change at different time of the hour, rate of charging and location.

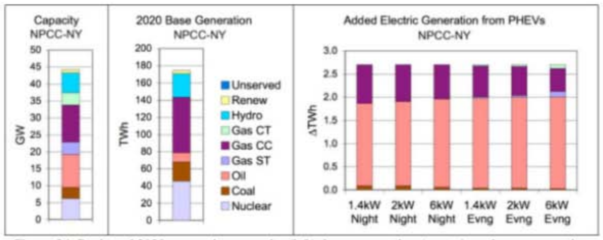


Figure 24. Projected 2020 generating capacity (left), base generation (center), and new generation dispatched to meet demand for each PHEV recharging scenario (right) for NPCC-NY.

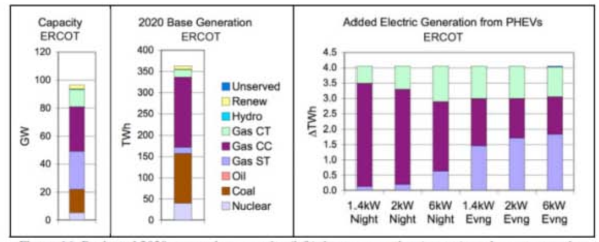


Figure 16. Projected 2020 generating capacity (left), base generation (center), and new generation dispatched to meet demand for each PHEV recharging scenario (right) for ERCOT.

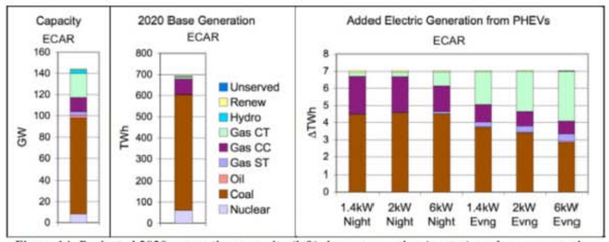


Figure 14. Projected 2020 generating capacity (left), base generation (center), and new generation dispatched to meet demand for each PHEV recharging scenario (right) for ECAR.

Figure 6.3 Projected Combinations of Dispatch with PHEV for Regions [23]

For a given time *t*, hours at a location (bus *k*), and with the charging rate of *r* kW/hour, let the added generation mix be: coal -*Pcoal* kW per hour per vehicle, oil -*Poil* kW per hour per vehicle, gas -*Pcoal* kW per hour per vehicle, nuclear – *Pnuc* kW per hour per vehicle and renewable (including hydro) – *Prenew* kW per hour per vehicle. Therefore CO2 emission for *ni* number of vehicles added at bus *k* would be;

$$E_{CO_2} = \frac{r}{\eta} \times n_i\left(2.095P_{Coal} + 1.969P_{Oil} + 1.314P_{gas} + 0P_{nuc} + 0P_{renew}\right)t \text{ pounds}$$

If we assume the average North American midsize car would travel 21 mpg [32] then CO2 emission per day, based on the average driving distance per vehicle would be;

$$E_{Gas-Vehi} = n_i \frac{Total\ Dist.Travled}{Average\ MPG} \times Emission\ per\ Gallon = n_i \frac{33}{21} \times 19.4 \text{ pounds}$$

Let's assume that the utility has developed the maximum limit on hourly CO2 emissions; this will be a function of hourly load profile, maximum cap on CO2 emission and the generation mix. Let's assume the limit on a given day would be $E_{t,d}$ and based on the load profile let the expected CO2 emission be $E_{t,d}$. Then difference in the maximum cap on CO2 emission and the expected CO2 emission as a fraction of maximum cap at time *t* would be,

$$E_B = \frac{\hat{E}_{t,d} - \left(E_{t,d} + E_{CO_2}\right)}{\hat{E}_{t,d}}$$

$$E_B = 1 - \frac{\left(E_{t,d} + E_{CO_2}\right)}{\hat{E}_{t,d}}$$

Then the factor for PHEV environmental impacts is given as,

$$f(E) = \begin{cases} -\dfrac{E_{CO_2}}{E_{Gas-Vehi} - E_{CO_2}} & if E_B > 0 \\ 0 & if = 0 \\ \dfrac{E_{CO_2}}{E_{Gas-Vehi} - E_{CO_2}} & if E_B < 0 \end{cases}$$

Component Maintenance:

Load increase on a component causes more stress on the component; and will result in reduced life of the component. This will have a significant effect on the system performance. Due to the nature of loads similar to PHEVs, large loads stochastic in nature, they cannot be modeled as regular loads. In this work we are developing a method to model these loads as irregular loads.

Reliability Analysis of Irregular Loads

The sustained interruption indices defined in the IEEE standards [33] consider the conventional loads in defining the indices. The introduction of non conventional loads, such as PHEVs, will introduce a new approach in reliability analysis for the following reasons:

- Location and time of charging the vehicle cannot be predetermined by the utilities; these are determined by consumers, based on their need. Even today we have similar loads, (eg. cell phone, portable music players, etc. – all in the range of mA) but their power consumption is really low and they do not affect the loading or the demand curve significantly. But large loads like a PHEV (~ 15 A), with several being charged at the same time, can affect the system loading.
- The duration of a battery being charged is limited, thus the time of interruption for this type of load is different from that of the conventional loads, which is equal to the total period of outage.

Since irregular loads are stochastic in nature, they are modeled through the probability distribution curve. Based on the loading in a particular system the probability distribution would be formed. For example, let’s consider a residential area, on a weekday, since most of the consumers are going to charge their PHEV’s during the off peak hours, after returning home, the demand curve would have a similar shape as Figure 4

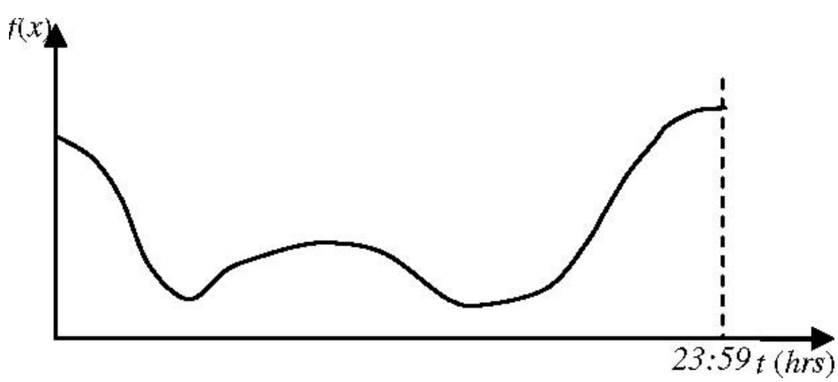


Figure 6.4 Probability of Number of PHEV’s Connected to Grid on a Weekday

From Figure 6.4 the number of PHEVs connected to grid at a geographical location *i*, at any given time interval *t*1~ *t*2 would be given as,

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

where, *NIR* is the total number of vehicles, on average, connected to the grid. These irregular loads are connected to the grid only for a limited time. Even though the power disruption due to a failure may be longer, the interruption duration for an irregular load will be determined only by the charging duration. Thus the total interrupted irregular load would be during the interval *t*1 to *t*2,

$$L_i = n_i r$$

In this work System Average Interruption Duration Index is taken as the reference for performance and the same approach can be extended for other indices. Definitions for the performance indices are taken from [33].

System Average Interruption Duration Index (SAIDI)

With a conventional load SAIDI is given as,

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

where e_i is the restoration time for each interruption event. With a definition similar to that of SAIFI the modified SAIDI could be given as [33]. Hazard rate would change with the introduction of PHEVs for any component in the system, if the component loading is increased by the PHEV. Let the modified hazard rate be $h_1(k)$.

$$SAIDI = h_1(k)\frac{\sum D_i + r\sum n_k}{N_T + N_{IR}}$$

Where (is the expected number of vehicles connected to the grid at the time of the failure. It could be observed that if the regulators are imposing limits on the performance (e.g., a maximum limit on SAIDI); if the maximum limit on the SAIDI is $\overline{SAIDI}$, then the following function could be used for the effect on the component reliability part of the function:

|

$$g(R) = \begin{cases} -\dfrac{|\overline{SAIDI} - SAIDI|}{\overline{SAIDI}} & if\ \overline{SAIDI} > SAIDI \\ 0 & if\ \overline{SAIDI} = SAID \\ \dfrac{|\overline{SAIDI} - SAIDI|}{\overline{SAIDI}} & if\ \overline{SAIDI} < SAIDI \end{cases}$$

Future Work The next step is to develop an optimization model to optimize the number of vehicles that could be charged at a given bus at a given hour of the day, while ensuring that the performance of the system is within the required levels.

6.2 Performance and Emission Based Electric Vehicle Charging Optimization

6.2.1 Introduction

The electric power system is experiencing a new type of load with the introduction of electric vehicles (EVs), because these are large stochastic loads. According to an Oak Ridge National Laboratory report dated October 2006, it is estimated that 25% of the vehicles in 2020 will be EVs [34]. According to a survey conducted by Duke Energy, demographic segments tend to use similar types of vehicles, which would result in the locational importance of EVs [35]. Therefore, it should be noted that even though the expected EV market share will be 25% by 2020, certain geographical clusters will have higher penetration of EVs and cause more threat to certain segments of the electric grid.

Introduction of non-conventional loads, such as EVs, will introduce a new approach in distribution system analysis for the following reasons:

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

Since irregular loads are stochastic in nature, they are modeled through the probability distribution curve. Based on the loading in a given system, probability distribution would be formed. For example, consider a residential area on a weekday. Since most consumers will be charging their EVs during off-peak hours, after returning home, the demand curve would have a shape similar to the one shown in Figure 6.5.

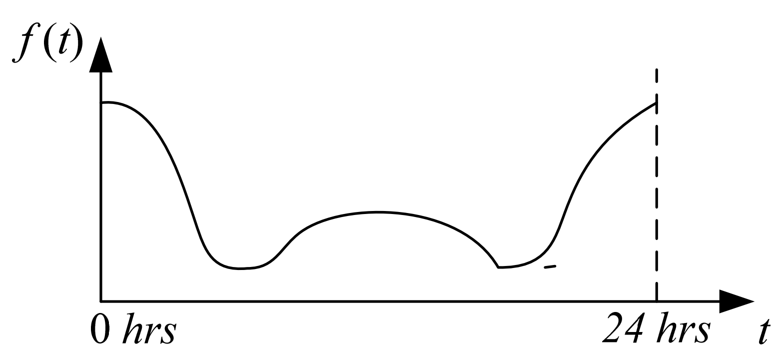


Figure 6.5 Probability of Number of EVs Connected to Grid on a Weekday

From Figure 6.5, the number of EVs connected to a grid from a geographical location *i* at any given time interval $t_1 \sim t_2$ would be given as

$$n_i := N_{IR} \cdot \int_{t_1}^{t_2} f(t)\, dt \qquad (I.1)$$

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

$$I_{c_i} = n_i r$$

In this work, it is assumed that all vehicles have same charging rate. If they are different, however, developed methodology is still valid but modifications are necessary.

Risk and reward from the penetration of EVs to the local distribution system should be properly managed by distribution utilities in order for their penetration to be successful. Therefore, proper pricing techniques, identification of charging venues, and infrastructure management are the critical components for better adaptation of EVs [35].

This work focuses on developing a methodology to analyze the effect of an EV charging based on the concerns given in [35] and to optimize the number of EVs connected to the electric grid for charging based on the following concerns:

- **Additional Load:** The EV is expected to increase electricity demand by 1.4 kW, if it is charged at a slow rate, and around 6 kW, if it is charged at a faster rate. Based on charging efficiency and locational marginal price (LMP), a relationship for a vehicle should be formed.
- **Greenhouse Gas Emission:** Even though an EV will reduce greenhouse gas (GHG) emissions of the transportation industry, it will increase GHG emissions of the electricity industry. Based on current developments to mitigate GHG emissions, the electricity industry may be penalized for higher GHG emissions. Therefore, emission limitations should be included in optimization calculation.
- **Component Maintenance:** Based on loading condition, component life will be affected; therefore, tools like component hazard rate, System Average Interruption Duration Index (SAIDI), and System Average Interruption Frequency Index (SAIFI) should be monitored/ controlled.

6.2.2 Performance and Emission Constraints

From a system point of view, it is ideal to charge vehicles when the LMP is low. This will result in the consumer charging the vehicle when the transmission congestion is less, resulting in more efficient operation. The predicted LMP for the next period (in this work, one day from 8:01 to 9:00 of the following day is considered a period) is compared with the minimum predicted LMP for that period. When the LMP is lower, more vehicles would be connected to the grid. The effect of the LMP is derived using the following relationship:

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

where n_i is the number of vehicles connected to grid at a given hour.

A. Loading Effects: Transformer Loss of Life

Using Arrhenius relationship, loss of life of a transformer could be determined by the following formula [36-37]:

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

where *A* and *B* are constants depending on transformer insulation, and $\tilde{T}$ is the hot-spot temperature. Since loss of life depends on the hot-spot temperature, it is important to limit it for longer life. According to IEEE C57.91-1995 [38], the hot-spot temperature could be given as

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

where θ_A is the average ambient temperature during the load cycle (hour) to be studied in℃, $\Delta\theta_{TO}$ is the top-oil temperature rise over ambient temperature in ℃, and $\Delta\theta_H$ is the winding hot-spot temperature rise over the top-oil temperature in ℃. Since most distribution transformers are cooled with natural-circulation self-cooling (OA), both constants given in [38], *m* and *n*, are fixed at 0.8.

Since EVs can be considered step loads, this work uses the model given in [38] to determine the rise in hot-spot temperature due to the addition of n_i number of EVs with a charging rate of r kW/hr during a given hour. Without losing generality, the steady-state increase in the hot-spot temperature due to step increase in load is considered in this analysis and compared with the maximum allowed hot-spot temperature increase for the transformer. In general, the tap position of the transformer will not be changed because of the addition of EVs, for any given time interval. Therefore, an increase in the steady-state hottest-spot temperature due to the addition of EVs, $\theta_{H,EV}$, could be determined using the following relationship:

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

where

$\Delta\theta_{TO,R}$ = Top-oil rise over ambient temperature at rated load on a given tap position in ℃.

R = Ratio of load loss at rated load, and no load loss on the given tap position.

$\Delta\theta_{H,R}$ = Winding hottest-spot rise over top-oil temperature at the given tap position in °C

L_{rate} = Rated load of the transformer at current tap position.

Using a binomial expansion, the above relationship could be written as

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

Since the load due to the addition of the EVs $(n_t r)$ will be less than the transformer rating (L_{rate}), higher-order terms in the above relationship are neglected, and the increase in the hottest-spot temperature due to the addition of EVs is

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

B. Emission Regulations

EVs would move CO_2 emissions from the transportation sector to the power sector. Higher CO_2 emissions from the power sector could result in higher penalties to the utility. GHG emissions differ for different energy sources, and different times of day use different combinations of energy sources. Figure 6.6 shows how generation mix would change with different times of the hour, rates of charging, and locations.

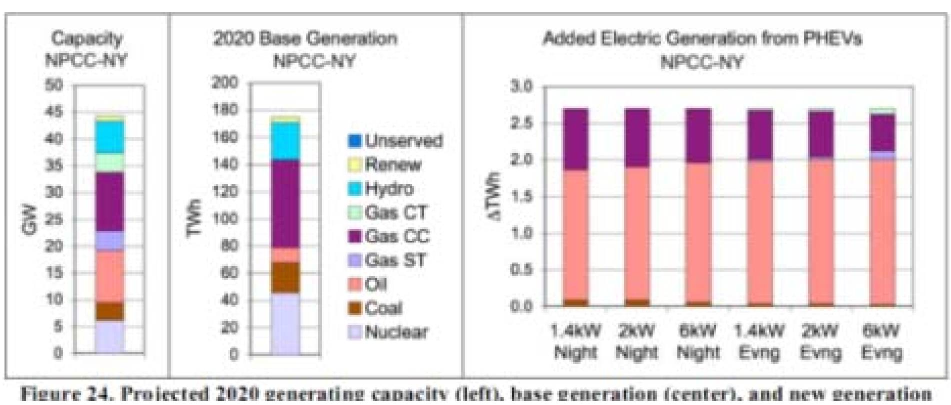


Figure 6.6 Projected Combinations of Dispatch with EV for Regions [34]

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

$$E_{CO_2} = \frac{r}{\eta} \times n_t \underbrace{\left(a_c P_c + a_o P_o + a_g P_g + a_n P_n + a_r P_r\right)}_{\beta} T \text{ lbs}$$

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

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

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

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

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

C. Component Condition

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

The SAIDI is taken as the reference for performance, and the same approach can be extended for other indices. Definitions for the performance indices are taken from [39], with the conventional load, and the effect of component k on the system SAIDI is given by

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

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

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

EVs are considered new customers, and n_k is found by (I.1)

6.2.3 Problem Formulation

It could be expected that EVs will penetrate the electric grid in segments, and each of these segments would be divided into zones in such a way that all vehicles connected through one transformer is considered a zone. A day is determined by the minimum number of vehicles needed to be connected to the grid. Based on the EPRI/NRDC study, the daily charging availability profile is given in Figure 6.7. Using this as a guideline, a *day* for the purpose of EV charging is defined from the 9th hour of one day to the 8th hour of the following day. For optimal operation, vehicles would be required to submit their available charging time for the following *day* by midnight. Vehicles that submit their requests would get higher priority in obtaining a time slot and could be given financial incentive as the utility plans its operation. Based on this, the utility would be able to determine the expected number of vehicles t to be charged at every hour t during the next charging period (*day*). This work assumes that every vehicle will be requested by the utility to start charging at the beginning of an hour.

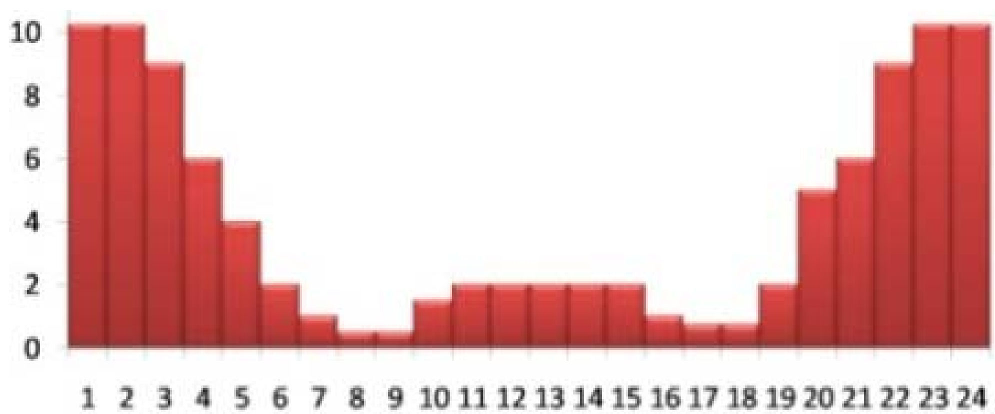


Figure 6.7 EV Daily Charging Availability Profile [40]

The objective of this work is to determine the expected optimum number of vehicles that each zone could handle during each time period based on the expected LMP of each zone and the impact on the SAIDI with addition of the EVs. At each hour, all vehicles requesting to be charged would be placed in a queue. The queue would be determined by the total time the vehicle would be available for charging. The maximum number of vehicles that could be shifted to the next hour to begin charging would be determined by the availability of each vehicle.

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

The aim here is to ensure that all vehicles are charged, while minimizing the impact on the SAIDI due to the presence of EVs. Based on historical data, the component of the SAIDI for each day could be determined from the allowed SAIDI for a year. The allowed SAIDI is defined as the maximum SAIDI that could be allowed by the utility to ensure that it will not be penalized for performance requirements by regulators. Optimization is constrained to ensure that LMP at the bus does not exceed its limit and that the sum of expected regular and EV loads is less than the transformer rating. The purpose is to minimize the duration of the increase in system average interruption for the *day*.

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

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

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

This objective could be rewritten as

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

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

Constraints for optimization are as follows:

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

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

2. All vehicles requesting charging during the following *day* should be charged. Number of vehicles charged in a day is

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

3. Each vehicle will submit following *day's* expected time to charge and duration for which it will be available. When E_k vehicles enter the queue at hour k, if V_k vehicles

could not be charged during hour $k-1$ and N_k vehicles were charged during hour k, then vehicles not charged during hour k and moved to the next hour, $k+1$, is

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

Note: To ensure that all vehicles requesting to be charged on a day do get charged, the following are fixed:

$$V_1 = V_{24} = 0$$

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

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

where TF_k is the maximum allowed peak loading of the transformer.

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

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

The solution to the above optimization could be determined using a linear program.

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

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

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

$$\max \quad n_i$$

Constraints for optimization could be given as follows:

1. To ensure that loss of transformer life is not accelerated due to the presence of EVs, the maximum limit for the hot-spot temperature is caped at Θ_i as

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

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

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

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

$$\delta + \alpha \cdot {n_t}^2 + \beta \cdot n_t \le \Theta_i,$$

where $\delta = \frac{\Delta\theta_{TO,R}}{(R+1)^{0.8}}$, $\alpha = \frac{0.8\cdot\Delta\theta_{TO,R}\cdot r^2\cdot R}{(R+1)^{0.8}\cdot {L_{rate}}^2}$, and $\beta = \frac{\Delta\theta_{H,R}\, r}{L_{rate}}$.

Determination of the cap Θ_i is dependent on the maximum allowed age-acceleration factor, F_{AA}, for transformer for an hour and ambient temperature Θ_A. Based on IEEE std. C57.91 [38], following relationship could be used to determine maximum allowed hottest spot temperature rise:

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

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

2. A maximum cap is enforced on weighted CO_2 emissions due to the addition of electric vehicles:

$$\underbrace{w_t \cdot \frac{r\cdot\beta}{30.5\eta}}_{\rho} \cdot n_t \le E_m$$

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

$$n_t \geq N_t$$

Therefore, Lagrangian for the above problem is given by

$$\mathcal{L}(n_t, \lambda_1, \lambda_2, \lambda_3) = n_t + \lambda_1(\Theta_t - \delta - \alpha \cdot n_t^2 - \beta \cdot n_t) + \lambda_2(E_m - \rho n_t) + \lambda_3(n_t - N_t)$$

KKT conditions for the above Lagrangian are as follows: **Stationary Condition:**

$$1 \quad 2\lambda_1 \alpha n_t \quad \lambda_1 \beta \quad \lambda_2 \rho + \lambda_3 = 0 \tag{1}$$

Complimentary Slackness:

$$\lambda_1(\Theta_t - \delta - \alpha \cdot n_t^2 - \beta \cdot n_t) = 0$$
$$\lambda_2(E_m - \rho n_t) = 0$$
$$\lambda_3(n_t - N_t) = 0$$

Primal Feasibility:

$$\Theta_t - \delta - \alpha \cdot n_t^2 - \beta \cdot n_t \geq 0$$
$$E_m - \rho n_t \geq 0$$
$$n_t - N_t \geq 0$$

Dual Feasibility:

$\lambda_1 \geq 0$, $\lambda_2 \geq 0$ and $\lambda_3 \geq 0$

The solution for the above problem exists only when $\{\lambda_1 \neq 0, \lambda_2 = 0$ and $\lambda_3 = 0\}$ and $\{\lambda_1 = 0, \lambda_2 \neq 0$ and $\lambda_3 = 0\}$. When $\{\lambda_1 = 0, \lambda_2 = 0$ and $\lambda_3 \neq 0\}$ and $\{\lambda_1 = 0, \lambda_2 = 0$ and $\lambda_3 = 0\}$, no feasible solution exists, and other combinations will not produce a unique solution. When $\{\lambda_1 \neq 0, \lambda_2 = 0$ and $\lambda_3 0\}$, the solution is found by modifying the following general conditions:

Stationary Condition:

$$1 - 2\lambda_1 \alpha n_t - \lambda_1 \beta = 0 \tag{III.1}$$

Complimentary Slackness:

$$\delta + \alpha \cdot n_t^2 + \beta \cdot n_t - \Theta_m = 0 \tag{III.2}$$

Primary Feasibility:

$$E_m - \rho n_t \geq 0 \qquad \text{(III.3)}$$

$$n_t - N_t \geq 0 \qquad \text{(III.4)}$$

Dual Feasibility:

$$\lambda_1 \geq 0 \qquad \text{(III.5)}$$

From (III. 2),

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

For the solution to exist,

$$\beta^2 < \beta^2 + 4\alpha(\Theta_t - \delta) \quad \Rightarrow \Theta_t > \delta$$

From (III.3),

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

From (III.4),

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

From (III.1) and (III.5),

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

Let, $g = \rho \frac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_t - \delta)}}{2\alpha E_m}$ and $h = \frac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_t - \delta)}}{2\alpha N_t}$.

Then if $\Theta_m > \delta, g \leq 1$ and $h \geq 1$, the optimal solution is

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

When $\{\lambda_1 = 0,\ \lambda_2 \neq 0$ and $\lambda_3 = 0\}$, the solution to the optimization problem could be determined by modifying the general conditions similar to the first case

$$1 - \lambda_2 \rho = 0 \qquad \text{(III.6)}$$
$$E_m - \rho n_t - 0 \qquad \text{(III.7)}$$
$$\Theta_t - \delta - \alpha \cdot {n_t}^2 - \beta \cdot n_t \geq 0 \qquad \text{(III.8)}$$
$$n_t - N_t \geq 0 \qquad \text{(III.9)}$$
$$\lambda_2 \geq 0 \qquad \text{(III.10)}$$

From (III.7),

$$E_m - \rho n_t = 0$$

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

For the solution to exist, from (III.8),

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

and for the above solution to exist,

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

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

From (III.9),

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

From (III.6) and (III.10),

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

Let $f - \frac{E_m}{\rho N_t}$. Then, if $\Theta_m > \delta,\ g \geq 1$, and $f \geq 1$, the optimal solution is

$$n_t = \frac{E_m}{\rho} \quad if$$

Further note,

$$N_t \leq n_t \leq \frac{E_m}{\rho} \quad \Rightarrow 1 \leq \frac{n_t}{N_t} \leq \frac{E_m}{\rho N_t}$$

Therefore, $\frac{E_m}{\rho N_t} \lesssim 1$ will result in violation of these conditions. Similarly the following condition should be met for a non-zero solution:

$$N_t \lesssim n_t \lesssim \frac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_t - \delta)}}{2\alpha}$$

Since $\frac{-\beta+\sqrt{\beta^2+4\alpha(\Theta_t-\delta)}}{2\alpha N_t} \lesssim 1$ or $\frac{E_m}{\rho N_t} \lesssim 1$ violates the necessary conditions, a solution is possible if the condition that is violated is relaxed or it is fixed at the boundary. Fortunately, daily assignment of N_i is expected to minimize this effect. Therefore, it could be expected that these violations are a rare possibility if the system is not operated close to its limitations. The following section discusses the options of relaxing a condition and finding the solutions.

Case 1: Relax $n_t \geq N_t$

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

$$n_t = \begin{cases} 0 & if\ \Theta_m < \delta \\ \left\lfloor \frac{-\beta+\sqrt{\beta^2+4\alpha(\Theta_t-\delta)}}{2\alpha} \right\rfloor & if\ \Theta_m \geq \delta, g \leq 1, h \leq 1 \\ \left\lfloor \frac{-\beta+\sqrt{\beta^2+4\alpha(\Theta_t-\delta)}}{2\alpha} \right\rfloor & if \Theta_m \geq \delta, g \leq 1, h \geq 1 \\ \left\lfloor \frac{E_m}{\rho} \right\rfloor & if\ \Theta_m \geq \delta, g \geq 1, f \leq 1" \\ \left\lfloor \frac{E_m}{\rho} \right\rfloor & if\ \Theta_m \geq \delta, g \geq 1, f \geq 1 \end{cases}$$

Case 2: Relax $\Theta_m \quad \delta \quad \alpha n_t^2 \quad \beta n_t \geq 0$ and $E_m \quad \rho n_t \geq 0$

This case ensures that all vehicles are charged according to the schedule at the cost of emissions and the increased loss of transformer life. The utility may impose additional charges on vehicles charged at that time period. The extra burden would be shared equally by all vehicles connected in that zone. The number of vehicles charged at any given time i would be

$$n_i = \begin{cases} 0 & if\ \Theta_m < \delta \\ N_i & if\ \Theta_m \geq \delta, g \leq 1, h \leq 1 \\ \left\lfloor \frac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_i - \delta)}}{2\alpha} \right\rfloor & if\ \Theta_m \geq \delta, g \leq 1, h \geq 1 \\ N_i & if\ \Theta_m \geq \delta, g \leq 1, f \leq 1 \\ \left\lfloor \frac{E_m}{\rho} \right\rfloor & if\ \Theta_m \geq \delta, g \geq 1, f \geq 1 \end{cases}$$

6.2.4 Numerical Analysis

From Environmental Protection Agency (EPA) estimates shown in [41], the CO_2 emissions from a coal-fired power plant (1999) are 2.095 lbs/kWh (e_c), the CO_2 emissions from a petroleum-powered plant (1999) are 1.969 lbs/kWh (e_o), and the CO_2 emissions from a gas-fired power plant (1999) are 1.314 lbs/kWh (e_g). Emissions from nuclear and renewable sources are zero $(e_n = e_r = 0)$. The average efficiency of an EV (η) is taken as 24.75% (EV driving efficiency at 75% electric generation and T&D efficiency at 33%) [42]).

For a midsize vehicle, CO_2 emissions from a gasoline-powered vehicle are 19.4 pounds/gallon [43], average driving distance in the U.S. (2001) is 33 miles per day [44], and the vehicle would get 21 miles per gallon [45]. Therefore, CO_2 emissions per day from a midsize vehicle are calculated as

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

The weighted function for the emissions could be given by

$$f(E) = w_t \frac{E_{CO_2}}{E_{Gas-Vehl}} = w_t \cdot \frac{r \cdot \beta}{30.5\eta} \cdot n_t$$

Based on the distribution system analysis subcommittee report [46], a 13-bus test feeder is used with a modification using ANSI/IEEE C57.92.1881 [47], developed by Allan et al. [48], to incorporate reliability data. A one-line diagram of the system with six zones is shown in Figure 6.8.

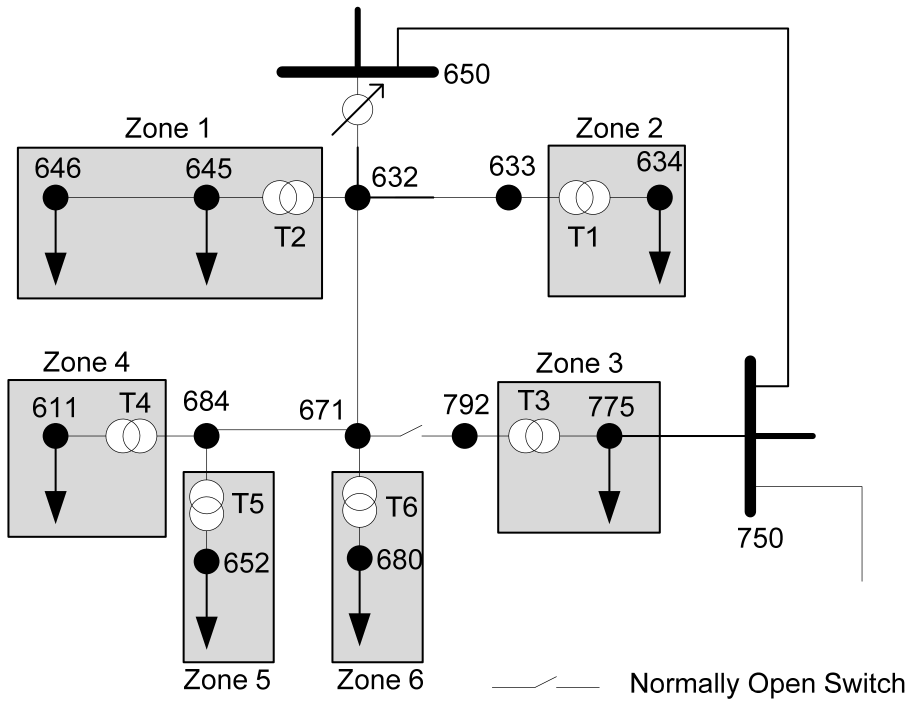


Figure 6.8 One-Line Diagram of System

Normalized LMPs based on the definition given in II.A $\left(\frac{LMP(t_i)}{LMP(Min)}\right)$ for busses 650 and 750 is given in Figure 6.9. Expected load profile for the *day* in consideration is shown in Figure 6.10.

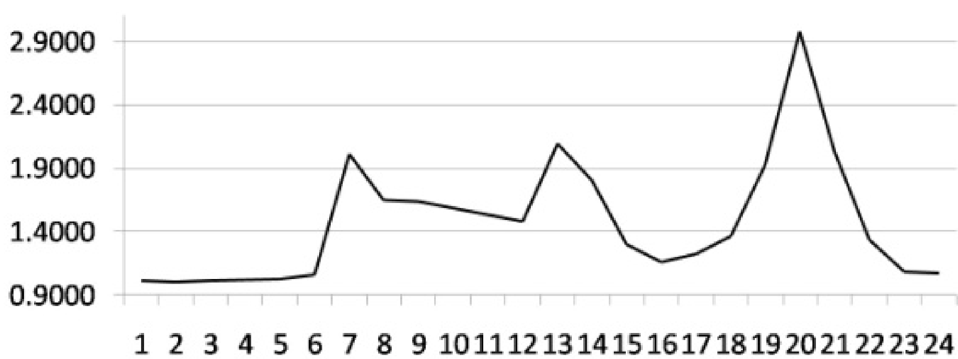


Figure 6.9 Normalized Locational Marginal Price for Three Cases

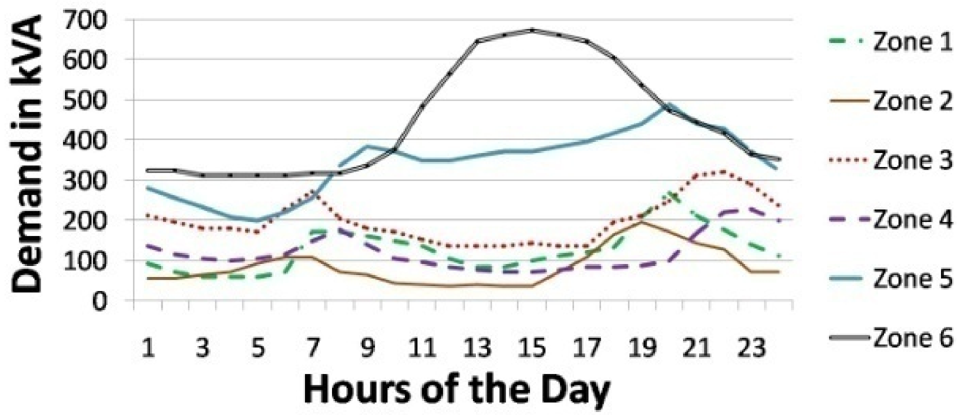


Figure 6.10 Expected Load Profile for the Following Day

All transformers (T1–T6) are assumed to be rated at $115\ kV : 13.2\ kV$. Transformer rating and failure rate data are tabulated in Table 6.1.

Table 6.1 Transformer Data

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

For illustration purposes, it is assumed that EVs are located in urban (zone 5) and suburban (zones 3 and 4) areas, and even though rural areas are capable of handling EVs, there is no regular EV load there. Based on the availability of the EVs at each zone, tabulated in Table 6.2, and the charging pattern given in Figure 6.7, the number of vehicles available for charging at each hour is determined.

Table 6.2 Total EVs at Each Zone

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

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

Generation dispatch results, as shown in Figure 6.11 [49], generated in using the IEEE reliability test system are used to determine the generation mix for each hour.

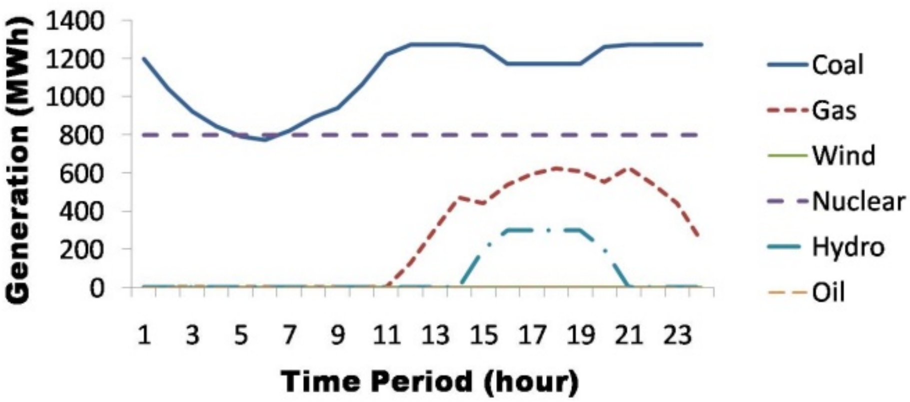


Figure 6.11 Generation Dispatch Results [49]

To determine the transformer loss-of-life parameters provided in III.B.1, values given in IEEE std. C57.92.1881 [47] are used. For more accurate analysis, values calculated by manufacturer could be used. The values given in IEEE std. C57.92.1881 are reasonable and could be used in practical applications where actual data is not available. From IEEE C57.92.1881[47], for natural circulation self cooled (OA) transformers, with a rating up to 100 MVA, the following values could be used:

$$R = 3.2,\ \Delta\theta_{TO,R} = 50°C,\ \Delta\theta_{H,R} = 30°C.$$

Furthermore, for analytical purposes, let the charging rate of a battery, based on Chevrolet Volt specifications [50], be $r = 2.5\ kW$. The calculated δ, α, β parameters for all zones are given in Table 6.3.

The effect of CO_2 δ emissions as a result of the addition is determined using the calculated efficiency of the EV based on the information given in [40], assuming that the weight w_r is 1. The choice of $w_r = 1$ is justified, when the consumer has no liability for CO_2 emissions. $\widetilde{P}$ is dependent on the generation mix, which is given in Figure 6.11.

$$\rho = w_r \cdot \frac{r \cdot \beta}{30.5\eta} = \frac{2.5 \times \beta}{30.5 \times 0.2475} = \frac{\beta}{3}$$

Table 6.3 Transformer Loss-of-Life Parameters

Transformer	Rating kVA	α	β	δ
T1	225	0.00501	0.33	12.67
T2	300	0.00282	0.25	12.67
T6	500	0.00102	0.15	12.67
T3	300	0.00282	0.25	12.67
T5	500	0.00102	0.15	12.67
T4	750	0.00045	0.10	12.67

Based on generation mix, ρ for every hour is given in Table 6.4.

Table 6.4 Transformer Emission Parameters

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

Zone 3 is used as an example to show the calculations. Table 6.5 shows the values assumed for zone 3. Vehicles requesting charging (E_k) and the maximum limit on vehicles that could be moved to the next charging period (Vm_k) based on information received by vehicles are plotted in Figure 6.12.

Table 6.5 Assumed Parameters for Zone 3

Parameter	F_{nn}	E_m	C_m	TF_k	Θ_n
Value	3	2.5	14	360	40

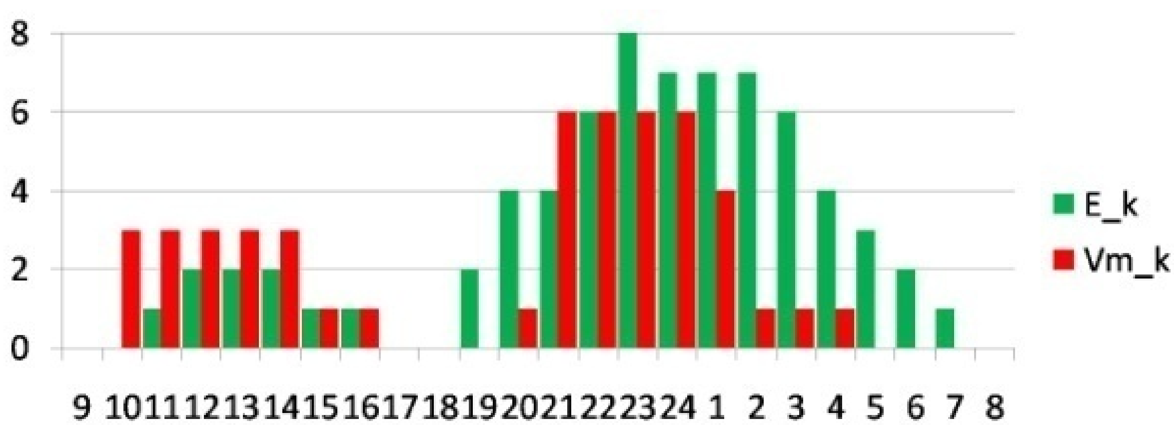


Figure 6.12 Vehicle Data for Zone 3

Based on the optimization technique defined in the "*First Step: Predict the number of vehicles for each zone at every period of the day,*" the optimum value of vehicles that could be connected to the grid for charging from zone 3 for the following *day* is plotted in Figure 6.13.

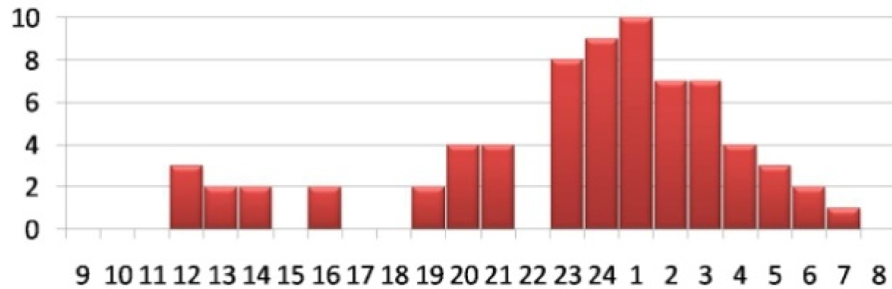


Figure 6.13 Hourly Optimum Number of Vehicles for the Following Day from Zone 3

Next step is to determine the maximum vehicles that could be connected to the grid in the next hour. This would be determined 15 minutes before the start of the hour. This analysis is based on the "*Second Step: Maximum limit on the vehicles based on the operating conditions*" Using the data given in Figure 6.14 as the system load (excluding EVs) calculated 15 minutes ahead of each hour, where 8p represents the last hour of the previous *day*, this analysis is based on case 1, where the utility will not relax the limitations on the emission but will relax the limit on the number of vehicles charging.

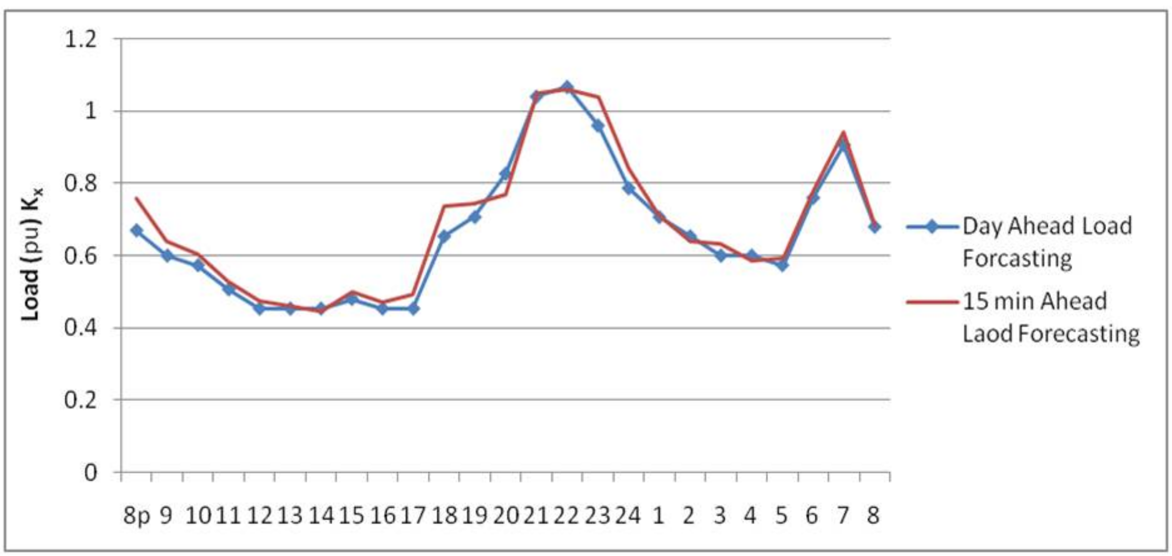


Figure 6.14 Per-unit Loading for Zone 3

For illustration purposes, the following calculation is made for the first hour 15 minutes ahead of time, based on loading and CO_2 emissions profiles. First, the expected temperature rise due to the regular load is determined using IEEE C57.91-1995, based on 15-minutes-ahead load forecasting:

$$\Delta\theta_{TO,t} = \Delta\theta_{TO,R}\left[\frac{K_t^{\,2}R+1}{R+1}\right]^n = 36.35°C$$

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

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

$$\Rightarrow \Delta\theta_{TO} = 35.05°C$$

$$\Delta\theta_{H,t} - \Delta\theta_{H,R}K_t^{\,2m} - 19.34°C$$

$$\Delta\theta_{H,U} - \Delta\theta_{H,R}K_U^{\,2m} - 14.69°C$$

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

$$\Rightarrow \Delta\theta_{H} = 14.69°C$$

Therefore, expected temperature rise due to the regular load is

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

The maximum allowable hottest-spot temperature rise due to the addition of the EVs for that hour is

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

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

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

$$g = \rho\frac{-\beta + \sqrt{\beta^2 + 4\alpha(\Theta_t - \delta)}}{2\alpha E_m}7.66 > 1$$

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

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

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

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

Using a similar argument, the number of vehicles that could be connected in zone 3 is plotted in Figure 6.15. It can be seen that for most of the day, the maximum possible vehicles charged will be less than the estimated optimum vehicles planning to charge in that hour. During peak hours (21, 22, and 23), transformer loading is above its rating; therefore, connecting any of the EVs will degrade the transformer, and thus the maximum is kept at zero. Furthermore, due to higher loading during the night, the maximum number of vehicles in the 7^{th} hour is lower (4) compared to other hours, in order to allow the transformer to cool down.

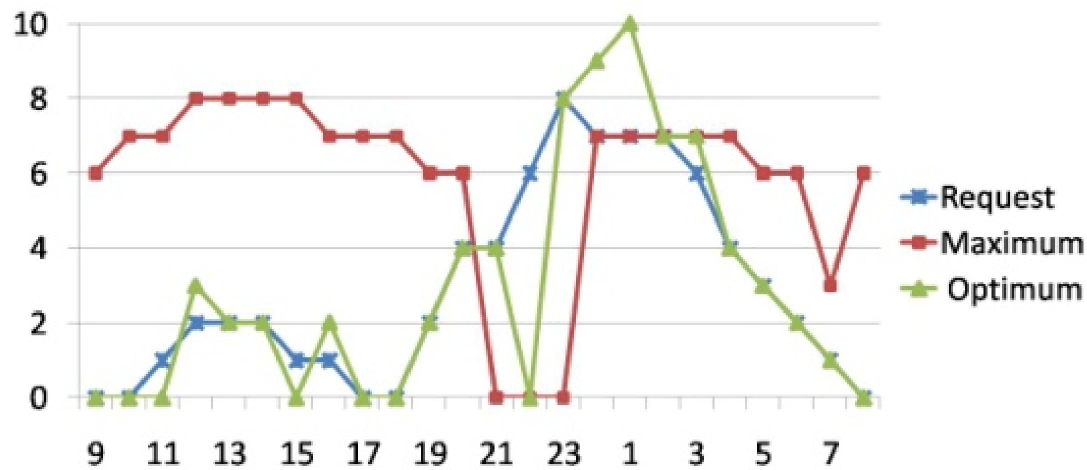
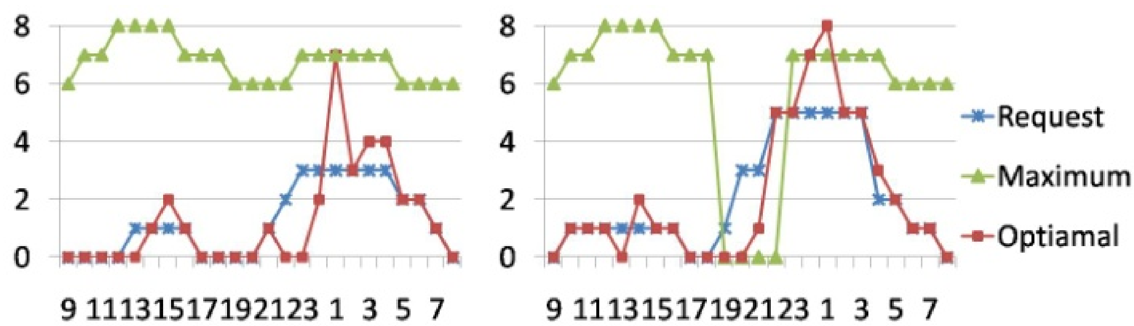


Figure 6.15 Optimum and Maximum Charging for Zone 3

Results obtained for zones 4 and 5 are shown in Figure 6.16. It can be seen that zone 4 is operated below the transformer rating, which is reflected by the maximum possible vehicles for any hour being greater than the optimum number of vehicles requesting to be charged. Since zone 5 is operated close to the transformer rating, this has resulted in zero maximum charging during 19, 20, 21, and 22 hours.



(a) Zone 4 (b) Zone 5

Figure 6.16 Optimum and Maximum Charging for Zones 4 and 5

6.2.5 Conclusions

This work proposes a technique to schedule charging of EVs to minimize their effect on the electric power system. A two-step approach is taken to ensure the addition of a large irregular load so that EVs will not degrade system performance. In the first step, based on the expected loading and LMP on the system for the previous day, requests received by the utility for the time-of-charging and the availability of each vehicle for charging, an optimal charging schedule is generated, and this will be communicated to the relevant vehicles. Due to loading uncertainties and unpredictability associated with charging EVs, a second step is used to determine the maximum number of vehicles that could be charged during the next hour. A firm maximum will ensure that the loading will not increase the loss of life of the transformer or degrade the reliability of the system. For the proposed work to be implemented, power system-level communication needs to be improved. Vehicles may need to communicate with the grid while on the move; this could be achieved through dedicated vehicular ad-hoc networks and at charging stations through smart meters. Smart Grid implementation will introduce more dedicated communication for the power grid, and then proposed work could be implemented at the distribution level.

6.3 Condition Assessment and Maintenance Optimization

6.3.1 Introduction

Distribution system performance is critical for the reliable operation of the system in terms of consumers. From historical data, on average, 80% of consumer interruptions could be attributed to failure in the distribution system [51]. The primary reasons for this are the increasing load, aging of the components [52] and the minimum redundancy in the event of loss. One of the growing concerns to the regulators in the deregulated market is utilities' postponement of preventive maintenance due to financial limitations. To ensure the performance level of utilities, regulators have gone to the extent of scheduling and benchmarking the maintenance for the utilities [53]. When the grid gets smarter it is expected that the performance bench will be raised further, thus making it necessary to have better maintenance scheduling techniques. A best option to optimizing the cost of maintenance would be to develop a periodic maintenance scheme based on each component's condition. By using a condition-based scheme, maintenance of a component could be scheduled (when and by how much) depending on the condition and expected life of the component.

A reliable condition-based maintenance scheme requires accurate assessment of the condition of components. Distribution system operates in a highly uncertain environment; therefore, modeling the system requires a probabilistic approach [54]. Obtaining historical failure information for the modeling is difficult, mainly because of the greater reliability of the components, which results in fewer failures, and utilities not recording complete information about these failures. As a result, it is necessary to identify a probabilistic component assessment model that requires few samples to calibrate.

Due to uncertainties and unavailability of data modeling, component condition based on a statistical approach would be more reliable. Component-condition assessment based on the statistical failure rate is presented in [55]. The authors have developed a methodology to predict the failure rate of a component-based condition of its weighted criteria. Shifted exponential function is used for the failure rate function. The developed technique is tested using reclosers, as in [56].

Using the scaled exponential failure rate in [55] reduces the computational complexity, but the downside of this technique is that not all hazard rates can be modeled as exponential. In order to develop a method that could deliver accurate results with fewer samples and accommodate various shapes of hazard rate, the Weibull distribution is considered an alternative. This work proposes a methodology to compute component reliability based on a series-parallel model. The methodology is explained using power transformers.

Presently most components are not monitored, or most of the condition data are not recorded. And due to manual inspection and data recording for the components placed along the feeders, not all data is current and accurate. Modernization of the grid and making it smarter requires the availability of communication not only at the substation level, but extended communication to the components in the feeder and the consumers through smart meters. Once the communication infrastructure becomes available, the ability to obtain accurate and up-to-date information becomes possible. Therefore, this work assumes that automated component monitoring will be available in the near future, which will increase the effectiveness and accuracy of the model.

The remainder of this paper is organized as follows: section II describes the guidelines to component criteria selection, with detailed discussion of a power transformer. A statistical reliability model is developed and presented in section III. Section IV discusses a weighing technique to accommodate the significance of different criterion. Section V formulates the reliability function for the power transformer, and concluding remarks are given in section VI.

6.3.2 Selection of Component Criteria

Most components in the distribution system are highly reliable, but with time, if desired level of maintenance is not conducted, the tendency of components to fail due to degradation of its integral elements is high. A component that fails while it is online will cause significant loss of revenue and poor reliability indices. Since components used in the power system consist of several elements, the condition of all the elements should be considered. In addition to the physical elements of the component, other factors such as environmental effects and experience with the component type should be included in the assessment in order to compute a more realistic reliability distribution. Not all elements have relatively equal impact on the component. For example, a small crack in the transformer tank has a higher impact than slightly increased core and winding losses, even though both show that the component condition is not up to standards.

Based on component monitoring, inspection maintenance records and a manufacturer data condition an assessment technique is developed. Once all likely failure modes are identified and measurable, all relevant criteria would be grouped to form the reliability model. This is elaborated using a power transformer.

A. Criteria for Power Transformer

Since forced outages are unpredictable and financially affect the utility, the developed hazard function model will be used for forced outages. Furthermore, the model will exert force on controllable failure modes, since these could be improved by the utilities. However, in order to develop a more realistic model, a probabilistic approach would be used for the uncontrollable failure modes. Table 6.6 shows some of the common causes for a power transformer to fail [57].

Table 6.6 Common Causes for Power Transformer failure

Causes	**Transformer failure**
Internal	Insulation deterioration; loss of winding clamping; overheating; oxygen, gases, and moisture in the oil; oil contamination; partial discharge; design and manufacturing defects
External	Lightning strikes, overloads, system faults

Ample techniques are available for component monitoring based on type, size, and application, particularly for transformers. This work focuses on finding optimal parameters that would represent the condition of the equipment by using cost-effective advanced monitoring systems. The following are considered critical criteria for condition assessment of a power transformer:

- *Age of Transformer:* Even though the average lifetime of a transformer is 30 years, due to the mechanical strength of the insulation, the material decay rate is higher as the transformer ages, thus the hazard rate increases with time.
- *Experience with Transformer Type:* The more experience with a transformer, the more awareness there is. Thus, as experience with the transformer increases, the hazard rate would decrease.
- *Noise Level:* A humming noise created by the energized transformer is associated with the condition of the core assembly. Based on field data, manufacturer's data on limiting the noise level, and NEMA Std. TR1-1993 [58], the relationship between the condition of the transformer and the noise level could be formulated.

- *Transformer Loading Condition:* Loading affects a transformer's lifespan. Therefore, the average loading of the transformer during a function of the nameplate loading should be considered a criterion.
- *Hot Spot Temperature*: Distortion of the insulation is a function of hot-spot temperature. IEEE std. C57.91 – 1995 [59] presents a procedure to find loss of insulation life for an oil-immersed transformer. Based on this hazard function, the hot spot temperature could be ascertained.
- *Core and Winding Losses*: For a given loading condition, losses should remain constant. The percentage increase in the total loss would increase the hazard rate.
- *Transformer-Turns Ratio*: As per ANSI 57.12-00 [60], the transformer-turns ratio test should be within 0.5% of the nameplate marking. Higher loss indicates trouble with insulation. Based on this standard and field data, a relationship between percentage change in the turns ratio and hazed rate could be formed.
- *Condition of Solid Insulation*: Resistance between windings and resistance between windings and the ground should be high enough. Using a megohm test, calculated résistance should be given as the percentage of the standard value. The lower the resistance, the higher the hazard rate. A polarization test could be used as an alternative.
- *Partial Discharge Test*: Partial discharge would result in gradual loss of strength of the insulation. Since partial discharge reduces the life span of a transformer, a reliability function should be developed based on partial discharge and a limiting value specified by manufacturer.
- *DC Winding Resistance*: The DC winding resistance converted to 75^{o}C should be completed with the manufacturer specifications. For healthy operation of the transformer, the DC winding resistance should be less than 2% of the specifications [57]. Based on this value and the field data, a relationship should be formed between the reliability and the DC winding resistance.
- *Oil Condition*: *Water in Oil, Acid in Oil, and Gas in Oil*: A relationship between these three criteria for a transformer and the reliability would be formed, based on maximum allowable limits. Generally, the Karl Fischer test [61] 61could be used to test the water in oil; titration methods, such as D664 or D974 [60], could be used for acid-in-oil test; and dissolved gas analysis could be used for the gas-in-oil test.
- *Oil Power Factor*: This factor, related to dielectric loss, could be used to determine the condition of the oil. Oil in excellent condition should have a power factor less than 0.05 at 20^{o}C [60]. A higher power factor indicates oil contamination, which will affect the life of the transformer
- *Physical Condition of Transformer Elements*: Along with the above-mentioned specific parameters, the satisfactory operation of various other auxiliary elements is very important to the health and operation of the transformer. Such auxiliary elements include the cooling system, tap-changer assembly, bushings, and tank condition. Thus, based on the physical inspection and historical data, a hazard rate function for each component should be developed.
- *Geographical Location*: Geographical location of the transformer will impact its life. Based on lightning strikes in the locale, air quality level, and location (e.g., close to the sea), impact on the transformer would be modeled, which, in most cases, would be constant with time.

Developing the reliability function for each component should be a collaborative effort by the manufacturer, personnel in the field, and statisticians working on distribution reliability. There is no single standard for all transformers, as not all of them are equipped with similar sensors, and different utilities use different approaches to determine the life of a piece of equipment and a maintenance schedule. It is recommended that one single standard be used for the same type of transformers with similar ratings. When the system-wise analysis is conducted, especially with a Smart Grid, using a single standard will improve the quality of the assessment.

6.3.3 Reliability Model

A unified procedure to determine the reliability of equipment is proposed here, based on the work by [62]. Reliability of a component is computed relative to the condition of each criterion. In most engineering practices, a constant hazard rate model is used, which reduces the computational complexity. However, experience shows that component failures follow certain patterns, mostly with time-varying hazard rates [63]. Overall, the hazard rate of a component that undergoes routine maintenance would have a saw-tooth pattern, as shown in Figure 6.17.

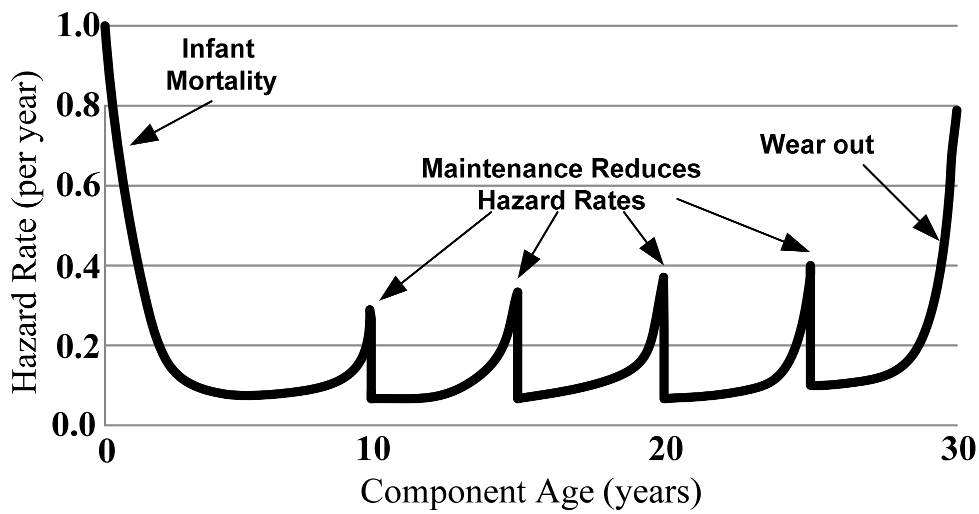


Figure 6.17 Saw-Tooth Failure Rate Model

Reliability between two successive maintenance practices is considered in this work, and it is assumed that at the end of each maintenance procedure or major change to the component, the reliability function would be updated.

When all criteria for a component are considered, not all of them will have a time-increasing hazard rate. For example, age of the transformer has a time-increasing hazard rate, since the older the transformer, the tendency for it to fail is higher. In most cases, the probability of failure in a given geographical location will not change with time; therefore, the geographical location will have a time-constant hazard rate. More experience with a certain type of transformer will ensure better accuracy in predicting performance; therefore, the hazard rate would decrease with increasing experience, which is proportional to time. In addition, different types of hazard rates (increasing with time increase, constant with time, and decreasing with time) are required for better predicting the component's condition. Some common distributions for different types of hazard rates are tabulated in Table 6.7

Table 6.7 Typical Distributions

Type of Hazard Rate	Distribution
Constant with time	Exponential, Weibull
Increasing with time	Normal, Weibull
Decreasing with time	Gamma, Weibull
Increasing and then decreasing with time	Lognormal

Weibull distribution could be used to represent the three types of hazard rates, and hazard rates of most of the components could be expressed in terms of Weibull distribution. Therefore, this work uses Weibull distribution to determine the reliability of each criterion. The hazard rate $h(t)$ for Weibull distribution is given by

$$h(t) = \frac{\beta}{\theta}\left(\frac{t}{\theta}\right)^{\beta-1} \qquad \text{(III.1)}$$

where β is the shape parameter, and α is the scale parameter. Figure 6.18 shows how the selection of these parameters affects the hazard rate. In general, $\beta > 1$ will result in an increasing hazard rate, $\beta = 1$ will produce a constant hazard rate, and $\beta < 1$ will result in a decreasing hazard rate.

Weibull distribution requires relatively few samples to estimate the parameters with relatively high accuracy [64]. Availability of historical failure data for distribution-level components is very minimal; therefore, Weibull distribution is the ideal candidate for modeling the component condition. However, Weibull parameters for each criterion of a component may not always be available. When parameters are not available, they must be estimated. Available historical data can be used to estimate parameters. In the absence of historical data, guidelines or standards governing the criteria could be used to estimate the parameters. In the event that both are unavailable, a hypothetical model could be used for the estimation. This would be ideal for nontraditional criteria. The following examples are given to illustrate these three methods.

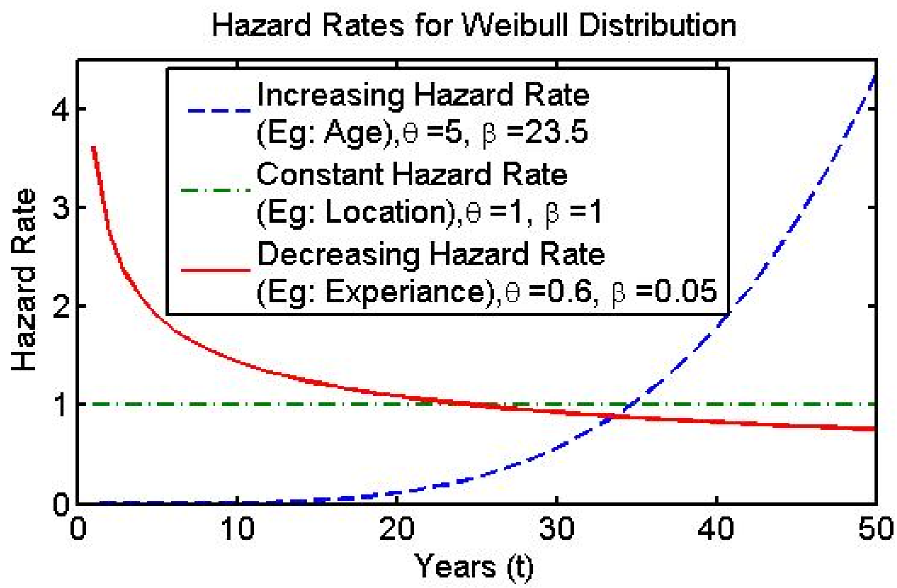


Figure 6.18 Hazard rate Functions for Weibull Distribution

Example 1: Reliability from Historic Data

For illustrational purposes, the relationship between the hazard rate and the age of the transformer given by Barnes et al. [65] is used. The hazard rate in (III.1) is written to estimate the shape and scale parameters as

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

Using the least squares method, the trend line for $\log_{10}(t)$ vs. $\log_{10}\left(h(t)\right)$ is determined, as shown in Figure 6.19, and the slope and the y-axis intercept are used to estimate the parameters.

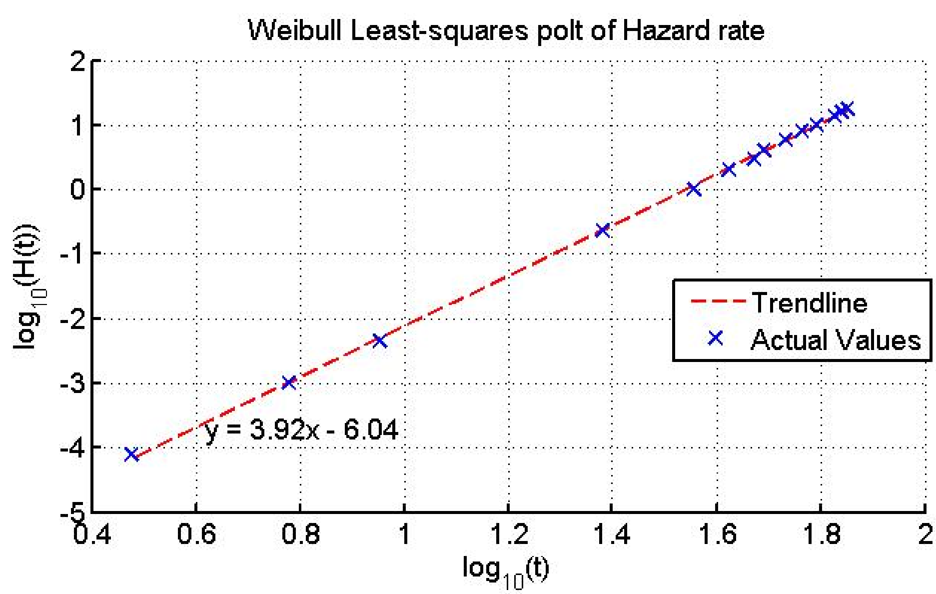


Figure 6.19 Weibull Least-Squares Plot of Hazard Rate

The slope of the trend line is used to determine the shape parameter as

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

Once the shape parameter is estimated, it is used along with the y-axis intercept to determine the scale parameter as

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

The hazard rate given in Barnes et al. [65] and the hazard rate estimated using the Weibull distribution are plotted in Figure 6.20, along with the estimated reliability function. The estimated parameters for the reliability function are acceptable, as the hazard rate determined by the Weibull distribution closely follows the data given by Barnes et al. [65].

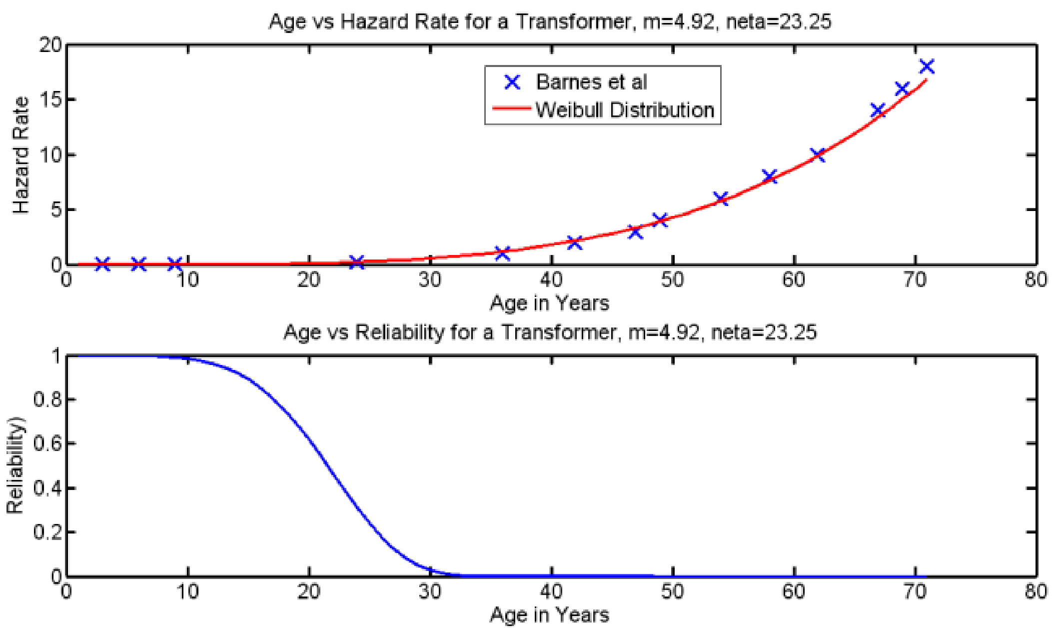


Figure 6.20 Comparing Hazard Rate Plot and Reliability Plot

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

$$R(t) = e^{-\left(\frac{t}{\theta}\right)^{\beta}} = e^{-\left(\frac{t}{23.35}\right)^{4.92}} \qquad \text{(III.2)}$$

If the reliability data is known in place of the hazard rate, then the relationship given in [64] could be used to estimate the Weibull parameters. If the relationship between $\log_{10}(t)$ vs. $\log_{10}(h(t))$ is not linear, then the particular criterion cannot be modeled using Weibull distribution; therefore, that criterion should be tested for the other distribution functions and the best fit should be determined and used.

Example 2: Reliability from Guidelines/Standards

To illustrate the parameter estimation using the guidelines/ standards, gas in oil is used as the example. It is assumed that no historical data is available for the reliability of the oil, based on the gas that is present in the oil. Therefore, IEEE Standard C57.104-2008 [66], which governs the level of dissolved gas in oil, is used to determine the reliability function. Four levels used to classify the risk for oil-immersed transformers due to dissolved gas are defined in IEEE C57.104-2008 [66]. Table 6.8 shows the relationship of the transformer condition and the total dissolved combustible gasses in parts per thousand (ppk).

Table 6.8 Dissolved Gas Standards (IEEE57.104-2008) [66]

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

If no other information is available, reliability for the four dissolved gas levels could be used to estimate the shape and scale parameters. Since Condition-4 indicates a very poor oil condition, a reliability of 0.02 is assigned to the TDCG[1] of 4.63 ppk. For the variable TDCG (x), the following relationship is determined using equation III.2:

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

The following hazard rate properties of Weibull distribution could be used to determine the shape parameter:

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

Most of the physical criteria demonstrate the convex hazard rate, as the *incremental rate of the hazard rate* (degrading) increases with time. Based on the expected incremental rate, the shape parameter β could be fixed. For this example, if the TDCG is higher than 4.63 ppk, then the dissolved gas will have an extremely adverse effect, and it is an indication that the oil should be treated to avoid catastrophic failure. A higher

[1] TDCG – total dissolved combustible gasses in oil

incremental rate is assigned to indicate this effect, and β would be fixed at 4. Therefore, the scale parameter θ could be found as

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

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

Example 3: Hypothetical Reliability

If a non-conventional criterion is used to determine the condition of the component, neither historic data nor standards will be available. A hypothetical approach would be the best option for the initial prediction of hazard rates. For illustrative purposes, experience with the type of transformer is used. Hazard rate due to experience with the transformer is a time-decreasing function.

The hazard rate is a function of the number of similar types of transformers. Since the number of similar transformers handled by the utility increases with time, a time-related relationship could be developed if needed. To estimate the Weibull parameters, the following relationships are used:

F – Total number of transformers failed
s – Total number of similar transformers handled
S_F –Total number of similar type of transformers failed
S_U –Total number of transformer reasons unknown (out of the same type of transformers failed)

Based on the expectation of the hazard rate function and its behavioral properties, the shape parameter β is defined as

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

and the scale parameter θ is defined as

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

Therefore, the estimated hazard rate function for the experience with the transformer type as a function of number of similar transformers handled (s) is

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

To verify the validity of the estimated hazard rate function, an analytical study was conducted. Three different cases were considered: change S_F while keeping S_U and F constant, change S_U while keeping S_F and F constant, and change F while keeping S_U and S_F constant. When S_F, S_U, and F are kept constant, the values used are 40, 10, and 90, respectively. Resulting hazard rates are plotted in Figure 6.21.

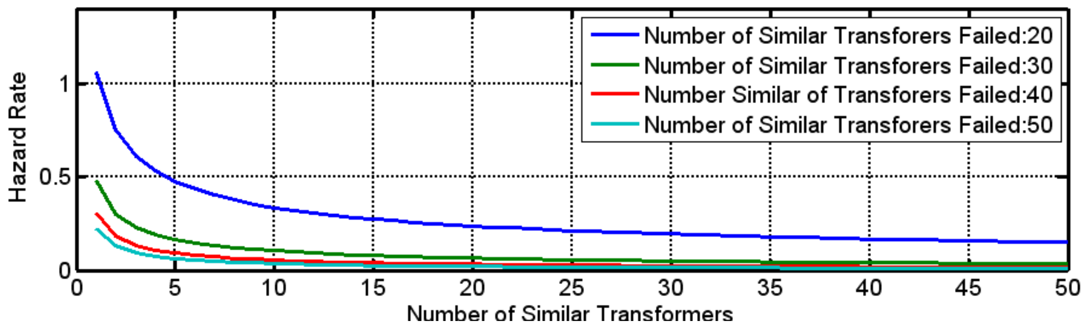
As mo78e transformers of a similar type fail, while keeping the number of transformers failed with unknown reasons constant, it is trivial that the number of transformers that failed with a known reason will increase. This should decrease the insecurity with that type of transformer, and thus the hazard rate should decrease. Numerical analysis using the developed hazard rate function in Figure 6.21(a) agrees with this expectation. Similarly, if a greater number of similar transformers failed with unknown reasons while the number of similar transformers failed was kept constant, then the hazard rate should be higher, as the utility company has less understanding about the transformer. Figure 6.21(b), from the numerical analysis, agrees with this. On the other hand, the total number of transformers failing should not have much impact on the hazard rate if the number of similar transformers that failed and the number of similar transformers that failed without any known reason is kept constant. Figure 6.21 (c) is also in accordance with this expectation. Therefore, it could be concluded that the developed hypothetical hazard rate is an accurate model.

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

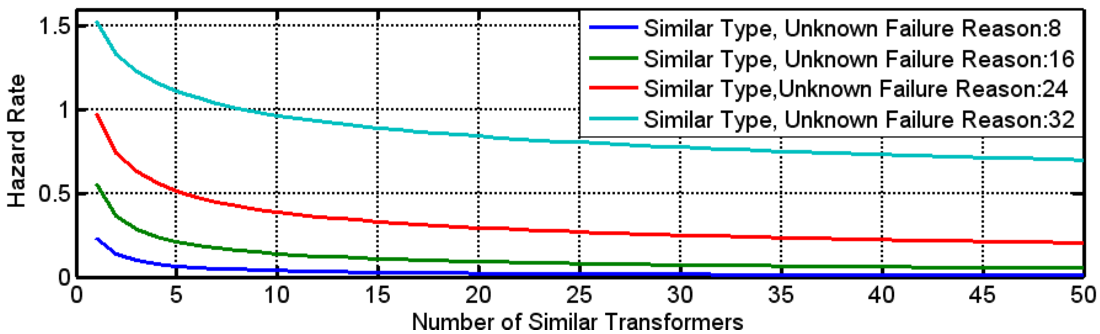
6.3.4 Series-Parallel Component Reliability Model

Once the reliability distribution functions for all criteria are known, the next step is to evaluate the reliability of the component. This work utilizes the series-parallel topology to determine the reliability of the component based on the physical failure mode of each criterion [67-68]. For example, if a transformer is loaded below its rating throughout its operation, then the transformer could be healthy for more than its predicted life; therefore, loading and age are connected in series. Water in oil, gas in oil, or acid in oil will adversely affect the transformer independent of each other; therefore, each of these criteria is connected in series. Proposed series-parallel reliability model for the transformer is given in Figure 6.22.

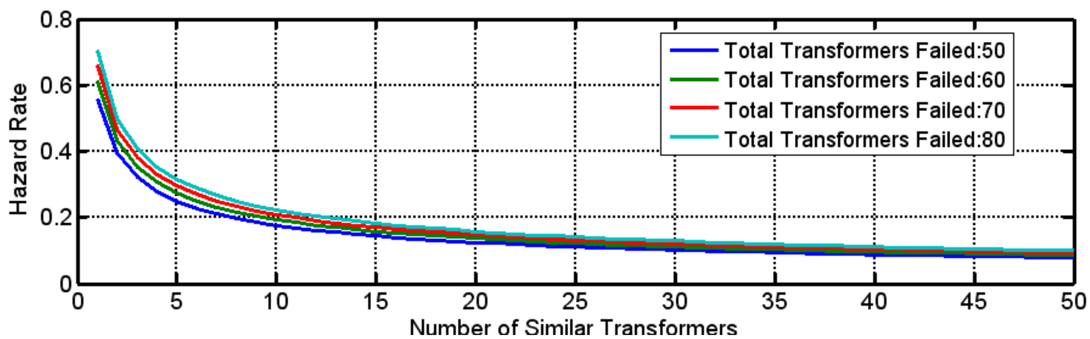
A series-parallel reliability topology model for an SF_6 circuit breaker developed by the authors is shown in Figure 6.23. Using a similar argument, a reliability model for all distribution-level components could be modeled.



(a) Change S_F for Given S_U & F



(b) Change S_U for Given S_F & F



(c) Change F for given S_F & S_U

Figure 6.21 Analytical Study for Hypothetical Hazard Rate

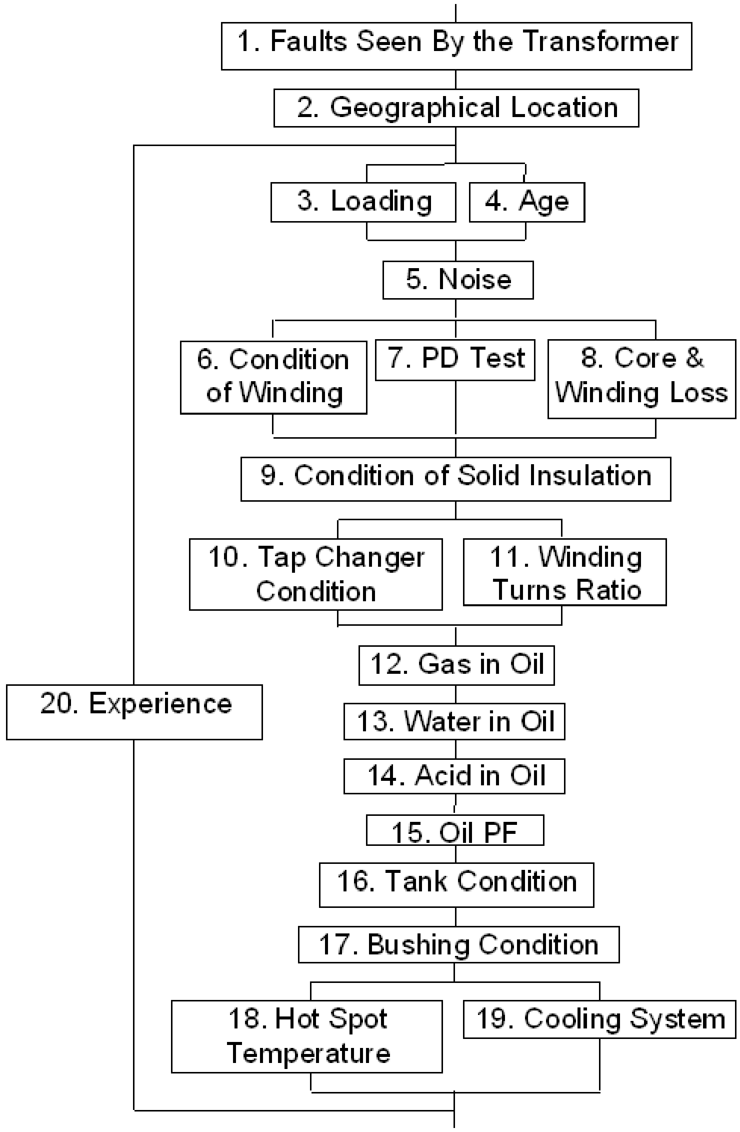


Figure 6.22 Series-Parallel Topology for Transformer Criteria

6.3.5 Weighting Technique

Not all criteria in a component will have the same level of impact on its failure. A weight is assigned to each criterion, depending on the importance of the criterion for the overall health of the component. Since the weights are system-specific, the operators should allocate them based on experience and manufacturer information. The following technique could be used to allocate weights:

1. The maximum weight that could be allocated to a criterion is one (1). Weight is proportional to the importance of the criterion needed for the healthy function of the component. For example, if gas in the oil is less then it will be less harmful than a small crack in the tank; therefore, the tank condition is given a higher weight than gas in the oil.
2. The weight for criterion i will have two parts:

a. *The effect that the criterion has on the failure of the component* (W_i^F): This part of the weight for each criterion should be allocated by experience out of 50 possible points. Based on experience, the weight for this part could be updated.

b. *The average number of maintenances/replacements for a criterion during the life of a component* (W_i^M): This part of the weight for each criterion shall be determined using the following relationship:

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

Where

MR_{same} = Total # of maintenance & replacement needed for a criterion during the life of component
MR_{total} = Total # of maintenance and replacement of all the criteria during life of the component

Therefore, the weight for criterion i shall be given as

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

Weighted reliabilities and failure distributions for a component with n criteria, is defined as $\widetilde{R_1}, \widetilde{R_2} \ldots \widetilde{R_n}$ and $\widetilde{Q_1}, \widetilde{Q_2} \ldots \widetilde{Q_n}$. The weighted failure distribution of criterion i is

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

where R_i is the reliability of criterion i. The weighted reliability for the same criterion is given by

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

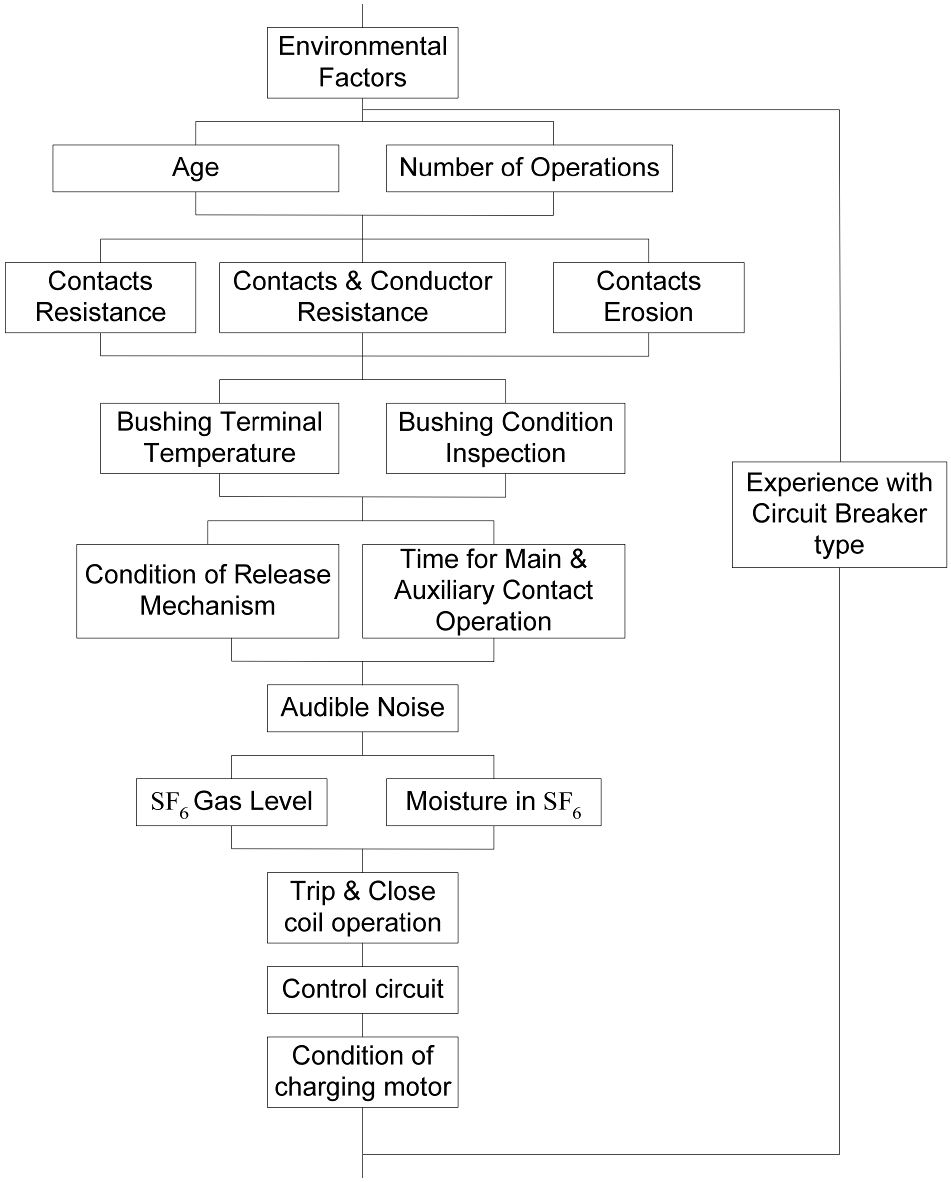


Figure 6.23 Series-Parallel Topology for SF_6 Circuit Breaker Criteria

6.3.6 Component Reliability Calculation

Series-parallel system is reduced to determine component reliability. To ascertain the reliability of a combined system, weighted reliabilities $(\bar{R}_i)$ are multiplied when two or more criteria are connected in series, and weighted failure distributions $(1 - \bar{R}_i)$ are multiplied if two or more criteria are connected in parallel. Based on the series-parallel topology of the power transformer, as given in Figure 6.24, the reliability of the component could be determined as in (IV.1).

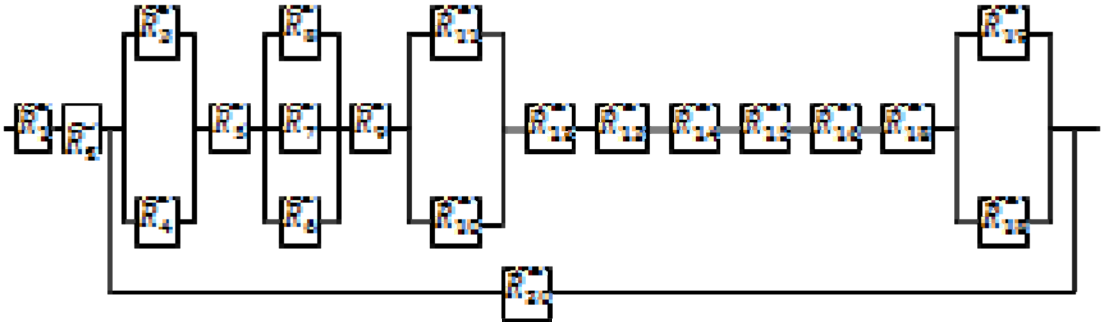


Figure 6.24 Series-parallel topology of transformer with reliability

$$\widetilde{R_{sys}} = \widetilde{R_1} \times \widetilde{R_2} \times \widetilde{R_{s20}} \qquad \text{(IV.1)}$$

where

$$\widetilde{R_{34}} = 1 - (1 - \widetilde{R_3})(1 - \widetilde{R_4})$$
$$\widetilde{R_{678}} = 1 - (1 - \widetilde{R_6})(1 - \widetilde{R_7})(1 - \widetilde{R_8})$$
$$\widetilde{R_{1011}} = 1 - (1 - \widetilde{R_{10}})(1 - \widetilde{R_{11}})$$
$$\widetilde{R_{1019}} = 1 - (1 - \widetilde{R_{10}})(1 - \widetilde{R_{19}})$$
$$\widetilde{R_s} = \widetilde{R_{34}}\widetilde{R_5}\widetilde{R_{678}}\widetilde{R_9}\widetilde{R_{1011}}\widetilde{R_{12}}\widetilde{R_{13}}\widetilde{R_{14}}\widetilde{R_{15}}\widetilde{R_{16}}\widetilde{R_{17}}\widetilde{R_{1819}}$$
$$\widetilde{R_{s20}} = 1 - (1 - \widetilde{R_{20}})(1 - \widetilde{R_s})$$

1. Component Condition Score

The next step is to translate the reliability to a qualitative measurement that would be easily understood by the maintenance crew. A component condition score (CCS), which would provide the relative health of the component, is used as a measure and defined as

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

where $\widetilde{R_{sys}}(t)$ is the weighted reliability at given time t, $\widetilde{R_{sys}}(worst)$ is the allowable worst weighted reliability based on historic data, $\widetilde{R_{sys}}(worst)$ is determined by estimating the worst reliability of each criterion using the historic failure data (except for geographical location, which will be kept constant), and $\widetilde{R_{sys}}(best)$ is the weighted reliability at the time of installation of the component.

2. Component Condition Report

Once the CCS is determined, a quantitative assessment should be done to identify the course of action. The following four grades established by CIGRE WG12.18 are used to decide the course of action [69]:

a. *Normal Condition:* Component is in defect-free condition with no obvious problems.

b. *Defective Condition:* Component has reversible abnormalities, which affect the life in the long term.

c. *Faulty Condition:* Component has irreversible faults, which could affect the reliability in the short term.

d. *Failed Condition:* Component cannot remain in service and needs remedial action.

A condition reporting guideline, shown in Table 6.9 and similar to the above standard, is proposed in this work.

Table 6.9 Equipment Condition Report

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

If a component is *Normal*, then there is no need to schedule a maintenance task immediately, and the component could wait to be inspected at the next maintenance period. If the component is *Defective*, then a maintenance task should be scheduled based on the subcategory, in order to give the utility some choices and visual understanding. A *Defective* condition is divided into seven sub-conditions. Depending on the severity of the condition and available resources, maintenance could be prioritized. If the component is *Faulty*, then immediate attention should be given to that component. Resources should be wisely utilized to ensure that no component is operated in *Faulty* condition, as this will adversely affect the reliability, and immediate replacement of the component is essential.

6.3.7 Numerical Analysis

Due to limited availability of component condition data, numerical analysis is done using assumed numerical values for the transformer. Based on the authors' perception of power transformers, weights are assigned for each criterion. A weight of 0.95 is used as the best reliability for each criterion except for geographical location (0.80), experience with the transformer type (0.65), and faults seen by the transformer (0.99) for trivial reasons. A weight of 0.10 is the worst possible reliability for each component, except experience with the transformer type and geographical location, which are kept the same as the best case. Table 6.10 shows the assumed weighs and the calculated component reliability;

highlighted criteria are connected in parallel. The component reliability is calculated using (IV.1).

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

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

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

$$R(18) = e^{-\left(\frac{18}{28.35}\right)^{4.92}} = 0.76$$

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

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

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

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

Therefore, the reliability of the experience with the transformer is

$$R(60) = e^{-\left(\frac{1.9}{0.44}\right)^{0.25}} = 0.03$$

Table 6.10 Condition Weights and Best Condition Reliability

Criterion	**Weight**	$R(t')$	$R'(t^*)$
Faults seen by transformer	0.70	0.99	0.965
Geographical location	0.60	0.80	0.940
Loading	0.80	0.95	0.960
Age	0.90	0.95	0.955
Noise	0.40	0.95	0.980
Condition of winding	0.90	0.95	0.955
PD test	0.75	0.95	0.963
Core and winding loss	0.80	0.95	0.960
Condition of solid insulation	0.80	0.95	0.960
Tap-changer condition	0.60	0.95	0.970
Winding-turns ratio	0.70	0.95	0.965
Gas in oil	0.90	0.95	0.955
Water in oil	0.90	0.95	0.955
Acid in oil	0.90	0.95	0.955
Oil PF	0.90	0.95	0.955
Tank condition	0.90	0.95	0.955
Bushing condition	0.90	0.95	0.955
Hot spot temperature	0.70	0.95	0.965
Cooling system	0.70	0.95	0.965
Experience	0.50	0.05	0.505
Component: $\widetilde{R}_{sys}(best)$			**0.800**

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

With similar analysis, reliability of all criteria could be determined. Due to the computational similarities, the calculations for the other criteria are not presented here. Table 6.11 shows the component reliability calculated for the transformer using calculated reliabilities for the three examples and assumed values for the others.

Using the reliability of the component estimated in Table 6.11, the CCS for the transformer will be

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

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

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

Table 6.11 Component Reliability for Healthy Component

Criterion	**Weight**	$R(t')$	$R'(t')$
Faults seen by transformer	0.70	0.80	0.86
Geographical location	0.60	0.90	0.94
Loading	0.80	0.80	0.84
Age	0.90	0.76	0.784
Noise	0.40	0.90	0.96
Condition of winding	0.90	0.80	0.82
PD test	0.50	0.82	0.91
Core and winding loss	0.80	0.80	0.84
Condition of solid insulation	0.80	0.88	0.904
Tap-changer condition	0.60	0.91	0.946
Winding-turns ratio	0.70	0.95	0.965
Gas in oil	0.90	0.92	0.928
Water in oil	0.90	0.87	0.883
Acid in oil	0.90	0.89	0.901
Oil PF	0.90	0.90	0.91
Tank condition	0.90	0.92	0.928
Bushing condition	0.90	0.90	0.91
Hot spot temperature	0.70	0.80	0.86
Cooling system	0.70	0.80	0.86
Experience	0.50	0.03	0.515
Component: $\bar{R}_{sys}(t)$			**0.598**

6.3.8 Conclusion

This work has developed a guideline for statistical component condition assessment based on historical data. The reliability of each component is estimated based on the calculated hazard rates of each condition criterion for the component. The criteria are defined from analysis of component failure modes. Hazard rates are estimated using available component monitoring information, historical failure data, manufacturer and utility experience with the component, and available standards and guidelines relevant to the component. Each of the criteria is assigned a reliability distribution function using the Weibull distribution, which is suitable for smaller failure samples. Component reliability is determined using the weighted reliabilities of the criteria. Quantitative and qualitative component health levels are determined to decide the appropriate maintenance action. The methodology is illustrated for power transformers. Since this approach uses time-varying hazard rates and current field data, the methodology can be used for maintenance scheduling. The automated condition monitoring needed for full implementation of this technique will be available as Smart Grid technologies are implemented on the system.

7 Communication Requirements

7.1 Current Trends (IEC 61850 application, etc.)

Reliable communications at the distribution level has high importance for the Smart Grid. There has already been significant work done on power system communication needs and applications. IEC 61850 and DNP 3 standardize the communication within the substation. ANSI C12.22 networking standards apply to advanced metering infrastructure [70]. Even though 80% of consumer interruptions are attributed to distribution component failures at the feeder level, getting reliable information is currently a challenging task. Because of this, only limited monitoring is done on components in the distribution system and the associated communication infrastructure. Due to these difficulties, distribution failure/abnormality analysis is done by harvesting information from the components at substation level. There has been a significant amount of work to analyze such data [71-74], but even analyzing the whole feeder using information from substations will not capture all the necessary information.

Accurate prediction and location of distribution failures are still in an early stage of development. If the communication infrastructure is improved a more reliable approach could be taken and this would also aid better asset management strategies. The motivation for this paper is to identify the needs for communication at different levels in the distribution system, the substation level, feeder level, distributed source level, and consumer level, with more emphasis on the feeder level. In addition to the asset and outage management tasks, communications will also help improve energy management and tariff related tasks.

This work considers wireless communication as a medium for feeder level communication. Leon, et al, have proposed a two-layer wireless sensor network for transmission towers, mainly to reduce the cost of operation while overcoming the limitations of wireless communication range [75]. Muthukumar, et al, proposed a wireless sensor network for distribution level automation [76]. Motivated from these, this work identifies the requirements for communication for distribution feeders and explores the feasibility of wireless communication. Specific contributions of this work include:

i. Explain the selection of a wireless medium for communication at the feeder level.
ii. Identify the specific requirements for wireless communication at the feeder level including metrics for reliability.
iii. Compare and contrast various wireless technologies and identify a feasible subset for the envisioned architecture.
iv. Describe how the chosen wireless technologies come together in a three-layer communication architecture.

7.2 Performance Requirements for Distribution Level Communication

Traditional system control and data acquisition (SCADA) level communication has limited bandwidth, 75 bits/s to 2400 bits/s [77]. Greater bandwidth is necessary if the information from the components is going to be used not only for monitoring (abnormality detection), but also for control and asset management tasks. Intra-substation communication is moving from binary or analog communication to Ethernet and TCP/IP based wide area network. IEC 61850 standardizes the communication network within a substation [78-79]. IEC 61850 could be extended to distributed sources. Smart meter technologies are capable of using TCP/IP based communication to/from the control center. The emerging standard ANSI C12.22 standardizes the communication network for smart meters [70].

Advancements in signal processing with low cost processors and networking technologies have made communication through TCP/IP more secure, cheaper and reliable. Using a common networking protocol for all the different levels of communication in a distribution system will optimize the infrastructure at the control center and increase its performance. A common connection oriented layer 3 (Open Systems Interconnection (OSI) model) based reliable communication network would be an ideal solution for smart-grid applications. IEC 61850 uses reliable TCP/IP and priority flags for Generic Object Oriented Substation Event (GOOSE) and Sampled Measured Values (SMV), using IEEE 802.1Q (VLANs) which offers more secured and intelligent usage of Ethernet switches [78].

Based on the above discussion, this work recommends a similar approach for the entire distribution system. The proposed communication network with different levels of communication is presented in Figure 7.1.

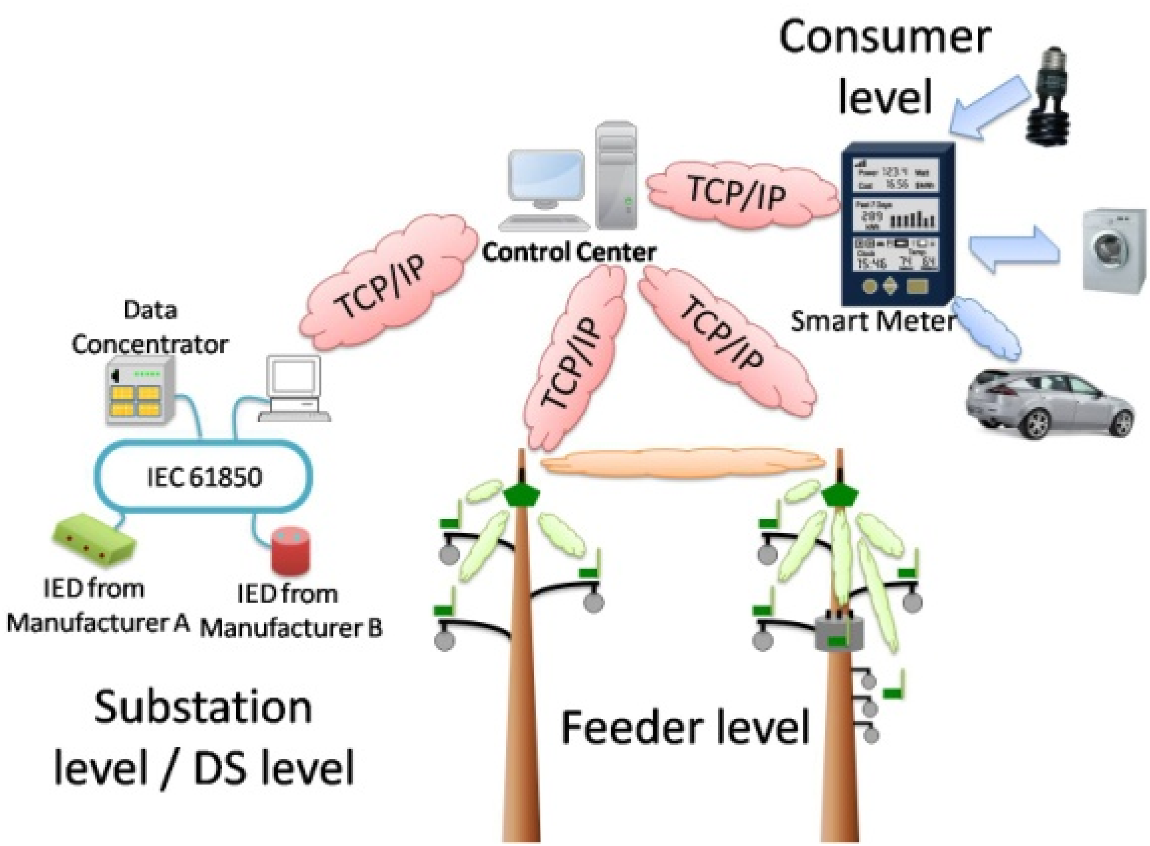


Figure 7.1 Communication Network for Distribution System

Figure 7.1 shows three levels of communication. Each of these networks would have two states of communication. The higher priority state would be the abnormal event state, where a detected event with estimated location would be transmitted to the control center for further action. The low priority state will transmit component condition data for asset management tasks. Substation level communication will have higher priority than the feeder level and consumer level communication, which will be operated with lower priority. Data (packets) traffic in the communication network can be prioritized using IEEE 802.1Q standards similar to priority tagging in IEC 61850.

Except for substation level communication, other parts of the distribution system currently lack standards, which are needed for efficient use of equipment from multiple vendors/manufacturers. It is also necessary to increase security of transmitted data to mitigate the effect of hacking and modifying data. Security and connectivity of components should be given a higher priority at the consumer level. Utilities have the burden of ensuring all components used are connected to the appropriate smart meter. These will all have significant impacts on choosing the medium of communication.

7.2.1 Choice of the Communications Medium

Potential communication media for distribution system networking include power line carrier (PLC), wireless, and dedicated wired. When the substation is considered due to the confined physical space, a dedicated wired medium such as Ethernet is the best choice. Substation communication networks use the well-established IEC 61850 and thus this paper will not discuss the requirements for substation level/distributed source level communication and medium.

When feeders are considered, PLC is well-suited, because it is a medium that is available throughout the distribution system. PLC has potential to transmit data at a maximum rate of 11 kbit/s; when the PLC has sufficient robustness and reliability, this maximum data rate can be achieved only in a narrow frequency range of 9-95 kHz [80]. This low rate of communication is not ideal for secure communication. Therefore, if more information has to be sent from all the components in a feeder, higher bandwidth is required. Current developments in broadband over power line (BPL) technologies suggest that it is a promising technology.

The distribution system will be affected by unpredictable voltage transients and harmonics, and these affect the reliability and speed of BPL. High frequency BPL signals need to bypass transformers to avoid high attenuation [81]. BPL signals may also be blocked by voltage regulators, reclosers and shunt capacitors which are common for long radial feeders [82]. The attenuation in a radial distribution feeder is high and this would increase the number of regenerators needed. It is expected that a typical 20-mile rural feeder would need 30-110 regenerators [82]. This shows that even though the medium is free, BPL costs are significant.

Further, when a pole fails the PLC/BPL communication link fails as well. This would be a major concern when the communication is used for automatic fault location and system restoration. For Smart Grid applications highly reliable communications is necessary. Prior work recommends having 99.995% availability of communication [77] for a reliable Smart Grid system. The 99.995% requirement would result in unavailability of communication to less than 44 hours per year. This would further initiate the discussion on performance indices for the communication network as an additional measure for Smart Grid performance. All these concerns develop a case to explore other options for the communication medium at the feeder level.

Another option is dedicated wired communication. One of the problems with copper wire connections is interference and attenuation. Fiber optic cables are a solution for interference but increase the cost. It should be noted that investment for a fiber optic network would be $10-100 million for 100 nodes [83]. Newly developing communities could install a fiber optic communications network close to the feeders, so that this infrastructure could be shared for both Smart Grid and consumer communication needs. One of the advantages of this medium is that the utility has to bear only the terminal equipment cost and costs associated with leasing the line. This will reduce the overhead for the utility while improving communications. On the other hand the utility will not have control over the medium as it will not own the dedicated wired medium in most cases. This will require physical connections and will reduce the flexibility. Further when a pole goes down, the communication link will be broken and may result in poor performance.

Wireless communication is another promising alternative for distribution level communication. One of the important characteristics of wireless communication is the feasibility of communication without a physical connection between two nodes. This would ensure the continued communication even with a few poles down. In other words redundant paths for communication are possible without additional cost.

According to Huertas et al, discharges between the line components which arise in power lines under 70 kV and the corona effect which arise in power lines over 110 kV have the dominating frequency spectrum in the range of 10 – 30 MHz [84]. Selection of medium with communication frequency spectrum above these limits would minimize the interference. Wireless Fidelity (WiFi / IEEE Standard 802.11), ZigBee (IEEE Standard 802.15.4) or Worldwide Interoperability for Microwave Access (WiMAX / IEEE Standard 802.16) could be utilized in the distribution system with minimal interference.

Another advantage of using wireless communication is that the utility has to own only the terminal units, which are relatively cheap and could be integrated with cost effective local processors. When multi-hopping is used in wireless communication, especially in WiFi and ZigBee, the range of communication can be extended and the nodes located in the feeder could be able to communicate with the control center.

Disadvantages of wireless communication would be interference in the presence of buildings and trees which could result in multi-path; this can be avoided with improved receivers and directional antennas, which will increase the cost. Another major concern with wireless medium is easy accessibility, which could result in security issues. This can be avoided by using secure protocols. Rural feeder sections would be long and range of communication could become a concern; however, directional antennas could mitigate this issue.

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

7.2.2 Feeder Level Requirements

The expected communication need for the feeder level is shown in Figure 7.2. At the smart meter level, a consumer will have three types of appliances, the ones which will not be controlled by the smart meter, e.g.: lights, cooker, etc, the ones which can be controlled by the smart meter, e.g.: washer, dryer, air condition, etc and the ones which needs to be controlled by the utility through the smart meter, e.g., electric vehicles (EV). This work suggests three different types of communication for these three types.

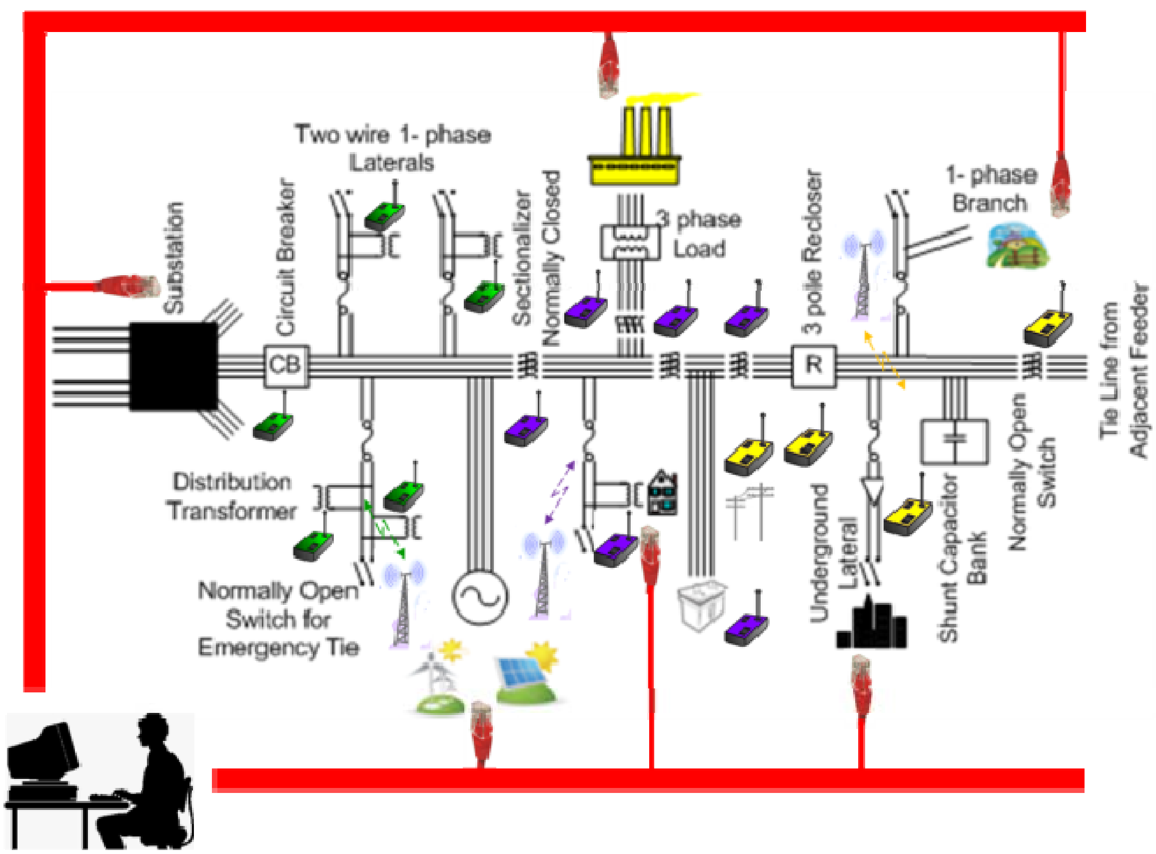


Figure 7.2 Communication Requirement at Feeder Level

The ones which need not be controlled by the smart meter needs only unidirectional communication, whereas the other two will need bidirectional communication. In order to minimize the cost the ones which may not be controlled could use PLC as the medium for communication. Due to the large amount of data and the possibility to communicate with the smart meter from different locations EVs needs to have wireless capabilities and should be able to have a secured connection to the smart meter via Internet. It should be noted that for controlled charging applications, EVs may have to communicate with the utility while on road and from locations where wired communication is not possible.

To minimize the cost, overcome the restriction of range issue of sensor nodes, and increase the redundancy, a three layer communication model, shown in Figure 7.3 is proposed for feeder level communication. This “no new wires” technology is developed to ensure easy installation on the existing system.

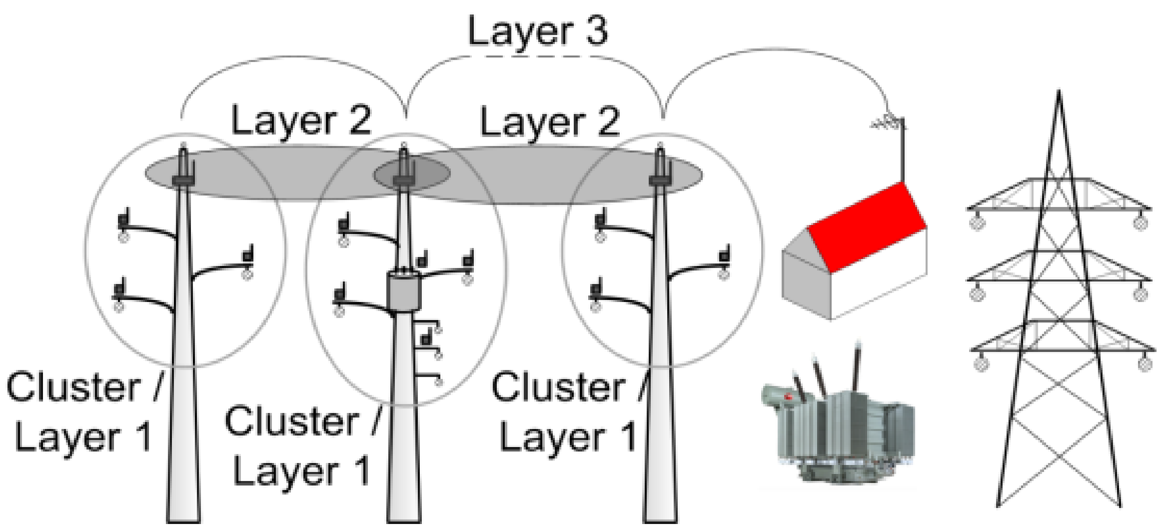


Figure 7.3 Three-Layer Communication for Distribution Feeder

Wireless sensor nodes with minimum processing capacity and with short transmission range are installed on the towers of the distribution system. Functionality of both transmitter and receiver are combined in these wireless sensor nodes. Since these sensors need to be deployed massively, the cheaper wireless sensor nodes are more economical. Each tower with the group of sensors is termed as the cluster. Each cluster is equipped with a processing unit with long transmission range, which is known as the master node. Layer-1 communication, showed as Cluster in Figure 7.3, occurs between the wireless sensor nodes and master node. Readings from these sensor nodes are communicated in this step.

The master node continuously monitors data from all wireless sensor nodes belonging to its cluster. In case of an abnormality observed by a master node, communication among clusters will be initiated. Observed abnormality will be shared among the clusters and the abnormality and location is identified by processing the cumulative information. This process is expected to reduce the false alarm and missed detections. This will be known as Layer-2 communication as shown in Figure 7.3, and will occur among master nodes of adjacent clusters.

Layer-3 communication in Figure 7.3 is between a master node which saw the abnormality and the control center. WiFi is used in this layer due to its cost effectiveness. To overcome range constraint of WiFi, Layer-3 communicates detected abnormal event from the master node which saw the abnormality first to the control center. Due to longer distance, multi-hop approach is utilized to transmit data as shown in Figure 7.3.

In the process of assuring that the necessary information is not a false alarm, it could communicate with neighboring master nodes which would be the second stage of communication. It should be noted that any information loss in a cluster would result in missing an event and when the master node is communicating with the control center, it should ensure that any abnormality in the system should reach the control center, requiring redundant paths for higher reliability. When the master node tries to send asset management information, it could wait and ensure that reliable communication is possible before sending the information.

7.2.3 Reliability

Availability of communications infrastructure will have a direct effect on Smart Grid and power system performance. The electric power system is a reliable system already, so any communications system supporting it must have a similar high reliability. If the availability of the communication system is lower than the availability of the power system, then the communication infrastructure may not serve its purpose or even be worth the investment. Therefore a way to measure the performance of the communication system and benchmarking it is very important. Communication requirements for smart meter applications should be higher than that of the feeder level. Household appliances will depend on this information received by the smart meter for the operation and any error could cause unexpected outcomes. Following reliability standards for distribution level communication is derived based on the power system and communication reliability standards.

Active Communication should be available both during the sustained interruption (any interruption longer than five minutes) and momentary interruptions. Since sustained interruptions for the smart meter directly involves the consumer satisfaction, sustained interruption indices for distribution communication similar to sustained interruption indices for distribution reliability (IEEE std. 1366-2003) [85].

Average Communication Failure Frequency Index (ACFFI)

A common metric to measure the feasibility that wireless communication can be done on a link between two points is based on signal-to-noise ratio (SNR). If the SNR at the receiver is below the threshold then that information could not be accessed by the smart meter. Each set of information sent to the smart meter needs to be received above the required SNR value. Therefore as a tool to ensure reliable communication, the number of times the SNR was less than the required as an average over all the components could be used. It should be noted that not all piece of equipments in a household will have same level of importance. For example information from a dryer is more important to the smart meter than an electric bulb. Therefore this work proposes a predefined weighed index to measure the reliability. This is defined as;

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

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

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

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

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

Average Communication Interruption Duration Index (ACIDI)

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

$$ACIDI_k = \frac{\sum_{\forall\, i \in k} \begin{array}{c}\text{Duration of communication failure for}\\ \text{each node due defect } i \text{ in cluster } k\end{array}}{\text{Total number of nodes in a cluster}}$$

Therefore the average interruption duration would be,

$$ACIDI = \sum ACIDI_k$$

Energy Not Served Due to Communication Failure (ENS-C)

One purpose of the Smart Grid communications infrastructure is to increase distribution reliability, and thus increase the total energy provided by the system in a time period. Measure of energy not served due to communications system failure is thus proposed:

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

This ENS-C index provides another measure of the performance of the Smart Grid, and any return on investment it will provide.

8 Feeder Level Communication

8.1 Introduction

The need for improved communication at the power distribution level takes on greater importance with the introduction of the Smart Grid approach. Significant work has been done on power system communication needs and applications. IEC 61850 and DNP 3 standardize communication within the substation. ANSI C12.22 networking standards were built for advanced metering infrastructure [70]. Even though 80% of consumer interruptions are attributed to distribution component failure (at the feeder level), obtaining reliable information is still a challenging task. This is due to lack of component monitoring in the distribution system and the communication infrastructure. As a result, failure/ abnormality analysis is done by harvesting information from the components at the substation level. A significant amount of work in analyzing such data [71-74] has been done, but even investigating the entire feeder using the data from substations (beginning or end of a feeder) will not capture all the necessary information.

Due to the non-trivial nature of failures/abnormalities, the exact prediction and location of a failure, independent of the feeder model, is still in premature stages. By improving the communication infrastructure, a vital ingredient for the Smart Grid, a more reliable approach could be taken to better manage assets. In addition to asset and outage management tasks, communication will also aid in better energy management and tariff-related information.

The motivation for this part of the project is to propose a wireless mesh architecture for meeting the communication requirements between the control center and smart meters deployed in residences and commercial end points. This work considers wireless communication as a medium for feeder-level communication. It identifies the requirements for distribution feeder communication and explores the feasibility of wireless communication. Specific contributions of this work include the following:

i. Encourages the design choice of using a wireless medium for communication at the feeder level.

ii. Compares and contrasts various wireless technologies, and identifies a feasible subset for the envisioned architecture.

iii. Evaluates how existing communication protocols designed for wireless mesh networks perform for network topologies expected in the power grid.

iv. Provides direction on how the wireless mesh architecture should be deployed to meet application requirements and optimize communication performance.

8.2 Wireless Communication in Smart Grid

In this section, we provide the motivation for choosing a wireless communication medium over other possible communication technologies. Furthermore, we compare our contributions to prior work in this area.

8.2.1 Choice of Communication Medium

A Smart Grid communication network is an emerging technology that allows power utility companies to access electricity usage data and services remotely, regardless of their geographic position. Real-time monitoring of transmission and distribution lines for protection against natural disasters or even malicious attacks are all reasons to have a secure, reliable, and scalable network in Smart Grids. Several last-mile options are available for getting a Smart Grid network to be operational. Broadband technologies like Digital Subscriber Line (DSL, Fiber Options (FTTX), and Power Line Communication (PLC) are all examples of last-mile options for consideration. Here, we will explain the limitations of the above-mentioned technologies due to their fixed nature and inflexibility.

When distribution feeders are considered, PLC is well-suited, because it is a no-cost medium for the utility and is spread along the distribution system. PLC has the potential to transmit data at a maximum rate of 11 Kbit/s, when it has sufficient robustness and reliability and the maximum data rate can be achieved only in a narrow frequency range of 9 to 95 kHz [80]. The lower rate of communication is not ideal for secured communication. Therefore, if more information has to be sent from all the components in a feeder, higher bandwidth is required. The current developments in the Broadband over Power Line (BPL) would create an impression that this is the best technology.

The distribution system will be affected by voltage transients and harmonics consistently which are unpredictable, therefore this is prone to high disturbance. High-frequency signal (BPL) needs to bypass transformers to avoid high attenuation [81]. The attenuation in a radial distribution feeder is high, and this would increase the number of regenerators needed. It is expected that a typical 20-mile-long rural feeder needs regenerators on the order of 30 to 100 [82]. This shows that, even though the medium is free, communication does not occur free of cost. High-frequency signals may be blocked by voltage regulators, reclosers, and shunt capacitors, which are common in long radial feeders [82].

Furthermore, when a pole goes down, it takes the communication link down as well. This would be a major concern when the communication is used for automatic fault location and system restoration. For Smart Grid applications, very high, reliable communication is necessary, and some prior work recommends having 99.995% availability of communication [77] for a reliable system. This percentage requirement would result in the per-year unavailability of communication to less than 44 hours. All these concerns build the case to explore other options for the communication medium at the feeder level.

Another option would be to use dedicated wired communication; however, one problem with copper wire connections is interference and attenuation. Fiber optic cables would be a solution to the interference but would increase the cost. It should be noted that the investment required for a fiber optic network would be on the order of $10-100 million for 100 nodes [83]. Newly developing communities could install a fiber optic communication network close to the feeders, so that the infrastructure could be shared for both Smart Grid and consumer communication needs. One of the advantages of this medium is that the utility would bear only the costs of the terminal equipment and for leasing the line, which would reduce the utility's overhead and improve communication. On the other hand, the utility would not have control over the medium because, in most cases, it would not own the dedicated wired medium, and it would require physical connections and reduce flexibility. Furthermore, when a pole goes down, the communication link would be broken and may result in poor performance.

Wireless communication is a promising alternative for distribution-level communication. One of the important characteristics of wireless communication is the feasibility of communication without a physical connection between two nodes, thus ensuring continued communication even when a few poles are down. In other words, redundant paths for communication are possible without additional cost.

Another advantage of using wireless communication is that the utility must own only the terminal units, which are relatively cheap and could be integrated with cost-effective local processors. When multi-hopping is used in wireless communication, especially in WiFi and ZigBee, the range of communication could be extended, and the nodes located on the feeder would be able to communicate with the control center.

The disadvantages of wireless communication would be interference due to the presence of buildings and trees, which could result in multi-paths; this could be avoided with improved receivers and directional antennas, which might increase the cost. Another major concern with a wireless medium is easy accessibility, which could result in security issues. This could be avoided by using secure protocols. Rural feeder sections would be long, and the range of communication could become a concern; however, directional antennas could mitigate this issue.

8.2.2 Impact of Interference Due to Transmission Lines on Wireless Medium

One of the concerns in using wireless communication along power lines is the interference from high-voltage transmission lines. Electromagnetic noise generated around high-voltage power lines is an undesirable disturbance, which can affect wireless data transmission. This noise can be observed as an additive signal to the original one, and it can interrupt, obstruct, degrade, or limit the performance of communication systems. According to [84] this noise is due to the following:

Discharges between line components: This occurs only in power lines under 70 kV. This type of noise is generated in insulators, in metallic parts, or in faulty or not properly installed equipment. The noise tends to dominate the frequency spectrum between 10 and 20 MHz. Its effects can be controlled by ensuring a correct power line installation and proper maintenance.

Corona effect: This affects power lines over 110 kV and tends to dominate the frequency spectrum between 10 and 30 MHz. It is generated due to partial discharges in areas with a very high electric field and causes acoustic noise, electric current, energy loss, radio interference, and mechanical vibrations.

In [84], it was concluded that the radio interference generated by high-voltage lines diminishes logarithmically with the distance to the power line and with increasing frequency. Therefore, it is recommended that communication modules be operated at frequencies greater than 100 MHz. A selection of wireless communication technologies like WiFi, ZigBee, or WiMax, which operate in the GHz range, could be utilized in the distribution system with minimal interference.

8.2.3 Prior Work

Recently, many attempts have been made to deploy wireless technologies in a Smart Grid. Some of them involved metering options and how to read their data, some focused on sensor networks and receiving their data, and others were based on feeder-level communication. As one work that considered most last-mile options for telecommunication in a Smart Grid, [86] talks about backhaul solutions for the distribution network. Recall from Section 9.2.1 that one approach for interconnecting a Smart Grid is using Power Line Communication. The authors of [87] considered PLC in low- and medium-voltage distribution grids to connect network nodes (e.g., meters, actuators, sensors) through multi-hop transmission. They investigated the application of geographic routing protocols and gauged their performance with respect to energy consumption and transmission delay. They investigated the use of Beacon Less Routing (BLR), Implicit Geographic Forwarding (IGF), and Beacon-Based Routing (BBR). They also included Shortest Path Routing (SPR) and flooding as benchmark schemes. In fact, they used Greedy Perimeter Stateless Routing (GPSR) as a general geographic algorithm and BLR, IGF, and BBR as approaches of this algorithm to see which one achieved a performance close to that of SPR. What is remarkable in this paper is that SPR assumed perfect knowledge of instantaneous link qualities and relied on a centralized optimization. BBR performed better than IGF, assuming that the frequency of hello messages was set commensurate with the network (connectivity) dynamics.

The connectivity of smart meters and their connectivity in Smart Grids is another subject with a significant body of work. The authors in [88] proposed a unified solution for Advanced Metering Infrastructure (AMI) integration with a Distribution Management System (DMS). They found that a challenge of the integration of AMI and DMS is that it entails different communication protocols and requirements for handling various meter information models. They claimed that by caching and delivering meter data back and forth between DMS and AMI systems, the proposed solution architecturally isolates the two systems, minimizes the influence of the AMI meter data load on DMS systems, and vice versa. Leon et al. proposed a two-layer wireless sensor network for transmission towers, mainly to reduce the cost of operation while overcoming the limitations of a wireless communication range [75]. Muthukumar et al. proposed a wireless sensor network for distribution-level automation [76].

While the prior work above discusses how to design a network, some researchers have looked beyond. For example, [89] discussed one of the key components of a future Smart Grid called load leveling, i.e., shifting the demand in time so as to match the available supply and in so doing improving utilization of resources and reducing the reliance on environment-unfriendly reserve sources of energy as much as possible. The challenge here is in achieving such load leveling, and this work elaborates on how existing techniques from networking research could be potentially applied to solve these problems. Regarding connectivity of home area networks to smart meters, [90] studied the connection of a home-area sensor network to an energy management unit. They proposed the Appliance Coordination (ACORD) scheme, which uses an in-home Wireless Sensor Network (WSN) and reduces the cost of energy consumption. The cost of energy increases at peak hours; hence, reducing peak demand is a major concern for utility companies. With this scheme, they aimed to shift consumer demands to off-peak hours. Appliances use the readily available in-home WSN to deliver consumer requests to the Energy Management Unit (EMU). EMU schedules consumer requests with the goal of reducing the energy bill. The authors of [91] described an approach to modeling wireless communications at the link layer of the power grid, which first identifies the various applications utilizing a specific link. Second, it translates the requirements of these applications to link traffic characteristics in the form of a link-layer arrival rate and average message size. Third, it uses a coverage analysis to determine the maximum range of the technology under an outage constraint and for a given set of channel propagation parameters. Finally, using the link traffic characteristics and coverage area determined above, it employs a Medium Access Control/Physical (MAC/PHY) model to measure link performance in terms of reliability, delay, and throughput.

Some researchers believe that wireless communication is not enough to meet the entire needs of Smart Grid communication. The authors in [92] describe a hybrid Wireless-Broadband over Power Lines (W-BPL) technology. They believe that this combination is suitable for rural and remote areas. The hybrid approach employs BPL technology for the transmission of communication signals via the medium voltage (MV) grid and wireless technology for providing broadband access to end users. They showed the advantages and opportunities of this approach in a case study of Larissa, a rural area in central Greece. This network offers broadband access and Smart Grid applications along a 70 km MV power grid.

In this section, we focus on feeder-level communication requirements and challenges. Having chosen the wireless communication medium for the grid, our goal is to compare different technologies and pick one, considering the characteristics of the grid. After identifying a suitable technology, we determine the best architecture for it and optimize it for parameters like transmit power and receiver sensitivity of individual nodes, distance between nodes, protocol data rate, and other factors that specify the network's performance. We study network performance by first selecting a suitable routing protocol and then use it as the basis for evaluating other parameters mentioned above.

8.3 Wi-Fi Mesh Network Architecture

8.3.1 Essential Features

In our envisioned wireless communication architecture, the following features are essential for end-to-end communication:

Security: Since the network is for a large nationwide electric grid, protecting connectivity and keeping its data confidential are critical. Design choices in developed protocols should include aspects for secure communication. Several reliable security solutions have been proposed and tested in different wireless architecture like mesh.

Low latency: Since grid functionality can be critical, having fast and real-time reaction in the case of an abnormal event is vital. Wireless architecture should strive for high-priority, low-latency alerts during abnormality.

Fixed stations (and few mobiles): In a Smart Grid, almost all nodes are fixed. Therefore, the communication architecture does not have to factor in node mobility explicitly. However, the ability to support mobility for some nodes would be helpful for situations like a maintenance vehicle trying to connect to the network through the grid.

Low overhead: Excessive use of control packets and multiple nodes trying to send the same information constitute high overhead. This reduces available bandwidth for data traffic and can result in higher latencies for critical-alert packets. Therefore, it is necessary to ensure that overhead is kept low.

Scalability: The network of wireless nodes is expected to be quite large considering the scale of towers from the substation to residential units. The communication architecture must work equally well for a small network as for a large network.

We leave the issue of security for future work; in this project we propose an architecture and evaluate it with respect to the other four features mentioned above.

8.3.2 Selection of Appropriate Wireless Technology

Among the choices of wireless technologies, WiFi (peak bandwidth 54 Mbps), WiMAX (peak bandwidth 100 Mbps), and cellular data service (peak bandwidth 10 Mbps) are compared in Table 8.1. Based on the information in this table, WiFi mesh seems to be the superior technology for Smart Grid applications at the feeder level, and WiMAX could be used as a gateway for long-haul communication based on availability and cost considerations. Taking into account the above considerations, a final architecture could be as shown in Figure 8.1. For WiFi, unlicensed frequency bands are preferred, due to cost benefits and additional robustness that could be possible by leveraging community WiFi networks.

Table 8.1 Comparison of Possible Wireless Technologies

Customer Need	WiMAX	Wi-Fi Mesh	GSM/UMTS
Cost	High	Medium	High
Range	Rural 4 km Urban 500–900 m	200–400 m	1–2 mi
Maximum Data Rate	70 Mbps	54 Mbps	20–800 kbps
Frequency Band	2–11 GHz and 10–66 GHz	2.4 GHz and 5 GHz	700 MHz– 2.1 GHz
Band License	Free and Licensed	Free	Licensed
Flexibility	High	Medium	Medium
Robustness	Medium	High	Low

Among the unlicensed bands, we chose the 2.4 GHz range because of its greater communication range when compared to higher-frequency bands. Our focus in this work will be on the WiFi mesh architecture, leaving long-haul communications for future work.

8.3.3 Architecture

In general, there are two possible architectures of a WiFi network: infrastructure mode and infrastructure less (Ad hoc) mode.

Infrastructure network: This type of network consists of a network with fixed and wired gateways. A mobile host communicates with a bridge in the network (called a base station) within its communication radius. The mobile unit can move geographically while it is communicating. When it goes out of range of one base station, it connects with a new base station and starts communicating through it. This is called a handoff. In this approach, the base stations are fixed.

Infrastructure less (Ad hoc) network: In this type of network [93], without the existence of a base station, all nodes are connected together dynamically in an arbitrary manner. Since the range of each host's wireless transmission is limited, in order to communicate with hosts outside its transmission range, a host must enlist the aid of its nearby hosts in forwarding packets to the destination. Therefore, all nodes of these networks behave as routers and take part in discovery and maintenance of routes to other nodes in the network. Ad hoc networks are very useful in emergency search-and¬-rescue operations, meetings, or conventions in which persons wish to quickly share information and data-acquisition operations in inhospitable terrain.

Smart Grid wireless architecture is more likely to behave in Ad hoc mode where no central base station exists in a long chain of transmission or distribution lines. There is no central node for controlling communication between nodes. The Ad hoc mode operation of WiFi can be used in the formation of a mesh network among all nodes. Of course, each of these modes has its own specific communication protocols and standards, namely a routing protocol. Ad hoc routing protocols will be discussed later in Section 9.3.5.

In a multi-hop wireless network, a source node relies on intermediate nodes on a routing path to forward packets toward the destination. Therefore, a data packet should pass several hops to reach the destination. A Smart Grid network is expected to have this behavior. Each item (poles, smart meters, control center computers, etc.) can be a source, destination, or intermediate node to send, route, or receive a data packet. Also, each utility in these networks can be connected to more than one other utility. For example, a smart meter in a residence area can be connected to two or three distribution line poles in its vicinity.

This interconnectivity in a network is said to be mesh connectivity. Because of this similarity, the envisioned Smart Grid network is called a multi-hop mesh network. Multi-hop architecture will ensure that the necessary redundancy is available upon the failure of a master node. A typical range using 2.4 GHz with a stock antenna is 300 feet outdoors, which fits the typical distance between distribution poles.

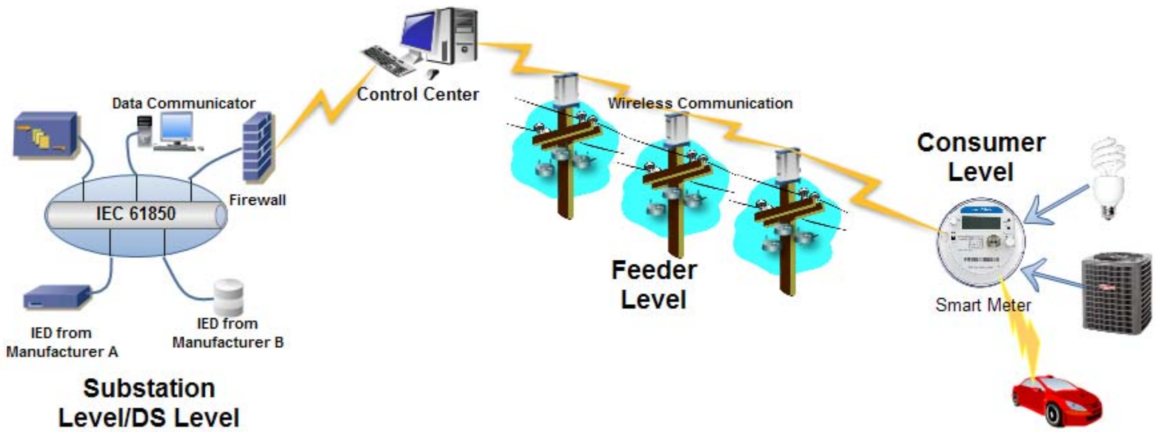


Figure 8.1 Proposed WiFi Mesh Architecture

8.3.4 Possible Application Scenarios

Fault location: Having an established wireless mesh topology has the benefit of speeding up the location of a fault or failure in the network. Each pole could have sensors monitoring the power lines that could then communicate to nodes on the mesh network. Such capability enables immediately reporting any event and its geographic location in a matter of seconds.

Bi-directional communication: All appliance parts of consumers' Advanced Metering Infrastructure (AMI) could be connected to the network via smart meters. This requires bidirectional communication: control commands from the control center of the utility to smart meters, and load profiles and logs from smart meters to the control center.

8.3.5 Communication Protocols

Ad hoc routing protocols can be divided into two categories: reactive (on-demand) and proactive (table-driven).

Table-driven routing protocols: In table-driven routing protocols, consistent and up-to-date routing information to all nodes is maintained at each node. The Destination-Sequenced Distance-Vector (DSDV) [94] routing algorithm is based on the idea of the classical Bellman-Ford routing algorithm, with certain improvements. Every mobile station maintains a routing table that lists all available destinations, the number of hops to reach the destination, and the sequence number assigned by the destination node. The sequence number is used to distinguish stale routes from new ones and thus avoid the formation of loops. Stations periodically transmit their routing tables to immediate neighbors. A station also transmits its routing table if a significant change has occurred in it from the last update sent. Therefore, the update is both time-driven and event-driven.

On-demand routing protocols: In on-demand routing protocols, routes are created as and when required. When a source wants to send to a destination, it invokes route-discovery mechanisms to find the path to the destination. The best example of these protocols is the Ad Hoc On-Demand Distance Vector (AODV) routing [95], which discovers routes on an as-needed basis via a similar route-discovery process. However, AODV adopts a very different mechanism to maintain routing information. It uses traditional routing tables, with one entry per destination. This is in contrast to another on-demand routing algorithm, Dynamic Source Routing (DSR), which can maintain multiple route cache entries for each destination. Without source routing, AODV routing relies on routing table entries to propagate the Route Reply (RREP) back to the source and, subsequently, to route data packets to the destination. AODV routing uses sequence numbers maintained at each destination to determine freshness of routing information and to prevent routing loops. All routing packets carry these sequence numbers.

These routing protocols for mobile ad hoc networks have been extensively evaluated in prior work [96]. One of our goals in the next section will be to evaluate these protocols for topology characteristics of the power grid.

8.4 Evaluation of Proposed Mesh Architecture

The vision of using a collection of cost-effective, fixed wireless nodes that form a mesh network is evaluated here. We base the feasibility of the architecture on connectivity and end-to-end delay. The transmit power used by each mesh node has the largest impact on connectivity, and hence will be the focus of our preliminary evaluations here. We begin by describing our experimental setup, and subsequently examine impact of antenna transmit power levels on end-to-end delay.

8.4.1 Experimental Setup

Simulation environment: Simulations are carried out in the open-source network simulator-2 (NS ver-2.31) [94], which allows abstraction of all communication protocols and their performance evaluation for different network topologies and configuration of various network traffic types.

Traffic model: Continuous bit rate (CBR) traffic sources are used. The source-destination pairs are the first and last nodes of the network. Small data rates of the order of Kbps are used which we believe are typical for Smart Grid scenarios. The measurement data (e.g., synchrophasor measurements) may send continuous data, but the packet size is expected to be small. Any asset management data with a moderate packet size would typically not be continuous, and thus, again requiring only a small data rate.

Network Topology: The nodes are placed using linear topology (mimicking electric poles on a distribution line) on a 10 km long scenario, each node separated by 100 meter distance from its neighbors, unless we are varying node density. An example linear topology is shown in Figure 8.2. The first node or Node (0) represents the control center, which is located at the furthest left part of the topology. The destination, or Node (n), is assumed to be the node from which the control center is requesting information (for example a smart meter).

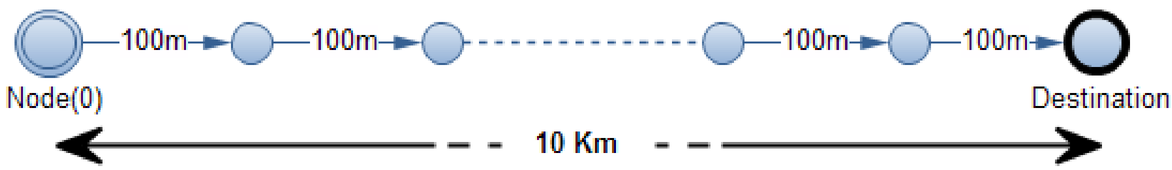


Figure 8.2 Simulation Scenario Schematic

Performance of the message delivery is analyzed in this work. For all simulations, a fixed antenna model is used. The transmit power is set to be fixed at 0.28 Watt, providing a range of 100 meters in our simulator, which is consistent with practical values for WiFi.

Performance measures: The following performance measures are used for the routing protocol:

Packet delivery fraction (PDF): This is the ratio of packets delivered to packets sent by the traffic generator.

Average end-to-end packet delay: This is the average of delays of each successfully received packet from the source node to the destination.

Node density: This term is used to describe the number of nodes within a certain geographic length.

Selection of Routing Protocol: Ad hoc routing protocols that we can use for our mesh architecture can be divided into two main categories: reactive (on-demand) and proactive (table-driven). Other possible categories include location-based routing (e.g. [95] and prediction based routing [96]). There has been extensive prior work on evaluating routing protocols for ad hoc networks. (e.g. [96-99]). We picked Ad Hoc On-Demand Distance Vector (AODV) routing protocol [100] as the representative of routing protocols in this work due to prior evaluation results [101] and our own comparisons with proactive routing protocols. In on-demand routing protocols, routes are created as and when required. When a source wants to send to a destination, it invokes route-discovery mechanisms to find the path to the destination. These discovered routes time-out after a fixed duration, requiring new routes to be created to replace them.

For our evaluations we had to modify some default parameters of the AODV protocols to support a topology that spans many thousands of meters with route lengths expected to many hundreds of hops. For example, the default network diameter for AODV in NS2 is 30 hops; we modified it to be larger than the number of hops expected in long chain topologies.

8.4.2 Transmit Power Effect on Coverage Range and End-to-End Delay

Increasing the transmit power of a node's antenna would be possible in the event of failure of any node along a route. Typically, we envision using directional antennas, in comparison to Omni-directional antennas, for nodes to allow maximum range and to reduce interference among nodes and with other wireless networks in the vicinity. To perceive the idea of interference among nodes, or contention, an understanding of the implementation of the concept of physical carrier sense in the IEEE 802.11 standard for WiFi [102] is needed. Usually a node that wishes to transmit a packet must first assess the channel. If the energy detected on channel is greater than a Carrier-Sense Threshold

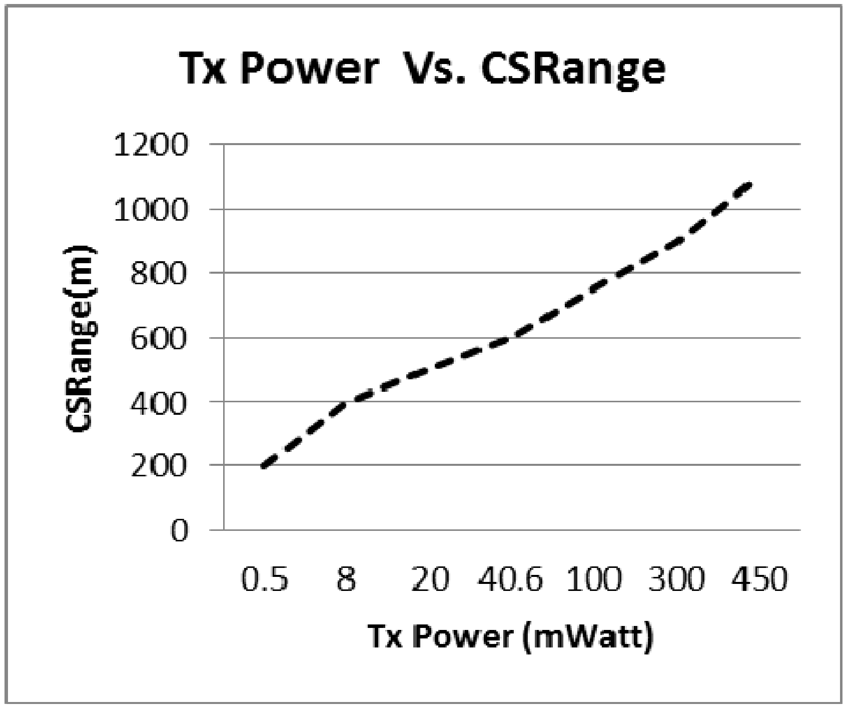
(CSThresh), the station must assume that the channel is busy, and defer. Thus, a small CSThresh implies that even nodes quite far away from a transmitting node shall detect the channel as busy, and defer. On the contrary, a large carrier-sense threshold implies that only nodes very close to a transmitter shall assess the channel as busy. Recall that carrier-sense range (CSRange) is the distance from the transmitter up to which nodes assess the channel as busy, and thus CSThresh and CSRange possess an inverse relationship with each other. A larger CSRange implies more space is "reserved" by a transmission as a "guard zone" to avoid interference/collisions. A smaller CSRange implies there can be more concurrent transmissions, but chances of collision are higher.

To observe this property, a simulation is performed that evaluates the effect of antenna's transmit power on carrier-sense range with a fixed receiver sensitivity (default NS2 value of 3.65e-10 Watt), and the delay between source and destination of packets. The simulation scenario is shown in Figure 8.3. Here we just assumed a simple 2 nodes communicating in 100 meter distance but it could be any other scenario.

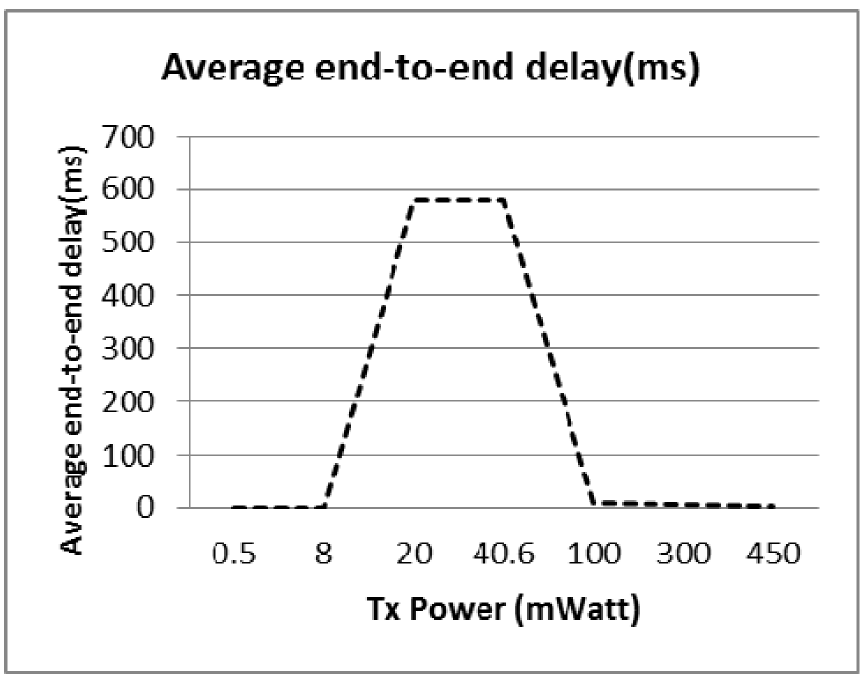
Figure 8.3 Simulation Scenario Scheme

This simulation is performed using AODV routing protocol starting with a power of 0.5 mW, which results in a 200 meter CSRange, and continuing the simulation to reach a power of 450 mW, which results in a CSRange of 1,094.8 meters. Increasing the transmit power any more will provide the same behavior as output results in PDF and delay. Figure 8.4 represent the results of these experiments.

The results from this experiment show us that we can take advantage of increasing an antenna's transmit power in the event of a failure, such as collapsing of a pole.. Increasing the transmit power helps to increase the communication radius (Figure 8.4(a)), and consequently the Smart Grid wireless communication remains operational. Figure 8.40 shows how increasing the transmit power will affect the delay and transmission range. Initially with increasing transmit power, the delay also increases due to greater interference among nodes. However, as the transmit power reaches a point where it has reduced the number of hops from source to destination, the delay decreases.



(a) Carrier Sense Range



(b) Delay

Figure 8.4 Transmit Power Effect on (a) Carrier-Sense Range and (b) Delay

8.4.3 End-to-End Delay

In this section, we study the average end-to-end delay in a linear chain topology when multiple sources are involved for various transmit power levels. Five sources in a ten-node scenario were used, with each node 100m apart. Results in Figure 8.5 indicate a cyclical pattern due to the competing impact of transmit power on interference levels and delay. As we increase the transmit power, the delay initially decreases due to a reduction number of hops to the destination. Subsequently, the delay suddenly increases after a transmit power value due to increasing contention among multiple flows. As the transmit power keeps on increasing, however, the delay again decreases when the shorter routes provide more benefits than the penalty due to increased contention among nodes.

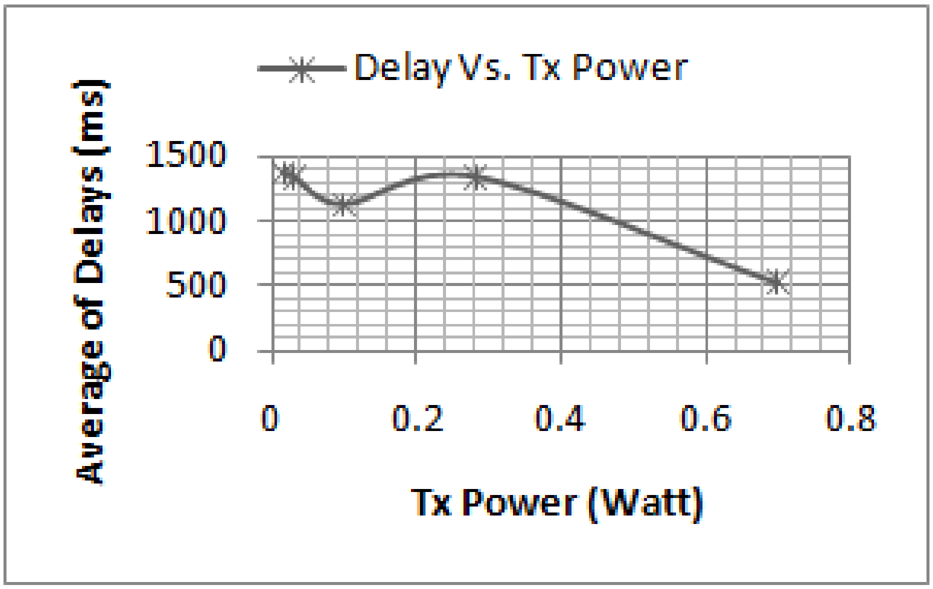


Figure 8.5 Transmit Power vs. Average of Delays Plot

In any scenario, there could be multiple optimal transmit power values depending on requirements; For example, the best value could depend on the wireless router power supply. If the power is obtained from a battery, then the best transmit power could be the local minimum point on the plot above. But if the supply is from a power line or a source that is not limited, then we can afford to use higher transmit powers to reduce delays, in which case the optimal transmit power would be the absolute minimum point on the overall delay plot. Again, these transmit powers are only for this specific experiment; results could vary for other scenarios that vary the number of nodes and amount of data rate.

8.5 Feasible Operating Conditions for Mesh Architecture

As a first step, it was decided to determine the appropriate node density when deploying the proposed wireless mesh architecture. Data rates of 0.01 and 0.5 Mbps were used. Actual distribution level data communication would be in this range, since the requirement is to transmit only the power system operation information in a secured manner. The end-to-end network delay for varying node density is shown in Figure 8.6.

The drop seen for node densities of 20 to 21 in Figure 8.6 is due to a sudden decrease in the number of hops taken by the AODV routing protocol from the source to the destination. This protocol considers all possible paths from the source to the destination and picks the one that can reach the destination with the least delay, which typically is the route composed of the shortest number of hops. As node density increases, there is a certain point at which the routes taken can skip over some nodes on the path to the destination. From Figure 8.6, it can be seen that node density of 10 nodes per km, which is also the minimum needed for end-to-end connectivity for the transmit power level used, performs better for both 0.01 Mpbs and 0.5 Mbps cases. The smaller the node density, the cheaper the feeder-level communication in terms of number of nodes that needs to be deployed. Therefore, this work suggests using the minimum possible node density of 10 nodes per km as the best option.

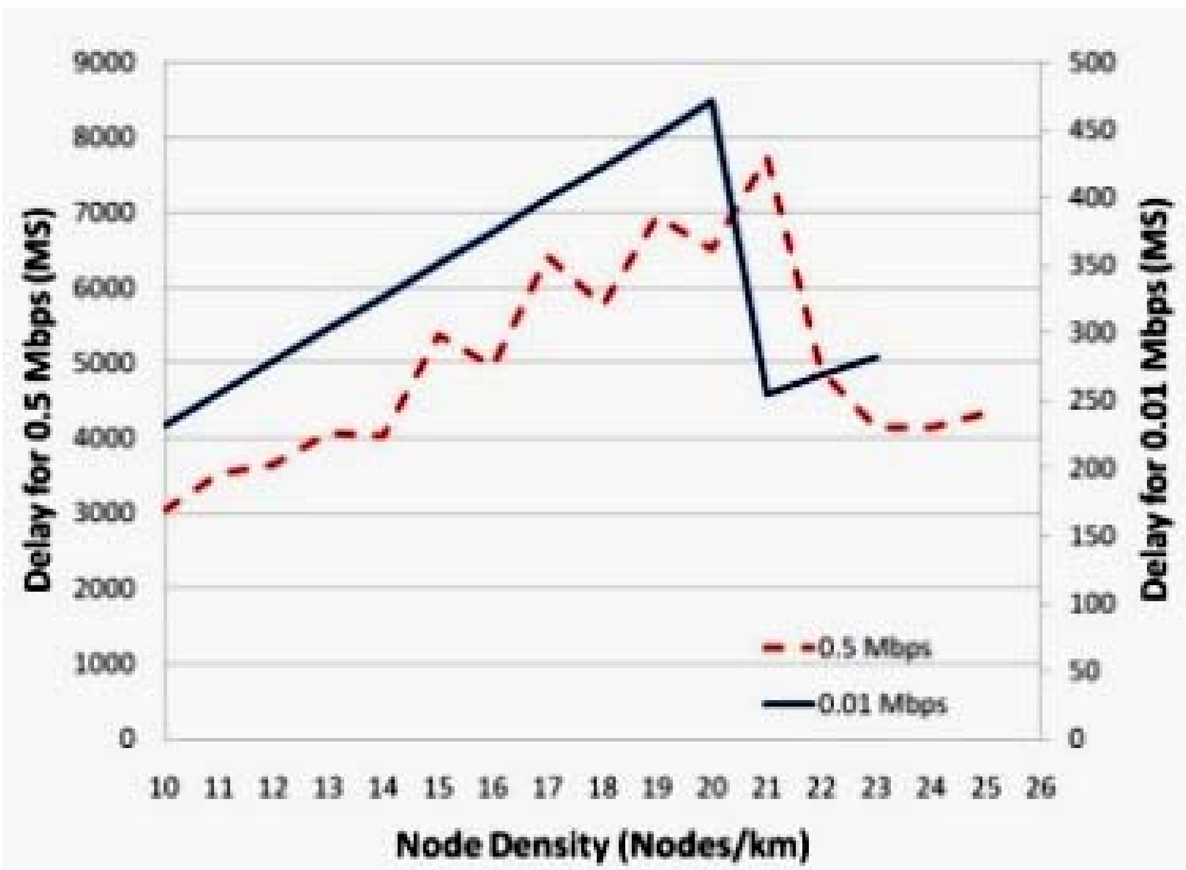
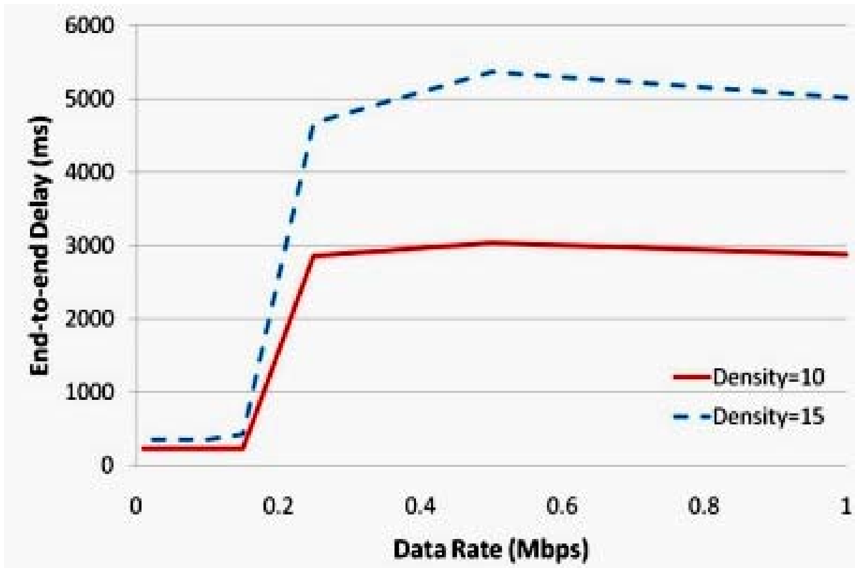


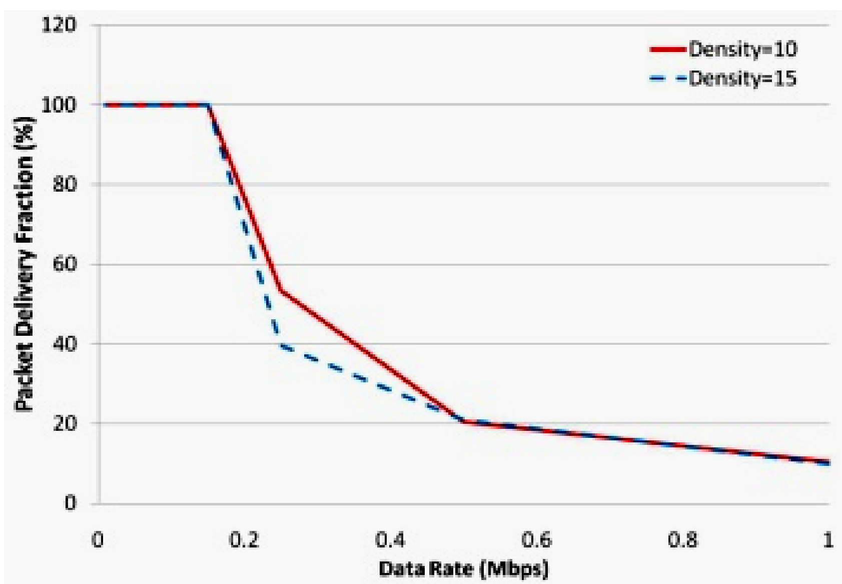
Figure 8.6 Comparison of 0.01 and 0.5 Mbps Communication

Further analysis was done for delay and packet delivery for data rates between 0.01 and 1 Mbps. To compare the effect of node densities, both 10 and 15 nodes per km were simulated. Figure 8.7 shows the simulation results for these cases.

From Figure 8.7(a) and (b), it could be seen that when the data rate exceeds 0.15 Mbps, the delay increases significantly, and the packet delivery fraction decreases from 100%. The selection of 10 nodes per km is validated in this plot, since increasing the node density to 15 nodes per km would decrease performance. Based on this simulation for a reliable communication, the data rate should not exceed 0.15 Mbps with a node density of 10 nodes per km.



(a) Delay



(b) Packet Delivery Fraction

Figure 8.7 Simulation Results for Different Data Rates

From our simulations, it can be seen that even with the ideal communication scenario (no interference and only one node is sending information), there is a limit for the data rate, node density, and length of the WiFi chain. Based on these experiments, Table 8.2

presents a configuration that could be used in a WiFi multi-hop network at the feeder level of the distribution system of the power grid.

Table 8.2 One Feasible Configuration for the WiFi Mesh Architecture

Property	Feasible Value
Routing Protocol	AODV
Node Density	10 nodes /km
Transmit Power	0.28 Watt
Number of Nodes	250
Data Rate	0.15 Mbps

8.6 Evaluation of a Real-World Power Distribution Topology

Our final goal in this section of report is to show that, given the chosen feasible parameter values earlier in section 8.5, we can expect good performance in terms of communication in a real-world power distribution topology.
Figure 8.8 shows the abstracted topology of the power distribution system that we took from a local utility company. All connections are bi-directional, and all can either send or receive data packets. We evaluated the scenario where the source (Node (0)) sends packets to the shown destination.

Table 8.3 shows some values used in the simulation settings and obtained results. We can conclude that the performance obtained in terms of delay and PDF was satisfactory and bodes well for utilizing wireless mesh architecture for communication at the distribution level of the smart grid.

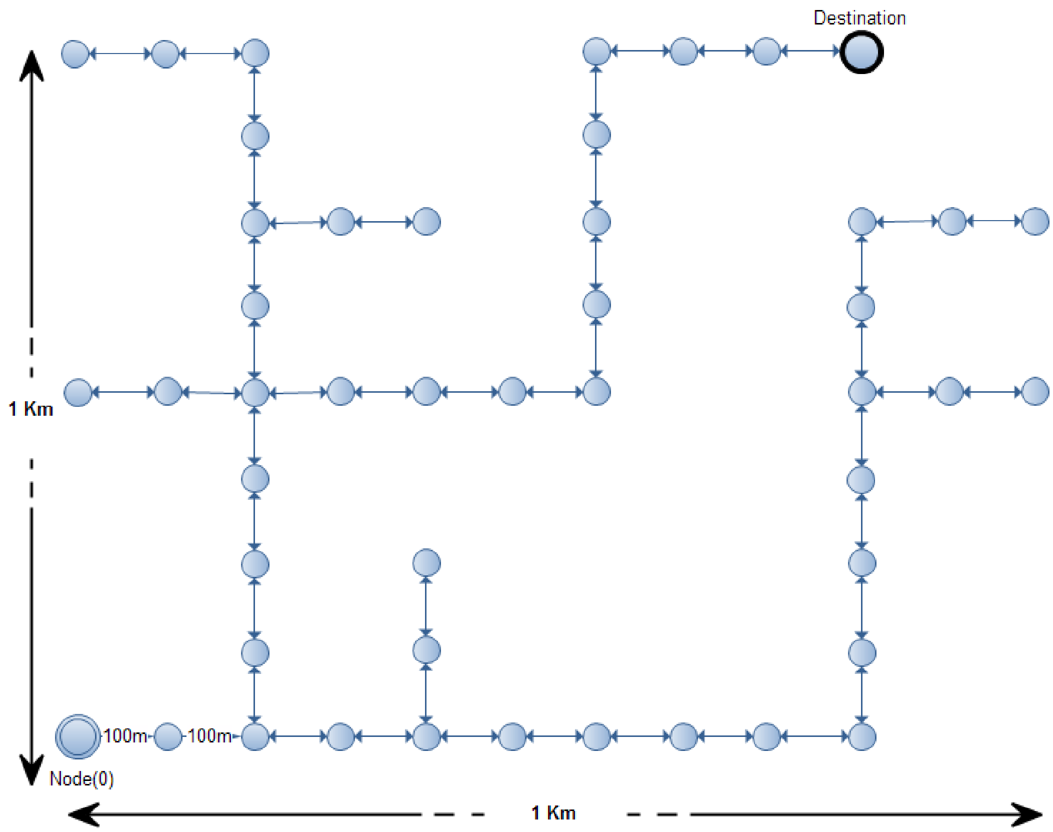


Figure 8.8 Real-World Topology

Table 8.3 Simulation Output for Real-World Scenario

Property	Reasonable Output
Data rate (mb)	0.15
Simulation time (s)	300
Packet Delivery Fraction	100
End-to-End Delay (ms)	41.37
Packet Loss (%)	0

9 Home Area Network for Metering in Smart Grids

9.1 Introduction

The electric power industry is undergoing major changes in the twenty-first century. Significant developments are in the area of advanced measurements (synchrophasors, optical sensor technologies, etc.), improved communication infrastructures, renewable energy sources and electric vehicles (EV). These changes are expected to influence the way energy is consumed by residential customers. Advanced metering infrastructure (AMI) is introduced at residential levels to incorporate these changes. With the introduction of AMI technology, two-way communication between smart meter (SM) and the control center, as well as between the smart meter and residential loads would be facilitated for demand response, dynamic pricing, and system monitoring [103]. In addition, AMI could be used for greenhouse gas-emission mitigation [104].

This work focuses on security aspects of communication between a SM and terminal residential appliances. The home area network (HAN) used for an AMI application should ensure adequate and secure communication between a SM and the terminal appliances. Terminal appliances are divided into four groups to limit the data communication based on the applications. Figure 9.1 shows different residential appliances and the groups (details are presented in the next section).

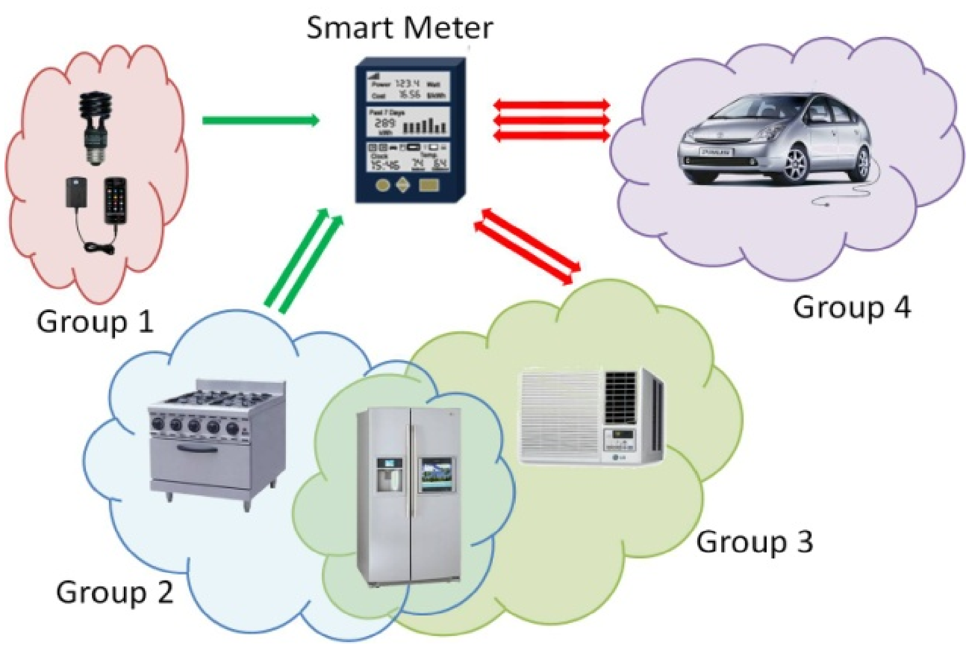


Figure 9.1 HAN Appliance Classification for AMI Application

A recent article in *IEEE Spectrum* highlights the importance placed on the issue of security and role of communications for AMI [105]. Possible malicious behavior that could hinder the secure communications include any information not reported to the SM by an intentional action of the customers, or any action by a third party to intentionally or inadvertently modify the information of a customers that would give them higher priority or other benefits.

Wireless communication is considered as an appropriate mode for communication between SM and loads in the home [106]. ZigBee is considered to be a good candidate for a cost effective HAN solution [107]. A wireless communication-based network requires minimal infrastructure support in terms of cabling, and allows zero-configuration; where appliances can be added or removed easily, and possible integration with increasingly common wireless-based access networks and home-security systems. Power line carrier (PLC) is another option available within the home, but home wiring is designed for low-frequency electric power delivery and not high-frequency data communications. PLC also is unavailable when home electric system is faulted or open. A wireless medium enables communication between the SM and the appliances, even with a fault in the electric connection between them. Comparatively, options like Ethernet cabling have extensive infrastructure costs with little flexibility to reconfigure.

A wireless-based home area network for AMI (WHAN-SM) has more security challenges than possibly any other solution due to the shared wireless medium. There have been visionary documents on Smart Grids that call for improved security [108-109]. There are researchers who have specifically focused on security for AMI and called for more work to be done in ensuring a secure framework, with some actually proposing such a framework or architecture [110-114] on which to build solutions. Based on a survey of the literature and discussions with engineers and experts, what has been lacking, however, is a concrete, low-level approach that looks at various possible attacks to such a WHAN-SM.

This work takes a comprehensive look at security in WHAN-SM. Further, a common security framework is developed work to mitigate several possible attacks. A key aspect that differentiates security in WHAN-SM from that in conventional HANs is the presence of two different entities whose interests must be kept secure: (i) the utility company, who must be sure that no one, including the customer, can tamper with the measurement and control of appliances as agreed upon, and (ii) the customer, whose privacy must be guarded at all times when the SM is collecting and relaying data, and that personal appliance management preferences are honored at all times. Traditional wireless local area network security protocols are based on a single party application. Very limited work has been done for wireless local area network security solutions under the presence of more than one stakeholder. This work pays special attention to possible attacks and countermeasures needed with the existence of these multiple parties. Following can be attributed as contribution from this work:

1) Development of a communication and control model for home area networks for AMI.
2) Identified important security objectives for home area networks and related vulnerabilities.
3) Development of solutions for vulnerabilities and an integrated framework for securing WHAN-SM.

Securing wireless networks is not a new topic, and many solutions are well known (e.g. [115-117]). Contribution from this work is in its inter-disciplinary nature of applying networking techniques and their solutions to the power systems area with the goal of hastening the adoption of AMI by customers.

9.2 The Home Area Network Concept for the Smart Grid

9.2.1 Motivation for AMI

The AMI will enable energy meters installed in all customer premises to communicate with the utility or third party operated control center and with appliances installed in the premises. In future, the SM will have the ability to control the number of appliances operated at a given time and thus implement demand-side management for the utility. In such a scenario the utility control center looks at aggregate loads from all its customers at a given time and then issues specific control instructions to the SM. It is envisioned that a customer participating in AMI would allow control over some specific class of appliances (typically high-load appliances that the customer can operate with some tolerance in delay). Under such a scenario, time of the day tariffs could become popular, allowing customers to benefit from having appliances operate at times of lower tariff.

If control is done manually customers are less attentive to varying tariffs and thus less likely to optimize the energy cost by using appliances at off-peak times [118]. Any infrastructure that allows reduced human intervention in energy cost optimization is of high interest.

9.2.2 Role of Communication

AMI is expected to introduce two new categories of communication. The first, already employed by many utilities in the U.S., is between the energy meter and the utility control center. This facilitates observation of real-time power consumption and any abnormalities in the system, and allows demand-side management. If real-time pricing in introduced, this category of communication will enable the customers to track the current price. In addition to the ANSI C12.22 standard [70], significant work has been done on ensuring secure communication between the meter and the utility [119-120]. Many utilities in the U.S. have implemented AMI that have the capability of this level of communication [121-122].

If the AMI is to allow load and cost management, a second category of communication between the meter and the users' appliances is also necessary. One of the major concerns of implementing this category of communication is the question of customer's privacy [105], [123]. Customers have concerns about the utility knowing what electrical appliances they are using at any given time. Therefore, a separate layer of communication, limited to the customer facility, is required. Using this communication layer, the SM will communicate with and control the customer's appliances without sharing this information with any other stakeholders. It should be noted that if the second layer of control is achieved by enabling demand-side management, then greenhouse gas emissions can be controlled as well. Utilities subject to existing and proposed state and federal emissions regulations could benefit greatly.

Further, the introduction of electric vehicles (EV) is a serious concern for utilities. EV charging will be stochastic in nature and a large increase in load on the distribution transformers. Therefore, EVs require a higher level of bi-directional communication; some of the information about EV charging should be communicated to the utility (e.g. time required for charging, availability, and charge level of the battery). Therefore EVs should be categorized separately when the communication architecture is developed. As this scenario is still only emerging, we do not address this appliance class in this work. This work focuses on the network within the home and how SM deals with appliances classified in groups 1, 2, and 3, as described in Figure 1.

9.2.3 Communication Requirements in a WHAN-SM

It may not be economical to have equal communication capability for all components; for example, a light bulb needs only minimal communication infrastructure whereas an air conditioner needs to communicate more information. Communication needs are used to divide components into the four categories of Figure 1.

Controlling small loads such as light bulbs, phone chargers, and laptop computers will significantly increase the installation cost and data traffic. Since control of these loads will not change the total load profile significantly, these Group 1 loads need to inform the SM only when they are connected to and disconnected from the system. Group 2 consists of large loads, such as stoves, that will not be controlled because the customers need them to be available at their demand, not delayed to a later time. This type of appliance needs minimal communication infrastructure, but will need to send its power usage and expected duration of usage.

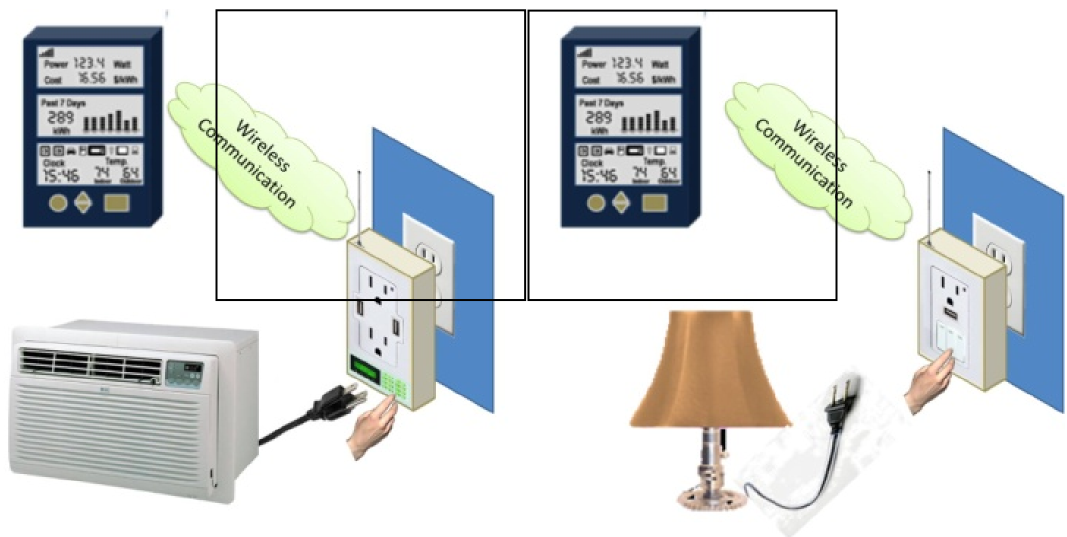
Group 3 loads are large loads, such as air conditioners and clothes washers and dryers, for which usage will be controlled. These loads will send a request through SM and wait for acceptance before operating. They will need to send extensive information such as expected load, expected duration of usage, and duration of availability. Therefore, they may send more data packets than the other two types of loads. Furthermore, the acknowledgement from the SM is essential for this type of load as they wait to begin operation. The decision to operate a component will depend on dynamic pricing and duration of availability. Depending on the customer’s agreement with the utility, they will likely be able to override a delay in operation by paying a higher energy price.

Group 4 loads, EVs, are new to the power grid. Since these are very large and stochastic in nature, it is vital for the SM to communicate in advance the time of charging of EVs and to plan the charging. Due to the extensive need for communication, these are categorized as separate loads. It is essential to build a communication architecture that can manage this new load through timely and adequate control.

In addition to confirming and enabling device operation, the SM would be required to control power consumption for load management initiatives. For example consider a residence that is heavily loaded and close to the utility’s limit on power consumption at a given time. If customer decides to use the stove (a device from group 2) which would increase the total power consumption beyond the utility limit, SM should step in and reallocate load. For example, it could adjust the duty cycle for a refrigerator or heater/air conditioner from group 3.

9.2.4 Communication and Control Model in a WHAN-SM

There are two options for communications between appliances and the SM. The first option is to make appliances smart, whereby they will have the capability to communicate with the SM and make the decisions (when to switch on, when to switch off, etc.). The main disadvantage of this method is the lack of communication/processing capability in currently manufactured appliances. The second option is to make the power outlets smarter by connecting a transceiver with processing capability. The work in this part of the project is based on this second option because it can be implemented with existing appliances. Migrating to the first option in the future as smart functions are added to appliances will not change the communications security concerns, and will allow those appliances to be designed to a standard widely adopted at the time. Figure 9.2 shows two different models for outlet communication.



(a) Controlled Outlet (b) Uncontrolled Outlet

Figure 9.2 Communication and Control Enabled Power Outlets

The first model (Figure 9.2a) is for controlled operation; this is for appliances clustered in group 3, which need approval from the SM to operate. The customers will connect the appliance to the power outlet and program the outlet with the following information: required operation, availability, and priority. This information will be communicated to the SM. Based on the system loading profile and the information provided by the customers, the SM will allocate the time of operation of the appliance and send that information back to the outlet transceiver. On the other hand, for group 1 and 2 appliances, which will not be controlled by the AMI, the only information the SM needs is the type of appliance. Figure 9.2b shows uncontrolled operation; once the customer switches on the appliance, outlet will share this information with the SM.

A downside to using wireless communication for the WHAN-SM scenario could be the data transfer rate, which can be slower than wired solutions. However, a WHAN-SM is used more for control than as a high-speed access network, and thus, lower data rates are adequate. Current wireless solutions that are possible candidates for WHAN-SM are Wi-Fi, ZigBee, and Bluetooth, and their comparison can be found in [124]. The ZigBee technology based on the IEEE 802.15.4 standard [125] is considered a good solution for the WHAN-SM scenario as it has a communication range varying from 10-100m, allows large-scale network configurations, and uses a low-power radio. The data rate capability for this technology is a modest 250kbps, but is more than adequate for the WHAN-SM application scenario. As a result, ZigBee seems to be the front runner in the race to be the wireless solution of choice. Thus, this work makes periodic references to the security architecture in place for ZigBee; however, for the most part, *a general wireless network is assumed* that could be based on any of the above solutions. The work in [126] presents an integration point for different types of wireless networks for HAN through unified metrics that could be utilized to implement any of the proposed general solutions.

9.3 Possible Security Attacks

In this section possible security attacks in a WHAN-SM application scenario are identified. The unique two-party dynamics present in AMI and security objectives which are important for the application scenario are discussed first.

9.3.1 Two Party Dynamics

In traditional home area-based networks the customer is the only entity responsible for the operation of the network and acquiring benefits from the deployed applications. For example, consider the case of a home surveillance system. It is in the interests of the customer that the network functions properly as intended. The customer must correct any unintended behavior of the network.

WHAN-SM scenario has the additional dynamic of there being two parties with interests in the network. If the WHAN-SM does not function properly, it could prevent controlled appliances from operating at request. Similarly, a misbehaving network could take away the ability to manage load based on the utility requirements. Such network misbehavior could benefit one party at the expense of the other.
Further, distributed control that exists between two parties could allow a third party to threaten the security of the network by impersonating one or the other party, or both. It should be noted that capturing shared secrets among network entities is easier when more than one party is involved.

9.3.2 Security Objectives

The following five main objectives are identified to ensure a secure WHAN-SM:

Confidentiality: The goal of confidentiality is to ensure that any sensitive data is not disclosed to parties other than those involved in the communication process. In the WHAN-SM scenario this could mean that apart from the customer and utility, no other party gets access to the appliance usage behavior of the customer. Further, the customer would prefer the utility to have only an aggregate view of power consumed.

Integrity: This requirement is to ensure that a received message is not altered from the way it was transmitted by the sender. In the WHAN-SM scenario, this is important to allow timely and accurate control. If an attacker manages to change the source of the request, it could happen that the SM ends up communicating and controlling the wrong appliance.

Authentication: Authentication is used by one node to identify another node or verify the source of origin of data in the network. Authentication is important for administrative tasks like association, beaconing, and identifier collision. This is critical in the WHAN-SM scenario to ensure that a customer is sure of the authenticity of a SM with which its appliance is communicating, and for the SM to ensure that it is communicating only with the assigned customer's appliance.

Availability: This property is to ensure that network services are available and will survive possible attacks or failures that could occur. In the WHAN-SM scenario, resource depletion is typically not a concern when it comes to a resource like energy which both the SM and appliances are assumed to have access to through grid power. But computation capabilities and memory constraints could be exploited by keeping these resources fully loaded, affecting the ability of the network to function as desired. Equipment failures may also be more common, especially with the low cost of WHAN-SM radios.

Time Sensitivity: Any message delayed over a specific tolerable time frame may be of no use. A network must ensure relevance of communication by enforcing latency constraints. In the WHAN-SM scenario, a customer request for appliance operation must reach the SM in a timely manner; similarly, control commands from the SM to appliances must be timely to ensure scheduling practices of the SM.

Security objectives such as fairness, which are common to more general wireless networks, are not applicable in WHAN-SM, as all appliances that compete for access to the medium belong to the same customer. Further, the WHAN-SM network is expected to be used mainly as a control network and is not expected to be highly loaded in terms of bandwidth, thus providing no incentives for selfish behavior by nodes.

9.3.3 Attacks and Misbehavior Scenarios for WHAN-SM

Figure 9.3 shows possible attacks on a WHAN-SM[2]. These attacks can be classified as *local* or *remote* attacks. The scope of this work is limited to local attacks within the HAN where all appliances communicate to their SMs using a one-hop network from their power outlets. Remote attacks, which typically exploit weaknesses in the routing mechanisms and multi-hop nature of networks, will not occur in the WHAN-SM scenario.

[2] More details on some of these attacks can be found in [131].

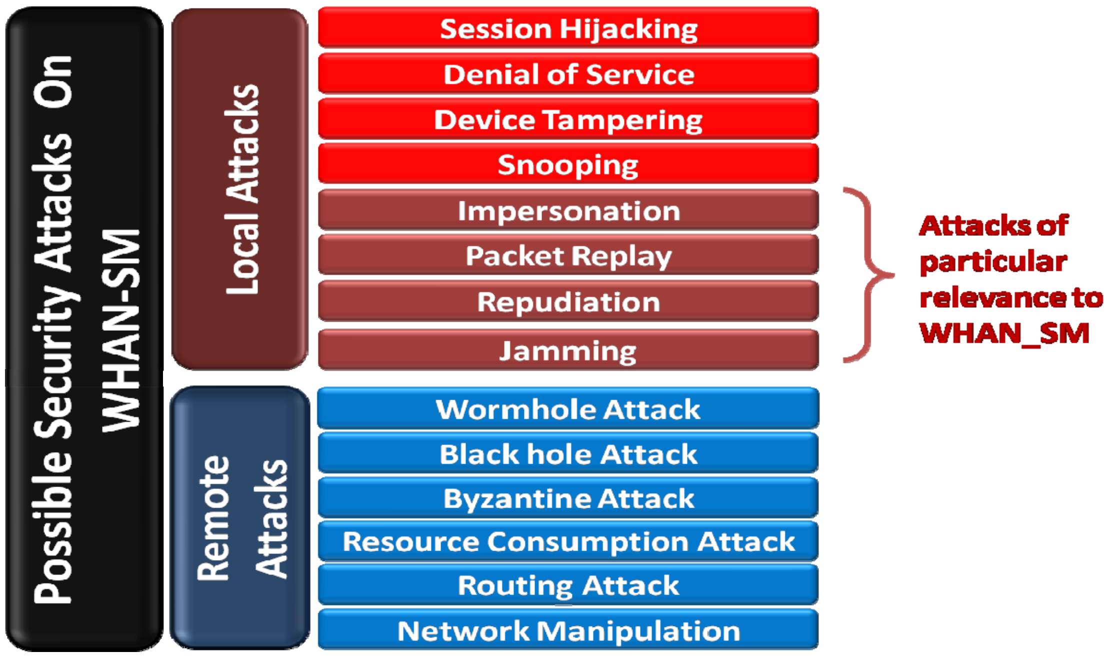


Figure 9.3 List of Attacks on Wireless HAN scenario

Various attack scenarios are considered with the following assumptions:

(i) The customer is provided with a password by the utility for authentication. A common authentication procedure, outlined in Section 9.4, is assumed for appliances to join the network and prevent unauthorized access.

(ii) The available encryption level is strong. This is a standard assumption, and could be based on the encryption suite present in technologies like ZigBee.

As a result of these precautions and assumptions any authentication and snooping type of attacks from Figure 9.3 can be ruled out. Local denial-of-services are typically based on de-authentication attacks that force appliances to repeatedly re-authenticate instead of using the network for useful purposes. Instead of considering such denial-of-service attacks, this work focuses on the stronger attack of jamming later in this section.

Physical device tampering with the SM, appliance, or power outlet are not considered in this work. The SM could be made tamper proof by periodic communication with the control center that allows adequate monitoring of its operations. The case of customer appliance and power outlet tampering would be handled in the attack category of "device impersonation," discussed later in this section.

The rest of this section describes the attacks which are relevant to WHAN-SM in Figure 3 in more detail. These attacks are a representative set of attacks possible in the WHAN-SM scenario.

1) *Jamming Attacks:* In these attacks, an adversary disrupts communications in a wireless network by sending deliberate signals on the shared medium. In a wireless network, packet communication is successful only if a receiver is able to successfully decode the sender's packet. If the medium is jammed by an

adversary, sender cannot begin communicating or its transmitted packet will be corrupted by the adversary's signal when received. Jamming can be carried out by sending a continuous or intermittent busy tone on the channel used for communication. A simpler form of jamming is for an adversary to send a continuous stream of packets using the same wireless technology, but at a much higher data rate, possibly after tampering with the medium access control protocol to gain an unfair advantage [127]. Based on the investigation carried out by the authors for an experiment with a six node scenario using the NS-2 simulator [128], it was found that a jammer could reduce each node's packet delivery ratio from 80-90% to about 40% by just using a data rate 10 times that of an average node with a data rate of 100 kbps on a 2 Mbps channel. It is fairly simple for an adversary to use a signal analyzer or similar device based on common off the shelf components to determine the channel used in a network. Such attacks are the most difficult to defend against and could cripple a HAN based on a wireless architecture.

2) *Appliance Impersonation:* Based on the customer-utility agreement, the customer agrees to let the utility control a group of their appliances. However, there could be instances where the customer would want to renege on this agreement and not relinquish control. This could occur, for example, when a customer tries to control the air conditioning for better comfort. Under the customer-utility agreement, the utility controls appliances from only a certain subset of classes, typically high power devices. The customer could therefore exploit this fact and have a high power consuming appliance impersonate an appliance from another non-controlled class. For the utility, an inability to control the appliance could result in unexpected loading conditions. The details of the attack are shown in Figure 9.4 where a customer masquerades their air-conditioner (a group 3 appliance) as a television (a group 2 appliance). This attack is one example of vulnerabilities arising out of the two party dynamic where one party might try to cheat the other.

3) *Replay Attack:* A neighbor could capture an appliance request made at some other time by a customer and replay it another time when no actual request was made. The neighbor does not gain any benefit, but it can hurt the customer, and could even be a safety hazard. Such fake requests could overload the AMI and have repercussions on the whole grid due to overloading if not handled properly.

4) *Non-repudiation:* Non-repudiation is a concept whereby no party can refute some aspect of their participation in the communication process. Specific to the WHAN-SM scenario, the customer cannot later refute having received certain control messages from the SM to operate their appliance. Alternately, an SM cannot later deny how it tried to control a customer appliance.

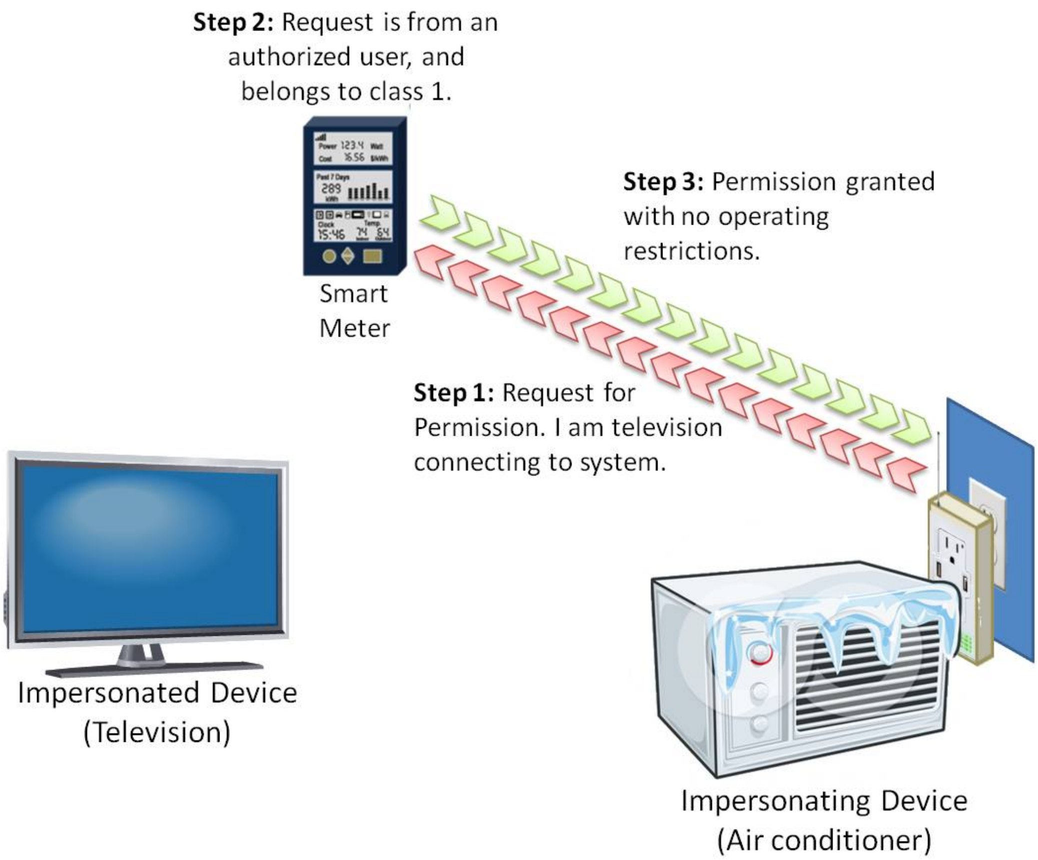


Figure 9.4 Example of an Appliance Impersonation Attack

9.4 Security Solutions

To ensure a reliable WHAN-SM, security attacks must be prevented. This work focuses on developing solutions to these security attacks based on the operating conditions of the electric power system at the residential level, and conventional wireless local area network applications.

The solutions developed in this work to overcome each of the identified attacks are presented in this section. An authentication procedure that will form the basis of the solution to all attacks is presented first.

9.4.1 Authentication Procedure

To ensure strong authentication the following key distribution algorithm is assumed:

1. The SM is installed by the utility at the customer premises. The customer is given a password to be manually supplied to the power outlet through which an appliance is connected. This password can be used to generate a public-private key pair for encryption purposes.
2. The power outlet for any appliance that connects to the network for the first time is challenged by the SM for the password. A correct response authenticates the appliance to the SM and sets up the required bi-directional control between the

SM and the power outlet. The communication in this step can use the common public key cryptographic technique.

3. The SM and the authenticated power outlet with the newly joined appliance now decide on whether to use the established encryption keys or to generate new ones on a per-session basis.

When an appliance tries to authenticate and join the network, it uses the pre-defined authentication channel. Once authenticated it moves to a different data channel used by the SM. The SM is assumed to have two interfaces, one for receiving authentication requests, and another for communication with authenticated devices. Any attacks aimed at preventing authentication can be handled manually as these are rare and customer involvement can be expected at a time when appliances are added.

9.4.2 Jamming

Jamming is one of the most difficult denial of service attacks to defend against. The best defense against intentional jamming is the use of multiple alternate frequency channels if the current channel has significant interference that results in packet losses above a certain threshold. The SM and any nodes deployed can be hard-coded to move through a pre-defined and common random sequence of channels, if communication on the default channel is unsuccessful for a specified period.

The nature of the WHAN-SM scenario is different from typical wireless sensor network research problems where battery life is a critical factor. Battery energy is not a constraint in WHAN-SM due to access to power outlets for charging. Hence, each packet could possibly be re-transmitted multiple times and on multiple channels until it succeeds.

The SM, being a high functionality node compared to typical customer nodes, could be equipped with more spread spectrum capabilities that could reject interference to a greater degree, and possibly help monitor the network and call for manual intervention. Directional reception through the use of directional antennas, taking into account appliance locations in the residence and appropriate SM placement, can further mitigate the impact of jamming.

The approach shown in Figure 9.5 is proposed to move the entire network through a sequence of predefined channels, which could mitigate the impact of a jammer.

Each SM on deployment will have a pre-defined sequence of channels through which it moves as a function of time. When a new node authenticates to the network on the control channel, the SM sends the encrypted channel sequence to the node using the customer’s public key. Each node can then decrypt using the customer’s private key and adopt the sequence, beginning with the current data channel being used. Methods for generating and exchanging pseudo-random sequences using public key encryption are well known [129], with the U.S. National Institute for Standards and Technology (NIST) offering several standards from which to pick [130]. If such pseudo-random sequences are used, the jammer can at best make a guess on what channel will be used, with prior history of channels used being of no help.

Depending on tolerable complexity and cost factors, additional protections like directional reception capabilities could be used at the SM and possibly the nodes at the power outlet. It is important to note that in technologies like ZigBee, the physical layer is based on Direct Sequence Spread Spectrum (DSSS) [125] which provides some protection against noise on a channel.

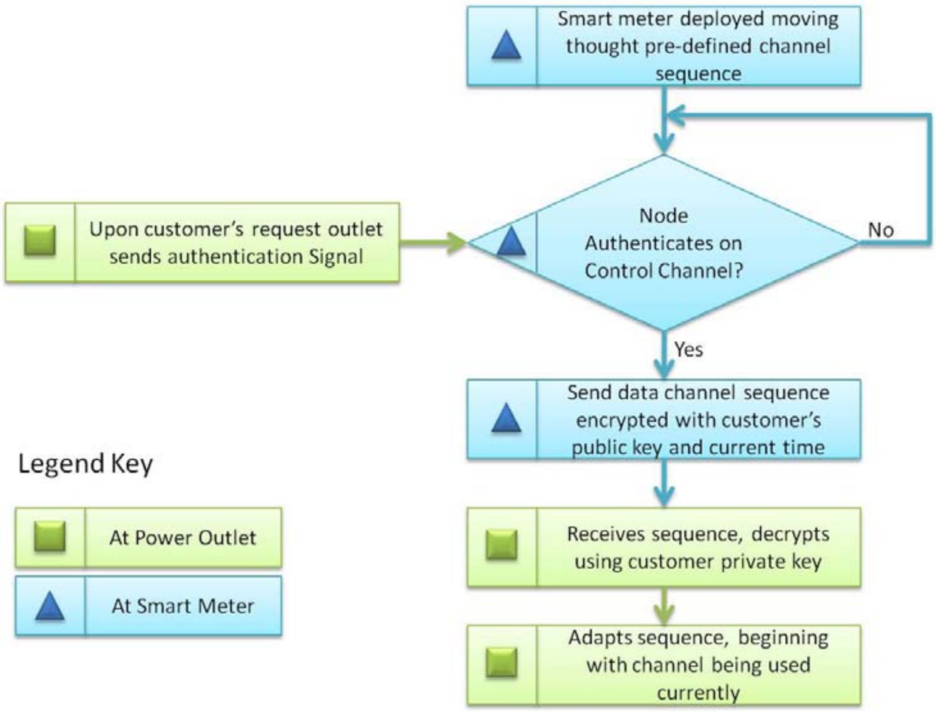


Figure 9.5 Channel Switching Algorithm

The proposed channel switching algorithm complements this by moving across channels as well to avoid attacks based on overloading a specific channel with data[3]. This approach is different than the one in [127] which assumes that some communication is possible between the SM or network coordinator and nodes to move to a different channel upon interference. The proposed scheme assumes the worst case that communication may not be possible under a strong jamming scenario, and thus is more resilient.

9.4.3 Load profiling algorithm to prevent impersonation

Device impersonation, as mentioned in the previous section, could be done by a customer to bypass stringent control on some appliance on an as-needed basis. This prevents the utility from having demand side management control. A load profiling scheme is proposed whereby the SM compares the device's load profile to the type of device it is announced to be. This is based on the premise that different appliances or devices have

[3] This makes the proposed scheme mimic the behavior of Frequency Hopping Spread Spectrum (FHSS) which is not possible under ZigBee's underlying 802.15.4 standard specifications. ZigBee defines a Frequency Agility capability, and this algorithm can be used to implement this capability.

unique signatures that can be exploited to identify them. A simple experiment collecting power values of common household appliances with a power meter supports this premise as shown in Figure 6.

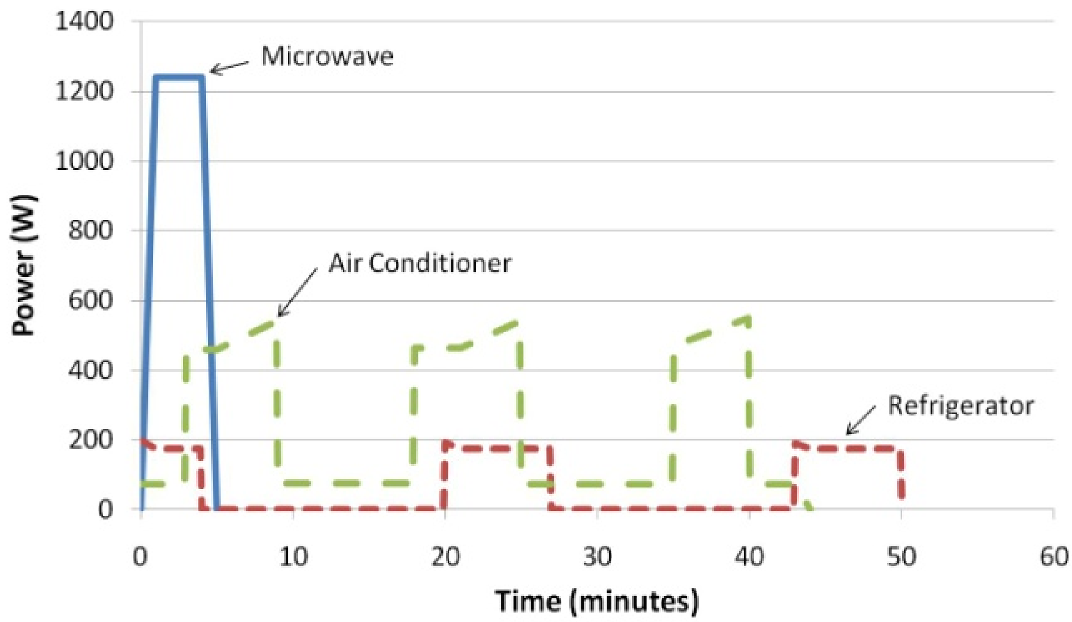


Figure 9.6 Appliance Loading Patterns

Figure 9.6 shows the sequence of steps that will be taken by the appliance, the power outlet, and the SM. On receiving an appliance operation request, the power outlet seeks permission from the SM. Based on the advertised class of device that needs to be operated, the SM either allows operation (for group 1 and 2), or schedules operation based on current load it is handling (for group 3). For all cases, the SM sends a previously formed load profile of the advertised device to the power outlet for verification.

If the peak load of the currently operating device ($L_{current}$) is higher than the known peak of the advertised device L by factor δ, or if the loading pattern does not match the known profile, the power outlet does not allow device operation.
Each device's profile can be pre-stored based on manufacturer's data, or verified against prior device operation history.

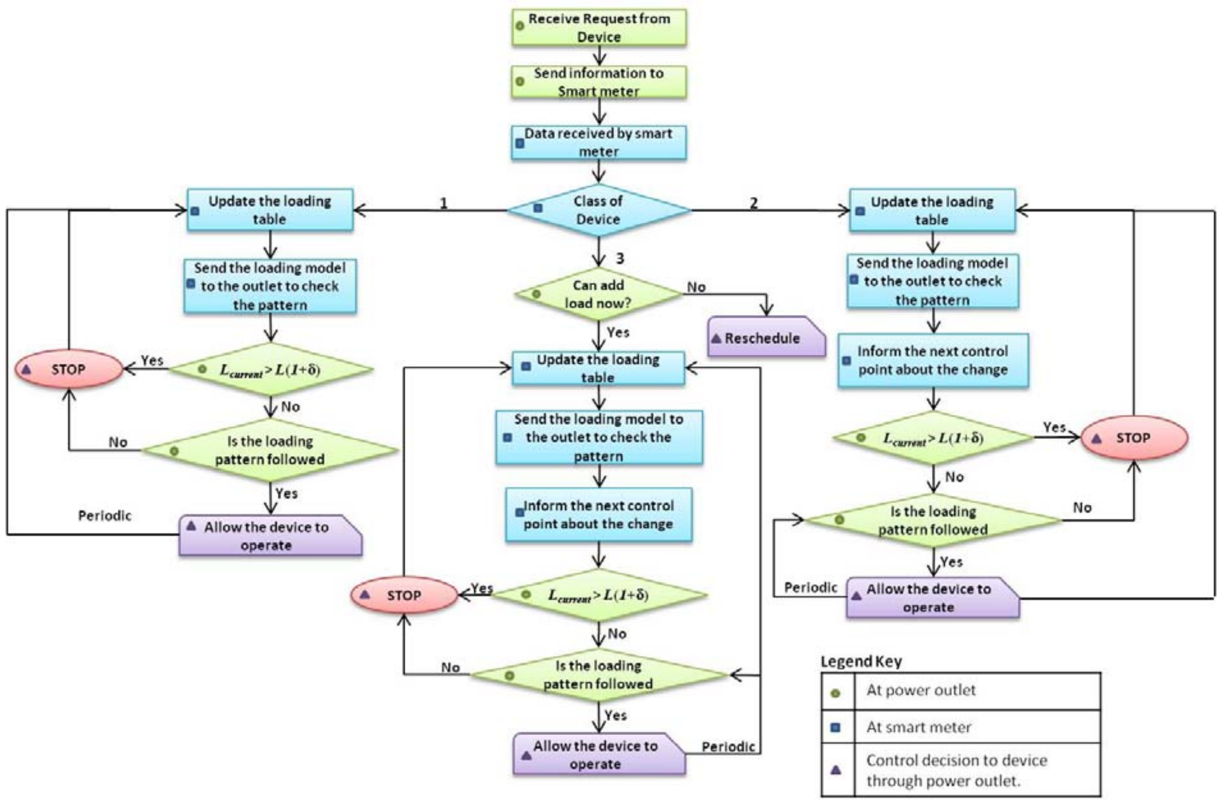


Figure 9.7 Load profiling algorithm to counter the possibility of device impersonation

9.4.4 Replay Attack

Replay attacks, where a neighbor requests operation of a customer's device, can be prevented using timestamps, packet sequence numbers, or session keys. If the network is time-synchronized, each packet can include sent time. If the SM sees a packet that differs significantly from current time, it can ignore it. Similarly, if packets from each appliance's power outlet have sequence numbers, the SM can filter packets significantly out of sequence. The use of session-based keys can also catch replayed packets, but this is more complex than the timestamp or sequence number methods. If the overall security framework uses session based keys, then additional mechanisms will not be needed to prevent replay attacks.

Figure 9 shows an example scenario where the SM could detect the presence of a replay attack by monitoring sequence numbers of packets sent from the power outlet of an appliance. Timestamp based approaches would work similarly.

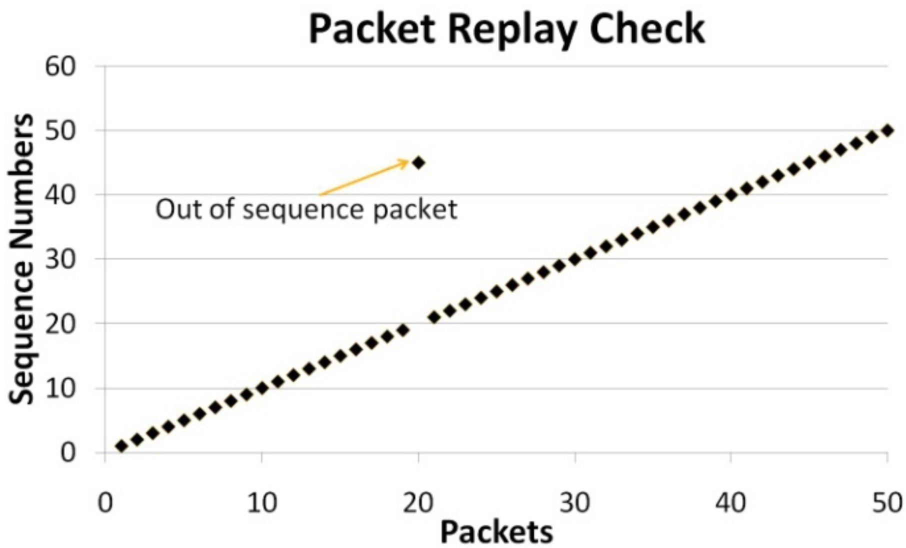


Figure 9.8 The sequence number technique to detect packet reply attacks

9.4.5 Non-Repudiation

In the proposed approach, non-repudiation can be achieved by ensuring that customers and the SM use unique keys for encryption, possibly after initial authentication using pre-assigned public-private key pairs. Further, the SM would be required to keep a log of all communication for a specified number of days. If either party files a complaint, the logs can be used to trace back events. Regulations will need to be enforced to ensure that the utility does not tamper with these logs and are available for third party investigations.

9.5 Design of a Common Security Framework Against Attacks

A comprehensive, integrated framework for a secure WHAN-SM is proposed in this section. It addresses the security issues previous discussed while preserving customer privacy and minimizing interference from other wireless equipment.

9.5.1 Integrated security framework for HANs

An integrated framework for a secure WHAN-SM should address the above mentioned security challenges with a clear demarcation of responsibility among the three entities involved, namely: (1) the SM, which obtains aggregate power consumption requirements from the utility and manages the customer's power consumption, (2) the device that is requesting operation through customer input, (3) and the power outlet, which acts as the agent between the SM and the device by communicating with SM and executing control decisions to operate the device. The proposed integrated framework for secure WHAN-SM shown in Figure 9.9 provides this separation and while following a sequence of operations to counter possible attacks.

Each device's request for operation is sent to its power outlet, either by the device, if capable, or else manually by the customer. Upon receiving such a request, the power outlet completes an authentication exchange with the SM and sends a packet with the details of the device it is representing and the requested operation. The device is not allowed to operate if authentication fails, or if the SM finds the request to have an invalid sequence number or any other characteristics indicating a replay attack.

Jamming attacks can be made when the outlet and SM try to exchange data packets. In the secure WHAN-SM framework, the outlet and SM move through a pre-decided sequence of channels that make it very difficult for an adversary to intentionally jam communications. Prior work done for a pair of nodes that move through a sequence of channels shows that reasonable throughput can be expected from the network if the time spent on each channel is very small [117]. Further, the relatively low communication throughput expected in an SM scenario reduces the potential impact of jamming significantly. The jamming solution proposed in Section 9.4 is similar, but works between one coordinator and many other nodes in the network. Other techniques like directional reception at the SM as mentioned in Section 9.4 could be employed as well.

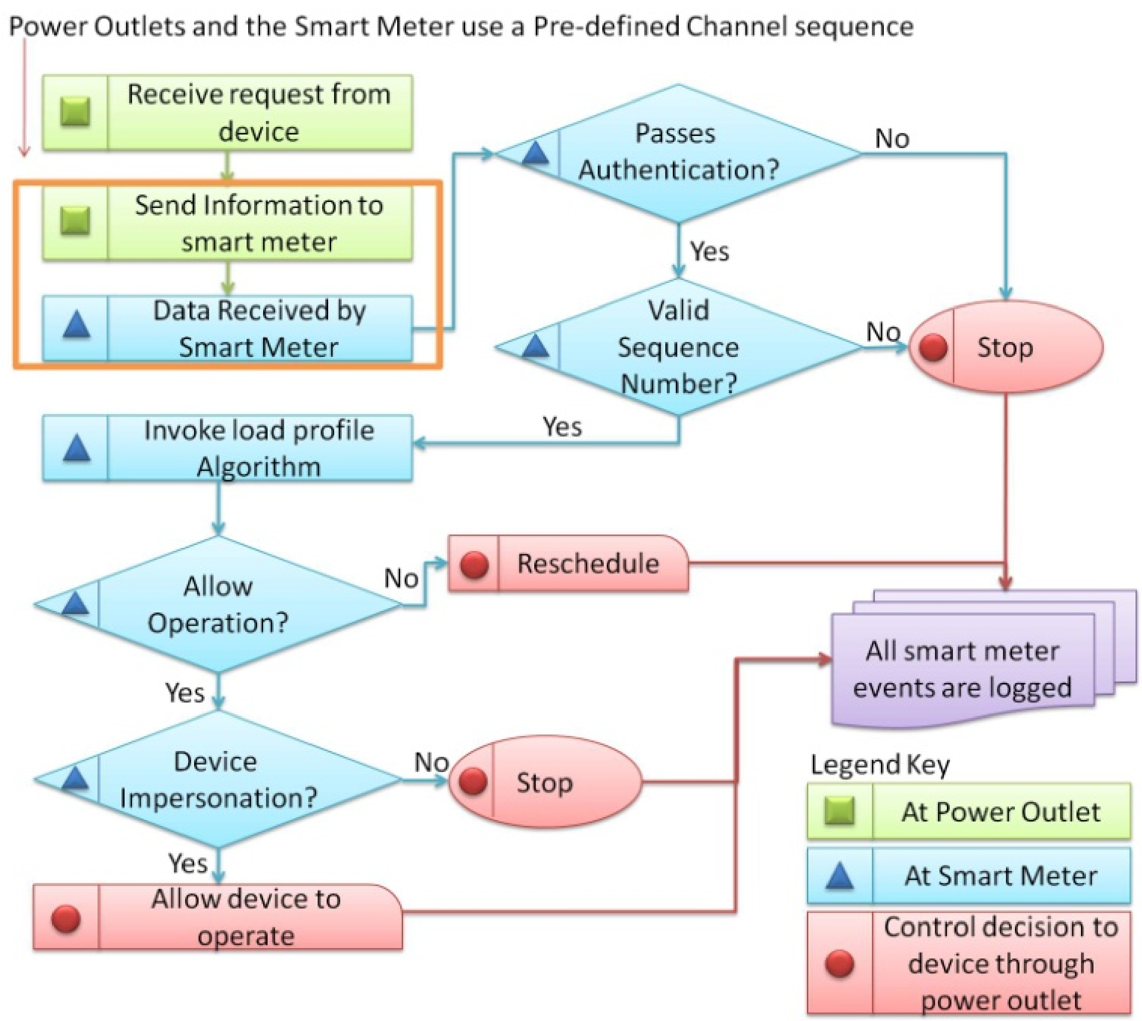


Figure 9.9 Overview of the Secure WHAN-SM framework

Once the SM confirms that the requested operation is from one of the authorized customer devices, it decides whether to allow device operation based on the load profiling algorithm introduced in section 9.4-C. The algorithm serves the dual purposes of controlling the load when necessary, and detecting device impersonation. Operation decisions are then sent as control messages to the power outlet which then enforces them to the device it controls. A decision to re-schedule can lead to the request being queued at the power outlet for a later attempt without customer intervention, or having the customer manually retry at a later time. All decisions taken by the SM on requests from power outlets are logged for later review if needed at the power outlet. These logs can help provide non-repudiation of actions in the network.

9.5.2 Progress towards meeting security objectives

The authentication procedure along with defense against packet replay attacks is directed towards the objectives of *integrity* and *authentication*. In this subsection, meeting the remaining security objectives defined in Section 10.3-B for a WHAN-SM scenario is discussed.

For *confidentiality,* the utility will only be allowed a periodic aggregated view of the whole residence. The SM will not share instantaneous load information with the utility, but will instead provide an aggregate load profile.

Load profiles of devices are checked for impersonation by individual power outlets, leading to decisions on controlling the device. This information will be shared only between the SM and the power outlet. Power outlets need to be tamper-proof, and their event logs can only be read by the utility with permission from the customer or through a trusted third party. If tampered with, these units should be configured to disallow operation of equipment until manually resolved by the utility in cooperation with the customer, where authentication from both parties is necessary to reset the outlet, something that can be done remotely.

Requests for device operation by a power outlet to the SM present the customer's requirements to the SM. Decisions are made by the SM without involving the utility except for collecting instruction on how to handle loading requests in any given time period. Any decisions made by the SM are then relayed to the power outlets, which keep a log of all decisions made relevant to the equipment connected to it.

If WHAN-SM uses an unlicensed band like the 2.4 GHz spectrum, it would need to consider the impact of interference from other wireless equipment on those frequencies. Currently this spectrum is shared by technologies like Wi-Fi, Bluetooth, ZigBee, WirelessUSB, Microwave ovens, and Cordless phones. Technologies like Wi-Fi and ZigBee have collision avoidance mechanisms built in at the medium access level (e.g. carrier sense multiple access) to minimize impact of other node operations of the same technology. However, interference across technologies is more difficult to handle.

The most likely scenario of interference would be an access network based on heavy data-rate Wi-Fi impacting the WHAN-SM. The secure WHAN-SM channel switching function is useful in moving communication to a frequency that has reduced interference. Further, directional reception capabilities of a SM will allow interference from other networks to be limited to certain directions only. Current technologies like ZigBee do not by default provide such automatic channel switching or directional reception capability and require manual configuration. The low data-rate requirements of the SM application are also an advantage in reducing interference with other networks.

Interference and jamming attacks would be the primary reason for reduced *availability* and *delays* in the WHAN-SM, and this framework will help address these aspects as well. As the SM application in residences is expected to have low data rates, the impact of queuing delays and other high data rate issues are not likely to have an impact. Issues like power failures impact not only the network, but also all the equipment that need to operate, and hence need not be addressed in this framework.

9.5.3 Conclusions and Future Work

This work presents a comprehensive secure framework for smart metering in a wireless home area network scenario. Such a framework was designed by first examining the communication requirements for AMI in the WHAN-SM scenario and then studying the security challenges that had to be addressed, and combining solutions to these challenges. Contributions of this work also included the development of a communication and control model in home area networks for smart metering.

Future work in the area involves looking at the wireless communication path between the SM of individual residences and the utility's control center. This will involve studying a different class of attacks that are remote in nature and involve exploiting vulnerabilities at the network layer. Such research is ongoing and complementary to the work presented here, which was local in nature to the WHAN-SM. Additional work also needs to be done by standards organizations to provide capabilities to appliances and other equipment that are expected to be part of future WHAN-SMs.

10 Conclusions

Through studies of example Smart Grid applications on transmission and distribution, the communication needs for the Smart Grid are defined and protocols for communications are recommended. The applications evaluated on the transmission system are advanced alarm processing, automated fault location, detection and mitigation of cascading events, and condition-based maintenance of circuit breakers. Distribution applications are optimized electric vehicle charging and condition assessment and optimized maintenance of distribution system components.

For the transmission system a three level communication hierarchy is proposed. The three levels are intra-substation, substation-control center, and utility-level communications. For distribution, the protocol proposed is a wireless (WiFi) mesh architecture. In addition, a wireless-based home area network for advanced metering infrastructure is proposed. The home area network protocol addresses the unique security issues associated with the advanced metering infrastructure application.

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Project Publications

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Appendix 1: Transmission Level Smart Grid Applications Communication Use Cases

Use Case: Intelligent alarm processing

Goal: To extract fault information from alarms and send it to system operator and other programs.

Summary:

Alarm processing serves system operators by performing alarm suppression, alarm prioritization, and reduction of alarms on the basis of cause-effect analysis. It assists power system operators responding more efficiently to the stressed power system conditions. It also provides data resource for optimized fault location and cascading event analysis. On system level, information that is required by different functional modules is extracted from field measurements according to their respective needs. On local level, it could be observed that the data required by this alarm processor is a combination of SCADA measurements and measurements from other IEDs (e.g. DPRs).

Actors:

Actors	Role Description
Substation application	Collect data from substation IEDs and send it to centralized location within a utility.
SCADA System	A computer system that monitors and controls power system operations. SCADA database is updated via remote monitoring and operator inputs. Required scope, speed, and accuracy of real-time measurements are provided; supervisory and closed-loop control is supported.
Operator	Indentifies and resolves the problem or advises the field crew and acknowledges the alarms.
Outage management	Locates fault if the problem is caused by a fault.
System analyzer	Analyzes events and provides solution if the alarms are related and caused by cascading events.

Pre-conditions:

The SCADA system is in operation. Data from IEDs is available. Historical data is available and can be retrieved from archive. Multiple alarms occur in a short period of time.

Assumptions/Design Considerations:

None.

Normal Sequence:

Use Case Step	Description
Alarms appear	Alarms can have different priority levels and are accordingly displayed.
Retrieve data from SCADA, massages sent by substation and archive	Status of CBs, historical data, electrical quantities, etc.
Analyze sequence and cause of alarms	An alarm can have various causes, it can come from: a RTU device, an error in the communications lines, a problem with servers, an external indication, an overloaded element and even from an illegal operator action. This information can indicate that an operator procedure must be started, or it can simplify visualization of a complex unfolding situation.
display results in operation room	Displayed on operator's console
Generate reports	The result from alarm processing may be needed from system operation, fault location and cascading analysis, depending on the information revealed from alarm processing: how severe the problem is and which department should participate in solving it.
Clear alarms	Alarm log is made and alarms are cleared
Close alarm list	Alarms are removed and stored to historical file

Exceptions/Alternate sequences:

Alarms appear→retrieve data→analyze the cause→ display results→clear alarms→close alarm list

Post-conditions:

Alarms are removed.

Use Case: Optimal fault location

Goal: To select the fault location algorithm that locates fault with least error given the data condition, and performs fault location functionality.

Summary:

The optimized fault location method selects a suitable Fault Location (FL) algorithm from three types of algorithms: two-end FL algorithm based on synchronized samplings, single-end or multiple end phasor based FL algorithm, and system-wide sparse measurement based FL algorithm. The measurement equipment used is sparsely located Digital Fault Recorders (DFRs), Digital Protective Relays (DPRs) or other GPS-based IEDs (e.g. PMUs or digital relays). Commercial software like PSS/E and PowerWorld is utilized to run power flow analysis and display the fault location results.

At substation level, the availability of data collected from DFRs, DPRs and PMUs makes it possible for implementing some fast fault location algorithms. Integrating the data from these IEDs into traditional SCADA solution enables real-time monitoring of power system and fast operator actions.

Actors:

Actors	Role Description
Substation application	Collect data from substation IEDs and send it to centralized location within a utility.
Operator	Advise the field crew
Metering system	The system used for collecting metering information.
SCADA System	A computer system that monitors and controls power system operations. SCADA database is updated via remote monitoring and operator inputs. Required scope, speed, and accuracy of real-time measurements are provided; supervisory and closed-loop control is supported.
GIS System	An information system that integrates, stores, edits, analyzes, shares, and displays geographic information.

Pre-conditions:
The SCADA system is in operation. Data from IEDs is available. Historical data is available and can be retrieved from archive. Information from GIS system and metering system can be shared. A fault occurs.

Assumptions/Design Considerations:
None.

Normal Sequence:

Use Case Step	Description
A fault occurs	The occurrence of a fault can be indicated by report from the field, loss of service determined from metering system, or result from alarm processing.
Retrieve data from SCADA, GIS and Metering system, archived and massage sent from substation	Status of CBs, historical data, electrical quantities, etc.
Fault location	This procedure selects and runs the algorithm that produce results with highest accuracy, according to the network scenario and availability of data.
display results in operation room	The operator advises field crew according to the information provided by fault location.
Generate reports	The reports are stored in archive for future reference.
Close fault list	Fault location results are removed and stored to historical file

Exceptions/Alternate sequences:
None.
Post-conditions:
A fault is cleared.

<u>Use Case:</u> Cascading Analysis

Goal: To detect cascading event in an early stage, and prevent it from unfolding.

Summary:

Power system cascading event is quite often a very complex phenomenon with low probability of occurrence but potentially can cause catastrophic social and economic impacts. Recent study reveals that early and proper control actions at the steady state stage can prevent the possible cascading events from unfolding. Power system operators lack sufficient analysis and decision support tools to take quick corrective actions needed to mitigate unfolding events.

Actors:

Actors	**Role Description**
Substation application	Collect data from substation IEDs and send it centralized location within a utility.
Operator	Advise the field crew
Relaying system	The system used for protecting power system and monitoring its behavior.
SCADA System	A computer system that monitors and controls power system operations. SCADA database is updated via remote monitoring and operator inputs. Required scope, speed, and accuracy of real-time measurements are provided, supervisory and closed-loop control is supported.
GIS System	An information system that integrates, stores, edits, analyzes, shares, and displays geographic information.

Pre-conditions:

The SCADA system is in operation. Data from IEDs is available. Historical data is available and can be retrieved from archive. Information from relay system and GIS system can be shared. A cascading event is indicated by results from alarm processing.

Assumptions/Design Considerations:

None.

Normal Sequence:

Use Case Step	**Description**
Cascading event indicated	A cascading event can be triggered by a heavy-load condition, a fault or equipment failure.
Retrieve data from SCADA, GIS and relaying system, archived and massage sent from substation	Status of CBs, historical data, electrical quantities, etc.
Analyze cascading events	This procedure analyzes the cause and consequence of cascading events, and provide solutions for system operator
display results in operation room	The operator take action to mitigate cascading event.
Generate reports	The reports are stored in archive for future reference.

Exceptions/Alternate sequences:
None.
Post-conditions:
Cascading is mitigated.

Use Case: Reliability-centered Maintenance of circuit breakers and power transformers

Goal: To obtain the health condition of circuit breakers and power transformers, and schedule inspection and maintenance based on condition of equipment and budget.

Summary:
Reliability-centered maintenance (RCM) is a cost-effective maintenance scheduling mechanism. It prioritizes maintenance activities based on quantification of likelihood and consequence of equipment failures. as the two most common types of equipment, transformers and circuit breakers are selected because 1) expenditures for maintenance of this equipment represent a large percentage of maintenance budgets; 2) failures adversely affect system reliability; and 3) monitoring technologies presently exist within substations. Three steps are included in RCM of transformers and circuit breakers: Failure mode identification, failure rate estimation and maintenance-scheduling based on risk reduction.

Actors:

Actors	Role Description
Monitoring devices	Send condition-related data to substation. Online monitoring measurements include: 1). Transformer monitoring system: voltage & current from PT and CT; winding temperature from fiber-optic sensors; dissolved gas-in-oil from gas sensors; moisture-in-oil from moisture sensors; tap position (digital) from tap-changers. 2). Circuit breaker monitoring (CBM) system/digital relay: current transducers; contact signal; temperature.
Substation application	Executes primary analysis and sends results to control center. The analysis includes: 1). Transformers: operation condition monitoring, temperature monitoring, dissolved gas-in-oil analysis (DGA), moisture-in-oil monitoring, partial discharge analysis (PDA). 2). Circuit breakers: timing test; vibration analysis; PDA, etc.
SCADA	Provides on-line topology and system-wide load information.
Maintenance group	Decides target and timing of maintenance activities based on budget and system reliability.

Pre-conditions:
System operates in normal condition; no occurrence of equipment failure; data acquisition and communication are available.
Assumptions/Design Considerations:
None.

Normal Sequence:

Use Case Step	Description
Condition monitoring is done at a regular interval	Condition-monitoring includes collection of condition-related information and substation-level condition-related analysis.
Monitoring devices send condition information to substation	Sensors and types of data have been listed in the previous table.
Substation application executes condition-related analysis	To process raw data.
Substation application calculates failure rate for each of the failure modes of every transformer and CB	Failure modes of transformers include: cellulose insulation degradation, oil decomposition, LTC failure, partial discharge, bushing failure, short or open winding circuits, loss of sealing, pressure relief blocking and heat exchange device failure. Failure modes of circuit breakers include: failure to operate, false opening, false closure, delay for dielectric isolation to build up, false energization, short circuits, insulation failure, etc.
Substation application send results and raw data to utility	Substation data is transferred from substation to an engineering office or control center
Maintenance group retrieves system information from SCADA	Information includes real-time load condition and topology.
Maintenance scheduling application computes the risk deduction for all possible crew dispatch plans	Improvement in reliability is calculated based on failure rate of equipment before and after maintenance.
Selects the most cost-effective crew dispatch plan	Maintenance crew is dispatched
Schedules maintenance activity	Maintenance activity is performed
Sends report and raw data to archive	Data and reports are archived

Exceptions/Alternate sequences:

Start monitoring→ execute substation-level analysis→ calculate failure rate→ send failure rate and raw data to utility→ retrieve data from SCADA→ compute risk reductions→ no maintenance needed→ store report and data to archive.

Post-conditions:

Maintenance activity that can improve system reliability most effectively is scheduled and executed.

__**Use Case:**__ Substation Communicates with IEDs

Goal: To get data from IEDs for applications described in other use cases.

Summary:

Different IEDs communicate with substation in different ways. IEDs for real-time monitoring purpose like Power Quality meters send real-time data to substation concentrator continuously, and substation concentrator sends the data to corresponding department in utility; IEDs for off line monitoring and protection purposes like Digital Fault Recorders (DFRs) and Digital Protective Relays (DPRs) generate reports and send them to substation concentrator only when an event occurs; some others send data to substation concentrator only when requested. When an event occurs in a transmission system, substation detects the event by receiving alarms and reports from DFRs and DPRs. To allow advance operation applications described in previous use cases to execute, substation concentrator needs to collect data from every IED and send send it to utility in a packaged massage. When data is needed for reliability-centered maintenance, the procedure is triggered by a request sent from utility office to substation.

Actors:

Actors	Role Description
Substation appliocation	Executes initial analysis and sends results to control center. The analysis includes: 1). Transformers: operation condition monitoring, temperature monitoring, dissolved gas-in-oil analysis (DGA), moisture-in-oil monitoring, partial discharge analysis (PDA). 2). Circuit breakers: timing test; vibration analysis; PDA, etc.
Monitoring IEDs	Intelligent Electronic Devices such as RTUs and PQ meters installed for real-time monitoring
CBMs	Circuit Breaker Monitors installed to report CB operations.
DPRs	Digital Protective Relays, installed for protection.
DFRs	Digital Fault Recorders, installed for recording waveforms pre- and during faults.
Smart Meters	Advanced meters that identify consumption in more detail than conventional meters; and optionally, but generally, communicate that information via some network back to the utility office responsible for monitoring and billing activities.
Operation Department in Utility	Receives data from substations and executes alarm processing.
Maintenance Group in Utility	Sends request to substation application and initiates data collection

Pre-conditions:
System operates in normal condition; data acquisition and communication are available.
Assumptions/Design Considerations:
None.

Normal Sequence:

Use Case Step	Description
Substation receives alarms from protective devices	The alarms could be sent by Circuit Breaker Monitors (CBM), DPRs and DFRs (as event report).
Substation sends out request for data collection to IEDs	Request is broadcasted to IEDs located in switchyard, in system and at customer side.
IEDs send data to substation	Data is sent in a format required by substation communication protocol.
Substation compiles data into data massage	Data massage is formed
Substation sends data massage to utility	Data massage is in format that follows communication protocol between substation and utility.

Exceptions/Alternate sequences:

Substation application receives request from maintenance group in utility→substation broadcast request to Circuit Breaker Monitoring (CBM) devices and Transformer Monitoring (TM) devices→ CBM/TM devices send data to substation application→ substation application compiles data into massage→ substation sends massage to a location within the utility

Post-conditions:

Applications are executed in utility offices.

Actors:

Table 1 is a summary of the key Actors from three use cases discussed in this report and the domains they participate in.

Table 1: Actors

Actor	Domains	Description
IEDs	Transmission	A microprocessor-based device aimed at controlling and monitoring power system equipment and communicating with SCADA, as well as distributed intelligence applications for automatic operation.
Substation application	Transmission	Substation is a point in, transmission and distribution system where voltage is transformed from high to low or the reverse using transformers. Electric power may flow through several substations between generating plant and consumer, and may be changed in voltage in several steps. Substation application runs on a substation computer.
SCADA	Operations	A computer system that monitors and controls power system operations. SCADA database is updated via remote monitoring and operator inputs. Required scope, speed, and accuracy of real-time measurements are provided, supervisory and closed-loop control is supported.
Wide Area Monitoring and Control System	Operations	Measurements from phasor measurement units located in a wide area of power systems and determining actions to perform with transmission actuators.
Metering System	Customer	The systems used for collecting revenue and operator metering information.
GIS	Operations	An information system that integrates, stores, edits, analyzes, shares, and displays geographic information.
Power System Control Center	Operations	Center for Power system central operations.
EMS	Operations	A system of computer-aided tools used by operators in electric utility grids to monitor, control, and optimize the performance of the generation and/or transmission system. EMS also provides input to DMS with transmission/generation-related objectives, constraints, and input data from other EMS applications.