DEVELOPING A HYBRID MODEL FOR NETWORK PLANNING IN ABU DHABI DISTRIBUTION COMPANY
SUBSIDIARY OF ADWEA

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ABSTRACT

The past decade witnessed an evolutionary move in power-sector restructuring which led and is going to lead utilities companies to be deregulated in the form of independent power generation, separate transmission as well as distribution companies. New technological advancements are also being introduced in the electricity field and expected to be utilized in networks planning as well as in operation.

Advanced digital technologies are becoming an integral part of the utility business environment to cope with the fast growth of the network infrastructure and the privatization process. Among these technologies is the Geographical Information System (GIS) which is an integrated set of hardware, software, databases, and processes designs that have the ability to handle information of multiple sources and formats such as maps, photographs, satellite images, tables, records, historical time series, and to mirror the assets and the business in geo-spatial platform. Another technology is the Distribution Management System (DMS) whose aim is to increase utility service reliability, improve customer response, reduce operational costs, and meet regulatory requirements. DMS technology consists of Distribution Supervisory

Control And Data Acquisition (SCADA) which is expected to become more valuable in the planning process when SCADA-compatible devices are introduced into system feeders.

This thesis presents a strategic planning Decision Support Tool based on extracted best functions which can be employed in the GIS and DMS technologies and reflects the impact of those functions on the operation's capital costs as well as the organizational benchmarking reliabilities. In this investigation, system reliabilities are measured by indices such as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). The evaluation of the indices is performed by applying Multi-Attribute Trade-Off analysis (MATA) technique to identify Pareto Superior options in order to resolve situations where conflicting objectives or attributes are present. MATA analysis technique is chosen for the analysis of the electrical system evaluation since investments decisions are to be made considering both the system reliability and the related costs. Remarkable effect on system reliability and costs was found through the use of proposed model. In addition to identifying the "Pareto Optimal" designs, the model clearly showed the benefits from the use of the GIS and DMS technologies in enhancing the system reliabilities without significant increase in cost.

The results of the thesis were tested and applied to Abu Dhabi Distribution Company (ADDC), which is an affiliate of Abu Dhabi Water and Electricity Authority (ADWEA). ADDC was established on November 1998, and have been operating as an electricity and water distribution utility since January 1999. ADDC network covers around 28,439 kmtr of under ground cables serving over 201,500 customers. The vision of ADDC's management is to become one of leading companies in water and power service provider in the world. This necessitates the need for management to strategically plan for the company to operate in-line with the service cost and service quality performance norms. The thesis provides concrete recommendations for the reengineering of ADDC network with quantified impact on the improvement of the up to 20% with the most optimal increase in capital and operational costs.

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LIST OF ABBREIVATIONS

AADC–	Al Ain Distribution Company
ADA–	Advanced Distribution Automation
ADDC–	Abu Dhabi Distribution Company
ADWEA–	Abu Dhabi Water and Electricity Authority
AM–	Automated Mapping
AMS–	Asset Management System
ANN–	Artificial Neural Network
BPM–	Business Process Management
CAD–	Computer Aided Design
Capex–	Capital Expenditure
CBD–	Central Business District
CIS–	Customer Information System
CMMS–	Material Management and Maintenance System
DA-	Distribution Automation
DISCOs–	Distribution Companies
DG–	Distributed Generator
DMS–	Distribution Management System
DR–	Distributed Resources
DSM–	Decision Support Model
EHV–	Extra High Voltage
EPRI–	Electric Power Research Institute
ER–	Eastern Region
ESCOs–	Energy Service Companies
FM–	Facility Management
GENCOs–	Generation Companies
GIS–	Geographical Information System
HV–	High Voltage
IT–	Information Technology
KWH–	Kilo Watt Hour
KV–	Kilo Volt

LR–	Logistic Regression
LV–	Low Voltage
MATA–	Multi Attribute Trade of Analysis
MDDS–	Modernization and Development of Distribution Systems
MV–	Medium Voltage
MVA–	Mega Volt Amper
MW–	Mega Watt
NERC–	North American Electric Reliability Council
NPV–	Net Present Value
NPO–	Normal Open Point
O&M–	Operation and Maintenance
OMS–	Outage Management System
Opex–	Operation Expenditure
PLCs–	Programmable Logic Controllers
RSB–	Regulatory and Supervisory Bureau
SAIDI–	Service Average Interruption Duration Index
SAIFI–	Service Average Interruption Frequency Index
SCADA–	Supervisory Control And Data Acquisition
SMC–	Sequential Monte Carlo
S/S–	Substation
TLM–	Transformer Load Management
TR–	Transformer
TRANSCO–	Transmission Companies
WMS–	Work Management System
WR–	Western Region

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DEDICATIONS

I dedicate this thesis to my parents and family, without their patient, understanding, support, and most of all love; the completion of this work would not have been possible.

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CHAPTER 1

1. INTRODUCTION

1.1. Background

The past decade witnessed evolutional move toward power-sector restructuring, since then, this move has been taking over in many regions around the world. Power-sector restructuring led and is going to lead to an independent power generation, transmission as well as distribution. Competition; decentralization; privatization; and unbundling of the three groups in power system are simply expected results of the deregulated power industry.

The changes in power sector are accompanied with lots of new technological advancements that are caused by the enormous non-stop increase in energy demand consumption. Beside the new technological advancements there is another factor that introduces new concepts that impose severe planning and operational restrictions on electric utilities in generation, transmission and distribution. These concepts are set by the Supervisory and Regulatory Bureau (SRB), and it is the electric utilities' obligations to follow those standards when running their business. This means that future power system is expected to be adaptive to changes, interactive with consumers and markets and at the same time deliver the best possible service with the most reasonable cost.

This in turn creates an incentive for distribution utilities to do their best in order to maintain their competitive position in the industry by investigating what capabilities and potentials they have and establish strategies on how to utilize the offered technologies in the market to plan and operate their networks effectively and efficiently [39].

1.2. Problem Statement

Over the time it is becoming clear that generally most of the new contributions in all innovations in our daily life-style is actually the ability to use and control electricity. This is mainly due to the fact that all technologies around us do use electricity to achieve the purpose they are made for. This electricity is taken from what is known as the electric distribution system. The distribution system is an important element to electrical utility for two reasons: its proximity to the end users and the high investment cost involved. Therefore one of the main objectives for distribution system planners is to ensure that the increased demand for electricity is being met with minimum possible total cost of the distribution system expansion.

The design of electrical distribution networks is an everyday task for electric utility engineer that was manually done few years ago. This classical approach usually results in over design schemes that are considered waste in system capacity and investments taken. Correction of that approach is very important; solution could be by restructuring the applied processes, revising O&M costs, correction of misclassification of consumers and reducing the time between reading the meters and collection of revenues to improved performance and turnover for these distribution utilities. However, Information technology can introduce easy solution to all of that especially when considering the following:

1. Improve financial performance via improved customer service methods
2. Enrich decision analysis and system simulation tools for more efficient valuation evaluation.
3. Improve technical efficiencies to reduce cost and to improve reliability
4. Enhance reporting standards to meet requirements of all levels

Distribution utilities then must set their objectives and goals according to a clear strategic plan that takes under consideration their technological competencies and potentials. The aim of this research is to highlight the possible areas for improvement in the distribution planner approaches by exploring new technological capabilities like Geographical Information System (GIS) and Distribution Management System (DMS) that are expected to ease planning decisions and enhance service reliabilities levels.

1.3. Research Objectives

The Thesis results are to be applied to Abu Dhabi Distribution Company with tangible recommendation on system planning and performance improvement with emphasis on the impact of the socio-economic development of the Country

Electric distribution utilities face major challenge in the new deregulated power sector. The challenge lies in achieving their customer satisfaction in terms of quality of power supplied with a reasonable price. Electric utilities have to do that with a dramatic demand increase, however with a limited governmental funds and a more restricted constrains imposed by Regulatory and Supervisory Bureau (RSB).

Therefore, adoption of new technologies should be taken into consideration when setting up strategic development planning principles to assure reliable and efficient operation of the distribution networks. Therefore, the ultimate core objective is to evaluate current power utilities performances in light of new available technologies and integrate the functionalities of Advanced Systems in the Planning process to support the utilities decision makers in Policy and Strategic Development.

This research takes Abu Dhabi Distribution Company (ADDC) located in Abu Dhabi as an example to illustrate the impact of privatization and employment of new technologies in achieving the best possible outcome with regard to cost and system performance. As Abu Dhabi presently experience a rapid load increase, it is becoming very essential for ADDC to investigate the capabilities of its current system and determine it is actually capable of withstanding expected boost in demand, ADDC present electric network was developed to meet demand as and when it arises, which would not serve its purpose in the new circumstances.

This research is intended to study and evaluate the following:

1. Examine the trend in the power sector restructuring
2. Review applied planning practices in utility companies around the world and evaluate specifically Abu Dhabi Distribution Company (ADDC) current practices. This is to be done with respect to current operation guidelines, security of supply standards and reliability of supply standards.
3. Perform gap analysis to identify possible improvement opportunities in the planning processes for distribution companies (ADDC) in the light of advanced adopted technologies: Geographical Information System (GIS) and Distribution Management System (DMS)
4. Developing Modified decision support planning tools via introducing advanced (GIS) and (DMS) functionalities and perform comprehensive analysis of the new approach on the network planning with different structure and configuration
5. Perform trade off analysis obtained from the decision support tool to evaluate different scenarios with respect to the impact of demand growth and economic development of the country.
6. Develop recommendations on how to overcome present ADDC constraints by presenting the directions that ADDC management recommended to follow.

1.4. Significances of Research

The anticipated large increase in energy demand requires immediate expansion of the present electrical systems. However, the decision to define direction and strategies for this expansion is to be based on some scientific analysis for more accurate results in the future which is one of the challenges that utilities management face. In this research Abu Dhabi Distribution Company (ADDC) is examined as a typical case study. The results of this research is expected to assist decision makers of ADDC to proactively assess future electrical power needs in Abu Dhabi and properly set the strategic as well as tactical plans to meet those needs. Though this research, the findings shall improved responsiveness of the system. Results of this investigation expected to present to ADDC management all possible design options with their different system capacities, reliabilities and best customer restoration times with their relative cost expenditure, therefore, decision makers can compare and select the ones that are in line with the company vision.

Moreover this research reintroduces the present decision tool applied in ADDC, however, with new factors taken from new technologies impact such GIS and DMS. These factors can easily be applied to predict ADDC performance position in relevant to its past performance and in the same time can be benchmarked with other best practice utilities in the same industry. However, the most important finding in the research will be in identification of the impact of automation systems like GIS and DMS on planners approach in developing utilities strategic plans for future expansion schemes.

1.5. Thesis Organization

This research investigates the importance of adopting new technologies when for utility companies when setting up their tactical development maps. This chapter introduces thesis background, the statement of the problem, research objectives as well as significance of the research. The remaining chapters will be organized as follows.

Chapter two will comprise a review of open literature on power systems planning, operating principles as well as the up to date research work that was done on the new technologies in automation of power systems. Chapter three will concentrate on the electric power companies in their traditional environment, structure, culture, environment constraints, as well as planning and operating with different network structures, where simple explanation on the basics of electrical distribution system from Extra-High voltage(EHV) up to the customer end network known as Low Voltage (LV). In chapter four, Abu Dhabi Distribution Company (ADDC) is considered to be a benchmark investigation of this research. Detailed discussions on ADDC present system structure, culture polices and its present environmental obstacles are presented. In addition identification of ADDC current practices and its supply standards, engineering planning guidelines and reliability indices and performance Gap analysis will be presented and analyzed.

Chapter five highlights the potentials and capabilities of new technologies such as Geo-Spatial Technology (GIS) and the Online/SCADA Technology (DMS). The different functions of both technologies are illustrated. The impact of the new digital environment will be covered in chapter six, where the new model in decision making will be introduced along with the implementation methodology and results.

Following in chapter seven, a comparative analysis for design options is presented. Taking under consideration the GIS and DMS technologies influence and comparing results to the same options performances when those technologies are not utilized. Finally, the research will be concluded with the findings and recommendations for future development in chapter eight.

CHAPTER 2

2. LITERATURE REVIEW

1.2. Background

Power distribution systems importance comes from our daily life dependency on it. For instance in situations of power energy outages, there is a great need for a fast and appropriate response to immediately restore the power in order to maintain customer loyalty as well as satisfaction. One way to do so is via a method called root cause identification tools, these tools are important to achieve successful outage restorations. Some studies that investigated this problem classified outcomes into two methods, They are logistic regression (LR) and artificial neural network (ANN). LR is rarely used in power distribution fault diagnosis, whereas ANN has been widely applied in power system reliability studies, which discussed at the same time the practical application problems like data shortage, and threshold setting that are often faced in power distribution fault cause identification problems [23].

Current distribution utilities used to perform one function, which is distributing power to end users. As the energy demand consumption continue to increase, power utilities around the world began to realize the difficulties arising with the traditional vertically integrated electric power structure, therefore they are moving towards unbundled generation companies (GENCOs), transmission companies (TRANSCOs), and distribution companies (DISCOs), not to mentions the energy service companies (ESCOs) [27].

Above unbundling of electricity market puts electricity customers in an increasingly competitive market environment; this forms one challenge that is facing the electric power utilities of today. From customers' side, they expect reliable and efficient supply of power from their utilities. Some studies introduced distributed generator (DG) as one solution that a can provide power supply to customers which guarantees the continuity of supply by implementing intentional islands in the event of upstream utility supply outage. This implementation of intentional islanding of DG in the current deregulated environment will have an impact on electricity market prices; however, it doesn't solve the optimal power flow problem.

Examining electric power distribution functions in the past, one can see that they were somehow transparently coordinated along the complete supply chain. However, the same distribution companies in the future would probably manage third-party contacts by delivering bulk power from GENCOs and TRANSCOs to meters owned by ESCOs mainly due to the broad geographical distribution of the network. Coordinating and managing such vast network can't be successfully accomplished without the intervention of information technology. Such technologies applied in monitoring and controlling electric distribution networks is known as "Distribution Automation (DA)" system. As information technologies uncover significant capabilities, many studies have been carried out on the impact of automation on distribution power system performance. Following is a review on the history of DA researches and their findings [5].

Distribution automation started back in 1970s. The basic concept was to utilize the evolving computer and communications technology to improve operation and performance of the system. After that, the development of distribution automation was pushed by the sophistication of presented monitoring, control, and communication technologies; Small pilot projects were implemented by some power companies to test the theory of distribution automation in the 1970s. In the 1980s, there were more pilot projects. In 1990s, the DA technology had matured and that resulted in several large and many small projects at many utilities [10][14][20][28].

Studies globally are being carried out to investigate the automation of the electric power distribution system utilizing recent advancement in the area of Information Technology (IT) and data communication system. For instance, the Electric Power Research Institute's (EPRI) Advanced Distribution Automation (ADA) program facilitate for power utilities to convert their traditional distribution systems into multifunctional systems that make the best of new capabilities in power electronics, I..T., and system simulation [13].

Another advantage for D.A. is that it helps power utilities reach customer loyalty. This is done through increasing system capacity by putting the utility in a position that makes it able to take advantage of anticipated new opportunities emerging on both the supply and demand sides of power business. Studies have shown that utilities must now act on this, as for the next five to ten years, the utilities that realize those technologies including distribution automation and exploit them today would be taking the lead in the power market penetration in the future. In another words, those utilities will be able to do more with less, they will be able to deliver to their customers higher quality services at relatively low costs, which for sure will distinguish them from their competitors, as well as it would increase their companies' value for their shareholders and customers. New automated technologies in distribution systems includes microprocessor-based subsystems that are capable of providing digital relays with communication ability, remote tripping or closing of breakers on command, digital oscillography, and self-testing. Moreover, utilities just begun to apply programmable logic controllers (PLCs) in substations for system integration process. This option enables network engineer to monitor and control this equipment, which eliminates the need for using multitude of timers and other hardwired devices [15].

The significance of the new information technologies were presented in several studies; for example; The majority of utilities implement Distribution Management System (DMS) mainly to increase their service reliability, improve customer responses, and reduce operational costs (mostly labor), or even to meet regulatory requirements. There is an increasing effort toward utilization of DMS to maximize return on investments by extending DMS applications in manners that reduce the lifecycle costs of distribution network assets. DMS technologies, consisting of Distribution Supervisory Control And Data Acquisition (SCADA), which is expected to become more valuable in the planning process when SCADA-compatible devices are hocked to the system feeders [17].

In the integrated DMS, a set of hardware and software network would be capable of monitoring and controlling network substations and feeders operations. Results of several studies had shown that the processing ability would achieve improved performance than the traditional operation processes, this due to the feeder automation functions that are included in the modern operation processes. In addition system operation with the presence of distributed automation functions would improve the response times, and introduce a highly efficient outage management [6][24].

On the other hand, the Geographical Information System (GIS) offers various applications that are used in electric power planning, wind energy evaluation, solar energy and biomass resources. GIS is really a very powerful analytical tool. It is an integrated set of hardware, software, databases, and processes designed to handle information of multiple sources and formats such as maps, photographs, satellite images, tables, records, historical time series, etc [19].

GIS also provides the capability of the integration into management different infrastructure systems, for instance, in San José, California Public Works Department; management took the initiatives to integrate its geographic information system (GIS) data management process with their single database that works with software provided by their multiple vendors. This integration resulted in improving productivity as well as saving the department's 400 staff members' time. The same department plans to wirelessly push out GIS to maintenance crews and engineers in the field, which they expect will improve project turnaround time, enhance spatial accuracy because of the improved field data verification process, and ultimately, eliminate paper reports [31].

GIS provides the capability to speed up the planning process because all the data in such system would be centralized in single database, therefore; having to extract data from different resources and administrative authorities would be avoided, this feature alone provide practical easy solution for utility planners in selecting the appropriate routes while designing utility infrastructure, hence; it reduces risks of damaging existing utility services, and at the same time it definitely minimize cost and duration for project implementation [25].

Going back to electric sector restructuring, it puts distribution utilities in a competitive performance position, where the importance of cost and reliability is becoming a main goal. Distribution planning must now clearly identify the reliability/cost tradeoffs. This raises a very important question, or even series of questions; how is reliability defined for distribution systems, how is reliability valued for distribution systems, how is reliability controlled and maintained in distribution systems, and what methods used to measure reliability? The literature survey did not show one known single accepted method of measurement, however; there is what is known as utility practices, which varies among utilities as no generally accepted framework is available to guide thinking and methodology to implement reliability-based planning and decision making. However, methods are either historical, designed to assess the past state of the distribution system, or predictive, designed to assess future performance [29].

In some of the studies done to answer questions like how to control and improve reliability, new concepts were introduced on operating distribution equipments like distribution transformers. In the same study it was concluded that based on the visual analysis method obtained, network operator can determine efficient ranges for running network transformers. Benefits of this method can be used in analyzing efficiency of transformer loading based on databases of the distribution automation system, and the real-time operational data recorded on each distribution transformer [42].

Many articles had shown the importance of service quality and reliability as two essential factors in the new competitive electric energy market. These researches chose distribution automation as one of the most reliable measures that can be applied to improve outage time within their networks. As a result a new concept of value-based planning method is proposed in these papers to find the optimal numbers and locations of switches in feeder automation systems. The proposed method considers reliability costs, maintenance and investment costs to achieve the optimal feeder automation plan with the maximum benefit and best system reliability requirement. Automated numerical processing procedures efficiency proposed in these papers are compared to those obtained from a genetic algorithm [36].

System reliabilities usually measured with some indices such as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). System Average Interruption Duration Index (SAIDI) or Availability index measures service quality in regard to interruption duration. Outage management system gives real time data as and when they occur, and System Average Interruption Frequency Index (SAIFI) measures the average interruption frequency experienced by the customers, it is also known as “Security of Supply’. Those indices are anticipated to be improved with automation systems [12].

One paper introduced methods for estimating reliabilities’ indices such as Sequential Monte Carlo simulation (SMC). SMC can be used to estimate bulk electric system reliability indices by simulating the actual chronological process and random behavior of the system in fixed discrete time steps. The technique consequently provides accurate frequency and duration assessments compared with those obtained using other traditional methods. Delivery point reliability indices obtained using the sequential technique, therefore, can be realistically used to forecast future system reliability performance. Operating policies like load shedding procedures can have a considerable impact on the predicted reliability indices in a bulk electricity system. The same paper examines the impact of utilizing different load shedding philosophies in bulk electric system reliability studies. The results concluded from using the developed sequential software show that the adopted load shedding policy has a significant impact on the delivery point indices, but has relatively little impact on the overall system predictive indices. The load shedding philosophy, however, has a considerable impact on the system performance indices. The results obtained using three different load shedding policies are presented and compared using two test systems [38].

Regardless of above findings, generally; planning of distribution system has two aspect, reliability and capacity of the system to meet load growth. The capacity of the system is one outcome of system capacity planning and is applied to determine when and how much network expansion or reinforcement schemes are needed. Reliability, on the other hand is essential to identify good or poor system performances [1].

Proper system capacity planning requires accurate forecasts of the future magnitude and timing of peak electricity demand. Since electricity demand is affected by many factors like the day of the week, seasonal variations, holiday periods, feast days, and the weather, several investigations were done to deliver models that provide probabilistic forecasts of both magnitude and timing for lead times of one year is presented. The models presented are capable of capturing the main sources of variation in demand and uses simulated weather time series, including temperature, wind speed, and luminosity, for producing probabilistic forecasts of future peak demand. Having access to such probabilistic forecasts provides a means of assessing the uncertainty in the forecasts and can lead to improved decision making and better.

Automation of distribution system gives planners the ability to utilize all available resources with the maximum full installed capacity. Results of many studies that investigated the possible advantages of information technologies through integrating different systems and algorithms, indeed confirmed a faster and more accurate results, especially when associated with appropriate skills of planners [41].

It is worth pointing here that during this research preparation, there were no one dedicated research that studied the specific impact of automation on planning methods, nor the new technologies influence on applied reliabilities indices known in the electric industry. Additionally, during this literature review, and as per the list of references enclosed in this report, there were no research was found that reported the cost implications on applying new technologies in power distribution companies' budgets.

This thesis aims at investigating the possible outcomes of information technologies such Distribution Management System (DMS) as well as Geographical information System (GIS) on utility networks performance.

CHAPTER 3

3. PRESENT UTILITIES ENVIRONMENT

6.1. Traditional Utilities

Meeting customer's demand for electricity is the fundamental purpose of any electric supply system. Electricity system is usually composed of Power generation, power transmission and power distribution. Power generation produces electricity with respect to the most economic selling cost. The transmission part transfers bulk amounts of energy from the generation point to load distribution centers. As for the distribution system, it distributes the energy to the end users on different voltage levels. Usually there are individual supply entities that handle each of these functions within a particular area or region. Following Figure 3.1 illustrates the basic power distribution system configuration:

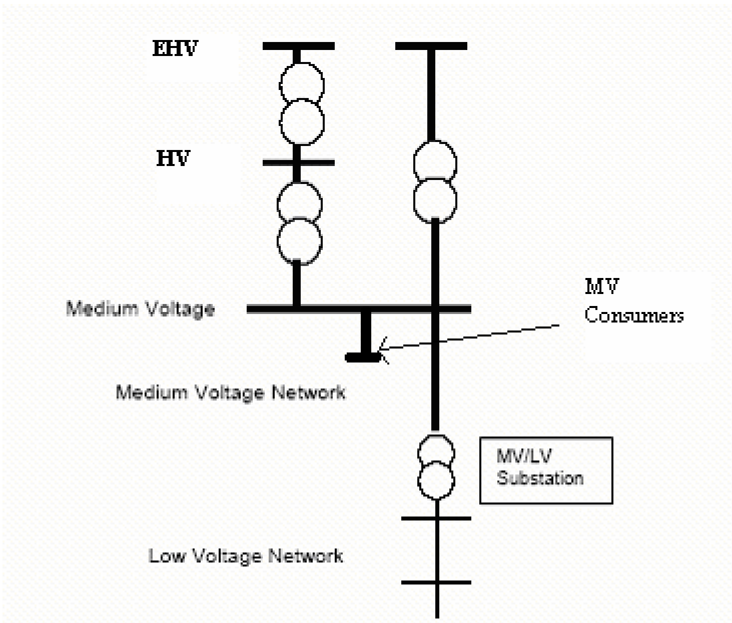

Figure 3.1 Basic Distribution System

Figure 3.1 describes the relation between the three entities of generation, transmission and distribution. The medium voltage (MV) networks are connected to High voltage (HV) transmission systems, which in turn get their supply from Extra High voltage (EHV) substations. Customers, end users or sometimes referred to as consumers get connected as per the distribution level they are suitable for. These distribution levels are categorized according to Table 3.1.

Table 3.1

Voltage Level Categories

Voltage Category	Nominal Voltage
Extra High voltage	Above 400KV
High voltage	220 KV
	132 KV
Medium voltage	33 KV
	11KV
Low Voltage	425 V
	220 V

Majority of customers are connected at the Low Voltage (LV) network through MV/LV distribution substations (S/S's). The distribution part of a power supply system is the closest one to the customers, hence, any failures in this portion immediately affect customers service in a more direct way compared to failures that might occur in the transmission and generation system, which usually do not cause customer service interruptions. Therefore, in traditional utilities, bottom-up approach is followed, in a sense that distribution system planning starts at the customer level, and works its way up to the primary distribution system [37].

3.2. Present Environment

3.2.1. Structure

There is no specific known practice applied in designing distribution networks. Structure of electric networks can be presented in several different ways, depending on the load density and system voltage level. Figure 3.2 shows simplified different arrangements of electric networks such as mesh, radial and interconnected networks. More detailed graphical description on those networks is presented in Appendix A of this report.

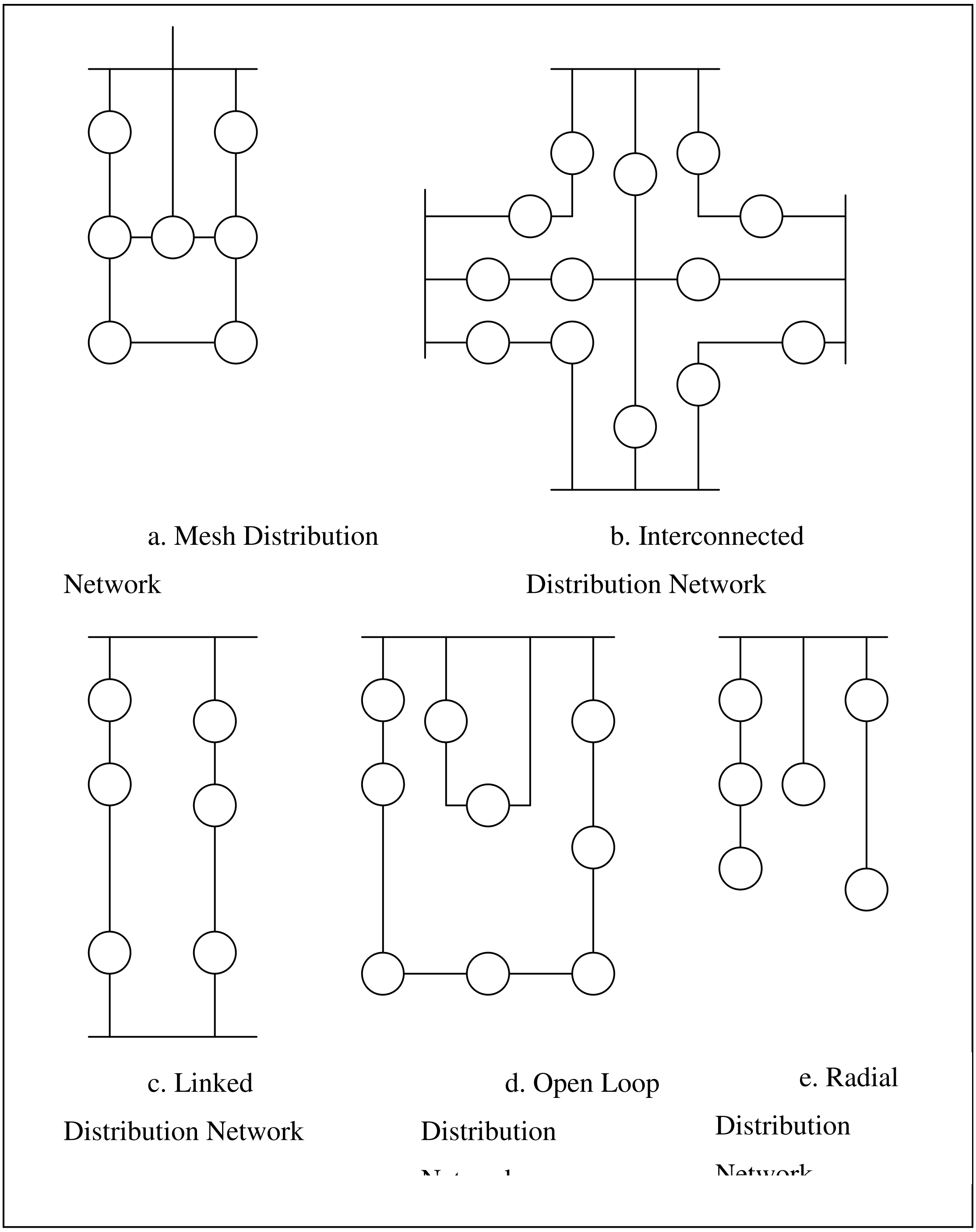

Figure 3.2 Types of Network Configuration [8].

Circles in Figure 3.2 symbolize distribution substations (S/S); (a) is a Mesh network; (b) interconnected network; (c) Linked arrangement; (d) open loop; and (e) represents radial system. Interconnected and mesh networks are similar, however, in the interconnected arrangement the individual substations security is higher, and therefore it is often used in HV systems. Drawbacks on this is that mesh network record high network losses, and usually require more substation equipment like switchgear, protections and electrical connections, however, it is usually more efficient in terms of total circuit costs in regard to expendability and utilization of circuits when compared to the ring system. Figure 3.2b reduces the total transformer capacity within the group transformers connected. Moreover, loosing one supply does not cause any interruption within the network as long as fault levels calculated in the network are within acceptable limits. Figure 3.2c is similar to 3.2b, though introducing normal open point (NOP) somewhere along the feeder makes it work as radial system as in 3.2e, where losing supply from one side, the restoration is done by opening and isolating faulty section and closing the open point to feed from the other side of the circuit. Traditional utilities use the common option at MV and LV with open-loop arrangement as in Figure 3.2d. In normal operations the network is operated radially. For L.V. rural systems, the common option is simple radial network with no back-up feed as in Figure 3.2e [8].

Substations in above schemes include switchgears, transformers as well as the power lines, they are called as tangible asset investments, from grid point of view; the whole network is considered as invested assets.

3.2.2. Culture

In previous section described arrangements, maximum number of substations that can be connected to each circuit and still considered to be most efficient is function of network voltage, distances, average demand at each node, and voltage drop. The networks' structure it self is a function of the topography of the area through which network circuits pass. Usually, the practice in electric system planning for urban areas and down town centers, commonly known in utilities as Central Business District (CBD) areas, tend to have mesh under ground networks, where as rural areas as well as valleys and high ground areas tend to have radial structure.

Existing networks is for sure influenced by the philosophies and policies of its planners and designers. Therefore, it is not strange to notice networks in the same region but with mixture of practices. For operational reasons networks are equipped with switchgear, automatic disconnector and reclosers to provide day-to-day flexibility to cover all likely network problems. No matter what network arrangement is applied, planning engineer is to ensure that the reached configuration is achieved at the lowest cost, with some flexibility to cater for unforeseen future developments. Another issue worth highlighting in the followed utilities practices is the judgment of reliability of supply to customers. Reliability is usually measured by the frequency of interruptions, the duration of each interruption and the value a customer places on the supply of electricity at the time that the service is not provided. Those factors depend on variables like the reliability of individual network components, circuit length and loading, network configuration, distribution automation, load profile and available transfer capacity [11].

3.2.3. Policies & Strategies

Analyzing any electric distribution network over a wide area, the following main characteristics of electrical power systems come to attention:

1. Heterogeneity of technologies:
    a. Generation from different power plants like hydro, thermal and nuclear power plants
    b. Transmission and distribution of energy via under ground cables or over head lines with rated voltage exceeding 1 MW (AC or DC)
    c. Consumption of energy by individual end users each with different perceptions and expectations in regard to power quality.
2. Broad geographical area of operation.
3. Electric energy can not be reserved or stored, therefore require simultaneous generation and usage of the electric energy. [22]

Above impose the necessity to explore and utilize the best technological solutions in running such systems; hence, utilities now began to realize the need for the application of computers in each stage of power system development. For instance; controlling massive power systems, not to mention the involved cost of investments if no proper forecasting and planning methods, as well as careful load-flow control were used.

Apart from technologies applied, and despite market liberalization, regulated electric power utilities continue to operate like monopolies, especially where fixed costs cannot be reduced. Typically, between 30-50% of power utilities costs are fixed in the form of debt repayments on assets such as power stations, transmission lines and distribution lines, therefore, electric power utilities in a deregulated market tend to buy innovative technologies to sustain their positions and achieve competitive advantage, however, if profits continue to be small and capital markets fail to provide finance; then it is unlikely for utilities to self-finance effective innovation efforts. This might explain the restructuring of the market happening all over the world, hoping that the costs of the system be more accurately placed in order to achieve enhanced benefit for customers and society from innovation [26].

3.2.4. Constraints in Present Environment

Examining structure, culture, policies and strategies in electric power utilities, the following constraints needs to be highlighted:

1. Despite that during the past century substantial effort was made on the application of some type of systematic approach to generation and transmission system planning, unfortunately those applications to distribution level has been to some extent neglected.
2. Voltage levels and reactive power flows in extended mesh-interconnected systems in parallel operation of the infeed points could cause a reverse power flows all the way through the source power transformers under outage conditions on the higher-voltage system.
3. Since soul purpose of the Asset Management System (AMS) is to support the management tasks with respect to the organizational objective of maximizing the return on investment, and referring to Asset Management definition stated by the Government of Victoria "The process of guiding the acquisition, use and disposal of assets to make the most of their service delivery potential (i.e. future economic benefit) and manage the related risks and costs over their entire life", then it is essential for AMS to do so for the entire lifecycle of the assets, i.e. the planning phase of the asset and during the operation phase [30].

   Based on that definition, AMS would need to acquire data from both the utility's operations systems as well as the finance and business systems. This shared access is crucial. A data warehouse must be provided and integrated with the asset management applications in a homogeneous way regardless of the physically distributed and heterogeneous data sources. Better information about system and equipment operations and new analytical tools allow planners to use traditional system margins for revenue generation.
4. Now a days, cost rather than technical considerations drive planning and construction of distribution system improvement. Good planners should know the business side like; the forced reduction in capital spending, focus on

reliability, in particular how to achieve system reliability with aging system infrastructures, tighter equipment operating margins, modularity of equipment, and distributed generation [9].

5. Change includes culture risk; in budget-constrained environment, limited finances come with a call for system expansion and renovation. The old message to engineers was that if it fails, you are in trouble. The new message is: Build it to work without gold plating and provide quality service at a reasonable cost. Therefore, human factors from engineers to economists are becoming part of the same team.
6. The escalation in customer generation: as distributed resources (DR) expected to provide considerable benefits for utility system like reduced system losses, better voltage regulation, and increased reliability; these benefits are function of the new installed transmission and distribution system equipment. Therefore; inadequately planned DR might cause problems for the utility system and as result problems to the connected customers. Proper control and screening studies to align DR with utility control and protection devices is a must. From the different readings it is clear that DR is here to stay. Utilities that include the strategic installation of DR in their planning probably will benefit the most.
7. Reliability analysis can be used to evaluate the reliability of individual systems configurations- not only to compare relative levels of reliability, moreover; to assess the costs of providing a particular level of reliability. Cost/ benefit studies then enable a decision to be made on whether to adopt a specific configuration [11].
8. As power system operation highly depends on the state of the system, which in turn requires proper methods of forecasting and planning. Forecasting and resulting planning is to be based on wide set of data measured from the real power system in strictly defined intervals of time. Data acquisition is a major subject in power system, however the following operational problems may hinder that:
    1. Load and voltage control linked with an economic dispatch and a security-constrained dispatch, which contains a number of operational tasks.

2. Fault diagnosis, including alarm processing, protection, power system restoration and repair of damaged equipment.
3. Environmental protection against power plant operation, and electromagnetic.
4. Training (especially dispatcher training) for selected groups of power system personnel
5. Research and development concerning all elements of the power system, the goal being maximum economic an deficient operation with minimum environmental pollution [22].

All above stated constraints hinder electric distribution sector advancements; therefore, Successful solutions for above operational problems need enormous support via the new digital systems.

3.3. The Technology and Organization of Work

Following sections describe the known practices in traditional utilities planning of distribution networks as well as operating it.

3.3.1. Planning with Different Network Structures

During the literature search, it is found that there is no uniformly accepted definition of system planning regardless of network structure type described in section 3.2.1, this is because tasks involved differ among distribution utilities. However, planning process can basically be considered to have two phases as follows:

1. Parameters identification for plant to meet the system requirements.
2. Design of specific reinforcements using standard plant ratings; which is basically a continuous process with the reinforcements mainly to meet increases in demand and expansion of the body of the system [22].

Those two phases are influenced by some factors in distribution system planning, these factors are:

1. Load Forecasting: The initial step in planning is anticipating the load growth of the geographical area served by a utility company. Usually in predicting future demand two common scales of importance are considered; long-term which range between 5 to 20 years time span, and short-term, with horizons of up to 5 years distance. Figure 3.3 shows the factors associated with load forecasting mode.

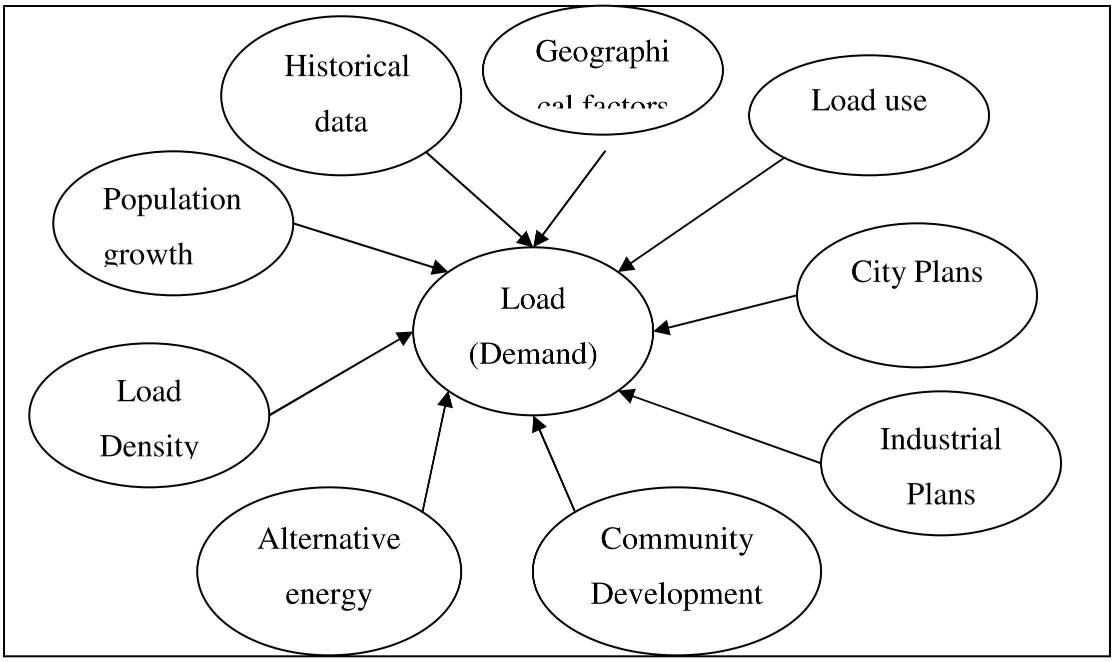

Figure 3.3 Factors Affecting Load Forecast [37]

2. Substation expansion: this define the system scalability plan, where load forecast is only one input to substation expansion along with present system configuration and capacity.
3. Substation site selection: above two points in there turn are part of substation site selection along with other factors that affect the site selection as shown in Figure 3.4.

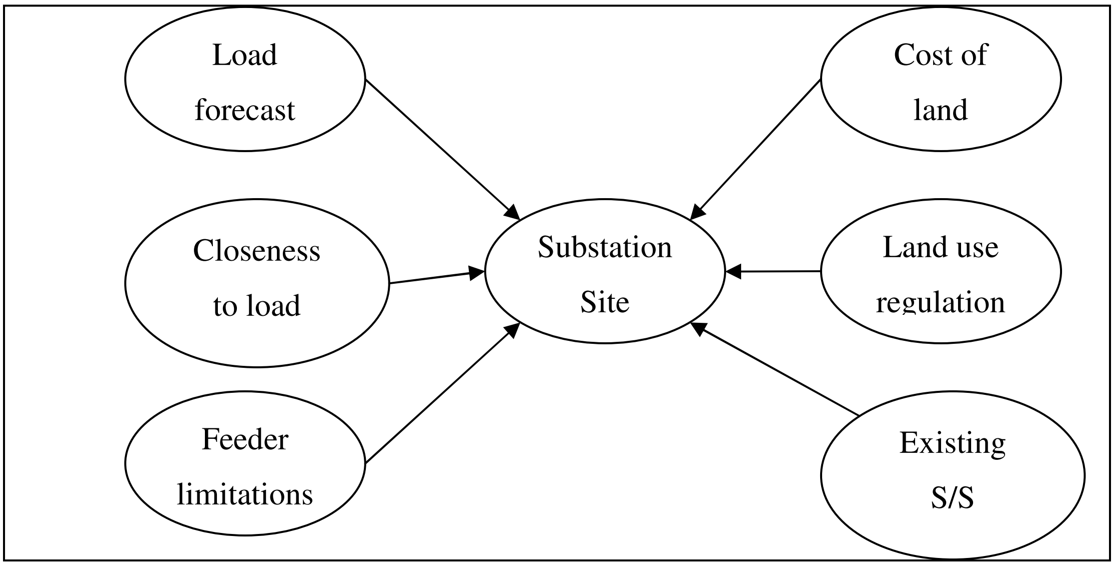

Figure 3.4 Factors Affection Substation Site Selection [37]

Again, planning process in defining planning parameters and designing detailed scheme is very simple process. Figure 3.5 shows a functional block diagram of a typical distribution system planning process currently followed by most of the utilities. In the same Figure 3.5, the flow chart show the relation between factors discussed in previous sections and where do they fit in the overall planning process.

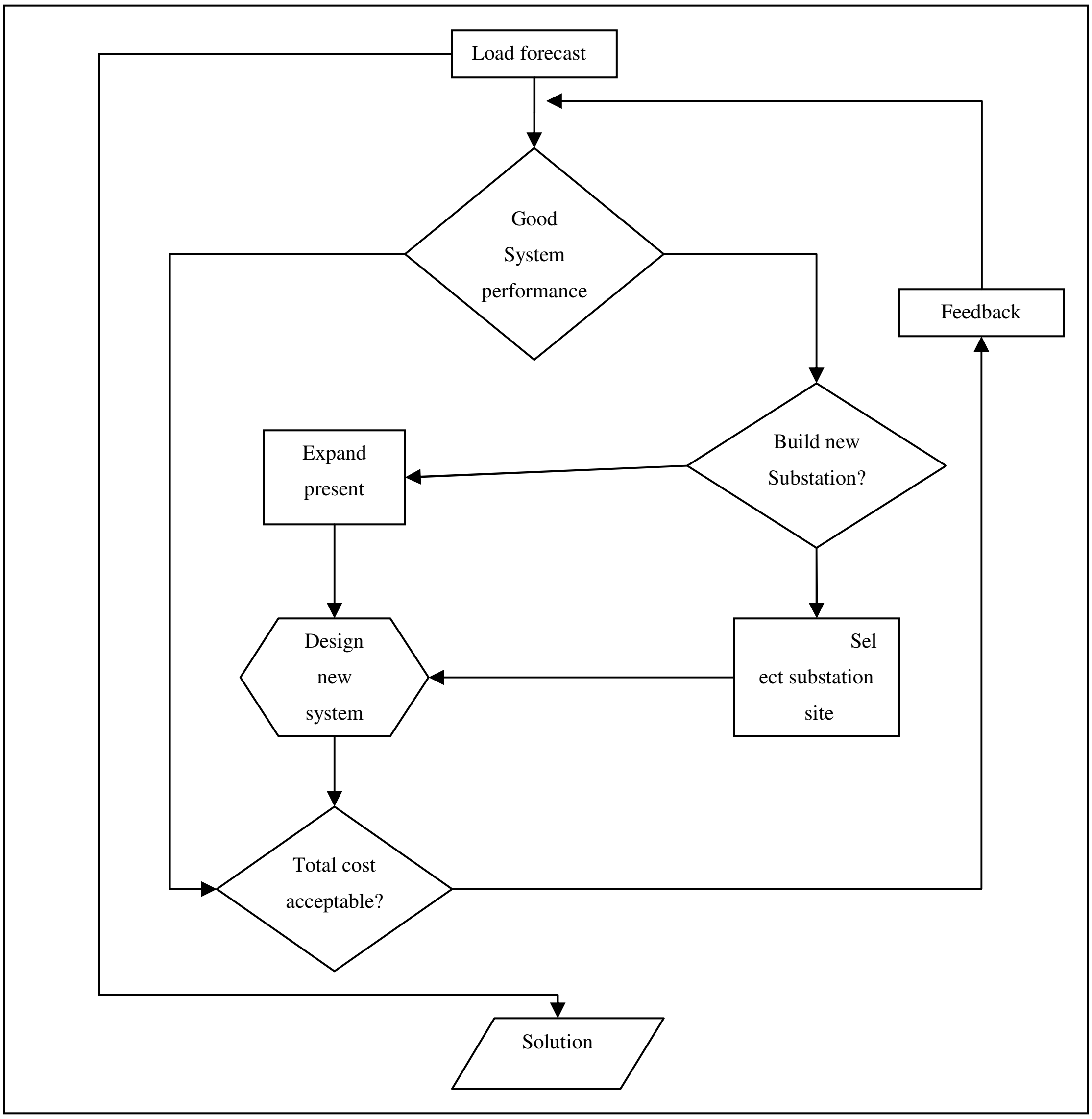

Figure 3.5 Block Diagram of a Typical Distribution System Planning process[37]

3.3.2. Operation with Different Network Structures

Similar to system planning; there is no uniformly accepted practice for system operation regardless of network structure type. It is found that out of thousands of papers published, the majority of which were in system operation and control fields. Based on a survey in 1990, long and short term planning applications in Japan accounted for some 11% of the total, and applications in control and monitoring formed 86%. Judging from reviews, these figures represent the typical case of the situation worldwide. [22].

Talking about distribution network operation necessitate the discussion of system emergency control and restoration processes. Emergency control is related in fact to restoration procedures, which simply means energy distribution loss reduction through feeder reconfiguration manually or automatically via utilizing information technologies available. Restoration of supply automatically brings into the picture the role of artificial intelligence, which is known as Intelligent Knowledge Based Systems (IKBSs). IKBSs have been evolving for more than 50 years; it began to penetrate into the power system planning and operation in the mid 1980s. Now a days the IKBSs are being in fact considered as complementary to, rather than a replacement for, traditional methods. Practices around the world showed that procedures and rules are needed. IKBS application papers so far breaks-up the restoration into three groups; bulk power system restoration, sub-transmission system restoration and distribution system restoration [22].

Operating power systems require access and deployment of real time data, which is a critical dilemma in power system operation. However, literature generated over the last few years basically covered the power system monitoring, fault diagnosis, feeder operating conditions and restoration, and voltage and reactive power control. In addition to real time data issue, IKBS is applied in power system component testing, as operational system reliability depends on the reliability of the system's components and this necessitate proper testing of protection relays, switchgears and line circuit breakers, generators, transformers etc [22].

CHAPTER 4

4. EVALUATION of CURRENT STRATEGIC PLANNING MODEL - ABU DHABI DISTRIBUTION COMPANY

This chapter discusses the distribution system at ADDC and presents its current applied security standards and planning principles. The aim is to highlight reliability indices such as SIADI and SAIFI as a result of implementing those planning principles. The chapter also compares wherever possible those standards and guidelines with other best peer group companies in order to analyze and evaluate the existing gab of the variations in the performances between ADDC recorded reliability indices and those of the best practitioners in the same field.

Abu Dhabi Distribution Company (ADDC) is an affiliate of Abu Dhabi Water and Electricity Authority (ADWEA). ADDC was established on November 1998, and have been operating as distribution-only electricity and water utility service provider since January 1999. The company's board of directors is presided by H.E. Shaikh Dhiyab bin Zayed Al-Nahyan, Also the chairman of Abu Dhabi Water Electricity Authority (ADWEA). ADDC is experiencing dramatic growth in load and a resultant major capital expenditure to increase its system capacity to meet that growth.

ADDC vision is to become one of leading companies in water and power distribution service provider in the world, therefore, management goal is to operate in line with the service cost and service quality performance norms established by Regulatory and Supervisory Bureau (RSB).

4.1. Present Environment

ADDC network extend to cover almost 28,500 km of under ground cables with total number of customers over 201,500 as per ADDC annual report of 2005. They are connected via open loop network though normal open point (NOP) someplace along the feeder which makes it works as radial system. ADDC network in the city of Abu Dhabi consist of 11kV open loop connected between 132/11kV primaries via switching station as a majority or loops in and out within or between primaries. This structure is maintained in Eastern Region (ER) and Western Region (WR) covered by ADDC network however, the tie connections and actual radial feeds with no back feed source is highly noticed particularly in WR.

ADWEA management has taken the lead to improve the productivity of their group of companies operations like implementing of the Geographic Information System (GIS) and the Computer Material Management and Maintenance System (CMMMS), the initiation of a sophisticated Distribution Management System at each company and the creation of a Modernization and Development of Distribution Systems (MDDS) committee.

The Regulation and Supervision Bureau (RSB) is focusing on efficient capital spending during their periodic price-control reviews. Based on experiences in other markets, cost reductions around 10-15% of Capital Expenditure (Capex) and Operational Expenditure (Opex) for water and power, which translates to somewhat around 200M AED based on 2002 accounts.

4.2. Present Environment Constraints

Since ADDC establishment back in 1999, ADWEA and ADDC management has given great attention to developing application of some type of systematic approach to distribution system planning, however; those applications in distribution level do to some extent need further enhancements.

One of the possible obstacles that might face ADDC in its selection of future system configuration is the voltage levels and reactive power flows in extended mesh-interconnected systems where parallel operation of the infeed points is present, a reverse power flows may be generated all the way through the source power transformers under outage conditions on the higher-voltage system, this does not form a problem in ADDC present system, however when considering mesh design alternative, then this issue need to be thoroughly addressed.

Those future plans are to be established to meet demand increase; however, there is another type of demand increase, which is the escalation in customer distributed resources (DR) or what is known as distributed generation (DG) around the world. DR is expected to provide considerable benefits for utility system like reduced system losses, better voltage regulation, and increased reliability. ADDC planners should not neglect this option as proper control and screening studies to align DR with utility control and protection devices is a must.

Moreover and as stated in previous chapter, Asset Management System (AMS) purpose is to support the management tasks to align them with the organizational objectives; therefore, AMS in ADDC need to acquire data from

ADDC's operations systems as well as the finance and business systems. More accurate information about system and equipment operations and new analytical tools gives AMS planners better chance to use traditional system margins for revenue generation.

In addition, ADDC tend now to cut cost wherever possible as cost rather than technical considerations direct future plans of distribution system improvement. Therefore, ADDC planner should now the business side too.

As power system operation highly depends on the state of the system which in turn requires proper methods of forecasting and planning. Forecasting and resulting planning is to be based on wide set of data measured from the real power system in strictly defined intervals of time full utilization of new technologies in ADDC is a subject that is still didn't reach maturity level.

One of the major obstacles facing ADDC is its system dependency on the transmission company (TRANSCO), in a sense that ADDC present system configuration is governed by TRANSCO imposed limitations like loading of power transformers, the limited load transfer capability between primaries and controlled operational option in parallelling different grind stations from the 11kV side.

4.3. Supply Standards

ADWEA and ADDC supply standards are being set by the Regulation and Supervision Bureau (RSB), by which the quality of service that ADDC is expected to provide is established. ADDC as a distribution company is to design, construct and operate its network to meet these security standards at the least cost.

As the goal of security standards is to show the trade off between service quality and service cost, they directly influence the capital investment as well as the type of network structure to be adopted by the utility. The security standards are often characterized by "N-1" criteria, this means that for any design, when a failure occurs in a component no sustained outage do result because there is always a secondary backup from the remaining component to cater for that out of service unit. ADDC measures supply standards implementation by recording and monitoring on monthly basis, those indices cover System Average Interruption Frequency Index (SAIFI) or Security of Supply and the System Average Interruption Duration Index (SAIDI) or Availability. SAIDI and SAIFI basically focus on two elements;

(1) “Capacity” of the system to supply sufficient energy via making sure that network is capable of meeting the peak demand.

(2) “Transfer capability” of the distribution system to transfer customers to alternative sources of supply in the event of an outage in their primary service.

Current security standards recommend that network should be designed to be capable to transfer load in any sector. This transfer or restoration is classified according to the group demand affected by an outage, and accordingly it specifies the time within the power to all, or a portion of, the group demand must be restored. Table 4.1 shows the recommended level of security in regard to restoration time. At this stage it is worth highlighting that Table 4.1 is currently being reviewed by RSB, ADDC and Al Ain Distribution Company (AADC) for more detailed one, which is up to the time this report is prepared the review is not finalized yet.

Security standards also emphasis that network components not be overloaded as a result of load transfers caused by the restoration process. This restriction on overloading during contingencies is to prevent reductions in the expected life of system components. Obviously, the restoration process differ depending on the area geography it self, as in urban areas, and due to the close proximity of multiple distribution feeders serving customers, alternative power sources may be available to supply loads of less than one MW during outages. However, in rural areas, most likely there will not be an alternative

Class A group demand typically is served by a single distribution transformer rated 1500 kVA, 1000 kVA or smaller transformer sizes. Losing power supply is probably due to a low voltage system fault or a distribution substation failure. Restoration time to such outage usually is the time taken to repair or replace the transformer.

Typically, class B group demand is served by an 11 kV feeder or a distribution substation with more than 3,000 kVA of capacity. An outage in this class is to be restored within three hours. In order to fulfil that standard the network design should have alternative sources to which the affected group demand could be transferred, typically, three hours is required to repair an underground 11 kV cable fault, which is the maximum time it usually takes to manually re-configure the circuit and isolate a faulted section. A distribution substation experiencing an 11 kV bus fault would create an outage that may be difficult to restore within three hours or to transfer load from alternative sources within three hours. This is not a major concern because the probability of this type of fault in the indoor distribution substations is low. Thus, the security standard requires transfer capacity be available to all feeders with 1.5 MVA of load or higher.

Table 4.1

Recommended level of security in regard to restoration time [35]

Class of Supply	Range of Group Demand	Minimum Demand to be Met After First Circuit Outage
A	Up to 1.5 MVA	Demand within repair time
B	1.5 to 6 MVA	Group Demand within 3 hours
C	6 to 30 MVA	(a) 1/3rd of the Group Demand within 30 minutes (b) Group Demand within 3 hours

For Class C supply the group demand, that includes the load on a primary substation transformer or a 33 kV feeder, is normally being supplied by at least two normally closed circuits or by one circuit with supervisory or automatic switching of alternative circuits. An outage on this group could be caused either by transformer failure or 11 kV bus failures. The standard requires one-third of the load affected by such an outage to be restored within 30 minutes and the entire affected load to be restored within three hours. The 30 minute in fact reflects the time required to restore part of the lost demand by local manual or remote switching at the substation. Therefore, in order to meet this standard the network design should have alternative sources to which the affected group demand could be switched as the primary substation equipment cannot typically be replaced within three hours. In other words, transfer capacity should be available for the primary substation transformer and the 11 kV bus [17].

4.4. Planning Guidelines

The design guidelines cover the electrical distribution system that is within the area covered by the distribution companies, ADDC and AADC. The guidelines cover the following areas:

1. 33 kV feeders
2. Primary Transformer
3. 11kV distribution feeders
4. Distribution Substations
5. Low voltage equipment
6. Street lighting design
7. Equipment loading design
8. Protection of electrical equipment design

In the following section, an illustration will be given for some of the design guidelines that are relevant to the discussions of this research.

4.4.1. Primary Transformer

In this section, definition of power transformer capacity, number of transformers in each primary as well as number of outgoing 11kV feeders is presented.

- Substation Configuration: 132-11 kV using 40 MVA transformers with two or three primary transformers for the initial installation and a maximum of four primary transformers in a substation.
- 11 kV Bus: Five feeders for each 20 MVA transformer. Ten feeders for each 40 MVA transformer. Additional feeder positions should be reserved for auxiliary power, capacitor bank connections and express feeders.
- 132-11 kV Primary Transformers: Two 40 MVA transformer substation serving up to 52 MVA of peak load; three 40 MVA transformer substation serving up to 92 MVA of peak load; four 40 MVA transformer substation serving up to 123 MVA of peak load.

This section also gives the allowable power transformer loading level as in Table 4.2

Table 4.2

Recommended Peak loading for various substation configuration [35]

Primary Substation Configuration	Isolated Primary Substation Peak Loading (MVA)	Interconnected Primary Substation Peak Loading (MVA)
Two 15 MVA Transformers	15	21
Three 15 MVA Transformers	30	36
Two 20 MVA Transformers	20	26
Three 20 MVA Transformers	40	46
Two 40 MVA Transformers	40	52
Three 40 MVA Transformers	80	92
Four 40 MVA Transformers	107	123

4.4.2. 11kV Distribution Feeders

Another guideline presented in this section is the percentage acceptable loading of the 11kV outgoing feeders as in Table 4.3

Table 4.3

Distribution substations per feeder based on feeder configuration [35]

Number of Feeders Interconnected	Load on Feeder as a % of Capacity	Maximum Quantity of Distribution Substations
2	55%	3
3 or more with an express feeder	100%	6
3 or more without an express feeder	55%	3

where express feeder in table 4.3 represent the direct non loaded cable connection from source to destination substation or switching station.

4.4.3. 11kV Distribution Substations

Maximum numbers of distribution substations to be connected on 11kV feeders are given in the following Table 4.4

Table 4.4

Recommended Number of Distribution Substation per Feeder [35]

Number of Feeders Interconnected	Recommended Number of Substations per Feeder		
	Two 1500 kVA Transformers	Two 1000 kVA Transformers	Two 750 kVA Transformers
2	2	3	4
3 or more with express feeder	3	6	8
3 or more without an express feeder	2	3	4

Above four categories described here form the basis for this report model calculations, where the low voltage side is not covered within this illustration because the design alternatives that are going to be discussed in next chapters do not model the low voltage side.

4.5. Reliability Indices

As illustrated earlier, these indices cover SAIDI and SAIFI which are important criteria for system planners to judge system productivity enhancement, process re-design, technology and automation requirements, and material cost.

4.6. Benchmarking with Best Performers

Security supply standards for Scottish Power, which is a utility in Great Britain, , and for the United States utilities is compared to ADDC and AADC security standards in order to define the consistent among these utilities. Following table 4.5 shows those securities applied in Scottish Power.

Security standards in the United States are known as Reliability Standards. The North American Electric Reliability Council (NERC) defines reliability standard as defined commitments of utilities that operate, plan and use the bulk electric systems of North America. Those obligations must be material to reliability and measurable too. They include technical, performance and preparedness standards. The reliability standards for distribution companies in the United States are usually based on the reliability indexes of SAIFI and SAIDI. The investor-owned utilities are required in some states to report these indices to their regulatory agencies.

Table 4.5

Security of Supply Standards in Scottish Power Company [2]

Class of Supply	Range of Group Demand	Minimum Demand to be Met After First Circuit Outage
A	Up to 1.0 MW	Group demand within repair time
B	Over 1.0 to 12 MW	(a) Within 3 hours: group demand minus 1 MW (b) In repair time: group demand
C	Over 12 to 60 MW	(a) Within 15 minutes: smaller of (group demand minus 12 MW) and 2/3 group demand (b) Within 3 hours: group demand

The utilities that do not report to state regulators, like as municipal and cooperative electric utilities, report their outage performance on a voluntary basis. However, some state regulatory agencies in the United States ask the utilities to prepare reliability plans. Plans include standards for system design, construction, operation, maintenance and programs that are related to reducing outages. Moreover, some of the regulatory agencies establish reliability benchmarks. The utilities are required to be within certain limits of the benchmarks, such as within 10%. The utilities may be rewarded or penalized by rate increases or reductions based upon their performance in meeting benchmarks. The majority of utilities in the United States attempt to have capacity in the distribution facilities to provide back-up capability for outages due to primary transformers and feeders, which is similar to the security standards applied in ADDC and AADC. As the case here, distribution of urban areas has more back up opportunities than facilities in rural and remote areas. However, majority of utilities do not have a document that provides the required time to restore outages based on the magnitude of the demand that is affected by the outage. The regulatory agencies usually require the utilities to provide reports to the agencies on outages. The reporting requirements are based on the duration of the outage and the number of customers affected by the outage [2].

4.7. Reliability and Cost Gab Analysis

The security standards of Scottish Power in Europe are similar to the ones applied in ADDC. The only difference is in the "Range of Group Demand" category, as security standard for ADDC has a group demand of up to 1.5 MVA for the Class A supply category, where Scottish Power has a group demand of 1.0 MW for this same category. The use of MVA for the units of group demand is recommended because MVA is related to capacity of feeders and transformers. The security standards of utilities in the United States are similar to the security standards of ADDC as the utilities the United States distribution companies principle is to provide back-up capability for outages due to primary transformers and feeders. Again, the difference between the security standards of utilities in the United States and the security standards of ADDC is that majority of utilities do not have a document that provides the required time to restore outages based on the magnitude of the demand that is affected by the outage.

From above, one can clearly state that ADDC security standards are somehow in line with other utilities around the world, however, despite of all investments taken by ADDC, there are still opportunities for improvement that do show up, this is because ADDC Capex and Opex spend are high compared to power and water peer groups, also, ADDC power Capex per customer three times of that of peer companies, moreover; ADDC power Opex per customer at six times that of peer companies. Following Figure 4.1 through Figure 4.2 show ADDC position relevant to the best performance companies in the sector [2].

4.8. Present Decision Support Model:

ADDC in its present network structure described in earlier sections apply the current Decision-Support Model (DSM) in order to provide ADDC decision makers with a an easy graphical evaluation method to compare different network design options with respect to the goal objectives of ADDC management, which are service cost and service quality. The technique used in the evaluation is the Multi-Attribute Trade-Off Analysis (MATA) as it gives decision makers the possibility to identify Pareto Superior options, in order to resolve situations where conflicting objectives or attributes are present. MATA is chosen here for electrical system evaluation of decisions to be made among several investments that will ensure reliable service at reasonable cost**.**

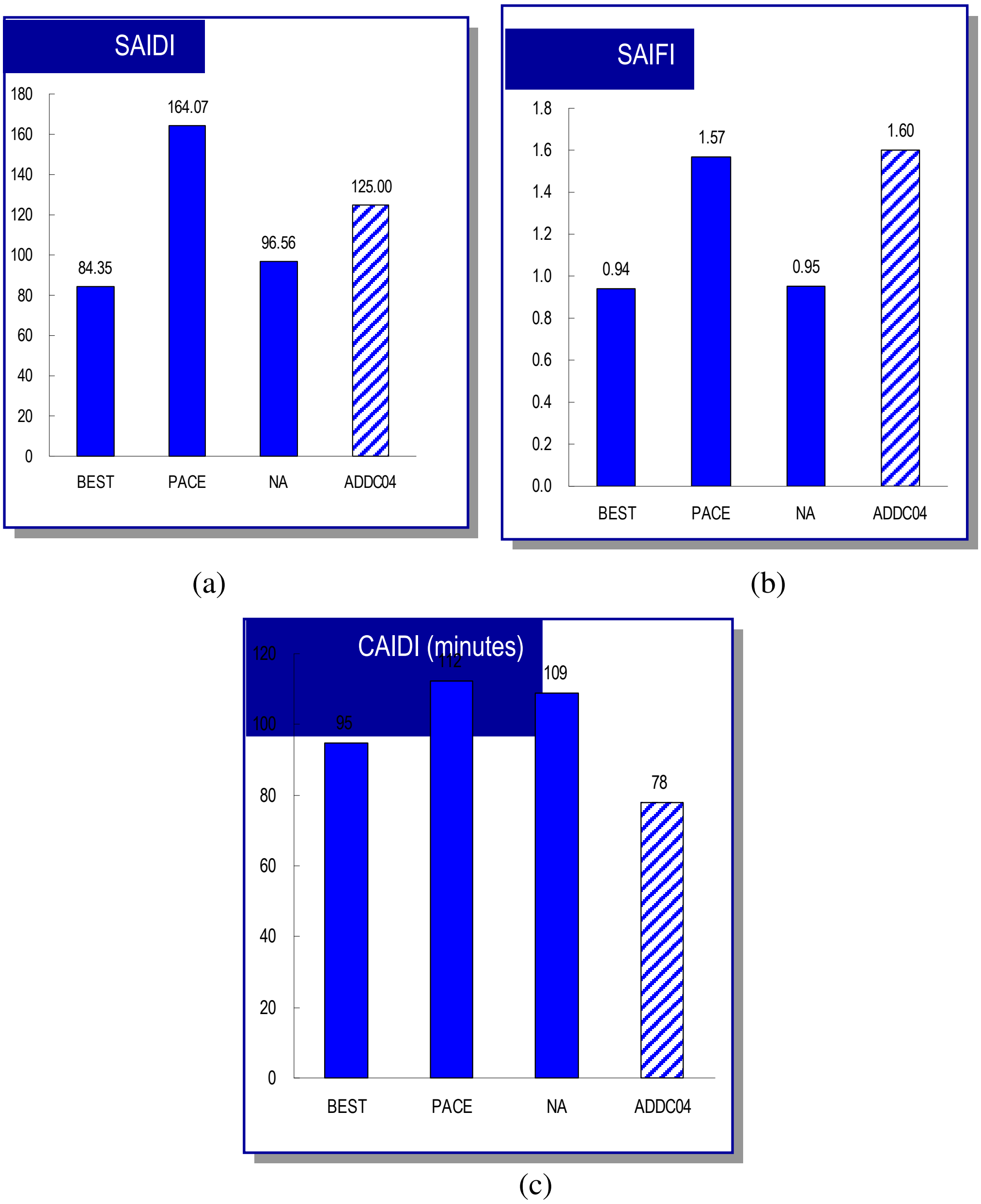

Figure 4.1 ADDC reliabilities comparison with best performance utilities [4]

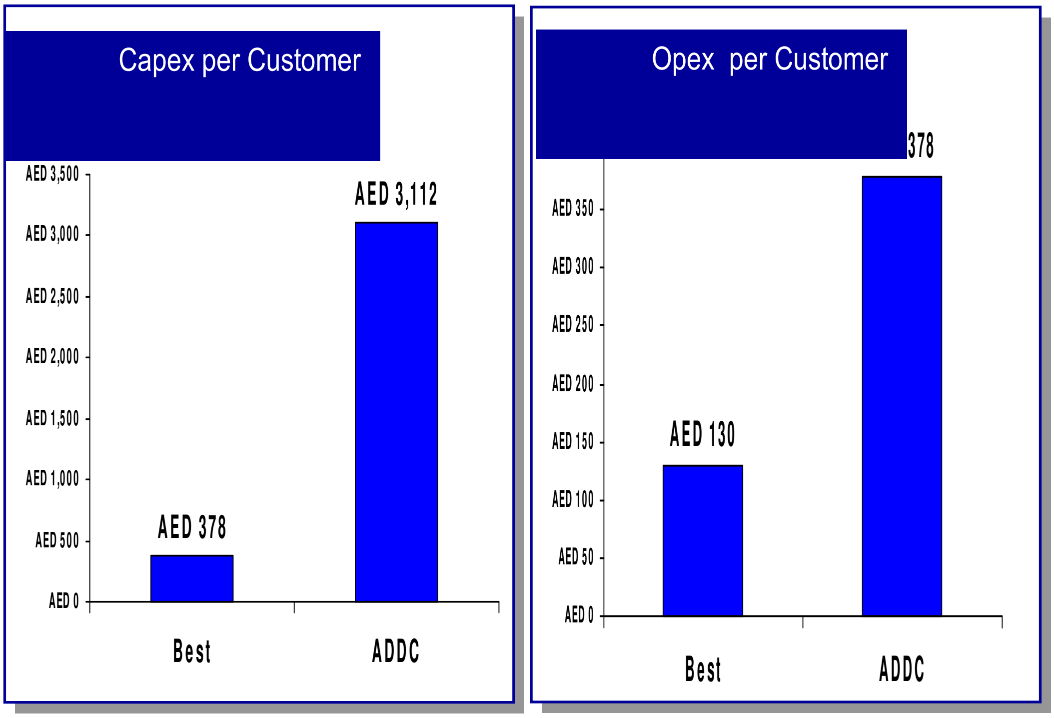

Figure 4.2 ADDC Opex and Capex comparison with best performance Utilities[4]

The evaluation of the existing system with its present configuration to determine if it is capable of meeting the projected load increase over the time is done by comparing its cost service, as measured in the net present value (NPV); and performance with respect to the other designs of 11kV ring system with 55 MVA power transformers, 11kV mesh design, 11kV mesh double bus bar design, 20kV ring system and 20kV ring double bus bar design.

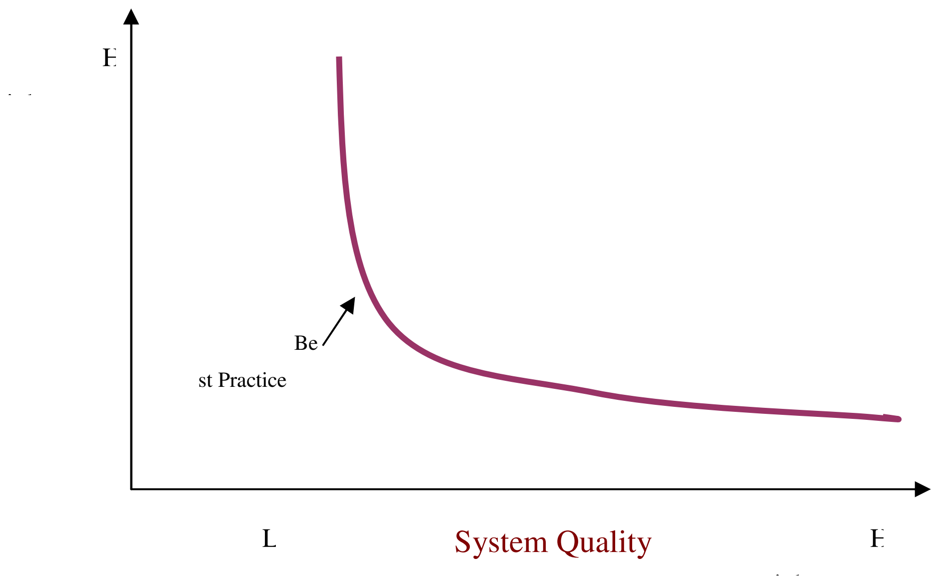

Figure 4.3 MATA example

Figure 4.3 is an theoretical example of MATA results, where alternative that are located on the frontier line, usually balance between both axes criteria, however outliner options, do not provide that balance and there for can be rejected. Bottom line, decision makers must choose options that results in minimum deviation from the frontier line or put strategies to reduce the gap in order to reach better satisfactory results.

4.8.1. Current System Evaluation

The different designs defined in previous section differ in the level of securities supplied according to the different planning concepts applied in each one of them, out of those design; the 11kV ring system is actually the present design of ADDC network, which is formed of 11kV rings connected via open loop network though normal open point (NOP) someplace along the feeder which makes it work as radial system.

The decision support tool findings examine service reliability in terms of SIADI, SIAFI and un-served KWH per customer and their relation with the cost expenditure of capital and operational costs to achieve each reliability.

4.8.1.1. Service Interruption Duration Index (SAIDI)

Decision support model results in Figure 4.4 show that SAIDI vs. Cost attributes reveal three options that do actually lay on the Pareto curve, they are the 11kV ring switching station with 55MVA power transformers (pink square), 11kV mesh design option (yellow triangle) and the 20kV ring option (purple x). These three designs are considered to be Pareto optimal because the 11kV ring with 55MVA power transformer capacity resulted in the lowest cost possible among the other options, where the 20kV ring design resulted in the best SAIDI value among the six designs. The MATA curve here gives trade-off between SAIDI and cost attributes, and it is up to the decision makers to define their strategic selection to be in line with ADDC objectives. However the 11kV ring switching station with 40 MVA power transformer capacity (blue diamond), which represent the current ADDC system structure, in its location on the curve in Figure 4.4 show that it is not Pareto optimal option, this is because there is a possibility to move to the left with the same reliability however with a reduced cost. The remaining alternatives are not optimal options because it is possible to move horizontally left to the frontier to alternatives of lower service cost or even move vertically with the same cost to a better service reliability, the 20 kV ring design is an example of such alternative, another example in Figure 4.4 is the 11 kV mesh where we have the same service quality for both designs however cost wise the 11kV Mesh (yellow triangle) is achieved with lower cost than the 11kV Mesh double bus bar (light blue x). Looking at this from another point of view, it is possible to move horizontally left to the frontier to other alternatives that have the same service cost but higher service quality.

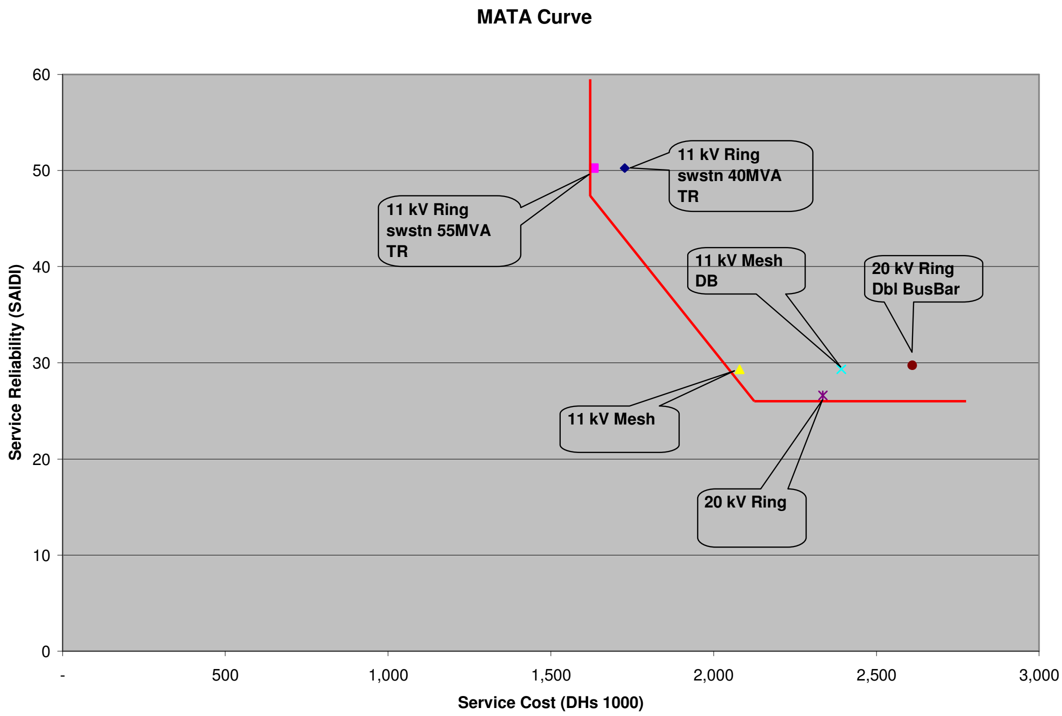

Figure 4.4 SAIDI vs Cost for different design alternatives

4.8.1.2. Service Interruption Frequency Index (SAIFI)

Examining Figure 4.5 of SAIFI vs. Cost for the different design alternatives, both options of 11kV ring switching station with 55MVA power transformers (pink square) and 11kV mesh design (yellow triangle), are obviously the best to selection as both are located on the Pareto curve. Moreover, the current ADDC system which is the 11kV ring switching station with 40 MVA power transformer capacities (blue diamond) can be shifted to the left to maintain the same reliability and reduce its cost; therefore it is not one of the optimal options. In the same graph, all other alternatives are dominated by the Pareto optimal options. This is because for those options it is still feasible to move horizontally left to the frontier to alternatives of lower service cost or even move vertically with the same cost to a better service reliability, like in the case of 20 kV ring design.

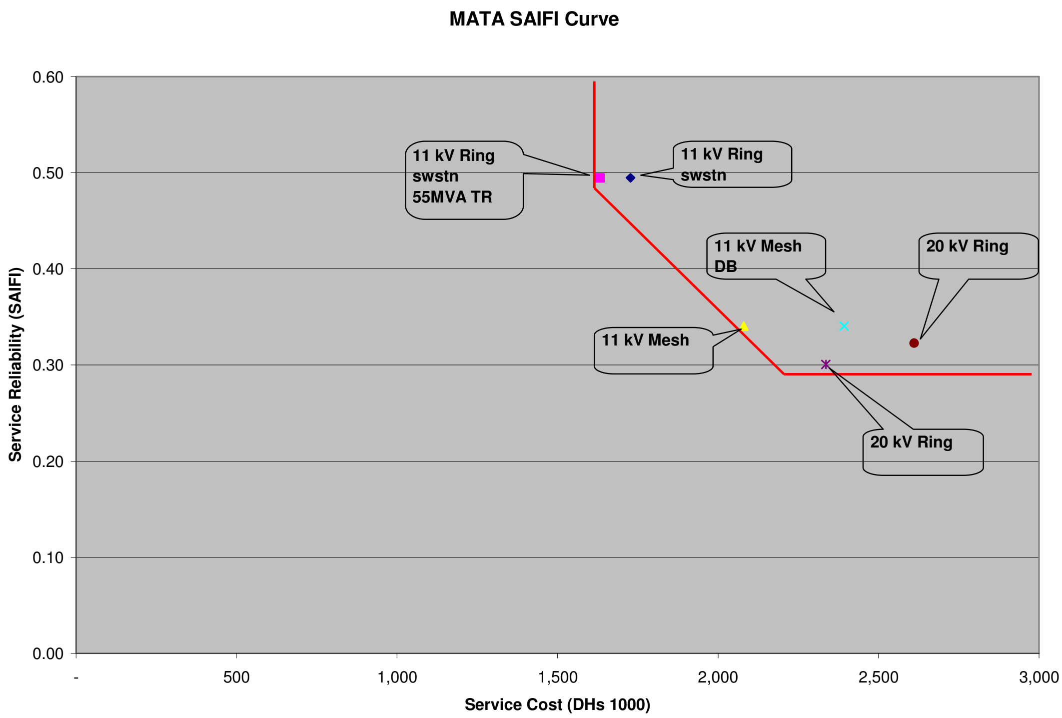

Figure 4.5 SAIFI vs Cost for different design alternatives

4.8.1.3. Energy Loss Index (un-served KWH per customers)

The decision support tool third comparative index is the un-served KWH per customers. This index reflects the energy losses that could have otherwise generated revues to ADDC, the lower the value, the higher the return on investments taken. The different design options have different values for this index as in Figure 4.6. Again the same previous two results for SAIDI and SAIFI are presented here; they are the 11kV ring switching station with 55MVA power transformers (pink square) and 11kV mesh design option (yellow triangle) as the feasible alternatives in addition to the 20kV ring system(purple x). Moreover, this index shows that all other alternatives except the 11kV ring switching station with 40 MVA power transformer capacity (blue diamond) relatively deliver the same reliability however with different costs. For the 11kV ring switching station option, it is still lagging the 11kV 55MVA transformer capacity in the cost expenditure.

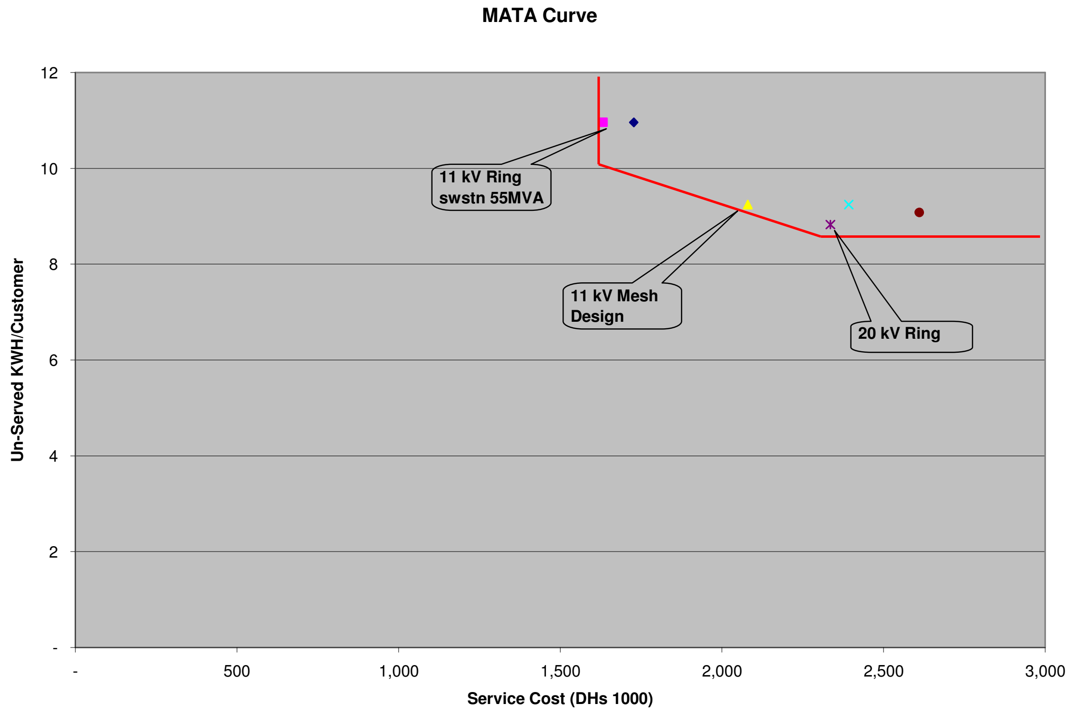

Figure 4.6 Un-served KWH per Customer vs Cost for different design alternatives

CHAPTER 5

5. POTENTIALS AND CAPABILITIES OF NEW TECHNOLOGIES

5.1. Potentials and Capabilities of New Technologies

This chapter explores the different capabilities of some new technologies, like Geographical Information System (GIS) and Distribution Management System (DMS). The purpose of this chapter is to exhibit the value-added for system planning and operation in order to minimize capital and operational projects requirements.

5.1.1. The Geographical Information System Technology, GIS

GIS with its different applications used in electric power planning form a powerful tool of geographical analysis with its integrated set of hardware, software, databases, and processes designed, that can handle information of very diverse origins and formats. The processing features in GIS make it easy to manipulate geo-referenced data in different formats and models, which is vital to plan optimal utilization and allocation of resources. Out of the various tools offered by GIS technology, Network diagnostic tools are the most important, these tools are used to define errors in electric network information such as Network tracing and connectivity, Loops detection, and Multi or not energized objects detection. GIS also offers the ability to easily virtually manage different projects. Project tracking and Project design are two applications worth the attention of planners and project execution engineers. [40]

To make it short, GIS implementation in an effective way helps in meeting customers' expectations. It has been noticed an improvement in services and a significant reduction in customer interruption time caused by the greater accessibility to information and the use of powerful tools for electric network analysis.

5.1.2. The Online/SCADA Technology, DMS

Distribution Management System (DMS) main objectives are to increase service reliability indices, achieve regulatory service targets, enhance customer responses, and reduce operational cost, this is done by automating tasks that are traditionally carried out by operation and maintenance (O & M) staff. DMS technologies are composed of two major functions:

First: Distribution Supervisory Control And Data Acquisition (SCADA)

SCADA system, which is a data acquisition system used to monitor and control electrical distribution network. Network monitoring is done to observe load increase over the system, where as network control is used to obtain faster response for a better restoration time. Usually there are two types of alarms initiated by SCADA system, High and Very High alarms. The first one, the High alarm, is flagged whenever loading of specific segment exceeded 90% of rated capacity, Very High alarm is the tripping point of the relative breaker in the system. High alarm indicator intended to give some lead time to the control operator to take preventive action before reaching the Very High alarm trigger, normally this lead time is around 30 minutes.

Second: Automation Applications; which are the functions layered on top or integrated with SCADA system to facilitate network monitor and control.

Back in the early 1990s, DMS was designed to focus particularly on meeting regulatory standards and reducing outage durations. Another objective in improving operational efficiency came into the picture in the Late 1990s; DMS was then used to improve communications internally within the utility and externally with customers. However, today DMS employment is extended to Enterprise Asset Management (EAM) for increased asset utilizations and financial return on assets [17].

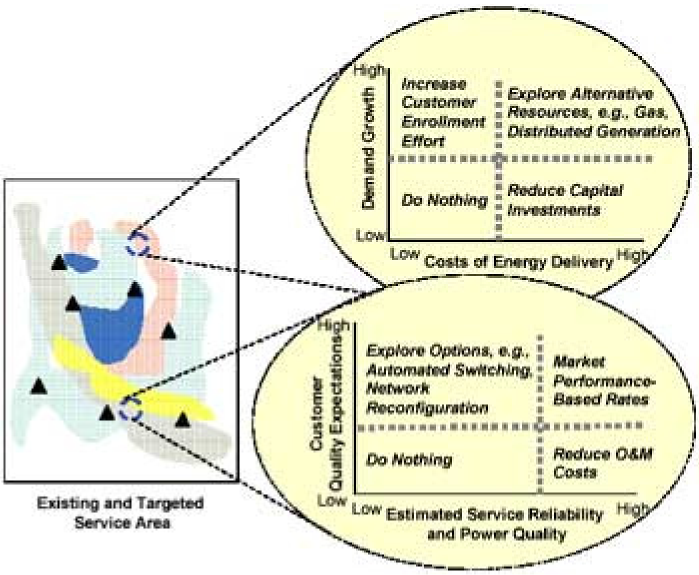

Figure 5.1 DMS impact on reliability performance [18]

Figure 5.1 shows the impact of DMS utilization on reliability performance when compared to data of customer anticipation extracted from marketing, which can be used to shape O&M plans. Similarly, the incremental cost of improving the energy delivery network form distribution management and planning systems may be combined with distribution load forecasts to drive asset investment plans [18].

5.1.3. GIS Integration Into Utilities Practices

Incorporating GIS into utility day to day activities should improve the performance of distribution systems. Advantages of doing so can be summarized as follows;

- Visualization: planner can visualize the actual network, as it will be laid out on ground.
- Convenience: User friendly and ease of data entry
- Flexibility: Flexibility of choosing what other systems to share or exchange data with (i.e. network analysis, inventory, trouble call)
- Better comprehension [16].

Once the electrical database of the network is imported form the Geographical Information System/Automated Mapping/Facility Management (GIS/AM/FM) into an Electrical Engineering Analysis platform, planners can perform various analysis studies, such as; Modeling load for different consumer categories, Modeling unbalanced load, Voltage drop/load flow analysis, Fault current & fault flow analysis, Automatic capacitor placement, Load balancing, and Contingency analysis etc [16].

Having a geographical reference of the network will provide necessary information on land use pattern for optimum expansion of network as well as for setting up new facilities, for example; spatial load forecast tool, which subdivide the region into small sectors, each have its growth rates and the load characteristics, is the ideal method for optimal planning of the distribution system of the area. More benefits offered by GIS are easy special handling of customer's inquiries, network configuration, right of way and compensation, easy and speedy retrieval of information, data update and possible sharing of data among different users simultaneously, it also gives up to date information on what is where, the state of it, the reaction other actions on it would cause, how it can be harnessed for optimum use of the people and economy [21].

Examples of applied GIS applications are the last mile planning, which is a remarkable capability of GIS, with the kind of accuracy available. The last mile planning, including customer connectivity is very accurate, the planned quantities and the theoretically most optimal quantities can hardly be more different than 1%

traditionally, this figure is seldom lower than 3%, adding to that the repairs and maintenance functionalities, where a high precision maps, coupled with decimeter GPS; repair and maintenance works can be automated to a large extent and the cost drastically reduced. This can save up to 70% of the cost of the repairs and maintenance of the network [7].

The importance of GIS for utilities can simply be stated in that for utilities that look forward to run an efficient day-to-day operation and to manage and develop its services effectively should know what asset it has, where they are, their condition, how they are performing, and how much it costs to provide the service [34].

5.1.4. DMS Integration Into Utilities Practices

With the trends now to reduce utility engineering and operating personnel, along with the increased regulation, and high strict standards for customer satisfaction, there is a critical need to provide tools that can optimize employee and system performance. Distribution Management System (DMS) offers one solution to this dilemma, the applications offered by DMS can be categorized as:

a) Schematic analysis tools that tracks actual network conditions or test different scenarios in the safety of a simulated study-mode environment, line coloring on one-line diagrams and geographic displays that indicate the state of the distribution network in both real-time and study modes, and study mode, which is used to provide short circuit analysis and energy loss minimization, or to simply test different configurations of the network [33].
b) Data acquisition and calculation tools like; fault location, Isolation and Service Restoration, customer Substation management, in a sense when customer substations are equipped with RTUs, the set of data regarding the low voltage (LV) side was designed to be collected an deficiently utilized for better operation and maintenance of the low voltage system, distribution operation analysis tools as DMS designed to include modeling software that allow non-monitored data to be estimated and modeled for solving “what if” problems.
c) System maneuvering functions; distribution Substation Load modeling, distribution System Connectivity Modeling, operational power flow modeling, including state estimation, and voltage controls that permit DMS to minimize violation of the voltage quality limits on a “per customer” basis, as well as to keep the system operating within designated limits.

DMS indeed deliver several tangible benefits such as; minimizing power and energy losses, optimizing voltage profiles, reducing switching errors, improving dispatch operator efficiency, improving accuracy of distribution planning, rescheduling of capital investments, and the most important is that DMS provide a central circuit model for outage management, engineering analysis, and real-time switching maps [33].

Listing above functions does not necessitate that all are to be incorporated within the same system, however; to be practical those functions are customized for each utility depending on its environment, followed culture and financial status.

5.2. The Digital utility infrastructure

From a process point of view, the enterprise application integration is the link between different applications and the business processes within the company. Business processes are modeled to map the business processes design, where tasks that are relevant for the integration are extracted. As in Figure 5.2, integration process defines the process part which will be handled by the integration. Via the application interfaces, the integration process will be executed such that the initially intended data exchange between the systems is performed [32].

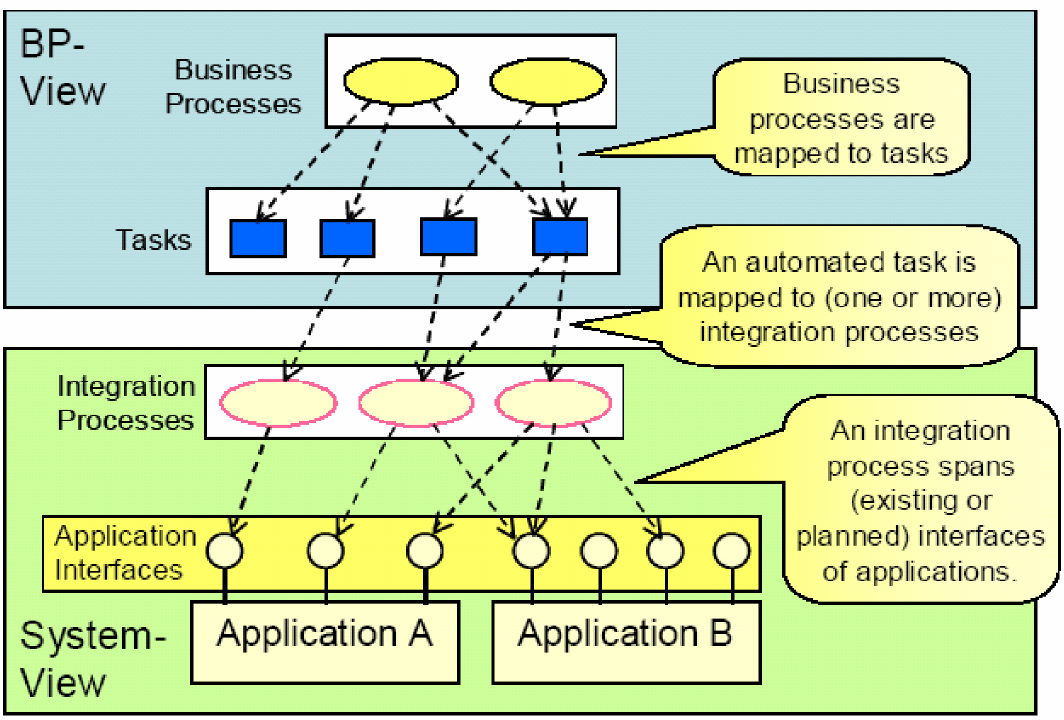

Figure 5.2 Integration Processes [32]

In ADWEA-ADDC functional specification integration project, the original customer (ADDC) requirements have been analyzed. The functional customer requirements for the integration have been gathered from the output of the business processes design. Non functional requirements had to be considered too. An example of that is the Integration will be triggered to update the GIS with the NOP status data from the DMS [32].

Another example is the incident records for LV devices, they will not be sent to the DMS, they remain for solution in the GIS, and however, in case there is a change to the attribute Normal Status in the DMS, an update of the NOP Status data in the GIS is done. This happens on demand (near real time exchange). For data export/import procedure detect differences in the NOP Status data between GIS and DMS the integration will be triggered to update the GIS with NOP Status data from the DMS [32].

Studying potentials and capabilities offered by both technologies, one can summarize those tasks as under:

- Asset Management:
  - Real-time links to GIS, AM/FM and Mapping Systems
  - Condition-based Asset Maintenance
- Work Management:
  - Customer Trouble call system
  - Work order management
  - Switching procedure composition and management
  - Transformer load management
  - Vehicle location and field crew management
  - Links to customer information system
- On-line Monitoring and Operator Advice:
  - System Topology and connectivity Coloring
  - Distribution Automation
  - Fault Identification/location
  - Feeder load transfer
  - Automatic service restoration
  - Load management system coordination
  - Interruptible load control

- Supervised load shedding

As stated earlier in this chapter, ADWEA-ADDC functional specification integration project is taken as an example, following are the expected outcomes of integrating both systems:

1. System Design "GIS"; calculating voltage drop, 11kV feeder capacity, physical locations of primaries and substation all lead to decisions regarding present network, how to expand it or reinforce it. i.e. moving from open ring interconnected network to islanded substations then to zonal substations design.
2. Enhance Security of Supply: for example, planned outages for the different departments or sections within the utility, like maintenance schedules, Testing schedules and construction schedules, those planned outages can be combined into one time table that would minimize shutdowns on the different network component except for the one time scheduled in that time table every year. Customers can then be notified of this service discontinuity and precautions are taken by both sides. To make it short it would deliver better customer handling and service.
3. Contingency plans; what if analysis for different scenarios. Doing so would prepare network operator for unplanned outages caused by unexpected system faults.
4. Load forecast: operational forecasting can be done by taking the planned forecast data and apply on it load profiles and peaks recorded to come up with weekly load forecasts for more accurate planned operational activities.
5. Dispatching Crew: time to locate the faulty section or tripped substation and reach it is faster. In this GIS plays very important role as it can be used to identify the location accurately, also GIS database can provide information on the history of the equipment; type, age. Those historical data are very important in minimizing restoration time as dispatch crew would leave with the necessary spare parts needed to the pre-defined location and perform noted repair tasks from control operator.
6. Interruption Notices for client, better control on restoration of supply which means better customer service. GIS system impact on this side can be obtained

by comparing the records on the NOCs issued before and after GIS application is applied.

7. Better Safety Control: tags on segments or network items under maintenance that would block any further activity on it until the flag is cleared.
8. Training simulator: training on different scenarios like planned outages or contingencies, this should prepare staff to be able to handle such situations when they happen in future.
9. Integrated Alarm Processing; to identify which equipment or specific breaker triggered the alarm on the system.
10. Distribution management centralization allows t reduction of the number of dispatcher centers as consequence of the use of a complete, unique Call Center to register customers' complaints and reduced the number of dispatcher centers from 16 to 3 [40].

CHAPTER 6

6. DEVELOPMENT OF THE STRATEGIC PLANNING MODEL

6.1. Introduction

Technological advancement is associated with the constant escalation in energy demand; which requires reinforcement and expansion of the electric systems wither in the generation, the transmission or even in the distribution level. Moreover, the restructuring shift in the power sector has brought into the power field new concepts that are set by the Regulatory and Supervisory Bureau (RSB); RSB is a governmental body that is responsible for controlling and monitoring electric utilities performances in the emirate of Abu Dhabi as well as issuing and reviewing the operational license for the same utilities. Therefore, utilities are to explore the available technologies, adopt and deploy them when setting up strategic development planning principles to assure reliable and efficient operation of the distribution networks.

Additionally, distribution utilities need to maintain their competitive position in the industry. To do so, they must explore their potentials and capabilities in order to set up their plans to employ the offered technologies in the market for efficient and effective system planning and operation. Due to these reasons; this research intend to highlight, for power distribution utilities, the importance of adopting new technologies when setting up their tactical development maps. Example of these technologies are mapping systems, geographical information system (GIS), customer information system (CIS), work management system (WMS), outage management systems(OMS), Computerized maintenance management systems(CMMS), computer-aided design(CAD), transformer load management(TLM) and Business Process Management (BPM). These technologies are applied around the world in power utilities but the applications are done on the level of generation and transmission systems planning and rarely were the applications implemented on the distribution level. In this research, the emphasis will be on two major technologies which are the GIS and DMS. GIS and DMS are selected here because of the various processing features available in both technologies that make it easy to manipulate geo-referenced data in different formats and models, enhance service reliability indices, meet regulatory service targets, and most important reduce operational cost due to automating tasks that are usually executed by operation and maintenance (O & M) team.

In this research; Abu Dhabi Distribution Company (ADDC) is chosen as an example to illustrate how the new technologies such as DMS and GIS can impact its future plans. ADDC is currently facing a rapid load growth that would require setting up an immediate strategic action plans, not to mention that ADDC management vision is to become one of leading companies in water and power distribution service provider in the world.

The anticipated peak of power load forecast in the Emirate of Abu Dhabi for the coming 10 years in the selected high Density sectors based on historical recorded data of previous years peaks of 2002, 2003, 2004 and 2005; indicates that peak demand will reach 1,916 MVA by end of 2015 as shown in Figure 6.1. Due to the rapid load increase in Abu Dhabi in the past two decades, it is becoming more obvious that the current electric network that was developed to meet demand as and when it arises is becoming in a great need to be strongly traced and improved. By 2015, the load will be increasing to 26 % of the current 2005 peak which will require an immediate action to cater for this huge increase. Abu Dhabi is moving toward encouraging and facilitating tourisms activities that would with no doubt boost that Figure to be doubled in the next 10 years.

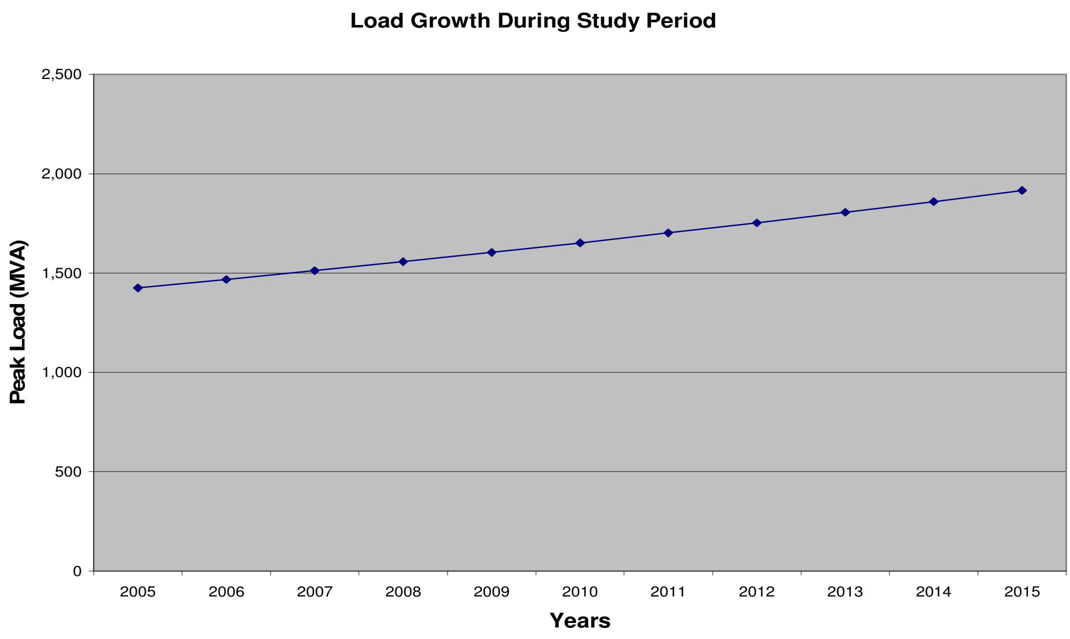

Figure 6.1 Load Growth from year 2005 up to 2015

The need for a self-healing adaptive network to make best use of the available resources is becoming very important. The model presented in this thesis links the technological evolution in power system automation technologies to the increase in energy demand, which is coupled with the different physical restrictions available now. Therefore, setting up strategic plans that assure reliable and efficient operation of the distribution networks is vital. Information technologies exploitation is one way to reach faster more accurate decision-making, with regard to two main aspects; economic and system performance context.

As mentioned in previous chapters, this research examines the current ADDC Decision Support Tool which is used to help decision makers in ADDC to develop and implement a decision framework among different design alternatives. However; the present model does not consider the new advancements in the information technologies field, particularly those technologies that ADDC already invested in but still did not fully utilize all the potential capabilities that can be employed in planning and running its network. The research is an attempt to modify the current ADDC Decision Support Tool based on the extracted best functions that can be employed within GIS and DMS. Through this investigation economical analysis is performed based on results obtained from the decision support tool, this is done by evaluating different scenarios via applying trade off analysis with respect to financial as well as technical objectives of ADDC management. Another addition to the model introduced in this research is the presentation of new system design option, which is the 11kV zonal design. The 11kV zonal design is added because of the decision imposed by the transmission company (TRANSCO) to restructure the transmission network, therefore the model expected to study the feasibility of this option and give decision makers in ADDC the supporting data wither to go ahead with zonal option implementation or not.

6.2. Development of Strategic Planning Model Including New Technologies

The expected rapid peak load growth in Abu Dhabi electric network puts ADDC management in a challenging position, in where it has to supply the required energy demand and at the same time maintain and improve its service quality and cost. Furthermore, the new deregulated environment resulted from privatization shift in power field forces ADDC to reduce O&M costs and push back capital investments, which means that planners must employ the limited capital in the most efficient manner possible. Automation of distribution system allows planners to fully utilize all available resources with maximum if not full installed capacity as well as enhance customer interruption time.

The model modifications proposed here introduce new factors into the present tool, the new factors are simply those extracted from the GIS and DMS applications, which are integrated within the processes, as they form the link between different applications and the business processes within the company. Since power system operation highly depends on the state of the system, it requires suitable and accurate methods of load forecasting and planning. Forecasting and resulting planning is to be based on wide set of data measured from the real power system in strictly defined intervals of time. This again necessitates the use of a modern systematic approach that only is possible to achieve via digital technology deployment. This functionality is available in DMS by monitoring system day to day loading. The results of this research should assist in guiding decision makers in selecting the best option that is expected to improved responsiveness of the system's reliability as well as ensure best customer restoration times. GIS and DMS different applications offer one way for predictive reliability assessment that are essential for distribution planners to increase effectiveness of the system. Planners in the new digital environment should understand different aspects of data acquired; hence know how to process them and how results can be interpreted. The model gives top management an over all view on the different design alternatives performances and costs after diffusion of new technologies, based on those outputs; top management can then decide if a further investment in these two technologies is justified in its expected outcomes.

In addition to the above expected automation impact, another addition to the model is include, which is the 11kV zonal design option. The 11kV ring system which is the current ADDC system consists of a set of 132/11kV primary stations that are simply connected via 11kV switching stations all over the network. Recently, the transmission company (TRANSCO) moved toward reconfiguring its transmission system to meet the RSB requirements. This reconfiguration resulted in dividing the transmission system into three operational zones, which reflects operational restrictions on ADDC network, in which ADDC can not parallel any two primary stations located in two different zones. As an impact ADDC have to reconfigure its network to isolate the primaries according to the zones they belong to. The 11kV zonal design gives one solution to this problem as each primary in this design has its own zone and hence the resultant network can be operated independently of the transmission network changes now or in the future. Graphical description of this design is presented in appendix A.

6.3. Model Process and Methodology:

The current decision support model is an Excel workbook consists of a set of linked spreadsheets, for data inputs, calculations and finally graphical results representations. ADDC decision makers use the model to evaluate and weigh system design alternatives against each other in order to come up with the optimal strategic plan for their company. In this research the model is modified by adding one more system design option which is the zonal design, and by introducing new factors of expected improvement in reliabilities as an automation outcome. Figure 6.2 shows the relation between the different inputs in the model, such as load growth rate, unit cost of different network segments, inflation rate, expected automation impact on system performance, the model also provide their effect on the overall system performance indices such as SAIDI, SAIFI, Un-Served MWH per customer and network asset capital costs as well as operational and maintenance costs for the different network structures. A listing of the detailed input/output factors is presented in Table 6.1.

In Table 6.1 the different decision support model sheets are presented as per the sequence of processes done, for instance, the model starts with the demand forecast on each primary where the primary capacity in MVA along with the associated number of transformers and the 11kV feeders are set as per the design guidelines of each design option sheet, the output of that is used to define the load allocation and the necessary network components in each design, the sheet that does this is the transition to design sheet, where inputs to this sheet are taken from the demand forecast as well as the rules sheet. The rules sheet define the loading limits for every equipment in the design, in addition to restoration standards applied, where the recorded failure historical data used as an input to estimate the individual equipment expected future service interruptions. In parallel to that operation, the model also performs another operation in calculating the different capital and operational cost for every component added that is resulted from demand forecast

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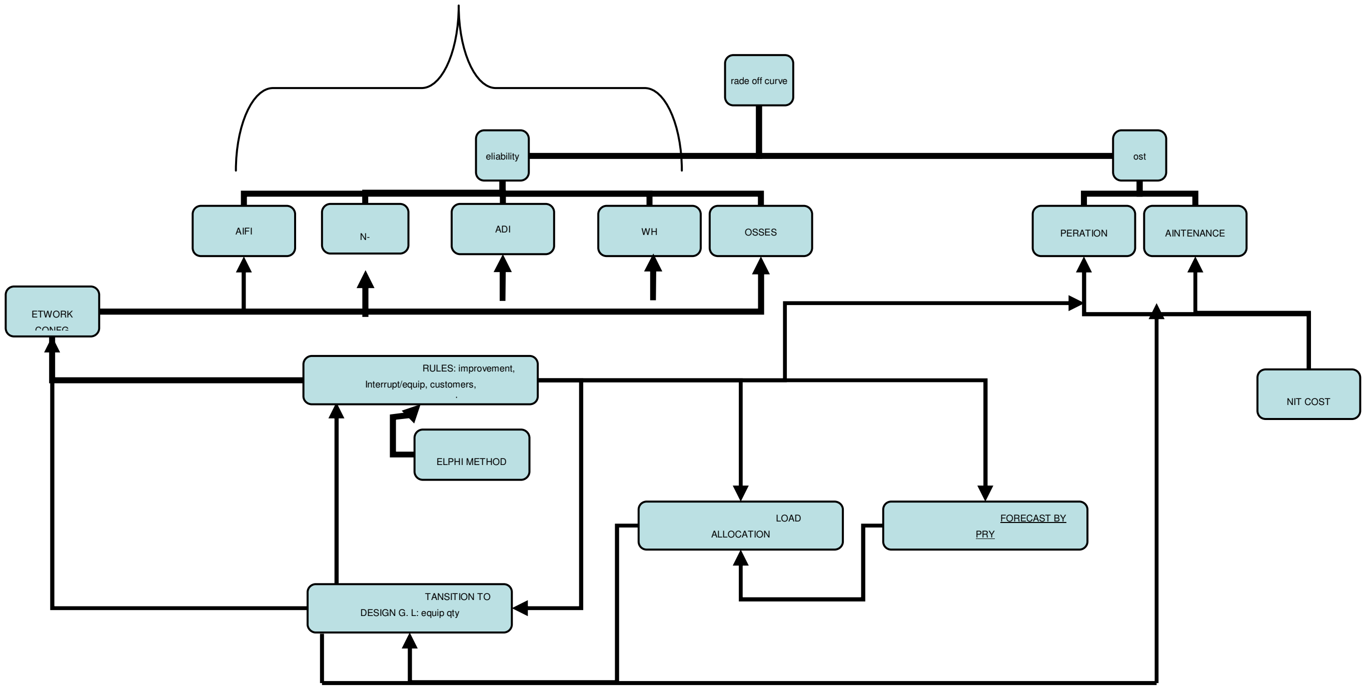


Figure 6.2 Model Input/Output

step. Both failures and cost outputs are then used to produce the different design reliabilities versus costs trade off curve for later evaluation.

Table 6.1

Model for Input/Output Representation

	Input	Output
Unit Cost	Cost/equip, Tot employee cost (HV,LV), # of employees, record maintenance events & hrs	Labor Dhs/hr, Capital, O&M costs
Forecast by primary	Pry Sub-Region: MVA Pry Capacity MVA Peak, #TR, # Feeders, Load Growth%, PF, Sector Km2	Feeder/Tr, MVA/Fdr, system capacity: Qty of SS, TR, KVA/Km2
Load Allocation	Load Growth% from forecast by pry.	Qty of SS & load forecast for 10 yrs
Transition to Design Guidelines	Load Growth at present yr from load allocation.	changes on exist system: Qty required of equip as per DGL rules
Delphi Method	Improv% on exist & new equip fault classes & fdr loading	Improvement in existing and new equipment faults
Network configuration	Qty equip from Trans to design, Cost from Unit cost, Discount rate, Inflation%, Depreciation, SAIFI & SAIDI & Un-served MWH, mint/equip & Interrupt/equip & MWH/equip & Improv% from Rules	Tot capital & O&M cost per each as per design, outage mint, # Interruptions, SAIFI & SAIDI end forecast period, Losses on Pry & Fdr & TR, Regulatory assets value, annual revenue

As illustrated earlier, the model starts with demand forecast. However, the anticipated growth differs as per the type of load projected. Therefore, the first step in forecasting was identifying consumer classification segments that are currently present in ADDC network. Table 6.2 shows the customers connected to ADDC network as they vary from Residential, commercial as well as industrial and agricultural groups.

Table 6.2

ADDC - Feeder-Loading Factors by Customer Classification

Load Type Feeder	Loading Factor
Owner Built House/	0.30
Government Low Cost House/Schools	0.30
Market – 2 Story Building/ Commercial	0.40
Mosque	0.20
Malls	0.60
Industrial	0.70

Now that the load classifications are established, the area of investigation is to be defined. This modified model is applied on the high density area of Northern Abu Dhabi which includes both residential as well as commercial consumers. Since the define customer types in this area are almost similar, it is then logical to assume constant growth rate for this particular region. The evaluation of the existing system with its present configuration to determine if it is capable of meeting the projected load increase over the time and is done by comparing its cost service measured in the net present value (NPV); and performance with respect to the other designs of 11kV ring system, 11kV mesh design, 20kV ring system and 11kV zonal design concept.

During the following sections, each selection will be presented and justified financially as well as technically by applying the multi-attribute trade off analysis (MATA) which was explained in the previous chapter. Time frame for the study period in the model is selected as a long term of 10 years, and is applied for a selected high density area in Abu Dhabi. In addition the model goes through the following steps:

1. Peak Load Forecasting
2. System Design Alternatives to evaluate
3. Identification of Guidelines for each design alternative
4. Application of Guidelines for each system design
5. Evaluation of System Design Alternatives

6.3.1. Peak Load Forecasting

In this step; the model develop forecast of peak load on yearly basis for the planning period by sector. Each network design option has a different capacity because of the projected area load density and is measured in MVA peak demand.

Usually the higher the load density the more complex the design is, which is one justification for increasing investments in such high load density area. The model in this research is applied to the high density area in Abu Dhabi as a case study, which is the North sectors starting from E1 and up to E17 in addition to W1 through W36 sectors as shown in Figure 6.3

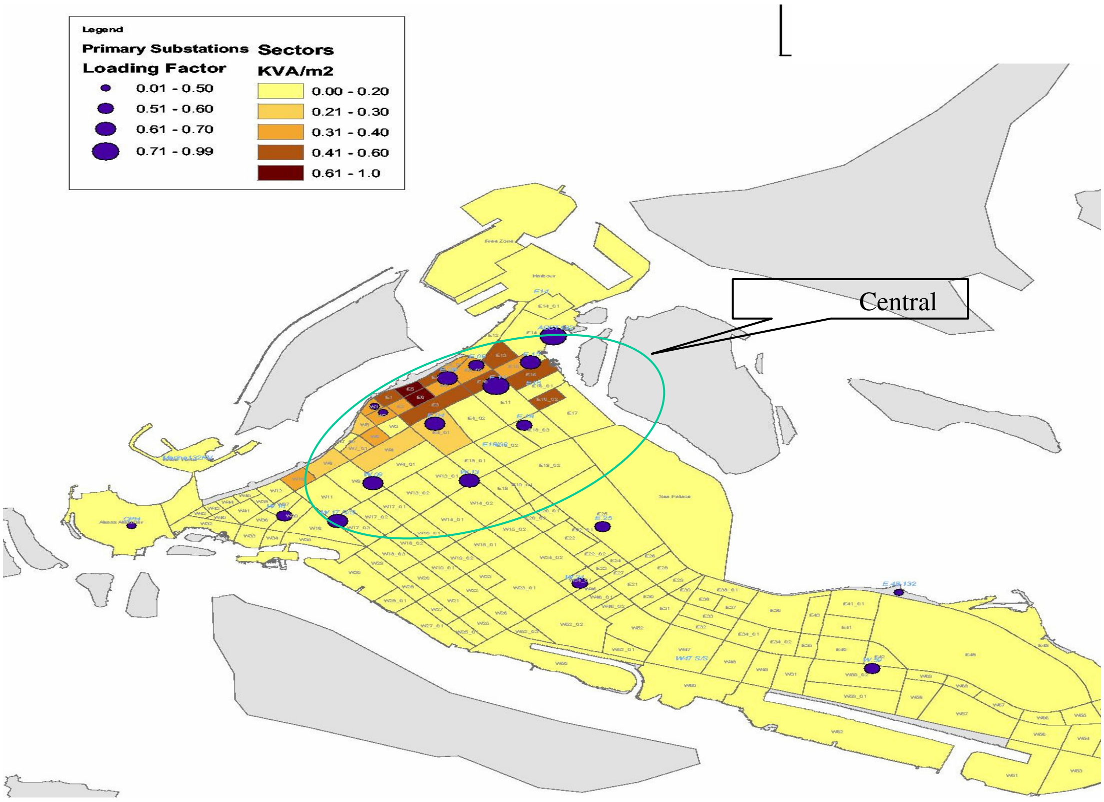


Figure 6.3 High density area covered in the study

For comparison purpose, the load growth rate for this high density area will be assumed at 3% per year per primary at first. This growth rate is the one used by the strategic planners at ADDC when they evaluated the original distribution system and this will allow the results of this research to be compared with original investigation of ADDC.

In the first step the load growth in each design is calculated with respect to the individual primary firm capacity along with the respective sectors it is planned to cover, for instance; Table 6.3, gives the allocated areas in year 2005 for each primary as per the design option for the 11kV ring, 11kV mesh & 20 kV ring designs.

Table 6.3

Primary Stations with respective areas coverage (11kV Ring, 11kV Mesh & 20 kV Ring)

Primary Station	Region	Sectors Covered	Firm Capacity (MVA)
E04	North	E4	123
E04I	North	E4	31
E08	North	E7,8	123
E09	North	E9,12	92
E11	North	E10,11	123
E12	North	E12	46
E14	North	E14	123
E15	North	E13-15	123
E15I	North	E15	31
E18	North	E16-18	92
E18	North	E18	23
E18-02	North	E16,18	123
W01	North	W1-7, E1-3, E5-6	123
W02	North	W1-7, E1-3, E5-6	92
W09	North	W9, E18	123
W13	North	W8, 10-13	123
W16	North	W16-17	123
W17	North	W36-45	123

Table 6.3 shows that ADDC strategic plan is to combine some sectors to be shared among assigned primaries, for example; E4 and E4I primaries; which the name given for each refer to their actual physical locations; those two primaries share the load of sector E4, similarly; E15 sector and E18 sector. One thing to notice in this distribution is that the operational concept for those design options sets boundaries for the radius that each primary intended to cover.

The forecasted load in the designated areas in table 6.3 is then used to define the number of primary stations required. This is calculated by the following formula;

$$No.of.\Pr irmaries_n = \frac{(F_j)_{n-1} \times (1 + Growth\%)}{(Peak\_MVA\_Capacity)} \qquad (6.1)$$

Where F_j F is the forecasted MVA peak load in sector j.

n is the year of respect forecast

However; in the 11kV Zonal design option as in table 6.4; there are no boundaries around each primary, this is because the operational concept of this design does not require that, each primary is independent of the others in the area it covers. This design option was not evaluated in the current decision support tool. This research aims to study this option and correlate it to the other design alternatives that are considered by ADDC.

Similarly, in table 6.4 the required number of primaries for the forecasted load in this case is calculated as per next formula

$$No.of.\Pr irmaries_n = \frac{\left(\sum_{1}^{j} F_j\right)_{n-1} \times (1 + Growth\%)}{(Total\_Peak\_MVA\_Capacity)} \qquad (6.2)$$

Where F_j is the total MVA capacity in the area j and is the sum of capacities of all power primary stations in the assigned area and n is the study years.

The formulas above calculate the number of primaries required as a function of the total peak MVA capacity. This capacity is given by:

$$Total\_Peak\_MVA\_Capacity = (TR\_Loading\%) \times (Total\_TR\_MVA) \qquad (6.3)$$

Where TR stands reefers to Transformer.

The model defines the design guidelines for each system, which are covered in next step and transformer loading percentage for each design guideline is given in Table 6.5 next.

Table 6.4

Primary Stations and their respective areas coverage (11kV Zonal Design)

Primary Station	Region	Sectors Covered	Firm Capacity (MVA)
E04	North	E4, E7-E8, E9-E12, E10-E11	123
E04I	North		31
E08	North		123
E09	North		92
E11	North		123
E12	North		46
E14	North	E14, E13-15, E16-18,	123
E15	North		123
E15	North		31
E18	North		92
E18	North		23
E18-02	North		123
W01	North	W1-7, E1-3, E5-6, W9, E18, W16-17, W36-45	123
W02	North		92
W09	North		123
W13	North		123
W16	North		123
W17	North		123

Table 6.5

Transformer Loading % for each Design Guidelines

Design Rules	11 kV ring HD sw/s	11 kV Mesh	20 kV ring sw/s & dbl bus	11 kV Zonal SS
Primary Substation Loading- MVA	0.77%	0.77%	0.77%	0.75%

Where HD stands for High Density area and sw/S stands for Switching Station.

6.3.2. System Design Alternatives to Evaluate

As stated in step one, the model presents seven design alternatives: (1) 11kV ring system with power transformer capacity of 4 x 40 MVA in each primary station with switching stations connecting loads and primaries, (2) 11kV ring system switching stations connecting loads and primaries however with power transformer capacity of 4 x 55 MVA in each primary station; (3) 11kV mesh system with two feeders connecting each of two primaries stations; (4)11kV mesh double bus bar system with two feeders connecting each of two primaries stations; (5) 20 kV ring system with switching station connecting loads and primaries; (6) 20 kV double bus bar ring system with switching station connecting loads and primaries; and (7) a new added design, that is the 11kV zonal design substation with each of two transformers in the same primary stations running in parallel. Appendix A present the different structure of those alternatives.

6.3.3. Identification of Guidelines for Each Design Alternative;

The engineering design guidelines of each system design alternative are applied in the model for each system design option based on the following criteria:

➢ Number of primary substations, their loading capacity and number of 11kV busses introduced in each design option.

In step one, the number of primary stations is calculated, accordingly and as per the design guidelines, it is possible to define the detailed requirements for each option. The planning guidelines for each design alternative specifies the ratio of non-express feeders to express feeders, average quantity of non-express feeders to be allocated to each primary transformer, in addition to the loading percentage of these feeders and their carrying capacity. This information is essential for the planning engineer in defining the down stream configuration of the network.

- Number of 11kV feeders per primary transformer.

This is the starting point in the down stream network configuration, where the 11kV feeder cable size, percentage peak loading, and its estimated average length in km are to be defined accordingly in the design rules. Following is an illustration on how design rules for the 11kV current system for the average length of feeder is used to estimate the value of the same parameters in the 20kV design option as in table 6.6.

Example:

Based on the current ADDC system, the existing km of 11 kV cable length is estimated using GIS to be 716 km; this quantity is for 416 feeders. The estimated outlet length from the primary substation to the first distribution substation) is 0.3 km.

$$\text{The outlet cable length} = 0.3 \times \text{No\_of\_11kV feeders} \tag{6.4}$$

For the 11kV option the outlet cable length is 125 km, therefore, the feeder cable used to connect to the distribution substations is calculated as after;

716-125 = 591 km and considered similar for all options for year 2005. Now the average feeder length in km is estimate for 20 kV systems is based on 11 kV voltage ratio of 20/11. For the 20kV option, the estimated number of 20 kV feeders required for the 2005 peak load is 148 feeders, then;

$$\text{The outlet cable length} = 0.3 \times 148 = 44km \tag{6.5}$$

Thus, the total 20 kV cable length is 591+ 44 = 635 km or 4.3 km/feeder which is similar to the estimate of 3.5 km using the voltage ratio of $\frac{11kV}{20kV}$.

- Number of switching stations per primary transformer as well as the resultant number of express and non-feeders per each switching station are also basic parameters in the design rules. The number of switching stations is given by:

$$No\_of\_Switchinbg\_stations = \frac{\text{number of non - express feeders}}{(\text{Ratio of non - express to express feeders}) \times 2} \tag{6.6}$$

Up to equation 6.6 the defined parameters were calculated for the up-stream network. In order to move to the next step in detailed design, planner refers to the design guidelines given in Table 6.6. Expected utilization of the distribution transformer as per the design guidelines stated.

Table 6.6

Design Guidelines for System Design Options

Inputs	11 kV ring HD sw/s	11 kV Mesh	20 kV ring sw/s & dbl bus	11 kV Zonal SS
Average feeder length in km	1.9	1.9	3.5	2
Ratio of peak demand to nameplate for distribution transformers	0.55	0.55	0.55	0.75
Ratio of LV cable km to distribution substation quantity	3.0	3.0	3.0	3.0
Ratio of feeder pillars to LV cable km	0.36	0.36	0.36	0.36
Ratio of service turrets to LV cable km	0.51	0.51	0.51	0.51
Average MVA nameplate of distribution transformers	1.4	1.4	1.4	1.4
Average number of transformers in distribution substations	1.7	1.7	1.7	1.7
Power factor at primary substations	0.9	0.9	0.9	0.9
Power factor at distribution substations	0.8	0.8	0.8	0.8
Inflation rate	2.5%	2.5%	2.5%	2.5%
Ratio of km of 6-way encased ducts to km of 11 or 20 kV cable	0.0	0.0	0.5	0.0
Type of MV cable - 240 or 500 mm^2 copper (enter 240 or 500)	240	240	500	240
kVA/Customer at peak MVA load	13	13	13	13

6.3.4. Application of Guidelines for Each System Design;

In this step a detailed calculations similar to the one illustrated in previous sections is performed for each design in the following sequence;

a. Allocate load among primary substations from the forecasted growth.

b. Calculate changes in physical system segments; similarly; the details of those changes in each system design are enclosed in the appendix C.

c. Calculate service capital cost and O&M cost

In table 6.7, the cost values are taken as a lump sum, the details for each item are calculated with its detailed component costs, those detailed calculations are enclosed in Appendix D, which in turn taken from different ADDC consultants estimates as well as the applied ADDC Bill Of Quantity (BOQ) List.

d. Calculate service quality attributes each year (SAIDI, SAIFI, Un-Served kWh/customer)

Reliability indices are calculated for each system design using the following formulas:

$$SAIDI = \frac{(\#Exist\_equipt)(M / Equipt) + (\#New\_equipt)(M / Equipt)}{N} \tag{6.7}$$

$$SAIFI = \frac{(\#Exist\_equipt)(I / Equipt) + (\#New\_equipt)(I / Equipt)}{N} \tag{6.8}$$

and

Un-Served KWH per Customer is calculated as in the following formula;

$$= \frac{(\#Exist\_equipt)(KWH / Equipt) + (\#New\_equipt)(KWH / Equipt)}{N} \tag{6.9}$$

where; N: Total number of customers

M: Interruption duration in minutes

I: Interruption frequency

Table 6.7

Service Capital Cost and O&M Cost

Equipment	Capital Cost		O&M Cost
	11 kV	20 kV	11 and 20 kV
Substations - 132 - 11 kV and 20 kV	84195.00	70863.82	1683.92
Feeder panel - non-express	320.00	395.80	1.54
Feeder panel - express	320.00	395.80	1.54
240 mm^2 feeder cable - per km	165.70	205.71	2.35
500 mm^2 feeder cable - per km	220.00	272.80	1.18
Switching Substations	980.00	1215.20	17.66
Substations 11/20 - 0.415 kV Indoor	549.00	680.76	14.20
Package Unit Substations	128.00	158.72	5.45
QRM Substations	325.00	404.24	5.45
TRM Substations	325.00	404.24	4.45
Pilot wire - km	78.40	78.40	1.18
Mesh switchgear	140.00	173.60	7.33
Mesh relaying	10.00	10.00	0.00
Ducts encased 6 way - per km	405.00	405.00	0.00
Transformers - 11 or 20 to 0.415 kV	55.50	70.06	4.16
LV feeder cable - per km	78.40	78.40	1.18
Feeder Pillars	4.00	4.00	0.00
Service Turrets	2.90	2.90	0.00
Substations 11 - 0.415 kV Mesh	700.00	868.00	14.20
TRM Switchgear Unit	35.00	44.64	
QRM Switchgear Unit	35.00	44.64	
Circuit breaker switchgear panel	168.00	208.32	
Substations - 132 - 20 kV dbl bus		78482.38	1417.28
Substations - 132 - 11 kV dbl bus	93412.00		1868.24
Substations - 132 - 11 kV 3X55MVA	76933.80		1538.68

6.3.5. Evaluation of System Design Alternatives

In this step the outputs of step 4 are compared for the different system designs for the most optimal selection, that selection can be considered by ADDC decision makers as feasible strategic option.

6.4. New Technologies Impact on Strategic Planning Model

This is done according to the new input of expected improvements of GIS and DMS mmodeling process which is based on two major Components, they are:

1. Functional Modeling

   In this step the same electric network planning process and performance are examined in order to account for the GIS and DMS introduced functionalities in chapter 5 of this thesis.

2. Experts' Assessment

   To obtain cumulative practice knowledge in classical utilities in order to estimate the tangible impact of diffusing GIS and DMS technologies into these utilities planning as well as operation processes.

6.4.1. Functional Modeling

First step in doing that was in investigating each technology individually for its possible capabilities and applications. For the GIS technology and as per the several reviews and researches, GIS applications were classified into three groups; (1) Engineering analysis which covered Visual Modeling load per customer categories, Connectivity and network tracing, Loop detection, Multi or not energized object detection, Load Forecasting Visually, and Data update, (2) Project management such as project tracking and project design, and (3) Design functions like network reconfiguration, network design, Refurbishment, Right of the way, Last mile planning and Capacitor placement.

In addition, DMS technology investigation resulted in again four areas, (1) Monitoring tools, for instance; State Estimation with Load Estimation, Load flow, and Performance indices, (2) Dispatching tools as in Under load switching, and Switching sequence management, (3) Optimization tools like Network reconfiguration, Relay protection, Voltage control, VAR control, and (4) Engineering analysis tools like Fault calculations, Energy loss, Reliability analysis, Load forecasting and Capacitor placement.

Second step was in integrating both technologies and correlating those functions to different tasks and procedures defined in business processes for distribution utilities in order to reach what is considered the most feasible applicable functions from both GIS and DMS. The integration was based on the ability to share and transfer data between the two databases of both technologies as well as processing the data imported from one into the other. Appendix B-1 shows the details of these integrated functions along with their expected impact on distribution operation processes. GIS and DMS application areas results for network distribution identified and classified earlier resulted in the following groups:

- Asset Management:
    - Real-time links to GIS, AM/FM and Mapping Systems
    - Condition-based Asset Maintenance
- Work Management:
    - Customer Trouble call system
    - Work order management
    - Switching procedure composition and management
    - Transformer load management
    - Vehicle location and field crew management
    - Links to customer information system
- On-line Monitoring and Operator Advice:
    - System Topology and connectivity Coloring
    - Distribution Automation
    - Fault Identification/location & Restoration
    - Feeder load transfer
    - Automatic service restoration
    - Load management system coordination
    - Interruptible load control
    - Supervised load shedding

Each application area effect is modeled with the present network structure to identify its possible enhancements on the classical utilities planning and operational practices. For instance; the optimization tools are applicable in three different entities within the distribution utility structure, they can be applied in asset management team for gathering condition based asset assessment, and they also can be used by the customer call center for trouble calls as well as vehicles and field crew work management processes. Moreover, fault identification and service restoration tasks can be performed through the functions available in optimization tools. An example of that are the Fault Identification and Restoration Functions. Figure 6.4 shows typical circuit in any distribution system, where the power flows from the source up to the NOP. When a fault occurs in a point along the feeder, the breaker at the source opens and the supply is interrupted along the whole circuit.

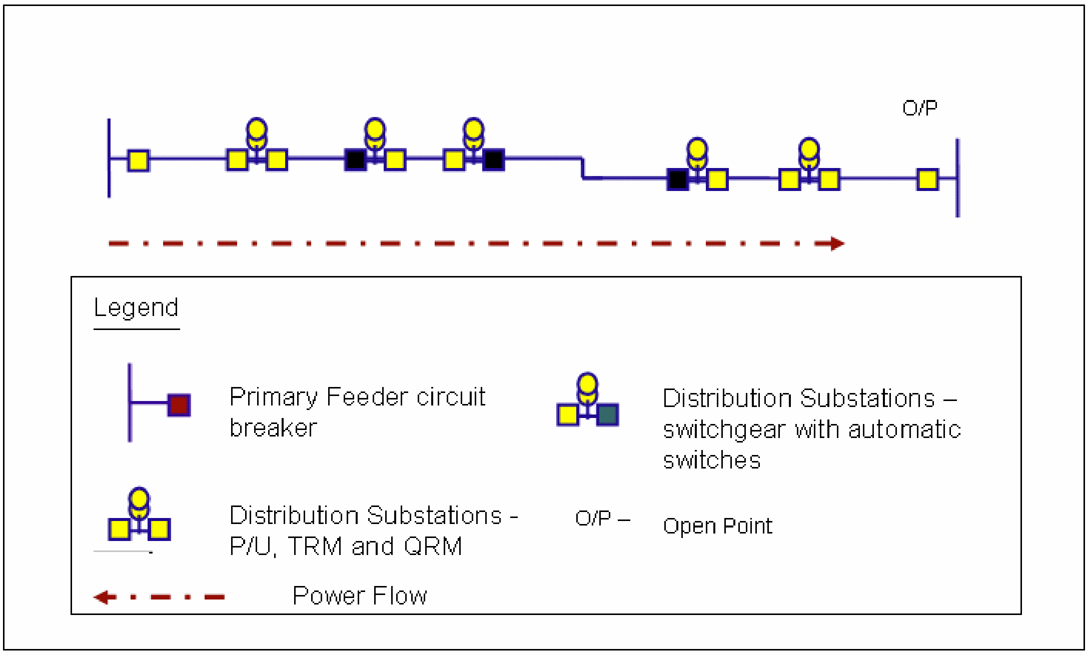
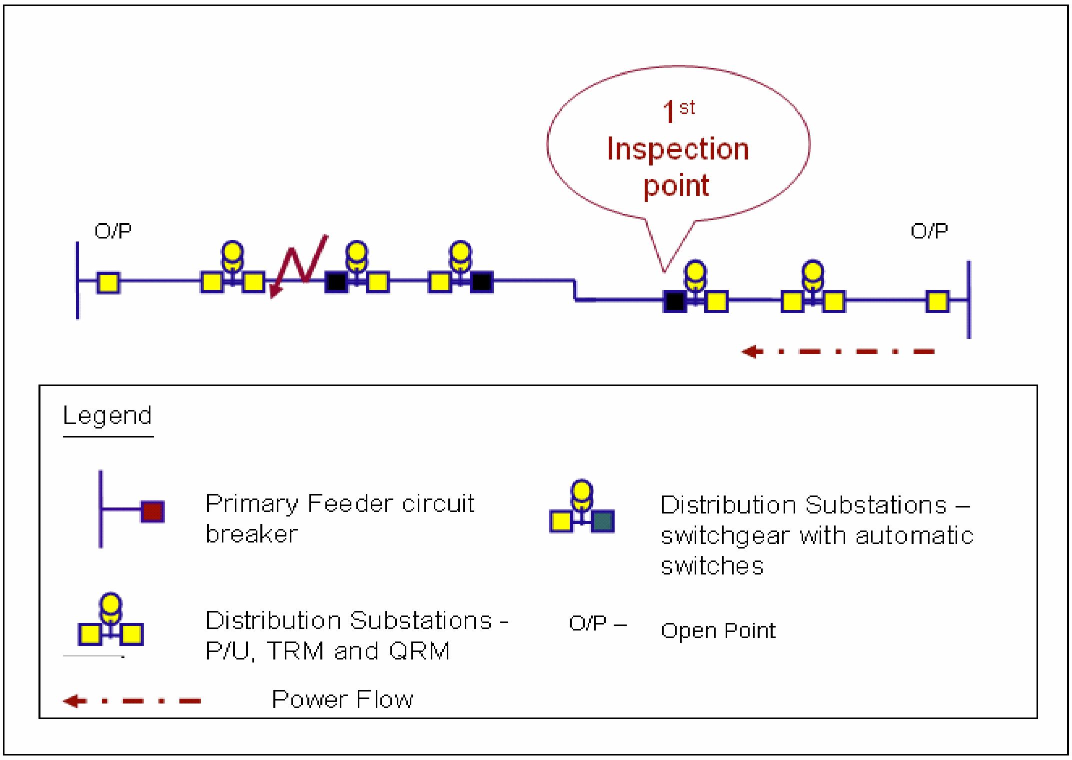
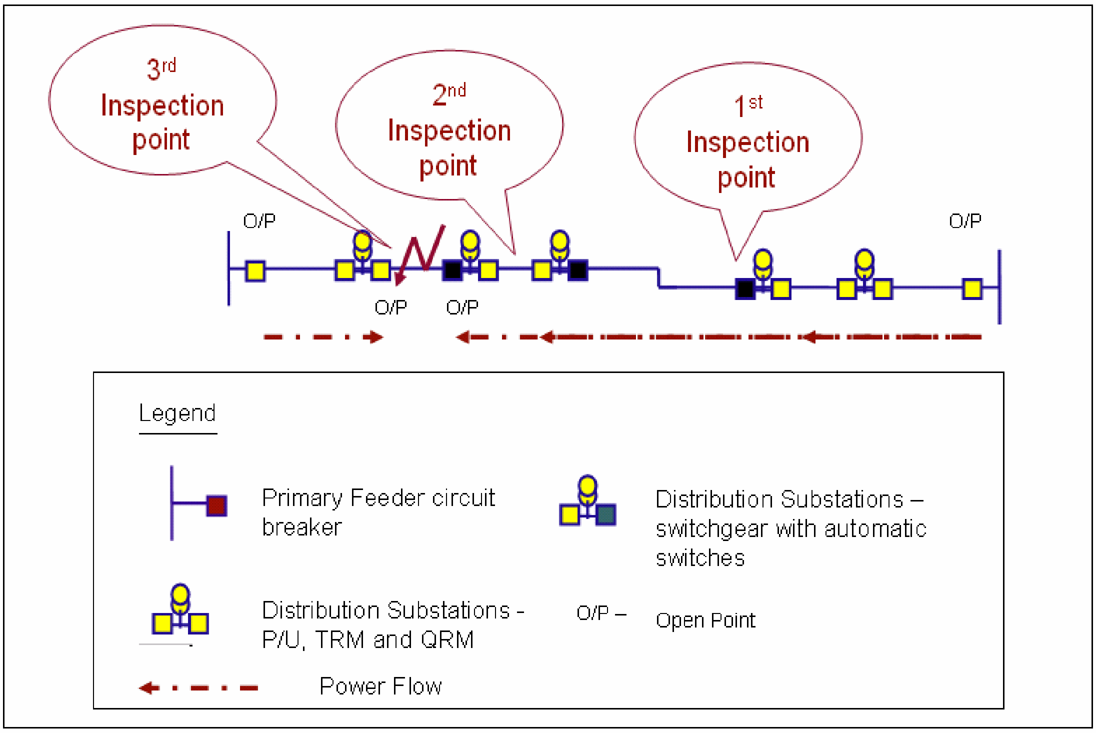


Figure 6.4 Typical Distribution Network Circuit

The conventional way in restoring the supply is done in several steps, where the identification of the fault location is done by selecting a middle point along the feeder and inspecting it manually, if that point is healthy then the supply is restored up to that point in the circuit as in Figures 6.5 a. a second and a third or even, in some cases a fourth inspection point, is again selected in a middle point along the remaining faulty circuit to track the fault location and manually restore the supply for the healthy portions as in Figure 6.5 (b). The restoration of supply process is classified as per security of supply standards to be within repair time of 3 hours, however with the presence of the advanced functionalities of GIS and DMS, operating staff manage to automatically identify the open breaker via Intelligent Fault Indicator function and easily spot out the location of the faulty distribution equipment along the circuit through GIS special facilities shorten that 3 hours into a matter of minutes.

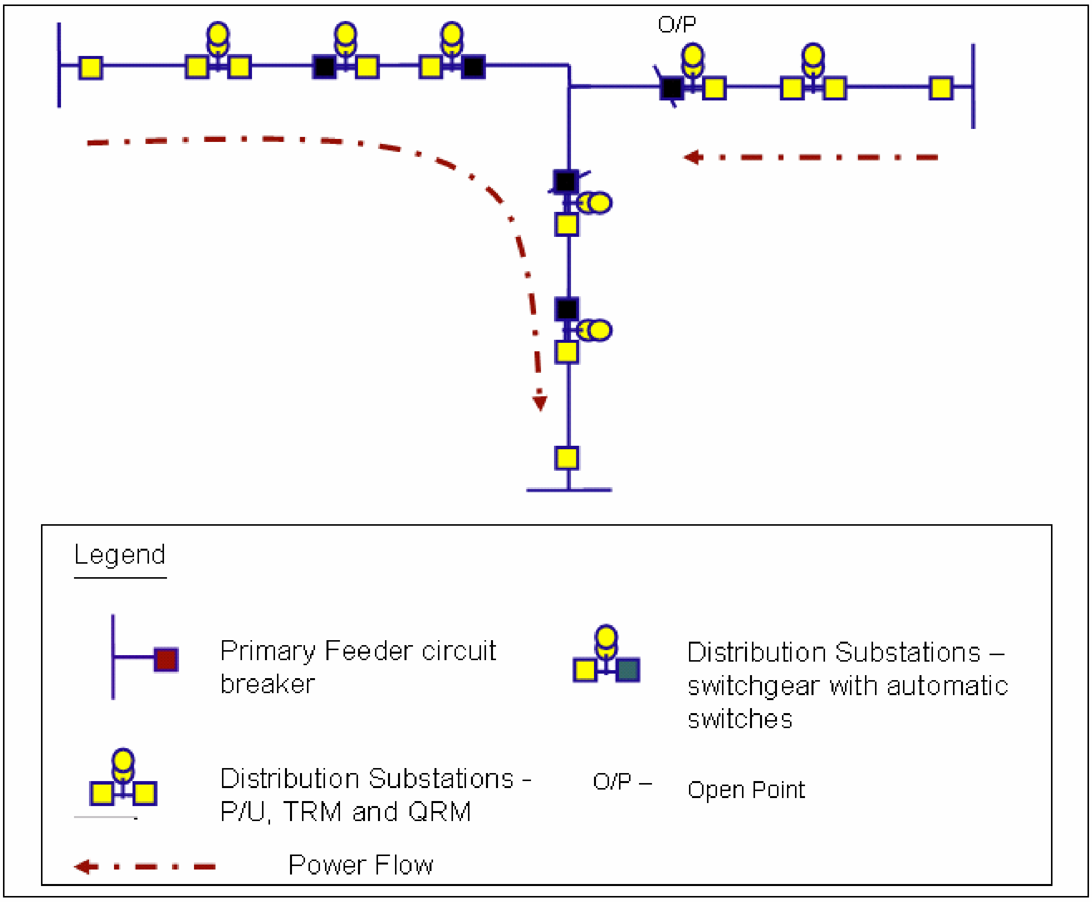


Figures 6.5 (a) Conventional Fault Identification and Restoration of Supply Process



Figures 6.5 (b) Conventional Fault Identification and Restoration of Supply Process

Another example is the possible application areas that can be obtained from forecasting functions and switching procedure composition and management tools. Figure 6.6 shows typical tie connection in distribution network. In this tie connection configuration the normal power flow in shown as indicated by the arrows. Distribution utilities design standards limits the loading of each branch to a certain limit that security standards does not permit to exceed.



Figures 6.6 Typical Tie Connection in Distribution Network

The forecast application allow planner to anticipate the demand increase on each branch, moreover it anticipates the overloading conditions that might occur in the system as in Figure 6.7 (a), therefore, planner in coordination with operational planning staff can alter such situation simply by a remote automatic switching process that is done from operation station by introducing a new NOP as in Figure 6.7 (b).

The new functionalities of GIS that facilitated the special forecast process and DMS online feeder status enables planners to avoid going through any network physical reinforcement actions and it provides preventive action plan for any expected tripping in the network due to anticipated overloading that can result from energy demand consumption increase.

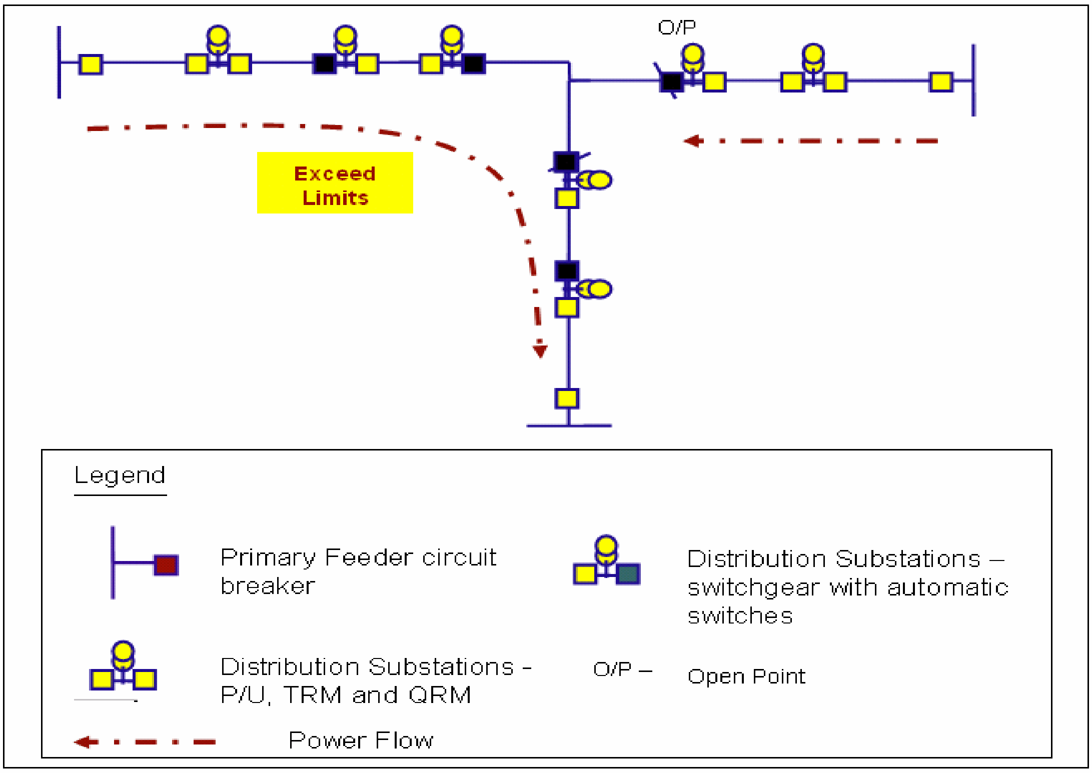
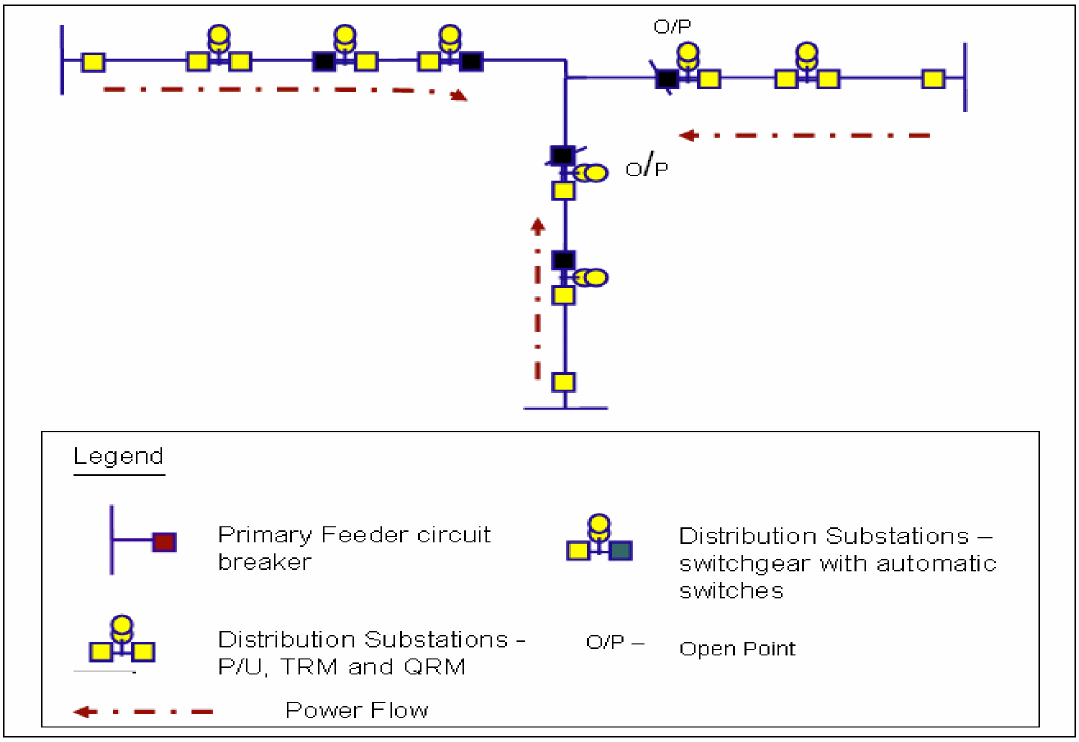


Figure 6.7 (a) Expected Over Loading Condition with New Technologies tools



Figures 6.7 (b) Typical Tie Connection in Distribution Network

6.4.2. Experts' Assessment

The Delphi technique is applied here to determine expected improvements that the new technologies of GIS and DMS might have on electric system performance indices, such as SAIDI, SAIFI and Un-served KWH per customer.

Delphi method was originally developed by the RAND Corporation back in 1969 where it was introduced for technological forecasting. The Delphi method is a series of steps used to reach consistency in decision process about the likelihood that certain events will occur. However, the same technique is being used today for, marketing, environmental and sales forecasting. The most important benefit of the Delphi Method is that the experts never need to be brought together physically regardless of their actual geographical locations. There are seven steps to the Delphi method:

1. Identification of topic whose possible, probable, and preferable futures are to be investigated.
2. Construction of a questionnaire as an instrument of data collection.
3. The selection of topic expert whos opinions are to be studied.
4. Pass questionnaire for feedback as a first round
5. Develop summary of the data resulting from the initial questionnaire.
6. AObtain re-measurement of the opinions by narrowing questionnaire and making them more specific.
7. Analysis, interpretation and presentation of the data and the writing of the final report if results are consistant.

The determination of the different functions followed by identification of the group of experts. Since the required feedback intended to cover different netowrk component performances, then the selection of experts panel was based on the experties in their actual work, the selected group included eight people that covered electric network planning as well as distribution located in Abu Dhabi and Dubai.

Next step involved contacting the individual experts and communicating to them the selected GIS and DMS functions along with the seven different network structures. The functions selected was presented for the group to obtain their feedback wither those functions covered most of expected functionalities and capabilities in both technologies. Fortunatly, the experts showed satisfaction regarding the selected functions.

Since overall network performance is measured by the performance of the individual network components. Formation of questions was build on the major network component items such as medium voltage cables, equipment, planned outages, distribution transformers and LV cables as in Figure 6.8. The questions intended to acquire experts openions on how much GIS and DMS presented applications would limit fault occurance on those electric network components. Appendix B-2 show the sample of questionnaire used.

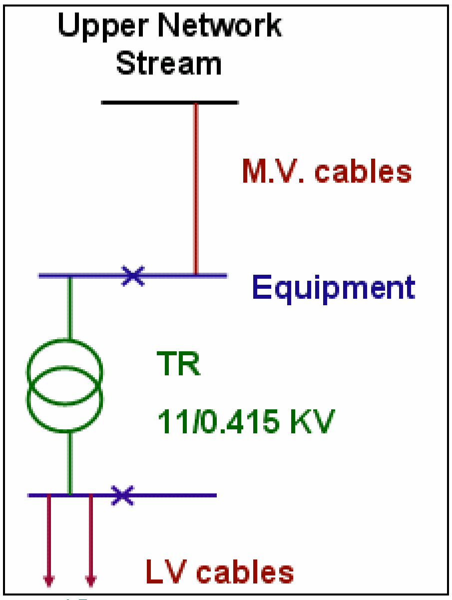


Figure 6.8 Network Segments Covered in the Analysis

The quesitons also presented to cover the existing equipments in the system as well as the new equipment expected to be added due to load growth and system expansion. This segregation between existing equipments and new equipments is due to several reasons, for instance, ADDC historical data on medium voltage cables showed that majority of outages recorded were due to joints and terminations, where as the minority were due to mechanical damage. Hence new medium voltage cables would eliminate the cause for majority faults as joint and termination failures. Another example is for planned outages where the new pequipment should require less maintenance and therefor, the maintenance cycles on new equipment would be reduced if compared to existing one. Moreover, ADDC historical records on equipment outages showed that around 50% were because of equipment aging, therefor, for the new equipments and during the study period of ten years this reason should be eleminated. Table 6.8 present the questions in the survey.

Table 6.8

Delphi Method Tables

1- Existing equipment is kept, but the system is operated as in the following structures:

Fault Class	Current Practice	11kV ring HD SWSTN	xp Improvement	11kV Mesh	xp Improvement	20 kV ring SWSTN	xp Improvement	11kV Zonal S/S exp improvement
MV Cable	0%	0%		0%		70%		
Equipment	0%	0%		0%		50%		
Planned	0%	0%		0%		50%		
TR	0%	0%		0%		25%		
LV Cable	0%	0%		0%		50%		

2- New Equipment is introduced to replace existing one:

Fault Class	Current Practice	11kV ring HD SWSTN	xp Improvement	11kV Mesh	xp Improvement	20 kV ring SWSTN	xp Improvement	11kV Zonal S/S exp improvement
MV Cable	50%	50%		90%		70%		
Equipment	50%	50%		90%		50%		
Planned	50%	50%		50%		50%		
TR	25%	25%		25%		25%		
LV Cable	50%	50%		50%		50%		

The first round in the questionnaire resulted in consistency in all feedbacks except one, where a second questionnaire was passed to that individual with a defined ranges to select from. The feedback on the second round showed the same ranges of results obtained from other experts in the first round. The process does not require complete agreement by all panel experts, since the majority opinion is represented by the median. Therefore, the average of the individual responses for each component is taken. Table 6.9 summarize these results.

Table 6.9

Experts' Opinion on Improvements in Different System Component Performance

Estimate of improvement in security of supply - Base case or existing design					
	Cable	Equip	Planned	TR	LV
Existing equip	48%	48%	29%	29%	2%
New equip	85%	87%	60%	55%	50%
Estimate of improvement in security of supply - Ring or engineering design guidelines					
	Cable	Equip	Planned	TR	LV
Existing equip	48%	48%	29%	29%	2%
New equip	85%	87%	60%	55%	50%
Estimate of improvement in security of supply - Mesh					
	Cable	Equip	Planned	TR	LV
Existing equip	94%	94%	74%	29%	2%
New equip	94%	94%	60%	55%	50%
Estimate of improvement in security of supply - 20 kV					
	Cable	Equip	Planned	TR	LV
Existing equip	114%	128%	60%	55%	2%
New equip	85%	87%	60%	55%	50%
Estimate of improvement in security of supply - 11 kV Zonal Design					
	Cable	Equip	Planned	TR	LV
Existing equip	60%	60%	74%	29%	2%
New equip	94%	94%	60%	55%	50%

Output of above table is inserted in the following formulas to obtian the three index for each network component reliabilities;

$$SAIDI = \frac{(1-E)(\#Exist\_equipt)(M/Equipt) + (1-E)(\#New\_equipt)(M/Equipt)}{N} \quad (6.10)$$

$$SAIFI = \frac{(1-E)(\#Exist\_equipt)(I/Equipt) + (1-E)(\#New\_equipt)(I/Equipt)}{N} \quad (6.12)$$

and the Un-Served KWH per Customer is calculated as in the following formula;

$$= \frac{(1-E)(\#Exist\_equipt)(KWH/Equipt) + (1-E)(\#New\_equipt)(KWH/Equipt)}{N} \quad (6.13)$$

where; E : Expected improvement

N: Total number of customers

M: Interruption duration in minutes

I: Interruption frequency

The total system performance reliabilities are summarized at the end of study period by summing up all equipment reliabilites in the individual three index categories.

6.5. Automated System Evaluation

Chapter 3 presented the evaluation different design alternatives with no consideration of new technologies, however, since the new technologies are already in the market, and it's in ADDC best interest to explore how these technologies can assist in achieving the management vision of becoming one of the leading power and water service providers in the world, this section provide an assessment on the expected impact of automation systems such as Geographical Information System (GIS) and Distribution Management System (DMS) on traditional utility performance; DMS employment is expected to increased asset utilizations and financial return on assets, in addition, having a geographical reference of the network via GIS technology would grant essential information on land use pattern for optimum expansion of network as well as for setting up new facilities, this defiantly would improve the overall system planning as well system operation. Now it is a good time to remind the reader that the different capabilities and functionalities of both systems already discussed with their impact in Chapter 4, detailed illustration of these functions is enclosed in Appendix B-1.

6.5.1. Service Interruption Duration Index (SAIDI)

In Figure 6.9 showing SAIDI versus Cost, the system design options located along the frontier are the 11kV ring switching station with 55MVA power transformers (pink square), the 11kV zonal design option (green plus), and 20 kV double bus bar ring design (red circle). The automation here did not only change the best options identified earlier in chapter three, rather it also improved the previous chapter three established reliabilities as the 11kV mesh system interruption duration index improved from 29 to almost 14. Moreover, the introduction of the new zonal design did change the priorities as the 11kV mesh design is not Pareto optimal. Moreover, the new technologies of GIS and DMS enhanced the reliabilities of the ranked options while maintaining the same cost. The improvement in the 11kV ring system reliability was from 32 to 20. Additionally, the 20 kV ring design (purple x) moved to become closer to the frontier line, which means that it is a possible reasonable option, never the less, the 20 kV ring design cost more if compared to the 11kV zonal design which gives relatively better reliability with 11% cost reduction. 11kV Mesh (yellow triangle) and 11kV Mesh double bus bar (light blue x) for example, demonstrate that those two options are not preferred ones because a better service reliability and cost are possible to achieve via other alternatives in Figure 6.9 However, the dominated options still exhibited better reliability when applying automation in system planning and operation.

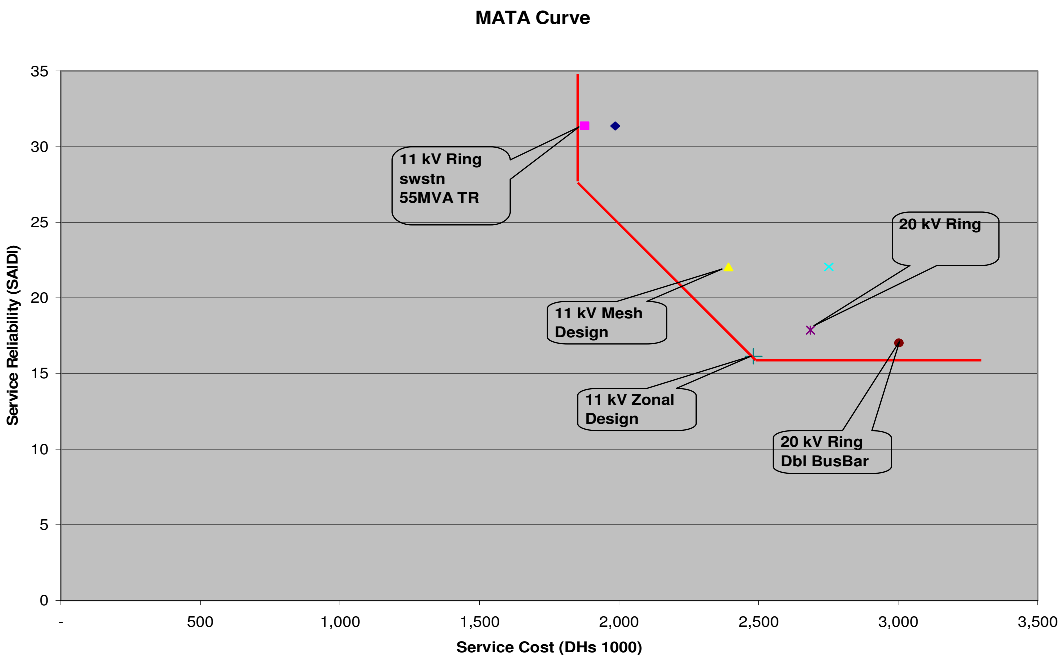


Figure 6.9 SAIDI vs Cost evaluation in automated network

6.5.2. Service Interruption Frequency Index (SAIFI)

SAIFI results presented by the model as in Figures 6.10 supports mentioned above results for the SAIDI, as it clearly indicate that the dominant options to select are the 11kV ring switching station (pink square) and 11kV zonal design option (green plus) which are similar to results obtained in section 6.5.1. Moreover, the 11kV ring switching station (pink square) SAIFI value improved from 0.32 to 0.21.

Although for the 11kV mesh design is not optimal anymore, but its service interruption index improved due to automation from 0.32 to 0.15. Again, SAIFI values versus the cost show that the new zonal design have pushed back the previously optimal design of 11kV mesh. All other designs are graphically considered to be dominated. This is a strong indication that new technologies do enhance the performance of the systems.

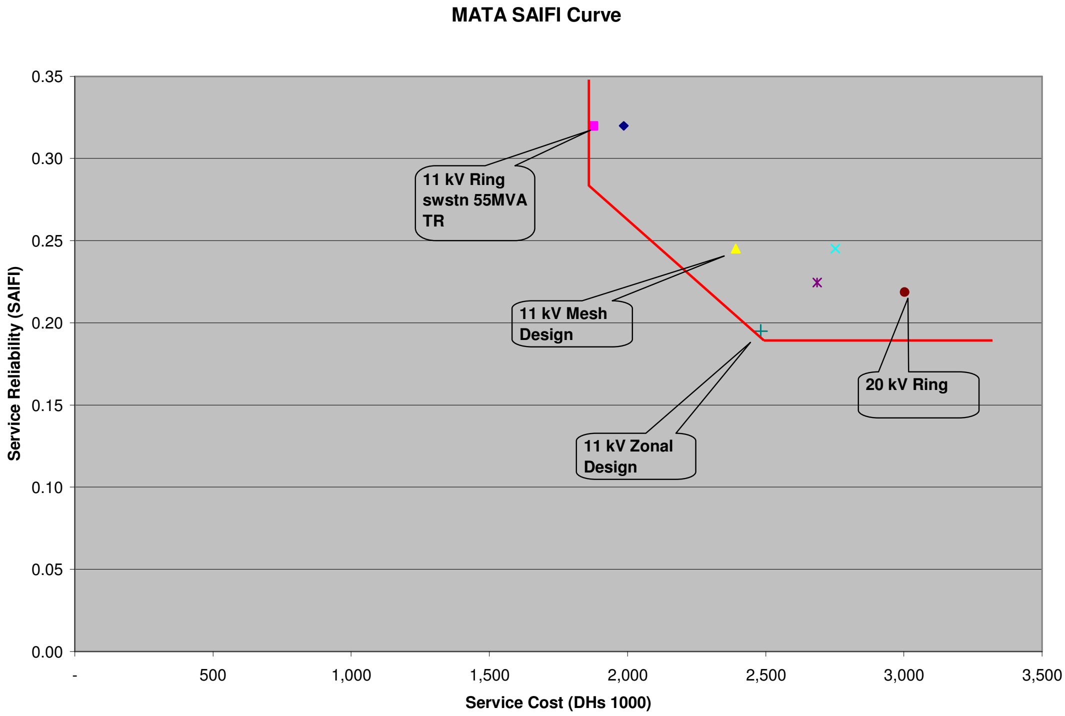


Figure 6.10 SAIFI vs Cost evaluation in automated network

6.5.3. Energy Loss Index (un-served KWH per customer)

The same result as in previous two sections appears again in the energy losses to ADDC as in Figure 6.11 for un-Served KWH per customer versus service cost. This system performance index is estimated with GIS and DMS deployment in the system planning and operation of the network, for example the 11kV ring system showed jump from 11 to 9 in the expected KWH loss per customer, where the 20kV ring option shift was from 9 to 8.6 due to automation. Figure 6.11 for this index also eliminate all alternatives. Though the 11kV ring switching station with 40 MVA power transformer capacity (blue diamond) alternative is somehow close to the MATA frontier line, but both options of 11kV ring switching station with 55MVA power transformers (pink square) and 11kV zonal design option (green plus) supersede this option.

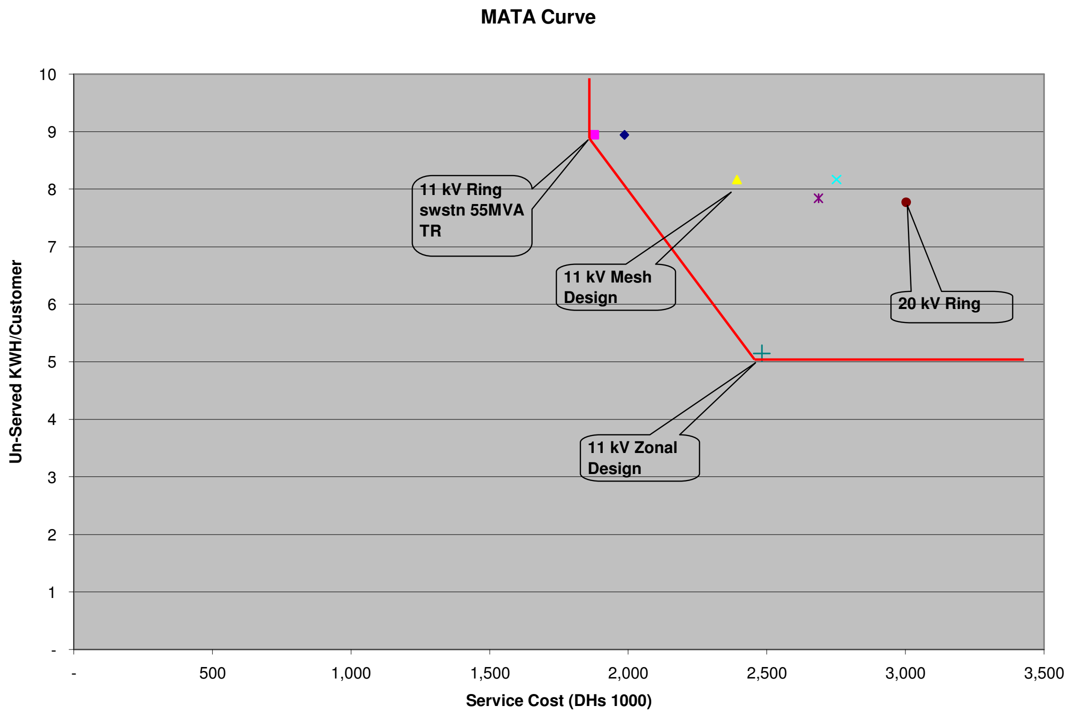


Figure 6.11 Un-served KWH per Customer vs Cost Evaluation in Automated Network

6.6. Sensitivity Analysis

Long term planning is associated with certain levels of risk since it is based on assumptions that may or may not actually materialize within the planning period. In the proceeding sections, the assumptions of 3% peak demand growth rate and 2.5 % yearly increase in were the bases of the presented results. In this section, sensitivity analysis are performed in order to check how the results will change if the actual growth values in peak demand and inflation turn out to be different than what has been assumed.

To perform the sensitivity analysis, several values for an increase/decrease in inflation and peak demand load were tried and the corresponding change in the optimal designs was observed. The results of these trials show that a small percentage fluctuation in the values of these two variables will have a negligible effect of the optimal design found using the previously assumed values. Therefore, in this section of the analysis, effect of an appreciable change in inflation and peak demand load ($\pm$ 50%) will be presented as shown in Table 6.10.

Table 6.10

Sensitivity Analysis Scenarios

Input assumption	Inflation	Load Growth
50% Increase in Inflation	3.80%	3%
50% Increase Load Growth	2.50%	4.50%
Base	2.50%	3%
50% Decrease in Inflation	1.30%	3%
50% Decrease Load Growth	2.50%	1.50%

The sensitivity analysis results shown in Figure 6.12 through Figure 6.14, show that future fluctuations in inflation rate within 50% of the assumed rate will not affect the choice of the optimal design. However, the 50% increase in inflation caused a total horizontal shift for the MATA curve to the left because the individual costs of the different designs relatively increased. This result was common for all design options except the zonal design where the cost stayed almost the same. Similar effect on the negative direction was caused by the 50% decrease assumption in inflation as in Figures 6.15 through 6.17 while the same level of reliabilities is maintained.

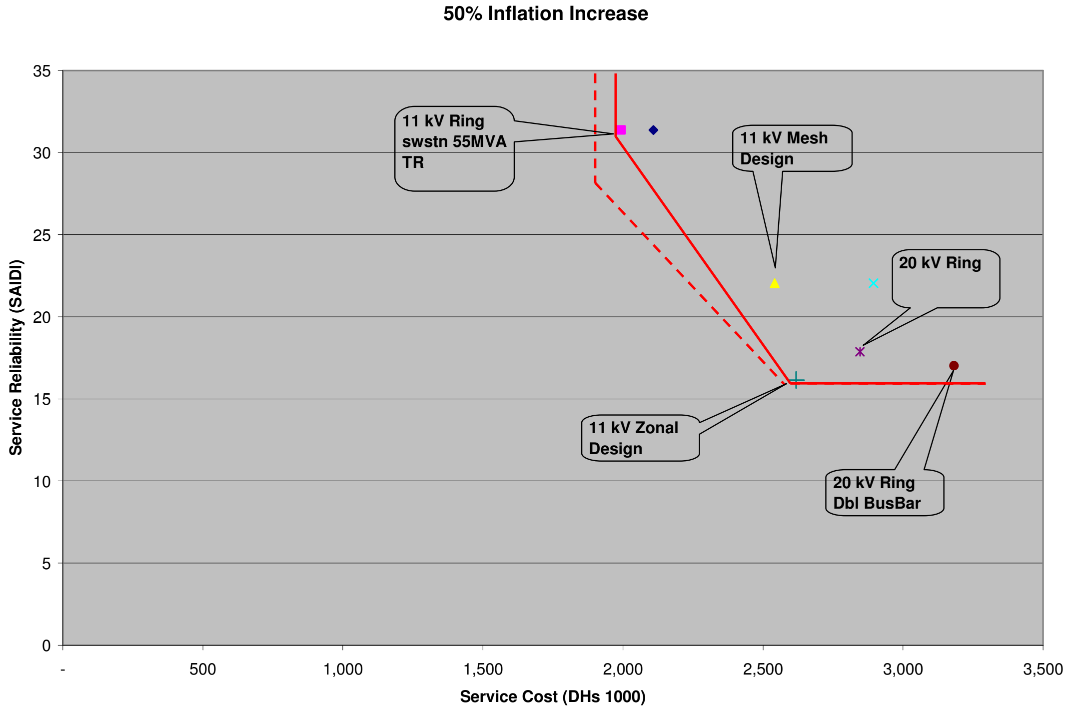


Figure 6.12 SAIDI vs Cost Evaluation with 50% Increase in Inflation Rate

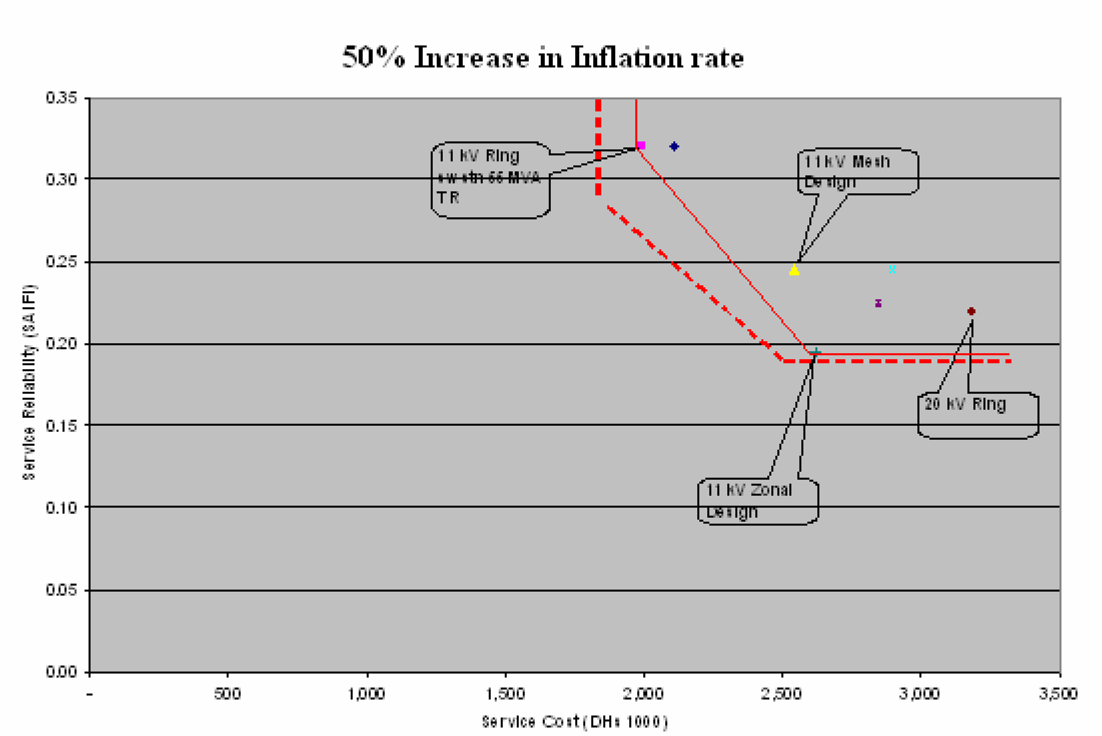


Figure 6.13 SAIFI vs Cost Evaluation with 50% Increase in Inflation Rate

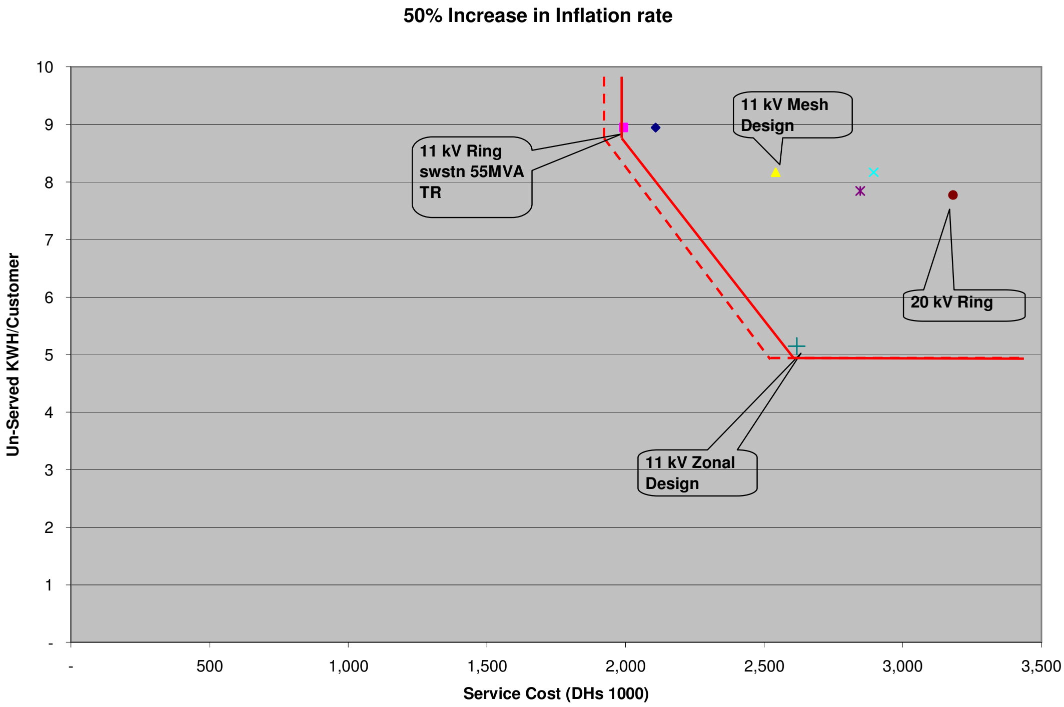


Figure 6.14 Un-served KWH/Customer vs Cost evaluation with 50% Increase in Inflation rate

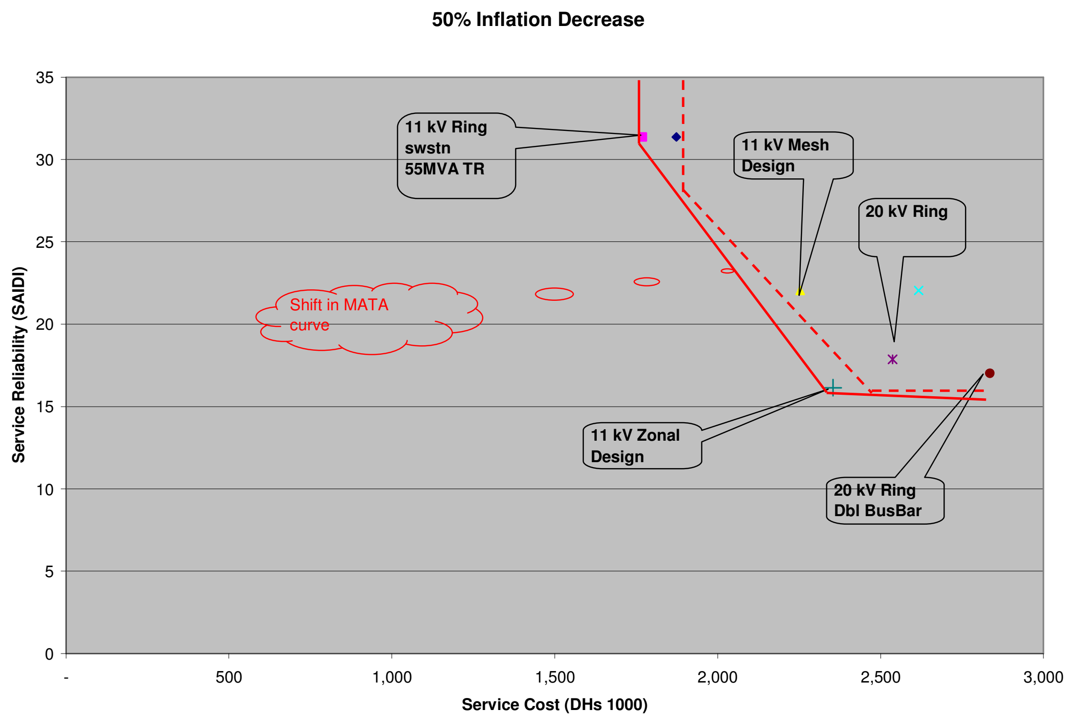


Figure 6.15 SAIDI vs Cost Evaluation with 50% Decrease in Inflation Rate

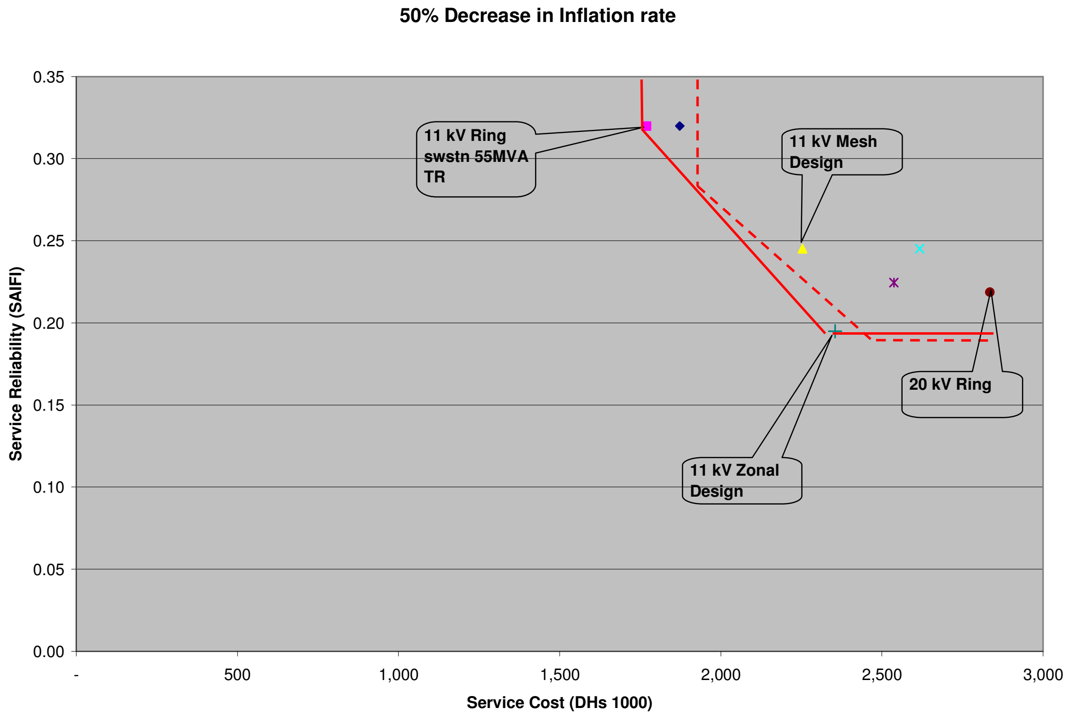


Figure 6.16 SAIFI vs Cost Evaluation with 50% Decrease in Inflation Rate

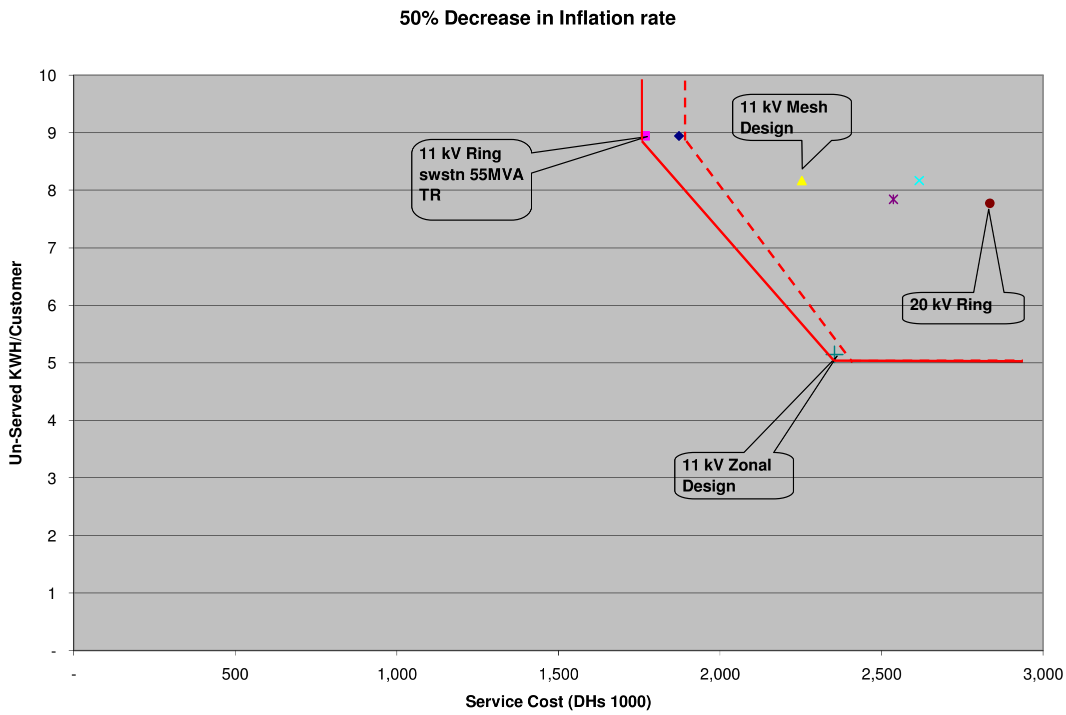


Figure 6.17 Un-served KWH/Customer vs Cost Evaluation with 50% Decrease in Inflation Rate

On the other hand, fluctuations in the demand peak will have a significant effect on the optimal design. As shown in Figure 6.18 through Figure 6.23, the optimal design corresponding to a 50% increase in the peak demand load for the zonal design which is similar to the two options of 11kV ring switching station option if the actual peak load rate is the assumes rate of 3%.

An interesting result was obtained for above scenarios of sensitivity analysis which indicates that reliability values which are presented here as an example, do assure that 11kV ring switching station with 55MVA power transformers (pink square), 11kV zonal design option (green plus) are the most reliable and feasible solution for ADDC future strategic plans. In addition, the 11kV Zonal design is actually the best optimal design as the cost savings resulted as the maximum in all cases tested. This remarkable outcome for the 11kV zonal design option improvements are achieved actually with relatively no cost implications at all, if compared to other design options, the infrastructure is the same and automation impact really have enhanced system reliabilities. Above stated Figures prove that new technologies have relatively no cost impact on system expanding neither system operation nor system maintenance.

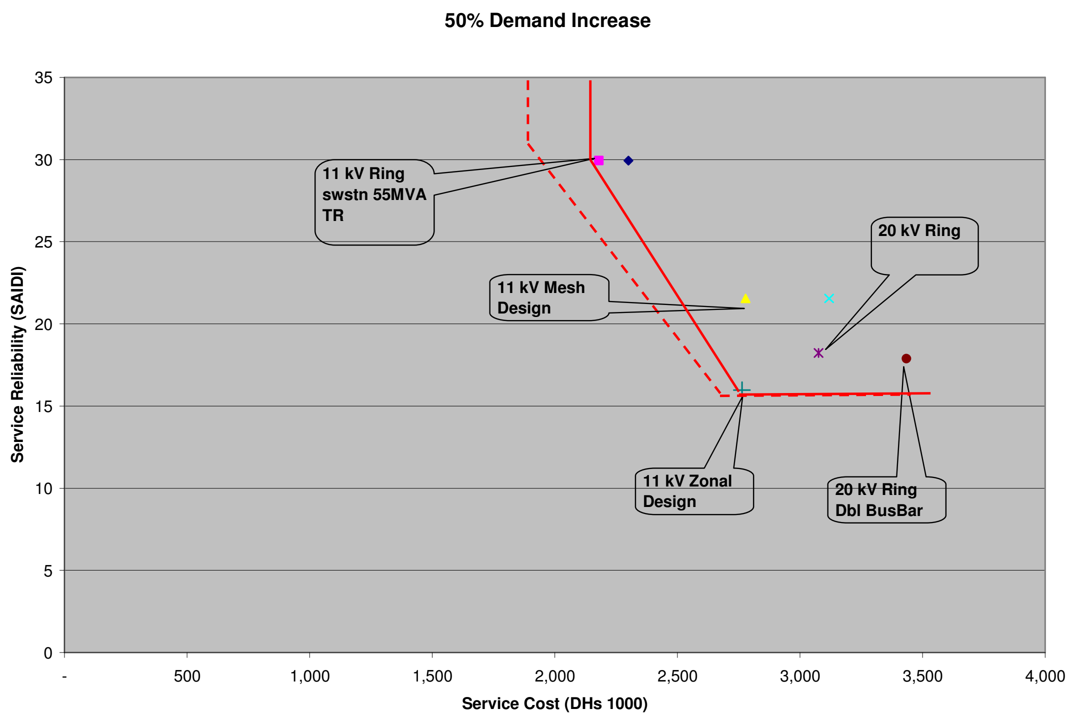


Figure 6.18 SAIDI vs Cost Evaluation with 50% Demand Increase

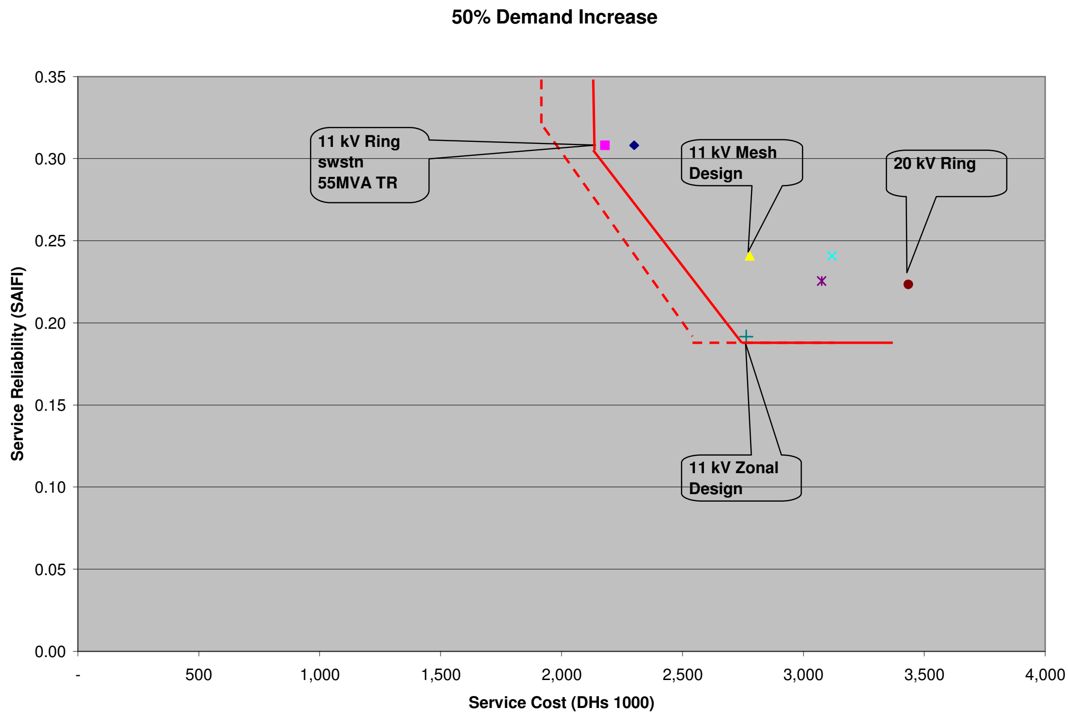


Figure 6.19 SAIFI vas Cost Evaluation with 50% Demand Increase

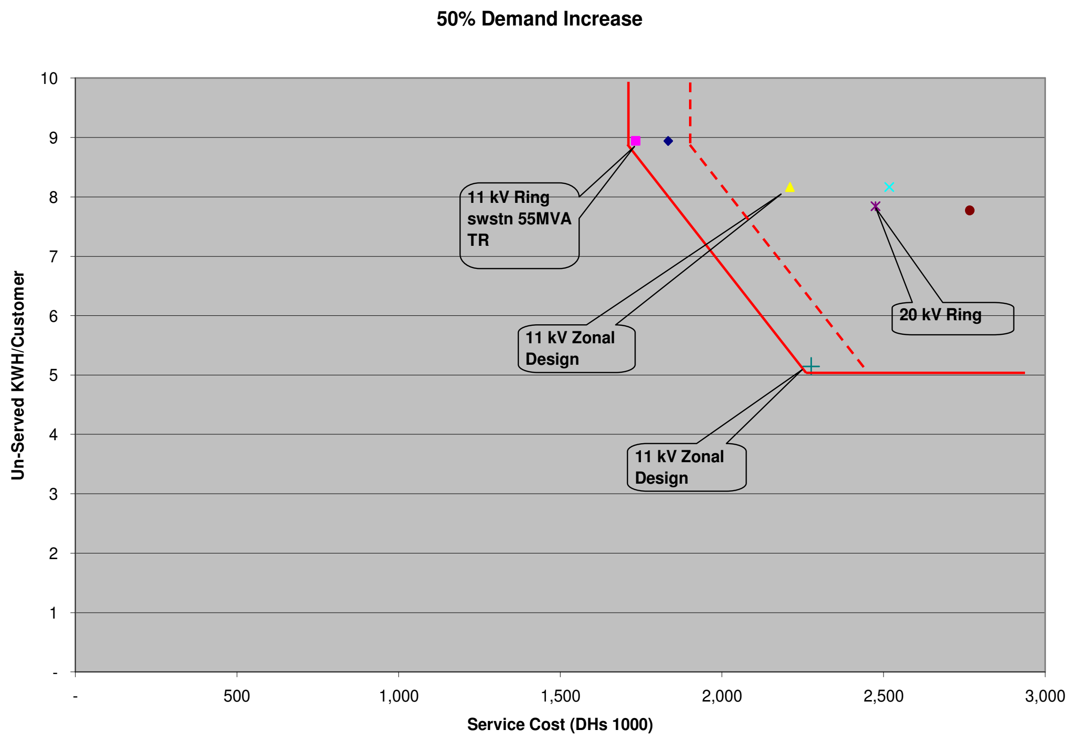


Figure 6.20 Un-served KWH / Customer Evaluation with 50% Demand Increase

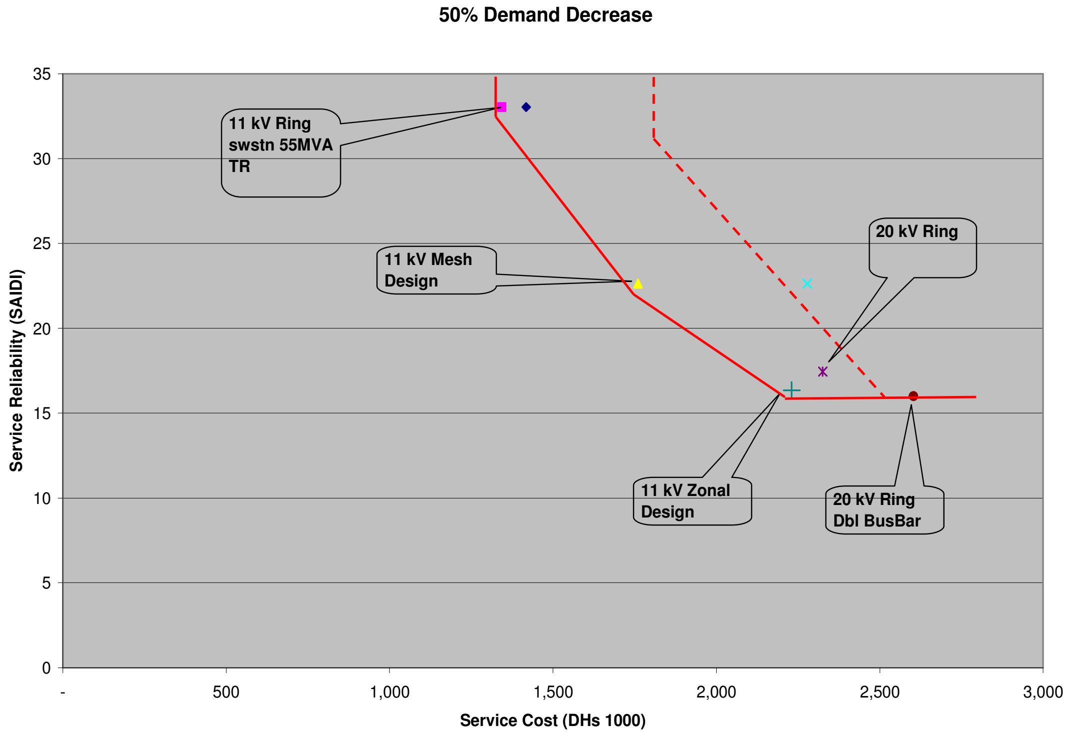


Figure 6.21 SAIDI vs Cost Evaluation with 50% Demand Decrease

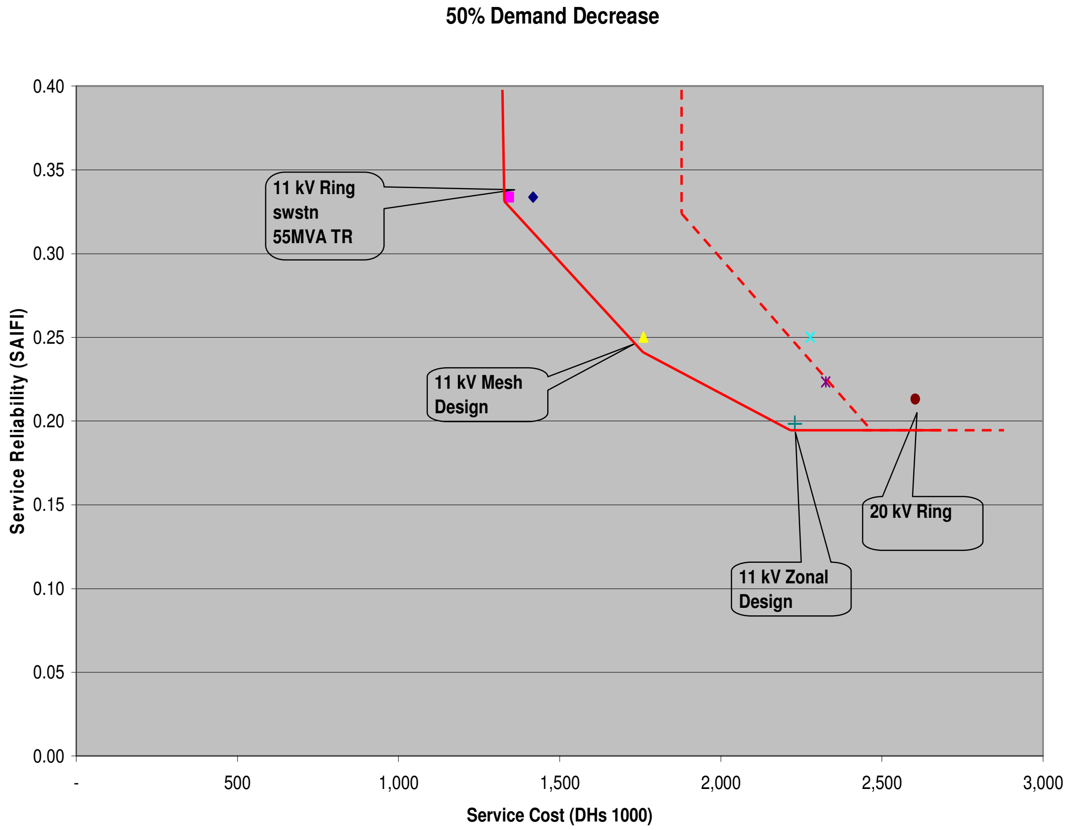


Figure 6.22 SAIFI vs Cost Evaluation with 50% Demand Decrease

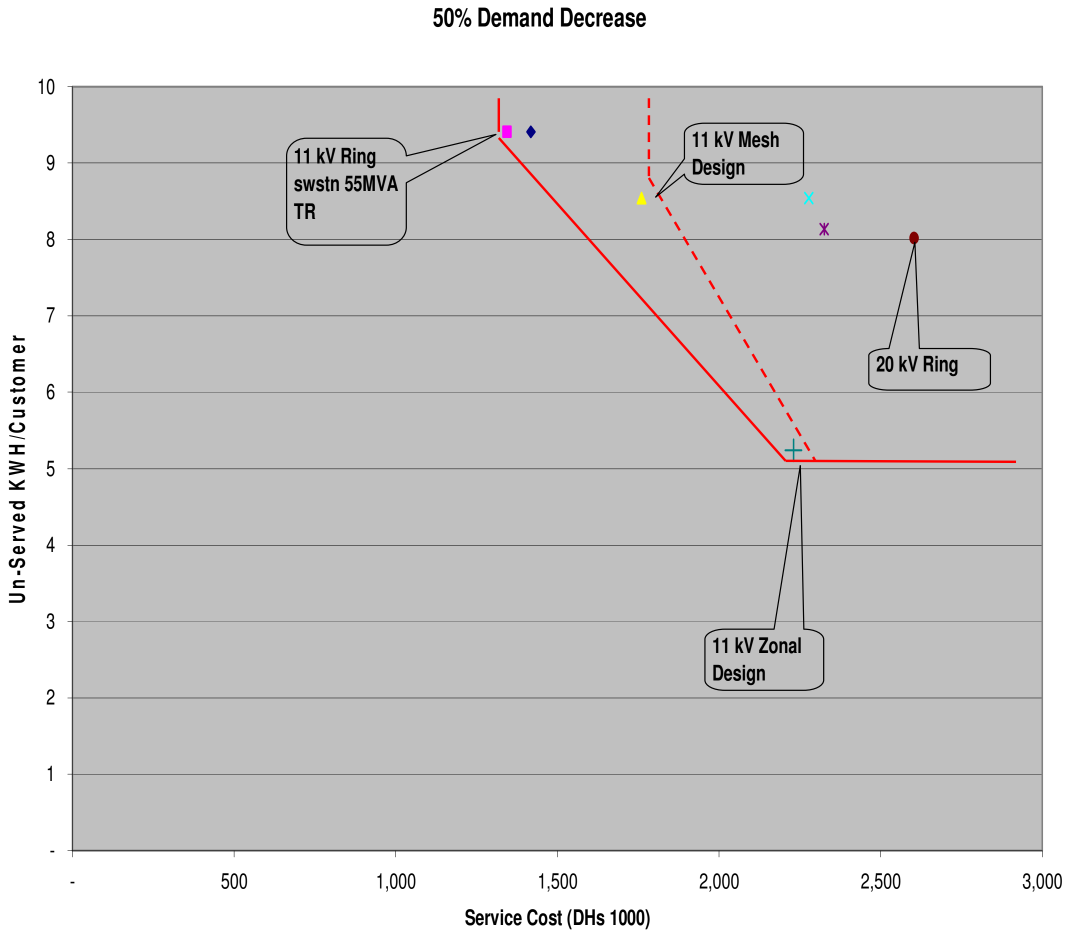


Figure 6.23 Un-served KWH / Customer Evaluation with 50% Demand Decrease

CHAPTER 7

7. COMPARITIVE ANALYSIS BETWEEN THE CURRENT AND THE DEVELOPED SYSTEM

So far, this report presented the current ADDC electric distribution system and the performance reliability indices resulted from using the decision support tool in Chapter four. Chapter five introduced the GIS and DMS technologies. The expected improvement on the same reliability indices were presented in Chapter six along with the results from the application of the new technologies. In this chapter, the current system's performance as measured by the reliabilities indices is compared to the same indices after the inclusion of the proposed new technologies

7.1. Comparison of Utilities Performance before and after Digital Environment Intrusion.

7.1.1. Service Interruption Duration Index (SAIDI) Improvements

Combining results in previous chapters and plotting them on the same graph the following Figure 7.1 for SIADI vs. Cost; which is taken as an example, indicates that utilizing GIS and DMS functions explained in previous chapters indeed improve system performance regardless which system option is applied. For example in the 11kV ring HD switching station (blue dash) SAIDI value has been improved with the automation from 32 to 20 (blue diamond) with the same cost for both. Similarly, the 11kV zonal design (pink x) SAIDI value has dropped from 11 to a better level of 10 (light blue plus) again with no cost implications.

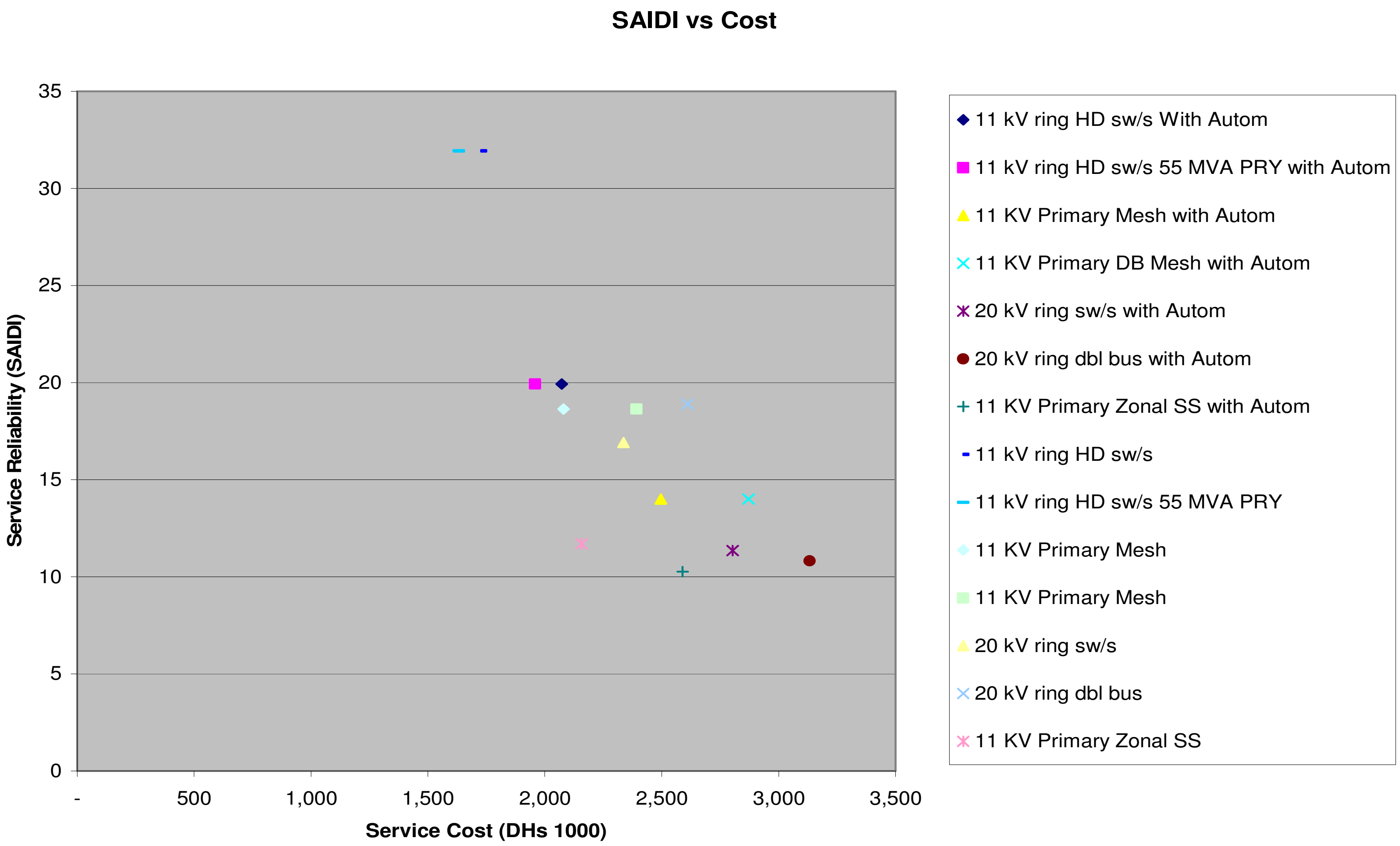


Figure 7.1 SAIDI vs Cost for Different Design Alternatives before & after Automation

7.1.1.1.Improvement Over 10 Years

Figure 7.2 is a comparative summary for the ten year different design operational performance before and after introducing DMS and GIS technologies. The graphs show that regardless of cost expenditure the automation of distribution system is improved. At end of planning period, the 11kV zonal design option gives the best among all other alternatives. Also, the 11kV ring system shows a very high value for the service interruption duration when compared to the other alternatives, in particular when compared to the 11kV zonal design option.

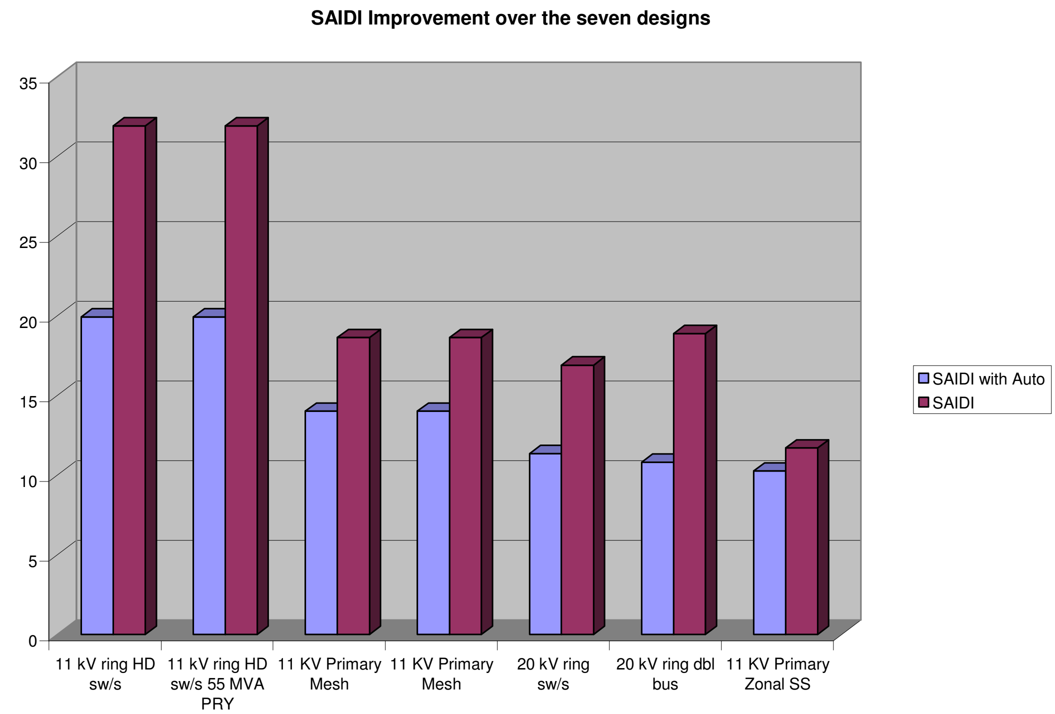


Figure 7.2 SAIDI Improvements Comparison at End of Study Period

The same Figure 7.2 shows that SAIDI values of 20kV double bus bar option and 11kV ring of 40MVA and 55MVA power transformers options have increase mainly because this index express the duration of service interruption and in these

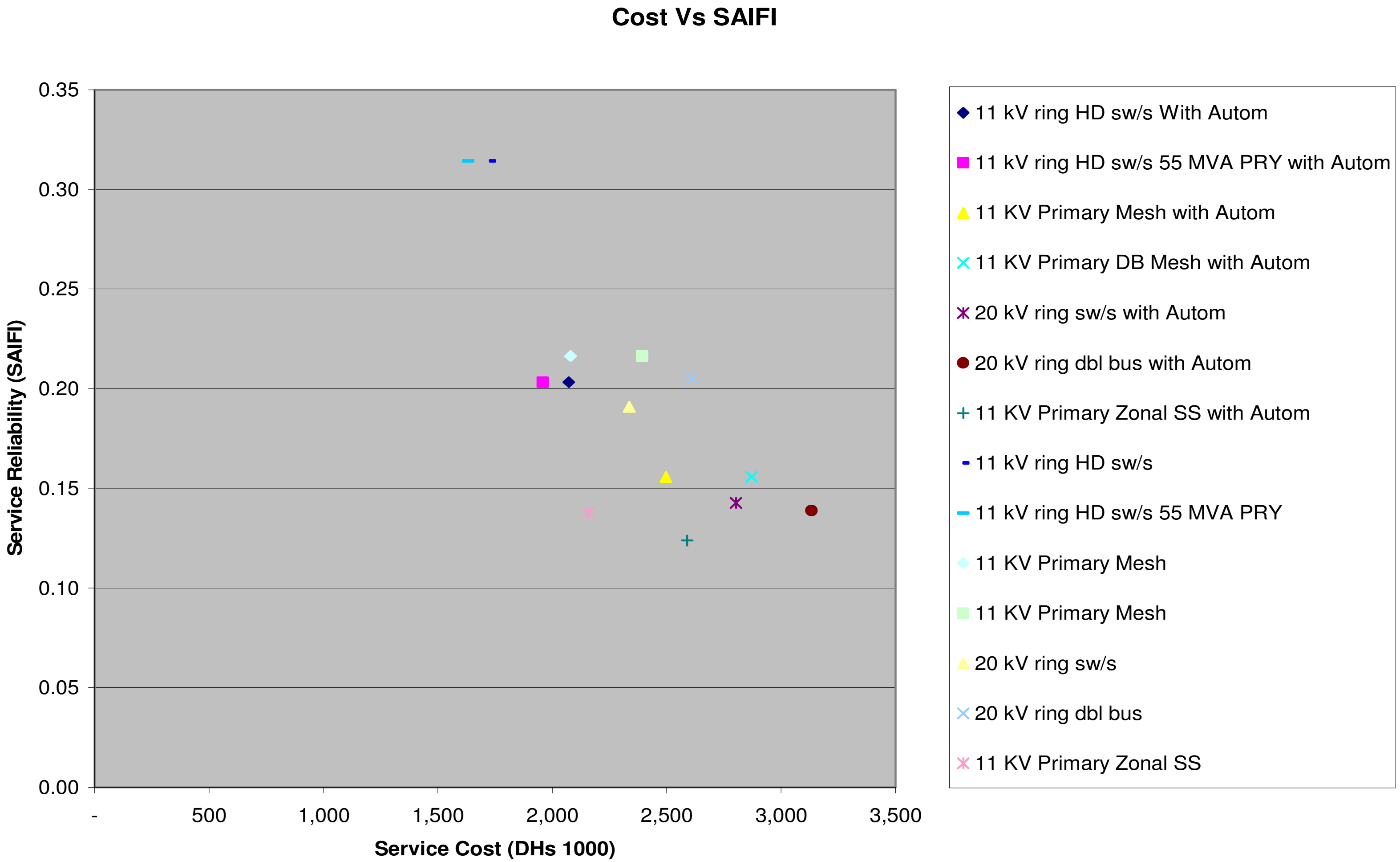


Figure 7.3 SAIFI vs Cost for Different Design Alternatives before & after Automation

designs the instantaneous alternative feedback does not exist, therefore, the automation with the load increase did help in improving this index.

7.1.2. Service Interruption Frequency Index (SAIFI) Improvements

Similarly as in previous section, the values for SAIFI versus cost also show improvements after introducing the new technologies as in Figure 7.3.

7.1.2.1. Improvement Over 10 Years

Examining the same index at the end of study period however for the seven designs reveals Figure 7.4.

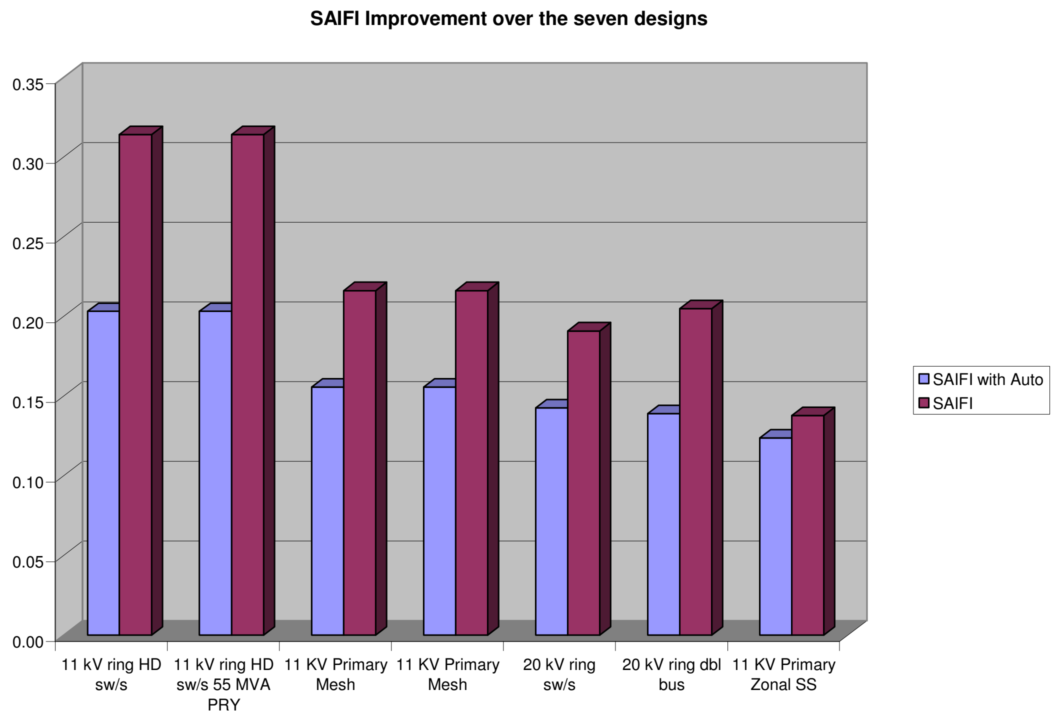


Figure 7.4 SAIFI Improvements Comparison at End of Study Period

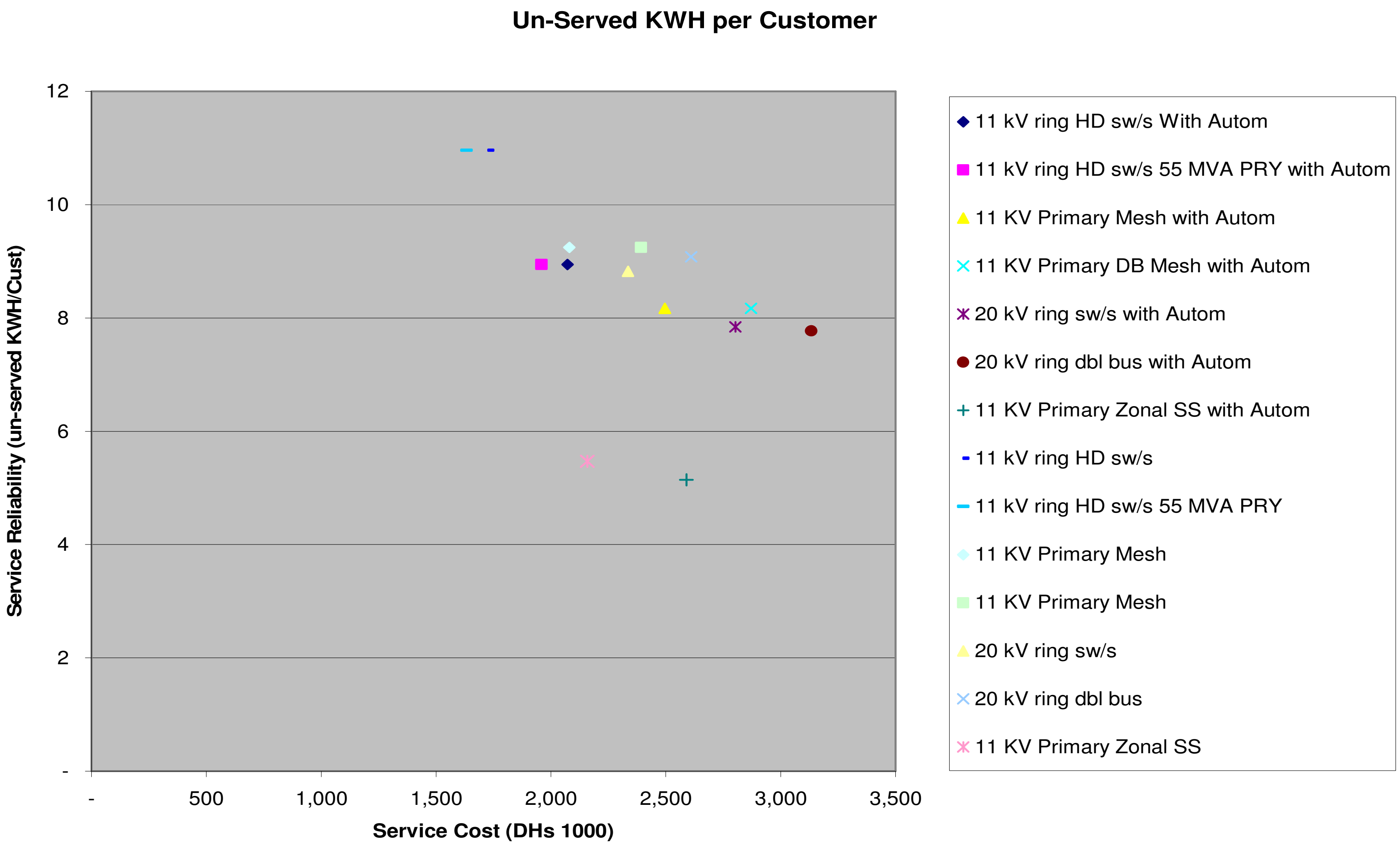


Figure 7.5 Un-served KWH per Customer vs Cost for Different Design Alternatives before & after Automation

7.1.3. Energy Loss Index (un-served KWH per customers) Improvements

Un-served KWH per customer versus cost values exhibit similar trend among the seven designs, the impact of the new technologies is clearly shown in Figure 7.5

7.1.4. Service Delivery Cost Savings

Results of spreadsheet tool also present service delivery cost for each design alternative with no consideration of automation. Figure 7.6 reflects the Net Present Value of expenses for both capital and operational costs for the seven design alternatives. The results show that 20 kV design with double bus bar is the highest, followed by the 11kV zonal design, and 11kV switching station 55MVA power transformer is the lowest, where the present ADDC system, that is the 11kV ring design with 40 MVA power transformers, is second less costly design.

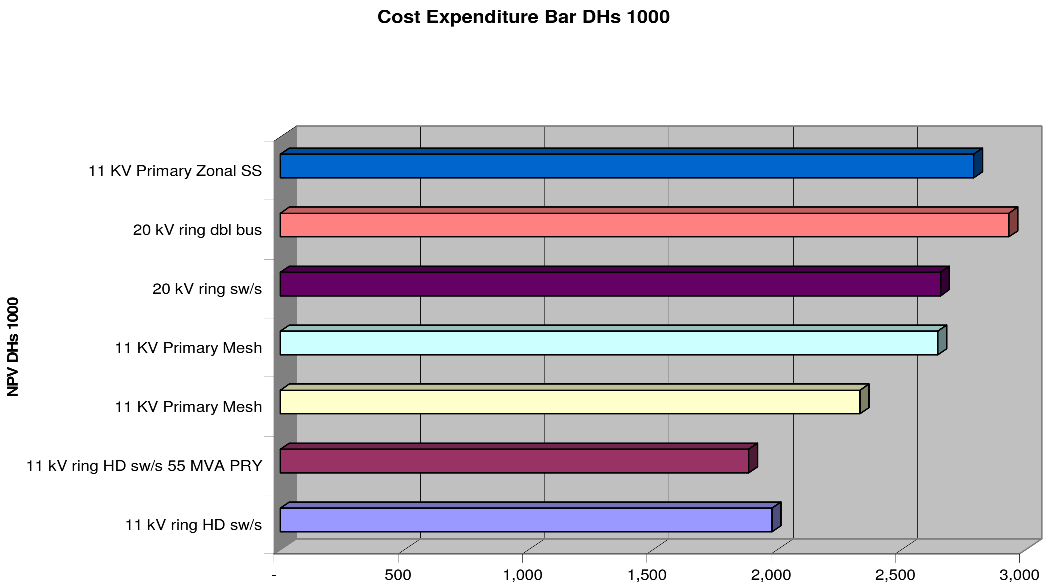


Figure 7.6 Cost Expenditure for Different Design Alternatives before Automation

Figure 7.7 shows similar results even with the introduction of new technologies. The comparison of system performances over the ten years for the seven design alternatives regardless of cost expenditure is illustrated. It is obvious that the 11kV zonal design option gives the best among all other alternatives for both SAIDI and SAIFI indices. This by it self is a starting point that gives ADDC management enough

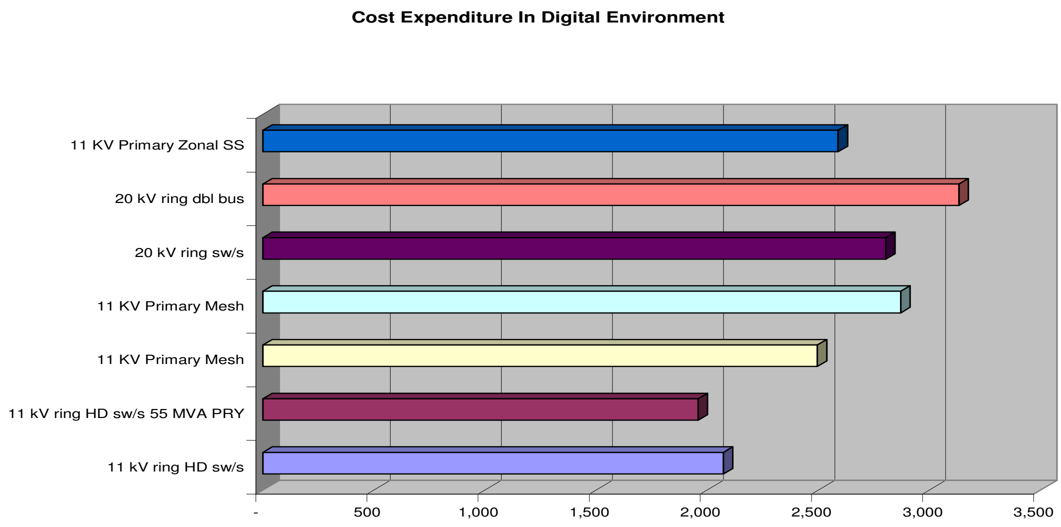


Figure 7.7 Cost Expenditure for Different Design Alternatives in Digital Environment.

initial justifications to further investigates this subject. Additionally, one remarkable outcome of this report is that, is that the 11kV zonal design option improvements are achieved actually with relatively no cost implications at all, as in most of designs, the infrastructure is the same and automation impact really have enhanced system reliabilities. Above Figures prove that new technologies have no cost impact on system expanding neither system operation nor system maintenance. This is clearly exhibited in Figure 7.8.

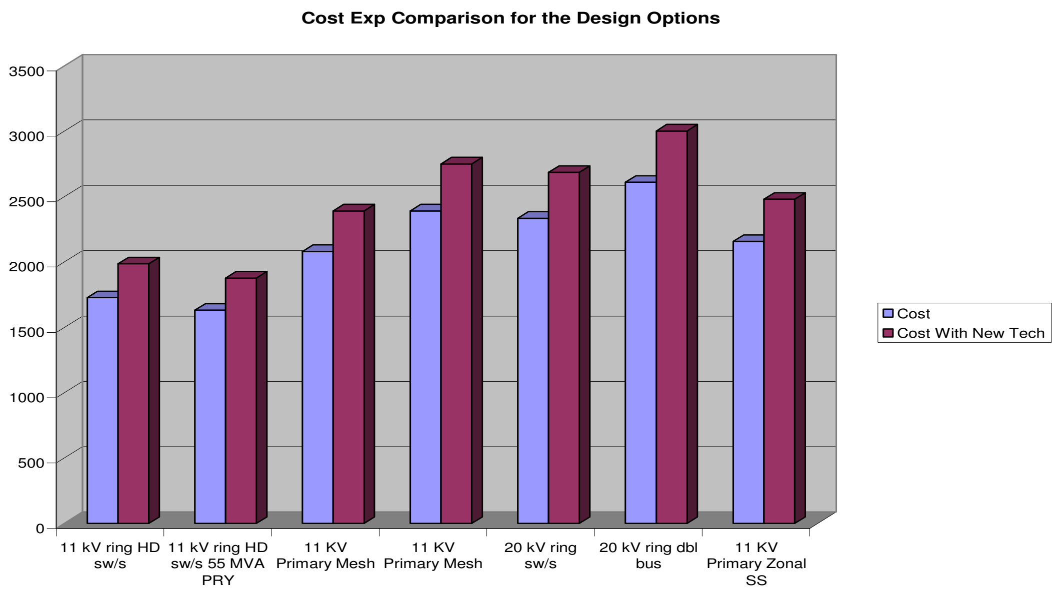


Figure 7.8 Cost Expenditure Comparison in the Different Design Alternatives

8. CONCLUSION AND RECOMENDATIONS

8.1. Conclusion

In general, this research examined the power sector's network structures, environments and constraints and related these factors to performance metrics represented by system reliability and service delivery costs. The research also demonstrated the benefits from the use of GIS and DMS technologies on the reliability indices as well as the service delivery costs.

The research focused on ADDC as real example in examining it planning strategies and the potential enhancements in its distribution network performance from the use of the GIS and DMS technologies. The developed Decision Support Model which includes effect of integrating the two technologies on the performance of the network distribution system will assist the Asset Management System (AMS) team at ADDC to properly plan for the anticipated future demand growth in the Emirate of Abu Dhabi and to balance between the investment capital requirements and the desired reliability levels.

This thesis managed to develope a new modeling technique for network palnning by incorporating GIS and DMS advanced functionalities by using Delphi Method and reformulating basic functional requirements. Where in the Delphi technique, thee research estimated the expected improvements from the use of the GIS and DMS on the electric distribution system performance indices. Those technologies are already available at ADDC and the company will not incur additional cost for its acquisition, the only additional investments will be on the enhancement and customization of the technologies to suit ADDC's network distribution system. Seven alternative network distribution designs were evaluated and their performance indices were compared before and after the integration of the GIS and DM technologies.

The results of the research demonstrated clearly that application of the GIS and DMS will have a major positive impact on the system's performance indices. The Decision-Support Model showed that the 11kV ring with 55MVA power transformer design option and the 11kV zonal design option are the most optimal designs. If the GIS and DMS technologies are to be implemented, these two designs will achieve the best possible system reliabilities with reasonable investments because as most of the designs incorporate the cost of GIS and DMS within the cost of designs implementation.

All seven design alternatives were investigated further in order to validate the choice of the optimal design if actual peak demand growth rate as well as the projected inflation rate would be different than the values assumed in developing the optimal network design. Pareto-optimal design sensitivity analysis was performed for different future levels of inflation and peak demand growth rate. The results of the sensitivity analysis showed that the choice of the Pareto superior alternatives will be the same even if either inflation or peak demand increased/decreased by 50%. However, the cost will increase for all the designs by 6% except the zonal design where the increase is slightly less at 5%. This means that in general the anticipated load increase resulted in a noticeable push up in the over all system capital and operational development costs, however, the push in the 11kV zonal design was the least and therefore it is the best option ADDC should consider as a strategic direction to move toward. It is worth noting that that the 11kV zonal design in this research view is the best alternative for ADDC because it overcomes the restrictions imposed by Transmission Company formation of the up stream network. In this structure, ADDC can be more flexible to those changes in operating as well planning its network regardless of the number of islands proposed by them.

In conclusion, the results of this research ADDC's current network design will not serve its purpose to meet future demands if the peak demand load is higher than the one forecasted. In this case, ADDC will have to invest more capital for a small gain in system's reliability. However, the developed model provides better strategic options for the decision makers at ADDC to adopt. These options are the 11kV ring with 55MVA power transformers and the 11kV zonal design. The first option achieves the same reliability as the current system applied now in ADDC but with lower costs in the long run while the second option achieves better system reliability at the forecasted inflation and peak demand growth rate as well as if the actual forecasts differ than projected even by +/- 50%. It is worth noting also that the 11 KV zonal design will also resolve the complications for ADDC from the restrictions imposed by the transmission company (TRANSCO) on its network operation. This will not be resolved if the other designs are adopted.

8.2. Recommendations

Based on the findings of this research, it is highly recommended that strategic planners at ADDC should consider integration of the GIS and DMS technologies in its electric distribution operations since the estimated improvements due to such integration on performance indices are significantly high and the cost of implementation is relatively modest. Moreover, based on the results reported in this investigation for the achievable reliability indices and the associated cost of each design option available to ADDC, the option of the 11KV zonal design should be adopted. It is worth noting that the 11KV zonal design will remain to be the best feasible selection among the available options whether or not the GIS and DMS were to be implemented by ADDC in the future.

In addition to providing the best balance between the distribution system's reliability measured by SAIFI and the SAIDI indices and the cost, the 11 KV zonal design is expected to solve the restrictions and constraints on ADDC since this design allows ADDC's distribution system to be independent of TRANSCO defined operational zones which are not fixed and are subject to change in the future. This thesis recommended immediate implementation of these findings in ADDC planning practices.

VITA

Aseya Mohammed Al Haddabi was born on 1975. She was educated in local public schools and graduated from United Arab Emirates University in Al Ain in 1999.

Ms. Al Haddabi joined Abu Dhabi Distribution Company (ADDC) in 1999 as a trainee, and made her way up in the company where she is working now as a Senior Strategic Planning Engineer in the Power Network Division.

She began her higher studies in 2004 as she enrolled in the American University of Sharjah (AUS) as a student in the Engineering Systems and Management program (MESEM) and graduated in June 2006.

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APPENDIX A

NETWORK STRUCTURS

Figure A-1 11kV ring 40MVA Transformer network

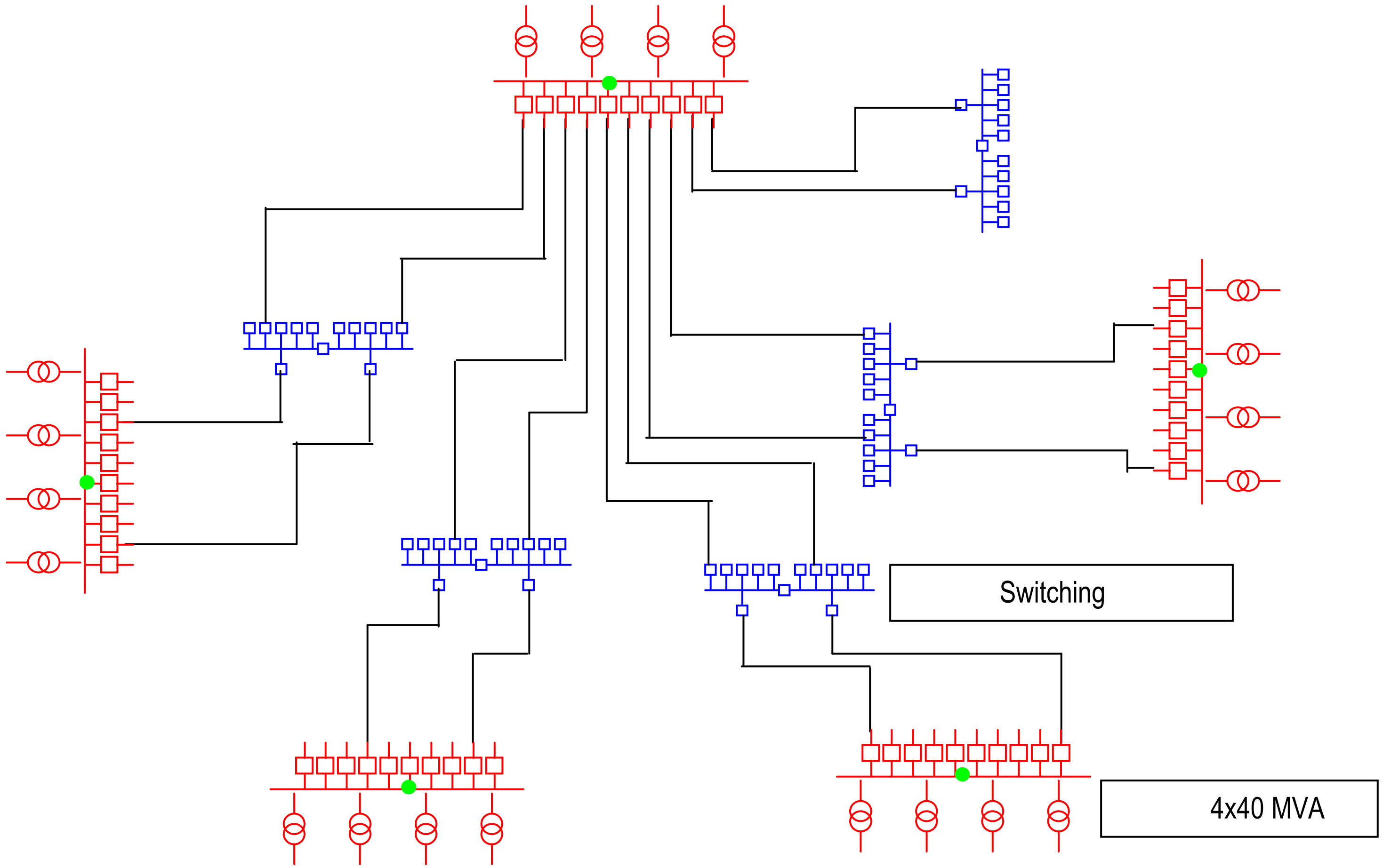


Figure A-2 11kV ring 55MVA Transformer network

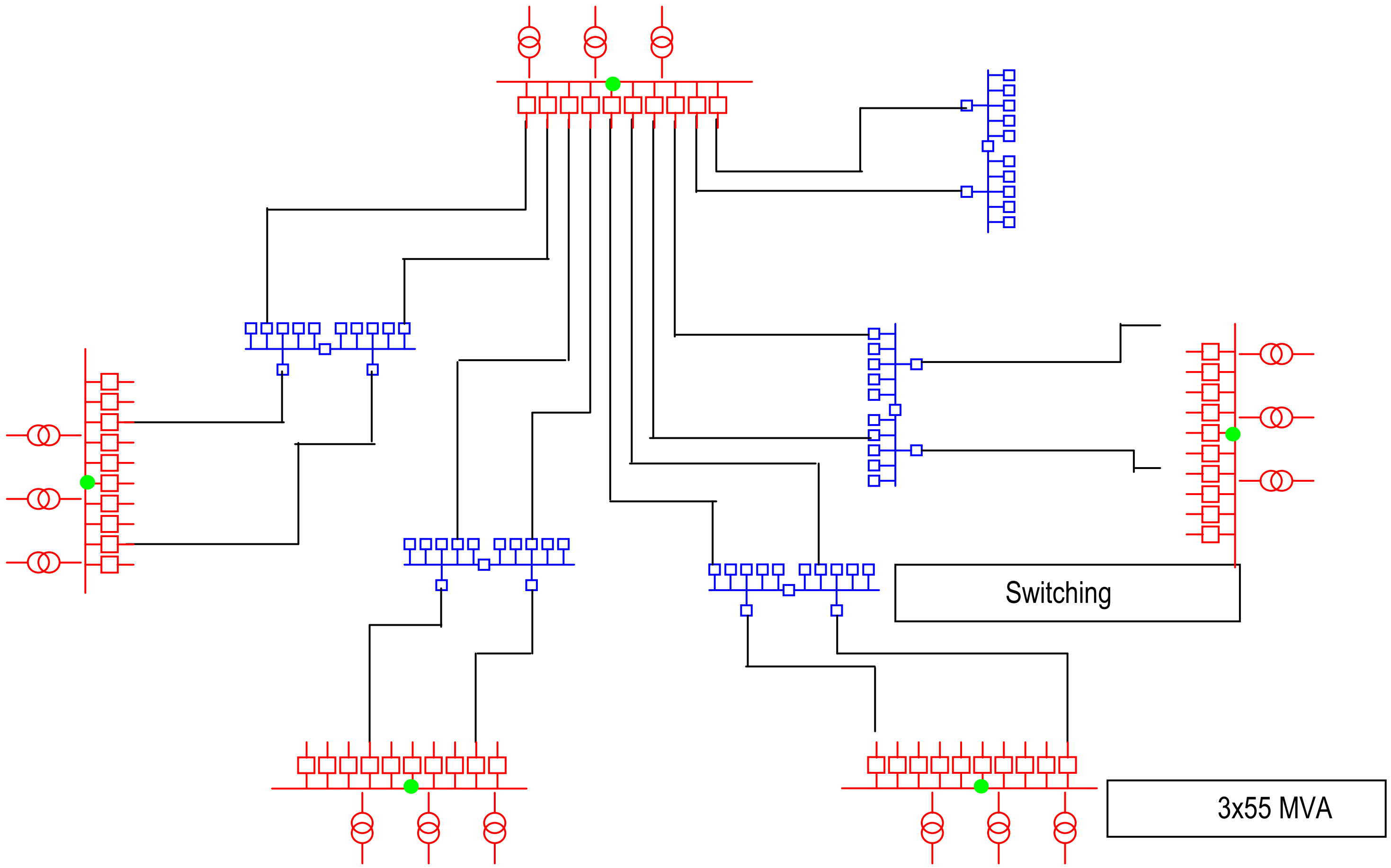


Figure A-3 11kV mesh network

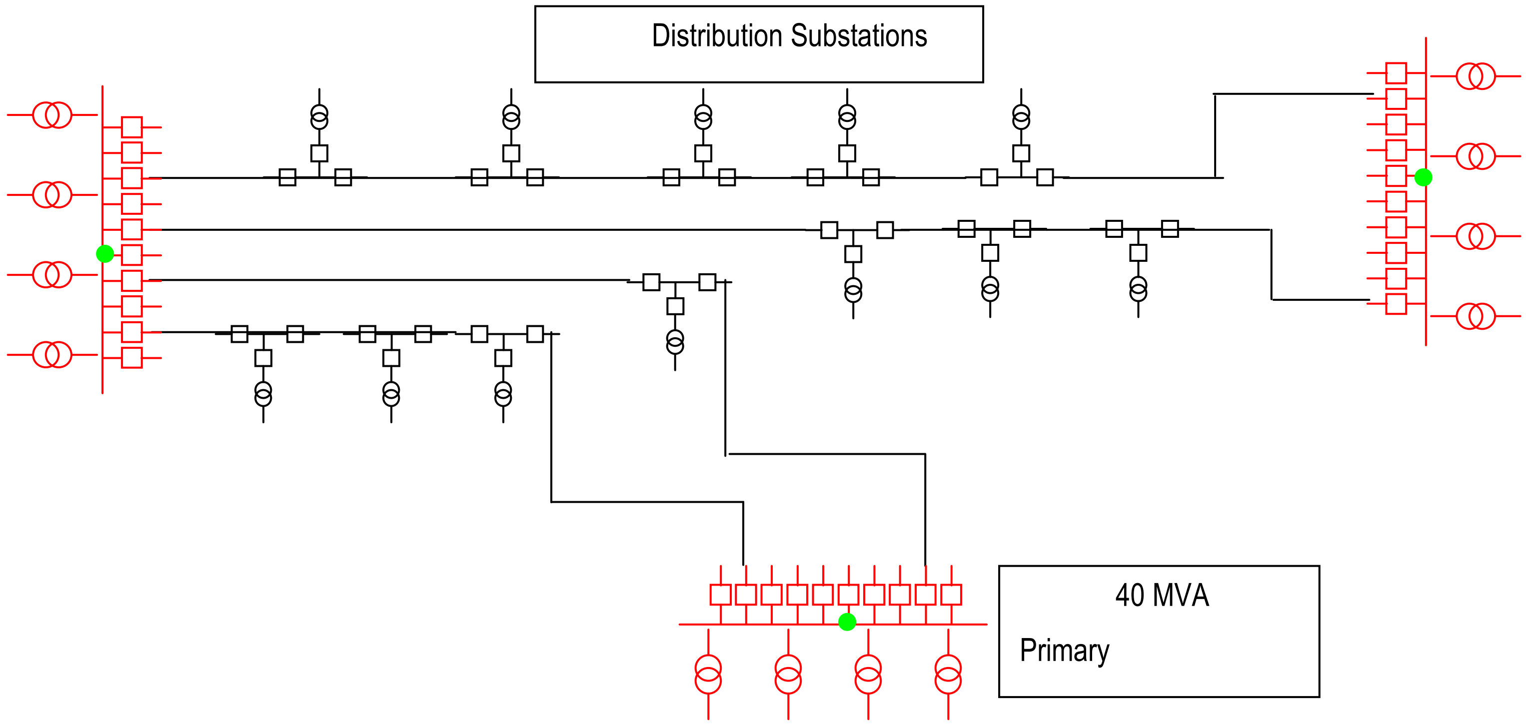


Figure A - 4 11kV mesh Double Bus bar network

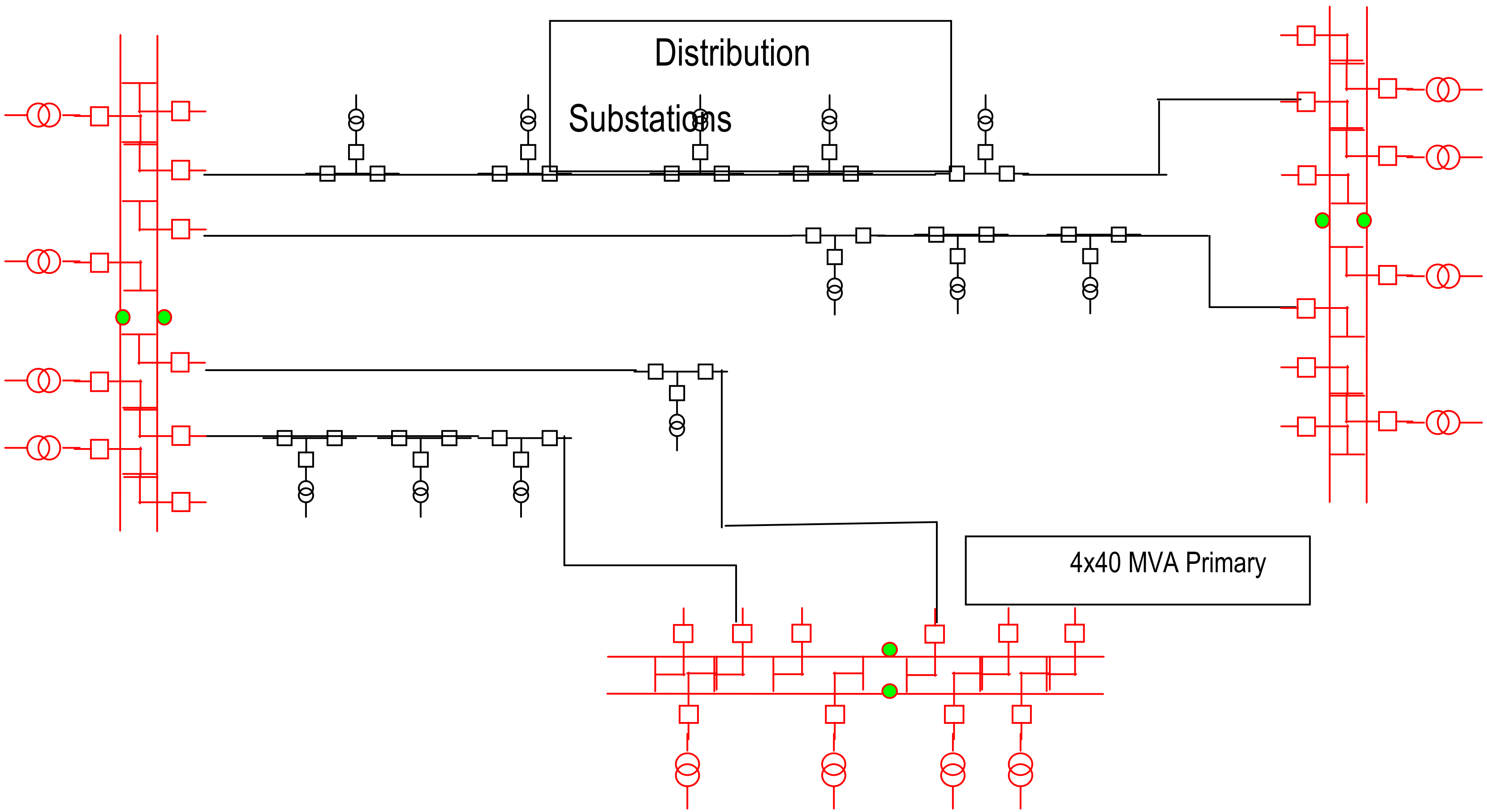


Figure A- 5 20kV ring network

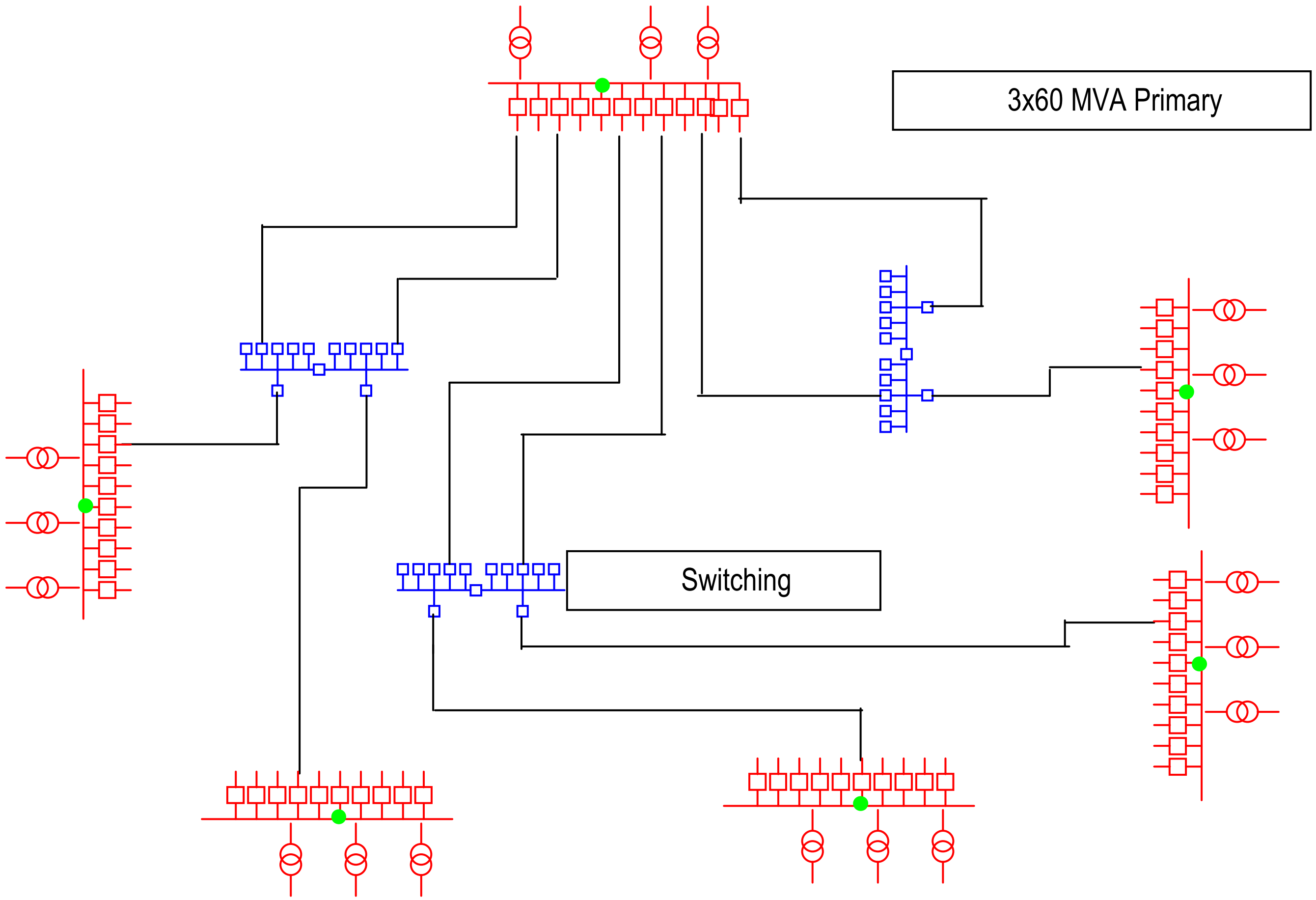


Figure A - 6 20kV ring Double Bus bar network

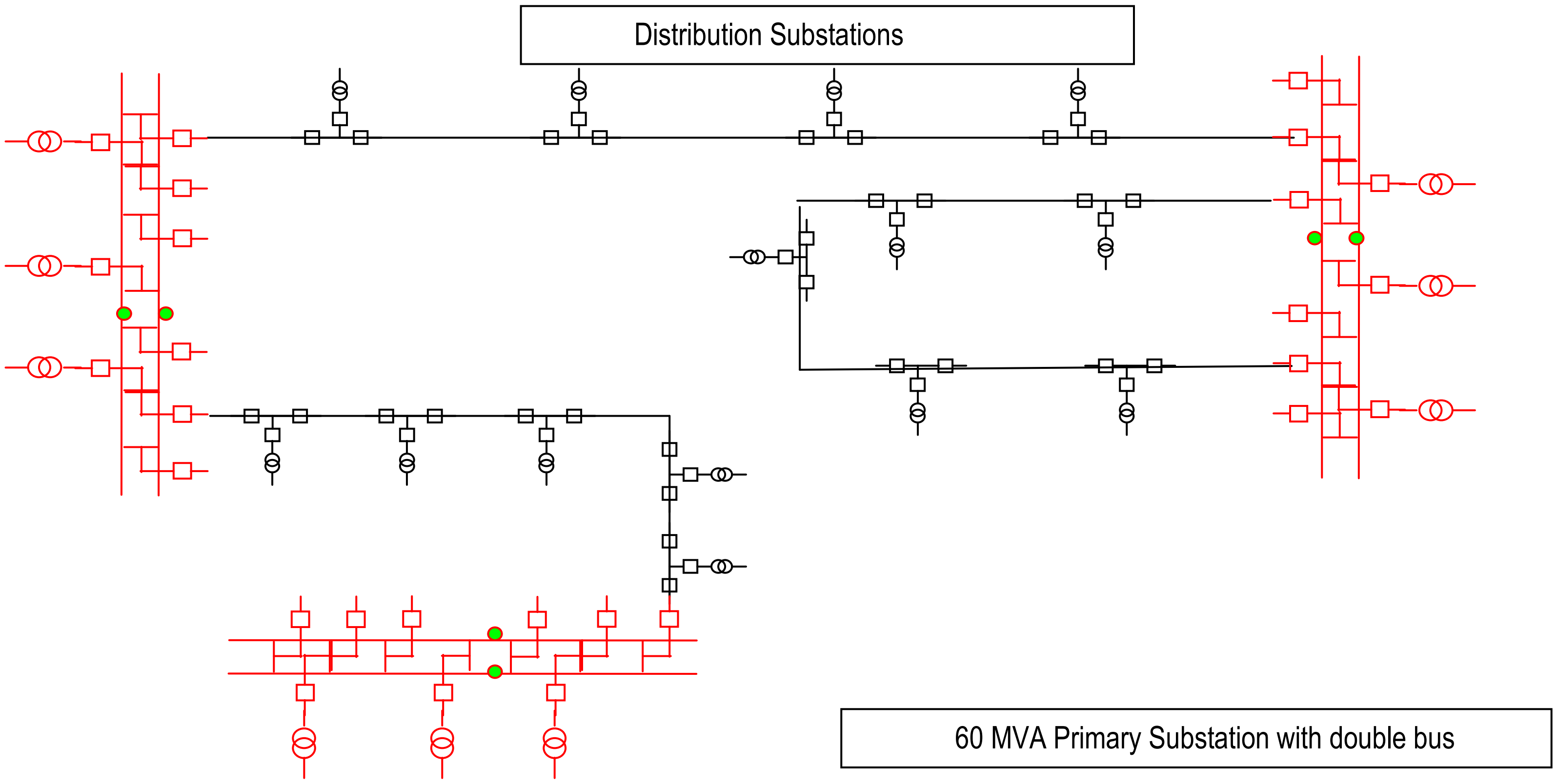
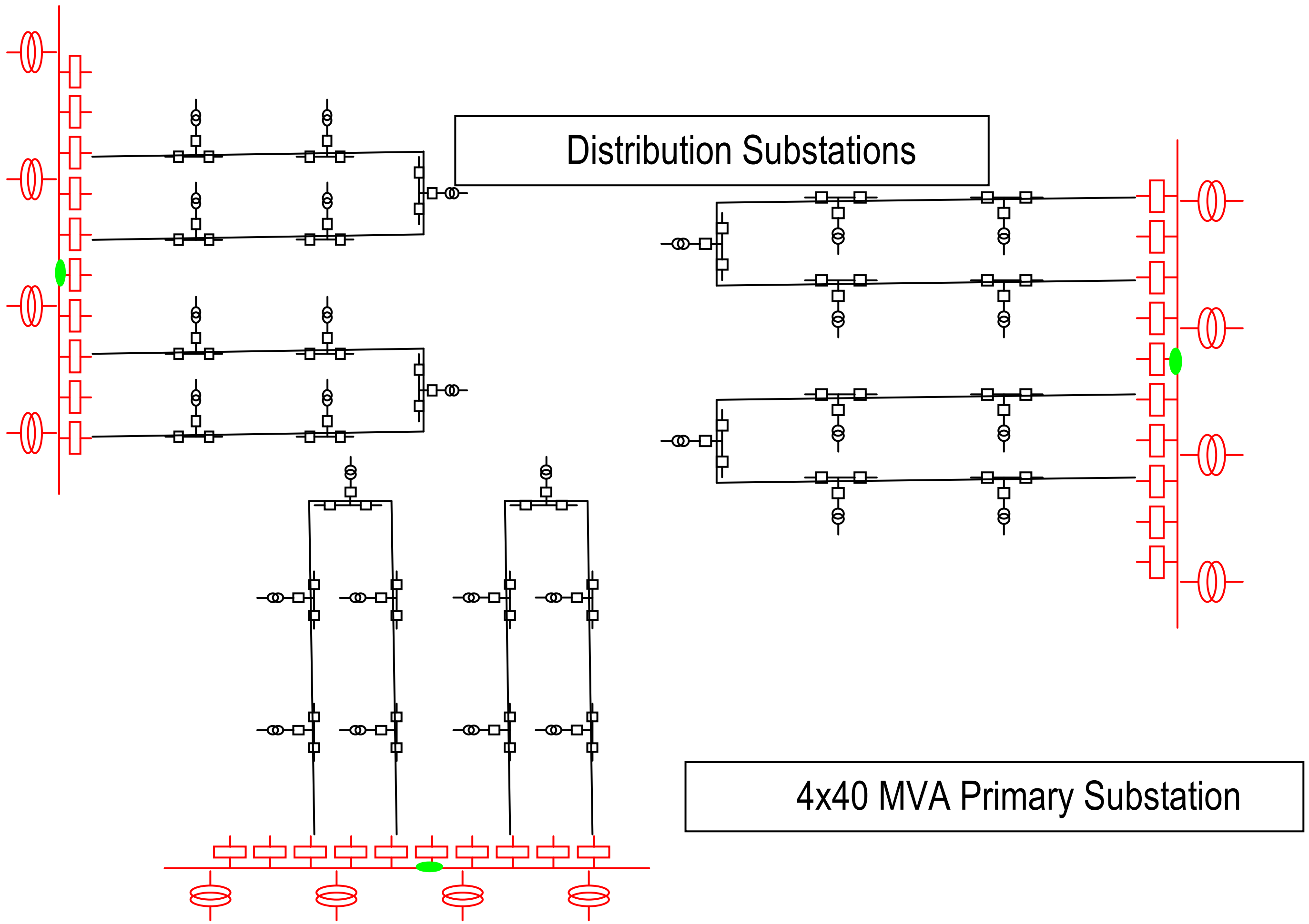


Figure A - 7 zonal design network



APPENDIX B-1

GIS & DMS FUNCTIONS

Table B1

Tech	Category	Function	Description	Impact	Remarks
GIS	Engineering Analysis	Visual Modeling load per customer categories	Displays spatial representation of customer types	Impact the network design application, such as Spatial Forecasting Visually	Dependent on GIS Load Forecasting
		Connectivity and network tracing	Trace the network up to NOP or up to specified flag by system user.	Results are used as inputs to applications of Network reconfiguration as well as Network design.	
		Loop detection	Trace the network up to NOP or specified flag	Results are used as inputs to applications of Network reconfiguration as well as Network design.	This is a dependent function on Connectivity and network tracing function.
		Multi or not energized objects detection	Identify the Multi or not energized network component.		Similar to Connectivity and network tracing function, with one additional output for status of cable.
		Spatial Forecasting Visually	Land-use spatial load forecast simulation methods are used to model the process of the load growth in order to predict load evolution in a spatial and temporal basis	Generation of continuous and stationary maps of potential-to-development and potential-to-decline which leads to generation of scenarios for development.	Can be used as bases for operational load forecasting
DMS		Fault Calculations	The Distribution Short Circuit Calculation (DSCC) function is designed to compute the fault level by type of faults in determining the protection devices capacity and its relay performance. This function is mainly suited to a distribution network, particularly in the design of radial or weakly meshed configuration.	The violation of the ratings will be identified and provided in the fault violation lists. This function is conducted either in the real time or study case mode, both of which reside in the relational database. By using the real time case, the operators are able to assess the limitation of the settings of any protective devices and coordination among them, to check if there are any excessive fault currents over the limit of device ratings. Whereas, the study case mode are intended for the use against hypothetical conditions that may results from "what-if" scenarios, such as the status of system protection after feeder reconfiguration.	This function improves System performance. It consider several aspects of analysis in this function as fault types, fault location selection, short circuit ratings at protective devices, as well as its maximum and minimum fault current contributions. It is to calculate the fault currents to assess the limitation of the settings of related protective device. This is then stored in the violation list, if there is any, against the limitation defined. It should be noted that DSCC is not meant to determine the settings of protective devices or to examine coordination among protective devices, but to check whether the system is properly protected by current trip settings.

Table B1

ech	Category	Function	Description	Impact	Remarks
	Engineering Analysis	Energy Loss	Estimate the total energy losses of technical and commercial losses by computing the technical losses from the results of the network analysis.	For optimal location of new sub-stations and augmentation of the existing facilities, several alternatives, subject to their meeting the agreed planning criteria, will be evaluated on basis of the capital cost of equipment and work and net worth present worth of the energy losses over the total horizon period. The plan objective will be the minimization of losses while maximizing the net benefit i.e., the present worth of loss reduction less the annual cost of capital investment. The cost estimates will be based on the prevailing market rates for each item of equipment and work.	Once feeder-wise energy losses are established, feeders having high-energy losses should be further investigated for localizing pockets of high-energy losses by installing energy meters after distribution transformers.
		Reliability Analysis	Display data extracted from DMS database.	Reliability indices calculated from DMS studies of Performance indices module	
		Short Term Load Forecasting	The Short Term Load Forecast function (STLF) is to calculate the global load (power system load) for the future hours and days (two weeks). Power system load is the sum of all individual demands distribution network global load. Each demand or usage pattern is random from the point of view of the computer system. Due to the unpredictability and the diversity of the individual demands, power system load cannot be calculated exactly by extrapolating the estimated individual demand usage patterns. But the totality of the individual loads results in a distinct consumption pattern which is predicted with statistical methods	To derive the load curve data for a distribution transformer load, the Load Modelling feature supports the usage of generic load curves for up to ten load types. These load types are: ■ Residential ■ Commercial ■ Industrial ■ Agricultural ■ Other Each generic load curve is a hourly profile over several seasons and day types. The number of seasons and day types can be configured for each DMS installation.	The system load behaviour is general influenced by: Economic factors, long time trending, time factors, seasonal trending, day type (Monday, ... Sunday), state and religious holidays, weather effects, temperature (the most significant single factor), light intensity, number of daylight hours, humidity, other weather factors, special events, strikes, shutdown of facilities, TV programs, unexpected events, load reduction due to failure of network part
IS	Project Management	Project tracking	Tracking of tasks and subtasks in project chart	Cost impact on design, cost of contracting works follow-up	
IS		Project design	Scheduling new designs	Budget allocation	

Table B1

Tech	Category	Function	Description	Impact	Remarks
DMS		Outage Scheduler	The Outage Scheduler (OS) gives the dispatcher a comprehensive view of affected equipment that helps avoid outage conflict and keep outages to a scheduled minimum. Affected equipment includes switching devices, feeders, transformers, and capacitors. The OS schedules outages for planned maintenance of distribution equipment. An outage schedule is a list of devices that are scheduled to be taken out of service. There can be one or more device entries. Each entry contains: device identification, outage start time, outage end time, and other pertinent data. The dispatcher can create or modify outage schedules for up to two months in the future. Up to 1000 device schedules can be stored. Other applications besides OS can access OS schedules.	avoid outage conflict that might happen among different parties like O&M, T&P, and Construction projects and keep outages schedule to its minimum	
GIS	Planning	Network reconfiguration	The Feeder Reconfiguration function determines switching actions which allow the operator to reconfigure distribution primary feeders. Through feeder reconfiguration, loads on one feeder are transferred to another feeder, resulting in changes in feeder voltage profiles, line and transformer loadings, etc.	Operator can eliminate adverse operating conditions such as line/transformer overloads and low voltages that customers may experience. Feeder reconfiguration can also provide operating benefits such as reduction in distribution system losses.	The types of benefits that can be obtained from feeder reconfiguration may be classified into tangible and intangible benefits. Improvement in service quality and reliability may be an example of intangible benefit. In the Feeder Reconfiguration function, only tangible benefits are dealt with. Specifically three types of objectives (benefits) are supported by the Feeder Reconfiguration function. They are: Removal of constraint violations, Load balancing among supply substation transformers, Minimization of feeder losses To consider load balancing and loss minimization objectives simultaneously, the value of each objective function is per-unitized and weighted by user-specified weighting factors. System operational constraints such as line loading and customer voltage limits are automatically accounted for within the model

Table B1

Tech	Category	Function	Description	Impact	Remarks
GIS		Network design	Edit mode for planners	Based on inputs from Visual Modelling load per customer categories, Right of the way, Last mile planning	For new schemes and projects, this function is dependent on the data accuracy of Right of the way and Last mile planning inputs
GIS		Refurbishment	Asset replacement plan, asset utilization	Database contains equipment historical data that can be utilized in defining depreciation rate for system components as well as payback period for every investment.	
GIS		Right of the way	To extract land base from latest database of city planning authority with regard to allocated corridors for different services		Information extract
GIS		Last mile planning	To extract land base from latest database of city planning authority in regard to up to date town plans	Better last mile planning and better cost control of the project execution	Information extract
GIS/DMS		Capacitor Placement	Optimal Capacitor Placement (OCP) is a real–time application that uses your historical system data to optimize your network configuration by exhaustively testing alternate locations for capacitor banks on feeder lines. Since changes are not implemented until you have determined the best possible combination of important network factors, you can perform a complete analysis without compromising the real–time operation of your network. OCP dynamically minimizes feeder losses when capacitor bank voltages and power factors must be maintained within specific limits. It allows you to specify the capacitor banks based on whether they are moveable or non–moveable. You can also determine if a network bus must be located with or without a capacitor bank. OCP then determines the optimal location and on/off status required to meet the optimization objective.	Problem allocation on network segments	OCP performs at any scale you need, from feeder to full–scale network. But regardless of the scope of your study, OCP operates in the same way. It performs an exhaustive search evaluation of each feeder in the network. Utilizing a simplified load flow algorithm, it evaluates every possible capacitor bank location to find the optimal location to minimize energy loss without causing overloading and voltage violations in the normal feeder configuration. Starting from the initial locations of all the candidate capacitor banks, OCP selects one capacitor bank to relocate, starting at the feeder breaker, and tries every available network node down to the feeder end to see if there is any improvement.

Table B1

Tech	Category	Function	Description	Impact	Remarks
DMS	Monitoring tools	State Estimation with Load Estimation	Load Estimation (LE) estimates individual loads on a feeder based on load classes, load type, load curve, and load measurements. • The Load Class specifies the nature of a load, such as residential, commercial, or industry load. It is used to divide the feeder load into several components, each of them having the same nature or class. • The Load Type specifies the characteristics of a load in terms of its relationship between its real and reactive power. There are two different load types: conforming and non-conforming load. A conforming load uses power factor as a fixed ratio between its real and reactive power; while in a non-conforming load, its real and reactive power are defined by its "load versus time" curves respectively. • Load measurements are telemetered load values through the SCADA system. They can be either an individual load measurement or a branch load flow measurement. Calculate the voltage at each node, load on each feeder, as well as setting up contingency plans	Results can be used as inputs to optimization of NOP.	individual loads on each node are calculated by two methods: • Static Load Estimation (SLE): individual loads are identified through the ownership between loads and the feeders carrying those loads. Dynamic Load Estimation (DLE): the real time branch flow measurements are used to adjust load values obtained by static load estimation to produce a dynamic load estimation

Table B1

Tech	Category	Function	Description	Impact	Remarks
DMS		Load Flow	The *Distribution System Power Flow* (DSPF) is used to study electric power distribution networks under different loading conditions and configurations	(DSPF) includes the following features: ■ Real-time DSPF, which provides the operators with kW, kVAR, kV, Amp on the present state of the distribution network. The current electrical connectivity information is derived from the SCADA database It executes periodically and upon any change in the distribution network affecting the results as well as on operator's demand, such that it reflects the actual state of the distribution network. ■ Study DSPF, which provides the operators and planners with kW, kVAR, kV, Amp on the distribution network, not necessarily reflecting its actual state. It uses "what if" scenarios. A number of saved cases are available to store input parameters and results, which can be retrieved to be used as input base cases for further scenarios that are executed upon demand.	
DMS		Performance indices	measures are: 1. Total harmonic distortion (THD): The ratio of the RMS value of the sum of the individual harmonic amplitudes to the RMS value of the fundamental frequency 2. K factor: The sum of the squares of the products of the individual harmonic currents and their harmonic orders divided by the sum of the squares of the individual harmonic currents 3. Crest factor: The ratio of a waveform's peak or crest to its RMS voltage or current 4. Flicker: A perceptible change in electric light source intensity due to a fluctuation of input voltage. It is defined as the change in voltage divided by the average voltage expressed as a percent. This ratio is plotted vs. the number of changes per minute to develop a "flicker curve."	Reliability indices typically consider such aspects as: the number of customers, the connected load; the duration of the interruption measured in seconds, minutes, hours, or days; the amount of power (kVA) interrupted; and the frequency of interruptions.	

Table B1

Tech	Category	Function	Description	Impact	Remarks
DMS	Dispatching tools	Under-load switching	The *Free Placed Jumpers, Grounds, and Cuts* (JUGCUT) function is a way for a dispatcher to easily make temporary changes to a world-map that reflect changes to the network made in the field. These changes could be either planned such as a lineman doing maintenance work or unplanned such as a tree falling and breaking a power line.	This feature allows an operator to change the network model to show a feeder being cut, grounded, or attached (jumpered) to another feeder. When the repair is completed, the change can be backed out and the network model returned to its original state. These changes can be made without a formal SDM editing session to modify the database. The Jumpers, Cuts and Grounds function is intended for use on real-time displays. This function is not available during Study Case.	The JUGCUT function can be used to add the following changes to a world map: _ Cut This is used to indicate a break in a feeder which could occur from any number of causes. A line could break from natural causes such as ice or a tree falling or a line could be purposefully cut or disconnected by a lineman performing maintenance. _ Ground This is used to indicate that a lineman attached a jumper wire to a feeder or a busbar and then grounded the other end. _ Jumper This is used to indicate that a lineman attached a jumper wire to a feeder or busbar and then attached the other end to another feeder or busbar. This function is commonly used in overhead line networks.
DMS		Switching sequence management	The Feeder Reconfiguration function determines switching actions which allow the operator to reconfigure distribution primary feeders. Through feeder reconfiguration, loads on one feeder are transferred to another feeder, resulting in changes in feeder voltage profiles, line and transformer loadings, etc.	For the operator in the dispatch center the results of the IAP in the SCADA system are represented as report list and may be additionally displayed graphically in the network overview displays. E.g. a fault at a line causes setting a graphical tag of type “disturbed” at the UI. Resetting this tag can either be done like resetting any other tag manually in the network image or by switching on the tagged operational device again.To enable this kind of representation, the single line diagrams have to be designed for it separately. The results are displayed in the report list.	Output of both switching functions as well as IAP Optimal Switching (OSw) programmatically analyzes the system and recommends changes in order to optimize the network operation. Its operation does not affect the real time operation of any other functions.

Table B1

Tech	Category	Function	Description	Impact	Remarks
DMS	Optimization Tools	Network reconfiguration	Network operations in a distribution network are normal day and emergency operations which change the network topology. Within conventional environments the changes always involve some risks for the operator, because of the complexity of the system and the huge amount of data which have to be considered. Thus dangerous situations or even blackouts may be caused by network operations and thereafter great efforts under stress situation have to be done to get out of all the difficulties.	Emergency operations are caused by external events like climate irregularities (e.g. thunderstorms, storms, snow, ice, flooding, etc.), outside works, accidents, etc. In such a case the operator is confronted with a completely unexpected situation, which he has to manage in a correct manner in a short time. The Advanced Network Operation System (ANOP) is a system which performs the network operation for normal day and emergency operations by creating complete switching sequences automatically for the particular situations and therefore • avoids critical situations • assures safe network operation • avoids stress • gives complete assistance when unexpected critical events occur. • shortens the consumer outage time	Linked to network switching functions
DMS		Relay Protection	Intelligent Alarm Processor (IAP). This expert system is integrated into a SCADA system for power generation, transport and distribution networks. The purpose of the IAPis to perform an immediate evaluation in case of a disturbance within a few seconds, in order to provide the operator with sufficient information about the nature and the consequences of the disturbance. With this result it is easier for the operator to decide, how to proceed: either remove the problem or avoid getting into a worse situation.	The Intelligent Alarm Processor provides information about the kind of the fault, fault location and possibly a failure of protection devices after a network disturbance, as well as an explanation of its consequences. The IAP is based upon an hierarchical, multi-level problem solving architecture, which combines model based and heuristic techniques and works with an object-oriented data structure. The expert system, which is operating in a real-time environment, covers processing of the incoming real-time data, intelligent alarm processing, as well as automatic creation and updating of the knowledge base. The expert system forms an operator support system.	Protection Coordination (PCN) is an analysis application that uses a unique library of products and specifications to optimize deployment of relays, switches and other protective devices throughout your network. Since changes are not implemented until you have determined the best possible combination of important network factors, you can perform a complete analysis without compromising the real–time operation of your network. PCN gives your system operation engineers and dispatchers a way to review, edit and analyze the protective device settings of: - circuit breaker relays - automatic re-closing relays - fues

Table B1

Tech	Category	Function	Description	Impact	Remarks
DMS		Voltage Control	Integrated into a SCADA system for tap changer monitoring and adjustments.	Minimize losses through out the system especially when Distributed Generation concept is adopted into the system	

APPENDIX B-2

STUDY QUESTIONNAIRE

Appendix B -2 Delphi Questionnaire

Typically, between 30% to 50% of costs for electric Power utilities around the world are fixed in the form of debt repayments on assets such as power stations and electric infrastructure including transmission lines as well as distribution lines.

Now with the presence of the deregulated market, power utilities are being forced to explore innovation via other alternatives such as new technologies in order to achieve a competitive advantage, however, one constraint arises here and that is financing effective innovation efforts. I believe that electricity market should allow the costs expenditure to be more accurately placed by enhancing the benefit that customers and society can receive from technology innovation, specifically from system automation.

This questionnaire explores the different capabilities of Geographical Information System (GIS) and Distribution Management System (DMS) by introducing some of the functions and getting the anticipated impact those systems might add.

I would like to express my gratitude and thanks for your participation in this selected banner of experts. Your advice and experience shall be most helpful in clarifying my questions on the anticipated enhancement in the distribution system operation performance.

Again, thank you all so much for taking time from your busy schedule to attend my questions.

Example of suggested functions:

<u>Engineering Analysis:</u>

1. Spatial load forecasting for long term planning, Short term load forecasting for operational purposes, Visual representation of customer categories: these three functions complete each other as planner can extract from GIS temporal load evolution that is subdivided as per the different customer classifications known within the utility such as residential, agricultural, industrial as well as public and VIP areas, therefore, proper planned configuration suited to each category is reached. The output of that information is certainly very vital for DMS engineer daily and short run operational planning.
2. Electric circuit tracing on GIS for live or not energized feeders: one can look at it as a complementary task for geographical representation and forecasting above. It is an easy way to expand, reconfigure or even arrange the contingency plans for anticipated emergency situations.

3. Short circuit and Fault calculations for network characteristics settings as well as reliability analysis system over all performance: output of such functions improves system performance, in respect to better selection of future protective devices as well as better identification of system limitations with regard to existing protective devices and settings.

Dispatching tools:

1. Under-Load switching and Switching sequence management functions: number of customers connected, customer classification type as well as duration of interruptions are organized and properly managed with the GIS location identification being faster in addition to the DMS ability to record equipment historical data, coordinate and minimize the different shut-downs for different purposes.
2. Performance indices: are a great function for system planner to know where do there system stands in relevant to benchmarked targets.

Other functions:

Please refer to enclosed sheet for additional featured functions.

Please mark the expected improvement in the security of supply for the following equipment as per the illustrated different network structures, after the introduction of DMS and GIS functions illustrated in Table 1.1 of the functions. Kindly note that the 0% means that the measured item is taken to be the same as the present recorded performance now on the current ADDC system.

Existing equipment is kept, but the system is operated as in the following structures:

Fault Class	Current Practice	11kV ring HD SWSTN	Exp Improvement	11kV Mesh	Exp Improvement	20 kV ring SWSTN	Exp Improvement	11kV Zonal S/S exp improvement
MV Cable	0%	0%		0%		70%		
Equipment	0%	0%		0%		50%		
Planned	0%	0%		0%		50%		
TR	0%	0%		0%		25%		
LV Cable	0%	0%		0%		50%		

New Equipment is introduced to replace existing one:

Fault Class	Current Practice	11kV ring HD SWSTN	Exp Improvement	11kV Mesh	Exp Improvement	20 kV ring SWSTN	Exp Improvement	11kV Zonal S/S exp improvement
MV Cable	50%	50%		90%		70%		
Equipment	50%	50%		905		50%		
Planned	50%	50%		50%		50%		
TR	25%	25%		25%		25%		
LV Cable	50%	50%		50%		50%		

Following table gives the 80% feeder loading of system design guidelines.

Design Option	MV Cable	Cable MVA Capacity	Avg Load % of Capacity	Peak Load % of Avg Load
Current Practice	240	5.3	80%	100%
11kV ring HD SWSTN	240	5.3	80%	100%
11kV mesh	240	5.3	80%	55%
20kV ring	500	13.1	80%	100%

Design Inputs:

Design Option	Fdrs length Km	LV km per SS	FP to LV cable km	SC to LV cable km	Duct to km of cable
Current practice	1.9	3	0.36	0.51	0
11kV ring HD SWSTN	1.9	3	0.36	0.51	0
11kV Mesh	1.9	3	0.36	0.51	0
20 kV Ring SWSTN	3.5	3	0.36	0.51	0.5
Zonal Design	2	3	0.36	0.51	0

Design Guide Lines:

Feeder Configuration Rules”

Design Option	Fdrs per Pry	Express Fdrs per SWSTN	Express Fdrs per Pry	Pry per SWSTN	Fdrs per SWSTN
Current practice	10-12	2	2	1	10-12
11kV ring HD SWSTN	10-12	2	2	1	10-12
11kV Mesh	10-12	NA	NA	NA	NA
20 kV Ring SWSTN	10-12	2	2	2	10-12
Zonal Design	24	NA	NA	NA	NA

Glossary:

MV Cable: 11kV 3c x 240 mm2 Copper Cable
Equipment: 11kV switchgear
Planned: Planned outages, which is expected to be reduced for new equipment due to the increase in the maintenance cycle of the new equipment
TR: distribution transformers 1000KVA, 1500 KVA, Package Units, TRM, QRM
LV Cable: LV copper cable size and Ampacity limits are 25 mm^2 - 80 amps, 50 mm^2 - 120 amps, 120 mm^2 - 200 amps, 240 mm^2 - 300 amps, 500 mm^2 - 400 amps.

APPENDIX C

DESIGN GUIDELINES TABLES

Appendix C

Table 1C

Transition to 11 KV Ring HD sw/s Based on Engineering Design Guidelines

Equipment	Qty Existing	Qty Required	Additional Qty required	Qty made available
Substations - 132 - 11 kV	14	11.57107	0	2.428932
11 kV feeders non-express	382	378.2429	0	3.757075
11 kV feeders express	34	75.64858	41.64858	0
11 kV 240 mm2 feeder cable - km	776	776	0	0
11 kV 500 mm2 feeder cable - km	0	79.13231	79.13231	0
Switching Substations	30	37.82429	7.824292	0
Substations 11 - 0.415 kV	464	1188	724	0
Package Units	167	0	0	
QRM Unit Substations	179	0	0	
TRM Unit Substations	378	0	0	
Ducts encased - km	0	0	0	
Transformers - 11 to 0.415 kV	2044	2044	0	0
LV feeder cable - km	3564	3564	0	
Feeder Pillars	1283.04	1283.04	0	
Service Turrets	1817.64	1817.64	0	
Package Units %	0.230663			
QRM Unit Substations %	0.247238			
TRM Unit Substations %	0.522099			

Appendix C

Table 2C

Transition to 11 KV Mesh Configuration Based on Rules and Guidelines

Equipment	Qty Existing	Qty Required	Additional Qty required	Qty made available
Substations - 132 - 11 kV	14	12	0	
11 kV feeders non-express	382	688	306	-306
11 kV feeders express	34	0	0	
11 kV 240 mm2 feeder cable - km	776	776	0	
11 kV 500 mm2 feeder cable - km	0	581	581	
Switching Substations	30	0	0	
Substations 11 - 0.415 kV	464	1188	724	
Package Units	167	0	0	
QRM Unit Substations	179	0	0	
TRM Unit Substations	378	0	0	
Ducts encased - km	0	581	581	
Pilot wire - km	0	1357	1357	
Mesh switchgear	0	0	0	
Mesh relaying	0	722	722	
LV feeder cable - km	3564	3564	0	
Transformers - 11 to 0.415 kV	2044	2044	0	
Feeder Pillars	1283	1283	0	
Service Turrets	1818	1818	0	

Appendix C

Table 3C

Transition to 20 kV ring sw/s Configuration Based on Rules and Guidelines

Equipment	Qty Existing	Qty Required	Additional Qty required	Qty made available
Substations - 132 - 20 kV	0	10	10	-10
20 kV feeders non-express	0	153	153	
20 kV feeders express	0	31	31	
20 kV 240 mm2 feeder cable - km	0		0	
20 kV 500 mm2 feeder cable - km	0	635	635	
Switching Substations	0	15	15	
Substations 20 kV	464	0	1188	
Package Units	167	0	0	
QRM Unit Substations	179	0	0	
TRM Unit Substations	378	0	0	
Ducts encased - km	0	635	635	
Transformers - 20 kV	0	2044	2044	
LV feeder cable - km	3564	3564	0	
Feeder Pillars	1283	1283	0	
Service Turrets	1818	1818	0	

Appendix c

Table 4C

Transition to 11 KV Zonal Design Substation Configuration Based on Rules and Guidelines

Equipment	Qty Existing	Qty Required	Additional Qty required	Qty made available
Substations - 132 - 11 kV	14	12	0	
11 kV feeders non-express	382	663	281	-281
11 kV feeders express	0	0	0	
11 kV 240 mm2 feeder cable - km	776	1439	663	
11 kV 500 mm2 feeder cable - km	0	0	0	
Switching Substations	0	0	0	
Substations 11 - 0.415 kV	464	1188	724	
Package Units	167	0	0	
QRM Unit Substations	179	0	0	
TRM Unit Substations	378	0	0	
Ducts encased - km	0	0	0	
Pilot wire - km	0	0	0	
Mesh switchgear	0	0	0	
Mesh relaying	0	0	0	
LV feeder cable - km	3564	3564	0	
Transformers - 11 to 0.415 kV	2044	2044	0	
Feeder Pillars	0	0	0	
Service Turrets	0	0	0	

11Kv switchgear cost included in conversion cost of substations

Appendix C

Table 5C Implementation Strategy

This option assumes the existing equipment is changed and re-configured as required to meet the new design rules over a 10 year period. This requires replacing the existing package unit substations, TRM and QRM substations with substations with circuit breaker type switchgear for the ring, mesh and 20 kV option.

Load Growth Level 3%

Component	11 kV ring HD sw/s	11 kV ring HD sw/s - 3X55 MVA	11 kV mesh	11 kV mesh - 2	20 kV ring HD sw/s	20 kV ring double bus	11 kV Zonal SS
Distribution Transformer Utilization	55%	55%	55%	55%	55%	55%	75%
Cable size	240 mm^2 11 kV	240 mm2 11 kV	240 mm^2 11 kV	240 mm^2 11 kV	500 mm^2 20 kV in conduit	500 mm^2 20 kV in conduit	240 mm^2 11 kV
Feeder design	Switching substations used for interconnecting feeders	Switching substations used for interconnecting feeders	Two-feeder primary mesh between primary substations	Two-feeder primary mesh between the same primary	Switching substations used for interconnecting feeders	Two-feeder open ring between primary substations with a double bus	Each group of two TR will have 12 rings loop back to the same DB
Distribution substations	New Indoor substations with switchgear for new loads and replace existing P/U, TRM and QRM equipment with new Indoor substations with switchgear	New Indoor substations with switchgear for new loads and replace existing P/U, TRM and QRM equipment with new Indoor substations with switchgear	New Indoor substations with switchgear with mesh relaying for new and existing substations	New Indoor substations with switchgear with mesh relaying for new and existing substations	New Indoor substations with switchgear	New Indoor substations with switchgear	New Indoor substations with switchgear with mesh relaying for new and existing substations, no switching stations
Primary substations	4 X 40 MVA 132 to 11 kV	3 X 55 MVA 132 to 11 kV	4 X 40 MVA 132 to 11 kV	4 X 40 MVA 132 to 11 kV - 11 kV DB	3 X 60 MVA 132 to 20 kV	3 X 60 MVA 132 to 20 kV -20 kV double bus	4 X 40 MVA 132 to 11 kV

APPENDIX D

COST CALCULATION TABLES

APPENDIX D: COST CALCULATION TABLES

Table 1D

132 - 11 kV substation estimate - costs in 1,000s AED

Source - Lahmeyer International (LI)

Equipment	Quantity	km	Unit Cost	Total Cost
132kV GIS switchgear	9		1,148	10,332
11kV switchgear	48		320	15,360
132/11kV 40MVA transformers	4		2,148	8,592
Reactive power compensation	4		526	2,104
AC and DC distribution	1		3,691	3,691
Control, supervision, protection	1		9,274	9,274
Telecommunication equipment	1		3,892	3,892
Connection cables - power, pilot, control	1		3,052	3,052
Civil works	1		13,589	13,589
132kV cables (1x500mm2 cu xlpe)	2	3	2,385	14,310
Total 132 - 11 kV equipment				84,196

Table 2D

132 - 11 kV substation double-bus estimate - costs in 1,000s AED

Source - Lahmeyer International (LI)

Equipment	Quantity	km	Unit Cost	Total Cost
132kV GIS switchgear	9		1,148	10,332
11kV switchgear	48		512	24,576
132/11kV 40MVA transformers	4		2,148	8,592
Reactive power compensation	4		526	2,104
AC and DC distribution	1		3,691	3,691
Control, supervision, protection	1		9,274	9,274
Telecommunication equipment	1		3,892	3,892
Connection cables - power, pilot, control	1		3,052	3,052
Civil works	1		13,589	13,589
132kV cables (1x500mm2 cu xlpe)	2	3	2,385	14,310
Total 132 - 11 kV equipment				93,412

APPENDIX D: COST CALCULATION TABLES

Table 3D

132 - 11 kV substation 3X55 MVA estimate - costs in 1,000s AED

Source - Lahmeyer International (LI) and EMA

Equipment	Quantity	km	Unit Cost	Total Cost
132kV GIS switchgear	7		1,148	8,036
11kV switchgear	48		320	15,360
132/11kV 55MVA transformers	3		2,954	8,861
Reactive power compensation	3		526	1,578
AC and DC distribution	1		3,322	3,322
Control, supervision, protection	1		8,347	8,347
Telecommunication equipment	1		3,503	3,503
Connection cables - power, pilot, control	1		2,747	2,747
Civil works	1		10,871	10,871
132kV cables (1x500mm2 cu xlpe)	2	3	2,385	14,310
Total 132 - 11 kV equipment				76,934

Table 4D

132 - 20 kV substation estimate - costs in 1,000s AED

Source - Lahmeyer International (LI)

Equipment	Quantity	km	Unit Cost	Total Cost
132kV GIS switchgear	9		1,148	10,332
20kV switchgear	32		-	-
132/20kV 60MVA transformers	3		2,148	6,444
Reactive power compensation	3		-	-
AC and DC distribution	1		-	-
Control, supervision, protection	1		-	-
Telecommunication equipment	1		-	-
Connection cables - power, pilot, control	1		-	-
Civil works	1		-	-
132kV cables (1x500mm2 cu xlpe)	2	3	2,385	14,310
Total 132 - 20 kV equipment				31,086

APPENDIX D: COST CALCULATION TABLES

Table 5D

132 - 20 kV double bus substation estimate - costs in 1,000s AED

Source - Lahmeyer International (LI)

Equipment	Quantity	km	Unit Cost	Total Cost
132kV GIS switchgear	9		1,148	10,332
20kV switchgear with double bus	32		-	-
132/20kV 60MVA transformers	3		2,148	6,444
Reactive power compensation	3		-	-
AC and DC distribution	1		-	-
Control, supervision, protection	1		-	-
Telecommunication equipment	1		-	-
Connection cables - power, pilot, control	1		-	-
Civil works	1		-	-
132kV cables (1x500mm2 cu xlpe)	2	3	2,385	14,310
Total 132 - 20 kV equipment				31,086

APPENDIX D: COST CALCULATION TABLES

Table 6D

Installation and supply of distribution equipment - costs in AED

Source - ADDC BOQ format updated 16.01.04

Cable - per kilometer - 11 kV	Qty	Install	Supply	AED
11 kV cable 240 mm^2	1	15,000	130,000	145,000
11 kV cable 240 mm^2 joints	2	450	1,200	3,300
11 kV cable 240 mm^2 terminations	2	400	1,300	3,400
Trench	1	15,000	-	15,000
Total cost/km				166,700

Cable - per kilometer - LV	Qty	Install	Supply	AED
LV cable 240/120 mm^2	1	11,000	90,000	101,000
LV cable 240/120 mm^2 joints	2	250	500	1,500
LV cable 240/120 mm^2 terminations	2	200	350	1,100
Trench	1	15,000	-	15,000
Total cost/km				118,600
LV cable 240/120 mm^2 - average cost of 240 and 120 mm^2 cable				

Continuo Table 6D

Cable - per kilometer - pilot	Qty	Install	Supply	AED
Pilot wire	1	5,000	50,000	55,000
Pilot joints	0			-
Pilot terminations	2	200	4,000	8,400
Trench	1	15,000	-	15,000
Total cost/km				78,400

Equipment	Qty	Install	Supply	AED
TRM/QRM	1	1,000	35,000	36,000
Package units	1	3,000	125,000	128,000
Feeder Pillar	1	500	3,500	4,000
Service cabinet	1	400	2,500	2,900
Transformer - GMT	1	1,500	55,000	56,500

APPENDIX D: COST CALCULATION TABLES

Table 7D

Indoor substation	Qty	Install	Supply	AED
Building	1	-	200,000	200,000
Civil work	1	75,000	-	75,000
Earthing work	1	15,000	-	15,000
Panels - 4 or 6	1	8,000	160,000	168,000
Batteries	1	5,000	-	5,000
LV Panel	2	1,000	32,000	66,000
Testing of equipment	1	20,000	-	20,000
Total - Indoor substation				549,000

Indoor substation does not include the cost of the transformers

Table 8D

Switching substation	Qty	Install	Supply	AED
Building	1	-	250,000	250,000
Civil work	1	75,000	-	75,000
Earthing work	1	15,000	-	15,000
Panels - 11	1	15,000	570,000	585,000
Batteries	1	5,000	-	5,000
Testing of equipment	1	50,000	-	50,000
Total - Switching substation				980,000

TRM/QRM Substation	Qty	Install	Supply	AED
Building	1	-	200,000	200,000
Civil work	1	75,000	-	75,000
Earthing work	1	15,000	-	15,000
TRM/QRM	1	1,000	35,000	36,000
Batteries	1	-	-	-
Testing of equipment	1	-	-	-
Total - TRM/QRM substation				326,000

TRM/QRM substation does not include the cost of the transformers

APPENDIX D: COST CALCULATION TABLES

Table 9D

Concrete encased duct - 6 way	Qty	Install	Supply	AED
Conduits - 150 cm	6	5,000	60,000	390,000
Trench	1	15,000	-	15,000
Total cost/km				405,000

VITA

Aseya Mohammed Al Haddabi was born on 1975. She was educated in local public schools and graduated from United Arab Emirates University in Al Ain in 1999.

Ms. Al Haddabi joined Abu Dhabi Distribution Company (ADDC) in 1999 as a trainee, and made her way up in the company where she is working now as a Senior Strategic Planning Engineer in the Power Network Division.

She began her higher studies in 2004 as she enrolled in the American University of Sharjah (AUS) as a student in the Engineering Systems and Management program (MESEM) and graduated in June 2006.