EVALUATION OF SMART TECHNOLOGY FOR THE IMPROVEMENT OF RELIABILITY IN A POWER DISTRIBUTION SYSTEM

by

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DECLARATION 2 - PUBLICATIONS

Published conference paper:

1. GC Dumakude, AG Swanson, R Stephen and IE Davidson, "Evaluation Of Smart Technology For The Improvement Of Reliability In A Power Distribution System," presented at Southern African Universities Power Engineering Conference (SAUPEC), Johanesburg, South Africa, January 2015.

2. GC Dumakude, AG Swanson, R Stephen and IE Davidson, "Reliability Analysis and Improvement of a Power Distribution Network using Selected Smart Technologies ," presented at International Council on Large Electric Systems (CIGRE), Cape Town, South Africa, 2015.

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To all of you, May God showers his blessings upon you, shows you mercy and grants you his favour always.

ABSTRACT

Electricity distribution networks are susceptible to random faults. On occurrence of a fault the upstream breaker on the faulty section trips. This leads to supply interruption to all customers connected to that affected section. Depending on the network configuration, opening and closing of breakers to try and restore supply to unaffected sections does take some time. This dissertation evaluates the application of selected smart technologies with the aim of improving the reliability of Eskom's medium voltage (MV) networks. The intent is to reduce the outage duration, frequency of outages, maintenance costs, and operational expenditure while improving overall system performance. The reliability of a distribution system depends on a number of factors including the location (urban or rural), environment, the type of system and the type equipment installed. Factors that affect the customer supply availability include the failure rate of equipment and the duration of an outage. The outcome of the application of smart technology on the MV network will influence the availability of customer supply as the technology could not only be used to reduce the failure rate of the system but also decrease the time spent on fault finding and maintenance due to greater visibility system wide. Historical and predictive approaches are the two power system reliability assessments that are predominantly used. Both approaches are applied whereby expected performance is modelled, given the specific network topology, past performance, customer numbers, operating environment, etc. A number of network components including transformers, lines, isolators, and fuses are used and applied in a systematic manner to calculate the expected downtime experienced by the customer supplied on different connections of the network with different smart technology interventions. To achieve this, a methodology is developed and verified by comparing the calculated results with DigSilent PowerFactory simulations using a few selected samples of the existing networks from the KwaZulu Natal Operating Unit (KZN OU). The application of smart technology has confirmed an improvement on overall outage duration while improving system performance.

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NOMENCLATURE

AMI: Advanced Metering Infrastructure
AMR: Advanced Meter Reading
AFS: Automatic Feeder Switch
CAIDI: Customer average interruption duration index
CID: Customer Interruption Duration
CIS: Customer Information System
CT: Current transformer
DA: Distribution Automation
DMS: Distribution Management System
DOE: Department of Energy
EHV: Extra high voltage
EMS: Energy Management System
EPRI: Electric Power Research Institute
ETTF: Expected time to failure
FMEA: Failure mode and effect analysis
FLISR: Fault Location, Isolation & Service Restoration
FPI: Fault Path Indicators
GHG: Green House Gases
GIS: Gas insulated switchgear
HV: High voltage
IEEE: The Institute of Electrical and Electronic Engineers
kVA: Kilovolt ampere
kWh: Kilowatt hour
KPI: Key performance indicator
KZN OU: KwaZulu Natal Operating Unit
LV: Low voltage (≤1kV)
MDMS: Meter Data Management Systems
MS Excel: Microsoft Excel
MV: Medium voltage
MVA: Megavolt ampere
MW: Megawatt
MTTR: Mean time to repair
N/O: Normally open

OMS:	Outage Management System
PowerFactory:	DIgSILENT PowerFactory Version 15
RBTS:	Roy Billinton Test System
RTU:	Remote Terminal Unit
SAIDI:	System Average Interruption Duration Index
SAIDI-N:	System Average Interruption Duration Index-Network
SAIFI-N:	System Average Interruption Frequency Index-Network
SAIFI:	System Average Interruption Frequency Index
SASGI:	South African Smart Grid Initiative
SANEDI:	South African National Energy Development Institute
SCADA:	Supervisory Control and Data Acquisition
TTF:	Mean Time to Failure
VT:	Voltage Transformer

CHAPTER 1

INTRODUCTION

1.1 Background

The distribution system is a fundamental part of the entire electrical power system, as it is the last link between the generators and the customer. In many cases, these links are radial in nature and thus susceptible to power outages due to a single event (no redundancy in the distribution system). It has been stated that most of interruptions that occur in the power systems are due to failures in the distribution system[1-2]. The distribution network is not only geographically large but has a complex and interconnected nature. It is exposed to a number of faults including theft, weather, structure failure, vegetation and animals.

In general, many distribution systems have normally open points in a meshed configuration, so that the system is operated as a radial feed. However during fault conditions normal open switches can be closed so that the supply can be restored to unaffected areas. The idea is to isolate the faulted part and reconnect the healthy part of the system as soon as possible to enhance overall system reliability. The reliability of a distribution system depends on a number of factors including the location (urban or rural), environment, the type of system and the type of equipment installed. Events that affect the customer supply availability include the failure rate of equipment and the duration of an outage. A number of traditional systems including devices such as over-current relays, reclosers, fuses and sectionalisers are commonly used to protect the distribution system[3-5]. Eskom Distribution also uses these protective devices to minimise the customer impact per load point.

The Smart Distribution Grid has gradually become an obvious choice to face future challenges in the power system because it provides integration and greater visibility over traditional approaches. It delivers a system that can remotely monitor the condition of the equipment, diagnose the faulted section while employing measures that will keep the system operating optimally [6-9].

1.2 Problem Statement

Adequate energy is essential to South Africa’s economic growth and development, and to the needs of the society. Power distribution systems are geographically large in nature and they include a large number of components thus making them extremely susceptible to system configuration and environmental difficulties. This means that the system has a number of interconnections that do not necessary follow easily accessible routes, but are naturally guided by laws[1]. Eskom Distribution is constantly under enormous pressure to improve network performance, and is continuously investigating methods of monitoring this using the recognised key performance indicators[10]. This research evaluates the application of smart technologies with the aim of improving the reliability of Eskom’s medium voltage (MV) networks. The scope of this study only covers MV feeders connecting the distribution substations to the customers. Customers, substation equipment and sub-transmission networks are excluded. It is limited to calculating the customer based reliability indices and does not include the calculation of load based or economic indices.

It will also answer these key questions:

a) What Smart devices are there in the market?
b) What effect do these devices have on improving the reliability of distribution systems?

c) What smart technologies are valid for which kind of network?

1.3 The aims are

a) Reduction of unplanned outage duration,
b) Reducing the frequency of unplanned outages,
c) Reduction of maintenance and operational expenditure associated with outage management while improving overall system performance

1.4 Hypothesis

Smart technology applied in a correct manner can enhance system performance and improve reliability of the power distribution system by making use of digital and advanced technologies.

1.5 Dissertation organization

The organization of this report is as follows:

a) Chapter 2 presents the literature review conducted which covers past work done by different authors and their contribution to this study as well as introducing the smart grid technologies evaluated for the improvement of reliability in the distribution system.
b) Chapter 3 introduces the reliability concept, indices, evaluation approaches, as well as the mathematical approach for reliability indices. It touches on the key components that cover overall outage duration on MV network and how they affect the reliability indices.
c) Chapter 4 shows the fault analysis for the KZN OU
d) Chapter 5 covers application of reliability evaluation on the sample network developed.
e) The application of the reliability evaluation methodology on one of the existing networks in the KZN OU is discussed in Chapter 6.
f) Finally, Chapter 7 provides concluding remarks and recommendations for future studies.

CHAPTER 2

LITERATURE REVIEW

2.1 Power Distribution System

The electrical power system serves to generate, transport and distribute electrical energy to consumers in an efficient, economic and reliable manner, and consists of generating stations, transmission lines and distribution networks[11-12]. At the distribution networks, electric power at medium voltage is supplied to industrial, commercial and domestic loads as shown in Figure 2-1. Medium voltage ranges from 1 kV to 33 kV[13]. The focus of this study is on the MV feeders connecting the distribution substations to the customers. Customers, substation equipment and sub-transmission networks are excluded

Figure 2-1: Power Distribution System [14]

The MV network is made up of a number of components including fuses, conductors, distribution transformers, reclosers, switches, etc. The length of feeders is related to the load density and location. For example the rural network has a small customer density but the feeder length may be long as shown in Figure 2-2[13]. This is a typical 22 kV network which has 200 km of line to feed 400 customers. This type of network has a large amount of equipment, low revenue and the expected performance will be poor based on the increased equipment failures and increased travel and fault finding time as it covers a large geographical area.

Figure 2-2: Rural MV network [14]

The urban network has an overhead or underground cable that covers a short geographical area as shown in Figure 2-3[13]. The same network feeds 400 customers but has 20 km of line. The performance of this urban line is better as compared to the rural network due to high customer density, short travel and fault finding time. For a cable network the performance is even better because it is not exposed to faults due to bad weather, due to vegetation and due to live wire contact; however more customers are affected by the outages and outage duration is longer due to different types of fault finding technique associated with this network as components are not all visible[15-16].

These examples illustrate that network topology and configuration have an impact on the network performance and this must be accounted for when considering the use of smart technology.

SCADA is a system that Eskom Distribution is currently using to control its distribution network. SCADA is a central monitoring and control system that involves a system operator in decision making, through the available data, who then controls the distribution network. Even though some features are automated like reclosers and section breakers, there is no full Distribution Automation (DA). For example, if there is a fault on the system, the protection will operate to isolate the fault from the rest of the network. Thereafter the maintenance crew will be dispatched to travel to site to manually investigate the faulted section. With smart technology, the investigation of the faulted section is done automatically[17-18].

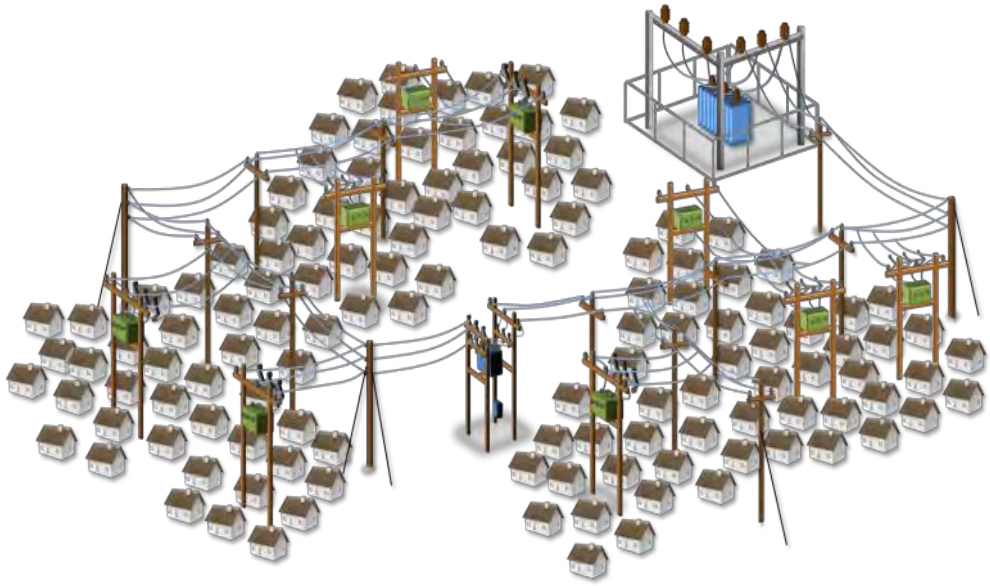


Figure 2-3: Urban MV network [14]

A literature review has been conducted into the application of smart technology with the aim of improving the reliability of power distribution system by reducing the duration and the frequency of outages and improving overall system performance. The first part deals with reviewing the past work done by different authors concerning reliability improvement of distribution system. The second part is aimed at finding the smart grid technologies that can be applied on the distribution system with the purpose of enhancing overall system reliability.

2.2 MV reliability studies that have been conducted in the past

The reliability analysis of the power distribution system has received significant attention over the years, because it forms a final link to the customer so that any fault taking place in this link directly affect consumers and has a negative effect on the utility revenue. The reliability indices of a power distribution system for the conventional system, the automated system and smart grid configurations can be calculated and the results can be compared. A number of traditional reliability studies on distribution networks have been conducted in the past, where the reliability improvement obtained is due to different interventions such as tree trimming, changes in design and operating policies [19-20]. In [21] two mitigation techniques to maximize reliability were classified as electric and non-electric. Electric measures involve direct impact on the distribution system, examples include addition of protective devices such as reclosers, fuses and switching devices and system reconfiguration. While non-electric measures do not have direct impact on the distribution system, examples include vegetation management and bird guards.

In [22-23] the reliability evaluation of smart grids, benefits, the growth core, forecasts and trends are described. Also the models for reliability evaluation are presented. Cost estimates and benefits of the Smart Grid applied to the distribution system were analysed. Today's investment on Smart Grids is significantly higher compared to 7 years ago; however, based on the outcome of this study, the fundamental assumptions and evaluation indicate that the benefits of the anticipated Distribution Automation (DA) significantly outweigh the costs as further illustrated in[24-27]. Artificial Neural Network techniques were used to evaluate the reliability of distribution systems [28-31].

A comparative analysis of distribution system reliability enhancement was done through application of different devices such as manual and automated switching devices. Also the reduction of maintenance and operational costs is determined [32-34]. However significant improvement can be realised by taking a holistic approach, where an overall system is fully integrated through the use of smart technology and communication network abilities. In[35], distribution automation systems and Intelligent Electronic Devices (IEDs) that are broadly used in smart distribution systems are applied by Xcel Energy to meet their reliability goals by maximizing the already present but often overlooked smart grid capabilities of the delivery and distribution network including smart in-home devices and electric vehicles.

In an attempt to improve Eskom Distribution's network, a number of refurbishment and capital projects have been initiated and executed[36]. As a means of reducing the customer impact, the KZN OU has conducted a study to install fuses on transformers only, by application of the expulsion type fuse on medium voltage overhead lines. The intention is that when a transformer fails, ideally the fuse should operate, isolating the faulty transformer from the rest of the network. This yields benefits with regards to overall system performance in that fewer customers are affected due to the fuse operation rather than an upstream breaker or recloser operating[37].

A study was also conducted in [38] on a method aimed at clearing single phase-to-earth faults without causing a three phase supply interruption to customers. This work only focused on improving reliability of momentary interruptions.

In [10, 39-40] the high-level benefits of smart grid technologies for Eskom's medium voltage network were evaluated. The application of Remote Terminal Units (RTUs), auto reclosers and Fault Path Indicators (FPIs) was simulated on a sample MV network. The above studies have produced better results compared to traditional approaches.

Nowadays utilities in general are investing in the applications of smart grid technology on power systems. The results proved a huge improvement of the automated system compared to the conventional system[41-43]. The U.S. Department of Energy (DOE) has started an initiative to deploy smart grid technologies nationally since 2010 and the results have shown huge improvement on overall system performance. These technologies include the installation of sensors, upgrading of communications systems, and control technologies that, when integrated with field devices (automated switches, line sensors, etc.), provide highly responsive and effective grid operations[44].

The following shortfalls have been identified with regards to the above mentioned reliability approaches:

a) Some of the reliability improvement approaches have been limited to one possible solution, meaning the impact of the number of solutions on affected customers has not been looked at.
b) It is a very good practice to ensure maintenance standards are upheld at all time as per the utility's specification. The challenge with the above mentioned studies is that there is no real-time monitoring of the equipment. The control center has to wait for the customers to call and report the fault.
c) The majority of the previous work takes into account the application of auto reclosers or sectionalisers to speed up the fault isolation and service restoration. The reliability enhancement for these devices has also been analysed. However the integrated effect of different technologies has not been considered.
d) The majority of this work is conducted and applied in utilities abroad. This means the evaluation of some of these technologies needs to be conducted with the purpose of finding suitable technologies for the Eskom Distribution network.

e) In addition, during power outages the new technologies provide automatic circuit re-configuration and reroute the power to minimize the impact on the affected customers.

The implementation of smart grid technology differs from utility to utility. This depends on many factors including infrastructure, location, policies, etc. The Eskom Distribution network topology, customer numbers and distribution on the network, operating environment and other network topology related variables are very different from that of utilities abroad, and hence other smart devices that work well in other countries may not be compatible for the Eskom Distribution network. Also the network protection and configuration has a huge impact on the reliability

This research is aimed at overcoming the above mentioned shortcoming by the investigation of new smart distribution technology capabilities and their application on the Eskom distribution system. The modelling of additional smart grid technologies including remotely controlled or automated tie point switches, line monitors, transformer remote monitoring, and integration of Distribution Management Systems (DMSs) and SCADA systems was also included. The integration of these technologies enhances the overall system performance through automation of power restoration, reducing both the impact and duration of interruptions.

Smart technology provides greater visibility of disturbances over traditional approaches. Traditional approaches mostly rely on customer calls to report the outage and the operation of switches to isolate the faulted part and restore supply to the healthy part of the system is done manually [45]. Visibility is an engineering solution that allows network control operators to have immediate knowledge of network operations taking place for all breakers on the distribution network. This means that when a breaker trips, network control is immediately aware of the loss of supply as opposed to only being made aware when a customer calls in to the contact centre [36]. Visibility of breakers creates opportunity for improved fault management and reduced restoration times.

2.3 Smart Grid Technologies

In a nutshell, the term “Smart Grid” refers to a conventional power system that uses digital technologies via two way communications to improve reliability, security and efficiency of power systems from generation through transmission and distribution system to the consumers [46]. The seven areas in the Smart Grid Conceptual Model contain customers, markets, service providers, operations, bulk generation, transmission and distribution as illustrated in Figure 2-4 [47].

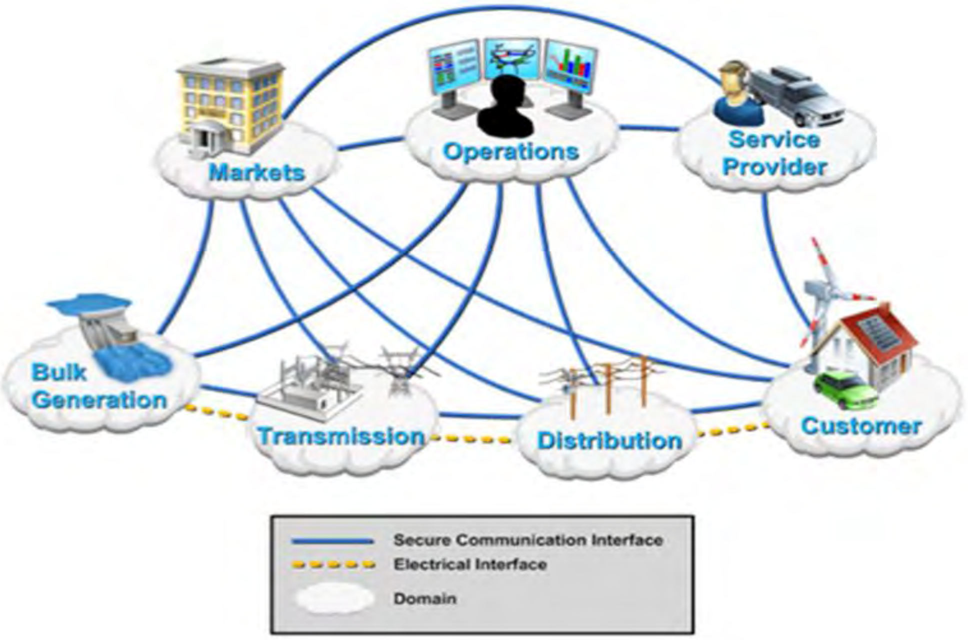


Figure 2-4: Smart Grid domain in conceptual model [47]

The smart grid technologies can be characterised in the following five key areas [48-50]:

a) **Sensing and Measurement** – this aspect requires technologies that will acquire and transform data into information to enhance decision making, through evaluation of plant health and integrity of the whole system.
b) **Integrated Communications** – the modern grid cannot exist without fully integrated communication systems that will include digital communication technologies for real time information and power exchange.
c) **Advanced Control Methods** – this ensures appropriate response for mitigation measures to any event through equipment monitoring, enabling rapid diagnosis and timely return service to customers.
d) **Advanced Components** – these components play an important role in determining system behaviour. They result in improved real-time diagnostics, producing improved quality and reliability of supply, improved power densities and electrical effectiveness which creates major environmental developments.
e) **Improved Interfaces and Decision Support**– decision making has been shortened to seconds. An algorithm associated with this application requires extensive, continuous, real-time use of tools that enable grid operators and managers with quick decision making. At all level of the grid, it strengthens human decision making through the decision support system with improved interfaces.

Traditional distribution system communications interfaces within this domain were unidirectional. Two way communication capabilities and distribution automation now exist through the application of smart technologies the advancement of distributed storage, distributed generation, demand response, system integration, load control and monitoring as shown in Figure 2-5 [47].

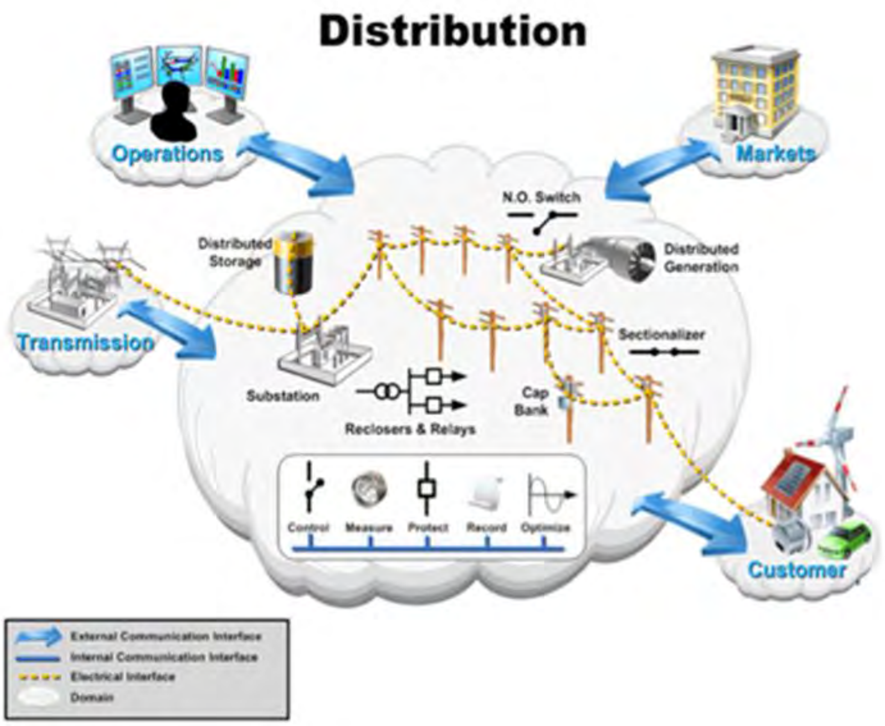


Figure 2-5: Distribution domain model [47]

2.4 Smart Grid benefits

Smart Grid benefits are classified as follows [24]:

a) **Quality and reliability of power supply**: The Smart Grid is expected to improve the quality and reliability of power supply through reduced frequency and duration of outages.
b) **Benefits of cyber and safety security:** Through constant monitoring the system will detects hazardous situations that could threaten the reliability and security of supply.
c) **Energy efficiency**: Ability to encourage consumers to reduce electricity usage during peak demands and system constraints which will eventually reduce energy losses and improve overall system performance.
d) **Conservation and environmental benefits**: The Smart Grid supports renewable energy and enables an improved environment through reduction of pollutants and greenhouse gases (GHG).
e) **Financial benefits**: Operational and maintenance cost savings are realized through the use of the smart grid. The utility has more control over its assets and optimal use of resources. Stake holder benefits are also realised.

2.5 Smart Grid challenges

There are a number of procedural and technical challenges experienced as the migration from traditional and conventional systems to smart grids is taking place therefore collaboration from all stakeholders is desired. These challenges are discussed below [26].

2.5.1 Procedural challenges

As the migration to a smart grid is taking place all these challenges need to be addressed for a successful migration.

a) The need to understand and address all stakeholder requirements
b) Complexity of the smart grid and understanding the fact that some aspects need human interaction and intervention while others need intelligent and automated controls.
c) Migration is a lengthy process therefore gradual deployment is encouraged
d) On-going risk assessment and training is encouraged to ensure cyber security of systems
e) Consent based standard is encouraged
f) Research and Development to ensure continuous improvement

2.5.2 Technical Challenges

Full integration across different areas of the system may pose technical challenges such as [24]:

a) Robustness to handle smart equipment for future applications without any replacements.
b) Communication system technologies and its various maturity stages
c) Handling of data management
d) Special care must be taken to ensure information and data privacy
e) Special care is vital in software applications for every function and node of the Smart Grid.

The application of specific smart grid technologies is used for achieving various functions in the electric power systems. For every application, there are a number of smart grid technologies available that can be categorized in the above described manner to achieve a specific goal.

Table 2-1 presents a list of smart technologies that are currently available in the market to improve MV network reliability [51-53]. Some of this technology is already used in utilities abroad.

Table 2-1: List of Smart Devices

Device	**Impact on the number of interruptions**	**Impact on duration of interruptions**	**Impact on number of customer interrupted**
Smart fuse saver	Will reduce number of faults by improving fuse failure rates, as a fuse tends to operate for temporary interruptions	Will reduce the outage duration where fuse has blown due to transient fault. Will also provide visibility to SCADA for all fuse operations without intervention from the customer.	Number of customers affected by interruptions will not change
Transformer remote monitoring	No impact on number of interruptions	Will reduce the duration by a significant amount because it will provide visibility for all transformer interruptions without customer interventions.	Number of customers affected by interruptions will not change
Smart fault path indicator	No impact on number of interruptions	Will reduce the duration of interruption by a significant amount	Will reduce the impact of number of customer affected, by quick identifying the faulted section. This will reduce the sectionalizing and fault finding time.
Automatic feeder switches	Will reduce the number of interruptions through self-healing	Will reduce the duration of the interruption	Will reduce the impact of number of customers affected by interruption through self-healing
Fault Location Isolation & Service restoration (FLISR)	Will reduce the number of faults through self-healing and alternative source transfer	Will reduce the duration of interruption with a significant amount	Will reduce the impact of number of customers affected by interruption through self-healing
AMI & Smart meter for outage detection	No impact on number of interruptions	Will reduce the duration with a significant amount, by providing visibility all the way to the consumer.	No impact on number of customers affected by interruption.

2.6 Smart Fuse Saver

This device is installed in series with a fuse and clears a fault in as little as a half-cycle before the fuse operates for a transient fault as the fuse is unable to distinguish between transient and permanent faults. The fuse blows on all faults. The smart fuse saver can also be easily integrated with the RTU to provide network visibility and events history of the spur line [54].

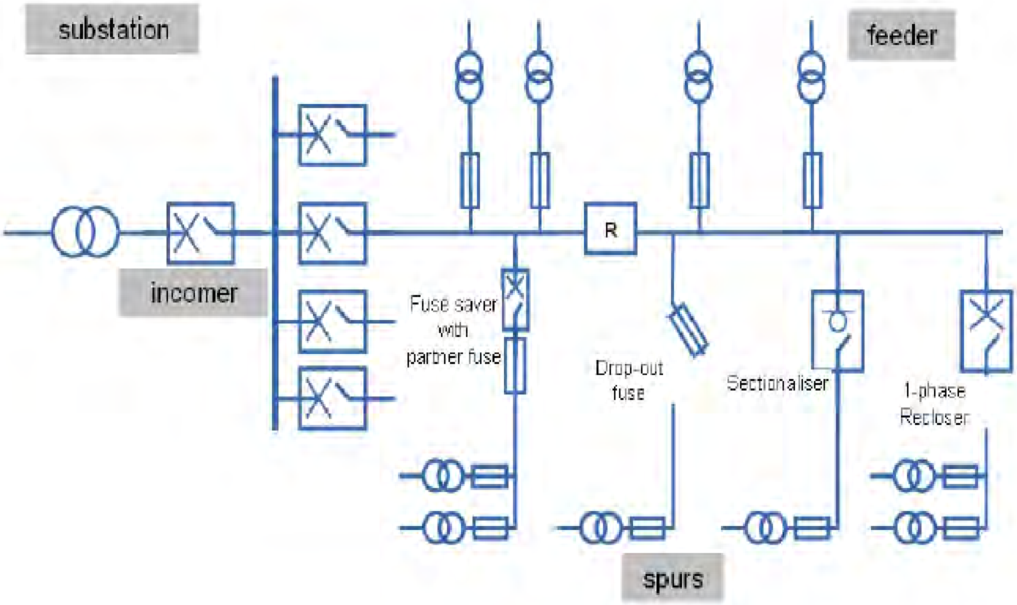


Figure 2-6: Fuse saver operation on a spur line [54]

As noted in Figure 2-6 above, for a transient fault only the spur line customers would experience momentary interruption. When a permanent fault is experienced, after closing, the fault current will flow again and the fuse will now operate to clear the fault. Again, only the customers on the faulted spur line will experience an outage.

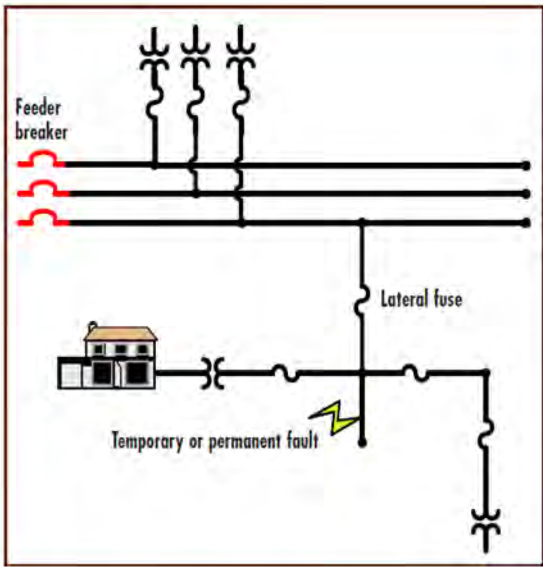


Figure 2-7: Fuse saving methodology [54]

KZN OU is currently fusing the transformers only, by application of expulsion type fuses on medium voltage overhead line networks. The intention is that when a transformer fails, ideally the fuse should operate isolating the faulty transformer from the rest of the network.

Therefore operation of a fuse means the protection has operated correctly. The installation of a smart fuse saver in series with the fuse in this instance was evaluated. The benefits for this device are achievable when the fuse is applied as a spur line protective device.

Other utilities practise a “fuse saving” methodology by purposely mis-coordinating the fuse characteristic with the network breaker characteristic so that the breaker operates faster than the lateral fuse to clear a fault downstream of the lateral fuse as indicated in Figure 2-7.

Others practice “fuse blowing” methodology by properly coordinating the lateral fuse with the network breaker, so that the fuse will clear any downstream fault within its rating and not the breaker as indicated in Figure 2-8. Eskom is fusing the transformers only with the aim of isolating the faulty transformer, both fuse blowing and fuse saving practices are not employed by Eskom, therefore this technology is not a recommended solution for the KZN OU because it is not suitable for their network protection philosophy.

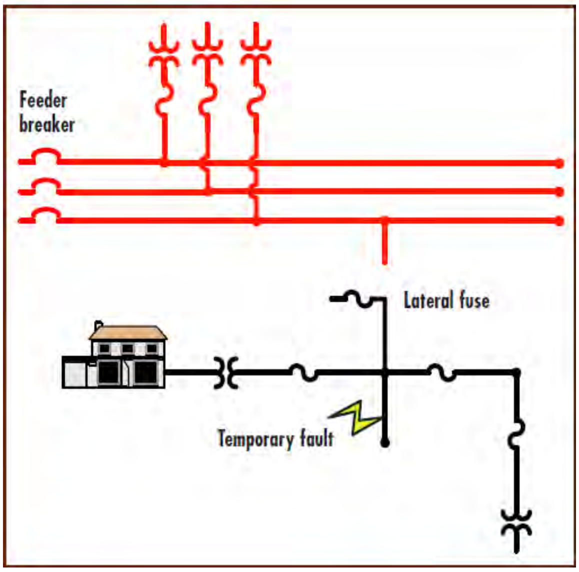


Figure 2-8: Fuse blowing methodology [54]

This device eliminates the permanent outages which are caused by fuse operating for a transient fault. It is for this reason that a huge improvement on SAIFI will be realised for utilities using “fuse blowing” methodology .

2.7 Transformer Remote Monitoring

During power outages or interruptions when the network breaker trips, the majority of the outage duration is spent patrolling the lines to try to locate the fault. The patrolman will first start by sectionalizing to find out exactly which section has faulted, and further sectionalizing on the section to identify which spur line has the problem. Once the faulted section is isolated, more time is spent on fault finding. Transformer remote monitoring will reduce sectionalising and fault finding time during transformer faults by providing transformer visibility as indicated by figure 2-9. This will yield improvement on both the duration and the frequency of the interruptions of impacted customers.

The transformer’s remote monitoring dry contact outputs will be monitored to detect a change of state, which would indicate a trip. This data will be transmitted via communication network to a central control room, where a final visual output and identification of which transformer has tripped will be indicated[55].

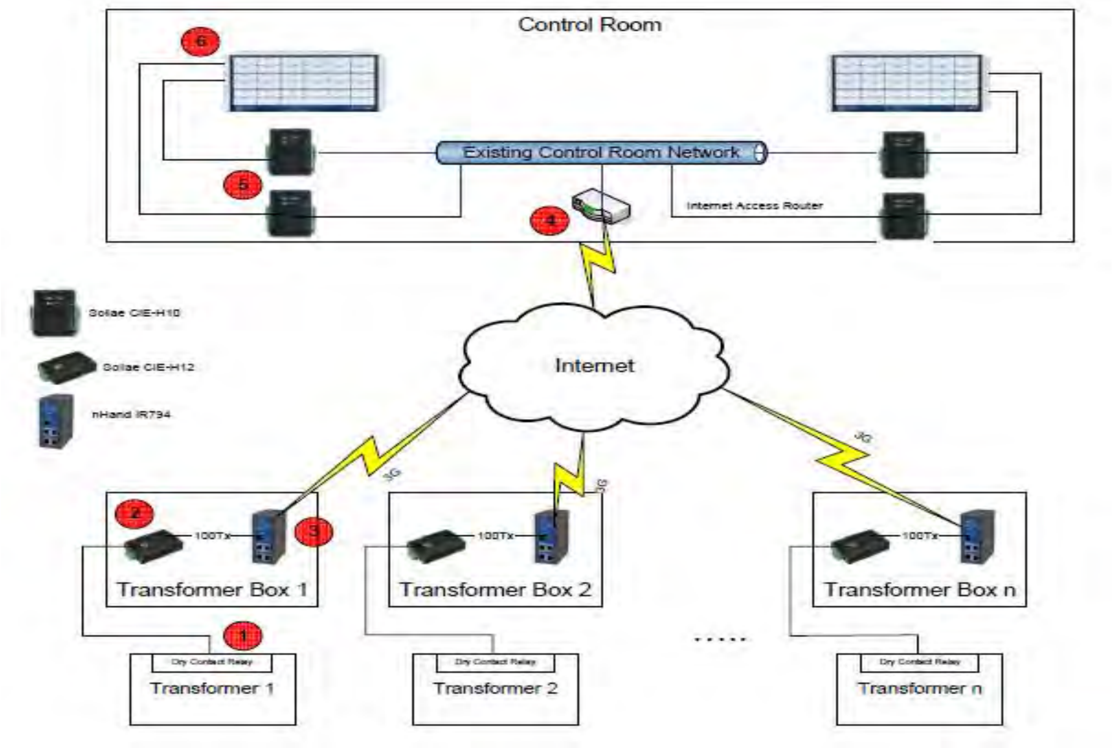


Figure 2-9: Transformer remote monitoring overview diagram [55]

2.8 Fault Path Indicators (FPI)

Power utilities measure reliability by monitoring interruption frequency and duration, through reliability indices. FPI are a smart solution that will improve reliability by reducing overall interruption duration. After a fault occurs and the protection clears the fault, the FPI communicates the location of the fault to the SCADA. There is either a cable fault indicator or an overhead line fault indicator. For overhead lines there is a portable handheld, pole mounted or conductor mounted electronic sensor, specifically designed for the detection of phase- and earth faults on overhead distribution lines [56-58]

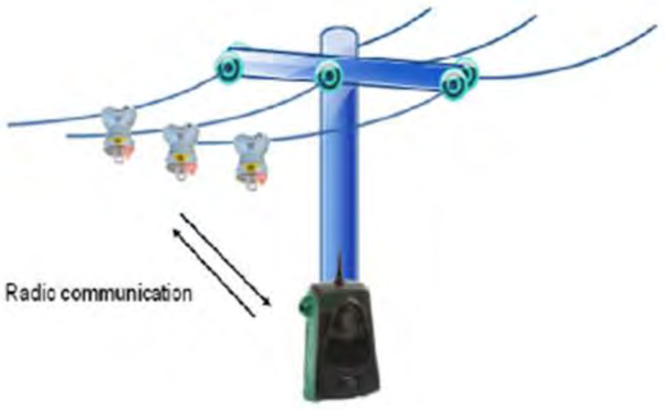


Figure 2-10: Conductor mounted FPI [59]

This device as shown by Figure 2-10 operates by monitoring the current at a specific location on the feeder. To identify a fault, it monitors the feeder for a loss of voltage following a rapid rate of rise of current (di/dt) over a 30ms period, or an overcurrent condition.This reduces the impact of the number of customer affected, by quick identifying the faulted section.

2.8.1 Benefits for using the smart FPI

a) Most beneficial method of reducing the overall outage duration. Most cost effective approach for reducing the fault finding time by at least 50% or more.
b) Return on Investment (ROI) is realised within a year or two
c) It allows rapid restoration of power to the unaffected section of the line
d) Reduces the wear and tear of the equipment that is caused by the sectionalising time and also allows optimal utilisation of resources.
e) Ideal for cable networks - it eliminate the need to open cable enclosures during fault finding time , overall outage duration usually longer than for overhead lines
f) If there is an interruption the meter stops running. By applying the FPI the interruption time is reduced which leads to increased revenue.
g) Proactive maintenance approach, the use of time reset on FPI to get to the root of temporary interruptions before they become permanent faults in the indicators and fault counters in areas affected.

2.9 Automatic Feeder Switches

Migration to a smart distribution system needs to be done gradually; due to the cost associated with it and it gives the organization enough time to learn the new technology. Therefore SCADA communications can also be extended to many existing reclosers and sectionalizers by interfacing communications technology such as wirelesses to the switch controller [33].

Similar to the network breaker monitoring function at the substation level, adding the communications infrastructure outside the substation allows network visibility to the control centre operators. Automatic feeder switches as indicated by Figure 2-11 are equipped with a tool that can automatically close the breaker after it has been opened due to a fault. It serves to detect and interrupt both load and fault current. They are able to clear momentary faults without interference from the operator. They improve service continuity by automatically restoring power to the line after a momentary fault. If there is a permanent fault in a system then protection equipment is designed to minimize the impact by interrupting the supply to a faulty part of the network. The supply will remain off until the operator arrives to site for fault finding, repairing the faulty equipment and returning the service back to normal. These devices can operate independently in response to local events or in response to signals from a central control system [60].

Applying these devices together with the FPI can assist in quick fault identification. Significant improvement is realised on the duration of an interruption as well as the number of customers affected. In addition, on complex or interconnected networks intelligent controllers and more advanced automated feeder switches with greater scope can be employed. Additional benefits are realised on networks with a normal tie point where power flow can be bi-directional. The switch immediately upstream of the faulted section will trip; the downstream switch will change the protection settings in anticipation of changing the power to flow the opposite direction. The normally open tie switch will then close automatically to back feed the healthy part of the network; this is later demonstrated on simulations.

Figure 2-11: Automated Feeder Switch [60]

Fault Location Isolation and Service Restoration (FLISR) technologies include automated feeder switches and reclosers, line monitors, communication networks, distribution management systems (DMSs), supervisory control and data acquisition (SCADA) systems, outage management systems (OMSs), and data processing tools.

These are more sophisticated automatic control strategies that act with a larger scope of responsibility and are ideal for more complex or interconnected feeder arrangements. As part of smart devices deployment, the intelligent controller needs to be added at the regional or local level.

This capability will allow automated feeder switches to react to a fault by opening switches based on local data, then isolate the fault and restore service based on intelligence provided by nearby switches on the same feeder loop. The intelligent controller would depend on communications to adequately manage the local level while the SCADA controller acts independently for other supervisory control functions and not have any dependence on centralised control. Due to the local responsiveness, the intelligent controller can easily support enhanced fault location through line monitors, making automatic switching decisions and managing distributed generation connections [33].

These technologies work together to automate power restoration, reducing both the duration and impact of power interruptions while minimising maintenance and operational costs. The impact on customers affected by the outage is also minimised through automatic restoration of power supply to unaffected sections of the network. Where back feed capabilities are available the service to affected customers is also restored by transferring them to an alternative supply. The minimised number of affected customers and the associated customer minutes of interruption are the primary benefits of reliability improvement in a power distribution system. [61]

Figure 2-12 shows an algorithm a smart distribution system follows during outage conditions, where fault detection, isolation of the faulty part of the network and service restoration to a healthy part of the network is done automatically. FLISR technology makes time, resources and corporate commitment key components for success through implementation of greater automation, network visibility and integration when compared to traditional technologies.

A key component for any smart grid technology to effectively and efficiently perform the work intended is the communications network for remote monitoring and control of technologies and systems. FLISR communication networks need greater flexibility as they function under conditions where the grid itself is not fully functional. The two-way communications network needs to have adequate coverage and capability to interface all grid operations. The placement of automatic switches in the network is very critical. If you move the location of the automatic switch, the frequency and the duration of an outage changes accordingly, this is demonstrated on PowerFactory simulations in the later Chapters[52].

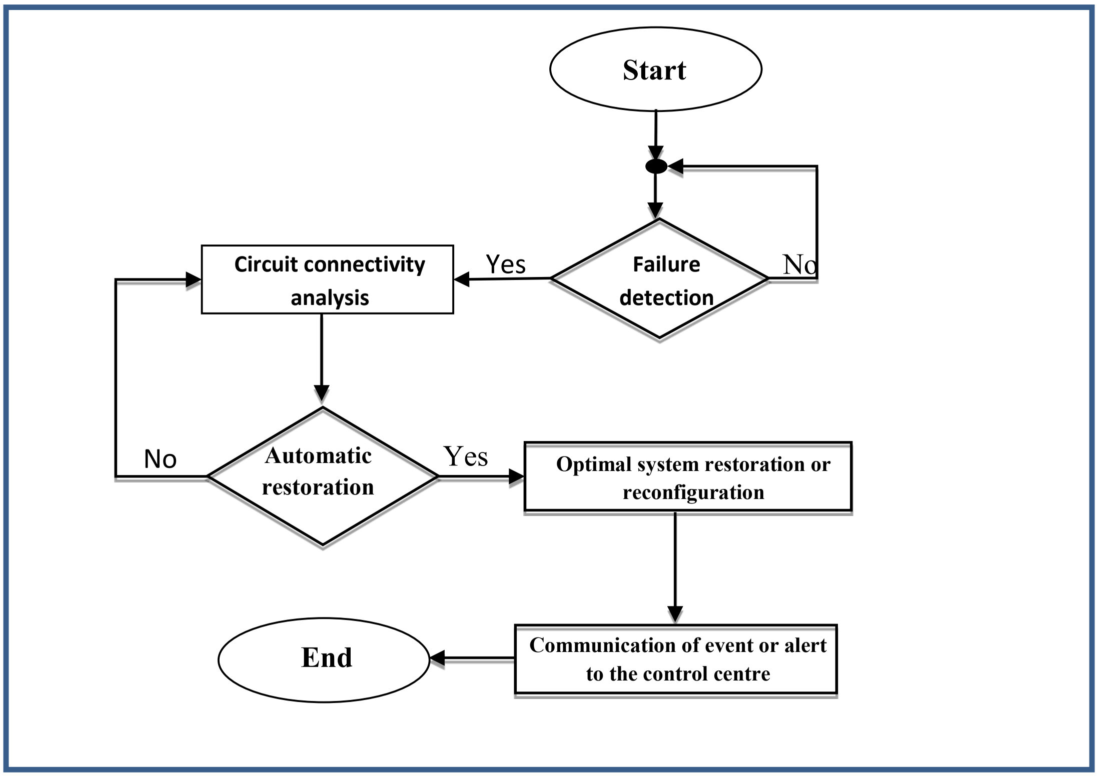


Figure 2-12: Automated monitoring and control of MV network

2.10 Advanced Metering Infrastructure (AMI) and Smart meter for outage management

Conventional metering functionalities include meter reading, switching services which are connecting and disconnecting the meter, and supporting customer billing requirements. All these tasks are achieved manually.

Prior to introducing AMI, certain power utilities including Eskom used automated meter reading (AMR) systems in some of their sites, which included electronic meters and one-way communications to reduce the necessity for manual meter reading. AMI introduces two-way communications capabilities and allows smart technologies for improvement of operational effectiveness. The transition from conventional meters to AMI requires the expenditures for new meters, communications networks, and information systems, as well as system integration [52].

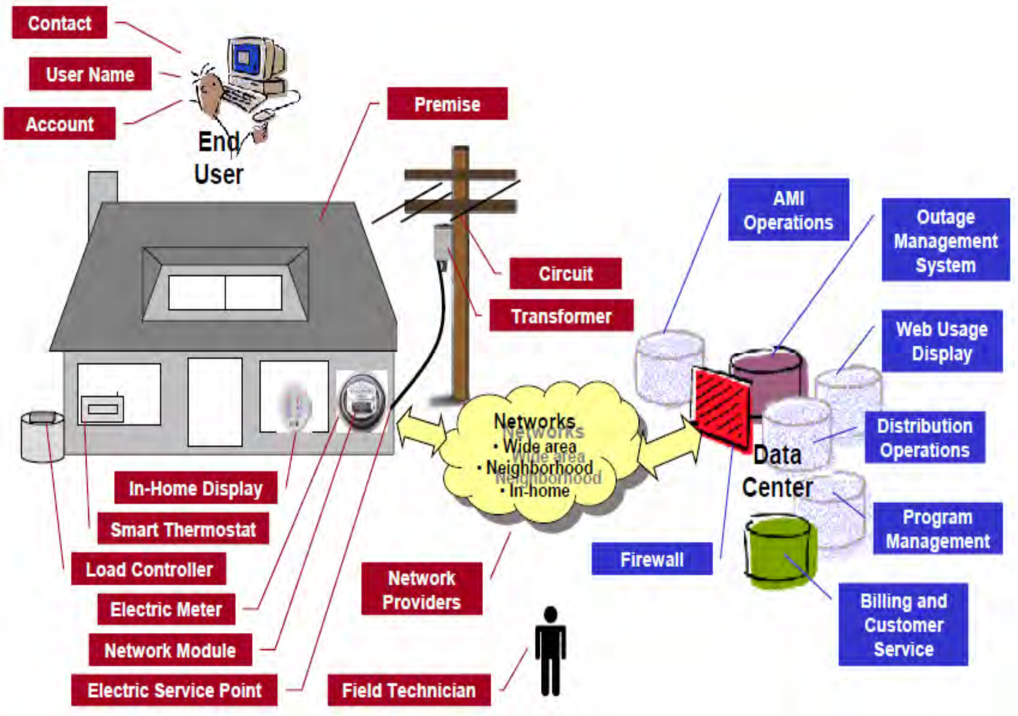


Figure 2-13: AMI overview diagram [62]

2.10.1 Information Systems for AMI

Full integration of smart meters and a communications network that supports various types of functions is crucial, for a utility to appreciate full benefits of AMI systems effectively, and control the complete set of smart meter functions. For example, varieties of utility operations that are supported by the smart meter include:

a) **Meter Data Management Systems** (MDMSs), which process and store interval load data for billing systems, web portals, and other information systems.
b) **Customer Information Systems** (CISs), which process data from MDMS and are linked with billing systems for storage of data on customer locations, demographics, contact information, and past billing information.
c) **Outage Management Systems** (OMSs), which process data about meter on/off status to locate outages and often connect with geographic information systems (GIS) for managing of resources during restoration times.
d) **Distribution Management Systems** (DMSs), which process data on outages and customer voltage levels for system reliability and voltage and volt-ampere reactive enhancement measures.

For the purpose of this study outage management systems are further looked at as measures of minimising frequency and duration of outages while reducing maintenance and operational costs savings through optimal use of resources in the power distribution system. The diagram below depicts how outage management is done through AMI.

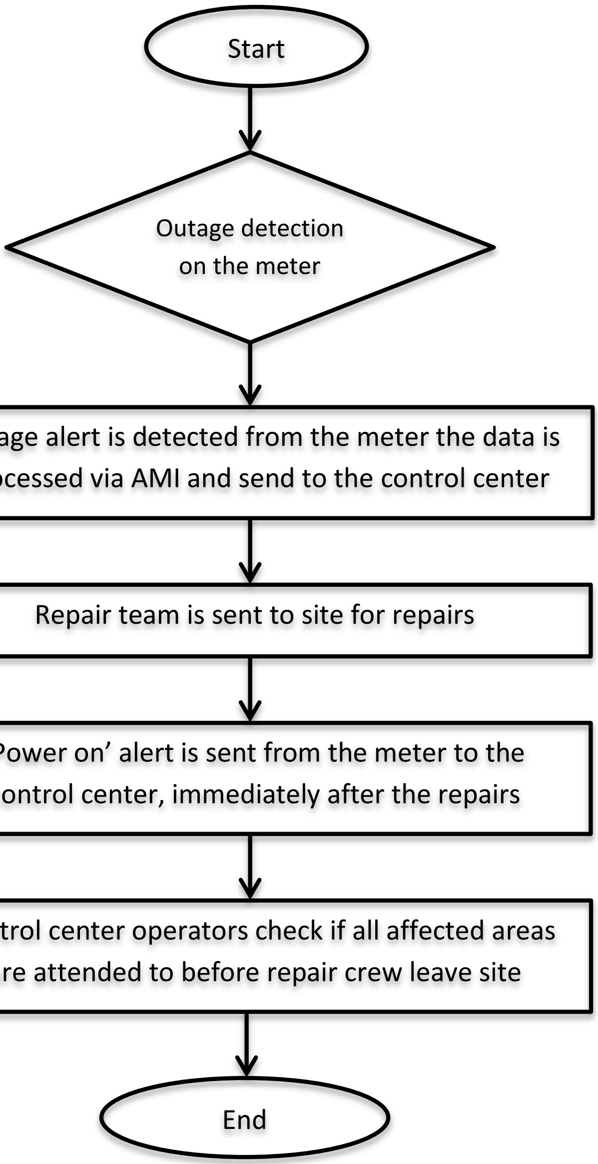


Figure 2-14: Outage management through AMI

Smart fault path indicators notify the control centre when faults occur, so does an outage notification system through smart meters. The difference between these two outage notification systems is that over and above outage notification, there are more other added benefits that come with AMI technologies. In the traditional system, a utility will get notified of a fault by the customer calling in.

The scope of this study is restricted to the smart grid technologies that can be applied in the MV network for improving the reliability of electric power delivered to the customers and improve overall system performance as discussed in Table 2-1. Currently, there are numbers of smart grid technologies already available in the market while others are still in the research and development stage. The main emphasis in this study is on the technologies which have already been implemented in the field either as a commercially available product or as a pilot project as listed on Table 2-1, and are from the following well-known companies.

a) ABB (http://www.abb.com/)
b) Siemens (http://www.siemens.com/)
c) S&C Electric Company (http://www.sandc.com/)
d) GE Energy (http://www.gepower.com/)
e) SEL (http://www.selinc.com/)
f) G&W Electric (http://www.gwelec.com/)
g) Schneider (http://www.schneider.com)
h) Silver Springs Networks (http://www.silverspringnet.com)
i) Varentec (http://www.varentec.com)
j) Tollgrade Lighthouse (http://www.tollgrade.com)

2.11 The state of Eskom in Smart Grid

It is important to know where Eskom stands with regards to available tools and infrastructure to support a smart grid. During the year 2012, the South African National Energy Development Institute (SANEDI) launched the South African Smart Grid Initiative (SASGI). Amongst other things its main objectives were to draw up industry expertise and develop a smart grid vision for the country. It is important to note that the current grid was not built with the 21st century challenges in mind. The network is limited to design issues and cannot allow the intelligence to fully migrate into smart grid. Also it does not allow bi-directional flow of energy. The fact that SASGI was launched in 2012 shows that migration to smart grid is still in early stages in South Africa. And there are not many tools available yet to support smart grids [63].

Supervisory functionality is provided by SCADA through the use of Energy Management System (EMS) and Distribution Management System (DMS) functionalities. Metering is the only interface the Eskom has with the customers, which is used for data collection, billing and load forecasting analysis. It is therefore evident that there is a huge gap between consumer and power utility with respect to fully achieving a smart grid. The benefits will add value to a more improved and intelligent network but the implementation and migration will be a costly exercise that requires huge capital investment. [64].

The electricity infrastructure in the country is in urgent need of refurbishing and expanding to meet demand and incorporating additional sustainable energy possibilities. Eskom needs to establish a 15% reserve margin which has been dropped to 5-6% since 2007 In addition, Eskom is facing its individual challenges with regards to aging of asset fleet. In the past the maintenance has been delayed and running of the plant to its full capability to meet demand and to avoid the economic and social impact of load shedding [65].

Eskom is currently evaluating the potential options of different sensor technologies as shown in Table 2-2; these technologies are being tested and implemented [64].

Table 2-2: Some of the current initiatives taken by Eskom [64]

Assessment of Visualisation tools	Replacement of existing SCADA system to EMS and DMS	Metering system (AMI)
Distribution Automation (completed 3 sites)	Utility Load Manager	Research in sensor technologies applicable to Eskom
Pilot of Phasor Measurement Units	Substation Automation	Asset management (condition monitoring)

CHAPTER 3

RELIABILITY ANALYSIS AND RESEARCH METHODOLOGY

3.1 Reliability

Reliability in a power distribution system is the probability of a network or piece of equipment effectively performing its intended function within a specified duration and under specified operating conditions. Reliability is associated with sudden failures of products or services and understanding why these failures occur and the impact thereof is crucial in terms of reliability improvement.

3.2 Network outages

The major cause of network outages or supply interruptions to customers is component "failure", and the frequency of which the failure occurs. A failure is defined as any issue with a power system component that causes any of the following events [66, 67]:

a) Limited or complete plant shutdown or below-standard plant operation;
b) Undesirable performance of operator's equipment;
c) Operation of the electrical protective relaying or emergency operation of the plant electrical system;
d) De-energization of any electric circuit, component, or equipment.

Power system components can fail in numerous ways and are classified as either active or passive failures [1].

a) Active failures are defined as a component or equipment failure mode that causes the operation of the upstream breaker around the failed component and can result in the other energized components and branches being removed from service. The failed component is isolated, and the protection breakers are reclosed. This results in part or full restoration of supply to all load points.
b) A passive failure is when a component failure mode does not cause operation of protection breakers and does not interfere with the rest of the system. Service is restored by repairing or replacing the failed device. Examples are open circuits, inadvertent opening of breakers or stuck breaker conditions.

For the purpose of this study, only active failures are considered. They classify outages as either scheduled outages (planned outages) or unscheduled outages (unplanned outages) [68]. Only unplanned outages are considered for this study.

The main reasons why failures occur include [69, 70]:

a) The product or service is not fit for purpose intended for or inherent design issues
b) Overstressed piece of equipment
c) Component wear-out which eventually lead to failures.
d) Incorrect specifications or may be applied incorrectly.
e) Human errors or misuse of the equipment.
f) Using the equipment outside operating environment specified for.

Generally the load and strength of the component is known, however element of uncertainty will always be there. The actual strength values of any set of components will differ; some will be fairly strong, while others may come up as reasonably weak, but most will come up as fairly average strength. Likewise some loads will be greater than others but mostly they will be average. If there is an overlap between load strength relationships as illustrated by the two distributions in the Figure 3-1, then failures will occur. Therefore there is a need for a safety margin to ensure that there is no overlap of these distributions.

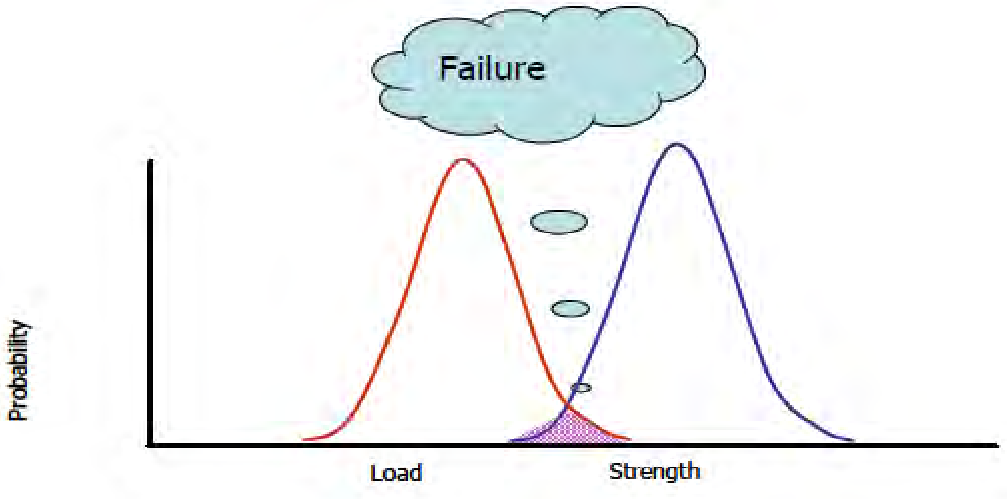


Figure 3-1: Overlap of load and strength relationship [69]

In order to ensure a good relationship, it is clear that the causes of failure need to be identified and controlled. Indeed reliability engineering objectives include:

a) To apply engineering knowledge to reduce the probability or frequency of failures
b) To perform trend analysis, identify and correct the causes of failures and
c) To determine ways of coping with failures that do occur such as reducing the outage duration

The scope of this study includes the application of engineering solutions to evaluate smart technology for improvement of reliability in a power distribution system by reducing duration and frequency of both momentary and permanent outages and improving overall system performance.

Voltage sags, sustained and momentary interruptions are three major aspects of the reliability of electric power supply delivered to the customers. A sustained interruption for MV networks is an unplanned interruption with a duration ≥ 5 minutes. A momentary interruption is a brief disturbance in the electric service of greater than 3 s but less than 5 min. Voltage sag is a sudden reduction in the voltage, for a period of between 20 ms and 3 s, of any or all of the phase voltages of a single-phase or a polyphase supply. The duration of a voltage dip is the time measured from the moment the voltage drops to below 0.9 per unit [71]. The degree of reliability may be measured by the frequency, duration, and severity [1].

3.3 Reliability Indices

Reliability indices are used to assess history statistics and to expose developments, patterns, determine challenges and indicate how and where reliability can be improved. They are classified into customer load point indices and system indices [72-73].

A detailed description on reliability indices is found in [1]. The indices that are commonly used for benchmarking and reporting are summarised below. There are also internal indices that Eskom uses such as SAIDI-N and SAIFI-N where transformer interruptions duration and frequency are measured [74]. Reliability indices also allow customers and investors to make an informed decision about the security of supply.

Load point indices are indices that measure the anticipated number of outages and their duration for a specific customer include factors such as:

a) Interruption frequency;
b) Interruption duration;
c) Availability.

System indices measure overall system reliability and can be used to compare the effects of different designs, strengthening alternatives and maintenance strategies on the system's reliability. They can be further divided into customer-based indices and load-based indices. The customer-based system indices are used to analyse and evaluate different smart technology interventions in this study.

3.4 Customer-based system indices

SAIDI (System Average Interruption Duration Index): The SAIDI of a network indicates the average duration of a sustained interruption the customer would experience per annum. For example, if a network has a SAIDI of 40 hours, a customer supplied by that network will not have electricity for an average of 40 hours in the year. It is commonly measured in customer minutes or customer hours of interruption. Mathematically SAIDI is expressed as:

$$\text{SAIDI} = \sum \frac{Customer\ interruption\ duration\ p.a}{Total\ number\ of\ customers\ served} \qquad (1)$$

SAIFI (System Average Interruption Frequency Index): The SAIFI of a network indicates how often on average (frequency) the customer connected would experience a sustained interruption per annum. For example, if a network has a SAIFI of 20, a customer supplied by that network will not have electricity for an average of 20 times in the year. Mathematically SAIFI is expressed as:

$$\text{SAIFI} = \frac{Total\ number\ of\ customer\ interruptiona\ p.a}{Total\ number\ of\ customers\ served} \qquad (2)$$

SAIFI-N (System Average Interruption Frequency Index-Network): The SAIFI-N of a network indicates how often on average (frequency) a transformer connected would experience a sustained interruption per annum. Only the number of events (no state changes) are used in the calculation and the number of transformers connected are used in the denominator. Mathematically SAIFI-N is expressed as:

$$\text{SAIFI-N} = \frac{Total\ number\ of\ transformer\ interruptiona\ p.a}{Total\ number\ of\ transformers\ \ connected} \qquad (3)$$

SAIDI-N (System Average Interruption Duration Index-Network): The SAIDI-N of a network indicates the average duration of a sustained interruption a connected transformer would experience per annum. Only the number of sustained events (no state changes) are used in the calculation and the number of transformers connected are used in the denominator. It is commonly measured in transformer minutes or transformer hours of interruption. Mathematically SAIDI-N is expressed as:

$$SAIDI\ N = \sum \frac{Transformer\ interruption\ durations\ p.a}{Total\ number\ of\ transformers\ connected} \qquad (4)$$

SAIDI-N and SAIFI-N are internal network performance KPI's that measure the interruption performance of the network. These KPI's do not take into account the amount of switching performed on the network in order to fault find. It is assumed that a customer regards himself/herself as off until supply is restored permanently. In terms of the network performance, the number of events affecting the customer is more important than the number of state changes recorded.

3.5 Unplanned outage duration

The overall outage duration for each event can be broken down into single steps as illustrated in Figure 3-2. SAIDI and SAIFI values are calculated from the moment the fault is captured in the system. Measured outage duration does not represent the entire outage duration, because it does not reflect the moment the fault took place. It depends on the response time of the customer to report the fault. Smart technology will bring in real time monitoring, where the organisation will be aware of the fault the moment it happens and actions will be taken thereafter. Each of these steps is further explained.

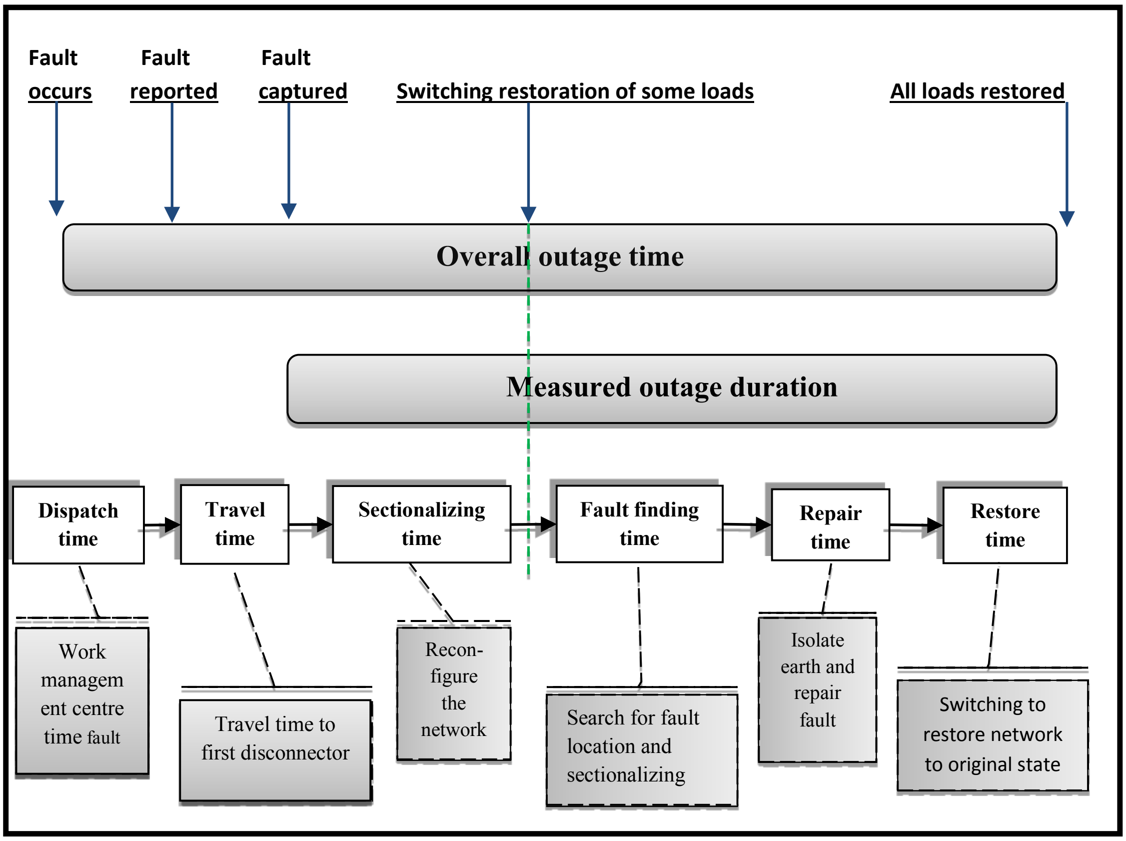


Figure 3-2: key components for overall outage duration on MV network

Fault occurs: this is the time before the fault is reported and captured on the system, only known to the customer or through the RTU. To quantify the exact time depends on the individual customer reaction to report the fault or through network visibility on the RTU. Hence SAIDI and SAIFI are calculated based on the measured outage duration and not overall outage duration. Some of the smart grid benefits may be realised during the overall outage duration.

Dispatch time: the call has been logged on the system during this period through customer reporting or through Remote Terminal Unit (RTU) alarms at the station and the operator has been advised to travel to site.

Travel time: the time for an operator to travel to site to operate the first disconnector or isolator.

Sectionalising time: customers are partially restored during this period through back feeding and network reconfiguration. The operator is performing switching (opening and closing of breakers and disconnectors) on different locations along the network with the aim of isolating the faulted part of the network.

Fault finding time: the faulted section is already isolated from the rest of the network at this stage; an operator is doing a visual inspection on the components with the intent of identifying the faulted equipment.

Repair time: the faulted equipment is repaired at this stage and the customers affected are only those connected to that section. Fairly reasonable assumptions for different equipment were made.

Restore time: after replacing or repairing the faulted equipment the network is returned to its original state.

The combination of these intervals represent the overall outage duration that is experienced by the customer from the moment the interruption takes place. Planned outages are when maintenance work is being undertaken. Therefore the total outages that are experienced by the customer on the MV feeder include both planned and unplanned SAIDI.

$$U_D = SAIDI_{unplan} + SAIDI_{plan} \tag{5}$$

Where:

U_D= total outages experienced by the customer on the MV network

$SAIDI_{unplan}$ = unplanned SAIDI for a specific feeder

$SAIDI_{plan}$ = planned SAIDI for a specific feeder

3.6 Evaluation techniques

The reliability of a power distribution system has been calculated by applying different evaluation techniques. Mainly two approaches are predominantly used: analytical and simulation[1]. In this study both approaches are applied whereby expected performance is modelled, given the specific network topology, past performance, customer numbers, operating environment, etc.

Due to the amount of computing time needed for the simulation technique, the majority of analyses that have been conducted in the past are analytical. Analytical methods evaluate the system by means of a mathematical model, and calculate the reliability indices by means of numerical solutions. Simulation methods evaluate the reliability indices by simulating the real practice and random behaviour of the system. Therefore, the method treats events as series of real experiments[1]. A few of the commonly-used reliability evaluation techniques are further discussed in this section.

3.6.1 Failure mode and effect analysis (FMEA)

FMEA is a technique that identifies all possible component failure states and their associated impact on system reliability [72, 75]. The following information is required for each component:

a) List of failure modes;
b) Possible root cause of each failure mode;
c) How is the system affected by each failure mode;
d) Likelihood of each failure mode occurring;
e) Possible actions to mitigate the failure rate

3.6.2 Markov models

These models are often used for quantitative reliability analysis. A Markov model describes the different states of a system and the transitions between these states. In reliability modelling, these states are referred to as failures and repairs.

These two basic assumptions are made with regards to system behaviour

a) No memory exist on the system state, no events occurred prior to the current state are taken into consideration, therefore the future probability of events is only a function of the existing state of the system.
b) The state of the system is stationary, meaning that the probability of conversions between one state to another is constant and does not vary with time.

In simple terms a two-state model can be used to describe the system, as shown in Figure 3-3. Availability is represented by one state of the system, and unavailability for the other. The systems are therefore either in the available state, illustrated by "U", or in the failed state, illustrated by "R". The MTTR is the repair rate. At the start of the model, the distribution line is assumed to be in UP state, meaning the system is in service or operational.

$$\text{Mean Time To Failure, } TTF = \frac{1}{\lambda} \tag{6}$$

$$\text{Mean Time To Repair, } MTTR = \frac{1}{r} \tag{7}$$

$$\text{Availability, } U = \frac{TTF}{(TTF+TTR)} \tag{8}$$

$$\text{Unavailability } R = \frac{TTR}{(TTF+TTR)} \tag{9}$$

The availability is the fraction of time when the component is in service; the unavailability is the fraction of time when it is in repair; and

$$U + R = 1.0 \tag{10}$$

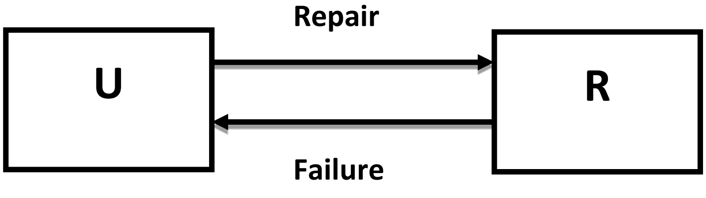


Figure 3-3: Two states Markov model [72]

A three states Markov model is shown in Figure 3-4. A network state in between the available and failed state is included; this is a state before switching has occurred in reliability modelling.

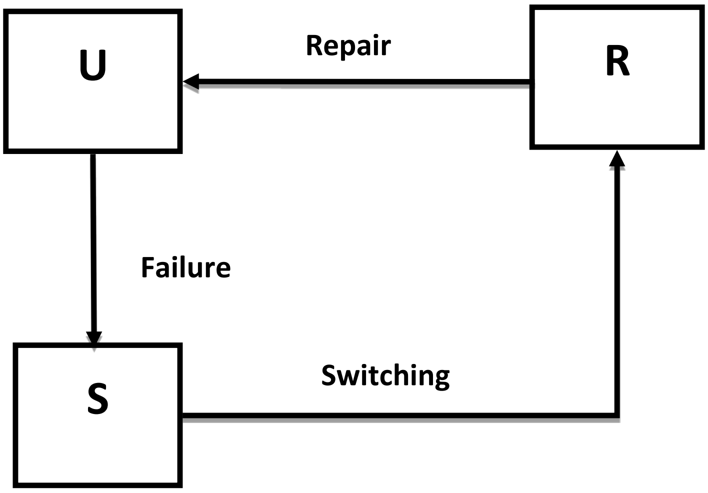


Figure 3-4: Three state Markov model [72]

Another model that considers passive failures is shown in Figure 3-5. It shows that the system can only be transferred to either switching state or the repair state, if it is available. This transition is referred to passive failures. Many studies relating to reliability analysis have successfully applied Markov models.

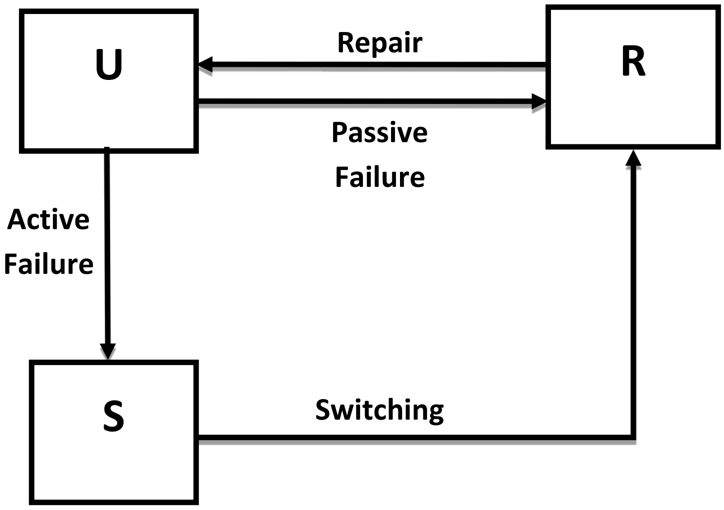


Figure 3-5: Markov model with passive state [72]

A Markov model was used in this study where a radial distribution system consists of a set of series components, including lines, transformers, isolators, bus bars, etc. was used to calculate anticipated SAIDI and SAIFI values. A customer connected to any load point of such a system requires all components between himself and the supply fully functional. Failure of any one component results to supply interruption whether momentary or permanent.

Calculations were performed on a small network model developed by the author to demonstrate the understanding of how the system is supposed to behave when doing PowerFactory simulations. It is not possible to perform calculations on a complex network because of the huge number of components and the process will be time consuming and tedious hence there is software designed for this job.

The past performance of the faults was analysed to develop the failure rate (λ_i) and outage duration (r_i) of each component. The three basic reliability parameters of average failure rate (λ_s), average outage time (r_s) and average annual outage time (U_s) were evaluated and calculated for historical analysis approach. It is a normally found practice that lines and cables have a failure rate which is approximately proportional to their length. More details about equipment failure rates and high level assumptions that were made will be further discussed in later chapters.

$$\lambda_s = \sum_i \lambda_i \tag{11}$$

$$r_s = \sum_i \lambda_i r_i \tag{12}$$

$$U_s = \frac{U_s}{\lambda_s} \tag{13}$$

3.7 Unplanned SAIDI and SAIFI approach

The approach followed in this study started with a very basic model and then fuses were added on a similar model. Thereafter analysis in PowerFactory was performed. Transformer fuses are used on MV networks to isolate MV/LV transformer faults. These fuses can be installed just before a transformer, at a tee-off to a transformer or on a section of line[37]. The intent is that when there is a transformer fault, the fuse must operate to isolate the faulted transformer from the rest of the network. The position of the fuse has a significant impact on the number of customers interrupted and the outage duration. For the purpose of this study it was assumed that all fuses are installed at the transformer and no fuses are installed on the backbone.

3.8 Customer restoration

The following factors were considered for the SAIDI calculation:

a) If a customer is affected, the customer will be affected for at least the response time, i.e. the time it takes an operator to drive to site, open an isolator on one/both side(s) of the fault and closes the substation breaker and/or back feed point.
b) The customers that are not restored will remain unsupplied for the full outage time.
c) Supply can be restored to some of the interrupted customers before the failed component has been repaired. The percentage of customers that can be restored depends on the isolating equipment, back feed capability and configuration of the network

The unplanned SAIDI algorithm for a feeder with was calculated as follows:

$$SAIDI = \frac{CID}{Cust_T} \tag{14}$$

$$\begin{aligned} CID = {} & (line \times FR_L + Disc \times FR_D + fuse \times FR_F + Trfr \times FR_T) \times Cust_D + \\ & (line \times FR_L \times R_{timeL}) \times Cust_R + (fuse \times FR_F \times R_{timeF})Cust_R + (Disc \times FR_D \times \\ & R_{timeD} \times Cust_R) + (Trfr \times FR_T \times R_{timeT})Cust_R \end{aligned} \tag{15}$$

The unplanned SAIFI algorithm is similar to SAIDI except that frequency is considered instead of duration. The SAIFI algorithm for a feeder with fuses as well as smart technology intervention is shown below:

$$SAIFI = \frac{CI}{Cust_T} \tag{16}$$

$$CI = (line \times FR_L \times Cust_D + (fuse \times FR_F \times Cust_D) + (Disc \times FR_D \times Cust_D) + (Trfr \times FR_T \times Cust_D) \tag{17}$$

Where:

Line = total line length in km (km)

Fuse = total number of fuses on a feeder

Trfr = total number of transformers on a feeder

Disc = total number of isolators on a feeder

$Cust_D$ = customer interrupted for dispatch, travelling and sectionalising time

$Cust_R$ = customer interrupted for fault finding, repair and switching the line back to its original state

$Cust_T$ = total number of customers in a specific feeder

CID = customer interruptions duration

CI = customer interruptions

FR_L = line failure rate (occ/km/a)

FR_D = Isolator failure rate (occ/a)

FR_F = fuse failure rate (occ/a)

FR_T = transformer failure rate (occ/a)

D_{time} = sum of dispatch, travelling and sectionalising time

R_{timeT} = sum of fault finding, transformer repair and switching the line back to its original state

R_{timeL} = sum of fault finding, line repair and switching the line back to its original state

R_{timeF} = sum of fault finding, fuse repair and switching the line back to its original state

R_{timeD} = sum of fault finding, isolator repair and switching the line back to its original state.

These indicators yield a good picture of the quality of service of the entire system. The larger the value of these indicators, the poorer the quality of the grid will be and vice versa. For each delimited segment *i* between two switches, if a fault occurs on the segment *i*, reliability indicators are calculated as follows [76]:

$$SAIDI(i) = \frac{D_{pc}(i) \times N_{cus}(i) \times N_{pc}(i)}{N_{tot}(i)} \tag{18}$$

$$SAIFI(i) = \frac{N_{cus}(i) \times N_{pc}(i)}{N_{tot}(i)} \quad (19)$$

$$ENS(i) = \frac{P_{pc}(i) \times T_{pc}(i) \times N_{pc}(i)}{N_{tot}(i)} \quad (20)$$

Where:

$D_{pc}(i)$ = outage duration for the segment i (min)

$N_{cus}(i)$ = number of customers experiencing an outage

$N_{pc}(i)$ = number of times an outage is experienced

$N_{tot}(i)$ = total number of customers

$P_{pc}(i)$ = the total rating of the outage

To calculate the total *IND* reliability indicator, where *IND* represents the SAIDI, SAIFI or ENS, the following formula is used:

$$IND = \sum_{i=1}^{n} IND(i) \quad (21)$$

Where n is the total number of segments in a system, the calculation of $D_{pc}(i)$, $N_{pc}(i)$, $N_{tot}(i)$ and $P_{pc}(i)$ depends on the switching device used, the location of the devices as well as the status of the system . For example, if the main feeder is sub divided into 3 segments such as A_1, A_2 and A_3. Equations are re defined as follows:

$$SAIDI(i) = \lambda \times L_i \times \left(T_d + T_m \times \frac{N_i}{N_1 + N_2 + N_3}\right) \quad (22)$$

$$SAIFI(i) = \lambda \times L_i \times \left(\frac{N_i}{N_1 + N_2 + N_3}\right) \quad (23)$$

$$ENS(i) = \lambda \times L_i \times \left(T_d \times P_{feeder} + T_m \times P_i\right) \quad (24)$$

Where:

λ = conductor failure rate

T_d = outage times for stages 1 and 2

T_m = outage time for stage 3

N_i = number of affected customers for A_1

L_i = conductor length for A_1

P_i = total affected power for A_1

P_{feeder} = total power for the whole feeder

L_{feeder} = total length for the whole feeder

SAIDI, SAIFI and ENS for the whole feeder are therefore equal to the amount of SAIDI, SAIFI and ENS for the three sub segments. Therefore:

$$SAIDI_{feeder-j} = \sum_{j=1}^{3} SAIDI(i) \quad (25)$$

$$SAIFI_{feeder-j} = \sum_{j=1}^{3} SAIFI(i) \tag{26}$$

$$ENS_{feeder-j} = \sum_{j=1}^{3} ENS(i) \tag{27}$$

Where n is the number of feeders in a system, then:

$$SAIDI = \frac{\sum_{j=1}^{n} SAIDI_{feeder-1}}{n} \tag{28}$$

$$SAIFI = \frac{\sum_{j=1}^{n} SAIFI_{feeder-1}}{n} \tag{29}$$

$$ENS = \frac{\sum_{j=1}^{n} ENS_{feeder-1}}{n} \tag{30}$$

3.9 Reliability specialized simulation software

A number of specialised software packages are available in the market for reliability modelling of electrical networks including:

a) PowerFactory,
b) NEPLAN,
c) ReticMaster, and
d) PSS/E
e) MATLAB

These packages require detailed network models to model the expected reliability of power networks. When the mean durations are modelled in PowerFactory all failure and load models are analysed through a Markov model[77]. The reliability calculation flow diagram is shown in Figure 3-6.

The failure models define how system components can fail, how often they might fail and how long it takes to repair them when they fail. This information is based on the trend analysis and history performance of the system. The load models can be based on a user's specification or they can consist of a few possible load demands. System state is when there is a combination of one or more concurrent events and a specific load condition is called a 'system.

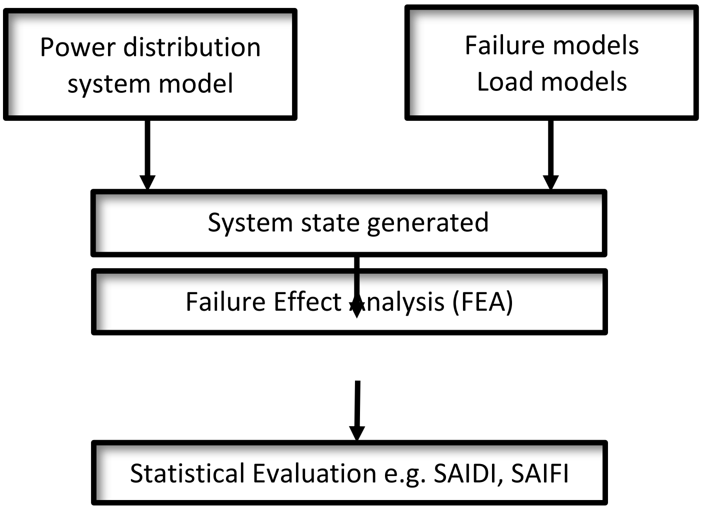


Figure 3-6: Basic reliability analysis flow diagram

FEA takes the power system through a number of post-fault operational states that can include:

a) Fault clearance by tripping of protection breakers or fuses.
b) Fault separation by opening separating switches.
c) Power restoration by closing normally open switches.
d) Overload alleviation by load transfer and load shedding.
e) Voltage constraint alleviation by load shedding

The data that is provided by the system state generation module together with FEA results are used to create the reliability statistics including indices such as SAIFI, SAIDI and CAIFI.

CHAPTER 4

KZN OU FAULTS STATISTICAL ANALYSIS

4.1 Introduction

This chapter gives a detailed analysis of KZN OU fault data from January 2010 till January 2014 and the anticipated effect of smart technology intervention. The aim is to demonstrate that when network visibility is improved, the outage reduction of as little as 10 minute per event has a significant improvement on the reliability of the power distribution system in terms of SAIDI improvement. Smart grid costs benefit analysis is conducted and the KZN OU performances as well as the sample networks selected are also discussed.

4.2 Eskom Distribution network

Eskom Distribution currently supplies more than 4.5 million customers through 8 000 MV feeders ranging from 1 kV to 33 kV, most of which have limited redundancy and back-feed capability. These feeders are geographically spread across South Africa as highlighted in Figure 4-1. The black marks inside the map indicate MV networks.

A test network model was developed in PowerFactory to validate the application of several smart technologies thereafter the methodology was validated on the few selected KZN OU networks. Eskom has nine Operating Units, it is important to note that even though sample networks were taken from the KZN OU, this methodology is applicable to the rest of the OUs with similar network characteristics.

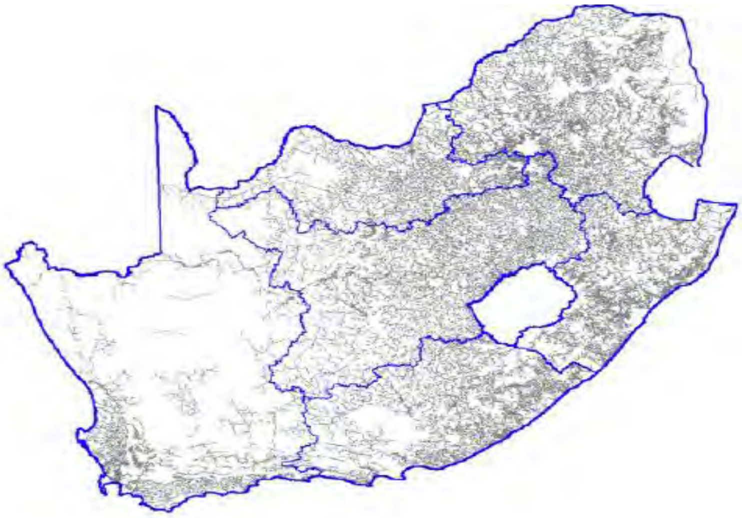


Figure 4-1: Geographic view of Eskom MV network across South Africa [78]

4.3 KZN OU faults analysis

KwaZulu Natal is located in a very interesting part of the country: there are coastal and inland areas. Along the coastal network faults may occur as a result of corrosion, vegetation, sugar cane fires and pollution. Inland network faults may occur due to veld fires and soil erosion. These makes the KZN OU unique in that all fault types from across the country occur on KZN networks. Currently the KZN OU is supplying 805 000 customers through 1200 MV feeders, which equates to 45 000km of length.

An analysis of faults for the KwaZulu-Natal Operating Unit (KZN OU) MV network was conducted for the period January 2010 to January 2014. There are 595 network feeders which have approximate 20 000 faults. The outcome of the analysis is summarised in Figure 4-2.

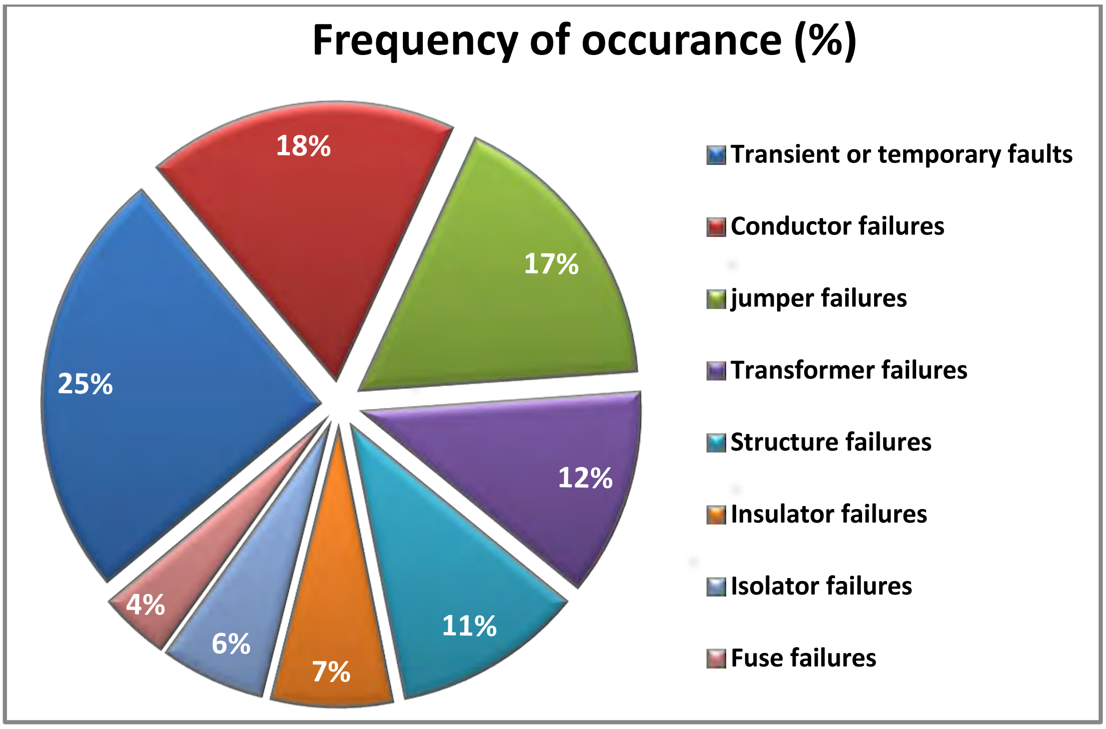


Figure 4-2: KZN OU faults analysis

As seen in Figure 4-2, a substantial proportion of the MV network faults are transient faults which are caused by factors including tree branches touching the conductors, birds and weather. It should be noted that the duration for all these faults are greater or equal to 5 minutes and this means that they contribute to SAIDI measures. Transient faults less than 5 minutes are not counted as an interruption and therefore does not contribute to SAIDI.

Eskom Distribution is continuously under considerable pressure to improve network performance and ensure future performance in international benchmarking analyses. Executive management is constantly investigating mechanisms to make a significant change in performance levels as measured by the reliability indices[79].

4.4 KZN OU Performance overview

The KZN OU SAIDI and SAIFI targets for the past financial years are shown in Figure 4-3; the downward trend on SAIDI shows that the target each year is to reduce overall outage duration while minimising the customer impact.

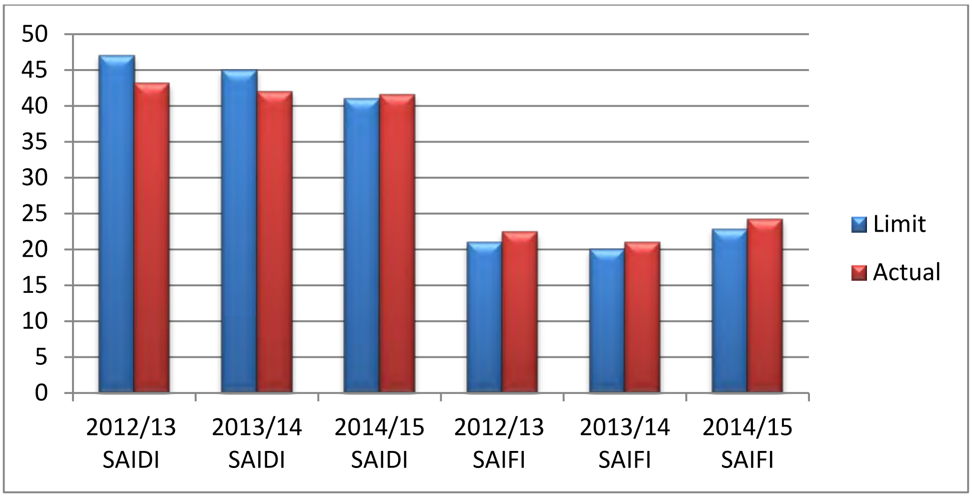


Figure 4-3: KZN OU SAID and SAIFI for the past 3 years

A detailed analysis that illustrates the month to month performance is shown in Figure 4-4, the limit for the 2014/15 financial year was 41, and the actual was 41,58.

KZN OU SAIDI and SAIFI for 2014/15 financial year

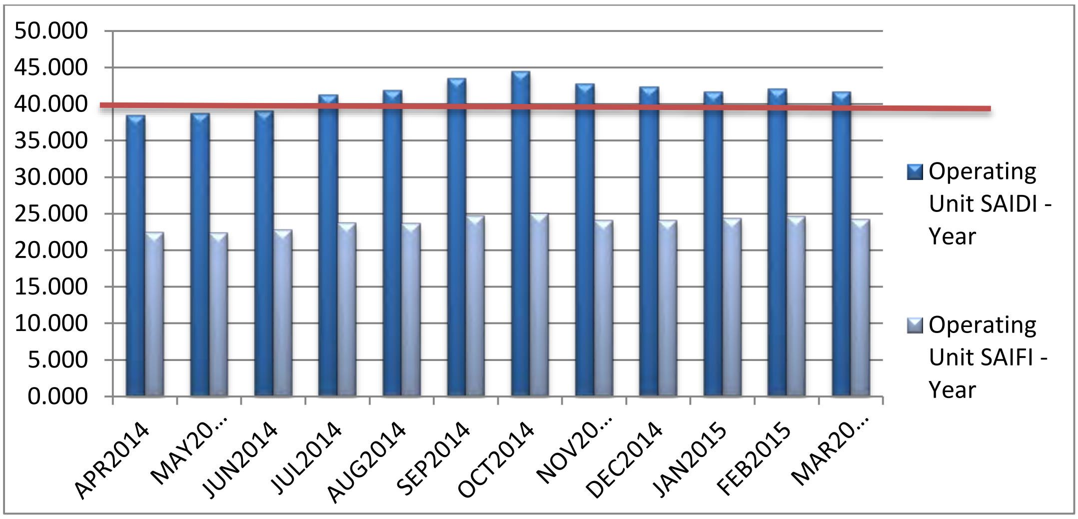


Figure 4-4: KZN OU 2014/15 performance

4.5 SAIDI and SAIFI for the KZN OU zones

The KZN OU is divided into three zones i.e. Pietermaritzburg, Newcastle and Empangeni. It is noted from Figure 4-5 that the Empangeni zone contributes significantly to the SAIDI because the majority of their networks are long rural networks. As a result their limit is higher as compared to the other zones.

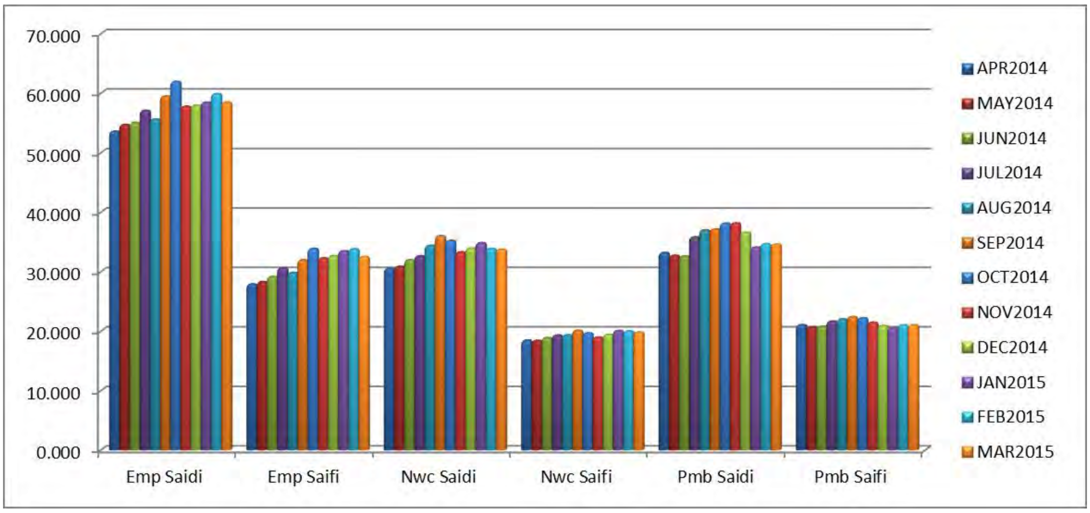


Figure 4-5: SAIDI &SAIFI for KZN OU zones

4.6 Sample networks selection

The sample networks used were selected from the Pietermaritzburg and Empangeni zones. This is because both these are exposed to different environmental conditions and their characteristics are quite different. Wartburg NB 22 and 23 11kV overhead lines can be 100% backed from each other and they are located in the Pietermaritzburg zone. Mtonjaneni NB1 11kV overhead line is a long rural network that is located in the Empangeni zone. More details and simulation results on these networks are further explained in Chapter 6. The selected networks are overhead lines because generally overhead networks contribute significantly to poor SAIDI and SAIFI values due to:

a) Outages caused by vegetation
b) Live wire contact faults
c) Conductor failures
d) Storm related faults
e) Structure failures
f) Bird Related faults

All of these are the major contributors to the KZN OU fault causes. This means if the focus can be placed on overhead networks, it will help improve the overall reliability of the networks by reducing outage duration while improving customer hours due to sustained interruptions.

Even though selected networks are overhead, the evaluated smart devices in Table 2-1 are also applicable to underground networks. Mostly cable / underground networks are short networks which are exposed to fewer faults due to:

a) Reduced live wire contacts
b) No momentary outages caused by vegetation
c) No structure failure caused by vehicle accidents
d) Reduced storm related faults

Generally, cable networks do not contribute much on longer durations due to sustained interruptions because they are not prone to faults causes such as tree branches touching the conductors, wind, animals and storm. However when they fail, they experience longer outage duration which leads to more customer hours per single event. This is mainly due to operational process involved associated with its maintenance.

4.7 Equipment distribution

The reliability modelling applied in this study does not take into account the actual contribution of customers along the length of the feeder due to the unavailability of this information at the time of this study. The homogenous model is therefore considered, meaning that all customers are evenly distributed beyond all transformers, as per the total number of customers on a specific feeder.

4.8 High level system model

The key is to analyse the network's characteristics, configuration and customer type before implementing a specific technology, as highlighted in Figure 4-6. This will also provide guidance with respect to locations of these devices.

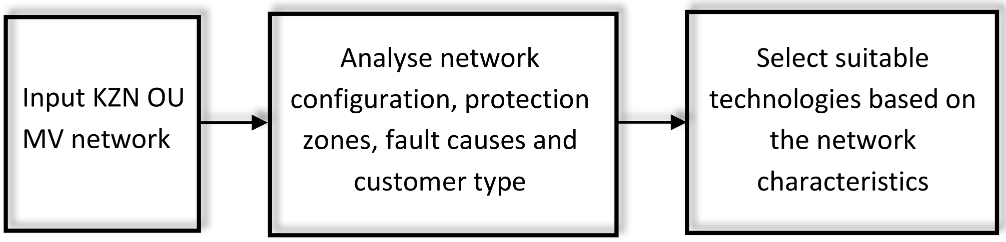


Figure 4-6: High level system model

4.9 Equipment failure rate, maintenance frequency and repair duration

Failure in a system is inevitable however the impact of failure can be minimized through the application of smart technology. As discussed in Chapter 2, smart technology has the ability to improve system reliability through reducing the frequency of outages and the duration of outages.

Travel times to site; travelling speed for fault finding, repair times, used for reliability analysis were based on performance history of the feeders as well as interviews and interactions made with site engineers and operators. Visits were made to different sites at Stanger Technical Service Centre (TSC) KZN OU, which falls under the Empangeni zone to validate the information. Reference with [79] was made to ensure that the information used is according to Eskom's standard practice. Component failure rates used for reliability studies were taken from [79].

Key Assumptions

a) KZN OU MV networks are maintained and operated well according to Eskom maintenance standards and are in a fairly good condition
b) LV networks are excluded, although MV/LV transformers are included;
c) Only overhead lines are included;
d) Equipment loadings are within the design limits;
e) No network component on the relevant part of the Distribution System is out of service due to an outage.

According to [80] , all Eskom MV networks were classified based on a spatial analysis, considering both network characteristics and operational environments, and were classified according to environmental modifier types as mentioned in Table 4-1. Because environmental factors play a significant role in terms of power distribution network performance, this line type information was taken into consideration when populating equipment failure rates information.

Table 4-1: Environmental modifier line type information

Type	Lightning	Vegetation	Corrosive pollution
Type 1	Low	Low	Low
Type 2	Low	Low	High
Type 3	High	Low	Low
Type 4	High	Low	High
Type 5	Low	High	Low
Type 6	Low	High	High
Type 7	High	High	Low
Type 8	High	High	High

According to the fault trend analysis for the Mtonjaneni NB1, Wartburg NB 22 and NB23 networks, it was concluded that they fall under type 2 in term of environmental factors, therefore their failure rates information were assigned as such.

The failure rates applied in the reliability analysis refers to sustained interruptions only, as shown in Table 4-2. No momentary interruptions were considered for the analysis. The failure rate of a fuse refers to a failure to operate, meaning that the protection on the fuse did not operate to isolate the faulty transformer from the rest of the network. This is simply classified as fuse failure. It does not refer to a fuse that needs to be replaced due to a protection operation because this will imply the fuse operated correctly and did not fail.

Table 4-2: Component failures

Equipment	Failure rates								
	Type 1	**Type 2**	**Type 3**	**Type 4**	**Type 5**	**Type 6**	**Type 7**	**Type 8**	**Unit**
Lines & branch lines	10.6	17.5	13.6	19.5	15.2	15.1	15.3	19.5	/100 km·a
Cables	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	/100 km·a
Switch	0.009	0.014	0.012	0.028	0.008	0.012	0.013	0.022	/a
Fuse	0.014	0.022	0.019	0.043	0.012	0.020	0.021	0.033	/a
Transformer / voltage regulators	0.048	0.062	0.052	0.065	0.060	0.060	0.056	0.070	/a

4.10 Component-specific repair times

The outage time associated with all faults is not the same, i.e. the time required to repair a transformer fault is much longer than the time required repairing a line fault. The outage duration associated with each of the different components should therefore be considered as shown in Table 4-3. Again these assumptions were based on the fault data analysis as well as Eskom’s current practice [79].

Table 4-3: Component repair times

Equipment	Repair times (hours)
Transformer	5.00
Lines and lateral line	2.00
Cables	5.00
Fuses	0.35
Disconnect / Isolator	0.50
Travelling time	2.00

Having investigated the application of smart technologies and its anticipated outcome in Chapter 2, an investigation across the entire KZN OU MV faults data from 2010-2014 was undertaken in MATLAB. Based on the savings shown by the fault path indicator during the work done by the author[81], the question posed is, what the impact on these networks will be if these FPI or any other smart device that makes the network visible are installed? A change in the SAIDI value would indicate the value of these.

A further analysis of fault data was conducted to determine the SAIDI and manipulate the recorded customer hours to indicate the value of smart technology. The minimum number of customers per line was 10. While the data is not perfect and there may be some mismatch, there is value in the results presented.

The histogram in Figure 4-7 illustrates the distribution of lengths of lines within the analysed data, where it can be seen that the majority of lines are below 100 km. It is anticipated that after installing fault path indicators or any smart device that increases network visibility; the SAIDI for these lines will improve simply due to the length of the line and the operational procedure for repairs. Most of the time is spent on sectionalising and fault finding as discussed in the previous chapters, this involves temporal restoration of healthy part of the network. This does not tell the perfect picture as it excludes the number of customers. A better representation would be a histogram relating the number of customers to length and number of lines.

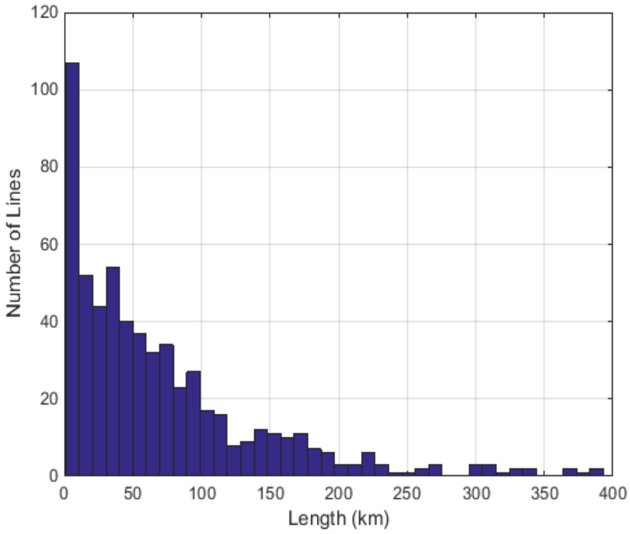


Figure 4-7: Line length distribution

Figure 4-8 illustrates that the number of customers for the lengths of the line. Comparing the two graphs it is now evident that the majority of customers exist in the networks over 100 km.

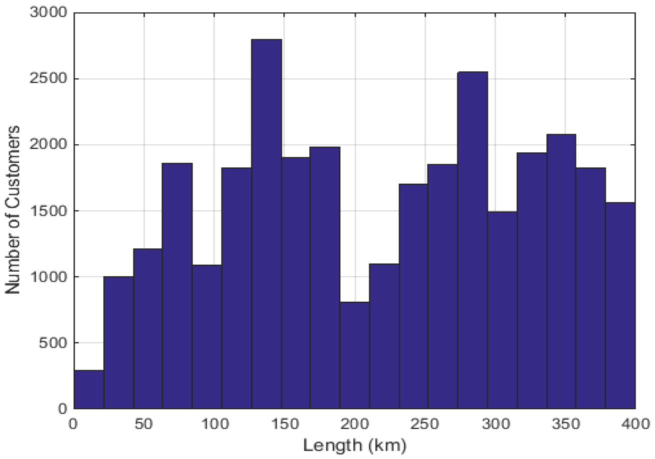


Figure 4-8: Customer distribution

Further correlating all the information in a single plot in Figure 4-9 confirms this point that there are fewer lines of length but the total customers are much larger. The small blue sphere for line lengths less than 25 km indicates a large number of lines but a small number of customers, whereas the large yellow sphere for networks between 125 and 150 km indicates a low number of lines and high number of customers.

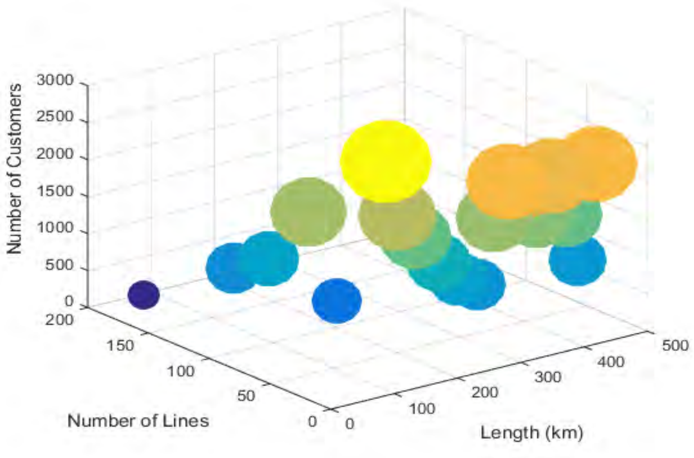


Figure 4-9: Correlating customers and lines

As SAIDI is dependent on the number of customers and the fault time, it becomes critically important to focus on the lines with a large number of customers and long fault durations i.e. lines from 100 to 400 km. Smart technology that makes this visible is key to reducing the fault finding and maintenance durations and hence improving SAIDI by reducing the customer hours. However lines with fewer customers cannot be excluded totally as the customer type information needs to be taken into consideration.

Figure 4-10 illustrates the SAIDI for different kilometres of line. The x axis illustrates 0 to 80 km, this indicates the SAIDI value for every length of line above the value shown. It is illustrated that the SAIDI increases as you exclude the lower lengths of line; this is expected as any fault on a longer line with more customers would result in more customer hours and a greater SAIDI value. SAIDI is directly proportional to the duration of the affected customers, which is the duration of the affected customers over the customer base within specified boundaries. As expected outage duration is longer in long lines because more time is spent on sectionalising and fault finding as opposed to short lines. Therefore this graph is behaving as expected and the sudden reduction on SAIDI is because the line is long but feeding few customers.

Two savings are illustrated by Figure 4-10, the first is just a 10 minute saving per fault and the second is a 1.67 min saving per km per fault. These time estimates are based on the test model which is further discussed in the next chapter. It is evident that a 10 minute saving per fault significantly reduces the SAIDI value, of more significance is the saving in SAIDI produced by the 1.67 min saving per km per fault. The value reduces as the length of line increases, again indicating that the long lines with high customers may be the focus for network visibility and means that by installing fault path indicators on strategic positions on the network, the operator will go and operate the correct isolator to isolate the fault from the rest of the network instead of doing multiple operations during sectionalising depending on other factors including the terrain and environmental.

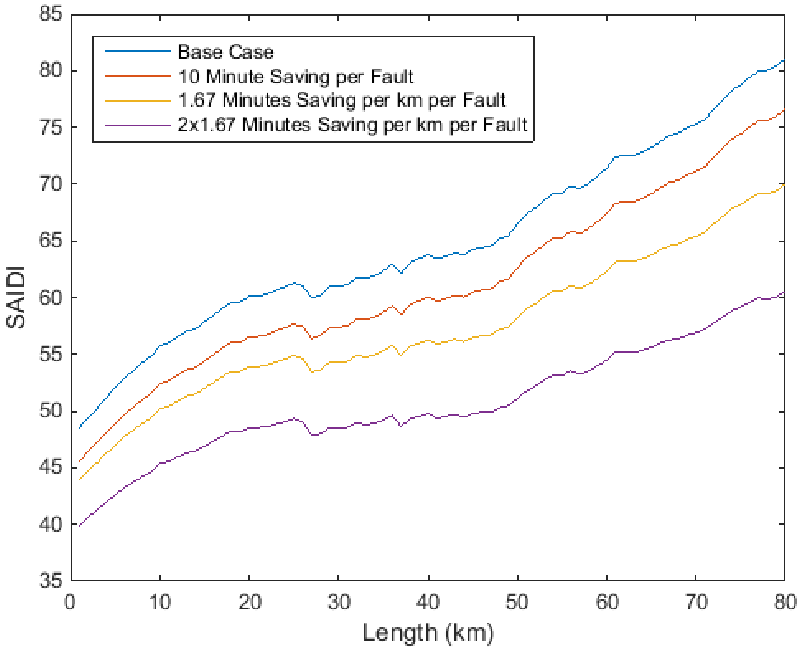


Figure 4-10: SAIDI - KZN OU MV networks

4.11 Cost benefit analysis

The Distribution Network Code requires all shared network investments to be justified on a least economic life-cycle cost basis. The shared network is that network that is not dedicated to a single customer. This implies quantification of the following typical costs and benefits[79]:

4.11.1 Life-cycle costs to be considered

a) Project capital costs (including overhead cost, interest during construction, discount rate etc.)

b) Infrastructure operating costs, including any associated telecommunications costs.
c) Planned maintenance and refurbishment costs to ensure the infrastructure performs as per the design for the expected asset life.
d) Unplanned maintenance and repair costs to restore failed equipment back to service.

4.11.2 Life-cycle benefits to be considered

a) Reduced interruption costs to Eskom, e.g. SAIDI due to planned/unplanned interruptions
b) Reduced interruption costs to customers, as a function of the cost of un-served energy as a function of planned/unplanned interruptions)

To quantify different smart grid's financial costs and benefits, typical installed equipment costs as shown in Table 4-5 and the standard COUE rates as shown in Table 4-4 were used. The expected lifetime of network visibility equipment was assumed to be 15 years[82]. The details are further explained in the next chapters.

Table 4-4: COUE rates used on different customer classes

Customer classification	COUE rate (R/kWh)
Industrial	6.69
Mining	14.14
Commercial	102.90
Agricultural	20.16
Residential	20.83
Prepaid	5.22
Redistributors	29.53
Traction	111.90
Other	27.95

Table 4-5: Estimated costs for different equipment

Component description	Estimated costs
RTU installation at substation	R200 000
Installation of FPI integrated with RTU	R20 000
Installation of transformer remote monitoring per transformer	R20 000
Communications to a feeder for AMI and distribution smart circuits	R170 000
Intelligent recloser (tie point)	R400 000
Remotely controlled switches	R400 000
Distribution Automation (DA)	R3 000 000

4.11.3 Basis of Smart Grid costs

According to [24] Smart Grids are by their nature difficult to estimate for different reasons as follows:

a) The smart technology always requires integration of digital technology. Mostly distribution infrastructure has different failure and life cycle than the majority of today's grid technologies; the rate for this equipment needs to be estimated.

b) It is easy to declare smart technology inoperative before the end of its life cycle due to defective Information and Communication Technology (ICT) Therefore; rational replacement costs must be estimated.

c) Most smart grid technologies are still new and therefore there is uncertainty in its performance.

d) Its marginal cost declines as it matures due to any additional costs required for new installations.

Distribution's feeder base SAIDI was calculated based on Centre of Mass theory which is defined as the point in a system at which the whole quantity may be considered as concentrated, therefore overall SAIDI improvement can be defined as[83]:

$$X = \frac{(a_1 M_1)+(a_2 M_2)+(a_3 M_3)}{(a_1+a_2+a_3)} \tag{31}$$

Where:

a_1 = coefficient for sample network

a_2 = coefficient for Mtonjaneni network

a_3 = coefficient for Wartburg network

M_1 = SAIDI for each smart grid intervention using sample network

M_2 = SAIDI for each smart grid intervention using Mtonjaneni network

M_3 = SAIDI for each smart grid intervention using Wartburg network

The results indicate that increasing network visibility through smart technology application will always have a high positive benefit-cost ratio, and that its investment can always be economically justified as indicated by Figure 4-11.

Depending on capital investment, this technology can slowly be introduced by allowing the operators to manually do the operating sequence until full automation is allowed. Operational and maintenance cost savings can also help justify capital investment.

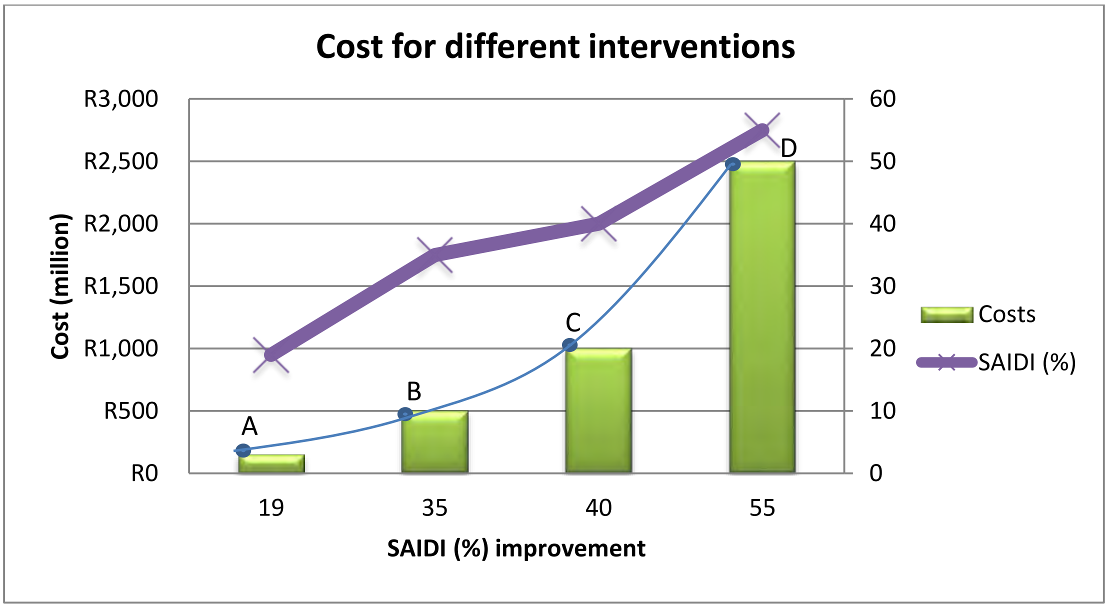


Figure 4-11: Benefit and cost analysis for different smart grid interventions

The assumption is that all distribution substations already have an RTU installed; therefore RTU costs were not encompassed.

a) At point A, is when transformer remote monitoring is installed at feeders prone to transformer related faults,
b) Point B is when FPIs are installed,
c) Point C is when advanced automated feeder switches are installed
d) The combination of these technologies is specified by point D as indicated by the benefit-cost ratio in Figure 4-11

As smart grids mature, and the rate of new installations increases, its marginal costs are likely to decline rapidly as shown by Figure 4-12 [24].

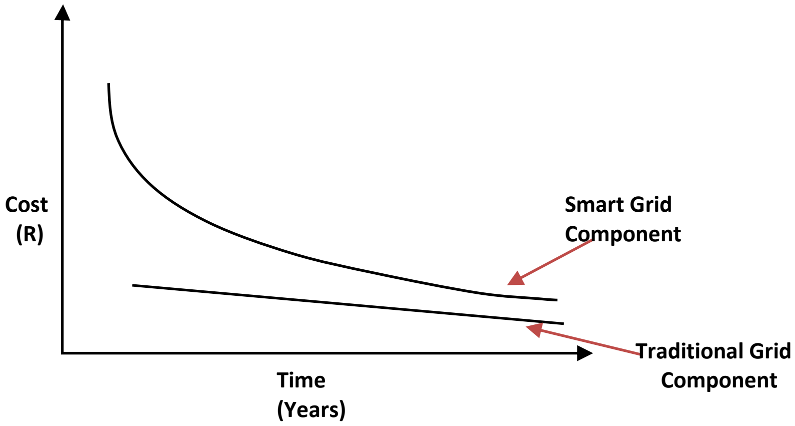


Figure 4-12: Costs for Grid components

4.12 Discussion

This chapter has highlighted the performance for KZN OU networks and how their performance can improve with as little as 1.6 minutes savings per kilometre on sectionalising and fault finding time. It was highlighted that a 10 minute saving per fault event significantly reduces the SAIDI value by reducing customer interruption hours and improves the overall system performance. The question asked earlier in this chapter about the impact of any piece of equipment that makes the network visible on KZN OU networks was answered.

It was demonstrated that the focus on the feeders with a large number of customers and long fault duration is critical since SAIDI is dependent on the number of customers and the fault duration. Analysed networks performed as expected by demonstrating the improved SAIDI value as the length of line increases, this also verify the theory discussed in Chapter 2 which states that the longer network feeders mean more components on the network which eventually leads to poor performance. Again demonstrating that the long lines with high customers may be the focus for network visibility as compared to short lines with fewer components means that by installing fault path indicators on strategic positions on the network does reduce customer hours. Fault Path Indicators are further explained in later chapters where the criticality of its installation is demonstrated.

KZN OU fault data analysis was performed and overhead networks were selected as sample networks due to their significant contributions to the unreliability of the network. A cost benefit analysis was performed and the results indicate that increasing network visibility through smart technology application will always have a high positive benefit-cost ratio, and that its investment can always be economically justified.

CHAPTER 5

TEST MODEL EVALUATION AND RESULTS

5.1 Introduction

The test network developed is aimed at demonstrating how the network is expected to perform with different smart devices placed in different locations. In Chapter 4 the sectionalising plus fault finding time was reduced to as little as 10 minutes per event and this was applied to all faults (2010 - 2014) in the KZN OU network regardless of the position of the device. The application of smart devices discussed in Table 2-1 is simulated. Also there is a need to determine that the application of the devices in the suitable test network validates that there will be an improvement in performance. The behaviour of this network is crucial before smart devices are simulated on real networks.

5.2 Results on sample network developed

The test network in Figure 5-1 resembles a typical 11 kV overhead radial network, the base network consist of disconnect switches which are important to isolate the network during maintenance or fault conditions.

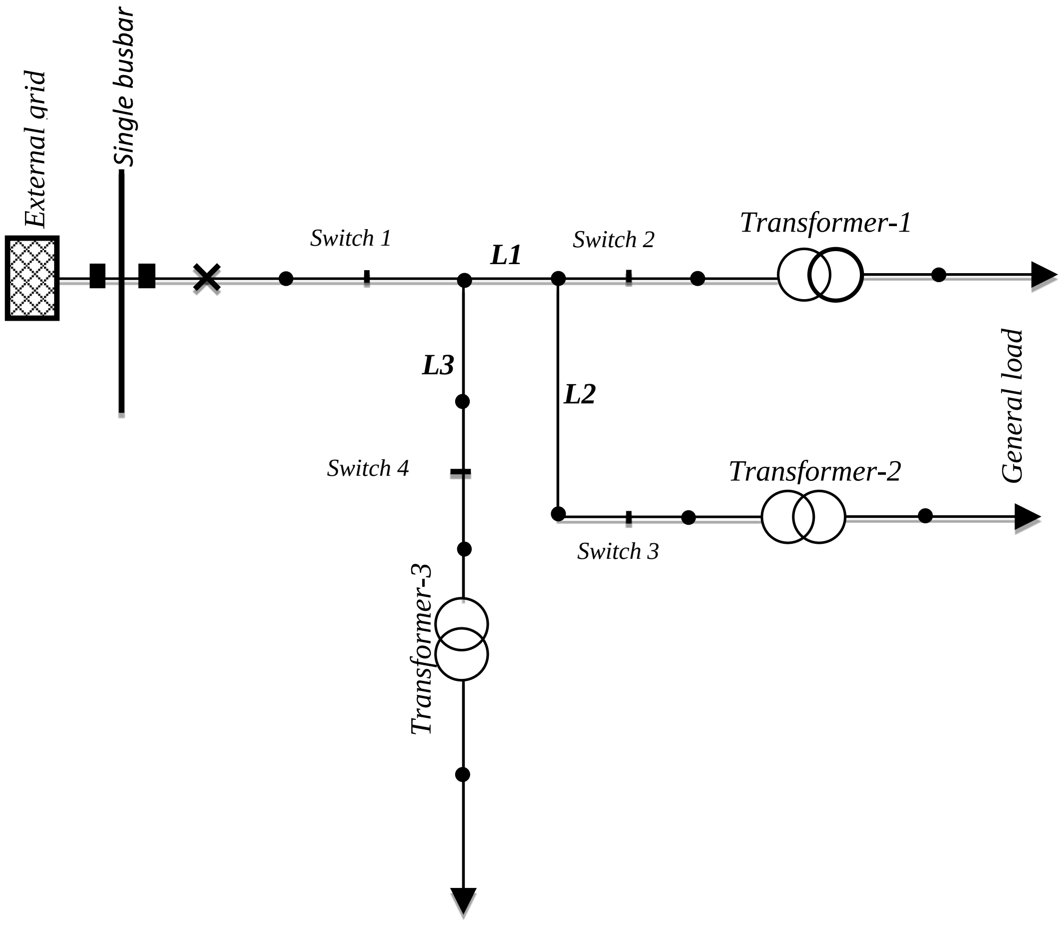


Figure 5-1: Test network model

Since the KZN OU is fusing their MV transformers and the intent is that for transformer faults the fuse should operate thus isolating the faulty transformer from the rest of the network. It was important to demonstrate both networks and see how they will perform. All the different smart grid interventions were evaluated on both a fused and an un-fused network. The network in figure 5-2 was developed to represent fused transformers.

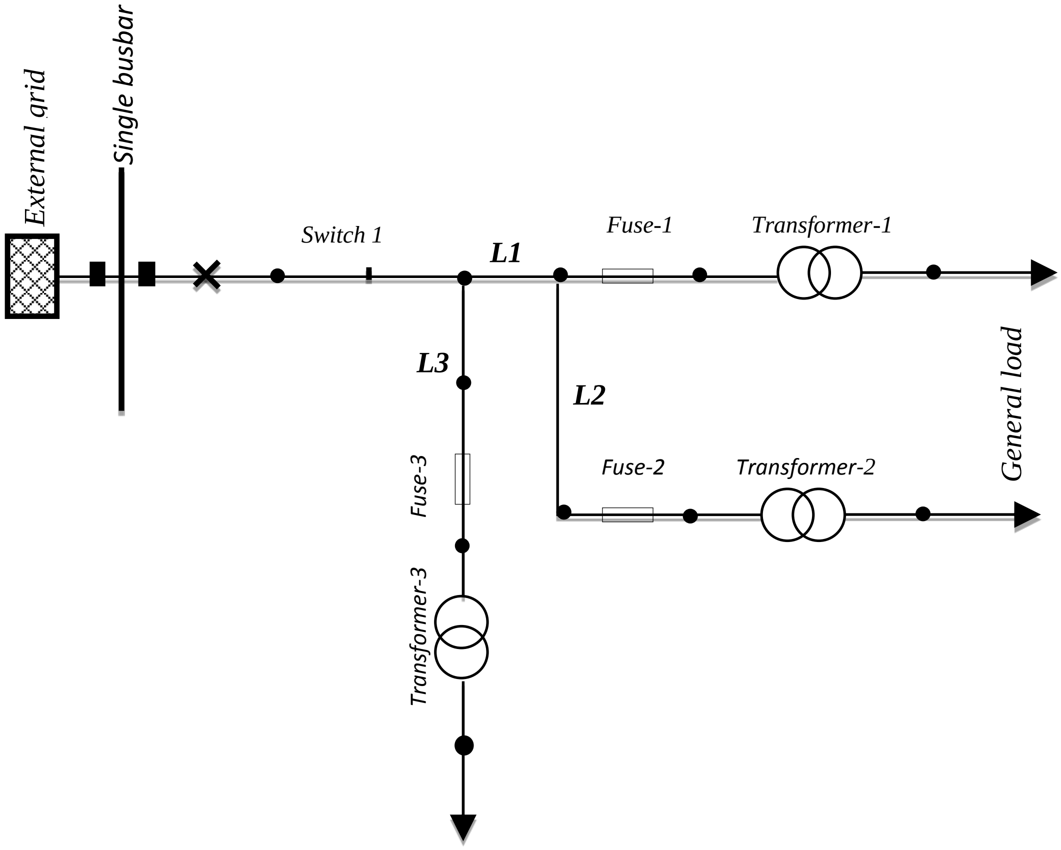


Figure 5-2: Test network - fused transformers

The components for this test network are shown in Table 5-1. Through system reliability modelling it has been observed that system configuration and topology, line length as well as the number of customers play a major role in network reliability.

Table 5-1: Equipment exposure

Equipment count	
#Transformers	3
#Switches	4
#Overhead lines	L1 and L2 at 50km each, L3 at 20km
#Customers	500
#Breakers	1

Mathematical analyses as well as PowerFactory Version 15.1 were used to verify the MV network reliability modelling. The failure rates and repair times as listed in Table 4-2 and Table 4-3 were assigned to the relevant components, as shown in Table 5-2.

Table 5-2: Mathematical approach for SAIDI and SAIFI

	km	λ (km.f/yr)	λ (f/yr)	Dispatch & Travelling (hr)	r (hr)	Customers interrupted for Dispatch/Travelling time	Customers interrupted for Repair duration	Customer interruptions	Customer interruption durations	SAIFI	SAIDI
Line 1	50	0.15	7.5	2.00	5.0	500	500	3750	26250		
Line 2	50	0.15	7.5	2.00	5.0	500	500	3750	26250		
Line 3	20	0.15	3	2.00	5.0	500	500	1500	10500		
S1			0.66	2.00	0.5	500	500	330	825		
S2			0.66	2.00	0.5	500	100	330	693		
S3			0.66	2.00	0.5	500	100	330	693		
S4			0.66	2.00	0.5	500	300	330	759		
TRFR1			3	2.00	10.0	500	100	1500	6000		
TRFR2			3	2.00	10.0	500	100	1500	6000		
TRFR3			3	2.00	10.0	500	300	1500	12000		
		Total	**29.64**					**14820**	**89970**	**29.64**	**179.94**

Table 5-2 also shows SAIDI and SAIFI values for the base network. These values are used to validate the impact of fused transformers and various smart devices on the network.

It should be noted that in PowerFactory a failure rate and repair duration cannot be assigned to an isolator or breaker. To address this shortcoming the failure rate and repair duration were assigned to the terminal to which the isolator/breaker is connected. The breaker operating times were set to 1 minute. The time required to switch the disconnectors was set to 120 min, which is the expected response time of 2 hour. It should however be noted that this two hours include travelling time for the operator to get to site and conducting switching on the first disconnector, thus temporarily restoring customers that are on the unaffected part of the network.

The smart technology has the ability to analyse and restore supply to a healthy part of the network without human intervention. Thus improving overall system efficiency and minimising operational costs.

Figure 5-3 and 5-4 show the placement of automated feeder switches in different locations along the feeder. Automated feeder switches improve the reliability of the network by reducing the outage duration, frequency of interruptions as well as reducing the impact of the affected customer. This is a crucial step as the position of automated feeder switches has a big impact on SAIDI and SAIFI measures.

a) At point number 1 there is the base network - no automated switch added.
b) Point number 2 is when the automated feeder switch was placed in line 3. Line 3 is a lateral line that feeds 300 customers as highlighted in Figure 5-3.
c) Point number 3 is where the automated feeder switch is placed in line 2; this lateral line feeds 100 customers.
d) And point number 4 is when the automated feeder switch was placed in line 1; this portion of the network also feeds 100 customers.

Customer base and length of the line need to be taken into account when placing these switches. Also the number of customers that will be affected by a single breaker operation is significant. Line 3 is 20km long but because 300 customers will be affected it contributes poorly to SAIDI and SAIFI values. This is because of its position in the network; switch 1 will have to be open for any fault that may occur on line 1. This simply means, for optimal performance of the network, configuration and topology is key when it comes to the placement of any device on the network.

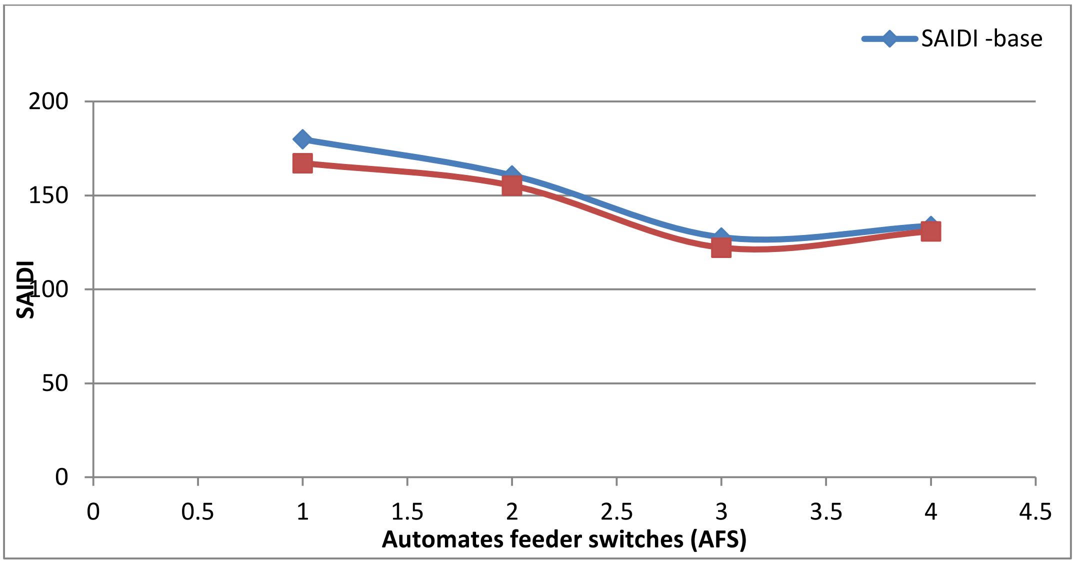


Figure 5-3: SAIDI - automated feeder switches

Integration of auto reclosers with RTU reduces sectionalising time by isolating the downstream network through the remote switching. This is the part of the network closer to the load. All loads on the upstream breakers remain supplied; this is the part of the network closer to the source. This is recommended for all networks as it gives an indication of whether the fault is downstream or upstream, meaning only customers on the faulted section of the line are affected by a sustained interruption, the rest of the customers will be unaffected. The position of these devices along the network is very important as it trips and isolates the downstream network during fault conditions.

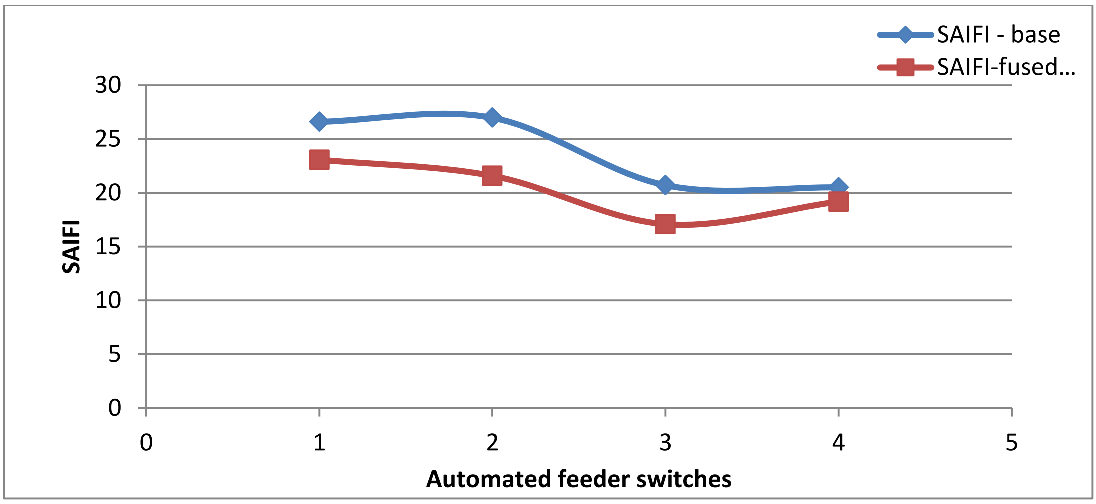


Figure 5-4: SAIFI - automated feeder switches

Different positions of automated feeder switches were modelled. In this network the best performance is achieved at point number 3 when the automated feeder switch is placed on line 2 (L2). Improved results are achieved on the network with fused transformers. It was also noted that network length as well as number of customer connected have a big impact on network reliability.

5.3 Application of Fault Path Indicators

Fault path indicators remotely report the passage of fault current. This device is expected to significantly reduce the impact of number of customer affected, by quickly identifying the faulted section. It provides network visibility to the control center immediately when there is an interruption; sectionalizing and fault finding time will be minimized because the operator will go straight to the faulted section and back-feed the rest of the customers. Without this device the operator will have to perform switching to try and figure out where the fault is situated. For this network, two smart fault path indicators are installed on line 2 and line 3.

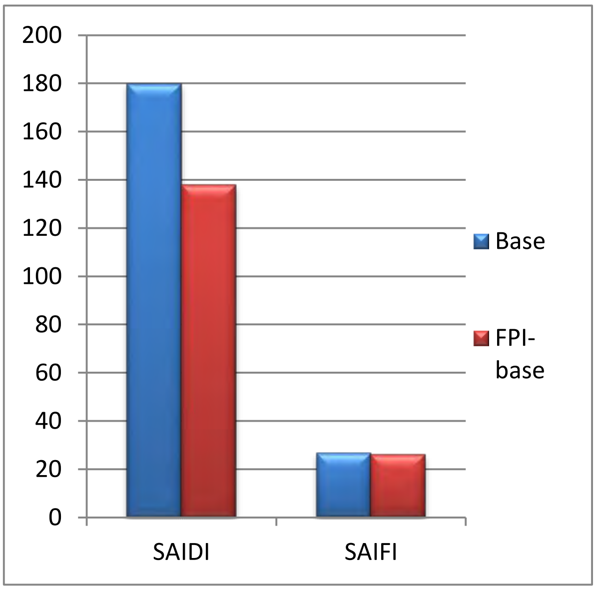


Figure 5-5: Base network SAIDI and SAIFI – FPI

The results of the smart fault path indicators are demonstrated by Figure 5-5 and Figure 5-6, which indicate both SAIDI and SAIFI for the base and fused network. As anticipated, there is a significant improvement on SAIDI, a greater improvement is achieved on the fused network. It is expected for a fused network to perform better than un-fused due to its ability of isolate the faulty transformer from the rest of the network without interrupting the whole network.

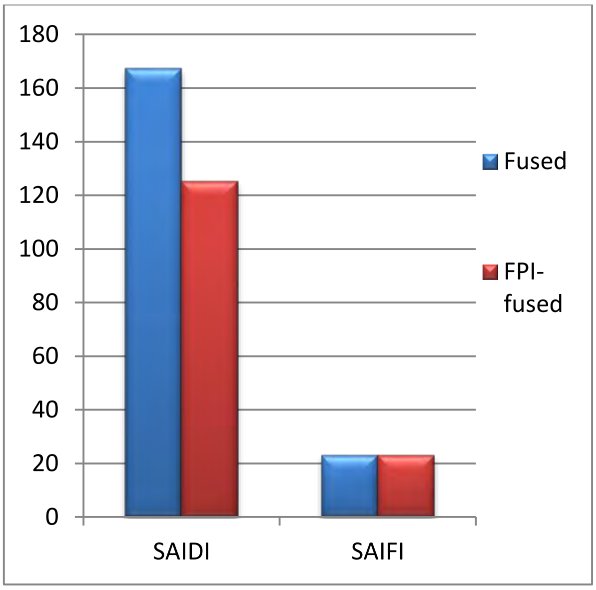


Figure 5-6: Fused network SAIDI and SAIFI- FPI

The interruption frequency of the faulted customers did not change only the duration through minimising sectionalising and fault finding time. This is mainly because this device reduces the duration of the outage. This could be due to network configuration and the fact that there are very few components in this network.

5.4 Application of transformer remote monitoring

If there is a transformer fault on the network, then on the faulted section the patrolman has to drive to every single transformer to identify which transformer has faulted**.** The application of a transformer remote monitoring device on the test network has reduced sectionalising as well as fault finding time during transformer faults as it provide visibility for any outages taking place at the transformer. The fault finding time contributes significantly to outage duration as the operator has to drive at less than 20 km/h to perform visual inspection. In this instance fault finding time was eliminated as the transformer failure is visible to the RTU.

As demonstrated in Figures 5-7 and 5-8, there is not much improvement on SAIDI with this device. The reason is that the rest of the faults will behave as normal. This means that this device will only benefit transformer faults. In order to get maximum benefit from this device, it is better to install it on networks that are susceptible to transformer related faults. Also the SAIFI remained unchanged because this device reduced fault duration, it does not stop the fault from happening, it just makes the location of the fault visible.

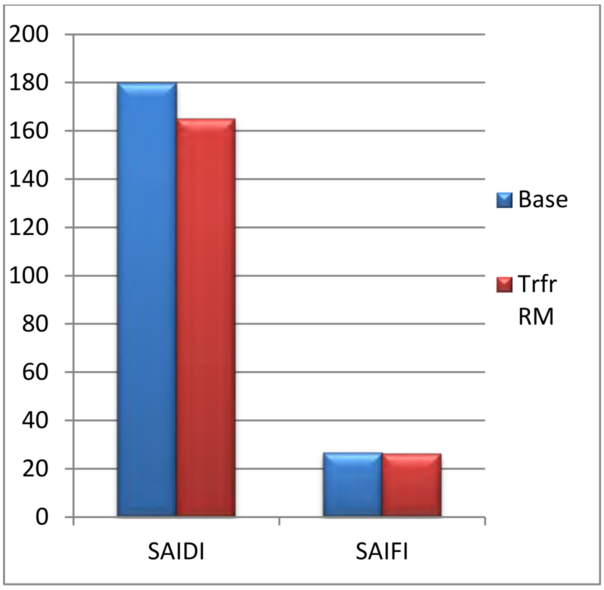


Figure 5-7: Base SAIDI and SAIFI - transformer remote monitoring

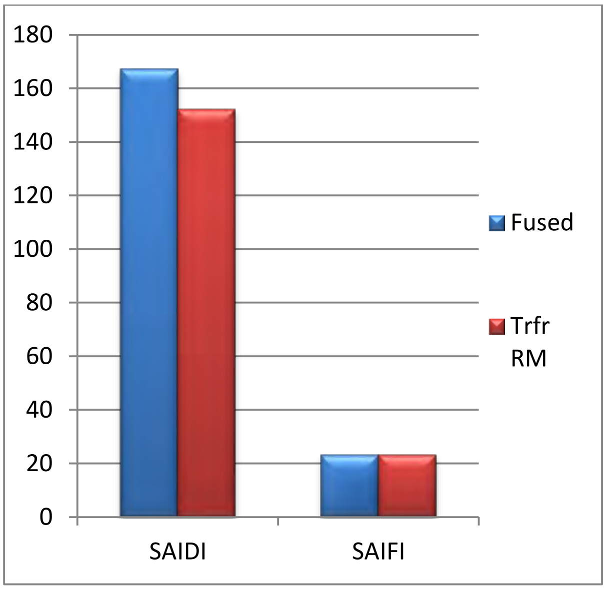


Figure 5-8: Fused network SAIDI and SAIFI - transformer remote monitoring

5.5 Application of Fault Location, Isolation and Service Restoration (FLISR)

This technology was looked at and it was noted that it is ideal for the network with a back feed capability. It provides optimal feeder re-configuration during unplanned outages. It detects feeder faults, determine the fault location (between 2 switches), isolates the faulted section of the feeder (between 2 switches) and restore service to “healthy” portions of the feeder. It also provides the facility of restoring some customers before patrolmen arrive to site. The network may require additional tie points to accomplish FLISR. This technology was not modelled in this case as it is best, suited for networks with an alternative source, it is however modelled in the next chapter.

5.6 Combination FPI and automated feeder switch

As highlighted earlier, the automated feeder switch performed well when placed in line 2. Futher demonstration was done where distribution automation was simulated through the application of both automated feeder switch and smart fault path indicator on the test network.

The automated feeder switch is installed in L2, and the FPI is installed in L1 and L2. Figures 5-9 and 5-10 illustrate Distribution Automation(DA), where two or more devices are installed in one network. There is a significant improvement on both SAIDI and SAIFI. As expected, optimum results are achieved when the smart technology is applied on the network with fused transformers.

It should be noted that results are network specific and only one automatic feeder switch is installed in this instance. Different results may be obtained for different network configurations. However to achieve maximum benefits of the smart technology, it is recommended to first analyse some key factors including network topology, configuration, equipment type, environment, number of customers and the customer type that will be interrupted per single breaker operation as well as the history of faults on the network.

It is also important to highlight that even if the second automated feeder switch is added on this network it does not make any difference in terms of improving the reliability of the network any further. Therefore this means that the amount of smart devices added in the network is irrelevant in terms of reliability improvement; however the application of smart devices in the strategic positions along the network is key.

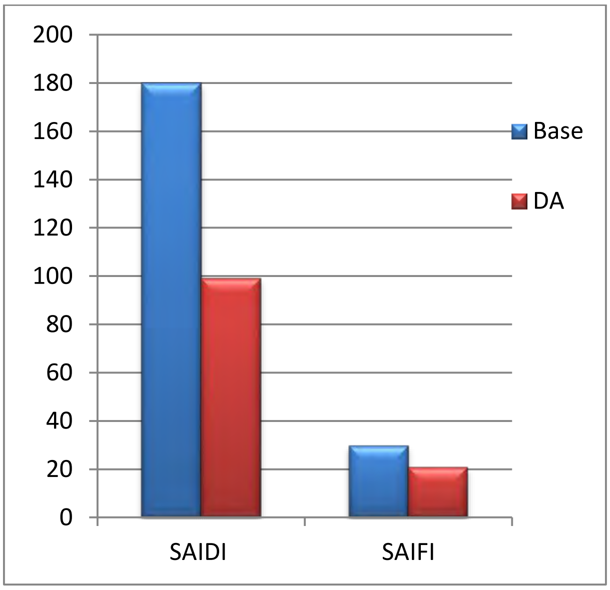


Figure 5-9: Base network SAIDI and SAIFI - Distribution Automation

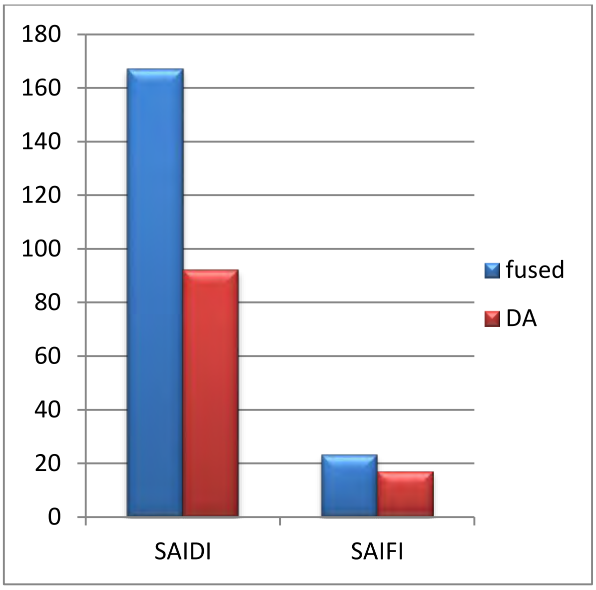


Figure 5-10: Fuse network SAIDI and SAIFI Distribution Automation

5.7 Discussion

Different smart technology intervention has been simulated in the test network. The results have proven that smart technology provides greater network visibility to disturbances over traditional approaches. This means that when a breaker trips network control is immediately aware of the interruption as opposed to only being made aware when a customer calls in to the contact centre. The results are summarise in Table 5-3. It has also highlighted the importance of the location of the device along the network.

Table 5-3: Results for different smart devices

Smart device	SAIDI (hour/yr)				SAIFI(times/yr)			
	Base	Smart device	Fused network	Smart device	Base	Smart device	Fused network	Smart device
Automated Feeder Switch	180	128	167	122	27	20	23	17
Fault Path Indicator	180	138	167	125	27	27	23	23
Transformer remote monitoring	180	165	167	152	27	27	23	23
Distribution Automation	180	100	167	95	27	20	23	17

a) Installation of FPIs has yielded SAIDI improvement through minimizing fault location time. It was expected that the SAIFI of the network will not change due to the fact that the device does not improve the number of times the customer is affected, but improves the sectionalising and fault finding time. There is a 30% improvement of the SAIDI

b) Automated feeder switches have improved both the SAIDI and the SAIFI of the network through automatic isolation of the faulty part of the network before the operator gets to site. Application of this technology has reduced fault finding as well as maintenance costs. It also minimises the number of customers exposed to a fault within seconds as opposed to waiting for an operator to get to site. There was a 32% improvement on the SAIDI and a 37% improvement on the SAIFI

c) Transformer remote monitoring has also reduced the sectionalising and fault finding times for transformer related faults. For optimal performance of this device , it needs to be installed in networks that are prone to transformer related faults. It provides visibility in such a way that by the time the operator get notified of a fault , they will also be made aware if it is a transformer failure, so they will have to carry a spare transformer to site to avoid delays. There was only a 15% improvement on the SAIDI using this device.

d) Distribution automation highlights the fact that two or more smart technologies can be installed in one network to achieve optimal performance; however, certain factors such as customer base and network configuration need to be looked at very closely. Each technology needs to be justifiable, as demonstrated in the test network just one automated feeder switch and two FPIs were enough for optimal performanceAdding more on this network was not improving the performance of the network any further. Both the SAIDI and the SAIFI were improved by this technology by 44% and 37% respectively.

Importantly, the migration to a smart grid can be done gradually, where devices can be installed in stages depending on the needs of the utility. Whether the focus is SAIDI or SAIFI or both. It was also established that FLISR technology is suitable for interconnected networks. In the next chapter a more complex and interconnected sample network will be analysed.

CHAPTER 6

KZN OU NETWORKS EVALUATION AND RESULTS

6.1 Introduction

Smart devices are applied on selected networks in the KZN OU. The aim is to demonstrate the benefits of smart technology on real networks. Significant benefits of smart devices were realised in the test network discussed in Chapter 5. Since the test network is a simple radial feeder, not all smart devices were tested so the intent now is to test all smart devices discussed in Chapter 2. Selected sample networks with different characteristics were simulated to validate the results.

6.2 Sample networks

The sample networks used are selected from Pietermaritzburg and Empangeni zones. This is because both these are exposed to different environmental conditions and their characteristics are quite different.

Table 6-1: Component exposure

Networks	#Transformers	#Switches	#Overhead lines	#Customers
Wartburg NB 22 11kV	62	94	50km	151
Wartburg NB 23 11kV	88	120	57km	266
Mtonjaneni NB1 22kV	193	259	175km	925

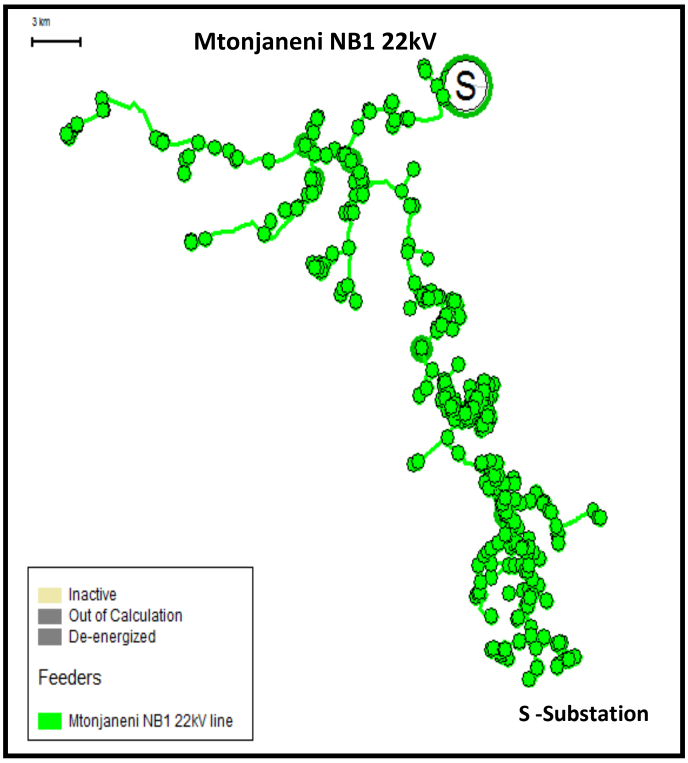


Figure 6-1: Geographic view of Mtonjaneni NB1

The number of equipment for these networks is indicated by Table 6-1. Wartburg NB 22 and 23 11kV overhead lines can be 100% backed from each and Mtonjaneni NB1 11kV overhead line is a long rural network. Each network consists of different components which can fail and result in an outage on a feeder.

The approach taken for the reliability calculation of MV networks recognizes that, from first principles, certain components like length of line, number of transformers, location of fuses and breakers etc. have a significant impact on the reliability of a feeder. The operational environments in which the different types of equipment operate also influence their performance. Therefore the expected level of performance (SAIDI) of these networks will be sensitive to network topology, customer numbers, operating environment etc. As noted in Figure 6-1, Mtonjaneni NB1 has a high number of equipment and a high number of customers and is therefore expected to be less reliable when compared to Wartburg NB 22 and NB23 shown in Figure 6-2.

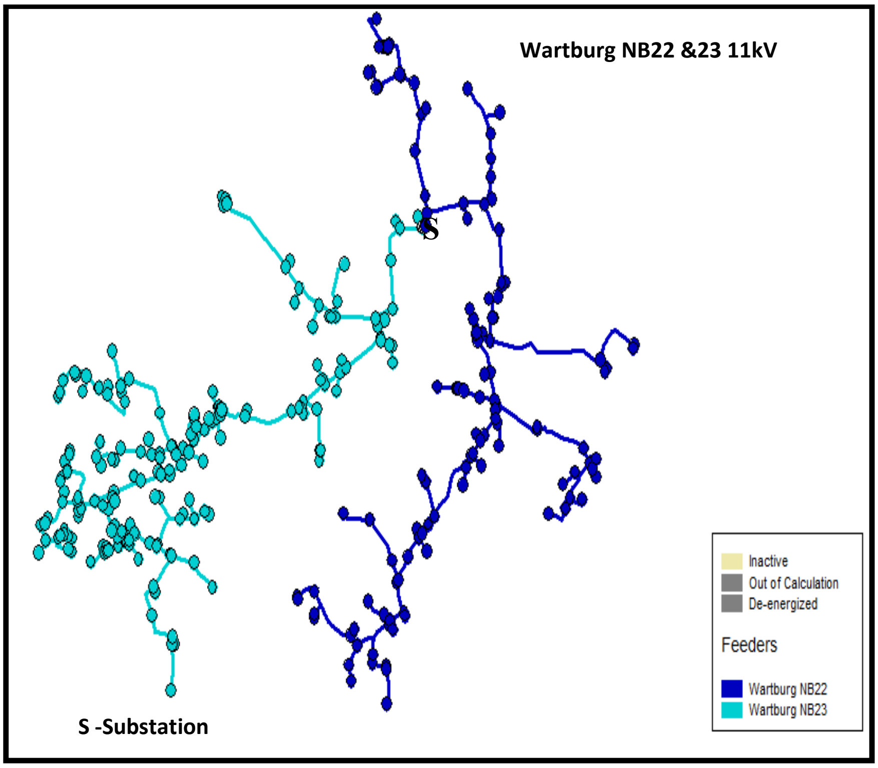


Figure 6-2: Geographic view of Wartburg NB22 & NB23

6.3 Mtonjaneni NB1 22kV and Wartburg NB22 and NB23 11kV network results

The failure rates and repair times as listed in Table 4-2 and Table 4-3 were applied on these networks and assigned to each component.

Mtonjaneni NB1 22kV network is separated into 5 protection zones, which is the section of the line bounded by an upstream breaker or a recloser that will trip for a downstream fault that is S366, S330, S320, S329 and S325 as indicated by Figure 6-3. These breakers are visible to the control centre through a Remote Terminal Unit (RTU) and this makes it easier to sectionalise and fault find without interrupting the rest of the network. It should be noted that SAIDI and SAIFI calculations are based on all possible faults thrown in different parts of the system.

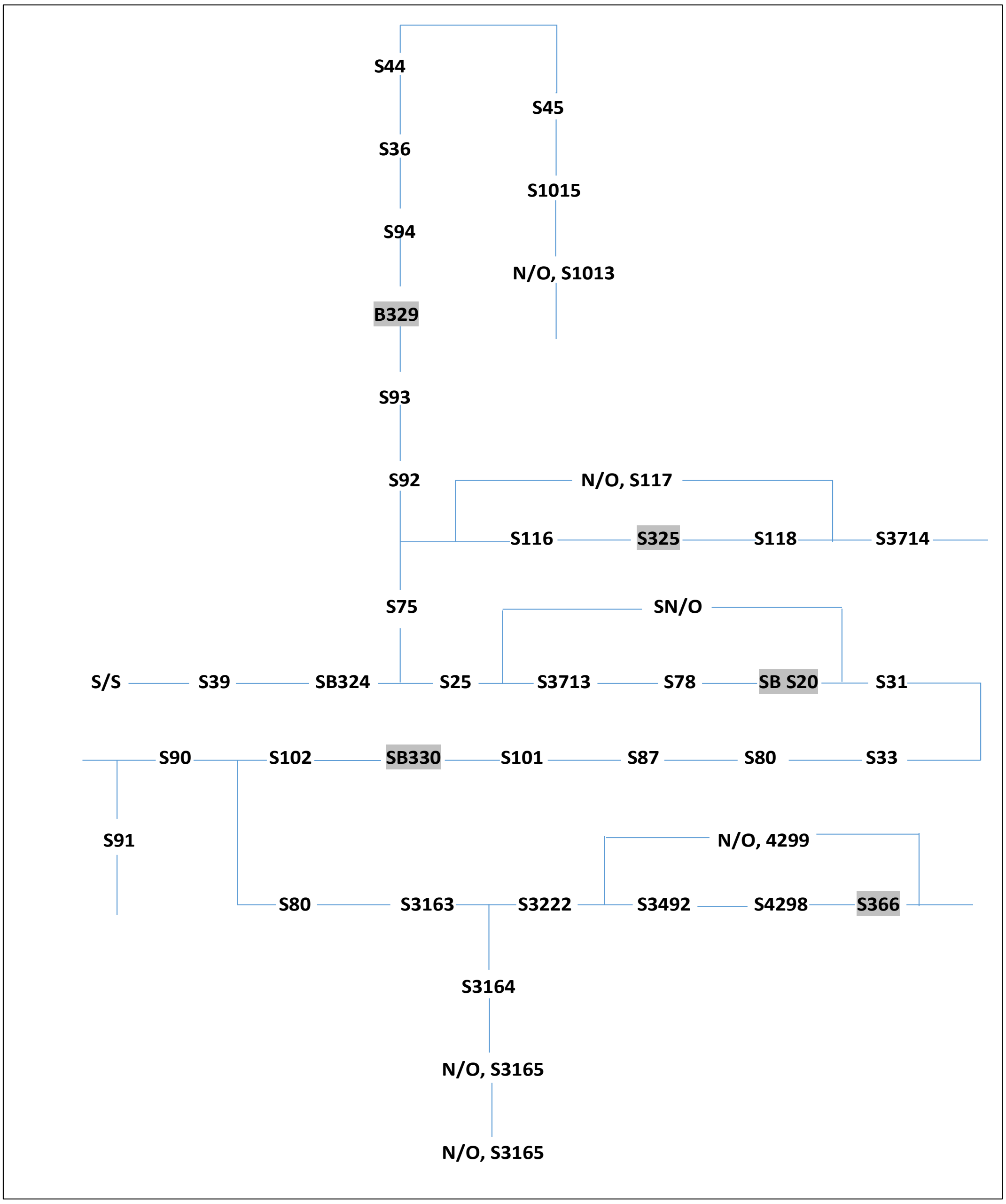


Figure 6-3: Mtonjaneni network single line diagram

Figure 6-3 also indicates the high level single line diagram for the Mtonjaneni NB1 22kV network. This is a very long network therefore not all switching points are represented by this diagram, only the critical points to reflect how the customers are connected from each load point are indicated.

6.4 Applications of automated feeder switches

The behaviour of the switches in the network model is crucial in reliability analysis. Basically automated feeder switches are circuit breakers controlled by relays or with communications from a control room. Analysis of key factors including network topology and characteristics is vital. Integration of auto reclosers with RTU reduces sectionalising time by isolating the downstream network through the remote switching. All loads on upstream breakers remain supplied. The estimated time for the operator to get to the first disconnector and operate with the purpose of isolating the faulty section is 2 hours.

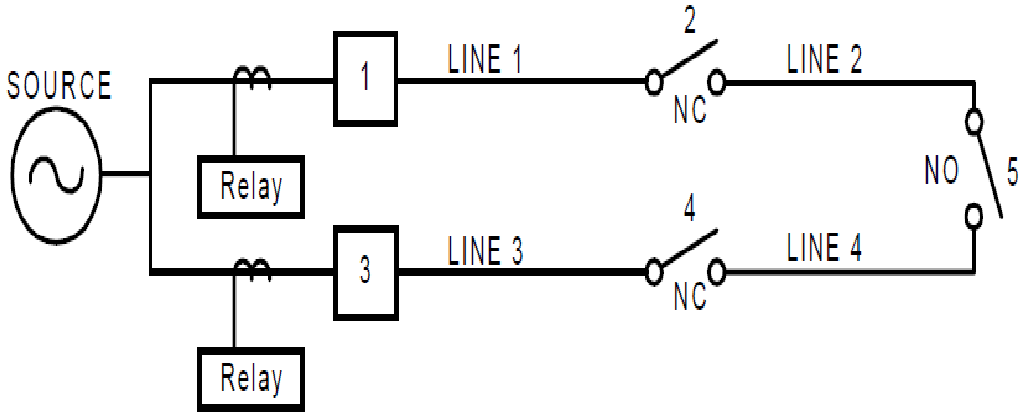


Figure 6-4: Operation of automated switches

Figure 6-4 indicates two radial distribution networks with three manually operated switches for network isolation and load transfer. The relay 1 will trip for any permanent fault experienced on Line 1 resulting in supply interruption on all loads on both lines 1 and 2. To restore load in the unaffected section of the network, in this case line 2, operators need to be dispatched and go to site to manually open switch 2 and then close switch 5. The assumption is that it takes an operator 2 hours to operate the first switch thus partially restoring load to the network which is fed by line 2. The network will be returned to its normal state once the fault in line 1 has been repaired.

With the automated feeder switches, the time to restore network to the unaffected section of the network will be reduced to 1 minute, this actuation time is taken from the global 'remote controlled' switch actuation time [77].

Figure 6-5 indicates the same network where manual switches are replaced with automatically controlled fault interrupting switches (i.e., electronic reclosers, breakers, etc.). In addition, the protection provided for all of the breakers and automatic switches is connected together via a communications link.

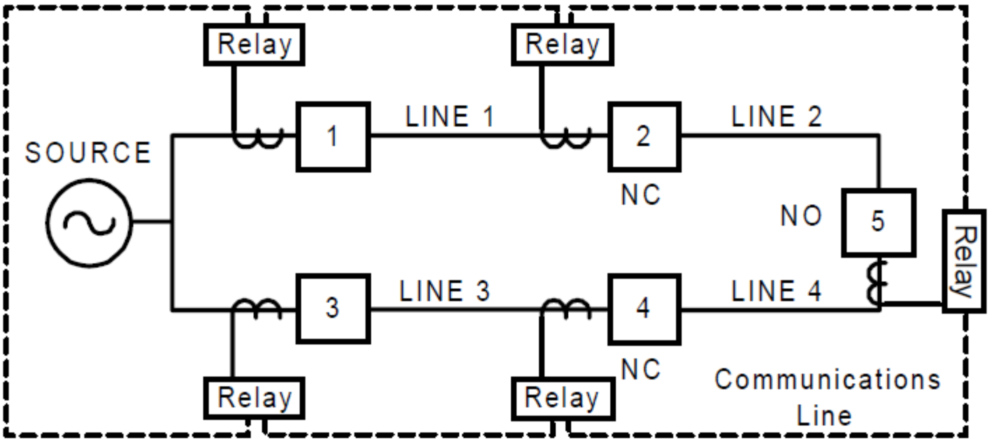


Figure 6-5: Operation of automated tie switch

Communications link provide significant improvements for the automation and control possibilities. As indicated in Figure 6-5, each protective relay communicates with the adjacent relays that have control functions. This methodology allows fast automatic restoration of load to line 2 and avoids dispatching an operator to restore load manually. It also saves approximately one hour fifty minutes in restoring service to the Line 2 load.

In long networks like Mtonjaneni NB1 22kV network the position of these switches along the network is very important for remote monitoring and control, as it trips and isolates the downstream network during fault conditions this is the section of the line closer to the affected load. Different positions were modelled and verified that optimum performance is achieved when it is placed at S330 as shown in figure 6-6.

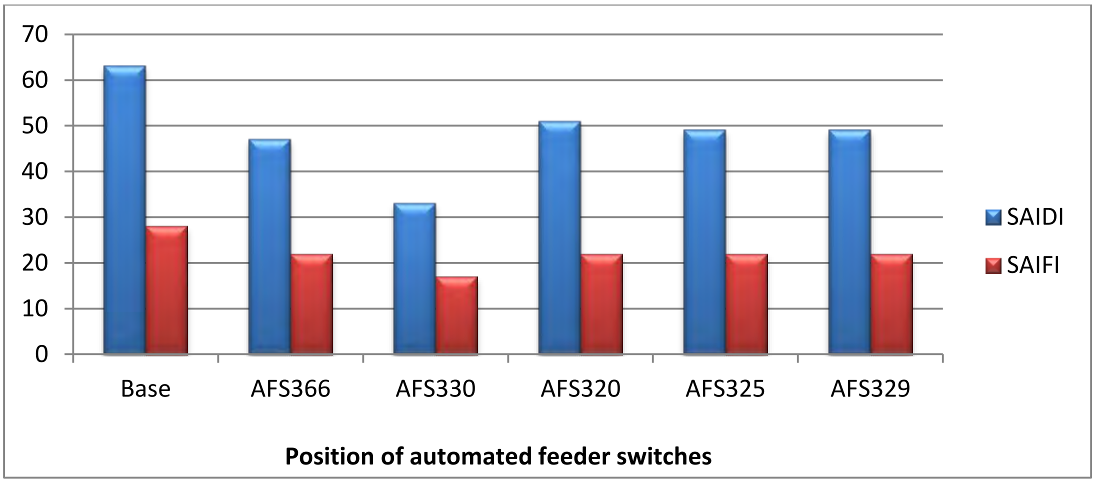


Figure 6-6: SAIDI and SAIFI for Mtonjaneni network - automated switches

Because the Mtonjaneni network does not have back feed capabilities, Wartburg network was modelled to see how the tie point switch (N/O) reacts during fault conditions. S66, S39 and S356 are tie point switches that can provide back feed capabilities to both the Wartburg NB22 and 23 networks as indicated by single line diagram in Figures 6-7 and 6-8.

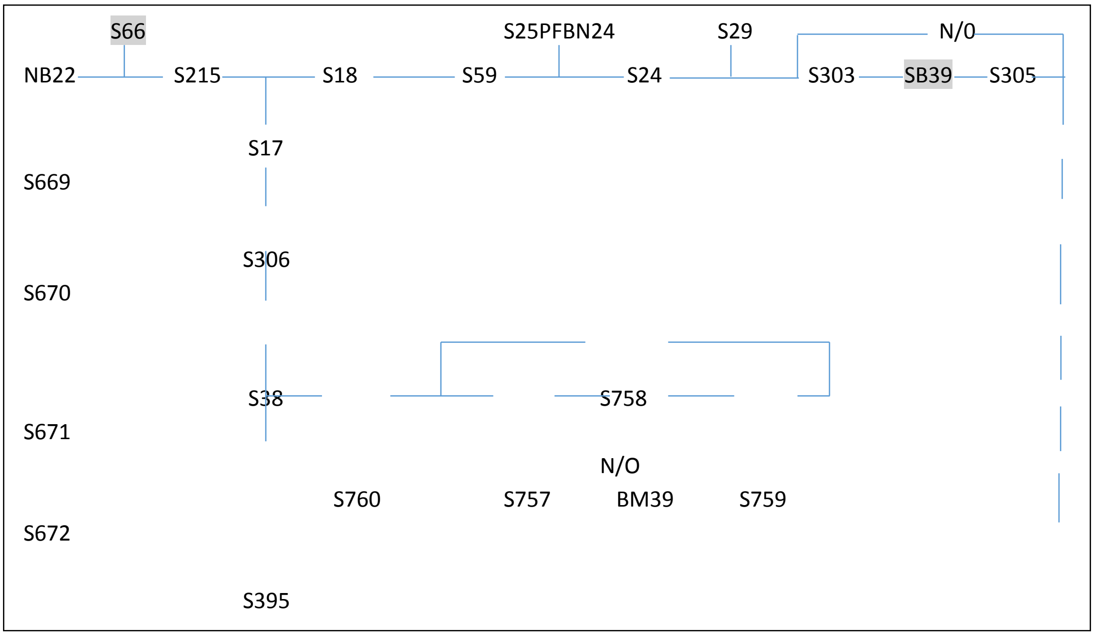


Figure 6-7: Wartburg NB22 single line diagram

These control system were modelled in such a way that they transfer loads automatically to balance load between feeders after an outage.

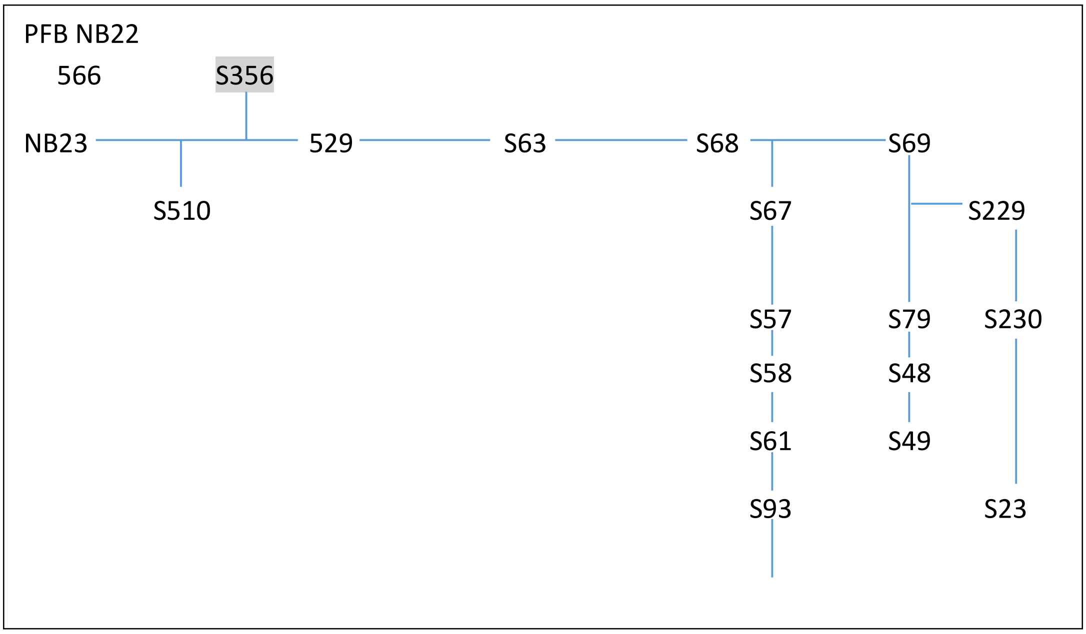


Figure 6-8: Wartburg NB23 single line diagram

During fault conditions it is not always practical for an operator to perform all the essential instructions and checks to analyse loading conditions before transferring load to an alternate source. Each instruction may require several operations to be performed in a specific sequence including switching, tap position changes, capacitor banks, and protection optimization. In addition system and safety checks must be performed to ensure equipment ratings are not exceeded and personnel safety is not compromised[84].

Fault Location Isolation and Service Restoration (FLISR) technology automates these tasks to allow utilities to take advantage of the opportunity for increased reliability in complex distribution networks. It has capability of locating a fault and automatically restores supply to the upstream side of the faulted section. This function is fully co-ordinated, it can be centralised or decentralised, as discussed in Chapter 2. Ideally an organisation should introduce this technology step by step, starting from being manually operated by the operators to fully integrating it with a Distribution Management System (DMS) for full automation. DMS has the global overview of the entire distribution network.

Automated feeder switches were also simulated in different locations along the Wartburg NB 22 and 23 11 kV overhead lines, which can be back- fed from each as shown in Figure 6-9.

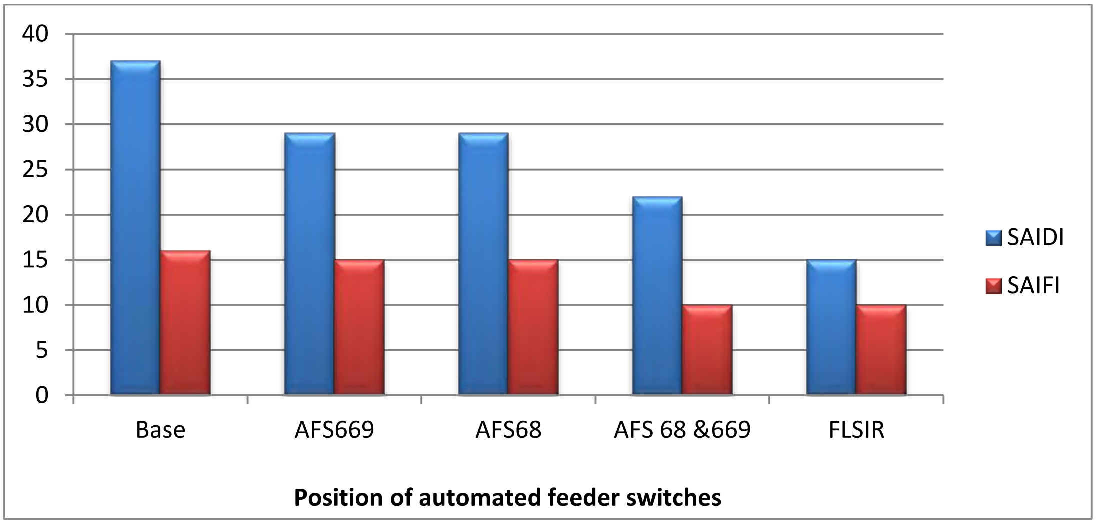


Figure 6-9: SAIDI and SAIFI Wartburg Automated Feeder Switches

As noted the automated feeder switches were installed at S669 and S68, thereafter the combination of these switches were simulated. The best performance is achieved when both these switches are installed. The improvement on the SAIDI and the SAIFI is 41% and 38% respectively. These devices play a huge role in terms of improving the frequency of the affected customers, because it provides fast automatic restoration to the unaffected customers without human intervention.

6.5 FPI in Wartburg and Mtonjaneni networks

During system modelling, it was evident that the smart technology has the ability to analyse and restore supply to a healthy part of the network without human intervention. Thus minimising operational costs and improving overall system efficiency.

In case of any disturbance, the protection equipment indicates the fault location through the SCADA. The starting point for fault finding is the open disconnector. An average protection zone has about 15 switching points. With the fault path indicator these switching points are reduced to about 2 to 3 operations. This translates to about 90 minutes savings on sectionalising and fault finding.

According to[81], the simulation work done by the author indicates at least 20 minutes improvement on sectionalising time on the network with fault path indicators hence improving overall system performance.

The benefit of the Fault path indicators (FPI) are realized when installed on the long networks with high number of customers rather than network with fewer customers. Three FPI's were installed at the Mtonjaneni NB1 22kV network on S75 in zone 1, S33 which is in zone 2 and S3222 in zone 3 as per Figure 6-10.

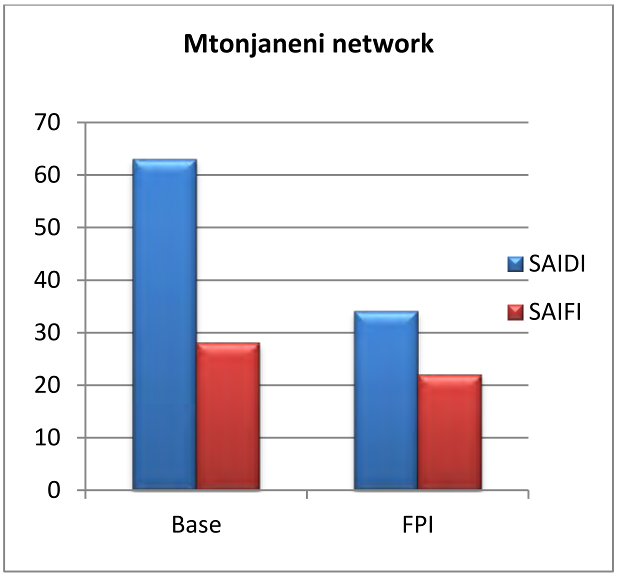


Figure 6-10: SAIDI and SAIFI Mtonjaneni network – FPI

Two FPIs were installed in the Wartburg NB 22 and 23 11 kV network, at S69 and S29 as demonstrated by Figure 6-11. There is 46% and 21% improvement on the SAIDI and the SAIFI respectively in the Mtonjaneni network. On the Wartburg network, there is a 46 % improvement in the SAIDI and a 7% improvement in the SAIFI. Changes in the SAIFI value are also insignificant especially in the Wartburg network. These results prove that each network is different. Network topology, equipment exposure as well as number of customers play a vital role. This also highlights the fact that for long networks, the interruption frequency of the interrupted customers does reduce because the opening and closing of breakers is minimised through reduction of the sectionalising and the fault finding time.

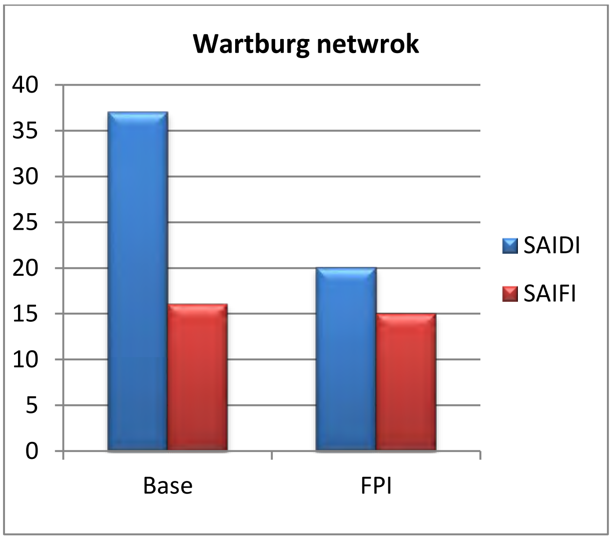


Figure 6-11: SAIDI and SAIFI Wartburg network - FPI

6.6 Transformer remote monitoring on the Mtonjaneni and Wartburg networks

During unplanned outages or interruptions when the network breaker trips, most of the time is being spent patrolling the lines and fault finding. The patrolman will first start by sectionalizing to isolate the faulted section from the rest of the network and back feeding some customers. If it is a transformer fault, then on the faulted section the patrolman has to drive to every single transformer to identify which one has faulted. The huge benefit of transformer remote monitoring is that is there is a transformer fault, it will be visible to the control centre so the operator will be dispatched to go and repair a faulted transformer right away, instead of doing sectionalising and fault finding prior the repairs.

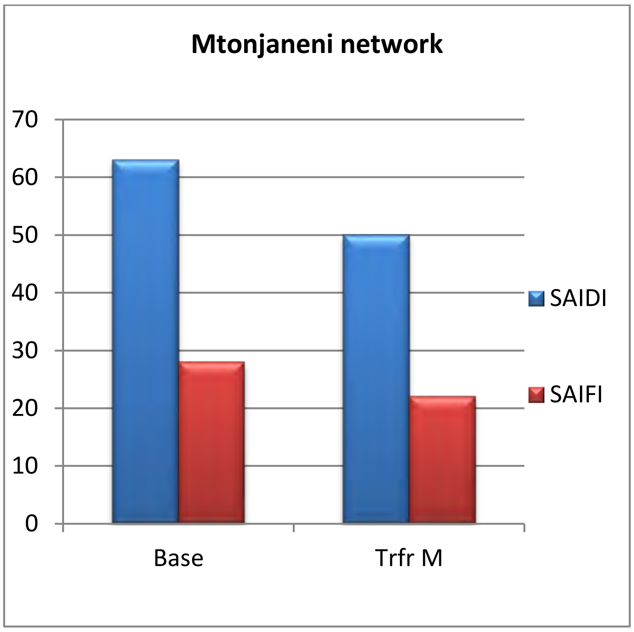


Figure 6-12: Transformer remote monitoring Mtonjaneni SAIDI and SAIFI

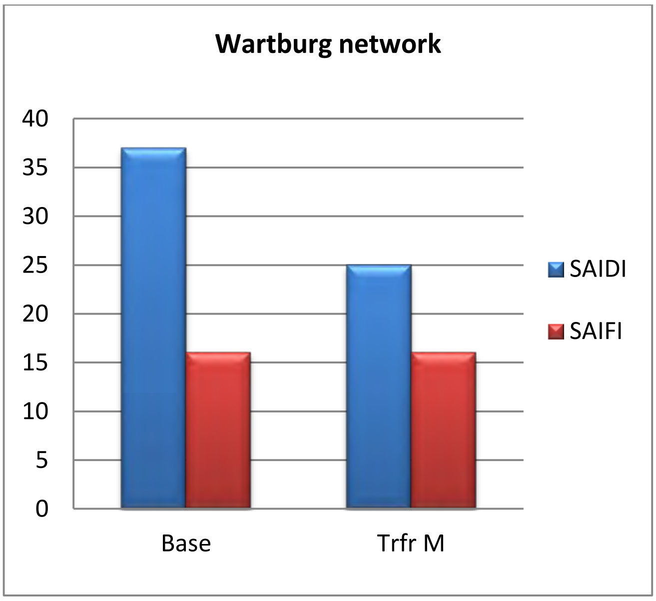


Figure 6-13: Transformer remote monitoring Wartburg SAIDI and SAIFI

When doing SAIDI and SAIFI calculations for a network, all possible faults and scenarios are placed in each component at a time. Transformer remote monitoring will only benefit transformer faults; all other faults duration will remain unchanged. Ideally this device will benefit those networks that are prone to transformer failures. This device was modelled on the Mtonjaneni and Wartburg network as shown in Figures 6-12 and 6-13.

At the Mtonjaneni network there is a 21% reduction for both the SAIDI and the SAIFI. This improvement is not so significant as compared to automated feeder switches. The reason is that it only improved transformer related faults whereas the SAIDI and the SAIFI calculations are based on all possible faults on the system. For the Wartburg network there is 32% change in the SAIDI and no change in the SAIFI.

6.7 Combination of devices

As earlier discussed, the best performance at the Mtonjaneni network is achieved when FPIs are installed at S7, S33 and S3222. The combination of these FPIs and the automated feeder switch is demonstrated by Figure 6-14. It should be noted that 2 automated feeder switches are installed at S330 and S329. The response time for automated feeder switch is 1 minute, by the time the operator get to site the faulted section of the line is already isolated.

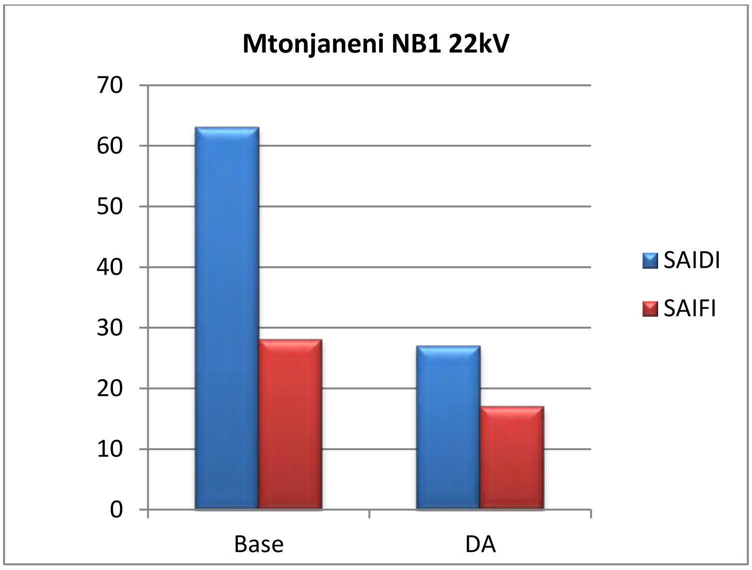


Figure 6-14: Distribution Automation for the Mtonjaneni network

6.8 Application of Advanced Metering Infrastructure (AMI) outage detection

Smart fault path indicators notify the control centre when faults occur, so do outage notification systems through smart meters. The difference between these two outage notification systems is that over and above outage notification, there are more other added benefits that come with AMI technologies. For the traditional system, a utility will get notified of a fault through the customer calling in.

AMI technology involves not only metering functionality but also communications infrastructure, software applications, and data exchange interfaces between the electric utility, the meter, the consumer. This technology is used to alert the organisation of any interruption and its location in the distribution network. Therefore sectionalising and fault finding time is minimised.

Once the power to the meter is lost, smart meters are designed with outage notification functionalities that allow the meter to transmit a "last gasp" alert to the system. The alert has the meter number information, the time of interruption and its location. This information is processed through the AMI and sends a notification to the control centre about the event. Once the fault is repaired the "power on" alert is sent to the control centre through the AMI from the smart meter. Effective resource management is undertaken to ensure service restoration on all sites before operators leave site.

6.9 Discussion

Significant benefits are realized with the application of smart devices in real networks. The Wartburg network has back-feed capabilities, so the normal open (N/O) switches were modeled in such a way that when the fault occurs, they are able to sense the fault and automatically close to temporary back-feed the customers in a healthy part of the network. After implementing the advanced automated switches, FLSIR technology SAIDI improvement is 60% as compared to the base, and 38% improvement on SAIFI as shown by Table 6-2. For the Mtonjaneni network there is a 48% and 40% improvement on both the SAIDI and the SAIFI respectively.

More benefits of the FPI are realized when installed on the long networks with high number of customers rather than networks with fewer customers. Based on the Mtonjaneni NB1 22 kV and Wartburg NB22 and NB23 11 kV network results, for any single event there is 10 minutes savings on sectionalising time per 60 km of line which equates to a 1.67 min per km per fault saving. There is a 46% and 21% improvement on the SAIDI and the SAIFI respectively in the Mtonjaneni network. On the Wartburg network there is a 46% improvement on the SAIDI and no improvement on the SAIFI as demonstrated by Table 6-3.

Table 6-2: Results summary for the Mtonjaneni network

Mtonjaneni NB1 22kV overhead line				
	Automated feeder switch	Fault path indicators	Transformer remote monitoring	Distribution Automation
SAIDI base	63	63	63	63
SAIDI smart	33	34	50	27
SAIFI base	28	28	28	28
SAIFI smart	17	22	22	17

It was expected for these networks to perform differently because their characteristics are quite different. This simple means that you cannot take one network's results and implement for all. Each network is to be treated on its own merits.

Transformer remote monitoring is only justifiable for feeders that are prone to transformer related faults. This device is only effective if something goes wrong in the transformer, for any other faults it will not operate. At the Mtonjaneni network there is a 21% improvement on both the SAIDI and the SAIFI. This improvement is not so significant as compared to other devices; the reason is that it only improved transformer related faults whereas SAIDI and SAIFI calculations are based on all possible faults on the system. For the Wartburg network there is a 32% change in the SAIDI and no change in the SAIFI

Table 6-3: Results summary for the Wartburg network

Wartburg NB 22 and 23 11kV overhead line			
	Fault Location Isolation & Service Restoration (FLISR)	Fault path indicators	Transformer remote monitoring
SAIDI base	37	37	37
SAIDI smart	10	20	25
SAIFI base	16	16	16
SAIFI smart	15	15	16

It was also confirmed in this chapter that smart fault path indicators notify the control centre when faults occur, so does the outage notification system through smart meters; therefore the simulation results for both these devices are the same. For the Wartburg network there is a 46% improvement for the SAIDI and a 7% improvement for the SAIFI. There is a 46% and 21% improvement on the SAIDI and the SAIFI respectively in the Mtonjaneni network.

Technology that yields significant improvement on SAIDI and SAIFI and also operational costs savings is the technology that reduces the interruption frequency of customers while reducing overall outage duration. This is demonstrated when achieving the best performance through Distribution Automation for the Mtonjaneni network is when SAIDI is 57% and SAIFI of 40%. For the Wartburg network the improvement is 60% for the SAIDI and 38% for the SAIFI.

CHAPTER 7

CONCLUSION

7.1 Conclusion

This research was aimed at evaluating the application of smart technologies with the intent of improving the reliability of Eskom’s medium voltage (MV) networks. This included the use of smart technology for the reduction of unplanned outage duration, reduction of frequency of unplanned outages and the reduction of maintenance and operational expenditure associated with outage management while improving overall system performance. This confirms that smart technology applied in a correct manner can improve reliability in terms of reliability indices such as SAIDI, SAIFI, etc. of power distribution systems by making use of digital and advanced technologies, thus the hypothesis was proved positively.

Various smart grid technologies applicable for this function were identified. Smart fuse saver, smart fault path indicator, automated switches, transformer remote monitoring, Fault Location Isolation & Service Restoration (FLISR) and AMI and Smart meter for outage detection were recognized as the key smart grid technologies applicable for distribution system reliability improvements. Therefore, in order to demonstrate the capabilities for the identified smart grid technologies, it was necessary to conduct reliability analysis and evaluations on a test network as well as real networks from KZN OU. It is also important to note that failure in the system is inevitable however the impact of failure can be minimized through the application of smart grid technologies.

It has been observed that results are network specific, different results may be obtained for different network configurations. Hence the performances of the studied Smart Grid cases varied in the simulated networks. This was mainly due to the following reasons:

a) The network with a high number of equipment will have a poor performance as compared to a network with less equipment because SAIDI calculation is based on every possible fault thrown on every piece of equipment. The test network had less equipment as compared to the other networks.

b) The length of the line plays a significant role in reliability analysis; this is expected as any fault on a longer line with more customers would result in more customer hours and a greater SAIDI value and hence the line’s failure rate are calculated based on the kilometre.

c) What is more significant is the customer distribution in a network. The number of customers that are affected by a single breaker operation has a major impact on the overall network reliability. As SAIDI is dependent on the number of customers and the fault duration, it becomes critically important to focus on the lines with high customers and long fault duration. This need to be taken into account during the planning stage when connecting new customers.

As the smart grid matures and the rate of new installations increases, its marginal costs are likely to decline rapidly. In conclusion, smart grid investment can always be economically justified and the huge capital costs are outweighed by the benefits that come with it.

7.2 Recommendations

The identified smart grid technologies were applied in the test network as well as the selected networks from KZN OU to validate the results and these were the following outcomes and recommendations:

a) For greater network visibility, reliability can be improved by implementation of automated feeder switches as well as automated feeder switches with advance features (FLISR technologies). It is recommended to apply this technology in the worse performing feeders. Analysis performed in this study has confirmed that networks with automated feeder switching were able to reduce the frequency of outages, the number of customers affected by both sustained outages and momentary interruptions, and the total number of outages. In short, these changes are in line with the objectives of this study which is the improvement of SAIDI and SAIFI.

b) From the previous fault data analysis it was noted that only 9% of faults in the KZN OU are caused by transformers. Therefore, transformer remote monitoring was also evaluated as a possible solution to improve reliability of the power distribution system during transformer failures. The results confirmed that this solution can be applied to networks that are prone to transformer related faults as they reduce fault finding time.

c) FPIs are the most beneficial approach to reducing the overall outage duration, and are the cost effective approaches for reducing fault finding time by at least 50% or more. FPI’s are an immediate recommended solution as a starting point for distribution’ s feeder base as a cost effective solution that will yield huge benefits within 1-2 years in terms of SAIDI improvement. Outage management through AMI technologies is also recommended depending on capital investment however the added benefits that come with this technology should help justify the project. Applying this basic time saving model to recorded faults across the KZN OU network illustrates that there is a significant improvement in SAIDI.

d) The smart fuse saver was also evaluated. This device opens and clears a fault in as little as a half-cycle before the fuse operates for a transient fault as the fuse is unable to distinguish between temporary and permanent faults, and it blows on all faults. It can also be easily integrated with the RTU to provide visibility for any operations taking place on the fuse. KZN OU is currently fusing the transformers only, by application of expulsion type fuses on medium voltage overhead line networks. The intention is that when a transformer fails, ideally the fuse should operate isolating the faulty transformer from the rest of the network. The installation of the smart fuse saver in series with the fuse in this instance was evaluated. The benefits for this device are achievable when the fuse is applied as a spur line protective device. This device is therefore not a recommended solution as Eskom KZN OU is only fusing the transformers and not using fuse as a spur line protection.

However to maximise the benefits of the smart technology, it is recommended to first analyse some key factors including network topology, configuration, customer type, number of customers per single breaker operation and history of faults of the network. A reliable communication link is needed for the effectiveness of a smart technology.

Having investigated three sample feeders on DigSilent to illustrate the application of smart technology, an investigation across the whole KZN OU, based on the savings acquired, was undertaken, as detailed in Chapter 4. Applying this time saving model to recorded faults across the KZN OU network illustrated that there is a significant improvement in the SAIDI.

Based on these results, the application of this technology to the entire Distribution's feeder base will continually have a positive benefit on the SAIDI. The benefit-cost ratio analysis for Distribution's feeder base was conducted using cost estimates in Chapter 4 and the results indicate that increasing network visibility through smart technology application will always have a high positive benefit-cost ratio, and that its investment can always be economically justified.

7.3 Further Research

As mentioned earlier in this report, the smart grid is a conventional power system that uses digital technologies via two way communications to improve reliability, security and efficiency of power systems from generation through transmission and distribution system to the consumers and provides greater visibility to disturbances over traditional approaches. The content of this study touched parts of these areas. Future work could include the following:

a) Continue research to interface Distributed Generations system

b) Improve reliability by energy savings scheme through the use of volt/VAR optimization (VVO) and conservation voltage reduction (CVR).

APPENDICES

Appendix A:

SAIDI code calculations

```
function [ttl_name,ttl_l,ttl_cst,SAIDI_b,SAIDI_s,SAIDI_a,SAIDI_a2] =
main(min_cust,min_l,t,tkm)

display('Reading Data');

[fault_num,fault_txt,fault_raw]=xlsread('fault_KZN.xlsx');
[net_num,net_txt,net_raw]=xlsread('network_KZN.xlsx');

%save calc.mat
%load calc.mat


ttl_net=0;
[r,c] = size(net_txt);
%net_r = round(r*rand(1));

% I could iterate here to look at all networks above distance x

% Need to implement loop here and remove the data that we don't want
to see
% For example we want to look at lines longer than 10 km, if there
are no
% customers we wish to skip that iteration, if we want to look at
overhead
% line/cable

display('Iterating through Network Data');

for net_r = 2:r

net_name = char(net_txt(net_r,6));
net_cst = net_num(net_r-1,19);
net_l = net_num(net_r-1,13);
% Analyse and remove the networks that are irrelevant

% No customers / or lines
net_cst(isnan(net_cst))=0;
net_l(isnan(net_l))=0;
net_l(net_l>400)=0  ;

% Min customers
if net_cst < min_cust;
    continue
end

% Min length
if net_l < min_l
    continue
end

% Record information in new array
```

```
ttl_net = ttl_net+1;
ttl_name(ttl_net) = {net_name};
ttl_l(ttl_net) = net_l;
ttl_cst(ttl_net) = net_cst;

display('Capturing Fault Data');
flt_name = fault_txt(:,5);
flt_idx = strfind(flt_name,net_name);
flt_r = find(~cellfun(@isempty,flt_idx));

% We need to analyse the data here and remove the irrelevant data,
such as
% minimum 5 customers affected?

flt_hrs = fault_num(flt_r-1,9);
flt_hrs(flt_hrs<1)= 0;
flt_cst = fault_num(flt_r-1,11);

display('Calculating Base SAIDI');



SAIDI_b(ttl_net) = sum(flt_hrs)./net_cst;
%SAIDI(ttl_net) = sum(flt_hrs)/net_cst;

display('Calculating Saving in SAIDI');

% Save t minutes per fault or t minutes per 10 km per fault
flt_s = (flt_hrs./flt_cst-t/60).*flt_cst;
flt_s(flt_s<1)= 0;

SAIDI_s(ttl_net) = sum(flt_s)/net_cst;

% Save t minutes per fault or t minutes per 10 km per fault
flt_a = (flt_hrs./flt_cst-tkm/60*net_l/10).*flt_cst;
flt_a(flt_a<1)= 0;

SAIDI_a(ttl_net) = sum(flt_a)/net_cst;

% Save 2t minutes per fault or t minutes per 10 km per fault
flt_a2 = (flt_hrs./flt_cst-2*tkm/60*net_l/10).*flt_cst;
flt_a2(flt_a2<1)= 0;

SAIDI_a2(ttl_net) = sum(flt_a2)/net_cst;

end
```

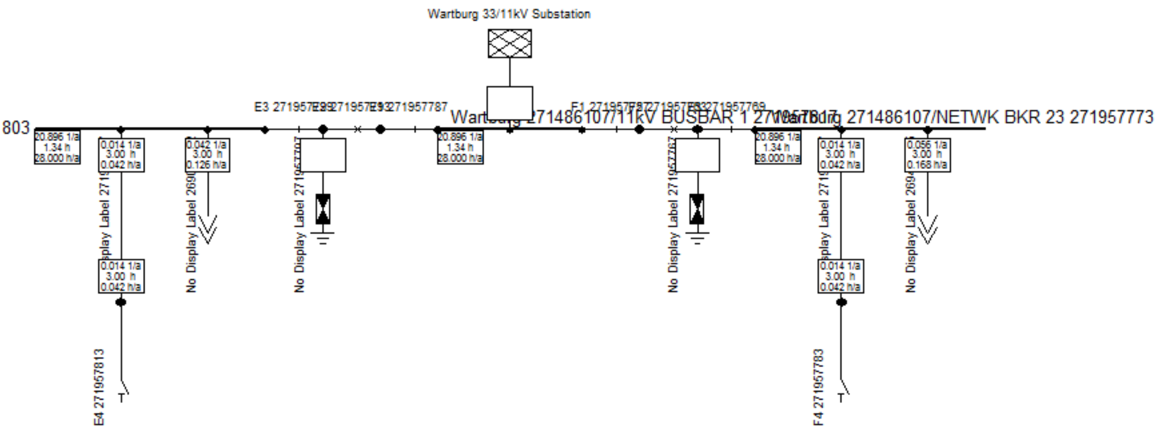
Appendix B

SAIDI time saving code

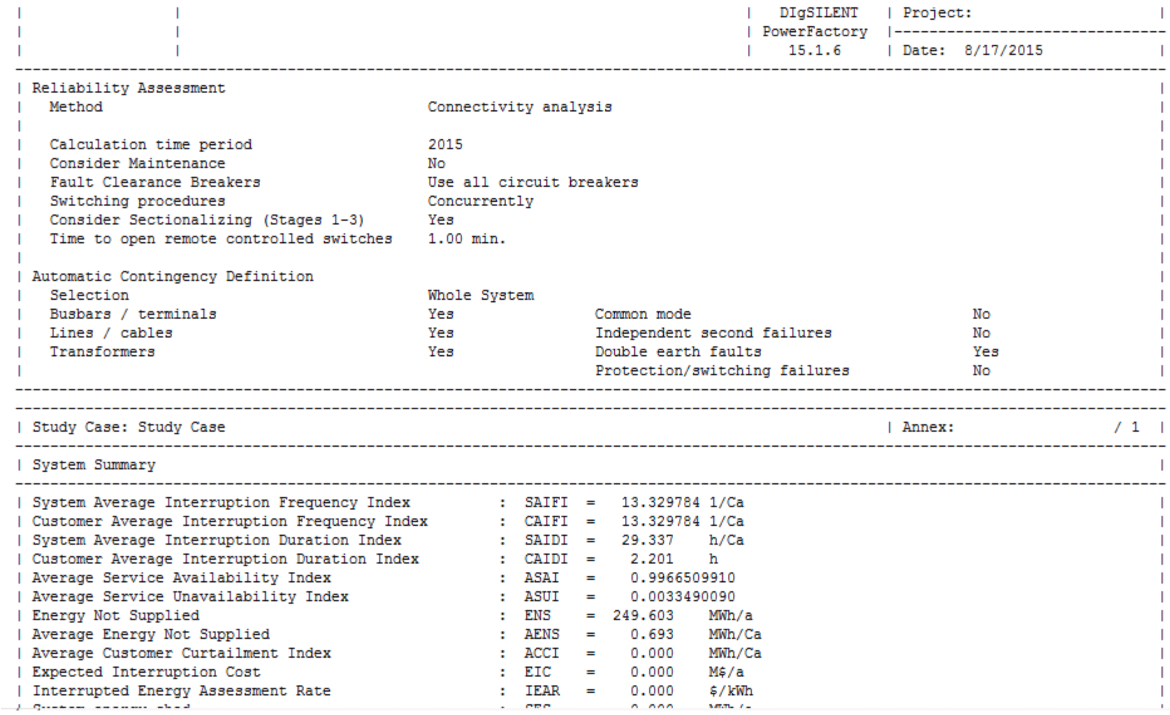
```
function [len,ttl_l,average,average_s,average_a,average_a2] =
saidi()

for l = 1:80

% 10 minutes time saving per fault
[ttl_name,ttl_l,ttl_cst,SAIDI_b,SAIDI_s,SAIDI_a,SAIDI_a2] =
main(10,l,10,1.67)

average_b(l) = sum(SAIDI_b)/length(SAIDI_b);
average_s(l) = sum(SAIDI_s)/length(SAIDI_s);
average_a(l) = sum(SAIDI_a)/length(SAIDI_a);
average_a2(l) = sum(SAIDI_a2)/length(SAIDI_a2);

l_cst(l)=sum(ttl_l./ttl_cst)
ave_l(l) = sum(ttl_l)/length(ttl_l)



end


len = 1:80;

figure,plot(len,average_b,len,average_s,len,average_a),xlabel('Lengt
h (km)'),ylabel('SAIDI'),legend('Base Case','10 Minute Saving per
Fault','1.67 Minutes Saving per km per Fault')
figure,plot(len,average_b,len,average_s,len,average_a,len,average_a2
),xlabel('Length (km)'),ylabel('SAIDI'),legend('Base Case','10
Minute Saving per Fault','1.67 Minutes Saving per km per
Fault','2x1.67 Minutes Saving per km per Fault')
%
figure,plot(l_cst,average_b,l_cst,average_s,l_cst,average_a),xlabel(
'Length/Customer (km/customer)'),ylabel('SAIDI'),legend('Base
Case','10 Minute Saving per Fault','2 Minutes Saving per km per
Fault')
%
figure,plot(ave_l,average_b,ave_l,average_s,ave_l,average_a),xlabel(
'Length (km)'),ylabel('SAIDI'),legend('Base Case','10 Minute Saving
per Fault','2 Minutes Saving per km per Fault')
%
% [ttl_name,ttl_l,ttl_cst,SAIDI,SAIDI_s,SAIDI_a] =
main(10,1,10,1.67);
%
%
% size(ttl_l)
%
% figure,histogram(ttl_l,10),xlabel('Length (km)'),ylabel('Number of
Lines')
%
% [x,y] = histcounts(ttl_l,10)
% d = 0;
%
```

```
% for k = 1:length(y)-1
% Z = ttl_cst;
% Z(Z<y(k))=0;
% Z(Z>=y(k+1))=0;
% z(k)=sum(Z);
% end
% % k = length(y)
% % Z = ttl_cst;
% % Z(Z<y(k))=0;
% % z(k)=sum(Z);
%
% figure,bar(y(1:length(y)-1),z),xlabel('Length
(km)'),ylabel('Number of Customers')
% figure,scatter(y(2:length(y)),x,z,z,'fill'),xlabel('Length
(km)'),ylabel('Number of Lines')
% figure,scatter3(y(2:length(y)),x,z,z,z,'filled'),xlabel('Length
(km)'),ylabel('Number of Lines'),zlabel('Number of Customers')
%
%
```

Appendix C:
Powerfactory – Simulations

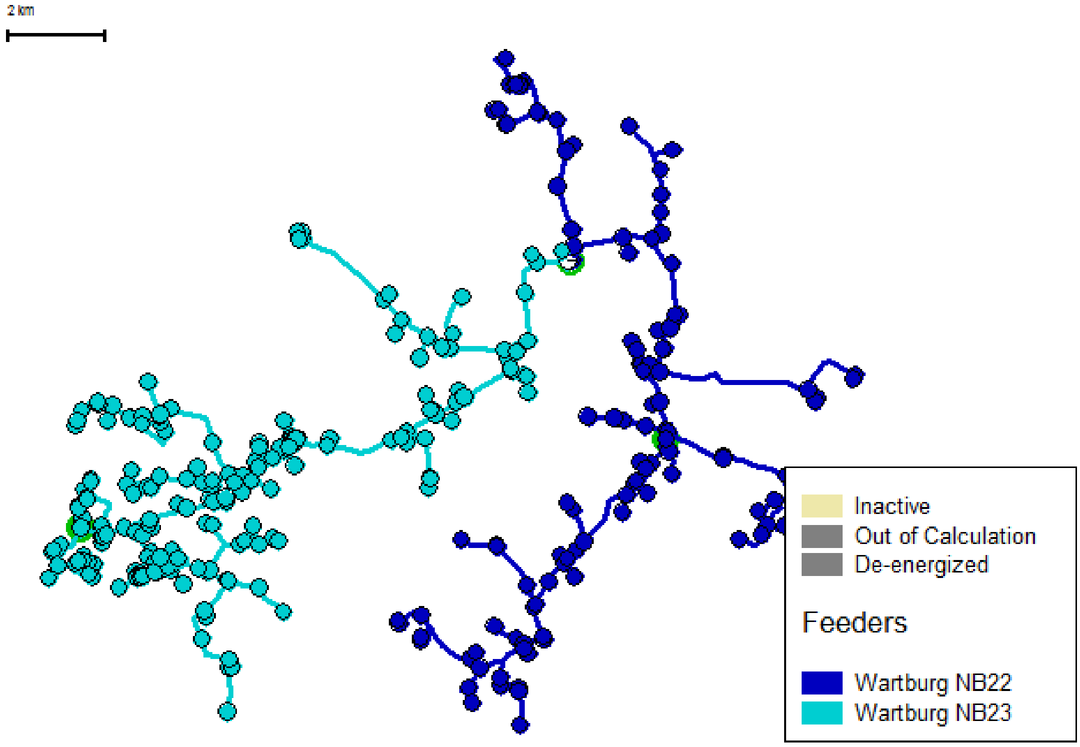


C1. Wartburg Substation layout

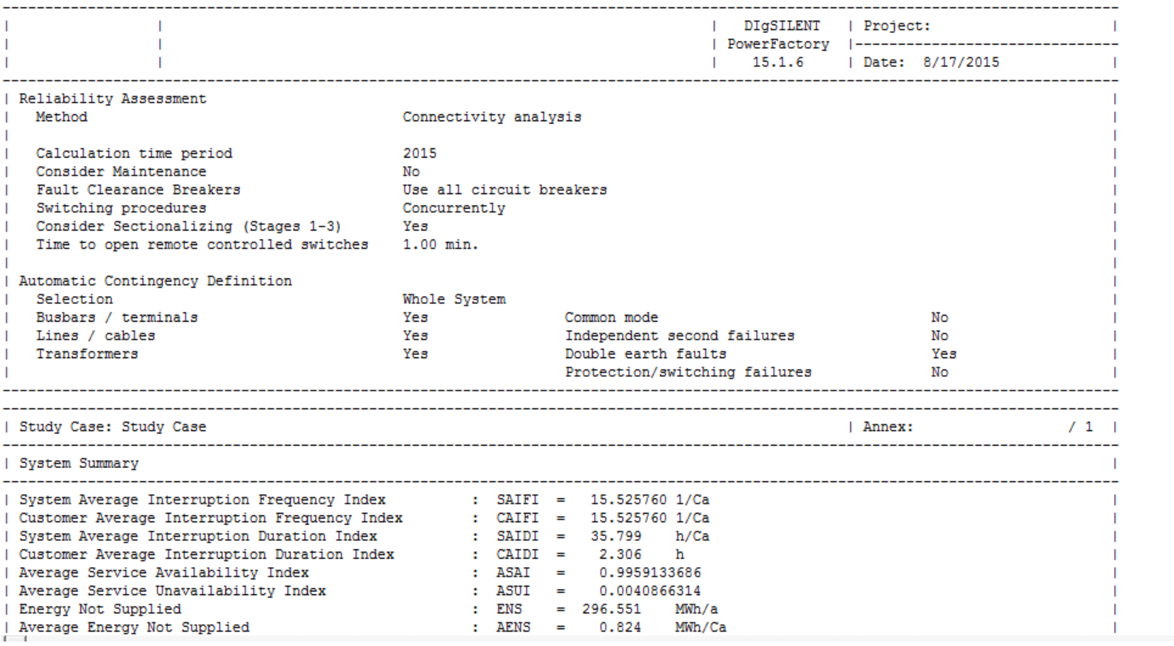


```
|                |                                                  |   DIgSILENT   | Project:                       |
|                |                                                  | PowerFactory  |--------------------------------
|                |                                                  |    15.1.6     | Date:  8/17/2015               |
-----------------------------------------------------------------------------------------------------------------------
| Reliability Assessment                                                                                              |
|   Method                                   Connectivity analysis                                                    |
|                                                                                                                     |
|   Calculation time period                  2015                                                                     |
|   Consider Maintenance                     No                                                                       |
|   Fault Clearance Breakers                 Use all circuit breakers                                                 |
|   Switching procedures                     Concurrently                                                             |
|   Consider Sectionalizing (Stages 1-3)     Yes                                                                      |
|   Time to open remote controlled switches  1.00 min.                                                                |
|                                                                                                                     |
| Automatic Contingency Definition                                                                                    |
|   Selection                                Whole System                                                             |
|   Busbars / terminals                      Yes                 Common mode                                 No       |
|   Lines / cables                           Yes                 Independent second failures                 No       |
|   Transformers                             Yes                 Double earth faults                         Yes      |
|                                                                Protection/switching failures               No       |
-----------------------------------------------------------------------------------------------------------------------
-----------------------------------------------------------------------------------------------------------------------
| Study Case: Study Case                                                                    | Annex:            / 1  |
-----------------------------------------------------------------------------------------------------------------------
| System Summary                                                                                                      |
-----------------------------------------------------------------------------------------------------------------------
| System Average Interruption Frequency Index          :  SAIFI  =   13.329784 1/Ca                                   |
| Customer Average Interruption Frequency Index        :  CAIFI  =   13.329784 1/Ca                                   |
| System Average Interruption Duration Index           :  SAIDI  =   29.337    h/Ca                                   |
| Customer Average Interruption Duration Index         :  CAIDI  =    2.201    h                                      |
| Average Service Availability Index                   :  ASAI   =    0.9966509910                                    |
| Average Service Unavailability Index                 :  ASUI   =    0.0033490090                                    |
| Energy Not Supplied                                  :  ENS    =  249.603    MWh/a                                  |
| Average Energy Not Supplied                          :  AENS   =    0.693    MWh/Ca                                 |
| Average Customer Curtailment Index                   :  ACCI   =    0.000    MWh/Ca                                 |
| Expected Interruption Cost                           :  EIC    =    0.000    M$/a                                   |
| Interrupted Energy Assessment Rate                   :  IEAR   =    0.000    $/kWh                                  |
```

C2. SAIDI results for FPI

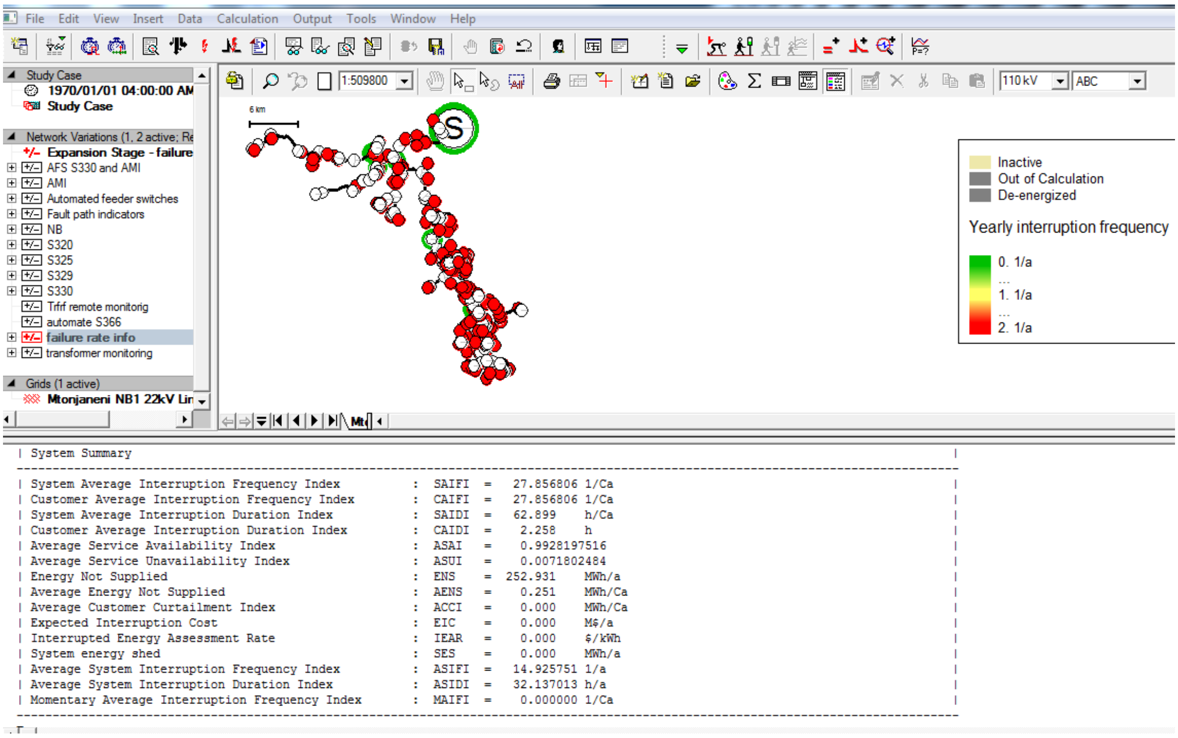


C3. Wartburg NB22 and NB23 combined networks



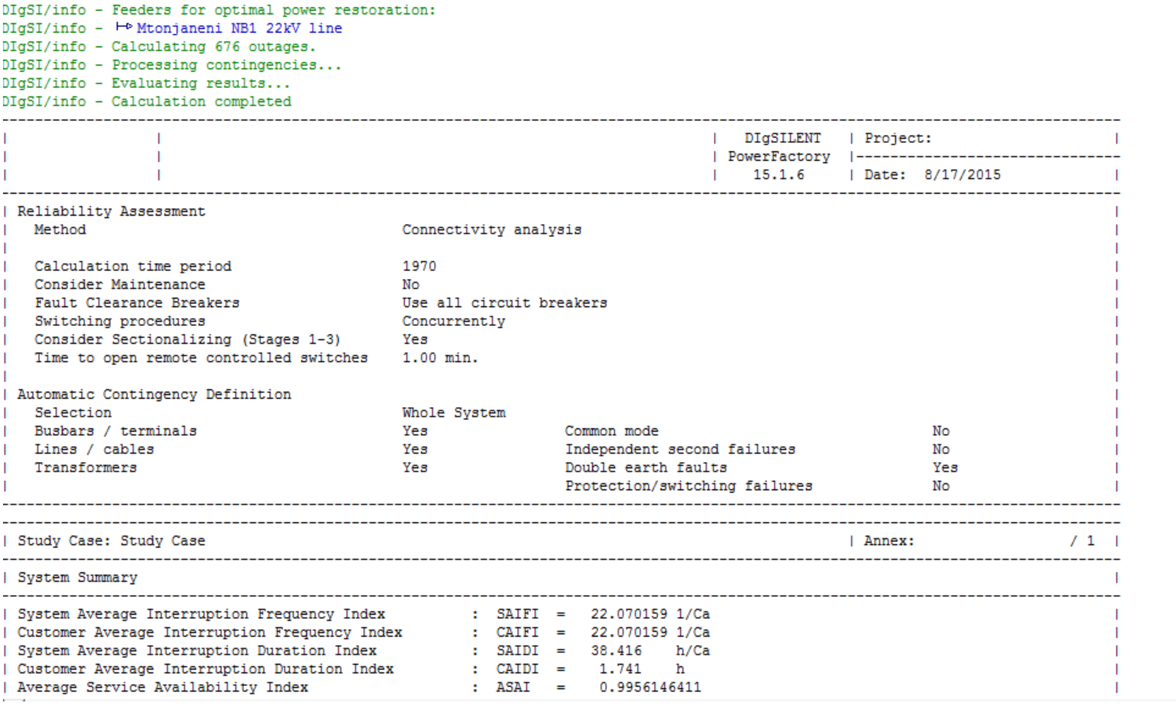
```
-----------------------------------------------------------------------------------------------------------------
|                  |                                                              |   DIgSILENT    | Project:        |
|                  |                                                              | PowerFactory   |-----------------|
|                  |                                                              |    15.1.6      | Date:  8/17/2015 |
-----------------------------------------------------------------------------------------------------------------
| Reliability Assessment                                                                                        |
|   Method                                    Connectivity analysis                                             |
|                                                                                                               |
|   Calculation time period                   2015                                                              |
|   Consider Maintenance                      No                                                                |
|   Fault Clearance Breakers                  Use all circuit breakers                                          |
|   Switching procedures                      Concurrently                                                      |
|   Consider Sectionalizing (Stages 1-3)      Yes                                                               |
|   Time to open remote controlled switches   1.00 min.                                                         |
|                                                                                                               |
| Automatic Contingency Definition                                                                              |
|   Selection                                 Whole System                                                      |
|   Busbars / terminals                       Yes                Common mode                         No          |
|   Lines / cables                            Yes                Independent second failures         No          |
|   Transformers                              Yes                Double earth faults                 Yes         |
|                                                               Protection/switching failures       No          |
-----------------------------------------------------------------------------------------------------------------
-----------------------------------------------------------------------------------------------------------------
| Study Case: Study Case                                                                  | Annex:          / 1  |
-----------------------------------------------------------------------------------------------------------------
| System Summary                                                                                                |
-----------------------------------------------------------------------------------------------------------------
| System Average Interruption Frequency Index          :  SAIFI  =   15.525760 1/Ca                             |
| Customer Average Interruption Frequency Index        :  CAIFI  =   15.525760 1/Ca                             |
| System Average Interruption Duration Index           :  SAIDI  =   35.799    h/Ca                             |
| Customer Average Interruption Duration Index         :  CAIDI  =    2.306    h                                |
| Average Service Availability Index                   :  ASAI   =    0.9959133686                              |
| Average Service Unavailability Index                 :  ASUI   =    0.0040866314                              |
| Energy Not Supplied                                  :  ENS    =  296.551    MWh/a                            |
| Average Energy Not Supplied                          :  AENS   =    0.824    MWh/Ca                           |
```

C4. Base network SAIDI



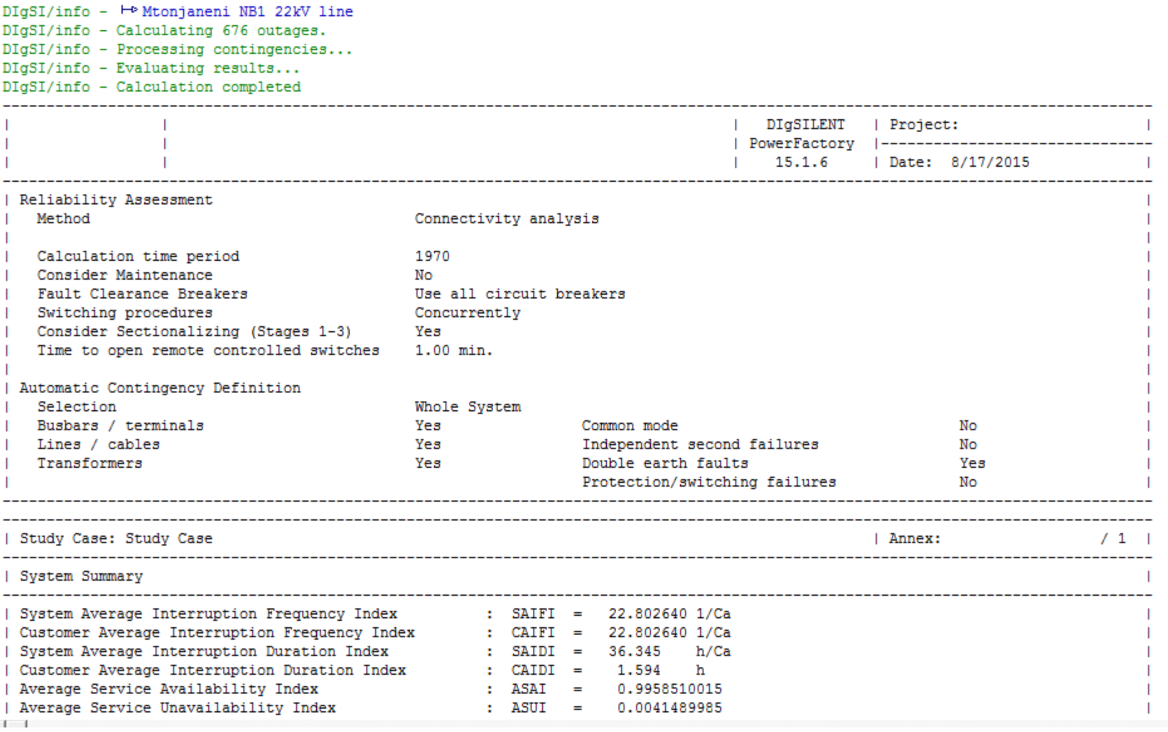
```
| System Summary                                                                                      |
-------------------------------------------------------------------------------------------------------
| System Average Interruption Frequency Index          :  SAIFI  =   27.856806 1/Ca                   |
| Customer Average Interruption Frequency Index        :  CAIFI  =   27.856806 1/Ca                   |
| System Average Interruption Duration Index           :  SAIDI  =   62.899    h/Ca                   |
| Customer Average Interruption Duration Index         :  CAIDI  =    2.258    h                      |
| Average Service Availability Index                   :  ASAI   =    0.9928197516                    |
| Average Service Unavailability Index                 :  ASUI   =    0.0071802484                    |
| Energy Not Supplied                                  :  ENS    =  252.931    MWh/a                  |
| Average Energy Not Supplied                          :  AENS   =    0.251    MWh/Ca                 |
| Average Customer Curtailment Index                   :  ACCI   =    0.000    MWh/Ca                 |
| Expected Interruption Cost                           :  EIC    =    0.000    M$/a                   |
| Interrupted Energy Assessment Rate                   :  IEAR   =    0.000    $/kWh                  |
| System energy shed                                   :  SES    =    0.000    MWh/a                  |
| Average System Interruption Frequency Index          :  ASIFI  =   14.925751 1/a                    |
| Average System Interruption Duration Index           :  ASIDI  =   32.137013 h/a                    |
| Momentary Average Interruption Frequency Index       :  MAIFI  =    0.000000 1/Ca                   |
-------------------------------------------------------------------------------------------------------
```

C5. Mtonjaneni base SAIDI



```
DIgSI/info - Feeders for optimal power restoration:
DIgSI/info - ↦ Mtonjaneni NB1 22kV line
DIgSI/info - Calculating 676 outages.
DIgSI/info - Processing contingencies...
DIgSI/info - Evaluating results...
DIgSI/info - Calculation completed
-------------------------------------------------------------------------------------------------------------------
|               |                                                            |  DIgSILENT   | Project:                      |
|               |                                                            | PowerFactory |-------------------------------
|               |                                                            |    15.1.6    | Date:  8/17/2015               |
-------------------------------------------------------------------------------------------------------------------
| Reliability Assessment                                                                                           |
|   Method                                  Connectivity analysis                                                  |
|                                                                                                                  |
|   Calculation time period                 1970                                                                   |
|   Consider Maintenance                    No                                                                     |
|   Fault Clearance Breakers                Use all circuit breakers                                               |
|   Switching procedures                    Concurrently                                                           |
|   Consider Sectionalizing (Stages 1-3)    Yes                                                                    |
|   Time to open remote controlled switches 1.00 min.                                                              |
|                                                                                                                  |
| Automatic Contingency Definition                                                                                 |
|   Selection                               Whole System                                                           |
|   Busbars / terminals                     Yes               Common mode                                No         |
|   Lines / cables                          Yes               Independent second failures                No         |
|   Transformers                            Yes               Double earth faults                        Yes        |
|                                                             Protection/switching failures              No         |
-------------------------------------------------------------------------------------------------------------------
-------------------------------------------------------------------------------------------------------------------
| Study Case: Study Case                                                                  | Annex:            / 1  |
-------------------------------------------------------------------------------------------------------------------
| System Summary                                                                                                   |
-------------------------------------------------------------------------------------------------------------------
| System Average Interruption Frequency Index          :  SAIFI  =   22.070159 1/Ca                               |
| Customer Average Interruption Frequency Index        :  CAIFI  =   22.070159 1/Ca                               |
| System Average Interruption Duration Index           :  SAIDI  =   38.416    h/Ca                               |
| Customer Average Interruption Duration Index         :  CAIDI  =    1.741    h                                  |
| Average Service Availability Index                   :  ASAI   =    0.9956146411                                  |
```

C6. Mtonjaneni Transformer remote monitoring - SAIDI



```
DIgSI/info - ↦ Mtonjaneni NB1 22kV line
DIgSI/info - Calculating 676 outages.
DIgSI/info - Processing contingencies...
DIgSI/info - Evaluating results...
DIgSI/info - Calculation completed
-------------------------------------------------------------------------------------------------------------------
|               |                                                            |  DIgSILENT   | Project:                      |
|               |                                                            | PowerFactory |-------------------------------
|               |                                                            |    15.1.6    | Date:  8/17/2015               |
-------------------------------------------------------------------------------------------------------------------
| Reliability Assessment                                                                                           |
|   Method                                  Connectivity analysis                                                  |
|                                                                                                                  |
|   Calculation time period                 1970                                                                   |
|   Consider Maintenance                    No                                                                     |
|   Fault Clearance Breakers                Use all circuit breakers                                               |
|   Switching procedures                    Concurrently                                                           |
|   Consider Sectionalizing (Stages 1-3)    Yes                                                                    |
|   Time to open remote controlled switches 1.00 min.                                                              |
|                                                                                                                  |
| Automatic Contingency Definition                                                                                 |
|   Selection                               Whole System                                                           |
|   Busbars / terminals                     Yes               Common mode                                No         |
|   Lines / cables                          Yes               Independent second failures                No         |
|   Transformers                            Yes               Double earth faults                        Yes        |
|                                                             Protection/switching failures              No         |
-------------------------------------------------------------------------------------------------------------------
-------------------------------------------------------------------------------------------------------------------
| Study Case: Study Case                                                                  | Annex:            / 1  |
-------------------------------------------------------------------------------------------------------------------
| System Summary                                                                                                   |
-------------------------------------------------------------------------------------------------------------------
| System Average Interruption Frequency Index          :  SAIFI  =   22.802640 1/Ca                               |
| Customer Average Interruption Frequency Index        :  CAIFI  =   22.802640 1/Ca                               |
| System Average Interruption Duration Index           :  SAIDI  =   36.345    h/Ca                               |
| Customer Average Interruption Duration Index         :  CAIDI  =    1.594    h                                  |
| Average Service Availability Index                   :  ASAI   =    0.9958510015                                  |
| Average Service Unavailability Index                 :  ASUI   =    0.0041489985                                  |
```

C7. Automated feeder switch - SAIDI

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