

**A guideline for optimizing outage management of
Eskom's transmission network**

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Abbreviations

ARC	– Auto-Reclose
A-MAP	– Asset Management Advancement Program
AMP	– Asset Management Policies
BPC	– Botswana Power Corporation
CBM	– Condition Based Maintenance
CLN	– Customer Load Network
CT	– Current Transformer
DC	– Direct Current
EA	– Engineering Assistant
NC	– National Control
NMC	– Network Management Centre
OCGT	– Open Cycle gas Turbine
O&I	– Open and Isolate
OI&E	– Open Isolate and Earth
PM	– Preventative Maintenance
PT&I	– Predictive Testing and Inspection
QLD LG	– Queensland Local Government
RCM	– Reliability Centered Maintenance
SCADA	– Supervisory Control and Data Acquisition
SOH	– South of Hydra
SVC	– Static Var Compensator

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Abstract

A streamlined process is needed to optimize the outage management of the Eskom transmission power system, as well as a ranking system in order to determine the best window of opportunity for an outage to occur thus positively impacting on Eskom's asset management.

The outage data captured between 2007 and 2011 was analysed for all cancelled, turned down and completed outages. This data indicated that there were 19 902 completed outages, 5 312 cancelled outages and 1 889 turned down outages in the 5 years. These numbers increase Eskom's costs in terms of resources and risks to system security. The reasons for the cancelled and turned down outages were investigated, while the completed outages were further broken down into transformer, reactive devices and line outages.

For the cancelled and turned down outages, it was ascertained that should the suggested changes occur in the form of better training and communication, the cancelled outages can be reduced by up to 11% while the turned down outages may be reduced by 2.5%. A guideline for a maintenance plan, based on the manufacturers' specifications was suggested and implemented on the historic 5 year data in order to determine if the outage numbers could be reduced. This proved to be effective, as the transformer outages could be reduced by 40%, the reactive devices reduced by 36% and the line outages could be reduced by up to 60%. A ranking system was also developed in order to assist maintenance planning by suggesting a window of opportunity for the outages to take place.

1. Introduction

Eskom is a government owned entity providing South Africa with electricity. The Eskom power network is divided into three major role players namely transmission, distribution and generation. Each of these entities has some form of hardware that needs to be maintained. For some of the maintenance to be done, plant needs to be taken out of service. For Generation this means that a generator will be taken off load and will not be available to generate any power. In Transmission and Distribution the equipment that needs to be taken out of service for maintenance, project or emergency reasons, includes lines, circuit breakers, isolators, busbars and transformers. To control when plant gets taken out of service, Eskom relies on asset management processes. When the plant is taken out of service according to a maintenance plan, it is referred to as a planned outage.

In this research only national transmission outages will be considered. Eskom's power grid is subdivided into seven grids, each with a grid outage scheduler who is responsible for coordinating the equipment designated to their grid. National control has a national outage scheduler who coordinates all the grid outages on a national scale.

Eskom's current outage management process is documented in Eskom document 32-650 – Outage Procedure. The document defines the role of various outage schedulers. Grid schedulers ensure that there are no conflicting outages on a day, resources are arranged and all the key customers that might be affected by an outage have been notified. Once an outage has been processed, the national outage scheduler will evaluate the outage in view of the entire system as to ensure system security. Some outages are season and loading dependant. Others may require a generator to be off load in order to assist with the remaining equipment should another incident occur during the outage. This document also outlines the timeframes for the different stages in the outage booking process. The current process states that outages need to be booked at least two weeks in advance.

1.1. Research Problem

Currently, the outages are not being coordinated optimally. There is no correlation between the project and maintenance outages which results in equipment being unnecessarily on outage numerous times during a financial year. Some of the project work will also conflict with normal maintenance, which would result in one of the two outages being delayed. These delays can be very costly to both Eskom and South Africa.

A streamlined process is needed to optimize the outage management of the Eskom transmission power system, as well as a ranking system in order to determine the best window of opportunity for an outage to occur thus positively impacting on Eskom's asset management. The streamlining will also include the coordinating and management of all the stakeholders involved.

An optimized outage management process will ensure that outages are prioritised correctly according to a ranking system developed specifically for Eskom. Duplicate and cancelled outages will be avoided by identifying the correct window of opportunity for the outage to occur.

The knowledge gained by identifying the correct outage window will benefit Eskom financially. It will also benefit the South African public by ensuring security of supply by minimising risks associated with the outages.

1.2. Research objectives

The aim of this dissertation is to investigate the possibility of reducing the use of Eskom's resources and risks associated with taking plant out of service.

By optimising this outage management process the researcher will strive to reduce Eskom's network risks by:

- finding optimal windows of opportunity for the outages to occur
- reducing cancelled outages due to conflicts
- minimising delays in maintenance and projects due to outages being turned down
- minimising equipment failures via regular maintenance
- reducing the likelihood of an interruption of supply to customers by decreasing the amount of outages

In order to achieve the reduced risks listed above, effective coordination procedures between stakeholders will also be required and developed in conjunction with the asset management maintenance plan guideline to obtain optimized outage management.

1.3. Dissertation outline

Chapter 2 contains literature studies in order to determine the importance of maintenance and asset management within a utility. It investigates the best practices when it comes to developing a maintenance strategy. It compares the asset management strategies followed by other utilities to those of Eskom.

Chapter 3 supplies background on the experimental data and how the analysis of this data will assist with the optimisation of the current outage management process followed by Eskom.

Chapter 4 presents the analysis of the data on the Eskom network and highlights the problematic areas that this project addresses.

Chapter 5 discusses the results and interpretation in order to optimize the current outage management process. It also discusses a ranking system that will serve as a guideline to identify the correct window of opportunity for outages.

Chapter 6 outlines a conclusion for the solutions presented as well as some recommendations for future improvements.

2. Literature survey

The following chapter will investigate some the different asset management strategies that exist and the approach that different utilities follow with regards to asset management.

2.1. Background of Eskom

Eskom is a state owned entity that supplies South Africa with electricity. Eskom has 12 coal fired power stations across South Africa, as well as the Koeberg Nuclear Power Station. They also have two pump storage water schemes at Palmiet and Drakensburg as well as two Hydro Power Stations at Gariep and Vanderkloof. The most expensive by far to operate is the Open Cycle Gas Turbines (OCGT), 9 at Ankerlig in the Cape and 5 at Gourikwa near Mossel Bay. These OCGTs cost approximately R2000/MWh and is considered to be emergency supply. Eskom's total installed capacity is approximately 38 000 MW while the winter peak demand can go up to 36 500. The summer peak demand is considerably lower at approximately 33 000.

In order to transport the power from generation to customers, Eskom has 153 transmission substations and 28 995km of transmission lines. Transmission substations work with voltages that range from 132 kV to 765 kV. These substations consist of equipment such as busbars, lines, breakers, isolators, coupling transformers, current transformers and voltage transformers.

2.2. Asset management

The term asset management can be defined as the following:

“Asset Management is the strategic management of physical assets during their life in the organisation. Physical assets have a life: they are planned and created, used, managed and maintained, and when no longer required prepared for disposal (iwmsnews, 2008).”

Assets can include, but are not limited to, any of the following that are used in the operation of a utility:

- buildings
- tools

- piece of equipment
- pipes
- machinery
- people

Managing assets ensures that a system gets the most value from each of its assets and has the financial resources to rehabilitate and replace them when necessary (EPA, 2008).

2.2.1. Importance of Asset Management

The capacity to produce output of value to customers is directly related to sustained performance of a company's assets using the process of triple bottom line evaluation of the services provided utilizing environmental, social and economic analysis. Failures in the asset base directly affect system performance. Sustained system performance is the result of successfully managing failure within the asset base.

The management of failure in the asset base is highly constrained by cost; that is, customers are not typically willing to pay for zero likelihood of failure. Different assets have different probabilities of failure, as determined by age, materials and assembly processes, operating environment, demand/usage and maintenance. Failures vary substantially in their consequence to the organization in terms of the production of valued output to the customer. Investment in assets (their acquisition, operation, maintenance, renewal and disposal) should be guided by the likelihood of failure and its consequence to customers and the regulator.

The more a company understands about their assets - the demand for their assets, their condition and remaining useful life, their risk and consequence of failure, their feasible renewal options (repair, refurbish, replace) and the cost of those options - the higher the confidence that their investment decisions are indeed the lowest life cycle cost strategies for sustained performance at a level of risk the company is willing to accept (SIMPLE).

2.2.2. Asset management strategies

Organisations typically outline their methodology on how they intend to best achieve their targets in a broad based plan known as a strategy. This strategy is normally determined by senior management and will address issues such as responsibilities and authorities associated with the asset management tasks.

Assets

When considering the physical assets, a replacement plan needs to be determined. This plan would also need to be reviewed when any significant changes occur. It may also be decided that this plan can be reviewed timeously for example annually. During the planning phase, the history and condition of the assets need to be audited in order to determine how reliable these assets are and what risk they pose to the current utility. This will help to minimise any unexpected interruptions that may occur to business operations. Capital expenditure proposals are to be prepared in accordance with the organizations standard procedures and timings, and will include a financial and/or cost benefit analysis and a risk analysis (Hastings, 2010).

Procedures and documentation

As previously discussed, an appropriate maintenance plan must be adopted, documented and captured on the organisation's maintenance management system.

A maintenance plan will be developed and reviewed as necessary in order to ensure that the assets are maintained to ensure maximum service of these assets. Asset maintenance plans are to minimize life cycle costs.

A risk analysis needs to be conducted according to specified procedures. Strategies to manage the risk identified by this analysis needs to be produced as well as contingency plans for the assets. The specified information management system is to be used for recording plans, procedures and work management (Hastings, 2010).

Any incidents, failures or defects to the assets needs to be analysed and the mitigation actions documented. These can be captured in a form of a reporting procedure that should be customised for each establishment.

Indicators need to be defined and implemented and needs to be defined and captured in a procedure. Procedures for asset management and maintenance operating budgets are to be established and followed.

The asset strategy must be responsive to and interact with the business strategy. Influences might include (Hastings, 2010):

- Changes in demand for product or service.
- Changes in revenue and costs.
- Technological developments.
- New business developments
- Acquisitions
- Divestment, sale or phasing out;
- Redeployment;
- Changed operating practices;
- Equipment replacement/Leasing;
- Outsourcing or In-sourcing of services.

Human factors also need to be considered when determining the asset management strategy. It has to be a long term commitment from the establishment regarding the in-house repair and logistic report rather than outsourcing these functions. Other operational considerations are the degree of reliability that the company requires. This can be achieved by increasing redundancy or maintaining the one individual piece of equipment to ensure its reliability. Coordinating all the parts in the supply chain like, in Eskom's situation, generation, transmission and distribution is important as well as the maintenance strategy that the institution chooses to implement.

2.2.3. Asset management within other utilities

2.2.3.1. NetworkRail

The railway declares their case for having a asset management strategy as the following:

“Asset management of the railway infrastructure is fundamentally about delivering the outputs valued by our customers and funders and other key stakeholders, in a sustainable way, for the lowest whole life cost” (NetworkRail, 2011)

The railway has structured their asset management strategy to provide the following information:

- How the infrastructure is currently performing, as well as set targets
- The capability of their assets, as well as targets for the capabilities
- The framework for the asset management
- The activities needed to implement the asset management framework
- The governance process and monitoring implementation of the asset management framework

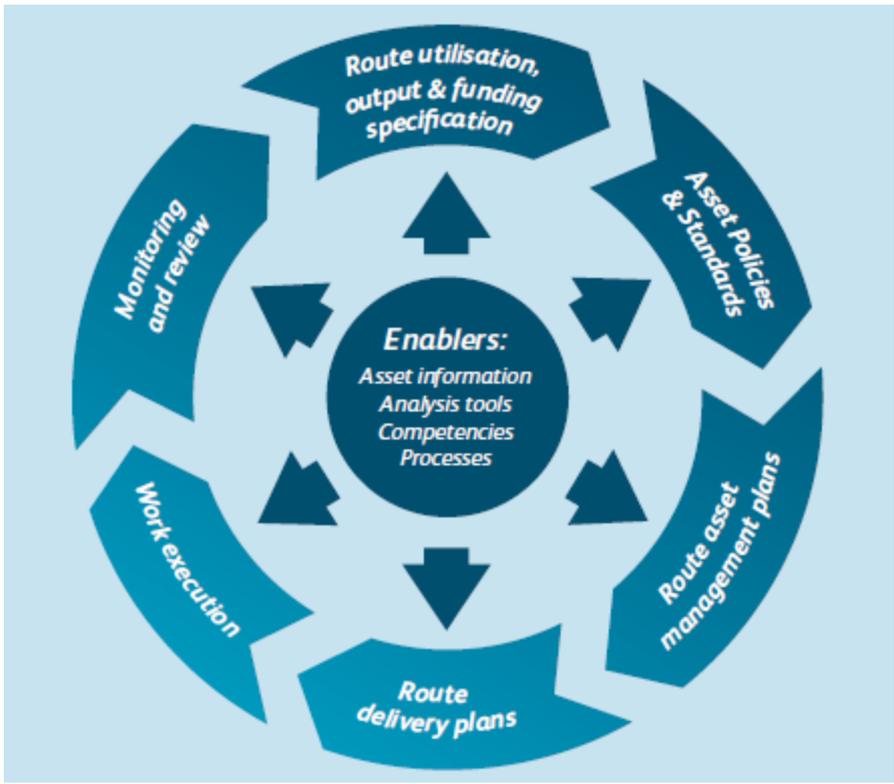


Figure 1: NetworkRails asset management framework (NetworkRail, 2011)

NetworkRail has categorised their asset management framework into three major areas namely primary decisions and activities, enabling mechanisms and review mechanisms. These areas consist of the following activities:

Primary decisions and activities:

- Route utilisation, output and funding specification - includes the capacity, capability and availability of the network

- Asset policies - maintenance, renewal and enhancements of assets. Their policies are currently based on experience and engineering, but will in future be based on whole life costing methods and tools.
- Route asset management plans - show the cost of delivering volumes of work and a forecast of the outputs that the work volumes give rise to.
- Route delivery plans - translates the work specified in the Route asset management plans into a detailed plan for execution. The objectives of the route delivery plans are to optimize the delivery of maintenance, renewal and enhancements, grouping work and combining work to be delivered at the same time.
- Work execution - mobilisation of the project or maintenance team, and the scheduling of resources. It also includes the provision of tools, facilities and equipment.

Enabling mechanisms:

- Asset information – includes asset type / location, age, capability, and condition. It also includes failure histories and consequences, work histories, unit costs and as-built drawings.
- Lifecycle costing tools - supports the optimisation of decisions taken throughout the asset lifecycle, including the maintenance versus renewal trade-off.
- Asset management competencies - represents the skills, aptitudes and behaviours required by individuals and teams.

Review mechanisms:

- Audits
- Key Performance Indicators (KPIs)
- Management reviews
- Corrective actions

2.2.3.2. Infrastructure and Land

The asset management strategy vision of Infrastructure and Land is stated as the following:

“To develop and maintain asset management governance, skills, process, technology and data in order to provide the desired level of service for present and future customers in the most cost effective and fit for purpose manner” (Gold Coast City Council, 2010).

Their objectives of the asset management strategy are also listed as the following:

- To develop and maintain effective asset management accountability and direction across the organisation
- capture and maintain relevant and reliable asset related information for effective decision making
- effectively and efficiently manage all physical assets under Council's control through each phase of their lifecycle
- engage the community in discussions on desired service levels and ensure asset investment decisions consider the 'whole of life' cost and balance the funding for investment in new/upgraded assets with the investment in asset renewal

The Infrastructure and Land asset management strategy contains the following key actions and outcomes:

- Accountability and direction - Asset management accountabilities are defined, understood and accepted along with clear direction for asset management improvement.
- Asset information management - Quality asset information informs asset management decision making and supports improved asset management
- Asset lifecycle management - assets are managed from a 'whole of asset life' perspective (i.e. from planning & design through to disposal)
- Service level management - a service level approach is taken to ensure long term infrastructure and financial sustainability

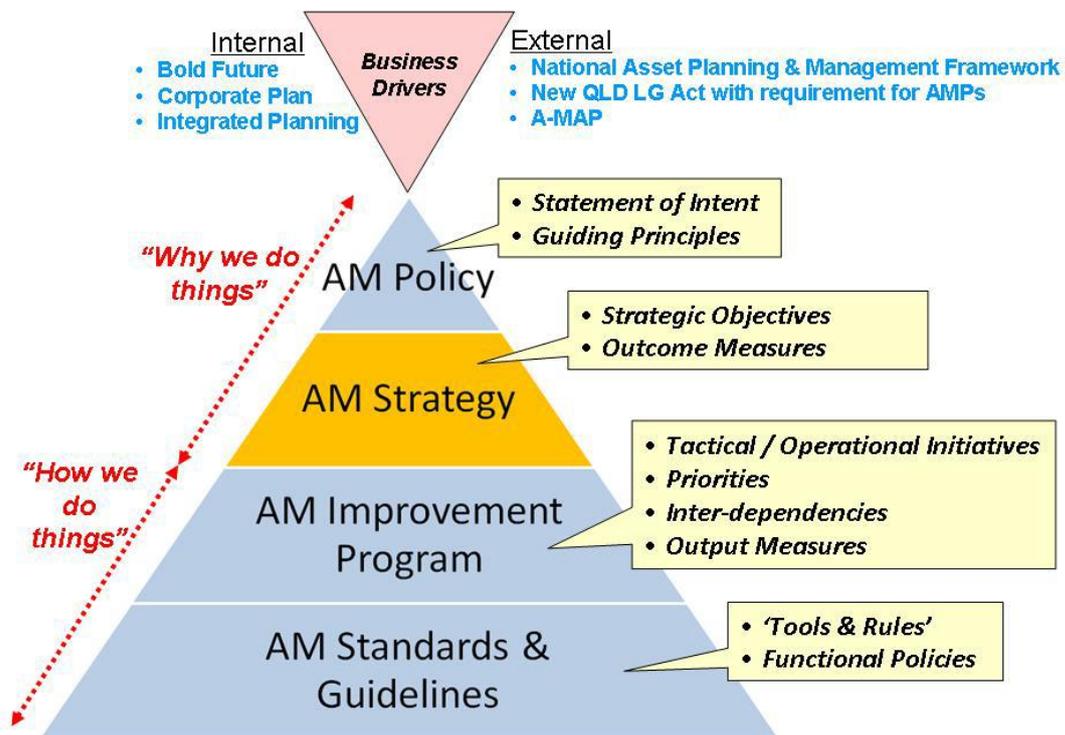


Figure 2: Infrastructure and Land asset management framework (Gold Coast City Council, 2010)

2.2.3.3. Eskom

Eskom's asset management strategy utilises some of the guidelines stipulated in PAS 55. Therefore, the guidelines of this publicly available specification will be discussed (IAM, 2008). This PAS 55 summarises the following about an asset management strategy:

The strategy shall

- Be derived from and be consistent with the asset management policy and the organisational strategic plan
- Be consistent with other organisational strategies
- Identify and clearly state the functions, performance and condition of its assets, asset types or asset systems as appropriate
- Take account of the risk assessment and identify those assets that are critical
- Be optimized
- Provide sufficient information and direction to enable effective asset management objectives, targets and plans to be produced

- Consider the lifecycle of the assets
- Be reviewed periodically to ensure that it remains effective and consistent with the asset management policy and the organisational strategic plan

Eskom's asset management policy is summarised in the points below. Eskom shall (Eskom, 2009):

- Establish , document and maintain an asset management system in line with international best practices and integrated with management systems, to ensure an optimum and sustainable balance between costs, performance and risk
- Have investment plans that are prioritised, optimized
- Efficiently execute all work with due regard to safety, health, environment, quality, legal requirements and statutory requirements
- Continuously train and develop employees in all aspects of asset management
- Maintain excellent relations with all stakeholders including customers , land owners and suppliers
- Build an organisation centred around the asset management principles
- Establish and maintain procedures for identification and assessment of asset and asset management related risks and control measures in line with Eskom and Transmission Integrated Risk Management.
- Develop a long term asset management strategy which will be in line with the asset management policy, organisational strategy and risk assessment, to provide sufficient information and direction including an action plan with a defined time scale to enable effective asset management targets and plans.
- Develop asset management objectives which will be contained in the Transmission Balanced Scorecard
- Develop and maintain an asset management performance target which will be contained in the Transmission balanced scorecard

2.2.4. Maintenance

Asset management is normally distinct from maintenance, but the technical services functions which support maintenance are part of asset management. Therefore, maintenance is discussed as this will form part of the asset management policy.

2.2.4.1. Benefit of maintenance

Blanchard (Blanchard, 2004) defines maintenance as all actions necessary for retaining a system or product in, or restoring it to, a serviceable condition. Some of the benefits of maintenance are listed below:

- reduced total operating costs,
- on-time delivery,
- consistent product quality,
- maintenance preserves capital assets,
- fulfils safety, insurance and regulatory obligations,
- reduces the stress on production equipment generated by breakdowns.

Maintenance may be categorised as either reactive or proactive approaches.

A maintenance philosophy comprises elements from various policies in the organisation, and the maintenance approach. Characteristics of a successful maintenance philosophy are that it is (Vosloo & Visser, 1999):

- comfortable
- compatible with the culture of the company
- results in improved performance of the company as a whole.

2.2.4.2. Corrective Maintenance

Corrective Maintenance is categorised under the reactive maintenance approach. Corrective Maintenance is described as maintenance tasks that are intentionally withheld until an asset stops working or starts failing. Maintenance is then performed as necessitated. This is also referred to as a “Run to Failure“ approach.

Corrective maintenance has a legitimate role to play in the overall maintenance program, albeit a limited one. The advantages of corrective maintenance can be viewed as a double-edged sword and therefore skill and care is required when determining which assets should be allowed to run to failure (The Condomium Home Owners Association of B.C, 2011). Corrective maintenance may be considered when the following criteria apply to the assets:

- Assets that are not maintainable
- Assets that are disposable and cheaper to replace than to fix
- Small assets without significant financial value
- Assets whose downtime is non-critical
- Assets that are not subject to wear and tear
- Assets that are unlikely to fail during their life cycle
- Assets that are prone to technological obsolescence

2.2.4.3. Preventative maintenance

Preventative maintenance tasks are performed at regular intervals, based on industry expected equipment life spans and failure patterns. These tasks are initiated based on predetermined intervals or, alternatively, triggered after detection of a condition that may lead to failure or degradation of functionality of the equipment or component (DoD, 2008).

A Preventative Maintenance approach is most appropriate when assets meet one or more of the following criteria (The Condomium Home Owners Association of B.C, 2011):

- Assets that are subject to predictable wear-out and consumable replacement
- Assets whose failure patterns are known and can be modelled.
- Assets that are highly regulated for health and safety reasons (Examples: elevators and fire protection equipment).
- Assets that can be effectively captured under a service contract

2.2.4.4. Predictive maintenance

Predictive maintenance is based on monitoring and measuring the condition of the assets to determine whether they will fail during some future period and then taking appropriate action to

avoid the consequences of that failure. The Predictive Maintenance approach lends itself well to some electrical and mechanical systems and assets with the following attributes (The Condominium Home Owners Association of B.C, 2011):

- Assets with random failure patterns.
- Assets that are not subject to straight-line wear.
- Assets that will significantly impact the business' operations if there is any downtime.
- Assets with measurable performance thresholds.

2.2.4.5. Reliability centered maintenance

Reliability-centered maintenance (RCM) is defined as a more advanced maintenance philosophy. It involves structuring a maintenance program based upon the understanding of equipment needs and priorities, — as well as available financial and personnel resources — to plan activities such that equipment maintenance is prioritized while operations are optimized (AberdeenGroup, 2006).

Reliability-Centered Maintenance integrates Preventive Maintenance (PM), Predictive Testing and Inspection (PT&I), Repair (reactive maintenance), and Proactive Maintenance to increase the probability that a machine or component will function in the required manner over its design life-cycle with a minimum amount of maintenance and downtime. These principal maintenance strategies, rather than being applied independently, are optimally integrated to take advantage of their respective strengths, and maximize facility and equipment reliability while minimizing life-cycle costs (NASA, 2008).

2.2.4.6. Condition Based Maintenance

Condition Based Maintenance (CBM) is the application and integration of appropriate processes, technologies, and knowledge-based capabilities to improve the reliability and maintenance effectiveness of systems and components. At its core, CBM is maintenance performed based on evidence of need provided by RCM analysis and other enabling processes and technologies. CBM uses a systems engineering approach to collect data, enable analysis,

and support the decision-making processes for system acquisition, sustainment, and operations (DoD, 2008).

2.2.4.7. Business – centered maintenance

The Business centered maintenance approach was developed in response to a need for a more cost effective approach towards maintenance, but with a high priority for safety. Nel (2006) explains that this approach is a review of the objectives of the overall enterprise in order to develop a maintenance life plan. This maintenance life plan is then used to determine the workload for preventive maintenance with historical data used to estimate the workload for corrective maintenance (Nel, 2006).

2.2.4.8. Total Productive maintenance

Total Productive maintenance emphasizes proactive and preventative maintenance to maximize the operational efficiency of equipment. It blurs the distinction between the roles of production and maintenance by placing a strong emphasis on empowering operators to help maintain their equipment. This holistic approach strives to eliminate all losses by adopting a zero defect, zero loss and zero failure approach (Nel, 2006). Some of the main features of total productive maintenance are:

- The maximisation of equipment effectiveness through the elimination of all machine losses;
- Creating a sense of ownership in the operators of the system
- The promotion of continuous improvement through small-group activities involving all departments of the enterprise

2.3. Operations management

Operations management is concerned with the planning, organising and controlling of activities that affect human behaviour.

2.3.1. Plan, organise, control

In order to do proper planning, one has to define the objectives of the department or organisation. Once these objectives have been defined, the policies and procedures for achieving these objectives have to be identified and well defined.

Organising activities involves the structuring of roles as well as defining the flow of information. This assists with identifying the activities required to achieve all goals and helps assign the authority and responsibility for carrying out these activities.

Control must be exercised to ensure that all goals are accomplished. This can be done by measuring the actual outputs and comparing these outputs to the planned operations. This will include the control of costs, quality and schedules.

It is important to know how human behaviour will affect the planning, organising and control of activities. This is especially important when it comes to decision making.

2.3.2. Objectives of operations management

The objectives of operations management can be categorised into customer service and resource utilisation. A department or organisation will aim to achieve certain standards. Operations management is concerned with attempting to achieve these standards and will thus aim to achieve the required customer service. Customer services must be provided with the achievement of effective operations through efficient use of resources (Stevenson, 1999). The objective of resource utilisation is obtaining maximum effect from resources or minimising their loss, underutilisation or waste. It is imperative that the balance be achieved between satisfactory customer service and resource utilisation. Often both cannot be maximised. Often an improvement in one will give rise to deterioration in the other. In a power utility such as Eskom, the objective is to identify how many duplicate outages are taken every year. Identifying this number will help improve customer satisfaction by reducing the risk to the customers.

2.3.3. Human factors

“An organisation is a system of interdependent human beings, and their characteristics affect both its structure and its functioning. Human relations management studies the characteristics and inter-relationships of individuals and groups within organisations and takes account of these factors when designing and administering those organisations.” (Anonymous, 2002)

When identifying the human factors in an organisation, the following needs to be considered (Anonymous, 2002):

- It is important to differentiate between human factors and the actions that influence them
- Human factors can interact, e.g., morale affects motivation.
- Some researchers consider that some human factors, such as goodwill towards the company, can be considered as dominant.
- Some performance indicators provide a measure of certain human factors, e.g., the level of absenteeism is an indicator of morale

The literature suggests one of the key elements to motivating an employee is the feeling of ownership towards the equipment or service. The personal interest that the employee invests will lead to a sense of pride in the function that the employee performs in the organisation. This in turn, leads to increased morale, with an increase in performance. Another key function that has been suggested is that of goodwill. This involves the employees feeling a sense of belonging with the company and wanting it to prosper. It is closely allied to ‘loyalty’ but is something more than this. This feeling can take years to cultivate in employees, and is a function of management treating the employees fairly and with respect. The employee with a feeling of goodwill will be more inclined to productive problem solving in their daily chores.

A third key factor worth mentioning is that of motivation. In the case of the maintenance employee, the most realistic indicators of his level of motivation are (Anonymous, 2002):

- the extent to which he knows what is wanted from him and
- the level of his effort to provide it with a minimum of external control

When trying to influence, understand or audit motivation within a maintenance department the following aspects must be taken into consideration (Anonymous, 2002):

- The factors that influence job content and job environment.
- The external social and political environment and its influence (because this governs the extent to which internal change is possible).
- The employee's identification with the maintenance objectives (the most important factor in their motivation).

Lastly, Morale within the maintenance department may be defined as:

“an individual's perception, which may be positive or negative, of his future work prospects, and which may be induced by the success or failure of the company employing him and the ability (leadership, organisational and engineering performance) of its management.” (Anonymous, 2002)

The following factors may lead to a negative morale:

- A company's poor economic performance;
- Poor company organisation and systems, inducing problems with product quality
- Recent workforce redundancies and the threat of more to come.

2.3.4. Decision making tool for risk

One of the biggest problems that are faced in conducting maintenance activities, are the prioritising these activities. The decision as to which activity is more important for the business needs to be an informed decision, not to be taken lightly. One needs to determine what the risks are to the business when one activity is deferred for another, as well as what the consequence of deferring this activity will have for the business. One of the suggested methods for prioritising these maintenance activities is to develop a risk matrix. It then becomes possible to compare the overall level of risk between individual identified maintenance activities by estimating the likelihood of an event occurring, and multiplying it by the estimate of the likely outcome of that event (Dept of Treasury and Finance , 2005).

Likelihood		Consequence				
		Insignificant 1	Minor 2	Moderate 3	Major 4	Catastrophic 5
Almost certain	5	Moderate	Significant	High	Extreme	Extreme
Likely	4	Moderate	Significant	High	High	Extreme
Moderate	3	Low	Moderate	Significant	High	High
Unlikely	2	Low	Low	Moderate	Significant	High
Rare	1	Low	Low	Moderate	Significant	Significant

Figure 3: Example of a risk matrix (Dept of Treasury and Finance , 2005)

Using the results of the risk assessment phase as a basis, the collective list of maintenance tasks that were identified through the asset condition assessments should be prioritised. This prioritisation will aid decision making with regard to implementing appropriate asset management strategies.

When considering how important maintenance is according to the literature studies that have been conducted in this chapter, and the different approaches that are followed by other utilities such as NetworkRail and Infrastructure and Land, it needs to be investigated how to optimize the outage management process that is currently being followed by Eskom. Even though Eskom's asset management strategy is dictated by PAS 55 as specified earlier, the human factors influencing the management of outages seems to be undermining the effectiveness of a good asset management strategy. This statement will be investigated in the following chapters.

3. Empirical Investigation

A data analysis will be conducted to ascertain what the problem with the current outage management process within Eskom is. The results of this data analysis will then be used to address the research problem that has been stated.

In this chapter, the process of how an outage is captured on the current database used by Eskom is described in detail. The terminology involved when making these bookings are explained, and the integrity of the data is discussed.

3.1. Phoenix data capturing

Eskom uses a data capturing system called Phoenix. This tool serves as an auditing trail for all plant that has been taken out of service. All equipment that is taken out of service is captured on Phoenix with reference to a unique plant slot that has been created for that type of equipment. This enables Eskom to track plant that have been taken out of service and completed thus far, and that are booked for future outages. However, it has been noted as a concern by the National Control Outage Scheduling Office that these outages are not being coordinated properly, the extent of which is the focal point of this investigation.

Since the historical data for outages have been captured on Phoenix, with their relevant outage status, the data between 2007 and 2011 have been selected in order to analyse the amount of outages per equipment that have taken place over the last five years. This should give an indication of the efficiency of the current process that is being followed for outage coordination. It will also give guidance on how to streamline the process with the goal in mind to maximise network security.

3.2. Data Processing

The data for every outage is captured manually. The following describes the process that needs to be followed in order to capture an outage. It also describes what information is required in the fields that have to be populated.

3.2.1. Booking an outage

The information has to be manually captured by the Grid Outage Scheduler.

The information required for each outage booking involves the following:

- Outage plant slot – the reference to the plant that will be taken out of service. Examples:
 - Apollo transformer 1
 - Kendal – Minerva 400 kV line
 - Hydra 400 kV bus 2
 - Muldersvlei SCADA

- Description of the outage – a description of the work that will be performed during the outage. Examples:
 - Breaker and isolator maintenance
 - Cutting trees
 - Safety panel
 - Protection maintenance

- Outage requirements – a description of operations required to enable the work to continue. Examples:
 - Open, isolated and earthed (OI&E)
 - Open and isolated only (O&I)
 - Off auto re-close (Off ARC)
 - Off supervisory

- From and To date – the dates that the equipment is required for
- Outage times – the duration of the outage per day from start time to end time
- Shortest return time – this time indicates the shortest time period necessary to return the equipment back to service in case of an emergency
- Daily or Stay Out – indicates whether the equipment will be returned each day, or if it will stay out of service for the duration of the outage period
- Requestor – which supervisor requested the outage

- Scheduler – which Grid Scheduler scheduled the outages

3.2.2. Outage status

There are several different outage statuses associated with each outage. First the outage needs to be **requested**. The outage with all the necessary information is requested by the Customer Load Network (CLN) supervisor. The outage is then processed by the Grid Scheduler. The Grid Scheduler then has certain requirements that have to be fulfilled before the outage status can be changed to **scheduled**. These activities include:

- Ensuring that all the resources are arranged and available for the requested period
- Notifying the customers involved of the possible risk
- Ensuring that all procedures required for the outage are available to National Control
- Ensuring that no conflicting outages are booked within the grid

Once the status has been changed to scheduled, the National Control (NC) Scheduler will evaluate the outage. The duties of the NC Scheduler include:

- Ensuring there are no conflicting outages on the network
- Ensuring the generation pattern expected for the outage period is favourable
- Ensuring no network violations will occur for the duration of the outage period
- Ensuring all necessary documentation regarding the outage is signed and filed in the NC Centre
- To identify and evaluate all risks associated with taking the plant out of service

If all of these requirements have been met, NC Scheduler will then change the status of the outage to **confirmed**. On the day of the outage the network operators will change the status to **taken** once the plant has been handed out for the maintenance. Once the plant has been successfully handed back in service to the network operator, the status will be changed to **completed**.

If the requirements have not been met, the NC Scheduler will **turn down** the outage. When this option is chosen, Phoenix requires a reason to be entered for referencing purposes. When the outage has been turned down the outage process will start from the beginning again.

The network operator and the Grid Scheduler both have the option of **cancelling** an outage. The network operator will change the status to cancelled when the outage is cancelled on the day that the equipment was supposed to be taken out of service. A reason must be entered when this option is chosen in Phoenix. The Grid Scheduler may also cancel the outage if it is more than 24 hours before the outage was meant to start. They will also supply a reason for the cancellation.

When the outage date has passed, but the equipment was not taken out of service, and no reason was supplied to the network operator will change the status of the outage to **not taken**.

3.3. Data integrity

All of the information necessary to conduct this analysis is available on the data capturing system Phoenix that Eskom uses. One needs to obtain training and authorization to have access to the Phoenix database. There are also different levels of authorization that allows a user restricted access to the data that they are allowed to capture. Each user has a unique username and password. The password expires every 30 days and must be changed accordingly or the account will be locked. The username also allows for tracking of the outages, as the user's name is logged with any entries and changes that are made.

There are some Customer Load Network (CLN) supervisors who have been granted Requestor Rights. This means they are allowed to request an outage on Phoenix, but can do nothing else. The Grid Schedulers have the Scheduling Rights to schedule the outage from requested mode. They can also request an outage with these rights. As indicated previously, the Grid Schedulers may also cancel an outage within a specified timeframe. The next level of access rights granted, are the Controller Rights. This includes the right to request, schedule, cancel and confirm an outage. These rights are granted to the control staff from the various control centres. No information can be changed by any of these access levels after an outage has been confirmed. The highest level of access rights are the Master Rights. These rights are only granted to the National Control Schedulers. The Master Rights grants the user access to all the functions available in Phoenix. It also allows changes to be made, no matter which status the outage is in. As there are only two National Control Schedulers at a time, this allows for fairly accurate data representation.

When an outage has been captured, it cannot be deleted, not even with Master Rights. It has to be closed using one of the methods as discussed in the previous section. One of the problems with the data capturing, is that it has to be done manually. The description for a specific outage may not always include all the work that will be done during that outage, which makes risk assessment inaccurate. The reasons that has to be entered when closing a booking with the options “cancelled” or “turned down” also has to be captured manually. There is no list available to choose a reason and is open for the Phoenix user to interpret as he sees fit. This may lead to confusion as to why an outage was cancelled or turned down, as the user may choose to specify the reason as “unknown”, which does not assist when tracking an outage. However, if the outage was captured as completed, the data is accurate in the fact that the outage did in fact take place and must be acknowledged as plant that was taken out of service.

There is also a limited sorting function in Phoenix. One can sort for data by name or by date, but not at the same time. One cannot sort the data by different plant such as lines or transformers. The data can however be exported to Microsoft Excel where data can be sorted and analysed. This is however, also hampered by the fact that not all plant slots are captured in unified forms as the naming conventions differ.

3.4. Data analysis objectives

The objectives of analysing the historical data are to identify the following for cancelled and turned down outages:

- Controllable factor
- Uncontrollable factor
- Semi-Controllable factor
- Window of Opportunity

Controllable factors are factors that could have been better managed and was in the control of the outage scheduler to change. Better management of controllable factors will allow the outage scheduler to reduce cancelled outages. This will include aspects like resources that were not properly arranged.

Uncontrollable factors are those factors that are outside the control of the outage scheduler. This could include external customers cancelling an outage due to constraints on their side, which could not be anticipated by the outage scheduler. Weather would also be an uncontrollable factor.

Semi-controllable factors are factors that may or may not be in the control of the scheduler. This is especially true for projects, as all the resources may have been arranged from Eskom's side, but the contractors may not have been ready, or vice versa. One scenario was controllable, the other uncontrollable. This is also associated with internal customer related outages. Semi-controllable can be either controllable or uncontrollable depending on the situation.

Outages need to be booked in the best window of opportunity. This may include seasonal outages that are winter load or summer load dependant. It also includes outages that are generation dependant. This will also be included as a controllable factor, as network simulation studies may indicate where the best opportunity to take out equipment may be.

The following chapter will analyse the data captured in the Phoenix database between 2007 and 2011. This data analysis will demonstrate the current problem that needs to be addressed within the Eskom transmission outage management process.

4. Data analysis

Before the outage coordination process can be optimized, one first needs to identify the problem by analysing historical trends. When a piece of equipment gets taken out of service, it compromises the integrity of the network. Especially when removing a transformer or a line, the network is weaker than it was designed to be. Another danger that is faced when taking equipment out of service is that of operator errors. One cannot anticipate the likelihood of an operator error, however, the probability of it occurring can be minimised by reducing the amount of switching to be done, by reducing the number of planned outages.

In this chapter, the historical data will be analysed to ascertain how many outages were completed during the last five years to indicate whether the network has been unnecessarily strained. The cancelled and turned down outages will also be analysed to determine the level of maintenance and project planning that has been done. This data will then be used to propose a maintenance procedure that can optimize the outage management process, once the problem areas have been identified.

4.1. Phoenix data 2007 – 2011

All the outages that were booked on Phoenix from 1 January 2007 to 31 December 2011 were analysed to determine the effectiveness of the current outage management process. The reasons for the “turned down” and “cancelled” outages were recorded and summarised.

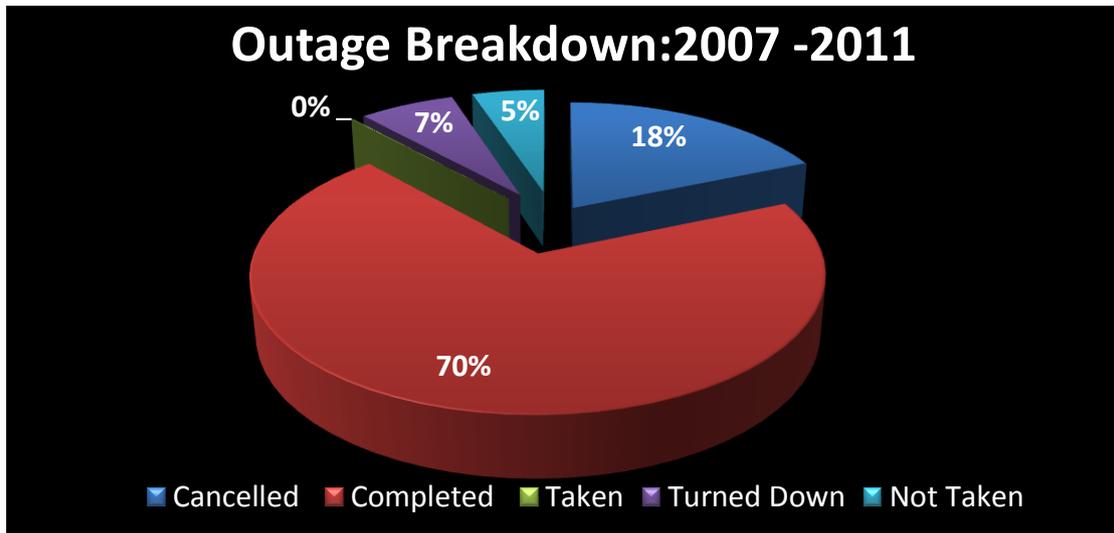


Figure 4: Outage breakdown from 2007 to 2011

In this time period, 28 557 outages were booked. 19 902 of these outages was successfully completed, 5 312 outages were cancelled, 1 889 were turned down and 1 435 outages were not taken. 19 outages are still taken, due to faulted plant. The reason for these cancellations and turned down outages will now be discussed in more detail.

4.1.1. Cancelled outages

It is of concern that 18% of all these outages were cancelled, and even though the outages may be cancelled more than 24 hours before an outage commences by the Grid Scheduler, majority of these outages were cancelled on the day of the outage by the network operator. Various reasons may be stated why the outage was cancelled. A breakdown of these reasons can be seen in Figure 5. The reasons were grouped under the following categories:

- Weather
- Generation constraints
- Network constraints
- Already completed
- Resources not available
- Project delay

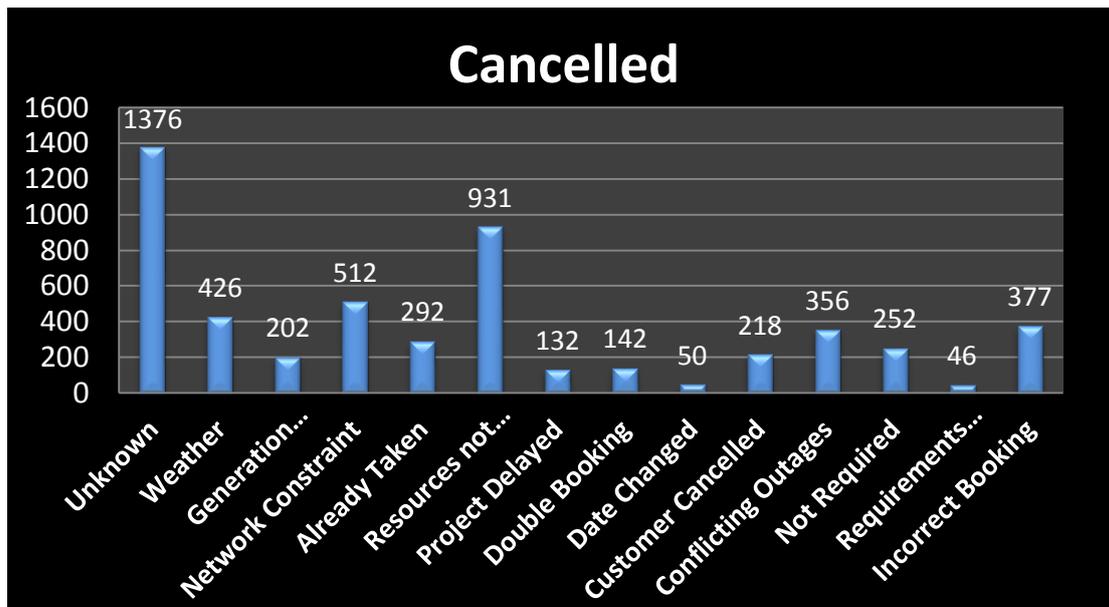


Figure 5: Cancelled outages between 2007 and 2011

- Double booking
- Date changed
- Customer cancelled
- Conflicting outages
- Not required anymore
- Outage requirements not met
- Incorrect booking
- Unknown

Unknown

One of the flaws of Phoenix, is that there is no drop down menu where one is forced to choose the reason for cancelling an outage. The user has free range to state the reason in his own words. Therefore, some of the reasons stated are not clear when recalled. That is why such a high number of outages were categorised in the “unknown” category.

Weather

Conditions that prohibited outages from continuing due to weather include rain or strong winds. Weather is considered to be an uncontrollable factor.

Generation constraints

In some cases outages may require certain generators to be on line. If one of the specified generators tripped or were out of service on the day of the outage, the transmission outage will be cancelled, as generation takes precedent in Eskom. Some outages may require some generators not to be running at full load due to overload conditions. In the case where the country is experiencing a generation shortage, all the available generators will be required to run at maximum out. Therefore the transmission outage will not be accommodated. These are normally unforeseen generation patterns that were not planned. Generation constraints are thus considered to be an uncontrollable factor.

Network constraints

Network constraints are situations where other equipment have faulted prior to or on the day of the outage which will conflict with the planned outage. It may also be an unexpected deviation in expected load in the area which may cause system violations to occur like high or low voltages or overloading of remaining plant. Network constraints are also considered to be an uncontrollable factor.

Already completed

Outages are often captured on the Phoenix database well in advance. Sometimes these outages have been completed at an earlier opportunity due to equipment shared by two grids, when an outage was taken by the one grid and the other grid used the opportunity. This is considered to be a controllable factor, as these outages should be aligned.

Resources not available

Resources not being available on the day of the outages are the largest contributor to cancelled outages. All outages should be secured and ready when the outage status is changed to "scheduled". This includes Engineering Assistants (EA) who are responsible for the switching of the equipment, contractors and all tools required for the outage. Resources not being available is considered to be a planning issue, and therefore labelled as a controllable factor.

Project delay

Project related outages are often delayed with an indefinite date of continuation due to the many aspects and resources involved in organising a project. This is considered to be a semi-controllable factor.

Double booking

When equipment is already out of service, another team might like to do some work on the equipment and have already put in a booking for that equipment, not realising it was already out of service. Therefore, the booking is not necessary. An example is when a live line team would like to work on a line that has already been open, isolated and earthed. The live line team only requires the auto re-close function to be switched off. As the line is already out of service, this function is inherently off, therefore no booking is required. This is classified as a controllable factor, as the additional work may be noted in the description of the original booking and should be aligned.

Date changed

When the date of the outage is changed, but a new date is not yet available, the outage is cancelled by the Grid Scheduler until further notice. As these dates are entered by the Grid Scheduler, it is considered to be a controllable factor.

Customer cancelled

In order for the status of an outage to be changed to “scheduled” the customer notification and consent have to be completed. If the customer cannot accommodate the outage for whatever reason, the outage will have to be cancelled. This is considered to be an uncontrollable factor.

Conflicting outages

Conflicting outages should be identified before an outage commences by the Grid Schedulers. These are equipment that cannot be taken out of service at the same time as they will cause system violations. If a Grid Scheduler notices a conflict within his own grid, the outage can be cancelled well ahead of time. When a conflict exists with equipment from another grid, the grid schedulers should negotiate which outage takes preference. Conflicting outages should not have to be cancelled on the day of the outage. This is considered to be a controllable factor.

Not required anymore

When the scope of work for an outage have changed, the outage is sometimes not required anymore. This is considered to be a controllable factor.

Outage requirements not met

Certain requirements have to be met when scheduling an outage. If these requirements have not been met in time for the outage, the outage has to be cancelled. This is a controllable factor.

Incorrect booking

When the outage is booked for the wrong date, wrong time or with the wrong plant slot, the network operator will cancel the outage as an incorrect booking. As this is human error, it is considered to be a controllable factor.

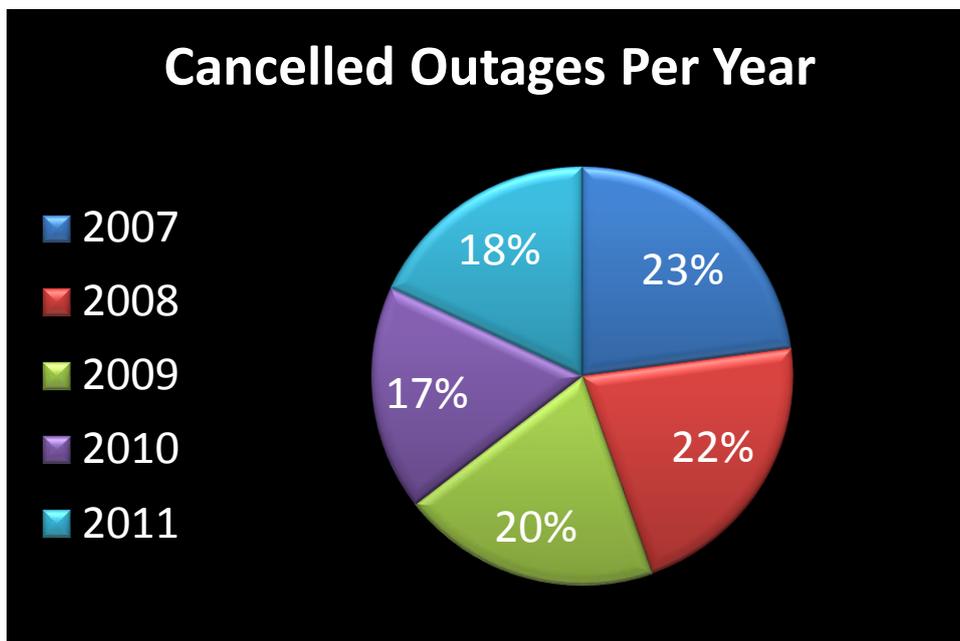


Figure 6: Cancelled outages per year

There seems to have been a slight increase in cancelled outages in 2007 and 2008 due to the load shedding that was taking place, but the cancelled outages seem to account for about 20% of the outages per year on average.

4.1.2. Turned down outages

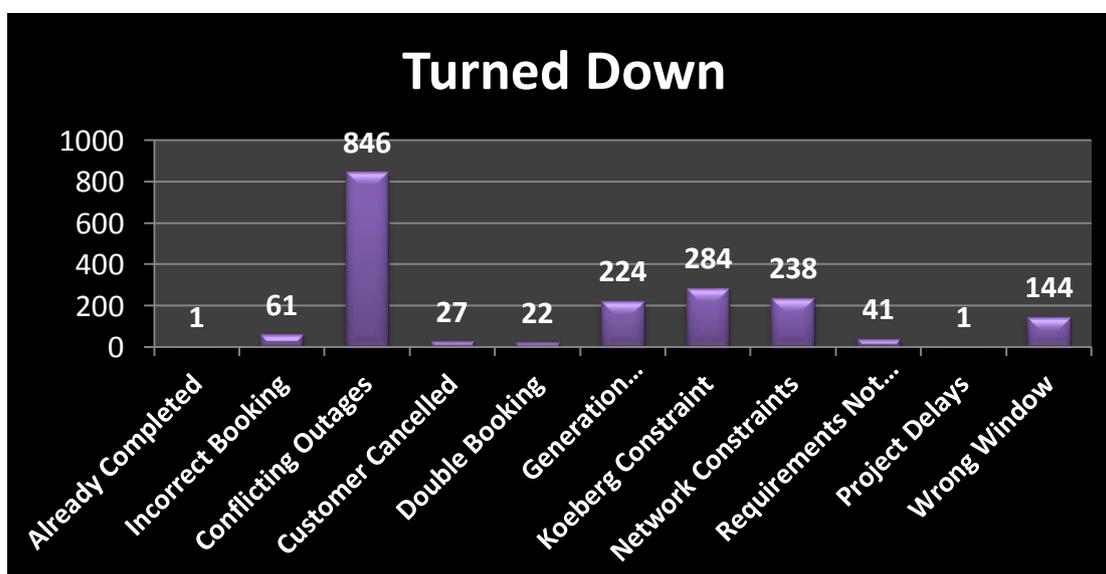


Figure 7: Turned down outages from 2007 to 2011

The reasons for the outages to be turned down were grouped under the following headings:

- Already completed
- Incorrect booking
- Conflicting outages
- Customer cancelled
- Double booking
- Generation constraint
- Koeberg constraint
- Network constraint
- Outage requirements not met
- Project delays
- Wrong window

Some of the categories may have the same name as the cancelled outages, but have different interpretation when referred to in the turned down outages. These categories are discussed below.

Already completed

This outage refers to a booking that has already been completed and was no longer required. This status should have been cancelled instead of turned down. There is only one booking in this category.

Incorrect booking

The incorrect bookings are the same as the cancelled outages. It refers to plant slots that have been incorrectly chosen, outage requirements that have been incorrectly selected or description that are contradicting the outage requirements. These are all considered to be controllable factors.

Conflicting outages

The conflicting outages are bookings that were made within the same grid, or in an inter-grid situation, where the equipment cannot be taken out of service together, as this will result in system violations. Conflicting outages are considered to be a controllable factor.

Customer cancelled

When an outage will affect distribution or international customers, the NC Scheduler will liaise with the Network Management Centre (NMC) scheduler or the international scheduler to ensure their necessary equipment will be in service for the duration of the requested outage. If they have conflicting outages in their networks, the outage will be turned down. This is considered to be a semi-controllable factor, as negotiations may be done before hand.

Double booking

Double bookings are the same for cancelled and turned down outages. If the equipment is already out of service, it is not necessary to make another booking to work on the same equipment. This is a controllable factor.

Generation constraint

The difference between the cancelled outages and the turned down outages for generation constraint, is that for a turned down outage, this is a semi-controllable factor. For cancelled outages, this is an uncontrollable factor. A generation plan is available to align transmission outages that require generation involvement. However, outages are processed without consulting this generation plan, which results in the generation not being suitable for that specific outage. The reason that this factor is only semi-controllable is that Generation may change their plans at short notice, which results in the transmission outage that cannot be accommodated anymore.

Koeberg constraint

Koeberg has a set outage plan for its generators which involves one of the generators being out of service for 60 days at a time for refuelling. This is at least once a year. There are a lot of transmission equipment that cannot be taken out of service during this time. This factor is only semi-controllable, as Koeberg does trip more often than it should throughout the year. As these dependant outages are planned around the scheduled Koeberg outages, the sudden trip of Koeberg results in many outages having to be turned down.

Network constraint

Network simulation studies are conducted before an outage is to commence to determine if the outage will violate any of the system criteria. If the studies indicate that an outage may cause high or low voltages, or even overload certain equipment, this is considered to be a network constraint. This is a semi-controllable factor, as a better window of opportunity may be identified. But in some cases a better window is not available, and alternative arrangements may have to be made for example load shifting or even shedding.

Outage requirements not met

There are certain requirements that an outage has to adhere to before the status can be changed to “scheduled”. If any of these requirements are not met, the outage may be turned down. This is considered to be a controllable factor.

Project delays

The project delays are similar to the cancelled outage category however; this is known in advance when it is turned down. These project delays are considered to be a semi-controllable factor.

Wrong window

When an outage that can only be accommodated during summer loadings, is booked in winter period, this is labelled as a wrong window outage. This is also true for outages that can only be taken during a weekend, or is preferable with an identified loading pattern. This is considered to be a controllable factor, as the information on the equipment that are loading dependant is published every year in a Network Appraisal report, compiled by the Operations and Planning department within Eskom. This report is accessible to all schedulers.

4.2. Completed Outages

70% of all the outages booked between 2007 and 2011 were completed successfully. However, this involved 19 902 outages. It needs to be determined how many of this equipment was taken out more than once due to inefficient outage management.

4.2.1. Outage breakdown

The outages were categorised into the following groups:

- Lines
- Busbars
- Breakers
- Transformers
- Reactive devices
- SCADA and Buszones
- Risk of Trip (ROT)
- Poles

The Lines include all 765 kV, 400 kV and 275 kV lines. There are a few 132 kV lines that have also been included, as they supply important customers and have been demarcated to transmission rather than distribution.

A busbar is “an electrical conductor, maintained at a specific voltage and capable of carrying a high current, usually used to make a common connection between several circuits in a system” (FARLEX, 2003), in this case transmission lines. All stations have at least two busbars, where some stations have multiple busbars due additional protection schemes to ensure security of supply. When one wants to work on the busbar isolator of a line, the busbar has to be taken out of service with the line. One busbar can service multiple lines.

Breakers are switching devices designed to break the current that is flowing on the equipment in a safe way. This group includes section breakers that separate busbars, buscoupler breakers that couples or split busbars from each other as well as line breakers that have the ability to be bypassed or taken out of service due to transfer facilities at the station. This ensures that the line or transformer is still in service, while the breaker is out of service, ensuring network security.

The Transformers Group include all voltage transformation equipment that are demarcated to transmission.

The Reactive devices include all the capacitors, reactors and static var compensators (SVC) that are on the Eskom network. These devices are extremely important for controlling the voltage on the network at all times.

SCADA and Buszone bookings are made when some forms of protection work is carried out at the station. It may include equipment that cannot be operated remotely when the SCADA is switched off, or the protection not operating correctly when the buszone monitoring has been switched off. For these outages, Engineering Assistants are required to be at the affected substation for the duration of the outage in order to operate the equipment manually, or report any abnormalities should they occur.

Risk of trip (ROT) outages are also booked, even though they are not taking plant out of service. It is booked as a notification for the control room that should the affected equipment trip, they know what the cause is.

The pole group refer to the DC converter poles at the Apollo converter station.

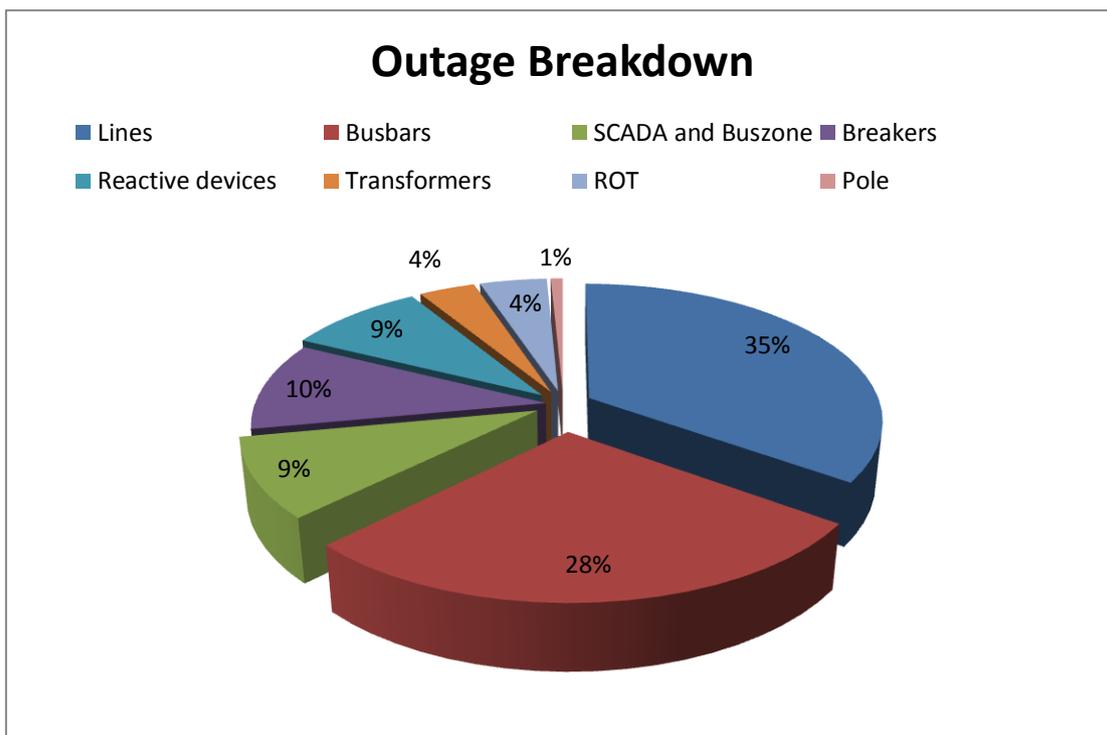


Figure 8: Outage breakdown for Completed Outages

From Figure 8 it can be seen that out of the 19 902 completed outages, the biggest contributor is the lines. Lines have a total number of 6 940 outages. Even though busbars have the next highest number of outages, it is expected that busbar outages would be higher, as they serve

multiple lines. A busbar outage would be required every time the busbar isolator of the line needs to be maintained. By reducing the line outages, the busbar outages would automatically reduce.

Breakers are considered to be less critical outages, even though there is still switching involved, the network is not severely weakened by having the section or buscoupler breaker out of service. It is recommended to rather have a line put on bypass or transfer that allows work on the breaker only, as the line would still be in service.

ROT outages are booked and noted, but has a minimum risk on the network, and should the equipment trip, it is normally accompanied with a very short return time.

SCADA and Buszone outages contribute 10% of the total completed outages. However, since the Engineering Assistant must be present during the outage, it is also not a high risk outage.

Pole outages at the Apollo DC converter station are outages that are controlled by international customers, and are therefore deemed uncontrollable outages.

The amount of Reactive devices outages are of great concern at 9% of the total amount of completed outages. This is a total of 1771 capacitors, reactors and SVCs that have been removed from the system in the last 5 years. This makes controlling the voltages on the system very difficult and should be reduced where possible.

Even though Transformers only contribute 4% of the completed outages, this is still 723 outages on critical transformers. For these reasons, a more in depth investigation will be done for Lines, Transformers and Reactive devices, as these are the critical equipment that puts the network at greatest risk when removed from service.

4.2.2. Transformers

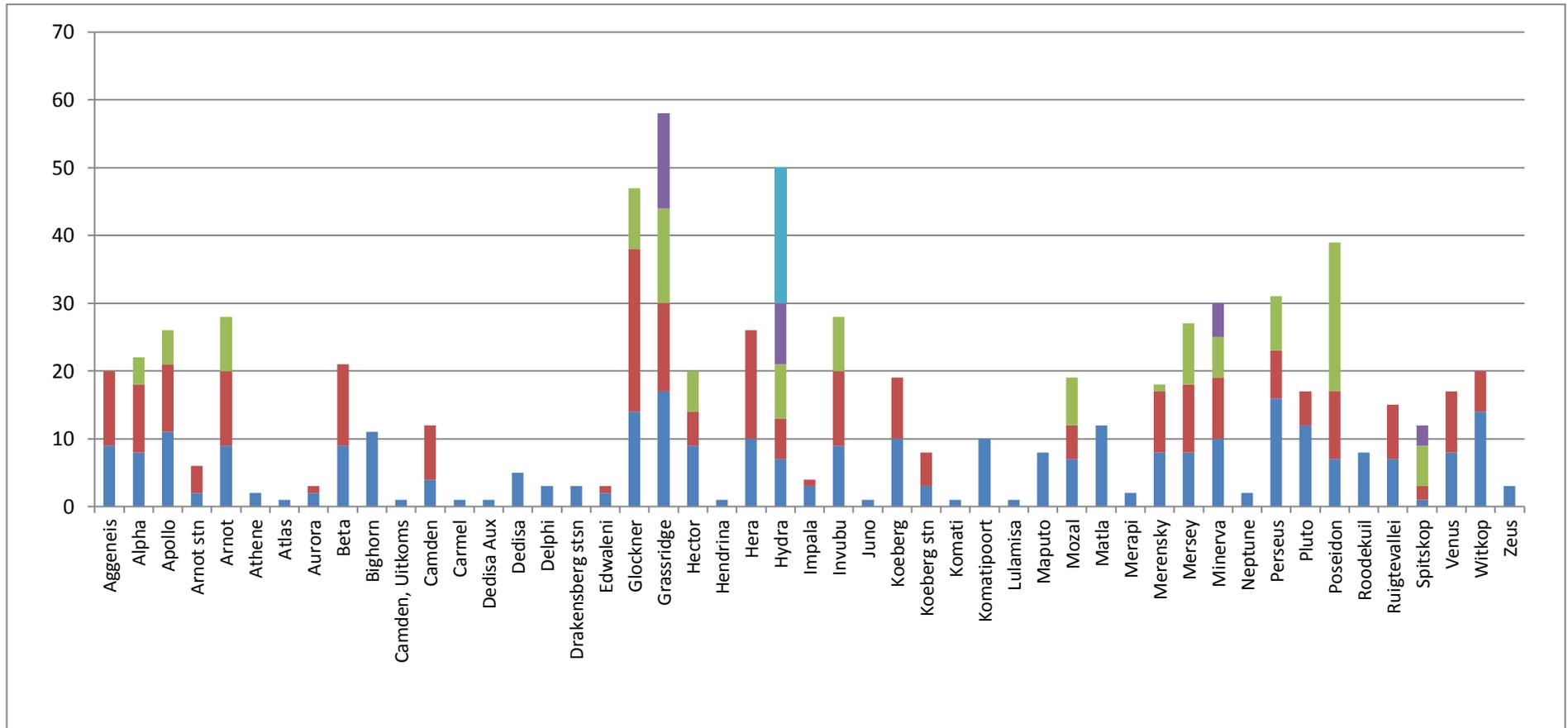


Figure 9: Transformer outage breakdown

It is of concern that some stations have 20 and more outages per station. Although not all of the transformers cause a network problem when taken out of service, it is still concerning the amount of switching and resources that are necessary to take a transformer out of service.

Some of the critical transformers are discussed below.

4.2.2.1. Critical Transformers

Arnot transformers

Arnot has three transformers. Transformers 1 and 2 both have a 400 MVA capability while transformer 3 has an 800 MVA capability. Arnot Power Station feeds the Lowveld area, which is already riddled with a low voltage problem. When taking out the one of these transformers, the voltage problem is increased, as the transformers supply voltage support to this area. One also has the additional risk that should another transformer trip, while one is out of service, the remaining transformer will overload. When the remaining transformer overloads, the protection will operate to ensure no harm is done to the transformer due to the overloading conditions and that transformer will also trip. This will result in customers being interrupted in the Lowveld area to the extent of a 100 MW of load lost. There were 28 Arnot transformer outages collectively during the last 5 years, which put the Lowveld at risk 28 times.

Ruigtevallei Transformers

Ruigtevallei has two transformers with a capacity of 250 MVA each. These transformers are critical equipment in the network, as they are the only link to the Hydro Power Station Gariep. Gariep has four generators that can each supply 90 MW to the system. This is considered to be a peaking station, as it can start generating within minutes in an emergency and is cheap to operate as it uses water. However, when one of the Ruigtevallei transformers are taken out of service, Gariep can only generate using two units at a time, as the remaining transformer will overload with more generation. Should the remaining transformer trip all generating capacity will be lost from Gariep side. That is 360 MW of generating capacity that is at risk in an already generation constraint network. These transformers were taken out of service a total of 15 times between 2007 and 2011. In 2011, the remaining transformer did fault while the other transformer was out on an extended outage and caused the network severe strain as it took more than a week to return the transformer that was out. A very costly emergency bypass had to be erected in the meantime, as the network was severely constraint generation wise, and needed the generation from Gariep.

Witkop transformers

Witkop has two transmission transformers with a capacity of 400 MVA each. Witkop is a highly loaded area with a lot of low voltage problems under a system condition. When one transformer is removed, it immediately jeopardises the network as a 100 MW of load must be reduced in order to avoid overloading on the remaining transformer. This can either be done by load shedding the customer, or by moving load away from the area by reconfiguring the distribution network. Should the remaining transformer trip during the outage, a voltage collapse situation will occur in the surrounding network, where up to 450 MW of load will be lost. These are outages that have to be planned in advance where many customers including the distribution are involved. The majority of the customers are mining loads, and thus interruption of these supplies must be avoided at all costs. These transformers were taken out of service a total of 20 times.

Perseus transformers

Perseus substation has three transformers. Transformer 1 has a capacity of 800 MVA while transformers 1 and 2 can supply 400 MVA each. Perseus is considered to be a fairly critical station as it is one of the few stations that supply the Western Cape area. Taking out one of the transformers at a time is not a problem. However, losing a second transformer, either big or small, will result in an overload of the remaining transformer. To minimise damage to the remaining transformer due to overloading conditions, the protection will operate and open the breakers for the remaining transformer, thus also removing it from the network. This will cause an interruption of supply to the surrounding network of up to 900 MW. These transformers were taken out of service 31 times collectively over the last 5 years.

Beta transformers

There are two Beta transformers. Each of these transformers can supply 2000 MVA. These transformers are critical, as they have an influence on the transfer capabilities to the Western Cape area. There are official transfer limits that have been calculated and entered into the agreement with Koeberg Nuclear Power Station. These transfer limits have to be adhered to as they have an effect on the nuclear safety of the country. Under system healthy conditions, 3900 MW can safely be transferred to the Cape. When a Beta transformer is taken out of service, this transfer limit gets reduced to 2000 MW. Depending on the loading in the Cape area, the difference will have to be supplied by using the Open Cycle Gas Turbines (OCGTs) that are situated at Ankerlig and Gourikwa Power Station. These OCGTs cost approximately R2000/MWh. Since there is a potential supply difference of 1900 MW, one transformer outage could potentially cost up to R3.42 million per hour. This is the order of supply that is required

especially during a Koeberg unit outage. There were a total number of 21 outages taken between 2007 and 2011. The best window of opportunity needs to be found for these Beta transformer outages and coordinated with the aim of reducing the amount of outages, as these outages have the potential to cost Eskom millions of rands.

Below is a table summarising the critical transformer outages. The table indicates the number of transformers at each station, the risk involved and how many outages were completed between 2007 and 2011.

Table 1: Summary of critical Transformer outages

Station	Number of Transformers	Risk	Number of outages between 2007 and 2011
Arnot	3	100 MW – Load	28
Ruigtevallei	2	360 MW - Generation	15
Witkop	2	450 MW - Load	20
Perseus	3	900 MW - Load	31
Beta	2	R3.42 million per hour	21

4.2.3. Reactive devices

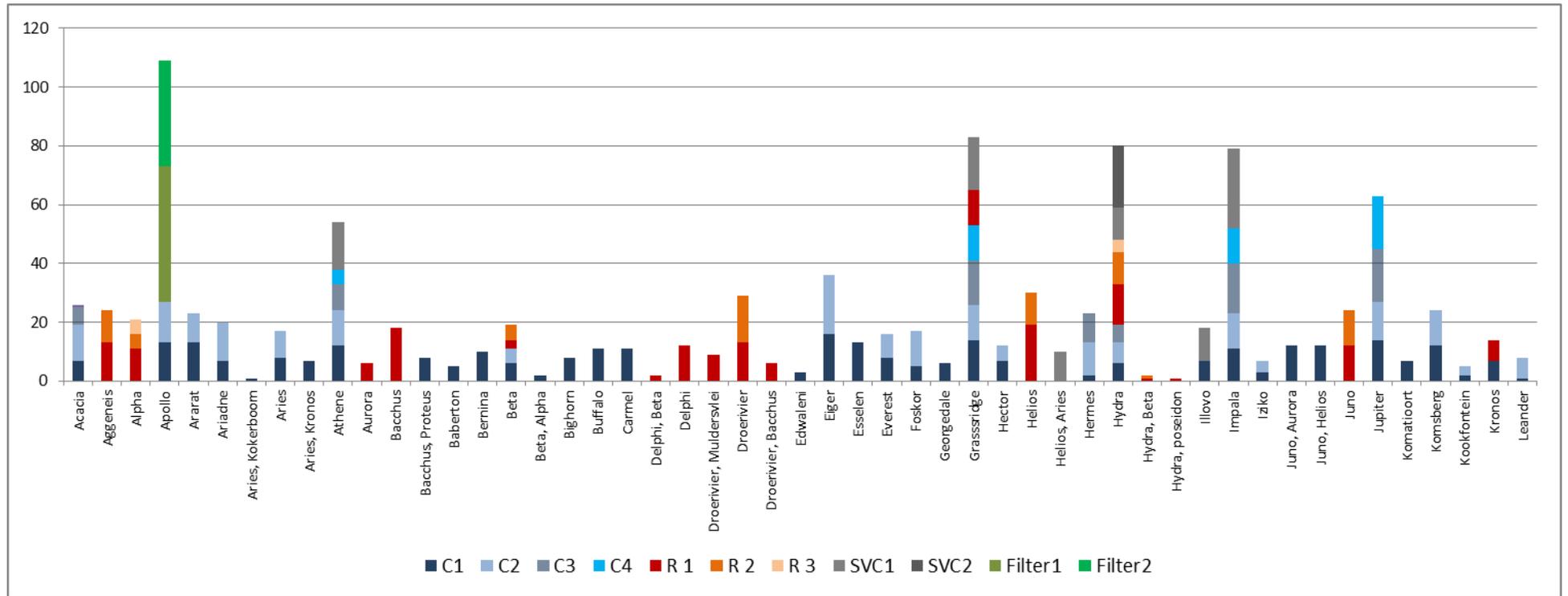


Figure 10: Reactive devices breakdown 1

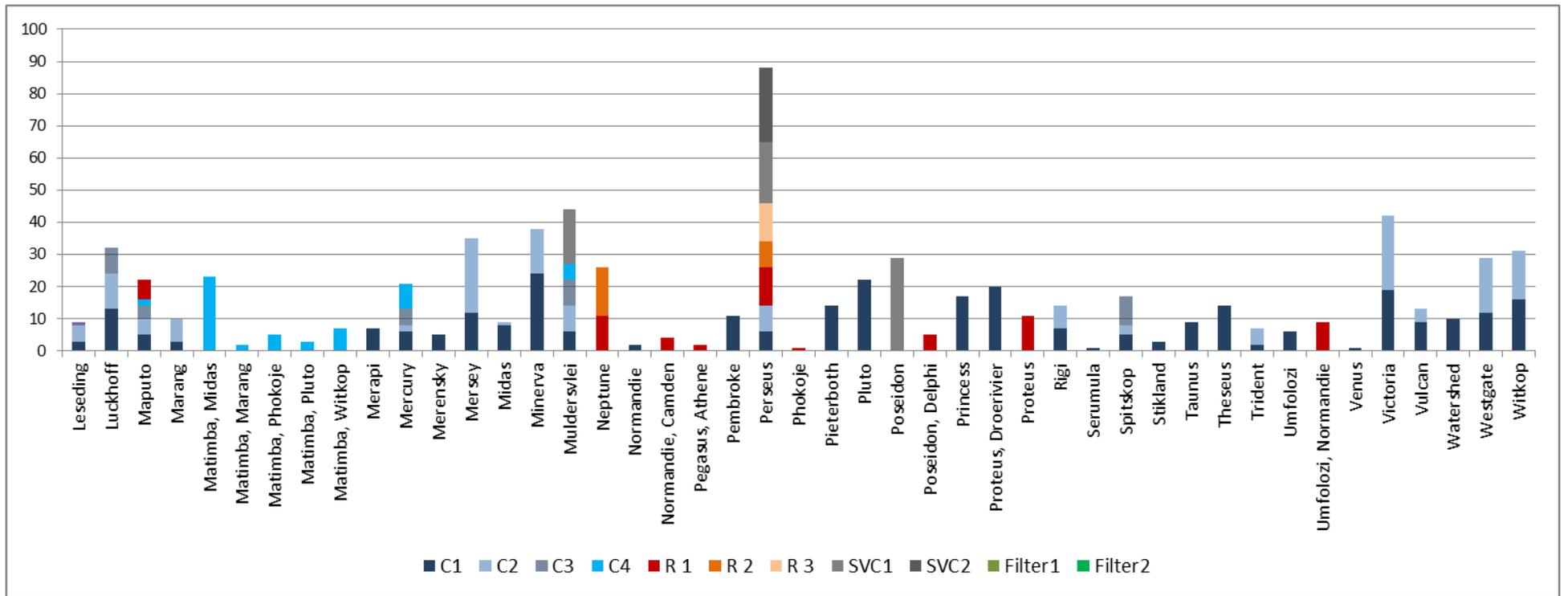


Figure 11: Reactive devices breakdown 2

A total number of 1771 outages were reported for reactive devices. Not all of the reactive devices are deemed as critical. This means that while the device is out of service, the network can handle another piece of the equipment that might fault during the outage. The following describes some of the reactive devices that have a risk involved should something else happen on the network during the outage.

4.2.3.1. Critical Reactive devices

Perseus SVCs

There are two SVCs at the Perseus substation. These reactive devices are deemed critical as they assist with voltage support in the event of the loss of a Koeberg unit. The SVCs are designed to automatically switch out the reactors at Perseus and switch in the capacitors in an attempt to help save the Cape network from a voltage collapse in the event of the loss of a Koeberg unit. If the SVC is not available, this function will have to be performed manually and may not be quick enough to stop the voltage decline until it ends in a voltage collapse. There were a total of 41 outages completed in the last 5 years.

Hydra SVCs

Hydra SVCs are identical to Perseus SVCs. They perform the same function with switching the reactors and capacitors when it detects a voltage decline. However, since Hydra is situated closer to Koeberg, it has more of an impact on the Cape network. It will detect the voltage decline first and will reactively saturate before Perseus. Another impact that Hydra SVCs have, that Perseus SVCs do not have, is that an outage on a Hydra SVC has an effect on the transfer limit to the Western Cape. Under system healthy conditions the transfer capabilities to the Western Cape is 2700 MW. With a Hydra SVC taken out of service, only 2550 MW will be able to be transferred down to the Western Cape. This leads to potentially 150MW that might need to be supplied by the OCGTs. This has a potential cost implication of R270 000 per hour. There were 32 outages completed on these SVCs between 2007 and 2011.

Eiger capacitors

Eiger shunt capacitors are deemed critical due to the highly loaded network it supports. When one of the two Eiger capacitors is out of service, and another critical piece of equipment trips, the voltages will reduce below 95% of the specified voltage for that area. This violates the system reliability criteria as stipulated by Eskom's operating guidelines and must be restored immediately. This is done by load shedding up to 200 MW in the surrounding area. This load

has been at risk 36 times between 2007 and 2011 due to outages on the Eiger shunt capacitors.

Jupiter capacitors

Jupiter shunt capacitors are a very critical part of the network, as Jupiter substation supplies most of the Johannesburg load. It is also a struggling part of the network when it comes to voltage support. When another critical piece of equipment is lost during a capacitor outage, it may lead to a voltage collapse of the Johannesburg network. This will result in the loss of approximately 600 MW of load. This is why it is concerning that the capacitors were taken out of service 63 times between 2007 and 2011.

Victoria capacitors

The Victoria series capacitors are situated on the Hydra – Droerivier 1 and 2 400 kV lines. There are only four lines that feed the entire Western Cape load and these two series compensated lines are two of them. The Western Cape transfer limit is based on the load on these four lines, therefore the series capacitors directly influence the transfer limit. Taking one of these series capacitors out of service reduces the available transfer capability from 2700 MW to 2300 MW. The 400 MW difference will now have to be supplied by the OCGTs and therefore has a potential cost implication of R720 000 per hour, depending on the Western Cape loading during the outage. These Victoria series capacitors were taken out of service 42 times between 2007 and 2011.

Table 2: Summary of Critical Reactive Devices

Station	Reactive device	Risk	Number of outages between 2007 and 2011
Perseus	SVC	Voltage collapse of the Cape Network	41
Hydra	SVC	R270 000 per hour	31
Eiger	Shunt Capacitors	200 MW - Load	36
Jupiter	Shunt Capacitors	600 MW - Load	63

Victoria	Series Capacitors	R720 000 per hour	42
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4.2.4. Lines

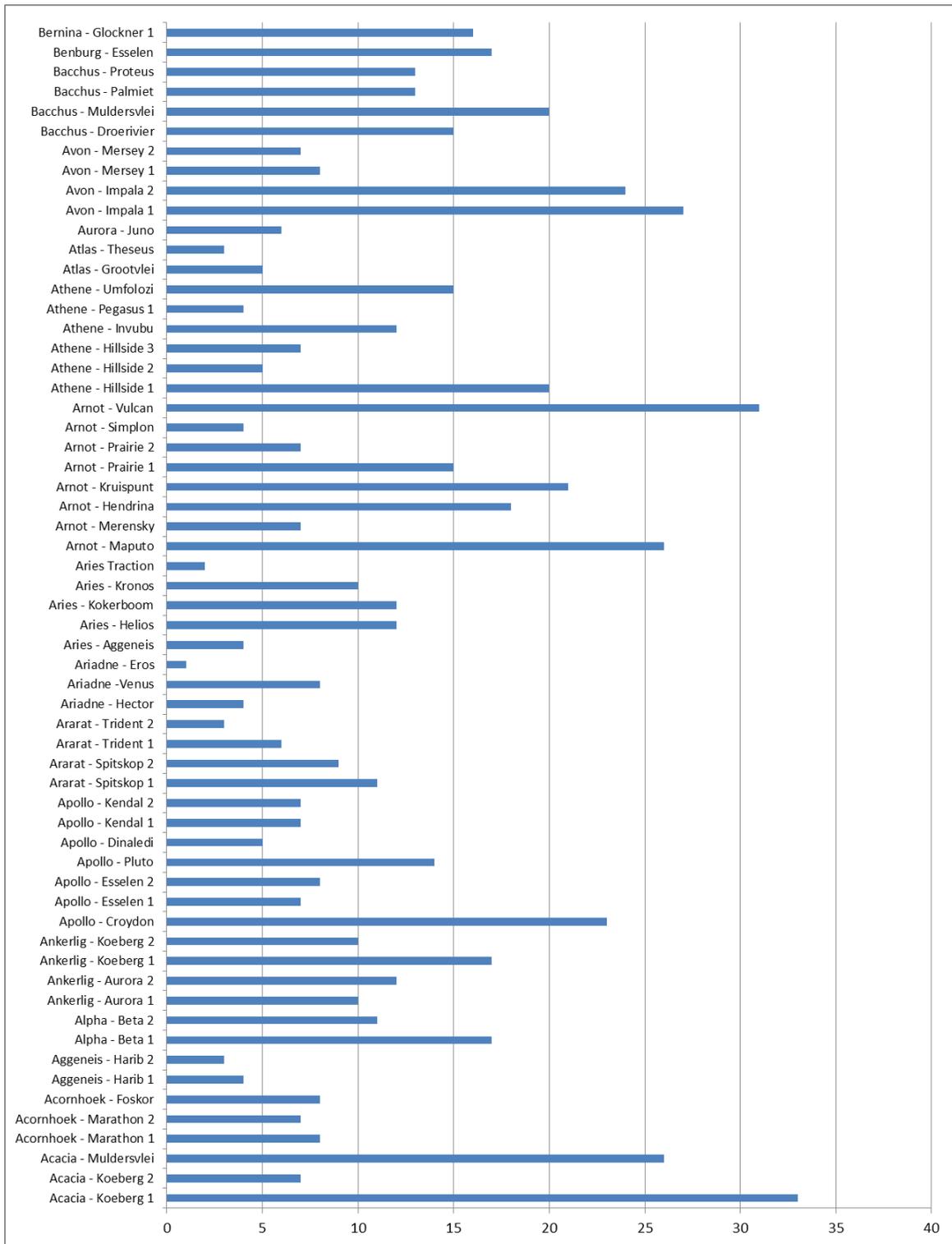


Figure 12: Lines outage breakdown 1

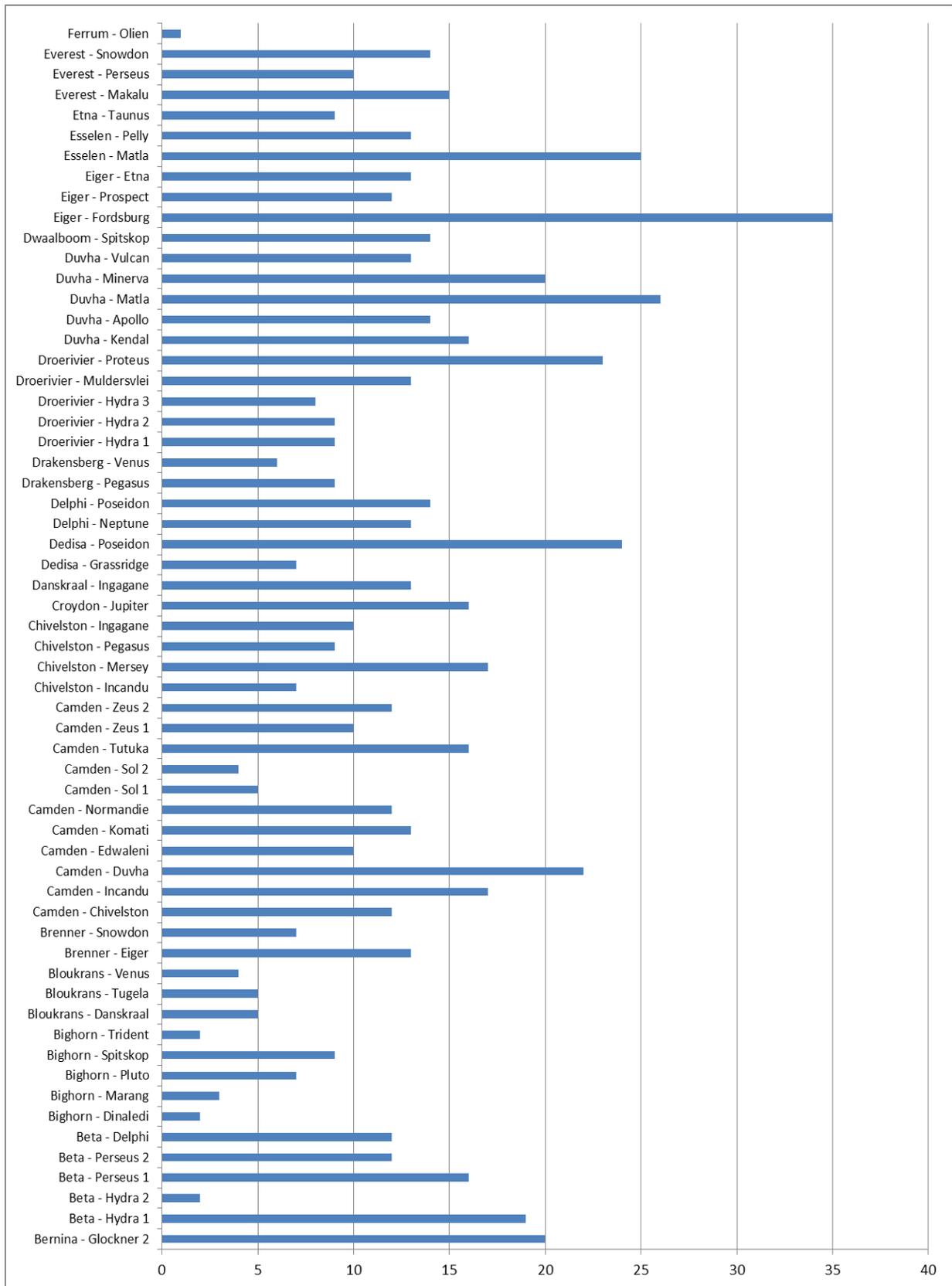


Figure 13: Lines outage breakdown 2

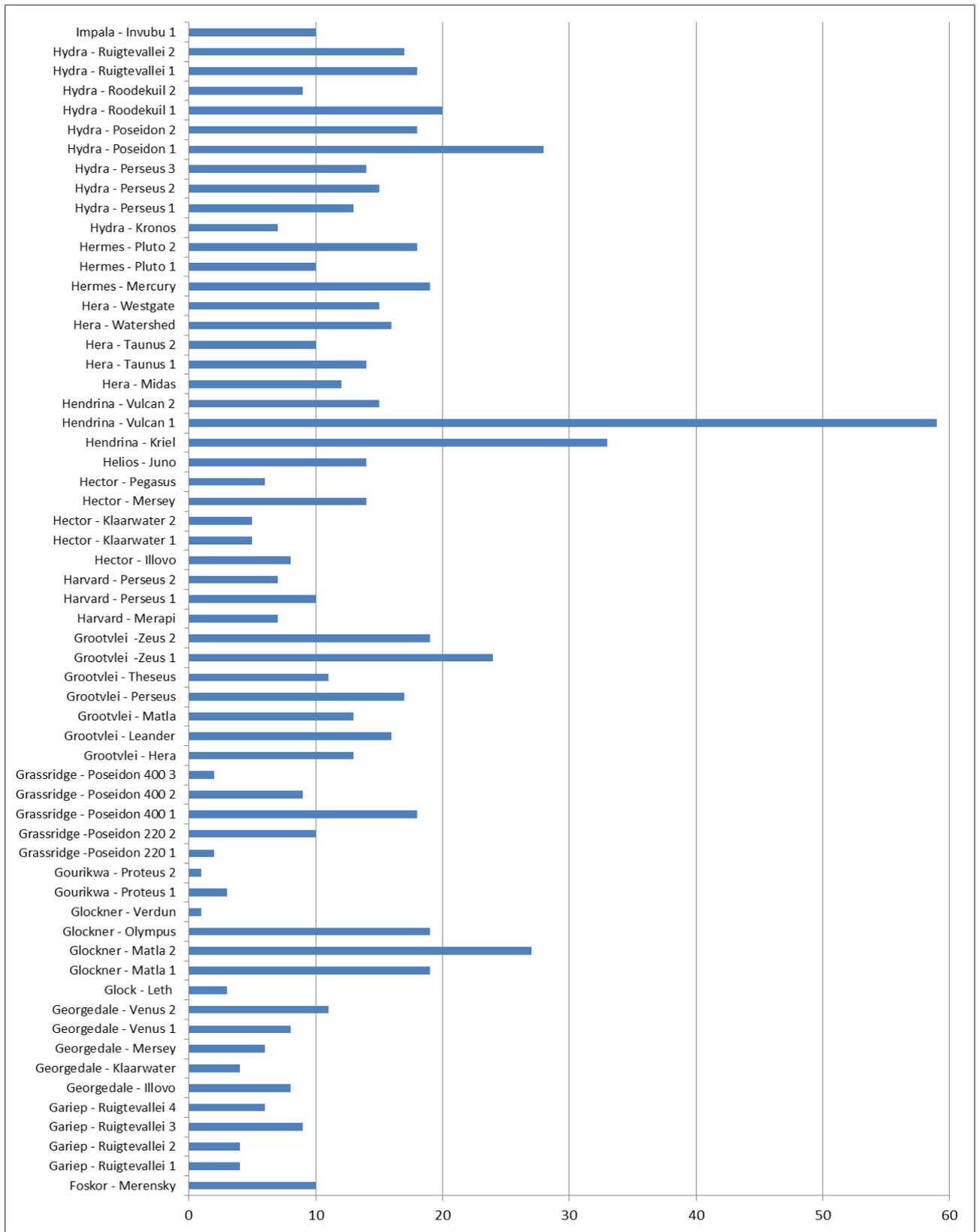


Figure 14: Lines outage breakdown 3

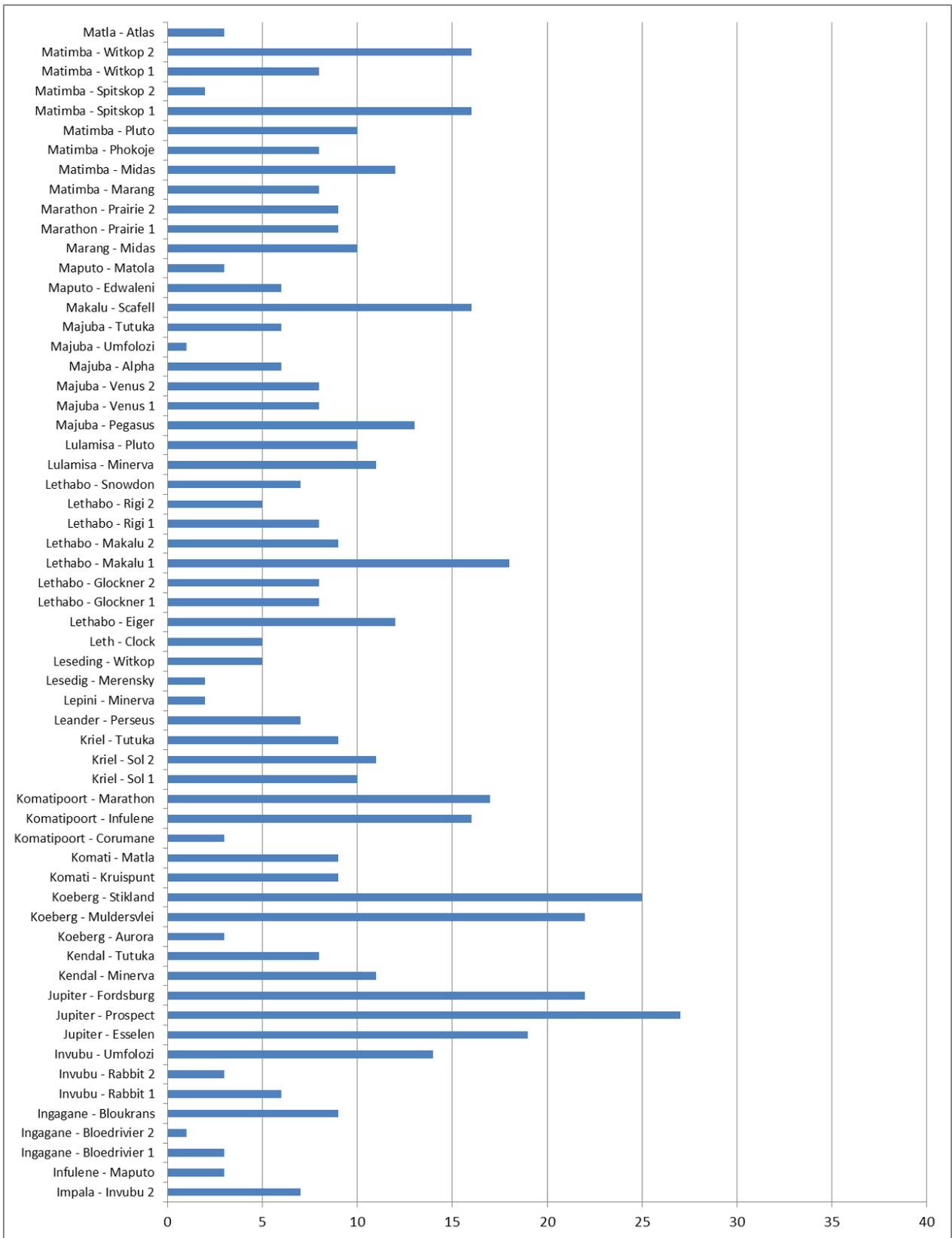


Figure 15: Lines outage breakdown 4

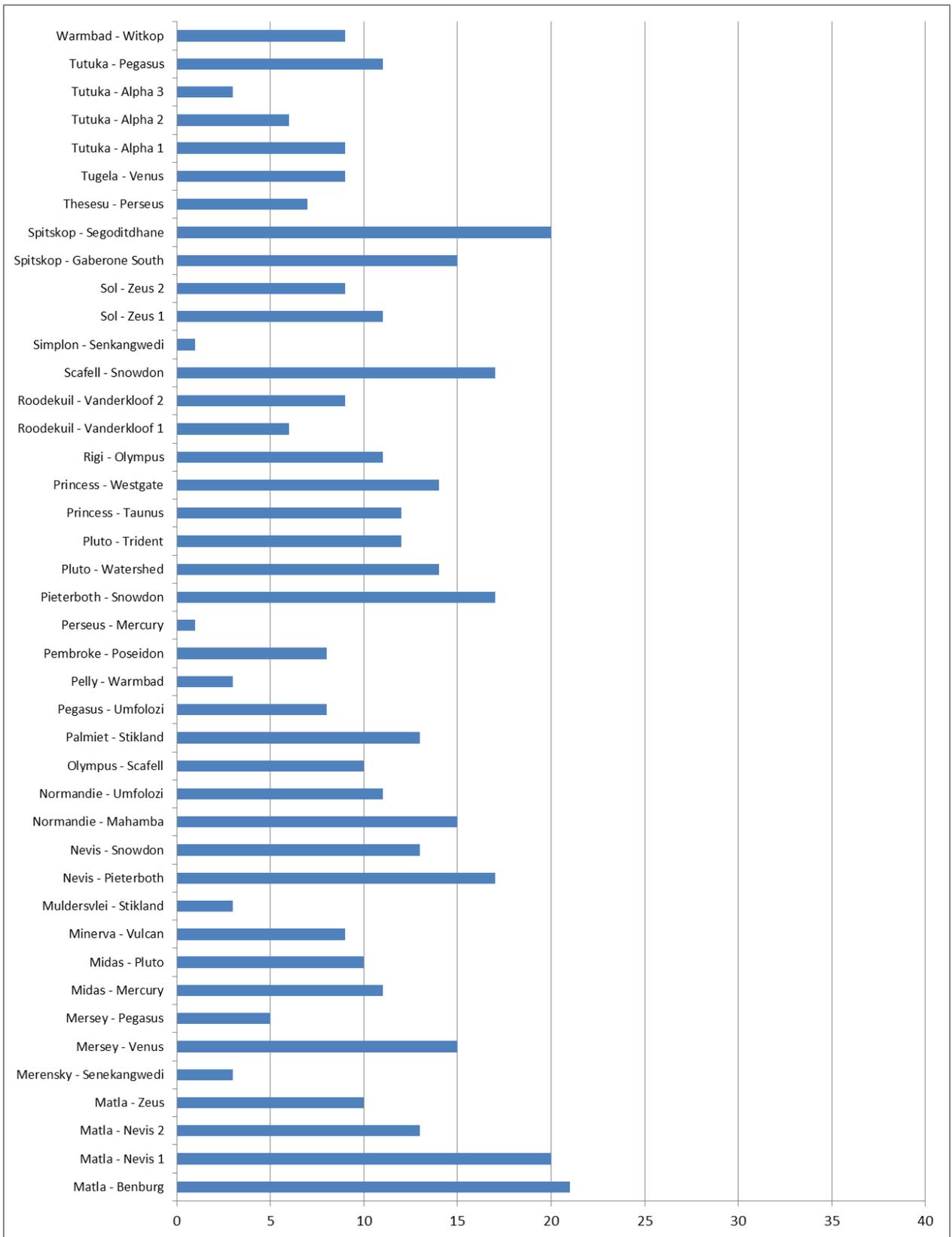


Figure 16: Lines outage breakdown 5

In total, there were 6 940 line outages between 2007 and 2011. These can be further categorised in live line work, cane burns and dead line outages.

For live line work, the only switching involved is the switching off of the auto-reclose function. This means that should the line trip, it will not attempt to reclose itself without a signal generated from the National Control Centre. The line is thus still in service and all the maintenance is done with special live line techniques. The live line outages account for 1 415 of the total line outages.

The cane burns are requested by customers and can only be done during designated times of the year. These outages are deemed uncontrollable as they are mostly farmers that burn their farms. However, to assist Eskom with minimising the associated risk, they do burn in the early hours of the morning. These outages account for 2 339 of the total line outages.

The dead line outages are of the greatest concern, as they introduce the greatest risk to the system. These dead line outages amounted to a total of 3 186 and are represented in Figure 12, Figure 13, Figure 14, Figure 15 and Figure 16.

Some of the lines that are deemed critical are stations that only have two infeeds. When taking one of those lines out of service, the biggest risk is losing the remaining line and thus losing all supply to the station. The other outages of concern affect international customers.

4.2.4.1. Critical Lines

Spitskop – Segoditshane 132 kV line

The Spitskop – Segoditshane 132 kV line is one of the international lines that are shared between South Africa and Botswana. When this line is taken out of service, there are multiple stakeholders involved. Eskom's transmission resources have to do the operating on the Spitskop substation side, while Botswana Power Corporation (BPC) has to operate on the Segoditshane substation side. However, when this line is switched out of service, there are distribution customers that have no supply. They can be backfed via another line, but there is additional switching required from Eskom's distribution resources in order to reconfigure their network. It is inevitable that these customers will have loss of supply of approximately 10 MW for up to 2 hours while this switching takes place. Thus, not only is it increased risk for both

Eskom and BPC, but the customers are inconvenienced which Eskom should try and avoid at all costs. This line was taken out of service 20 times between 2007 and 2011.

Komatipoort – Marathon 275 kV line

The Marathon – Komatipoort 275 kV line is one of the lines that feed into a part of the Mozambique network. When this line is taken out of service, depending on the time of day and year, there are up to 80 MW of load that needs to be shed in order not to overload a Maputo transformer, which is shared between Eskom and Mozambican Electricity Company (EdM). Should this transformer now fault during the line outage, approximately 480 MW of total load will be lost due to loss of supply, as the transformer was the only remaining infeed into that part of the network. There were 17 completed outages recorded for this line between 2007 and 2011.

Eiger – Fordsburg 275 kV line

Eiger – Fordsburg 275 kV line is one of the lines that feed the City Power network. Should the remaining Jupiter – Fordsburg 275 kV line trip during the outage, City Power will lose all supply to that part of its network and customers will be interrupted. This is a total of 500 MW of load that will be lost. These are predominantly commercial customers and city centres. This includes the politically sensitive Soweto area. This line was taken out of service a total of 35 times during the study period.

Jupiter – Prospect 275 kV line

The Jupiter- Prospect 275 kV line also feeds the City Power network. However, there are only two infeeds into Prospect. Should the remaining Eiger – Prospect 275 kV line trip City Power will lose all supply to that part of its network and customers will be interrupted. The loss of supply will amount to approximately 710 MW. This line was taken out of service a total number of 27 times between 2007 and 2011.

Acacia 400 kV lines

Acacia is the main supply for the City of Cape Town. It has two infeeds into Acacia namely the Koeberg – Acacia 400 kV line and the Muldersvlei – Acacia 400 kV line. When the one line is taken out of service, City of Cape Town is at the risk of the remaining 400 kV line. Should the remaining line trip, it will result in approximately 1000 MW loss of supply to City of Cape Town. These lines were collectively on outage for 59 times in the duration of the study period. In 2011, the inevitable did happen, and the remaining line tripped during an outage of the other line. The City of Cape Town was left without power for several hours. There was also the added incident that the National Control Centre incident communication system, used to send out sms's when

an abnormal event has occurred, was also down because the server was located in Cape Town and the uninterrupted power supply failed. These outages have been classified as high risk outages since that incident.

Table 3: Summary of Critical Line outages

Station	Line	Risk	Number of outages between 2007 and 2011
Spitskop	Spitskop – Segoditshane 132 kV line	10 MW – customer load	20
Komatipoort	Marathon – Komatipoort 275 kV line	480 MW – International load	17
Fordsburg	Eiger – Fordsburg 275 kV line	500 MW – City Power load	35
Prospect	Eiger – Prospect 275 kV line	710 MW – City Power load	27
Acacia	Muldersvlei – Acacia 400 kV line, Koeberg – Acacia 400 kV line	1000 MW – City of Cape Town	59

5. Discussion and interpretation

The following chapter will discuss the results obtained from chapter 4.

5.1. Cancelled outages

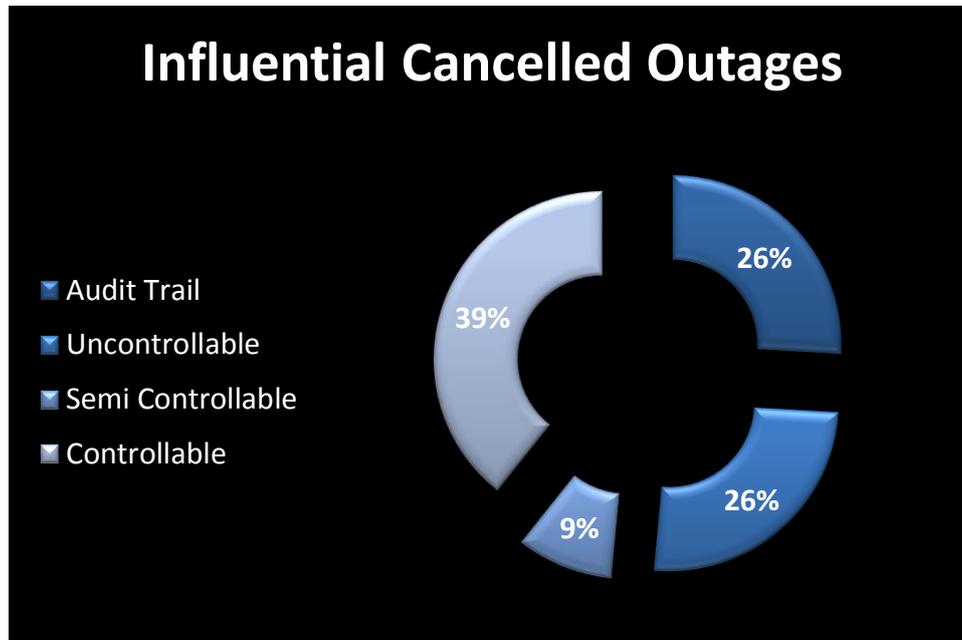


Figure 17: Cancelled outages breakdown

5.1.1. Controllable factors

Already completed

Booked outages that have already been booked and completed on a previous occasion, is purely due to scheduling errors. It is a combined effort between the CLN supervisor who requested the outage and the Grid Scheduler who scheduled the outage. If they were working according to a predetermined maintenance plan, there should be no room for errors such as these. If an opportunity was taken during a previous outage, then this should be updated in the maintenance schedule. This is purely an administrative duty that should be undertaken by the Grid Scheduler by means of monthly meetings with all of the CLN supervisors. Therefore, all of the outages that were cancelled due to already completed outages can be completely eliminated.

Resources not available

Arranging the resources is part of the duties of the CLN supervisors who request the outage. They must ensure they have personnel available to do the necessary switching to take the plant out of service. When contractors are involved, appropriate dates need to be arranged. These dates need to be discussed with the Grid Scheduler, who should have a better overview of the rest of the outages that have already been requested or scheduled. The Grid Scheduler should also be in a position to advise the best window for these outages, as will be discussed in another section. By improving this line of communication between the CLN supervisors, the Grid Schedulers and the contractors, it will ensure that all resources are available before the booking is made. Most importantly, no plant will be taken out of service, only to find out that the proper resources have not been arranged. It will also optimize the booking times, which will ensure no overtime is paid unnecessarily for outages that have to be taken after hours, with only half the personnel showing up. These overtime fees will have to be paid again should the outage be cancelled on the day of the outage and rescheduled for another overtime period. With proper planning and communication, the outages that are cancelled based on resources not being available can be eliminated.

Double booking

Double bookings can only originate between departments that are not coordinating their work. It is advised that outages between the high voltage, protection and lines departments be coordinated according to the maintenance schedule. When this coordination is optimally achieved, one booking can be made with all the requirements stated in the outage description. This will assist with accurate dates and resources that are not wasted on outages that are cancelled on short notice due to another outage opportunity.

Date changed

Again, communication between Grid Scheduler, CLN supervisors and contractors is crucial to ensure the correct dates for an outage are booked from the start. As this can again lead to resources that are wasted due to personnel showing up for an outage that was meant to be booked for a different date, this can become costly to Eskom.

Conflicting outages

Conflicting outages are also a result of bad planning. Phoenix has a built in function that involves corridor checking on behalf of the user. This function will indicate when a conflicting outage is booked at the same time as the new requested outage. The yearly Network Appraisal also indicates all outages that are conflicting, presented per grid. Conflicting outages only occur

when Grid Schedulers ignore these help functions that are provided to them. This can also be fixed with additional training for the Grid Schedulers to help identify these conflicting outages with a better understanding of the workings of the integrated power system. With the help of the conflict identification aids, cancellations due to conflicting outages can be completely eliminated.

Not required anymore

Outages that are no longer required are outages that may have been completed on a prior opportunity, much the same as already completed outages. With proper communication, these outages will not be booked in the first place if maintenance schedules are updated with the work that has been done, or they can be moved to the next maintenance cycle date. This will allow resources to be free for other maintenance activities.

Outage requirements not met

As all customers that might be affected by an outage must be notified prior to the outage, it is advised that these forms of communication take place before the outage is entered onto the system. When these outages are entered onto the Phoenix system, it is understood that resources have already been allocated for this outage. When all the requirements for making this booking have not been adhered to, it affects all planning for the rest of the outages. These cancelled bookings can again be attributed to improper communication and can be eliminated when the current procedures are followed.

Incorrect booking

Outages that have been incorrectly captured on Phoenix can be better controlled by proper training for the Phoenix users, as well as communication between the requester and the scheduler to determine when a mistake has been made. By controlling these factors, the cancellations and wasted resources due to incorrect bookings can be eliminated.

5.1.2. Semi-Controllable factors

Project delay

Cancelled outages due to project delays are the only outages in this section that has been deemed to only be semi-controllable. This is due to the many external factors that contribute to project outages. The ordering of parts and equipment might be delayed due to reasons beyond the project manager's control. Or the project manager's training and experience might be

inadequate and not understand the process of outage management. However, when the outages are requested by the project manager, it is necessary that he is advised by the Grid Scheduler and CLN supervisor as to the best opportunity for his outages to occur. There might also be regular maintenance work that may be combined with this project work or vice versa.

5.2. Turned Down Outages

Turned down outages are outages that were not approved by the National Control Schedulers. In the following paragraphs the controllable and semi-controllable factors that could influence the statistics for the turned down outages, are discussed.

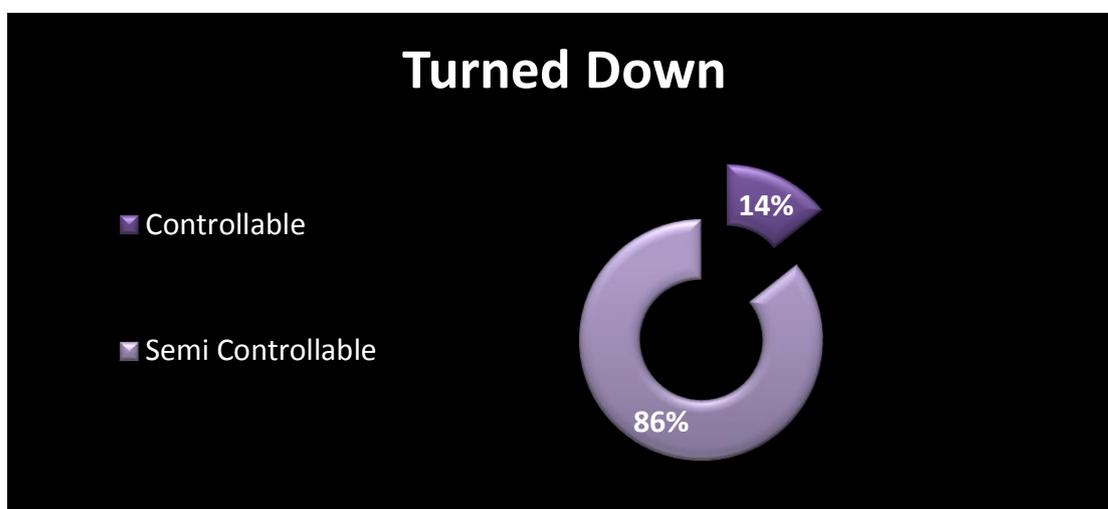


Figure 18: Turned down outages that may be influenced

5.2.1. Controllable factors

Incorrect booking

The incorrect bookings are turned down due to plant slots being booked incorrectly, or not being clear about the outage bookings to the scheduler. This is purely an administrative flaw of the Grid Scheduler, who should make sure that all of the details of the outage bookings are correct before scheduling the outage. This can be completely eliminated with proper training to ensure accuracy from the schedulers.

Conflicting outages

Conflicting outages most often occur between two or more grids. As Phoenix has a built in function that warns the schedulers of other outages that might be booked at the same time as the requested outage, there is no reason why conflicting outages should be booked. Communication between the different Grid Schedulers is very important as they can negotiate resources between them. With proper communication the outages turned down due to conflicting outages can be eliminated.

Double booking

Double bookings can only originate between departments that are not coordinating their work. It is advised that outages between the high voltage, protection and lines departments be coordinated according to the maintenance schedule. When this coordination is optimally achieved, one booking can be made with all the requirements stated in the outage description. Communication between the different departments is very important when attempting to eliminate turned down outages due to double bookings.

Outage requirements not met

It is the duty of the Grid Scheduler to ensure that all the outage requirements are met when the outage is scheduled. Communication between all the relevant stakeholders is very important. There is a process in place for the schedulers that indicate who has to be informed and what needs to be in place before scheduling an outage. The Grid Scheduler needs to enforce this process before the outage is scheduled in order to eliminate outages that are turned down due to outage requirements that are not met.

Wrong window

A Network Appraisal document is published every year. This document indicates which outages are a problem during winter months when the loadings on the network is high, as well as which outages will be problematic should they be taken together.

5.2.2. Semi-Controllable factors

Customer cancelled

Customer negotiations can be partially controlled by ensuring that the outage is negotiated with the customer with sufficient lead times or even better when it is aligned with their own maintenance schedules.

Generation constraint

Outages that need to be aligned with a generator need to be coordinated with the generation schedule that is distributed and updated on a weekly basis. However, generation still has the prerogative to cancel the outages should the network require it.

Koeberg constraint

Most of the Cape outages are dependent on both Koeberg units being on line. However, the three major lines that are exporting power from Koeberg are better taken with a Koeberg unit out of service. Koeberg releases a schedule a year in advance, but might start their outages early or return the unit late. When a Koeberg unit is off load, outages that could normally be taken during the week are now only possible during a weekend. The weekend outages are not possible during a Koeberg outage due to the higher import into the Cape area. A Cape transfer limit report has been published for the reference of the schedulers, and expected load profiles can be requested from the Operations and Planning department to assist with planning the outages better. This will minimise the turned down outages that are dependent on Koeberg units.

Network constraint

Network constraints involve plant that has failed in the network that might affect the outages that are already booked. However, some of the outages are newly booked, even though the plant has been faulted for a while. These are the elements that can be controlled by ensuring training to make sure the schedulers understand the impact that some plant has on the surrounding outages.

Project delay

In this case, project delays refer to equipment that is still out of service due to delays and is now interfering with other outages that are already booked. This can be a controllable factor if the outages are not booked close to projects, but rather to overlap with projects. It can also be controlled if better planning is done regarding the outages for the projects to ensure that they are not delayed.

5.2.3. Managing the human resources

There are two subjects that were raised as concern areas when investigating the controllable and semi-controllable factors with respect to cancelled and turned down outages. These two issues are lack of sufficient training and proper communication.

Training

Even though the scheduling staff are trained to use the data capturing system Phoenix, they do not seem to have the technical background as to how the different outages influence each other and what the impact of those outages are. There also seems to be a lack of understanding what the consequence would be should something else go wrong during an outage.

It is suggested that the position of Grid Scheduler be filled with a person with at least a technical diploma who has the capability of understanding the network from a load flow point of view. It is also suggested that this person be trained with respect to field experience and load flow simulation studies as to better understand the impact of their decisions with regards to the network.

Even though Phoenix users are trained to use the application, it needs to be investigated whether a different approach is not required for the training as there are still a lot of incorrect bookings appearing. It is suggested that there should be a warning system implemented on Phoenix that should a booking be noted as incorrect three times in one month, that the user's account be frozen until re-evaluation has certified that the user may resume their authorized rights after sufficient training. This will ensure that requesters and schedulers make sure of all the details required for a booking.

Communication

The communication channels between the Grid Scheduler, the CLN supervisors, project managers and the customers need to be regulated by having a monthly meeting where all stakeholders are involved. The outages that are booked for the following three months must be discussed and coordinated. This will allow for opportunities to be identified by customers and project managers.

In the same month a meeting must be held between all the Grid Schedulers, the National Control scheduler and the NMC schedulers where the three month rolling outages will also be

discussed. This will allow the National Control scheduler to give feedback on study requests that may have been issued for the requested outages, and to raise any concerns regarding the network risks that may be present that was not anticipated during the original booking. The Grid Schedulers will also have the opportunity to align their outages should a line outage cover two grids. The Grid Schedulers will then be expected to give feedback to their respective grids and amend the outage plan if needed with the necessary resources in place.

The Grid Schedulers and CLN supervisors will be expected to attend the Operations Appraisal presentation once a year where all the risks to the network are analysed and explained in detail. This will also create an appreciation for an ever changing network and highlight the risk periods when certain outages cannot be booked.

5.3. Completed outages

As reported in Chapter 4, there were 19 902 completed outages between 2007 and 2011. The lines, the transformers and the reactive devices were discussed in detail as these outages were considered to pose the most risk to the system. These equipment outages were also deemed to be controllable outages, as minimising these outages would automatically reduce the busbar outages as well. The lines, transformers and reactive devices amounted to 5 680. This accounts for 28.5% of all the completed outages.

There were a total of 723 outages taken on the 98 transformers that are demarcated to National Control. 1 771 outages were conducted on the 182 reactive devices in the national grid, while 3 186 outages were taken on the 283 lines during the study period.

These outages can now be broken down into two classifications of outages namely: faults maintenance and projects related outages. The following table indicates the breakdown:

Table 4: Completed Outages breakdown

	Projects	Maintenance and faults	Total outages	Total number of equipment
Transformers	74	649	723	98
Reactive devices	111	1660	1771	182

Lines	412	2774	3186	283
Total	597	5083	5680	

Faulted plant is deemed to be an uncontrollable factor. The number of project related outages can be better controlled if it is combined with some of the maintenance activities. The ranking system discussed later in this chapter will address the matter when there is a conflict between project related work and maintenance related work.

The maintenance related outages however, needs further addressing, as 86.8% of the total outages discussed are due to maintenance.

5.3.1. Managing the assets

In Table 5, a summary is given of the manufacturers requirements for maintenance on the different equipment. This includes the high voltage equipment maintenance as well as the protection maintenance.

Table 5: Summary of maintenance cycles

Equipment	Maintenance Cycle	Maintenance Type
Breakers	6 yearly	Bay maintenance
	3 yearly	Bay maintenance (Coastal)
	6 yearly	Preventative Maintenance Task
	3 yearly	Preventative Maintenance Task (Coastal)
	12 yearly	Major Overhaul Task
	3 yearly	Protection Maintenance (phase 1 & 2)
	6 yearly	Protection Maintenance (phase 3,4,5 & 6)
Isolators	6 yearly	Bay maintenance

	3 yearly	Bay maintenance (Coastal)
	6 yearly	Preventative Maintenance Task
	3 yearly	Preventative Maintenance Task (Coastal)
	12 yearly	Major Overhaul Task
	3 yearly	Protection Maintenance (phase 1 & 2)
	6 yearly	Protection Maintenance (phase 3,4,5 & 6)
SVCs	1 yearly	Bay Maintenance
	3 yearly	Protection Maintenance (phase 1 & 2)
	6 yearly	Protection Maintenance (phase 3,4,5 & 6)
CT's	6 yearly	Bay Maintenance
	3 yearly	Protection Maintenance (phase 1 & 2)
	6 yearly	Protection Maintenance (phase 3,4,5 & 6)
Capacitors/Reactors	1 yearly	Bank Maintenance
	6 yearly	Bay Maintenance
	3 yearly	Protection Maintenance (phase 1 & 2)
	6 yearly	Protection Maintenance (phase 3,4,5 & 6)
Series Capacitors	5 yearly	By-pass isolator maintenance
	1 yearly	Bank Maintenance
	3 yearly	Protection Maintenance (phase 1 & 2)

	6 yearly	Protection Maintenance (phase 3,4,5 & 6)
Transformers	6 yearly	Maintenance
	3 yearly	Protection Maintenance (phase 1 & 2)
	6 yearly	Protection Maintenance (phase 3,4,5 & 6)
	10 yearly	Painting
	6 yearly	Oil/bushing sampling
Lines	3 yearly	maintenance

5.3.1.1. Different maintenance cycles

As can be seen from the above table, there is a difference in the maintenance cycle between coastal substations and substations that are located inland. When determining what the optimum maintenance plan must be for the equipment discussed, it must first be stated which substations are to be considered coastal and will thus have more frequent maintenance cycles allocated than the inland substations.

Table 6: Coastal Transformers and Reactive Devices

Transformers	
Transformers	Reactive Devices

Coastal		Coastal	
Substation	Number of equipment	Substation	Number of equipment
Aurora	2	Acacia	3
Athene	1	Athene	2
Grassridge	4	Aurora	1
Impala	2	Buffalo	1
Invubu	3	Grassridge	5
Juno	1	Illovo	2
Koeberg	4	Impala	5
Maputo	1	Juno	2
Neptune	1	Maputo	5
		Muldersvlei	5
		Neptune	2
		Stikland	1
Total	19		34

So from this table it can be seen that 19 out of the 98 transformers are considered to be in the coastal area and would have a 3 yearly maintenance cycle on their breakers and isolators. Only 34 of the 182 reactive devices are in the coastal area and will be maintained on a 3 yearly maintenance cycle.

The following table contains the lines that originate from a coastal substation. For interest sake, the lines have been categorised according to lines that have a coastal substation on both ends, as well as the lines that start from a coastal station and ends in an inland substation. In the latter case, the coastal substation has also been indicated.

Table 7: Lines originating from coastal substations

Lines		
Both stations Coastal	One station Coastal	
Line	Line	Coastal substation
Aurora - Juno	Avon – Impala 1	Impala
Ankerlig – Koeberg 1	Avon – Impala 2	Impala
Ankerlig – Koeberg 2	Bacchus - Muldersvlei	Muldersvlei
Ankerlig – Aurora 1	Athene – Umfolozi	Athene
Ankerlig – Aurora 2	Athene - Pegasus	Athene
Acacia - Muldersvlei	Droerivier - Muldersvlei	Muldersvlei
Acacia - Koeberg	Delphi - Neptune	Neptune
Athene - Invubu	Dedisa - Grassridge	Grassridge
Athene – Hillside 1	Helios - Juno	Juno
Athene – Hillside 2	Hector – Klaarwater 1	Klaarwater
Athene – Hillside 3	Hector – Klaarwater 2	Klaarwater
Koeberg – Stikland	Gourikwa – Proteus 1	Gourikwa
Koeberg – Muldersvlei	Gourikwa – Proteus 2	Gourikwa
Koeberg - Aurora	Georgedale - Klaarwater	Klaarwater
Invubu – Rabbit 1	Maputo - Matola	Maputo
Invubu – Rabbit 2	Maputo – Edwaleni	Maputo
Impala – Invubu 1	Maputo - Infuleni	Maputo
Impala Invubu 2	Umfolozi - Invubu	Invubu
Muldersvlei - Stikland	Palmiet - Stikland	Stikland

From this table it can be seen that 38 lines out of the 283 lines in the case study will be maintained on a 3 yearly cycle due to the specifications for the coastal breakers and isolators.

The protection maintenance will also vary in between a 3 yearly and a 6 yearly maintenance cycle depending on the current protection scheme that is implemented. For the older protection schemes, phase 1 and 2, the protection needs to be maintained on a 3 yearly cycle. The new protection schemes, phase 3 and higher, need only be maintained once every 6 years. From data provided by the protection specialists, the current distribution of old and new protection schemes are divided across the network at a ratio of 55:45. 55% of all the current protection schemes are still the old phase 1 and 2 schemes which require a 3 yearly maintenance cycle. As an average, this ration was implemented for the three outage groups to determine how many outages would be required in the 5 year cycle. The following was determined to be old protection:

Table 8: Protection maintenance breakdown

	3 yearly cycle	6 yearly cycle	Total
Transformers	54	44	98
Reactive devices	100	82	182
Lines	156	127	283

5.3.1.2. Failure rate

To determine what improvement the implemented outage plan will have, one needs to determine the failure rate that could occur in the 5 year cycle that cannot be accounted for with preventative maintenance. Some of the causes of failures are listed below:

- Abnormal wear
- Corrosion
- Veld fires
- Bird streamers
- Industrial pollution
- Lightning
- Mist/fog
- Snow

- Wind
- Theft
- Vandalism

From the data provided by the protection specialists, the average failure rate for lines per year was determined to be 22 lines per year. For transformers, studies have indicated that an average failure rate that can be expected is 29 faults per year (Dolly, 2008). The same failure rate can be assumed for the reactive devices as they are also dependant on some form of transformer. Based on these failure rates, an additional 110 line outages for the 5 year study period have been assumed. An additional 145 outages for transformers as well as reactive devices for the 5 years have been assumed.

5.4. The final process

The guideline on optimising the outage management process can now be implemented on the same data that was collected between 2007 and 2011 to ascertain if the suggested guideline would have made a significant difference.

5.4.1. Cancelled outages

The unknown outages have been categorised as an audit trail that has gone awry, and accounts for 26% of the cancelled outages. For analytical purposes, this 26% will be divided between the controllable, semi-controllable and uncontrollable factors based on their ratios with respect to each other.

If this is considered, 65% of all the cancelled outages are assumed to be controllable in some way. This means if all these cancelled outages can be minimised due to better outage management, the 18% cancelled outages represented in Figure 4, can be reduced to 7%. This yields an improvement of **11%** in cancelled outages.

5.4.2. Turned down outages

The turned down outages account for 7% of the total outages booked according to Figure 4. Figure 18 indicates that 14% of this 7% can be eliminated completely by incorporating better outage management. A part of the semi-controllable outages may also be minimised by incorporating better outage management. If the assumption is made that 50% of the 86% of semi-controllable outages can be minimised, contribution of turned down outages will decrease from 7% to 4.5%. This yields a **2.5%** improvement.

5.4.3. Completed outages

With the suggested maintenance cycles, it is possible to combine high voltage equipment, protection and line maintenance in one outage as they are all based on a 1 year, 3 year or 6 year maintenance cycle. This will require managing and planning the resources appropriately with the goal of combining the different disciplines. When this can be achieved the following can be determined:

Transformers

Assumptions:

Worst case scenario was assumed. The three yearly outages required for 3 yearly maintenance cycles due to coastal and protection implications were considered to be at different stations. Therefore, all transformers will be done at least once in the 5 year cycle, which are 98 outages. The maximum amount of outages that could be done twice is 19 outages for coastal conditions and 54 outages for protection. (Please refer to Table 6 and Table 8)

Calculations:

Total outages required for maintenance on all transformers for 5 years = 171

Total outages assumed for failure rate of 29 faults per year for 5 years = 145

Total outages required for transformers for a 5 year period = 316

Total outages completed between 2007 and 2011 = 649

Total improvement = $\frac{(649-316)}{649} \times 100 = \mathbf{51.3\%}$

Reactive devices

Assumptions:

According to the maintenance cycles, each reactive device will have to be taken out of service at least once a year.

Calculations:

Total outages required for maintenance on all reactive devices for 5 years = 910

Total outages assumed for failure rate of 29 faults per year for 5 years = 145

Total outages required for transformers for a 5 year period = 1055

Total outages completed between 2007 and 2011 = 1660

$$\begin{aligned}\text{Total improvement} &= \frac{(1660-1055)}{1660} \times 100 \\ &= \mathbf{36.4\%}\end{aligned}$$

Lines

Assumptions:

Worst case scenario was assumed. The three yearly outages required for 3 yearly maintenance cycles due to coastal and protection implications were considered to be at different stations. Therefore, all line outages will be done at least once in the 5 year cycle, which are 283 outages. The amount of outages that will be done twice is 38 outages for coastal conditions and 156 outages for protection. (Please refer to Table 8). It is also assumed, as part of the worst case scenario, that it will require two outages per line to complete maintenance on both sides of the line.

Calculations:

Total outages required for maintenance on all lines for 5 years = 954

Total outages assumed for failure rate of 22 faults per year for 5 years = 110

Total outages required for transformers for a 5 year period = 1064

Total outages completed between 2007 and 2011 = 2774

$$\begin{aligned}\text{Total improvement} &= \frac{(2774-1064)}{2774} \times 100 \\ &= \mathbf{61.6\%}\end{aligned}$$

5.5. Ranking System

To assist with maintenance planning, it is necessary to identify different windows of opportunity for the outages. This will assist with minimising overtime for outages booked during the wrong periods of a year. The most popular time for outages to occur is during the summer on a weekend. However, there are not enough weekends in this summer period to accommodate all the outages. Therefore, a ranking system was developed to act as a guideline to ensure that outages are not booked unnecessarily in these scarce weekends, when it can be booked during a winter weekend when the outages are significantly less, or even during a weekday, eliminating the need for overtime.

The following is a classification of the categories when outages can be booked:

Table 9: Categories for outages

Category	Season	Weekend or Week
1	Anytime	Anytime
2	Summer	Weekday
3	Summer	Weekend
4	Winter	Weekend
5	Winter	Weekday
6	Customer or Generation dependant	
7	Studies required	

Before categorising the equipment that must be booked for maintenance outages, one must consult the latest Network Appraisal report that is published annually. This will give an indication of network configurations that may have changed or load networks that may have increased or decreased, affecting the classification of the plant.

Table 10: Ranking System

Equipment	Category
Reactors	5
Capacitors	2
SVCs	3

N lines	1
N-1 lines	3
N-2 lines	4
SOH lines	7
Firm transformers	1
Unfirm transformers	6
Any line outages from Matimba, Arnot, Lethabo, Gariiep and Koeberg	6

Reactors

Reactors are classified as a category 5, which from Table 9 can be seen, means they are preferred outages during winter weekdays. During winter the loading is higher in all areas of the network. With an increased loading pattern, the voltages tend to be lower in those areas. Reactors function in the network in terms of voltage control is to lower the voltages when they are high. As this is generally more of a problem during summer months and weekends, winter weekdays are the ideal place to take reactors out of service.

Capacitors

Capacitors have the opposite function of reactors, which is to increase voltages when they are too low. As voltages tend to be higher during summer months due to lower loading patterns, it is not as essential to have all of the capacitors available. That is why capacitors have been categorised as a category 2 which means they are ideal outages for summer weekdays.

SVCs

SVCs are a bit more critical than capacitors and reactors, as they perform both those functions automatically as the network requires. They are more important to have in service in winter months, as the impact of capacitive reactive power is more severe during highly loaded conditions. This is also true during summer weekdays, as the peak loads are a bit more unpredictable than weekend loads. For this voltage support reason, SVCs have been classified as a category 3, which means outages on SVCs are best taken during summer weekends.

N-Lines

N-Lines are lines that pose no problem if they are taken out of service during system healthy conditions. This means that no system criteria are expected to be violated during this outage,

even if another plant or equipment should fail. These are lines that can be taken anytime during the year, which is why they are deemed as category 1.

N-1 lines

N-1 lines are the most critical and difficult outages to obtain. They cause a system security criteria violation when they are taken out of service such as under- or over voltage or overloading of remaining plant. These lines are listed in the annual Network Appraisal report and are re-evaluated every year. As an example, the Network Appraisal report 2011 states the following:

“The loss of the Brenner – Snowdon 275 kV line results in:

- Low voltages of 0.928 p.u at Brenner substation
- Lethabo – Eiger 275 kV line overloads by 16% (191 MVA) of its Rate B”

This Brenner – Snowdon 275 kV line will then be classified as a category 3 outage. This means it can only be taken during summer weekends when the loads are at their daily minimum. If this still proves to be difficult, it can also be investigated to take the line during the night, as this is the absolute minimum the loading in the area will be. If there is any doubt, studies can be done to confirm.

Figure 19 represents a typical line loading for the Brenner – Snowdon 275 kV line during winter and summer, which indicates the decreased load over a summer weekend.

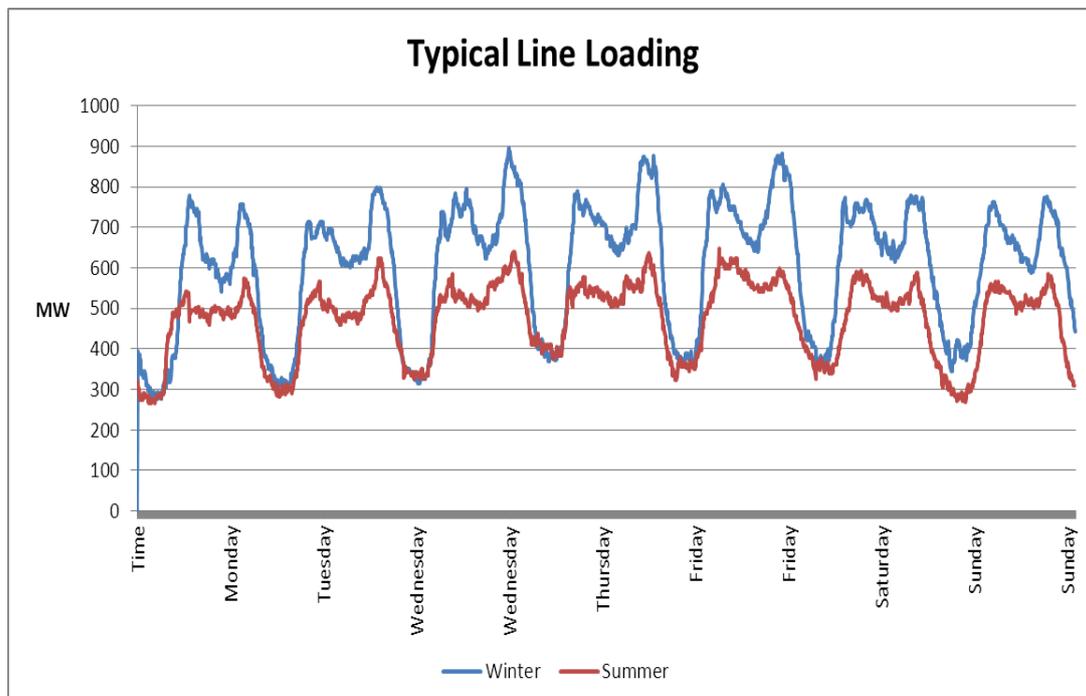


Figure 19: Example of decreased loading during a summer weekend

N-2 lines

These are lines that pose no problem when taken out of service, but will violate system criteria should another piece of equipment fail during the outage. A list of these lines is also stated in the Network Appraisal document. Therefore, these outages are recommended as category 4 outages. They can be taken anytime during the year, but to minimise the risk should something go wrong, they are preferred over weekends during winter time. This will also ensure that outages that are limited to summer have more opportunity and will not cause conflicts.

SOH lines

South of Hydra (SOH) lines do not pose a voltage or overload violation when taken out of service. However, they form part of the transfer limit agreement with Koeberg Nuclear Power Station. This means that the power that is allowed to be transferred on these lines are limited. Should this limit be exceeded due to an increase in loadings, the OCGTs at Ankerlig and Gourikwa will be despatched at great cost to Eskom. When one of these SOH lines are taken out of service it decreases the transfer limit. Therefore, further studies are required to find the best window of opportunity for these lines as there are many factors that affect them. These factors include summer and winter loadings, the Koeberg units in or out of service as well as the pump storage scheme at Palmiet with its dam levels. These lines are category 7.

Firm transformers

Firm transformers are transformers that do not cause an overload on the remaining transformers on the network. These transformers can be taken out of service anytime during the year and is thus classified as category 1.

Unfirm transformers

Voltage transformations are considered unfirm when the outage of one transformer at the time of substation peak results in the remaining transformer(s) being loaded above its/their continuous rating before remedial action may be implemented. Single transformer substations, whose loss result in a load at risk, are also considered unfirm. The Network Appraisal report lists all the unfirm transformers. These unfirm transformers will result in an interruption of load. Therefore, the customers relying on supply from these transformers must be notified. This category 6 outage indicates that negotiations can be done to shift load or reduce load on the customer side to assist with completing the outage. An example of the Olympus transformer is given with the shaded area indicating customer reduction after negotiations.

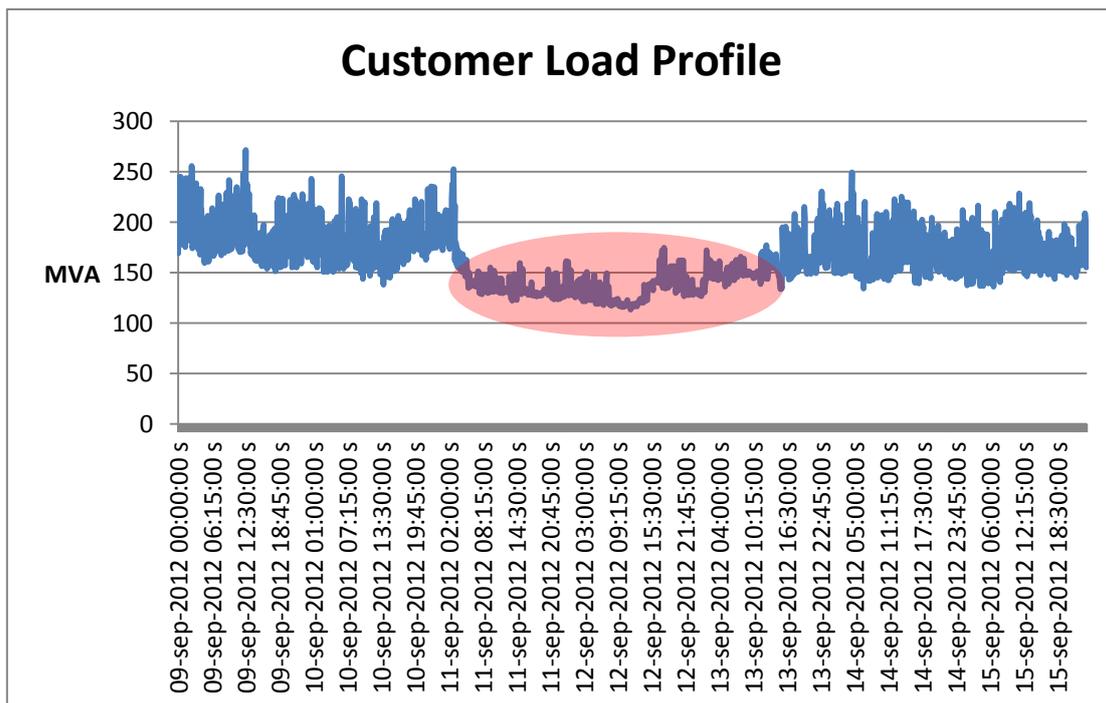


Figure 20: Olympus transformer loading during customer reduction

Any line outages from Matimba, Arnot, Lethabo, Gariep and Koeberg

Any line outages from the following power stations are generation dependant and must be aligned with the generation schedule:

- Matimba

- Arnot
- Lethabo
- Gariep
- Koeberg

These lines might require the generators to be on load for the duration of the outage, or require a generator off load for the duration of the outage. In the case of the Gariep units, there may be a restriction on the output of the generators during an outage. Therefore, these lines all form part of category 6, which implies further negotiation with the Generation department is necessary.

Combination outage and exceptions

When more than one outage needs to be taken together for whatever reason, studies will be required. This is especially true when it comes to project outages, where the duration of the outages are usually abnormal or the combination of outages would be considered conflicts. This ranking system is only a guideline for single equipment outages. As in all systems, exceptions do exist. However, these exceptions will be pointed out and discussed when the first draft of the maintenance plan proposal is presented. This will allow for enough time to amend the plan.

The following chapter summarises the conclusions and recommendations from the data analyses and implementation of the suggested guideline for the optimisation of the outage management process of the Eskom transmission network.

6. Conclusion and Recommendations

As was stated in the research objectives of this dissertation, it was necessary to investigate ways of reducing some of the risks associated with taking equipment out of service due to maintenance. It was also necessary to develop a ranking system in order to assist with the maintenance planning by indicating the best window of opportunity for an outage to occur.

The data collected on Phoenix between 2007 and 2011 for cancelled, turned down and completed outages were analysed. It was found that by incorporating better communication suggestions and expanding the training of the Phoenix users that cancelled outage can be reduced by 11 % and turned down outages by 2.5%. However, the greatest improvements could be seen in the completed outages. By following the recommended maintenance cycles provided by the manufacturers of the equipment and allowing for proven failure rates of equipment, the completed outages could be significantly reduced. This would not only ensure that regular maintenance be done on the equipment as per specifications, but would also reduce the likelihood of an interruption of supply to customers by decreasing the amount of outages. The risks associated with the switching of plant for every outage would also be significantly reduced. By evaluating the data separately for transformer, reactive devices and line outages, the scope for improvements was determined. If the guideline for the maintenance plan was followed, the number of transformers outages could have been reduced by up to 51%. The number of reactive device outages could have been reduced by 36% while the line outages could have showed an improvement of 61% less outages in the 5 year study period

A ranking system was developed which indicated a ranking system from 1 to 7 categories. The categories were explained in terms of periods where outages would be best suited, with the goal of avoiding conflicts by booking outages in time frames that were best suited for other outages. A guideline was given on how to group the different equipment within these categories. This would assist outages being cancelled due to conflicts as well as reduce outages being turned down due to them being booked in incorrect windows of opportunity.

6.1. Recommendations

A recommendation for improvement on this suggested process is that the Phoenix database functions be expanded to eliminate any human errors. The function for entering the reasons

why outages are turned down and cancelled should have standard reasons to choose from, instead of the freedom to enter a description of any kind. This would assist with the audit trail in future analysis of outages. It is also suggested that a filtering function be added in Phoenix, in order to sort different plant such as lines or transformers instead of manually filtering for these items. An increased training program for Phoenix users has also been suggested.

Some improvements in the communication channels between stakeholders of the outages have been suggested. It is recommended that a detailed study be undertaken and a procedure be written to present the best form of communication possible to assist the schedulers in managing these stakeholder meetings.

Future study recommendations can be made for the cost benefits of optimising the outage management process of transmission assets within utilities, in order to further motivate better planning of the stakeholders.

It has been proven in this dissertation that Eskom's transmission outage management plan can be significantly improved by following the guideline presented.

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