EVALUATING THE EFFECTIVENESS OF PHASE OVERCURRENT PROTECTION ON OVERHEAD MEDIUM-VOLTAGE FEEDERS

by

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SUMMARY

EVALUATING THE EFFECTIVENESS OF PHASE OVERCURRENT PROTECTION ON OVERHEAD MEDIUM-VOLTAGE FEEDERS

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Keywords: Medium voltage, protection, operating time, let-through energy, reliability, voltage dip, radial feeder

Traditionally, the effectiveness of a phase overcurrent protection philosophy has been assessed by only considering a fault level versus protection operating time graph (only selectivity). In this research, an improved method was created to evaluate different phase overcurrent protection philosophies for medium-voltage feeders. A focus was placed on reliability, sensitivity, selectivity, speed of operation, performance and minimising risk.

The hypothesis stated that it is possible to develop a method that allows for the evaluation of the effectiveness of phase overcurrent protection. To test this hypothesis, an application was created that allows for the analysis of an overcurrent protection philosophy. This application made provision for changes in source impedance, evaluation of protection backup contingencies, different conductor types, user-definable protection equipment, the placement of protection equipment, user-definable protection settings, primary plant equipment damage information, user-definable safety margins and source transformer protection information.

The application provides graphs that allow the user to evaluate the protection philosophy in terms of the following criteria:

- The protection operating time at specific positions in the network.

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- The PU sensitivity of the feeder-installed protection equipment.
- The PU sensitivity of the source transformer protection (backup function).
- The let-through energy and associated equipment damage criteria.
- The energy-area over the analysed path.
- To classify the busbar voltage dip.
- To determine the position of the fault on the analysed path for the associated busbar voltage dip.
- To quantify the occurrence of a specific voltage dip category on the analysed path.

The graphs that were generated by the application allowed for the analysis and optimisation of the applied protection settings. This optimisation includes determining operating time, operating curve selection and the number of auto-reclose attempts. It is possible to determine the preferred protection philosophy using the application. The application does not prescribe how settings are to be calculated, or the placement of the devices; it evaluates if the applied philosophy is protecting the feeder and how well it is protecting it.

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OPSOMMING

DIE EVALUERING VAN DIE DOELTREFFENDHEID VAN FASE-OORSTROMINGSBEVEILIGING OP OORHOOFSE MEDIUMSPANNINGVOERDERS

deur

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Sleutelwoorde:	Mediumspanning, beveiliging, bedryfstyd, deurlaatenergie, betroubaarheid, spanningsknik, radiale voerder

Tradisioneel word die doeltreffendheid van `n fase-oorstromingsbeveiligingsteorie bepaal deur die inagneming van beveiligingsbedryftydgrafiek teenoor ‘n foutpeilgrafiek (slegs die selektiwiteit). In die navorsing is `n verbeterde metode geskep om verskillende fase-oorstromingsbeveiligings-filosofieë vir mediumspanningsvoerders te evalueer. Fokus is op die betroubaarheid, selektiwiteit, spoed en werksverrigting van die beveiligingsfilosofie geplaas. Nog `n fokuspunt was om die risiko’s wat met foute in die netwerk geassosieer word te verminder.

Die hipotese in die verhandeling sê dit is moontlik om `n metode te skep wat die doeltreffendheid van fase-oorstromingsbeveiliging kan evalueer. Om die hipotese te toets is `n sagtewaretoepassing geskep wat oorstromingsbeveiliging analiseer. Die toepassing maak voorsiening vir verandering in bronimpedansie, verskillende geleiertipes, gebruiker-gespesifiseerde beveiligingstoerusting, beskadigingsinligting vir die primêre masjinerie, gebruiker-gespesifiseerde veiligheidsmarges, sowel as brontransformator beveiligingsinligting.

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Die sagtewaretoepassing skep grafieke wat die gebruiker in staat stel om die beveiligingsfilosofie te evalueer in terme van die volgende maatstawwe:

- Die beveiliging se operasionele tyd by bepaalde posisies in die netwerk.
- Die sensitiwiteit van die voerder-geïnstalleerde beveiligingstoerusting se stroomvlak.
- Die sensitiwiteit van die brontransformator beveiligingstoerusting se stroomvlakke (rugsteunfunksie).
- Die deurlaatenergie en die geassosieerde beskadigingsmaatstaf.
- Die energie-area oor die geanaliseerde roete.
- Om die stamspanningsknik in `n sekere kategorie te klassifiseer.
- Om die stamspanningsknik se posisie op die geanaliseerde roete te bepaal.
- Om die voorkoms van `n bepaalde spanningsknikkategorie op die geanaliseerde roete te kwantifiseer.

Die sagtewaretoepassing genereer grafieke wat die gebruiker in staat stel om die toegepaste beveiligingsverstellings te analiseer en ook te optimaliseer. Sleuteleienskappe wat optimaal verstel kan word sluit in: die operasionele tyd van die beveiliging, die aantal hersluitpogings en die operasionele kurwes van die beveiliging. Die toepassing maak dit moontlik om die voorkeurbeveiligingsfilosofie te bepaal. Die toepassing skryf nie voor watter metode gebruik moet word om verstellings te bereken, of die plasing van die beveilingstoerusting nie. Dit evalueer wel die verstellings om te bepaal of die voerder wel beskerm word en hoe goed dit beskerm word.

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LIST OF ABBREVIATIONS

2PH	Phase-to-phase
3PH	Three-phase
ARC	Auto-reclosing cycle
CB	Circuit breaker
DT	Definite time
EI	Extremely inverse
HSI	High source impedance
HV	High voltage
IDMT	Inverse definite minimum time
LSI	Low source impedance
LV	Low voltage
MMT	Minimum melting time
MV	Medium voltage
MVA	Mega volt ampere
NERSA	National energy regulator of South Africa
NI	Normal inverse
OC	Overcurrent
PCC	Point of common coupling
PU	Pick-up
RC	Auto-recloser
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
TCT	Total clearing time
TM	Time multiplier

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CHAPTER 1 INTRODUCTION

1.1 PROBLEM STATEMENT

1.1.1 Context of the problem

The principle power generation, transmission and distribution organisation in South Africa is Eskom. They have a medium voltage (MV) overhead network in excess of 300 000 km [1]. Eskom has embarked on a drive to become one of the top five utilities in the world. As part of this drive, the utility wants to improve the reliability of its MV feeders. The reliability of a network is impacted by incorrect primary plant design, primary plant commissioning, incorrect protection settings and fading service levels [2].

When considering the impact of faults on high voltage (HV) feeders, the number of customers and the size of the load impacted are much greater than that of MV feeders. The frequency of faults on MV feeders is, however greater than that of HV, due to the larger exposure area [3]. Exposure area defines the physical square kilometres of land that the feeder covers. The distribution of power and the continuity of supply are key objectives of any power system and power utility for that matter [2], [4]. Faults on the feeder or network are detrimental to continuity of supply, pose a risk to life and can lead to capital and operational expenditure. A line designer and protection engineer cannot prohibit network faults from occurring. They can only minimise the likelihood and effects of the fault. The key protection elements that are applied to MV overhead feeders are phase overcurrent (OC) protection, earth-fault protection and sensitive earth-fault protection. The research documented in this dissertation focusses on phase OC protection (no earth-fault path) of MV overhead radial feeders in support of this objective.

Traditionally, protective equipment on MV feeders consists only of OC elements. This holds for both phase-and earth-fault protection. This is due to the uncomplicated nature of the OC protection approach. To effectively protect the MV feeder, it was simply an exercise of determining the current pick-up (PU), choosing an operating curve and grading the successive protection devices in time and current. This gave rise to the traditional time-

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current curves. Time-current curves for a specific reduced network diagram for different circuit breakers (CB) on a radial path are shown in Fig. 1.1.

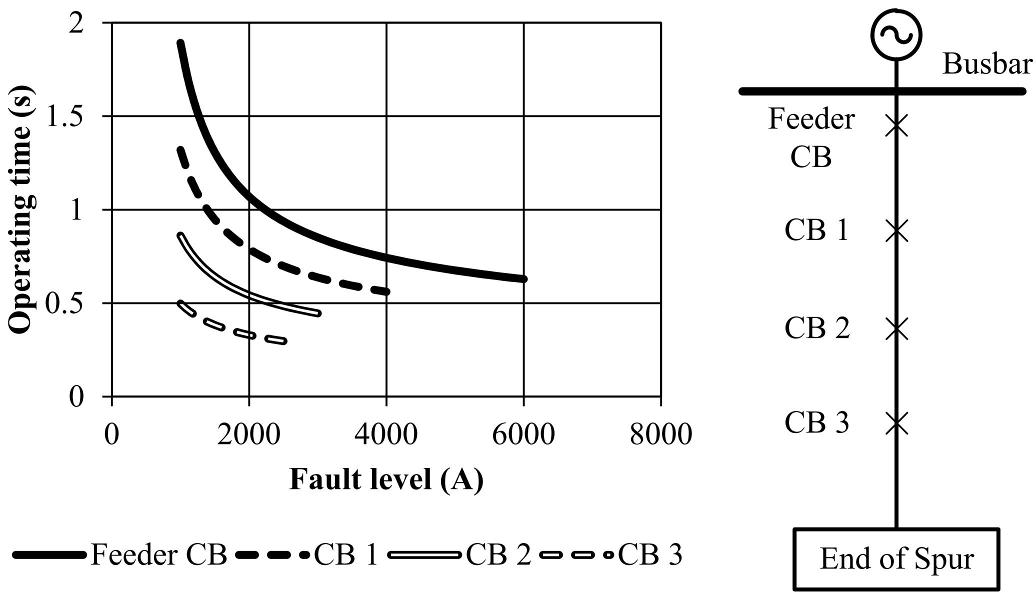

Figure 1.1 Traditional time-current curves and reduced network diagram for checking grading and operating times.

The use of time-current curves is well documented in the literature. It is seen as an industry standard when evaluating protection performance of installed protective devices in a network. However, the traditional PU sensitivity and grading approach never ensured that the feeder is optimally protected, nor did it consider the impact of protection on the power quality that the customers experienced. The aforementioned cannot be determined from the time-current graphs either. Network analysis software such as DigSilent Power Factory does provide some equipment withstand curves. These curves do go some way in ensuring that the equipment is protected. The survey in [5] indicates that 65 % of the utilities that participated ensure that protective devices are graded with upstream devices and 63 % ensure grading with downstream devices. Of the utilities that participated, 51 % consider the conductor thermal limit and only 39 % of the utilities ensure that the protection will detect a fault at the end of the line. After protective devices have been commissioned in the network, their effectiveness is seldom evaluated [6].

In order to obtain background on current protection practice in South Africa, a medium-voltage protection philosophy questionnaire was created. This questionnaire was

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distributed to the nine regions in South Africa to obtain information on the philosophy that they apply when protecting MV feeders. The questions relevant to phase OC protection from the actual questionnaire are provided in Addendum B. Some differences included the number of auto reclose-cycle (ARC) attempts, the curves that should be used, the grading method and how sensitive the OC PU should be. More information is provided in chapter 2. Published literature, such as from IEEE working groups and independent authors, provides yet more options that can be applied in an MV feeder protection philosophy. From all of these different protection philosophies and approaches, it is difficult to determine what the best philosophy or approach is.

1.1.2 Research gap

A protection scheme refers to the hardware (relays and their protection elements) that are used to protect the power system equipment. The protection philosophy refers to how the protection elements are configured or set. The same protection scheme can be applied to two feeders with different protection philosophies applied on each scheme. Various protection equipment types are available for MV feeders. This includes conventional substation-based equipment, auto-reclosers (RC) and fuses. This protection equipment can be applied in various network philosophies, such as fusing all spurs vs. fusing at the load point. The network can have various configurations under numerous network configurations. A good example of this is high source impedance (HSI) conditions vs. low source impedance (LSI) conditions.

Every protection device has associated settings which control the behaviour of the device. This can be a PU setting when considering RC, or the type of fuse chosen to protect a transformer. These settings also determine if the network is protected, how well the network is protected and the effect of protection on power quality. When small changes are made to protection settings, the results captured on the time-current curves are not quantifiable for evaluation purposes.

The current body of knowledge makes mention of using let-through energy, or I^2t energy, to determine the extent to which a network is safely protected. The IEEE guide for

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protecting power transformers [7] presents damage curves for different transformer sizes at various fault currents. Damage information for equipment is normally specified as a fixed value such as 100 A for 1 s (also known as a short-time rating). This is, however only a point on the equipment damage curve. The complete curve is not provided in the case of transformers. It is thus difficult to evaluate if the equipment is protected, especially if we consider that the only commonly-used protection graphs are the time-current curves of Fig. 1.1. With the number of protection approaches available, it is thus difficult to ensure protection of the equipment when the only information available to the engineers are the time-current curves.

Besides total loss of supply, the biggest effect that protection equipment operation has on the quality of supply is the voltage-dip effect. A voltage dip is a reduction in the nominal voltage for a brief period of time. Many of the international voltage-dip standards specify equipment immunity levels. This is specified in terms of residual voltage and the allowable withstand time. Little consideration is currently given to the effect of the MV protection philosophy on the voltage dips experienced by customers. The NRS 048-2 standard does allow the protection or quality of supply engineer to categorise the different voltage dips on a power network [8]. As with the let-through energy consideration, there is no recognised method of illustrating the voltage-dip effect in MV feeders.

The IEEE does have recommendations on how to protect an MV feeder [9]. There are also recommendations made in literature, such as in the Network Protection and Automation Guide [2]. Mason and Warrington have contributed to the OC protection philosophy of feeders [10], [11]. Nonetheless, no literature was found on the holistic testing of an OC protection philosophy.

1.2 HYPOTHESIS AND RESEARCH METHODOLOGY

Due to the number of variables that influence MV feeder phase OC protection philosophies, it is difficult to evaluate the effectiveness any specific philosophy. Thus the hypothesis that is to be tested in this research is:

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A method can be developed to determine the effectiveness of an MV feeder OC protection settings philosophy.

The main objective of this research is to develop a method of evaluating and optimising MV feeder OC protection philosophies. The hypothesis can be tested by meeting this objective. To develop this method, focus is placed on the following:

- To minimise the risk at the fault position.
- To ensure that the feeder primary plant equipment is protected.
- To promote the continuity of supply.
- To develop illustration methods for evaluation and optimisation purposes.

Risk is a collective for safety to life and the environment. This can be utility personnel working on the feeder, or people and animals at the fault location. There is risk to the environment due to arcing at the fault position in veld fires (such as grass lands) or plantation fires [12]. Ensuring that primary plant equipment does not exceed its safe operating area by the fault current that it carries, improves the reliability of supply in that the availability of the equipment is improved. The safe-operating area limits are enforced by the protection equipment and are set by means of the applied protection settings on the protection devices. The continuity of supply can be improved by having good selectivity of the protection devices, by backing up protection devices, and improving the availability of the primary plant equipment. Continuity of supply can also be improved by ensuring that the protection devices only operate when necessary and that they limit the effect on the quality of supply during a fault-condition period. As mentioned in the problem statement of section 1.1, the only recognised illustration method that is currently used to evaluate the effectiveness of the protection philosophy is time-current graphs. An assessment of the effectiveness of a phase OC protection philosophy cannot be determined from a time current graph alone, hence more illustration methods are required.

From the problem statement provided in section 1.1 and the objectives that were identified to test the hypothesis, the following research questions are presented:

- What factors can be used to evaluate an OC protection philosophy?

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- What are the key elements that determine if a MV feeder is protected?
- How do protection settings influence quality of supply, and can this be managed?
- For what period of time can a fault be allowed on the network?

Once the various influencing factors on the protection effectiveness have been identified and quantified, it will be incorporated into an evaluation method. A software application will be developed that incorporates the method for the evaluation of protection philosophies. The application will allow for new illustration methods to supplement the traditional time-current graph so as to meet the objectives as stipulated above. Since the power utilities have large MV networks consisting of various primary and secondary plant technology types, the method should be able to accommodate and evaluate this.

The number of variables to consider in a protection philosophy is vast, and the approach that will be used to try and test the hypothesis is thus one based on comparative case studies.

1.3 RESEARCH GOALS

The main goal of this research is to develop a method and an application based on the method that allows for the illustration and evaluation of MV feeder phase OC protection philosophies. Optimisation points for the evaluated OC protection settings should be identifiable from the evaluation results. The evaluated protection settings are calculated based on a certain protection philosophy, thus the application of the philosophy is tested. To achieve this, influencing factors on network and protection performance have to be identified. In turn, the elements that can control these factors from a protection settings perspective have to be identified. By answering the research questions and implementing the results in the application, a tool is created that allows for the testing of the hypothesis in terms of comparative case studies.

1.4 RESEARCH CONTRIBUTION

The contribution that is made is in developing a method to evaluate phase OC protection for MV feeders. This method allows for a protection philosophy consisting of conventional

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protection relays, RC and fuses, or a combination of these, with their relevant settings to be evaluated. In creating this method, novel ways of illustrating the effect of protection settings on the relay operating time, let-through energy, busbar voltage dips and PU sensitivity are developed. A novel way of quantifying the let-through energy in terms of area is also developed. This allows for the effect of changes to settings parameters and different protection philosophies to be quantified and compared for evaluation purposes.

1.5 OVERVIEW OF STUDY

This dissertation is structured in such a way so as to build towards a method that can be used to evaluate MV OC protection philosophies.

Chapter 2 start with a detailed literature review related to OC protection of the MV feeder and investigates different protection philosophies. The protection equipment, their associated settings and the primary plant equipment are identified from the survey. The literature survey introduces key influencing factors on the network from a protection settings perspective. Chapter 3 focuses on the concept of let-through energy followed by the voltage dips associated with protection-related aspects in chapter 4. In chapter 5, the influencing factors are used to develop a method for evaluating protection philosophies. These are incorporated into a software application. The illustrating methods that are created to evaluate philosophies are discussed in this chapter. In chapter 6, the software application (evaluation method) is applied in two case studies comprising three different protection approaches on a real feeder from the South African distribution network. The case-study protocol and resulting graphs are documented here. The case study results are discussed in chapter 7. This discussion serves to illustrate how to interpret the results for evaluating a philosophy and to attempt to prove the hypothesis. In the final chapter, chapter 8, the research is concluded and the key results are highlighted. Future work based on this research is also listed here.

There are three addendums in this dissertation. This includes the Excel based software application user input, the protection questionnaire used in South Africa (relevant phase OC questions) and the publication titles from this research.

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1.6 FORWARD[1]

The main objective of this research is to develop a method that can be used to evaluate and optimise phase OC protection for MV feeders. The method has to minimise risk at the point of the fault, ensure that the feeder is protected and reduce the effect on power quality. This method is to be implemented in a software application that allows for the application thereof and the evaluation of case studies with the main objectives of proving the hypothesis and answering the research questions. The first steps in identifying the settings' influencing factors are to understand what an MV network consists off, what protection devices are used and work that has been done to protect the feeders. This is covered in the next chapter, chapter 2.

1 The section named "forward" is used to help with the flow of the dissertation. It highlights key points of what has just been discussed in the chapter and then introduces the next chapter.

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CHAPTER 2 LITERATURE STUDY

2.1 CHAPTER OVERVIEW

This chapter will provide background for the research questions that are to be answered by considering work that has been documented in scientific journal articles, conference papers, standards, textbooks and reports.

Background is provided as to how a typical network layout looks and the type of equipment that can be found on MV feeders. The equipment is divided into energy-supplying equipment and then protective equipment. Since there is little documented work on evaluating an OC protection philosophy, the approach taken is to use prominent authors and standards and look at the recommended protection practice. From this, key elements are to be identified for evaluation purposes.

2.2 MV NETWORK LAYOUT, EQUIPMENT AND LOADS

In South Africa, MV is defined as voltages ranging from 1 kV to less than 44 kV [13]. A generalised radial (one source or point of supply) network diagram is shown in Figure 2.1. This diagram indicates the typical placement of protection equipment [9], [14]-[18]. In Eskom, distribution networks are predominantly radial and overhead. The load is distributed randomly on the feeder and there can be a combination of large and small loads (MVA rating). Radial feeders are the simplest network configuration and the least expensive to construct [19]. The drawback is that this feeder (network) configuration is detrimental to network performance when considering power quality incidents [15], [20]. The reason for this is that one fault on a radial feeder will influence all other customers downstream from the fault [15]. This is illustrated in the network diagram of Fig. 2.1 for a fault at RC 1. All the customers below RC 1 will experience a loss of supply and all the customers above RC 1 will experience a voltage dip. The system average interruption duration index (SAIDI) is a measure of the number of minutes the average customer was without supply [8]. This is dependent on how long it takes for a fault to be repaired and supply restored. The system average interruption frequency index (SAIFI) is a measure of how many times the customer was without supply [8]. Both of these indexes are dependent

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on the number of customers interrupted, the total customer base for the feeder and are only considered if the power system event is present for more than 5 minutes [8]. In a radial distribution system (as shown in Fig. 2.1) a fault at RC 1 will influence the feeder power quality indexes significantly if the bulk of the load (number of customers) is below RC 1.

In radial networks, the protection is normally non-directional OC elements [9]. When there is more than one source present on the feeder, whether it is from an independent power producer or another feeder (via a normal open point), the need for directional protection is created.

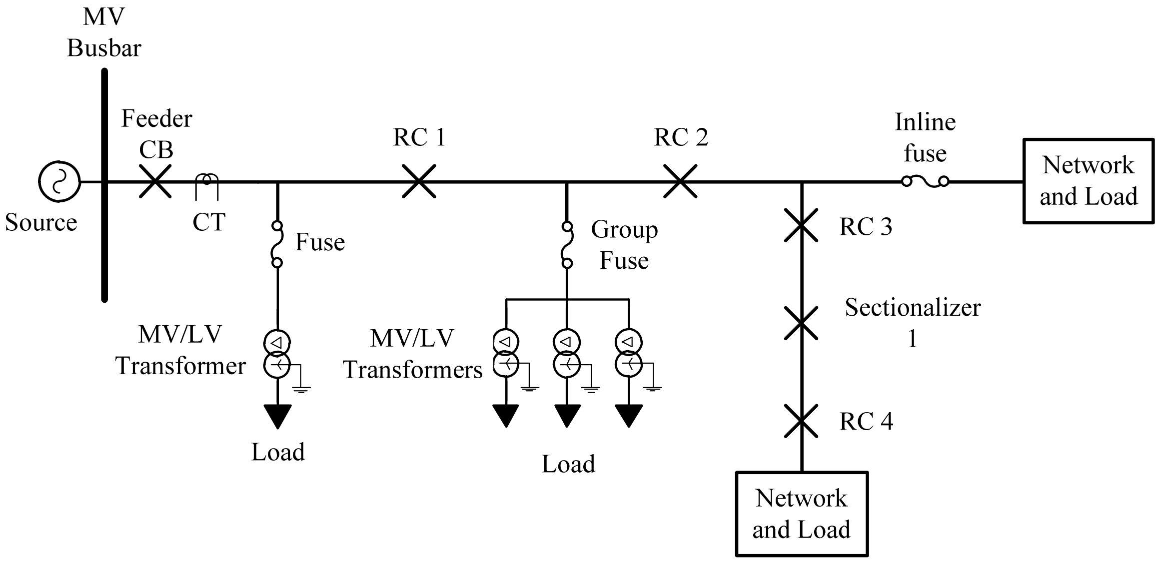

Figure 2.1 Typical protection equipment use and feeder layout on a radial MV feeder.

There are two main categories of equipment that are used in MV networks. The first is to supply energy to customers and the second is for the protection and control of the network.

To supply energy to customers (limited to the MV network), the following is required:

- A conductor to transport the energy from the source (HV to MV substation) to the customer supply point (MV to low-voltage transformer) [14], [15]. Typical conductors that are used on MV networks in South Africa are Squirrel, Fox, Mink and Hare conductor.

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- A structure to keep the conductor off the ground and to maintain a certain physical distance between the respective phases [14], [15]. This is for safety purposes and so that energy is not leaked to the surrounding area.
- Terminating equipment at each structure and supply point. This is used to isolate the structure from the live conductor and to fix the conductor to the pole. This includes both strain-and suspension equipment.
- Transformers are required to step down the voltage from MV to low voltage (LV) [15]. In Eskom the nominal voltage for the secondary of these transformers is 400 V line-to-line.

The minimum phase spacing for the structures is dependent on the voltage level and the distance between the structures [21]. The minimum spacing between conductors are provided in [21] and these are based on the clearances specified in the Occupational Health and Safety Act of 1993 (South Africa). A helical dead-end is used to terminate the conductor to the structure when it is a strain section. A dead end will normally not carry current, except under fault conditions. A dead end on one phase is shown in Fig. 2.2 [22].

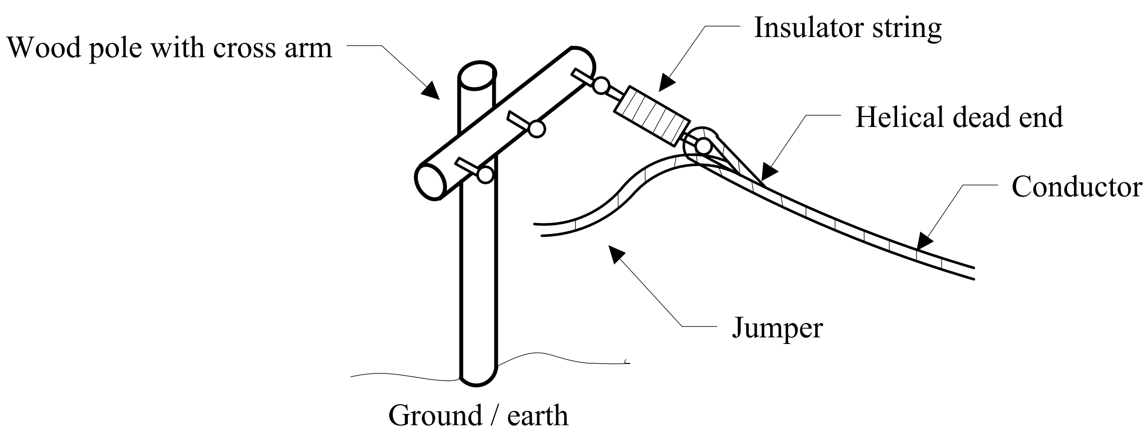

Figure 2.2 A helical dead-end connection on strain structures.

The most common protection equipment (current based) that are used to protect MV networks are listed below [14], [23].

- A substation CB and current transformer (CT) [9], [15]. To operate the CB there would be a protection relay installed in the control room that is dependent on the

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current from the CT [9]. In some instances an RC can be installed instead if the CB, CT and substation relay [9].

- There can be multiple RC's installed at various positions in the network [9], [14]. These RC positions are determined by the number of customers, network exposure area, the size of the load, or a combination of these [24]. Reclosers improve the reliability of the network by automatically closing after a transient fault was cleared on the network and isolating permanent faults [25].
- There are two types of fuses available, namely current-limiting and expulsion fuses [9]. Expulsion fuses only clears the fault at a current zero and hence it allows for more let-through energy to pass to the circuit compared to a current limiting fuse [9]. Expulsion fuses are used in Eskom. This can either be in-line fuses (or sectionalising fuses) on the backbone of the conductor, fuses at the MV to LV transformers, or group fusing (a fuse protecting a group of MV to LV transformers) [15], [26]. This is illustrated in Fig. 2.1. The I^2t rating of a fuse should always be less than the equipment it is protecting [14].
- A sectionaliser is an extension of either a substation breaker or an RC. It cannot break load current. A sectionaliser makes use of the auto-reclose (ARC) capabilities of an upstream protective device to isolate a network section (cannot break fault current) [9], [14], [16], [27].
- Finally isolators (disconnectors) are installed in the network. These disconnectors can only be opened when there is no current flowing, so as to isolate a section of the network. This will normally be used during maintenance and when field personnel conduct fault finding.

Loads can be subdivided into four categories, namely agricultural, residential, commercial and industrial [15]. All four load categories are present on MV feeders. Many of the types of loads, such as lighting and water heating, are common to all four categories [15]. When considering the annual electricity sales for the South African utility, Eskom, in Table 2.1, it can be seen that the residential customers only account for about 5 % of the total sales [1]. A large portion of the electricity sales are accounted for by the redistributors

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(municipalities). The redistributors do have a large number of residential customers, consisting of overhead line-and cable networks. When the redistributors and the Eskom residential load are added together, it accounts for almost 46 % of the electricity sales. In South Africa, most of the agricultural load is also supplied via MV overhead feeders. When considering the individual number of customers, residential customers account for 97 % of the total number of customers in Eskom [1].

Table 2.1 Energy sales and customer numbers for Eskom during 2010 [1].

Field	**Energy usage**		**Customer numbers**	
	(GWh)	(% of total)	(number)	(% of total)
Redistributors	90712	41.499	773	0.017
Residential	10350	4.735	4325550	96.914
Commercial	8889	4.066	47984	1.075
Industrial	55816	25.534	2925	0.066
Mining	31733	14.517	1134	0.025
Agricultural	5010	2.292	84415	1.891
Traction	2854	1.306	510	0.011
International Utilities	4109	1.88	7	0.000157
End users across the border	9118	4.171	3	0.000067

2.3 PROTECTION EQUIPMENT SETTINGS

The primary function of protective equipment is to ensure the continuity of supply by isolating the affected network during a fault [4]. The three OC elements that are used to protect distribution feeders are phase OC elements, earth-fault elements and negative phase-sequence elements [9]. OC relays are best suited for distribution feeders due to their simplicity and low cost [10]. This research focuses on the phase OC element.

The functionality of the relay that is used in the substation is dependent on the relay technology [9]. There are four main categories (technology types) of relays, which are

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electro-mechanical, static, digital and numerical [2]. All four types are currently in service in Eskom. Each technology type has its own constraints. These constraints can be the availability of operating curves, the number of ARC attempts the relay provide, the minimum and maximum ranges of specific elements, the step sizes of these elements, the CT burden of the relay, the relay accuracy, etc. The reclosers that are currently used by Eskom are mainly of a numerical technology type. Electromechanical-type protection relays are still operational in some supply substations as a feeder relay at the MV busbar. The functionality on the reclosers is similar to that found on modern numerical relays. There can be small differences between the two. A good example of such a difference is recloser curves (such as a TCC 117 curve) that may not be present on the substation relay. The main OC protection element functions are listed below.

- The OC element PU
  - The OC element PU determines how sensitive the protection is to faults. This defines the boundary between the load region and the fault region for OC faults, since both consist of positive sequence current [9].
- The protection operating time.
  - The operating time is dependent on the type of operating curve. The operating curves can broadly be divided into two types of curves:
    - Inverse definite minimum time (IDMT) over current curves (various curves are available). These curves have a time multiplier (TM) associated with them to adjust the operating time of the curve [2].
    - Instantaneous OC element (definite time (DT) OC element). For this curve there is a specific time delay associated with the curve. Instantaneous curves normally have a zero-second time delay [2].
- The ARC settings.
  - For this research only the number of trips to lock-out is considered. There are other settings associated with the ARC element, such as the dead time and reclaim time. These three settings are the prominent protection settings when setting the ARC element [2].

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A fuse has two operating characteristics. The first is the minimum melt characteristic, also called the minimum melting time (MMT), and the second is the total clearing time (TCT) [9]. Upstream devices grade with the fuse MMT and downstream devices grade with the fuse TCT. The operating characteristic can only be changed by changing the type of fuse.

2.4 PHILOSOPHY EVALUATION FACTORS

To aim of this section is to identify the key elements that influence the OC protection philosophy, and work that has been done in this field.

2.4.1 Protecting an MV feeder

A protection system is characterised by the speed of operation, the reliability, the sensitivity of the system to faults, the selectivity of the protection devices and the stability of the protection system [2], [28]. There is almost no documented research done on holistically comparing different OC protection philosophies. Due to this, the approach that is taken to identify factors that are influencing the network performance from a protection perspective is to consider how MV networks are to be protected. This is done by considering prominent authors, manufacturers, research publications and standards.

The IEEE has made various recommendations for the protection of distribution lines [9]. This included phase OC, earth-fault and negative phase-sequence protection. For this research, only the phase OC element protection is evaluated. When considering the fault levels, it is recommended that protection settings be calculated by using specific fault levels such as three-phase- (3Ph), phase-to-phase- (2Ph) and single-phase-to-ground fault levels under minimum and maximum network conditions. A value between 0 Ω and 40 Ω is typically used for the fault impedance. The conductor I^2t damage curve has to be taken into account so as to ensure that the conductor is being protected. The damage that occurs is due to the annealing effect on the conductor material. To ensure that the conductor is protected, fault current, relay operating time, the conductor damage curve and the ARC philosophy have to be considered. The source transformer (HV to MV transformer) damage curve should also be taken into consideration, as this, too, has an I^2t characteristic.

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The IEEE recommended that when determining the OC element PU, the cold-load characteristic, the transformer inrush current and the expected load should be considered. A recommended value of 1.5 to 3 times the load current is given so as to avoid maloperation. The sensitivity of the PU creates a conflict between the insensitivity to load currents and the sensitivity to fault currents. To maintain the selectivity of the protection devices, the devices have to be graded by making use of a grading margin. The fault-clearing time has an influence on the voltage dip that the customers can be exposed too. The customers below the fault-clearing protective device will be exposed to an interruption and the customers above the device will be exposed to a voltage-dip. This voltage-dip will affect customers being supplied from adjacent feeders from the same source MV busbar. The ARC function should be applied to feeders, as the majority of faults are transient (temporary) in nature. A fuse-saving philosophy can be adopted, based on this high frequency of transient faults and the single operation of a fuse.

In Alstom's Network Protection and Automation Guide (NPAG), similar recommendations for protecting an MV feeder are made as by the IEEE [2]. The similarities include damage to equipment based on energy, and voltage dips due to protection operation. The NPAG does recommend that the same operating curves be used when protection devices are in series. The NPAG also recommends that grading be conducted not only in time but also in current (grading the PU's) to ensure selectivity. The use of instantaneous tripping curves to reduce the operating time and damage at the fault location is also promoted. The operating time should be kept to a minimum under maximum network conditions (high-fault currents) and then it should be checked under minimum network conditions. Mention is made of the benefit of using extremely inverse (EI) IDMT operating curves, as these curves have similar operating characteristics as the let-through energy curve. The EI curve is beneficial in fuse-saving schemes as well. The PU/drop-off ratio of the PU has to be considered when determining the PU value, and a typical value of 105 % of the rated current of the conductor is recommended as a minimum. The protection element PU should be insensitive to load current, but sensitive to minimum fault current. In terms of the number of trips in an ARC cycle, it is mentioned that that there is no definite number of trips. The number of trips does get influenced by the circuit breaker limitations and system

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conditions. These system conditions can be a type of fault such as a semi-permanent fault and the fuse-blow or fuse-safe scheme. To create a backup for protection, it is recommended that protection zones should overlap each other.

Mason also contributed to the art of phase OC protection philosophy of feeders [10]. The EI curve is recommended by Mason for its grading ability between reclosers and fuses. Again, it is advisable to set the PU above the loading on the feeder. When grading subsequent devices, the maximum current between the devices should be used and a bottom-up approach should be applied. Both time and current grading are to be used when grading subsequent protective devices. The OC element PU has to be sensitive to all faults and it should provide backup to downstream RC under certain contingencies. To set the sensitivity of the PU, a 2Ph fault is recommended, with the addition of arc resistance. When grading subsequent devices, the maximum current between the devices should be used to ensure selectivity under changing network conditions. The use of instantaneous curves to reduce the operating time is also advisable. By applying instantaneous curves there is an added advantage in that grading margin can be created for upstream devices, or the total feeder operating time can be reduced. This is because the downstream device only grades at the start of the IDMT curve (lower-fault level) and not the start of the instantaneous curve (higher-fault level).

Another contribution to the OC protection of feeders was made by Warrington [11]. He indicated that current-based grading can only be done when there is sufficient change in fault current between the protected zone and unprotected zone. A good example of a current-based curve is an instantaneous operating curve. When there are many devices in series, it can result in high operating times for breakers close to the source. This slow operating area close to the source is the area where high fault currents are present. The use of an instantaneous curve for breakers close to or at the source is thus recommended. It is desirable to set the PU of the OC element above load and below the minimum fault level. A recommendation to use EI curves is made in situations where the fault levels stay fairly constant over the protected zone. This is because a small change in current will produce a large change in operating time. The EI curve provides good protection against the heating

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effect on apparatus and also good time grading with fuses. When determining the operating time, it should be set as fast as possible for an end-of-zone fault, thus it will become faster as the fault gets closer to the start of the zone. To maintain selectivity, a grading margin has to be introduced.

Based on the recommendations of the above authors and standards, the following philosophy evaluation factors are identified:

- Protection operating time
- The OC protection element sensitivity
- The let-through (I^2t) energy
- The voltage-dip effect

2.4.1.1 Current practice in South Africa

Eskom is the principal utility in South Africa and is responsible for the generation, transmission and distribution of electricity. Eskom Distribution is divided into nine regions that coincide with the nine provinces of the country. The Eskom MV network represents the majority of South Africa's installed MV overhead network. A questionnaire was sent to the various Distribution regions to determine how they are protecting their MV networks. The questionnaire covered phase OC protection, earth-fault protection and standalone functions such as cold-load PU. Only the feedback related to the phase OC protection is used for this research. Of the nine regions, there was a response from eight regions and the Technology division in Eskom. The related questions are shown in Addendum B.

The response indicates that all of the regions consider the conductor emergency rating (thus maximum load), current grading with the upstream device and some sensitivity measure when considering the OC PU. Some of the conductor rated current safety margins (for max. load) differ amongst the regions, e.g. 120 % or 110 % of the conductor emergency rating. 67 % consider the short-time ratings of conductors to ensure that the conductor is protected. 11 % consider other equipment, the equipment is not specified. When the PU sensitivity response is analysed, it is found that the intended reach differs amongst the regions. Some regions set the feeder breaker to be sensitive to the lowest fault

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level on the feeder, others set each device and some only bypass the immediate downstream RC.

The ARC philosophy differs amongst the regions, with some applying four trips to lock-out and other applying 2 trips to lock-out for overhead lines. All the regions do mention that the first ARC attempt is for transient-type faults. The curves that are used with every ARC attempt differ from a fast curve for the first attempt to slow curves for all attempts. The dead-and reclaim times are also different amongst the regions, but these values are not used in this research. This can form part of future research work. The relay technology is considered by most regions when determining the time-grading margin. The margin used range from 200 ms to 500 ms.

From the questionnaire feedback it is found that the response is similar to the recommendations of the IEEE [9], Mason [10], Warrington [11] and the NPAG [2], but there are also differences, for instance in curve selection and the number of ARC attempts. The number of ARC attempts is not explicitly stated by any of the above main authors.

2.4.2 Protection operating time

To reduce the let-through energy during a fault, the protection operating time has to be reduced [2], [29]-[36]. Faults and arcing faults, in particular, hold many risks. These risks include a fire risk to the surrounding area due to the incandescent conductor particles at the fault position [12], [30], [31], [37], [38]. This fire risk increases with an increase in fault current [37]. Equipment damage can occur if the fault current is high enough, or present on the network for a long period [2], [29], [30], [32], [39]-[41]. Radiant heat is generated at the fault position and this can lead to burn wounds [29], [31], [39]. By decreasing the equipment's exposure time to fault current, the availability of the equipment will be increased and this, in turn, will increase the network reliability [33], [42]. Source transformers get damaged by through faults and this damage is cumulative. It can be different faults, or ARC attempts on the same fault. By unnecessarily reclosing on to a permanent fault, the risk for equipment failure is increased [25], [40]. Transformers that supply distribution networks are exposed to a greater number of through faults [7]. This

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exposure reduces the life expectancy of the transformer [43]. It also increases the financial risk of replacing the transformer, revenue lost due to energy not supplied and the risk of having a safety incident due to personnel working under pressure in the substation to restore supply. The damage at the fault position can be reduced considerably if instantaneous operating curves are used [40].

The number of protective devices in series has an influence on the operating time [44]. The operating time increases when the number of devices increases and selectivity is to be maintained between the devices. The grading margin has a direct influence on this selectivity. In [44] it was also indicated that slowest operating time occurs at the higher fault currents, as the fault is placed closer to the source on the same grading path.

The operating time has a direct influence on the voltage-dip duration [33], [35]. The operating time also influences the amount of let-through energy that the network equipment is exposed to.

2.4.3 The OC protection element sensitivity

The protection sensitivity for OC protection is defined by the protective device OC element PU. It is indicated in [2], [9]-[11], [34], [40] that the PU is normally set above the expected load. The PU thus defines the border between the fault region and the load region. Not only must the relay not trip for load current, but it has to trip for fault current as well [36], [45]-[47]. If the protection is too sensitive, it will result in nuisance tripping, and if the protection is insensitive, it will result in an increased risk and a reduction in the reliability of the network due to network faults.

There are errors that occur due to measurement equipment. The typical relay errors are stated as 7.5 % for electromechanical and 5 % for other relay technologies such as numerical relays [2]. The percentage CT error is stated as less than 10 % when it is producing 20 times the rated current [9].

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2.4.4 Let-through (I^2t) energy

Let-through energy refers to the amount of I^2t energy that is transmitted to fault before the fault current gets interrupted [48], [49]. The let-through energy is also referred as Joule Integral, or thermal energy [39]. This energy can heat the equipment beyond its thermal capabilities, which will result in equipment damage, unnecessary outages, capital expenditure and loss of revenue. To ensure that a feeder is protected, the let-through energy has to be considered [38]. All equipment installed in the network has a certain level of current it can withstand for a certain period of time. This is called the short-time rating of the equipment. Circuit breakers have a 3 s rating (certain current for 3 s) that indicates the stresses that the breaker can withstand during a fault. By determining this maximum time at various currents, a damage curve can be generated for the equipment [36]. By assuming that there is no energy transfer to the environment (adiabatic process) during a fault, equation 2.1 can be applied to calculate the let-through energy (I^2t energy) capability of the conductor [14], [38], [39], [50].

$$\left(\frac{I}{1000A}\right)^2 t = K \cdot log_{10}\left(\frac{T_2 + \lambda}{T_1 + \lambda}\right) \qquad [2.1]$$

where

I = *fault current, A*

t = *fault duration, s*

A = *cross-sectional area of the conductor, kcmil*

T_2 = *conductor temperature from the fault, ºC*

T_1 = *conductor temperature before the fault, ºC*

K = *conductor constant that accounts for the conductor resistivity, density and specific heat.*

λ = *inferred temperature of zero resistance, ºC*

The normal rating, emergency rating and short-time rating for common conductors that are used for Eskom distribution networks are listed in Table 2.2 [51], [52]. The normal and emergency ratings for the conductors are considerably less than the short-time rating. The normal and emergency ratings indicate the loading capability of the conductor and this is used when determining the PU, as this is the maximum load that the feeder can supply. The

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short-time rating provides the mechanical limit of the conductor due to the thermal effect of the fault current. The normal and emergency ratings specified in Table 2.2 are for a templating temperature of 50 ºC [52]. The short-time ratings are based on a pre-fault conductor temperature of 75 ºC and a post fault temperature of 200 ºC [51]. No mention is made of the voltage level of the conductor ratings provided in [52], but it is stated that the ratings is applicable to the whole utility (Eskom). This does then include MV levels.

Table 2.2 Conductor current ratings including 1 s short-time ratings.

Conductor	Normal [A]	Emergency [A]	Short time for 1s [A]
Hare	280	329	8970
Mink	206	285	5400
Fox	148	203	3140

Based on this information, damage curves can be created for the equipment. The protection operating curves have to be coordinated with the damage curves [46].

2.4.5 The voltage dip effect

Power quality has to be considered when setting protective devices [53]. A voltage dip is a reduction in the RMS voltage for a short period of time, after which the voltage reverts to its normal operating margin. [54]-[56]. Some of the literature refers to voltage sag, as opposed to a voltage dip. These terminologies describe the same voltage event [57]. Voltage dips can be caused by the starting of big loads, but more often it is caused by network faults [2], [3], [6], [53]-[64]. In [65] a previous study it was found that lightning and wind account for most (46 %) of the voltage sags. A four-year study was conducted in [66] where birds or animals accounted for the majority of faults during the first three years. In the last year, faults were dominated by wire slapping. In another study, lightning is claimed to be the major cause, with birds being second [57].

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There are many voltage standards and guides available. Most of these curves are related to customer equipment and specify the equipment voltage dip ride-through criteria. Prominent voltage-dip curves include the Computer and Business Electronic Manufacturers Association (CBEMA) curve, the Information Technology Industry Council (ITIC) curve, ANSI curve (standardised as the IEEE 446), the Semiconductor Equipment and Materials (SEMI) E10 curve and the SEMI F47 curve [3], [57], [61]-[63], [67], [68]. South-Africa is governed by the NRS 048-2 standard, where a dip table is used to categorise the dip in terms of magnitude and duration [8]. The EN 50160 standard also classifies voltage dips in terms of a table [61], [68]. The EN 50160 dip table is divided into five time regions, whereas the NRS 048-2 table has only has three regions. For this research the NRS 048-2 dip table is used to classify the voltage dips.

The CBEMA and ITIC curves were developed to set the voltage dip ride-through capability of IT-based equipment [3], [27], [67], [69]. The ITIC curve is based on the CBEMA curve, thus only the ITIC curve is considered for comparison purposes. The SEMI E10 curve was developed for the semiconductor industry [67]. The BS6100-4-34 curve specifies the preferred voltage dip test levels for equipment drawing more than 16 A per phase [55].

The effect of voltage dips on domestic appliances was tested in [69]. This study was done in Australia where the supply is at 230 V and 50 Hz. The appliances that were tested included televisions, printers, computers, clock radios, air conditioners, fridges, microwave ovens, DVD players and portable hard disk drives. All of the appliances that were tested and the results were well documented in [69] and individual voltage dip susceptibility curves were created for these household equipment. A domestic appliance (DA) curve was created from this study to show the combined susceptibility of all the tested household equipment to voltage dips.

In Eskom, the majority of customers (96.9 %) are residential customers when considering only the number of customers that are supplied on distribution feeders. This justifies using the DA curve to reflect the voltage susceptibility of household equipment in South Africa.

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Current voltage-dip curves do not adequately consider the effect that protection has on power quality when stating what the distribution network should meet [3], [57]. The study in [3] indicated that many customers experience voltage dips that do not meet the ITIC criteria. In [65], 42 % of faults fall outside the CBEMA (or then ITIC) limits. The impact of a network fault that results in a voltage dip can be annoying, or even stall motors at the customer load centre [2]. To reduce the effect of a voltage dip on customer installations, the protection operating time have to be reduced [27].

2.5 FORWARD

In this chapter different types of network equipment have been identified. The two main categories the energy-delivery equipment, such as conductors and transformers, and control equipment, with a focus on protective equipment such as RC and substation-based relays. Prominent work on OC protection was done by the IEEE, in the NPAG, by Mason and Warrington. These protection philosophies allowed for the identification of the key factors to evaluate an OC protection philosophy. The factors are the protection operating time, the sensitivity of the PU, the amount of let-through energy and the voltage-dip effect due to faults. In the following chapter the let-through energy will be explored. The effect of let-through energy is to be considered and an evaluation method developed.

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CHAPTER 3 LET-THROUGH ENERGY

3.1 CHAPTER OVERVIEW

In the previous chapter four main focus areas were identified as protection operating time, PU sensitivity, let-through energy and voltage-dips. In this chapter the let-through energy is used as a measure to evaluate the protection philosophy.

3.2 LET-THROUGH ENERGY

As indicated in the literature survey, the let-through energy has a thermal damaging effect on equipment. This effect can be controlled from a protection settings perspective by controlling the time period that the equipment is exposed to this energy. To determine the limits of the equipment, equipment damage curves are to be created and then an evaluation philosophy will be created for this.

3.2.1 Equipment damage curves

In the literature survey (section 2.4.1) the IEEE recommended that the let-through energy have to be considered to ensure that equipment is protected [9]. To evaluate if the equipment is being protected from excess energy exposure, a damage curve has to be created for the equipment. The prominent energy-delivering equipment that is considered is the conductor and the terminating equipment, as this is the main equipment that the substation-based breaker and line-installed RC's have to protect.

Equation 2.1 was introduced in the literature survey. This equation can be used to determine how much let-through energy equipment can withstand when the initial and final equipment temperatures are set (for fault conditions). With the known let-through energy limits in Table 2.2 and by simplifying equation 2.1, equation 3.1 can be developed that allows for the creation of a damage curve for each conductor. This curve is obtained by calculating the new current withstand time for the conductor over a range of currents. This is similar to the equation in [38].

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$$t_{new} = \left(\frac{I_1}{I_2}\right)^2 t_{old} \qquad [3.1]$$

where

t_{new} = *new fault withstand time at I_2 current, s*

t_{old} = *previous fault withstand time at I_1 current, s*

I_1 = *previous fault current for t_{old}, A*

I_2 = *new fault current for t_{new}, A*

The damage curves for Hare, Mink and Fox conductors are shown in Fig. 3.1. The time the conductor can withstand the specific fault current before it gets damaged can be determined from this curve. At a lower fault current than the one specified in Table 2.2, the conductor can withstand the thermal effect of the fault current for a longer period before it gets damaged.

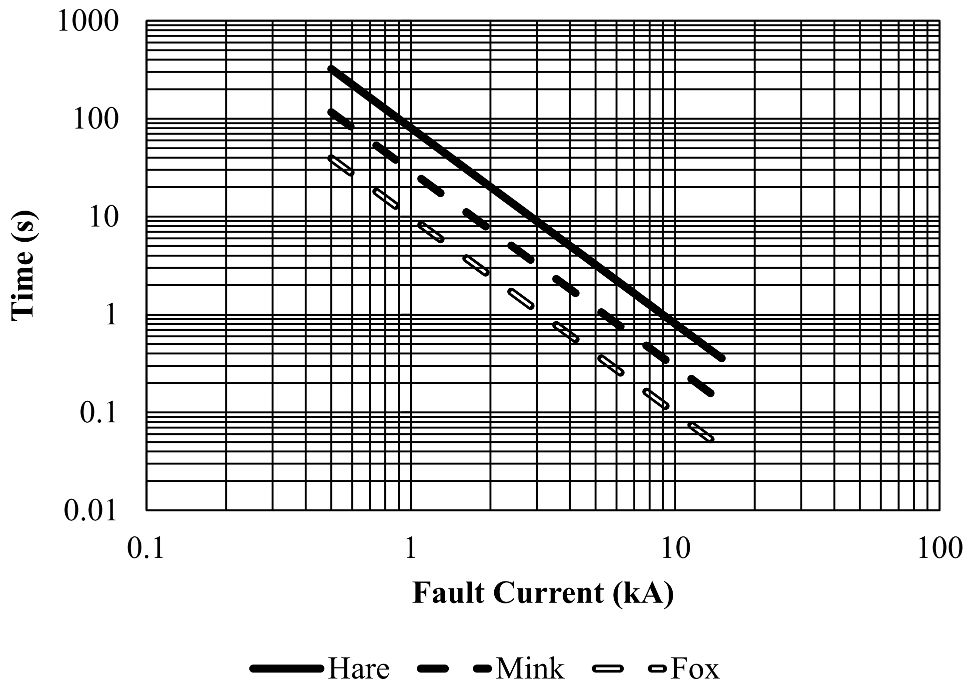

Figure 3.1 The damage curves for Hare, Mink and Fox conductors.

The damage that will occur on a conductor is as a result of the material that elongates due to the excessive heat in the material [27]. The conductor will anneal if an excessive current is passed through it for a long period [9]. When the conductor cools down, it should return

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to its previous form. This is also termed an elastic deformation. If the material does not return to its previous form (stays elongated), it is termed a plastic deformation and the conductor is considered damaged. Hook's law governs the relationship between stress (σ) and strain (ϵ) for metals, and Young's modulus of elasticity (E), captures the material properties [70].

The dead-end terminating equipment shown in Fig 2.2 has low short-time rating of 3000 A for 1 s. This was determined by the Eskom technology team and is currently one of the key failure points on MV feeders in South Africa. By reducing the time that equipment is exposed to fault current, the damage to equipment can be limited and it can be recommissioned quicker [30].

3.2.2 Let-through energy evaluation philosophy

In the previous section it was shown how damage curves can be created for the equipment. To evaluate if the equipment is being protected, the let-through energy that the equipment is exposed to has to be below this damage curve. This let-through energy is a function of the protection operating time.

By using the fault level at the fault position and the protection operating time for that fault the let-through energy curve that the equipment can be exposed to can be calculated. By reducing the operating time, the amount of let-through energy can be reduced. This can be done by changing the OC protection settings. The fault level cannot be changed by changing the OC protection settings, as this is dependent on the system voltage and the impedance to the fault position.

The main settings for the ARC function were indicated in chapter 2. This is the number of trips to lock-out, the dead time and the reclaim time. The assumption is made that there is no energy loss from the heated equipment during the dead time [39]. This assumption allows for the let-through energy of different ARC cycles to be added together, thus creating a total let-through energy exposure curve for the equipment. This total curve should be below the equipment-damage curve to ensure the protection of the feeder

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equipment. A similar cumulative approach to fault-clearing times for every shot in the ARC was taken in [50]. To account for errors such as CT and relay errors, a safety margin has to be applied. A value of 20 % is recommended, as this is greater than the combined error magnitudes of the CT's and relays. This safety margin is to be applied to the equipment damage curve. This let-through energy evaluation concept is illustrated in Fig. 3.2 for one conductor and one RC. The RC makes use of a two-trip-to-lock-out philosophy (same protection settings). It can be seen in Fig 3.2 that the total energy curve exceeds the safety margin. In this case the number of trips to lock-out or the operating time of the protection, has to be adjusted.

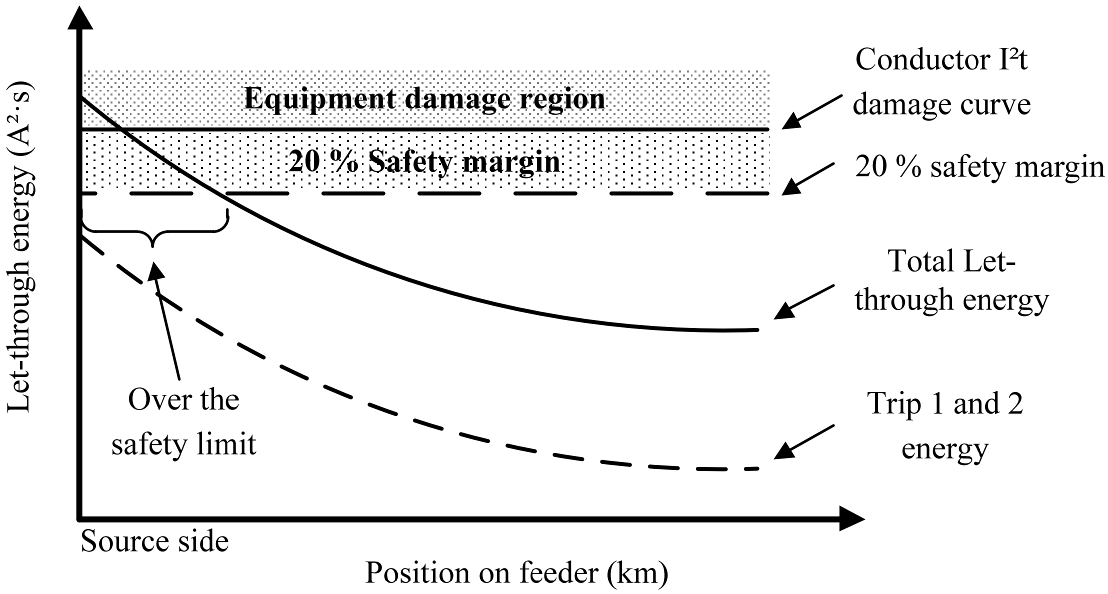

Figure 3.2 The let-through energy evaluation concept.

3.3 FORWARD

A method to determine the equipment damage curves was introduced in this chapter. By using the fault level and the protection operating time at the fault level, the let-through energy can be calculated and a curve generated. By adding the let-through energy of every ARC attempt together, a total energy curve can be created that should be below the equipment damage curve (with a safety margin). The factors that are to be evaluated was identified in this chapter. An evaluation method for the voltage-dip effect due to faults will be developed in chapter 4.

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CHAPTER 4 VOLTAGE-DIPS

4.1 CHAPTER OVERVIEW

The four OC protection philosophy evaluation criteria were identified in chapter 2. The let-through energy evaluation criteria were defined in chapter 3. In chapter 4 the voltage-dip effect is investigated, with the goal of creating an OC protection philosophy evaluation criteria based on the voltage-dip effect.

4.1.1 Comparing voltage-dip standards and curves

In the literature survey of chapter 2, various international equipment voltage susceptibility curves were identified. The ITIC curve, BS 61000-4-34 curve, the SEMI E10 curve and the DA curve are shown in Fig. 4.1.

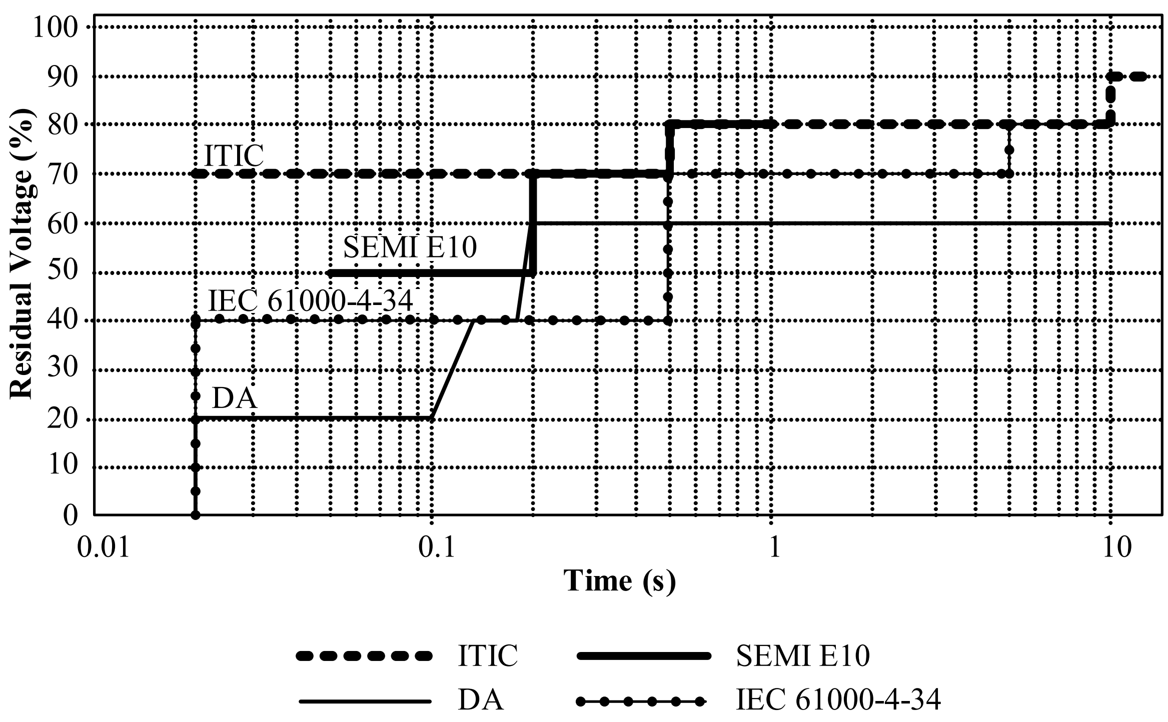

Figure 4.1 Equipment voltage-dip curves.

Any voltage-dip value above the respective curve is acceptable. Current voltage-dip curves do not adequately consider the effect of protection on what the distribution network is capable of delivering [3], [57]. The study in [3] indicated that many customers experience

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voltage dips that do not meet the ITIC criteria. When comparing the curves in Fig. 4.1, it is evident that the ITIC curve places the least stringent requirements and the IEC 61000-4-34 curve places the most stringent requirements on equipment. The DA (domestic appliance) curve indicates that the actual household equipment performs well when it is compared to the equipment immunity curves. This is true except for a small portion from 180 ms to 500 ms, where the DA curve is above the IEC 61000-4-34 curve. All of these curves allow for a deeper voltage dip (lower residual voltage) if the dip duration is short, and then only a small dip can be accommodated if the dip duration is long. From a utility perspective, the IEC curve provides the biggest advantage (not considering the DA curve, as it is an actual equipment performance curve). One possible reason for this is that the IEC 61000-4-34 caters for larger equipment when it is compared to the ITIC and the SEMI E10 curves.

Typical distribution end-user loads are classified for each of the different load categories in Table 4.1 [15]. Many of the loads are common across the different categories for distribution feeders.

Table 4.1 Loads and load categories [15]

Agricultural	Residential	Commercial	Industrial
Lighting	Lighting	Lighting	Lighting
Water heating	Water heating	Water heating	Water heating
Space heating	Space heating	Space heating	Space heating
Air conditioning	Air conditioning	Air conditioning	Air conditioning
Computer	Computer	Computer	Computer
Air circulation	Air circulation	Air circulation	Air circulation
Cooking	Cooking	Cooking	Filtration
Water well pump	Water well pump	Elevators	Fluid pumps
Grain dryers	Clothes dryers	Inventory systems	Finishing dryers

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When considering the DA curve, it can be seen that it is very much applicable to almost all of the load categories when considering the types of loads in Table 4.1. The DA study was conducted in Australia, which has a 230 V, 50 Hz system (similar to South Africa).

The ITIC and DA curves are compared to the NRS 048-2 dip table in Fig. 4.2. The magnitude of the residual voltage and the voltage dip duration are specified in the NRS 048-2 dip table [8]. The table is divided into seven voltage dip categories, ranging from 20 ms to 3 s and 0 % to 90 % residual voltage. Any number of Y-type dips can be tolerated. From the comparison in Fig. 4.2 it is observed that the household equipment can sustain Z1-type, X1-type and X2-type voltage dips. The household equipment can also sustain a large portion of S-type dips. The T-type and Z2-type dips can only be sustained to a certain degree. When the ITIC curve is compared, it is found that the equipment can almost not cater for any voltage dip below 70 %. This makes the IT-based equipment susceptible to almost all categories of voltage dips in the NRS 048-2 table.

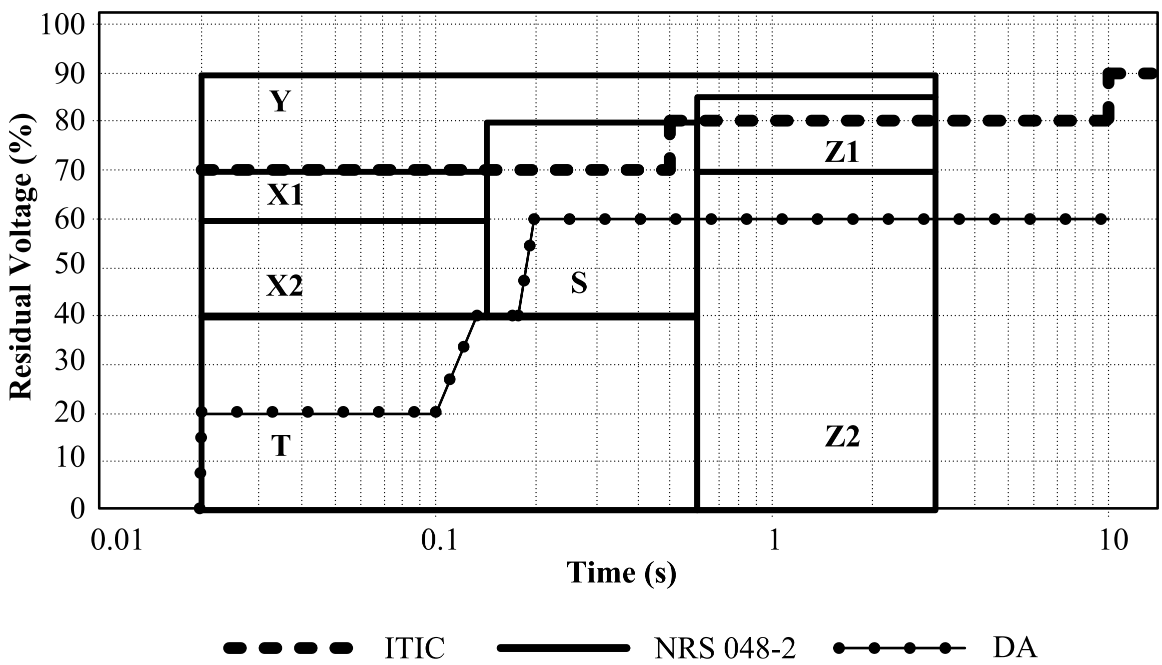

Figure 4.2 The ITIC and DA curves compared to the NRS 048-2 voltage dip table.

In [69] various household equipment has been tested and a resulting susceptibility curve was created. Electronic appliances that were tested included a laser printer, personal

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computer and a microwave oven. Information technology appliances that were tested include an LCD monitor, an all-in-printer, a portable hard drive, a laser printer and a personal computer. Refrigerator type appliances that were tested included a refrigerator and a portable air-conditioner.

From the results in [69] it is found that most household equipment can sustain T-type dips (up to 100 ms), whereas microwave ovens and refrigerators cannot sustain a T-type dip. None of the household equipment tested can sustain X1-or X2-type dips. From 100 ms to 200 ms there is a steep decrease in the voltage dip magnitude which moves the household equipment into the S-type region. Most of the household equipment tested can sustain an S-type dip, except for a microwave oven. All of the household appliances can sustain a Z1-type dip and the results are varied for Z2-type dips.

4.1.2 Voltage-dip evaluation philosophy

A simplified network model is shown in Fig. 4.3. In this network model a fault is placed on feeder 1, some distance away from the MV source busbar. The voltage at the fault position is equal to zero when no fault resistance is included [3]. All customers below the fault position will be exposed to a voltage interruption, as the voltage will be equal to zero. From the fault position back to the source MV busbar, the voltage will increase based on Ohm’s law (fault current and conductor impedance) [3]. The voltage at the busbar will be below rated. All the other feeders (feeders 2 and 3) connected to the same point of common coupling (PCC) will be exposed to the same voltage dip [27], [60], [59], [63]. The PCC for this philosophy is the MV busbar.

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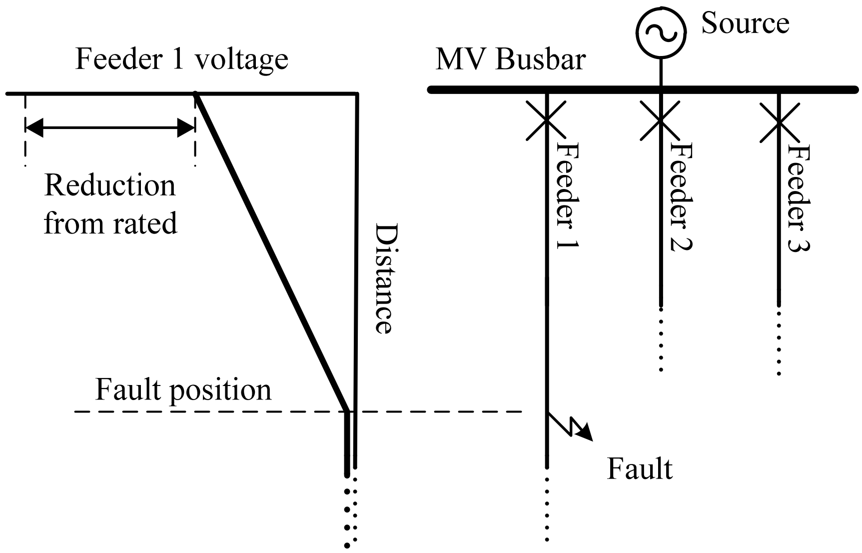

Figure 4.3 Simplified network diagram to illustrate the voltage-dip effect.

The three time ranges of the NRS 048-2 dip table are of interest when evaluating an MV feeder phase OC protection philosophy. The magnitude of the voltage dip cannot be changed by changing relay settings [3]. As an example, a voltage dip classified as a Z1-type dip in Fig. 4.2 cannot be changed to a Z2-type by changing any of the OC protection settings. The voltage dip magnitude is a function of the source impedance, fault location, type of fault and fault resistance. The magnitude of the dip can only be changed by network augmentation which may require significant investment from power distribution companies [3]. It is more cost effective to dip-proof customer equipment than to improve the voltage-dip magnitude of a distribution network [62]. The voltage-dip duration is influenced by the protection operating time [3], [27], [35], [39], [56], [58]-[60], [62], [63], [71]. When considering the equipment curves in Fig. 4.1 and the DA curve of Fig 4.2, it can be observed that the equipment can accommodate a deeper voltage dip when the dip duration is short. By reducing protection operating time, a voltage dip can be moved from the right side of the voltage dip table (e.g. Z2 type) to the left side of the table (e.g. S type).

By minimising the operating time for a fault, hence changing the voltage dip and moving it to the left side on the NRS 048-2 dip table, the phenomenon of sympathetic tripping can be countered. Sympathetic tripping occurs when a non-faulted feeder trips for a fault on

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another feeder due to the voltage drop that is experienced at the PCC [9]. Sympathetic tripping is dependent on the type of loads that are supplied on the feeder [9]. An example of this would be an induction motor that will slow down during the dip period and then speed up again during the voltage restoration period, drawing more current [34]. This speeding-up of the motor can result in an extended voltage dip, termed a post-fault dip [27].

From the voltage-dip criteria it can be concluded that the voltage dip is affected by the protection operating time. It is thus recommended that for a residential distribution network, the protection operates as quickly as possible (while maintaining selectivity), so as to move the voltage dip as far left on the NRS 048-2 dip table as possible. This is the region where domestic appliances are least susceptible. Even though the Z1 region does not pose a problem to domestic appliances, having a fault on the network for up to 3 s might violate the energy capabilities of the network equipment during a fault [30]. This is again detrimental to the continuity of supply and increases the risk at the point of fault. In general, long fault-clearing times are detrimental to power quality [9]. The NRS 048-2 voltage dip table also gives some guidance on how long a fault can be tolerated on the network from a quality of supply perspective.

4.2 FORWARD

In this chapter various equipment voltage dip susceptibility curves were compared to each other and to the NRS 048-2 dip table. It was found that, by changing the protection operating time, the voltage dip can be moved to the left of the voltage dip table. This is then not only beneficial to manage the quality of supply, but also in reducing the let-through energy. The protection settings will be explored in chapter 5. The influencing factors on the protection operating time will be shown, and an evaluation method for the OC PU sensitivity will then be defined.

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CHAPTER 5 PROTECTION SETTINGS AND PHILOSOPHY

5.1 CHAPTER OVERVIEW

In chapters 3 and 4 it was shown that there is a benefit in reducing the protection operating time. This reduction in operating time will reduce the let-through energy and minimise the voltage dip effect on the network at the PCC. In this chapter the factors that influence protection operating time from a settings perspective will be discussed, with the goal of setting an evaluation method for the protection operating time. As part of the settings section, the OC element PU sensitivity will also be discussed and an evaluation method set. The key focus areas in this section are grading, fault types, curve selection, PU sensitivity, source transformer protection and the breaker failure philosophy.

5.2 GRADING

To achieve selectivity between protection relays in the MV network, grading of protective devices has to be introduced [5], [32], [36], [46], [72]. Devices should be graded using current-and time discrimination [2], [72]. If the coordination is not optimal, it can result in poor-performing networks [18]. The fault current that should be used is the current where the downstream device measures its maximum fault current in a radial network [9], [10]. By using the maximum current, it will ensure that the selectivity of the protection devices for smaller currents in the network is maintained [10]. To obtain the maximum fault current at a certain position in the network, a bolted (no fault resistance) 3Ph fault calculation should be used [10]. When considering a radial feeder that is resistively earthed at the source, the impedance used for the 3Ph fault calculation will be the smallest. This will result in the maximum fault current in the network. The grading margin and fault position in the network is illustrated in Fig. 5.1.

If the grading margin is too small, the selectivity of devices will be sacrificed [27], [35]. If selectivity is sacrificed, a larger portion of the network than was required will be isolated [2]. The minimum grading margin that can be applied between protection relays depends

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on the relay technology type (relay errors such as timing and overshoot), CT errors and breaker clearing time [2], [31], [72]. Breaker-clearing times of 5 cycles (100 ms at 50 Hz) are reported for breakers between 1 kV and 35 kV [31], [72]. In [30] an allowance of 80 ms is made for the breaker opening time.

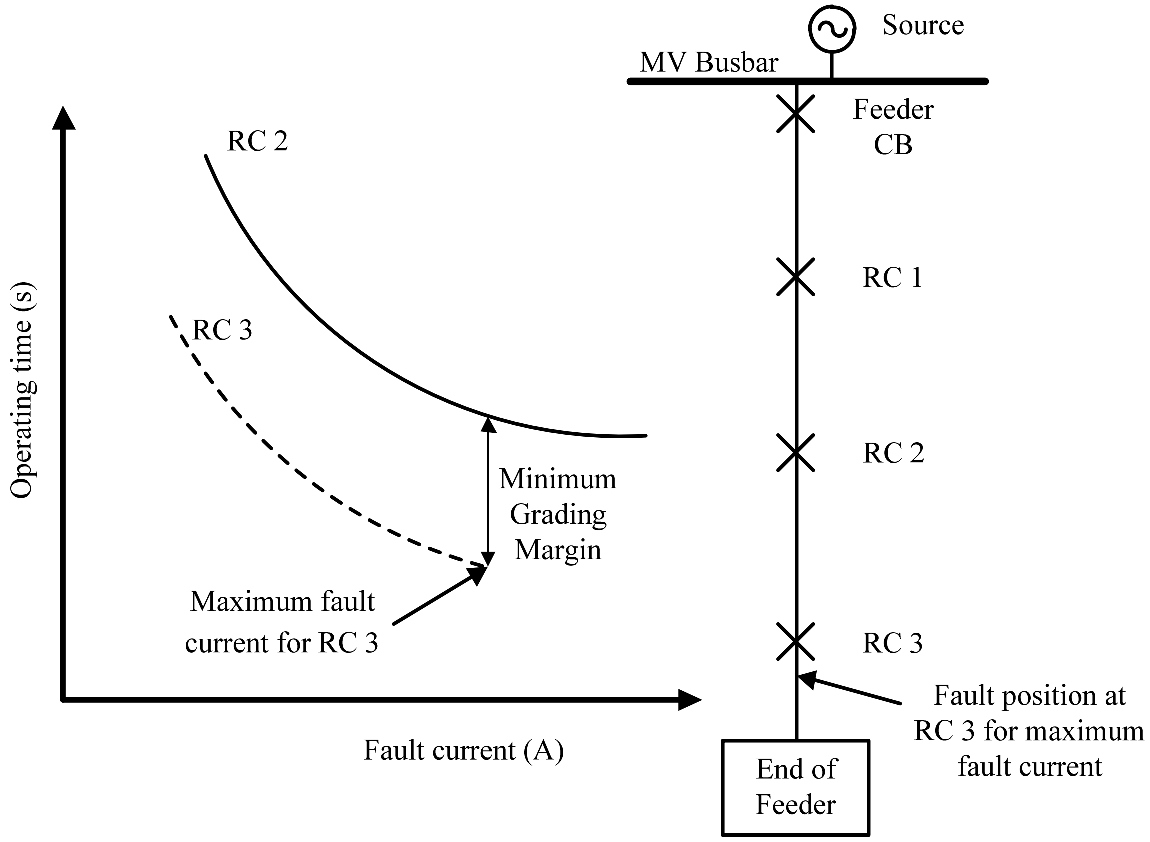

Figure 5.1 The fault position and minimum grading margin when grading RC 2 and RC 3

A minimum grading margin of 0.3 s is recommended [2], [31], [72]. A margin of 0.3 s to 0.4 s for electromechanical relays and 0.1 s to 0.2 s for microprocessor-based relays are recommended in [28]. From field experience, we have set a grading margin of 0.2 s when numerical relays are used and 0.4 s when electromechanical and electronic relays are used in Eskom MV distribution networks. This grading margin does differ between the regions in Eskom.

The greater the number of protection devices in series, the slower the device will operate at the source when selectivity is to be maintained. A bottom-up grading approach is described in [2], [10]. In this approach the operating time for the last protective device (furthest from

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the source) is set. The upstream device is then set to operate slower than the downstream device (by the grading margin) for the fault current at the downstream device position. This method results in faster fault-clearing time in the network when comparing it to a top-down approach. The bottom-up approach is recommended so as to reduce the let-through energy (I^2t) and to move the voltage dip as far left on the NRS 048-2 voltage dip table shown in Fig. 4.2. This will also minimise the voltage dip that all the other feeders connected to the PCC will experience. For an MV network, this is normally the MV busbar at the source substation.

5.3 FAULT TYPES AND CURVE SELECTION

There are two types of faults in the MV network, namely transient and permanent faults [9]. Transient faults can be caused by lightning, wind, trees or animals [9]. An example of a permanent fault is a broken conductor [2]. Permanent faults require humans to repair the network [16]. In [2] a semi-permanent fault is mentioned in addition to the transient and permanent fault types. An example of a semi-permanent fault is a tree branch touching the overhead conductor. The philosophy in clearing this fault is to allow the fault current to pass for a longer period and hence try and burn away the branch [2], but when we consider the risk of veld fires (or a plantation fire) due to incandescent particles [12] the philosophy might be to rather avoid this fault-clearing approach.

The percentages differ amongst authors, but all of the percentages stated indicate that transient faults account for the majority of faults in the MV network [2], [9], [10], [15], [23], [35], [40], [41], [73], [74]. Since transient faults are not permanent, one operation of the CB can clear the fault from the network [15]. In a fuse-saving philosophy, the number of momentary interruptions will increase, while the number of permanent interruptions will decrease [9]. The opposite is true for a fuse-blow philosophy. An RC fast curve is recommended to clear transient faults on the feeder (part of fuse-saving philosophy) [9]. This RC fast curve is not always available, hence an EI curve is used to clear the fault. This curve is best suited for distribution networks [9], [10]. The Hare conductor damage curve, EI curve and a normal inverse (NI) curve are shown in Fig. 5.2. The equations for the IEC NI curve and the IEC EI curve are shown in equations 5.1 and 5.2 respectively [2].

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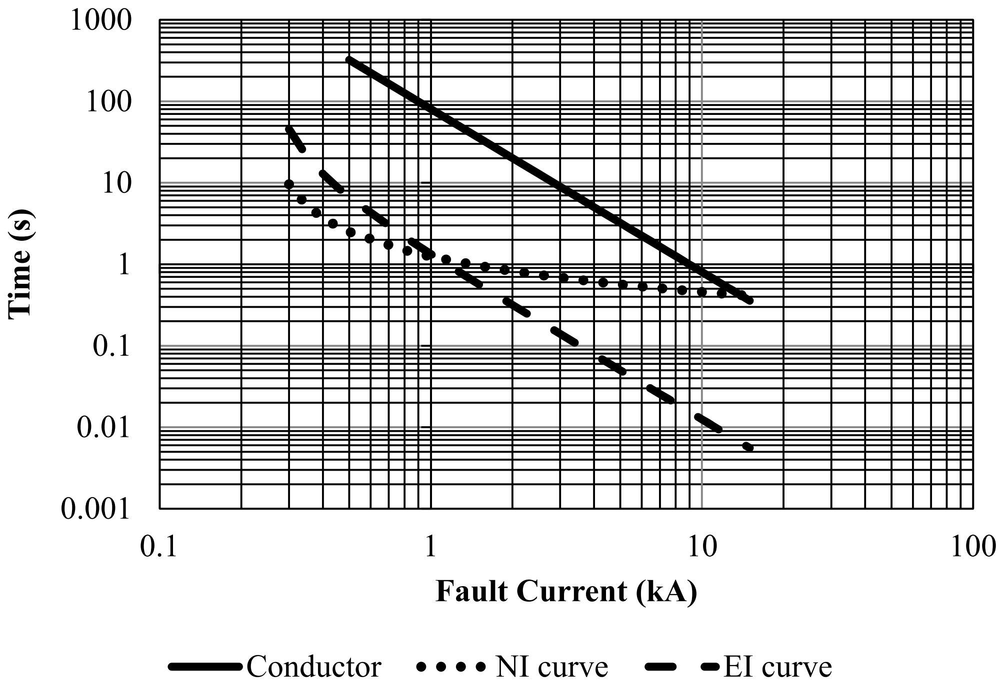

Figure 5.2 Grading curves for a NI curve, EI curve and Hare conductor damage.

When evaluating the conductor damage curve, the EI and NI curves in Fig. 5.2, it can be seen that the EI curve grades well with the conductor damage curve, whereas the NI curve does not grade that well towards the higher fault current region. This confirms the EI curve benefit, as was mentioned in section 2.41 [2]. The EI curve will promote fast clearing of high-fault currents. This contributes to the philosophy of minimising the let-through energy and moving the voltage dips to the left side of the table. The drawback of the EI curve is that once the curve is set to grade, it will take a longer time to operate than the NI curve at lower fault levels. This is detrimental to the let-through energy concept. It does, however, promote selectivity in that it allows more time for the fuse to clear the fault if the fault is beyond the fuse and it is a permanent fault [2].

$$t_{opp} = \frac{0.14 \cdot TM}{\left(\frac{I_f}{I_{pu}}\right)^{0.02} - 1} \qquad [5.1]$$

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$$t_{opp} = \frac{80 \cdot TM}{\left(\frac{I_f}{I_{pu}}\right)^2 - 1} \qquad [5.2]$$

where

t_{opp} = *Operating time, s*

TM = *Time multiplier, unit less*

I_f = *Fault current, A*

I_{pu} = *Relay element pick-up current, A*

There is consensus in the literature that the ARC function improves the continuity of supply for overhead feeders. An ARC success rate of 89 % is reported for the first shot, 5 % for the second and 1 % for the third in [35]. Based on this success rate it is recommended not to use more than one ARC attempt (2 shots to lock-out), as the success rate decreases drastically after the first attempt. This is similar to the OC ARC philosophy in [17], [40], [74]. The first shot can be a fuse-saving shot, used to clear temporary faults [19]. The second can be a delayed trip for a fuse-blow shot if the fault is downstream from the fuse. The fuse-blow shot is used to isolate the permanent fault on the network. The fuse-save and fuse-blow philosophies are well documented in [9], [10], [15], [16], [75], [76].

An NI curve is used for the second attempt. The NI curve shown in Fig.5.2 does not follow the damage curve or the fuse curve over a wide current range. This time-delayed operation is required to try and clear faults by allowing more current to flow to the fault for a longer period. The drawback of this is that the damage criteria can be exceeded due to the grading requirement (long time delay) in the network in areas of high fault current. This is a trade-off between dependability and security [42]. This is similar to the semi-permanent fault-clearing technique, as discussed at the start of this section. The area where the feeder is operational will have to be considered so as not to create unnecessary risks. By reducing the number of ARC attempts, the cumulative damage on upstream source transformers is also an advantage (reduce the damage on the transformers) [7], [43].

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If the assumption is made that the equipment does not cool down during the dead-time period of the ARC cycle, the let-through energy of each ARC cycle can be added together to obtain the total energy that the equipment will be exposed to [50]. This total energy should be below the respective equipment damage curves. ARC dead time should allow for an arc to deionise before the breaker is closed [2], [9]. A de-ionising time of less than 11.5 cycles is recorded in [9], and [2] a range of 0.1 s to 0.2 s is recommended for distribution feeders. Long ARC dead times on distribution feeders only irritate customers. It does not pose serious problems when considering the equipment used (type of load) on distribution feeders [2].

Instantaneous tripping curves are applied whenever possible. It is normally active for faults close to the CB [77]. A safety margin of 25 % is applied to an end-of-zone fault level to determine the PU in [10]. This safety margin is there so as to ensure that the instantaneous curve does not overreach the next protective device (compromise selectivity). The reduced tripping time is illustrated in Fig 5.3 [2], [10].

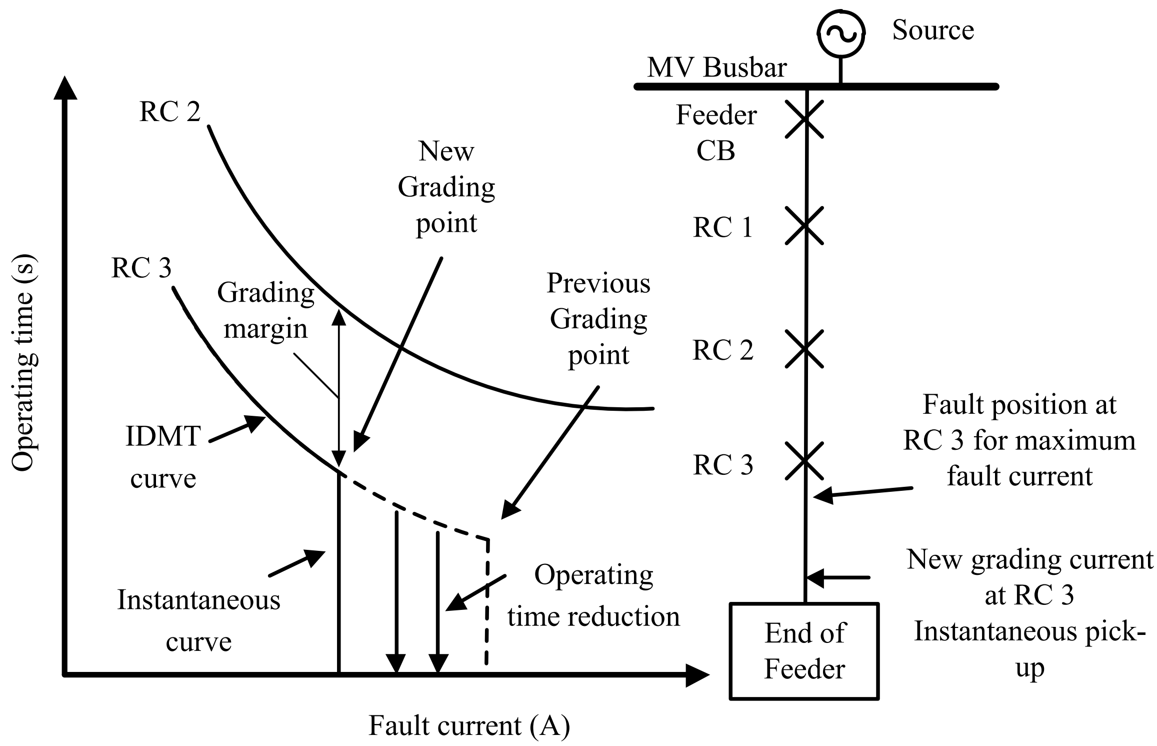

Figure 5.3 Illustration of instantaneous curve grading current.

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The instantaneous curve assists in reducing the let-through energy by reducing the operating time. It speeds up protection operation for upstream devices, since they can now grade with the downstream device's instantaneous curve PU value [2], [10]. This is in contrast to grading at the downstream device fault level. This fast operation will also move the voltage dip to the left on the NRS 048-2 dip table. The reduction in operating time will aid in reducing damage at the point of fault [2]. The instantaneous operating curve still has some time delay due to the breaker operating time. Hence if the fault current is exceptionally high, the instantaneous curve may not operate fast enough to limit damaging equipment. In this case, the fault level will have to be reduced.

5.4 SENSITIVITY

The OC PU sets the threshold that will initiate the tripping sequence. This then defines the sensitivity of the OC element to a fault (or abnormal condition) in the network. The factors to consider when determining the PU are equipment current ratings, cold-load PU and the maximum expected load current [9]. To ensure selectivity, the upstream device PU should be larger than the downstream device PU [10]. This allows for the PU drop-off ratio of the OC element. Other factors are the fault type, fault resistance and the back-up of protective devices.

5.4.1 Transformer inrush

It is possible for the transformer inrush current to influence the OC PU. The inrush can be estimated as 10 times the transformer-installed capacity (rated current) for 100 ms [9]. Due to the short time this phenomenon is present on the feeder, it normally does not influence the IDMT element [9], [27]. The fast and instantaneous OC elements are influenced by this [9]. Where there are a multitude of different small power transformers, such as on a distribution feeder, the inrush current tends to cancel each other, rather than to summate [9]. Inrush has a bigger effect on larger power transformers and the associated OC protection elements. Numerical relays do provide a filter function to remove or block operation for the harmonic number associated with transformer inrush. This is valid for the IDMT element, but many manufacturers bypass the filter stage to decrease the relay operating time (faster trip time) for the instantaneous element.

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5.4.2 Protective device back-up

To provide back-up to protective devices in series on a radial MV distribution feeder, two successive devices have to be able to sense the same fault [5], [9], [10], [19], [72]. This is illustrated in Fig. 5.4, where the protective reach for each of the four devices are indicated with an arrow.

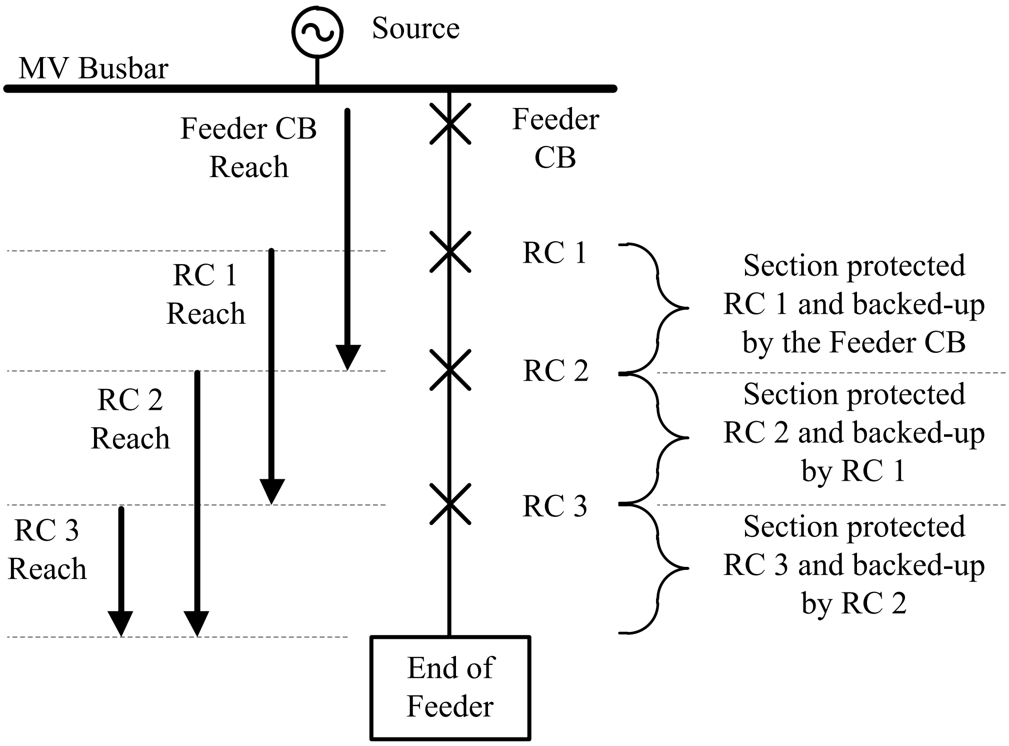

Figure 5.4 Device back-up reach on a radial MV distribution feeder.

This over-reaching of the immediate downstream device can have an influence on the PU when considering the fault level at the immediate downstream device end-of-reach. An example of this would be that RC 1 should be sensitive to a fault up to RC 3 (end of zone for RC 2) in the network of Fig. 5.4.

5.4.3 Fault type and arc resistance for setting the sensitivity

Equation 5.3 [21] can be used to adjust the minimum 2Ph conductor distance (C) that is specified in [21], based on the span distance (L) for a horizontal feeder configuration (distance between successive structures). For vertical and triangular configurations, the 2Ph distance will normally be less than that calculated by Equation 5.3 [21].

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$$Distance = 5 \cdot L + C \qquad [5.3]$$

where

L = Span length, km

C = Recommended 2Ph distance between conductors, m

When setting the sensitivity of the OC device, the smallest fault current that the breaker needs to be sensitive to has to be used. In [10] the smallest fault current that should be used is a 2Ph fault at the intended reach, with a certain safety margin to account for the CT and relay errors (chapter 2). Equation 5.4 shows how a 2Ph fault level can be calculated using sequence components [78]. When setting the 3Ph fault equation equal to the 2Ph fault equation, it can be shown that a 2Ph fault calculates to 86.6 % of the 3Ph fault magnitude.

$$\overline{I_1} = \frac{\overline{V_f}}{\overline{Z_{pos}} + \overline{Z_{neg}}} \qquad [5.4]$$

where

I_1	=	*positive sequence current, per unit*
V_f	=	*Thevinin equivalent prefault voltage, per unit*
Z_{pos}	=	*Sum of the positive sequence source, line and fault impedance, per unit*
Z_{neg}	=	*Sum of the negative sequence source, line and fault impedance, per unit*

When setting the sensitivity, a certain amount of fault impedance should be included [10]. The value to be used can range from 0 Ω to 40 Ω [9]. To calculate the arc resistance, Warrington's equation (equation 5.5) can be used [2], [79]-[81].

$$R = \frac{28710 \cdot L}{I^{1.4}} \qquad [5.5]$$

where

R	=	*Arc resistance, ohm*
L	=	*Arc length, m*
I	=	*Arc current, A*

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There are also other arc resistance models that were developed by Mason, Goda, Terzija, Blackburn and Domin [81]. When analysing Warrington's equation, it can be seen that it is dependent on the arc length and the fault arc current. The arc will increase in length (start to curve upward), depending on the weather conditions [10]. The arc-length increase due to wind can be calculated using equation 5.6.

$$L = 3 \cdot \upsilon \cdot t + L_0 \qquad [5.6]$$

L = *Length of arc, feet*

υ = *Wind velocity, miles per hour*

t = *time since the arc was fist struck, s*

L_0 = *Initial arc length, feet*

This increase in arc length was not considered, as the recommendation is that the initial arc-resistance length should be used when calculating the PU sensitivity [10]. The general system fault levels for the Eskom grid in 2002 are listed in Table 5.1 [82]. Since the fault levels in Table 5.1 is different on each of the voltage levels, different general source impedance will exist for each voltage level. The arc length will also be dependent on the structure and voltage level, as the phase-to-phase clearance tends to increase with an increase in voltage level.

Table 5.1 The fault levels at MV busbars in the Eskom grid (2002).

Voltage level [kV_{L-L}]	**Current 20th percentile [A]**	**Current 50th percentile [A]**	**Current 80th percentile [A]**
11	2152	4619	8765
22	1286	2204	4356
33	3919	7436	12194

It was indicated in the literature study that arc resistance should be included when calculating the 2Ph fault level in minimum network conditions [10]. This is used to set the sensitivity of the OC element. Fig. 5.5 is generated by using Warrington's equation (equation 5.5), the recommended phase clearances in [21], the phase-to-phase distance

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adjustment equation (equation 5.3) and the fault-level study of the Eskom grid in Table 5.1. The distance between poles varied from 60 m up to 140 m. A good assumption in the Eskom grid is for a pole distance of 100 m. From Fig. 5.5 it is observed that the distance between the poles at high fault levels, and hence the direct arc length, does not change the fault resistance significantly. At lower fault currents, the distance between poles almost doubles the arc resistance.

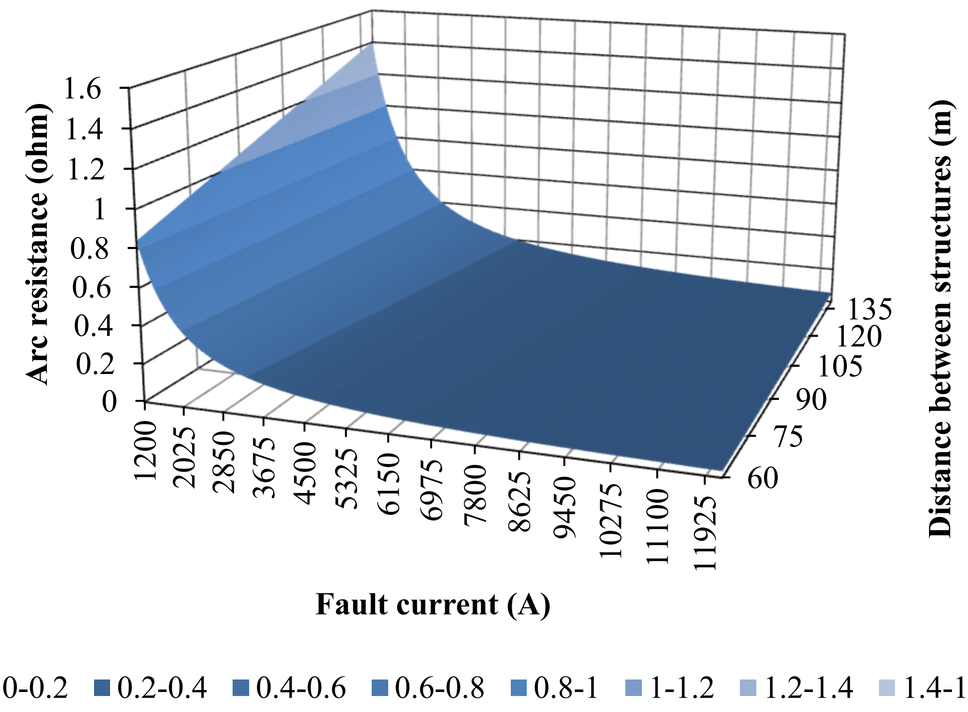

Figure 5.5 The arc resistance for an 11 kV feeder.

Fig. 5.5 is for a system operated at 11 kV. The largest arc resistance is obtained at the lowest fault level (1200 A) with the biggest phase displacement (at 160 m). This state is applied to calculate the worst-case arc resistance for a 2Ph fault at 22 kV and 33 kV. The minimum phase-to-phase distance from [21] is 0.3 m for 11 kV, 0.4 m for 22 kV and 0.5 m for 33 kV. The results for these calculations are shown in Table 5.2. The minimum fault current for the three voltage levels from Table 5.1 of a 1200 A (actual is 1286 A) is used.

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Table 5.2 Arc resistance calculated at 1200 A for 11 kV, 22 kV and 33 kV

Pole to Pole distance [m]	**11 kV Arc resistance [Ω]**	**22 kV Arc resistance [Ω]**	**33 kV Arc resistance [Ω]**
60	0.84	0.98	1.12
140	1.40	1.54	1.68

In Table 5.2 the maximum arc resistance is shown as 1.68 Ω. To allow for a safety margin, a value of 3 Ω is used for all MV voltage levels when calculating the 2Ph fault level for sensitivity purposes. A fault resistance value of 2 Ω or less was determined by [27]. This is in line with the 1.68 Ω, and the 3 Ω added a reasonable safety margin to this. The actual safety margin will thus be at its biggest for 11 kV (214 %) and its smallest at 33 kV (178 %). The reason for choosing a large safety margin is that the source impedance on the MV busbar is generally quite large when comparing this to HV networks. The conductor used on the feeder adds additional impedance to this.

5.5 SOURCE TRANSFORMER OVER CURRENT PROTECTION

There can be multiple source transformers in parallel at the source of the MV feeder. The fault current for the transformers is divided based on the percentage impedance and size (MVA rating) of each transformer. To determine the current distribution between transformers equation 5.7 is developed (based on the current division law), which is illustrated in Fig. 5.6. This equation is based on four transformers that are operated in parallel. An assumption is made that every transformer has the same vector group and voltage ratio, and the copper losses can be ignored. The current distribution for transformer 1 is shown in equation 5.7. This equation can be applied to determine the percentage current distribution for the other parallel transformers as well.

$$I_{T1} = \left(\frac{I_{total}}{X_{T1}}\right) \cdot \left(\frac{1}{X_{T1}} + \frac{1}{X_{T2}} + \frac{1}{X_{T3}} + \frac{1}{X_{T4}}\right)^{-1} \quad [5.7]$$

where

I_T = *respective transformer current, A*

I_{total} = *total current on MV busbar, A*

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X_T = *respective transformer reactance, ohm*

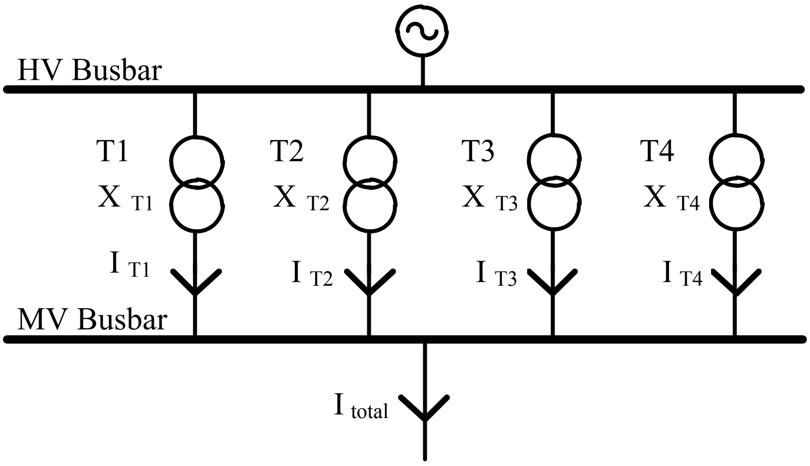

Figure 5.6 Source transformer fault-current distribution.

Because this application makes use of the per unit system and sequence components, equation 5.8 is developed from equation 5.7 when all transformer impedance values are converted to the same per-unit base values. The percentage current distribution for transformer 1 is shown in equation 5.8.

$$I_{T\,ratio} = 100 \cdot \left(\frac{S_{T1}}{X_{T1}}\right) \cdot \left(\frac{S_{T1}}{X_{T1}} + \frac{S_{T2}}{X_{T2}} + \frac{S_{T3}}{X_{T3}} + \frac{S_{T4}}{X_{T4}}\right)^{-1} \qquad [5.8]$$

where

$I_{T\,ratio}$ = *respective percentage transformer current, %*

X_T = *respective transformer reactance on transformer own base, per unit*

S_T = *respective transformer MVA size, MVA*

Only one phase OC element is currently used on HV to MV transformers in Eskom. This OC element (and current transformer) is situated on the HV side of the transformer. The phase OC element will trip the transformer MV breaker and if there is a breaker failure, the transformer HV breaker will be tripped via the sustained fault timer. The transformer instantaneous phase OC element will trip both the HV and MV breakers. This transformer protection scheme is illustrated in Fig. 5.7. When the transformer operating time is to be calculated for a 2Ph fault on the secondary side of the transformer, the fault current has to be converted to the HV side of each source transformer.

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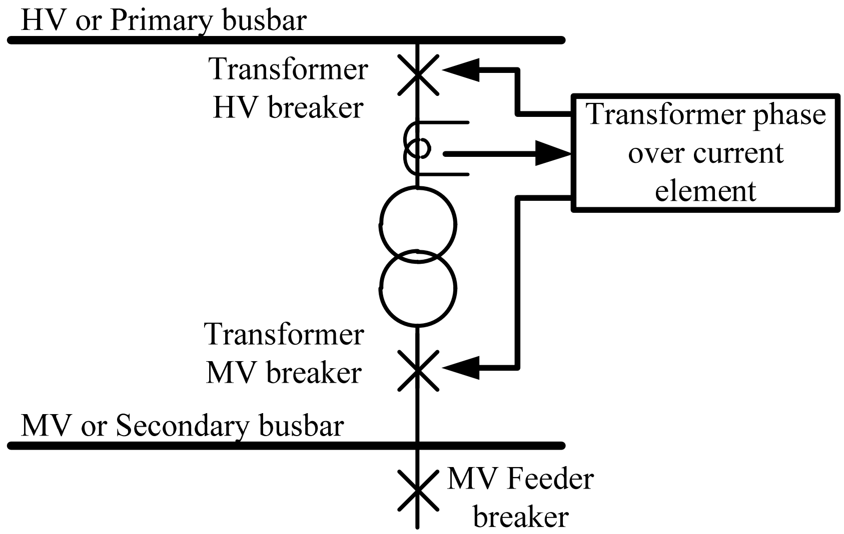

Figure 5.7 Source transformer phase OC protection scheme operating principle.

The phase OC protection on the transformer is non-directional. The angle information of the fault current is therefore not required. The magnitude of the 2Ph fault current is changed by the number of transformers in parallel, the transformer turns ratio and the transformer vector group. The vector group influence can also change the faulted phases when comparing the primary (HV) and secondary (MV) side of the transformer phase currents. There will be no change in the faulted phases for a star-star vector group. To refer the fault current to the primary side of the star-star transformer, equation 5.9 can be used [14].

$$I_{pri_{(max)}} = I_{sec} \cdot \left(\frac{V_{sec}}{V_{pri}}\right) \qquad [5.9]$$

where

$I_{pri\ (max)}$	=	*maximum line current on primary side of transformer, A*
I_{sec}	=	*maximum line current on secondary side of transformer, A*
V_{sec}	=	*transformer secondary side rated voltage, V*
V_{pri}	=	*transformer primary side rated voltage, V*

If a star-delta or delta-star transformer is used, it will result in a 2-1-1 current distribution between the phases on the primary side of the transformer for a 2Ph fault on the secondary

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side. This 2-1-1 current distribution is illustrated in Fig. 5.8, with a 100 A 2Ph fault on the secondary side.

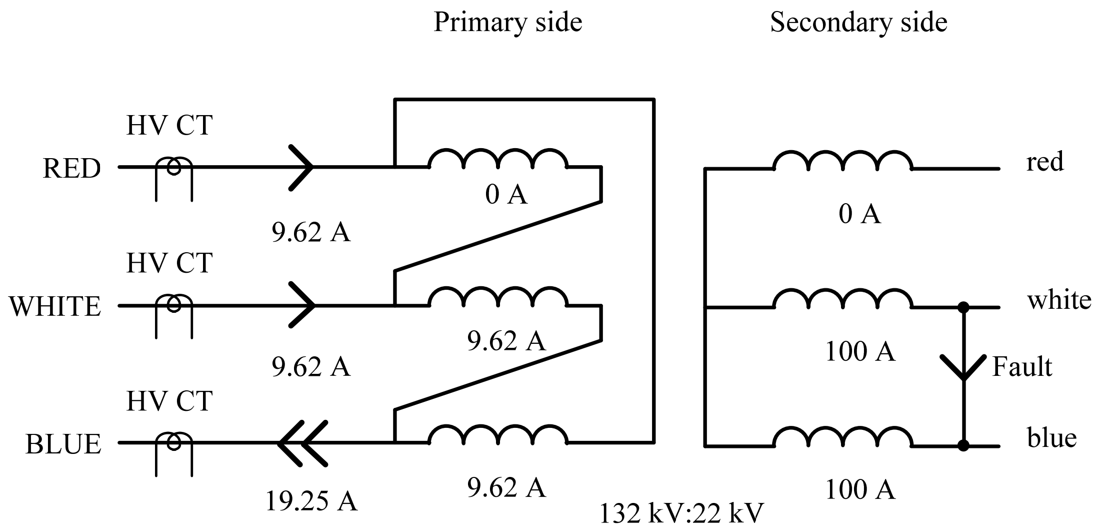

Figure 5.8 A 2-1-1 current distribution for a 2Ph fault on a delta-star transformer.

The magnitude of the current that the current transformers will measure on the primary side of the transformer is calculated using equation 5.10. From this equation it is observed that the fault current is changed by a factor and the turns ratio.

$$Ipri_{(max)} = Isec \cdot \left(\frac{2}{\sqrt{3}}\right) \cdot \left(\frac{Vsec}{Vpri}\right) \qquad [5.10]$$

where

$Ipri_{(max)}$	=	*maximum line current on the primary side of transformer, A*
$Isec$	=	*line current on the secondary side of transformer, A*
$Vsec$	=	*transformer secondary side rated voltage, V*
$Vpri$	=	*transformer primary side rated voltage, V*

5.6 BREAKER FAILURE

Breaker failure is traditionally not applied to distribution feeders [9]. This is also currently the case in Eskom. If this is to be applied, bus-over current relays or transformer relays (source to MV feeder) can be used. This breaker failure function can be initiated by the fault current, the feeder breaker contact status, or both [9]. When considering the back-up function of the upstream protection device to the downstream device when setting the

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sensitivity of the device, breaker failure for a RC installed on the feeder is used. This is shown in section 5.4.2.

5.7 FORWARD

The four protection influencing factors were identified in chapter 2. In chapter 3 and 4 the let-through energy and voltage dip effect were discussed. The protection settings and philosophy were explored in chapter 5. The influencing factors on the protection operating time were identified (from a protection settings perspective) as the grading margin, the grading method, the operating curve and the fault current. The influencing factors for the OC element protection sensitivity are the transformer inrush, the back-up of series RC, arc resistance and the fault type. The source transformer protection philosophy was also discussed. The information from the preceding chapters is applied in the creation of an application for evaluating phase OC protection philosophies in chapter 6.

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CHAPTER 6 APPLICATION FOR EVALUATING THE OC PHILOSOPHY

6.1 CHAPTER OVERVIEW

The time protection takes to clear a fault influences the let-through energy, the voltage dip classification and the amount of damage at the fault location. The operating time is influenced by a multitude of elements such as the relay operating curve, the grading margin, the number of protection devices in series, fault levels, type of relay technology and the PU current. The ARC philosophy has an impact on the amount of let-through energy if one considers all the ARC attempts. In this chapter the application that was developed to evaluate the philosophy is discussed. The application assumptions, operating principle, inputs and outputs are discussed. Finally the approach to evaluate a protection philosophy is presented.

6.2 CONCEPT

Historically the setting of phase-over-current protection has focussed on ensuring that subsequent protection devices grade with each other in both time and current. This was then graphically illustrated on a time-current graph. An example is shown in Fig. 1.1.

These curves (Fig. 1.1) allowed the protection engineer to visually assess the grading under a wide fault-level range (high fault-current network conditions). This traditional grading exercise ensured that the protective devices would trip selectively and that adequate fault sensitivity was provided. It did not consider whether the protection was adequate to safeguard the primary plant equipment, the environment and life. It also did not consider the effect of protection settings on the quality of supply-voltage dips in particular.

The approach that was taken to answer the research question and test the hypothesis in chapter 1 was to develop an application that can calculate the effect of different OC protection settings philosophies and settings changes on a MV network. The key focus

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areas in this application are then the various OC philosophy-influencing factors that were identified.

The various influencing concepts are to be graphed so that easy evaluation of the results can be achieved over a wide fault-current region. The application was completed in Microsoft Excel. The reason for choosing Excel was that it is a software application that is widely used within Eskom. It is relatively uncomplicated to produce graphs and to add functionality to the developed application. If this was to be done in a power system simulation package, first one has to evaluate what the package can give, without knowing if it can provide the desired results.

The author [83] made use of DIgSILENT Powerfactory to model a network and its protective devices and to adjust the operating times so as to obtain grading. The author also noted the equipment damage curves (time-current curve) and the voltage drop at busbars that the software can generate. No mention of the PU sensitivity is made, however. The illustration methods are also based on the traditional time-current concept of Fig 1.1.

6.2.1 Overview of the application

An overview of the application in terms of the three main functions is shown in Fig 6.1. These are the user input, the calculation process and the output. The main function blocks in each of these are shown. The main inputs that are to be completed by the user in the input function block are the network layout, the protective device positions and then the protection settings that are applied to the protective devices. The principle calculation in the calculation function is the 3Ph and 2Ph fault levels. The various operating times, let-through energies, PU sensitivities and voltage-dip effects are calculated from this. Once the calculation is done, the results are presented in graphs under minimum (low fault levels) and maximum (high fault levels) network conditions. For these, graphs distance instead of fault current is used for the independent variable on the x-axis.

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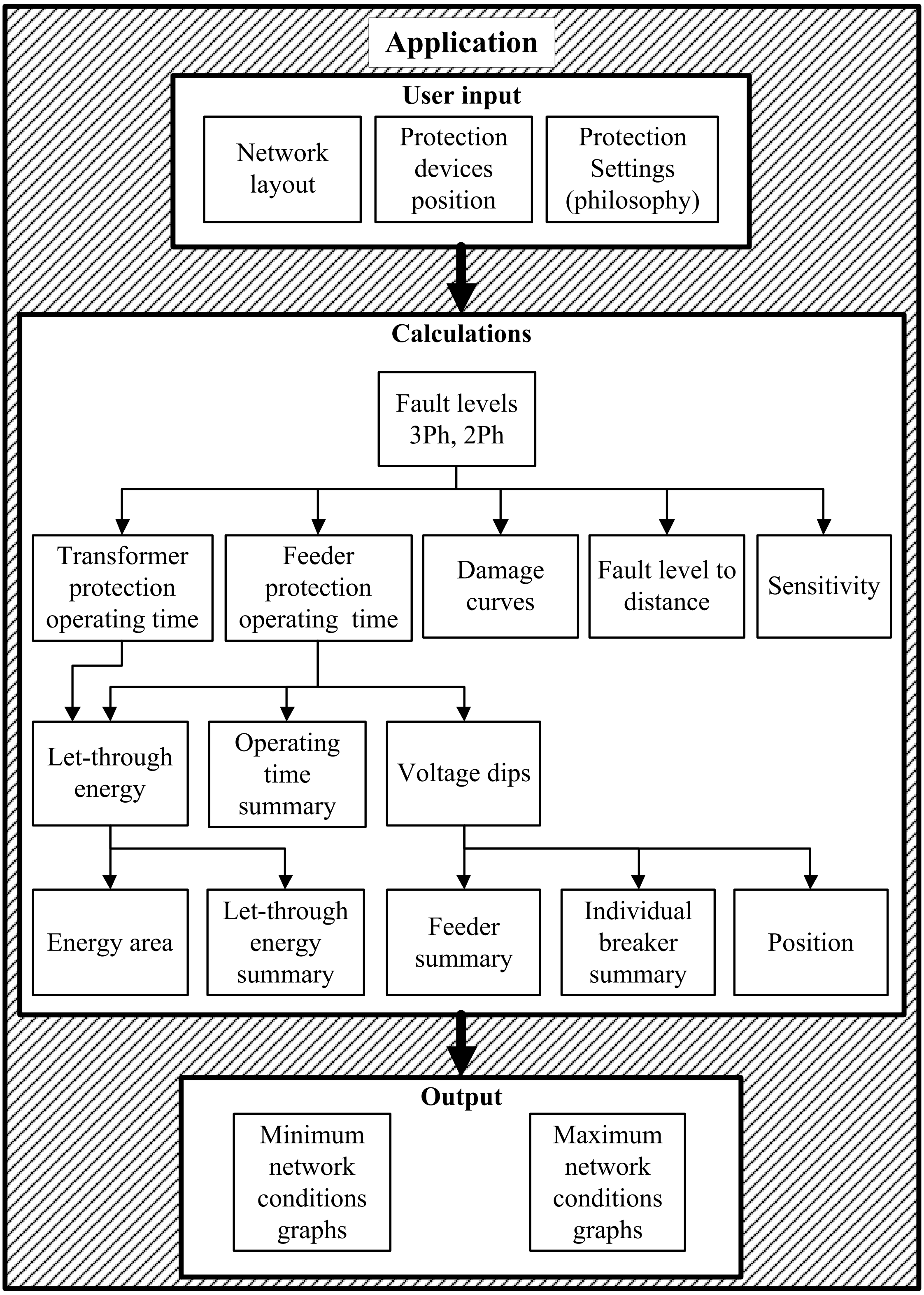

Figure 6.1 Overview of the operating principle of the application.

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6.2.2 Assumptions

In this application, the Excel application approximates the MV feeder as a single radial line section, ignoring the presence of spurs. The spurs that are being ignored are automatically covered due to the protection reach (sensitivity) of the upstream protection device PU. Essentially an area (half-circle shape for feeder with one source) with a radius equal to the sensitivity (current PU) is defined. If this feeder had more than one source at different positions, the area can be a full circle. This is the same network reduction that will be applied to an actual network so as to generate a reduced protection network diagram. The generation of this protection diagram is illustrated in Fig. 6.2 and the sensitivity areas on the reduced network diagram are illustrated in Fig. 6.3.

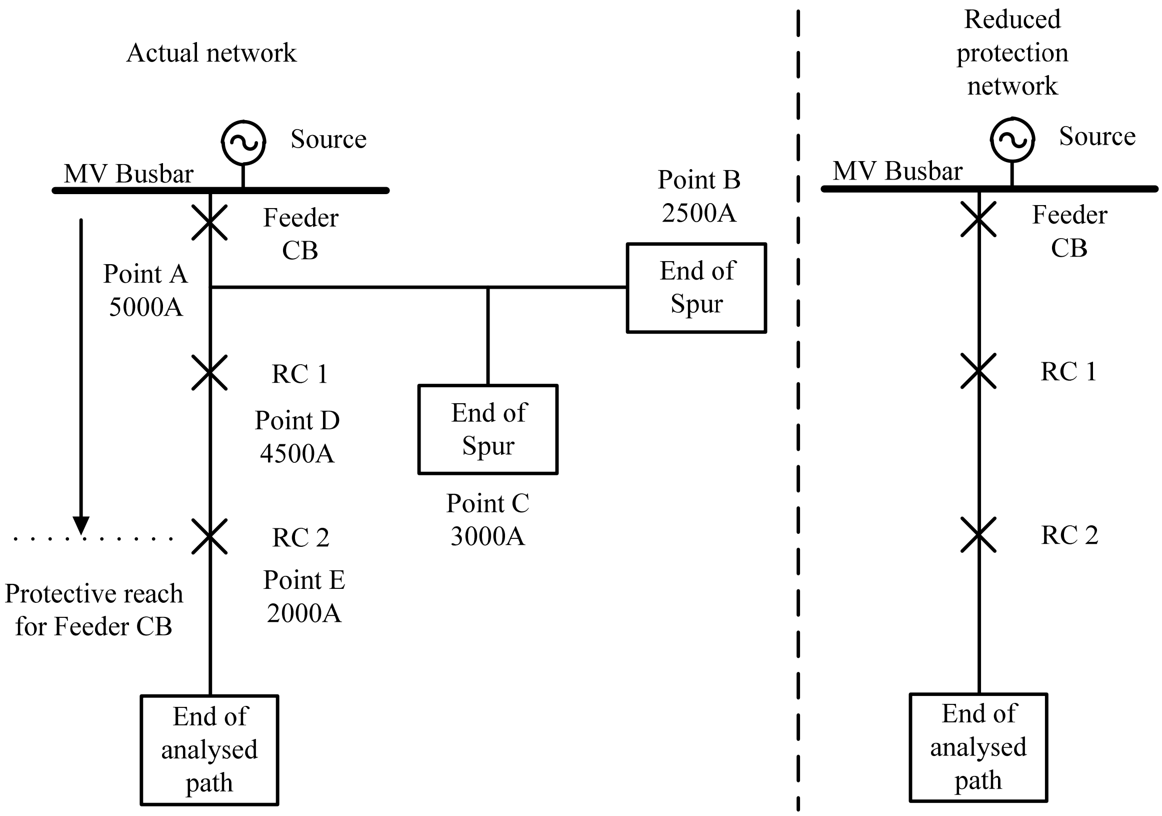

Figure 6.2 Actual network and reduced-protection network illustration.

When setting the reach for the feeder CB, the immediate downstream protection device (RC 1) will be bypassed. Next, the feeder CB has to be sensitive enough to PU for the lowest fault level in this network configuration (backup to RC 2). In the network of Fig. 6.2 it will therefore be sensitive for a fault at point E. Inherently the spurs at point B and

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point C will be covered, and hence the network will reduce to the network shown on the right side of Fig. 6.2. The MV feeder backup principle is also illustrated in Fig 5.4.

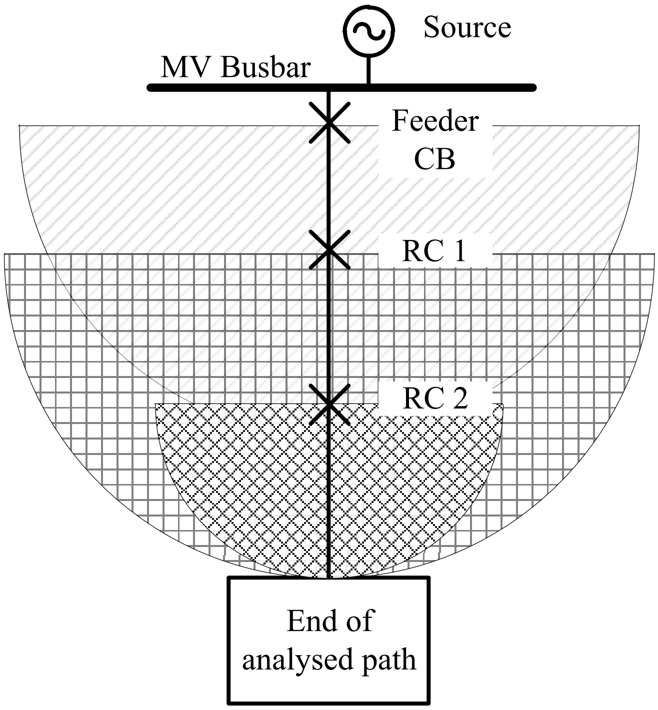

Figure 6.3 Sensitivity areas for each protective device on the reduced network diagram.

The next assumption is that the faults are distributed uniformly across the feeder [58]. This assumption is valid since a fault can occur at any position on the feeder. The protection still has to detect and clear that fault. Future work can include probabilities of faults on network sections due to equipment failure rates, the amount of equipment installed and the exposure area of the feeder. This can create high-and low fault probability areas on a feeder.

The let-through energy can be added together if the assumption is made that the power system equipment that was exposed to the fault current does not lose energy to the surrounding environment during the dead time of the breaker. In the field there would be a loss of energy to the environment as a result of heat loss due to convection. By assuming that there is no loss, it results in the worst case scenario end, hence a certain safety factor.

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6.2.3 Calculation concept

The tool is designed to analyse a radial path on a radial feeder. The results from each analysed path can then be compared to each other. The application allows for a maximum of up to three different conductor types in series on the same analysed path. These conductors have user-definable lengths. The tool makes provision for up to four RC, fuses or a combination of RC's and fuses in series with a feeder CB. This then totals a maximum of five protective devices in series. The position of the four protective devices that are installed on the feeder is defined by the user. The five protective devices and three different conductor types then create seven sections on the radial analysed path. This is illustrated in Fig. 6.4. The equipment can be arbitrarily placed. The figure only illustrates one possible feeder protection configuration. Each of the seven sections is then broken down into 50 analysis points.

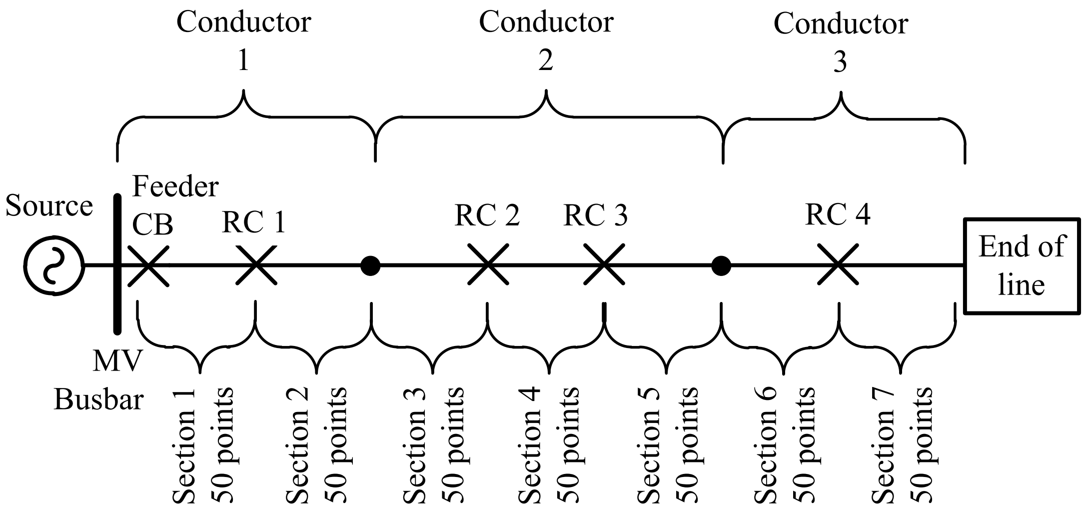

Figure 6.4 Calculation concept and section illustration.

At every analysis point (50 analysis points per section) in each section (350 points in total) the program calculates the following:

- the feeder impedance up to that point,
- the total impedance (source and feeder) up to that point,
- the 3Ph fault level,
- the 2Ph fault level,
- the busbar voltage for a fault at each analysis point,

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- the voltage at each analysis point for a fault at every start and end of a section,
- the equipment short-time rating (at the new fault level),
- the protection operating time,
- the percentage current distribution between the source transformers,
- the source transformer protection operating time,
- the let-through energy (I^2t) as a result of the fault current and the protection operating time,
- the primary plant equipment damage curves, and
- the area under the let-through energy curves.

All of these quantities are calculated for HSI and LSI conditions. The above quantities are also calculated for every shot in the ARC cycle. The type of fault used to calculate the grading margins, let-through energy and voltage-dip category are all 3Ph faults with no fault impedance. This is so as to obtain the maximum fault current. To assess the sensitivity of the device PU's, a 2Ph fault is used with some fault resistance (arc resistance) and a safety margin. This is because it will result in the lowest fault current that is required for sensitivity purposes.

6.3 OPERATING PRINCIPLE AND EVALUATION METHOD

In this section the way in which the evaluation method is implemented in the application is discussed. This includes the input data required, the output graphs that are generated and the evaluation of the protection philosophy elements.

6.3.1 Inputs to the application

The user has to input the following data to the application:

- The feeder operating voltage. This is used for fault-level calculation and voltage dip reference. The fault levels are calculated using the per-unit system and sequence components [78].
- The system MVA base has to be specified. This is used for the fault level and per-unit calculations.

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- The HSI and LSI on the MV busbar have to be specified. The source impedance will be used to calculate fault levels on the analysed path under these two network conditions. The HSI fault levels (n-1 contingency) will be used for the PU sensitivity analysis. The LSI fault levels will be used to determine the relay operating time, grading, let-through energy and voltage-dip.
- The number of active HV to MV source transformers for the HSI and LSI conditions have to be specified. This will be used to calculate the transformer percentage current distribution between the transformers.
- Each source transformer vector group, percentage impedance, size (MVA) and phase OC protection element settings have to be provided. The application allows the user to choose a star-star, or a star-delta vector group configuration. This is used for referring the current across the transformer.
- The transformer MV (secondary side) circuit breaker short-time ratings have to be specified. This is obtainable from the circuit-breaker specification.
- The conductor types (max. three in series) can be chosen from a predefined conductor list. The user can add other conductor types by specifying the new conductor sequence impedance values and current ratings. The length of each conductor type has to be specified.
- The physical position measured from the source busbar of the various protective devices on the analysed path. The application makes provision for a maximum of 5 series devices, including the feeder protection device at the MV busbar.
- For the feeder CB and the downstream protective devices on the analysed path, the equipment short-time rating and protection settings have to be specified. The protection settings include the number of ARC cycles, the operating curve, PU current, TM or time delay, and if an instantaneous element is applied.
- There are 122 predefined operating curves for the user to choose from. This includes IEC operating curves, RC curves, fuse MMT curves and fuse TCT curves. The user can also create custom curves in one of three ways. First, an operating curve equation can be specified, secondly a fixed operating time can be specified and thirdly the curve can be specified by time-current points on a plot. When time-

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current plots are used, the application will calculate the interposing data by making use of linear interpolation. The more data points provided by the user, the more accurate the approximation from the interpolation.

- There is a safety margin that has to be specified by the user for all the primary plant equipment short-time ratings. For this research a value of 20 % was used. This means that the calculated let-through energy damage curves shown in the graph for the various equipment are 20 % below the equipment actual rating.
- There are also four user-definable primary plant equipment damage curves that can be specified on the feeder. This does not include the conductor, feeder CB and RC damage curves that are there by default. For this research the conductor dead end (see Fig. 2.2) is specified under this category.
- For the sensitivity analysis, the user has to specify the amount of fault resistance in ohm that should be included when calculating the 2Ph fault level. The user also has to specify the associated safety margin for this calculation. This is to compensate for measurement errors caused by the CT's and relays. A value of 20 % on the 2Ph fault level is used with 3 Ω of fault impedance.

The main user input screen is shown in Addendum A.

6.3.2 Source transformer operating time

This application makes provision for up to four transformers in parallel at the source. These transformers are enabled or disabled depending on the source impedance specified for the MV busbar. The source impedance is specified for high impedance (minimum network conditions) and low impedance (maximum network conditions) conditions.

In Eskom, the HV to MV transformer phase OC element (and CT) is situated on the primary (HV) side of the transformer. This is illustrated in Fig. 5.7. The application will calculate the transformer percentage current distribution between the source transformers and convert the fault current to the HV side (OC element measurement side) of the transformer by making use of equations 5.8 and 5.10. The fault current for each transformer on the HV side is adjusted based on the vector group and type of fault (see

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section 5.5). This fault current is then used to calculate the transformer operating time, sensitivity and the let-through energy that each transformer's equipment will be exposed to for a fault on the MV feeder. This operating time is dependent on the protection settings of the transformer specified by the user.

6.3.3 Feeder protective device operating time

The protective device operating times are calculated based on the user-selectable operating curve. This can either be an equation, pre-defined data points of a curve, or a user-defined operating curve (based on data points). The application will calculate the operating time in every section at every analysis point (as shown in Figures 6.4 and 6.5). This operating time is then plotted against distance and not fault current. The reason for this is that the graph provides a better illustration of an increase in operating time as the distance from the source increases. This is similar to the illustration methods used by [10], [44]. This is in contrast to the traditional approach, where the operating time starts with a high value and then reduces to a lower value as the fault current increases from left to right on the axis. The traditional time-current graph is shown in Fig. 1.1. The new time-distance graph is shown in Fig. 6.5. The time-distance graph assists in determining the physical positions on the feeder where the slow operating times are situated. These slow operating areas indicate to field service personnel where high-risk positions are situated on the actual feeder. The distance approach is applied to the other graphs in the application as well. The application does provide both the HSI and LSI operating time graphs, thus the risk areas can be identified under both contingencies. The traditional time-current graph is also generated if the fault current is required instead of the position.

The maximum operating times of the feeder-installed protective devices for n-0 and n-1 protection back-up contingencies can be determined from the time-distance graph. The selectivity of the protection devices can be determined from this graph for all contingencies, whether it be source impedance changes, protection devices out of service or different ARC attempts. The minimum grading margins can be determined in this graph and compared to the recommendations in section 5.2.

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The operating time of the various curves are also compared to the primary plant equipment damage curves in the new time-distance graphs. The equipment damage curves are calculated using equation 3.1 in section 3.2.1. This allows the protection engineer to ensure that the primary plant equipment is protected. If the operating time of the protection element exceeds an equipment damage curve during any ARC shot, the operating time or curve type can be changed by the protection engineer.

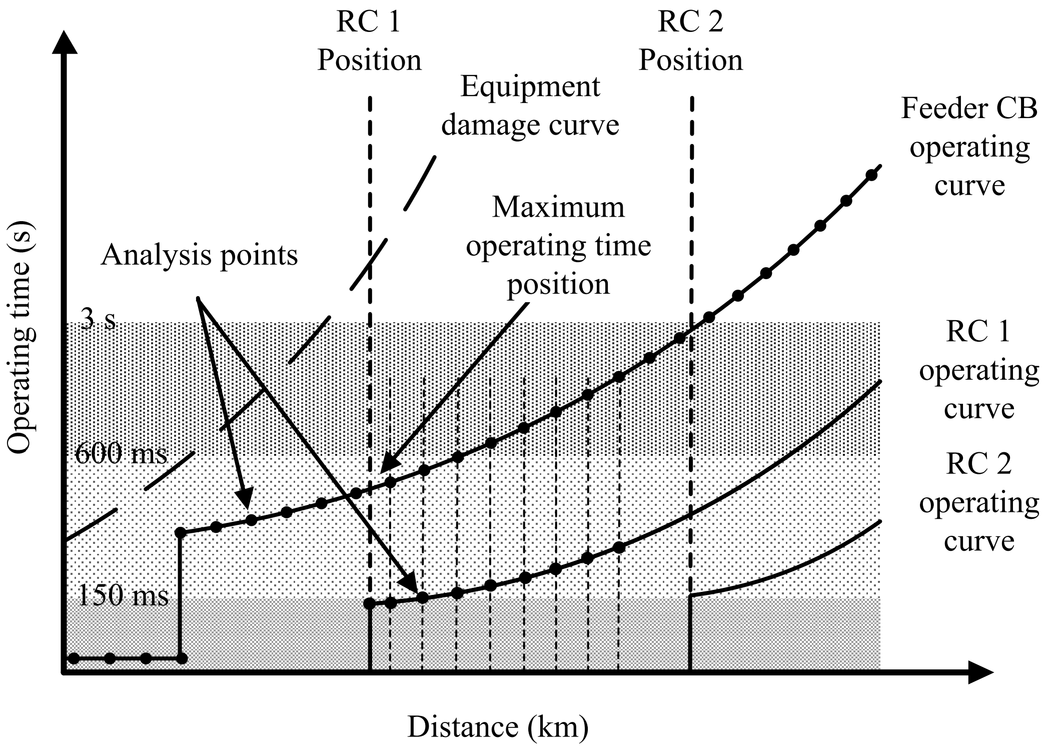

Figure 6.5 The protection operating time over the analysed path.

The NRS 048-2 dip-time categories (Figure 4.2) are also indicated on this graph. This is to indicate to the protection engineer what the possible vertical voltage dip category is and where optimisation of the settings (dip movement) are required.

6.3.4 Let-through energy

The let-through energy is calculated using the protection operating time and the square of the fault current at the fault position (I^2t energy). The let-through energy is used to determine if the primary plant equipment is damaged by the heating effect of the fault current. This is accomplished by comparing the let-through energy that the equipment will

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be exposed to with the damage curve (generated using equation 3.1) for that equipment. If the let-through energy is above (greater than) the damage curve of the equipment, the equipment can get damaged and the settings will have to be adjusted to protect the equipment. The adjusted settings include the operating time of the protection element, the ARC cycles, or both. This is illustrated in Fig. 6.6. The energy capability (damage curve) of the primary plant equipment is exceeded between point A and B in Fig. 6.6. This is where the equipment can get damaged.

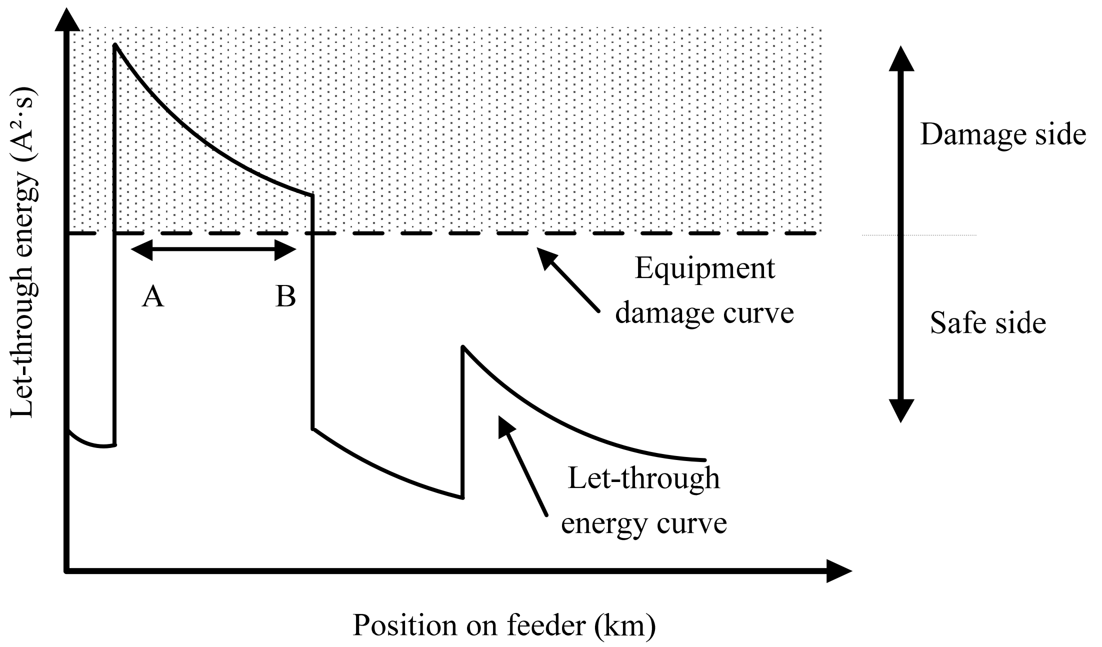

Figure 6.6 The let-through energy curve and equipment damage curve.

6.3.5 Energy-area evaluation

It is, however, not easy to determine the effect of small setting changes for comparing OC protection philosophies. An example of a small setting change can be a change in the TM of an element from 0.2 to 0.21. This is where the energy area calculation provides an advantage. It provides an actual number that can be used for comparison. The area underneath the let-through energy curve is calculated using a Riemann sum with a right-hand alignment [84]. The reason for choosing this approach, compared to integrating the operating curve equation, was that the user can specify protection operating curves by means of time-current position points (actual points). The Riemann approach does

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introduce some error, but for comparing two setting approaches it provides adequate results.

This energy-area calculation is based on the 50 points of each section, hence a total of 350 points for the analysed path. The area is calculated starting at the protection device actual position up to the next downstream device position for each protective device. This area calculation is illustrated in Fig. 6.7. This energy-area calculation is also done for each shot in the ARC cycle. The total energy area for all the shots on the protective device is then calculated by adding the individual shots for the device. This allows the ARC philosophy and different operating curves to be compared with each other. If there is an increase in the one approach compared to the other, it is indicative of higher risk at the fault position, a greater chance of equipment being damaged and a greater chance of detrimental quality of supply impacts. A lower energy area is more beneficial.

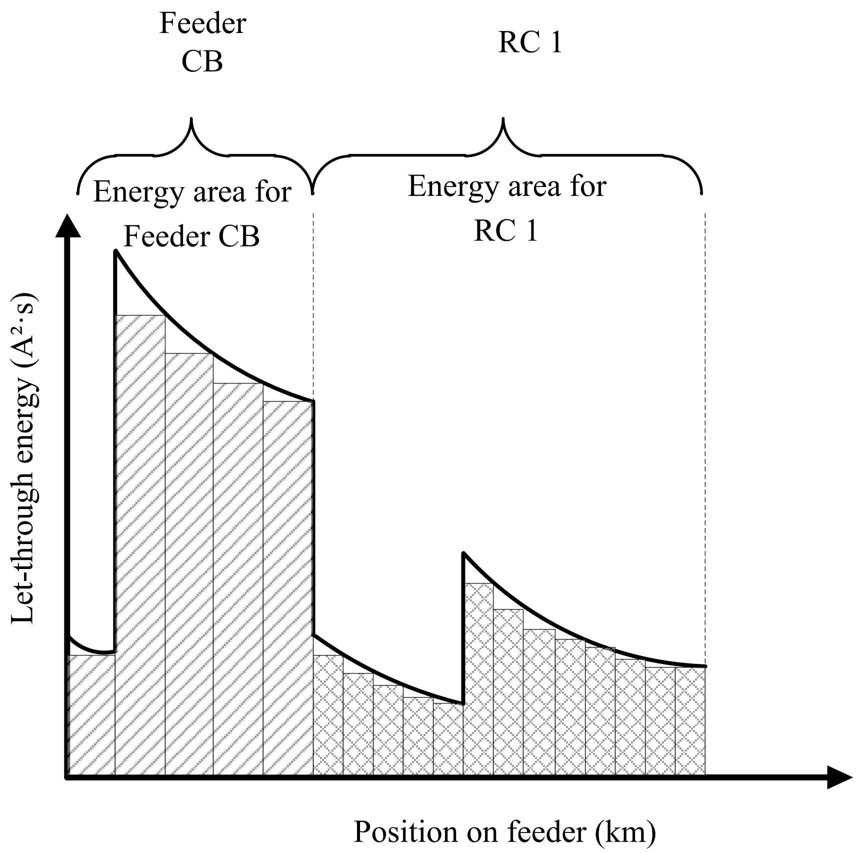

Figure 6.7 The energy area calculation illustration.

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6.3.6 Voltage-dips

The voltage dips are classified in terms of time and residual voltage in accordance to Fig. 4.2 [8]. The time used for the voltage-dip classification is the phase OC protection element operating time. The residual voltage is calculated using the fault current and fault impedance to determine the source MV busbar voltage. The busbar voltage-dip effect of each protective element is then added and a summary for each element is created. This summary is based on the analysis points. Each point gets classified and the distances are then added together so as to determine the total distance to the fault position (also dip position) for each element that results in a specific dip category. This is illustrated in Fig. 6.8 for a section of 10 km and a step size of 200 m (50 points per section).

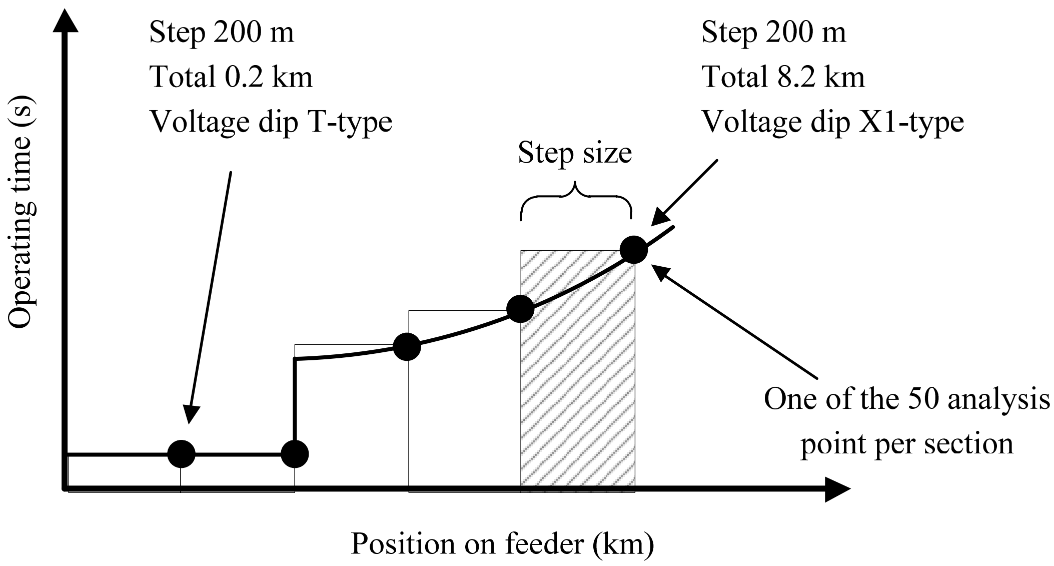

Figure 6.8 MV busbar voltage-dip classification on the analysed path.

The voltage dip for the step size is classified on the operating time and resulting busbar voltage at the end of the step-size distance. All of these different voltage dips are then added together for each protective device on the analysed path. A summary graph then adds all the resulting voltage dips from the protective devices together to give a holistic view of the total analysed path.

Once the let-through energy has been analysed, the voltage-dip effect at the PCC can be optimised. As stated previously, a voltage dip is classified by time-and residual voltage.

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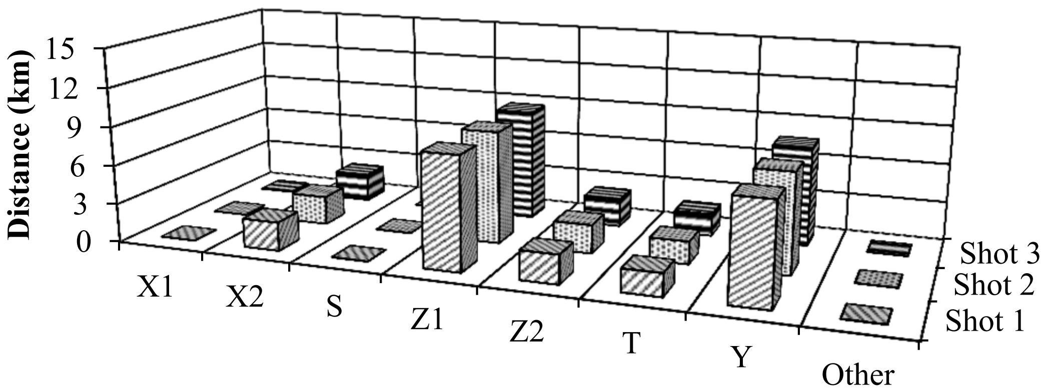
The residual voltage cannot be changed, but the dip time can be changed by changing the protection operating time. This will shift the voltage dip left or right on the NRS 048-2 dip table.

The total distance for a resulting dip type on the analysed path is calculated and this is shown in Fig. 6.9. This is used to determine the predominant voltage-dip types on an analysed path. It can also be used to compare it to other paths or philosophies on the same path. If the busbar voltage dip falls outside the NRS 048-2 voltage dip table, it is classified under the other category.



	X1	X2	S	Z1	Z2	T	Y	Other
Shot 1	0	2.212	0	8.7	2.212	1.738	7.656	0
Shot 2	0	2.212	0	8.7	2.212	1.738	7.656	0
Shot 3	0	2.212	0	8.7	2.212	1.738	7.656	0

Dip category

Figure 6.9 The combined MV busbar voltage dip profile.

An illustration method is shown in Fig. 6.10 that allows the fault position of busbar voltage dip types to be identified on the analysed path. It also allows for the protective device that is responsible for the busbar voltage dip to be identified. This can be done for every shot in the ARC.

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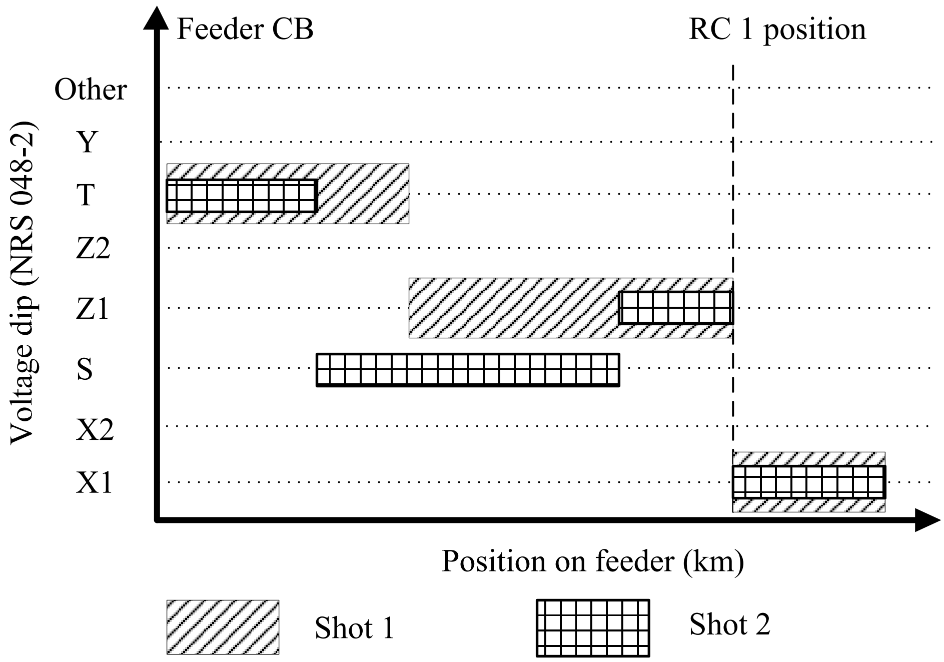

Figure 6.10 MV busbar voltage-dip classification and position on the analysed path.

In Fig 6.10 the feeder CB busbar voltage dip influence for shot 1 in the ARC attempts will start as a T-type and then progress to a Z1-type further down on the analysed path. When considering the second shot, it will start as a T-type, then change to an S-type and then it will change to a Z1-type. This is, however, only provided for n-0 network conditions regarding the back-up of one device beyond the subsequent downstream device. The voltage-dip positions are shown for n-0 (maximum) and n-1 (minimum) source transformer network conditions.

This voltage-dip effect of the feeder on itself for section four is illustrated in Fig. 6.11. The application provides an indication of the voltage-dip effect on the faulted feeder up to the PCC. The voltage at the point of fault will be equal to zero (no fault resistance). The voltage will also be zero from the faulted point to the end of the analysed path. The voltage will rise from the faulted point back to the source busbar. This rise in voltage is dependent on the fault current and feeder (conductor only) impedance to the fault. There will therefore be voltage, but it will not be equal to the rated value. This gives an indication of where voltage-dip sensitive customers should be situated. If the customer is situated close

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to the source busbar, he will experience more frequent voltage dips than when he is situated towards the end of the feeder. This is due to the larger exposure area of the feeder that is situated below the customer. If the customer was situated towards the end of the feeder, he will experience more supply loss (no voltage condition) than voltage dips.

This indication is only provided for the end points of the seven sections (refer to section 6.2.3). The reason for using the end points is that it is only an indication. There is an infinite number of positions available on the analysed path.

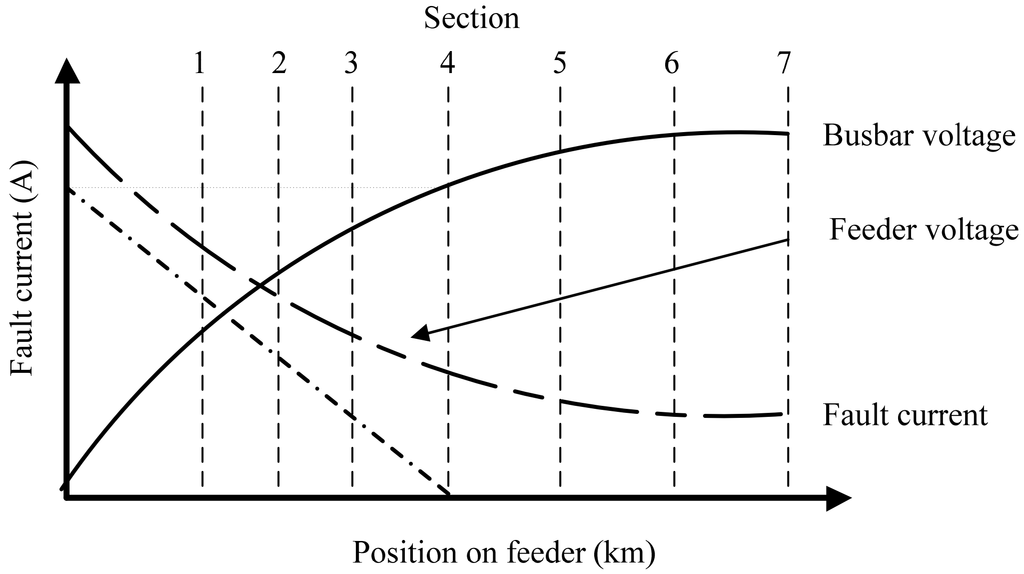

Figure 6.11 Voltage-dip effect of the feeder on itself.

This rise in voltage is dependent on the source impedance. If the source impedance is low, which results in large fault currents, the voltage rise to the source will be greater, and less of a dip will be experienced at the source busbar and on the feeder itself. The application provides the indication for both n-0 (maximum) and n-1 (minimum) source transformer network contingencies.

6.3.7 Sensitivity

The application provides a PU sensitivity indication for both minimum and maximum network contingencies. It also gives an indication of PU sensitivity for n-0 and n-1 protection device back-up contingencies. This feeder protection device sensitivity graph is

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illustrated in Fig 6.12. The fault level is calculated by using the 2Ph fault level with user-definable arc resistance and a user-definable safety margin applied (see section 5.4). The 2Ph fault level is used, as this will result in the lowest phase fault current where there is no earth path involved.

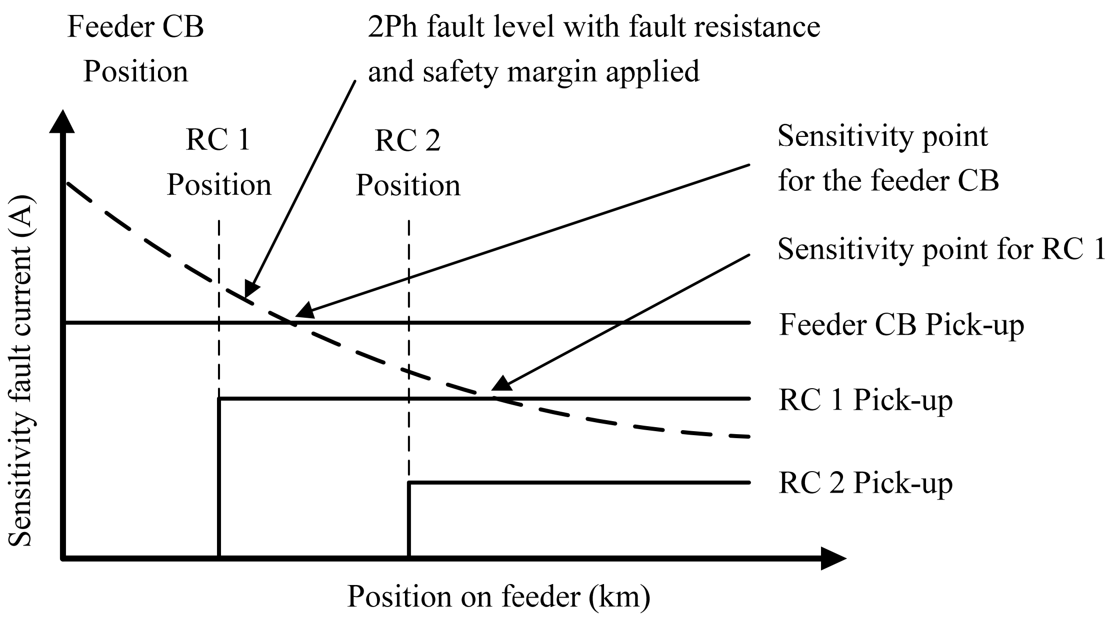

Figure 6.12 Feeder-based phase OC element PU sensitivity.

This graph should be evaluated under minimum network conditions, as the feeder-installed protective device sensitivity is evaluated. As long as the PU is below this curve, it is sensitive enough to detect a fault with no earth path. The point where the PU and the lowered 2Ph fault level cross is termed the sensitivity point for the protective device. Note that RC 2 in Fig. 6.12 has no sensitivity point.

The transformer sensitivity graph is shown in Fig. 6.13. This graph is used to determine if the transformer will detect a 2Ph fault on the analysed feeder. This fault current is also lowered by the user, based on a safety margin and fault resistance. This fault current is calculated under maximum network conditions. The reason for this is that the source transformer's current contribution lowers as more transformers are placed in parallel. The MV busbar fault level will increase. The fault current will then be divided amongst the

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source transformers. The 2Ph fault current is referred to the HV side of the transformer, using the analysis in section 5.5.

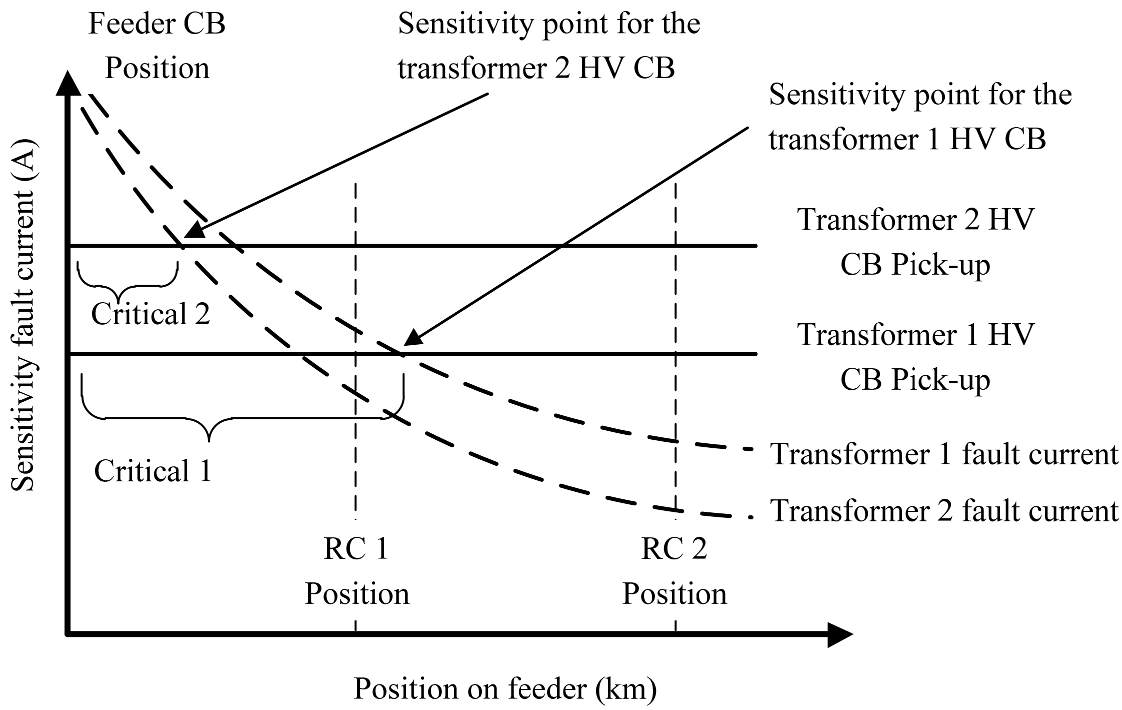

Figure 6.13 Phase OC transformer element PU sensitivity.

The transformers in Fig. 6.13 have different sizes (MVA ratings) and impedance values. This results in the two different transformer OC protection element PU's. There is a sensitivity point for each transformer. The fault current curves are different due to the current distribution that is different between the transformers. If the transformers were exactly the same, the curves would be on top of each other.

There is a critical region for every transformer in this example. The reason for this being critical is that the feeder OC protection element is only backed up in that region by the transformer OC protection element. The feeder breaker protection element requires a breaker failure element, or the transformer OC protection element has to cover the feeder breaker's intended reach. If the feeder breaker does not have breaker failure protection, there is no other protection element inside the transformer critical zone, the feeder breaker fails to operate for a fault beyond the critical zone, and the source transformers will most likely clear the fault on their winding temperature protection. This can lead to extensive

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damage at the fault position and an increase in risk due to the fault being present on the network for an extended period. If the feeder breaker fails to operate for a fault towards the end of the transformer critical zone, the transformer can also be damaged as a result of the long operating time and associated let-through energy. This long operating time is due to the transformer PU value and fault current being close to each other.

6.3.8 Fault types used for evaluating an OC protection philosophy

Since only the phase OC protection philosophy is evaluated, faults where an earth path is present is not considered. To evaluate the phase OC protection philosophy the following fault types are considered.

- 3Ph fault in minimum and maximum source impedance, and
- 2Ph fault in minimum and maximum source impedance.

A 3Ph fault in maximum network conditions results in the largest fault levels on the feeder. As a result, this fault level is used to determine the minimum grading margin, to evaluate the maximum let-through energy (for damage) and to evaluate the high-set reach (or its PU). The 3Ph fault in minimum network conditions is used to evaluate the grading between the source transformers and the feeder CB. For an MV feeder, the minimum network conditions will normally be with one of the source transformers out of service. Thus, this will maximise the current between the remaining transformer (assuming two at the substation) and the feeder being evaluated.

A 2Ph fault in minimum network conditions are used to evaluate the sensitivity of the line installed protection devices such as RC's. This will be the phase fault type with the lowest phase current where no earth path is involved. When the transformer sensitivity is evaluated, the 2Ph fault level in maximum network conditions is used. This is because the current that the transformer will measure will reduce as it is dividing between the source transformers. The source impedance is common to both source transformers. This results in the fault current being slightly lower for each transformer in parallel than when only one transformer is operational.

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6.4 OUTPUTS FROM THE APPLICATION

Different quantities, such as operating time and let-through energy, are plotted against distance (km) instead of current. The reason for this is that it provides a better feel for where the fault is on the actual network. An example of this is that, if you take a 1500 A fault level on two different feeders, it can refer to two different physical positions on the feeder, whereas if 3 km are specified, it will refer to the same distance if measured from the same position. It also gives an indication of the physical area that is covered by the protective device. The current distance relationship is based on the impedance of the feeder. The output graphs that are generated from the application are listed below:

- The bus voltage and fault-current profile.
- The line voltage and fault-current profile.
- The time-distance protection operating time.
- The let-through energy for the total feeder, including each ARC attempt.
- The energy area for each protective device ARC attempt and the total for each protective device.
- The feeder-installed protective device PU sensitivity.
- The source transformer protective device PU sensitivity.
- The busbar voltage-dip classification for the analysed path and each individual protective device.
- The combined breaker voltage-dip classification for the analysed path.
- The busbar voltage-dip position on the feeder.
- The protection operating time and fault current on the analysed path.

All of the above results are shown graphically for both minimum and maximum network conditions.

Summary graphs are provided to the user of the application to assist in analysing the various graphs that are provided. This was introduced to simplify the complex graphs. The complexity lies in the number of curves that are shown on one axis. It provides a clear, quick method to either assess the maximum value of a specific quantity across the analysed

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path, or to evaluate the specific quantity during one of the ARC shots. The user can choose to enable or disable the summary graphs. These graphs are also applicable to both minimum and maximum network contingency graphs. A maximum operating time summary graph is shown in Fig. 6.14. The summary graphs that are provided are listed below.

- For the let-through energy curves, it provides a summary graph of the maximum energy that every protective device will expose the feeder equipment to. This maximum summary graph will use the maximum let-through energy for a device. This maximum time includes all the ARC attempts. This is done for an n-0 protective device back-up contingency (does not reach beyond the next downstream device). The user can still conduct an n-1 or lesser analysis (downstream device back-up). The application does provide the information, but it will have to be done manually from the graph, or by considering the data in the calculation sheet of the application.
- The application provides a summary graph of the let-through energy for each individual ARC attempt of every protective device on the analysed path. This means that, if the summary for shot one is activated, it will show the let-through energy of shot one for the feeder CB, RC 1, RC 2 and RC 3 if the four devices were placed in series. It only shows the summary graph for an n-0 protective device back-up contingency. Again, if another protection back-up contingency needs to be evaluated, such as an n-2 contingency, it will have to be done manually.
- The application provides a similar summary graph as the maximum let-through energy summary graph, but based on operating time.
- The application also provides a similar graph as the individual ARC shot let-through energy, but for operating time.

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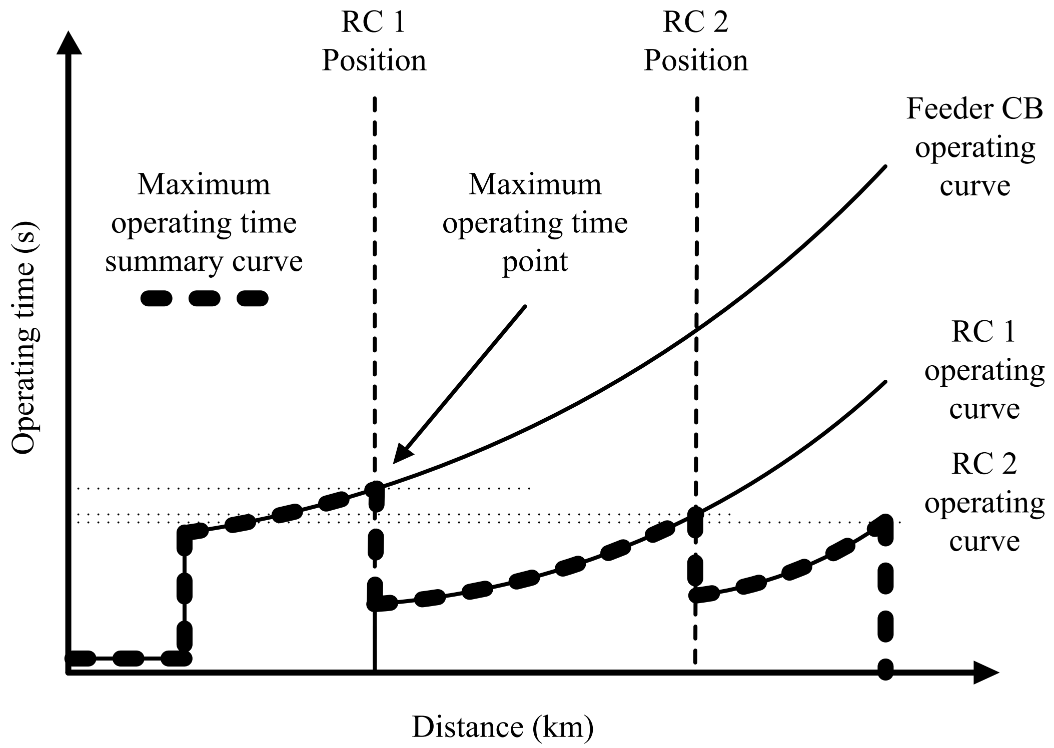

Figure 6.14 Maximum operating time summary graph.

The maximum operating time point is shown in Fig. 6.14. This is dependent on the protection settings and fault level. The maximum operating time point might be situated at a different position in the feeder. The individual breaker maximum operating time can also be determined from this graph. The maximum let-through energy point can be determined in a similar way if a let-through energy curve is used.

6.5 USING THE TOOL TO EVALUATE PROTECTION PHILOSOPHIES

When evaluating a protection philosophy, the recommended steps to be taken are listed below. The steps are also illustrated in Figures 6.15 and 6.16. The graphs associated with each step are provided on the right side of the flow diagram.

The first and most important step when evaluating an MV feeder OC protection philosophy is to evaluate the sensitivity of the protection devices. The protection element PU should be sensitive enough to detect fault conditions under minimum network conditions (low fault levels). First the feeder-installed protection devices have to be evaluated for

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sensitivity by using the feeder-installed protective device PU sensitivity graph. If there are no violations, the transformer protection sensitivity is to be evaluated using the source transformer protective device PU sensitivity graph.

If the applied protection settings are sensitive enough to detect faults in the network, the resulting operating time can be evaluated. The operating time should be below the equipment damage curves. The grading margin between devices can be evaluated from this so as to ensure selectivity. If there are no violations of any of the damage curves, the energy-distance curve can be used next. If there are violations, the operating time has to be adjusted.

The resulting let-through energy can now be evaluated against the equipment limits. Both the total (all ARC shots) and the individual let-through energy curves have to be below the equipment limits. The equipment damage limits can also be evaluated again as in the time-distance curves. If there are no violations, the energy-area values can be checked. These values only offer benefit if setting changes are to be evaluated. The lower this number, the better it is for the equipment and the risk in the network.

The voltage dips can finally be evaluated. The overall strategy surrounding this is to try and move the voltage dips to the left side of the NRS 048-2 dip table (Fig. 4.2).

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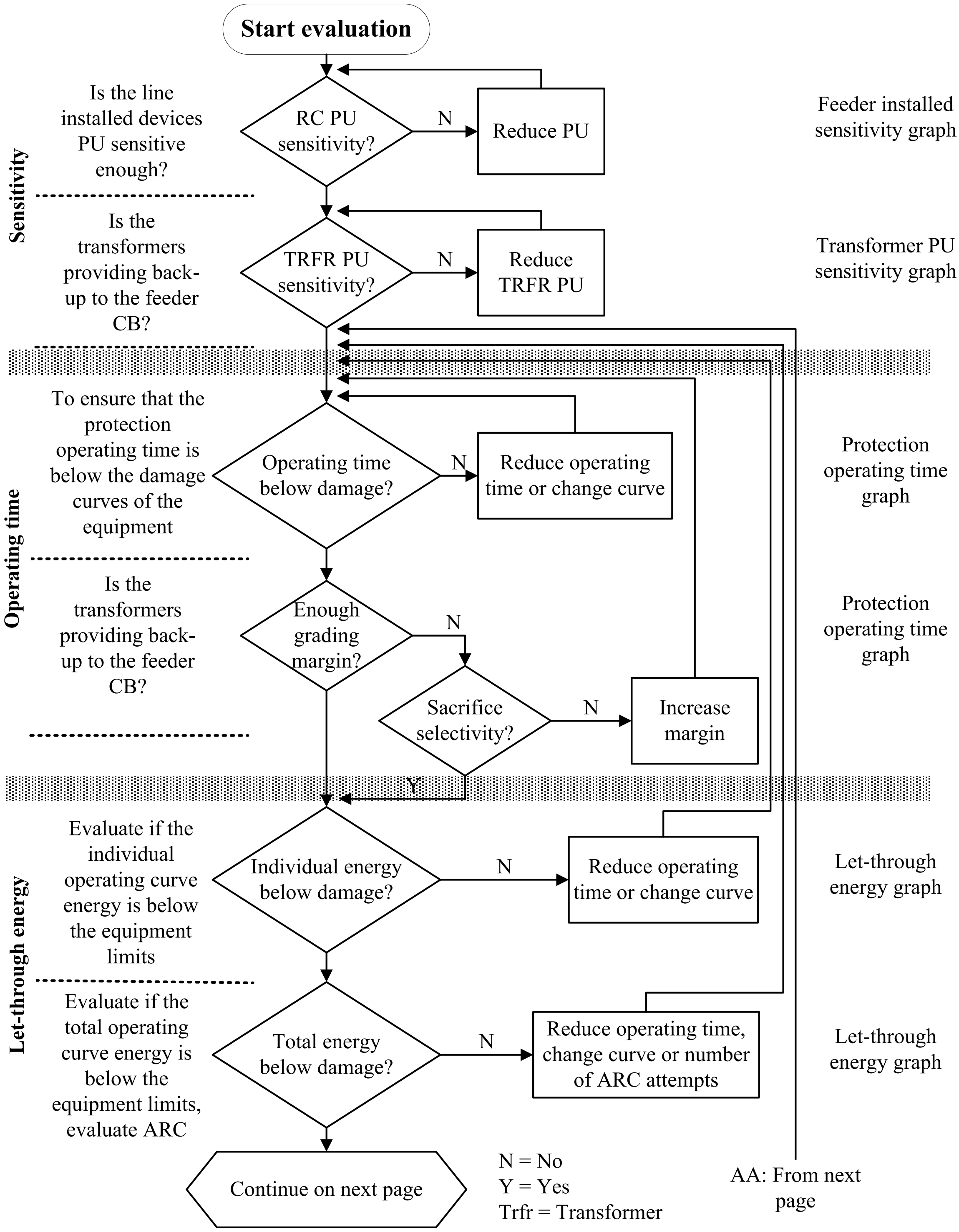

Figure 6.15 The flow diagram for evaluating a protection philosophy.

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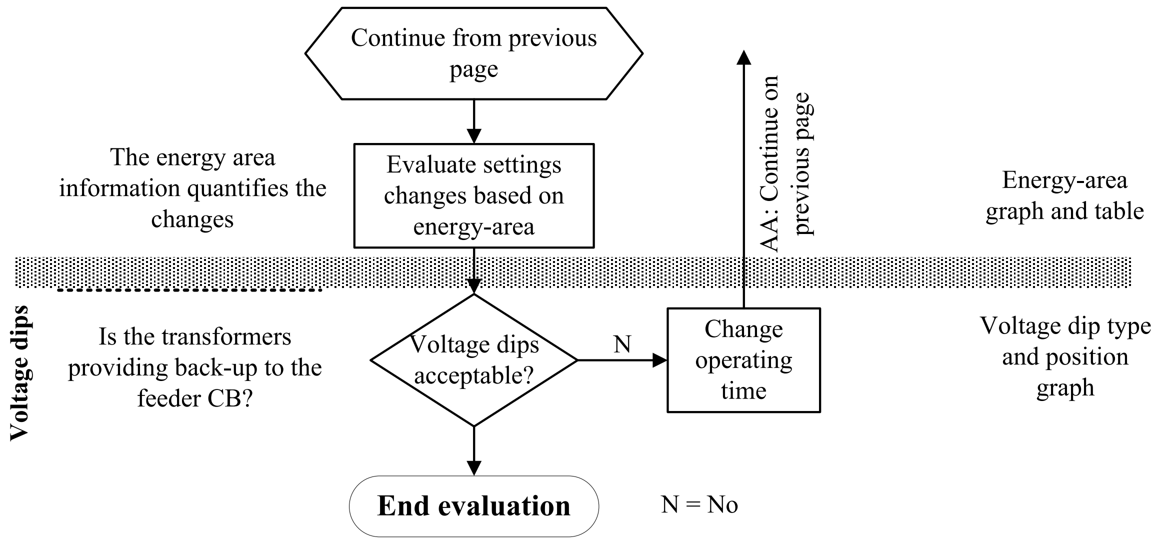

Figure 6.16 The flow diagram for evaluating a protection philosophy (continue).

6.6 FORWARD

In this chapter the identified evaluation factors were applied to a software application. This application is designed to evaluate phase OC MV feeder protection philosophies. Graphs detailing the PU sensitivity, the protection operating time, the let-through energy and the voltage-dip effects are generated. In chapter 7 this application is applied to an actual feeder in two case studies on the same analysed path. The resulting graphs are then shown.

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CHAPTER 7 RESULTS AND DISCUSSION

7.1 CHAPTER OVERVIEW

The key evaluation factors were identified in chapter 2. In chapters 3, 4 and 5 the let-through energy, voltage dip effect and the protections settings were discussed so as to determine evaluation criteria. The evaluation criteria were incorporated into an Excel software application in chapter 6. The application is now applied in two case studies to show the evaluation method. The first case study is for an actual network where different protection settings philosophies are applied to the same MV feeder in the network. The second is for a test network to illustrate that the protection philosophy can still be evaluated, even if the protection devices are different.

7.2 CASE STUDY 1

7.2.1 Qualification test protocol

7.2.1.1 The objective of the case study

The objective of this experiment is to show that the application can be used to evaluate phase OC protection settings. The key elements that are evaluated are the operating time, let-through energy and the resulting voltage dip.

7.2.1.2 The case study setup

An actual network in the Eskom grid is used for these case studies. The source substation consists of two HV to MV transformers, so as to evaluate the effect of minimum (low fault levels) and maximum (high fault levels) network conditions. The MV feeder that is radiating from the source substation consists of four protective devices in series. This includes the feeder CB. For the protection devices on the feeder, only the line-installed RC is considered in this experiment. The feeder consists of three different series conductor types. This is to evaluate the effect of conductor types on the protection settings. The reduced protection network diagram and the analysed path is shown in Fig. 7.1. There are multiple paths that can be analysed.

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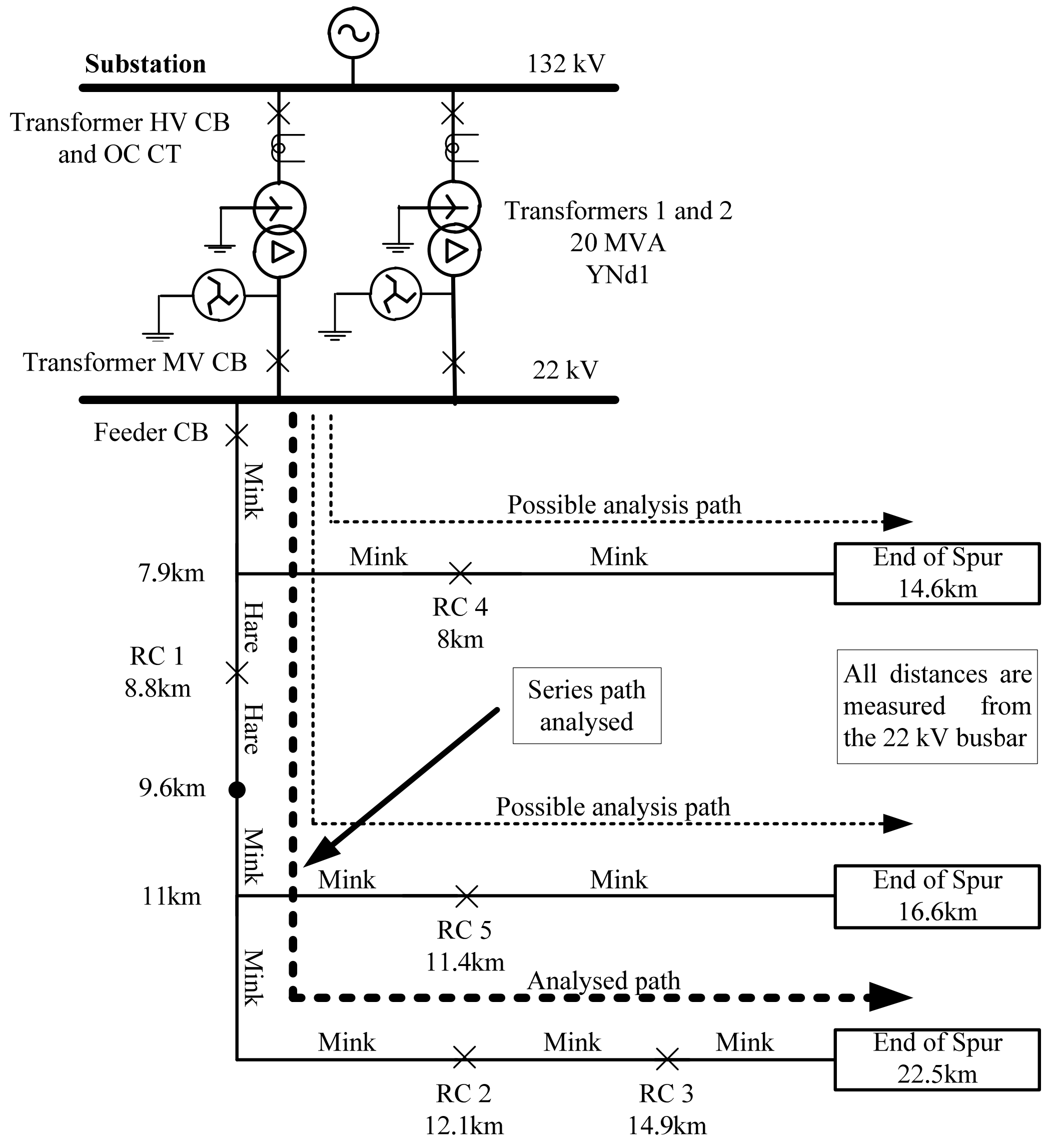

Figure 7.1 Reduced protection network of an actual Eskom MV feeder for case study 1.

7.2.1.3 Protocol

The protocol that is applied to the case study is listed below:

1. Determine the source impedance for minimum and maximum network conditions on the MV busbar at the source substation. This is done using an applicable power network simulation software package.
2. Reduce the actual network diagram to a protection network diagram.

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3. Calculate the 3Ph and 2Ph fault levels for the reduced protection network for minimum and maximum network fault-level conditions.
4. Choose the path on the feeder to analyse.
5. Calculate protection settings for the chosen analysis path using a top-down grading approach (see section 5.2).
6. Import these settings into the setting application to generate the result graphs.
7. Calculate protection settings for the chosen analysis path using a bottom-up grading approach (see section 5.2).
8. Import these settings into the setting application to generate the result graphs.
9. Compare the various result graphs obtained from the top-down and the bottom-up approaches.

7.2.2 Results and description

7.2.2.1 Experimental parameters

A portion of the actual network diagram used to generate the reduced protection network diagram of Fig. 7.1 is shown in Fig. 7.2. The conductor lengths and types are shown in the network diagram (Fig. 7.1). The path chosen consists of three different conductor types. Top-down and bottom-up grading approaches are used to generate parameters for the application. The MV busbar source impedance determined from the power network simulation software (DigSilent Power Factory) is listed in Table 7.1. This is done for both the minimum and maximum network conditions. The two transformers at the substation are identical in size (MVA) and impedance.

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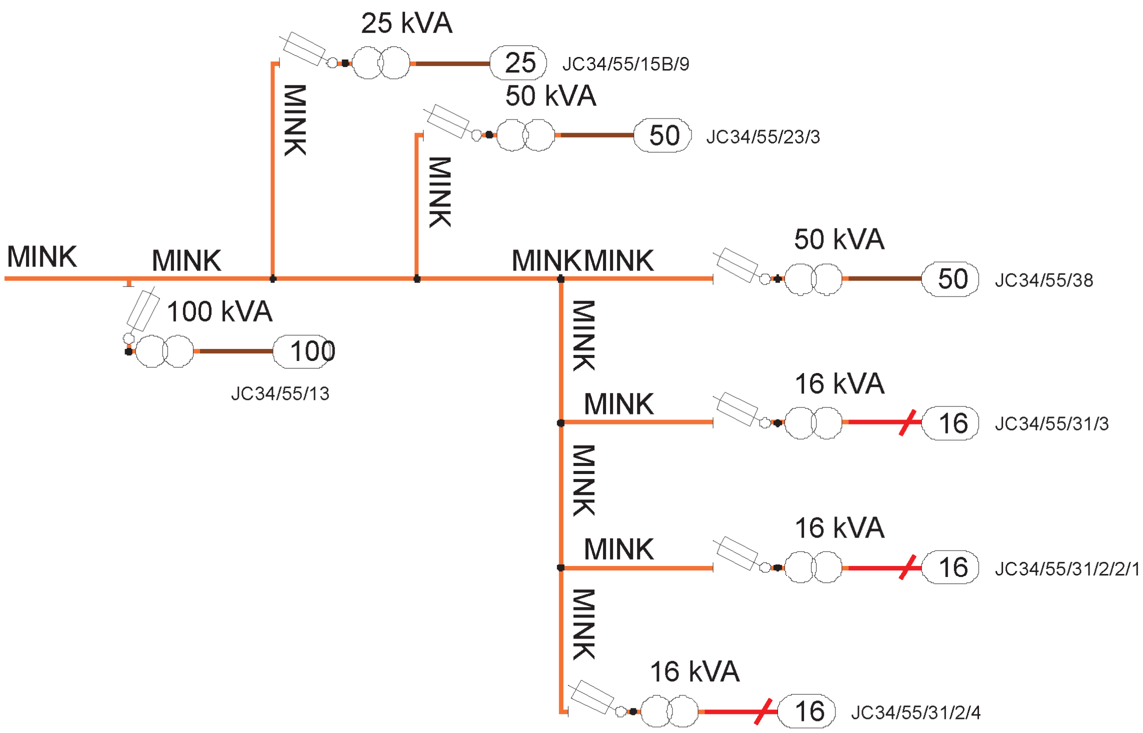

Figure 7.2 A portion of the actual network diagram used to generate the reduced protection network diagram. This is not available to the general public.

Table 7.1 The MV busbar source impedance.

Network condition	**Source transformers active**	**R_0 (pu)**	**X_0 (pu)**	**R_1 (pu)**	**X_1 (pu)**
Minimum	1 (n-1)	30.723	23.14	0.191	0.607
Maximum	2 (n-0)	15.362	11.57	0.132	0.395

The actual source transformer information and applied OC protection settings are provided in Table 7.2. These settings are constant for both the top-down and bottom-up approaches.

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Table 7.2 Source transformer information and protection settings.

Transformer	Size (MVA)	Vector group	Operating curve	Pick-up at 132kV (A)	Time multiplier
1	20	YNd1	NI	130	0.35
2	20	YNd1	NI	130	0.35

An arc-resistance value of 3 Ω and a safety margin of 20 % are applied when calculating the 2Ph fault level for sensitivity analysis. For the 3Ph fault levels no arc resistance is included. This is because the maximum fault current is required.

For the top-down approach, the operating time of the upstream protection devices at the downstream device position is determined. The fault level and fault position to be used is where the two grading devices measure the same maximum fault level. A grading margin is then subtracted from this operating time and the downstream device operating time is set to this new lower time value. The same method is applied to successive protection devices on the analysed path. To evaluate the effect of ARC, a three-shot to lock-out ARC philosophy is applied to the top-down grading approach. All the ARC attempts make use of the same curve and settings. The positions of the devices are indicated in Fig. 7.1. The top-down protection settings for the analysed path in the network is provided in Table 7.3.

Table 7.3 Top-down protection settings for the analysed path.

Device	Operating curve	Pick-up (A)	Time multiplier
	Shot 1,2 and 3	Shot 1,2 and 3	Shot 1,2 and 3
Feeder CB	NI	342	0.34
RC 1	NI	308	0.23
RC 2	NI	277	0.16
RC 3	NI	249	0.11

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An instantaneous curve is applied to the feeder CB with a PU of 2850 A and a time delay of 50 ms. The time delay is used to simulate the effect of the breaker operating time. A breaker operating time of 50 ms for SF_6 switchgear is reported in [45].

The operating time of the last device is set for the bottom-up approach. The upstream device is then set to operate slower than the downstream device by a certain grading margin for the fault current at the downstream device position. The same method is applied to successive protection devices on the analysed path. A two-shot to lock-out ARC philosophy is applied to the bottom-up grading approach. The first shot in the ARC cycle makes use of an EI curve. The second shot in the ARC cycle makes use of an NI curve. This is done to evaluate the effect of curve selection. The bottom-up protection settings for the analysed path in the network is provided in Table 7.4. The same instantaneous curve as for the top-down approach is applied to the feeder CB in the bottom-up approach.

Table 7.4 Bottom-up protection settings for the analysed path.

Device	**Operating curve**	**Pick-up (A)**	**Time multiplier**	**Operating curve**	**Pick-up (A)**	**Time multiplier**
	Shot 1	Shot 1	Shot 1	Shot 2	Shot 2	Shot 2
Feeder CB	EI	342	0.17	NI	342	0.2
RC 1	EI	308	0.13	NI	308	0.16
RC 2	EI	277	0.1	NI	277	0.12
RC 3	EI	249	0.07	NI	249	0.07

The data used to evaluate the energy limits of the primary plant equipment are listed in Table 7.5.

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Table 7.5 Primary plant equipment energy limits and applied safety margins.

Equipment	Short time current (A)	Short time (s)	Safety margin (%)
Mink conductor	5400	1	0
Hare conductor	8970	1	0
Dead ends	3000	1	20
Transformer MV CB	12000	3	20
Feeder CB	8000	3	20
RC 1, RC 2, RC 3	8000	3	20

The three quantities of importance here are the short-time current, the associated time and the safety margin when calculating the damage curve.

7.2.2.2 Resulting graphs

Both the HSI curve and the LSI curve are shown on some of the graphs. All the results shown are for maximum network conditions (high fault currents), except for specific graphs where LSI is required. For this instance the network condition (minimum network condition) will be specified in the graph header. The application does generate both the minimum and maximum network results for evaluation.

The result graph categories provided are listed below. The results for both the top-down and bottom-up approaches are provided in each category.

- Protection operating time vs. fault current.
- Busbar voltage and feeder fault current profile for HSI and LSI conditions.
- Sensitivity of the feeder protection device PU's.
- Sensitivity for the transformer protection PU's.
- Busbar and feeder voltage dips for HSI and LSI conditions.
- Protection operating time vs. position.
- Let-through energy vs. distance.

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- Let-through energy-area.
- Combined voltage-dip profile for the analysed path.
- Complete voltage-dip profile and the position of the dip for the analysed path.

Background to the result graphs are provided in chapter 6.

The approach for the discussion is to compare the results that was obtained for the top-down and bottom-up approaches. An action can then be assigned from the evaluation. This action can also be no action, based on the evaluation from the application, as the setting might meet the evaluation criteria.

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Protection operating time vs. fault current for LSI

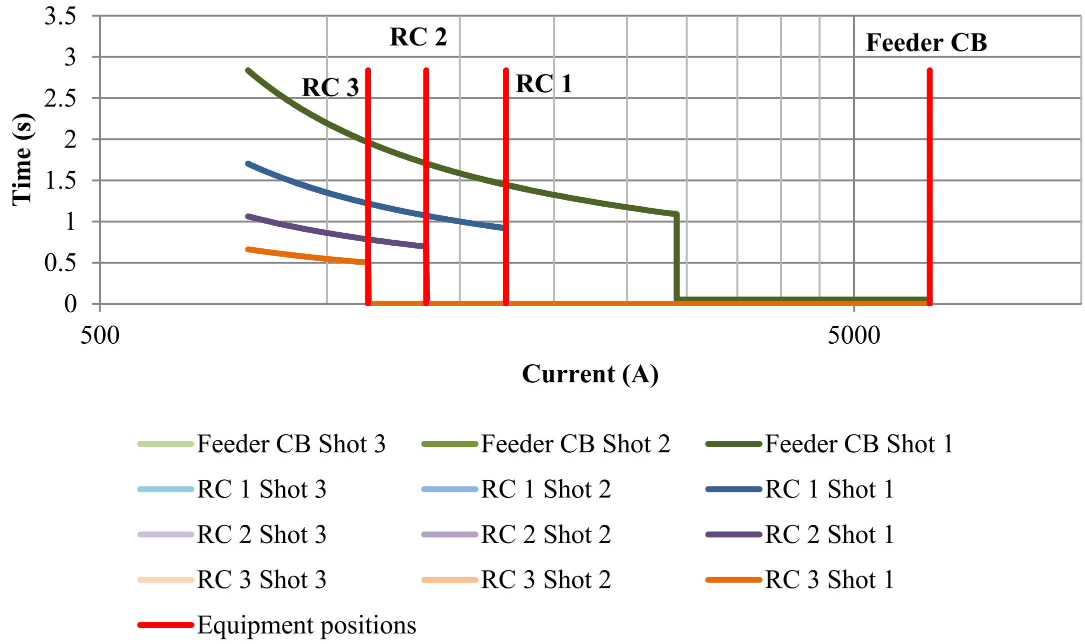

Figure 7.3 Protection operating time for a top-down approach.

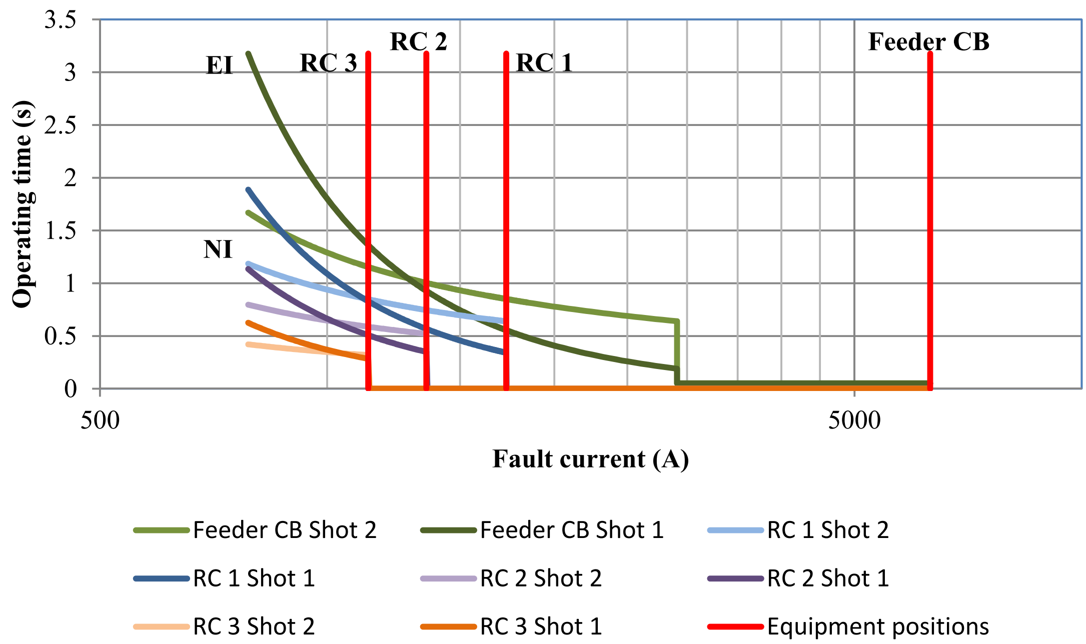

Figure 7.4 Protection operating time for a bottom-up approach.

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The traditional time-current curves are shown in Fig. 7.3 for the top-down approach and in 7.4 for the bottom-up approach. There is adequate selectivity under n-0 and n-1 protection back-up contingencies for both the top-down and bottom-up approaches. The minimum grading margins are used to ascertain this. Because the study was conducted under maximum source network conditions, the selectivity will improve for minimum network conditions. The selectivity will hold between different ARC shots for the top-down approach because only one curve type (NI) is used. The selectivity will only be true for the bottom-up approach if both the upstream and downstream devices are on the same operating curve (e.g. both on the EI curve).

The maximum operating time for both approaches can be determined from the graph and is shown in Table 7.6. The summary graphs (section 6.4) in the application will assist to determine these maximum operating time values. In Table 7.6 it is shown that the maximum operating time for the bottom-up approach is less than the top-down approach for the same NI curve type. When comparing the EI curve to the NI curve in the bottom-up application, it is shown that the EI curve operates faster than the NI curve. The EI curve performs better under high fault currents than the NI curve. The slowest operating time occurs at the end of the feeder-breaker zone under an n-0 network condition. This is the same for both the top-down and the bottom-up approaches. It is not easy to determine the position on the actual feeder from this graph, as it specifies fault current. The use of the instantaneous function (high-set function) on the feeder breaker is not influenced by the bottom-up or top-down grading process. If this high set was applied to one of the downstream RC’s, it can hold an advantage for upstream grading (see section 5.3).

In terms of evaluating the protection philosophy, there is a distinct advantage in using the bottom-up approach when considering the protection operating time. This is even more so with the EI curve application. By reducing the operating time, we reduce the time the fault is present on the network and this reduces the risk at the fault position. It also reduces the time that equipment is exposed to fault current and this increases the reliability of the equipment and the network in total by decreasing the equipment’s exposure to the fault current.

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Table 7.6 The maximum operating times on the analysed path

Settings approach	ARC shot number	Operating time (s) n-0 network condition	Operating time (s) n-1 network condition
Top-down	1	1.45	1.7
	2	1.45	1.7
	3	1.45	1.7
Bottom-up	1	0.55	0.91
	2	0.84	1

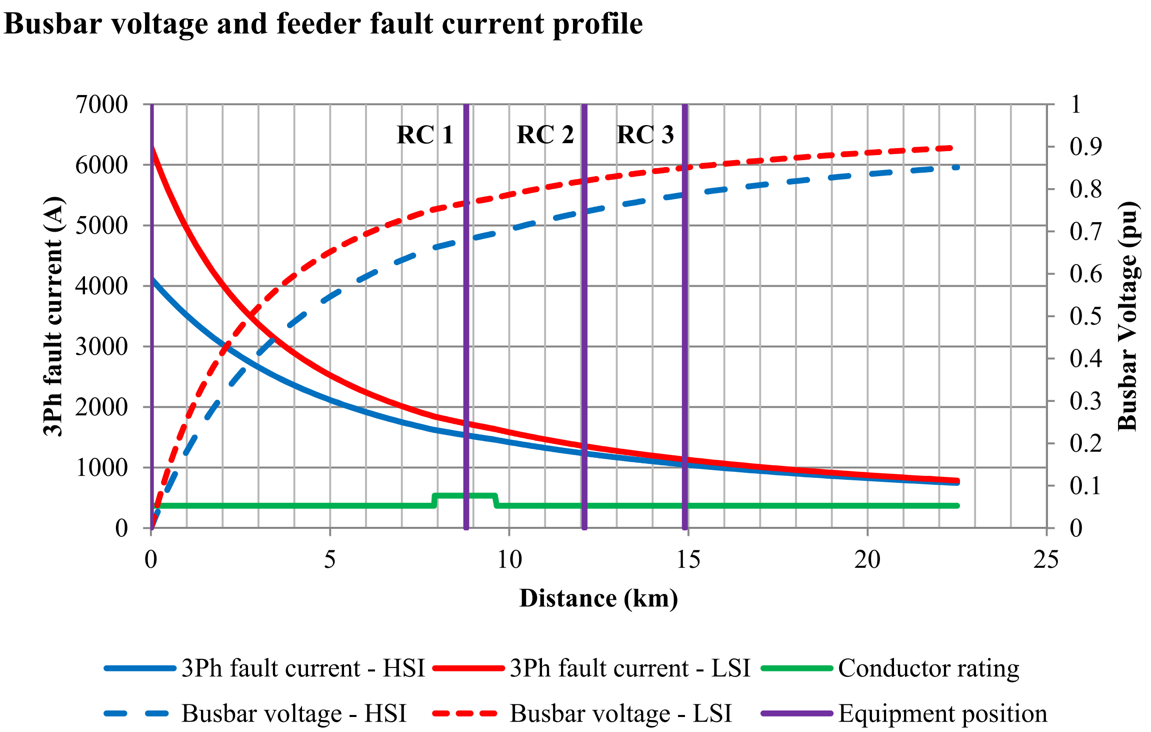

Figure 7.5 Busbar voltage and feeder fault-current profile for a top-down approach.

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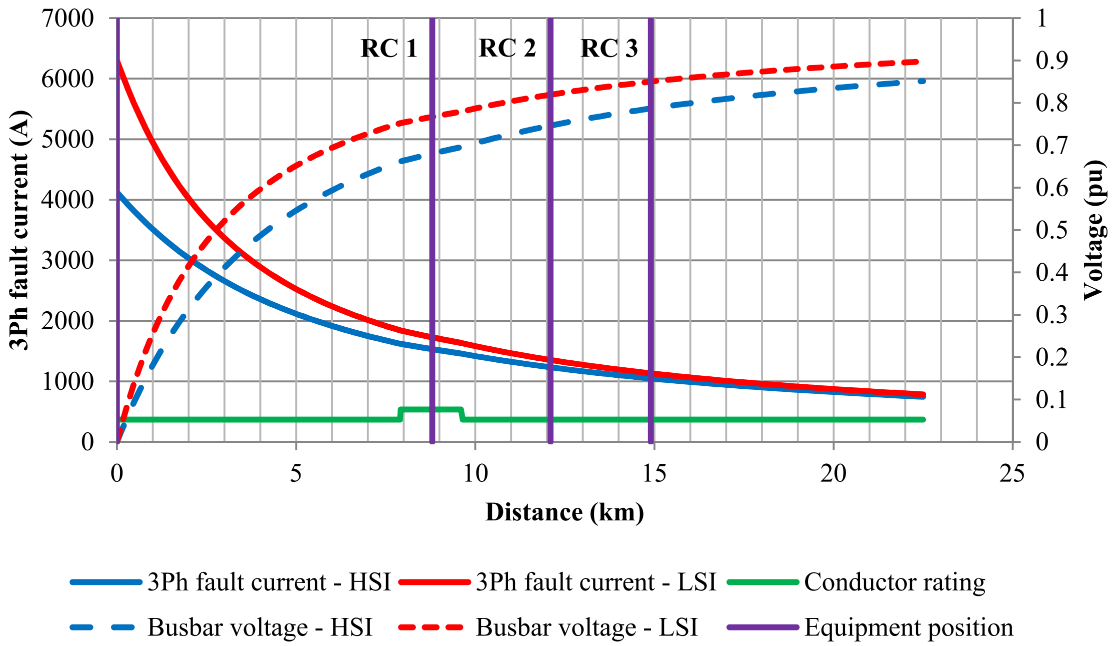

Figure 7.6 Busbar voltage and feeder fault-current profile for a bottom-up approach.

The busbar voltage and associated fault current are shown in Figures 7.5 and 7.6. This is for both minimum and maximum network conditions. From these graphs we can observe that the different grading approaches, operating curves and ARC philosophies do not change the fault current or the resulting voltage-dip magnitude at the busbar. Thus it confirms that the phase OC protection settings cannot change these values, since both Figures 7.5 and 7.6 are exactly the same. What can be seen from this graph is that the lower source impedance (maximum network conditions) is more beneficial because of the higher residual voltage at the PCC. The drawback of very high fault levels is the increase in risk, as the area close to the source is where the highest fault levels with the slowest protection operating times are. These graphs will have a benefit to primary plant design engineers in managing fault levels, equipment placement and customer placement. From a quality of supply perspective, this will determine the horizontal line on which the voltage dip can be moved by the protection settings engineer for a fault at the specific position on the feeder. By changing the protection operating time, the voltage-dip can be moved left or right in the NRS 048-2 dip table (see Fig. 4.2 and section 4.1.2). The voltage-dip magnitude cannot be changed by the protection settings, as this is dependent on the impedance to the fault position.

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Sensitivity of the feeder protection device PU's

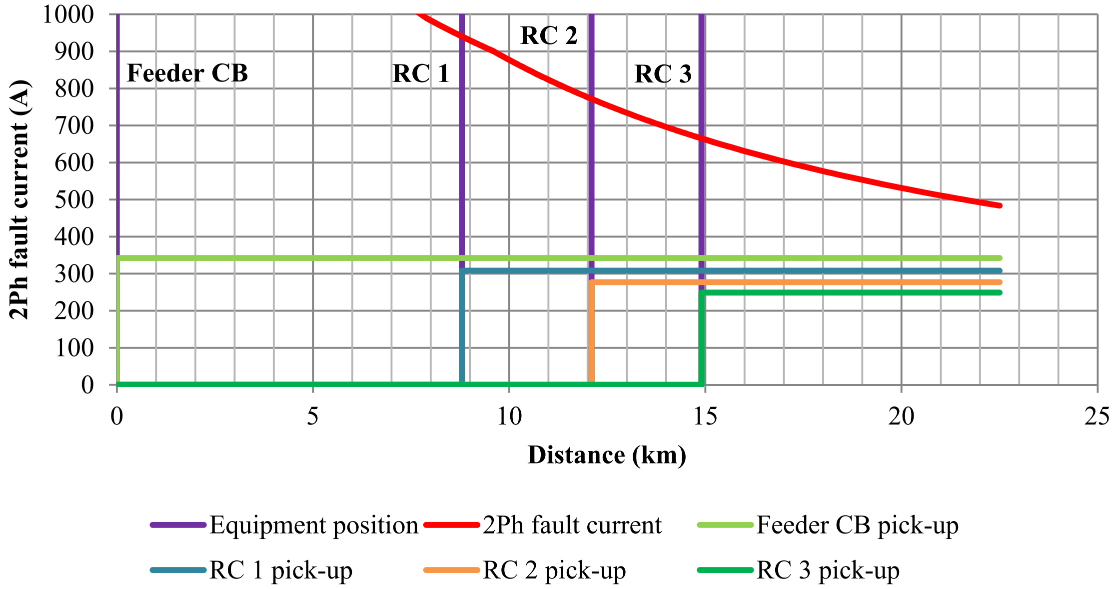

Figure 7.7 The protection element PU sensitivity for a top-down approach under minimum network conditions.

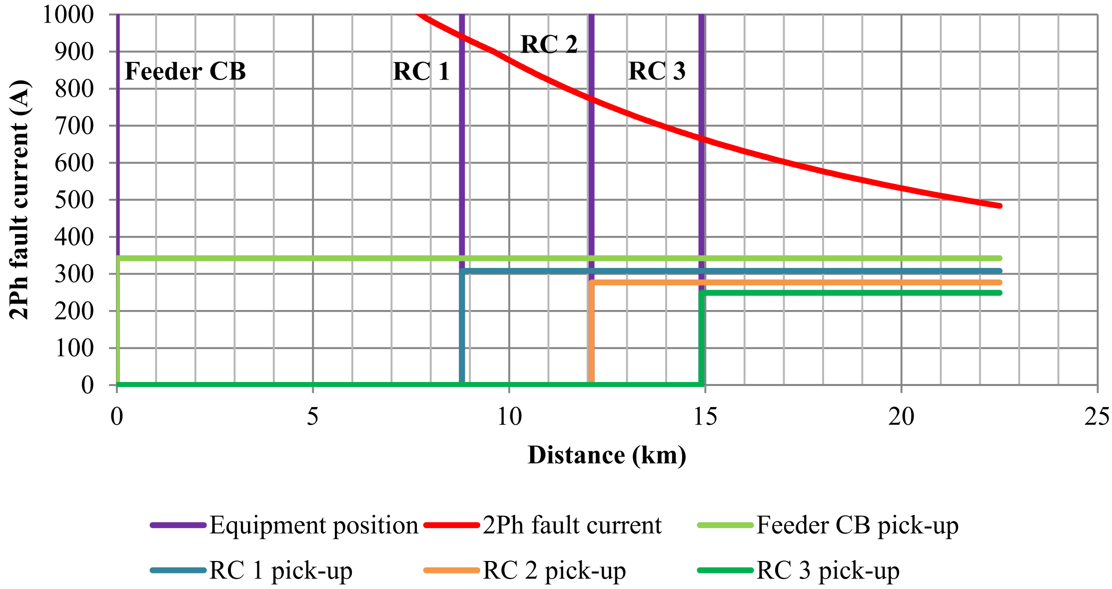

Figure 7.8 The protection element PU sensitivity for a bottom-up approach under minimum network conditions.

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The feeder-installed protection device PU sensitivity is evaluated in Figures 7.7 and 7.8. From the graphs it can be determined that the devices are all sensitive enough to detect faults under n-1 protection backup contingencies. This is evaluated under minimum network conditions. The reason for this is that it results in the lowest fault current for the feeder-installed protection devices (setting sensitivity). This fault current includes a safety margin of 20 % for errors and 3 Ω of fault resistance. Since the PU's are well below the 2Ph fault level, it can accommodate much more fault resistance in the fault path than the specified 3 Ω. The graphs are the same for the top-down and bottom-up approaches because the protection element PU was determined using the same method.

From these graphs the PU current grading margin can also be determined and verified. This PU grading between series devices should be used to allow for the PU drop-off ratio and relay errors (see section 2.4.1 and 2.4.3). Another observation is that all the feeder-installed devices are sensitive enough to detect up to the end of the analysed path. Even though this is not a requirement in some of the Eskom regions, it improves the reliability of the protection system (more devices for back-up). There is no sensitivity point for any of the protection devices on the feeder (see section 6.3.7). The application can thus give adequate information for the path that was analysed. A path should be chosen so that the lowest fault level for each protective device can be checked.

The two setting approaches are thus equal when considering the sensitivity of the protection devices installed on the feeder. No optimisation is required for this category.

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Sensitivity of the transformer protection PU's

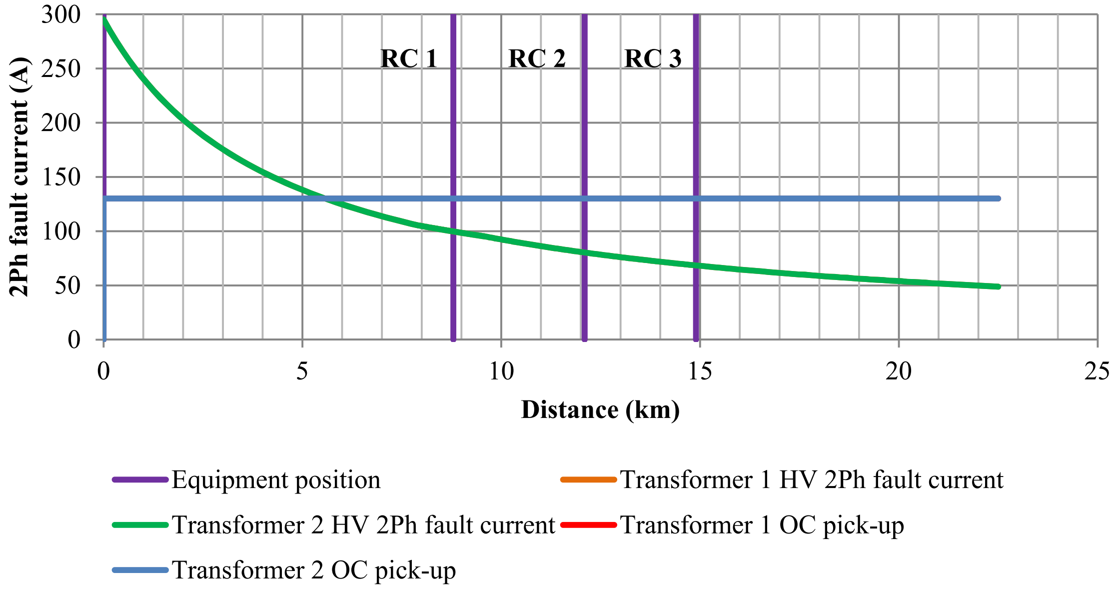

Figure 7.9 The transformer protection element PU sensitivity for a top-down approach under maximum network conditions.

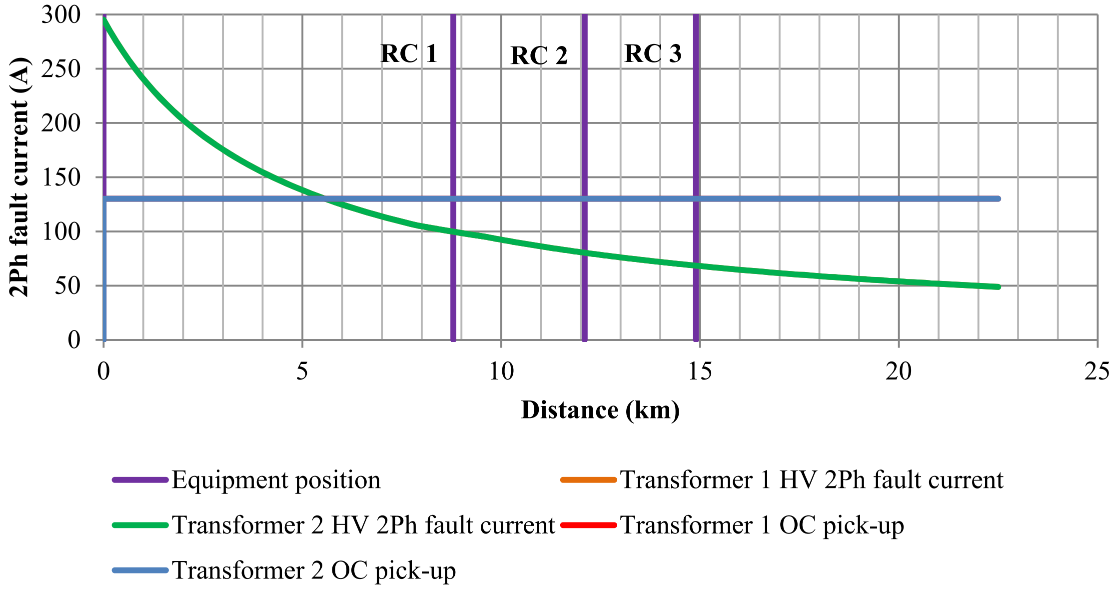

Figure 7.10 The transformer protection element PU sensitivity for a bottom-up approach under maximum network conditions.

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The sensitivity for the transformer phase OC PU's are shown in Figures 7.9 and 7.10. All currents shown in these graphs are at 132 kV (primary side of the transformer) and this study is done under maximum network conditions. The maximum network conditions on the feeder will result in minimum network conditions for the transformers. The two figures are identical, as the transformer settings have not changed and the different setting approaches do not change the fault level or current distribution between the transformers.

The PU curves for transformer 1 and transformer 2 are on top of each other, since the transformers are exactly the same and have the same protection settings. When evaluating these figures, it can be observed that the transformer protection will provide backup to the feeder CB for faults up to 5.5 km from the MV busbar. From 5.5 km to 8.8 km (end of feeder CB protection zone) there is no back-up protection for the feeder CB. Since there is no breaker failure protection on the feeder CB, this fault will probably be cleared by the transformer winding temperature protection. It is thus recommended that the first RC be positioned not further than 5.5 km from the substation, or that a breaker failure function be enabled for the feeder CB if it is available on the protection relay (see section 5.6).

The two setting approaches are thus equal when considering the sensitivity of the transformer protection. This is for providing backup to the feeder CB. The optimisation here is with regard to the placement of primary plant equipment, or enabling a breaker failure function on the feeder CB relay. The placement of the equipment will incur some capital expenditure for primary plant equipment. The breaker failure function will incur protection settings calculation cost and a small wiring change (depending on the technology used). Both approaches will require a supply interruption to the customers if no bypass arrangement is present in the network.

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Busbar and feeder voltage profiles

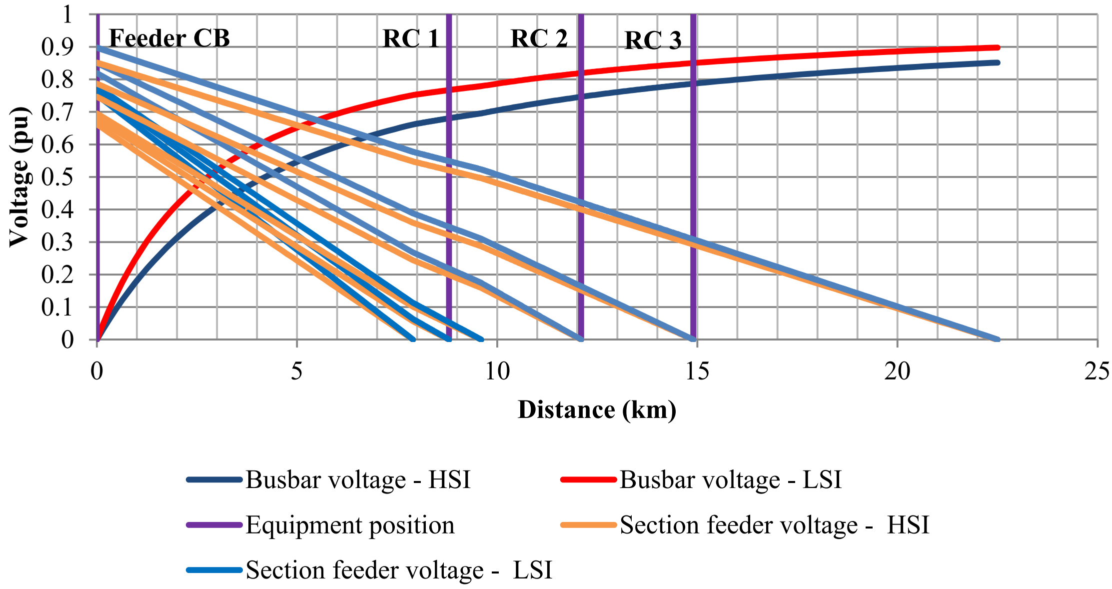

Figure 7.11 Feeder voltage dip and fault level for high-and low-source impedance. This is for the top-down approach.

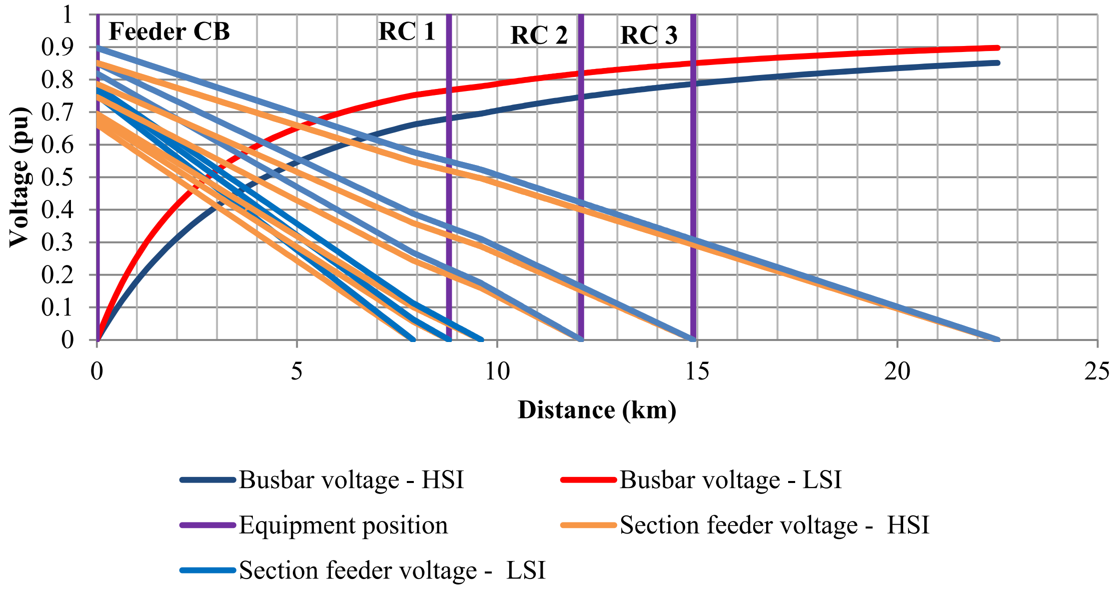

Figure 7.12 Feeder voltage dip and fault level for high-and low-source impedance. This is for the bottom-up approach.

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The feeder and busbar voltage for a fault at a specific position on the feeder for both minimum and maximum network conditions are shown in Figures 7.11 and 7.12. These graphs are the same for both the top-down and the bottom-up approaches. This indicates that the settings cannot change the voltage on the feeder. There will be a voltage equal to zero volts at the fault position. This voltage will then increase from zero volts to the busbar voltage, based on the fault current times of the feeder impedance (Ohm's law). The effect of the different conductor types can be observed in the voltage gradient change at 7.9 km and 9.6 km. This graph does not have real benefit to the protection engineer. It is more beneficial to a network planning engineer for the placement of voltage-sensitive customers.

Protection operating time vs. position

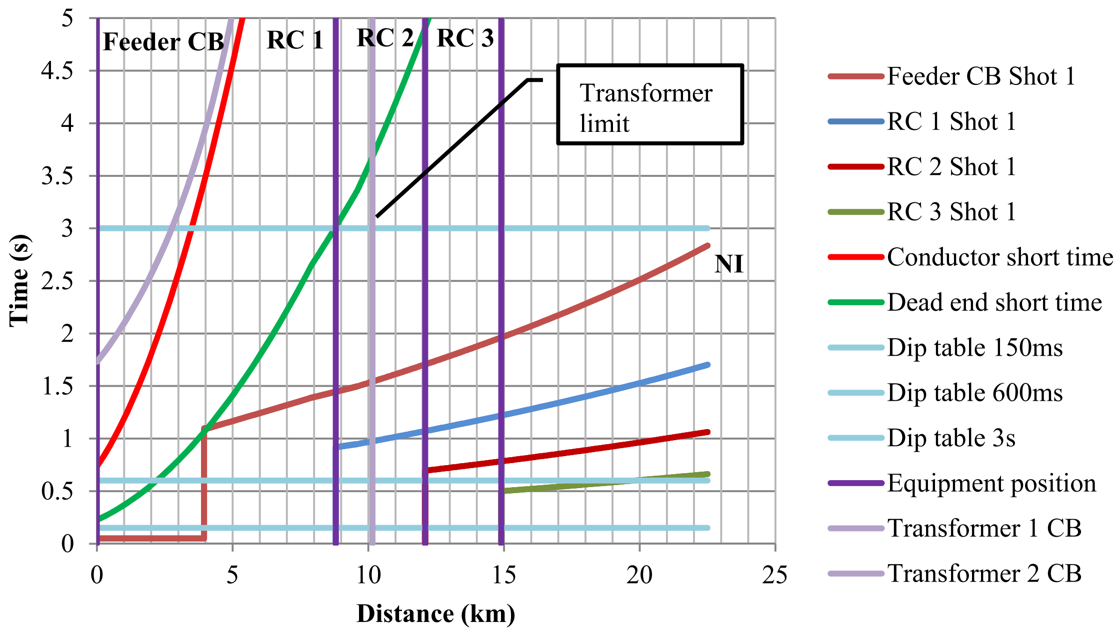

Figure 7.13 The protection operating vs. position for a top-down approach.

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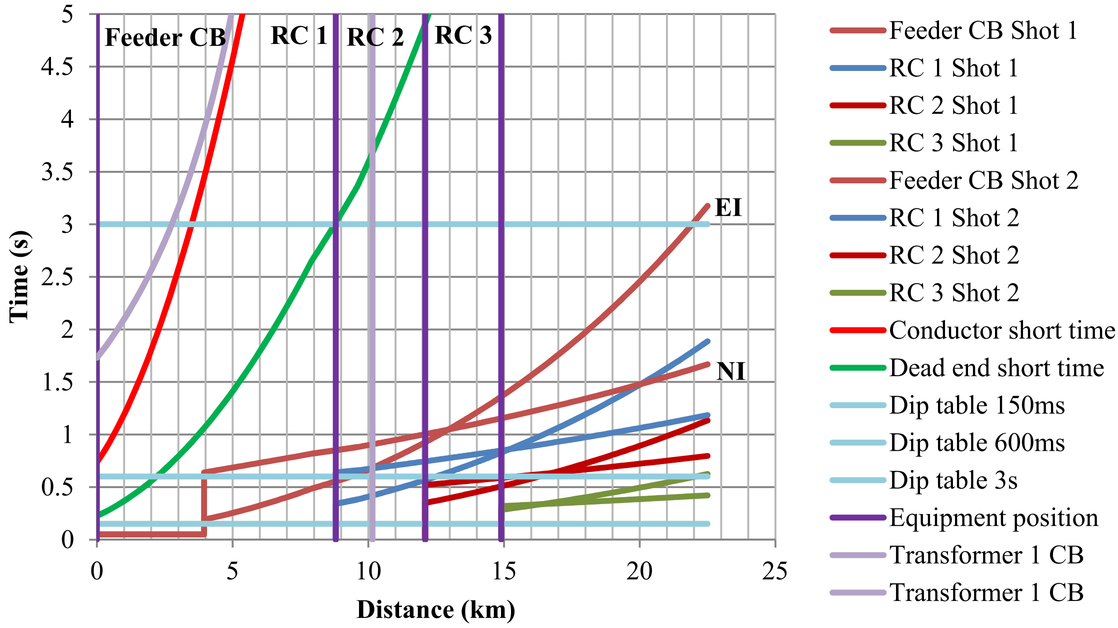

Figure 7.14 The protection operating vs. position for a bottom-up approach.

The protection operating time over the analysed path is shown in Figures 7.13 and 7.14. The various curve operating times can be determined from these graphs. The maximum operating times are the same as the values shown in Table 8.1. The operating times for the top-down approach are generally larger than the bottom-up approach. This can be seen when considering that most of the operating times are in the 0.6 s to 3 s range when using the NI curve in the top-down approach. This will result in voltage dip categories of Y, Z1 or Z2 types. When considering the DA curve and the NRS 048-2 dip table in Fig. 4.2, the Z2 type dips are to be minimised. For the bottom-up approach and the first ARC shot the operating time is in the range of 0.15 s to 0.6 s. This places the potential dips in the Y-, S- and T-type dip categories. The DA curve also allows for a deeper dip (less residual voltage) in this time range. For the second ARC shot, the operating time has increased when the NI curve is used. The operating time is still less than the top-down NI approach. It was indicated in section 5.3 that the predominant type of fault in the networks is transient in nature and that these faults generally require one CB operation to clear the fault. Based on this, most of the faults will be cleared on the EI curve of the first ARC shot. This has then also the fastest operating time. This reduction in operating time will also reduce the amount of let-through energy (see section 3.2.2).

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For the bottom-up approach, operating times are not exceeding any of the equipment damage curves for any operating time. The top-down approach is exceeding the dead-end short-time curve at a position 4 km from the busbar. The operating time will have to be reduced for the feeder CB in the top-down approach to avoid this crossing. The benefit of the instantaneous curve applied to the feeder CB is evident in the operating time reduction in the high-current zone close to the source MV busbar. This is for both the top-down and bottom-up approaches.

The source transformer's operating times and the point up to where the transformer will detect a 3Ph fault on the feeder are also indicated. This transformer reach and operating time are not dependent on the feeder settings.

In terms of evaluating the two setting approaches, the bottom-up approach with the EI and NI curve application reduces the operating time more than the top-down approach. This reduction is beneficial in protecting the equipment and managing the possible voltage-dip categories. More optimisation of the settings are required for the top-down approach.

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Let-through energy vs. distance

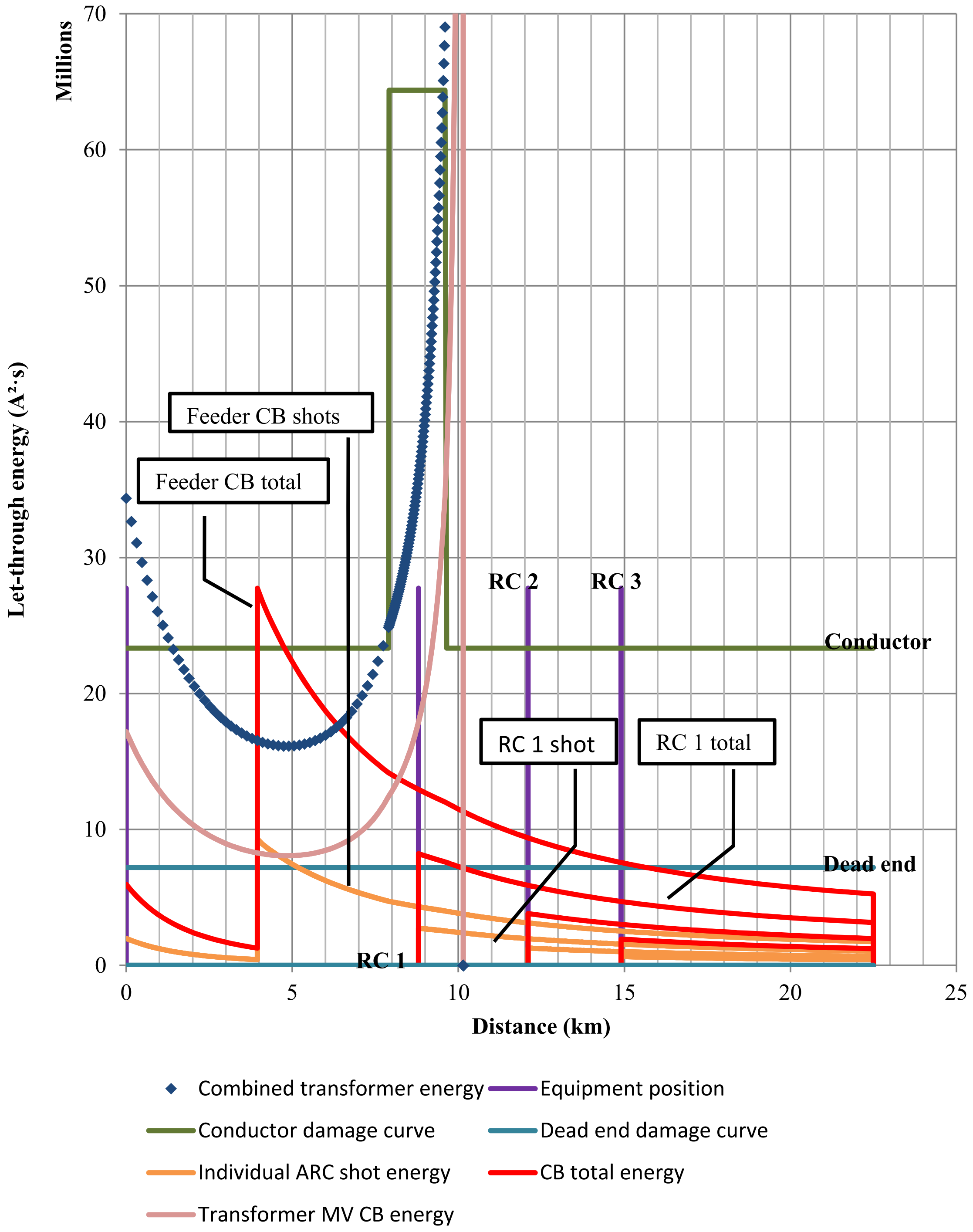

Figure 7.15 The let-through energy vs. position for a top-down approach.

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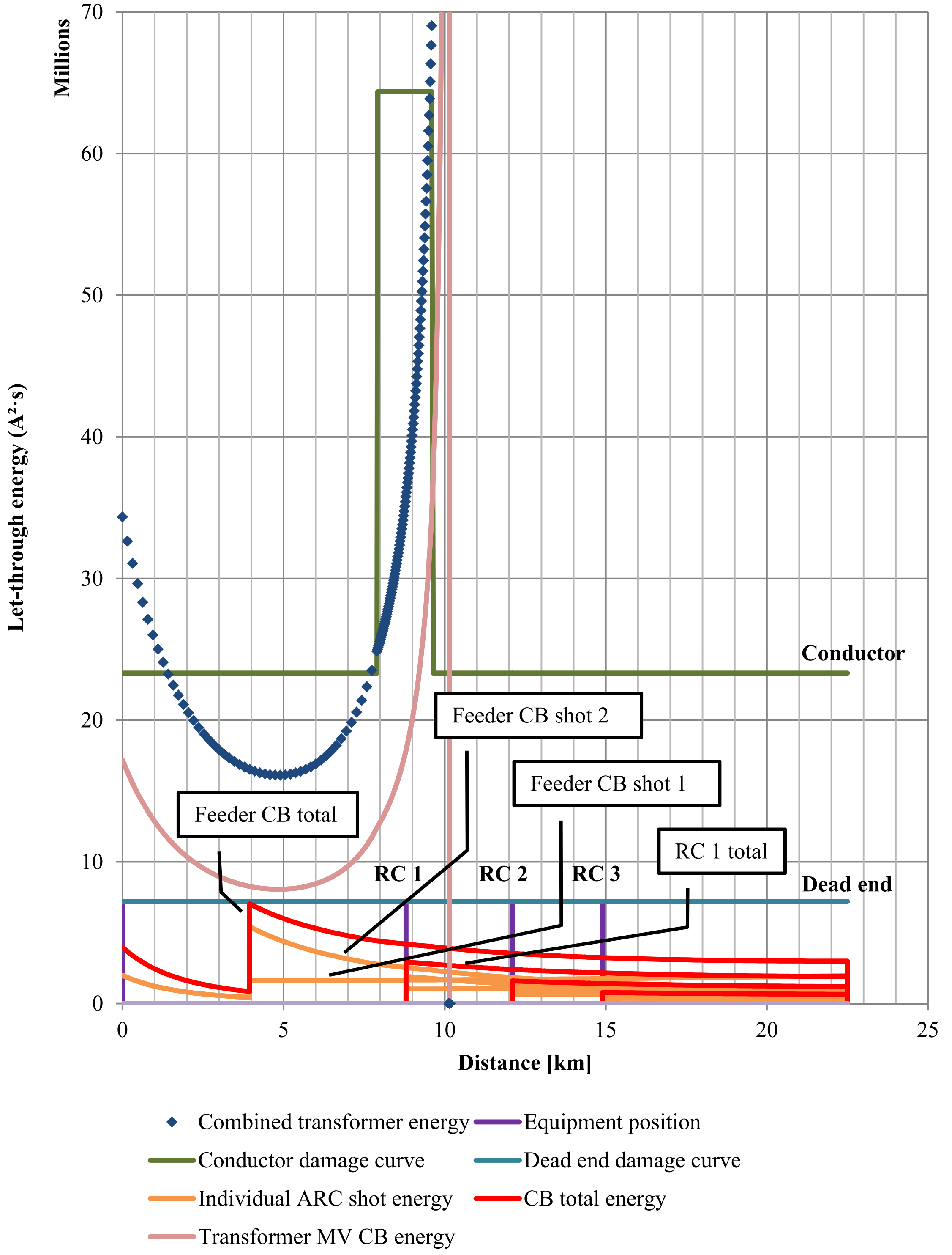

Figure 7.16 The let-through energy vs. position for a bottom-up approach.

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The let-through energy over the analysed path is shown in Figures 7.15 and 7.16. The let-through energy of every ARC shot and the combined let-through energy for every protective device are shown over the complete analysed path. This allows the protection engineer to consider various protection contingencies, such as devices out of service. The energy curves for the transformer CB's and the feeder-installed CB's are not shown in this graph, as they are well above the scale shown in both the top-down and bottom-up approach graphs.

Due to the breaker operating time of 50 ms, there is still energy that passes to the fault in the 0 to 4 km range even though the protection is set to operate instantaneously. The effect is the same for both the top-down and bottom-up approaches when considering the individual operating curves. But, when considering the cumulative effect of the ARC attempts, the top-down approach (three shots) is closer to the first equipment energy limit than the bottom-up approach (two shots). This is based on the assumption that there is no energy loss during the ARC dead time. The other observation is that, even with an instantaneous curve, the equipment energy limits can be exceeded under high fault currents, and if slow breakers are used for the feeder CB at the substation.

From the operating time-distance curves for the top-down approach (Fig. 7.13) it was determined that the operating time exceeds the equipment limit at 4 km. This is again shown in the energy curves of Fig 7.15. If the effect of ARC is now included and the total energy is considered, it is found that not only the dead-end limit is exceeded, but also the conductor limit at 4 km. To ensure that the equipment is protected (let-through energy analysis) for the top-down approach, both the operating time and the number of ARC attempts have to be reduced. For RC 1 the number of ARC shots have to be reduced by one, not to exceed the dead-end limit at 8.8 km. Alternatively, the NI curve operating time can be reduced if there is enough grading margin available. The let-through energy for RC 2 and RC 3 does not exceed the primary equipment energy limits and hence there is no change in settings required from an energy perspective to ensure that the network equipment is protected.

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The equipment energy limits are not exceeded for the bottom-up approach (Fig. 7.16) energy curves. This holds for all the ARC shots of every feeder-installed protective device. At a distance of 4 km, the let-through energy are close to the equipment limit. The number of ARC attempts can be adjusted for this. From the energy curves it is observed that the EI curve provides exceptional performance in terms of reducing the let-through energy in the high-risk area (high-fault current) close to the substation MV busbar. The EI energy curve follows the equipment damage curves well. This provides for good energy curve grading (see section 3.2.1). Almost no optimisation of settings is required for the bottom-up approach. The better approach in terms of protecting the feeder from energy damage is the bottom-up approach, with the EI curve application and the reduced ARC attempts.

There are two transformer let-through energy curves shown in the top-down and the bottom-up approaches of Figures 7.15 and 7.16. These curves are identical for both approaches, since the fault current, the current distribution and the transformer settings are unchanged for both approaches. These curves are required to operate when there is a feeder CB failure. Each transformer is exposed to half of the total energy for the fault. This is because the transformers are identical and they have identical protection settings. The feeder will be exposed to the total energy and this can exceed the equipment energy ratings, as shown in the two figures. The transformers and their related equipment energy limits can be exceeded when the fault current is close to the transformer PU current. This can be seen in the energy graphs for faults in the region of 10 km. To prevent this energy spike, a maximum operating time limit should be activated. This will stop the curve from peaking, as shown in the energy graphs for a fault close to 10 km.

In terms of evaluating protection philosophies, it is evident that the application allows for the ARC philosophy, operating time, curve selection and even equipment placement to be evaluated and the protection settings optimised to ensure that the network equipment is protected. The application allows the user to set the equipment damage limits for other equipment as well.

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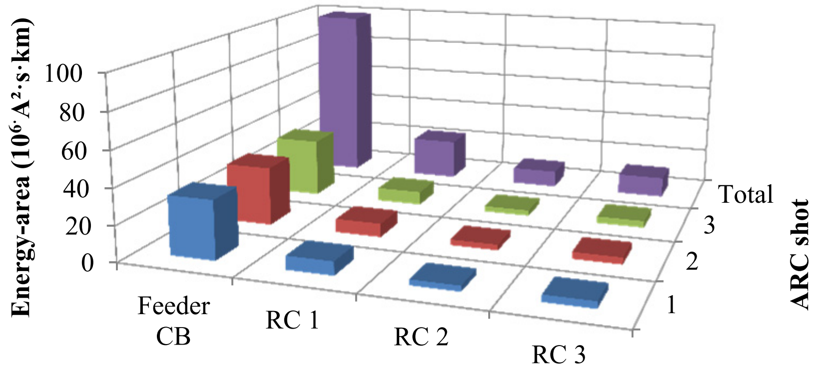
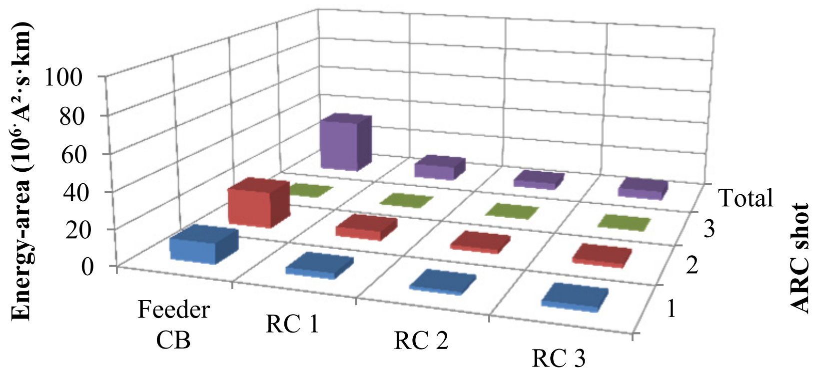
Let-through energy-area



	Feeder CB	RC 1	RC 2	RC 3
1	33.081	7.6591	3.1562	3.8361
2	33.081	7.6591	3.1562	3.8361
3	33.081	7.6591	3.1562	3.8361
Total	99.243	22.9773	9.4686	11.5083

Figure 7.17 The let-through energy-area for a top-down approach.



	Feeder CB	RC 1	RC 2	RC 3
1	11.5061	3.3955	1.8106	2.848
2	20.935	5.3281	2.3672	2.4412
3	0	0	0	0
Total	32.4411	8.7236	4.1778	5.2892

Figure 7.18 The let-through energy-area for a bottom-up approach.

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The let-through energy-area results are shown in Figures 7.17 and 7.18. In these figures the let-through energy for an n-0 protection backup scenario is shown. In other words, the energy area is calculated from the position of RC 1 up to the position of RC 2. The actual numerical values are provided in a data table below each figure.

For the top-down approach it is observed that the energy is the same for each shot in the ARC cycle due to the settings being the same. Only the feeder CB is considered for this evaluation. The same approach can be applied to the other protection devices installed on the feeder. When comparing the top-down NI approach (Fig. 7.17) with the bottom-up NI approach (Fig. 7.18), it is found that there is roughly a 30 % reduction in the energy-area. When considering the bottom-up EI curve to the bottom-up NI curve in Fig. 7.18, there is a reduction of roughly 50 % in the energy-area. If the bottom-up EI energy-area is compared to the top-down NI curve, there is a reduction of 66 % in the energy-area. When the total energy-area of the top-down approach is compared to the bottom-up approach, it is found that the top-down approach is three times larger than the bottom-up approach.

When evaluating the philosophies, the numerical values assist greatly in quantifying the benefit. This helps, especially when there are small setting changes. Thus by using the application it is found that the bottom-up approach is more beneficial than the top-down approach in reducing the energy over the analysed path.

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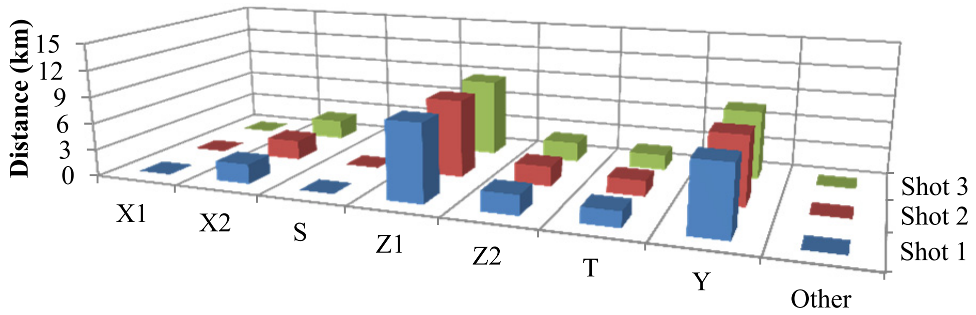
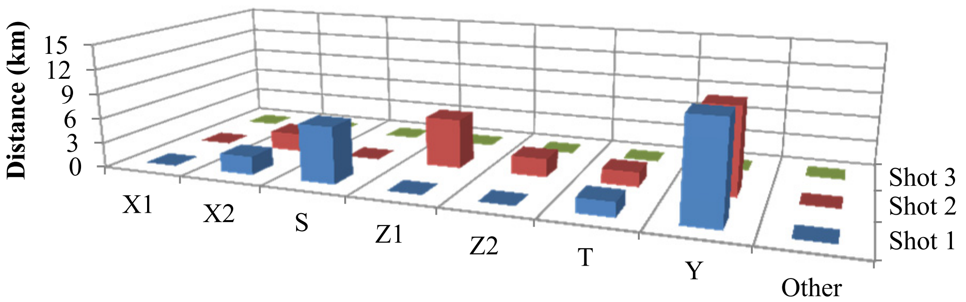
Combined voltage-dip profile of the analysed path



	X1	X2	S	Z1	Z2	T	Y	Other
Shot 1	0	2.212	0	8.7	2.212	1.738	7.656	0
Shot 2	0	2.212	0	8.7	2.212	1.738	7.656	0
Shot 3	0	2.212	0	8.7	2.212	1.738	7.656	0

Dip category

Figure 7.19 The combined voltage-dip profile of the analysed path for a top-down approach.



	X1	X2	S	Z1	Z2	T	Y	Other
Shot 1	0	2.212	6.818	0	0	1.738	11.75	0
Shot 2	0	2.212	0	5.956	2.212	1.738	10.4	0
Shot 3	0	0	0	0	0	0	0	0

Dip category

Figure 7.20 The combined voltage-dip profile of the analysed path for a bottom-up approach.

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The combined voltage-dip profile of the feeder for every shot in the ARC cycle is shown in Figures 7.19 and 7.20. This indicates the distance of the analysed path that is covered by a specific type of voltage dip as per the NRS 048-2 table (see Fig 4.2 and section 6.3.6).

For the top-down approach we can see that all three shots have the same profile, as they have the same settings. The biggest part of the feeder is covered by Z1-type dips and the second part by Y-type dips. There are other dip types as well, but they cover a small portion of the feeder. The Z-type dip distance is to be minimised in this approach by changing the operating time of the protection.

When considering the bottom-up approach, it is seen that the Y-type dips are the predominant type dip. The type of residential loads can handle any number of these dips, as shown by the DA curve in Fig. 4.2. For the first EI shot, there is also a large distance of S-type dips and for the second NI shot there is a large distance of Z1-type dips. The T-type dip cannot be removed completely, due to the voltage at the fault that will become zero for a bolted fault. This is for faults close to the MV source busbar.

When evaluating the philosophies, we can see that the differences in the voltage dips are as a result of the protection settings, since the actual network has not changed. The bottom-up approach with the EI curve is recommended in this case, since the Y-type dips are predominant and all the Z-type dips have been removed. This just provides an overview of the expected busbar voltage dips. The actual fault position for the resulting busbar dip cannot be determined from this graph.

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Complete voltage-dip profile and the position of the dip for the analysed path

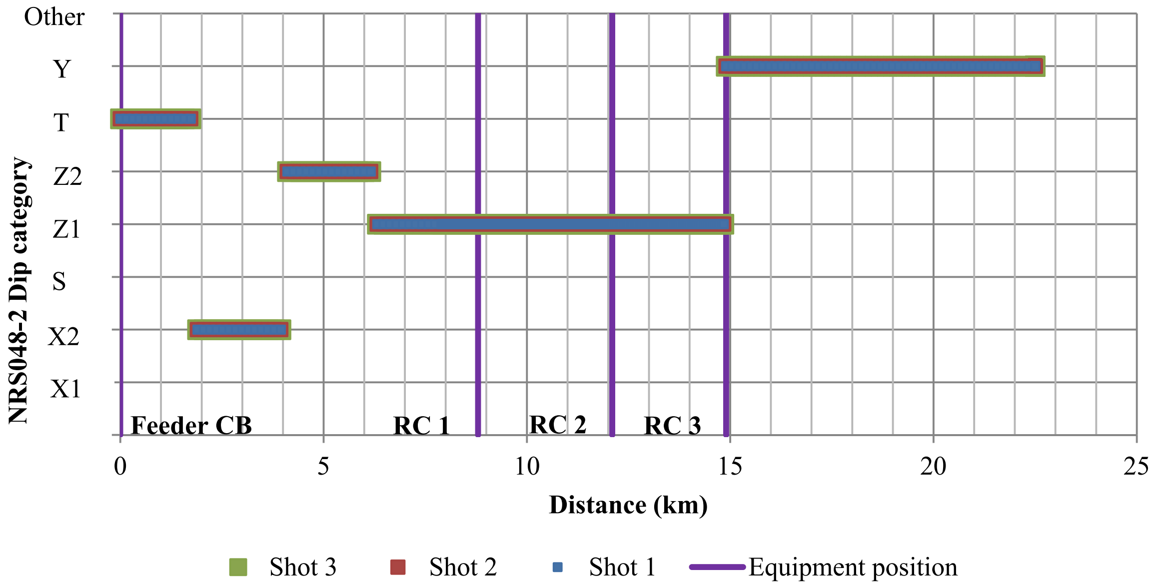

Figure 7.21 The complete voltage-dip profile and the position of the dip for the analysed path using a top-down approach.

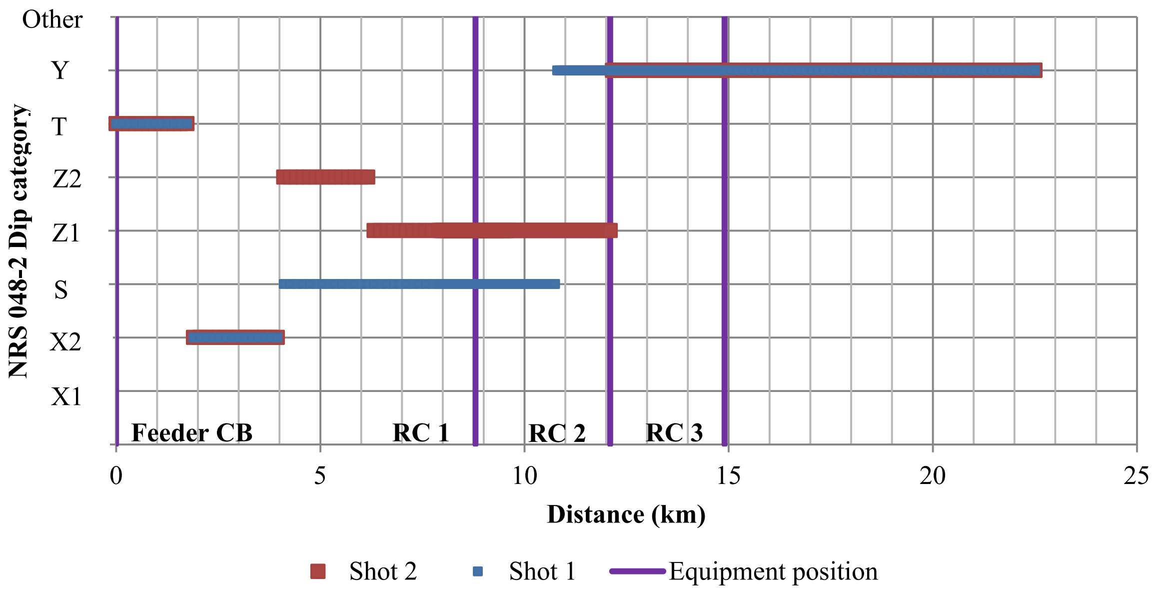

Figure 7.22 The complete voltage-dip profile and the position of the dip for the analysed path using a bottom-up approach.

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Figures 7.21 and 7.22 indicate the complete busbar voltage dip profile for the analysed path. For the top-down approach in Fig. 7.21, all three the shots are positioned on top of each other, since the protection devices have the same settings. When studying the top-down graph, we can see that the voltage dip starts as a T-type, then it becomes an X2-type, then a Z2-type, then a Z1-type and finally a Y-type. This graph assists in determining which protective device is responsible for the voltage dip and the fault position on the analysed path. It is observed from Fig. 7.21 that the Z2-type dip is situated from 4 km to just over 6 km. The protective device responsible for this dip type is the Feeder CB. Hence the operating time for the feeder CB has to be adjusted for faults in that area (4 – 6 km). The possible protection devices that require setting optimisation for voltage dip management are the feeder CB, RC 1 and RC 2. If the operating time is reduced, the let-through energy criterion is improved, but the selectivity of the devices will have to be assessed again.

When considering the bottom-up approach, we can see that the busbar voltage-dip distribution is different between each ARC shot and that it is also different from the top-down approach. These differences are as a result of the protection settings applied to each protective device. For the bottom-up approach the bulk of the dips are Y-type dips, as was shown by the combined voltage-dip graph. When considering the position, it is found that RC 2 and RC 3 only contribute Y-type dips and hence no optimisation is required at these devices. Shot 1 has a big S-type region when compared to shot 2 with a Z1-and a Z2-type busbar voltage dips.

When evaluating the philosophies we can see that the bottom-up approach with the EI curve provides the best busbar voltage-dip performance. The least number of protective device settings have to be optimised for the bottom-up approach.

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7.3 CASE STUDY 2

7.3.1 Qualification test protocol

7.3.1.1 The objective of the case study

The objective of this case study is to show that the application can evaluate protection philosophies even when the protection devices on the analysed path are not the same. The key elements that are evaluated are the operating time, let-through energy, energy-area and the resulting busbar voltage dips.

7.3.1.2 The case study setup

This case study is based on the actual network of case study 1 (Fig. 7.1). The new reduced protection network diagram with the chosen path for analysis is shown in Fig. 7.23. The source impedance and conductor types are the same as case study 1, but the protection devices and some settings have changed. The source substation consists of two HV to MV transformers. The MV feeder that is radiating from the source substation consists of three protective devices in series. This includes the feeder CB. The protection devices on the feeder consist of a feeder CB, an inline fuse and then a RC. All these devices are placed in series. The feeder consists of three different series conductor types.

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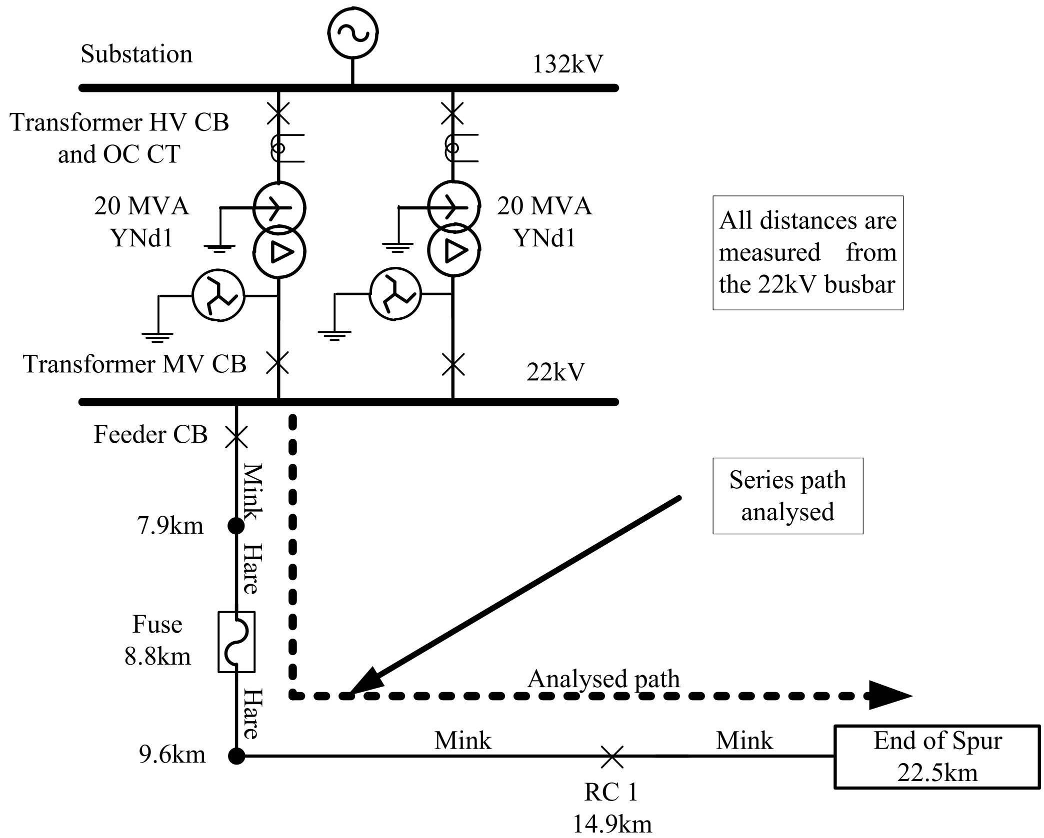

Figure 7.23 Reduced protection network for case study 2.

7.3.1.3 Protocol

The protocol that is applied to the case study is listed below:

1. Determine the source impedance for minimum and maximum network conditions on the MV busbar at the source substation. This is done using an applicable power network simulation software package.
2. Reduce the actual network diagram to a protection network diagram.
3. Calculate the 3Ph and 2Ph fault levels for the reduced protection network for minimum and maximum network fault-level conditions.
4. Choose the path on the feeder to analyse.
5. Calculate protection settings for the chosen analysis path using any grading approach (top-down or bottom-up).
6. Import these settings into the settings application to generate the result graphs.

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7. Evaluate the results by comparing the key results to that obtained in case study 1.

7.3.2 Results and description

7.3.2.1 Experimental parameters

The conductor lengths and types are shown in the network diagram (Fig. 7.23). The path chosen consists of three different conductor types. No specific grading approach is used to generate parameters for the protective devices. The MV busbar source impedance determined from the power network simulation software is listed in Table 7.1 of case study 1. The two transformers at the substation are identical in size (MVA) and impedance. The actual source transformer information and applied OC protection settings are provided in Table 7.2 of case study 1. No arc resistance is included for the 3Ph fault level calculation, because the maximum fault current is required.

Only one shot to lock-out is applied to the feeder CB and RC 2. The positions of the devices are indicated in Fig. 7.23. The protection settings for the analysed path in the network are provided in Table 7.7. The fuse TCT curve is used. A PU of 1 A and a TM of 1 are used for the program to allow for the algorithms to be able to do calculations. The fuse PU current can be increased to align with the actual fuse PU current. The MMT curve is also available in the application.

Table 7.7 Protection settings for the analysed path in case study 2.

Device	**Operating curve**	**Pick-up (A)**	**Time multiplier**
	Shot 1	Shot 1	Shot 1
Feeder CB	EI	342	0.17
Fuse	140K TCT	1	1
RC 2	TCC 117	249	1

The data used to evaluate the energy limits of the primary plant equipment are listed in Table 7.5 of case study 1.

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7.3.2.2 Resulting graphs

On some of the graphs both the HSI curve and the LSI curve are shown. All the results shown are for maximum network conditions (high fault currents), except for specific graphs where LSI is required. For this instance the network condition (minimum network condition) will be specified in the graph header.

The result graph categories provided are listed below.

- Protection operating time vs. position.
- Let-through energy vs. distance.
- Let-through energy-area.
- Complete voltage-dip profile and the position of the dip for the analysed path.

Background to the result graphs are provided in chapter 6.

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7.3.2.3 Resulting graphs

Protection operating time vs. position

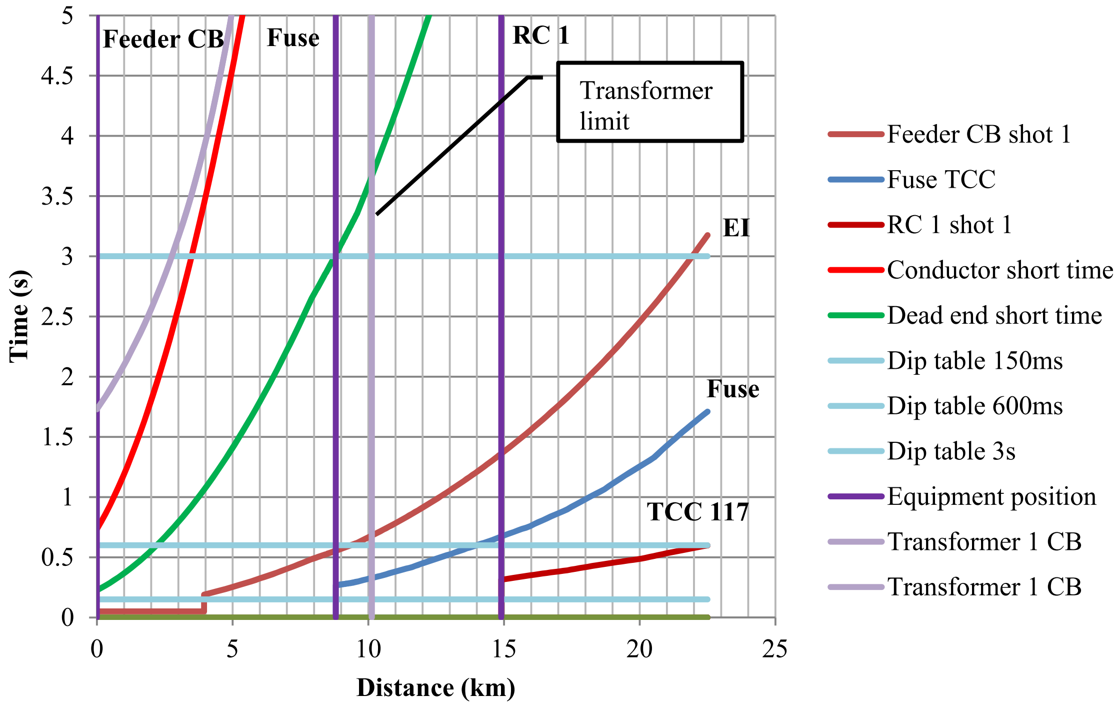

Figure 7.24 The protection operating time vs. position for case study 2.

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Let-through energy vs. distance

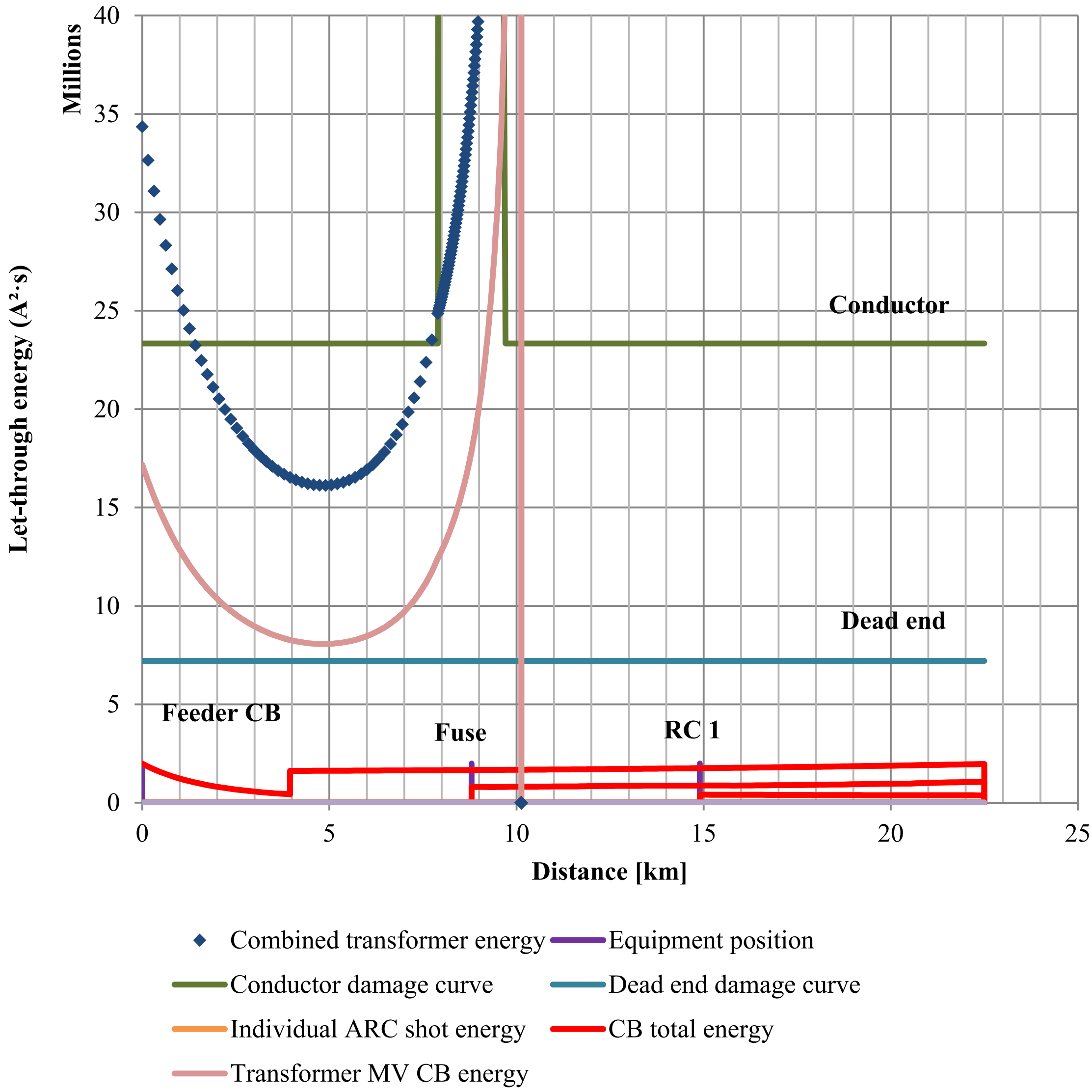

Figure 7.25 The let-through energy vs. position for case study 2.

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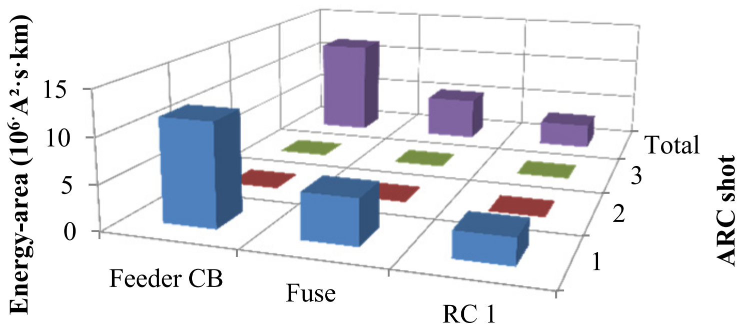
Let-through energy-area



	Feeder CB	Fuse	RC 1
1	11.5061	5.0773	2.9153
2	0	0	0
3	0	0	0
Total	11.5061	5.0773	2.9153

Figure 7.26 The let-through energy-area for case study 2.

Complete voltage-dip profile and the position of the dip for the analysed path

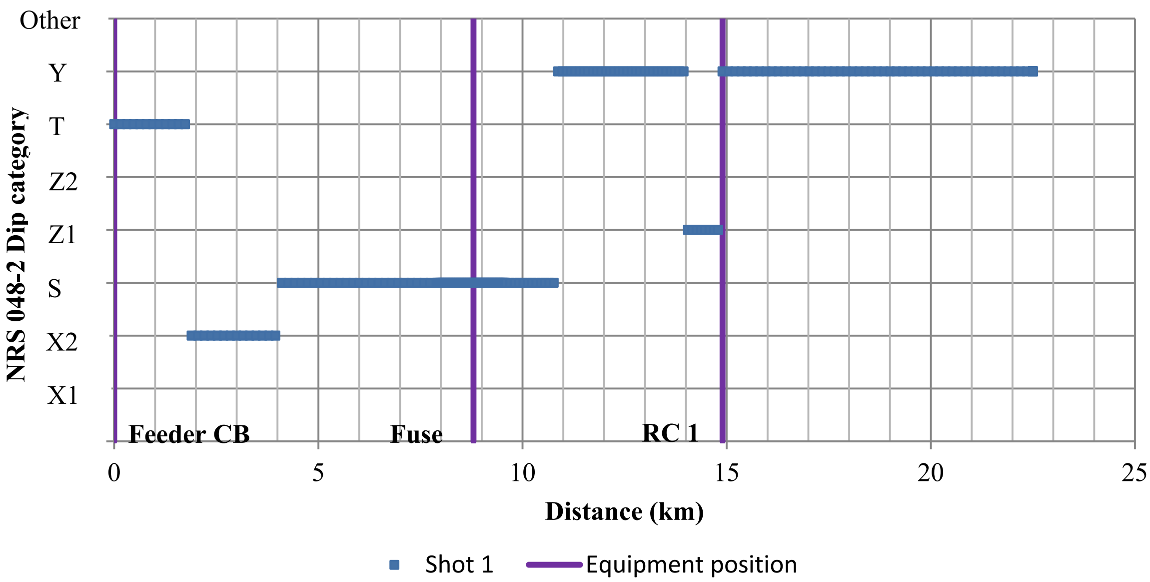


Figure 7.27 The complete voltage-dip profile and the position of the dip for the analysed path in case study 2.

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For case study 2, focus is placed on only key graphs, as most of the functionality of the application has been demonstrated in the first case study. The fuse curves and RC curves are demonstrated in the second case study. The four graphs are listed below.

- The protection operating over the analysed path (Fig. 7.24).
- The let-through energy over the analysed path (Fig. 7.25).
- The let-through energy-area over the analysed path (Fig.7.26).
- The complete busbar voltage dip profile (Fig. 7.27).

The protection operating time over the analysed path is shown in Fig. 7.24. In this graph the fuse TCT curve is shown. The fuse MMT curve is also available in the application. The fuse curves and the RC curves make use of data points and interpolation to calculate the operating time. For this case study it is observed that the method that is applied provide curves that can be used for analysing the various factors as shown in case study one. It is determined that the maximum operating times of the protection devices are in the region of 600 ms. This is similar to the maximum times of the bottom-up EI approach of case study 1. The maximum operating time point has moved to the 15-km position when this is compared to the results from case study 1 (Fig.7.13 and Fig.7.14).

The let-through energy over the analysed path is shown in Fig. 7.25. It is observed that the let-through energy in Fig 7.25 is less than the let-through energy in the top-down approach of case study 1 (Fig. 7.15) when comparing the first ARC shot. The let-through energy in Fig. 7.25 is comparable to the let-through energy in Fig. 7.16 for the bottom-up approach and the first ARC shot. To determine which approach does provide some advantage (fuse vs. RC) the energy-area curves are used. The total energy for this application is less than the top-down and bottom-up approaches due to the one-shot ARC philosophy. A fuse does have the drawback of only allowing for one operation.

The energy-area values of Fig. 7.26 are used to compare the protection philosophies; not only the settings, but the general protection philosophy (protection devices and protection settings) regarding let-through energy. For this analysis the total energy area for every first

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ARC shot of every protective device on the analysed path is added together. The same is then done for the second shot if the settings are different between the first and subsequent shots. This is done for case study 1 and 2. The results are shown in Table 7.8. Even though the devices may be at different physical positions and the settings may be different, the physical network (source impedance and conductor types) is still the same. This allows us to compare the energy results between case study 1 and 2.

Table 7.8 The total energy-area results for every respective shot on the analysed path.

Experiment	**Shot number**	**Total energy-area $[10^6 A^2 \cdot s \cdot km]$**
Case study 1 – top-down	1 (2 and 3 are the same)	47.7324
Case study 1 – bottom-up	1	19.5602
Case study 1 – bottom-up	2	31.0715
Case study 2	1	19.4987

When comparing the total energy-areas in Fig 7.26 it is found that the top-down approach produces the worst results. This is expected, as this approach also resulted in the longest operating times. The shot 2 (NI curve) of the bottom-up approach in case study 1 gave the second-largest energy-area value. When comparing the total energy-area of shot 1 (case study 1) to that of case study 2, the energy-area of case study 2 is marginally less than that of shot 1 (case study 1). The application thus indicates that the protection setup with the fuse is very similar to that of the RC from an energy perspective. The fact that the one device is an inline fuse does have an impact on the feeder reliability, though it does not have ARC capabilities. The application does allow the protection engineer to change the fuse to a RC, for instance, and then conduct the same evaluation.

The busbar voltage dip results in case study 2 (Fig.7.27) are compared to the results of case study 1 (Fig. 7.21 and Fig. 7.22). The results for case study 2 are similar to the first ARC shot of the bottom-up approach in case study 1. The only difference lies in the small portion of Z1-type dip that the fuse introduces. This is not a big concern when considering

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the DA curve in Fig. 4.2 and the type of loads on the distribution feeders. It is still preferable to move this dip to the left side on the NRS 048-2 dip table. Since this is a fuse, no optimisation can be done, except for changing the fuse type or by replacing the inline fuse with a RC.

The application allows for the protection engineer to compare the busbar voltage dips on the same analysed path for different protection devices on the MV feeder.

7.4 THE RESULTS IN TERMS OF THE HYPOTHESIS AND RESEARCH QUESTIONS

The hypothesis that is to be tested in this research is therefore:

A method can be developed to determine the effectiveness of an MV feeder OC protection settings philosophy.

The research questions that were to be answered are listed below (see section 1.2).

- What factors can be used to evaluate an OC protection philosophy?
- What are the key elements that determine if a MV feeder is protected?
- How do protection settings influence quality of supply and can this be managed?
- For what period of time can a fault be allowed on the network?

The results obtained from the application in case study 1 and case study 2 indicate that a phase OC protection philosophy can be evaluated using the Excel software application. It is shown that the reliability of the feeder is influenced by the protection settings. The factors that influence the reliability are the PU sensitivity and the protection operating time. If the protection is not sensitive enough to detect faults, the fault will damage the network equipment, create a risk to the environment and endanger life at the point of the fault. This is due to the fault not being detected. If the fault is detected, but the operating time is to slow, it will result in the same consequences. Damaging equipment leads to extended outages for repair and financial loss in the form of energy not supplied and the replacement of damaged equipment.

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The key factors that were identified as influencing factors in evaluating the effectiveness of phase OC protection are listed below.

- Operating time
- PU sensitivity
- Let-through energy
- The busbar voltage-dip effect

The operating time is the principal factor that has an influence on the let-through energy and the voltage dips. The general approach is to reduce the operating time. The long operating times can result in sympathetic trips for feeders at the PCC (MV busbar). This "incorrect trip" has an effect on the revenue stream for the utility since a healthy feeder is tripped for a fault on a non-healthy feeder. This unnecessary loss of supply is an inconvenience to the costumer. It is also detrimental to the image of the company (unnecessary and perhaps frequent outages).

By ensuring that the let-through energy of the line-installed protection devices are below the damage curves for the various primary plant equipment, the protection of the network equipment can be ensured. The setting elements that influence the let-through energy are the operating curve, operating time and the number of ARC attempts. By evaluating the let-through energy curve, these elements can be optimised. The effect can be measured by making use of the energy-area analysis.

The voltage dips can be managed once the feeder is protected. These voltage dips are dependent on the protection operating time. The application provides the means of identifying where the fault location is and which feeder-installed device is responsible for the dip. It allows system designers to place customers in areas where certain dips are not present, or to manage their exposure. Voltage dips and the loss of supply are the main effect of protection operations.

Protection has a more direct influence on SAIFI as compared to SAIDI. This is due to the duration of the fault being dependent on the time to restore supply by the field service

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personnel. SAIFI on the other hand is normally affected when the protection deems a certain network condition to be a fault and hence trip the breaker. SAIDI can be changed over a short period, but SAIFI requires a longer period to affect change [8]. The National Energy Regulator of South Africa (NERSA) created an incentive/penalty target for Eskom where the utility had to improve its SAIDI from 50 hours to 35 hours. If this was achieved, the incentive would have been R 210 million or if this was not achieved, the penalty would have been the same amount [85].

By means of the application and the related experiments, the effectiveness of different OC protection philosophies can be evaluated and optimised. The case study results thus indicate that the method can be used to evaluate phase OC protection philosophies.

7.5 FORWARD

In chapter 7 the developed application of chapter 6 was applied to an actual network in two case studies. In the first case study the network and the protection devices were kept the same. Only the applied protection settings were changed (twice) on the feeder-installed protective devices. The results that were obtained from the application for the changes in settings are compared in this chapter. In the second case study the physical network (power delivery part) remained the same as in case study 1, but the protective devices and the protection settings are changed. For the second case study the results from the first case study are compared to the results from the second case study. Based on this discussion the evaluation possibilities of the application are demonstrated, the research questions are discussed and the hypothesis is tested. It was shown that the application do allow the user to evaluate a phase OC protection philosophy. A conclusion for this research is reached in chapter 8.

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CHAPTER 8 CONCLUSION

8.1 SUMMARY OF THE WORK

The work that was done in this research was to prove that a method and an application based on the method can be developed that allows the user to determine the effectiveness of an OC protection philosophy. This was accomplished by identifying the equipment that is to be protected and their corresponding damage curves. The protection devices installed in an MV network were identified, as well as the protection settings that can be applied on each of these. The principal influencing factor was determined from the literature survey, which is the operating time of the protection elements. The other factors that influence the protection philosophy are the let-through energy, the sensitivity of the PU's and the resulting busbar voltage-dip effect. All of this was then used to generate an application that allows for the evaluation of MV feeder protection philosophies.

The application allows for the user to evaluate the results in terms of these elements for various network and protection contingencies and then to adjust the protection settings so as to meet the protection requirements. The application does not dictate to the settings engineer what protection devices are to be used, or how the protection device should be set. It does, however, indicate when the network is not protected adequately and what the effect of the applied protection philosophy is on the power quality (voltage-dips). The overall objective is to minimise the protection operating time, especially in high-current regions close to the source substation. To ensure that the network is protected, two criteria have to be met. Firstly, the total let-through energy should be below the network installed equipment damage curves. Secondly the protection should be able to detect network faults (sensitivity).

The main impact on the quality of supply from protection is the voltage-dip effect and the loss of supply. To manage this, the protection operating time can be decreased. By reducing the operating time, it will move the voltage dip left on the NRS 048-2 dip category, where equipment is less susceptible to voltage dips. The loss of supply is inherent to correct protection operations where the faulted region is isolated. The number

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can be reduced for certain customers by changing the number of ARC attempts. This is dependent on the fault and the customer location.

From all of these analyses it is concluded that the protection operating time should be kept to a minimum. This is subject to the protection philosophy regarding the selectivity of subsequent protection devices, the damage to equipment and the risk at the point of the fault. These factors have to be weighed against each other. Network protection is given priority over individual selectivity. The NRS 048-2 voltage-dip table's time regions do provide some guidance in what can be considered as the maximum time of a fault on the network (3 s), provided that the equipment let-through energy is not exceeded, else the let-through energy will dictate this operating time limit.

8.2 SUMMARY OF THE RESULTS AND THE DISCUSSION

Two case studies were conducted where the primary network (network layout) was left unchanged in both. For the first case only the protection settings were changed on each RC by making use of a bottom-up and a top down grading approach. For the second case study the type of protection equipment was changed to a RC and an inline fuse.

The results indicated that protection philosophies can be evaluated using the developed application, and that best philosophy can be identified. The settings can also be optimised, based on the result graphs that are generated by the Excel application. The key result graphs are listed below:

- The PU sensitivity graph
- The operating time-distance graph
- The let-through energy graph
- The energy-area results
- The busbar voltage-dip classification and fault position

From the results it was found that the bottom-up approach with the EI curve and reduced ARC attempts provided the best network performance. The operating time in the bottom-up approach was the fastest, the let-through energy the lowest and the busbar voltage-dip

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effect was kept to the region that appliances can withstand. By using the novel energy-area information the benefit between the different protection philosophies can be quantified. From the case study results it was determined that the bottom-up approach outperforms the top-down grading approach (both using NI curves). The best performance was obtained with an EI curve and a bottom-up grading approach.

In essence, the application can evaluate the effectiveness of protection philosophies, and allows for the optimisation of the protection settings and the protection philosophy.

8.3 SUGGESTIONS FOR FUTURE WORK

Possible future work on this research topic is listed below.

- To reduce the step size in the analysed sections. This will increase the accuracy of the results.
- The effect of dead-and reclaim time changes on the expected reliability of the feeder can be investigated.
- To add this illustration methods to a commercial power system analysis application.
- To expand the analysis to include fault probabilities in the network. This can then add to identifying high-risk areas and determine if they coincide with high current and slow operating time regions (high let-through energy areas).
- To expand the analysis to include all possible paths on the MV feeder automatically.
- To create a protection evaluation method for earth-fault protection philosophies (both low-and high impedance faults).
- The minimum grading margin points to be indicated for every device so as to aid in evaluating selectivity.

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ADDENDUM A

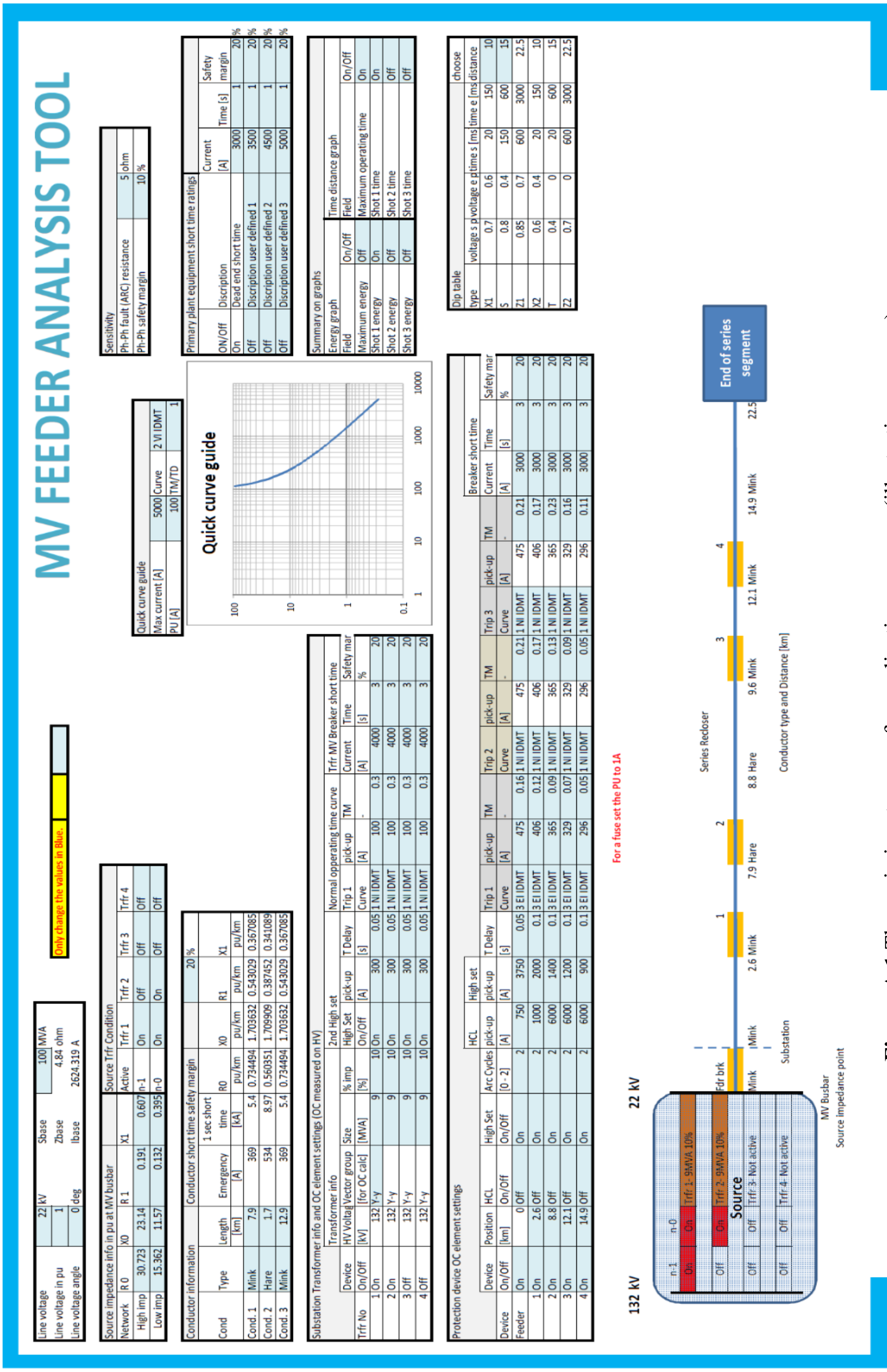

Figure A.1 The main input screen for application program (illustration purpose).

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ADDENDUM B

Settings practice questionnaire

The main questions from the questionnaire pertaining to the practice of setting the OC element are provided below.

Phase-OC settings

How do you determine the PU? (list all considerations e.g. conductor types, load, fault levels, contingencies, etc.)

How many devices on bypass are considered when determining the protective reach?

What is the minimum current grading margin used with the upstream PU?

Is this current grading different for different protection phases, such as phase 1 to phase 4 technologies?

Phase 1 – Electromechanical-based

Phase 2 – Electronic-based

Phase 3 & 4 – Microprocessor-based

What safety margin is applied to the conductor rating (e.g. 120 % of rate B (emergency))?

What conductor rating will be used for each of the protection devices in the scenario shown in Fig. B.1 when determining the PU?

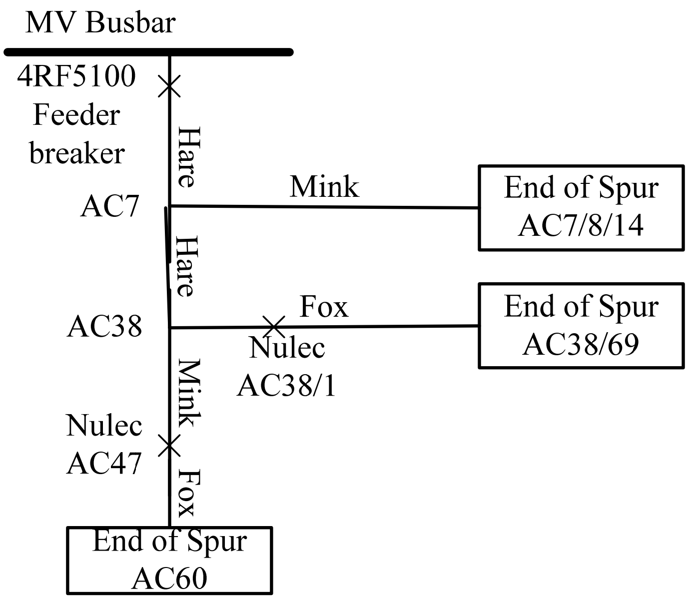

Figure B.1 A radial network for PU current determination.

How many ARC cycles are normally applied?

What is the dead time that is used with each of these cycles?

What is the reset/reclaim time that is used for the ARC cycle?

Provide feedback on why the number of ARC cycles is used.

What curves are used for each of the ARC shots (e.g. fast, slow, slow)?

What is the minimum grading margin (time) used? Is the same margin used irrespective of the curves being "fast" or "slow"?

Is there a standard grading margin that is applied between protection devices, and does this differ for protection phases (e.g. phase 1 and phase 4)?

Do you believe in or have evidence of semi-permanent faults? For example, faults cause by twigs that would burn off and "self-clear" if left on the system for a short time.

Do you have any criteria for the maximum operating time of a protective device? For example, those faults of a given current magnitude must be cleared in shorter than a given time, or an I^2t criterion for a given conductor type.

What criteria are used to determine the instantaneous PU?

What is the minimum time-grading margin used between overreaching instantaneous elements?

When do you apply a high-current lock-out?

Do you consider back-feeding (closing of normal open points with and without protection) when setting the protection elements? Refer to the diagram in Fig. B.2.

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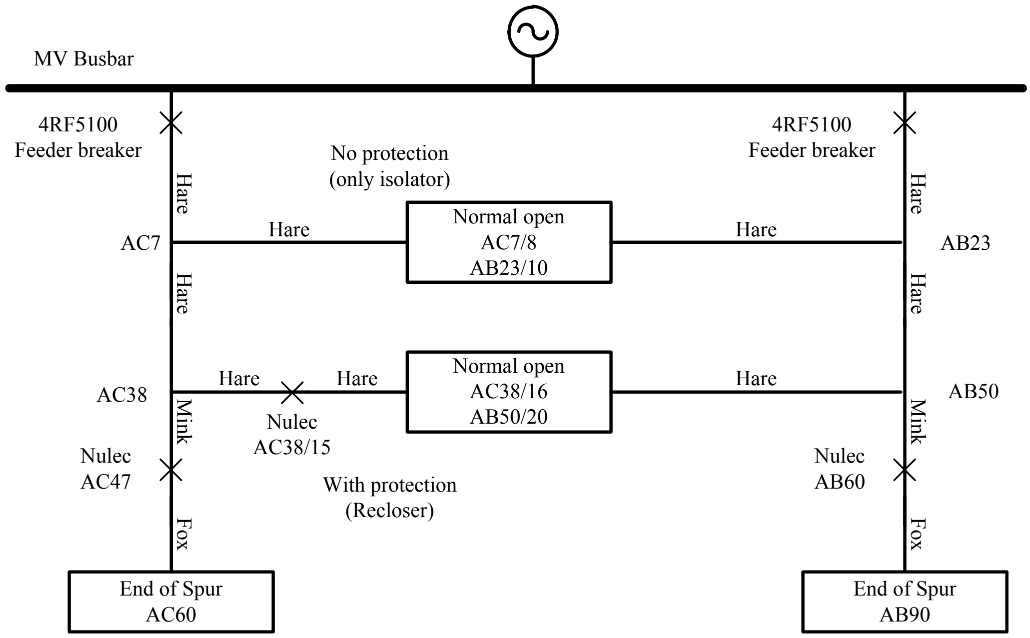

Figure B.2 An interconnected radial network.

Do you apply the cold load PU function, and if so, how do you determine the relevant settings?

Do you apply the inrush restraint function, and if so, how do you determine the relevant settings?

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ADDENDUM C

Journal Submission

At the time of this dissertation publication a journal article was submitted to the *Electric Power Components and Systems* journal of Taylor and Francis. The title of the article is: Evaluating Phase Over-Current Protection Philosophies for Medium-Voltage Feeders Applying Let-Through Energy and Voltage Dip Minimization
Manuscript ID: UEMP-2014-0765

The comments that have been received on the journal article are as follows:
"The reviews are in general favorable and indicate that, subject to satisfactory revisions, your paper could be suitable for publication."

Reviewer: 1
"*The authors presented an interesting approach to the phase over-current protection philosophies for MV feeders. I think the paper is suitable for publication.*"

Reviewer: 2
"*The let-through energy based over current protection is interesting and may be suitable for the proposed application. The research work done is good However, the paper needs improvement in some dimensions as mentioned follows:*"

Conference presentations

The research was presented at the following conferences:

PAC World conference 2013

Title: Analysing the effectiveness of phase over current protection on overhead MV networks
Cape Town, South Africa, 30 July-2 August 2013

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Eskom protection workshop 2013

Title: Analysing the effectiveness of phase over current protection on overhead MV networks

Johannesburg, South Africa, 13 November-14 November 2013

Award: Runner up award for best presentation.

Eskom reliability and power quality conference 2014

Title: Optimising phase OC protection settings on MV feeders

Johannesburg, South Africa, 27 August-29 August 2014

Award: Best presentation.

Southern African Power System Protection Conference 2014

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